



Tech Talk - Chemical floods to enhance oil recovery

Posted by [Heading Out](#) on June 4, 2011 - 11:08am

Before returning to look at the larger oilfields in the United States, I thought to describe ways of increasing the oil produced from the stripper wells that I [mentioned last time](#). It seems appropriate to tie this to the time that I am writing about Texas, since some 41% or so of marginal oil well production comes from that state. And I would acknowledge again the help of the [Stripper Well Consortium](#).

Top Ten Stripper Oil Well States (Number of Wells)



Source: IOGCC, 2009

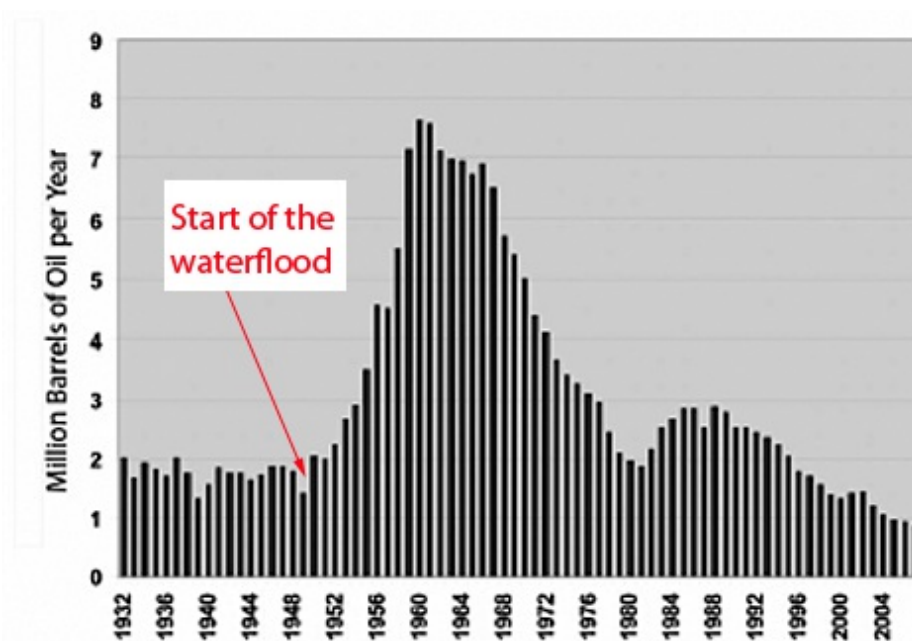
In the main, as [Rockman has pointed out](#), the economics of production severely limit the options for increasing the flow of oil from these strippers. However, changes in market price and the reduction in costs of some of these treatments can make enhanced oil recovery (EOR) techniques worthwhile. And even if not presently economic, as research studies ways of lowering the cost, driven in part by the size of the market, and the need for oil, so the likely increase in the price of that oil will change the economics in a positive (for the well owner) direction. This post is therefore going to look at the use of chemicals to stimulate enhanced oil recovery with a particular thought for stripper wells.

As an example I am going to consider the Lawrence field on the Illinois side of the Illinois:Indiana border, since this is part of an ongoing project.



Location of the Lawrence oil field in Illinois ([Rex Energy](#))

The field had, by 1950, peaked and was in decline. However, by waterflooding the field at that time, generally recognized as secondary recovery, the water displaced the oil while maintaining pressure in the reservoir as fluid left, thus increasing production. though that too then began to decline.



