BEST PRACTICES FOR PREVENTION AND MANAGEMENT OF SUSTAINED CASING PRESSURE

Joint Industry Project Report

OCTOBER, 2001

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EXECUTIVE SUMMARY

The Joint Industry Project, "Analysis of Reliability of Production Tubing Design" (ARPTD), had the originally stated objectives of documenting and evaluating the tubing string design and construction practices used in GOM (Gulf of Mexico) oil and gas wells that had experienced sustained casing pressure (SCP) in the primary (production tubing – production casing) annulus. The design of individual tubing strings is, of course, site-specific and requires comparing the maximum load capacity of candidate string components with the maximum anticipated loads that might be experienced by the production string during the life of the well. Assessing the acceptability of individual production strings and components used in actual wells thus requires that detailed data be available concerning the components of the production string, as well as the anticipated well conditions (temperatures, pressures, axial loads etc.) expected during the life of the well.

A previously assembled database initially envisioned by Mohr Research and Engineering as the source of the data to be used in the above evaluation did not contain information concerning the production tubing strings involved in the SCP events. Under the direction of the JIP participants, Mohr Research and Engineering and, later, Stress Engineering Services (SES) thus constructed a data collection and management system that could be accessed by the JIP participants by way of the Internet. Unfortunately, upon completion of the data management system (and after repeated requests by SES) only two of the participating operators in the JIP made any significant attempt to enter data into the database. As a result, there was not enough data entered into the JIP database for any significant correlations between well characteristics and SCP frequency to be developed. The primary original objectives of the JIP thus proved to be unattainable by SES.

As an alternative to the original JIP objectives, SES was asked by the JIP participants to prepare a document describing "best current practices" for preventing and/or managing SCP in the primary annulus. The aim of this document is thus to identify causes of SCP problems, define and describe modeling and design approaches to account for such problems, to identify occurrence of SCP, describe monitoring, detection and diagnostic procedures, and describe the state-of-art and best practices in design and management of SCP problems. This document is not prescriptive. Rather, it is intended to serve as a resource to better understand the SCP problem and to provide an engineering methodology for the design and operation of wellbores to properly manage SCP. Since the choice of best practice in any situation should be commensurate with the type of well, risk and consequences of SCP, and design basis, a single sequence of actions cannot be termed universal best practice for SCP management.

In some respects, SCP in one or more of the annuli of a well may be viewed as inevitable in the operational life of a well, particularly when the well is operated well beyond its original design life. All discussion of SCP management must therefore begin by recognizing that casing pressure is another load event in the well life cycle and that it must be treated as such. A suitable design basis can ensure that the pressure is manageable. In this document, the relationship between the annular capacity for elevated pressure and the design basis is discussed in detail. However, proper handling and running techniques are also required to ensure that the basis of design is preserved in the well and that components perform to their intended levels of design. Monitoring should be made (and it usually is) the key feature during well operation.

In the opinion of many operators, current regulations that dictate operator response in an SCP incident are adequate, and in fact, may be rather conservative. This could be especially true if the design basis and additional best practices discussed in this document are applied. The operators feel that there may be several situations where the SCP magnitude could exceed the current limits for departure application without compromising the safety of personnel or the environment.

The relationship between risk and consequence of an SCP incident can be established by a risk assessment study, which is outside the scope of this work. It is conceivable, however, that departures from current regulated limits can be tied to a quantitative risk assessment of the wellbore, and if it can be established that the risk is within acceptable limits, such departures could be granted, despite the extent to which they violate the current limits. Such risk assessment is implicit in the decisions an operator currently makes regarding additional testing or monitoring requirements. It can be aided immensely by a properly designed database of SCP incidents.

SECTION I: SUSTAINED CASING PRESSURE FUNDAMENTALS

1) Introduction

A well is usually constructed such that uncemented annuli do not experience abnormal pressures. The exception occurs in gas lifted wells where gas is injected into the production tubing–casing annulus. Under most circumstances, a proper design process will ensure that annuli do not experience abnormal pressures. Thermal expansion of the tubing and casing and the fluids in them may cause Annular Pressure Buildup (APB) when the wells are placed on production. But this pressure can be bled off. Once relieved, the pressure does not re-appear on the annuli if the well is in a normal production mode. If the casing pressure returns when the bleed valve is closed, the casing is said to exhibit Sustained Casing Pressure (SCP). In this light, the Minerals Management Service (MMS) defines SCP (MMS, 1995) as "a pressure measurable at the casinghead of a casing annulus that rebuilds after being bled down," and that SCP is "**not** solely due to temperature fluctuations," **nor "**a pressure that has been deliberately applied."

Annuli differ from other well components in that they are usually not the result of purposeful design. Rather, they are a consequence of the design of tubulars and the well construction process. Therefore, the ability of an annulus to withstand loads that occur on its components is (or should be) evaluated at the end of the design process. Figure 1 shows the different kinds of annuli in a well bore. The primary annulus (Type I) is formed by the production tubing and casing. It is bounded on the top and bottom by the wellbore seal assembly and completion hardware (including packers and seals) respectively. In addition, there may be an annular safety valve, gas lift valves and related equipment depending on the nature of the well. The secondary annuli can be of two kinds- Types II and III. The Type II annulus is formed by two adjacent casing strings. It is bounded at the top by the wellhead seal assembly and at the bottom by the cement. The cement top in this instance is above the shoe of the outer string of the annulus. The type III annulus is essentially similar, except that its bottom is open to the formation. The cement top lies below the shoe of the outer casing string, either by design or accident. Instances where a section of the annulus is deliberately left uncemented are discussed further ahead.

By definition (as well as design) an annulus is a sealed volume, and there should be no flow paths that cause migration of fluids into (from) the annulus from (into) its surroundings. In principle, given the annular configuration, all leak paths that can compromise its integrity should be identified. This identification is an integral part of the design process and is the basis for the diagnosis and management of SCP, later in the life of the well.

Figure 2 and Figure 3 are a high level representation of the annular structure and may be used to identify the potential leak paths that lead to annular breach or SCP. While these figures are by no means complete, it is evident that the primary annulus is significantly more complex in comparison with the outer annuli. The significantly larger number of components that comprise the primary annulus, creates a correspondingly higher potential for annular breach.

All discussion of SCP management must begin by recognizing that casing pressure is a load event that a well is likely to experience at some point in its life cycle, and that it must be treated as such. Just as a protective casing string is designed to handle a kick or lost circulation or drilling wear, production tubing and casing should ideally be designed for possible SCP scenarios among other things as described in section 5.1.

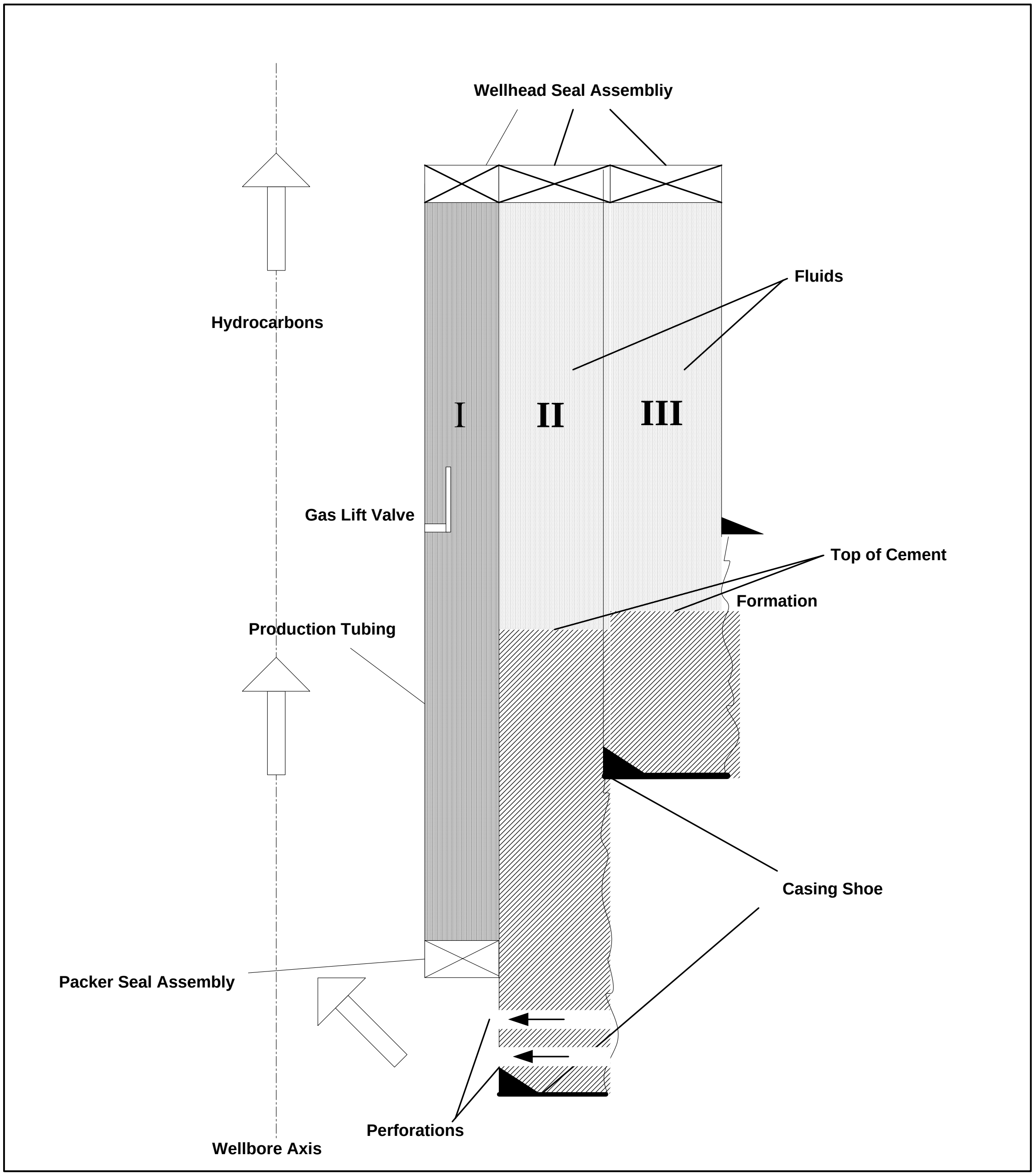


Figure 1 Types of annuli in a wellbore

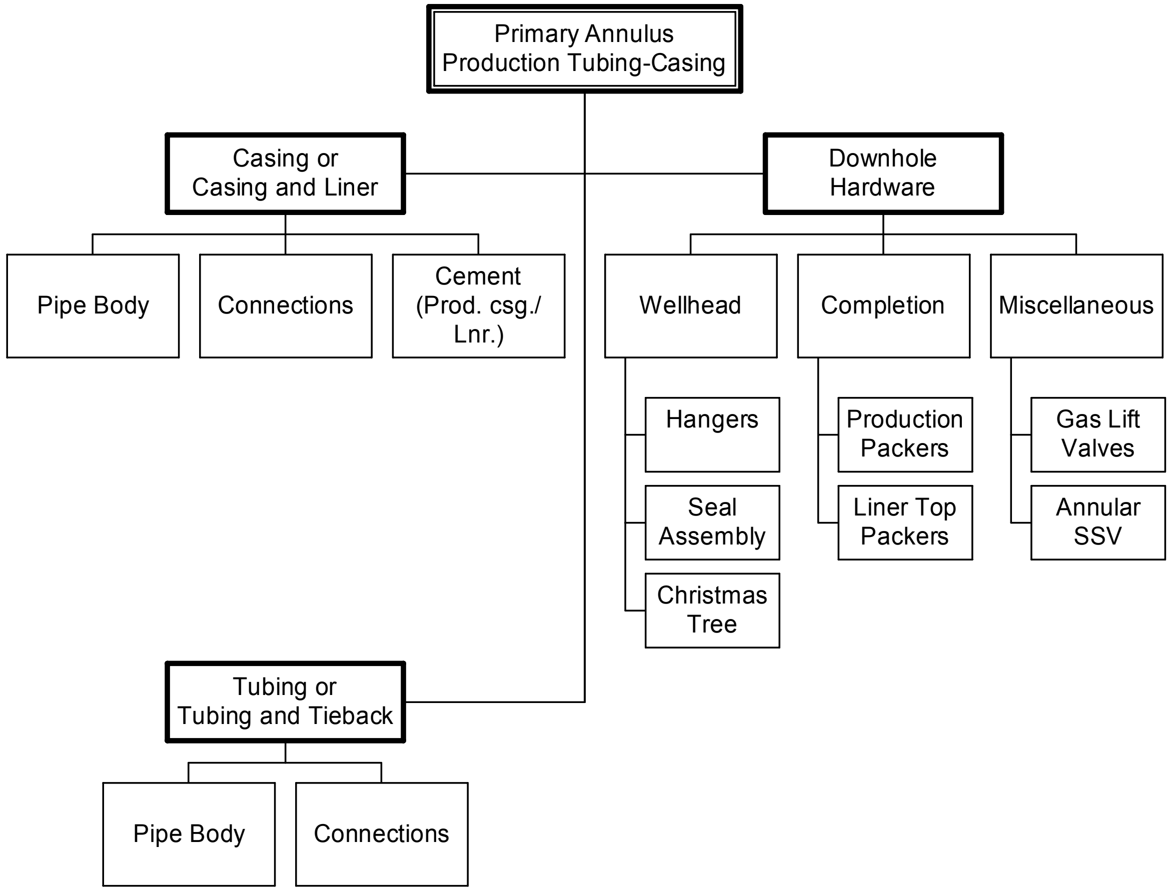


Figure 2 Potential weak points in the primary annulus

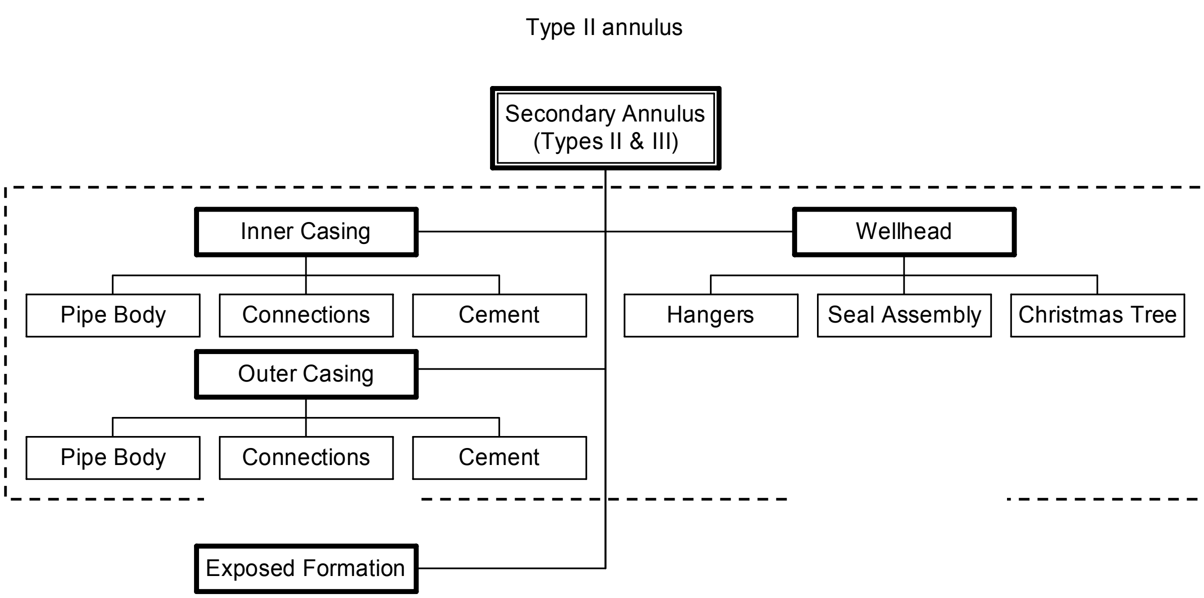


Figure 3 Potential weak points in the secondary annuli

The next step is to ensure that the basis of design is preserved during well construction. This is accomplished by handling and installation procedures that ensure continued performance of the components within the intended design envelope. For example, if the design calls for premium connections, care must be taken to follow special running procedures, if any, as recommended by the manufacturer. Alternatively, elevated levels of running and handling care may be required to achieve consistently higher performance from API connections. This requires special torque monitoring among other things. In short, appropriate operational techniques must accompany design recommendations and they must be implemented during well construction. Arbitrarily applying torque control or other methods will not necessarily ensure performance.

Component testing provides a limited level of assurance, i.e., an assurance that the component will perform to the level to which it was tested. Tests provide confidence about the reliability of performance at different load application levels. A test cannot guarantee performance for every condition the component experiences during its service life. For example, a connection tested to an internal pressure of 3,000 psi with a tensile load of 100 kips, is good till that load condition is exceeded. Whether the connection can perform at that level after being cycled thermally and mechanically several years after installation can only be assessed qualitatively (or sometimes quantitatively depending on data available). Design and proper implementation during well construction are thus the primary safeguards to minimize SCP occurrence. Nevertheless, testing has an important role in ensuring that the design basis is in place in the actual well.

In some respects, SCP may be an inalienable aspect of every offshore well. The principal aim of design is to ensure that the pressure is manageable. Monitoring should be made (and usually, it is) the key feature during well operation. In fact, a prescribed program of measuring pressures at the wellhead is followed by most operators. This is complemented by appropriate production logging and diagnostic procedures. Monitoring programs should be commensurate with age and characteristics of the well. This is analogous, for example, to drill pipe inspection, where inspection intervals depend on the type of the well being drilled. Obviously, short radius rotary drilling calls for more stringent inspection criteria. Similarly, the potential risk associated with an SCP event should determine the monitoring program. In fact, most operators believe that current monitoring and design practices are adequate for the management of SCP, and when implemented with prompt and appropriate diagnostic procedures, will go a long way in mitigating SCP incidence.

Finally, there is always a small but finite chance that SCP will occur despite implementation of best practices at every stage. When this occurs, proper diagnosis should be followed by a risk assessment and remedial measures. This assessment feeds into the assessment of well integrity which takes all the well characteristics into account.

The material presented in this document is a review of the state-of-the-art in SCP design and management. It is based on experience, conversations with drilling and production engineers in operating and vendor/service companies (including the JIP participants), and an exhaustive survey of well construction literature. Though the problem of casing pressure has been recognized for sometime by the industry, there is little documentation in open literature. In this respect, the present document is an attempt at piecing all the relevant information together. The goal is to create a resource for better understanding of the SCP problem, its relationship to the design basis, and current best practice choices available.

The authors acknowledge a significant debt to four (4) seminal papers attached to this document, i.e. the papers by Attard (1991), Oudemann and Bacareza (1995), Michel (1991), and Greenip (1978). Attard's paper describes the repeated occurrence of SCP in the primary and secondary annuli of wells in the Hutton field in offshore North Sea. This paper discusses the engineering basis for management and remedial actions that were necessary following the discovery of SCP in the wells. The paper by Oudemann and Bacarezza provides the seed for the development of a "unified" model of casing pressure. Though this paper is concerned with thermally induced APB and its role on casing design, it provides valuable physical insight into what SCP is and how it should be handled quantitatively. The paper by Michel deals with operational aspects of diagnosing SCP and isolating causes with specific details pertinent to wells on the North Slope of Alaska. Finally, Greenip's paper is about operational issues related to design and running of casing. Though the paper is twenty two years old, the issues addressed in this work continue to be as relevant today as they were at the time of publication.

2) Structure and Scope of this Document

In 1997, a Louisiana State University (LSU) study by Bourgoyne et al., (1999a, b) described the major incidences of SCP in offshore wells. The study concluded that nearly 50% of SCP incidents in offshore Gulf of Mexico (GOM) wells occurred on the production tubing-casing annulus, and that poor cementing was the major source of SCP in the outer annuli. The findings of this study were also published in a paper presented at the 1999 Offshore technology Conference (OTC paper 11029, Bourgoyne et al. 1999). Appendix E is the list of the conclusions excerpted from the LSU report. The present Joint Industry Project (JIP) was conceived in March 1999, mainly to assess the integrity of the primary annulus and develop guidelines for best practices to mitigate SCP in new wells and manage it in existing wells. In this light, our document focuses on the integrity of the production tubing casing annulus (hereafter referred to as the primary annulus). The problem of SCP management in the outer annuli are being addressed by other Joint Industry Projects.

The aim of this document is to identify causes of SCP problems in the primary annulus, define and describe modeling and design approaches to account for such problems, to identify occurrence of SCP, describe monitoring, detection and diagnostic procedures, and describe the state-of-art and best practices in design and management of SCP problems. In the course of this document, we hope to provide answers or best available guidelines to questions such as,

- Is the basic design approach appropriate to handle the presence of sustained casing pressure?
- Are the operations, testing and monitoring techniques adequate to identify and manage problematic occurrences of SCP?
- What choices exist when faced with SCP? Which choice is appropriate under what conditions?

The goal of this document is **not to be** prescriptive. Instead, the document is expected to serve as a guideline and resource to better understand the SCP problem and to provide an engineering methodology for design and operation of wellbores to properly manage SCP. Hopefully, such a document will be a useful resource and reference to regulatory authorities, operating companies and vendors alike.

This document begins with a brief section that identifies the causes of SCP which were first made known via the LSU study by Bourgoyne et al. (1999). This is followed by a re-examination of some of the conclusions in the LSU study. In particular, we draw attention to the purported severity of the SCP problem incidence based on reported case histories and statistical analysis of the data in the MMS database used in the LSU study. The rest of the document is devoted to a discussion of the management of the SCP problem from the perspective of design, running, installation and testing, and diagnostics. In each case, the focus is on tubulars, that form the primary annulus and the associated completion hardware. Cementing issues are not addressed in this report. Remediation of the SCP problem, by the very nature of the problem cannot be based on a general discussion. A key point that emerges from the discussion ahead, is that mere adherence to best practices as documented in a manual is not an automatic guarantee against SCP. Rather, the possibility of SCP must be incorporated into each stage of well construction like other load cases such as a 100 year storm or a 100 barrel kick. As a consequence, remedial practices to eliminate or mitigate the impact of SCP when it occurs must necessarily be treated on a case-by-case basis. As a result, in each of these sections we focus on current best practice, identify potential problems and describe the state of the art to the best of our knowledge.

We note here that this section (Section I) of the document must be read in conjunction with four other sections. Section I was prepared by Blade Energy Partners.

Section II examines the role of sealing elements, i.e., tubular connections. This section has been addressed separately by Tom Asbill of Stress Engineering Services.

Section III is a discussion of basic string design, properties of elastomeric seals and the characteristics of other components of the production string that may experience leak problems. Section III was prepared by Magnolia Global Energy.

Section IV is a discussion of the effect of corrosion and sour gas on tubulars and their role on annular integrity. Section IV was written by Ken Riggs of Stress Engineering Services.

Section V contains a brief review of the well data that was collected from participating operators as part of this JIP. This section was also prepared by Ken Riggs of Stress Engineering Services.

We only make a few summary remarks on the above topics to maintain internal consistency.

The document concludes with appendices and attachments. Appendix A contains the results of a survey of current operational practices for managing SCP that was sent to participants in this JIP. Appendices B and C discuss the modeling techniques used to quantify SCP problems. Also attached in Appendix F are four (4) seminal papers on the SCP problem. These papers, explicitly or implicitly contain most of the points made in this document. In fact we would go so far as to state, that by themselves, these papers form a “best practices document” for management of SCP.

3) Causes of Sustained Casing Pressure

Depending upon the well location (offshore, onshore, subsea) and type (HPHT, oil, gas, ERD), SCP may arise due to one or more of the following reasons:

3.1) Thermal Effects

As mentioned in Section 2, the temperature across the wellbore increases in comparison to its equilibrium initial magnitude when the well is put on production. The temperature causes thermal expansion of the incompressible annular fluids. Since the volume of the annulus does not expand to the same extent, the annular pressure increases. The problem here is one of multiple annuli responding together to a change in temperature. At equilibrium, the increase in pressure corresponds exactly to the final volume changes of the annuli and fluids. In designing for this load condition, care must be taken to include all the uncemented annuli in the analysis. Often, addressing the pressure build-up in one annulus may leave another annulus exposed to a failure-causing load. Such pressure abnormalities can (and are) typically accounted for in the well design process by most well designers. The procedures to do so are well documented in the oilfield literature (Adams, 1991; Halal and Mitchell, 1991; MacEachran and Adams, 1991). Trapped annulus pressures are a natural phenomenon and do not arise due to a problem of design or construction. Of course, they cannot be ignored and must be considered when designing equipment to handle the expected loads. Nevertheless, the design methodology to handle such "unsustained" casing pressure scenarios will prove instructive in our understanding of the causes and management of SCP, as discussed ahead.

