ARTIFICIAL LIFT WITH DECLINING PRODUCTION

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INTRODUCTION

Horizontal wells in low permeability or shale formations present artificial lift problems as the rates can be initially high but tend to drop off to low rates for much of the well's productive life. Artificial lift can be efficiently used only if a system can handle the high and lower rates or allow substitution of equipment to continue production at the lower rates. Initially the wells may flow for a while, then possibly require a high rate lift method, and later a lower rate lift method as production rates decline.

This paper will present a method to approximately characterize a reservoir's future performance given initial conditions. Methods of lift that can be applied as reservoir pressure and rates decline with time will be discussed.

RESERVOIR PERFORMANCE

Detailed horizontal well models may contain details to the extent of the reservoir and the fracture system that may not be known. Here the reservoir performance is characterized using test data and an inflow performance relationship (IPR) using a Vogel type expression or using a form of the back pressure equation which, depending on input options, can have a shape much like the Vogel. A data set is needed for an example problem to help explain the technique.

Example data:

WHT: 100 F; WHP: 500 psi initially and trends to 100 psi after 12 years
BHT: 175 F; Gas Gravity: .7, GOR: 1500, API: 38^o, Water Gravity: 1.01
Pr: 7500 psi (initial)
Water Cut: .6
Tbg ID: 2.441, Depth: 9500ft
Calculated:
Initial C: .00885619, n: .75

From Figure 1, the tubing performance curve (from SNAP with permission), the pressure is 4111 psi at the initial rate of 4400 bpd. So a test point for the reservoir curve becomes 4400 bpd at 4111 psi. For this analysis the back pressure equation will be used although the Vogel IPR could be used. The back pressure curve is selected because SNAP can best sensitize future IPRs using the back pressure equation and also some turbulence can be modeled using the back pressure equation with an "n" value of less than 1.0.

Back Pressure equation:

$Q=C(Pr^2-Pwf^2)^n$

Where:
Q: Rate, bpd
Pr: Reservoir shut-in pressure, psia
Pwf: Bottom hole producing pressure, psia
C: A coefficient that is obtained from data and is thought of containing permeability effects, downhole fluid properties, and geometry effects
n: Another coefficient determined from data that typically varies from .5 to 1. If 1 then more like Darcy flow while closer to .5 indicates losses in the well

(Note: the back pressure curve can be used for gas wells or gassy oil wells)

Selecting a value of n=.75, the back pressure equation becomes Q, bpd = $C(Pr^2\text{-}Pwf)^{.75}$. With n selected, Q and Pwf from the test point and Pr known, the only unknown is C. Solving for C gives Q/ $(Pr^2\text{-}Pwf)^{.75}$ = 4400 / $(7500^2\text{-}4111^2)^{.75}$ = .00856 bpd/psi^{2n}. The 4,111 psi is from Figure 1 at the rate of 4400 bpd (initial rate). Other values of n could be selected but .75 is assumed here. Only reservoir tests could firm up this selection. This allows the plotting of the current IPR. For future IPRs a typical decline curve of production with time is used. An example decline curve that might be developed from some wells is shown in Figure 2.

Now what is unknown for future IPR curves is the Pr or shut-in pressure. The same C will be used in the future as it is a measure of productivity and the fracture system and permeability. Also, if a Q is selected at a future time, then the question becomes at what reservoir pressure gives the bpd selected. For this analysis, the future rates with lift used are assumed to be a 1/10 of the shut in pressure mostly with lift but the initial flowing rate was at a higher percent of the shut in pressure. With these assumptions and using the back pressure curve for an IPR, the only remaining unknown at a future rate is the future Pr. Now future IPRs can be plotted as shown in Figure 3 as the reservoir performance into the future. This plot will then be annotated to show where various AL methods may be applied. Gas lift performance is found by adding gas to the tubing curves until a minimum is found where gas lift is lowering the producing pressure the most. Other artificial lift applications can be shown plotted on the reservoir performance plots but no claims are made as to the accuracy of the reservoir predictions which can only be somewhat verified with test data.