Production from the Lawrence field in Illinois ([DOE](#))

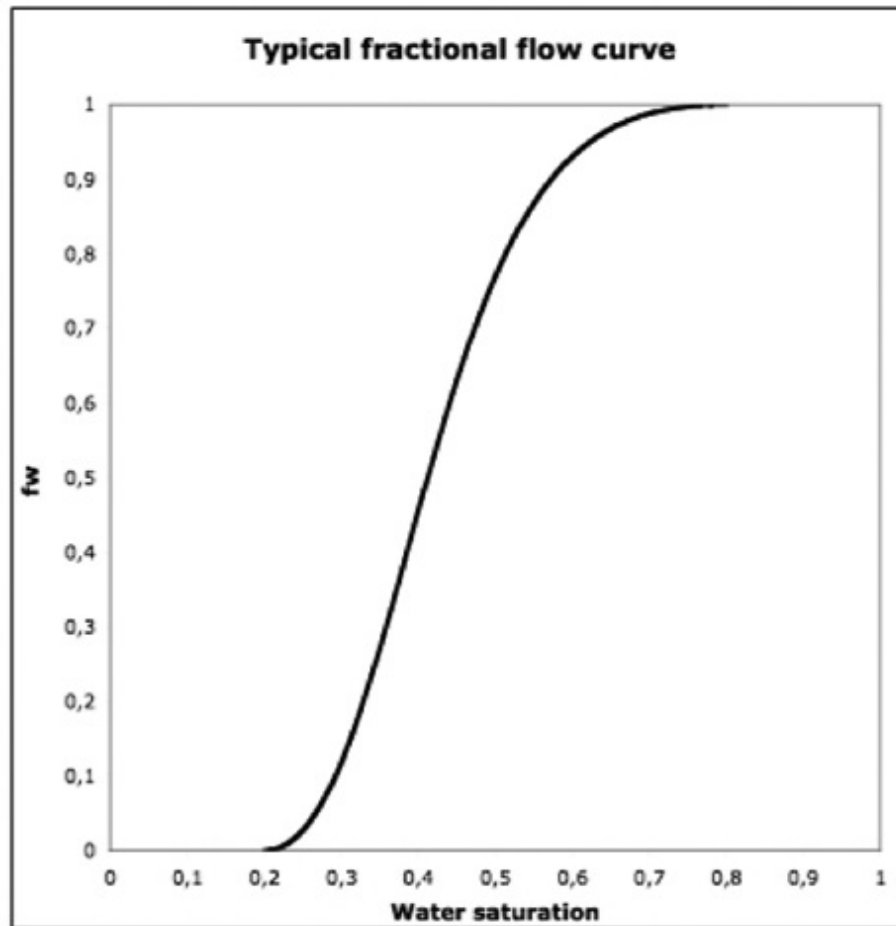
Some time ago [Stuart Staniford explained](#) some of the problems with a water flood, in terms of ultimately recovering all the oil from a formation. The post itself deals with what is going on in the Ghawar oil field in Saudi Arabia, but to understand that, one has to understand a little of the physics of fractional flow in a multi-phase fluid. And so he provided that explanation, which I am now going to borrow:

If there is 10% water and 90% oil in a particular volume of rock (.....), then a well into that part of the rock would be receiving 10% water and 90% oil. Similarly, an area with 60% water and 40% oil might be producing at 60% water cut into a well in that area. However, this is not so: the difference is much more dramatic than that. The reason has to do with the physics of two phase flow in a permeable medium. If you want a mathematical treatment, [try this](#), but let me try to illustrate the basic idea.

In a set of interconnected pores through which oil and water are being forced at pressure, the flow is too turbulent for large areas of the two fluids to separate out from one another. And yet, oil and water do not like to mix, and will tend to bead up in the presence of the other. If there is only a little water and a lot of oil, then the oil will form an interconnected network of fluid throughout the rock pores, whereas the water will tend to make small beads within the oil. Conversely, a little oil in a lot of water will result in a network of water throughout the rock, and small beads of oil within that network. Now, in either situation, the fluid that is interconnected can flow through the rock without making any change in the arrangement of beads and surfaces between oil and water. However, the fluid that is beaded up can only move by the beads physically moving around, and they are going to tend to get trapped by the rock pores.

