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Removing Mechanical Skin in Heavy Oil Wells

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Abstract

High-amplitude, low-frequency pressure pulsing was developed as a new workover technique, and has been used in >40 heavy oil wells in Alberta and Saskatchewan during the period October 1998 to October 1999, with a good success ratio. The method is particularly effective in initiation sand production and in cases where mechanical skin arising from blocked perforations, immobilized fines and asphaltenes are responsible for a high skin factor.

Perforation blockage, restriction of near-wellbore flow paths through fines accumulation, pore throat precipitation of asphaltenes, and sand re-compaction around the well are all thought to be responsible for observed rapid production rate declines in many wells. In heavy oil wells, chemical treatments alone are rarely useful, but large perturbations of the material around the wellbore have been found to be effective in re-establishing production.

A downhole device to apply large periodic pressure pulses to the perforation face was developed. Fluid can also be introduced into the near-wellbore region while executing prolonged (9-12 hour) high-amplitude perturbation. The action loosens mechanical skin, allowing the source of flow blockage to be physically removed through remolding and liquefaction of the sand around the wellbore. This liquefied zone is produced when the well is placed back on production, and in most cases the well is rejuvenated. In some cases, wells that never produced economic rates of oil because sand influx could not be initiated were turned into reasonable producers after a pressure pulse treatment. The method can also be used to deliberately introduce treatment chemicals while reducing the negative effects of channeling and fingering, as the front of treatment fluid ingress is well dispersed by the pressure pulsing.

Introduction

CHOP (Cold Heavy Oil Production) is a production technique for heavy oil in unconsolidated sandstone reservoirs that contain gas dissolved in the oil phase.[1] CHOP involves initiating and maintaining sand influx into the wells, and managing the sand successfully so as to maintain production without well impairment. The workover technique described in this article was developed to bring CHOP wells back onto good oil production rates.

There are thousands of heavy oil wells in Alberta and Saskatchewan using the approach called CHOP. In August 1999, after the low heavy oil prices of Nov 97 to June 98, there were also approximately 6500 inactive CHOP wells in Alberta alone, in addition to the producing wells generating ~240,000 bbl/day of viscous oil (600-12,000 cP live oil viscosity, 11-17ºAPI gravity). Many wells were shut-in because they were the worst producers in the corporate well portfolios; it proved more economic in times of low oil price to focus on better wells that required less maintenance to meet restricted production targets. Companies have also learned to achieve higher oil rates from the better wells, but production capacity is currently restricted. The restricted production capabilities for viscous oil are related to upgrading facility capacity limitations, not production technology handicaps.

Why are some wells poor producers? Mainly, this is because of mechanical skin of various types, but some of these effects are quite different from the conventional view of mechanical skin. Continued CHOP depends on sand influx: without it, wells are non-economic. If sand influx ceases, steps must be taken to re-initiate it through a workover technique. The pressure **P**ulse **W**orkover **T**echnique (PWT™) was developed to re-initiate sand influx after some blocking mechanism (generically called "mechanical skin") developed.

Production Mechanisms in CHOP

The economic incentive for implementing CHOP in heavy oil exploitation lies in dramatically increased oil production rates. Without sand influx, production rates of vertical wells in 1000-10,600 cP oil are 1-20 bbl/day. Long horizontal wells may give good production, but as often as not, such wells are economic failures. If sand influx is initiated and maintained in

™ Pressure pulsing workovers, reservoir excitation, and related applications are the subject of patents and patents pending.

vertical wells produced with progressive cavity (Moineau) pumps, production rates of 50-300 bbl/day can be achieved. Considering that operating expenses are on the order of $Cdn5.00-6.00/bbl (1999), typical CHOP wells are economical at heavy oil purchase prices greater than ~$Cdn10.00-12.00/bbl (remember that a $Cdn5.00-6.50/bbl differential refining fee is charged for heavy oil).

CHOP implies that sand enters the wellbore with the oil. This leads to non-conventional production enhancement mechanisms. First, if sand is permitted to move, intrinsic resistance to fluid flow in a porous medium is reduced. Second, as sand is produced, a region of enhanced permeability is propagated outward from the production well; this zone is likely a combination of dilated sand regions and piping channels. Third, a mechanism called "foamy oil drive" develops in heavy oil; because of the high viscosity, methane diffusion rates and bubble behavior are such that no continuous gas phase forms, and the oil remains as a bubble (foamy) phase.[2,3] Fourth, continued sand movement prevents and removes mechanical skin that may be caused by asphaltene precipitation, fines migration, near-wellbore gas bubble pore blocking, and other sources.

There are two driving forces involved in CHOP: pressure and gravity. Nucleation and growth of discrete non-coalescing gas bubbles creates an internal drive; and, the weight of the overburden acts to continuously destabilize the sand front and helps it to propagate outward as sand is removed from the producing well.

It is thought that exsolving gas bubbles restrict the permeability in the gas induction zone, allowing high gradients to develop, and these high gradients are accompanied by hydrodynamic body forces (seepage forces) parallel to the gradient.[2,3] The loss of lateral effective stress (σ'_r) from sand removal and the high vertical effective stress (σ'_v) from the overburden and from the pore pressure reduction cause shear yield of the formation when the peak strength is locally exceeded. Given that these are shallow dense sands with relatively competent grains, shear is accompanied by dilation from ~30% to ~38-45% porosity (observed on cased hole logs).

The gas remains as a bubble phase, meaning that an interconnected gas phase does not develop to bleed off the far-field gas pressures. The bubbles block the pore throats in the sanding zone, increasing the hydrodynamic drag in the direction of flow, and helping to overcome the reduced σ'_r, and liquefying the sand into bubble-rich slurry that flows to the wellbore. (There remains considerable debate as to the in situ geometry of this process, as it can occur as a compact process at a radially symmetric front, or as piping channels.)

Fig. 1 is an attempt to sketch the combined effects of these drive mechanisms. The zone where yield occurs is though to coincide with the zone of bubble induction, in advance of the zone that has yielded and is experiencing slow plastic extrusion toward the wellbore. The role of the vertical gravitationally induced stresses is obvious in this conceptual model. Note also that the porosity increases toward the wellbore, and the region of yield and dilation is also a zone of low seismic compressional wave velocity.

The combination of the various production mechanisms, combined with gradual increase of flow distance and slow pressure depletion, leads to an increase in oil production rates for weeks or months, thereafter followed by a gradual decline. This type of production curve proves that there must be at least two competing production mechanism groups: one tending to increase production rate (better drainage radius and sand mobility), the other tending to attenuate it (driving force depletion and increasing flow distance).

A CHOP well tends to come on production with remarkably high sand content – 25-45% by volume of the reservoir liquids. Because of gas bubble formation and the large drawdowns used, the material entering the PC pump at hole bottom is a slurry composed of sand, oil, a small amount of water, and a large volume of gas bubbles. This gas is largely driven back into solution as the slurry is re-compressed during transit through the PC pump and the tubing to the surface. In fact, a surface flow line specimen looks like black chocolate mousse, with no bubbles visible to the eye. In a few minutes, this sample will expand in volume by several times, bubbles will become visible, and gas evolves from the surface. It may be many hours before the sample loses all its gas and shrinks to or below its initial sampling volume.

In situ gas contents suggest that a Henry gas solution constant of ~0.2 vol/vol/bar is appropriate for heavy oil. For example, in oil field units, at a pore pressure of 5 MPa in a CH_4-saturated case, this is equivalent to about 50 standard cubic feet per stock-tank barrel of oil. Similar values are found throughout Alberta and Saskatchewan, and Venezuelan data are not far different.

Production data show that in some wells, sustained economic CHOP production may last in excess of 10 years, although the PC pump may have been changed 4-6 times in this period (the average PC pump life of 18-20 months is gradually increasing). During this life, a good CHOP well may produce as much as 40,000 – 100,000 m^3 of oil, perhaps 8,000 – 30,000 m^3 or more of water, and 500 – 3000 m^3 of sand. Of course, there are also many wells (~6-8%) that never produce much oil because of a failure to initiate sand influx. Also, CHOP wells that are too close to active water zones (bottom or flank water) will experience early high water-oil ratios because of channeling or disturbed zone intersection with the free water.

Fig. 2 is a histogram of the total oil and water production from 52 vertical CHOP wells in the Luseland Field in Saskatchewan; reservoir parameters are given in the diagram. Note that this is total production to Dec 98, and many of the good wells continue to produce oil. Furthermore, the gas-oil ratio (GOR) in this and other fields generally remains stable. This shows that the gas continues to be produced as a bubble phase, and most good CHOP wells do not show an interconnected and continuous gas phase (increasing GOR) until late in their lives, if at all. It is also worth noting that most of the 20 wells that have the lowest total production were either new wells or high-risk wells drilled near the pinch-off edge of the reservoir; the successful wells tend to be in the center of the structure where the oil zone is thicker and much farther from any mobile water. High-risk wells were low producers because they were abandoned after premature water-out.

