4 PHYSICAL PROCESSES IN CHOPS PRODUCTION

4.1 Reservoir Mechanisms Maintaining Sand Influx

4.1.1 Energy Sources and Stresses

In the CHOPS process, a set of driving forces is responsible for the continued sand influx that generates the higher oil production rates. These mechanisms operate at different scales with different effects. The major driving forces are the following:

- Gravitational forces (vertical stresses arising from the weight of the overburden strata) that help yield and dilate the sand;
- Natural fluid pressure gradients that cause flow and lead to entrainment (suspension) of the sand in the flowing fluid; and,
- Foamy oil flow phenomena (solution gas drive as entrained bubbles) that help sustain the pressure and flow rate, liquefy and keep sand in suspension, and accelerate the flow velocity to the wellbore through growth and expansion of gas bubbles.

The gravitational energy component acts at the scale of the entire reservoir and overburden. The sand liquefaction and entrainment effect happens at the grain scale where locally elevated pressure gradients pluck almost unconfined sand grains from their weak and dilated substrate to incorporate them into the slurry. At an intermediate scale, that of the wellbore region, the generation of a foamy bubble phase in the moving slurry has an important effect on the gradients and thus on the suspension of sand and on the flow velocity to the well.

As sand influx is initiated in a CHOPS well, a "cavity" is generated near the wellbore.[29] Stresses arising from the overburden weight and pressures arising from fluid flow to the wellbore both act upon the walls of this cavity. In the "solid" reservoir rock near the walls of the cavity, the radial stress is decreased and the tangential stress is increased (Figure 4.1). This results in an increase in the shear stress and a decline in the confining stress, and both of these effects tend to bring the "intact" formation to a condition of shear yield.

[29] The use of the terms "cavity" or "wormhole" in the context of heavy oil CHOPS processes refers to a volume in which there is no grain-to-grain contact. In other words, a "cavity" *in situ* is not actually empty: it is filled with sand suspended in a mixture of oil, water, and small gas bubbles (foamy oil).

Because the confining stress is low from the lateral unloading that takes place, shearing causes the high porosity UCSS near the walls of the cavity to dilate (expand in volume). Any small amount of mineral cohesion that may exist in the sandstone is destroyed as the sand is deformed and remolded by shearing. Because of dilation of the sand during shear at low stresses, the porosity will increase from the typical initial *in situ* value of 30% to much higher values, perhaps 35-38%, yet it will still remain as a solid mass held together by compressive stresses and having frictional behavior. Nevertheless, the sand has changed dramatically from a densely packed and intact sand to a sheared sand of much higher porosity. This increase in porosity has dramatic effects on the absolute and relative permeability values, and also leads to changes in phase saturations.

During CHOPS, all the important properties of the oil reservoir change. Three-dimensional geophysical seismic surveys carried out by some companies, notably PanCanadian Petroleum,[xxiii] show this clearly. These surveys show that a CHOPS well that has produced over 100 m^3 of sand in its lifetime (a long life production well may produce over 2000 m^3) is surrounded by elliptically shaped low- seismic-velocity regions Fig. (4.2). Wells that have produced more sand have proportionately larger regions of low seismic velocity, wells that never were successful in sand initiation have no detectable zone of low seismic velocity. Also, even though extensive data remain unavailable in the public domain, it appears that the “ellipticity” of the zones is consistently aligned in an individual field. Seismic waves that pass through the “disturbed region” may also show no shear waves in the wave train; this is because the transmission of shear energy in a high porosity medium at low stress and with some free gas is greatly impeded, and the waves may be completely attenuated. Note that it is difficult to quantitatively analyze the seismic wave velocity reduction in terms of the three possibilities (high porosity, low stress, gas bubbles). Mathematically, this becomes a challenging “non-unique” problem in these difficult circumstances.

High porosities of 35-44% around a wellbore may be deduced from geophysical “behind-the-casing” logs executed on wells that have produced large volumes of sand (Fig. 4.3). These high porosities are measured only after the tubing and PC pump have been removed from the well and a geophysical logging unit lowered down the wellbore. This usually takes from 4 to 10 hours after production is interrupted, so the geophysical log data may not represent the conditions when the well was actively producing. After stopping production, sand has some time to settle around the wellbore because it is not being drawn in actively through the perforations, and the gas bubbles in solution have more time to rise upward and segregate from the foamy oil.[30]

Nevertheless, the data indicate that during production it is likely that a liquefied zone exists near the wellbore, though the size and vertical extent of this zone is different from well to well, and borehole geophysical methods cannot probe far from the wellbore. Not only is there a general higher porosity in the near-wellbore region, but after a large amount of CHOPS sand influx, lithostratigraphic features such as thin coal seams, thin shale seams, and carbonate-cemented strata (usually less than 40 cm thick) can no longer be identified; they have been destroyed. Often, underneath the cap rock, a zone of exceptionally high porosity is found (>60%); this is believed to be a small gas cap in a limited volume void that can be sustained in a stable state because of the cohesion of the cap rock. Occasional "gas slugging" in CHOPS wells is thought to arise because of episodic draining of this small gas cap once it grows large enough to intersect the uppermost perforations. The gas then flows out of the "void" until it is drained before reversion to foamy oil and sand production takes place in the well.

Clearly, stress-related factors are important in the CHOPS process because the sand is yielding and dilating. It can be shown mathematically that stresses must be redistributed at the reservoir scale around a well, and even at the sub-metre scale around any channels that may be propagating or that may have been created by a piping process. Figure 4.4 shows the conceptual effect of producing sand on reservoir-scale stresses if the process is characterized mainly by a compact disturbed zone. Note that the compact zone does not have to extend the full height of the reservoir; it may be limited to the upper part of the reservoir, or to a zone that is overlain by parts of the reservoir with some cohesive strength.

Lateral unloading by sand production means that the confining stress drops, and this reduction in confinement generates yield and dilation. This also has the effect of reducing the high frictional resistance that arises from the dense packing of the sand in its natural state, making the sand much more ductile, susceptible to plastic extrusion, and more easily entrained in a flowing slurry. This process of weakening, dilation and increase in ductility is dynamically maintained by the weight of the overburden that continues to press down on the reservoir sand. No matter

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[30] Better instrumentation downhole, such as densimeters, is hoped for in the future to better manage CHOPS wells.

what happens in the reservoir, the total weight of the overlying rocks must be carried, and the downward movements that accompany this process provide energy to maintain it. The amount of work associated with this is expressed as:

$$\mathbf{W} = \mathbf{F} \cdot d = \sigma_v \cdot A \cdot \Delta z$$

where the vertical stress σ_v acting across an area A provides useful work as it moves through a vertical distance Δz. This work is unavailable to conventional production reservoir mechanics, where the reservoir rock is usually behaving in an intact and relatively rigid manner.[31]

In order to become fully suspended in a fluid (liquefied), sand must locally exceed a porosity of about 48-52%, at which point all forces transmitted through static grain-to-grain contacts disappear, so that stresses can no longer be transmitted through the solid phase. After liquefaction, and as long as the sand grains are in suspension, only pressure exists in the slurry, and all matrix stress has disappeared. This pressure near the wellbore is a small fraction of the overburden stress, less than 1 MPa in most CHOPS wells under aggressive drawdown. Thus, in the medium, a liquefaction front must exist where sand is undergoing a transition from a solid condition to a slurry condition. This "liquefaction front", whether it is relatively uniform around the wellbore or whether it occurs in long channels with liquefying tips, defines the boundary between the plastic flow zone and the liquefied zone in Figure 4.4. The "lines" between zones in the figure (and in the ground) are to be understood as generally diffuse and extensive boundaries, not sharp zones that can be delineated easily either mathematically or through monitoring.

Once the sand is locally suspended or fluidized in a slurry, only fluid pressure can be transmitted through the cavity. The vertical matrix stress that has been "lost" in the zone around the well must be redistributed outward around the well to more intact and stronger rock. The "solid" rock where frictional grain contacts exist is rock in a plastic condition or rock that has not yet been sheared and transformed into a ductile plastic state. These issues are revisited in more detail later in this chapter.

4.2 Flow Enhancement Mechanisms

The flow enhancement observed in CHOPS wells arises mainly from four factors:

- Sand flux increases general fluid mobility;
- Continuous sand production generates a growing zone of high permeability around the wellbore;
- Solution gas behavior in the form of bubbles (foamy flow) destabilizes sand, maintains pressure in the fluids, and accelerates flow to the wellbore; and,
- If sand is continually produced, the wellbore region cannot become blocked by precipitated asphaltenes, fine-grained particles, or mineral deposits.

4.2.1 Darcy Velocity Increase with Sand Influx

If a porous medium matrix is immobile, the Darcy velocity of the fluid, v_f, is taken relative to a fixed frame of reference. However, if the matrix is also moving, the Darcy velocity is the differential velocity: $v_D = v_f - v_s$. Sand movement thus directly increases the velocity of the fluid phase relative to the matrix, which has the effect of increasing the fluid velocity for a particular pressure drop with respect to the fixed frame of reference of the observer. There are several circumstances where this effect could be substantial.

In the early stages of sand influx in more viscous heavy oil reservoirs ($\mu > 5000$ cP), sand content usually approaches 40-45% by volume of the total dead (gas-free) produced material. In this phase the reservoir is almost being “mined” hydraulically. The massive sand movement is almost entirely responsible for the early flow enhancement that is observed in CHOPS wells. However, sand flux diminishes with time, and this effect gradually becomes relatively less important.

If the dominant sanding mechanism is the advancement of piping channels (“wormholes”), it seems likely that at the advancing tip the sand is being liquefied at almost the same rate at which the heavy oil is flowing into the channel tip. Therefore, at the local scale of the piping channel tip, the sand concentration in the liquid remains high as the channels continue to propagate into the formation. As the slurry with high sand content flows toward the wellbore through the channel, it is progressively diluted by slow liquid influx from adjacent reservoir zones (Fig. 4.5).

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[31] Exceptions to this statement may be found in high-porosity compacting reservoirs where vertical strains can be very large (2-5% and even 10% in North Sea Chalk), even without solids production.

The farther the tip from the wellbore, the more dilution occurs, and therefore the lower the sand cut becomes with time.

The process of sanding is a continued liquefaction of the sand fabric. Because of the high viscosity of heavy oil and elevated pressure gradients where liquefaction is occurring, the velocity of the suspended sand grains (v_s) is similar or somewhat less than the fluid velocity (v_s), giving as the pressure gradient:

$$\frac{dp}{dl} = -\frac{\mu}{k_p}(v_f - v_s)$$

Here, dp/dl is the one-dimensional pressure drop, μ is the viscosity, and k_p is a measure of the "permeability" of the sand-fluid mixture. Of course, it is difficult to define precisely what the permeability is in a medium that is experiencing gradual dilation from 30% porosity to the point of liquefaction (~50% porosity).

Thus, little impedance to flow and small pressure drops arise if the solid phase is moving at the same rate as the fluid phase. Theoretical analyses suggest that this process can perhaps double the liquid production rate at the well. Although it appears that this effect is negligible overall in cases where sand production rates drop below a few percent, it likely remains important locally at the sites where sand is being liquefied (and certainly at early time with high sand cuts).

4.2.2 Permeability Enhanced Zone Development

The withdrawal of solids from the reservoir through the process of liquefaction and transport to the producing well creates "space" within the producing horizon. This space is not a void: it is a "remolded" zone of higher porosity (dilated) sand, or it is filled with slurry composed of sand, oil, water and gas. The growth of this remolded zone causes an increase in the apparent permeability of the wellbore region; because this zone grows with continued sand production, the well behaves as if it has an increasing radius with time. Assuming that the permeability of the remolded and liquefied zones is much higher than that of the virgin formation, the enhancement effect may be expressed as:

$$\frac{Q}{Q_o} = \ln\left(\frac{r}{r_o}\right)$$

The remolded zone is unlikely to be a uniform zone with sharp boundaries; rather, the conceptual model shown in Figure 4.6 suggests the shape of the zone of enhanced permeability. There is a near-wellbore region filled with high porosity slurry (>50%) where the permeability is huge,[32] but for the most part, the remolded zone is viewed as a dilated, partially remolded region with diffuse gradational boundaries.

How large is the remolded zone radius? Assuming that on average the reservoir sand in a cylindrical body dilates from 30% to 35%, and that the reservoir cap rock does not deflect downward substantially, for each cubic meter of sand produced, a reservoir volume of up to 15-20 m^3 is affected. If sand is produced mainly from piping channels rather than a cylindrical zone, the affected region may be much larger. It seems reasonable to assume that after 100-300 m^3 of sand has been produced there is a remolded region of 1000 to 5000 m^3, giving a radius ratio increase of 50-100, depending on the thickness of the zone affected. The production enhancement factor from this effect alone should approach 4 to 5, providing other boundary conditions remain the same.

Seismic velocity measurements on older fields suggest that the zone approaches the interwell spacing distance after many years; therefore radii in excess of 100 m have been confirmed in the field. The remolded higher porosity zone may not extend over the entire vertical height of the reservoir; logging data and other lines of evidence suggests that the upper parts of the reservoirs are more prone to sanding. The remolding and yielding processes are thought to move outward and upward from the perforated interval, giving a larger effective radius than for a zone of uniform height.

The remolded zone porosity distribution *in situ* is not yet well known, but near-wellbore values of 42-45% have been determined (Fig. 4.4). Note that 45% is close to the maximum porosity for loose sands in grain-to-grain contact under very low stress. Whatever the geometrical details of the zone around the wellbore in a CHOPS well, the effect of continued sand production is outward propagation of a zone or channels of high permeability, so the flow capacity of the well continues to slowly rise.

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[32] Defining the permeability (resistance to flow) of a dense slurry is difficult, particularly if there are suspended gas bubbles in the slurry.

4.2.3 Foamy Oil Behavior in Viscous Oil

The third flow enhancement mechanism is related to exsolution of dissolved gas. This is a type of solution gas drive, but there are a number of important differences from conventional solution gas behavior.

