Annular pressure buildup: What it is and what to do about it

When tubing heated by hot formation fluids contacts colder fluids entrapped in the annulus, the result is fluid heating and pressure buildup. Proper well design is critical in subsea wells

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A very competent drilling engineer and his capable completion engineer were comparing notes about how they had done their best design work and installed robust hardware fully capable of withstanding anticipated load cases in the most expensive well their company had ever attempted. They were not yet fully into celebration mode—as the Gulf of Mexico deepwater well was just being brought online—when the phone rang. It was the production engineer calling from offshore. "The well has been online less than a day and they are shutting it in due to pressure on the casing. We think we've got collapsed tubing, and maybe even a hole in the casing," the engineer shouts. "Are you guys sure you checked all of your design factors?"

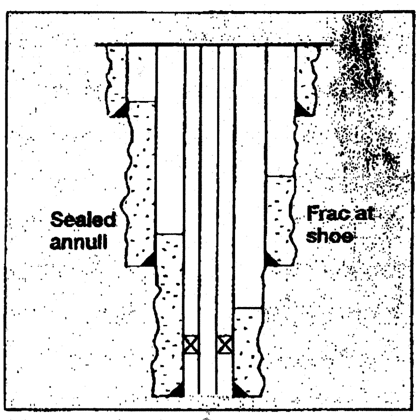
What happened? Did something go wrong during the drilling phase or installation of the production tubing or casing? Is the packer set properly? Is the tree connected as it should be? Each of these potential problems needs to be examined. But another force, an unanticipated load greater than those that can be absorbed by even generous design factors, may be lurking in the background—Annular Pressure Buildup (APB)!

The following discussion, which can help prevent problems like the hypothetical example above, explains APB and its causes, gives examples of fundamental equation use, describes why APB is just now showing up, and—most important—suggests what can be done about it.

APB: DEFINITION, CAUSES

The term Annular Pressure Buildup (APB) refers to a thermal phenomenon that has been present in every well ever produced and is generally ignored by rookie and experienced well designers alike. APB is the pressure generated by the thermal expansion of trapped wellbore fluids as they are heated. For a well to experience APB, several conditions must be present, as described here.

Sealed annulus. The annulus (or annuli) must be sealed. It is not uncommon that a section of formation must be isolated from the rest of the well. This is typically remedied by bringing the top of cement from the subsequent string up inside the annulus above the previous casing shoe. Unfortunately, by fixing one problem, another may have been created. Bringing cement up inside the casing shoe effectively blocks the "safety valve" provided by nature's fracture gradient (see figure). Instead of leaking off at the shoe, any pressure buildup will be exerted on the casing, unless it can be bled off at the surface.



Sealed annuli vs. fracture at shoe.

Most land wells and many offshore platform wells are equipped with wellheads that provide access to every casing annulus. Any observed pressure increase can be quickly bled off, thus preventing the damaging effects of APB from occurring. Unfortunately, most *subsea* wellhead installations do not have access to each casing annulus.

Temperature increase. The trapped fluids *will* be heated. Most casing strings and displaced fluids are installed at near-static temperature. When this system is heated, i.e., by production, the fluids expand. If one or more annuli are sealed, a substantial pressure increase may result. This condition is commonly present in all producing wells, but is most evident in deep water. Deepwater wells are likely to be vulnerable to APB because of the cold seafloor temperatures at installation, in contrast to elevated temperatures during production.

