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Producing Coalbed Methane at High Rates at Low Pressures

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Abstract

In the highly productive Coal Bed Methane (CBM) "Fairway" area of the San Juan Basin of Northern New Mexico and Southern Colorado, traditional reservoir-evaluation methods have failed to approximate production levels. The reservoir seems to have the potential to produce gas at nearly the same rates at reservoir pressures of under 100 psia as it had at 1,500-1,800 psia. This observation has a significant impact on the economics of late-life investments, on the design of wellbores, on well site equipment, and on pipelines. A non-traditional approach was taken to evaluate the long-term impacts of a mix of these interventions. This mix of interventions was taken and the analysis was generally a fair indicator of specific-well response to the proposed actions.

Introduction

Gases adsorbed to the surface of coal are a well-known phenomena—methane has always been a hazard in underground coal mining and several economic Coalbed Methane (CBM) fields have been produced around the world.

Only in the San Juan Basin "Fairway" have any wells been able to sustain individual-well production rates of 1,000-25,000 MCF/d over a decade. Fairway wells are characterized by: (1) initial reservoir pressures above overburden pressure; (2) sustained producing rates above 1 MMCF/d; (3) high CO_2 mole percent (above 8% and increasing with drawdown); and (4) low free-flowing water/gas ratios (1.5-12 bbl/MMCF). Generally, the CBM Fairway wells are completed with open-hole cavities that have been prepared by cavitation, which uses hydraulic surges to create and shape the cavity.

There were no processing facilities in the San Juan basin to remove the high CO_2, so a new infrastructure of gathering, compression, and processing was built and largely on line by early 1991. At the beginning of 1988, CBM production was about 7% of the 1.6 BCF/d that was being produced from the San Juan Basin (**Fig 1**). With the construction of new conventional processing facilities, new CBM facilities, and new pipelines to sales points, by early 1992, CBM accounted for about half of the 2 BCF/d that the San Juan Basin was then sending to market. Currently CBM accounts for 62% of the 4 BCF that leaves the San Juan Basin each day.

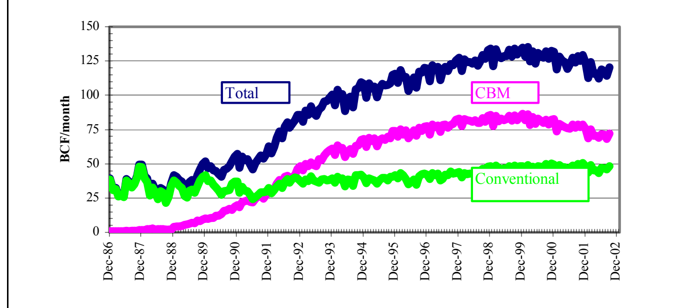

Fig 1: San Juan Basin Production

While the fairway has become a significant revenue stream, it has defied accurate rate prediction. The nature of CBM gas storage is such that the first 20% of the OGIP was produced by lowering average reservoir pressure to 30% of original pressure (**Fig. 2**). During this period, the main focus by all of the CBM operators was to expand facilities to handle the inclining production while not clearly understanding the mechanism of the incline. When high-rate wells began logging off in 1995, facilities plans were either abandoned or significantly modified, and efforts were undertaken to try to meet production goals at low reservoir pressure.

Reservoir Analysis

All CBM operators use sorption equations to determine gas-in-place and recoverable reserves. The most common method uses the Langmuir Isotherm (**Fig. 2**) to relate average reservoir pressure to remaining gas in place. This technique has stood up very well to many measurements over several years and generally seems to be quite valid in relating pressures and remaining volumes, but the technique does not address production rates.

If you can assume that production rate is dominated by the reservoir's resistance to gas diffusion, then equations based on D'Arcy's Law should predict CBM production rates just like they do in pore-volume-storage reservoirs. Since virtually all of the gas-in-place is adsorbed to the surface of the coal, gas production actually changes the reservoir characteristics. The coal matrix (which swelled in adsorbing gases) will shrink—increasing porosity. Overburden forces will try to compress the coal—decreasing porosity. The coal starts with very low mechanical strength (i.e., friability is generally less than 15 psi) and relatively small localized-pressure gradients can cause the coal to fail—increasing the apparent permeability. If any combination of these factors dominates production rates, then D'Arcy's equations are largely irrelevant.