The heavy oils being exploited by CHOPS have gas (>90% CH_4) in solution; the bubble point usually is at or near the pore pressure (i.e. the gas is close to saturation in dissolved form in the liquid). Wells are subjected to aggressive draw down, and the gas exsolves as bubbles; however, these bubbles do not coalesce rapidly to form a continuous gas phase; they remain as bubbles during flow to the wellbore, expanding in size as the pressure declines. Hence, the bubbles act as an "internal drive" force, expanding and driving the slurry to the wellbore at a velocity greater than that predicted by conventional liquid flow theories ($v \propto 1/r$). Because bubbles move with the fluid and discrete gas channels apparently do not develop in CHOPS wells, there is no direct drainage mechanism to deplete gas pressures far within the reservoir. Thus, gas-oil-ratios (GOR) remain constant, often for years, and virgin pressures may be encountered only a few hundred metres from producing wells during later in-fill drilling activity.[33]

Foamy oil is developed in an induction zone where bubbles nucleate in response to the pressure decline. Assuming that a bubble exsolves in a pore subjected to a pressure gradient, it will displace to block or impede flow through the pore throat, reducing the fluid flow capacity of the porous medium, and causing the local pressure gradient to rise (Figure 4.7). This helps destabilize the formation sand because it increases the hydrodynamic drag force on grains. In a porous medium, the hydrodynamic drag force on a single grain (or group of grains) can be expressed as:

$$\vec{F} \approx SAw \frac{\partial p}{\partial l}$$

Here, the hydrodynamic body force vector **F** is proportional to the cross-sectional area A, the grain width w, and the pressure gradient $\partial p/\partial l$, corrected by a grain shape factor S (<1). The

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[33] Even though virgin pressures may be so encountered, it is common for a drilling operation to lose circulation in this zone, indicating that the lateral stress has dropped below a fracture gradient of 10 kPa/m from a virgin value of 17-21 kPa/m. Stress changes are transmitted large distances through the solid matrix, but pressure changes can only

mechanics are sketched in Figure 4.7; it appears that the induced body force must be coaxial with the gradient direction. At some point, likely within or just downstream of the bubble induction zone, the pressure gradient becomes large enough and the restraining frictional forces small enough to permit individual sand grains to be removed from the sand matrix, a process known as liquefaction (or piping). This "plucking" of sand grains or aggregates of grains from the substrate must take place almost continually in many locations around a CHOPS well, regardless of the geometrical details of the altered zone.

Calculations show that large hydrodynamic forces can overcome only small amounts of grain-to-grain cohesion; it is almost certain that any true cohesion in UCSS is destroyed by the shearing and dilation that precede liquefaction. A shear distortion less than 0.5% is sufficient to destroy all the cohesion in a UCSS, and the zone of yield and dilation experiences shear strains much larger than this because the high shear stresses lead to dilation from an initial 30% porosity to values of 35% and higher. As mentioned before, these elevated shear stresses arise from and are maintained by gravity: the vertical stress is large, and the lateral (horizontal) stress is reduced through sand withdrawal. The destruction of cohesion by shear distortion implies that CHOPS may have applications in reservoirs with small amounts of cohesion, but there are also strong physical reasons to believe that if the cohesion is substantial (>50-100 kPa), the shearing will attenuate as the zone attains a large diameter, and the sand production cease. Nevertheless, if the enhanced production in such a case arises mainly from the enhanced permeability zone, this represents a possible beneficial well management mode for slightly cohesive reservoirs.

Figure 4.8 shows the probable distribution of pressure around a CHOPS well, arising from the foamy flow mechanisms.[34] Near the wellbore, in the region of high permeability, large pore throats, and partially liquefied material, the pressure gradient is thought to be low. Indeed, pressure measurements in wells that stopped production many years ago show that low pressures can be sustained for several decades near a well, despite the proven existence of higher pressures in the interwell regions. In the bubble induction zone, the pressure gradient is steep because the

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be substantially affected by discrete flow, therefore this is evidence that *in situ* the heavy oil may not flow as a conventional fluid: it may have a "yield point".

[34] No detailed pressure measurements are known to have been analysed at some distance from CHOPS wells, therefore all distributed data remote from the wellbore are to a large degree hypothetical, based on inference from known and probable mechanisms. The author is not aware of . . .

evolving bubbles block the pore throats: these steep local gradients are also thought to be partly responsible for the sand destabilization and liquefaction. Beyond the bubble induction zone, the reservoir pressures are almost at their virgin condition, and pressure gradients are again low.

4.2.4 Elimination of Skin Effects

The preceding three mechanisms are amenable to mathematical analysis once the details of the physical processes are quantified. The fourth factor cannot be analyzed because it is the absence rather than the presence of a process, but it is of great practical importance.

Heavy oil contains asphaltenes, semi-solid materials comprised of complex aromatic organic molecules, which give Alberta heavy oil its characteristic bituminous odor. These molecules aggregate ("precipitate") with pressure decline and with gas depletion. The asphaltene aggregates block pore throats, thereby degrading permeability and impairing the production rate of heavy oil wells.

In the interstices of typical heavy oil reservoirs, there are fine-grained siliceous minerals (silt-sized quartz, clay minerals…) that can be mobilized under high pressure gradients and under the effect of viscous drag forces and shear distortion. These forces tend to liberate particles that are weakly bonded through electrostatic attraction to the coarser-grained mineral substrates. These liberated particles migrate and accumulate at pore throats, where they form stable blockages.

Finally, some formation waters are saturated with mineral species that may precipitate in the near-wellbore environment, blocking pore throats. This is not expected to occur in the CHOPS region because the typical geochemistry is not appropriate, but in some high porosity sandstone oil field (e.g. $BaCO_3$ precipitation in North Sea oilfields), dissolved mineral precipitation is a difficult problem that impairs well productivity and necessitates repeated workovers.

If sand is kinematically free to shear, dilate, and undergo liquefaction, as in CHOPS, then pore throat blockages that build up the local pressure gradient will continually clean themselves up by sand movement and liquefaction. Furthermore, dilated sand has substantially larger pore throats, and liberated materials are more likely to be flushed through the system successfully without generating blockages. This behavior has been confirmed in sand management approaches for high-rate oil wells: these wells over time develop more and more negative skins as blockages are cleaned up through sand bursts (see articles by Dusseault, Tronvoll and Santarelli in the reference list).

Although it is not a physically correct view, a heavy oil well on CHOPS may be viewed as having a massively negative skin. (Skin is a mathematical correction factor included in petroleum engineering flow equations to account for impaired well performance; positive skin means blockage, negative skin means permeability enhancement in the near wellbore region.)

4.2.5 Change of Mechanisms with Time

During early production, drainage surface area is small, flow distance is short, gradients are extreme, and sand production rates are high. At this point, the effect of sand flow increasing fluid flux dominates enhancement. Foamy oil processes are already developing near the wellbore, and this aids destabilization. High initial sand cuts and gas contents in CHOPS wells confirm this.

After the process has produced 100-300 m^3 of sand, the drainage surface area is large, and larger quantities of oil can slowly ooze across interfaces under the local pressure gradients. Sand is destabilized locally, perhaps at channel tips where gradients are high, but the second process (large drainage surface area) now begins to dominate fluid flux. Foamy oil behavior continues to help as a driving force and as a local destabilization mechanism, particularly where pressure gradients are high. GOR values remain constant, an important and very revealing fact; this behavior confirms that there is no continuous gas saturation network that is depleting the gas content of the liquid at a distance from the well, a process that is typical of conventional oil production.

In the late life of a CHOPS well, after >1000 m^3 of sand have been produced,[35] general solution gas drive depletion gradually becomes important, and GOR values may now be observed to slowly climb, indicating that a partially connected gas phase or a small gas cap has formed. Gas slugging in wells may occur in this stage, indicating gas accumulation in the near-wellbore region to form small gas pockets that are episodically drained. Water influx is now more probable because of the high permeability zones that extend great distances; the probability of

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[35] The volume of sand that has to be produced before depletion effects become dominant is different from well to well, depending on the viscosity, zone thickness, solution gas content, and so on. The figure of 1000 m^3 is simply a typical value.

encountering mobile water is now much greater than during the early life of the well. The CHOPS process attenuates and decays as the driving forces from solution gas are depleted, and the disturbed, remolded zones are now large enough so that they interact between wells as the entire reservoir is now affected by the sand flux, disturbance, and pressure depletion.

Apparently, the dominant flow enhancement mechanism evolves during the CHOPS process. However, if sanding suddenly ceases, for whatever reason, oil rates invariably drop precipitously. Sudden oil production drop likely occurs because of perforation blockage or sand recompaction near the wellbore: stable sand arches form behind the casing, creating traps for asphaltenes, minerals, and blocking fluid flow almost totally. In practice, when a well suddenly ceases production without precursor phase changes (sudden water increase), workover strategies focus largely on re-opening perforations, perturbing the formation, and reducing capillary effects, so that the reason for the blockage is removed.

Because of a higher density, sand particles in flowing slurry may be slightly retarded during accelerative flow (inertial effects), and there is undoubtedly a tendency for larger particles to settle in the near-wellbore vicinity. Larger particles will settle more rapidly, and larger particles also arch around perforation openings more effectively. This hydrodynamic sorting may be responsible for stable producing wells often experiencing a sharp drop in sand and oil production rates, which can then be reversed by aggressive workover strategies.

It is important to note that the actual values of the pressures and the porosities in the extensive zone around CHOPS wells cannot be measured by any known means. Interpretation of the results of well testing is essentially impossible because of the large variation in properties that has taken place around the well. Permeabilities, reservoir compressibilities and stresses have all changed, and the values of these parameters can vary greatly over short distances. Since the distribution of these altered regions is not known a priori, the well test data cannot be analyzed rigorously. Furthermore, no well test model yet accounts for flow enhancement through sand flux and bubble growth; therefore, the models that are available are physically incomplete for CHOPS processes.

It is also difficult to predict the evolution of reservoir parameters over time using more complex mathematical models (reservoir simulators or well simulators): these models are “fitted” to production data history to give a “prediction” of future behavior, and this calibration process supposedly improves the usefulness of the model for predicting the behavior of other wells in the reservoir. However, if the physical processes that are specified in the model do not correspond with those that actually occur (sand flux, bubble growth, growing zone of high k…), then the model must be viewed only as an empirical fitting procedure. Using such a model to make inferences about physical states in the reservoir (saturations, porosities, permeabilities, compressibilities…) cannot be justified. CHOPS processes are extremely complex (Figure 4.9) and not fully understood at present. It remains necessary to monitor and attempt to understand the physical processes qualitatively in order to optimize well behavior. Nevertheless, predictive capabilities will improve as models that are based on real physical processes are developed.

4.3 Channels or Compact Growth Zone?

The two limiting physical mechanisms that can be responsible for sand production are compact growth of a yielded, remolded zone as a cylindrical (or spherical or ellipsoidal) body, or extension of an anastomosing piping channel system comprising a network of tubes ("wormholes"). These lead to different geometries *in situ*, although the impact on well productivity may not be quantifiable through measurements (see above).

4.3.1 Uniform Remolded Zone Growth Concepts

In compact growth, sketched in Figure 4.3, the ratio of the area of the fully yielded and liquefied zones to the volume enclosed approaches a minimum because a cylindrical or elliptical shape is spatially more compact than a channel network (energy minimization). A complex local boundary shape may exist, and the boundary between slurry and intact rock is undoubtedly diffuse; however, for analysis, the compact zone must be approximated by a geometrically regular shape with a distinct liquefaction front.

A circular two-dimensional (2-D) assumption is the simplest for analysis because the radius of the zone, and hence the pressure gradient, can be scaled directly to the sand production volume with no additional assumptions. Although a diffuse (gradual) phase transition zone develops, it may be mathematically treated as a thin front, just as in temperature and heat flux analysis in a melting alloy that does not have a sharp melting front. However, overburden stress (σ_v) plays a major role in the destabilizing and dilation process, and a 2-D model cannot capture this process in a rigorous manner, so additional assumptions have to be made.

There are strong physical arguments that support the compact growth hypothesis. The yielded and liquefied zones can support little of the overburden stress (σ_v), therefore much of the stress must be redistributed outward from the wellbore region (Figure 4.10). Of course, this adds to the forces that cause yield and dilation. However, the intact shale overburden does not yield and therefore cannot strain into a sharply bent shape or one with complex curvature. It behaves like a thick beam with high stiffness, and this smoothes out and homogenizes the geometry of the deformation and yield zones. Outward extensions of the disturbed zone will shed much of their vertical stress as they yield, so they carry less vertical stress, whereas stiffer intact zones that protrude inward must carry more stress (Figure 4.11). Intact regions located between yielded zones thus must be more highly stressed than average, and this stress concentration cannot be sustained; shear, dilation, and softening will occur in these zones. Thus, the stiffness of the overburden causes a smoothing of deformations, leading to the continual redistribution of stress stress to the periphery of the yielded zones (Figure 4.11 cross-sections). By an extension of this argument to three dimensions, one may deduce that the smoothness in deformation that is "enforced" by the stiff overburden beam tends toward a homogenization of yield within a compact growth zone, keeping the boundary approximately circular to elliptic, and suppressing fingering of plastic flow zones deep into the surrounding intact zone.

The surface area in compact growth remains close to a minimum because of the principle of energy minimization: a compact shape requires less energy to develop than a fingered boundary. For a 10 m thick reservoir that has produced 500 m^3 of sand, the disturbed zone volume may be ~5,000-10,000 m^3 (1:10 to 1:20 ratio), with a mean radius of ~13-20 m and a minimum surface area of ~800-1000 m^2. Any frontal perturbations, especially channel growth, will increase this area, and are therefore less probable. However, as mentioned above, complete dilation of the entire zone is improbable: CHOPS processes will occur dominantly in the upper part of the reservoir, so the compact growth zone will have a larger radius than that predicted by the assumption of yield of the full reservoir thickness.