Fig. 3 is a plot of the WOR versus the average production rate in bbl/month for the life of the well (note that many of the wells were converted to CHOP technology only late in their lives). Thus, overall production is normalized. A scattered hyperbolic relationship is suggested. The high-risk wells that were shut-in early in their lives plot up and to the left; the good CHOP wells plot low and to the right. Several outliers are circled to show that occasionally an acceptable CHOP well can also be a high water cut well. These data, along with a great deal of related information, will be the subject of an article on CHOP to be published in a conference.[4]

Good oil rates in CHOP wells means initiating sand, maintaining influx, and re-initiating it when it deteriorates, if possible. This was the initial driving force for the development of the workover technology described later.

Completion and Production Practices in CHOP

CHOP wells are generally vertical (0º) to 40º in inclination, cased with cemented 177 mm ID ordinary grade casing. To increase chances of initiating and maintaining sand influx, CHOP wells are typically perforated (or old wells are re-perforated) with 39 shot-per-meter "big-hole" charges that give entry port diameters on the order of 18-22 mm. The high shot density and relatively large explosive weight per charge cause severe perturbation of the fabric of the near-wellbore sand fabric, and this is conducive to sanding initiation. In thin reservoirs (3-7 m), the entire zone may be perforated; in thick reservoirs, the zone with the largest estimated $k \cdot h/\mu$ value is chosen. Debate remains as to whether underbalanced or overbalanced perforating gives the best chance of successful sanding initiation, but experience tends to favor moderately underbalanced approaches.

The well is placed on production by introducing a PC pump with the intake ~1 m below the lowest perforations and aggressively drawing down the well. The PC pump stator is placed on 89 mm to 115 mm diameter tubing, and the rotor is driven from the surface using solid drive rods through the tubing. The electrical drive units are computer controlled to limit torque, and pumping technology is moving toward control using down-hole pressure gauges so that an optimum fluid level of 10-30 m can be maintained in the annulus. This combined control approach reduces incidence of both rod twist-off and pump damage if wellbore fluid suddenly stops entering the borehole (a PC pump will experience serious damage in several hours if it is "pumping" gas from the annulus because the well has become blocked).

Different capacity PC pumps are used based on the height of lift and on the projected capacity of the well. A good producer warrants installation of a pump that can produce 45 m^3/d/100 rpm; a well that is far along the decline may warrant a smaller capacity pump. A deeper well (700-850 m in Canada) will require more lifts per meter of pump length to overcome the higher pressure difference requirements; a more shallow well (350-500 m) will use fewer lifts per meter. More and more, PC pumps with a "sloppy" fit between the rotor and the stator, rather than an interference fit, are being used, as it has been found that the viscous oil provides good efficiency as the result of the fluid hydraulic characteristics of the slurry being pumped.

Workovers involving pump change-outs are required if rod break or pump damage has occurred. This involves a complete withdrawal of the pump. If the oil rate simply drops below acceptable limits, either suddenly or slowly, there is an array of workover methods that may be applied to re-initiate production. These workover options are discussed in more detail later in the article.

Blocking Mechanisms in CHOP

CHOP wells show three basic types of mechanisms responsible for poor production; some may be classified as "skin", others not. First, there may be a <u>failure to initiate sand</u> influx when the well is initially placed on production. Second, the well may experience a <u>relatively sudden drop in production</u> after a period (months or years) of reasonable production; this drop may occur in a few days or in 3-5 months. Third, the well may display <u>gradual oil production drop</u> that is often, perhaps erroneously, called a decline curve.

Sometimes, despite generally aggressive perforation and initiation practices, a well that is seemingly similar to other good CHOP wells in a field simply cannot be brought into stable sand production. There are hundreds of inactive wells in Canada that have never produced more than perhaps 1-4 m^3/d, even after applying conventional workover methods. This is clearly a failure to sufficiently damage the sand fabric in the wellbore vicinity.

A sudden decline in oil production that is unaccompanied by WOR increase is thought to be the result of a near-wellbore blockage. Sand arching behind the perforations, plugging with cement of shale fragments, or a general recompaction of the sand near the well are possible reasons.[5] The suddenness of the oil production drop cannot be otherwise explained. Once perforations are blocked by immobile material, fine-grained material enhances the blockage, excluding oil entirely.

If a sudden oil decline is accompanied by a sudden water increase, it is evidence of communication with an active water zone, and there is excellent documented evidence that lateral coning in viscous heavy oils can take place over substantial distances. Another possible source of water is breaching of the overburden so that thin flow barriers between the reservoir and thin overlying and permeable water-containing beds is established. This overburden impairment may arise because of the generation of a soft zone that strains under overburden stress, causing downward overburden flexure until tensile cracks open (**Fig. 4**), allowing free water ingress.

The last type of production loss is a gradual decline over a time period of more than a half-year. We suggest that there are two mechanisms that can lead to this behavior. First, the reservoir may simply be experiencing general pressure depletion so that there is insufficient fluid pressure or gas to generate the foamy oil flow mechanism. This happens after large amounts of production from a CHOP well, generally more than 40,000 m^3.

The other long-term decline mechanism is “disconnection” of the well from the far-field. After some time, operators will infill a CHOP field, going from 40 acre to 20 acre spacing for example. Often, initial reservoir pressures (but not initial fracture gradients) can be encountered in the inter-well region, even after surrounding wells have been produced for many years (4-6 typically). Also, 3-D seismic surveys show that each CHOP well is surrounded by a zone of exceptionally low seismic P-wave velocity, and S-waves are not transmitted through this region (**Fig. 1**). This is clearly a region of sand dilation or liquefaction, and likely has a substantial amount of CH_4 bubbles as the result of exsolution. The size of the zone around each well is directly related to the amount of sand and oil produced, and a well that has produced no sand will have no seismically soft region around it.

Two effects may occur as the yielded zone becomes large. First, sand destabilization may slowly decay, even though there are virgin pressures in the interwell region. This is akin to the development of stable “pillars” in the interwell region that support the overburden entirely and do not provide the gravitational energy that yields the sand and helps drive it to the wellbore. As the disturbed zone around the wellbore becomes larger, the gradients decrease and the contact area becomes large enough so that the effective stress ratio is insufficient to locally yield the sand. Oil production drops off, perhaps with no increase in water cut.

The second explanation for the large zones at virgin pressure is that the oil in situ is simply too viscous to transmit pore pressures at the time scale of the production, or that a small yield gradient is required to overcome some existing structure (gelation) in the viscous crude oil. Non-Newtonian behavior of heavy oil is well known, and it does not seem unreasonable to postulate that over geological time, the static oil acquires an internal yield limit because of structure developed among the large polar molecules (asphaltenes and resins). This is akin to Bingham fluid behavior. If such a yield limit exists, a producing well will become disconnected from the far-field pressures.

A New Workover Concept

Usually, a new workover concept is based on practical evolution in the field. The PWT approach evolved from theoretical and laboratory work based upon the concept of porosity dilation waves, predicted from recent theoretical developments that allow diffusional flow theory and dynamic effects to be explicitly coupled in a thermodynamically rigorous framework, demonstrated theoretically[6,7,8] and experimentally.[9]

Considering the various mechanisms responsible for oil production impairment, we realized that long-term, high-energy perturbations would overcome most of the difficulties that arise around CHOP wells. Also, it was realized that this approach would be useful in all cases of mechanical skin, in impaired production or injection wells, and in conventional oil as well as in heavy oil wells. The theory indicated that if dynamic excitation was provided at a suitable high-amplitude frequency content, repeated transmission of porosity dilation waves would perturb the fabric, loosen minerals or asphaltenes in blocked pores, and propagate beneficial effects outward from the wellbore, perhaps even to the interwell region if excitation were continued for long enough.

Before the technique is described, it is useful to examine other workover methods to explain why they work poorly for the cases in which PWT has been found to be most effective. The discussion is confined to CHOP wells, as these concepts were developed and proven in this environment. However, physics is general; these mechanisms will occur in all porous media with interconnected porosity where the liquid saturation is at or very near 1.0. (Nevertheless, high gas contents attenuate the energy transmission and greatly reduce the distant transmission of porosity dilation beyond the near-wellbore region.)

Workovers in CHOP wells include methods that introduce fluids into the wellbore through the annulus with the PC pump in the hole, through the stator with the rotor temporarily withdrawn, or through the open hole with the PC pump withdrawn. Any fluid can be used, but usually the fluid is placed slowly or over a short period at a high rate. These approaches cannot have an effect beyond the near-wellbore environment (several metres) unless large amounts of fluid are introduced, initiating Darcy flow, or unless massive fracturing is accomplished. At best, and only just around the well, they may unblock some perforations, succeed in loosening some near-well skin, dissolve some blocking materials (acids and solvents), reduce viscosity locally (solvents or hot fluids), or lower the capillary forces that impede flow (surfactant agents). Furthermore, channeling and viscous fingering greatly reduce the efficacy of all injection workovers where maximum contact volume and symmetric dispersion into the reservoir matrix are desired.

Methods such as sand bailing, aggressive swabbing, re-perforating the well, or detonation of rocket propellant (Chemfrac™) create large physical perturbations. Limitations of these methods are related to only a single pulse (reperforating and propellant methods), to low excitation amplitudes (mechanical sand bailing), or to inward flow conditions, which may simply help consolidate perforation blockages (swabbing). These methods are widely used, with moderate success and many failures.