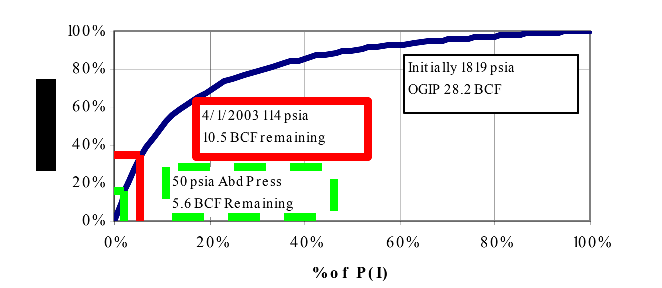

Fig 2: Example of Langmuir Isotherm

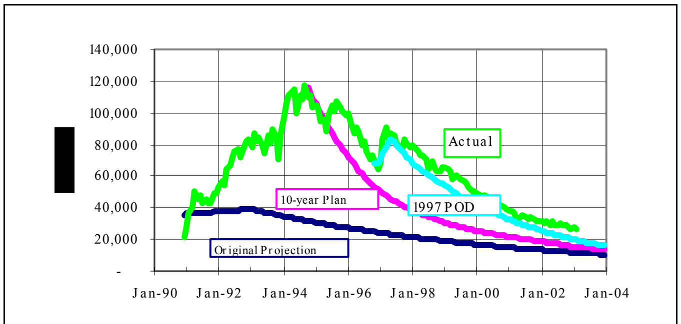

Fig 3—Comparison of actual production to various forecasts

During the first few years of production, inclining rates were attributed to "de-watering" in spite of the fact that water/gas ratios remained fairly constant after the first 14-45 days of production. **Fig. 3** shows a series of rate predictions that were applied to a group of Fairway wells on one gathering system. The original prediction (made in mid-1989, before any gas had been produced) was based on D'Arcy's Law and assumed a 24-month de-watering period with inclining production (to 39 MMCF/d), followed by a significant (semi-log linear) annual decline. In September, 1994, with rates 4 times the maximum production predicted by the original evaluation, a new set of forecasts was prepared which also used equations based on D'Arcy's Law and predicted an even steeper decline from this new rate.

The foundation for predicting production rates in gas wells is the *Bureau of Mines Method of Gauging Gas Well Capacity* [1]:

$$q = c_p(\overline{P}^2 - P_{bh}^2)^n \qquad (1)$$

The body of work to evaluate each term in equation 1 is very robust and has been refined frequently over most of the 20th Century. The field-techniques and equations that are associated with this work allow rate predictions in pore-volume-storage reservoirs to be done with reasonable precision. These rate predictions typically stand up well to actual conditions. If you can assume that both the Back-Pressure Coefficient (c_p) and Non-Linearity (n) term are constant then if you can determine reservoir pressure and anticipate a bottom hole flowing pressure you should be able to predict gas rates through time.

When we assumed that the Non-Linearity term was constant (and 1.0), observations have shown that the "constant" c_p can increase by as much as 30% per month in the Fairway[2][3][4][5][6]. If the n term is assumed to be a constant other than 1.0, then the computations are slightly more difficult but the results are very similar. **Fig 4** is the result of determining the Back-Pressure Coefficient (with n=1.0) very carefully on one CBM Fairway well before and after the well was re-cavitated (the c_p data is for June, 1994, and January, 1995) and applying that constant to the ΔP^2 term back to first production and ahead to December, 2000 to predict gas rates. It is obvious from this plot that determining the constant empirically at a point in time has little value in predictions of Fairway production rate.

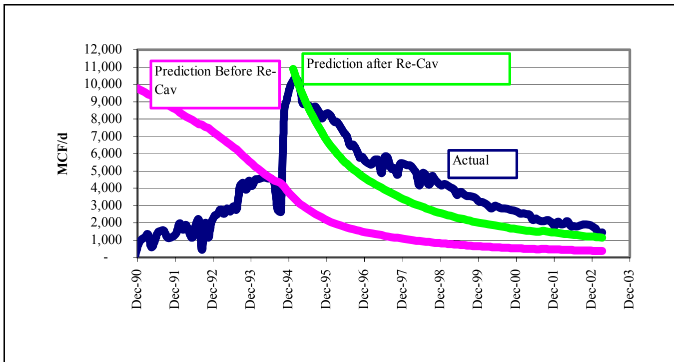

Fig 4: Actual production for a typical well compared to production with c_p held constant from a value computed 6/94 and 1/95

Fig 5 is the result of an attempt to determine the rate of change of the back-pressure coefficient historically over a fixed time period (January thru June, 1996) and then developing a non-linear function to project it into the future. This evaluation found the rate of change of c_p (about 0.5%/month for this well) to be dominated by the rate of change of ΔP^2 so even a rapidly increasing c_p could only reduce the rate of (semi-log linear) annual decline slightly. As you can see from the graph, actual results were about 18% higher cumulative production than predicted.