4.3.2 Piping Channel (Wormhole) Growth Concepts

It is reasonable to assume that piping channels that might develop are stable structures, approximately cylindrical and of constant cross-sectional area along their length (D ~ 25-50 mm?). The channel is filled with slowly flowing slurry, and the tips of channels are propagating away from the wellbore as sand is being produced. As the size of the affected zone is increasingly influenced by the impermeable upper and lower reservoir boundaries (intact cohesive shales), the nature of flow will evolve from a spherical pattern to one that is cylindrical, dominated by the radial growth of channels. This is analogous to reservoir drainage pattern changes as the radius of influence increases to a value larger than the reservoir thickness.

If the dominant mechanism for sand production becomes piping channel growth at some time during the history of the CHOPS well,, there are two reasonable limiting cases for the nature of the channel network. At one extreme, a number of channels develop outward from the wellbore, and that number is constant with distance (Figure 4.12). At the other extreme, channels bifurcate repeatedly (branching) and a three-dimensional anastomosing (dendritic) geometry is created where the volume density of the channels remains constant within the affected volume. These are considered to be limiting cases because it is difficult to rationalize either a decreasing number of channels with distance, or an increased channel volumetric density with distance.

The limiting case of constant channel density per volume with distance may be viewed as a self-similar process: within the zone containing channels, at all sampling scales which are substantially larger than the representative elementary volume (REV), the channel density is the same. This suggests that the mean flow-path length within the channeled zone remains constant with a characteristic value depending on the density of channels. Furthermore, it is reasonable to assume that the overall process zone characteristics remain the same with growth if the channel density remains constant. In this limiting case, it is possible to define an "equivalent permeability" of the REV in the channeled zone, leading to a flow model that has a far-field permeability (k_o), a near-field permeability (k_i in the remolded zone), and a diffuse but narrow transition zone between the two. New channels must be created continuously as the affected zone grows, and the number of channels (N) scales to the shape of the disturbed in the following manner:

$$N \propto r \quad \text{for } 2-\text{D radial growth}$$
$$N \propto r^2 \quad \text{for } 3-\text{D spherical growth}$$

The velocity of the affected zone boundary must also be related to the radius:

$$v \propto \frac{1}{r} \quad \text{for 2 – D radial growth}$$

$$v \propto \frac{1}{r^2} \quad \text{for 3 – D spherical growth}$$

The other limiting case for the channel network exists when the number of channels remains the same, neither growing nor shrinking with distance from the wellbore. Within the affected zone, there is no definable REV in this case: the spatial density of channels decreases with distance, the mean flow path length increases, and the "equivalent permeability" must be defined in a spatially dependent manner, becoming asymptotic to k_o at the "boundary" defining the location of the advancing tips. In this case, the velocity of the affected zone boundary remains constant, and the flow equations for the constant-N case differ from the flow equations for the dendritic case.

Figure 4.13 is a schematic plot of the "equivalent permeability" distribution for the two limiting piping channel cases, as well as a reasonable assumption for a compact growth model. One interesting point is that from a flow or well test perspective, it will be almost impossible to discriminate between the compact growth and the dendritic channel network case as the boundary (or transition zone) moves further and further from the wellbore. It thus appears impossible to make conclusions as to the physical nature of the processes in the reservoir based solely on tests performed at the wellbore face (Δp or ΔQ well tests). A more direct means of observation is required, but still lacking.

For piping channels, there are two possible cases with respect to fluid flow and drainage of the reservoir; these are called the strong piping case and the thin lens case (Figure 4.14). In the strong piping case, fluid flow is strongly channeled within the "wormhole" and the tip processes and pressure gradients that drain the reservoir beyond the tip dominate solids and liquid flux. In the thin lens case, individual channels serve also as drains for surrounding oil; the sanding at the tip is dominated by local gradients, but the permeable channels serve as lateral drains and dominate the overall oil production.

In extremely viscous oils (>10,000 cP), mobility is extremely low, and the sand cut remains elevated for a long time. These cases more closely approach the strong piping case, with much of the fluid coming from the tip region. In lower viscosity oils, the slurry is more highly diluted during transit to the well, and this more closely approaches the permeable thin lens model.

The reservoir contact area for channel growth is potentially far larger than for compact growth. Using the same figure of 500 m^3 of sand produced in the compact zone example, if channels average 30 mm diameter, the contact area is ~66,000 m^2, rather than ~800 m^2. Even an extremely slow-moving liquid can attain substantial production rates with such a large drainage surface.

4.3.3 Combined Compact and Wormhole Processes

Several arguments lead to the conclusion that sand production does not occur by either mechanism alone.

Assuming a mean stable channel diameter of 30 mm, after 1000 m^3 of sand is produced from a well, the total channel network length would exceed 1000 km. Stated otherwise, in a reservoir 10 m thick with ~20 acre well spacing, each cubic metre of formation will contain on average 10 m of 30 mm diameter channels, representing only 0.17% of the volume of the reservoir. This scenario seems improbable, but perhaps the piping channels are substantially larger than 30 mm in diameter.

Viscous slurry flowing in small channels with rough walls will generate large pressure drops along the channel length; this must severely limit the channel length because there is a finite pressure drop available in the reservoir between the liquefaction tip and the wellbore.[xxiv] It appears impossible to quantify this effect because there is no method to calculate the number of channels, yet this number is necessary to estimate slurry velocity and pressure drop. For these and other reasons, numerous channels of great length seem unlikely; a relatively short characteristic channel length, on the order of 2-20 meters, seems more probable.

During the early part of CHOPS production, when the remolded zone is small and the sand production rate is large, it appears that compact growth is dominant. The radius of curvature of the zone is small and the "intact" wall can thus sustain a high tangential stress (σ_θ) that counteracts piping channel development. The sharper the radius of curvature, the greater the stability of the sand face, and any perturbation on the surface will tend to heal itself, even though the local pressure gradients are high because of the focusing of the flow lines (Figure 4.15).

During intermediate to late time in the history of the well, the remolded zone is large, and a geometric perturbation of the surface of the zone may lead to the development of stable channels. Any perturbation tends to focus the flow lines, increasing the local pressure gradient at the leading tip of the perturbation. The destabilizing forces that are linked to pressure gradient magnitude are now large because of the spherically convergent flow at the channel tip. However, stabilizing forces linked to friction and arching also increase as the curvature increases; as is well known, a small hole in a granular material is far more stable than a large hole. Finally, note also that the presence of a "free face" will also lead to a stress concentration, and this favors yield, weakening and dilation of the sand, easing destabilization.

Whether a perturbation will heal itself or propagate depends on the balance of all the forces involved. If the rate of energy expenditure with time is positive, the perturbation will heal; if it is negative, the perturbation will propagate and the channel will grow. As the channel grows, the energy expenditure rate changes because of extra energy needed to sustain a thick slurry flowing long distances through a narrow channel. If the perturbation propagates, it generates its own high permeability channel that advances into a less depleted zone of the reservoir, accessing (and indeed perhaps seeking) zones where a higher pressure gradient at the tip can be maintained to maintain growth. This is the realm of stable channel growth, although components of compact growth nearer the wellbore will still take place because of large-scale stress redistributions that help trigger sand yield. The writer believes that stable channel growth cannot occur in intact formations: at a porosity of 30%, sands under any confining stress are extremely strong and resistant to piping stresses. The writer believes that piping channels propagate and grow only in zones that are already weakened and dilated because of high shear stresses.

This transition between compact and channel growth over time is not entirely speculative. In the field, communication between wells has repeatedly been observed, but mainly for mature wells which have produced appreciable amounts of sand. Furthermore, mathematical perturbation analysis of sand production models which couple both flow and stress confirm that stable channel growth is energetically favored late in the well life, whereas compact growth is favored during the early production history of the CHOPS well.

4.4 *Discussion of Stresses*

4.4.1 Stresses in the Wellbore Region

At the scale of the CHOPS wellbore, compact growth, yield and dilation of the sand matrix, and the existence of a liquefied zone all affect the stress distributions. These stress distributions are roughly similar to those found around a cavity in a rock, but are somewhat different, reflecting the weakening and dilation of the sand (Figure 4.10). Four "zones" with diffuse boundaries may be postulated.

In the **liquefied zone** (slurry zone), effective stresses (σ'_v, σ'_h) are zero, therefore the total stress is equal to the fluid pressure and is isotropic. The porosity in this zone must be greater than ~50%, which is necessary for the existence of a liquefied state. The lack of a static sand matrix with grains in contact means the permeability is extremely high, and the compressibility is dictated by the slurry composition (the aggregate compressibility of the oil, sand, water and gas bubble phases).

In the fully-remolded **plastic flow zone**, which is not yet liquefied, the ratio of effective stresses after shearing and dilation is limited by the residual friction angle for sands (≈30º at ~40-45% porosity), therefore $\sigma'_1/\sigma'_3 \approx 3.0$. The major principal stress (σ'_1, = σ_1 - p) is most likely to be σ'_v because of the downward force from the overburden, and undoubtedly $\sigma'_3 = \sigma'_r$ because of the lateral unloading that occurs with sand production. The porosity in the plastic flow zone changes from ~35% at the yielding zone boundary to ~50% at the liquefaction front, and this is likely to be a relatively smooth transition with radius, so that porosity does not evidence any sudden jumps. The absolute permeability will increase by up to an order of magnitude across the plastic flow zone, and the rock stiffness (matrix compressibility) gradually disappears altogether as the porosity approaches 50%.

Farther from the wellbore, in the region where there are high shear stresses, the formation experiences shear; it therefore loses strength and cohesion. This is the **yielding zone**. It carries a higher σ'_v, and the σ'_r is low because of continuous sand removal. Intact dense UCSS (ϕ ~ 30%) can withstand a σ'_1/σ'_3 ratio as high as 5-6 before yield, but after failure has occurred, the sand continues to yield and weaken, and gradually $\sigma'_1/\sigma'_3]_{max} \rightarrow$ ~3 as the porosity increases to >35%. The porosity in the yielding zone increases to ~35% during shear and dilation, before the fabric is totally disrupted by plastic flow. It is unlikely that there is much grain crushing because the individual sandstone grains are strong, and the confining stress is being reduced rather than increased. Permeability may double across the yielding zone, and it is believed that bubble nucleation begins at the 35% porosity region, triggered by the pressure drop and by the fabric dilation, which cannot easily be accommodated by more remote oil inflow because of the high oil viscosity. Probably the free volume generated by dilation is occupied by exsolved gas because of the impedance to flow.

In the **intact zone**, the porosity is still ~30%, and the sand has not yet experienced shear distortion, cohesion loss, dilation and shear yield, although the stresses have changed. This zone may be under a higher shear stress than in the virgin state because the vertical stress has gone up (to carry part of the overburden load) and the lateral stress is lowered because of the sand withdrawal, but it possesses all of the properties of intact virgin rock. It is believed that the pore pressures remain largely unaffected in the yielding and intact zones because of high oil viscosity (immobility) and absence of volume change. Indeed, in-fill wells drilled into intact portions of CHOPS reservoirs often encounter virgin reservoir pore pressures, even though the fracture gradient, i.e. the lateral stress σ_h, has diminished.

The stress distributions for such a model may be calculated from a combination of non-linear elastic theory in the intact zone, and plasticity or damage theory in the weakening and plastic flow zones. Specific stress predictions depend strongly on the choice of an appropriate constitutive law over a wide range of stress and yield conditions, and because the process is three-dimensional, at least for the early stages when the affected zone is small compared to the formation height, such a constitutive law must account for the material behavior in a fully three-dimensional stress field. This is not a simple issue.

The width of the zones is not known, therefore the dimensions are speculative, although the general concept appears to be sound. The writer believes that, as long as sand can be withdrawn from the well, the gravitational loading from the overburden continues to generate shear and dilation to the point where the interwell regions also weaken and dilate. However, there is also the effect of reservoir thickness: in a thin reservoir, a closer well spacing is required to have the interwell region affected by the shear and dilation.

4.4.2 Reservoir-Scale Stress Changes

Either compact or channel growth will lead to the development of a region of softer material that has yielded, and therefore is more compliant and can carry less of the overburden stress. The total overburden load must, however, still be supported in order to maintain overall stress equilibrium, therefore the inter-well σ_v value rises (Figure 4.16). At the same time, the lateral stresses (σ_h) within the reservoir drop everywhere because of continuous sand removal. The reservoir is thin (3-15 metres) compared to its length (hundreds or thousands of metres), so stress equilibrium is maintained by redistributing σ_h stresses into overlying and underlying strata (Figure 4.17), just as the vertical stresses are redistributed to the flanks of the "cavity". This behavior follows the principal that stresses cannot be destroyed, only redistributed to other parts of the structure, just as in a building: if one column gives way, the other columns must carry additional load.

Hence, one major macroscopic effect of sanding is the general lowering of σ_h in the reservoir. Attempts to inject fluids into wells that have produced large amounts of sand show that the fracture gradient has dropped from initial values of 17-22 kPa/m to as low as 7-9 kPa/m, approximately ⅓ of the vertical stress. Note that the stress limit in the plastic zone surrounding the well is undoubtedly about $\sigma'_v/\sigma'_h \approx 3.0$, and the pore pressure is also low; this suggests that the lower limit of σ'_h is controlled by frictional plastic flow (the ratio of 3 comes from soil mechanics consideration).