So for this reason, in a mixture of almost all oil, the water cannot flow at all. Conversely, once there is almost all water, the oil cannot flow at all (which sets an upper limit on the amount of oil that can ever be recovered by a water flood). In between, there is a changeover in which the proportion of oil flowing to water flowing changes much more rapidly than the changeover of the actual mixing ratio. The curve that describes this is called the fractional flow curve.

For example, [the tutorial](#) I referenced earlier shows this picture for a typical fractional flow curve:



"Typical" fractional flow curve (from [this tutorial](#)). f_w is the fraction of the flow out of the well that is water, i.e. a value of 1 is sensibly 100%.

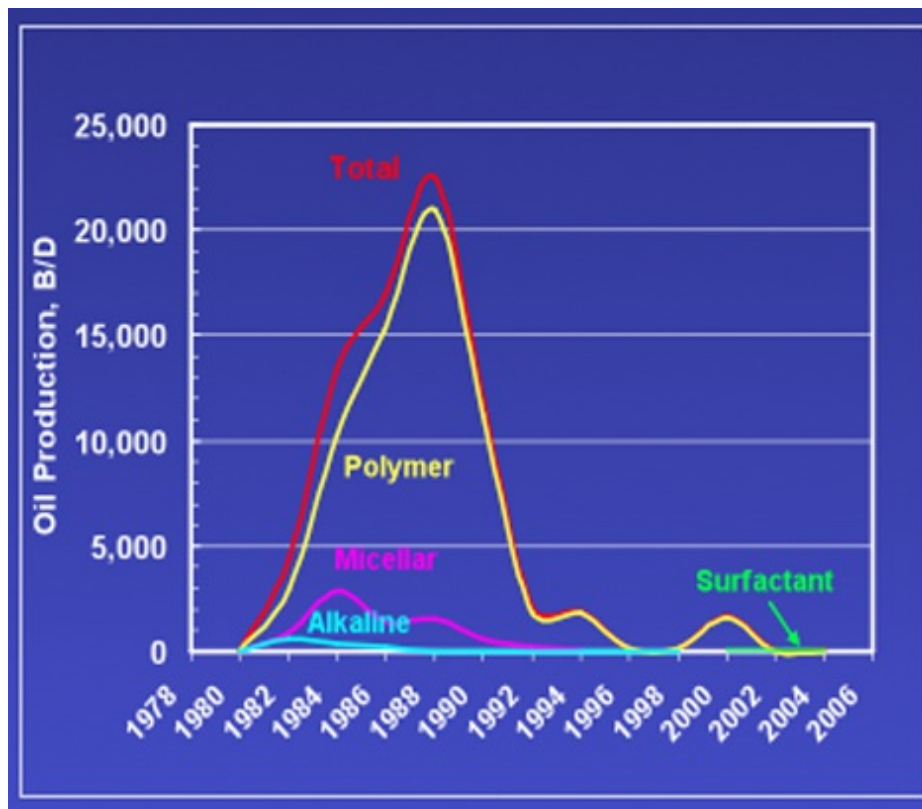
So, the way to read this is that when we are below 20% on the X-axis (less than 20% water in the oil), there is zero (water flow shown) on the y-axis (the water will not flow through the rock at all). As we get above 20% water saturation, the flow of water increases rapidly, until above 80% water, there is no flow of oil at all. In the linear region at the center of the curve, the slope is about 3.6. That is, each 1 percentage point increase in water saturation results in a 3.6 percentage point increase in water flow in the rock.

Now this is not absolutely true, in that the mechanical motion of the water through the rock will drag a small fraction of oil along with it. Thus, at flows above 80% there will still be a small amount of oil that comes out with the water.

The amount of water that comes out of the well, as a percentage of the total flow, is known as the "water cut." (And the obverse, or oil percentage is referred to as the "oil cut".) In Illinois, the wells in the Lawrence field are running at a water cut of 98%. In other words, for every 100 barrels of fluid pumped out of a well, only 2 barrels will be oil, and that must be separated from the water. In Saudi Arabia, one of the characteristics of production that initially caught Matt Simmons's attention was that the oil had a water cut of around 30 – 35%. But I'll leave that issue to another day – though in passing, if you haven't read Stuart's post in its entirety (and the debate between him and [Euan Mearns on Saudi productivity](#)) it is well worth taking the time to do so.