3.2) Leak in tubing or Sealing Elements

When the pressure integrity of the production tubing or the sealing element is lost, the primary annulus is exposed to the reservoir pressure, usually resulting in an increase in the pressure. This condition may arise due to poor tubing design, poor packer and seal design, or erosion/corrosion of the tubing and/or sealing elements. In general, however, both the tubing and casing are designed for this load condition. Proper design ensures that the casing can withstand the likely loads imposed due to a leak.

3.3) Failure of Casing

In some cases, the casing itself may fail, due to corrosion, wear, or thermal cycling. The failure could either be at the connection or in the pipe body itself. At such times, it is possible for the annulus to be exposed to the formation communicating with the failed portion. If this formation happens to be a high-pressure formation, once again, an increase in annular pressure is observed.

3.4) Failure of cement

In annuli where sealing and isolation are achieved by a cement column, the cement column may fail during the service life of the well, thus exposing the annulus to the pore pressure at the shoe of the shallower casing. This could result in either an increase in pressure in the annulus, or a loss of fluid to the formation, which in turn could result in a pressure increase. Poor cementing is a common cause of this condition.

4) An Overview of the LSU Study

The objectives of the LSU study were to compile data on the magnitude of the SCP problem, identify its causes and methods of management/remediation, and to assist in the development of new technology to reduce future SCP problems. A database of GOM wells for which SCP departures were given was compiled as part of this study, and the data in this database were analyzed. In brief, the final report of this investigation (available at ftp://www.mms.gov/TubingStudy/) contains

- a description of the current regulatory practices that MMS has in place to monitor SCP problems and grant departures,
- brief case histories of four (4) wells which suffered catastrophic consequences due to SCP (or rather its improper management),
- summary statistics of SCP occurrence in GOM wells grouped according to geographic location, type of well, type of annulus and casing pressure magnitude,
- a study of SCP causes, and
- a section on diagnostics and possible remediation techniques (illustrated with three (3) case histories of successful and unsuccessful applications.)

The conclusions drawn from this study are presented in Appendix E. Conclusions # 1, 8 through 11, 13 and 14 are relevant from the perspective of the current document and they are reproduced below for reference:

1. About 50 % of wells with sustained casing pressure have pressure on the production casing.
    8. About 10 % of the casing strings exhibiting sustained casing pressure are *intermediate* casing strings.
2. About 30 % of the casing strings exhibiting sustained casing pressure are *surface* casing strings.
3. About 10 % of the casing strings exhibiting sustained casing pressure are *conductor* casing strings.
4. Only about one-third of the casing strings exhibiting sustained casing pressure are in wells that are active and producing.
    13. About 90 % of sustained casing pressures observed are less than 1,000 psi in magnitude.
    14. More than 90% of all sustained casing pressures observed are less than 30 % of the minimum internal yield.

Further to these conclusions, the study reports that "…most serious problems have resulted from tubing leaks," and recommends "…the most promising area for improvement is through prevention of SCP by use of better tubular connectors, by use of better primary cementing practices, and by maintaining a reasonable margin between pore pressure gradient and fracture pressure gradient in the open borehole being cemented."

The purpose of this section is to examine some of the conclusions made by the LSU study, especially in the light of the database analysis.

4.1) Data Analysis

The discussion in this section is based only on information that was available to Blade energy Partners. We did not have access to the actual database or the raw data that was used to arrive at the conclusions reported by the LSU study.

The LSU report is essentially a study of incidence of SCP as reported into the database. As in any database, the only conclusions that can be drawn are a function of the data fidelity and characteristics. The report does an excellent job of cataloging the reported incidences by geography, annulus type, and pressure magnitudes. Several case histories are also reported, and the authors also attempt to identify causative factors in SCP. However, given the database (or at least based on the report) it is difficult to assign causative links between the incidence of SCP being reported and the design basis, well history, and diagnostic results. Operational reasons or physical causes of SCP therefore are impossible to ascertain from the reported incidences. This is the main reason why most of the conclusions of this report are statistical, and not phenomenological.

Since the present document addresses only issues related to the primary annulus, consider the statement (in the LSU report) that most serious problems have resulted from tubing leaks and that the most promising area for improvement is through the use of better tubular connectors. The only evidence cited for this is conclusion #1 which states that 50% of the SCP cases occur on the production casing. Although the conclusion is reasonable, the data analysis by itself does not lead to this conclusion. For one, the database is also populated by incidences of casing pressure as a result of thermal expansion of trapped annular fluids (recall that MMS regulations require the reporting of casing pressure, even unsustained, if it exceeds 20% of the minimum internal yield pressure (MIYP)[1] of production casing). Secondly, if the incidence of casing pressure in the primary annulus is accompanied by pressure in other annuli, then the cause of pressure in the primary annulus could be other than a leak in the tubing. Thirdly, the primary annulus (as discussed later in this document) is assembled of components that present several leak paths, all of which could have caused the leak, if a leak is the cause of the increased pressure. Despite these problems, as stated earlier, the conclusion is reasonable. In general, experience and operator input indicate that the primary cause of sustained pressure in the primary annulus is tubing leak, while the primary cause of sustained pressure in the other annuli is poor cementing.

The report also assigns the casing pressure incidences by field. This is reproduced as Figure 4 in this report (and is Figure 2 in OTC paper 11029). Although this figure is only for outer string annuli (i.e., not the primary annulus), it is instructive. The data indicate that up to 35% of the outer strings have sustained pressure in some fields. However, some fields exhibit a much higher incidence rate than others. The wells in Mississippi Canyon seem to experience an unusually high percentage (35%) of SCP problems with Ewing Bank wells following closely. Is there a reason for this (possibly geological, as hinted by the LSU report)? Why are only some wells in each field

[1] The minimum internal yield pressure of a casing string is the internal pressure rating of a tubular as described by API 5CT. It is given by

$$\text{API MIYP} = 0.875\ \frac{2\sigma_{yp}}{\left(d_o/t\right)}$$

where σ_{yp}, d_o and t are the yield strength, outer diameter and wall thickness of the tubular respectively.

exhibiting SCP? How close are these fields together? What is the age of these wells? What is the average period of SCP (i.e., how long has SCP been present on an average well)? Is there a higher incidence of sour gas (perhaps being produced late in life)? Many such questions need to be addressed before making conclusions on the efficacy of regulatory practice or SCP management.

Consider the data that shows the distribution of SCP by casing types. This is reproduced as Figure 5 in this report (and is Figure 3 in OTC paper 11029). This data would be very useful if we could also determine the percentage of cases where more than one string had pressure simultaneously. For instance, of all the surface casing strings, what percentage had pressure on production casing? What percentage had pressure on all the strings? Perhaps, a Venn diagram showing percentages of strings which experienced pressure simultaneously and strings that were the only afflicted ones would be more appropriate. For example, if all of the surface strings had pressure on other annuli as well as in a given field, conclusions about likely leaks paths could be made. However, given the current data, it is not possible to assess the seriousness of the problem. Curiously, conclusion # 11 through 14 indicate that only a third of the wells with SCP are live producing wells. This fact is important to the discussion of well integrity and risk assessment.

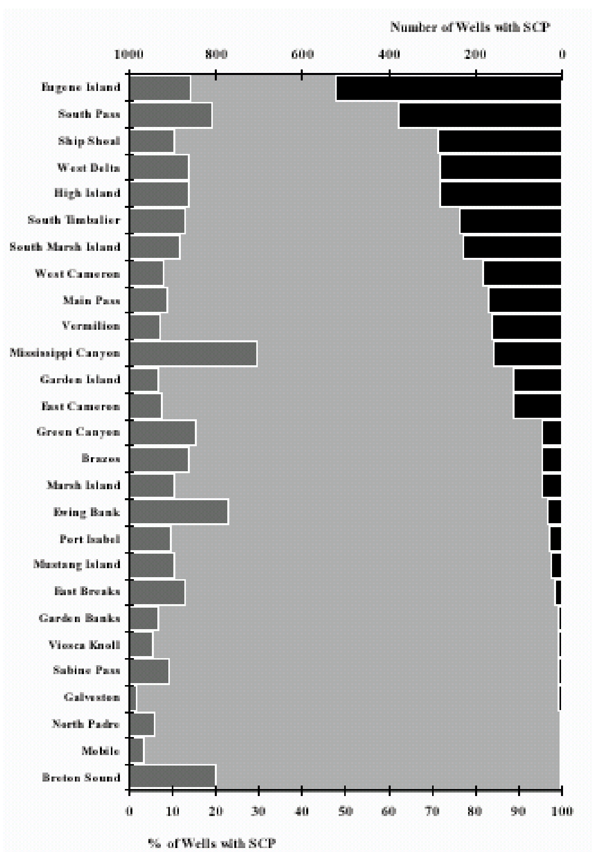


Figure 4 SCP by Area (Figure 2 of OTC Paper No. 11029)

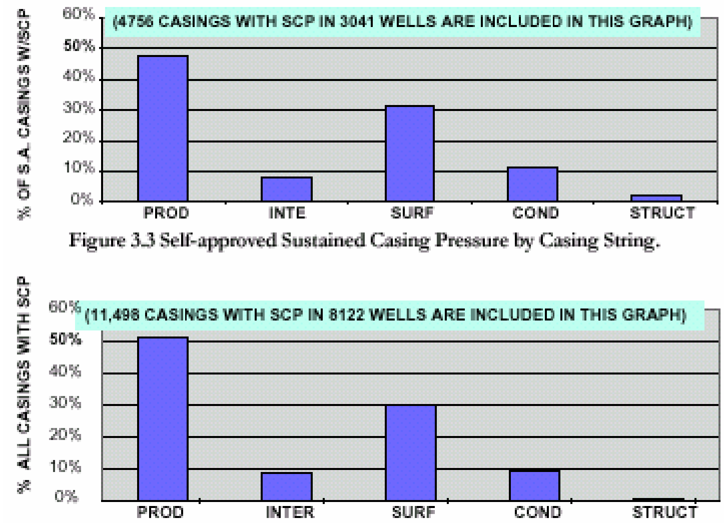


Figure 5 SCP in MMS database by string (Figure 3 in OTC Paper No. 11029)

Finally, one rather important correlation statistic would be valuable in assessing the impact of SCP. The report states that over 8,000 wells in the GOM have reported SCP. It would be useful to know the answer to the simple question “for how long?”. If management of the SCP problem has been successful enough to allow pressure for an extended period of time in some cases, this would indicate that adequate management practices are being followed in those cases.

In summary, we believe that SCP databases need to be structured such that the statistical analysis of their data can be correlated with the physical conditions of the wells. These well conditions should include factors such as the age of the well, casing data, quality of cement jobs, nature of produced fluids, potential for corrosion, etc. These are discussed further in the section on assessment of well integrity. This is arguably difficult, as the authors of the LSU report worked from a specific database. We raise these questions here to highlight this difficulty, and to suggest that making phenomenological conclusions from this work is also difficult.

Despite these difficulties, the report has successfully raised the issue of SCP incidence and potential for dangerous consequences.

4.2) Case Histories

Brief outlines of four case histories are provided in the report as well as in OTC paper no. 11029. Case 1 describes a well that cratered due to SCP of 3,400 psi on the production casing. The only detail pertaining to the well parameters is the MIYP of the production casing (6,900 psi). The case history concludes by stating that “It is believed that the production casing became pressurized through tubing or packer leaks. Failure of the production casing led to pressure on the outer strings through which the blowout occurred.” Though the outcome cannot be disputed, it is difficult to make definite conclusions in the absence of a design basis, post-mortem or even a well schematic. For instance, why did the production casing fail at 3,400 psi, if its pipe body yield is 6,900 psi? What was the load state on the production casing (i.e., what was the differential pressure on it?). What kind of connections were used? Is it possible that the blow-out was a consequence of pressure build up (or failure of cement) in the outer casings, and was independent of the fact that the production casing also saw pressure? The only clue to probable mismanagement of the problem during initial stages comes from the fact that the operator applied for a departure when the SCP was measured at 3,400 psi (which is nearly 49% of the MIYP). Unless the basis for granting departure and the diagnostic results prior to departure grant are known, among other things, it is difficult to re-construct the events leading to the explosion.

Case 2 describes a well with an underground blowout which eventually caused platform settling at the mudline. Holes in the tubing were discovered at 1500 ft. Once again, as in case 1, the cause and effect sequence is not clear from the data presented.

Case 3 is not directly relevant to this study, as the incidence of SCP was limited to the surface casing/conductor annulus, and the cause-effect analysis is also fairly clear from the reported history.

Case 4 describes a well on which departure was granted (soon after the well completion) when the SCP on the intermediate casing was 4,600 psi. Although this case is also one of pressure in outer strings, we discuss it here because of the possible role the primary annulus played in the case. The cause of the SCP was assumed to be thermal pressure buildup. Again, it is not clear what the pressure on the primary annulus was when the intermediate casing recorded 4,600 psi. Thermal pressure buildup effects are felt also in the primary annulus. It is surprising that the primary annulus pressure is not reported in the discussion of the case history. Based on what eventually happened, this case seems to be one of mis-diagnosis, since an underground blowout was the cause of the problem.

Regardless of the above comments, the case histories reported make a very important point which must not be ignored- that SCP can have (and has had) disastrous consequences if it is poorly diagnosed or managed.

In summary, the authors of the LSU report have achieved an important purpose- elevating the issue of SCP as a situation that must be addressed by regulatory authorities and operators alike. The most important conclusions that can be drawn from the LSU report are:

1. There is a large incidence of sustained casing pressure in one or more annuli in GOM wells,
2. If poorly managed, SCP has the potential for dangerous consequences.

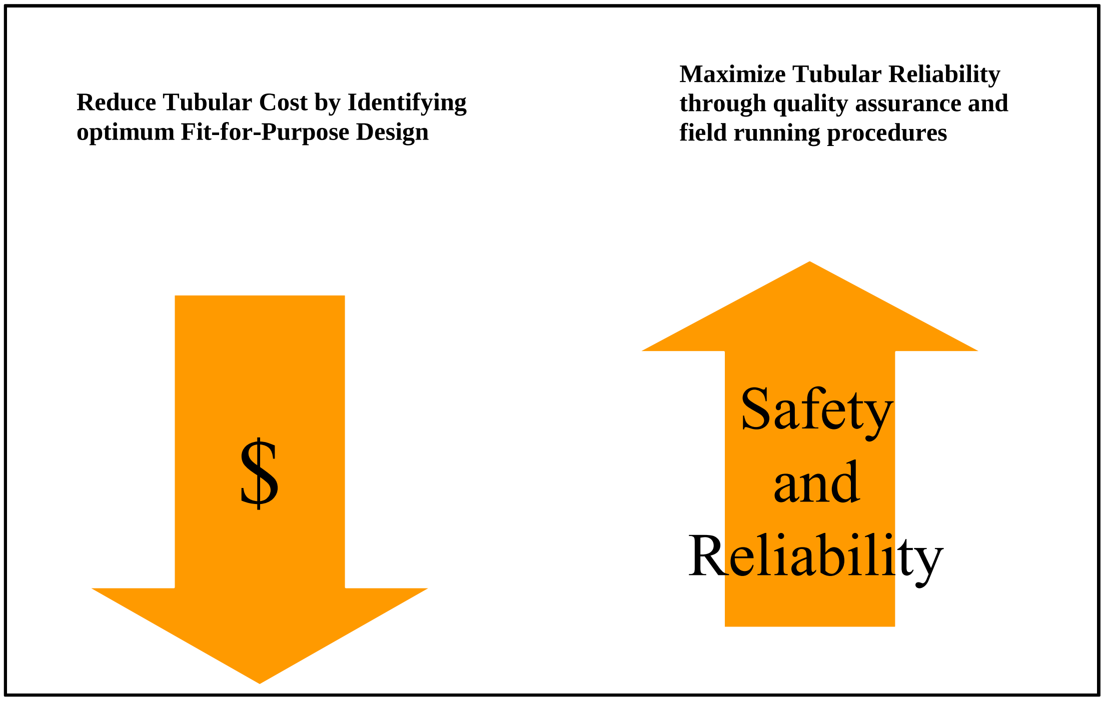
It is however, hasty to conclude from this report that current operational guidelines for well design must be drastically revised to mitigate SCP, based solely on these incidents. Such a conclusion can only be made after a more thorough review of the data and well histories, and a detailed post mortem of these and all other instances in the MMS database.

In this light the current document makes an attempt to unify the best practices in design, running, handling, monitoring, testing and diagnostics in order to provide a framework for operators, vendors and regulatory authorities to better understand and manage incidence of sustained casing pressure in GOM wells.

5) Management of Sustained Casing Pressure in the Primary Annulus

5.1) Design

Figure 6 Purpose of Design



As shown in Figure 6 the purpose of good casing design is to ensure that the tubular can sustain all imposed loads while ensuring safe well operation for the life cycle of the well, and minimizing material costs. The design methodology involves two steps:

1. identification and determination of loads that the tubular will experience during its service life, and
2. selection of a suitable tubular with an acceptable level of safety.

Traditionally, the oil industry has used a methodology known as Working Stress Design (WSD) to design oil well tubulars. Conventional WSD philosophy is based on maintaining a specific margin between the maximum anticipated field load and the "published rating" of the tubular. The anticipated load is usually based on the worst case load that can theoretically originate during given operations. For example, the worst load on the surface casing string might be the internal pressure at the casing shoe during a pressure test. In this case the appropriate "published rating" of the tubular could be the "MIYP rating" as given by the manufacturer. The specific margin between the maximum anticipated load and the published rating is known as the "safety factor" (SF) or the design factor, so that

$$SF = \frac{\text{Published Rating}}{\text{Max. Anticipated Load}} > 1. \qquad (1)$$

Since the late 1980s, an alternative design approach known as Reliability Based Design (RBD) has been applied by some operators (notably, ARCO, Mobil and Shell). This approach treats the anticipated loads and the tubular strength as statistical distributions rather than fixed quantities. The details, comparison of RBD with WSD, their relative merits and de-merits are beyond the scope of this document. In the context of the present document, it suffices to say that there are several competing design methodologies currently being used for well designs. The works listed in the bibliography by Payne and Swanson (1989), Payne et al. (1998), Brand et al. (1993) Gulati et al. (1994) represent the work by ARCO and Mobil, while those by Bradley (1971 a, b), Parfitt and Thorogood (1994), and Banon et al. (1991) highlight the work by Shell and BP Amoco.

Irrespective of which design methodology is used, the fact remains that tubing and casing design requires the identification of all loading scenarios in the life of the well. The approach should rely on a careful scrutiny of assumed "maximum load" field conditions. Additional focus should be placed on understanding the root causes behind tubular problems and failures and addressing them with appropriate remedial measures. In this light, Figure 7 illustrates the ever present battle between the designer and the field.

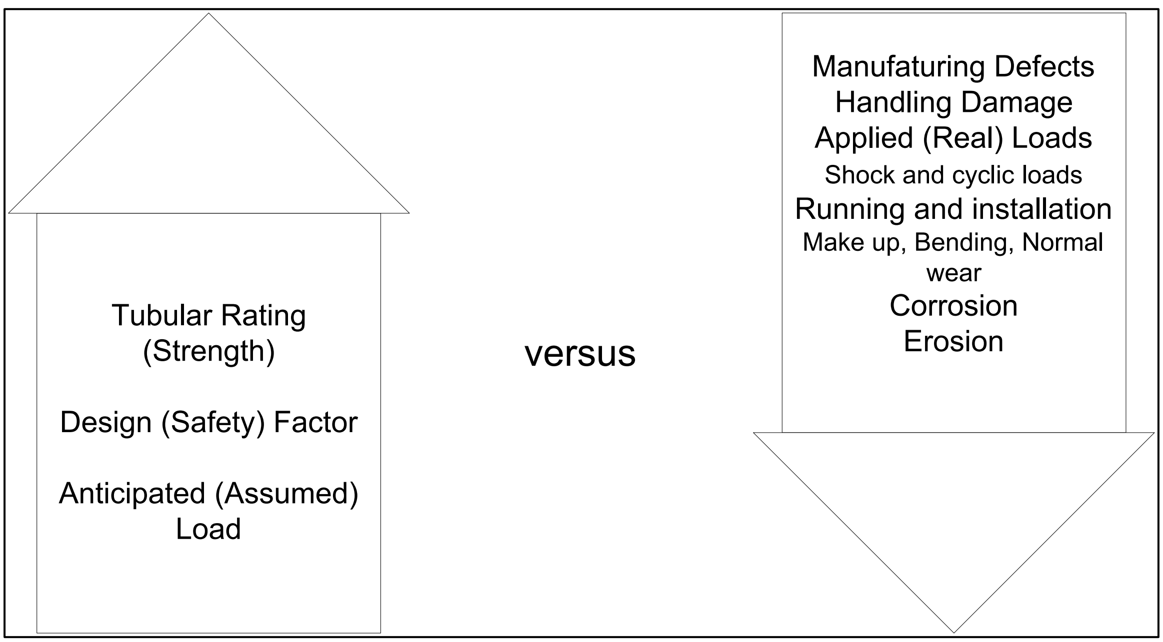


Figure 7 Design Methodology versus Field Conditions

5.1.1) Production Tubing

The production tubing probably experiences the widest possible range of loads as compared with the other tubulars in the wellbore. The standard design procedure accounts for running and installation, pressure testing, shut in of hot/cold production fluids, injection and stimulation, and tubing evacuation. If the reservoir requires stimulation, the design should consider the effect of fracturing or injection.

	AFP	IPP	EPP	TP	Other	Tbg. Limit state
Running and Installation	Running weight.	Drilling mud	Drilling mud	Geostatic	Bending & neg. dyn. loads	
Pressure Test	Buoyed weight plus slack off or pick up and end effects.	Surface pressure on mud column	Packer fluid	Geostatic	Bending*	Tension Burst
Production	Buoyed weight plus slack off or pick up and end effects.	WHFP + hydrostatic prod. fluids + flow losses	Packer fluid	Production	Bending* and buckling due to thermal loads+	Tension Burst
Well shut-in	Buoyed weight plus slack off or pick up and end effects.	Reservoir BHP + gas gradient for gas well. (Conservative for oil well.)	Packer fluid	Initially hot production temperature profile cools to geostatic after a few hours	Bending* and buckling+ due to thermal and SI pressure effects	Tension Burst
Evacuation or production from depleted reservoir	Buoyed weight plus slack off or pick up and end effects.	Near vacuum	Packer fluid	Production (hot)	Bending* and buckling+ due to thermal and SI pressure effects.	Collapse
Tubing Leak at surface	Buoyed weight plus slack off or pick up and end effects.	Reservoir BHP + gas gradient for gas well. Conservative for oil well	Reservoir BHP on top of packer fluid	Production (hot) and/or geothermal	Bending* and buckling+ due to thermal and SI pressure effects.	Collapse
Injection	Buoyed weight plus slack off or pick up and end effects	Inj. Press. + hydrostatic + frictional losses	Packer fluid	Injection temperature (cold)	Bending*	Tension Burst
Frac job	Buoyed weight plus slack off or pick up and end effects.	Screenout + hydrostatic	Packer fluid	Injection temperature (cold)	Bending*	Tension Burst
AFP	Axial Force Profile					
	End effects due to packer type must be included in the determination of AFP					
IPP	Internal Pressure Profile					
EPP	External Pressure Profile					
TP	Temperature Profile					
SI	Shut-In					
BHP	Bottom Hole Pressure					
WHFP	Well Head Flowing Pressure					
*	If well is deviated					
+	Depends on packer type					

Table 1 Standard tubing design load cases

Table 1 shows the loads normally anticipated by a tubing designer for production and injection wells. The loading modes experienced by the pipe body under these well conditions are also described in the table. In most cases, for a producing well, the tubing size and grade are ultimately governed by the loads experienced by it during well shut-in and evacuation.