There are two general methods of creating porosity dilation waves: mechanical excitation of the solid matrix, or pressure pulse excitation of the liquid phase. They are equivalent because if the excitation is provided with the right frequency content, the strong fluid-solid coupling that exists will generate such waves. Operationally, it is much easier to use a down-hole pressure pulse generator than any method that excites the solid phase. For example, surface seismic excitation may generate porosity dilation waves in the reservoir, but energy adsorption, reflection and frequency filtering effects make it an inefficient approach.

Why not pressure pulse at the wellhead? This is far less effective than a downhole method because the correct frequencies are largely filtered out by travel down the wellbore (flexing of casing), generation of tube waves, and general loss of energy by compression-rarefaction of the phases. Also, in many CHOP wells, it is not possible to have a liquid-filled casing because of depletion and fracture gradients below the hydrostat (~10 kPa/m). At the well bottom, it is possible to tailor the pulse so that the maximum amount of energy feasible is concentrated in the correct frequency range.

It is worth noting that all workover technologies that use acoustics are ill-adapted for the goals sought: they operate at much lower amplitudes and much higher frequencies than those required to maximize energy conversion into porosity dilation waves.

The use of repeated large-amplitude pressure pulses containing the right frequency content overcomes a number of limitations that other workover methods have. The pulsing can be repeated indefinitely until the desired effect is achieved (monitored through a BHP gauge). A designed amount of dynamic energy can be put into the reservoir. The larger the amplitude, in general, the greater the benefit in CHOP wells: the near-wellbore flow impulse is converted into a porosity dilation wave that propagates far beyond the near-wellbore, with beneficial consequences.

Methodology for a "Typical" PWT Workover

Technical applications of the PWT are evolving rapidly and the mechanics and tools are continuously being modified and improved; thus, it is difficult to specify a methodology. Nevertheless, all approaches have a basic commonality, though volumes, rates and timing are variable.

After the tubing has been withdrawn, a PWT tool is lowered downhole. The positive liquid displacement pulsing is applied downhole to avoid frequency filtering and energy loss. One version of the tool uses the full casing inner diameter (177 mm diameter) as the cylinder and a stroke of 8 m, giving a volume of ~200 l per stroke. **Fig. 5** gives a schematic of the concept. The casing liquid below the piston is expelled through the perforations in a time of 4-5 seconds with a sharp rise time and sharp deceleration. The pressure pulse is trapped at hole bottom to allow high energy efficiency transmission to the reservoir. The pulse is trapped for up to 15 seconds, allowing the pressure impulse to decay in the formation rather than permitting flow back into the well casing. Then, the tool is restroked slowly before another pulse is applied. Depending on stroke length, dwell time, workover goals, and which tool is used, pulses are repeated from 0.8 to 5 times a minute.

The liquid that recharges the tool may come 100% from perforation backflow during restroking, or a workover liquid may be introduced down the annulus or tubing so that the pressure pulse tool is also injecting liquid at an efficiency approaching 100%. (A special version for waterfloods has been field trialed.)

If a chemical or special fluid is being introduced, an excitation period of a few hours may be used to open all perforations before the treatment liquid is introduced at the desired rate. For example, each restroke could be 90% perforation backflow and 10% recharge by the workover fluid.

This PWT methodology achieves several goals: the entire interval can be accessed because all perforations have been opened; mixing with reservoir fluids is intense because of inward and outward flow alternation combined with high shear during the pulse; and, pressure pulsing suppresses viscous fingering and channeling, allowing more uniform dispersion into the near-wellbore environment.

Pulsing is continued for a period of 5 to 24 hours. Most workovers to date have not used chemicals, but reservoir compatible fluids (usually reservoir oil) may be introduced slowly to help force gas bubbles back into solution so that the porosity dilation propagation can be rendered more efficient. The maximum fluid input to date is 15 m^3, and all of this fluid was produced back from the well in the first few days after the PWT, alone with new oil. It is important to note that the beneficial effects are not the result of injection of a liquid, but because of the effects of the perturbation and the porosity dilation wave propagation.

Once sufficient excitation is applied, the PWT tool is withdrawn and the well is placed back on production.

Summary of the PWT Effects

The aggressive and repeated liquid surges open blocked perforations, apparently more effective than other workover methods (the privilege of detailed perforation production rate mapping has not yet been possible, given the low profit margins in CHOP wells). Although a single large impulse such as provided by Chemfrac™ will open perforations, repeated pressure impulses have a cumulative beneficial effect because of the accumulation of plastic straining at blocked pores. An analogy may be useful. A grain or sand hopper that has become blocked by development of a stable sand arch can be made to flow again by tapping on the hopper at a modest but adequate amplitude and frequency (a rubber mallet works best). This brings vibration energy to bear on the arch, and small amounts of slip at grain contacts take place until the arch collapses.

The next relevant effects are in the near-wellbore environment, perhaps up to 2-5 m distant. Changes in flow gradient direction that accompany the pressure pulses create an alternating direction hydrodynamic drag that loosens blocked pores and breaks apart mineral or asphaltene aggregates. This effect is largely independent of the porosity dilation wave itself, although porosity dilation takes place and is beneficial to the process.

It has been found that in many cases the pressure around a well will build up during the PWT, even though liquid introduction may net be occurring. This is a "recharge" effect and can propagate far from the wellbore.

Farther from the wellbore (>5 m), in addition to the effect of a gradual increase in pressure that diffuses outward, the induced porosity dilation wave propagates radially and of course experiences geometric attenuation, as do all spreading waves. Each pulse generates a packet of these waves. The waves propagate at a velocity of ~40-60 m/s in an intact but dense 30% porosity reservoir sand under confining stress. In the laboratory, using 32-34% porosity sand packs under low confining stresses (<1 MPa), the porosity dilation wave travels much more slowly (8-12 m/s) because of the high matrix compressibility. In lower porosity competent rocks, the wave will travel at velocities of ~100-160 m/s.

Porosity dilation wave velocity is predicated by the incompressible limit of the pore liquid and the compressibility of the framework. A brief explanation is warranted. At low excitation frequencies, pore liquids behave incompressibly (the Darcy assumption); at high excitation frequencies, pore liquids transmit compressional strain waves. At some frequency in any interconnected porous medium with liquid-filled pores, water will begin to behave incompressibility. This limit dictates the porosity wave propagation velocity. The mechanism is analogous to the generation and propagation of tsunami waves in the open ocean. The tsunami is a displacement wave, not a strain wave, and travels at a velocity of about 1/40th of the velocity of the P-wave in water (1500 m/s). Similarly, the small-scale tsunami waves in the porous media (that we call porosity dilation waves) travel at velocities of perhaps 1/40th to 1/80th the velocity of the P-wave, depending on a number of factors, but principally on the compressibilities of the phases.

The porosity dilation wave has a number of positive effects. It enhances the flow rate of any liquid (single or two phase) that is flowing through a porous medium under a pressure gradient.[10] It suppresses multiphase flow viscous fingering and permeability channeling (confirmed in unpublished laboratory results), promoting a more dispersed flow regime rather than one characterized by mobility ratio (viscous) instabilities. There is also a synergetic build-up of pressure that occurs in a porous medium under a gradient because near the excitation source, and propagating outward, the flow resistance is reduced. Futhermore, the dynamic energy that propagates outward apparently overcomes Bingham fluid effects and helps destabilize the “pillars” that develop at the interwell scale in CHOP processes in heavy oil.

These observations are not hypothetical, although limited documentation is available in these early development stages. For example, correlated annulus fluid level changes have been observed in offset wells 1-2 days after a PWT in another well. Seismic events that begin and increase in recurrence frequency in the interwell region have been measured using downhole accelerometers during prolonged excitation in a heavy oil reservoir. Pressure build-up in the near-wellbore to the point of reaching the fracture pressure has been induced by pressure pulsing with only small amounts of fluid introduction over a period of 8-10 hours.

PWT Results to Date

Some tempering comments are needed at this point. The PWT approach is not suitable for all wells in all conditions. Cases of massive depletion, high gas saturations (particularly continuous gas phases), gas drive reservoirs, and so on, will respond poorly or not at all to the PWT methodology outlined herein. For these and other reasons, not all CHOP well workovers have been successful; however, the success incidence has been rising because of better screening procedures and better identification of the actual reasons for reduced production rates.

Over 40 workovers have been completed (Nov 99) since the first workover carried out in 1998. The first fifteen may be considered exploratory, but the last 15 have been executed with the advantage of an experience base.[11] An unsuccessful workover, defined as a failure to restore CHOP well production to levels that allow workover cost recovery plus additional oil at a rate that exceeds OPEX, is now quite uncommon.

PWT Used in Sanding Initiation

The greatest success (100%) has been in initiating sand and oil production in virgin wells that, for no obvious reasons, have never produced sand and oil. In the most successful case, a well in which CHOP had never been successfully implemented was used as the excitation well in a trial of field-wide pressure pulsing,[12] in the period May-Aug 99. When excitation was terminated, the company decided to see if the well could be produced. For the period Sept-Oct 99, it has produced at 12-14 m^3/day.