CHOPS wells that have produced > 100-200 m^3 of sand cannot be maintained full of injection liquid; continued injection will lead to undiluted fluid breakthrough in near-by producing wells, indicating either open channels or the generation of wide induced hydraulic fractures. Carefully monitored field tests suggest the flow mechanism is fracturing, as the formation acceptance of fluid ceases rather suddenly, implying fracture closure when $p_{inj} = \sigma_{hmin}$. In channel flow, a gradual decline in pressure would be expected (Figure 4.18). In a massively perturbed stress field with low σ_h, fractures will propagate from the initiation point toward other zones of lowest σ_h; this leads to rapid inter-well communication during injection. Communication, however, does not take place with adjacent wells that have not produced sand. This behavior is an alternative explanation to the "wormhole" hypothesis,[xxv,xxvi] which although widely believed, remains conjectural. (All phenomena explained in terms of "wormholes" can be explained in terms of stress and dilation, but the converse is not true: “wormholes” do not explain all the phenomena observed.)

A low fracture gradient also creates difficulties in workovers, as fluids cannot be returned to the surface in the annulus. Therefore, pump-to-surface methods have to be employed or foam workovers used to generate surface returns.

Note that horizontal stress concentrations above and below the zone lead to excellent fracture containment if fluids are to be injected at a later date, and this may be important in considering other recovery technologies. Nevertheless, as in all thermal injection projects, large-scale injection of hot fluids will eventually result in both repressurization and restressing, so that fracture gradients can eventually return and even exceed original values.

4.4.3 Stresses Around a Channel

A small channel in a UCSS has a stress distribution around it that is governed by a combination of frictional yield and non-linear elastic response (the modulus of sand is also a function of the effective stress, $E = f(\sigma')$). Figure 4.19 shows how the effective stresses around a channel in an UCSS must be distributed. Right at the wall, both the radial and tangential effective stress must be small if there is no cohesion (cohesion has likely been destroyed by straining at this stage). A small amount of arching may act, and there may be capillary effects because of fractional water saturation giving an apparent cohesion, but of a few kPa at most. The stress reduction due to the cavity must be balanced by redistribution farther from the opening where the confining stress effect allows the sandstone fabric to withstand larger shear stresses. This stress distribution is similar to that around the large zone (Figures 4.10, 4.16, 4.17), except at a smaller scale.

One effect of the presence of a channel is a general softening (partial loss of structural rigidity) of a large volume around the channel, and this may also be a zone of dilation and enhanced permeability. In a reservoir, the presence of many channels must therefore have an overall softening effect (the “Swiss Cheese” effect), leading to large-scale stress redistributions between intact reservoir zones and zones that contain channels which, at the large scale, look quite similar to the compact growth model.

Figure. 4.1: Tangential and Radial Stresses Around a “Cavity”, Leading to Shearing and Dilation, Causing Peripheral Permeability Increases

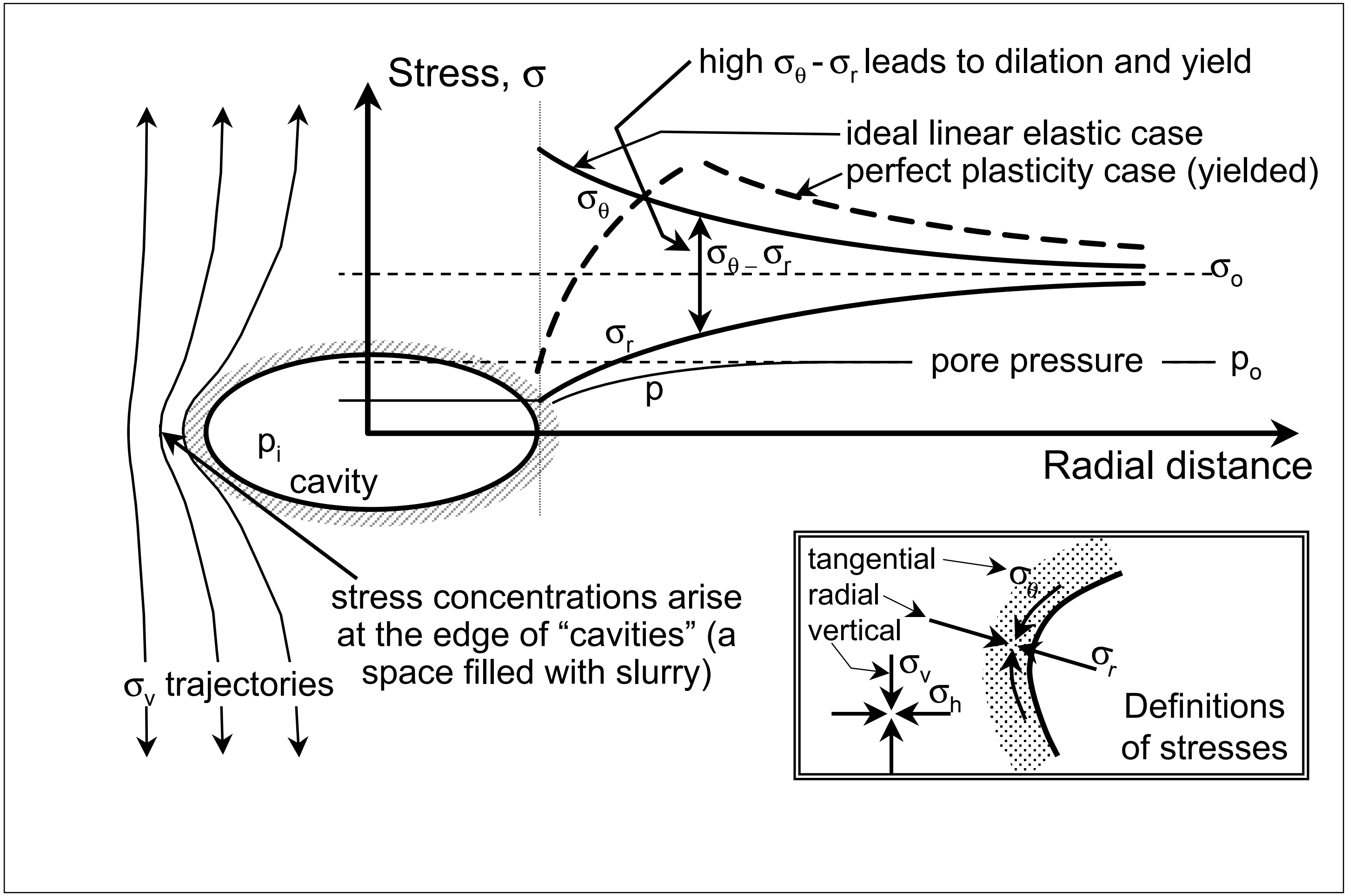


Figure 4.2: Low Seismic Velocities Around CHOP Wells

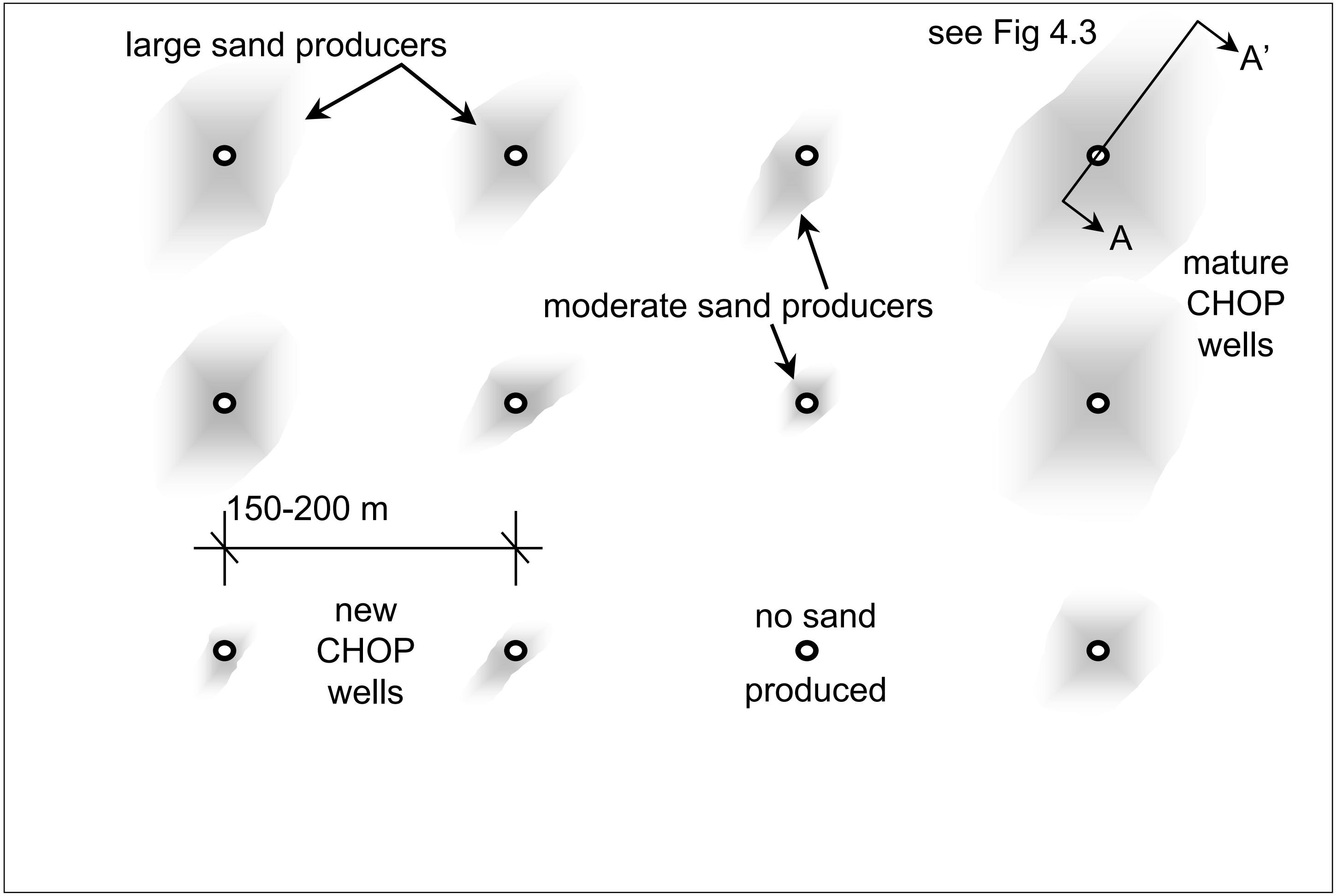


Figure 4.3: “Zones” Around a CHOPS Well After Some Sand Production

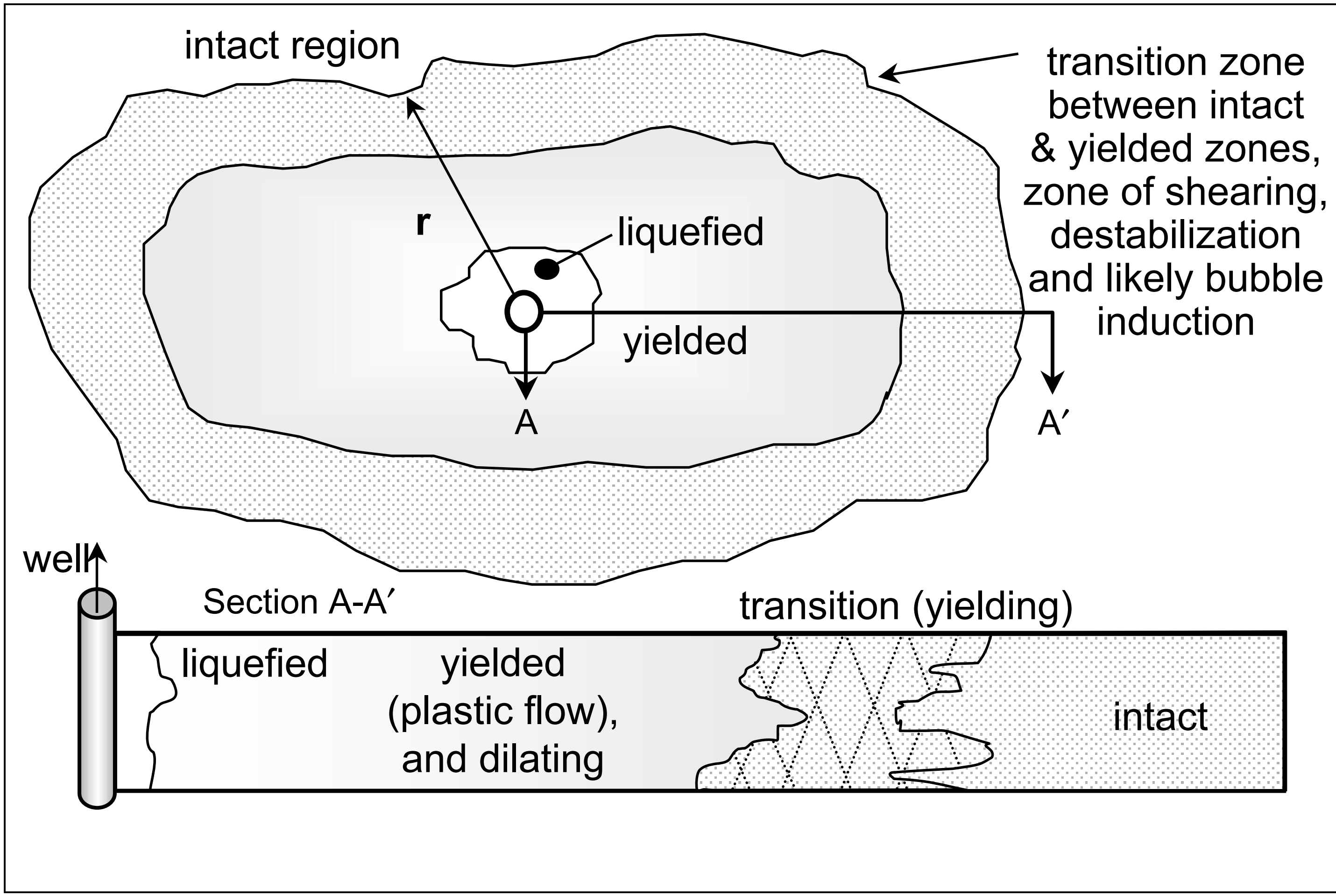


Figure 4.4: Geophysical Log Response in a CHOPS Well

- Before CHOP $\phi \sim 30\%$
- After, we see a number of formation changes:
- Top cavity or gas zone
- Shaley streaks are gone
- Thin cemented beds too
- Yielded zone $\phi \sim 40\%$
- Lower zones less so
- Channels or yielding?
- Logs only give a very near the wellbore sensing capability
- Other properties also changed