Artificial Lift:
Figure 4 simulates gas lift at various rates of gas injected at the bottom of the tubing. The lowest curve in the group of gasified tubing curves is the lowest pressure that gas lift can produce at the bottom of the tubing. Next dotted lines below are shown for approximate ranges of application of various lift methods.

For ESPs two correlations are used. First of all 60% of the downhole free gas present is assumed to be separated such as might be the case using rotary separators. Rotary separators can separate higher values but this value is perhaps a typical operational value. Then using the Turpin correlation and the Dunbar correlation the lowest pressure is found such that these correlations are satisfied. The correlations are calculated after separation before the pump intake. The variables VLR (vapor/liquid ratio) and PIP (pump intake pressure) are in the expressions. The expressions signify satisfactory conditions if the values are less than 1.0. The Dunbar greater than 1.0 signifies no head curve degradation due to gas and the Turpin factor (Φ) greater than one signifies no gas lock. A minimum pressure is determined for PIP such that the correlations are satisfied. This is how low the ESP can lower the pressure and still get good gas separation or it is essentially the limit of ESP drawdown. It is a function of the GOR or GLR and for this example is calculated as 830 psi regardless of rate but holding WC constant and GOR constant.

$\Phi = 666(VLR)/PIP$

Dunbar factor = $935(VLR)^{\wedge}(1.1724)(1/PIP)$

ESPs are shown to be feasible down to about 200 bpd. They can operate at lower rates but may have more problems. They are shown with the potential to produce high rates though the higher rates would be easier to accomplish in 5 ½" casing compared to 4 ½" equipment. For instance at 4000 bpd 300-400 stages with 350 HP would require 5 ½" casing but would be a big investment and as rates drop quickly the equipment output required would quickly drop. VSDs would help adjust the equipment to the reservoir as well as possible needing to downsize the equipment.

Note gas lift could be used initially and could move from high rates to low rates but the production and drawdown with gas lift would not be same as with ESP. For instance at year two, gas lift here would be predicted to produce about 800 bpd and an ESP would be predicted to be capable of 1020 bpd. With 4 ½ casing even at 1000 bpd about 500 stages would be required with 100 HP.

If ESPs are applied when the rate is down to about 400 bpd (the limit of flowing the well) the ESP equipment requirements in 5 ½" casing are much less, with a few hundred stages and about 60 hp. For 4 ½" casing at 400 bpd, more stages would be required but the HP requirement would be about the same.

As rates decline to lower values then beam pumps systems can be considered. Reference 1 shows the capacity of a packer type separator in 5 ½" casing would be about 738 bpd at 100% separator capacity. The capacity in 4 ½" might be around 357 bpd at 100% efficiency. However, in horizontal wells the slugging experienced reduces the effectiveness of the packer separators (though many are used) to some lower value, perhaps 60-80% of 100% effectiveness. This then would say that gas separation could begin to work better at perhaps 442 bpd in 5 ½" and 214 bpd in 4 ½". This could be used as selection criteria as to what rate one might begin to apply beam systems. If the separators are more efficient then beam systems could be started at higher rates and the reverse if well flow conditions cause separator efficiency to drop to lower values.

The initial equipment requirements would be on the high end at higher rates in the deeper wells but reduced as the rates decline. Another consideration is what intake pressure is possible for beam systems. In this example the initial surface tubing and casing pressure are stated to be about 500 psi. However as the rate declines the surface pressure also drops and would be about 360 psi. For an estimated intake pressure the pressure on the formation at this point would be the surface pressure plus the pressure from the casing gas and perhaps 100 psi more to account for fluid level.

