Title: Introducing Well Integrity Management Processes at 'Brownfield' Development Stage

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Abstract

Well Integrity within Qatar Petroleum relies on managing appropriate ‘duty of care’, with risk levels As Low As Reasonably Practical (ALARP), during the *design, construction, operational* and *abandonment* stages of a wells lifecycle. Adopting suitable well integrity management processes at the design and well construction phase of the lifecycle allows the most practical solution to implementing an effective Well Integrity Management System. It allows an organization to follow recognized, and highly desirable, industry standards and procedures. Introducing more modern, and subsequently well proven, well integrity management concepts at the post-design stage requires a different strategy. Whilst a 'fully cemented' well construction method is effective in providing 'solid well foundations', it is not necessarily favourable for the most effective well integrity management process. Annular Pressure Management is one example where different approaches and assumptions in well integrity management are made, with a likely result of highly conservative control processes (such a Maximum Allowable Working Pressures) for well integrity being adopted. This paper is a précis of the approach adopted by Qatar Petroleum in formalizing a Well Integrity Management System, given some of the challenges of doing so at the 'Brownfield' development stage in a wells life-cycle.

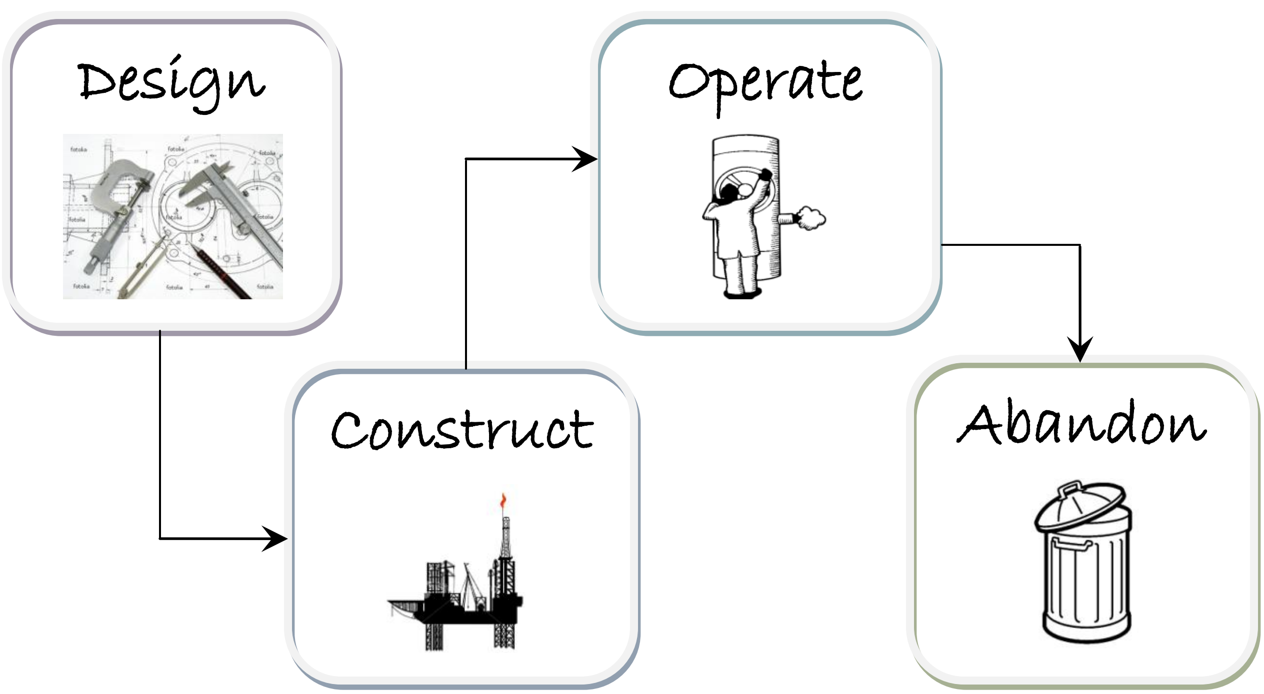
Introduction

Arguably the most definitive statement for the role well integrity plays is from the Norwegian Petroleum Industry Standard - Norsok D010. This particular standard defines well integrity as the “application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life-cycle of a well”.

The well integrity processes adopted within the Norsok Standard are generally integrated with other internationally recognized standards, such as International Organization for Standardization (ISO), American Petroleum Institute (API), and United Kingdom Design and Construction Regulations (DCR) 1996, to form the basis of a generally acceptable well integrity management strategy for an Oil and Gas Operator to adopt. By adhering to a well integrity policy derived from these general standards an Operator can be seen as being a socially acceptable, environmentally conscious and ethically respected member of the international oil and gas producing community.

