Production Well Water Coning – Is There Anything That We Can Do?

F.B. Thomas*, E. Shtepani, G. Marosi, D.B. Bennion
Hycal Energy Research Laboratories Ltd.

Abstract

The problem of water coning has plagued the petroleum industry for decades. Both gas and oil wells are assailed by this phenomenon which, in almost every case, results in eventual shut in of the well and substantial loss in revenue. The problem occurs in every quadrant of the globe and engineers view its resolution as a technical "holy grail".

This paper discusses the problem of water coning and offers a potential solution for serious water-coning reservoirs. The use of a coning simulation model, incorporating chemical treatment options, is also discussed wherein the optimal treatment volume is computed. An analysis of the axial and radial velocity gradients appears to hold promise as a means by which the size of a water shut-off treatment can be estimated. The time of water shut-off treatment in the life of producing well is investigated indicating that early application of water shut-off is better than after the cone is fully developed. A review of chemical solutions is included and some of the laboratory tests that can be conducted to analyze potential treatments.

This paper brings to the evaluation of water coning state of the art techniques which should help to separate fact from fiction concerning upside for water coning wells.

Background

Water production in oil and gas wells has been a problem for many years. Commonly, reservoirs have an aquifer beneath the zone of hydrocarbon. If the aquifer is large it may act as a constant-pressure lower boundary. In such cases, this bottom-water boundary condition constitutes an infinite aquifer. This results in excellent production support replacing all voidage induced by the production of the hydrocarbon. However significant the benefit of a strong water drive, if the water drive dominates and fills the near well-bore region with water (literally a cone of water in the region of the producer – thus the name of water coning) then hydorcarbon production suffers and in some cases the well may become uneconomic. Depending on the variables of the reservoir, in situ fluids, production protocol and completion interval, the well may exhibit more or less serious coning problems.

The Darcy equation is very useful in describing the phenomenon of water coning. Equations 1 and 2 define this simple relation for the case of oil and water flow.

Equations 1 and 2

Darcy stated that the velocity of the fluid is inversely proportional to the viscosity of the phase and proportional to the absolute permeability, the relative permeability and the pressure gradient of that phase. As the pressure gradient increases the more mobile fluid phase begins to dominate production. Typically, water is more mobile and therefore water production increases relative to the rate of production of oil. Dividing equation 2 by equation 1 shows the ratio of water velocity to oil velocity very clearly as equation 3, which is the common mobility ratio. This ratio expresses the tendency for water cut when viewed in the context of the fractional flow equation (equation 4). As M increases the tendency to flow water preferentially increases. With operators desiring more and more output from each well if M is large then water cut is going to be a problem.

Another reason for water production increasing quickly relative to oil production is due to the aspect ratio. Figure 1 presents the geometry of a standard production well. The aspect ratio is defined as the ratio of Radius to Thickness (H); the thinner the formation (H becoming smaller) the greater the aspect ratio. Since there is a common boundary condition at the well bore (constant pressure for example) the pressure gradients in the axial direction will be greater than the pressure gradient in the radial direction to the extent to which the thickness is less than the radial extent of the imposed pressure drop.

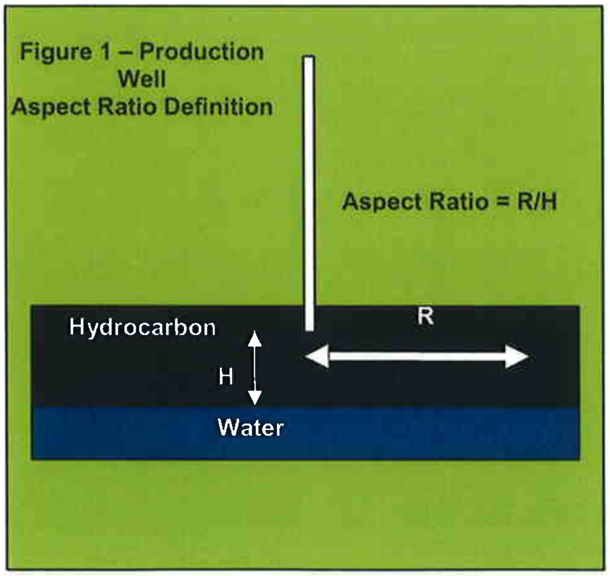


Figure 1 – Production Well Aspect Ratio Definition

Equations 5 and 6 express the simplified relationships between water saturation, water- and oil-phase pressures in the above physical system.

$$\frac{\partial S}{\partial \tau}=\left(\frac{H^2\alpha}{R^2\infty}\right)\frac{1}{R}\left(\frac{\partial}{\partial R}\left[Krw\,R\frac{\partial P}{\partial R}\right]\right)+\alpha\,\frac{Kv\partial}{Kh\partial Z}\left(Krw\frac{\partial P}{\partial Z}\right)$$