These two techniques were applied to dozens of wells before both methods were abandoned by the project team as not applicable in the CBM Fairway.

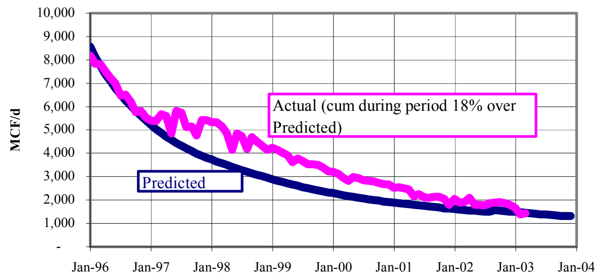

Fig 5—Results of a detailed statistical analysis of the back pressure constant on one well

Since empirical determination of c_p was found to be inappropriate, analytical methods were sought. One common statement of radial gas diffusion in a porous media [7] based on D'Arcy's Law is:

$$c_p = \frac{kh}{1422\mu ZT\left(\ln\left(\frac{re}{rw}\right) - \frac{3}{4} + Skin\right)} \quad \text{..................(2)}$$

While this equation assumes a great deal of homogeneity across the reservoir [8], it does an adequate job of predicting gas rates in pore-volume-storage reservoirs over both time and cumulative production.

Significant effort has been spent trying to determine what mix of reservoir parameters in *equation 2* are changing to yield inclining production in the CBM Fairway. Most operators use some sort of a numeric grid-to-grid reservoir model to predict production rates. The most sophisticated of these models allow either *kh* and/or S*kin* to vary with time (or with cumulative production) to account for observed anomalies in CBM production. None of these approaches has been particularly successful.

The current study tried to approach the rate-prediction problem without a strong dependence on *equation 2*. Values were assigned to all the terms (except *Skin*) in *equation 2* for each well. All of these parameters were held constant over time (while compressibility and viscosity will vary with drawdown, these effects were not included since they are second-order effects that are unlikely to be within the accuracy of the calculation). Using an empirical equation based on a rock mechanics model coupled with a numeric reservoir simulator, the "*Skin*" term was defined as:

$$Skin = -13.4 + 4.92\phi_0^{-0.167}\left(\frac{c}{b}\right)^{-0.438}\left(\overline{P} - P_{bh}\right)^{0.2636} \quad (3)$$

This equation treats skin as a function of drawdown. ($\overline{P} - P_{bh}$). All other terms in *equation 3* are treated as constant with time and with cumulative production. This technique allows an iterative approach to drawdown vs. Rate vs. Facilities capacity.

Putting *equation 3* into *equation 2* and the result into *equation 1* mutes diffusion-dominance of *equation 1*, but retains the ΔP^2 nature of *equation 1*. The authors feel that while retaining this nature has limited support in field data, they were unable to identify another viable relationship between established conditions and flow rates.

Study Parameters

This study looked at 62 Fairway wells that our company operates to integrate possible interventions at the coal face with interventions in the wellbore, artificial lift installations, well site design, and gathering system changes. The goal was to look at the revenue-impact of a mix of these interventions to maximize the net present value (NPV) of our part of the CBM Fairway.

We looked at each well from first production through the end of 2010. A well was assumed to be abandoned when either the reservoir pressure reached 80 psia or the rate reached 10 MCF/d. To reach reservoir pressures this low, wellhead pressures were modeled to below zero psig. Because of the nature of the CBM Fairway, there seems to be a very weak relationship between changes in flow rate and changes in reservoir pressure—which supports the theses that resistance to flow decreases with drawdown. Facilities to deal with very high flow rates at these low pressures were significantly different from the original design conditions (i.e., moderate to low flow rates at very high pressures) and several radical approaches have been incorporated in the design of the interventions recommended by this study.

At the end of the study, the set of interventions that were defined were assembled as a project that included well work, artificial lift, well-site modifications, and compression. This project was approved and the first phase of the work was completed in late 1997. The entire package of work was completed in 2000.