For example, Pwf = WHP*2.17828*(.01875*depth*SG/((Tavg+460)*Zavg) + 100 psi and for WHP of 360, the pump intake pressure would be about 546 psi. A design for the beam system for 300 bpd at 9500 ft with the above cited data could approximately be a 1.5" pump, 912 conventional (640 Mark) at 9+ SPM, 144" SL, high strength rods, with a 70 hp motor for a conventional unit or a 50 hp motor for a Mark. If beams are employed at higher rates, a larger unit might be needed along with a larger pump and possibly pumping from a shallower depth. As rates decline to 100 bpd or less however the equipment requirements drop substantially. For 100 bpd the unit size could be 640/456 Conventional/Mark, pump size 1.25", grade D rods, and SPM around 5. Equipment requirements would continue to drop at lower rates. Larger equipment can be applied at lower rates using VSD equipment or a jack shaft, but power efficiency suffers if equipment is oversized compared to what the reservoir would produce.

Once rates drop to 10 to 50 bpd plunger lift could be considered. Rough industry feasibility requirements are 400 SCF/(bbl-1000 ft) and the well should build CP to about 1.5 time surface pressure but in what time period? Since this would be operating CP (meaning what the CP would build to during a plunger cycle), one would think it should build pressure in an hour or so. For this example the well does not have the gas required since the GLR/9.5 is only 682/9.5 and does not reach the requirement of 400. For this example a well GLR of a little less than 5000 would be indicated for plunger lift using the rough industry rule. So perhaps gas assisted plunger or other modified plunger lift methods could be considered for lower rates or beam could be continued at low rates which creates problems as well.

This example is not intended to be a general solution but only an example to show how producing a horizontal well into the future at declining rates could be visualized and what some of the rules of selection of the AL system could be. There are many options.

You could flow as long as possible and then go to some initially high rate pump system. Or you could begin gas lift at a high rate and continue gas lift to low rates. If gas lift to be used at very low rates then a smaller tubing size would conserve gas and energy. Gas lift would not however have the drawdown as pumps if the pumps can operate with reasonable gas separation efficiency.

ALTERNATE METHOD OF SOLUTION

There can be a loss of accuracy in predicting production changes with time independent IPR equations such as the back pressure or Vogel equations with horizontal wells with multiple hydraulic fractures. This is because production rate typically declines rapidly early on even with constant drawn-down pressure, and for which an IPR equation would predict no change in rate. Consequently, to account for rapidly changing rate, multiple IPR curves at differing producing times are employed but the accuracy of calculating these IPR curves using field data to obtain "fitted" coefficients may also be affected by the concurrent rate decline during the measurement period(s).

An alternate and arguably more accurate method would couple the IPR equation with the well's historical or expected production decline curve. In essence, this is what pressure transient analysis (PTA) methods do; they couple an IPR relationship (Darcy or non-Darcy flow) with a well's production decline (equivalently, the transient solution of the diffusivity equation). These PTA solutions are frequently presented in dimensionless form or numbers, typically of pressure (p_D) or of rate (q_D) vs. time (t_D) and are frequently referred to as dimensionless type curves. These type curves are usually developed from analytical solutions of the radial diffusivity equation but they can also be developed using reservoir simulation data (model rate and bottom-hole pressure with time) for more complicated reservoirs and/or with more involved well completion scenarios (for example multiple transverse hydraulic fractures along a horizontal lateral wellbore). This is how the Agarwal-Gardner type curve solutions for hydraulically fractured vertical wells were developed.

We propose to do something similar conceptually, but in place of simulated rate and pressure data, to use the decline curve rate data itself along with a "reasonable" estimate of the accompanying bottom-hole pressures for the requisite rate and pressure data. In addition to rate and pressure, petro physical and PVT properties are required to generate the dimensionless qD and tD data for these type curves. This dimensionless "tailored" type curve as it was developed from the decline curve data itself, should more accurately predict the type-well's response to differing artificial lift methods (varying changes in the flowing bottom-hole pressure) that could be applied at differing times during the well's expected producing life. For example, one could compare the expected rate response to different lift techniques at different times in the well's life to see which method would tend to maximize the well's economics, for example, via an NPV analysis.