FUNDAMENTAL EQUATIONS

When an unconstrained fluid is heated, it will expand to a larger volume, as described by:

$$V = V_o(1 + \alpha \Delta T) \quad (1)$$

Where: V = Expanded volume, in.^{3}
V_o = Initial volume, in.^{3}
α = Fluid thermal expansivity, R^{-1}
ΔT = Average fluid temp. change, °F

If the fluid is constrained by a perfectly rigid container, the pressure increase is described by:

$$\Delta P = (V - V_o)/V_o B_N \quad (2)$$

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Where: ΔP = Fluid pressure change, psi
B_N = Fluid compressibility, psi^{-1}

Substituting Equation 1 into Equation 2 shows that, for a simple case of a fluid expanding inside a rigid container, the pressure rise is only a function of the fluid properties and the average temperature change of the fluid, i.e.:

$$\Delta P = \alpha \Delta T / B_N \qquad (3)$$

Fortunately, casing and tubing strings are not rigid containers. As pressure increases, the inner and outer strings encompassing the fluid offer some flexibility and move slightly as a result of the pressure change. The inner string becomes diametrically smaller, and the outer string becomes diametrically larger. This results in an increase in the contained volume and a subsequent reduction in pressure.

Depending on system constraints, wellhead growth may also result due to the temperature increase of the casing and tubing strings. Similarly, this results in an increase in the contained volume and a subsequent reduction in pressure.

In the most general case, multiple casing/tubing strings and annuli are coupled, and, thus, the equations of classical mechanics must be applied to each. Depending on assumptions and complexity of the analysis, this results in a set of equations that must be solved simultaneously. The interaction of tubular strings under the influence of fluid expansion has been rigorously documented [1,2] and is beyond the scope of this presentation. Nevertheless, Equation 3 can be easily used to provide a reasonable upper limit for the anticipated pressure rise, to determine if a more rigorous treatment is required.

Thermal expansivity and compressibility properties are functions of both temperature and pressure. Once the production temperatures have been established, these properties are generally available from service company sources. In the absence of detailed data, the accompanying table gives typical values for these fluid properties, where T_{abs} and P are absolute temperature and pressure, respectively.

Example application. Given 10,000-ft, 3½-in. tubing inside 7-in., 35-ppf (0.498-in. wall) casing, assume the 8.6-ppg water-based completion fluid heats up an average of 70°F during production.

1. Calculate the fluid expansion that would result if the fluid were bled off.

$$V_o = 10{,}000\,(\pi/4)(6.004^2 - 3.5^2)/144 = 1{,}298\ ft^3 = 231.2\ bbl$$

$$V = 231.2[1 + (2.5 \times 10^{-4} \times 70)] = 235.2\ bbl$$

$$\Delta V = 4.0\ bbl$$

2. Calculate the resulting pressure increase if casing and tubing are assumed to form a completely rigid container.

$$\Delta P = 2.5 \times 10^{-4} \times 70 / 2.8 \times 10^{-6} = 6{,}250\ psi$$

It is important to note that the 6,250 psi is not an *absolute* pressure, but a pressure *change* that must be added to static system pressure.

WHY IS APB A PROBLEM NOW?

The physics of annular pressure buildup and loads exerted on the casing and tubing strings have been experienced since the first multi-string completion in the 19th Century. APB has drawn the focus of drilling and completion engineers in recent years because all necessary factors have been pushed to the extreme—especially in deep water, i.e.:

- Installed completions are colder than prior hookups in shallower water.
- Produced fluids are drawn from deeper, hotter formations.
- Production rates are higher, as facilitated by more advanced sand control techniques, larger tubing strings and use of corrosion resistant alloys (CRAs) to combat erosion-corrosion.

What are the consequences? Annular pressure buildup occurs on every annulus of every well where the system is full of fluid—that includes most annuli. Wherever there is surface access to the annulus, a simple fluid-pressure-bleeding exercise during initial production defuses the threat of structural damage. Wherever the trapped column of annular fluid has access to a porous and permeable formation, an upper limit or natural "pop-off" valve will limit the buildup. Depending primarily on the local fracture gradient, the limit may be too high to prevent an overload of the casing.

The consequences of a pressure buildup without the benefit of bleed off or formation fracture can be catastrophic and manifest itself in one or more ways, for example: 1) the tubing/production casing annulus can build up enough pressure to collapse the tubing or rupture the production casing; or 2) the annulus between the production casing and the protective casing can be heated to the point where the production casing collapses or the protective casing ruptures; and so on, all the way out to the conductor.