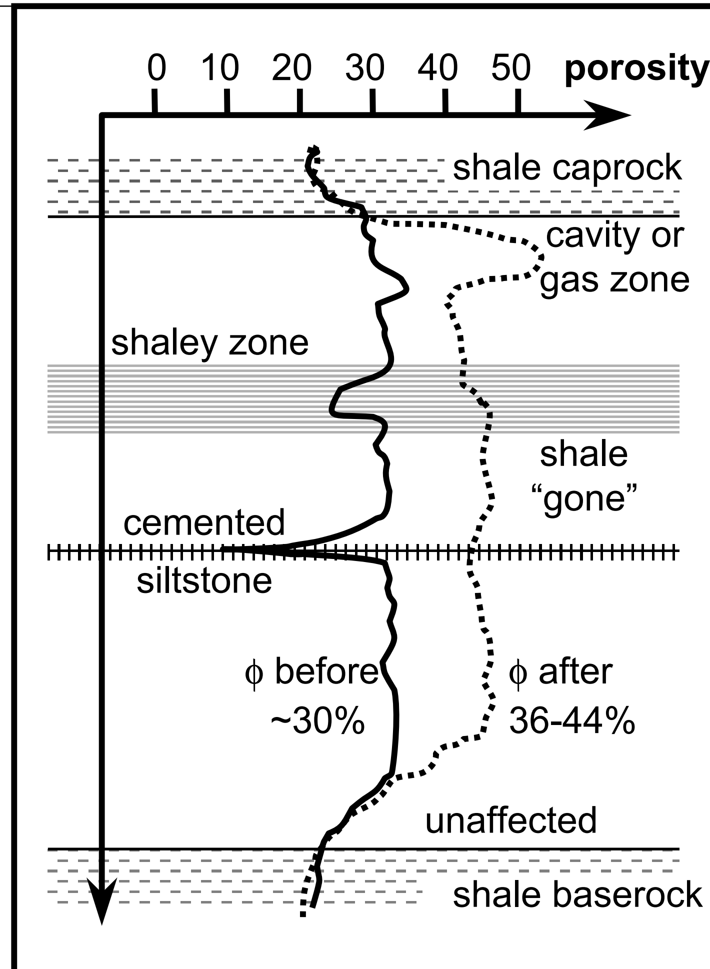


Figure 4.5: Dilution of Sand During Slurry Transit Along a Channel

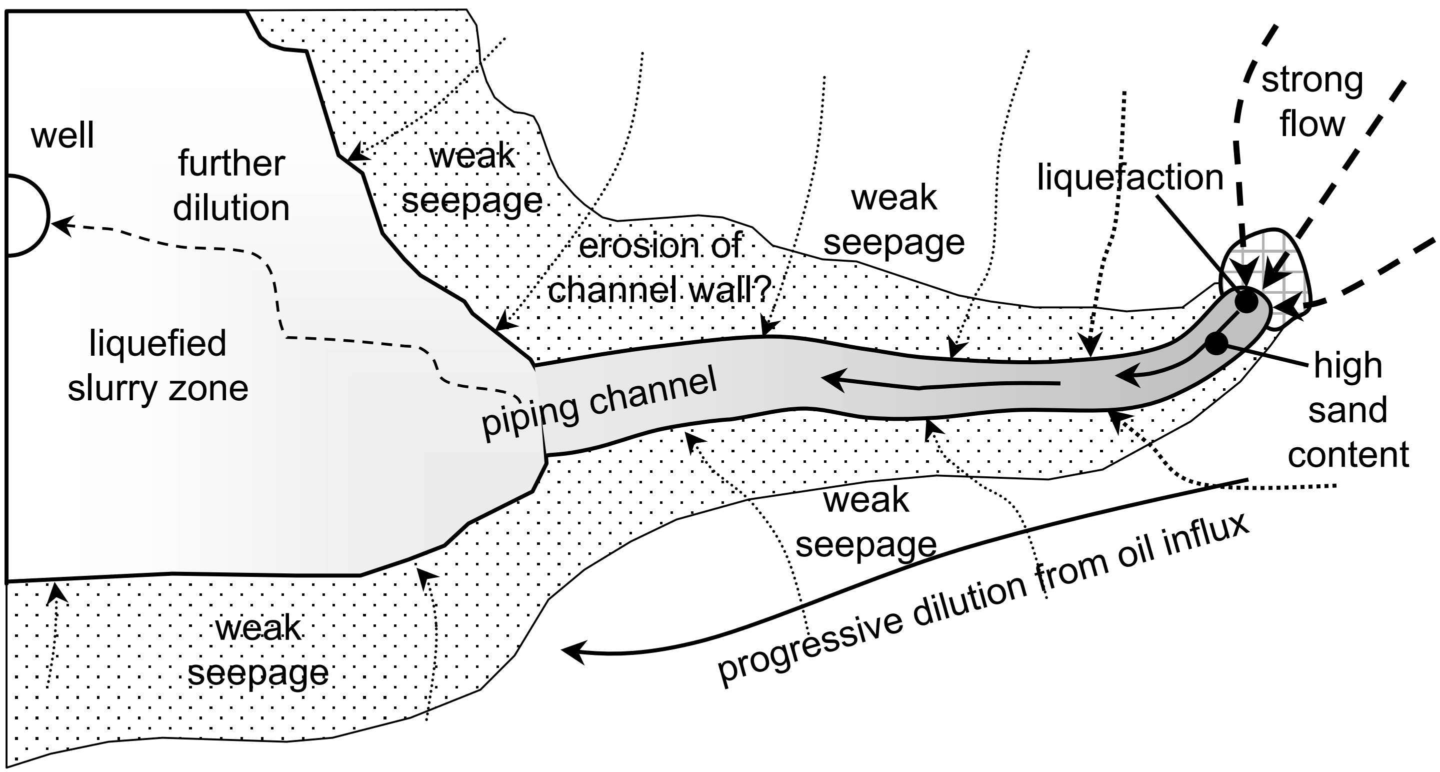


Figure 4.6: Enhanced Permeability around a Wellbore (r_w) that has Produced Sand

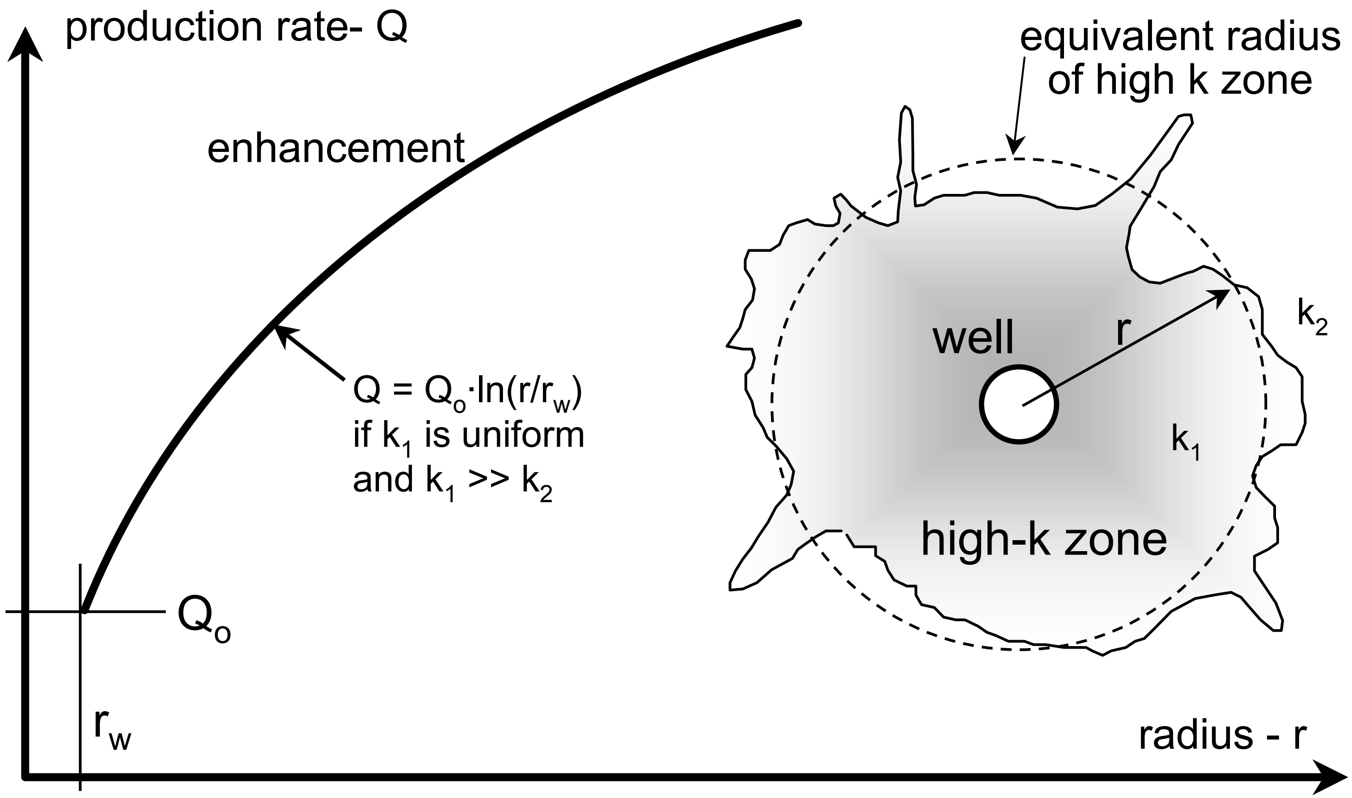


Figure 4.7: Evolving Gas Bubbles Block Pore Throats, Developing a Higher Pressure Gradient and Helping Destabilize the Sand