We believe that success in initiating sanding is related to a large perturbation of the near-wellbore fabric, generating remolding (fabric disruption) and pressures high enough to trigger destabilization of a large volume zone that then continues to self-destabilize. It is well known that large cavities in granular media are less stable than small cavities, and the failure to initiate a large-enough unstable zone that can be produced through the perforations is overcome by the generation of a large perturbed region.

PWT in Watered-Out Wells

There has been a limited experience base with prematurely watered-out wells (excessively high water cuts), but in several cases, water rates have been reduced and oil rates re-established. The continuous introduction of reservoir-compatible fluids during aggressive pulsing apparently has the effect of collapsing or “backing-off” the water channels. Insufficient time has passed to evaluate whether the beneficiation lasts for a sufficiently long time for the PWT to be considered a success. Also, we do not believe that mechanisms such as direct fracture communication with mobile water zones in the overburden (**Fig. 4**) can be overcome by this method.

Nevertheless, there is laboratory evidence that watered-out channels can be cured through the appropriate technique, using pressure pulsing in the oil phase. We believe that this will become an application for PWT in the future, in appropriate cases of fingering and permeability channeling, where flow is in discrete porous channels.

PWT in Blocked Wells (Near-Wellbore “Skin”)

In cases of near-wellbore blockage, PWT apparently opens perforations, destroys blocking arches and pushes back pebbles or lumps of shale and cement away from the perforations, allowing flow to be re-established. A 10-hour pulsing workover is also enough to propagate important effects far from the wellbore, and is likely sufficient to re-liquefy or perturb re-compacted sand in the intermediate region (2-20 m from the well). (It would be ideal to confirm all these hypotheses with wellbore seismic monitoring, measurements in close-by wells (20-50 m), and so on, but this is not possible in the heavy oil sector at this time.)

Many cases of success in blocked wells have been achieved, and some of the wells have shown stable production at rates of 5-10 m^3/d for many months; in one case, the well is still producing at a steady rate of 8 m^3/d a year after the PWT. A good overall success ratio (~75%) has been achieved in cases where there has been a sudden drop in production that likely arises from blocking.

PWT in "Depleted" Wells (Slow Production Decline)

Some success has been achieved in wells that have shown a slow production decline, but it is now apparent that in cases of massive depletion and high gas contents, success is problematic. Such candidates are now rejected during the screening process, using the long-term production histories and well behavior as indicators.

However, in cases of suspected disconnection from existing far-field pressures or where stable interwell pillars have formed, the PWT has had reasonable success. In such cases, because the distances to these regions of energy are large (~50-100 m ?), operating companies are considering longer pulsing periods to take better advantage of the porosity dilation wave benefits.

Given the small amounts of fluid that are typically introduced, the success in reconnecting to far-field pressures and in destabilizing "pillars" must be related to the cumulative effect of the porosity dilation wave that propagates into the far field. Analysis of the governing differential equations suggests that a porosity dilation wave that leads to local shear of grains that are under a differential stress can "extract" the energy arising from the displacement. This in turn implies that, under certain conditions, a porosity dilation wave can attenuate at a rate less than that predicated by geometrical spreading.

In nature, a large shallow earthquake will generate many kinds of waves: shear, compression, Stoneley, and porosity dilation waves. Is it possible that the latter are the trigger for sympathetically-induced earthquakes?

Some Field Results

Figs. 6, 7, 8 show a selection of PWT workover responses. These selections are neither the best nor the worst cases, but represent examples of different efficiencies of energy transmission to the reservoir, as well as examples of different amounts of repressurizing of the well. In all of these cases, significant production increase was observed.

In the first case, the pressure surges are all of the same magnitude, and the energy efficiency exceeded 50%. A gradual build-up of pressure is evident, especially in the last half of the excitation period. All pressure pulses show a Δp of about 475-500 psi, indicating that the formation was being substantially excited by the porosity dilation waves, and that these were propagating far from the wellbore. Considering the history of the well and the pressure pulse response, we do not believe that there was a large volume of free gas behind the casing, despite the relatively high local depletion, evidenced by the initial pressure, which is less than 20% of the virgin pressure.

The second case shows poor energy efficiency because the formation simply provided little back-resistance to the pressure impulses. This well had a reasonable history of production, and was therefore also partly depleted in the wellbore region. Nevertheless, after several hours, the resistance to the pressure impulses increased somewhat and the pressure began to rise. We hypothesize that the combination of the excitation and the addition of a few cubic metres of reservoir oil helped to partly drive the gas bubbles around the well back into solution. When this took place, the efficiency of energy transfer increased.

The third example shows moderate energy efficiency: about 25% of the potential energy was transferred into the reservoir. For the first two excitation periods, about an hour each, the Δp in each surge was only 60 psi. At about the 4 hour mark, a relatively rapid increase in the resistance to pressure impulses in the reservoir resulted in an increase of the energy transfer efficiency, with Δp on each pressure pulse of about 300 psi. This apparently is evidence of the gas being driven back into solution so that instead of simply compressing near-wellbore gas, the formation was becoming "stiffer" (i.e. less compressible) in its response to the pressure surges. Pressure build-up, however, was very poor, and only a 12 psi wellbore pressure increase was recorded between the beginning and the end of the pulsing.

In general, virgin wells that have had no depletion will show extremely good resistance as well as pressure build-up, even to the point of reaching the fracture pressure (this has happened in two cases). Such cases are more similar to the first example, **Fig. 6**. Conversely, wells that are massively depleted and also have free gas will show very small Δp on each pulse (as low as 10-30 psi), and only minor pressure build-up, and then only if substantial amounts of load liquid are used. The response of these wells is much poorer than the examples shown in **Fig. 7**. Screening candidates carefully tends to eliminate such cases.

Discussion and Conclusions

This article has concentrated on mechanisms, partly because case histories have been introduced elsewhere (refs) and because an exhaustive evaluation of long-term success must await the analysis of extended production records for a period of many months, perhaps 1-2 years. Nevertheless, the limited record to date clearly shows that the new workover method has considerable short-term success in CHOP wells. Recently (Sept 99), two chemical workovers have been done, placing treatment chemicals under conditions of pulsing after a period of perforation opening; results are awaited.

Despite a number of failures in the early development stages, it is now safe to make some broad conclusions:

- PWT workovers are successful in initiating sand production in CHOP wells that have never produced sand.
- Pressure pulsing unblocks perforations and destroys near-wellbore "skin", re-establishing CHOP well production.
- Pressure pulsing workovers often relink a CHOP well to far-field pressures and destabilize interwell zones so that gravitational energy can continue driving the process.
- Failures generally occur in cases where the reservoir is massively depleted, or where there is high gas saturation in the vicinity of the well.

The PWT approach will be useful in cases where perturbation of skin is required. The repeated liquid impulses into and out of the perforations and the porosity dilation waves loosen and mobilize pore throat blockages, likely disaggregating these blockages into their constituent particles. The disaggregated particles can be produced during excitation, exposed to treatment chemicals, or flushed out of the well during production.

Porosity dilation waves repeatedly applied to a porous medium generate both pressure build-up and increased flow rates. These effects cannot be predicted in a Darcy flow context: Darcy theory is a static construct containing no inertial terms, whereas porosity wave propagation is a dynamic process, acting at time scales several orders of magnitude shorter than Darcy processes, yet far slower than conventional seismic wave processes. These effects will occur in any porous medium, not just high porosity sands.

Workovers involving chemical or solvent placements usually suffer from channeling and viscous fingering. Back-production of undiluted treatment fluid and uneven acidizing are common effects. Because the porosity dilation effect brings inertial energy to the fluid phases at the pore scale, these viscous instabilities are reduced in magnitude. The result is a far more even displacement front, and the cyclic inflow and outflow through the perforations promotes excellent mixing. These are positive aspects for any liquid placement process.

Energy Considerations

Because continuous pressure monitoring is used, a comparison between the total energy input and the energy transmitted to the reservoir can be made (**Figs. 6, 7, 8**). Typically, 8-10 hours of pulsing with the 8 m stroke tool in a 177 mm casing involves about 190-220 MJ. In a successful workover, the amount of energy calculated from the pressure-time response of the BHP gauge is on the order of 70-110 MJ, about 40-60% efficiency. In a failed workover, because the wellbore region is so depleted that it offers no resistance to impulses, or because of large amounts of free gas, the work efficiency may be as low as 5%. By comparison with PWT, a Chemfrac™ involves application of about 6 MJ, over a period of perhaps 100 milli-seconds. Other methods involve far less energy input, and generally do not last long enough or are of the wrong frequency content to generate porosity dilation waves.

