Coalbed Methane Operations

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Coalbed Methane (CBM)

In1980, the U.S. Congress passed the legislation that came to be known as the “Section 29 Tax Credit for Unconventional Fuels” as part of the so-called “Windfall Profits Tax” [DOE] that was the facilitating event for worldwide development of natural gas production from coal beds (called Coalbed Methane in the U.S. and many other countries, Coalseam Gas or CSG in Australia). Prior to this legislation, the Oil & Gas Industry knew the location of significant gas in coal fields but lacked the technology to exploit it: we did not know how to complete the coal and we did not know what surface pressures we would need at any given time. We lacked the processing infrastructure for high-CO_2/low-BTU gas. All these things that we did not know were going to be expensive to learn and gas prices were low enough that the industry did not anticipate an adequate risk/reward balance. The tax credit provided a benefit that was worth approximately 4 times the value of marketing CBM gas (because it was a credit applied to a company’s tax bill, not to its gross income). Without the Section 29 tax credits it is unlikely that the technology and knowledge required to make any of the CBM/CSG fields in the world viable.

CBM highlighted the difference between oilfield techiques and techniques appropriate for unconventional gas as shown in Figure 1. When we drill a conventional gas well, all of the mechanical energy that will ever be in the gas is contained in the pressure and temperature of the gas in the pore volume, the life of the well is all downhill towards lower and lower energy. You reach a point reasonably early in the reservoir life where it simply stops being economical to lower the pressure further and it is common to abandon as much as half of the Original Gas in Place (OGIP) at the end of the well’s life. On the other hand, the gas in a coal bed is adsorbed to the surface of the coal and is not free in the (very limited) pore volume. As pressure is depleted, more gas desorps from the coal and replenishes the drive energy. In a conventional well, it is very difficult and often too expensive to lower reservoir pressure below about 60 percent of initial

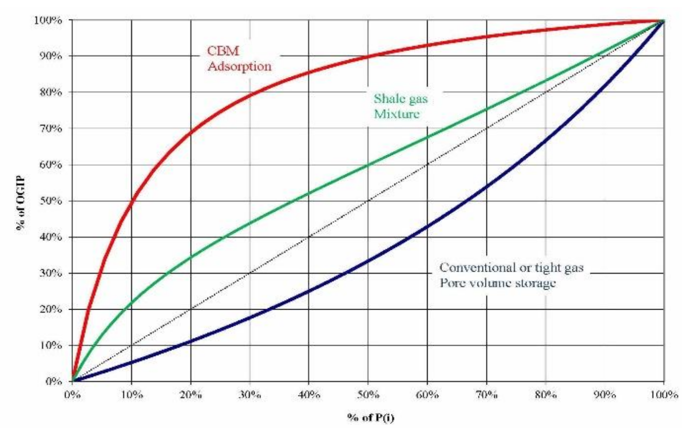

Figure 1. GIP vs Reservoir Pressure

reservoir pressure while it is generally quite economic to lower the pressure in a CBM reservoir to 2-5 percent of initial reservoir pressure, recovering over 95 percent of OGIP.

Gas has historically been considered a waste product that was only produced in the quantities necessary to recover valuable liquid hydrocarbons. Consequently, the industry spent little effort thinking about the differences. We used liquid-flow calculations with minimal adaptations for the differences between gas and liquid. It was often more important to get numbers than to get accurate numbers in our calculations about gas—gas was a waste product. Figure 2 shows and example of why this approach ever worked at all. Above about 145 psia [10 bara] the relationship between water content and pressure is a very good approximation of a straight line. This analysis has been done for many physical parameters (e.g., compressibility vs. pressure, enthalpy vs. pressure, entropy vs. pressure, and pipe flow capacity vs. pressure) and drawing transition lines at 43.5 psia [3 bara] and 145 psia [10 bara] on each of the charts leads to the same conclusions—as long as pressure is above 145 psia, the assumption that gas flows as an incompressible fluid is an excellent approximation. As long as conventional fields were abandoned considerably above 145 psia there was no incentive to reconsider this approximation. In the well used for the CBM line in Figure 1, 145 psia was 11 percent of initial reservoir pressure so the last 50 percent of the available gas in place would not necessarily follow incompressible flow rules. In the low pressure part of Figure 2 the deviation from linear behavior becomes too large to ignore.