Interventions

The interventions available were: (1) wellbore work; (2) installation of artificial lift to remove water; (3) well site equipment changes; (4) well site and/or lateral compression; and/or (5) gathering system improvements. To be successful, the project had to simulate the effect on gas rate of any combination of these five possible interventions. Since the gathering system is operated by the same company as is operating the wells, modifications to the gathering lines were just as reasonable as modifications to wellbore tubulars.

Wellbore Analysis. Typical wellbore configurations have 7-inch casing set above the top of the uppermost coal seam. Most of the original completions included 5-1/2 inch liners across the coal, but well-work over the years had removed liners to improve access to the coal face. The liners were not reinstalled because there was no evidence that they helped production. Most of the wells had tubing set at about the casing shoe. Tubing sizes ranged from 2.375 inch to 4.500 inch.

Since these wells all have large (up to 10-feet radius) cavities in the coal seams, fluid velocity through the uppermost seam is very slow (on the order of 0.1-3.0 ft/sec) and the upper seam generally acts like a separator to drop water back down on the lower (and more highly productive) seams. In early-time production this water was not a problem since the lower seams were pressured to over 1,500 psia and surface pressures were under 200 psia—a column of water several hundred feet high would not have significantly affected production. Reservoir pressures at the time of the study were under 400 psia with surface pressures at many uncompressed wells above 125 psia—600 feet of water will log a 10 MMCF/d well completely off under these conditions.

The main objective of well work was to manage the water production and improve overall gas flow. This was done through work at the coalface and modifications to wellbore tubulars.

Coal Face. Reviews of drilling reports, workover reports, production history, and discussions with pumpers suggested that many of the wells in the study area had consistently bridged off at about the same place after every operation and that some wells consistently flowed large amounts of solids to surface. Some of the bridges were made up of large coal pieces and sheets of sloughing shale. When these bridges clogged the bore-hole at the bottom of one of the upper seams there was a significant reduction in well-performance. The make-up of these bridges was confirmed in 1996 with a down-hole camera run in several wells. The authors felt that the bridges were allowing water to seep into the lowest cavity and flow back into the reservoir while restricting commercial flows of gas from that seam.

Managing water in the open hole was the next area that was addressed in the wellbore. Putting pumps into a cavity has not been successful for a variety of reasons. Also, a detailed analysis of a group of a competitor's wells with and without liners across the coal-seams showed that liner-wells consistently had significantly higher WGR than unlined wells (i.e., 8-12 bbl/MMCF vs. 1.5-6 bbl/MMCF). Experience has shown that the higher the WGR (within a narrow band), the more gas the well will consistently produce.

Water management and trying to keep the bore-hole between seams open has lead to a program of setting liners across the coal seam in the study wells.

Wellbore Tubulars. We looked at tubing size in each study well. Generally we had been using the tubing string for primary production and kept the tubing/casing annulus closed. To accommodate free-flow rates of up to 25 MMCF/d, 4.500 inch tubing was used in several wells. The strategy that this project adopted was to use the tubing for water management and the tubing/casing annulus for gas production. This decision caused us to standardize on 2.875 inch tubing in un-lined wells and wells with 5.500 inch liners. When specific-well considerations prevented 5.500 inch liners, we used 4.500 inch liners and 2.0625 inch tubing. The wells that we couldn't line for various reasons mostly got 2.375 inch tubing installed, but some still have other sizes.

The combination of 2.875 inch EUE tubing and a 5.5 inch liner caused an excessive restriction within the liner. The effective diameter of the annulus between the tubing boxes and the inside of the liner is less than 2 inches (outside the boxes the equivalent diameter is 3.2 inches—46% more flow area). This difference proved to be the largest bottleneck we had. By changing the tubing within the liner to 2.375 inch Hydril® the bottleneck went away. Since we saw no change in water production with 500-600 feet of 2.375 we started changing out entire strings of 2.875 for 2.375 (EUE above the liner and Hydril® in the liner) in late-1998 without a negative impact on water production and with a significant positive impact on gas production.

Finally, we looked at tubing depth. It was clear that setting the tubing above the coal seams would be ineffective in water management at low reservoir pressures. The other extreme was to set the tubing in a rat-hole below the lowest seam to pull water to the lowest possible level. After considerable modeling and spirited discussion, we decided to set the tubing in the upper 1/3 of the most productive zone in free-flowing wells and the lower 1/3 in pumping wells. Where we were able to clearly identify a dominant zone, this technique has worked well. The problem is that we have not always been able to say which zone is dominant—picking the wrong zone or the wrong height in the zone has caused several very large wells to have no flow up the tubing, much to the detriment of total production. We have had several examples of moving tubing 10-25 feet up or down the wellbore making 1,500-2,000 MCF/d change in rate.