Super-position can be a rigorous technique to account for changes in pressure or rate changes to the type-curve solution that assumes one or the other is held constant. This however requires an accounting and tracking of the effects of those changes for extended periods of time and can be somewhat computationally intensive, especially with rapidly changing rates. An alternate, approximate method to full-blown super-position, that is reasonably accurate for "smooth" monotonic changes in rates/pressures, is to use equivalent time (cumulative t)/q(t)) for the real time variable; which is what we initially propose doing.

An overview of the proposed method: given a representative "type well" and decline curve data set (for gas, MMSCF vs days data) over the expected life of the well, obtain the corresponding bottom-hole producing pressure at the same time values (or estimated, perhaps from nodal analysis using the well head pressures), use PVT data corresponding to the well streams to estimate viscosity (or pseudo pressure for gas), estimate the initial (or current average) reservoir pressure, the reservoir temperature, the total reservoir compressibility (requiring porosity, initial fluid saturations, rock, water, gas oil/condensate compressibility's), average fracture half-length, number of hydraulic fracs put on the well, expected drainage area (~mid-point between adjacent wells), net thickness (these will be needed for material balance to account for depletion affecting pressure and thus pressure dependent properties), estimated average effective permeability (this isn't generally known with any accuracy but shouldn't be critical as we're looking for the change in rate to a change in bottom-hole pressure and effective perm shouldn't change much with this). With this data, it is straight-forward to calculate q_D and t_D. These are then plotted on semi-log coordinates (log q_D vs t_D) and quality controlled for curve appearance, which should be monotonically declining, if not, this could suggest a bust in time the dependent data (rate or pressures), these will need to be rationalized to obtain a sufficiently smoothed curve that numerical derivatives can be calculated. Once an acceptable type-curve is generated, it can them be used to predict a change in rate history with a change in bottom-hole pressure brought about by a particular artificial lift method. This process reverses the steps that were used to create the type curve in order to find a new predicted rate with the trial bottom-hole flowing pressure change. This is done by entering the type-curve at the t_D corresponding to the time of interest (t), and using the corresponding q_D value to calculate a rate corresponding to the bottom-hole pressure at the time of interest.

$$t_D = \frac{2.637 \times 10^{-4} k_g t}{\phi \overline{\mu c}_g(t) x_f^2}, \quad q_D = \frac{1422\, q(t) \cdot T}{k_g h \cdot \Delta m(p)}$$

$$\overline{\mu c}_g(t) = \mu_i c_{gi} \text{(transient period)}$$

$$\overline{\mu c}_g(t) = \frac{2 p_i Q(t)}{z_i G_i \Delta m(\overline{p})} \text{(after boundaries reached)} \qquad \Delta m[\overline{p}(t_i)] = 2 \cdot \int_{\overline{p}(t_i)}^{p_i} \frac{p\,dp}{\mu(p) z(p)}$$

k_g = effective permeabity to gas

ϕ = hydrocarbon porosity

X_f = fracture half length

$T, \mu(p), z(p)$ = res temp, viscosity, gas z factor (functions of pressure)

p_i, z_i, G_i = initial: res_pressure, gas z, gas-in-place

$Q(t)$ = cumulative gas production at time, t

NPV:

Another way to look at comparison of lift methods is cumulative net present value. This method assumes that the lift method follows the declining rates. It does not give credit if one method or another has better drawdown capabilities over a range of overlapping rates. As long as the cumulative net present value is increasing, more profit is being made. Once it no longer increases, then costs equal or exceed income. Figure 5 is a Cumulative NPV plot calculated with flowing, ESP, Beam, and Plunger staged in. Typical values are used for oil and gas price, initial cost of the systems, energy efficiency, fixed and rate dependent costs and failures per year costs. Clegg and Boone offered spread sheets to the industry to do cumulative NPV calculations for one method of lift for life of decline curve input with somewhat different inputs and outputs. If the generic inputs are somewhat close to reality, the surprising thing is that most of profits, at least for this example, are obtained in the early times of production.