Whist it is highly commendable to have the policies in place to meet these standards, it should be recognized that these standards have only been in place, and more importantly actually implicitly adhered to, over more recent years. It is therefore much simpler to implement, and maintain a strategy, based on these standards with a well that can be uniquely designed and constructed with these standards in mind. A ‘Greenfield’ development can include specialist equipment and practices designed to manage well integrity to optimum standards. Well integrity control processes throughout the life-cycle of a ‘Greenfield’ well, *design, construction, operating* and *abandonment*, can be applied by adopting the respective components of these standards at these different stages. Managing older ‘Brownfield’ wells, that were originally designed and constructed when these standards were not in place, and then retrospectively working to them, is however considerably more difficult to achieve.

In adopting recognized well integrity standards, discrete assumptions need to be considered within certain areas of a wells envelope. Control processes (such as Maximum Allowable Annulus Surface Pressures (MAASP) in annuli) need to account for ‘unknown’ factors that may now need considering as a result of a wells age. Down-grading of casing, and unknown cement quality, are examples of areas where assumptions may have to be made. This likely will result in highly conservative control process boundaries (such as MAASP’s being set too low) being applied to a well.



The four well integrity stages to be considered throughout the life-cycle of a well are *design*, *construction*, *operating* and *abandonment*. The ability to implement effective well integrity management processes throughout each stage can vary significantly.

***Design*:** At the *design* stage, in an era where sound recognized standards are now firmly established, a blank piece of paper and unconstrained budget should yield the optimally designed well to allow the best chance of managing its well integrity. What would the 'best designed' well look like that would allow the most effective well integrity control throughout its life-cycle? Probably something like this (some concepts may or may not already exist):

- *Removable mud-line hangers*:- remove <u>any</u> casing hanger at the mud-line or surface, 'snap-on' a new one, and retain full integrity.
- *Distributed Temperature entrained lines*:- fiber-optic lines entrained throughout all casing and tubing to allow constant real-time data to detect any undesired flow regimes behind casing.
- *Multiple control-line components*:- multiple-line feed-through packers and wellheads that would allow operation of Flow Control Valves, Downhole Gauges, corrosion inhibition and even 'fluid-top' capability within both annuli and tubing at the 'flick of a switch'.
- *All annuli tied into production*:- imagine being able to overcome back-pressure issues, and simply being able to divert any well integrity problem through surface process systems (there will probably still be barrier issues to overcome).
- *Perfect cement bond*:- having a long-term permanent cement bond, without actually having to establish the bond still exists (some service companies may argue that this product already exists).

On a latter-day field development project this portrayed well integrity concept is unlikely to ever be realized, project economics would probably make these concepts largely unfeasible. At the design stage there remains the option to 'cherry-pick' what options, from a 'wish-list' such as the above, offer the lowest risk of loss of well integrity, are feasible, practical, and can still meet economic screening. What generally happens is that unrealistic and unfeasible options (such as tying in annuli to production systems) are rightly dropped at the 'concept' stage to fit into the economics of the project. The outcome should then remain a well integrity strategy for the project that fits the desired purpose, and meets the internationally recognized standards.

One of the most significant factors that can often influence well integrity later on in a wells life is often incorrectly accounted for at the design stage, and generally not a fault of the engineers. This is the period of time the well will exist (be that as a producer, injector or even suspended) until abandonment, and this is nearly always designed for far less than the actual period of time the well will be 'in service' for. There are endless examples throughout the world where something has been engineered to last a pre-determined period of time, and still exists far in excess of the originally established time criteria. Dated structures such as the Seven Wonders of the World are a very good example of this. Probably no more so is this observed in modern times than in the oil industry, and this is not applicable solely to well construction alone. Most ageing structures (platforms, jackets, etc.) within an oil and gas producing asset will probably still be operating considerably after the original design criteria time-frame. In an ageing well stock a loss in integrity can be difficult to actually visualize, most problems are subject to diagnosis, or inferred. A structural failure on a topside jacket is easily identified, a liner-hanger failure deep in a well not so straight forward. There are some easily identifiable losses in well integrity; clearly the recent BP GoM incident is one. The picture below shows a far less dramatic example, this is a gas leak from a conductor on a well more than twenty years old, and relatively straight forward to repair.

Figure 1 – gas leak from conductor

The design of a well should ensure that the objectives for which it is being constructed for can be met; clearly it needs to be capable of delivering its designed status. A producer that sub-optimally produces, or an injector that cannot inject, is not particularly desirable. As important is the ability for the integrity of the well to be maintained, and allow remedial actions where possible. A well construction with solid foundations and barriers suggests a very sound basis for a good well. However, is this the most favourable criteria for well integrity and production purposes?