Artificial lift requirements. A review of several nodal-analysis programs and textbooks pointed to a fluid velocity around 36 ft/sec as a cusp in the ability of a vertically-flowing gas stream to carry liquid water in a multi-phase flow regime. Since the authors have had very limited success applying any of the dozens of multi-phase vertical-flow correlation's to real-world conditions at low Reynolds Numbers, we chose to avoid the problem by assuming artificial lift in the model when the fluid velocity dropped below 36 ft/sec. This assumption allowed us to model single-phase gas flow in the annulus and single-phase water flow in the tubing.

Our initial artificial lift technique has been rod pumps. This technology was chosen because of both its easy availability and the wealth of knowledge that exists within our company in the design, installation, and operation of these units. A major concern is the amount of water above the pump required to open the standing valve (i.e., the "Net Positive Suction Head" or NPSH). This head could easily be enough to cause a large well to log off with significant remaining potential.

Our experience with rod pumps has been that about ½ of the installations have significantly increased production. The rest of the installations have either not made a difference or have actually decreased production. Evaluation of the less-successful installations has led to reconsidering exactly where the dominant zone is and to move the set-depths to be consistent with the re-determined dominant zone.

Because of low water rates and the potential for pump damage when a pump runs dry, we have spent considerable effort trying to develop a pump-off control strategy in this non-electrified field. This problem has two distinct facets: (1) determining when the well is pumped off; and (2) remote starting and stopping an engine-driven pump. The first problem has defied solution. With high flow rates and low water cuts, dynomometer readings are very ragged and difficult to interpret so dyno-based pump-off controllers were not an option. At our current bottom-hole pressures (i.e., 10-25 psig), by the time you see a tubing/casing differential, a change in total gas rate, or a change in tubing pressure the well has a significant problem. We've seen cases where flow rate would drop from 3 MMCF/d to 2.2 MMCF/d overnight to be followed within 2-3 days by zero flow. At these pressures liquid-loading problems have to be anticipated—you can't wait for them to be observed.

Effective techniques for automated start/stop processes for engine-driven pumps have also eluded us. Starting a natural-gas driven engine requires a certain "touch" on the choke and/or on the throttle that automatic processes lack. When we've tried this technique the usual result is a dead battery and a logged-off well. Automated clutches with either pneumatic or hydraulic actuators have shown real promise on wells with high gas-pressure on the surface, but they are fairly expensive and high pressures are rare. These clutches haven't been widely deployed.

Early experiences with pneumatic surface equipment operating rod pumps have been encouraging. In this scenario, a set of pneumatic rams replaces the traditional pumping-unit surface equipment while the downhole equipment is an unmodified rod pump. Pump-off control with these devices is very flexible—they can accept an external start/stop signal from well site automation and they come with clocks for timed start/stop. Our use has been limited to clock cycles, but the results have been extended pump run times with production profiles very similar to other rod-pump applications.

Experience with progressive-cavity pumps and with hydraulic jet pumps has been disappointing. Both of these technologies have had an unacceptable failure rate in high-solids production.

An unconventional lift method that has proven very successful has been surface eductors. An eductor is in the family of "thermo compressors" which includes air-ejectors, evacuators, jet pumps, and sand blasters. These devices use a high-pressure gas stream into a set of convergent/divergent nozzles to raise the pressure of a suction stream to an intermediate pressure. In our application, wellsite-compressor discharge pressure is used to drive the eductor. The eductor pulls on the tubing. The combined power-gas and tubing flow is then discharged into the flow-line from the tubing-casing annulus and back to the compressor suction. This device allows a small amount of compressor horsepower to be focused on the tubing string. When the system is working properly, the eductor can maintain the water level near the bottom of the tubing indefinitely. The net result is that wells on eductors have eliminated liquid-loading problems and have significantly flattened decline. When the system doesn't work it is usually because: (1) the well makes too much water for the eductor to keep up; (2) the tubing was set too low and the eductor is unable to kick-start tubing flow; or (3) the tubing ingested solids and sealed the end of the pipe. Sometimes, the last problem can be resolved by "reversing" the eductor to send compressor-discharge gas down the tubing to break the plug loose, but this doesn't always work.