SUMMARY

A method for visualizing declining reservoir performance into the future using IPR techniques requires several assumptions and accuracy can only be checked with test data. However, using the visual display of the reservoir into the future, several methods of AL can be shown and evaluated as to their applicability using gas separation rules, rates possible with the methods, and calculated possible intake pressures for the methods.

An alternate method of looking at tight shale reservoir performance that would use type curves is presented but an example is not presented at this time.

An NPV method can also be utilized to further evaluate the different artificial lift options.

References:

An Innovative Design for Downhole Gas Separation By Jyothi Swaroop Samayamantula, Don-Nan Pump & Supply, SWPSC, paper 19, 2010

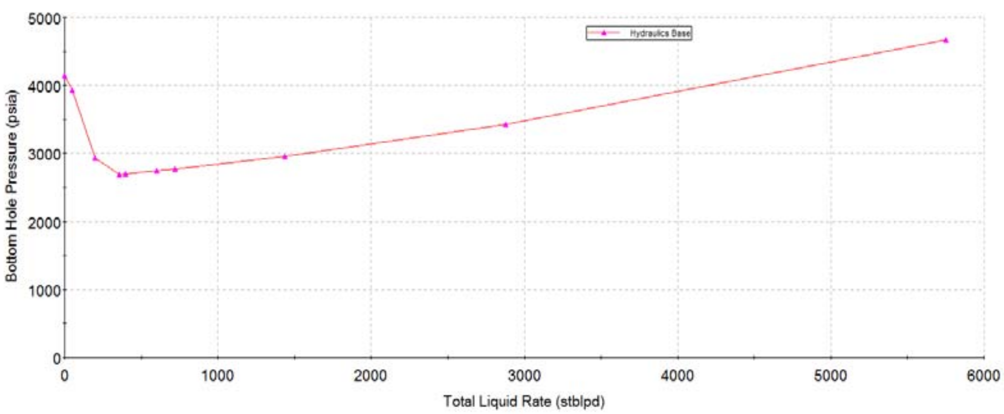

Figure 1 - Tubing Performance Curve

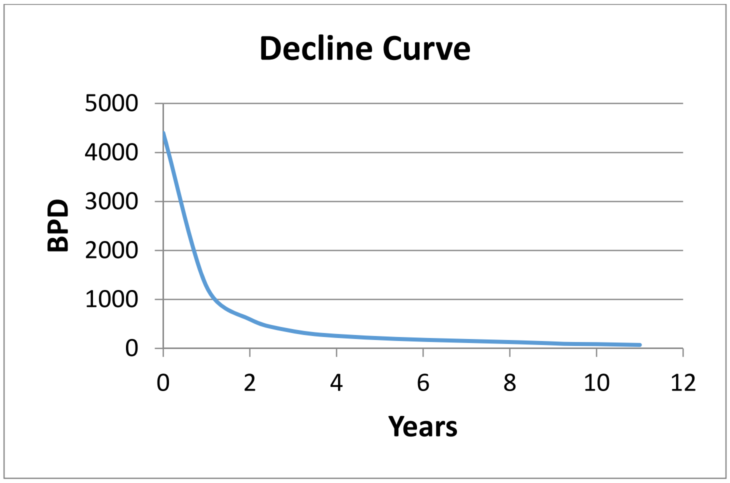

Figure 2 - Example Decline Curve

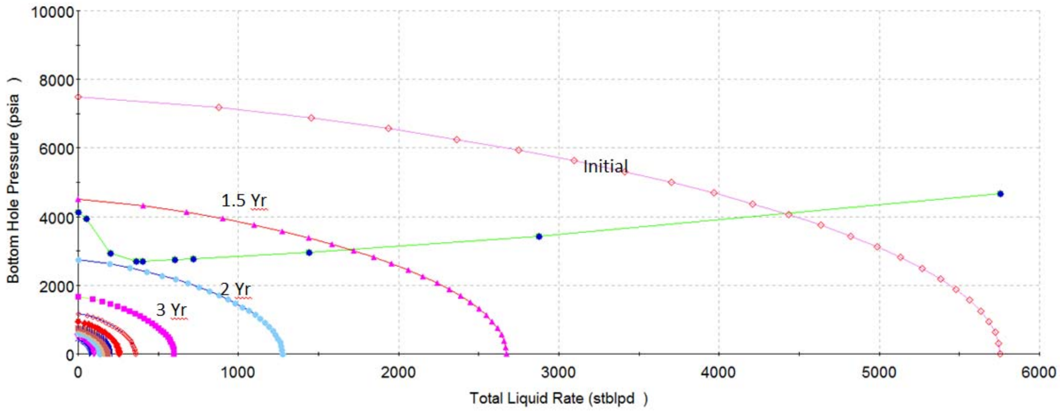

Figure 3 - Reservoir Performance into Future

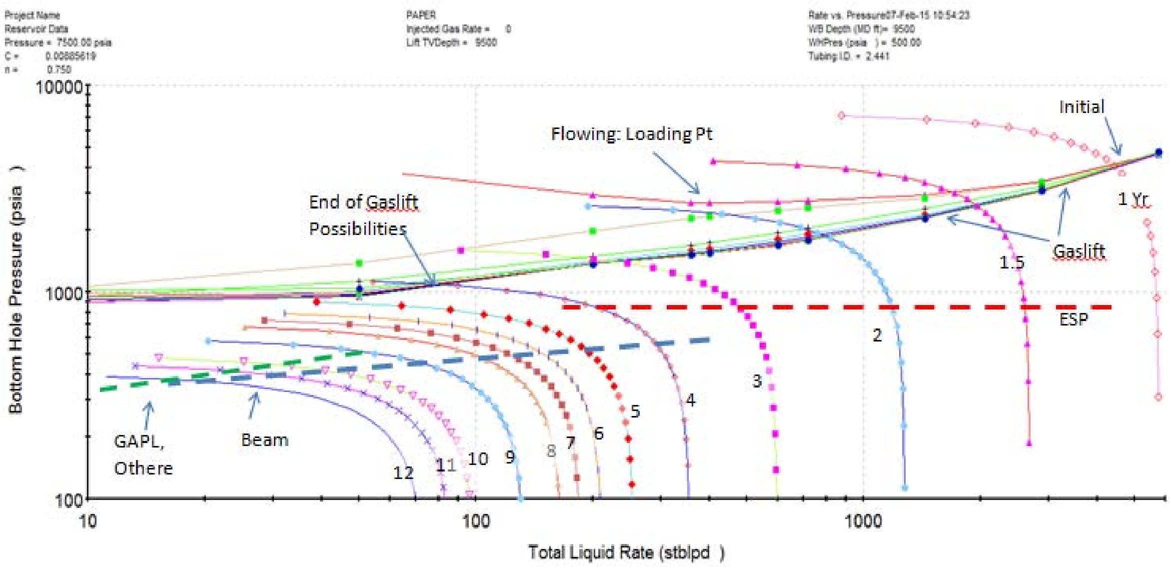

Figure 4 - Reservoir Performance with Ranges of Possible AL Application

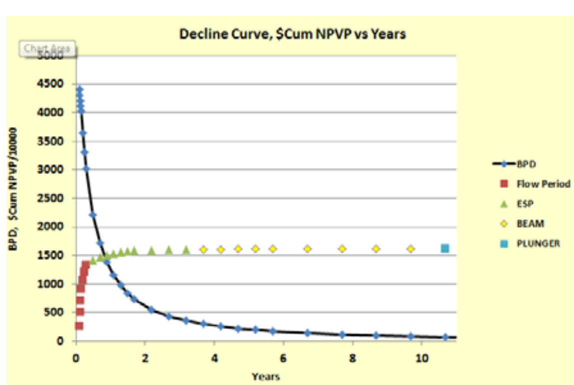

Figure 5 - Cumulative Net Present Value generated by methods of lift over the decline period