What I want to return to for today is the remaining oil in the field. To put it simplistically, under normal conditions that oil is attached to the particles of rock in the formation, and the water flowing past only marginally can dislodge it and carry it to the well (hence the low oil cut numbers). Now if the chemistry of the oil could be changed, so that, for example, it did not cling quite as strongly to the rock, and, at the same time the viscosity of the oil was reduced, so that it would flow more effectively, then perhaps the water could carry a higher percentage of the oil away, increasing not only the oil cut, but also the total amount of oil that could be economically recovered from the wells. (This might also require getting the oil into an emulsion with the water).

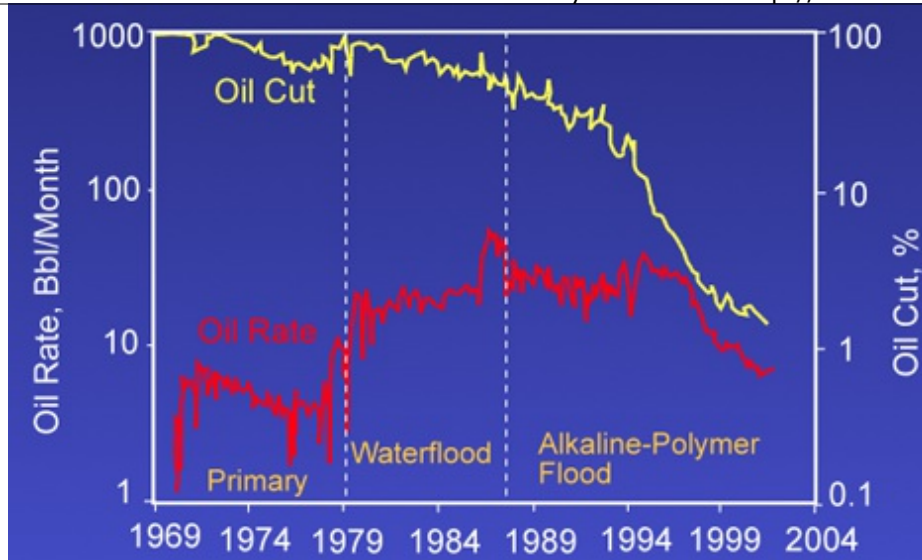
There are a number of different techniques and fluids that can be used to make this work. The idea is not new, and back in the '80's the hot topic was "Micellar flooding", although it, and its cousin ASP flooding, have not been that successful – in the United States.



Production from chemical flooding of oilwells in the USA. (Dr. Sara Thomas)*

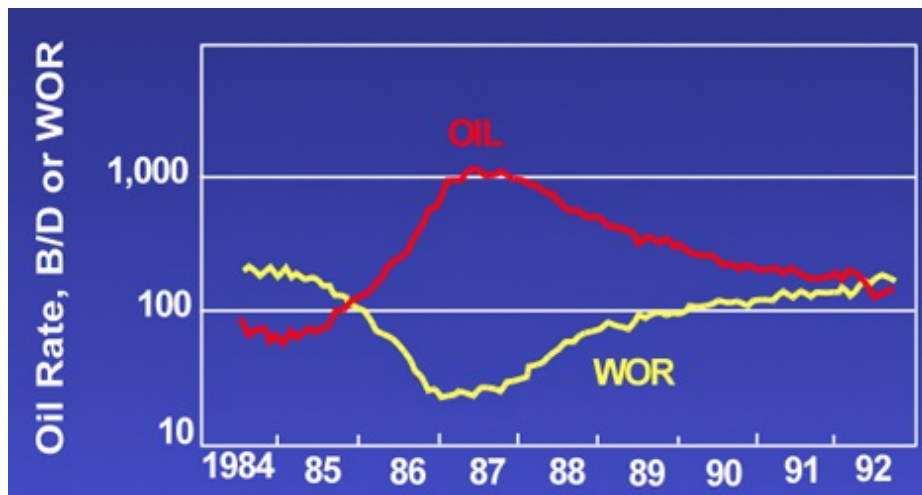
The letters that make up ASP stand for alkaline, surfactant and polymer. Generally the chemicals are injected as a slug, or a series of slugs, into the water injection well(s) and then pass through the formation to the collection wells, being pushed through by subsequent injections of more water.