(5)

$$\frac{-\partial S}{\partial \tau}=\left(\frac{H^2\alpha\,\mu_W}{R^2\infty\,\mu_O}\right)\frac{1}{R}\frac{\partial}{\partial R}\left(Kro\,R\left[P_c^{\,1}\frac{\partial S}{\partial R}+\frac{\partial P}{\partial R}\right]\right)+$$
$$\frac{\mu_W Kv}{\mu_O Kh}\alpha\,\frac{\partial}{\partial Z}\left(Kro\left[P_c^{\,1}\frac{\partial S}{\partial Z}+\frac{\partial P}{\partial Z}\right]\right)$$

(6)

where $\frac{\partial P_O}{\partial R} = \frac{\partial P_C}{\partial R}+\frac{\partial P_W}{\partial R}$

$= \frac{dP_C}{dS}\frac{\partial S}{\partial R}+\frac{\partial P_W}{\partial R}$

and $P_c^{\,1} = \frac{dP_c}{dS}$

where the dimensionless groups are defined as:

$$R=\frac{r}{R\infty} \qquad Z=\frac{Z}{H} \qquad P_W=\frac{\overline{P}_W}{P_{RES}}$$

$$P_O=\frac{\overline{P}_O}{P_{RES}} \qquad S=\frac{S_W-S_{WIRR}}{\left(1-S_{OR}\right)-S_{WIRR}}\ \&\ \alpha=$$

$$1-S_{OR}-S_{WIRR}$$

$$\tau=\frac{K_H P_{RES}t}{\mu_W H^2} \qquad \underline{\underline{D}}\ \frac{t\,v^*}{H}$$

From equations 5 and 6 the radial terms are multiplied by the aspect ratio squared and therefore as the aspect ratio becomes smaller the role of the radial terms on the water saturation decrease quadratically; thus the axial pressure gradient driving the water influx increases quadratically.

Many authors have written on the topic of minimizing water coning. Smith and Pirson[1] proposed water coning control by injection of other fluids in the production well including reservoir fluid. This idea was also analyzed, in a subsequent paper by Pirson and Mehta[2]. They investigate, by means of a numerical model, the influence of three remedial measures: 1) injection of reservoir oil below the production interval concluding that 50% oil re-injection may reduce water oil ratio by a factor of 4 times - the economics of this technique can be enhanced by bottom-hole re-injection to economize pumping costs. 2) Selective water and oil production from their respective zones into a dual-completion string. 3) Placement of a "pancake" of impermeable material out to a defined radius thus restricting vertical flow. They recommend reservoir oil re-injection if the injection can occur without pumping the oil to surface first. Their conclusion about pancake placement is that "it does not provide an absolute remedy to the water –coning problem and can suppress a water cone only up to a certain time in the production history". Karp et al[3] studied the placement of impermeable barriers for water coning mitigation. Their proposal was to fracture a production well and then place cement containing propping agents. Their technique was intimately connected to the technology of horizontal fracturing. They indicated that reservoirs containing high viscosity crude oil, thin pay zone and low permeability may not be good candidates for this approach.

Since the 1960's, there has been little written on the specific subject of water-coning mitigation. Yet there have been vast improvements in the technology of water control. Some of these improvements will be discussed next.

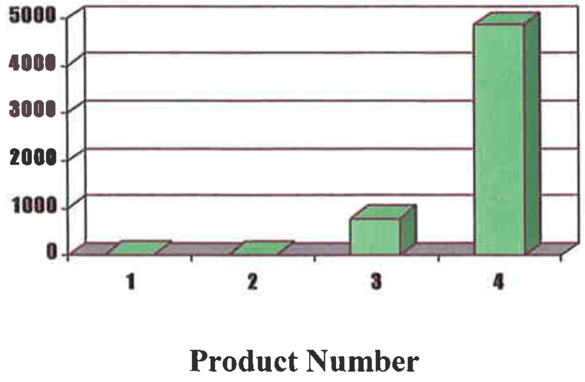
Water Shut-off Chemicals and Products

Due to the importance of water control in the petroleum industry much of ingenuity has been brought to bear on the development of products to reduce water production. Numerous polymers and gels[4-15] have been developed and used in water shut-off applications with mixed results. The authors have investigated a number of these chemicals and compared them for their relative merits on the basis of five characteristics:

1. Strength
2. Shrinkage
3. Viscosity at injection time
4. Set-up time characteristics
5. Rate of injection for treatment placement

The first parameter measured was the strength of the product. The different applications were prepared according to the instructions from the provider of the chemical. The treatment was then injected into a water-filled sand-stone core plug. All of the plugs used exhibited approximately the same permeability (100 mD). The treatment was isolated, after injected into the core sample, and the treatment was allowed to set up. Subsequently, a water pump was connected and the pump pressure was increased until water was observed from the production end of the core. The pressure at which water was observed passing through the core was classified as the treatments yield strength. Figure 2 suggests that some treatments (1 and 2) yielded at very low pressures (40 psi/ft). Treatment 3 yielded at 800 psi/ft and product 4 yielded at 4864 psi/ft.