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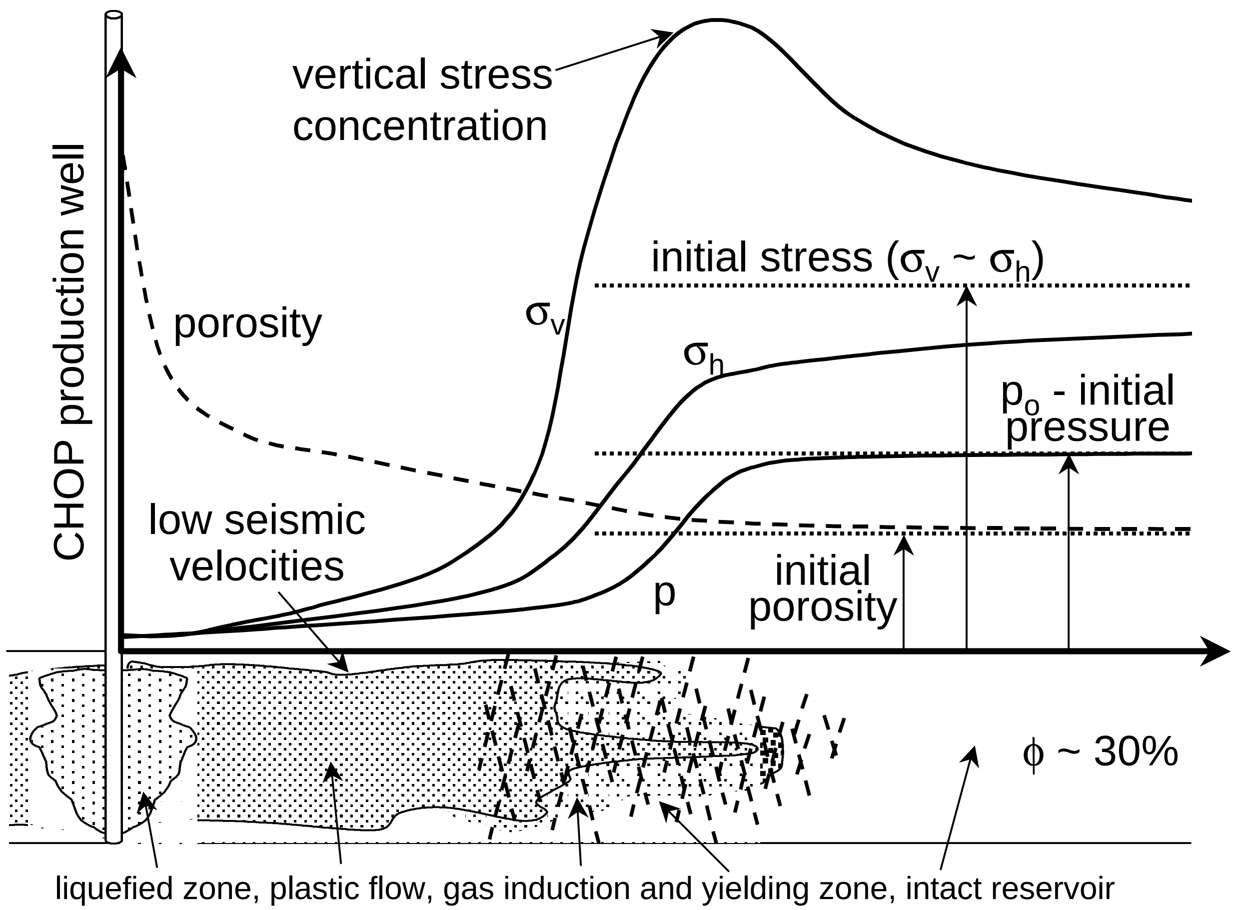


Fig 1: Stresses, pressures and porosities around CHOP wells

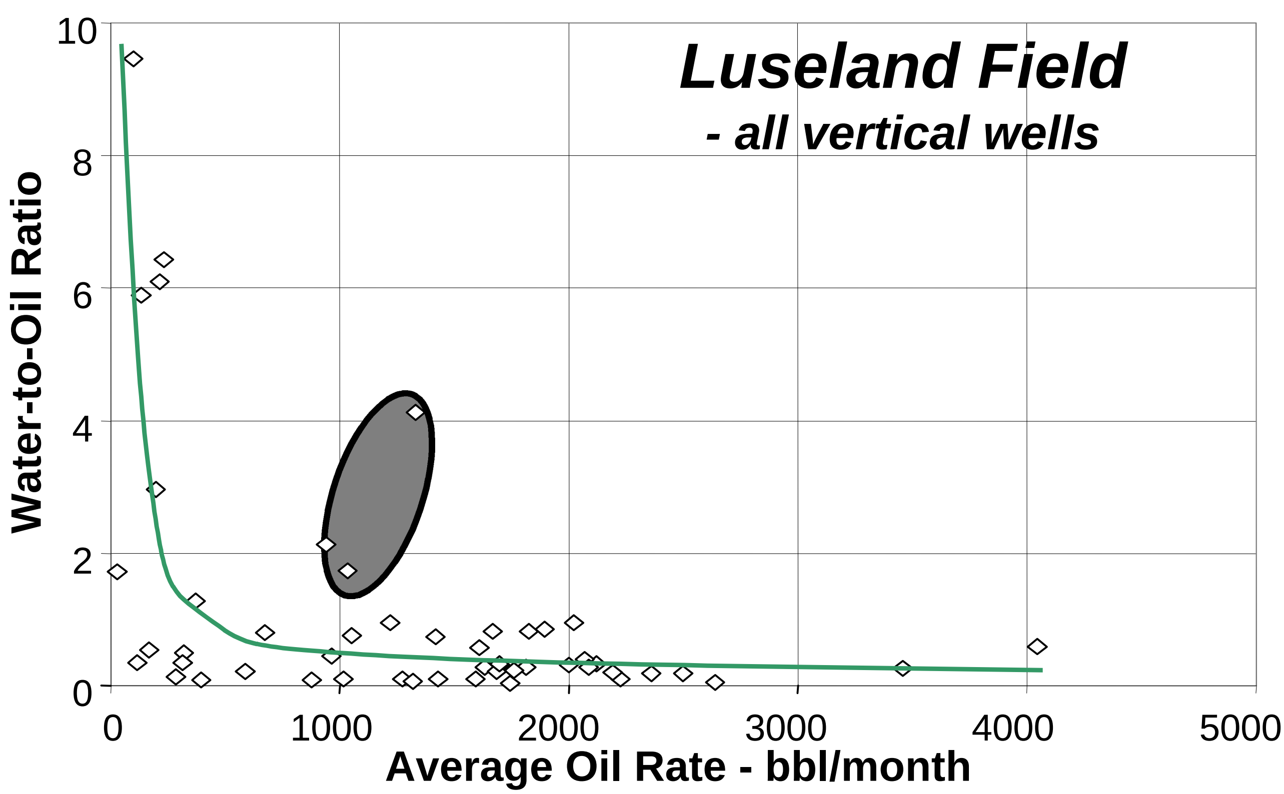


Fig 3: Normalized well behavior for the Luseland Field (Sask)