The other major piece of the difference is that D'Arcy flow (i.e., flow in a pourous media) is very nearly zero because of the nano-Darcy permiability in the coal matrix. The flow in CBM is much closer to channel flow or pipe flow than it is to D'Arcy flow. When we try to apply D'Arcy flow calculations to CBM we mostly get wrong answers.

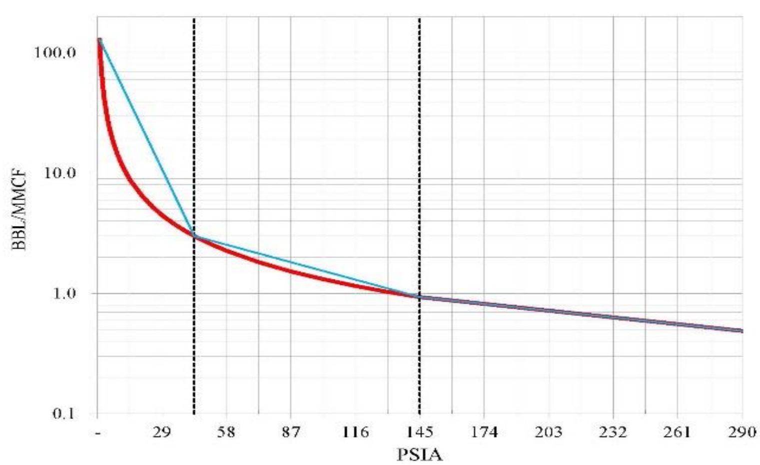

Figure 2. Water Content vs. Pressure for a specific temperature

Adsorbed gas acts as part of the coal matrix and does not behave like a gas. While the molecules are attached to the solid, the gas equation of state is not valid for those molecules. In short $PV \neq nRT$. This concept is crucial to understanding exactly how much gas a CBM field can contain. A good tight-gas field will recover about 0.5 BSCF/well. In the central "fairway" portion of the San Juan Basin CBM an average well will recover about 12 BSCF/well.

Desorption of adsorbed gas requires a drop in pressure (i.e., the gas content of the thin film layer is a function of the confining pressure). Once the gas has left the coal surface, it has all of the characteristics of any free gas. This free gas has expansive energy that acts to "push" reservoir fluids towards the wellbore while with conventional and tight gas reservoirs all of the reservoir energy that will ever be available is in the gas within the pore volume at initial completion, when the first molecule of reservoir fluid is produced, the energy has been diminished (I refer to this phenomena in a conventional or tight gas reservoir as "pulling" the fluids to the wellbore). This "pull vs. push" analogy begins to explain why it is nearly always economic to apply compression to late-life CBM wells while it is rarely economic to apply compression to late-life conventional and tight gas wells.

Water storage

Hydrostatic pressure in the cleat system is required for gas to remain adsorbed to the coal. Typically, the entire cleat system is water-full under pressure. Since all gas flow must initiate at the coal surface within a cleat, the water in the face cleats that intersect the wellbore must be (nearly) completely removed before there are pathways for gas to flow away from adsorption sites. Producing this "thoroughfare water" is commonly known as the "dewatering period" and can last from days to months. At the end of the dewatering period, the well will still produce water, but the water/gas ratio will tend to approximately stabilize and remain constant for most of the remaining life of the well.

As discussed below, there is no economic benefit of removing more water than is naturally flowing from the butt cleats, and there is strong evidence that over-pumping a well will actually reduce the ultimate gas recovery.