Figure 2 – Strength of Various Products at Reservoir Temperature in Porous Media (Psi/ft versus Product Number)



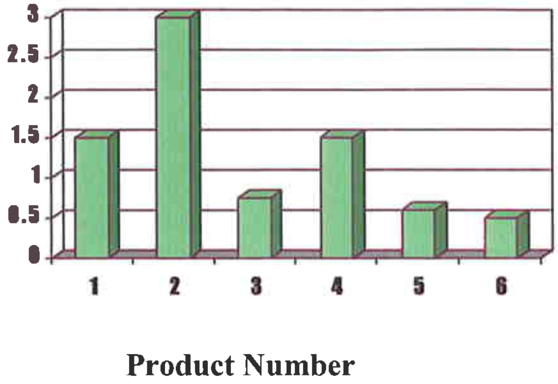
Pressure gradients in reservoirs, due to pumping can be in the tens of psi per foot magnitude. Products 1 through 3 could very likely break down and flow whereas product 4 would never yield to differential pressures found in the reservoir. Depending on the application, higher strength treatments may be necessary (for example - near-well bore blockage) whereas for other applications lower yield-strength treatments may be adequate (for example - profile modification far away from the well bore).

Shrinkage is another parameter that must be measured. If the treatment is placed and subsequently shrinks considerably then the water shut-off would be very short-lived. Figure 3 shows shrinkage of the treatment after solidification has occurred. The maximum shrinkage measured was about 3 % after six months. The other treatments exhibited shrinkage less than this value. Any shrinkage may result in some water starting to flow but if significant water reduction has been observed a second-stage treatment may be an easy decision to make since the size of the second-stage would only have to be on the order of the amount of shrinkage volume.

Another parameter of interest was the viscosity at injection time. Some products exhibit a close coupling between injection-time viscosity and the quality of the final product after set-up. This can impact selectivity of the treatment's placement.

Figure 3 – Shrinkage of Various Products after Set-up

(Percent shrinkage versus Product Number)



The range of viscosity at injection-time ranged from a low of 1.5 cP to a high of thousands of centipoises. Depending on characteristics of the reservoir, there may be advantages to using a low injection-time viscosity treatment or a high injection-time viscosity treatment. Typically, where high permeability contrast occurs, higher injection-time viscosity may help to create more of piston-like displacement and consequently better plug water conduits in situ.

Another parameter of interest is the set-up time character. In some cases the viscosity is a constant (for example, polymers which are not cross-linked). In other chemistries, where cross-linking occurs there is a right angle set-up signature. In these treatments the chemicals can be very invasive and once in place the theory indicates that they will set-up and effectively plug water flow conduits. Figure 4 presents a common set-up time profile for such treatments.

One of the more important parameters to consider is the rate at which the treatment is placed; indeed, it is really the differential pressure that drives the selectivity of the chemical treatment (which is intimately linked to flow rate). To measure the effect of rate on the selectivity of placement two core stacks were assembled in parallel. One possessed a permeability that was approximately ten times higher than the other. The two stacks were connected in parallel to a constant differential pressure pump and a water flood was conducted. There was production of oil exclusively from the higher permeability stack. The apparatus then had the characteristics common to many reservoirs that are producing excessive water: one zone that is at Sor and the other zone that has been by-passed and is at Soi. This is shown schematically in figure 5.

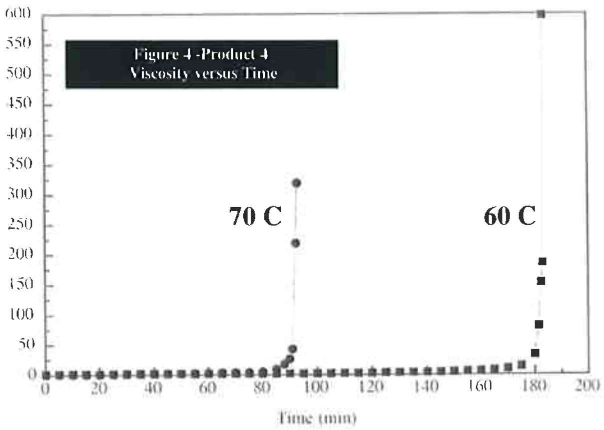


Figure 4 -Product 4
Viscosity versus Time

The object of a water shut-off treatment is to block water without reducing oil productivity. By so doing this should restore some oil saturation which will increase relative permeability to oil and increase oil production rates. With an aqueous-phase treatment, there is no interfacial tension (IFT) between the treatment and the water in situ. There is however a finite IFT between the treatment and the oil. Equation 7 expresses the common relationship of capillary pressure, where C_1 is a constant that includes contact angle. In order for two-phase flow to occur, the differential pressure must be greater that the capillary pressure in that porous feature.

$$P_{CAP} = C_1 \; \sigma / D \qquad (7)$$

Consequently, if the differential pressure applied is low enough, the treatment will only be able to invade the water-saturated zone. The authors have observed experiments where the IFT can create selectivity of flow tantamount to a valve, allowing invasion into one zone and none into another zone in parallel.