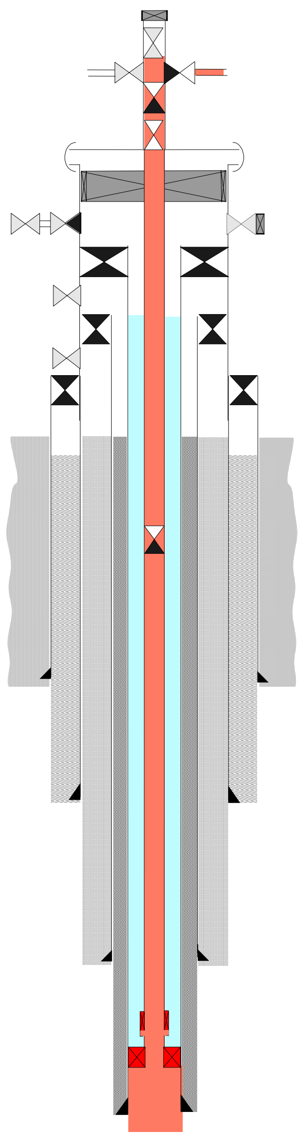


Figure 2 – well schematic, cemented to surface

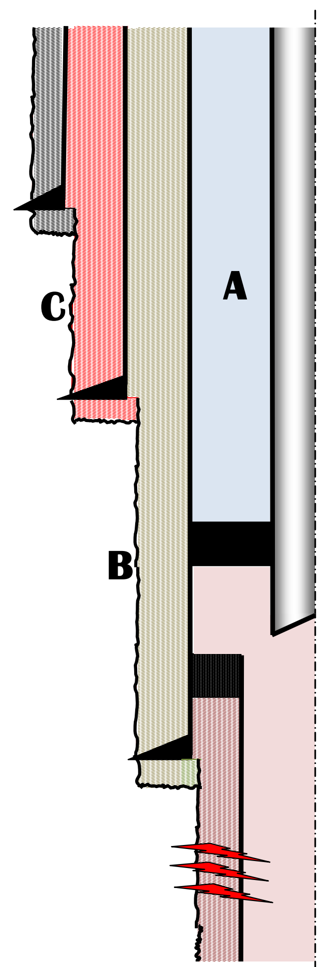


Figure 3 – well schematic, fully cemented casing

The above two figures depict how some well designs adopt fully cemented casings, in some cases the liner will be tied-back to surface also, and fully cemented. Providing cement bonds, sealing devices, casing and formations remain intact, well integrity problems should be largely irrelevant.

However, in adopting these design principles problems can occur if well integrity is lost at some stage. Quite simply, the space available for dynamic motion (fluids to expand) anywhere other than the inner A-annulus is very limited. Options for remedial repair outside of the inner annulus even more limited. This is particularly applicable when the length of service of the well is extended, especially in a corrosive environment. The onset of component failure is far greater.

Most wells are constructed by well engineering specialists; it is though desirable to have production personnel involved at the design stage. Many development wells nowadays are handed over to production with completion brine or acid as the base fluid, and the well not yet ‘opened to flow’. Restrictions on flaring, and costs of rig-based production tests, often result in drilling facilities being far removed from first production phase of a well. An understanding of the constraints in dealing with later well integrity problems at the design stage could fundamentally change the basis of design. To the extent where fully cemented strings may even been see as too impractical should the basis of design need to account for extended service life of a well. Appropriate weighting factors would need to be derived at the basis of design stage to accommodate such assumptions. If off-plateau recovery is negligible in terms of overall recovery the weighting applied to extending the wells life would probably be minimal. If recovery can be increased through Enhanced Oil Recovery (EOR) techniques then basis of design weighting factors also need to account for this. If EOR techniques ultimately change the wells status it is important to equally assess the well integrity concequences at the basis of design stage. This would be an appropriate requirement at any latter work-over stages of a wells life-cycle.

Construct**:** Clearly the *construction* part of the life-cycle is the key area where the well integrity status of a well can be determined. The best chance of minimizing well integrity problems is when they are observed during the well construction phase. The importance with which organizations now view well integrity can be seen in their willingness to spend rig-time remedying problems, rather than move off location and resolve later, normally when it is probably too late to actually do anything about it. Of fundamental importance in applying appropriate control processes during the well construction phase is Change Management. If the basis of design has determined discrete criteria, the changing of it must be highly controlled. The failure to do so may have the ultimate detrimental effect on the long-term integrity status of the well. Many organizations have seen countless resources allocated to ongoing well integrity management issues, as a result of changes at the well construction stage. This does not necessarily mean it is not appropriate, but only a Change Management review can determine if it is appropriate or not. Change Management must include basis of design and risk reviews.