Target pressure

Every reservoir has a "sweet spot" in flowing bottom hole pressure that optimizes ultimate recovery. In the San Juan Basin Fairway CBM wells that number was a flowing bottom hole pressure of ½ of current average reservoir pressure (discovered through few trials and many errors). These observations allowed a prediction of what pressure was going to be needed in the future. The Isotherm analysis does not have a rate or time component, but as part of our normal business activities we regularly do production forecasts. The forecast has an implied cumulative production, so matching the forecast with the Isotherm it is a reasonable thing to develop pressure drawdown schedules to allow budgeting compression and gathering system upgrades early enough to allow for budget cycles.

CBM Completions

A conventional well is drilled using mud that has a hydrostatic gradient that results in a mud-pressure higher than reservoir pressure. The drilling/completion operation then installs production casing across the productive seams, cements it into place, then perforates the production casing and cement sheath, and stimulates the formation. Coal has very low mechanical strength and putting a mud or concrete hydrostatic gradient on the coal always causes a considerable amount of mud and/or concrete to break its way into the target formation, often doing irreparable damage to the productivity of the well. To avoid this damage, it is good practice to set production casing above the coal and cement it to surface. Then the coal is drilled without mud (called "air drilling") and is left either open hole or with an uncemented liner installed across the coal.

It is common for coalbeds to consist of multiple coal seams. If we leave the entire interval uncemented (good practice) then control of stimulations becomes impossible. If you are doing a hydraulic fracture stimulation, you have no way to control which seam(s) will get any frac fluid at all and what proportions of the job will go to what seams will always remain a mystery.

Statistical analysis of upwards of 1,000 hydraulic fracture stimulations in various CBM basins around the world has been puzzling. There does not seem to be any type of stimulation that has a better track record than any other type. Proppant type or proppant volume does not correlate with success in any basin. Any given stimulation type that provides good results in one well may give poor results in the next well and vice versa.

Coal miners have always talked about coal being "self-healing". This means that any inclusion in the coal matrix will eventually become part of the coal matrix and will be indistinguishable from the surrounding matrix. This does not bode well for the ability of injected proppant to successfully prop open flow paths in the coal.

There is a weak correlation between carrier volume and success. Frac jobs that include a lot of liquid (or foam) carrier and just enough "proppant" to enhance the abrasive characteristics of the fluid have tended to have a higher incidence of success, likely due to scouring vertical channels in the coal matrix that are too large to "heal".

The very best results have been achieved by "cavitating" the wells. This technique either uses surface compressed air or reservoir pressure to build up high pressure in the near wellbore and then rapidly drop the pressure to "surge" the well. These surges tend to fracture large sections of coal and the high velocity flow carries much of the broken coal to surface. The pressurize/surge cycles are repeated until the coal has "stops flowing" (i.e., solid coal to surface has diminished). This process requires the coal to have very low mechanical strength and it simply does not work in most coals, but since production improvements up to a factor of 40 times have been reported, where it works it is foolish to avoid.

Horizontal wells are the flavor of the week in Oil & Gas and many operators have tried horizontal wells in CBM with mostly poor success. The mud used to drive the downhole motor damages the coal. Successful frac jobs in horizontal coals have been rare, open hole horizontal wells have a very high incidence of collapse, and cemented casing tends to damage the coal.

Producing CBM

Since CBM is so unique, we need to think about how to capitalize on the unique positives and minimize the impact of the unique negatives. The most effective method to accomplish this is to focus on optimizing the reservoir. Usually, we shift the focus towards artifacts that we have chosen to install after the wellhead. For example, if we think of CBM as "low pressure", then we will select wellsite equipment and gathering pipe that is rated for very low pressure. If initial reservoir pressure is 1400 psia [97 bara] and all of that pressure will be exhibited at the wellhead within a day of shutting the well in, then if we build wellsite equipment with an MAWP of 100 psig [6.9 barg] and gathering pipe with an MAWP of 80 psig [5.5 barg], we will have to take a 1300 psi [89.6 bar] pressure drop across the wellhead choke, throwing away any early-life reservoir energy that would otherwise be used to sculpt larger flow channels within the coal.