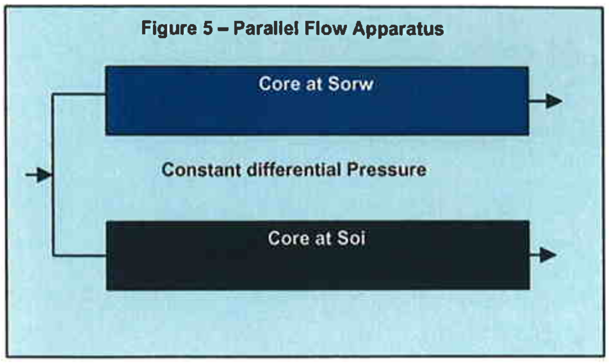
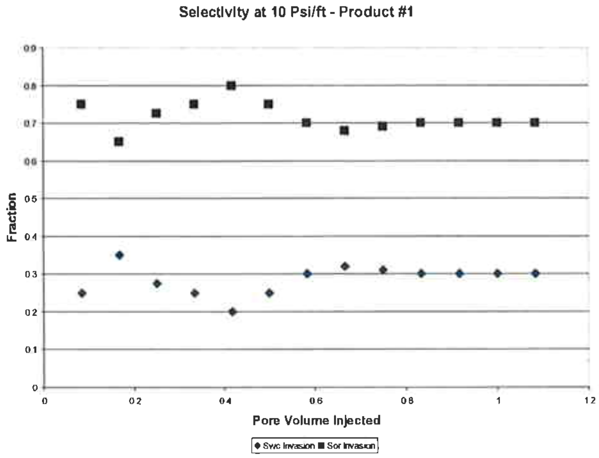


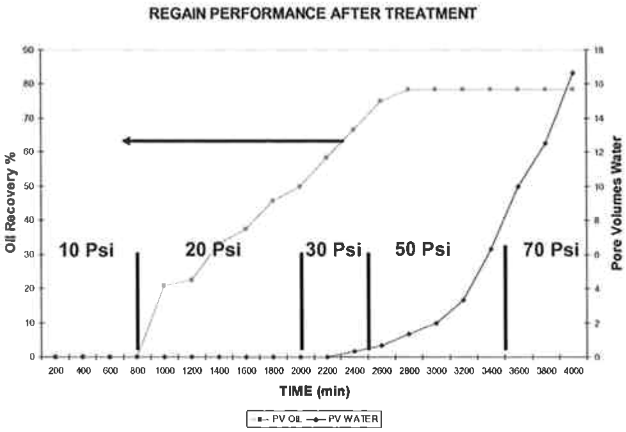
Figure 5 – Parallel Flow Apparatus

Figure 6 – Selectivity of Water Shut-off Treatment



At 10 psi/ft the aqueous-phase water shut-off treatment was approximately 70% selective for the water-filled stack. (This is due to each stack of porous media exhibiting multiple porous feature diameters which makes portions of the separate stack have different accessibility indices.) After the treatment, water was then injected (from the reverse end representing flow in from the reservoir – opposing the direction of the treatment). At 10 psi/ft there was a no-flow condition. All of the water-filled conduits were filled with gel and the tighter portions of the lower-permeability, oil-filled core stack could not be invaded at 10 psi/ft. To obtain flow, the differential pressure had to be increased to 20 psi/ft. The response is shown in figure 7.

Figure 7 – Parallel Flow Apparatus Response

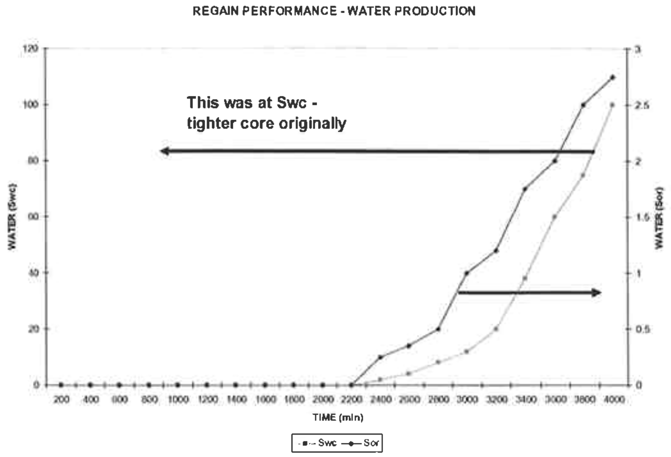


This is the response that is desired. There is no flow from the previously-water swept core stack and the recovery from the by-passed stack approaches 80%. As the differential pressure was increased the water breakthrough started to increase drastically but most of it was still through the previously-bypassed stack.