The tubing running procedure is designed such that before the well is set on production, the tubing is free of thermal stresses. The stress state at any point in the tubing string is determined by the string weight and internal and external pressures. The internal pressure is created by the completion fluid while the external pressure is created by the packer fluid. When the well is set in production, the tubing heats up and its thermal expansion (or rather its prevention due to constraints placed by the wellhead and the packer) causes thermal stress. This in turn can buckle the string, lead to tubing movement (depending on the amount of motion allowed by the packer at the tubing tail), and create corresponding stresses. The change in the internal pressure profile (from completion fluid to a less dense production fluid) contributes to tubing motion and stresses. The analysis of tubing movement, the resulting tubing to packer forces, and the forces transmitted to the casing via the packer are fundamental to tubing design. This analysis consists of determining the changes in the length of the tubing due to four separate effects- length change due to the string weight and mechanically applied axial forces (slack off or pick up), length change due to helical buckling of the tubing if it occurs, a length change due to temperature change, length change due to pressure forces on the tubing end (the piston effect) and a length change due to ballooning. The last effect refers to the axial response of length changes in the pipe due to changes in the internal and external pressure of the tubing (i.e. changes in fluid density and applied surface pressure) and is different from the length change due to the piston effect. These effects have been thoroughly studied and well documented in the literature by Lubinski and Blenkarn (1957), Lubinski et al. (1962), and Hammerlindl (1977). These well understood effects are included even in rudimentary casing and tubing design procedures of most oil companies and tubing manufacturers, and they are documented in textbooks on casing and tubing design (see for example, Craft et al. (1962), Aadnoy, (1996), Mitchell, Miska and Wagner, (1997)). From the point of view of annular integrity, it must be noted that tubing movement analysis for different operating conditions influences the design of the packer. As a result of the various length changes mentioned above, tubing to packer forces are generated. In turn, these forces are transmitted to the casing via the packer (such that the casing to packer force balances the resultant of the tubing packer force, the weight of the column of packer fluid, and the force due to reservoir pressure at the bottom of the packer). Needless to say, the packer forces and magnitude of its motion have a significant impact on the packer design which is one of the critical sealing components of the annulus. This is discussed ahead in section 5.1.4.

When the production fluids have to be shut in for any reason during the life of the well, the inside of the tubing is exposed to a hot column of pressurized fluid. The shut-in internal pressure profiles are likely to be less severe in the case of oil wells as compared to gas wells. However, it is conservative to design for gas shut-in, especially if it is an exploration well or there is uncertainty about the reservoir properties or the well has a high gas to oil ratio or is likely to produce gas later in its life. Typically, the most stressed point occurs at the top of the tubing where it experiences the vertical component of the buoyed weight of the tubing, thermal stresses, internal pressure (approximately the reservoir BHP less the gas gradient times well TVD) and zero external pressure (since the packer fluid has no backup pressure at surface under normal operating conditions). In WSD approaches, the body of the tubing is designed such that the maximum triaxial equivalent stress does not exceed the working stress for the tubing steel. For steel, the triaxial stress is the von Mises[2] Equivalent (VME) stress, and the working stress is the yield stress divided by an acceptable design factor. Finally, depending on the packer type, the worst case scenario could occur when the production fluids have cooled and reached geothermal temperature. For example, if the packer does not allow any motion, the tensile axial stress at the top of the tubing is mitigated by the compressive thermal stress developed during production. When the wellbore cools down, the axial stress in this section of the tubing is likely to be higher than the hot shut-in case. It is therefore prudent to check both hot and cold shut in conditions.

In injection wells, cold fluid is injected down the tubing and into the reservoir. This has the opposite effect of production, in that it cools the tubing and produces tensile thermal stresses. Again, depending on the packer, the tubing has to withstand internal pressure with tension.

The estimation of the thermal stresses in the above situations requires the calculation of the tubing temperature profiles with changing well conditions, i.e. production, injection, shut in, etc. The thermal behavior of wellbore has been studied under a variety of conditions (for example, see Ramey (1962), and Erpelding and Miller (1994), for production and injection, Raymond (1969) and Corre et al. (1984) for drilling and circulation). More recently, computer software programs known as wellbore thermal simulators are used in conjunction with casing design programs to evaluate temperature profiles and thermal stresses prior to the determination of tubing movement scenarios. These simulators are finite difference programs that are based on a two-dimensional axisymmetric formulation of the heat transfer equations. Given the wellbore geometry, descriptions of annular fluids, and ambient conditions, the programs calculate temperatures along the length of each casing string and annulus for the given flow condition, for example, production. Wooley (1979, 1980) provides a detailed description of how these thermal simulators are formulated and used in well design. Use of such simulators is now common in well design procedures. At the least, a rule of thumb to estimate the maximum wellhead flowing temperature is used.

As the reservoir is produced, the sand face pressure declines towards the end of the life of the well. In this instance, the pressure of the packer fluid in the annulus will exceed the internal pressure and the tubing should be designed against collapse. Also, if for any reason, the perforations are plugged and the tubing is evacuated, it should be able to resist collapse due to the external pressure of the packer fluid.

Apart from the above strength based considerations, the tubing must also be sized for erosion resistance, potential corrosion and sour service as dictated by the nature of the well. Depending on the life expectancy of the well and the anticipated solids production, acceptable erosional rates and production flow velocities are determined (API, 1981, Salama and Venkatesh, 1983). This information in turn is used to size the tubing ID (Payne and Hurst, 1986).

The role of corrosion and sour service in tubing selection is being addressed in another section of the current study (Riggs, 2000).

Sour service considerations place restrictions on the grade and metallurgy of the tubular steel (Ikeda, 1992, Monrose and Boyer, 1992, Crusco, 1981, Stair and McInturff, 1983).

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[2] See Johnson et al. (1987) or Greenip (1977) for a discussion of how the notion of triaxial load capacity is used in tubing and casing design.

5.1.2) Production Casing

	AFP	IPP	EPP	TP	Other	Pipe body Limit state
Evacuation	As cemented string weight	No fluid- complete evacuation	String mud weight	Geostatic	Bending*	Collapse
Tubing Leak at surface	As cemented string weight	Reservoir BHP or WH SIP on top of packer fluid	Pore pressure	Production (hot)	Bending* and buckling due to thermal loads if not cemented to surface	Tension burst
Annular Pressure Buildup (APB)	As cemented string weight	Thermally induced	Thermally induced	Production (hot)	Possibly wellhead movement in platform completions	Burst or collapse
AFP	Axial Force Profile					
IPP	Internal Pressure Profile					
EPP	External Pressure Profile					
TP	Temperature Profile					
SI	Shut-In					
BHP	Bottom Hole Pressure					
WHFP	Well Head Flowing Pressure					
*	If well is deviated					

Table 2 Standard load cases for production casing

Table 2 shows the load cases that normally drive the design of the production casing. Though the load cases are self-explanatory, it is important to note the following (assuming that the production casing is designed for these cases):

1. If the well has to be shut-in for any reason and the wellhead seal assembly fails during the shut in and breaches the primary annulus, the casing can withstand the tension burst load imposed on it. If the tubing is designed for complete internal evacuation (and collapse due to the packer fluid), this condition automatically protects the annulus to a pressure equal to the wellhead shut in pressure based on the initial reservoir pressure.
2. By designing the casing to resist collapse due to the natural pore pressure gradient, we are once again protecting the integrity of the tubing in the event of the annulus losing the packer fluid.

In high temperature, high rate wells, or subsea wells which do not have access to the outer annuli, annular pressure buildup effects must be explicitly considered during the design stage by using methods such as those outlined by Adams (1991) or Halal and Mitchell (1993). An example of how annular pressure buildup influences design is provided in the work by Goodman and Halal (1993) with respect to a high pressure high temperature (HPHT) wells. The implications of designing for annular pressure on the current SCP problem are discussed in section 5.1.4. When very high pressures are likely to be induced due to heating of the annular fluids during production, stronger casing (by weight and/or grade) is used. Alternatively, depending on the well, the formations in which the different strings are set and the pore pressure and fracture gradient profiles, an annulus where very high pressures are expected may be left unsealed, creating a Type III annulus that was discussed in Section 2. If the thermal pressure buildup exceeds the fracture pressure at the bottom of the annulus, the fluid leaks off, thus relieving the pressure on the strings (Oudemann and Bacarezza, 1995). Sometimes, a highly compressible foam is used to fill a part of the volume of the annulus in which pressure relief is sought (Leach and Adams, 1993).

In the event that a snubbing operation cannot be attempted if the tubing fails at surface, the casing must be strong enough to withstand a bullhead kill on the live tubing string. In this case, this would be one of the design criteria for the production casing.

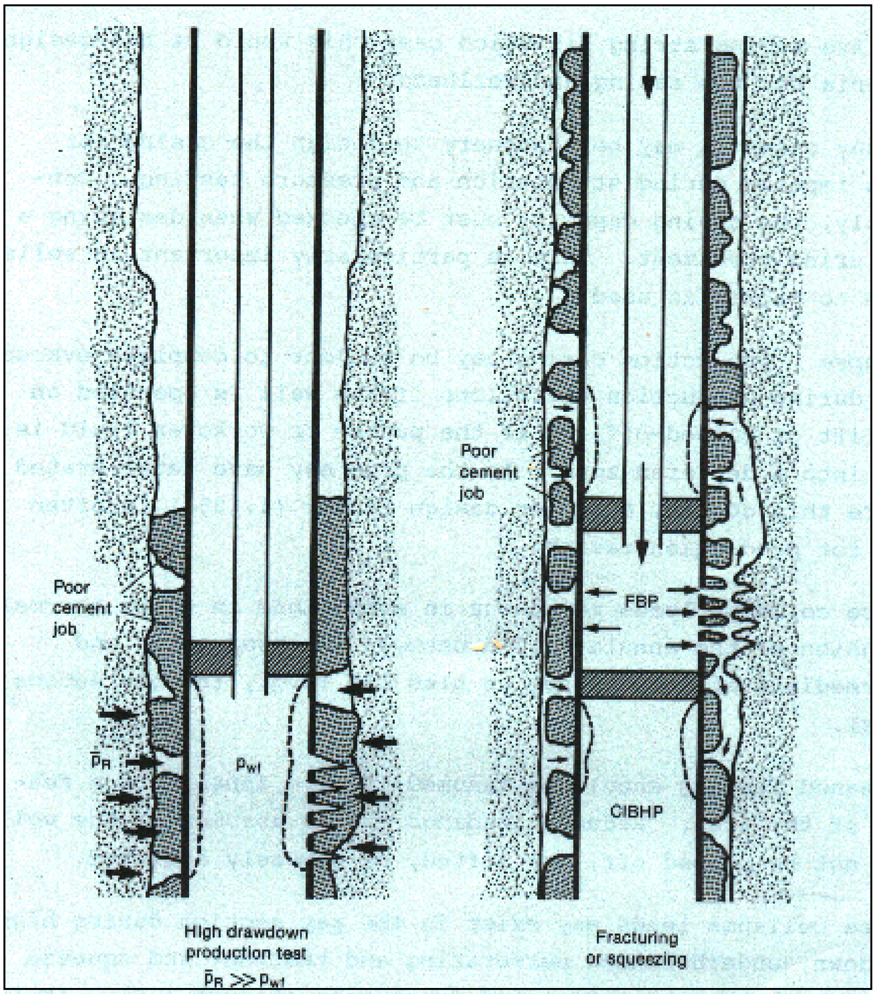

Figure 8 Production casing loads during stimulation

The casing must be designed to withstand all the loads imposed during well stimulation. Figure 8 shows possible scenarios when the production casing could be subject to severe collapse loads. If for some reason, the cement behind the production casing is poor, a high drawdown situation could lead to point loading and premature collapse of the casing. A similar situation could arise during fracturing in the neighborhood of a poorly cemented zone.

Apart from these standard load scenarios, based on the specific well conditions, other loads such as well subsidence may have to be considered. Gradual depletion of the reservoir leads to compaction of the producing formation. This compaction transfers axial buckling loads and transverse crushing loads to the production casing. The principal failure modes for the production casing have been identified as compression, buckling, shear and bending (Bruno, 1990). Philips experienced such problems in the offshore Ekofisk field in North sea. Yudovich et al. (1988) and Anvik and Gibson (1987) describe how to probabilistically predict such subsidence induced failures and plan for them during the design stage.

Also, in high rate and/or high temperature gas wells, large tubing-to-packer forces are generated. Depending on the design of the packer, these loads may be transmitted to the casing. This is an unlikely but possible mode of casing failure/ annular breach.

Finally, the effects of the packer fluid on the production casing and tubing must be considered during the design stage. This aspect is addressed in a separate document on corrosion (Riggs, 2000).

5.1.3) Connections

Connections and other sealing elements are discussed in greater detail in a separate section (Asbill, 2000). A few points relevant to the discussion in this section are included here for completeness.

The selection of tubular connections is critical when constructing a well to avoid SCP. It is estimated that connection failures account for 85% to 95% (or more) of oilfield tubular failures (Payne and Schwind, 1999). This has significant implication in the SCP problem in the primary annulus. From a probabilistic view point, as there are significantly greater numbers of connections than other sealing elements in the primary annulus, the probability of SCP being caused by a connection leak is correspondingly higher.

Tubular connections can generally be divided into two groups, API and premium. There could be significant differences in the reliability or leak resistance between connections. Choosing the proper connection for a particular application involves understanding the expected loads. Suggested application limits for different connection types have been published by connection suppliers and users of connections (Klementich, 1995). Note that many published ratings do not include combined load ratings, such as tension and burst. It is up to the designer to determine the suitability of the connection for the intended application.

Studies have shown that the leak resistance of API 8-round connections is sensitive to a number of parameters including variations in makeup turns, pipe diameter, grade, thread compound, and applied tension (Schwind and Wooley, 1989). It should also be stated that API connections can provide a reliable leak resistant connection for many applications. Proprietary makeup procedures for API connections have been developed to improve the reliability of leak resistance. These include Torque-turn and Torque-position (Day et al. 1990).

Proprietary connections have manufacturer published ratings, and these are often used as the basis for selection. There are instances when a connection is planned to be used in a well where the anticipated load conditions do not fall in the set of load cases that the connection was tested for. In such cases, operators augment connection tests performed by manufacturers with detailed finite element analyses or further testing to ensure connection performance in an application.

Regardless of connection type, make-up practice has a significant impact on the leak resistance realized from the connection. As discussed earlier, for API threads, proprietary make-up procedures have been developed to augment leak resistance. Proprietary threads have special make-up procedures, which are well documented by the manufacturer. These procedures must be followed, at a minimum, if the published performance is to be realized in an application.

Tension or compression can cause a significant reduction in connection leak resistance for both API and premium connections. The leak resistance under combined loading, such as, tension and burst, must be understood in order to determine the suitability of connection. Tests have shown that connections are susceptible to leak when loads are cycled. Since axial and bending stresses on a tubing vary considerably during its service life, the impact of cycling the load on connection performance must be considered when selecting a connection.

An important issue that has received little attention is that of corrosion in connections, especially in the threaded section of the runout sections (Moore, 2000). Moore speculates that residual stresses could initiate or even catalyze galvanic corrosion in these sections of the connection geometry. Since threading is a cold working process, it creates areas of residual stress concentration which can initiate corrosion. In principle, heat treatment can eliminate the residual stresses. But API requires hot working only on C-90, T-95 and Q-125 grades. A majority of tubing that is presently downhole belongs to the J, K, L, N and P grades. In this light, API Supplemental Requirement SR-22 which prescribes tolerance specifications for API threads may have to be re-examined.

5.1.4) Packers and Sleeves

A packer provides a seal between the tubing and the casing, isolates the fluids in the primary annulus from the reservoir. A sleeve is a downhole component used to obtain access from the tubing to the primary annulus to permit fluid circulation (for any reason) or produce a previously isolated zone. Sleeves are essential components of multi-zone completions, and they are typically placed above the packer in each producing zone. For a discussion of the different kinds of packers, sleeves and other completion equipment see Buzarde et al. (1972: Pearson, (1987; or Allen and Roberts, (1989).

In its simplest manifestation, a packer (Figure 9) consists of a sealing element surrounded by a set of slips on either side. The slips are driven by a mechanical (setting) force so that they cut into the casing wall (the inner surface) and engage to prevent relative motion between the slips and the casing. After the slips engage, the seal is energized mechanically or hydraulically. Depending on the application, there is a bewildering array of packers (retrievable, permanent-retrievable, inflatable) that are available from different manufacturers. However, from the point of view of annular integrity, the design should be primarily based on a consideration of the allowable tubing movement that the packer permits and the evaluation of the forces that are imposed on the tubing and the packer, as a result of the end constraint. From a mechanical stand point, there are three types of packers – those that permit no motion in the tubing at the packer end (latched), those that permit only upward motion and those that permit free motion in either direction (landed).

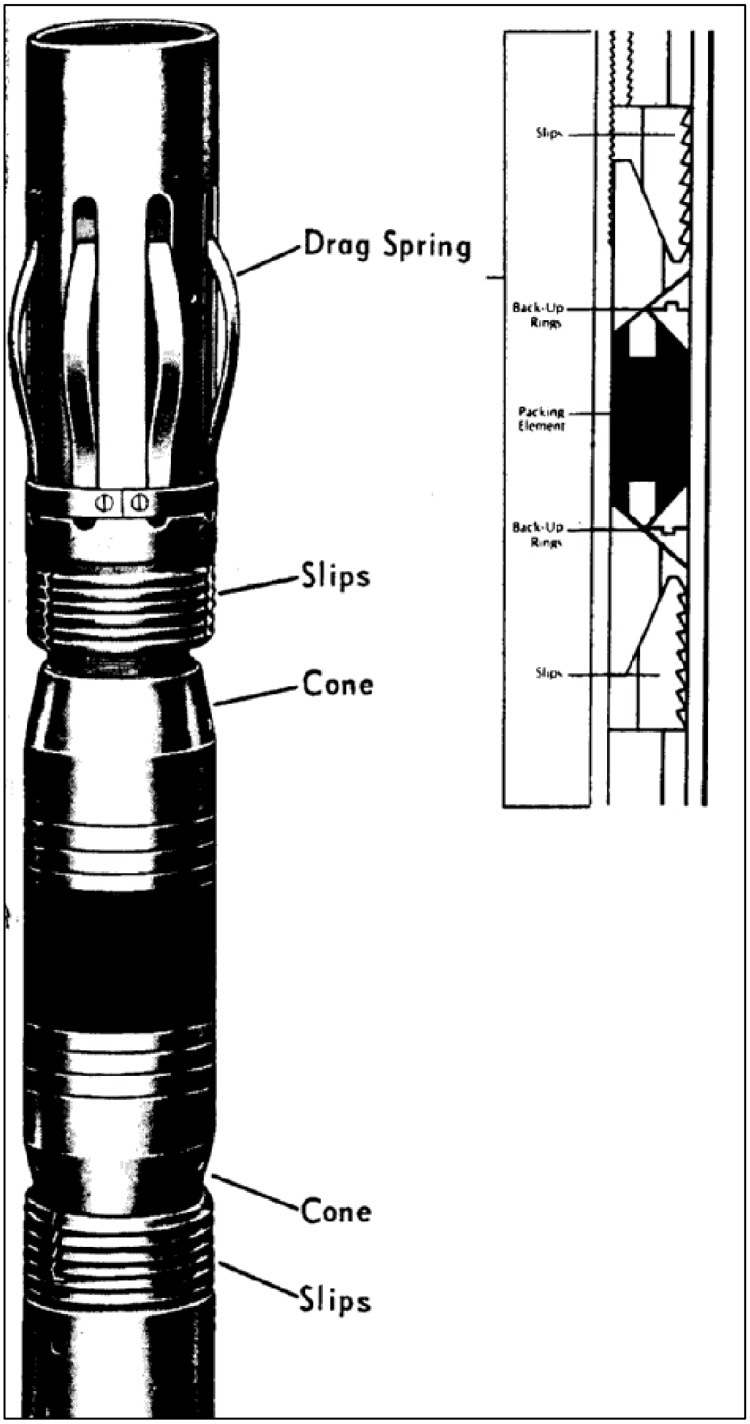

Figure 9 Packer mechanism (after Buzarde et al. 1972)

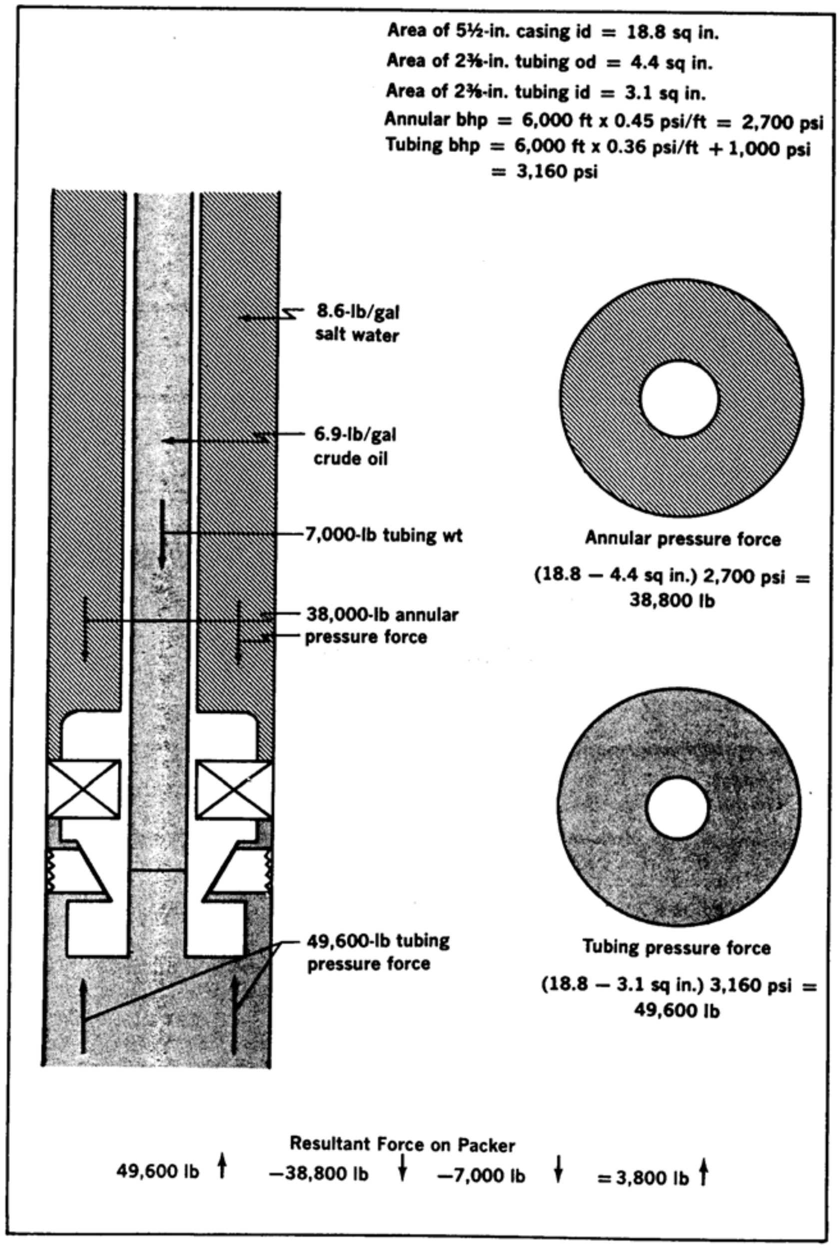

Figure 10 Example calculation – piston force on a packer during injection (after Allen and Roberts, 1989)

Figure 10 shows an example calculation for the piston force acting on a packer during injection. Forces exerted on the packer for different well operating conditions must be evaluated before selection of the packer. For example, consider the case of a limited motion packer (that does not permit downward motion of the tubing) in a producing well. During the initial stages of production, the pressure differential across the packer is very small, since in most cases the annular fluid has a density equal to the reservoir kill weight. Later in the life of the well, the depletion of the sand face pressure increases the pressure differential, thus possibly increasing the tubing to packer force. Once again, it is important to consider the service life of the tubing in design. Most casing/tubing design programs incorporate a procedure that allows quick evaluation of these forces. Alternatively, these forces can be calculated using the methods described by Lubinski et al. (1962) and Hammerlindl (1977, 1978) and implemented on a spreadsheet to analyze various scenarios that characterize the load situations faced by the tubulars during the life of the well. Finally, the mechanical action of the packer on the casing at the slips imposes local stresses on the casing. These forces must also be accounted for during casing design.

In packer selection, consideration must be given to the behavior of the packer material if CO_2 or H_2S is expected in the reservoir fluids. If alloys like K-Monel (which is resistant to hydrogen embrittlement) are used, the possibility of galvanic corrosion at the interface of packer and casing steel must be examined.