***Design* and *Construct* Stage Well Integrity Control Processes**

The control processes required at the *design* and *construct* stages for well integrity should be almost uniformly standard for any organization. Controls Processes should ensure:

- The well is designed and constructed as per recognized international standards.
    - Barrier Philosophy compliance.
    - Conductor, casing, completion, erosion and corrosion design.
    - Metallurgy, well bore seals, etc. qualification and assurance.
    - Zonal isolation capability of cement.
    - Ability to ‘plug and abandon’ the well.

- Performance Standards are in place for well integrity Safety Critical Elements associated with maintaining Primary/Secondary Barriers, and Emergency Shut-Down (ESD) processes.
- Failure modes have been determined (casing, formation, etc.).
- Operating conditions of the well are determined at production handover stage (potential casing wear, MAASP’s, maintenance schedule, etc.).
- Abandonment concepts covered within Field Development Proposal.

***Operate*:** There are critical ‘standard’ well integrity processes to adopt at the *operate* stage of a wells life-cycle. These processes are relevant regardless of whether wells are new or ageing, shut-in or suspended. The difference between ageing wells, and by ageing it is assumed the well is beyond the initial period of time it was designed for, is that failure modes are obviously more likely to occur. It is therefore implicit that the control processes require more focus. The escalation scenario for a well integrity situation worsening in an ageing well is far higher. The earliest remedial action therefore offers the best opportunity of re-establishing well integrity, and thereby hopefully maintaining production (or injection, etc.). A well that has started to exhibit initial signs of corrosion in the production tubing will be considerably more difficult to work-over after a continued period of service, than from the point corrosion was first observed. In this example remedial work-over operations will increase in difficulty with well ‘in-service’ time.

Operate Stage Well Integrity Control Processes

Some of the standard control processes that should be in place for establishing sound well integrity principles at the *operate* stage include:

- Identifying and implementing maintenance schedules for Safety Critical Elements to establish well/process containment (if subsea wells are part of the infrastructure Environmentally Critical Elements may also need identifying).
- Well Integrity Tests (inspection and testing) are performed as part of any maintenance schedule.
- Annular pressure management strategy is established.
- Leak criteria is established.
- Well Integrity Barrier Policy is derived and formally situated within an organizations Safety Management System.
- Corrosion monitoring strategy is established.

Annular Pressure Management is one key area where monitoring regimes allow early indicative observations of potential well integrity problems. The annuli in a well is the one particular area where the starting point is established in enabling effective control processes for well integrity.

Whilst a well is being constructed there are implicit control processes in place for actually building the well. Many of these rely on the observations from the operating environment within the actual annuli being formed whilst construction takes place. An example of this is formation leak-off. As the well is deepened and the eventual annuli formed the formation is effectively being constantly observed for changes (losses) that will determine the eventual operating envelope for the well, and thereby subsequently establishing well integrity and containment boundaries. The information gained during the well construction phase of the well life-cycle should form an integral part of the Annular Pressure Management strategy for the well at the *operate* stage. It is important to understand the differences between the construct and operating phases, and using results obtained during drilling may not be suitable for operating the well. A drilling MAASP for a hole-section is not the same as the annuli MAASP to be used for the operating phase, it is uniquely different in derivation, and eventual use.

After being drilled a typical well would probably look something like the figure below.

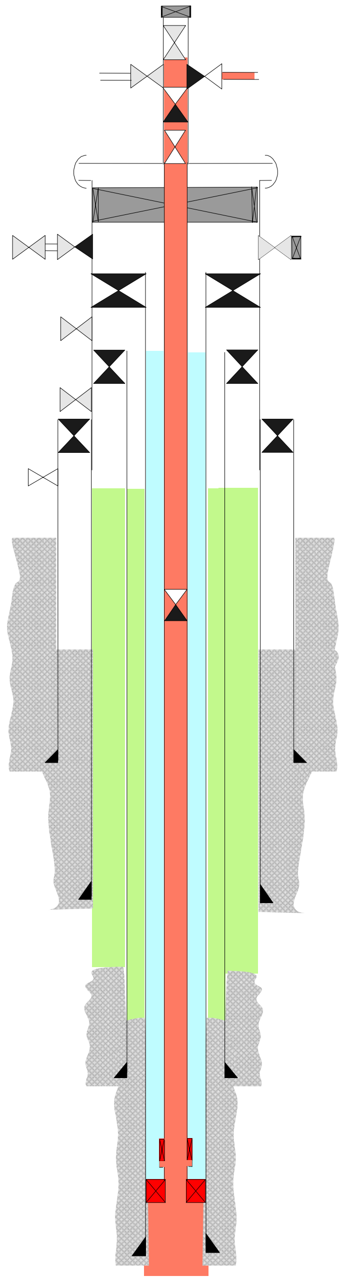


Figure 4 – typical well schematic

In this typical well example the inner A-annulus has a completion fluid to the packer, and the outer remaining annuli cemented lower foundations, and liquid filled upper annuli voids. Providing one knew where the top of cement was for each section, the completion brine/annuli fluid type and density, tubing/casing grades, formation strengths and associated equipment pressure ratings, a fairly precise MAASP could be derived as a control process for this well.