Figure 8 shows that almost 80 cc of water flowed through the previously-bypassed stack whereas even at differential pressures above 50 psi/ft these was less than 3 cc produced from the higher-permeability stack. The water shut-off treatment was very successful.

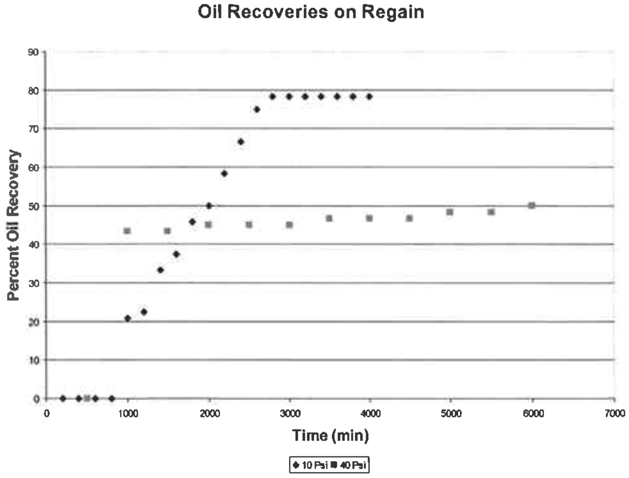
This data also emphasizes the phenomenon that accompanies water shut-off applications; injectivity should decrease. This is due to the fact that the highest –permeability conduits are plugged and the water is now being diverted to potentially lower-permeability stacks containing oil (and therefore exhibit a certain threshold pressure requirement in order to be accessed or invaded.

Figure 8 – Water Production Performance After Treatment



When the same type of treatment was conducted on analogous core stacks the efficiency of recovery was not nearly as good when the differential pressure at treatment time was not as closely controlled. Figure 9 shows a degradation of recovery from the by-passed core stack to about 50 % due to invasion of the oil-filled zone by the treatment. Indeed, differential pressure is a key parameter to control.

Figure 9 – Efficiency of Water shut-off Treatment



Application to Water Coning

After some of the laboratory factors have been measured there remains a lacuna relative to how to design the field treatment. Depending on the nature of the water influx there are different techniques used to diagnose the problem. Pressure build-up, pressure dissipation, tracers and type-curve analysis are some of the diagnostic methods used. The source of water problem can be fracture flow, near well-bore deficiencies, worm holes, paths of least-resistance (flow unit permeability contrasts) and coning. Of the five general water problems coning is the most deterministic since it occurs as a function of general reservoir operation and is not due to a path of least resistance such as a poor cement bond or a fracture that entered into an aquifer for example. Coning is due to the general interaction of the reservoir parameters along with completion interval and drawdown. How can water shut-off technology be used to solve coning problems therefore?

One way to analyze the benefit of water shut-off to water coning is by use of a mathematical model of the problem. Equations 5 and 6, with the addition of the convective diffusion equation can be used to construct a fairly representative model of the inflow into a production well and to analyze the benefit of water shut-off applications.

Field Problem – Water Coning into an Heavy Oil well

The well under study possessed a 16° API oil with an in situ viscosity of 252 cP. The reservoir temperature was about 25° C and the discovery pressure was approximately 7000 kPa. Some wells performed better than others. Typically the best wells would produce about 100,000 barrels after about three years by which point the water cut would approach 99%. Using the numerical coning model, described by the above-mentioned equations 5 and 6 with the dimensionless groups and accelerated by Newton-Raphson convergence, the results of the model were compared to the field data. Figures 10 and 11 show the data versus model for water and oil respectively. There were pump changes that occurred during the production in the field and therefore the irregular shape of the oil production is due to discrete changes in bottom-hole pressure incident to pump changes.

The object of this work was to design a coning treatment by pumping in a volume of aqueous-phase chemical that exhibited very low injection-time viscosity but which would set up very solid and thus create a pancake of impermeable water block. An analysis of the pressure gradients was made on the basis of the model predictions, as tuned to figures 10 and 11. Figures 12 and 13 present the pressure gradients computed in the radial and axial directions. It is obvious that by a radius of 5 meters the axial gradients (the dominant pressure gradient driving water into the production well bore) are almost an order of magnitude less than right at the well bore. By 16 meters the axial gradients are another seven times smaller. Of even greater significance however is the velocity of the water.