The first of these, the alkaline chemical (think caustic), is aimed to mix with the oil and lower its bond attachment (the interfacial tension) between the oil and the rock so that it can be removed more easily. By itself, however, it does not seem have that great a level of success in improving oil cut, but it sustains the flow of the oil for a longer period.



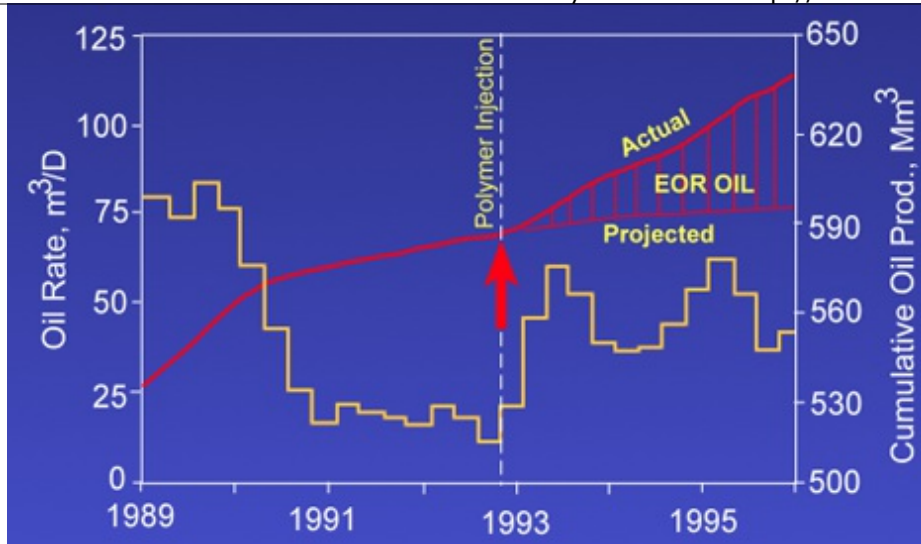
Alkaline - polymer flood of the David Field in Alberta (Dr. Sara Thomas)*

The S in ASP stands for surfactant, and this acts in much the same way as does the alkali in changing the adhesion of the oil, but acts more as a soap in helping to break the oil free. It has been shown to be more effective as a tool for improving recovery than the alkaline solution.



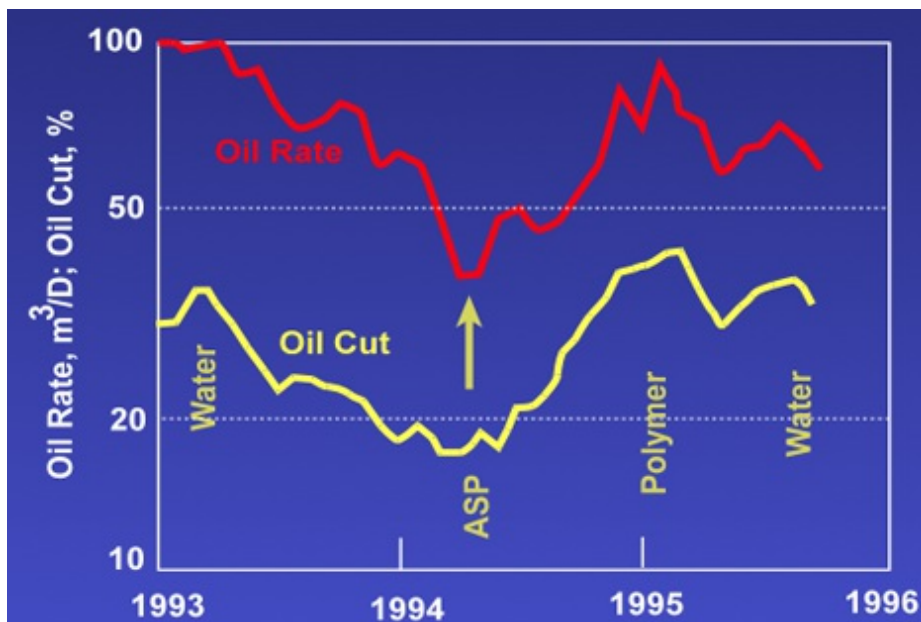
Effect of a surfactant flood on well performance and oil cut – Glenn Pool Field OK (Dr. Sara Thomas)*