Well Site Design. The pressure drop across a well site is the result of the influence of many factors including wellhead valve size, piping size and condition, number of bends and elbows in the pipe, production equipment size and condition, and measurement equipment size and condition. Each of these factors will have a different contribution to pressure drop depending on flow rate and surface pressures. Consequently, this project consolidated all the pressure drops into an equivalent length of 3-inch pipe by solving the American Gas Association (AGA) fully-turbulent flow equation (equation 4) [9] for L with $D=3.0$.

$$q = \frac{155.08T_s}{1000P_s}\left(\frac{P_{up}^2 - P_{dn}^2}{T_s ZL(SG)}\right)^{0.5} D^{0.25}\log_{10}\left(\frac{3.7D}{\varepsilon}\right) \quad .....4$$

Once the equivalent pipe length was determined, that value was completely scaleable over any anticipated rate/pressure combination. If this equivalent length was over 1,000 feet, then the well was considered for well site debottlenecking during 1997. If it was less than 100 feet then the well was considered to be adequately designed. Any well site with an equivalent length between 100 and 1,000 feet would be rebuilt in conjunction with later project phases.

The interventions available on the well site were changes to: (1) the wellhead; (2) well site and gathering system piping; (3) production units; and/or (4) measurement equipment. This mix of options allowed us to assume that after well site work the equivalent pipe length would be under 100 feet.

Wellhead changes. All wellheads were configured with two casing wing valves, a tubing master valve, and two tubing wing valves. Since reservoir pressures were under 400 psia and decreasing, the transition to line pipe took place at the tubing master-valve and at the casing wing-valves for a substantial cost savings without compromising either safety or functionality.

Piping. A major concern in operating at high flow rates and low pressures is water dropping out of the gas and standing in the flow line. To address this concern, we ran three independent lines from the wellhead to the production unit. Off one side of the tubing, we ran a 2-inch line into the separator. This line is intended to carry the pump discharge on wells with artificial lift and the tubing flow on the other wells.

Off each casing valve we ran a 3 or 4-inch line (depending on expected flow rates). At the production-unit end of each flow line we installed a flush connection and a block valve. This combination allows the well to normally see an effective pipe diameter (from the two lines) that minimizes the pressure drop across location while allowing the pumper to selectively raise fluid velocities to flush water from the line. If shutting off one side of the wellhead is inadequate to flush the line into the separator, the separator-inlet block valve can be shut and the flush connection can be used to blow the line into a tank. Also, this combination allows the lines to be chemically cleaned when there is a buildup of scale, coal, or paraffin (an occasional by product of inter-bedded sandstone lenses in the coal).

Production units. Well site separators had been sized to handle the maximum gas rate the well had ever made, and water rates of 15 bbl/MMCF at 10 psig. Since the anticipated conditions after the project were far different from the conditions we had seen in the past, we felt like this over-design was adequate.

Gas measurement equipment. The measurement equipment was sized for a 0.5 β-ratio (i.e., the ratio of the orifice plate bore to the tube inside diameter) and 30 inches of differential pressure at expected line pressures. These conditions minimize both measurement uncertainty and wasted horsepower.

Compression. With a need to minimize engine emissions, compression design has focused for several years on maximizing efficiency by designing lateral and transmission compression to operate in a narrow rate/pressure range. Single-stage booster compressors have been used within the gathering system to avoid the need to use three-stage machines at the transmission line to access the high-pressure (≈1,000 psig) transport system.

For this project, the choice was to use oil-flooded rotary-screw compressors on the wellsites to allow for very low suction pressures at moderate to low discharge pressures. Currently we are seeing 5-15 psig at the compressor suction and very good flow rates.

Gathering System Design. The gathering systems have evolved over five years to minimize the compression horsepower that is lost to friction drop. Additional lines, pigging facilities, and innovations in drip design have been applied to the gathering systems to prepare them for low-pressure operations. This approach has proven to be reasonably successful, but a great deal of diligence must be applied to the pigging schedule to keep water in the lines from increasing discharge pressures beyond what the well site compressors can handle.

Systems Integration

The integration of the reservoir calculations, the wellbore equations, the surface constraints, and the pipeline capacity into a predictive model required: (1) calibrating the system for each of the wells in the study area; (2) verifying that the system can match historical production; and (3) predicting future performance under various construction scenarios. The authors facilitated this analysis by writing a computer program that was integrated with a database and used a commercial computational engine.