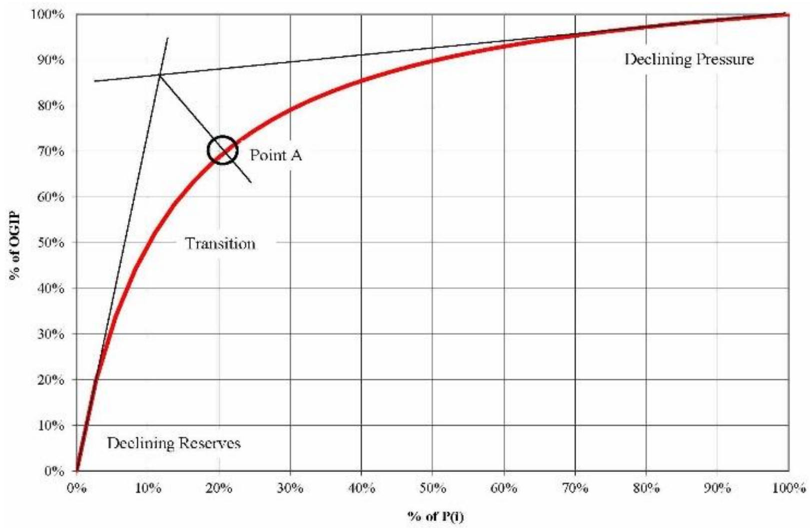

Figure 3. Life Cycle of CBM well

Life cycle

In early life, when pressure drops rapidly for a minor reduction in remaining gas in place (called the "Declining Pressure" region of Figure 3), that energy has value. If allowed to flow as rapidly as the reservoir will allow, the localized differential pressure will tend to pulverize coal that interferes with production. That pulverized coal will flow to surface as coal fines, but the space that it occupied within the reservoir will result in a larger flow conduit. Early-life coal to surface is a very good thing that should be maximized. In the early life, the reservoir "wants" us to produce as rapidly as possible with all valves and chokes fully open, brief shut-in periods are beneficial and wells should be shut in with block valves (not control valves) and when bringing them back on, the transition should be rapid to break more coal. You can define this period by drawing a straight line from the OGIP/Initial Reservoir Pressure point towards the y-axis and a second line from the 0,0 point towards OGIP in both cases the line should overlay the graph for a portion of its travel. Find where the two straight lines cross and draw a third line from the intersection normal to the graph. The early life ends at the point that the normal line crosses the graph. This period is generally less than 2 years and during this period there is little value to efforts to lower bottom-hole pressure.

The transition (or mid-life) period starts at the end of the early-life period and goes to the point where the left-hand straight line departs from the graph. From here to the end of the life of the well the reservoir performs best if the flowing bottom-hole pressure is about half of reservoir pressure. In the well in Figure 3, the transition point was at 315 psia [21.7 bara] which meant that we needed a flowing bottom-hole pressure of around 150 psig [10.3 barg], which called for a flowing wellhead pressure (with flow up the 7-inch/2-3/8-inch annulus) of 60 psig [4.1 barg] at (in this well at that time) 5 MMSCF/day [141.6 kSCm].

The late-life or "Declining Reserves" section of the production continues the transition draw-down schedule, but surface pressures need to change much more slowly than the transition period requires. Many wells spend this entire period with wellhead pressure at or near vacuum conditions.

Deliquification plan

Deliquefying CBM is one of the least understood concepts in this field. We learned in oil fields that we could increase ultimate recovery of reservoir liquids by setting pumps early and setting them well below the producing formation. This is effective because it flattens the hydrostatic gradient across the near wellbore and increases the reservoir volume that is impacted by the presence of the well. That is a very effective technique if you are pumping a commercial product. The further the pressure gradient extends from the wellbore, the lower the differential pressure available to cause reservoir liquids and gases to move towards the wellbore. It takes energy (differential pressure) to overcome inertia and start a fluid moving. If water is moving in this very low dP region, then gas isn't.