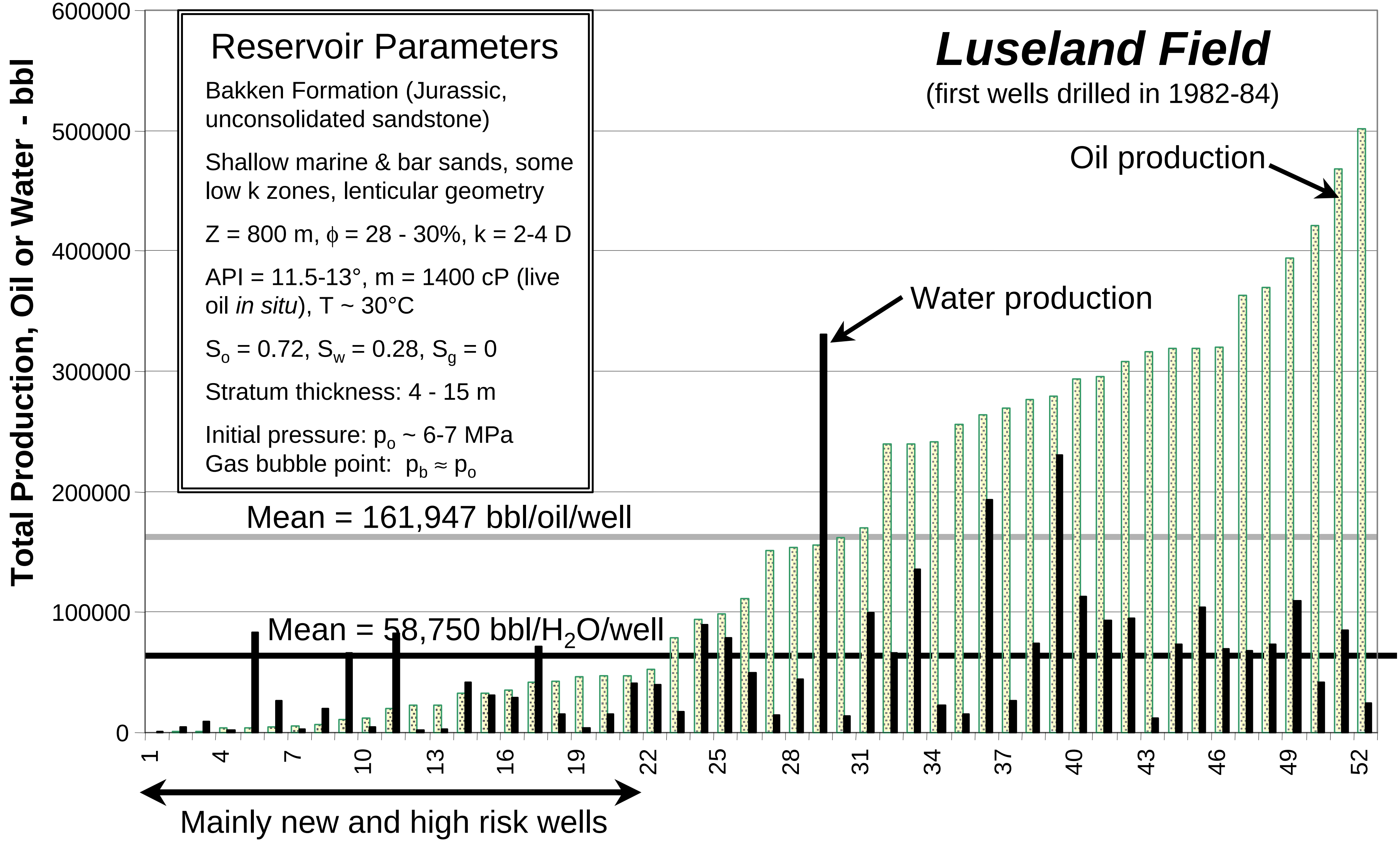


Fig. 2: Total oil and water production to Dec 98, all vertical wells

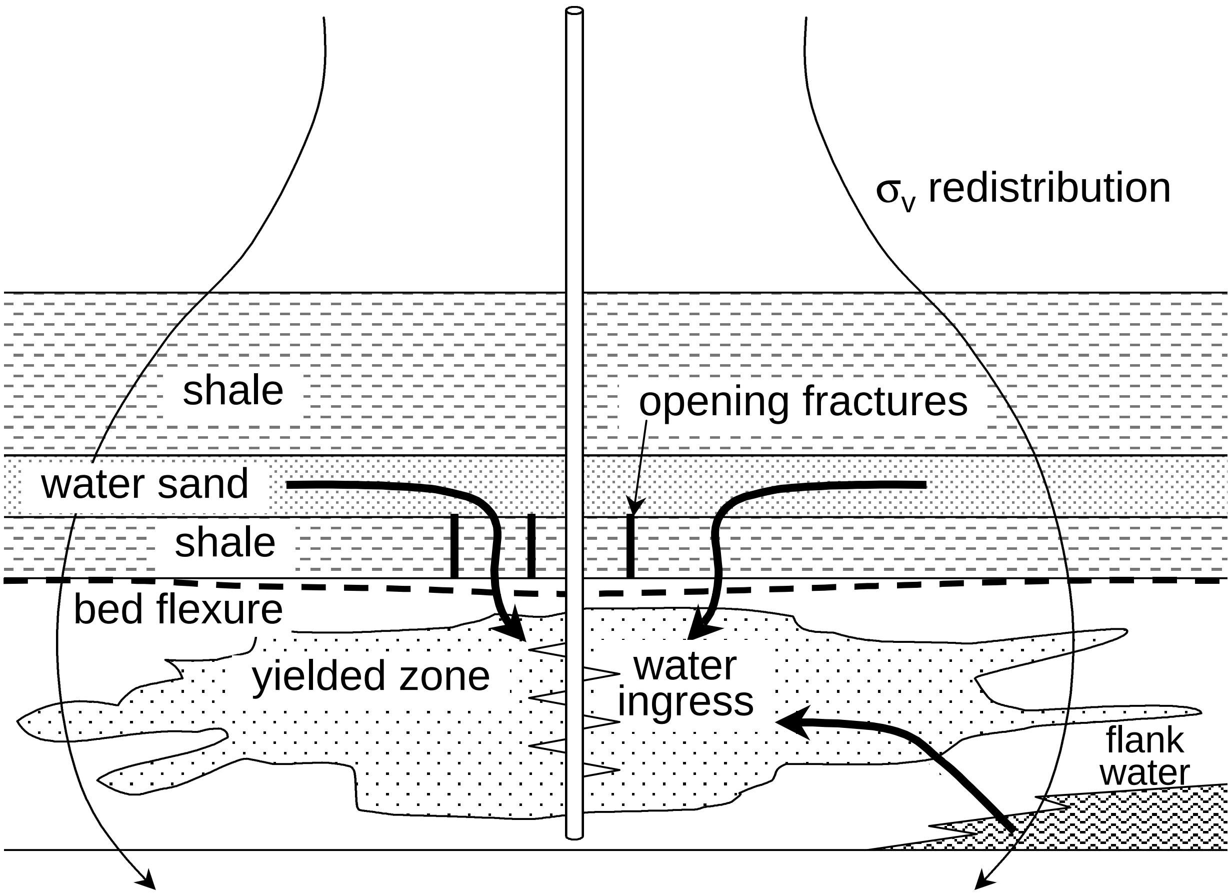


Fig 4: Water breakthrough mechanisms in CHOP wells