Calibrating the system. Original gas in place was calculated based on:

$$OGIP = 0.031214 AhV_m y\rho \frac{bP_i}{1+bP_i} \quad \text{........................5}$$

Most of the parameters were taken from logs, samples, or surface measurements. For the original OGIP calculations, the drainage area (*A*) was set at a constant 320 acres and the Langmuir Shape Factor (*b*) was held to a constant 0.002 psi^{-1}. These values hold up reasonably on the average across dozens of wells, but for any specific well they can be significantly off. The first step in the system integration was to calibrate drainage area and shape factor.

Equation 5 can easily be rearranged to yield current reservoir pressure as a function of cumulative production. Since the Fairway wells have a very low resistance to inflow, a 12 hour build-up test will generally yield approximate reservoir pressure and build-up data can be used to calibrate both *A* and *b*. This was done in 1994 and was verified in 1997 for the current study. The calibration resulted in drainage areas ranging from under 60 acres to over 600 acres (average 300 acres) and shape factors from 0.0008 psi^{-1} to 0.0044 psi^{-1} (average 0.0025 psi^{-1}). With this technique, remaining gas and average reservoir pressure both historically and prospectively can be easily and accurately determined.

Equation 2 and equation 3 can both be solved for *Skin* to determine a value for original porosity (ϕ_0) and matrix shrinkage (*c/b*) at the start of the analysis. Matrix shrinkage is assumed to be a constant relative to both cum production and time.

Verifying historical performance. Once the system was calibrated, historical surface pressures could be used to see if the programs would calculate historical rates. This step was crucial to determining if the system was able to predict inclining production. Major events such as re-cavitation were beyond the system's ability to deal with since these events make step-changes in the well's ability to produce (see **Fig. 4**, the re-cavitation took place in December, 1994). The model consistently matched cumulative production over the period from the last Re-Cavitation to the beginning of the study to within ±10%. It achieved this result with historical surface pressure as an input, but reservoir pressure computed from the cumulative production in the model. It is significant that the model was able to predict periods of inclining production rates on most wells—it does not explain why the production rate on the wells was inclining, but it did mimic the actual behavior.

Predicting future performance. Three different cases were evaluated for each well. The spending profiles and the production profiles were then compared to find the highest contribution to NPV at a proprietary discount rate. In all the cases there were mandatory spending points.

Mandatory spending. Artificial lift was installed whenever bottomhole velocity dropped below 36 ft/sec. The cost of the installation was borne in the month that it was required, and monthly operating costs and fuel were assumed to remain with the well until abandonment.

Also, if the well site pressure-drops exceeded the drop across 1,000 feet of 3-inch pipe, the debottlenecking costs were included in 1997 and the lower (i.e., 100 feet of 3-inch pipe) value was used from that point forward.

No wellhead compression case. This case looked at how the wells would perform at low reservoir pressures (80-200 psia) and moderate (70-150 psia) gathering system pressures. Typically the results of this case were to recover the reserves over a longer time frame and to leave more reserves in the ground at the end of the study. For 22 wells, this case had the highest NPV. Over time it has become very clear that all of these wells had significant down-hole problems. When the problems were corrected, wellhead compression was required to prevent the early-abandonment of significant reserves. Compression was installed in 1998-00 and this group has exceeded cumulative production (in early 2003) by almost 25 BCF (87% over estimates).

Early Wellhead Compression case. This case looked at the results of installing enough wellhead compression horsepower to pull the wells down to 10 psig during the first quarter of 1997. Expectations were that this case would yield the highest gas rates, most NPV, and best recovery factors. The nature of the Fairway is such that expectations are seldom realized. The model only showed 23 wells in the study area that should get immediate compression. In total, the wells in this case performed at 1% over the target rate through 1998 and by early 2003 they had produced 9% more cumulative production than the project predicted (8 BCF over).

Significant care must be applied to the wells in this case to prevent lowering coal-face pressure too far too fast. The phenomena of a "pressure window" has been observed throughout the Fairway since first production—each well seems to have a narrow range of pressures that maximize its production rate at a given point in time. Pressures substantially below that target are much worse than pressures slightly above the target window. Many theories have been put forth to explain this "pressure window", but none have held up to the realities of field tests.