In CBM we are pumping a waste product and when we maximize ultimate recovery of water we have increased our costs while reducing our recovery of the marketable gas. Remember that the hydrostatic pressure in the cleats is holding the gas onto the coal so removing that containing pressure faster than you can produce the desorbed gas will lead to unintended consequences (e.g., gas attached to the coal can't leak out the top and sides of the reservoir while it is attached but, gas in the cleats can leak out). We need to have an appropriate deliquification strategy tailored for each stage of a field's life.

In early-life pressures and gas flow rates tend toward a maximum at the end of a "dewatering period". This is an unfortunate term that implies that all CBM/CSG wells will need pumps on day one: they don't. Usually if you have the patience to wait a few days or a few weeks the wells will flow as well (or better) without pumps. "Dewatering" really means that the main channels away from the wellbore have been depleted of confining water (i.e., the water that is holding gas onto the coal) and the water that is now flowing to the wellbore has flowed from deeper in the reservoir. After the main flow paths have been cleared of confining water, the well will tend to have a fairly consistent gas/water ratio for the rest of its life. This makes logical sense if you realize that the water is confining the gas onto the coal and keeping pressure high enough to prevent desorption. Producing a mass of water will remove the confining pressure for some mass of gas that will then desorb. Over the life of the well the mass of water that must be removed to access a given mass of gas will tend to remain constant.

"Casing-Flow Control" is a deliquification technique that works well in early-life wells. This technique installs flow measurement on the tubing line and a large-bore variable choke on the tubing/casing annulus. Since early-life pressures are well above 145 psia [10 bara], oil-field techniques work well, and the Turner Critical Flow algorithms represent a workable solution. In Casing-Flow Control, you adjust your casing flow to ensure that tubing flow is above critical and is able to transport the liquids-inflow to surface without mechanical assistance.

During the transition period we tend to move away from pressures where it is reasonable to assume that gas will flow as an incompressible fluid, and the value of the Turner calculations begins to diminish. The casing flow-control scheme tends to work better at the beginning of the transition period than at the end. By the end of the period it can still work, but field techniques to determine critical flow rate by experimentation are required to keep it working.

During the late-life period, mechanical deliquification assistance is generally required. The author has found that dynamic pumps (i.e., electric submersible pumps or ESP, jet pumps, or gas lift) all tend to have too narrow an operating band to be a reasonable first choice for late-life wells. Positive displacement pumps are better suited for in this application. The most effective late-life CBM pump so far has been either electric or hydraulic linear rod pumps. These pumps have very flexible control that allows the downstroke speed to be independent of upstroke speed, allows changing stroke rate on the fly, and allows pauses to be programmed at either (or both) end(s) of the stroke. If the barrel on a rod pump is full of liquid, then any infinitesimal upward travel of the plunger will open the standing valve and any infinitesimal downward travel will open the travelling valve. A brief pause at the top of the stroke (with minimum plunger engagement in the barrel) will allow the pump to fill with liquid regardless of how much gas was in the pump at the beginning of the pause. This technology can turn a bad choice (i.e., “nodding donkey” pump jacks) into the best choice for deliquefying late-life CBM wells.

Every tubing configuration allows some amount of entrained gas to enter the pump. Downhole gas separators have proven to be quite ineffective at removing gas from a mostly-water stream. The most effective way to manage the performance of a downhole positive displacement pump in gas/water service is to minimize the space required for the gas [O&GJ] by raising the pressure in the tubing using backpressure.