There are generally four failure modes that can occur in typical annuli (B-annulus in this particular scenario):

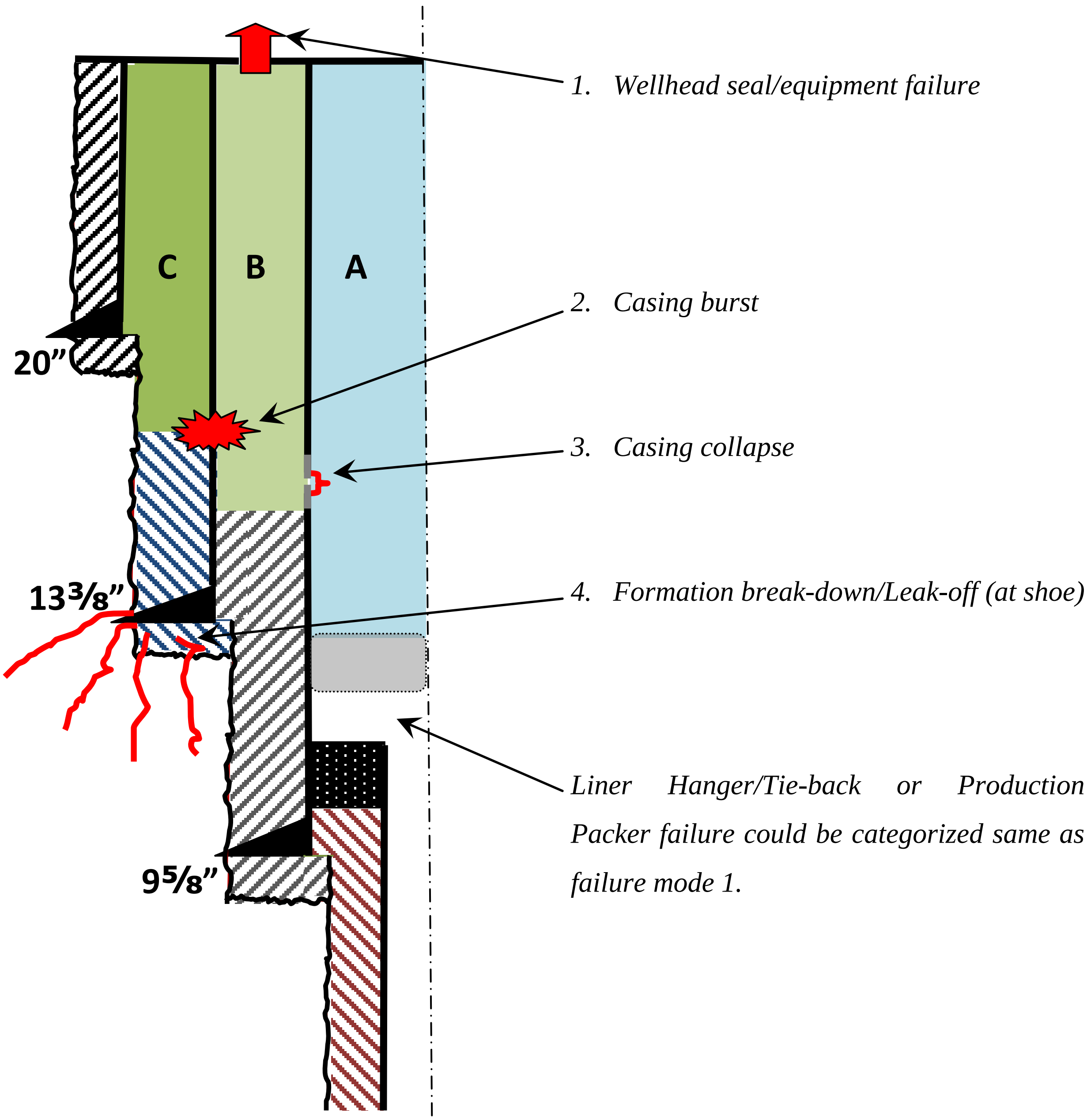


Figure 5 – typical annuli failure modes

Determining an operating MAASP for the B-annulus scenario in figure 5 is relatively straight forward, providing true vertical depth (with some assured accuracy), base fluid densities, top of cement (assumed 100% bond quality), casing grades and formation strengths are known in A/B/C annuli.