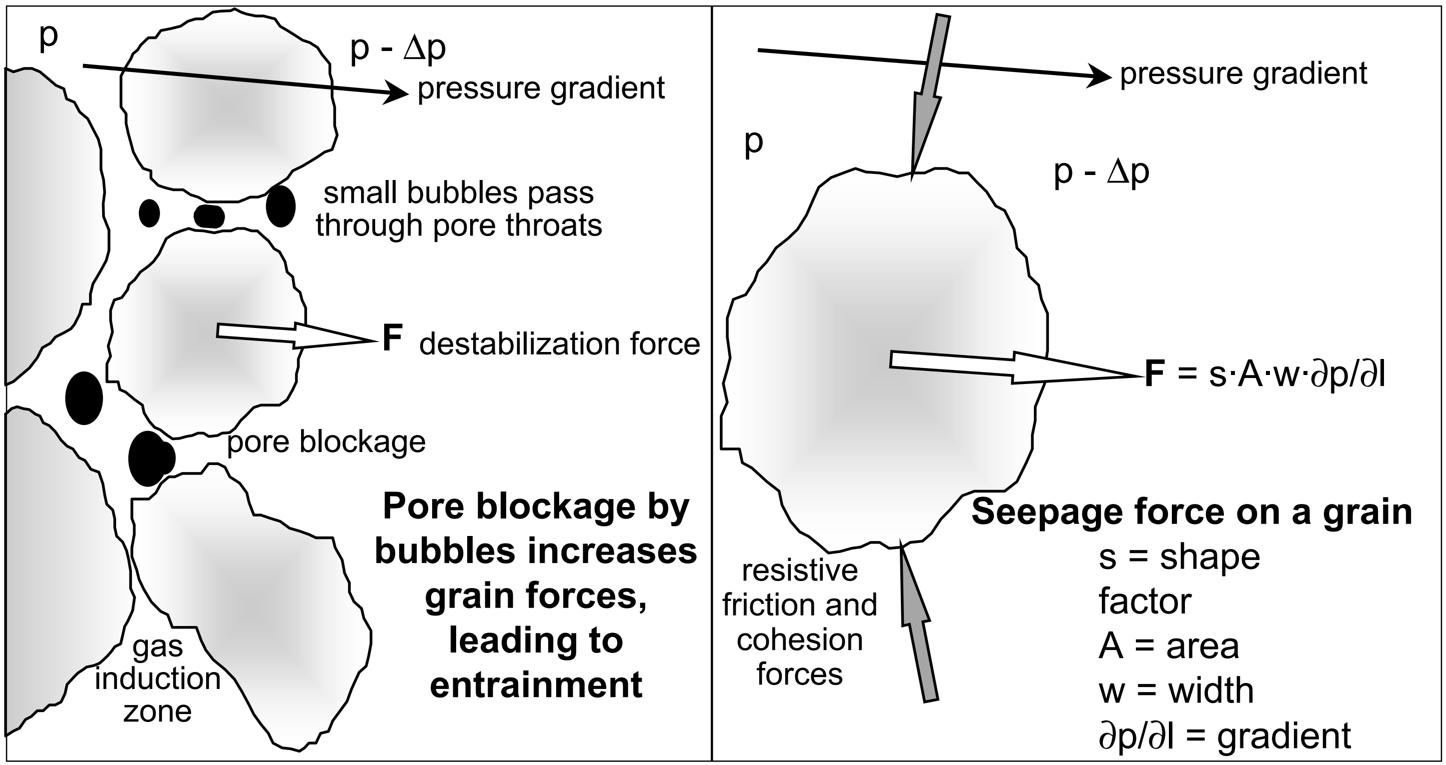


Figure 4.8: Pressure Distribution Around a CHOPS Well with a Foamy Oil Zone

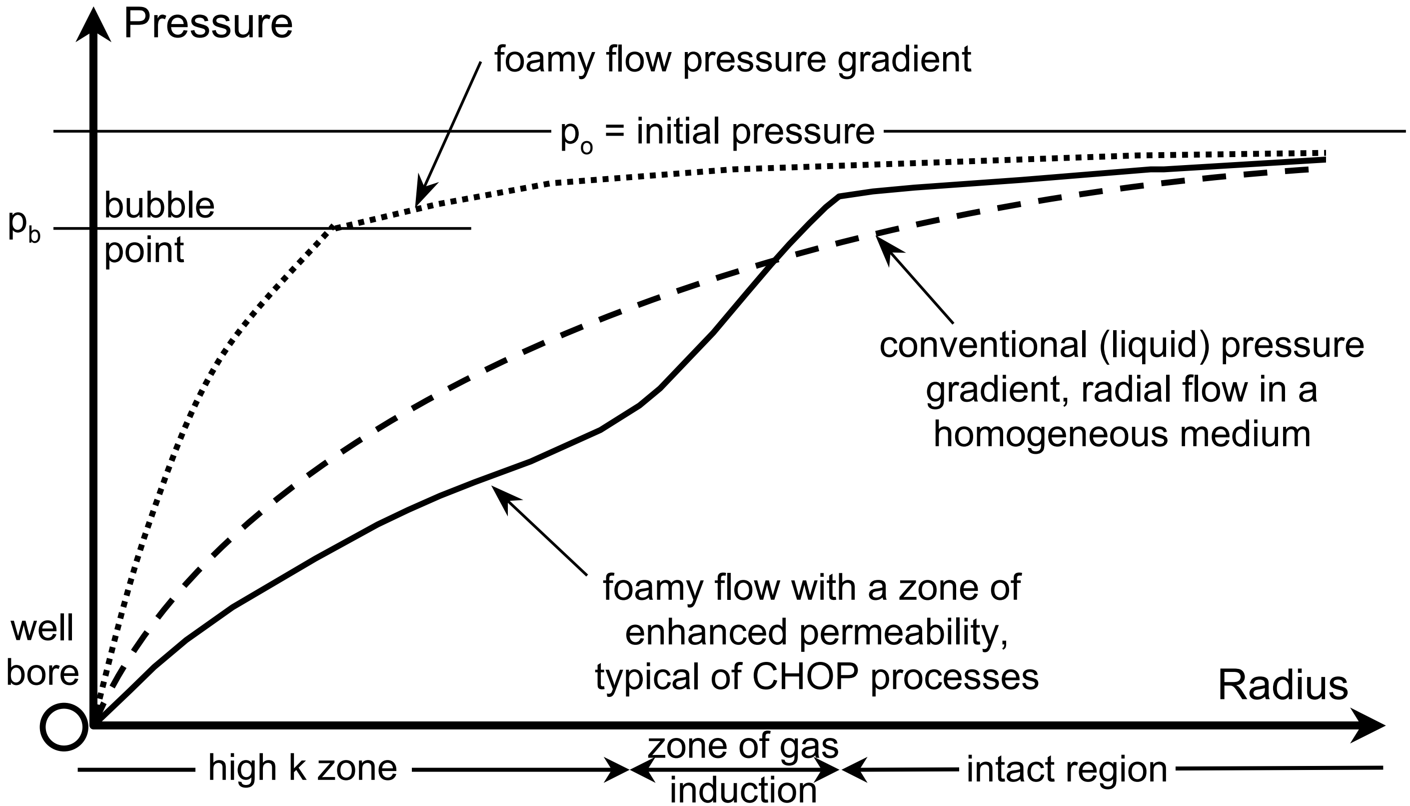


Figure 4.9: Complexity of Processes Around a CHOP Well

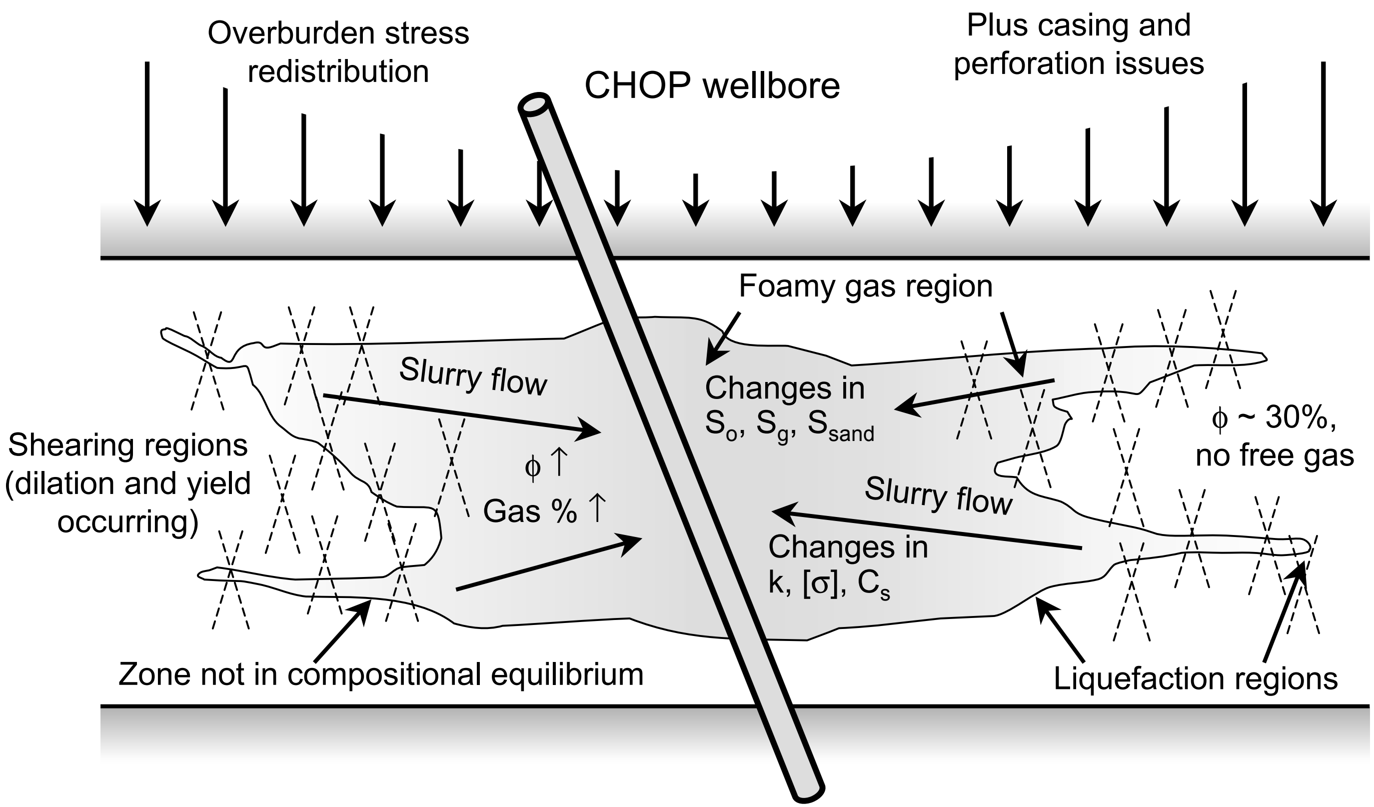


Figure 4.10: Distribution of Stresses Around a Compact Growth Zone

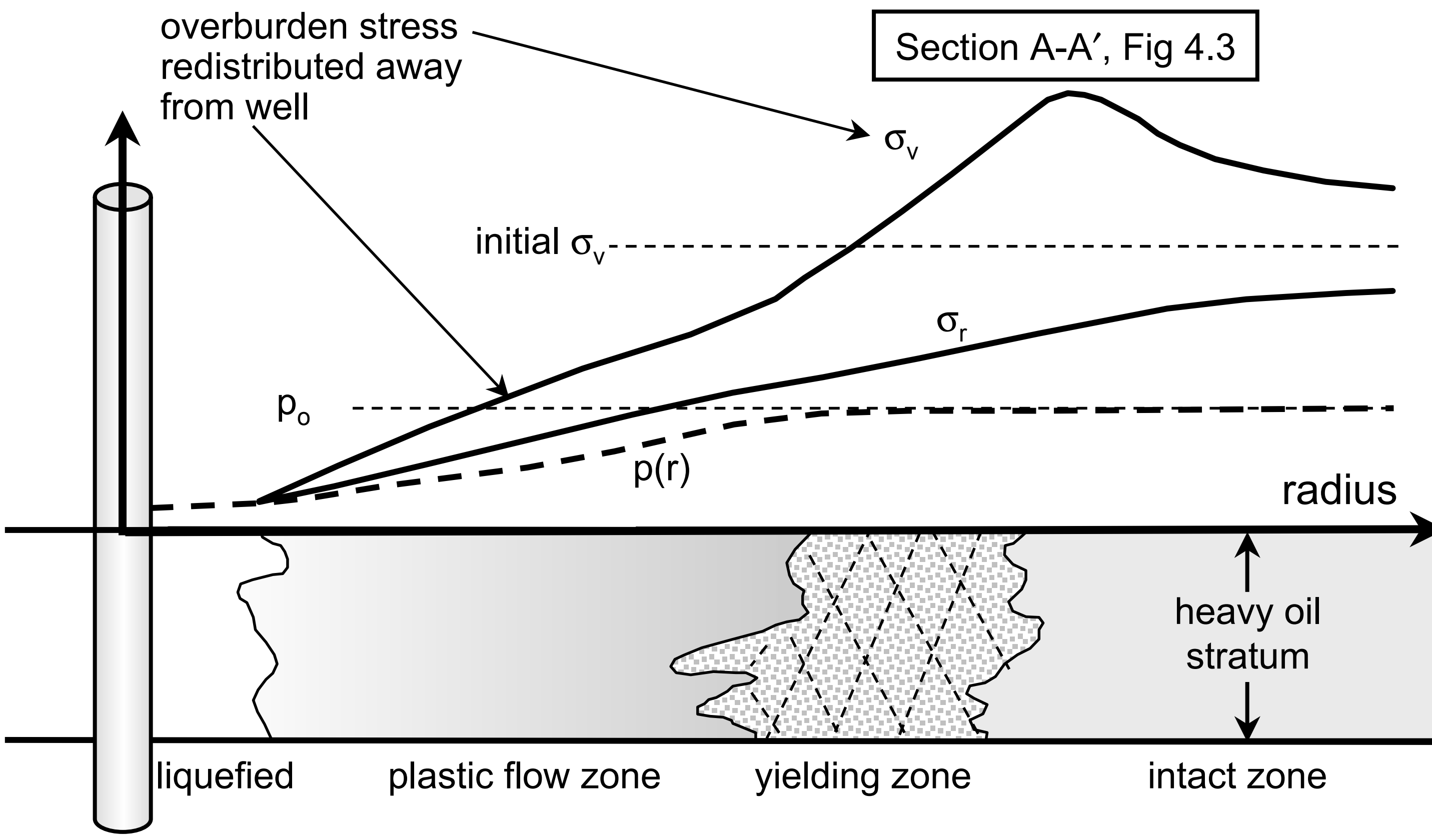