Gathering/compression

If we are going to operate early-life wells at the highest possible flow rate, the wellsite facilities and gathering system must be capable of containing nearly all of the initial reservoir pressure. It is not unreasonable to set the facility MAWP at some value below reservoir pressure and install emergency shutdown valves near the wellhead. For example, in a field with initial reservoir pressure in the neighborhood of 1500 psig [103 barg], it is probably reasonable to build your wellsite and gathering facilities to ASME B16.5 Class 300 (nominal MAWP 600 psig [41.3 barg]) and rely on the wellhead ESD (typically called an “XV” in upstream Oil & Gas) set slightly below 600 psig [41.3 barg] and setting a pressure safety valve (PSV) on the production unit at 600 psig [41.3 barg]. This is not optimum, but you can see from Figure 1 that pressure is depleted very quickly in early-life wells and the XV will only be needed for a very few years and is unlikely to trip after the first year.

Section 29 tax credits above coincided with FERC Order 636 in the U.S. that required severing the “common-carrier” function from the “merchant” function in gas gathering. Prior to FERC Order 636 ownership of all gas from gas wells was transferred from the producer to the gatherer at the well site. FERC Order 636 removed the resale value and just left (the much lower) common-carrier value. As new CBM fields were developed to take advantage of Section 29 tax credits, gas gathering companies saw wellhead collection as unacceptably low economics and producers were expected to aggregate the wells into a Central Delivery Point (CDP) for custody transfer. This change allowed primary gathering to become part of the reservoir management strategy. With producer-operated gathering, the producer is able to operate pigging facilities and line drips in the manner that maximizes well production (with the profit incentive of selling more gas instead of simply receiving a slightly higher gathering income). Producer owned and operated gathering is a powerful tool for maximizing revenue from a CBM field.

With producer-owned gathering, compression becomes fairly straightforward. If you plan on the inlet pressure to the CDP being fairly high (100 psig [6.9 barg] is common, 150 psig [10.3 barg] is also seen occasionally) and constant for the life of the field, then when the wells begin needing lower pressures you can set "straddle compression" on the gathering pipe to lower wellhead pressure while still meeting the required pressure into the CDP. When the straddle compressors do not provide low enough pressures (straddle suction below about 40 psig [2.76 barg] creates an excessive pressure drop in the suction piping) the wellhead compressors should be deployed. In most fields, the CDP compressors are 2 stage reciprocating compressors (recips) and the straddle compressors are single stage recips. Recips need to see a very constant suction pressure but can deal well with reasonably minor changes in discharge pressure. Wellsites do not accommodate constant suction pressure very well and wellhead compressors should be oil-flooded screw compressors that handle changing suction pressure very well. In the San Juan Basin, we were able to follow reservoir pressure from a 20 psig [1.39 barg] suction pressure down to a 26 inHg [880 mbar] suction over 10 years with the same compressor.

Conclusions

CBM/CSG is very different from conventional gas production, and successful exploitation of this resource requires that we divorce ourselves from most of the paradigms that have been the mainstay of Oil & Gas engineering for 150 years. Some of the key learnings include

- Mud drilling the formation has a high risk of the mud destroying the productivity of a CBM well
- Cementing across the coal generally results in significant reduction of production capacity
- Frac'ing gives very different results from similar stimulations in conventional or shale reservoirs

- There is a maximum containing pressure required to prevent desorption, and production requires to be below that containing pressure, and that containing pressure changes rapidly with time:
    - above the maximum pressure the gas will mostly stay on the coal
    - below the maximum pressure the gas will desorb
    - significantly below the maximum pressure degrades the efficiency of the flow conduits, often to the point that the pressure at the desorption sites is higher than it would be at a higher wellhead pressure
    - very low pressures in the early days will often increase water rate and total water at the cost of gas rate and ultimate recovery
- Deliquification needs to be done with the needs of the reservoir in mind instead of “company policy” or “that is the way we do it” mind sets.
- Surface equipment is not a “necessary evil” it is essential for reservoir management.

In short, you must treat CBM as a unique opportunity, it isn’t just mushy sandstone.

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