In most completions with packers (with the exception of gas-lift wells), a packer fluid occupies the primary annulus. The fluid is usually a brine, with low corrosive action. The density of the packer fluid is often chosen to be such that it is "kill weight" for the expected reservoir pressure on day one. However, as the reservoir depletes, the fluid places an additional differential pressure on the packer itself, and a collapse load on the tubing. These loads must be considered in the selection of the packer fluid, as well as in the design of the packer and the tubing. In rare instances, in the presence of SCP, the collapse load on the tubing could be severe, and must be checked for each case of SCP (see section 5.5). SCP can increase the differential pressure on the packer, thus compromising the seal integrity at the packer, and opening up an additional leak path.

5.1.5) Wellheads

Wellhead selection is generally the joint responsibility of the drilling and the production engineering teams. Wellhead specifications are governed by API Spec 6A and procedures for basic design and selection may be found in the works of Pearson (1987), Buzarde et al. (1972). References to advanced aspects of wellhead design and construction are provided in the bibliography (DaMota, 1982; Britton and Henderson, 1988; McIver, 1991; Cowan, 1993). Detailed evaluation of the wellhead design procedures is beyond the scope of this document. Instead, only issues relevant to the integrity of the casing annuli are discussed here.

The calculation of wellhead motion and forces exerted on the wellhead by the strings (especially during production of hot gas) in platform completed wells is a crucial stage of wellhead and string design. The temperature rise in the free standing sections of the tubulars (i.e. the sections above the mudline) causes thermal expansion. Depending on the well conditions (i.e flow rate, reservoir temperature), the movement can be of the order of magnitude of a few inches. In addition, thermally generated wellhead motion has the potential to generate very large forces between the strings and the wellhead (at the hangars) and between the drive pipe and the formation at the mudline.

Wellhead movement and forces are controlled by the steady state temperature distribution along the different strings during production, their initial temperatures, the lengths that contribute to thermal expansion, string stiffness, and frictional forces created due to differential motion between the conductor and formation and at steel-cement interfaces of the inner tubulars. To a lesser order, wellhead movement is affected by pressure buildup due to heating of fluids in uncemented annuli, well deviation, buckling of the relatively limber inner strings, and axial drag between them. These effects are not difficult to manage if they are anticipated during the design stage. Options such as pre-tensioning the strings, managing cement tops, tracking wellhead-tubing forces (through landing, cementing, production, and shut-in) will ensure the integrity of the wellhead and annulus.

Though most offshore operators recognize, anticipate and design for this problem, there is no comprehensive published literature that discusses these aspects of wellhead design. Kocian (1990) provides a method to compute the distribution of forces at the wellhead during landing and cementing. Halal et al. (1997) and Samuel and Gonzales (1999) discuss some of the basic modeling aspects of this problem.

In summary, the design of wellheads for critical wells- especially offshore hot gas wells (subsea as well as platform completed) must include an evaluation of string expansion and stresses at the wellhead.

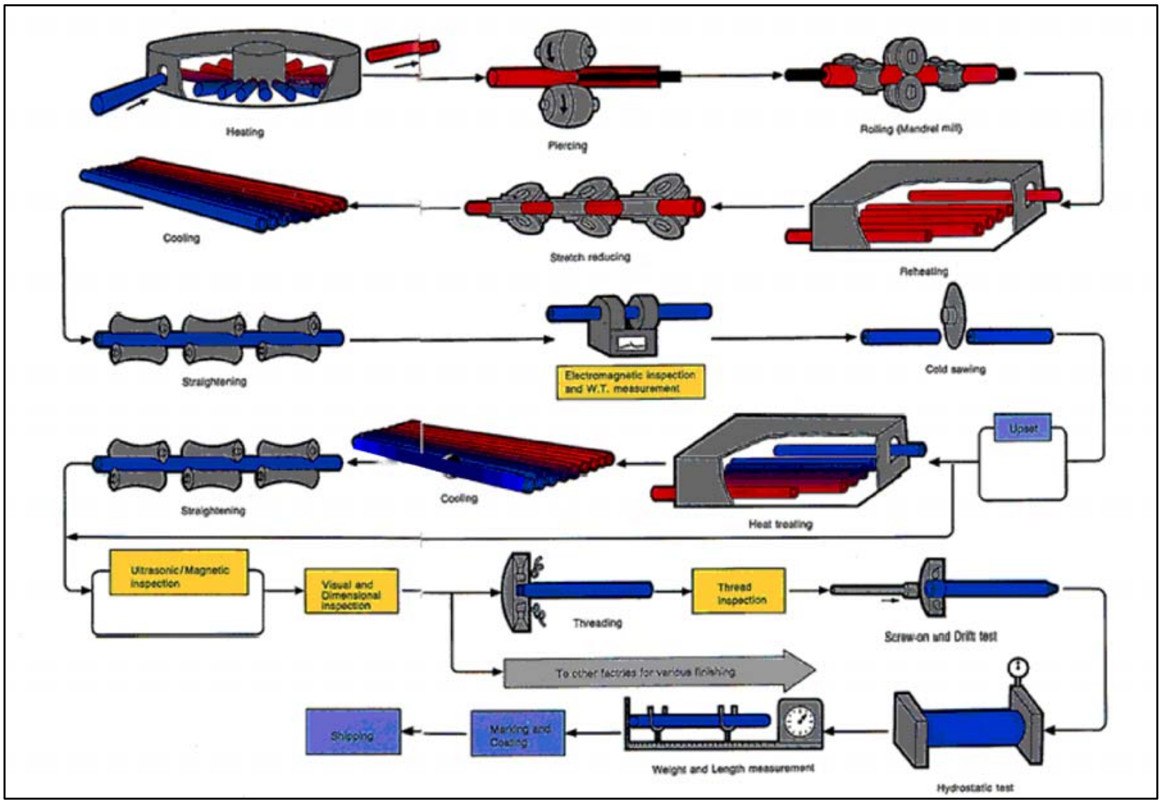

Figure 11 Tubing Manufacturing Process

5.2) Tubing Material Selection

This section highlights issues relevant to OCTG material performance properties and hence the tubular design process. The basic processes and a typical sequence for manufacturing steel tubular goods are shown in Figure 11. The preparation of a tubular for final use includes various finishing procedures apart from basic shape-changing processes (i.e., heat treating, inspection, testing). The dimensions that are produced by any process are subject to variation, and, in all cases, nondestructive inspection is necessary for controlling the process and for assuring that the final product meets the required specifications. These nondestructive processes are defined in the controlling API Specification 5CT. This specification defines an assortment of destructive and nondestructive tests required for casing and tubing products to be qualified to the desired grade (Table 3 and Table 4). In addition to the requirements defined in API 5CT, manufacturers have developed and implemented in-house testing procedures which may sometimes exceed API 5CT requirements.

Test	Required for API Spec. 5CT, Group: 1	2	3	4
1. Heat Analysis	X	X	X	X
2. Product Analysis	X	X	X	X
3. Tensile	X	X	X	X
4. Flattening	Welded	Welded	Welded	Welded
5. Impact	-	-	-	X
6. Hardness	-	L-80 C-90 T-95	-	Thru - wall
7. Hydrostatic pressure	X	X	X	X
8. Height & trim of electric weld flash	X	X	X	X

Table 3 API Spec. 5CT Test Requirements

Grade	Inspection: Visual	EMI	UT	MPI (Circular Field)
H-40, J-55, K-55, N-80 (N, N & T)	R	N	N	N
N-80 (Q & T), L-80, C-95	R	A	A	A
P-110	R	A	A	----
C-90, T-95, Q-125	R	B	C	B

R = Required, as specified in API 5CT Para. 9.6.

N = Not required.

A = One method or any combination of methods shall be used.

---- = Not applicable.

B = At least one method (excluding the visual method) shall be used in addition to UT to inspect the outside surface.

C = UT shall be used to inspect the inside and outside surface.

Table 4 API Spec. 5CT Inspection Requirements

5.2.1) Inspection and Material Testing

Commercial pressures within the OCTG manufacturing community have led to the development and application of very sophisticated process controls. These controls immediately detect processing parameters that go astray and lead to production of tubulars outside the specified dimensional and property tolerance levels. Because of the sophisticated nature of these process controls, properties of OCTG are strictly speaking not "random". Instead, tubular properties vary around fairly well controlled distributions. When tightly controlled, OCTG performance properties have higher degrees of reliability. The consistency and tightness of these property distributions varies between manufacturers, and should be well understood by the tubular designer (Payne et al. 1998). Most manufacturers create control charts for this purpose. A typical procedure to quality control is as follows. First, the process is examined to ascertain that it is normal (as in a Gaussian distribution) and that all assignable causes of variation have been eliminated so that its operation is stable within the limits of chance variation. Next, a historical record is made by plotting the mean values of a number of samples, the size, frequency, and selection of which have been carefully predetermined after consideration of the process characteristics. These values are placed on two charts, one for averages and one for ranges, and limits are calculated for each. If the limits used are $\pm 3\sigma$, where σ is the standard deviation, not more than 0.2% of any plotted points would be expected to fall outside these lines. Therefore, whenever a point does fall outside, the process is critically examined for an assignable cause. As the process continues, current samples are plotted and compared with past history to ensure that the process remains in control. In most processes, the mean is controllable by an adjustment of the process, but the range can be changed only by finding and eliminating assignable causes.

Material testing is essential to verify properties and to document specific material performance. Material testing is classified into non-destructive methods and destructive testing. A large number of direct tests are destructive, for example, the yield, tensile, charpy, and collapse tests. This testing is usually a part of the manufacturing process. Most OCTG manufacturers perform the API recommended tests (see Table 3) as part of the manufacturing and qualification process. Further, though API 5CT does not require collapse testing to be performed, many manufacturers can and do provide collapse data on various grades of tubulars, other than the commercially advertised “high collapse” grades (Payne and Sathuvalli, 2000).

The final consequence of controlled manufacturing, inspection and in-plant testing is to ensure that dimensional and material property specifications are in place. Specifications in turn guarantee product properties. For example, consider the case of the API specified minimum internal yield pressure. Specifying 87.5% minimum wall tolerance and no direct limit on the maximum wall thickness (other than maximum OD and drift) would theoretically allow an eccentricity in the range of 12.5% to 15%. A detailed discussion of the impact of manufacturing tolerances and specifications is beyond the scope of this document. Therefore we end this section with an example that describes the role of property tolerances and statistical control on the internal pressure rating of a tubular. Figure 12 shows a possible distribution for the wall thickness of a tubular. Assume that the distribution can be described by a normal curve. Assuming that the yield strength and the OD of the tubular are constant at their nominal values, we can calculate the variation in the internal pressure ratings of the tubular. Figure 13 illustrates this variation and the importance of assuring manufacturing controls on dimensional and property variation on the quality of tubular performance, especially in critical situations.

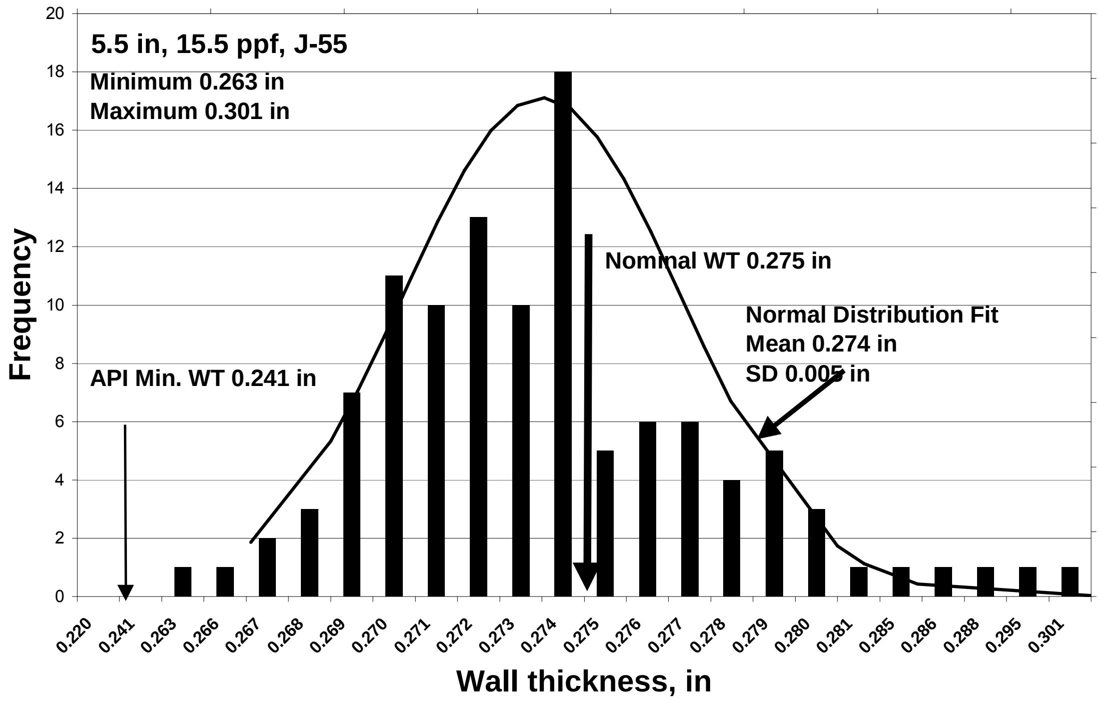

Figure 12 Example distribution of wall thickness

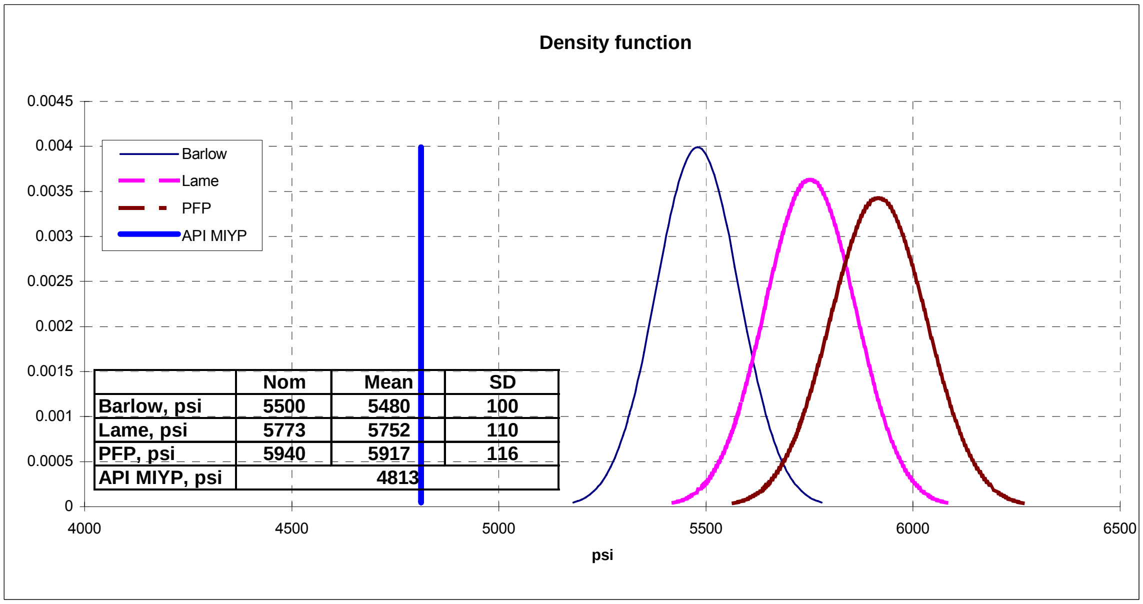

Figure 13 Variation of internal pressure ratings

5.3) Installation and Testing

5.3.1) Running and Handling

API RP 5C1 (1999) covers the use, transportation, storage, handling, and reconditioning of casing and tubing. Raney and Lamb (1999) and Walstad and Crawford (1995) discuss the importance of maintaining the quality of the equipment used in manufacturing and running. Field damage to connections during running is a leading cause of rejected joints. Damaged connections lead to improperly made-up connections which in turn, result in leaks.

A quality system is necessary to ensure that equipment used in well construction is manufactured and supplied according to the design requirements. A number of API specifications, Recommended Practices, Bulletins, and ISO documents, cover the manufacture, inspection, performance properties, transportation, handling, etc., of casing and tubing. Tubular quality control programs have been effective in improving the quality of tubing leak resistance (Ridwan and Hull, 1984).

Various types of quality systems can be developed to ensure that the equipment used in well construction meet some standard set of quality requirements. The quality system can be based on suppliers that are "qualified" to deliver products of known quality. For tubular goods, this could include tube and coupling stock suppliers, connection threaders, non-destructive testing services, and third party inspectors. The quality system must include documentation with regard to the source of all materials, inspection requirements, etc.

Visual inspection of any tubing string regardless of grade should always be mandatory before tubing is run in a well. Defects recognizable by visual inspection include mill defects such as seams, slugs, pits or cracks; poorly machined threads; or shipping or handling damage to the pipe body, coupling and threads.

An alert crew can often prevent installation of pipe weakened by excessive slip or tong damage. High-strength tubing can be more easily damaged by inadequate shipping and handling practices, or careless use of slips and tongs. Improper use of tongs and slips is probably responsible for more critical damage than all other factors combined. Proper handling practices are therefore absolutely essential for high-strength materials. Higher grade pipe should be unloaded with a ginpole truck using a spreader, and nylon or webbing slings which will not scratch the pipe. It must not be unloaded by the common practice of rolling from trucks to pipe racks. Woodsills should be placed between the pipe rack and first row of pipe, and between each row of pipe to minimize pipe contact. Pipe should be racked in a stairstep fashion away from the catwalk so that pipe from the top row never falls more than one pipe diameter as it is rolled to the pipe rack. Appendix F describes an example set of guidelines for running tubing. These guidelines have been excerpted from the monograph by Allen and Roberts (1989). These procedures should be supplemented by appropriate connection make up procedures for the same reason when using higher strength pipe.

The most critical part of running and handling that impacts the integrity of the primary annulus is the make-up of connections. As briefly discussed in the section on connections, strict adherence to recommended make-up practice is critical to achieving the highest possible leak resistance for a given connection. API threads have recommended make-up practices, which have been strengthened by the development of proprietary make-up techniques such as torque-turn and torque-position control. These methods essentially argue that a connection, in order to achieve adequate leak resistance, should exhibit a certain torque when a certain number of turns are completed, or a certain relative position is achieved between the box and pin ends. Failure to do so would indicate a bad connection. API threads are also given different platings to allow higher torques and higher leak resistance.

Several proprietary (or "premium") connections are also available, each of which has a published rating, limits, and make up procedures. The make-up procedures must be strictly followed. In some cases, qualified personnel from the manufactures assist in proper make-up, thus improving the chances that a given connection realizes the highest leak resistance it can.

Use of thread compounds (dope) is common for all types of connections. Several different dope types are available. As is well known, the dope also serves the function of creating a leak path barrier in the connection, thus assisting in maintaining the integrity of the annulus. Therefore, care must be exercised in the application of dope. Simple precautions such as maintaining the threads in a clean condition, and ensuring that no debris is trapped with the dope go a long way in improving the leak resistance of a made-up connection.

5.3.2) Testing

Tubing and casing are also subjected to in-field and post-assembly testing to ensure adequate performance. A number of different test methods have been used in the industry to pressure test tubulars and connections. These include internal and external pressure, testing with different fluids, i.e., water and gas, testing while running, testing after running, etc. The test procedure consists of applying a pressure load on the connection or tubular and waiting a short period of time to see if the pressure bleeds off a detectable amount. The test time period is usually seconds or minutes. Other procedures use a detector to "sniff" for the test gas that has leaked through the connection being tested.

At a minimum, a hydrostatic test of the as-assembled structure (casing run and cemented, tubing run and installed) is conducted, based on a maximum anticipated load. Although each individual component is already tested to assure strength (for instance, API monogrammed pipe must successfully pass the API 5CT requirements), it is very common for the user to seek an added measure of security and that the as-assembled structure is at least capable of handling some estimate of maximum load. In this respect, pressure tests in well construction are different from tests in all other engineered structures. In other structures, tests are based on strength, and are almost always designed to verify claimed or assumed strength. The role of assuring performance is taken up by the design process and the QA/QC process. Thus, although the implicit aim is to ensure the assembled tubing or casing has the assumed strength, tests are administered based on a maximum load estimate. A thorough discussion of a rational basis for testing is beyond the scope of this document, as modern structural testing practice invariably involves the use of reliability theory. It is understood, however, that the primary purpose of the test is to verify the ability of the *assembly* of the structure to withstand an arbitrary load, and to give the user a degree of confidence in the ability of the fully-assembled structure to continue doing so during service life.   Given this, the selection of a pressure test value can be based on a number of parameters. These include:

1. Maximum anticipated surface pressure (MASP). This is based on the highest load expected during the service life of the string. It is also the most arbitrary since it depends on the accuracy of the designer's ability to predict load magnitudes.

2. Pipe body minimum internal yield pressure (MIYP) times some factor of safety. This is a strength based value based on the tubular expected strength and is somewhat less arbitrary that Item 1.
3. Some statistical analysis of the probability of the load occurring, the magnitude of the load and the confidence level required such that the test value would exceed the load if it occurs. This requires the designer to have a sufficient amount of field data to be able to statistically determine a test value that will ensure that the load will not exceed the test value at a predetermined confidence level.

Most test pressure values are based on Items 1 or 2 since they are relatively easy to determine. The designer should try to determine test pressure values on a consistent basis and have an understanding of the purpose of the pressure test.

The main point to note here is that regardless of motivation, a hydrostatic test is imposed on tubing and casing in almost all wells. It should also be noted that such tests only assess the burst capacity of the structure, and collapse capacity is rarely tested. Thus, assurance of collapse performance is assumed, based on the design process and burst performance during the test.

Since hydrostatic tests are imposed using a column of liquid in the tubing or casing, they are of necessity incapable of testing the structure for the in-situ load which originally motivated the test (for example, casing is tested based on a kick load, or a maximum anticipated surface pressure. However, a liquid column can never recreate the load condition imposed by the kick). Moreover, since test pressures are typically held for time periods that are much less than time periods required to guarantee absence of leaks, they are incapable of testing for small leaks. Most small leaks are time dependent and require long periods of time (days to months) to pass before they are noticed. Finally, such tests are also placed on the tubular before the connections and other sealing elements undergo the unavoidable cycling of loads during the life of the well, they cannot test the capacity of the structure for the time when the capacity is demanded by the load condition. Despite these shortcomings, pressure testing is useful for finding gross leaks in connections and pipe bodies. Steps can be taken to locate and replace defective equipment before the well is placed on production.

Pressure testing casing strings after the cement has set can cause the bond between the cement sheath and the casing to fail, resulting in a micro-annulus leak path (Goodwin and Crook, 1984). The leak path created can result in SCP. Subsequent pressure testing should only be done in situations where it is absolutely necessary, due to the risk of causing the cement to fail, creating a leak path. The recommended procedure to test casing is therefore to apply the pressure test immediately after bumping the plug and then bleeding the pressure to zero, assuming the floats are holding.

In some cases where a high level of assurance of gas tight seals is desired (such as in high temperature, high pressure, high rate gas wells), additional tests are conducted on each connection as the tubing (or casing) is run. These include both internal and external tests, and several alternatives are available to conduct these tests. In some cases, the connection can be subjected to an axial load while testing is in progress. While these tests do provide an additional level of assurance as to the leak resistance capability of connections under both burst and collapse, they too share several of the features discussed above (small time period, inability to recreate in-situ or post-cycling conditions). An additional consideration for external testing is the hoop stress that is applied to the pin end of the connection during the test. The pin end hoop stress of a highly torqued connection can be close to the yield strength of the material. The additional stress from the pressure test can yield the pin end, causing a loss in bearing pressure and a loss of leak resistance.

From a point of view of best practice, at a minimum, a properly designed hydrostatic test should be an integral part of well construction. Coupled with proper running, handling and make-up, this gives satisfactory assurance that the tubular has a high probability of providing leak-resistant performance through its service life. This in turn gives the designer reasonable assurance that the annulus is unlikely to see pressure, and that if it does, the surrounding tubulars are strong enough to allow such pressure to be managed properly to avoid dangerous consequences.

5.4) Diagnostics

This section examines the notion of "annular" or "casing pressure" rating and it seeks to establish a causal relationship with the basis of well design and eventually develop diagnostic and remedial guidelines. The SCP problem immediately poses the following questions:

1. When does annular pressure threaten the safety of the well and the environment? Alternatively, what magnitude of pressure on a casing should set off the alarm for action?
2. What is the appropriate remedial action necessary to eliminate or mitigate the problem?