Figure 10 – Comparison between Data and Simulation

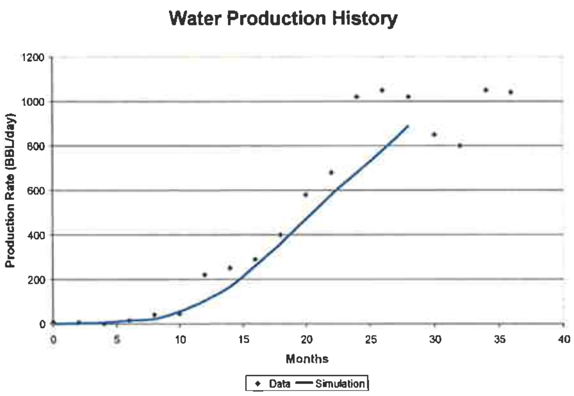


Figure 11 – Comparison between Data and Simulation

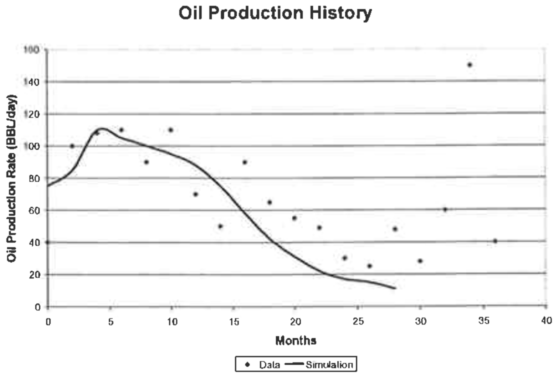


Figure 12 – Radial Pressure Gradients

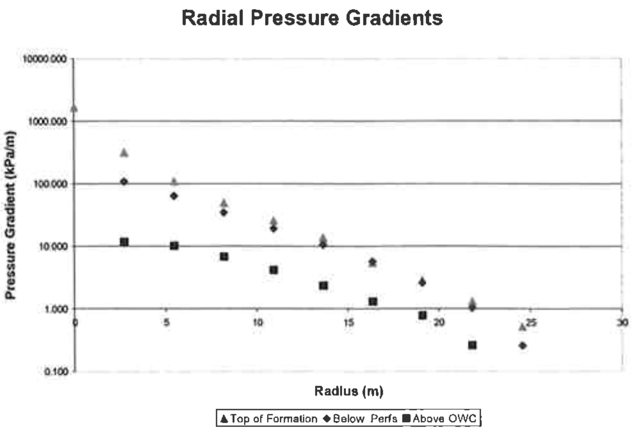


Figure 13 – Axial Pressure Gradients

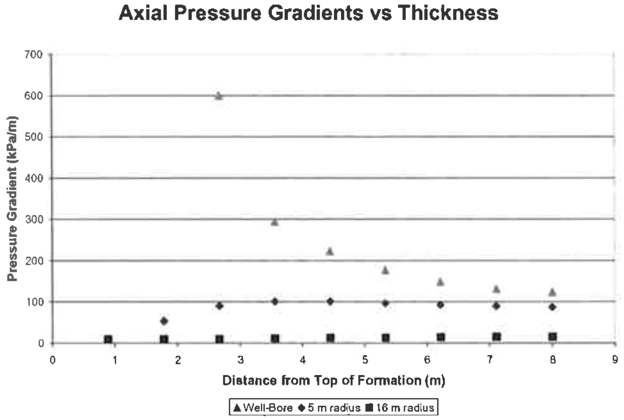
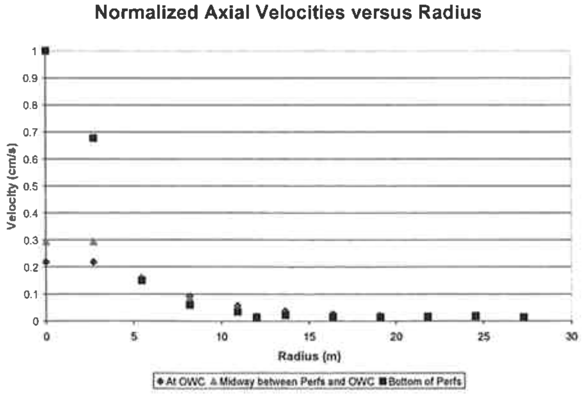


Figure 14 shows the relationship of axial velocity versus radius. By about 10 meters the axial velocity is greatly reduced. Consequently, if one were able to place sufficient "pancake" to cover the zone around the well where the axial velocities are high it may be possible to control the worst portion of the water cone.