Figure 4.11: Zone Homogenization Through Local Stress Concentrations

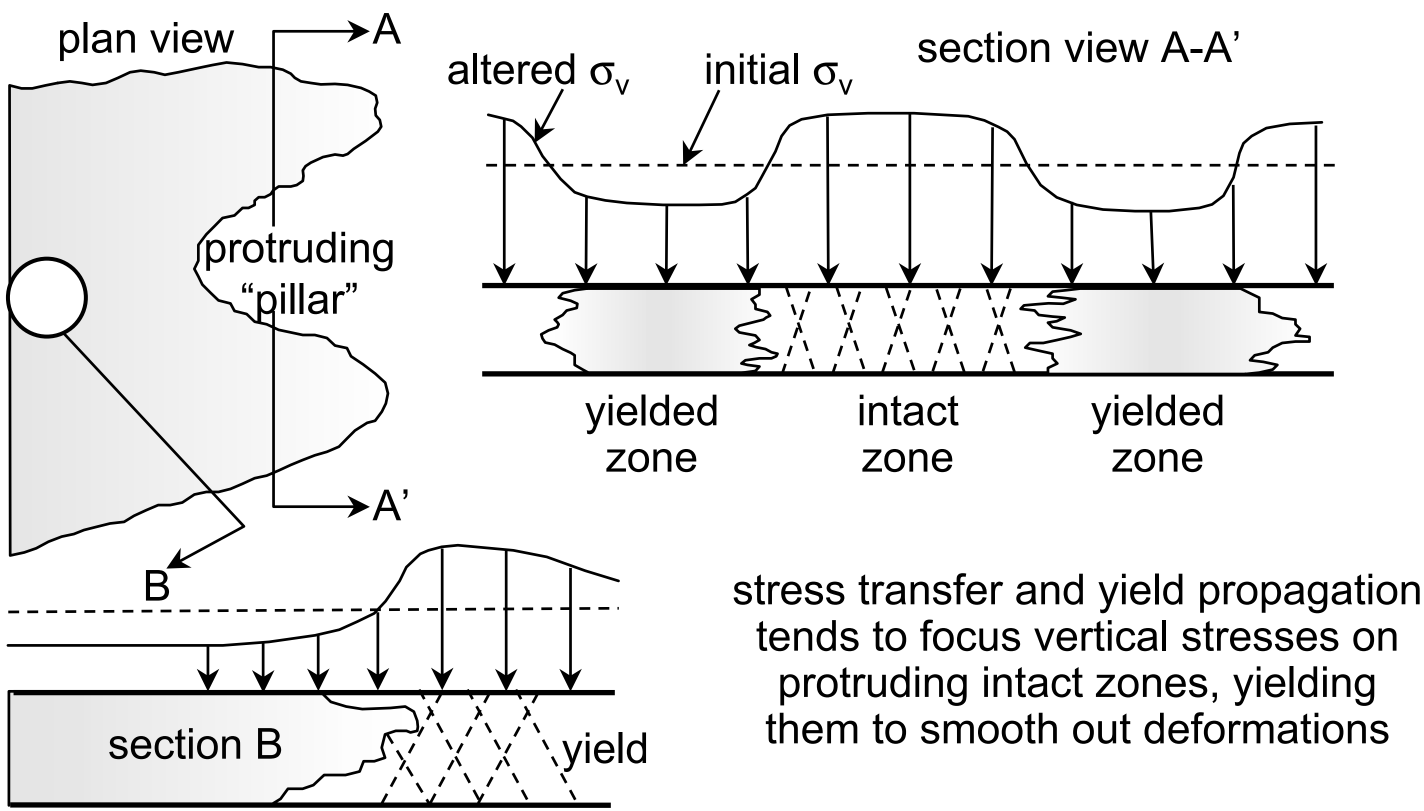


Figure 4.12: Channel Model Limits: Dendritic Pattern and N = Constant Pattern

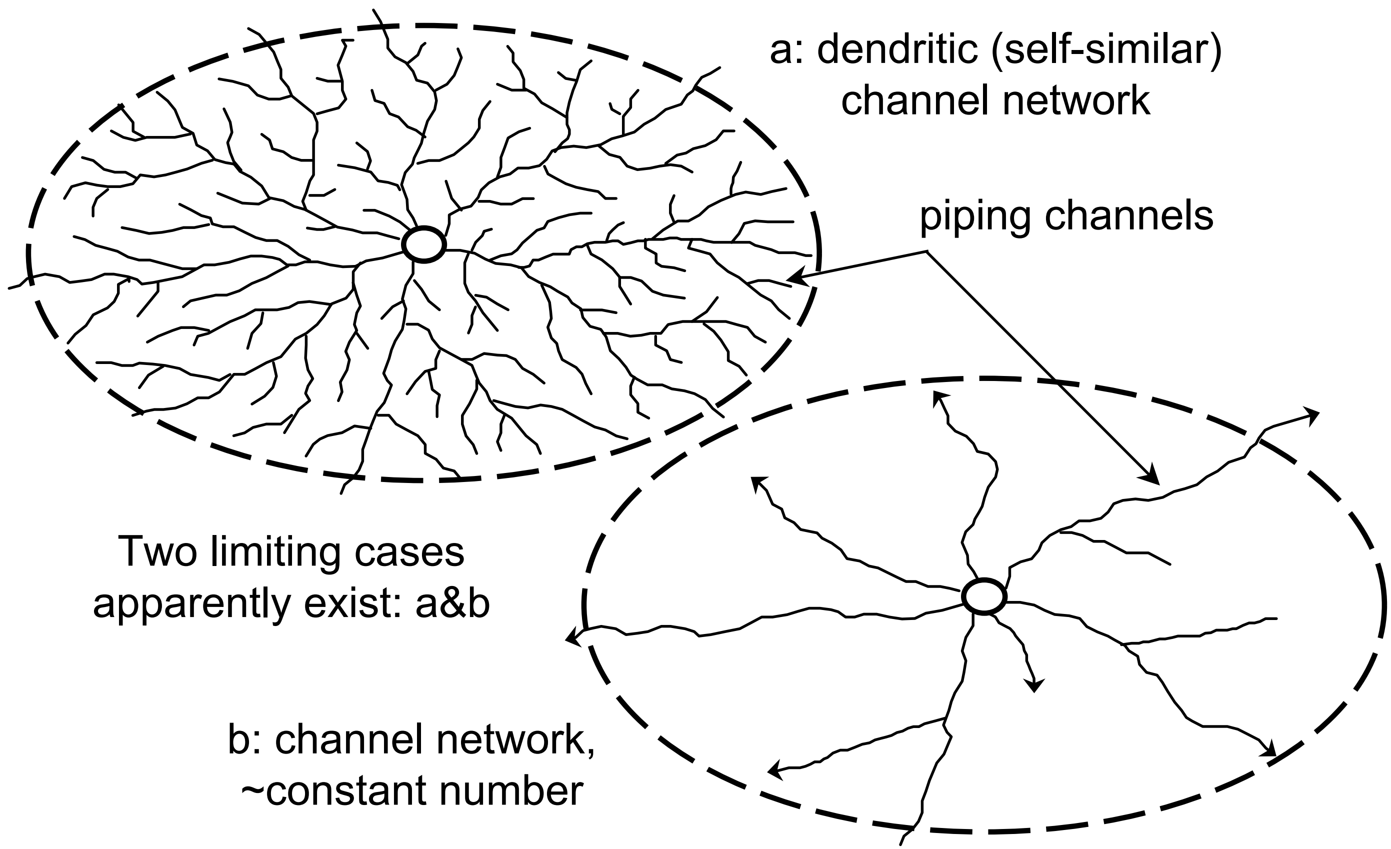


Figure 4.13: Equivalent Permeability in Different Models

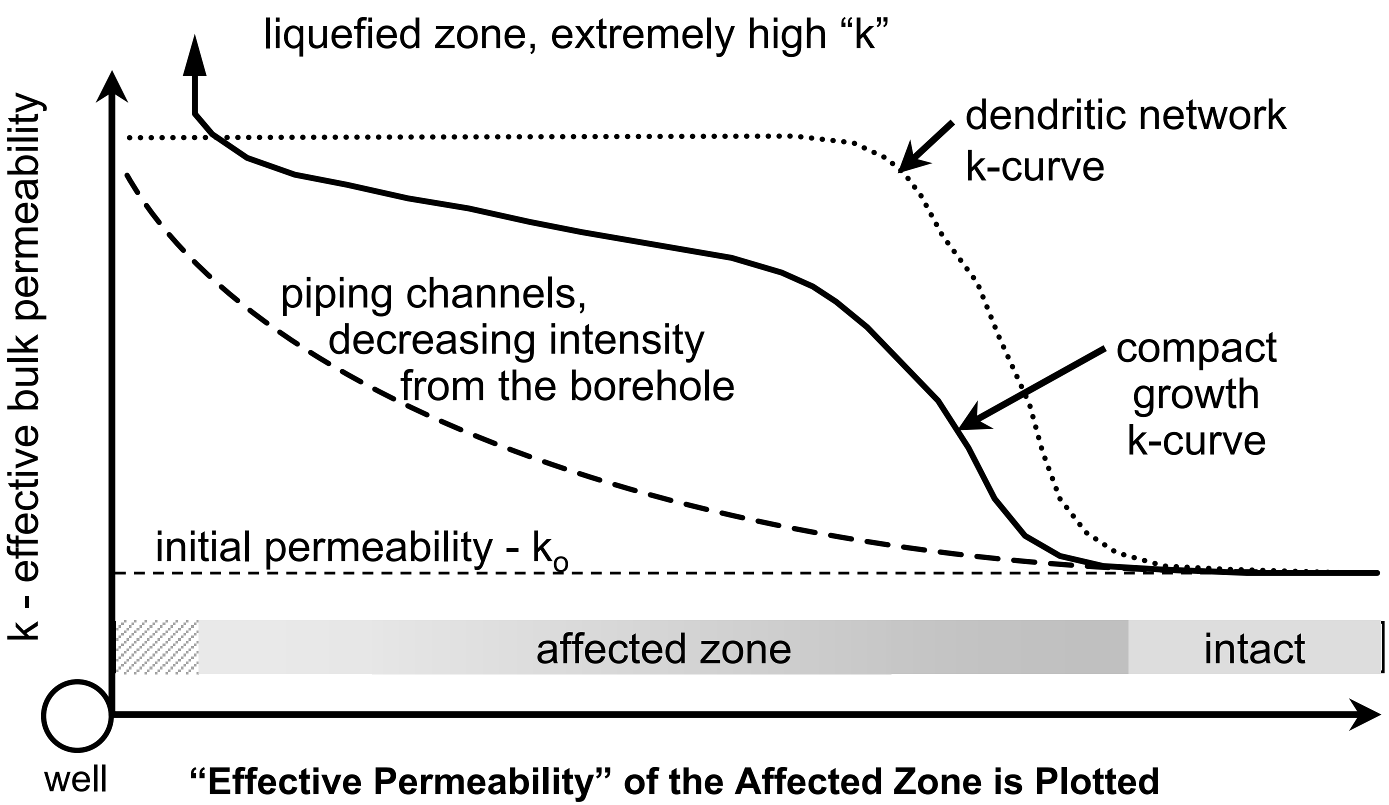
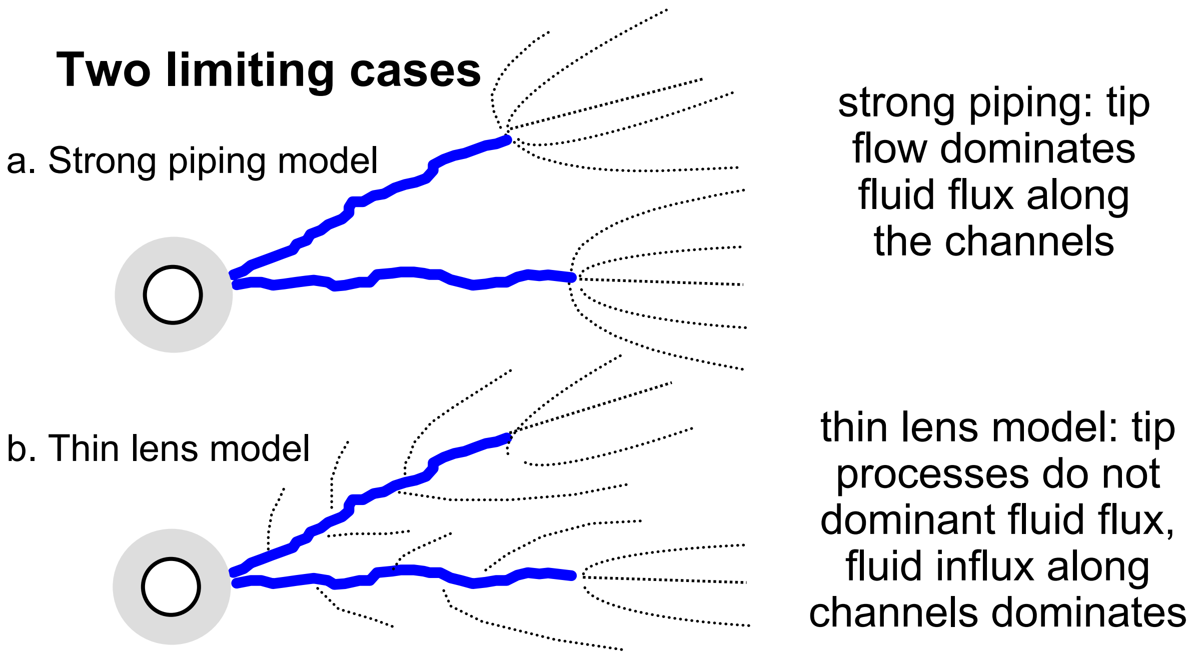