The polymer can either be used to thin the oil, so that it is easier to move, or to thicken the water so that it adds a more effective drag to move the oil. The benefits of this can be seen from a trial at the Sanand Field in India. Note that it also provides a more sustained effect.



Effect of injecting a polymer slug to enhance oil recovery (Dr. Sara Thomas)*

While each of these individually provided some gain, the impetus at present is to combine them in consecutive slugs (hence the acronym) and the benefit can be seen from the sustained improvement in oil recovery. (As you will note from the dates, this is not a totally novel concept).



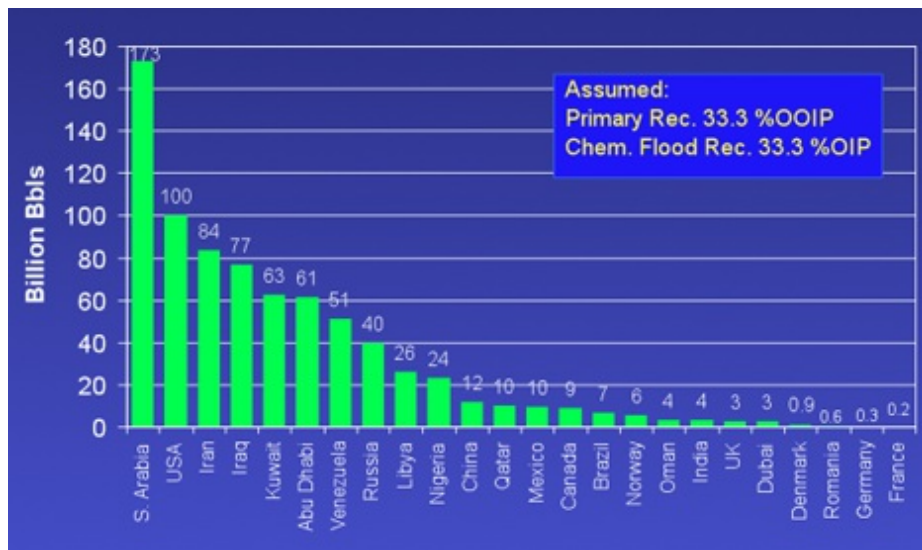
EOR from a field in Daqing, China after an ASP treatment (Dr. Sara Thomas).*

And here is a different example from [Tanner, WY](#).



Change in oil cut and monthly oil production following an ASP flood in Tanner, WY ([Oil Chem technologies](#)). The cost per incremental barrel including chemical and facilities was [estimated at \\$4.49](#).

With this understanding of the background to the potential use of the ASP treatment, lab tests have shown that it might be possible with this technique to recover an additional 130 mbbbl from the Lawrence field (until now it has produced a total of 400 mbbbl). The potential, if the technology can be proven to work, is quite significant.



Potential additional oil that can be recovered if Chemical EOR is successful (Dr. Sara Thomas*).