The first of these two questions obliquely states that all casing pressure is not necessarily deleterious to the health of the well. In fact, thermally induced annular pressure, when properly accounted for is inevitable in the life cycle of the well. The mere presence of annular pressure in a well does not signify the existence of a serious mechanical problem that requires a drastic workover. Also, implicit in the question is the notion of the "capacity of an annulus" or the pressure that an annulus can sustain without breach. This question is linked to the basis of design discussed earlier. As pointed out before, a designer chooses the casing strings and completion equipment and the annulus is a consequence.

5.4.1) Behavior of Annular Pressure

The capacity of an annulus is akin to the notion of a "rating". It is not a magical number above which dreadful things start happening immediately. Instead it is viewed as a number that defines the perimeter of a working envelope, and that when exceeded should start an investigation. As Figure 1 demonstrates, the capacity of the annulus is the capacity of its weakest link. In the case of the primary annulus, it is the lesser of the tubing collapse or casing burst[3], assuming that the wellheads, packers and other completion equipment are adequately rated. Similarly, in the case of the Type III annulus, where the bottom of the annulus is exposed to the formation, annular capacity is breached if the pressure exceeds either the burst or collapse of the bounding casing strings, or the fracture pressure at the shoe of the shallower string. From the above it is clear that:

- annular capacity is *not* determined by a universal formula or algorithm;

[3] For the sake of argument, assume tension effects are also included.

- it is well and annulus-specific and it is a function of the design basis;
- the capacity is determined by a close examination of the performance envelopes of the individual components that comprise the annulus and (very importantly) by using certain worst case assumptions about possible loading scenarios.

Consider an annulus filled with a fluid (either an incompressible liquid or a mixture of gas and liquid). The pressure in the annulus depends on the state of the fluid, i.e. its density and temperature. The change in annulus pressure can be wrought by one or all of the following:

1. a change in the volume of the annulus due to change in its physical dimensions;
2. a mass influx or efflux from the annulus volume;
3. a change in the temperature of the fluid.

The change in the volume of the annulus can be caused by thermal expansion (heating of the strings bounding the annulus) or a change of pressure inside and outside or axial expansion of the tubing strings. In the absence of the constraining annulus there would be no pressure increase due to effects # 2 and 3. Therefore, it is reasonable to state that:

$$\Delta p_{ann} \propto \frac{\left(\Delta V^{\text{fluid}}_{\text{therm.exp.}} + \Delta V^{\text{fluid}}_{\text{influx/outflux}}\right) - \Delta V^{\text{ann.}}_{\text{thermal/ballooning}}}{\Delta V^{\text{ann}}} \tag{2}$$

where Δ denotes a change and V and P denote volume and pressure respectively (with the subscripts and superscripts being self-explanatory). The right hand side (RHS) of the above expression is essentially a volumetric strain (since the denominator denotes the original volume of the annulus) and it can be considered as a “Hooke’s law” for fluids if the proportionality is linear with the state of the fluid. The constant of proportionality in Eq. (2) depends on the isothermal and isobaric bulk moduli of the fluid. The changes in the volume can be related to the pressure and temperature changes in the annuli, so that the above expression eventually results in a set of equations which relates the unknown pressures in the annuli to changes of state in the fluid and the strings and the bulk moduli of the fluid. This is the approach used by every APB model. The difference arises in the methods used to calculate individual volume changes which depend on the behavior of pressurized cylinders. The end result is a set of simultaneous equations of varying degree of algebraic complexity. When APB models are a part of integrated casing design and thermal simulator suites, it is not difficult to incorporate a detailed model as described by for example, Adams (1991).

Irrespective of the mathematical details, the pressure changes in the annuli are most sensitive to thermal coefficients of volumetric expansion of the fluid and to the fluid bulk moduli. This fact generates the following considerations. Firstly, the mud in the annuli contain solids which occupy a fraction of the annular volume that cannot be compressed (unlike the fluid). Effectively, the available volume in the annulus equals the annular volume minus the volume of solids present in the fluid. Thus neglecting the content of solids in the annular fluids will underestimate the increase in pressure. Secondly, the coefficient of volumetric expansion is a function of the temperature for gases. For liquids it is a weak function (White, 1991)[4] of temperature. Thirdly, to the best of the

[4] The effect of thermophysical property variation on the thermal behavior of drilling patterns has been discussed by Fontenot and Clark (1974) and more recently by Zamora (1997). These studies imply that the range of pressure and

authors' knowledge, there are no models that consider the effect of fluid influx or efflux in to the annulus. Oudeman and Bacarreza (1995) consider this effect in an experimental study of APB in an HPHT well. They consider the change of APB due to fracture at the base of an uncemented annulus in a HPHT well and interpret field data on annular pressure measurements. Ability to model this effect is an important step in the understanding of SCP. A few pointers and simplistic notions (which must be refined) to model this effect are described in Appendix C.

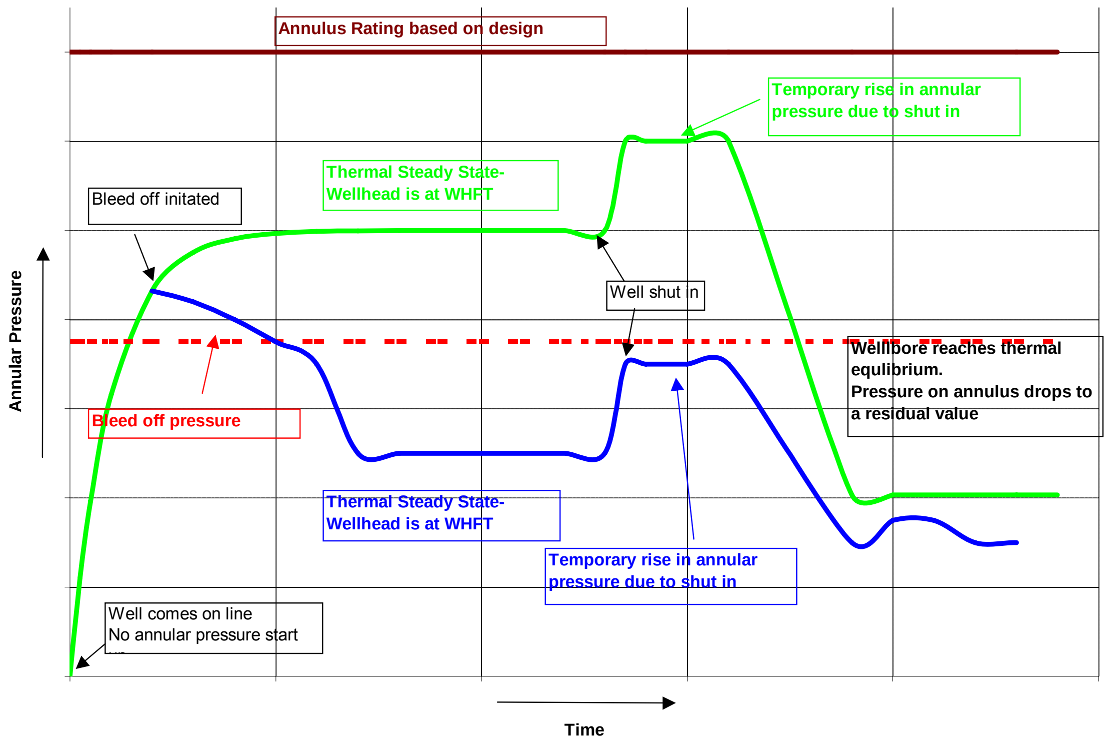

Figure 14 Annular Pressure Trends

However, in the present instance it is useful to understand the behavior of annular pressures during the well operation. Consider Figure 14. The figure shows a possible trend for the pressure in the primary annulus of an offshore well. Let us assume that the dotted red line represents a pre-set pressure at which the annulus is to be bled off. It could represent the API MIYP of the casing or the API rating for pipe body collapse for the tubing or a number such as the MMS defined 20% of the MIYP of the casing. Let the solid brown line represent the pressure that would cause breach of the annulus. This number can be rationally calculated from the basis of design for the well (as explained in the earlier sections). When the well is set on production, the fluid in the annulus heats up and

temperature in deep HPHT wells are wide enough for property variations to be accounted for. In the case of annulus pressure, the change in temperature from geostatic to wellhead flowing temperature in a high gas rate well could be large enough to examine the effect of variation of coefficient of volumetric thermal expansion.

the pressure slowly builds to a value that can be calculated. The well eventually reaches a thermal steady state[5] thus increasing the pressure in the annulus. Assume that the pressure is allowed to go past the dotted red line and reach a steady value. At this point, if the well is shut in for any reason, the annular pressure rises (by a small amount which is estimated in section B.4 of Appendix B) to account for the increased ballooning of the tubing. However, the well starts cooling down again (typically it takes about the same amount of time to cool down as to heat up) and reaches the geostatic temperature. The pressure in the annulus falls in response and reaches a residual value due to the ballooning in the tubing. Ideally, none of these pressures can or should compromise the annular integrity if due consideration is given to all the aspects of the design. If on the other hand, the annulus is bled off when the pressure exceeds the value represented by the dotted red line, the trend is depicted by the solid blue line for the same set of reasons discussed before.

Such trend curves can be plotted for all the annuli and kept on hand. Most programs for detection of problems in wells include regular monitoring of annular pressures[6]. Any abrupt pressure changes immediately trigger an investigation into their cause. This is the first step in the diagnosis and management of SCP. Finally, it must be noted that curves such as those shown in Figure 14 can be generated before the well comes on line and used as a basis to check for annular integrity. These curves can be generated by using computer based casing design programs, wellbore thermal simulators, and methods of analysis for pressure build up (analogous to those described in the Appendices to this document).

Once the annular pressure limits for the safe operation are established, criteria for the unsafe operation must be established. Examination of Figure 14 shows that the following criteria are potential trigger points for an investigation:

1. unexplained reduction in the wellhead flowing pressure (and rate)
2. an increase in pressures in any of the annular pressures under normal operating conditions (production, shut-in, start-up);
3. a sudden decrease in the annular pressure preceded by a gradual or sudden increase;
4. communication between annular pressures, when the pressures in different annuli follow each other;
5. inability to bleed off the annular pressure, i.e. the pressure does not decrease with continued bleeding or recurs soon after the bleed valve is closed.

In short, any continued unexplained change of pressure in tubing or the annuli is cause for investigation. Figure 15 shows an example decision tree for procedures needed to decide if SCP diagnosis and remediation should be initiated. This chart is based on a decision tree used by Amoco to diagnose and control SCP problems in wells in the Hutton field of North Sea (Attard, 1991).

[5] The time taken to reach steady state can vary from a few hours to a few days depending on the nature of the well. In high rate hot gas wells, thermal steady state is reached in a few hours. The time can be estimated using wellbore thermal simulators or the methods outlined by Ramey(1962).
[6] This is analogous to plotting curves showing the anticipated hook load while tripping in or out of the borehole with the drill string while drilling.

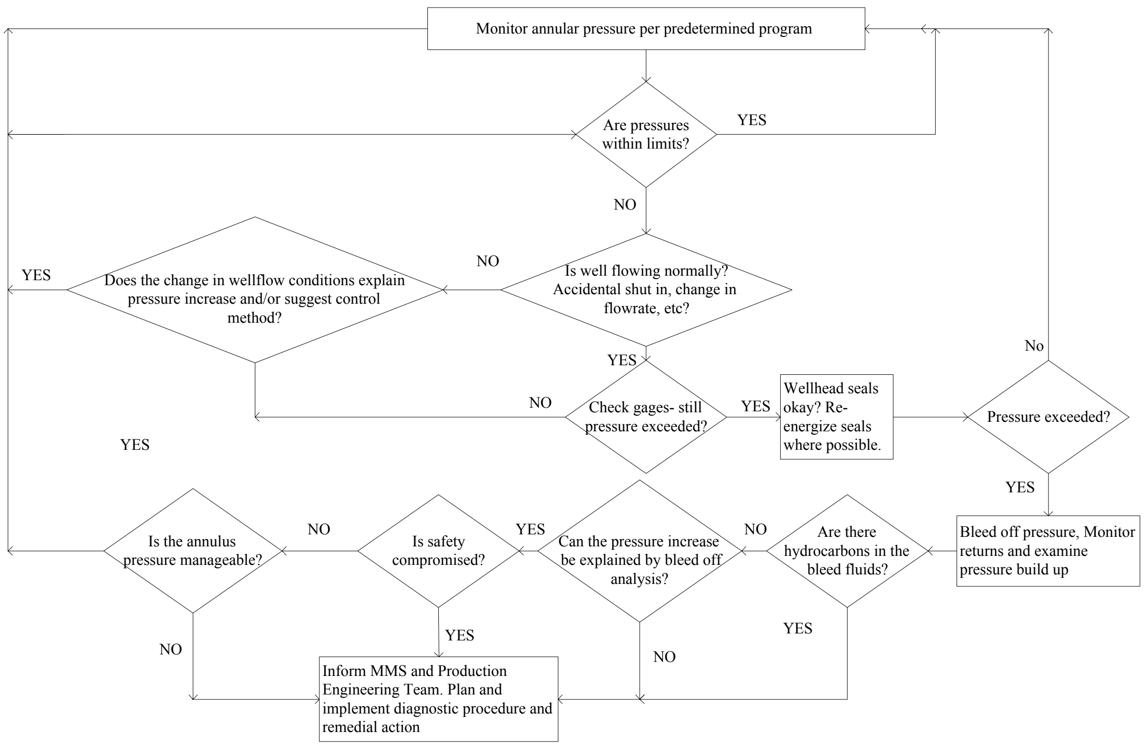

Figure 15 Example decision tree to initiate SCP troubleshooting

5.4.2) Problem isolation

For SCP to occur two self-evident conditions must be satisfied. Firstly, there should exist a leak path and secondly a pressure gradient is needed to activate the leak. The diagnostic process consists of identifying these two factors by using well geometry and methods commonly used in production logging analyses. In all cases the underlying strategy rests on obtaining baseline results with the well in static and thermal equilibrium and then altering conditions to induce temperature or pressure transients and analyzing them. An example of the baseline set of conditions could include pressure profiles of the type shown in Figure 14 and temperature profiles across the wellbore, etc.

Consider the case of the primary annulus. Pressure in the primary annulus is caused either due to a leak, failure of cement or thermal effects. Figure 16 and Figure 17 illustrate a possible a troubleshooting sequence for a leak in the tubing. Similar procedures must be developed to diagnose SCP problems in other annuli. These procedures are based on production logging techniques that are routinely used to diagnose problems in producing wells. In summary, the diagnostic process relies on the following:

- a well planned monitoring procedure that is commensurate with the well condition and the risk associated with a potential SCP situation. For example, very frequent monitoring may not be necessary in a well that is nearing depletion if it has had no history of SCP occurrence.
- Ability to verify stable operating conditions and respond to changes in conditions, as discussed in the preceding sections.

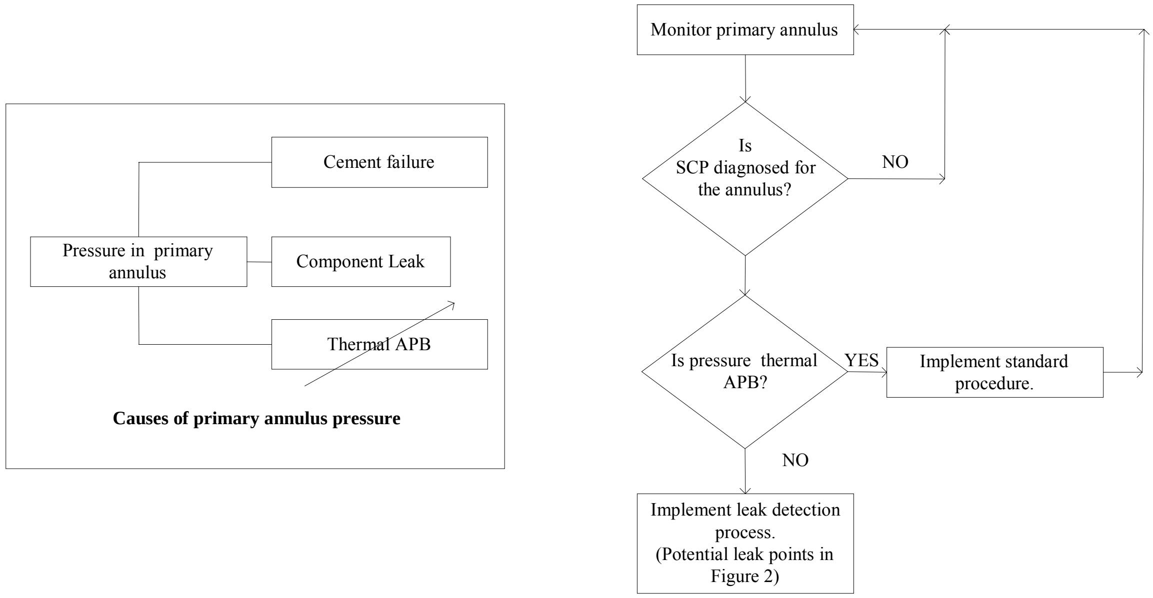

Figure 16 Diagnosis of the primary annulus

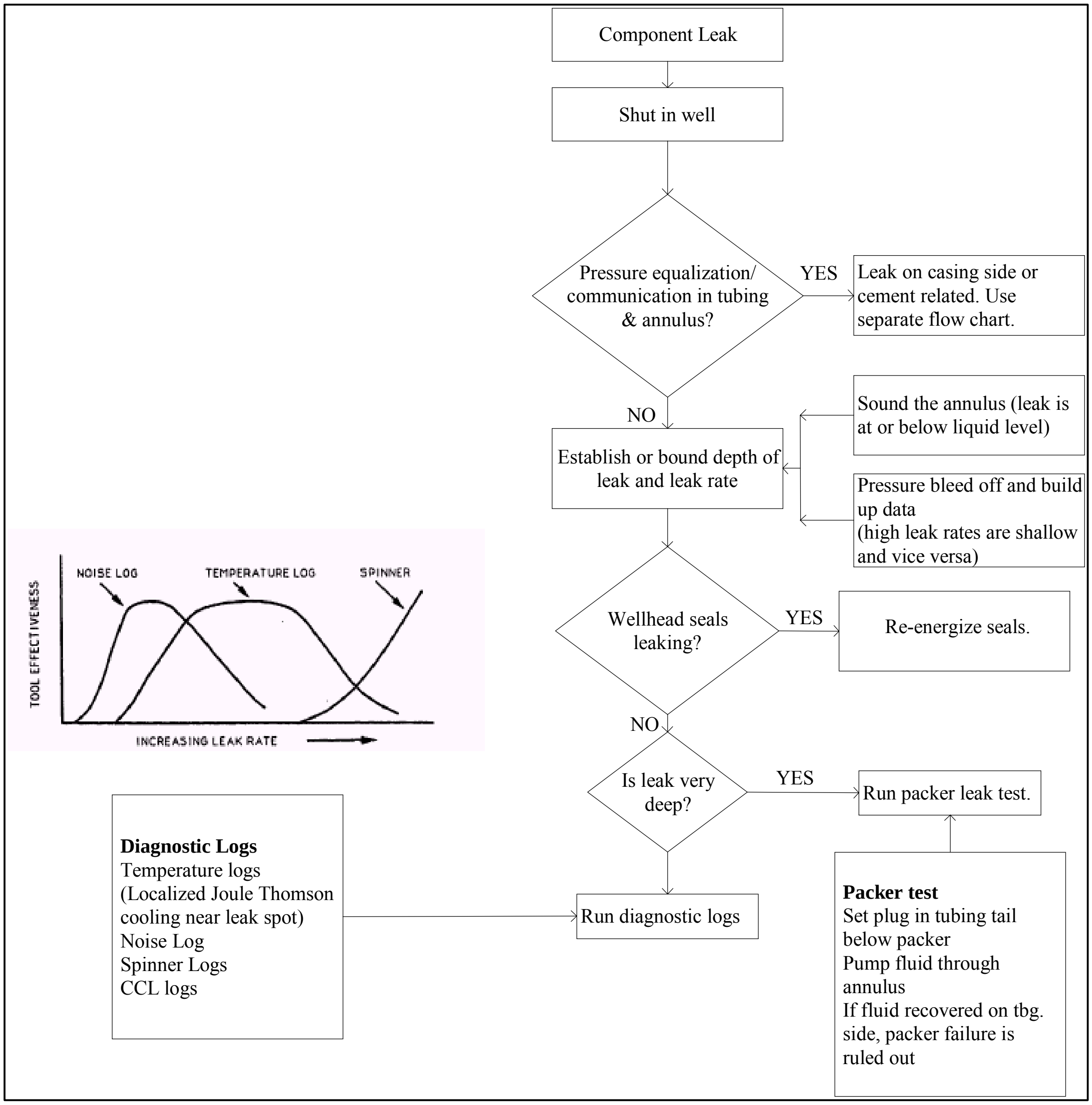

Figure 17 A possible tubing leak detection algorithm

5.5) What do current MMS regulations mean?

The MMS regulations for SCP are currently described by 30 CFR 250.517. Strictly speaking, these regulations require the operator to report **any** observed SCP immediately to the MMS. However, departures from these regulations can be obtained, if the observed SCP

1. is less than 20% of the minimum internal yield pressure (MIYP) and
2. the pressure will bleed down to **zero** if bled through a ½ in. needle valve in 24 hours or less.

If **both** of these conditions are satisfied, departure is automatic (and is known as a "self-departure'). If either of these conditions does not hold, the operator is expected to inform MMS and repair the well.

To the best of our knowledge, the sources or engineering bases for these criteria have not been noted in the MMS documents that were available to us. Therefore, this section examines the implications of these current regulations in the light of the design guidelines discussed until now.

Consider the first of these guidelines. As an example consider a production annulus formed by 4.5 in., 11.6 ppf, L-80 production tubing and 7 in., 23 ppf, J-55 production casing set at 10,000 ft. Assume the annulus is filled with 8.4 ppg completion brine. Since the API MIYP of the production casing in this instance is 4,360 psi, SCP of 20% MIYP implies a pressure of 872 psi acting on a column of 10,000 ft of brine. This translates to an external pressure of 5,240 psi on the tubing at packer depth, and is well within the API collapse rating of the tubing, which in this case is 6,340 psi. Considering that the tubing is typically in compression (tensile load would reduce the collapse rating of the tubular) near the packer, collapse of the tubing would not be an issue. In fact the collapse safety factor here is at least 1.2. Now consider an annulus with the same tubing, but an annulus with a 7 in. liner and 9-5/8 in., 53.5 ppf, J-55 tieback. Also, assume that the packer fluid is 10 ppg kill weight mud (for a reservoir with an initial BHP of 5,000 psi) and that the packer is set at 10,000 ft between the tubing and the liner. The MIYP for the 9-5/8 in. tieback is 7,927 psi. Therefore, SCP of 20% MIYP equals a surface pressure of 1,585 psi. This pressure acting on the top of the packer fluid creates an external pressure of 6,785 psi on the tubing at the packer depth. This pressure just exceeds the API collapse rating of the tubing, i.e. 6,340 psi[7]. However, if the tubing and the casing have been designed for a shut-in tubing leak at surface, this load would not pose a problem, since the tubing would have been designed to withstand a collapse load in the event of tubing evacuation (in which case the external pressure at packer depth would be 5,200 psi). It appears that the MMS guideline on the maximum permissible SCP at the surface seems to have been chosen such the pressure on the tubing at the packer could be in the neighborhood of its API collapse rating. Deeper wells would strengthen this line of reasoning. However, this in itself could not lead to a catastrophe since in most cases, the tubing would have its full collapse rating (i.e. not mitigated by tension) and be bolstered by internal pressure in the event of such a leak. If the design procedures for tubing and casing account for a hot shut-in

[7] This pressure would threaten the tubing only if the internal pressure in the tubing is very small. It is extremely unlikely to have such low internal pressures inside the tubing when there is a tubing leak. This unlikely scenario could threaten the tubing if a leak into the annulus from the casing side occurred and the perforations were plugged simultaneously!

tubing leak at surface, the annulus should be able to sustain an SCP of 20% MIYP with adequate safety margins. Nevertheless, using this pressure as a trigger to initiate diagnostic and investigative procedures seems appropriate.