Test data to give a basic indicative example of the output derived, may be as follows:

13⅜" Casing Burst:	3450 psi
9⅝" Casing Collapse:	3810 psi
13⅜" Top of Cement (ToC):	4000 ft (tvd)
9⅝" Top of Cement (ToC):	5000 ft (tvd)
13⅜" Casing Shoe Depth:	6000 ft (tvd)
9⅝" Casing Shoe Depth:	8000 ft (tvd)
Production Packer Depth:	6500 ft (tvd)
C-Annulus Fluid Density:	0.55 psi/ft
B-Annulus Fluid Density:	0.50 psi/ft
A-Annulus Fluid Density:	0.45 psi/ft
13⅜" Shoe Leak-off Gradient:	0.60 psi/ft
9⅝" Shoe Leak-off Gradient:	0.65 psi/ft
Well/Equipment Pressure Rating:	5000 psi

The MAASP to prevent Failure Mode 1. from occurring can simply be exceeding the wellhead (or equipment) pressure rating, and **is therefore 5000 psi**.

The MAASP to prevent Failure Mode 2. from occurring can be 13⅜" casing burst figure, minus the fluid hydrostatic supporting either side of the casing at ToC: 3450 - (4000*(0.55-0.50)) and **is therefore 3250 psi**.

The MAASP to prevent Failure Mode 3. from occurring can be 9⅝" casing collapse figure, and again minus the fluid hydrostatic supporting either side of the casing at ToC: 3810 - (5000*(0.50-0.45)) and **is therefore 3560 psi**.

There is an argument that the MAASP *to prevent Failure Mode 4.* from occurring in this scenario can be ignored. Providing the well construction phase verified the cement quality, and that no other problems occurred during the hole-section, formation or shoe failure could be considered to be irrelevant, particularly in the early 'in-service' period of the well.

The B-annulus operating MAASP on this particular well is therefore limited by the resultant lowest value failure mode, which in this case is the 13⅜" casing bursting.

This scenario is a very straight forward one, and probably typical of new well being handed over to the production operating group of an organization. For an ageing well 'uncertainties' when conditions change is the overlying concern when adopting well integrity control processes, such as re-determining MAASP's. It is for this reason that 'worst-case' assumptions are implicitly set as the starting point in well integrity control processes. There have been many technical papers written, trials and experiments performed, etc. on cement quality, and more importantly longevity. When the pressure changes in annuli in an ageing well it is most likely to be as a consequence of corrosion, or cement degradation. A further problem exists in that data acquisition techniques for cement evaluation still largely depend on acoustic technology, and this effectively precludes determining the quality of cement in anything other than the tubing or production casing. The following is the earlier scenario, modified to reflect a fully-cemented construction, and assuming worst case scenarios, to derive MAASP's.