The big question that I included in my second paragraph, and that Rockman, (our resident realist) reminds us of, is the need for this to be a significant cost benefit to the operator before it will be implemented. Technically, chemical floods can increase the oil cut from 1 - 20% of the flow, but in the earlier tests the chemicals used cost more than the oil recovered. It is not a simple process, since it depends on the rock geology to ensure that the chemicals have the proper access to, and path from the oil in place. And the additional services to ensure this also cost. Lawrence was the site where Marathon tried [using chemical EOR in the past](#) and achieved the technical success of increasing the oil cut to 20% from 1%) but it was uneconomic. With the new program,

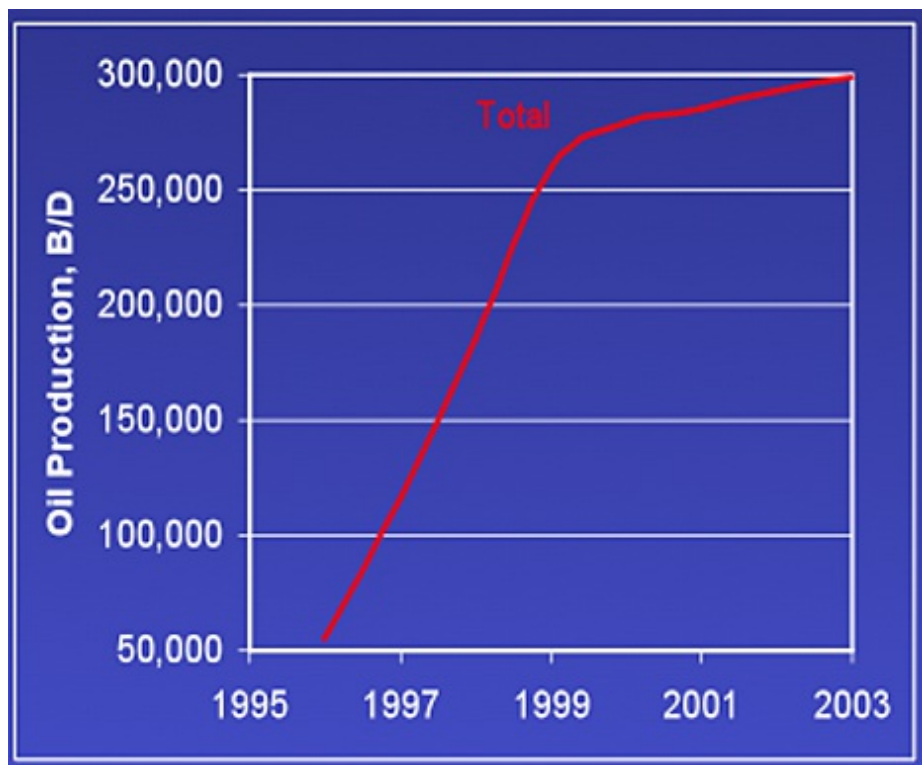
Rex Energy is reporting in their first quarter report that the program is successful so far.

We are seeing positive results from the Middagh ASP project area with increasing oil cuts and oil production.

As a result, we have the confidence to increase our capital budget for the ASP program by \$3 million to fund the larger 58-acre ASP project in the Perkins-Smith area. Results from the Middagh ASP are being analyzed to maximize oil recovery in the Perkins-Smith Unit. ASP injection on the Perkins-Smith Unit is expected to begin during the fourth quarter this year following brine water injection, which we expect to commence shortly.

The program is an area of considerable interest for the [Stripper Well Consortium](#) to whom I am indebted for some of the information in this post.

I would close, however, with a slide from Dr. Thomas's presentation:



The growth of oil produced by chemical EOR (ASP flooding etc) in China (Sara Thomas)

* The graphs identified as “Dr. Sara Thomas” were taken from the SPE Distinguished Lecturer Series 2005 – Dr. Sara Thomas [“Chemical EOR – the Past, Does it have a Future?”](#) (Abstract [here](#).)



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