Consider the bleed-off criterion next. Figure 18 shows the primary annulus with a tubing side leak being bled off. Assume that this is a gas well and that the annulus is full of gas due to a tubing leak[8]. We wish to determine the time taken to bleed the annulus to atmospheric pressure via the bleed valve shown. If p_t, p, and $p_{atm.}$ denote the pressure in the tubing, the annulus and the atmosphere respectively, the time $t(p_f)$ taken for the pressure in the annulus to fall from an initial pressure p_i to a final pressure p_f ($\geq p_{atm}$) is shown in Appendix E to be given by

$$t\left(p_f\right)=\frac{V_a}{A_n\sqrt{2RT}}\int_{\bar{p}=\frac{p_i}{p_{atm}}}^{\frac{p_f}{p_{atm}}}\frac{d\bar{p}}{\beta\sqrt{\bar{p}\left(\bar{p}_t-\bar{p}\right)}-\sqrt{\bar{p}\left(\bar{p}-1\right)}},\quad p_t\geq p\geq p_{atm} \tag{3}$$

where V_a is the volume of the gas in the annulus, R is the gas constant and T is the average temperature of the gas. β is the ratio of the flow area of the leak to the flow area of the nozzle, $\bar{p}_t$ and $\bar{p}$ represent the ratio of the tubing pressure and the annular pressure to the atmospheric pressure respectively. The model derived in Appendix C assumes that the gas obeys the perfect gas law, and neglects the effect of temperature variations across the length of the annulus. Further, it assumes that the influx from the tubing to the annulus and the efflux from the annulus to the atmosphere is of the Bernoulli[9] type. These effects can be added to the basic model described in Appendix C. While Equation (3) can be integrated analytically, its solution is cumbersome. It is best to integrate the above expression numerically (as was done in this study by using 32 point Gaussian quadrature in an EXCEL spreadsheet). When β is set to zero, the situation represents the bleeding of a closed annulus without influx, and the time required to bleed from an initial pressure, p_i to atmospheric pressure reduces to

$$t(p_{atm})=\frac{V_a}{A_n}\sqrt{\frac{2}{RT}}\ln\left[\sqrt{\frac{p_i}{p_{atm}}}-\sqrt{\frac{p_i}{p_{atm}}-1}\right] \tag{4}$$

The time taken for a 7000 ft column of methane gas at an average temperature of 100° F to bleed off from an initial pressure of 1,000 psi to atmospheric pressure (14 psi) is shown in Figure 19. The *x*-axis in the figure shows the ratio of the flow area of the leak and the nozzle. The tubing pressure is assumed to be equal to the annulus pressure at the time the bleed valve is opened, which would presumably be the case, since a tubing leak would equalize pressures in the two volumes. The figure shows that the bleed off time is of the order of half an hour till the leak size reaches a critical fraction of the nozzle size (i.e. 3.7%). When the leak flow area increases beyond this size, the curve indicates that the annulus can never be bled off to atmospheric pressure. This can be expected since the influx at these leak sizes is too much to be bled off. The drastic increase in the bleed off time occurs in the neighborhood of 3.67% for other comparable conditions (and the reader is urged to verify this using the equations

[8] There are three special cases of annular bleeding- gas bleed off , liquid bleed off and liquid-gas bleed off. The case of a pure liquid bleed off is relevant to thermally induced APB. The bleed off times are very small (~tens of seconds) as calculated in Appendix C. Gas takes longer to bleed off. Bleeding off liquid and gas is a more complicated problem that is beyond the scope of the present document.

[9] Bernoulli type flows assume the gas is inviscid, and incompressible and the flow is isentropic and isothermal. Each of these assumptions can be justified for nozzle flows (see White, 1986, pp. 356) and flows from large reservoirs to large sinks.

and solutions provided in Appendix C). This suggests that any casing pressure that cannot be bled off in twenty four hours indicates a fluid influx. The converse however is not true, since a pressure that can be bled off can still be due to a very small influx, as suggested by the horizontal section of the curve in Figure 19. A large bleed time, nevertheless, indicates a leak that could be a significant fraction of the bleed nozzle area. This regulation thus ensures that the influx volumes responsible for SCP are manageable (since they can be bled off in a short period of time). Another implication stems from the consideration of a leak due to a connection failure. Since connection leak paths are tortuous, they result in a massive pressure drop across the leak path. As a result, the volume influx rate may not be very high (Bollfrass, 1985). However, the ingress of fluids over a sustained period of time will be significant enough so that bleeding takes a very long period of time. In reality, estimates of actual bleed off times should account for these effects, i.e. the pressure drops across the leak path and the nozzle, the effect of viscous dissipation at the nozzle, thermal effects and the effect of gas leaking into the liquid in the annulus. As a result, the bleed off times are likely to be higher than those estimated in this document. The calculations shown here, however illustrate the physics of the problem and the spirit of the MMS bleed off time regulation very well.

The above analysis leads to two corollaries. Firstly, the bleed off signature (i.e. pressure versus time) provides very important information about the magnitude of the leak. The analysis of this profile (in conjunction with the pressure build up curve) by using a suitable model will help diagnose the magnitude of the SCP problem and isolate it (akin to a DST). Secondly, it may be impossible to bleed the pressure off to a zero value (as required by the MMS) due to the reasons discussed above. Also, recall from the discussion in section 5.4.1 and Figure 14 that there is a non-zero residual casing pressure, even when the well cools down and it is shut in. More importantly, considerations similar to those discussed in the thermal APB modeling (Appendix B) indicate that bleeding to zero pressure is not necessarily a solution. For example, bleeding the primary annulus could render the production casing susceptible to collapse by pressure in the intermediate annulus. Therefore, based on APB type modeling, the time required to bleed off the pressure in a given annulus to a sustainable value may have to be calculated. The inclusion of these details and the development of a more appropriate model though necessary, is beyond the scope of the present document.

In summary, the MMS regulations appear to have been conceived to minimize the impact of SCP. The 20% MIYP rule sets a limit on the manageable pressure while the 24 hour bleed off time rule sets a limit on the volume of influx. Together, it would appear that they set a qualitative tolerance level for an annular leak. Therefore, instances of casing pressure where these regulations are not satisfied should seek a departure. The departure application must implicitly be based on the design basis and a risk assessment of the possible breach in the annulus to the integrity of the well. Since SCP appears to be very likely in the life of the well, leak tolerance levels for the various components (connections, packer seals, wellheads, etc.) must be determined based on a risk assessment type approach. These tolerance levels can then be translated to regulations about the allowable SCP and how to react when the thresholds are exceeded.

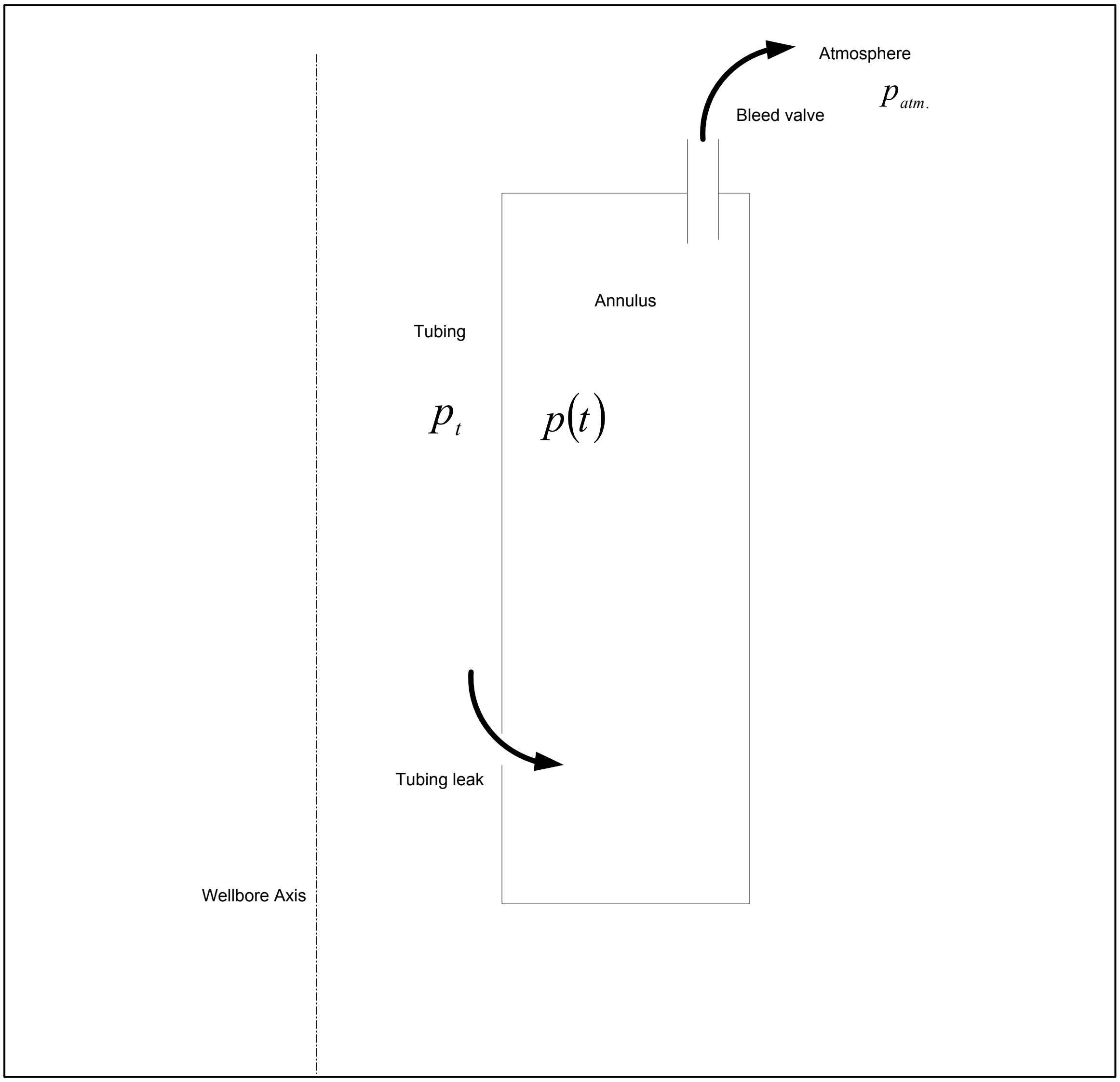

Figure 18 Bleeding Pressure from the annulus

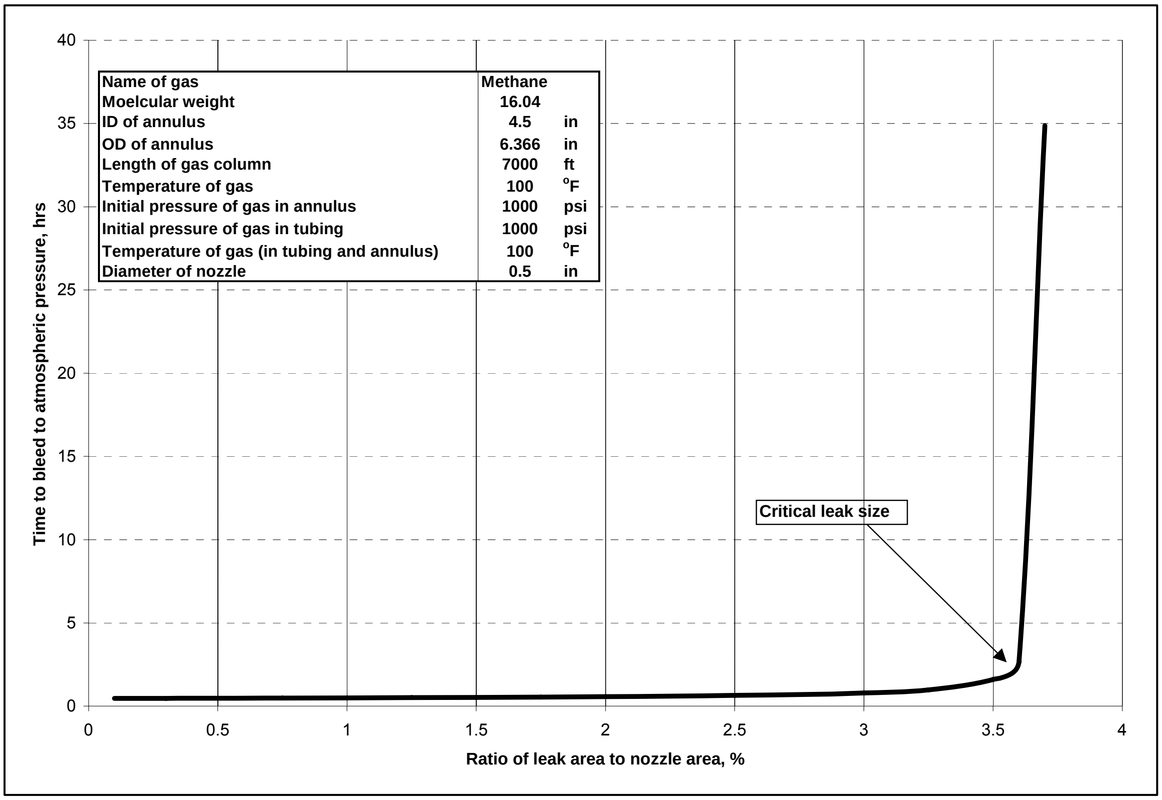

Figure 19 Bleed time as a function of leak size- an example

5.6) Well Integrity Assessment

For the most part, the discussion so far has considered the issue of how to mitigate the SCP problem in future wells. This leaves open the question of the potential risk of SCP occurrence in existing wells in the GOM. As the LSU study (Bourgoyne et. al., 1999) demonstrates, several existing wells exhibit SCP in the Gulf of Mexico. It would be highly desirable to develop a logic to assess, for each of these incidences of SCP, whether the level of SCP is manageable, poses no serious threat to personnel and environment, and is unlikely to worsen in time. For instance, it is apparent from the LSU study that in most cases, the SCP incidences in the GOM are manageable and pose little threat for uncontrollable and disastrous consequences. However, establishing this intuitive conclusion requires proper risk assessment, which uses techniques from the disciplines of QRA and Hazop Analysis. Although this is beyond the scope of the current work, we note here a few guidelines with the caveat that a detailed study justly deserves the resources of a separate project.

The chief goal here is to determine the risk of SCP occurrence in a well, given certain conditions, and the risk of danger to environment and personnel from the SCP occurrence. First, this depends upon the type of well and the stage in its life cycle. Subsea wells or wells under extreme conditions of temperature, pressure and rate must be treated differently from say, low pressure, low rate land wells far from human habitation. Likewise, gas wells pose greater threat under SCP conditions than oil wells.

Several other factors must be considered in risk assessment. Clearly, the design basis used in the design of the tubulars is a major factor in assessing the risk of SCP in a given well. The history of the field and the well are also major factors. For example, there may be other wells in the field that are experiencing SCP. The well may have been producing for a few years, and perhaps production logs indicate increasing levels of water due to coning in addition to CO_2 or other corrosive agents. Connection failures may have been reported on some neighboring wells. Also, there may have been a workover on an upper producing zone, so on and so forth. Given these circumstances, the goal is to determine the possibility of SCP occurrence and be able to respond to changing well conditions in a timely manner.

The first step in this exercise is an in-depth analysis of all cases of SCP relevant to the well in question. These analyses will identify factors which caused the problem and also explain situations when "assumed" conditions about loads or component performance did not hold true. The next major step would be to create a flow chart that would integrate the relevant well characteristics into a risk matrix or flow chart. The list should include factors such as the age of well, basis of design, well construction logs (cement logs, stimulation logs etc.), casing and tubular specifications, mud and cement programs, nature of produced fluids, corrosion potential of tubulars (metallurgy) and fluids, nature and proximity of other wells, etc. Using QRA principles, the risk of SCP for the well can be quantified based on these factors.

With this approach, it is possible to assess the risk of occurrence of SCP for a given well at a given time in its life cycle. The typical output of this approach is a probability of occurrence of SCP as a function of time. The implicit assumption here is that there is always a non-zero probability of occurrence of SCP in any well, which may increase with time, and in response to the different factors discussed above.

Once an SCP event occurs, we seek an assessment of the risk to personnel and environment from that SCP event. At this point, diagnostics and monitoring become paramount. Since one of the first diagnostic steps taken is the bleed off test required by MMS, the results from this test give important clues as to the risk from the SCP event. It has been argued in section 5.5 above that the bleed off signature, together with the build-up signature and annular response models can be used to obtain a sound idea of the risk from the SCP incidence being diagnosed. Models such as the ones discussed in section 5.5 above can be refined and improved to assist in this. In addition to the bleed-off, other diagnostic tests can be conducted to better understand the source of the SCP problem. The diagnostic results, together with the history and other factors discussed earlier in this section, can be used to assess the likely progression of the SCP incident. Once again, the design basis is a key factor. Using the results of this assessment, an SCP management procedure can be developed, be it a combination of diagnostics, bleed off and monitoring, or a complete workover. One advantage of this approach is the costs and risks can be tied, thus allowing rational decisions to be made.

The above assessment, which once again utilizes the techniques of QRA and HazOp analysis, is very important when analyzing an existing SCP incident.

As mentioned at the beginning of this section, however, a rigorous development of risk assessment is beyond the scope of this document. It is strongly recommended that the development of a risk assessment procedure for SCP in GOM wells be undertaken as a separate (and subsequent) phase of this project.

6) Conclusions

This document is an attempt to provide an assessment of the current technology and state-of-the-art as relevant to the problem of sustained casing pressure (SCP) in the primary tubing-casing annulus of oil and gas wells in the Gulf of Mexico. The role of design basis in the management of SCP is discussed in great detail. Since the annulus is a consequence of the design of the tubing, casing, packer and wellhead surrounding it, design and selection of these components will impact the integrity and pressure capacity of the primary annulus. Current practice and suggestions of best practices are discussed for running and handling (particularly make-up practice), monitoring and testing. A logic of diagnostics and decision charts to aid the process of diagnosis in an SCP event are provided. Current MMS regulations and their implicit basis and relevance to the management of SCP problems is discussed. Simple models for annular pressure response and bleed off response have been built, and these are used to illustrate the technical basis of the MMS regulations. Following is a summary of the key conclusions from this document.

3. The LSU study has elevated the concern surrounding SCP incidents in the GOM. The study itself is concerned largely with statistical analysis of SCP incidence, and makes some key statistical conclusions. Unfortunately, given the nature of data gathered and analyzed, the study does not make any phenomenological conclusions or provide statistically supportable causative links between factors causing SCP and the incidence of SCP itself.
4. The most important conclusions that can be made from the LSU study are that a) there is a large incidence of SCP in GOM, and b) poor diagnosis and management of SCP can lead to disastrous conclusions.
5. Current MMS regulations are reasonable and adequate to address the problem of SCP. The 20% MIYP limit implicitly limits the collapse load on the tubing while keeping the pressure at manageable levels. The bleed off time of 24 hours is designed such that if there is a leak, the size of leak is small enough that the SCP incident is manageable even in the event of breach at surface.
6. An analysis of the physical reasoning behind these regulations reveals that the bleed off times are hyperbolic with leak size, and that at a critical leak size, it becomes nearly impossible to bleed off the annulus to atmospheric in any finite time frame. Therefore, 24 hours is not a rigid upper limit, and in general, if a leak can be bled off in times in the neighborhood of 24 hours, the size of the leak is still very small. Conversely, a leak just larger than the critical size will take much longer time than 24 hours to bleed off, and in theory, can never be bled off to atmospheric.
7. Simple models are presented for annular pressure build up and bleed off behavior. These models can be refined and used as part of diagnostics. The models can also be used to allow bleed off to pressures higher than atmospheric, should this be desirable from an operational or mechanical integrity view point.
8. Design basis should include proper tubing design to, at a minimum, a shut-in condition, a producing condition, and an abandonment (collapse load) condition. A pressure test load should also be checked in design.
9. Packer design should be based on both differential pressure and forces acting on the packer.
10. Overall design basis can be used to establish the annular pressure capacity. This includes the design of tubing, casing, packer, and wellheads; as well as materials selection, quality assurance and quality control.

11. Care must be taken in running and handling of the tubulars, particularly in make-up. In general, recommended make-up procedures must be adhered to. Common sense care while running and handling could dramatically reduce the risk of SCP occurrence.
12. A hydrostatic pressure test of casing and tubing is a minimum test requirement.
13. Diagnostic charts have been provided to assist in the diagnosis of an SCP incident.
14. In order to select a course of action in wells that exhibit SCP, in particular at a magnitude greater than MMS regulated value for "self departure", a thorough risk assessment is required. Risk assessment is made up of two parts- risk of occurrence of SCP, and risk to personnel and environment from the SCP (i.e., risk of unmanageability), and is influenced by several factors including well type, well history and design basis.
15. A rigorous quantitative risk assessment (QRA) procedure should be developed and used to assess the existing cases of SCP in the GOM area. It is suggested that this be undertaken as part of a separate project.

7) Nomenclature and Abbreviations

7.1) Roman Symbols

A	Inner Area, in^2
B	Bulk modulus, psi
d_o	Outer Diameter, in
d_i	Inner Diameter, in
E	Modulus of Elasticity, psi
f	See Eq. C21
L	Length, ft
M	Mass, slugs
m	See Eq. C14b
n	See Eq. C14c
p	Pressure, psi
p_i	Internal Pressure, psi
p_o	External Pressure, psi
r_i	Inner Radius, in
r_o	Outer Radius, in
R	Perfect gas constant, ft^2/s^2/^{o}R
t	Wall Thickness, in, time, s
t_o	Scale factor for dimensionless time, s
T	Temperature, ^{o}F
v	velocity, ft/s
V	Volume, ft^3

7.2) Greek Symbols

α	Coefficient of thermal expansion of steel, /^{o}F
Δ	Change in a quantity
ε	Strain
γ	Coefficient of volume expansion of liquids, /^{o}F
Λ	Universal gas constant, (49, 720 ft^2/s^2/^{o}R)
ν	Poisson's Ratio
ρ	Density, ppg
σ	Stress, psi
σ_r	Radial Stress, psi
σ_h	Hoop Stress, psi

7.3) Abbreviations

APB	Annular Pressure Buildup
API	American Petroleum Institute
API RP	API Recommended Practice
Bull.	Bulletin
ERD	Extended Reach Drilling
GOM	Gulf of Mexico
HPHT	High Pressure High Temperature
ID	Inner Diameter
JIP	Joint Industry Project

LSU	Louisiana State University
MIYP	Minimum Internal Yield Pressure
MMS	Minerals Management Service
OCTG	Oil Country Tubular Goods
OD	Outer Diameter
OTC	Offshore Technology Conference
PFP	Plastic Failure Pressure
QRA	Quantitative Risk Analysis
RBD	Reliability Based Design
RHS	Right Hand Side
SCP	Sustained Casing Pressure
Spec.	Specification
SR	Supplemental requirement
SCSSV	Surface Controlled Sub Surface Safety Valve
TR	
TVD	True Vertical Depth
VME	von Mises Equivalent
WSD	Working Stress Design

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A.1) Casing and Tubing Design for Management of Sustained Casing Pressure - Participant Survey

Date:	
Name(s):	
Title or Position:	
Telephone No.	
Fax No.	
Email Address:	
Company or Organization:	
Type of Company: (Operator, Service Co., etc.)	

Please respond to questions that are relevant to your company's operations. This questionnaire is intended to be answered from a high level, overview perspective. The intent is not to get into much detail about specific wells, etc. Generalized answers as to what is done "most of the time" are adequate.

Casing and Tubing Running and Completion Practices

1. Does your company have a policy (or recommendation) with respect to a maximum pressure limit for API / proprietary tubing connections?
   a. If so, what is the limit:
2. Does your company have a policy (or recommendation) with respect to a maximum pressure limit for API / proprietary casing connections for production casing?
   a. If so, what is the limit:
3. Does the design procedure for casing and tubing strings consider abnormal annular pressures as a load case?
4. Does the design procedure account for wall loss due to corrosion, erosion or wear during the life cycle of the well?
5. Does your company use (or recommend) proprietary make up procedures for API casing and tubing connections, such as, Torque-Turn or Torque-Position?
   a. If so, what conditions determine the use?
6. Does your company use (or recommend) thread compound?
   a. If so, do you recommend specific application procedures?
7. What methods does your company use to determine the leak resistance of connections?

a. Supplier or vendor information and documentation.

b. Internal or external research.

c. Rules of thumb or past experience.

d. A combination of the above.

8. List any other best practices used (or recommended) that improve the integrity of tubing string to resist SCP problems?

9. What types of QA/QC procedures exist in your company for tubing and completion equipment?

Pressure Testing

1. What is your company policy (or recommendation) for pressure testing production casing?

   a. Always test.

   b. Never test.

   c. Test sometimes.