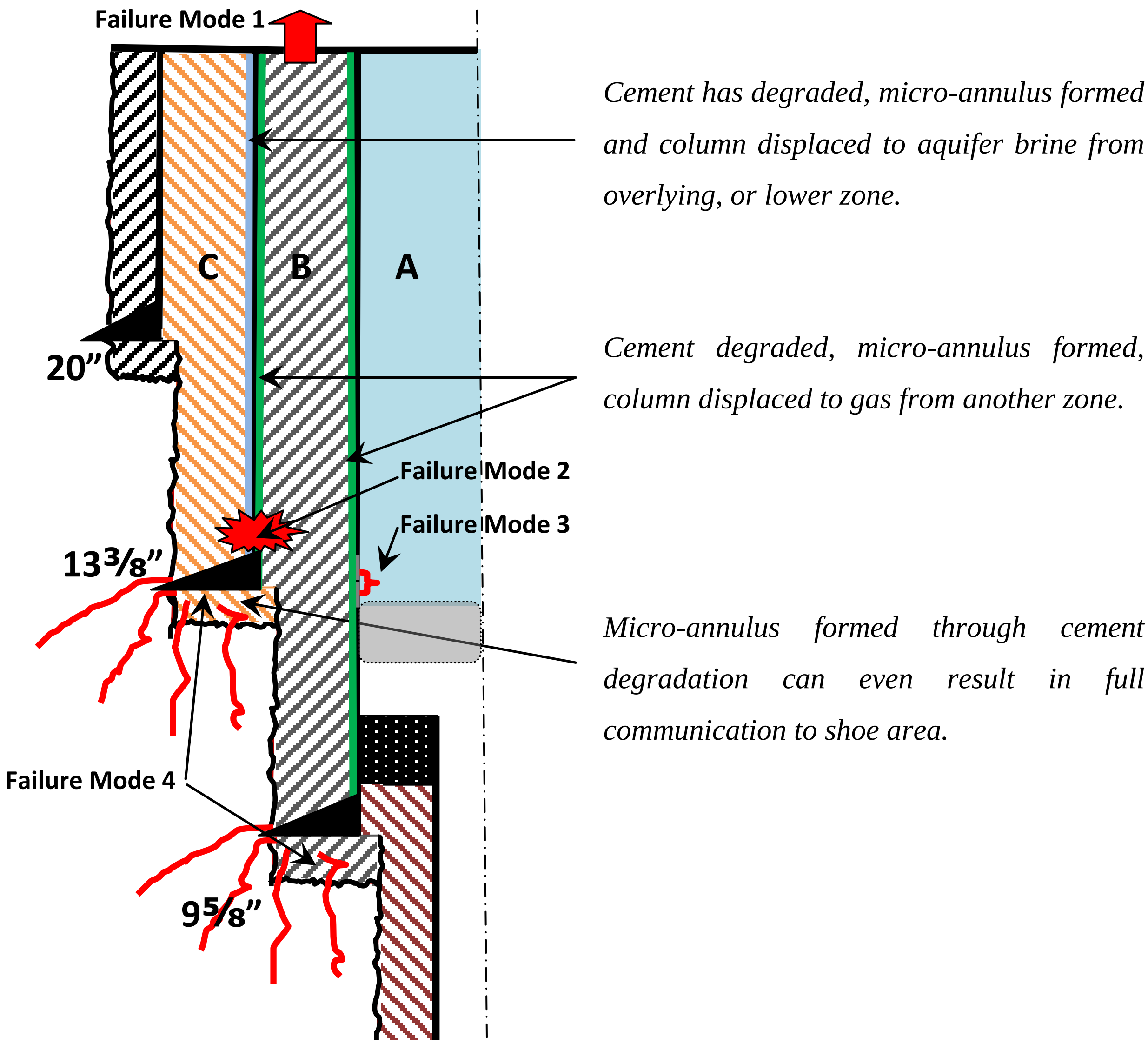


Figure 6 – fully cemented ageing well, annuli failure modes

Determining an operating MAASP for the B-annulus, in the revised fully cemented ageing well scenario in figure 6, results in a very different outcome.

It is assumed in this scenario that the ‘worst-case’ has materialized, cement degradation has occurred, literally to the extent it may as well not exist as a pressure containing medium, and that the <u>differential</u> fluid hydrostatic pressure supporting the casings is now no longer ‘near’ equal. This could occur as a result of a brine, or gas, influx from an overlying aquifer, or deeper gas producing zone respectively. It could even be a consequence of changing a wells status from that of a natural producer to one of artificial lift, specifically that the A-annulus fluid has been replaced from a liquid to a gas. It is now assumed, in this scenario, that the B-annulus has gas-filled micro-annuli, with an assumed density of 0.1 psi/ft. Therefore:

The MAASP to now prevent potential Failure Mode 1. has not changed, and **is still 5000 psi**.

The MAASP to now prevent potential Failure Mode 2. 13⅜" casing burst is: 3450 - (6000*(0.55-0.10)) and **is therefore 750 psi**.

The MAASP to now prevent potential Failure Mode 3. 9⅝" casing collapse is: 3810 - (6500*(0.45-0.10)) and **is therefore 1535 psi**. The lower density fluid in the A-annulus clearly has a significant effect on the B-annulus MAASP, as opposed to the higher density fluid in the C-annulus. Different rationale could be made for the actual values attributed to the differential support from the A-annulus fluid; however, the point of demonstrating this scenario is to use basic assumptions in deriving MAASP outcomes.

The MAASP to prevent potential Failure Mode 4. could be a subject of much further and lengthy debate. It could be argued that the ‘worst-case’ scenario could actually result in more than one shoe, or formation, being exposed to possible breakdown. Obviously the lowest ‘breakdown‘ value is the one that the MAASP should reflect.

If the situation depicted in this scenario at the 13⅜" shoe actually occurred, the differential between the fluid hydrostatic, and the leak-off, is only 0.05 psi/ft, and therefore at the shoe depth only a **300 psi window exists, and hence a very low operating MAASP**. At the 9⅝" casing shoe, in this modified scenario, the difference between the fluid hydrostatic, and leak-off, is considerably more, especially if the A-annulus fluid support is disregarded. A fluid hydrostatic of

0.1 psi/ft results in **the MAASP being some 4500 psi for 9⅝" casing shoe or formation breakdown.**

<u>Therefore, for the fully cemented ageing well scenario the B-annulus operating MAASP is now potentially an order of magnitude less than the original non-cemented design scenario.</u>

Some organizations will take these assumptions further to create a more ‘pessimistic worst-case’ for determining well integrity control processes with annular pressure management. Generally the more pessimistic the assumptions, the lower the operating parameters of the well when ‘in-service’. Evacuated tubing and casing scenarios can be used, more commonly so with tubing though. In extreme cases assuming vacuums are applied to the operating boundaries of the well may even be considered. In complicated well designs, such as deepwater HPHT wells, where gas cushions, etc. may be utilized, the importance of having realistic ‘absolute worst-case’ scenarios cannot be understated. Things can change very suddenly in these types of wells, especially with gas being the dominant fluid.