Staged Wellhead Compression case. This analysis started with the "Mandatory Spending" case and looked at the data mathematically. For *gas rate, decline, skin,* and c_p we developed empirical equations to describe each parameter as a function of time. Whenever one of the equations fit the predicted data (i.e., 45 of the 62 wells), the first and second derivative was taken of each curve. On those wells where either derivative showed a distinct local minimum for any of the equations, installing wellhead compression at that point always resulted in the maximum NPV. Seventeen wells exhibited this distinct local minimum and had compression installed in 1998-2000. This is the poorest-performing group with 92% of projected cumulative production delivered by early 2003 (under delivery of about 6 BCF). This group did deliver 23 BCF more than the do-nothing case predicted and the cumulative production was within the ±10% accuracy that the authors hoped for in the project design.

Gathering System Capacity. At the completion of each case, the expected rates and pressures were fed into a comprehensive pipeline model to evaluate gathering system bottlenecks. At that point a decision was made to either expect higher wellhead pressures or to increase gathering capacity. After making that decision, new pressure assumptions were put into the individual-well model and the case was run again. Final cases included gathering-system capacity in the recommended interventions.

Conclusions

This study suggested work on 50 of the 62 study wells during 1997. A project was authorized in August 1997, and completed by the end of the year. The remaining wells were worked on in 1998. The last of the wellhead compressors was installed by 2000.

As we start the sixth year of this project, the cumulative production is 61 BCF ahead of model projections and the daily rate is 27% over the projection. Comparing actual results to the base case without doing this work we are 164 BCF (124%) ahead and the current rate is 66 MMCF/d (434%) ahead.

These results were made possible through ongoing efforts by an entire team of people who were willing to search for innovative solutions to the new problems that have cropped up at each stage of the pressure draw down. The fundamental design that was described in this paper has carried us from almost 400 psia average reservoir pressure to 113 psia. This pressure-traverse has seen wellhead pressures too low to allow separators to dump, huge water volumes moving as water vapor (and then collecting in the gas-gathering system), and new kinds of scale that showed up with the water phase-change. Adequate solutions to each new problem have been implemented over time.

While the aggregate results are positive, the individual-well results are a bit more mixed as you can see in Table 1. The project reduced the aggregate decline from 26% to less than 12% and raised our confidence that we can economically recover an unheard-of proportion of the original gas in place.

Actual Compared to Target	Target 4/1/03 Gas Rate (MMCF/d)	Actual 4/1/03 Gas Rate (MMCF/d)	Well Count
<-50%	1.8	0.6	2
-50% < x < -10%	15.3	10.8	12
±10%	5.6	5.6	6
+10% >x>50%	15.2	20.2	19
>50%	12.7	27.1	23
Total	50.6	64.3	62

Table 1

Nomenclature

A= *Drainage area* (ft^2)
b= *Langmuir Shape Factor* (psi^{-1})
bbl= *Standard oil-field Barrel (42 gallons or 0.159* m^3*)*
BCF/d= *Billions of Standard Cubic feet per day (28,317,000* m^3*/day)*
c= *Cohesion (psi)*
c/b= *Matrix Shrinkage* (psi^2)
c_p= *Back Pressure Constant* ($MCFd/psi^2$)
D= *Inside diameter of a pipe (inches)*
h= *Thickness of pay (ft)*
k= *Relative permeability to gas (mD)*
L= *Length of a pipe (miles)*
MCF/d= *Thousands of Standard Cubic Feet per day (28.3* m^3*/day)*
MMCF/d= *Millions of Standard Cubic feet per day (28,317* m^3*/day)*
OGIP= *Original Gas in Place (SCF)*
n= *Non-linearity term*
NPV= *Net present value at an assumed discount rate.*
$\overline{P}$ = *Average Reservoir Pressure (psia)*
P_{bh}= *Flowing bottomhole pressure (psia)*
P_{dn}= *Downstream pressure on a pipe (psia)*
P_i= *Initial Reservoir Pressure (psia)*
P_s= *Standard Pressure (psia)*
P_{up}= *Upstream pressure on a pipe (psia)*
q= *Volume flow rate (MCF/d)*
re= *Drainage radius of the well (ft)*
rw= *Wellbore radius (ft)*
SG= *Specific Gravity*
Skin= *Resistance to flow into the wellbore*
T= *Temperature (Rankine)*
T_s= *Standard Temperature (Rankine)*
V_m= *Mineral Matter Free Coal (SCF/ton)*
y= *Mineral Matter Free Mass Fraction of total coal (fraction)*
Z= *Compressibility (fraction)*
μ= *Dynamic viscosity (cp)*
ε= *Pipe effeciency (ft/ft)*
ϕ_0 = *Original Porosity (percent)*
ρ= *Density (g/cc)*

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