Generally, the inner strings are more vulnerable, as the heat dissipates as it travels out to the larger strings, and the more-expensive production strings are often designed with lower design factors. Extreme caution should be exercised when determining whether the inner casing/tubing will collapse or the outer casing will "rupture." The industry typically refers to "burst" in designing casing strings when, in actuality, we are working with the minimum internal yield presssure. The minimum internal yield pressure is not the same thing as the casing rupture pressure.

Can APB be prevented? The truth is that APB *cannot* be prevented. Well designers can anticipate APB and take appropriate steps to avoid the expensive and dangerous results of pressure overload. Conventional design techniques do not allow for annular pressure buildup; but in an expensive deepwater environment, successful producing operations can be ensured with a little forethought. Available technology will not eliminate APB—only the disastrous consequences of a thermally-induced failure.

Don't be fooled. Even the most-detailed analysis has many inherent assumptions which, when varied, can substantially affect the calculated results:

1. Are trapped gases entrained in the drilling fluids when they are circulated in the well? A small volume of trapped gas makes a big difference toward mitigating annular pressure buildup. Gases—unlike drilling water and oil-based drilling fluids—are fairly compressible (see table) and act like giant shock absorbers.

2. What is the true static temperature? Since temperature change is the main driver for APB, knowing the static temperature is absolutely critical. The general trend for deep water is for static temperature to increase as an exponential buildup from the mudline to 500–1,000 ft below the mudline. Assuming a linear static profile from mudline to TD may result in significant error.

3. How does the formation respond to casing pressure? The formation not only has a thermal response, but a mechanical response as well. It is not perfectly stiff, as one might suspect, but has some flexibility.

4. Temperature modeling software offered by the industry ranges from simplistic to sophisticated. The most-sophisticated, commercial thermal models do a fairly good job at predicting production temperatures; but do not expect accuracy greater than ± 5°F for flowstream temperatures. Even more important, most thermal simulators have not had their annular temperature predictions rigorously validated.

APB SOLUTIONS

While not preventable, with good engineering judgment, annular pressure buildup can be predicted and its threat severely

Received Time Jun. 30. 7:23AM

reduced. Accurate and calibrated temperatures—recorded and simulated—can be utilized to calculate the forces generated by thermal expansion of annular fluids. This APB load can then be taken into account along with more-conventional load cases during the well design phase. If the design factors are unacceptable, some possible remedies include:

- If at all possible, avoid creating the trapped annulus.
- Attach crushable foam to casing:[3] Engineered foam products manufactured to crush above a threshold presure can be attached to the casing to provide the volume necessary to compensate for fluid expansion.
- Gas cushion: Circulating N_2 gas ahead of the drilling mud creates a relatively-compressible gas cap that can effectively mitigate APB problems.
- Insulate tubing: An insulated tubing string reduces heat transfer to the formation and—thus, reduces temperature increase of the surrounding annuli.
- Compressible fluids: A concerted effort by the service company community may lead to some physical relief through use of "compressible" packer fluids. The foams and gels developed to date are expensive and operationally intrusive.

Where can the reader go for help? The best move for the operator is to recognize the potential problem early—before the casing is cemented in the well. *DWT*

LITERATURE CITED

[1] Adams, A. J., "How to design for annulus fluid heat-up," paper SPE 22871, *Proc.*, SPE Annual Technical Conference, October 1991.

[2] Adams, A. J., and A. MacEachran, "Impact on casing design of thermal expansion of fluids in confined annuli," paper SPE 21911, SPEDC, September 1994

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Typical thermal expansivity and compressibility values

Fluid type	Thermal expansivity, $\alpha(F^{-1})$	Compressibility, $B_N(psi^{-1})$
Water based	2.5×10^{-4}	2.8×10^{-6}
Oil based	3.9×10^{-4}	5.0×10^{-6}
Ideal gas	$1/T_{abs}$	$1/P$

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