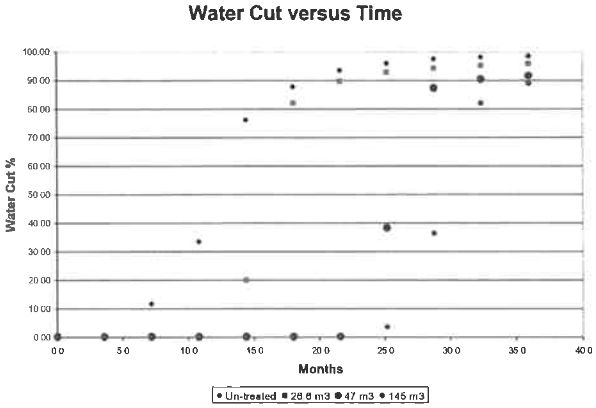
Figure 14 – Velocity Profile



Model Application of low-viscosity, Aqueous-phase water Block

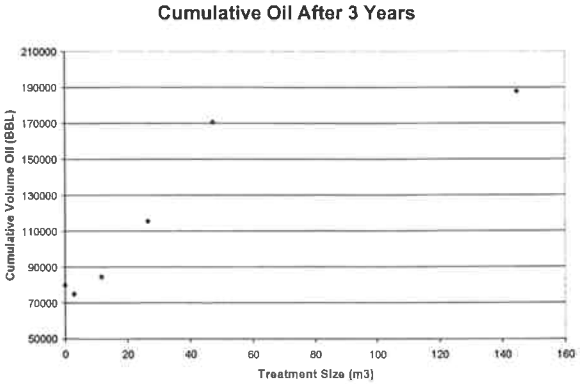
The model was then run with a series of different treatment sizes varying from about 3 to 145 m^3. The influence of the treatment on water cut is shown in figure 15.

Figure 15 – Influence of Treatment size on Water Cut



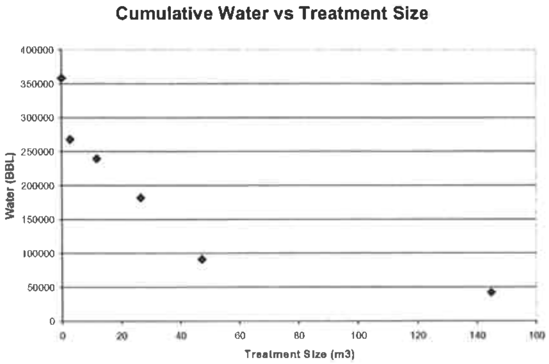
The transition between 26 and 47 m^3 treatment size was significant. At the 26 m^3 level the water cut started to increase quickly at about 12 months whereas with 47 m^3 the water cut did not start to increase until about 22 months. The major impact there would therefore be on oil production. Figure 16 shows the dependence of total oil production as a function of treatment size.

Figure 16 – Oil Recovered as a Function of Treatment Size



There is a significant increase in oil recovery with the change in treatment size from 26 to 47 m^3. The same trend for water production is shown in figure 17.

Figure 17 – Water Produced as a Function of Treatment Size



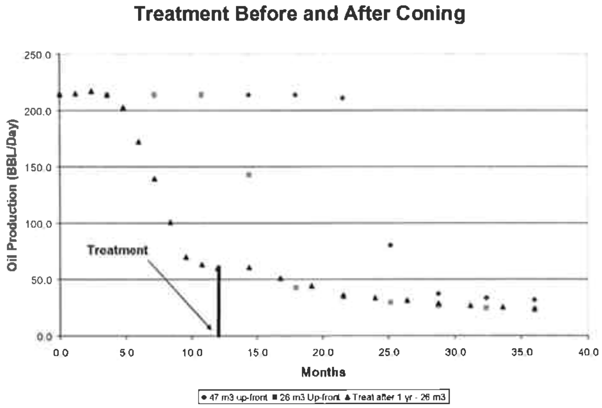
Beyond about 50 m^3 it appears that there is a law of diminishing returns; increasing treatment size does not significantly improve the performance of the well. To this point, the treatment of about 45 m^3 seems like the appropriate volume. How does this correlate to the axial velocities shown in figure 14? With a layer of low-viscosity treatment about 30 cm thick (1 axial grid block), a porosity of 35% and 12 meter radius the volume corresponds to approximately 45 m^3. At smaller volumes of treatment there is some benefit but the axial velocities are still quite high and the water tends to do "an end run" around the pancake. By placing a pad of water blocking material one effectively creates an impermeable layer where axial velocities dominate and extends the zone of zero flow out to where the radial velocities (which transport the oil) are more comparable to the axial velocities (which transport the water).

Treatment before or After the Cone Develops

Operators commonly do not want to implement any water control strategy until they know they have a problem, even though the history on analogous wells is completely clear; that is, the wells will flow for 3 months and then water breakthrough will result - water cut will approach 100% after one year for example. Therefore, is there any difference between implementing a water shut-off application before the cone or after the cone develops?

Figure 18 shows that it is better to treat the well before the cone develops and before a water-saturated zone is established. After it has developed it does not appear that it ever heals. Possibly if the zone beneath the perforations was filled with reservoir fluid it may tend to heal. This type of remedial approach is beyond the scope of the current work.

Figure 18 – Dependence of Time of Treatment



The conclusions of these applications are more clearly displayed in figures 19 and 20. Figure 19 shows the sensitivity of total oil production to the time and volume of treatment. Figure 20 shows the same trends but for water production.