      If so, what are the conditions that require pressure testing?

   d. What determines the test pressure?

   e. Is the test done before or after cement sets?

2. What is your company policy (or recommendation) for pressure testing production tubing?

   a. Always test.

   b. Never test.

   c. Test sometimes.

      If so, what are the conditions that require pressure testing?

   d. What determines the test pressure?

3. What is your company policy (or recommendation) for pressure testing production tubing while running?

   a. If used, is internal or external testing used?

   b. What determines the method used?

   c. What is the test medium used, i.e. water, gas, etc.?

   d. What determines the test pressure?

4. How do you pressure test liner laps?

SCP and Correction Action

1. What is the policy on monitoring pressure in the tubing and annuli of offshore wells?

	Continuously	Periodically
Tubing		
Primary annulus		
Outer annuli		

(Please specify frequency if pressure monitoring is not continuous).

2. What methods does your company use to diagnose leaks?
3. How do you estimate the depth of the leak?
4. How do you determine the string that most likely has the leak?
5. What methods of repair for SCP has your company had success with?
6. What methods of repair for SCP has your company had limited success with?

Cementing

1. Does your company have a document of "Cementing Guidelines"? If so,
   a. Does it require specific flow properties for the mud, prior to cementing?
   b. Does it specify the use of spacers and flushes?
   c. Does it recommend pipe rotation or reciprocation?
   d. If so, what percent of casing strings are moved before an dudring the cement job?
   e. Do the Cementing Guidelines specify casing centralization?
   f. Does it specify a displacement rate?
   g. Doe sit provide guidance on slurry composition?
   h. Does it provide guidance on preventing gas migration, such as the use of foamed slurries?
   i. Does it provide guidance on Wait and Cement Time?

List any cementing best practices that you have had success with.

A.2) Casing and Tubing Running and Completion Practices

CASING AND TUBING RUNNING AND COMPLETION PRACTICES	
QUESTION 1	Does your company have a policy (or recommendation) with respect to a maximum pressure limit for API / proprietary tubing connections? a. If so, what is the limit?
Company A	Proprietary
Company B	Yes. a. MASP <3000 psi.
Company C	
Company D	Pressure limits based on FEA and physical testing. a. Low stress connections used in sour service.
Company E	We have no specific policy. Each field or well is evaluated on its own merits.
Company F	Yes. a. If the Shut-in tubing pressure is expected to be above 3500 psi, them premium connections are recommended.
Company G	Yes. a. Recommendation - 5,000 psi or 60% of the internal/external pressure rating whichever is lower for service. Pressure-test pressures should not exceed 80% of the pipe pressure ratings.
Company H	
Company I	Yes. a. (1) For API thread seal connections, we recommend the operator consider auxiliary safeguards when the pressure exceeds 5000 psi for multi-phase systems and 3000 psi for dry gas systems. Corrosive environments and critical locations would reduce these pressures. Auxiliary safeguards include past experience with the product in that environment, utilizing specialized field service personnel to supervise the running operation, pressure testing during running, short term intermittent exposure, special torque application equipment. (2) For thread seal proprietary connections, we recommend the operator consider auxiliary safeguards when the pressure exceeds 8000 psi for multi-phase systems and 4000 psi for dry gas systems at temperatures above 250oF. Corrosive environments and critical locations would reduce these pressures. (3) For metal seal proprietary connections, no limitations below pipe body are recommended.
Company J	No.
Company K	Yes. a. 80% of the pipe body internal yield strength without limit.
Company L	
Company M	Not applicable. We cure leaks in tubing connections.

QUESTION 2	Does your company have a policy (or recommendation) with respect to a maximum pressure limit for API / proprietary casing connections for production casing? a. If so what is the limit
Company A	Proprietary
Company B	Yes. a. Pressure differential < 4000 psi.
Company C	
Company D	Pressure limits based on FEA and physical testing. a. Low stress connections used in sour service.
Company E	There should be no prescriptive policy on this topic.
Company F	No, but usually the casing design will cause premium connection on high pressure wells.
Company G	Yes. Recommendation. a. 5,000 psi or 60 % or the internal/external pressure rating whichever is lower. Pressure-test pressures should not exceed 80% of the pipe pressure ratings.
Company H	
Company I	Yes. a. (1) For API thread seal connections, we recommend the operator consider auxiliary safeguards when the pressure exceeds 5000 – 7500 psi. Corrosive environments and critical locations would reduce these pressures. Auxiliary safeguards include past experience with the product in that environment, utilizing specialized field service personnel to supervise the running operation, pressure testing during running, special torque application equipment. (2) For thread seal proprietary connections, we recommend the operator consider auxiliary safeguards when the pressure exceeds 8000 - 10000 psi. Corrosive environments and critical locations would reduce these pressures. (3) For metal seal proprietary connections, no limitations below pipe body are recommended.
Company J	No.
Company K	Yes. a. 80% of the pipe body yield strength.
Company L	
Company M	Not applicable. We cure leaks in casing connections.

QUESTION 3	Does the design procedure for casing and tubing strings consider abnormal annular pressures as a load case?
Company A	Proprietary
Company B	Yes.
Company C	
Company D	Yes. Production casing design for shut-in tubing pressure.
Company E	Yes.
Company F	Yes – our casing design assumes that we have a tubing leak at the surface.
Company G	Any anticipated abnormal annular pressures should be considered in the design and treated as the worst case scenario. This should include pressures both internal and external to either string, inclusive of the connections expected performance.
Company H	
Company I	Not considered unless specifically identified by the operator to be of concern.
Company J	No.
Company K	No.
Company L	
Company M	Not applicable.

QUESTION 4	Does the design procedure account for wall loss due to corrosion, erosion or wear during the life cycle of the well?
Company A	Proprietary
Company B	Yes.
Company C	
Company D	Design for production casing does not account for corrosion or erosion. Design accounts for wear while drilling. Safety factors applied. Use of internal coating and CRA's used for tubing in corrosive environment.
Company E	Yes.
Company F	Yes.
Company G	Every step should be taken to evaluate these conditions for any given well and the appropriate safety factors should be employed.
Company H	
Company I	No.
Company J	Wear (by increasing DF).
Company K	No.
Company L	
Company M	Not applicable.

QUESTION 5	Does your company use (or recommend) proprietary make up procedures for API casing and tubing connections, such as, Torque-Turn or Torque-Position? a. If so, what conditions determine the use?
Company A	
Company B	No. a. Not applicable.
Company C	
Company D	Torque position. a. All conditions in OCS.
Company E	No. a. Special make up procedures and equipment are only use on premium connections.
Company F	Yes. a. We use tubing torque-turn if we are using a high alloy tubing or if we are testing the connections
Company G	We recommend the use of these procedures to evaluate the mechanical integrity of each connector. We also feel that since these procedures measure averages that they do not offer an absolute guarantee of leak resistance. Leak resistance is a measure of hydraulic/flow resistance integrity. While the number of possible leaks is reduced with this procedure, it does not fully eliminate them as our testing history when pressure testing in conjunction, still finds leaks in connections.
Company H	
Company I	No recommendation.
Company J	No (make up in plant and check if torque is in nominal range).
Company K	Yes. a. Use is based on specification of operator. We recommend use of Torque Monitoring for all-types of connection make-ups as it incorporates torque control via dump valve.
Company L	
Company M	Not applicable.

QUESTION 6	Does your company use (or recommend) thread compound? a. If so, do you recommend specific application procedures?
Company A	
Company B	Yes Best-O-Life.
Company C	
Company D	Yes. a. Use manufacturer's recommendation for proprietary threads.
Company E	We have tried several over the years and found little consistent difference. We tend to follow the recommendation of the thread manufacturer. a. We do spell out that in the completion procedure that the thread compound "should be applied sparingly, to the pin end only, with a one inch paint brush".
Company F	Best-O-Life 2000.
Company G	No. a. Operators' discretion depending upon connection and well conditions.
Company H	
Company I	Yes. a. Application to the pin end only.
Company J	Best-O-Life 2000. a. Torque Book Enclosed.
Company K	Yes.
Company L	
Company M	Not applicable.

QUESTION 7	What methods does your company use to determine the leak resistance of connections? a. Supplier or vendor information and documentation. b. Internal or external research. c. Rules of thumb or past experience. d. A combination of the above.
Company A	
Company B	a. Yes. c. Yes. d. Yes.
Company C	
Company D	b. Rely heavily on FEA and physical testing.
Company E	All of the above are used, on most occasions.
Company F	d. Combination of vendor info and past experience.
Company G	Internal and External Pressure Testing with water, Nitrogen or Nitrogen with Helium Tracer a. attached b. attached
Company H	
Company I	a. Analytical methods (FEA, classical mechanics) b. In-house testing c. past experience and historical usage d. yes
Company J	API only: API method.
Company K	We provide internal water testing of couplings, internal water of full joint, external water of coupling, internal helium/nitrogen of coupling and a combination of gas for coupling and water for pipe body. We feel the only true direct means of determining "leak resistance" of a tubing connection on the rig floor is by internal gas testing.
Company L	
Company M	Not applicable. We perform leak diagnostics when leaks are discovered after the well is on production.

QUESTION 8	List any other best practices used (or recommended) that improve the integrity of tubing string to resist SCP problems.
Company A	
Company B	Use of chrome tubulars and associated hardware in corrosive environments.
Company C	
Company D	Tubing accessories (ie, landing nipplies, gas lift mandrets, etc) are assembled with pup joints to provide _+30" assemblies and pressure tested prior to delivery. IPC tubing is drifted with teflon drift bars
Company E	For high pressure or subsea or new connection design or exotic alloy or sour gas or other special considerations, we may request make and break tests, pressure sealing with bending load or other special shop testing.
Company F	Not applicable
Company G	Not applicable.
Company H	
Company I	Additional "best practices" include past experience with the product in that environment, visual inspection prior to running, utilizing specialized field service personnel to supervise the running operation, pressure testing during running, special torque application equipment during both running and buck-on.
Company J	Pitch diameter measurements on all casing strings.
Company K	The following are our recommendations for best practices to eliminate SCP problems resulting from tubular related leaks: a. Monitor the make-up torque of tubular to assure proper amount of torque (force) is applied to sealing surfaces in the connection per thread manufacturer's specifications. b. Perform internal helium test of each connection after monitored torque make-up.
Company L	
Company M	Not applicable.

QUESTION 9	What types of QA/QC procedures exist in your company for tubing and completion equipment?
Company A	
Company B	Failure analyses.
Company C	
Company D	100% full length ultrasonic inspection, special end area EMI by qualified inspection company. Full traceability. Thread inspection and gauge. Pressure test accessories. Quality vendors.
Company E	Depending on the application, the Quality Assurance department may be asked to review and comment on the manufacturer's quality plan, perform an audit of the manufacturing facility and/or assign a third party witness/inspector to the plant during manufacture of the tubing and/or cutting of the threads.
Company F	Typically, no inspection but the engineer can specify any type of inspection that he deems necessary. If he deems it a critical application (high pressure) then full length drift, special end area and EMI inspections are performed.
Company G	Not applicable.
Company H	
Company I	Employ conventional QA/QC systems for manufacturing – statistical process control, centrally programmed computer numerically controlled machines, hardened and ground functional ring and plugs gauges, statistical sampling at appropriate AQL.
Company J	
Company K	Not applicable.
Company L	
Company M	Not applicable.

A.3) Pressure Testing

PRESSURE TESTING	
QUESTION 1	What is your company policy (or recommendation) for pressure testing production casing? a. Always test. b. Never test. c. Test sometimes. If so, what are the conditions that require pressure testing? d. What determines the test pressure? e. Is the test done before or after cement sets?
Company A	
Company B	a. Always test. d. MASP e. After cement sets.
Company C	
Company D	Pressure test casing after it is in place and cemented. a. Always test. d. Regulatory requirements. Anticipated pressure during life cycle of well. e. After.
Company E	a. Always test. e. After the cement has set.
Company F	a. Casing testing is an MMS requirement. d. MMS requires test to be 70% of rated burst pressure e. After the cement has set.
Company G	a. Very few operators do this, that is pressure test production casing connections prior to running into the well. We are introducing a mill end tester at the SPE Show to check the coupling end. d. Percentage of pipe body pressure rating or well conditions, whichever is lower.
Company H	
Company I	No recommendation.
Company J	a. Always test. Mill Hydro all pipe: Plain end or T and C at operations choice 80% SMYS. d. API test pressure.
Company K	Not applicable.
Company L	
Company M	a. Always test. d. Maximum working pressure of the casing. e. Not applicable.

QUESTION2	What is your company policy (or recommendation) for pressure testing production tubing? a. Always test. b. Never test. c. Test sometimes. If so, what are the conditions that require pressure testing? d. What determines the test pressure?
Company A	
Company B	c. Test sometimes-Yes. Dual completion strings, premium connections used for high pressure gas wells d. MASP
Company C	
Company D	a. Always test. After tubing is installed. If well is unperforated, test internally. If well is perforated, test tubing/casing annulus. d. Regulation. Maximum SITP if well is unperforated.
Company E	a. Test Always. Yes. d. Maximum pressure the tubing will see during its life cycle; often treating pressure during a stimulation.
Company F	c. Test sometimes. Test internally only rotary sometimes. Test only if the expected shut-in tubing pressure is above 5000 psi. d. Completion engineer specifies a test pressure about 1500 psi above expected shut-in tubing pressure.
Company G	When testing with either internal or external pressure it should be done with the pipe held in tension. a. Always test - one third of the operators fall into this category. b. Never test - one third of the operators fall into this category. c. Sometimes test - one third of the operators fall into this category. d. We recommend testing tubing to 80% of the pipe body rating or at least to the expected worst case well condition, whichever is lower.
Company H	
Company I	No recommendation
Company J	a. Mill Hydro
Company K	Not applicable.
Company L	
Company M	a. Always test. d. Maximum working pressure of the tubing.

QUESTION 3	What is your company policy (or recommendation) for pressure testing production tubing while running? a. If used, is internal or external testing used? b. What determines the method used? c. What is the test medium used, i.e. water, gas, etc.? d. What determines the test pressure?
Company A	
Company B	Test sometimes-Yes. Dual completion strings, premium connections used for high pressure gas wells a. internal primarily b. company policy c. Water for lower pressure, dual oil well completions. Gas with helium tracers for high pressure, gas completions. d. MASP
Company C	
Company D	Do not test tubing while running.
Company E	We have almost completely stopped testing tubing as it being run because we use high reliability premium connections and rarely found any leaks. We do a full string test at some convenient point after the string is run.
Company F	Test only if the expected shut-in tubing pressure is above 5000 psi. a. Usually internal. b. Specific application, cost. c. Gas. d. Completion engineer specifies a test pressure about 1500 psi above expected shut-in tubing pressure.
Company G	Most threaders will say that their connections do not need to be tested, but they also do not object to the operator testing should the operator decide to do so as a risk management procedure. a. Both. b. The method used should be prioritized by 1) testing the connection to its lowest level of leak resistance; 2) tested based upon application and 3) tested based upon operational logistics and equipment capabilities. c. All can be used, but our experience shows that given the amount of test time when running pipe, that water with a surfactant can be just as effective as gas. The controlling factor is the pipe dope, its viscosity and the tortuous path of the threads. d. We recommend testing tubing to 80% of the pipe body rating or at least to the expected worst case well condition, whichever is lower.
Company H	
Company I	Generally not recommended for metal seal connections. May be useful for thread seal connections. a. If used, internal is recommended.
Company J	Not applicable.
Company K	Not applicable.
Company L	
Company M	Not applicable.

QUESTION 4	How do you pressure test liner laps?
Company A	
Company B	Both positive and negative.
Company C	
Company D	Typically perform a positive test and differential test.
Company E	The liner top is tested as soon as the casing above is cleaned out down to the liner top to remove any excess cement. The entire liner including the top is tested as soon as the liner is cleaned out down to the float equipment, but before drilling out.
Company F	Usually a positive test only but on critical liners we put both a positive and a negative test.
Company G	Not applicable.
Company H	
Company I	Not applicable.
Company J	Not applicable.
Company K	Not applicable.
Company L	
Company M	Not applicable.

A.4) SCP and Corrective Action

SCP AND CORRECTIVE ACTION	
QUESTION 1	What is the policy on monitoring pressure in the tubing and annuli of offshore wells? (Please specify frequency if pressure monitoring is not continuous.)
Company A	
Company B	Tubing: Continuously = in some cases, but seldom. Periodically = daily. Primary Annulus: Periodically = weekly. Outer Annuli: Periodically = monthly.
Company C	
Company D	Tubing: Continuously = yes. Primary Annulus: Periodically = yes. Outer Annuli: Periodically = yes. Typically monthly unless pressure is detected. Once pressure is detected, monitoring frequency is dependant on pressure level and results of diagnostic bleed down.
Company E	Tubing: Periodically = daily. Primary Annulus: Periodically = weekly. Outer Annuli: Periodically = monthly
Company F	Continuous monitoring of tubing and primary annulus. Monthly on the outer annuli.
Company G	Not applicable.
Company H	
Company I	Not applicable.
Company J	Not applicable.
Company K	Not applicable.
Company L	
Company M	Not applicable.

QUESTION 2	What methods does your company use to diagnose leaks?
Company A	
Company B	Caliper surveys, “D&D” hole finders, pressure tests, etc.
Company C	
Company D	Bleed down, pony-tail, D&D hole finder, caliper.
Company E	Analysis of gas/fluid bleed off. Response of pressure to bleed off. Reoccurrence of pressure.
Company F	Monitor pressure on annuli, test tubing if suspicious.
Company G	Not applicable.
Company H	
Company I	Not applicable.
Company J	Not applicable.
Company K	Not applicable.
Company L	
Company M	Test pressure differential between tubing and each annuli. Test pressure increases and leak off rates. Measure fluid level changes. Check for hangar leaks and other wellhead leaks using similar methods.

QUESTION 3	How do you estimate the depth of the leak?
Company A	
Company B	Wireline measurements and caliper surveys.
Company C	
Company D	Bleed down, pony-tail, D&D hole finder, caliper.
Company E	Analysis of surface pressures, downhole tubing pressure and expected fluid gradients.
Company F	Running wireline with a “ponytail”, caliper log or setting tubing plugs and bleeding.
Company G	Temperature log is one procedure
Company H	
Company I	Not applicable.
Company J	Not applicable.
Company K	
Company L	
Company M	Temperature survey on tubing and Echometer on annuli.

QUESTION 4	How do you determine the string that most likely has the leak?
Company A	
Company B	Pressure testing
Company C	
Company D	Diagnostic bleed downs are performed. One casing string at a time while monitoring other casing strings.
Company E	Analysis of gas/fluid bled off, analysis of well construction information such as cement tops with respect to sand bodies and other relevant data.
Company F	Test the tubing.
Company G	Not applicable.
Company H	
Company I	Not applicable.
Company J	Not applicable.
Company K	Not applicable.
Company L	
Company M	Test each annuli in sequence starting from the outermost annuli.

QUESTION 5	What methods of repair for SCP has your company had success with?
Company A	
Company B	Packoffs – both wireline and coiled tubing deployed.
Company C	
Company D	Tubing leaks are corrected by replacing tubing or installing tubing packoffs.
Company E	None.
Company F	Rig workover to change tubing, setting wireline pack-offs
Company G	Not applicable.
Company H	
Company I	Not applicable.
Company J	Not applicable.
Company K	Not applicable.
Company L	
Company M	We cure wellhead, hangar, tubing and casing leaks using a pressure activated sealant. We have a very good success rate with accurate leak data.

QUESTION 6	What methods of repair for SCP has your company had limited success with?
Company A	
Company B	Liquid sealants.
Company C	
Company D	Limited success with pumping sealants.
Company E	None.
Company F	
Company G	Not applicable.
Company H	
Company I	Not applicable.
Company J	Not applicable.
Company K	Not applicable.
Company L	
Company M	Not applicable.

A.5) Cementing

CEMENTING	
QUESTION 1	Does your company have a document of "Cementing Guidelines"? If so, does it require specific flow properties for the mud, prior to cementing? a. Does it require specific flow properties for the mud, prior to cementing? b. Does it specify the use of spacers and flushes? c. Does it recommend pipe rotation or reciprocation? d. If so, what percent of casing strings are moved before and during the cement job? e. Do the Cementing Guidelines specify casing centralization? f. Does it specify a displacement rate? g. Does it provide guidance on slurry composition? h. Does it provide guidance on preventing gas migration, such as the use of foamed slurries? i. Does it provide guidance on Wait on Cement Time?
Company A	
Company B	Yes. a. Yes. b. Yes. c. Yes. d. No-date. e. Yes. f. No. Varies from case to case. g. No. Varies from case to case. h. No. Varies from case to case. i. No. Varies from case to case.
Company C	
Company D	Training Course on primary and remedial cementing. a. Not specific. b. Yes. c. Yes. d. ~50%. Unlikely on high angle wells. e. Yes. f. Displacement rate is dependant on many factories (i.e. hole size, PIT, ECD, etc.) g. General guidance. Slurry composition varies widely based on wellbore characteristics. h. Yes. Apply pressure. Use gas block additive. Does not specify foam. i. Yes.
Company E	No. We use unwritten guidelines based on previous experience in the area. a. Yes. b. Yes. c. Yes. d. 90%. About 10% cannot be moved due to mechanical considerations. e. Yes. f. Yes. g. Yes. h. Yes. i. Yes.
Company F	Yes. a. Yes. b. Yes. c. Yes. d. All longstrings that are not stuck prior to cementing or have some other mechanical limitation (like a mudline suspension) - probably 50% are reciprocated while cementing. e. Yes. f. It says to pump at the computer aided design rate. g. It says "mix cement at the correct density even if pump rate must be reduced to achieve this". h. Not specifically. i. No.
Company G	Not applicable.

CEMENTING	
QUESTION 1	Does your company have a document of “Cementing Guidelines”? If so, does it require specific flow properties for the mud, prior to cementing? a. Does it require specific flow properties for the mud, prior to cementing? b. Does it specify the use of spacers and flushes? c. Does it recommend pipe rotation or reciprocation? d. If so, what percent of casing strings are moved before and during the cement job? e. Do the Cementing Guidelines specify casing centralization? f. Does it specify a displacement rate? g. Does it provide guidance on slurry composition? h. Does it provide guidance on preventing gas migration, such as the use of foamed slurries? i. Does it provide guidance on Wait on Cement Time?
Company H	
Company I	Not applicable.
Company J	Not applicable.
Company K	Not applicable.
Company L	
Company M	Not applicable.

QUESTION 2	**List any cementing best practices that you have had success with?**
Company A	
Company B	
Company C	
Company D	*Mud conditioning prior to running casing and immediately prior to cementing. *Centralization and pipe movement where possible. *Pre-flushed and spacers. *Cement slurry specifications. *Pump and displacement rate. *Bottom and top wiper plug designs. *Float shoe and float collar designs.
Company E	All of the above. Also, we prefer salt saturated cements for open hole plugs when using synthetic muds. For all other cementing situations, we prefer to base our selection of cementing materials and techniques on the specific situation and NOT on some "Generalized Best Practices Document".
Company F	Recommendations above are based on previous success.
Company G	Not applicable.
Company H	
Company I	Not applicable.
Company J	Not applicable.
Company K	Not applicable.
Company L	
Company M	We have a pressure activated sealant technology that is capable of curing microannular leaks in existing cemented annuli. The success of the process is dependant on the conditions of the cement and annular fluid.

Appendix B: Modeling Annular Pressure

When the pressure or temperature in an annulus changes, the strings and the annuli in the well react to reach a new state of mechanical and thermal equilibrium. In fact, the creation of a leak path is a response (albeit, undesirable in most cases) of the strings and annuli moving towards equilibrium. The pressure at any point in the annulus is a function of the mass of fluid m, volume V_{ann} and temperature, T, so that

$$p_{ann} = p_{ann}\left(m, V_{ann}, T\right). \tag{B1}$$

The changes in pressure due to the effects described in section 5.4.1, can be calculated from the definitions of the isothermal and isobaric bulk moduli for a fluid.