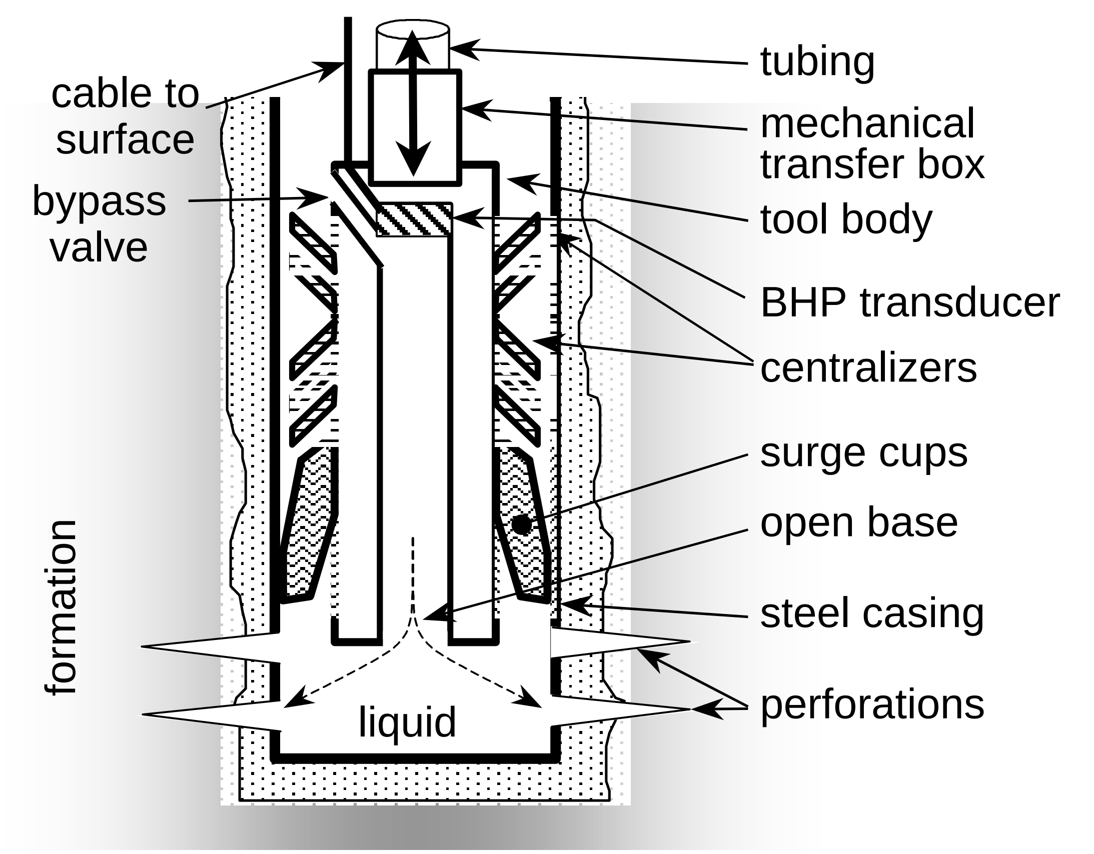


Fig 5: The basic elements of a down-hole pressure pulse device

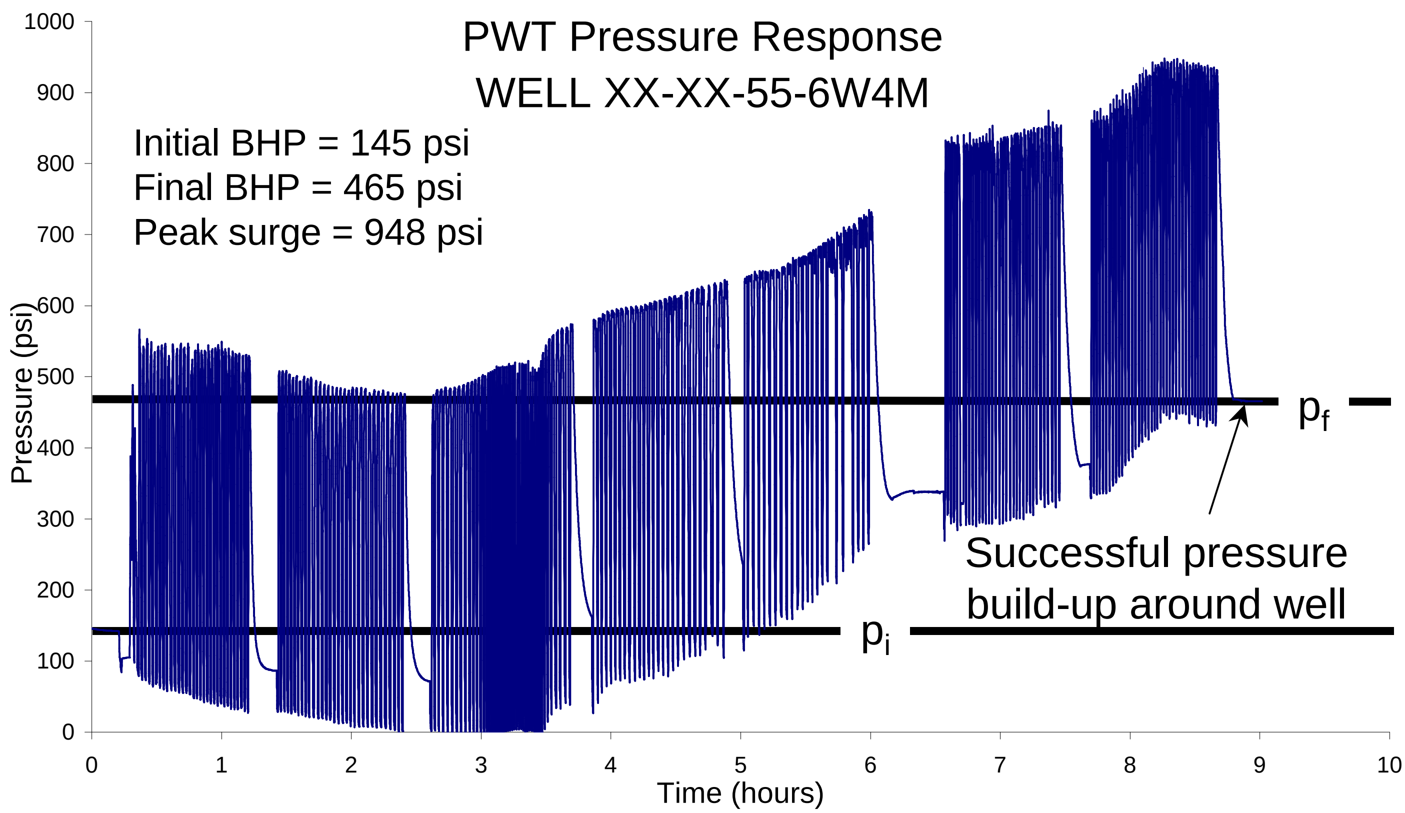
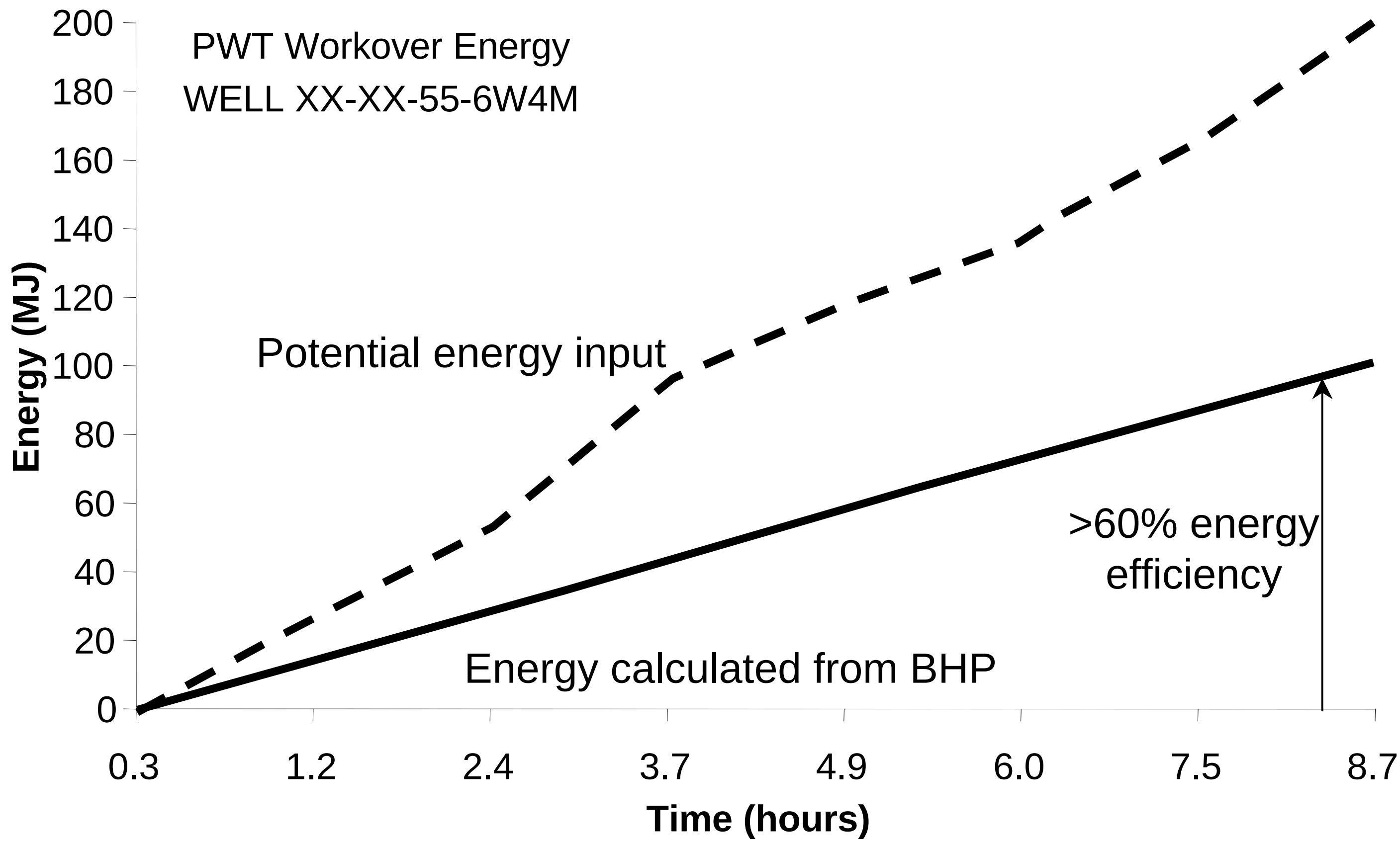