There cannot be ‘hard and fast’ rules for determining a control process such as a MAASP, there has to be flexibility depending upon the associated risk levels. There are the recognized guidelines discussed in this paper, but these may not be applicable for any well. Every well, especially an ageing one, should be treated on an individual basis. Appropriate well integrity management is simply a case of setting a control process (deriving the figure), with sound reasoning, competent engineering judgement, and ensuring all assumptions are clearly implicit from the end result. The important part to stress is that if the resultant output is unrealistic to operate a well, (i.e. MAASP too low) then the assumptions made in deriving the output should be revaluated to determine if they to are realistic. An example of this can be seen from the last scenario. If it can be almost certainly determined (weighted accordingly) that the 13⅜" shoe could not have ‘broken-down’ the MAASP effectively more than doubles, and 13⅜" casing burst now the limiting factor. Obviously ‘rebasing’ any assumptions should follow the sound reasoning principles from which there were originally structured from. ‘Rebasing’ just because ‘it keeps the well flowing’ should not necessarily be seen as adopting ALARP principles. Independent verification and technical assurance is a desirable process to also undertake. This is the external additional safeguard that the control processes adopted by an organization are sensible, and in-line with favourable recognized international standards.

Other assumptions that should be considered when deriving control processes for well integrity at the *operate* stage include:

- The effect on annular pressure management in the event a field goes into compression should also be considered. This change in operating conditions could effectively be no different, in terms of impact, to changing a wells status. There are certainly worldwide examples of wells ‘imploding’ upon undergoing compression.
- Compaction, especially in a carbonate environment, should be considered. Extending production past the original field development scope could have a significant effect on overlying formation strength, and therefore subsequent well integrity. This does depend on the EOR technique adopted (if applicable), but should be considered regardless.

***Abandon*:** This is without doubt generally the most overlooked stage of a wells life-cycle. Most Field Development Plans (FDP’s) are required to address an end-of-field strategy, which should include abandonment. Abandonment is however often left as ‘to be confirmed’ within the scope of most FDP’s. As the focus and profile of well integrity increases statutory authorities are likely to be less inclined to accept this. Appropriate abandonment strategies will probably become more of a requirement before production licenses are granted in future, in many more countries throughout the world.

***Abandon* Stage Well Integrity Control Processes**

- The possible recovery of hydrocarbon bearing formations to virgin pressure should be considered as a given in developing an abandonment strategy, unless it can be categorically proven otherwise.

- The deterioration of some components of the well over time, post-abandonment, may be very difficult to quantify, but must somehow be accounted for. Again, setting control processes with sound reasoning, competent engineering judgement, and ensuring assumptions are implicit, should ensure that generally it is accepted that, where best practice is adhered to, the principle of reducing risk to as low as <u>reasonably practicable</u> has been adhered to.

- The case for omitting a barrier must be justified, independently verified, and should gain appropriate technical assurance and justification within an organization.
- Define required standards for abandonment within the organization, namely acceptable permanent barriers, minimum requirements, verification and assurance of barriers, any special cases, and suspension guidelines.
- Formal abandonment guidelines and policy should form part of an organizations Safety Management System.

Conclusion

There are what are considered 'best-in-class' internationally recognized standards, depicting appropriate well integrity, that most Operators endeavor to adhere to. In adopting some of the principles from these standards the well integrity throughout the life-cycle of a well can be managed to present the lowest exposure to risk for an organization. From these standards discrete control processes can be formed to ensure risk-levels remain As Low As Reasonable Practical throughout the life-cycle of the well. Adhering to these control processes will likely require considerably more effort, and therefore resources, for an ageing well stock.

The ***design*** stage should be the basis for determining not just the well construction principles, but the production phase of the well and subsequent well integrity management. The basis of design should also address abandonment. The 'life' of the well at the *design* stage should be considered to probably extend beyond the design criteria, but this must be factored and accordingly weighted into the original field development objectives.

The ***construct*** stage should be seen as the best opportunity to rectify any well integrity matters that arise during this stage. It is important to understand the importance of Change Management at this part of the life-cycle, and the consequences for the wells integrity.

The ***operate*** stage in an ageing well, that was constructed prior to more modern standards and control processes being applicable, will probably require unique assumptions being made to form these control processes. These assumptions may prove highly conservative, but can be 'rebased' if unrealistic, however, 'rebased' with caution. Any control processes derived in the *operate* stage in ageing wells should be of sound reasoning, based on competent engineering judgement, and ensure assumptions are implicit.

The ***abandon*** stage of the life-cycle of a well should be included within the scope of any Field Development Plan. The ability to ensure absolute well integrity longevity post-abandonment is difficult to quantify. Control processes implemented to cover *abandon* stage should be structured to meet ALARP principles.