Figure 4.14: Two Limiting Flow Regimes for Channel Drainage



Thin Lenses or Strong Piping Channels Change Reservoir Drainage

Figure 4:15: Focusing of Flow Lines Near a Perturbation in a Smooth Interface

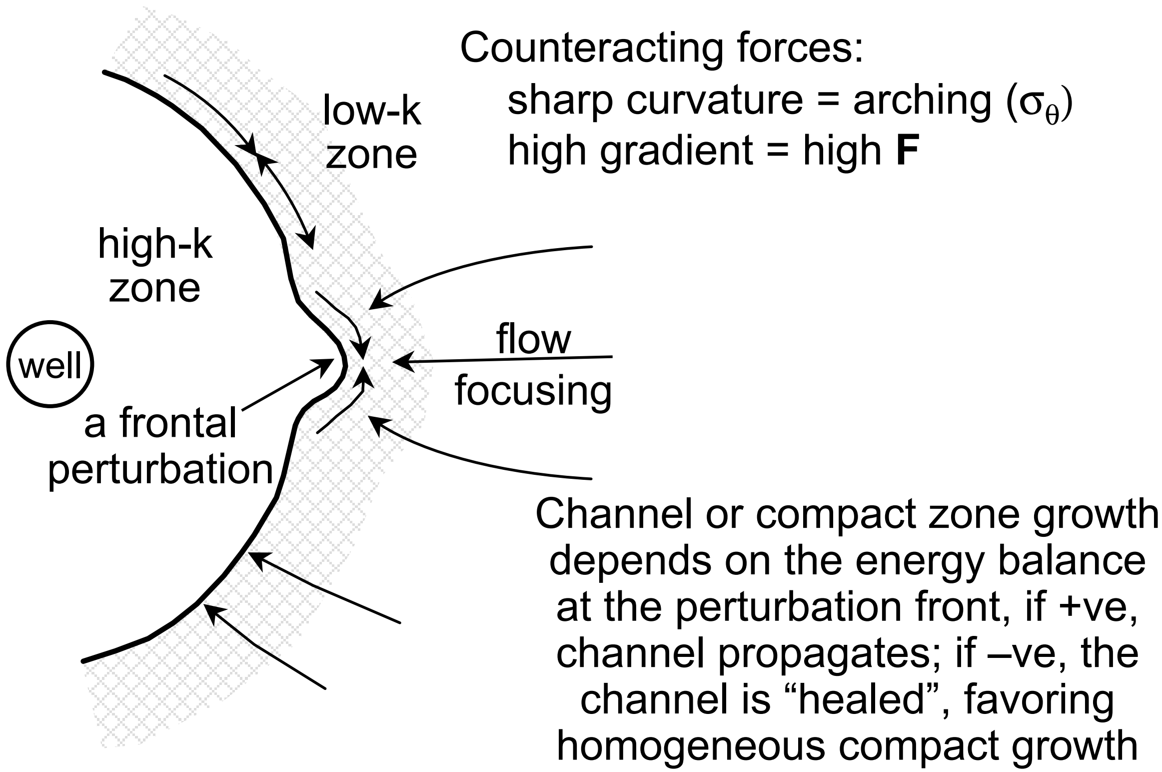


Figure 4.16: Vertical Stress Trajectories at the Interwell Scale

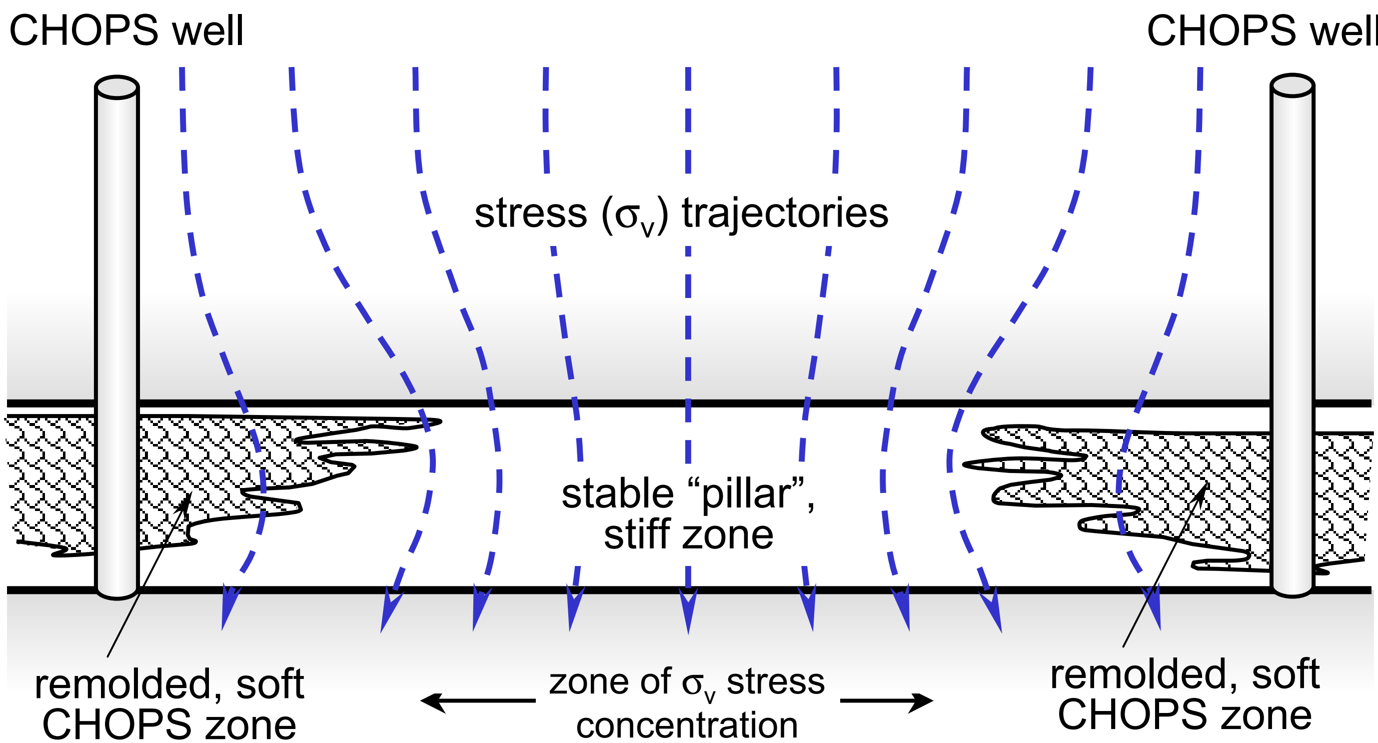
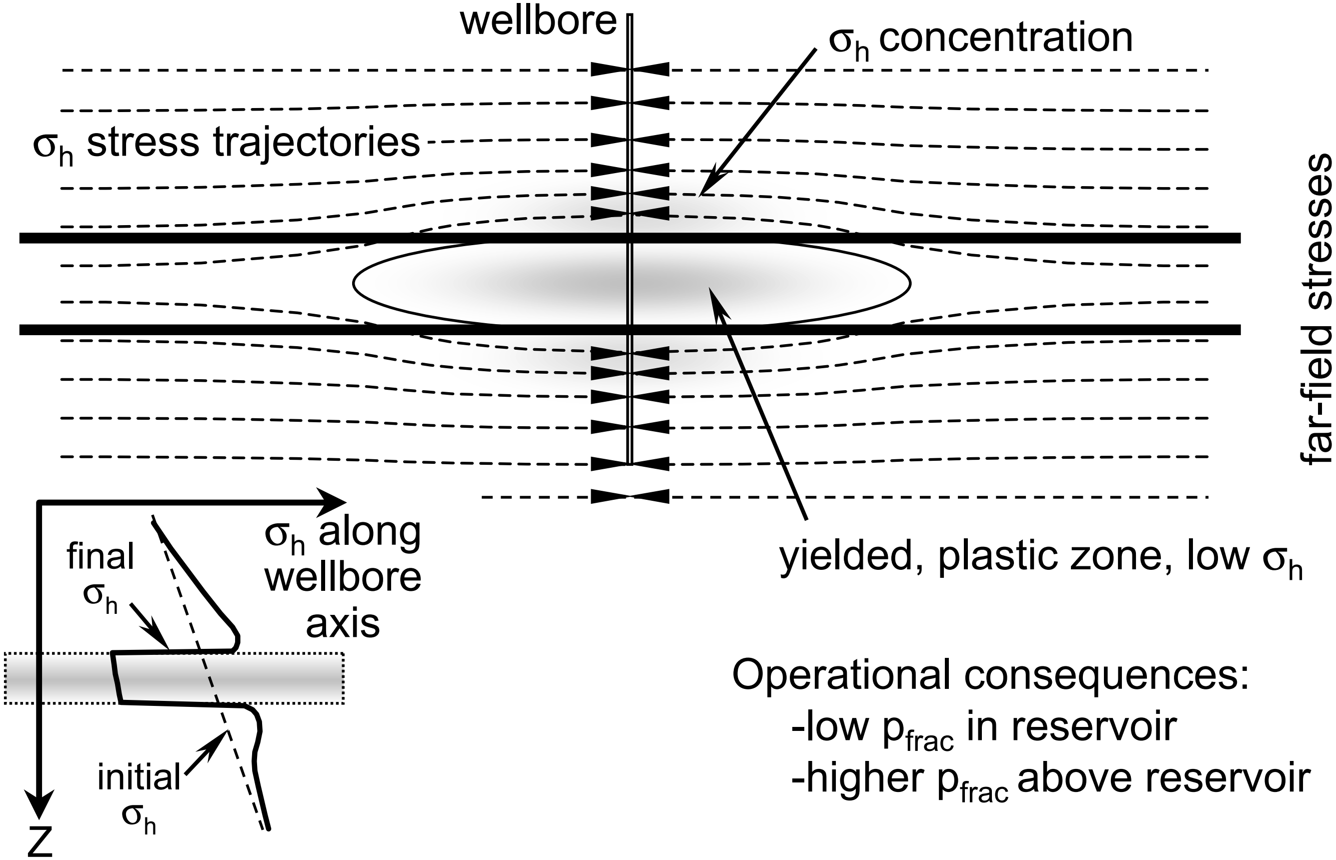


Figure 4.17: Horizontal Stress Trajectories at the Reservoir Scale



Operational consequences:

- -low p_{frac} in reservoir
- -higher p_{frac} above reservoir

Figure 4.18: A Falling Head Flow Test Indicates Fracturing at Low Stresses Around a CHOPS Well, Rather than Channel Flow or Darcy Flow

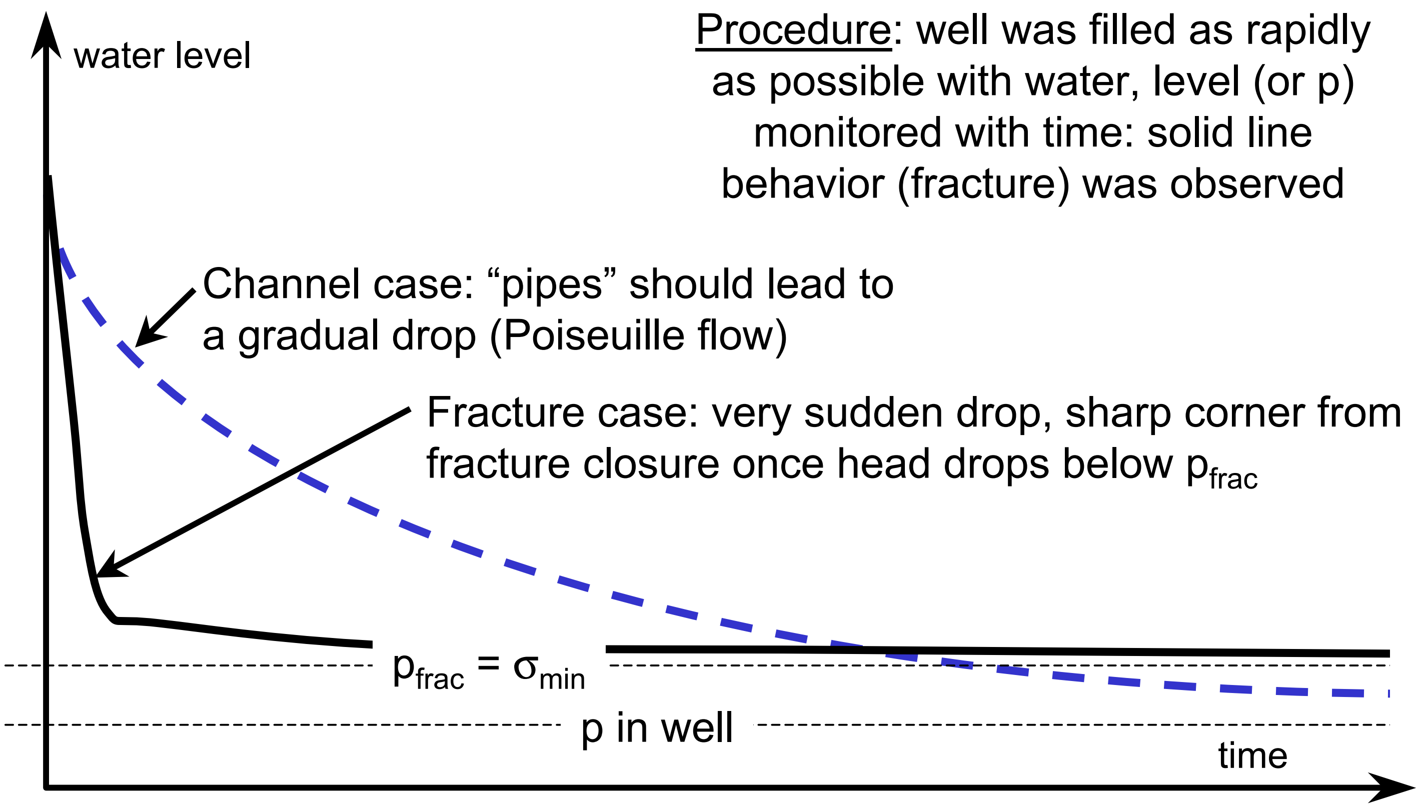
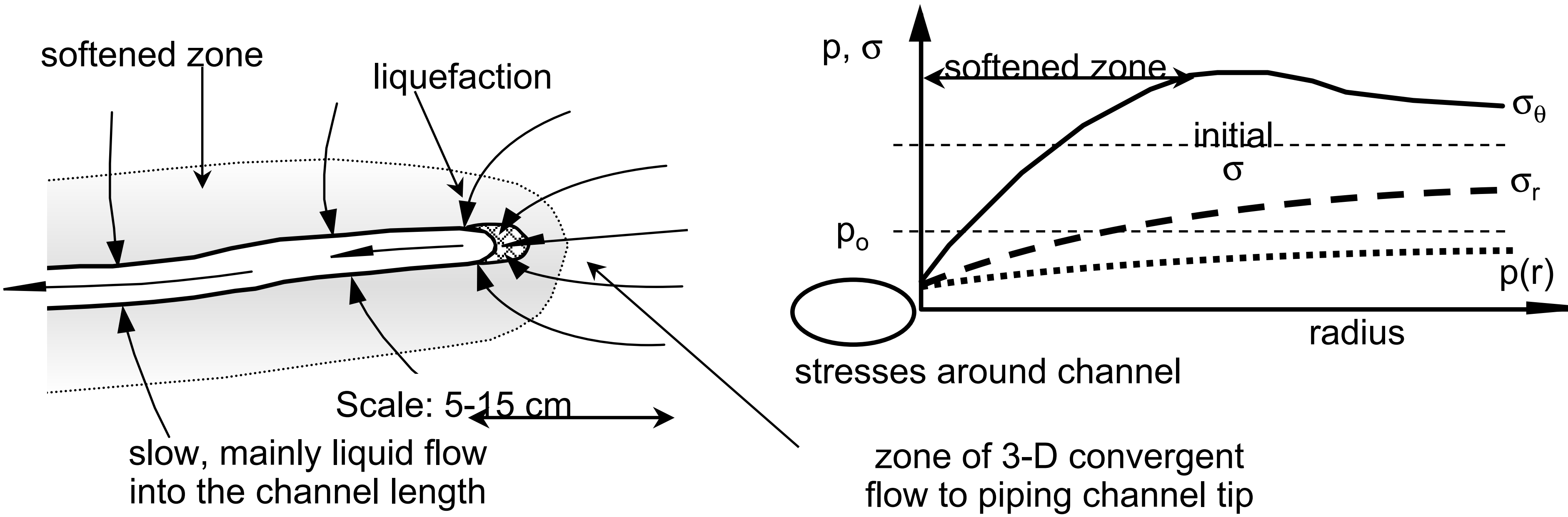


Figure 4.19: Stresses at the Small Scale Around a Hypothesized Channel



Non-Linear Behavior and Yield in Sand Around a Single Channel