Figure 6: Pressure response and energy, a case of good response



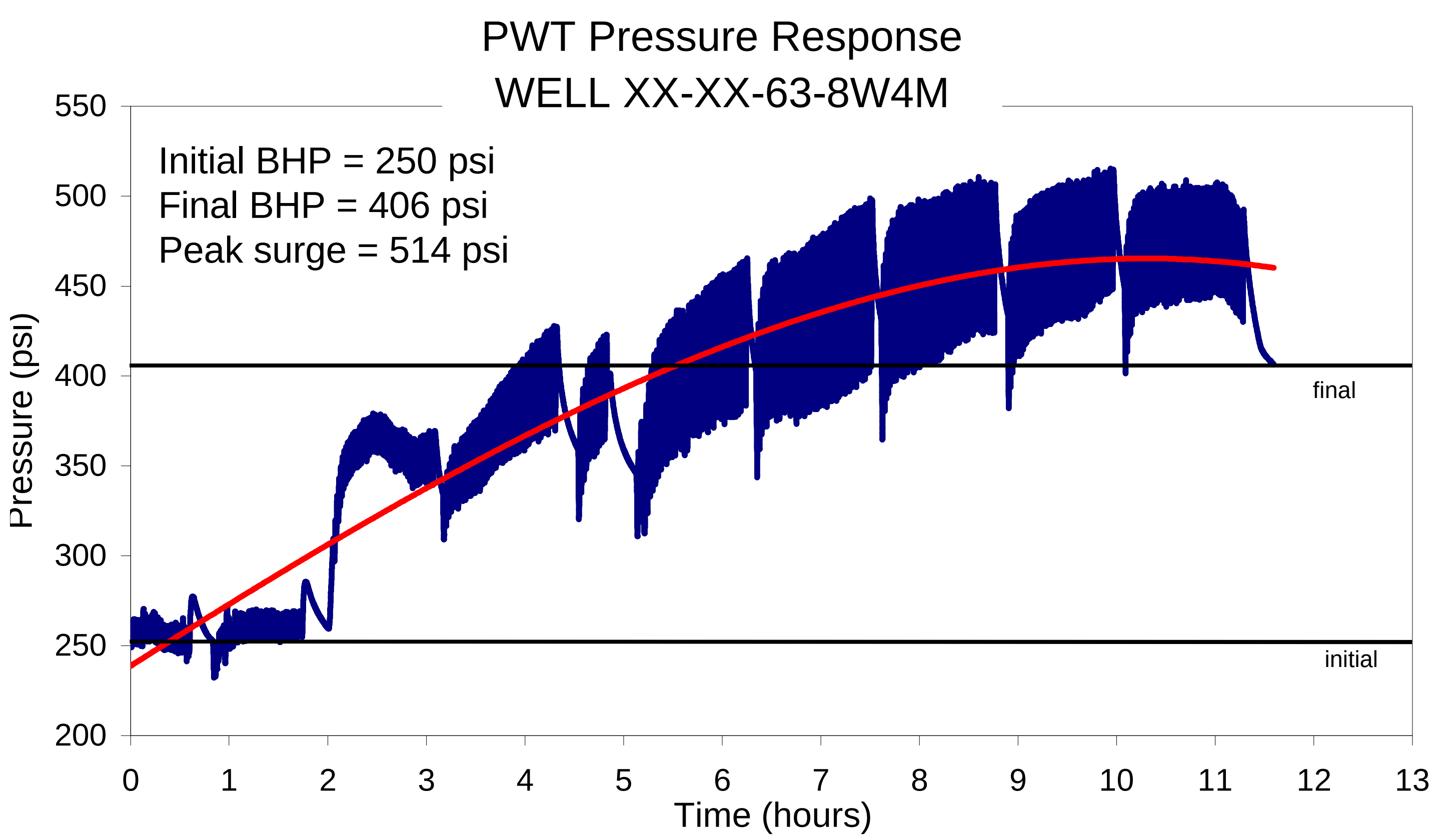
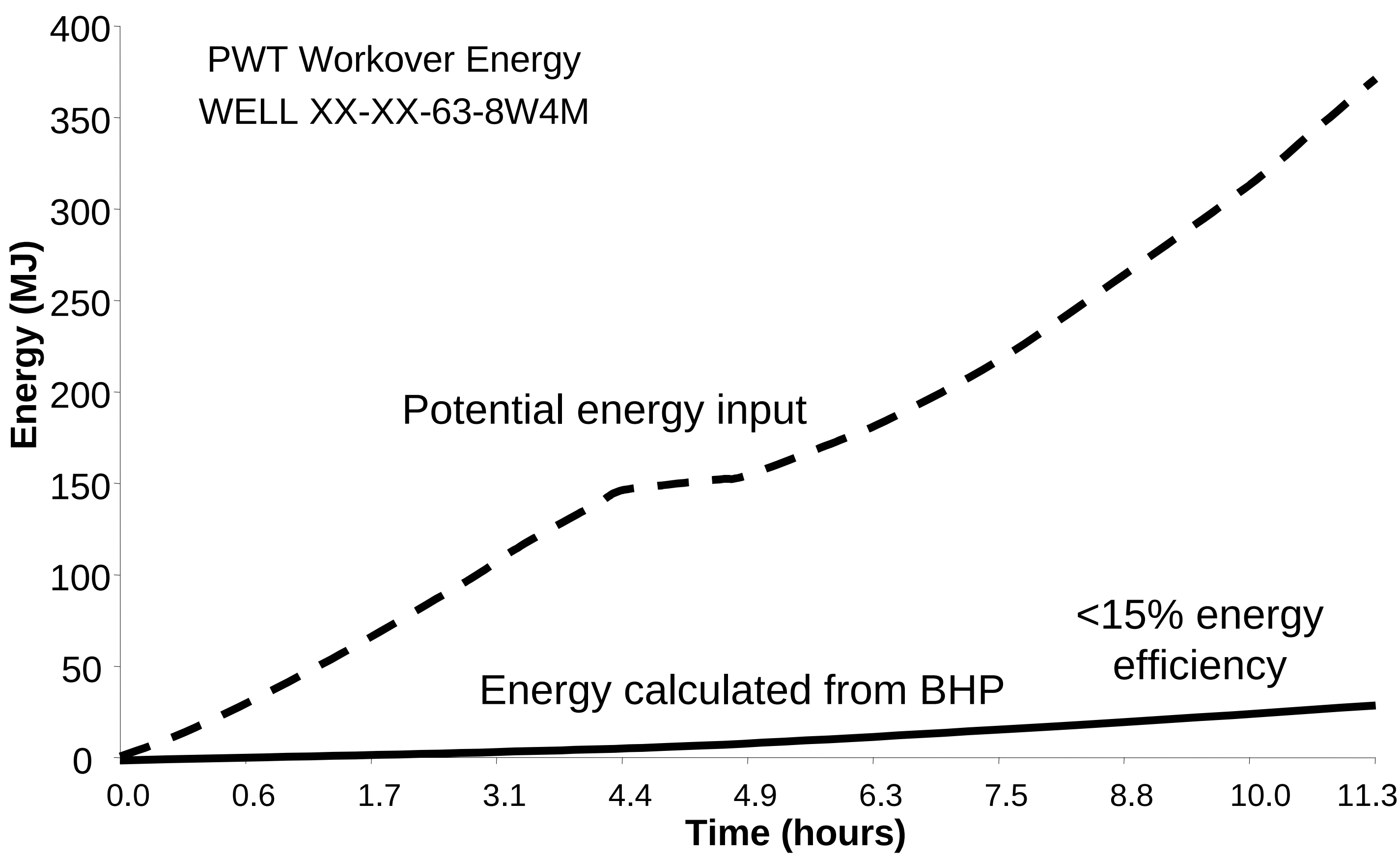


Figure 7: Pressure response and energy, a case of good pressure response despite poor energy transfer



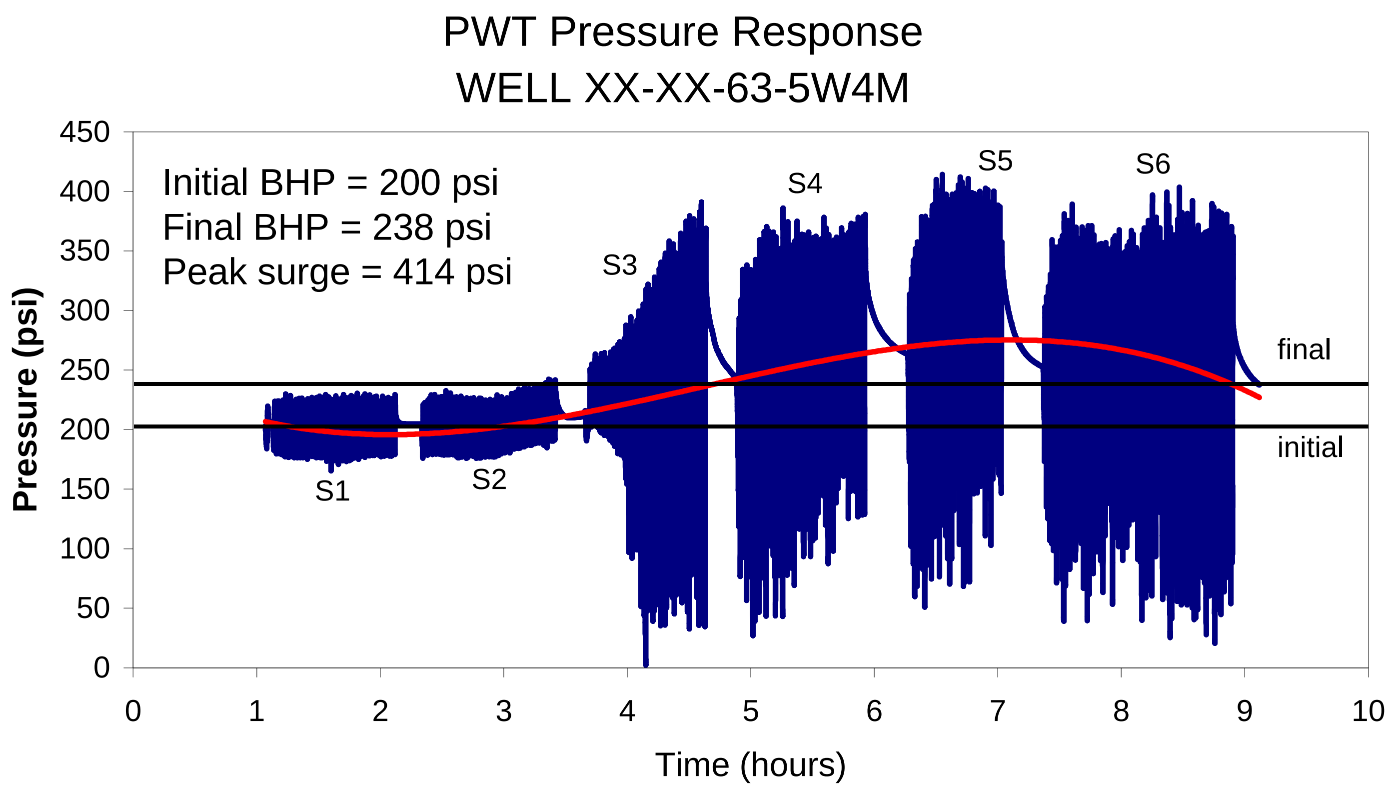


Fig 8: Pressure response and energy, a case of moderate response