Figure 19 – Sensitivity of Oil Recovery

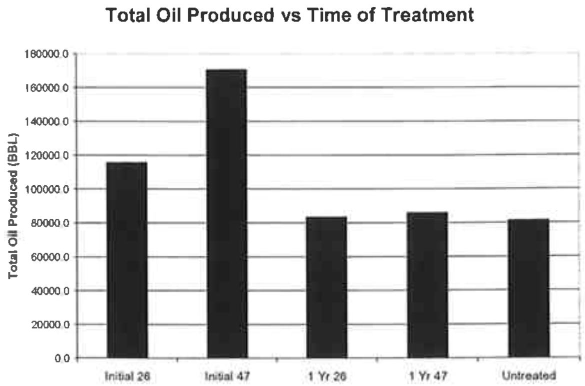
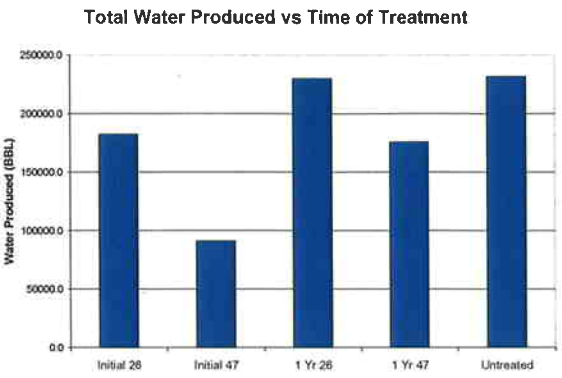


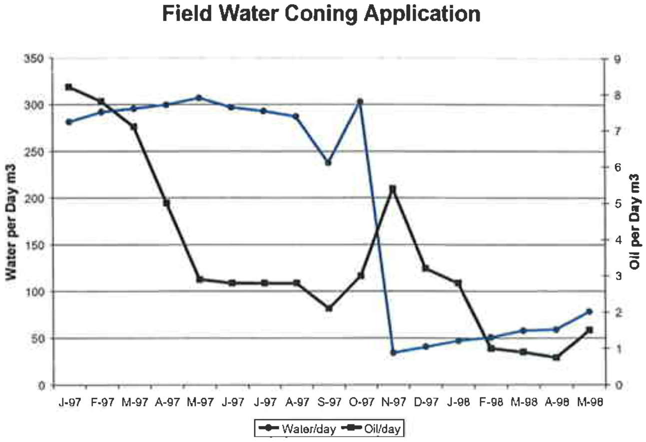
Figure 20 – Sensitivity of Water Produced



Field Application of a Chemical Coning Treatment

The technology summarized in this paper was implemented in a well that was producing at the economic limit. Very high water production rates were being experienced and with the cost of water disposal there was as much impetus to simply shut off water as there was to increase oil production. The operator however was not prepared to inject large quantities of treatment (20 m^3 was the maximum volume that they were prepared to inject). Although the volume required was closer to 40 m^3, 20 m^3 was injected. Figure 21 shows the result of the treatment. Oil was increased for about three months and water was reduced significantly. After three months the oil production fell while the water production remained low. This treatment was a success ($108,000 net profit over 3 months) in light of the water shut-off even though oil production was not impacted in the long term. The authors suggest that better use of the design criteria described in this paper will increase the success ratio in controlling water production in coning wells.

Figure 21 – Performance of Coning Treatment



Summary and Conclusions

1. Characteristics of some water shut-off chemistries were measured including strength, shrinkage, viscosity, set-up time and selectivity dependence on applied differential pressure.
2. For better selectivity of treatment (shut-off chemicals invading only the water-saturated zone) the lower the differential pressure the better. This is not as important for coning applications where a total “pancake” is desired for placement.
3. A two-phase, two-dimensional (azimuthal symmetry) numerical model of water coning was developed and used for analysis of water shut-off treatments. This model was used to “fit” field data and then employed to gain insight into water shut-off applications.
4. The radius at which water axial velocities approach less than 5% of the maximum appears to be the radius to which the treatment should invade. This criterion may therefore be profitably used for sizing the treatment volume. However, if there are preferential paths of flow that are not included in the deterministic

coning model the response may be significantly different from those described herein.

5. The science of water mitigation in coning wells, by placing a "pancake" of blocking chemical, may be analogous to manipulating the effective pressure gradients that are driving water and oil production. At the external radius of the "pancake" the axial pressure gradient may be more comparable to that observed in horizontal wells than that which normally drives water production in vertical wells.
6. The recovery of oil can be very sensitive to the size of the treatment. The time of treatment is also of significant importance treating a well before the cone developed recovered more than twice the oil after three years than what was recovered by producing the well for one year, treating and then producing for two more years. The impact on water produced was equally as significant.

References

1-15