The isothermal bulk modulus B_T of a fluid is defined as the rate change of pressure with respect to volumetric strain, at constant temperature, so that

$$B_T = \left.\frac{\Delta p}{\left(\Delta V / V\right)}\right|_T. \tag{B2}$$

The above definition enables the calculation of the change in pressure due to the effects described in section 5.4.1, so that

$$\begin{aligned}
\Delta p_{ann} &= -B_T \left.\left(\frac{\Delta V}{V}\right)\right|_T \\
&= B_T \frac{\left(\Delta V^{\text{fluid}}_{\text{therm.exp.}} + \Delta V^{\text{fluid}}_{\text{influx/outflux}}\right) - \Delta V^{\text{ann.}}_{\text{thermal/ballooning}}}{\Delta V^{\text{ann}}} \\
&= B_T \frac{\Delta V^{\text{fluid}}_{\text{therm.exp.}}}{\Delta V^{\text{ann}}} + B_T \frac{\Delta V^{\text{fluid}}_{\text{influx/outflux}}}{\Delta V^{\text{ann}}} - B_T \frac{\Delta V^{\text{ann.}}_{\text{thermal/ballooning}}}{\Delta V^{\text{ann}}}
\end{aligned} \tag{B3}$$

Oudemann and Bacarezza (1995) obtain a similar expression for the change in the pressure of the annulus by applying the chain rule of calculus to Eq. (1) and linearization so that

$$\Delta p_{ann} = \left(\frac{\partial p_{ann}}{\partial m}\right)_{V_{ann},T} \Delta m + \left(\frac{\partial p_{ann}}{\partial V_{ann}}\right)_{m,T} \Delta V_{ann} + \left(\frac{\partial p_{ann}}{\partial T}\right)_{m,V_{ann}} \Delta T \tag{B4}$$

The first term on the RHS of the above equation represents the change in pressure caused by the fluid influx into or efflux from the annulus. The second term on the RHS represents the change in the pressure of the annulus due to a physical change in the annular volume. The last term on the RHS represents isothermal fluid expansion. It is the volume by which the liquid or the gas (or the mixture) expands due to heating. The expansion is obviously governed by the PVT behavior of the fluid. It now remains to calculate the volume change terms described in Eq. (B3).

B.1) Change in annular volume

Consider a set of N annuli. The i^{th} annulus is shown in Figure 20. Let the outer and inner radii of the annuli be denoted by r_{i+1} and r_i. Also assume that the inner and outer surfaces of the annulus are concentric thin walled cylinders.

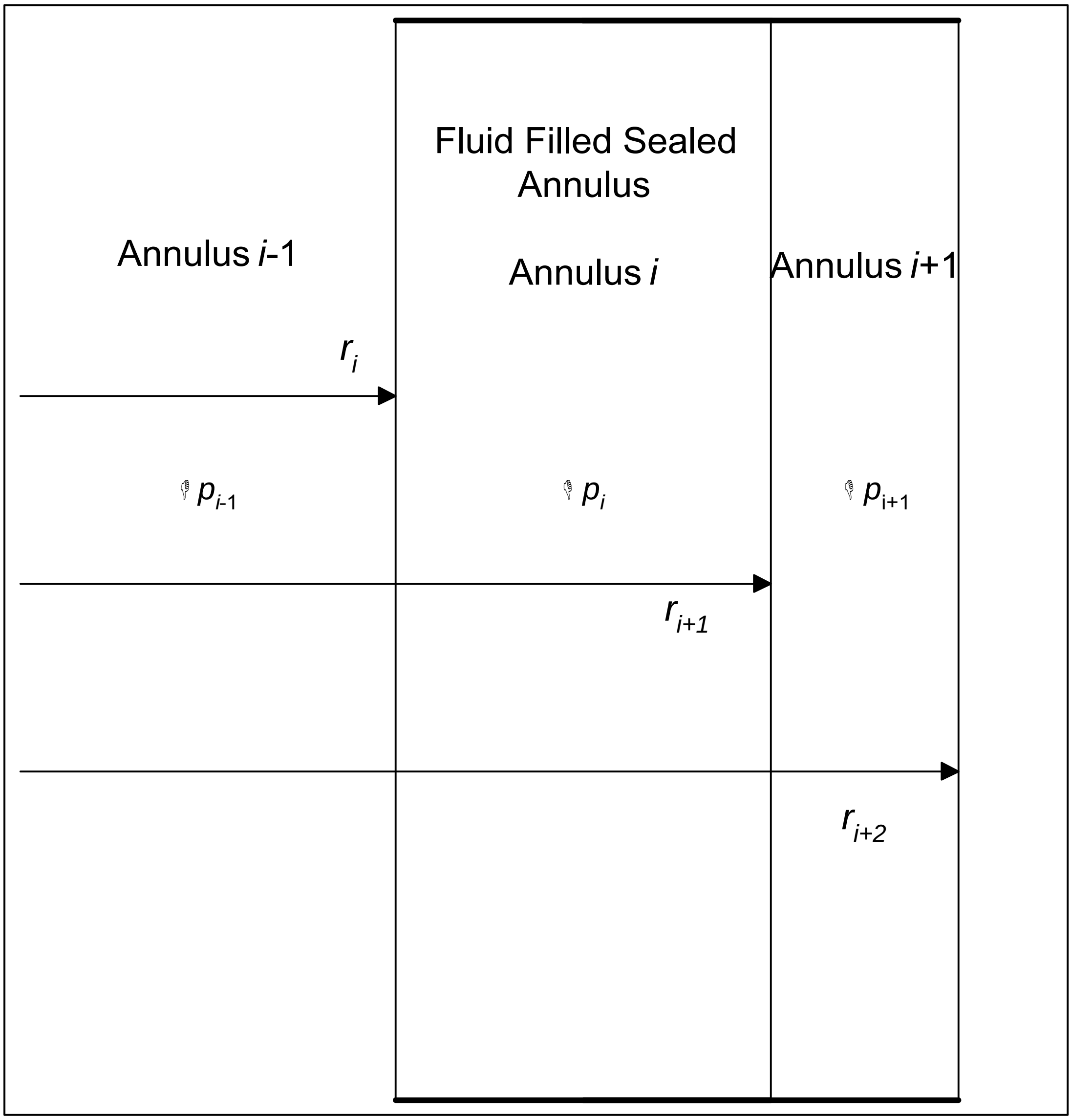

Figure 20 The ith annulus

Denote the thickness of the inner and outer cylinders by t_i and t_{i+1} respectively. In the following we assume that the cylinders are thin walled, i.e.

$$\frac{2r_i}{t_i} > 12 \tag{B5}$$

for all i. This assumption is justifiable for most casing strings. The tubing is a thick walled cylinder. However, the argument here serves to illustrate the physics of the problem. The volume of the ith annulus is therefore given by

$$V_i = \pi\left(r_{i+1}{}^2 - r_i{}^2\right)L_i \tag{B6}$$

where L_i denotes its length. The change in the volume of this annulus is given by

$$\Delta V_i = \frac{\partial V_i}{\partial r_{i+1}}\Delta r_{i+1} + \frac{\partial V_i}{\partial r_i}\Delta r_i + \frac{\partial V_i}{\partial L_i}\Delta L_i \tag{B7}$$

where Δr_i, Δr_{i+1}, and ΔL_i denote the change in r_i, r_{i+1}, and L_i respectively. Substituting Eq. (B6) in Eq. (B7), we obtain

$$\Delta V_i = 2\pi L_i\left(r_{i+1}\Delta r_{i+1} - r_i \Delta r_i\right) + V_i \varepsilon_{a,i} \tag{B8a}$$

where

$$\varepsilon_{a,i} = \frac{\Delta L_i}{L_i} \tag{B8b}$$

denotes the axial strain of the ith annulus.

B.2) Ballooning of a thin walled cylinder

Consider a thin walled cylinder of diameter d and wall thickness t subjected to internal pressure p_{in} and external pressure p_{out}. For an open ended cylinder (L/d >>1), the radial stress σ_r and hoop stresses σ_h in the wall are given by (Timoshenko, 1986)

$$\sigma_r = \left(p_{in} - p_{out}\right), \tag{B9}$$

$$\sigma_h = \frac{d}{2t}\left(p_{in} - p_{out}\right). \tag{B10}$$

From Hooke's law the hoop strain due to these stresses is given by

$$\varepsilon_h = \frac{1}{E}\left(\sigma_h - \nu\sigma_r\right) + \alpha\Delta T \tag{B11}$$

where ΔT is the temperature rise in the cylinder wall and α is its coefficient of thermal expansion. E and ν denote the elastic modulus and Poisson's ratio respectively. The change in the radius of the cylinder is given by

$$\begin{aligned} \Delta r &= \varepsilon_h \frac{d}{2} \\ &= \frac{d}{2E}\left(\frac{d}{2t} - \nu\right)\left(p_{in} - p_{out}\right) + \frac{d}{2}\alpha\Delta T \end{aligned} \tag{B12}$$

If the stresses are all elastic, then the above equation can re-written by replacing the pressures with changes in pressure, to get

$$\Delta r = m(\Delta p_{in} - \Delta p_{out}) + n \tag{B13a}$$

where

$$m = \frac{d}{2E}\left(\frac{d}{2t} - \nu\right) \tag{B13b}$$

$$n = \frac{d}{2}\alpha\Delta T \tag{B13c}$$

Equation (B12) relates the change in the radial dimensions of a cylinder subjected to changes in pressure and temperatures. Note that the first term on the RHS of Eq. (B13a) is the "ballooning" term since it describes the changes in the radial dimensions due to changes in pressure and axial length*.

B.3) Annular Volume Change and Loads

The change in the volume of the i^{th} annulus as given by Eq. (B8a) can be related to the annular pressures via Eq. (B13) so that

$$\Delta V_i = 2\pi L_i \begin{bmatrix} \{r_{i+1}m_{i+1}(\Delta p_i - \Delta p_{i+1}) + r_{i+1}n_{i+1}\} \\ -\{r_i m_i(\Delta p_{i-1} - \Delta p_i) + r_i n_i\} \end{bmatrix} + V_i\varepsilon_a$$

where all subscripted variables on the right hand side (except pressures), are evaluated at the corresponding radii shown Figure 20. The above equation can be rearranged as

$$\begin{aligned}\Delta V_i = &(-2\pi L_i r_i m_i)\Delta p_{i-1} + [2\pi L_i(r_i m_i + r_{i+1}m_{i+1})]\Delta p_i + (-2\pi L_i r_{i+1}m_{i+1})\Delta p_{i+1} \\ &+ (2\pi L_i)(r_{i+1}n_{i+1} - r_i n_i) \\ &+ V_i\varepsilon_a\end{aligned} \tag{B14}$$

Let the fluid in the volume experience a temperature rise ΔT_{fi} Then the fluid volume increase is given by ($V_i\gamma_f\Delta T_{fi}$) where γf denotes the thermal coefficient of volumetric expansion of the fluid. The net volume change is given by the thermal expansion plus the influx/outflux, $V_{in\text{-}out,}$ so that, the total unconstrained volume change is

$$\Delta V_i^{uc} = V_i\gamma_f\Delta T_i + V_{flux} \tag{B15}$$

The superscript "*uc*" implies that this is the unconstrained volume expansion. Since, the volume change in the fluid and the volume change of the annulus per Eq. (B14) are not equal, the annular fluid experiences a pressure increase. Since Eq. (B14) represents the volume change of the annulus in terms of the unknown pressure increases Δp_{i-1}, Δp_i, and Δp_{i+1}, the pressure increase in the annular fluid can be calculated. Using Eq. (B3), the definition of the fluid bulk modulus, we obtain

$$V_i\Delta p_i + B_i\Delta V_i = B_i\Delta V_i^{uc}\,. \tag{B16}$$

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* Examination of the thermal and pressure expansion terms shows that their ratio is of the order of $\frac{(d/t)}{400}\frac{\Delta p_{in} - \Delta p_{out}}{\Delta T}$ for steel, indicating that ballooning due to thermal expansion tends to dominate the volume change in most cases.

Equation (B16) can be written for each concentric annulus. For N concentric cylindrical surfaces that form N-1 annuli, there exist N -1 unknown pressure changes. If we know the pressure change in the innermost cylinder, we obtain a set of N-1 simultaneous equations that can be solved for the individual pressure changes. These equations become linear if the influx/efflux term is zero. If this term is not zero, the equations become non-linear. The model described so far can be easily implemented in a spreadsheet and used to estimate orders of magnitude of the pressure build up. If APB is serious enough, detailed calculations based on refined models can be attempted.

The modeling of the volume influx/efflux term is a separate subject in itself. The authors of this document are not aware of published work on this issue. Nevertheless, guidelines to estimate this quantity are proposed below. The change of mass in the annulus is a result of leakage into or out of the annular space. The leakage is either due to fracture into a formation (or influx from the formation) or mass diffusion into (or from) a neighboring annulus (or tubing) through a component leak. As a first approximation, flow into or from a formation can be modeled by methods used to interpret formation leak off tests, where the volume flow rate is proportional to the square root of the pressure differential driving the flow (Bourgoyne et al.1991). The flow of gas via a component leak into a neighboring fluid filled space is akin to the familiar problem of "time to empty a reservoir" formulated in undergraduate courses in fluid mechanics. In this type of a problem, a fluid reservoir is drained through a nozzle, and this process can be modeled as an isentropic efflux from a higher pressure to a lower pressure. The solution to the problem of gas leak from a closed volume by using this method is described in Appendix C.

B.4) Well shut-in

This section uses the above development to estimate the increase in the pressure on the primary annulus when a flowing well is shut in. As discussed in section 5.4.1 when the well is shut in there is an increase of ballooning in the tubing which could lead to a slight increase in the pressure on the annuli. In order to estimate this, it is sufficient to calculate the change in the pressure of the annuli due to the effect of the extra ballooning that occurs at the time of shut in.* For the purposes of order of magnitude estimation, it is sufficient to consider only the tubing and the primary annulus.

Let r_t denote the outer radius of the tubing and t its thickness. Let r_{ci} denote the inner radius of the casing. The volume capacity of the tubing of length L is given by

$$V_t = \pi r_t^2 L$$

and the change in its volume due to shut in is given by

$$\Delta V_t = 2\pi r_t \Delta r_t L \quad \text{.} \tag{B17}$$

Here Δr_t denotes the change in the radius of the tubing due to change in the pressure in the tubing and the annulus, and it can be calculated from Eq. (B13a). This gives

$$\Delta r_t = m_t \left(\Delta p_t - \Delta p_{ann} \right) \tag{B18}$$

* All other effects would have already been considered while calculating the APB when the well is flowing.

where

$$m_t = \frac{r_t}{E_t}\left(\frac{r_t}{E_t} - \nu\right),$$

E_t is the modulus of elasticity of the tubing, and Δp_t denotes the change in tubing pressure from the flowing to the shut-in condition, and Δp_{ann} is the corresponding change in primary annulus pressure. The term due to thermal expansion is zero since the wellhead tubing temperature does not change appreciably immediately after shut in. Assuming that casing diameter change is negligible, a reasonable assumption since the change in temperature is negligible, we note that the change in the volume of the primary annulus

$$\Delta V_{ann} = -\Delta V_t \tag{B19}$$

Thus from Eqs. (B3), (B17) and (B19), we get

$$\Delta p_{ann} = -B_{ann}\frac{\Delta V_{ann}}{V_{ann}} = \frac{2\pi m r_t L B_{ann}\left(\Delta p_t - \Delta p_{ann}\right)}{V_{ann}}$$

Noting that the volume of the primary annulus is given by

$$V_{ann} = \pi(r_{ci}^{\ 2} - r_t^{\ 2}),$$

we obtain,

$$\Delta p_{ann} = \frac{1}{1 + \dfrac{fE_t}{B_{ann}}}\Delta p_t$$

where

$$f = \frac{1}{2}\left[\left(\frac{r_c}{r_t}\right)^2 - 1\right]\left(\frac{r_t}{t} - \nu\right)^{-1} \tag{B20}$$

Consider the case of an annulus formed by 4.5 in., 21.6 ppf tubing and 7 in., 23 ppf casing. Assume that the annulus is filled with a fluid of bulk modulus 526,000 psi and that the modulus of elasticity of steel is 30,000, 000 psi. Substituting these values in the above expression we obtain f = 0.14 and E_t/B_{ann} =57.03. Thus,

$$\frac{\Delta p_t}{\Delta p_{ann}} = \frac{1}{1 + 7.98} = 0.11.$$

If the difference between the wellhead flowing and shut in pressures is 1, 000 psi a pressure increase less than or equal to 111 psi can be expected in the annulus. However, this pressure will decay as the wellbore cools. This pressure spike may be important if annuli are operating close to their limiting pressures.

B.5) Bleeding a heated annulus

This development in this section is very similar to the bleed off time calculations described in Appendix C with some variations due to the difference in the PVT behavior of liquids. Let $p(t)$ and $p(t+\Delta t)$ denote the pressure in the heated annulus at times t and $t+\Delta t$. These pressures are then related to the change in pressure Δp as

$$-\Delta p = p(t+\Delta t) - p(t) \tag{B21}$$

The change in pressure is related to the change in volume (in this case the bleed fluid), Dv of the incompressible fluid, as

$$\Delta p = B_T \frac{\Delta V}{V_a} \tag{B22}$$

where B_T is the isothermal bulk modulus of the fluid and V_a is the volume of the annulus. The bleed volume can be described as Bernoulli type efflux (see Appendix C for the details) so that the volume flow rate Q, of the liquid through the bleed nozzle is given by

$$Q = A_n \sqrt{\frac{2[p(t) - p_{atm}]}{\rho}} \tag{B23}$$

where p_{atm} is the atmospheric pressure and ρ is the density of the fluid. Therefore, the volume efflux in a time interval Δt is given by

$$\Delta V = Q\Delta t \tag{B24}$$

Substituting Eqs. (B23) and (B24) into Eq. (B22) and then into Eq. (B21) we obtain, the following differential equation for the pressure in the annulus during bleed off:

$$\frac{dp}{dt} = -\frac{B_t A_n}{V_a}\sqrt{\frac{2p_{atm}}{\rho}} A_n \sqrt{\frac{p}{p_{atm}} - 1} \tag{B25}$$

The time required to bleed the annular pressure to atmospheric pressure from an initial pressure p_i, is therefore given by

$$t(p_{atm}) = -\frac{1}{G}\int_{\bar{p}=\frac{p_i}{p_{atm}}}^{1} \frac{d\bar{p}}{\sqrt{\bar{p}-1}} \tag{B26}$$

where

$$\bar{p} = \frac{p}{p_{atm}}$$

and

$$G = \frac{B_T A_n}{V_a}\sqrt{\frac{2p_{atm}}{\rho}}\ . \tag{B27}$$

Integration of Eq. (B26) yields

$$t(p_{atm}) = \frac{p_{atm}}{G}\left[2\sqrt{\frac{p_i}{p_{atm}}} - 1\right] \tag{B28}$$

Finally, this enables the calculation of the volume required to relieve the thermally induced annular pressure. The volume of the bleed fluid is

$$V_{bleed} = \int_{t=0}^{t=t(p_{atm})} Q\,dt \qquad \text{(B29).}$$

Substituting Eqs. (B28) and (B23) into the above equation and subsequent integration leads to

$$V_{bleed} = -\frac{B_T A_n^2 \left[t(p_{atm})\right]^2}{2\rho V_A} \tag{B30}$$

Note that the bleed volume has a negative sign since we are calculating the change in the volume of the fluid in the annulus which is decreasing as the fluid is bled off.

This expression enables the calculation of bleed off times for a fluid and the associated bleed volumes. Once again, we note that this is a simple model that does not account for effects such as gravity, temperature and losses at the nozzle. This calculation however provides an order of magnitude estimate of the times involved, since gas bleed off times are significantly larger than fluid bleed off times.

Appendix C: Estimating Annular Bleed Time

Estimating the bleed time required to reduce the pressure in an annulus is a special case of the problems that involve pressure driven fluid migration from one volume to another via a nozzle or orifice. The case of a liquid migrating from one liquid filled space to another is usually treated in most undergraduate textbooks on fluid mechanics and involves the application of the unsteady Bernoulli equation for incompressible flow. The case of a gas bleeding from a high pressure to a low pressure is discussed in this note. The more complicated problem of a gas migrating into a liquid filled space requires solution for the complete understanding of the SCP problems. This is indicated as a subject for further work.

The following describes a method to estimate the time taken to bleed a closed volume containing gas. Let V_a represent the volume of the annulus. Let the gas be at an initial pressure p_i, and let $p(t)$ denote the pressure of the gas in the annulus at any time t after the bleed off valve is opened. We wish to determine the time taken for the gas to vent to atmospheric pressure via a bleed valve whose flow area is denoted by A. We assume that the bleed off takes place at constant temperature. If T is its temperature, assuming that the gas is perfect, we can write

$$p(t) = \rho(t)RT \tag{C1}$$

where $\rho(t)$ denotes the gas density in the annulus during bleed off. R denotes the gas constant for the gas and is given by

$$R = \frac{\Lambda}{M_{gas}}$$

where Λ denotes the universal gas constant (49,720 $ft^2/s^2/^oR$) and M_{gas} denotes its molecular weight. Multiplying both sides of the above equation by the volume of the annulus, we get

$$\begin{aligned} V_a p(t) &= (\rho(t)V_a)RT \\ &= m_a(t)RT \end{aligned}$$

where $m_a(t)$ denotes the mass of the gas in the annulus at time t. Differentiating both sides with respect to time, we get

$$\frac{dp(t)}{dt} = \frac{RT}{V_a}\frac{dm_a}{dt} \tag{C2}$$

The term on the RHS of the above equation is the instantaneous mass of gas in the annulus and depends on the influx and efflux of mass into the volume. Conservation of mass requires that

$$\frac{dm_a}{dt} = \overline{m}_{in} - \overline{m}_{out} \tag{C3}$$

where $\overline{m}_{in}$ and $\overline{m}_{out}$ denote the mass flow rate of gas into and out of the annulus respectively. The mass flow rate out of the annulus is given by

$$\overline{m}_{out}(t) = A\rho(t)v(t) \tag{C4}$$

where A is the flow area of the nozzle and $v(t)$ is the instantaneous velocity through the nozzle. The velocity $v(t)$ is obtained by applying Bernoulli's equation for isentropic isothermal flow from a pressure $p(t)$ to atmospheric pressure, p_{atm}. Neglecting gravitational effects, the velocity of efflux through the nozzle is given by

$$v(t) = \sqrt{\frac{2(p - p_{atm})}{\rho}} \qquad \text{(C5).}$$

Substituting the expression for velocity in Eq. (C4) and then in Eq. (C2), and simplifying, we get

$$\frac{dp}{dt} = \frac{RT}{V_a}\overline{m}_{in} - \frac{A\sqrt{2RT}}{V_a}\sqrt{p(p - p_{atm})} \quad . \tag{C6}$$

It is convenient to nondimensionalize the above equation by introducing dimensionless pressure and time as defined below respectively:

$$\overline{p} = \frac{p}{p_{atm}} \tag{C7}$$

$$\bar{t} = \frac{t}{t_o} = \frac{t}{\left(V_a / A\sqrt{2RT}\right)} \quad . \tag{C8}$$

Introducing these dimensionless quantities into Eq. (C5), we get

$$\frac{d\overline{p}}{d\bar{t}} = G - \sqrt{\overline{p}(\overline{p} - 1)} \tag{C9}$$

where the dimensionless mass influx is given by

$$G = \sqrt{0.5RT}\,\frac{\overline{m}_{in}}{Ap_{atm}} \tag{C10}$$

Therefore, the time taken to bleed off from an initial pressure pi to atmospheric pressure is given by

$$\bar{t} = \frac{t}{t_o} = \int_{\overline{p}=\frac{p_i}{p_{atm}}}^{1} \frac{d\overline{p}}{G - \sqrt{\overline{p}(\overline{p} - 1)}} \quad . \tag{C11}$$

The above expression can be integrated to yield a closed from expression. For the moment, however, we set the dimensionless mass influx term (G) equal to zero to obtain the following expression for bleed-off from a closed annulus without influx.

$$\bar{t} = \frac{t}{t_o} = \ln\left[\sqrt{\frac{p_i}{p_{atm}}} + \sqrt{\frac{p_i}{p_{atm}} - 1}\right] \tag{C11}$$

Figure 21 shows the dimensionless bleed off time curve. The figure shows the bleed off time for an annulus 700 ft long, formed by 4.5 in. OD tubing and a 7 in., 23 ppf casing. The gas at 3000 psi initial pressure and a temperature of 200^{o}F, takes 2.1 hours to bleed through a ¼ in. diameter nozzle.

The special case of bleeding the annulus in the presence of a tubing leak (as described in section 5.5) can be estimated by assuming that the influx into the annulus is of the Bernoulli type. Assuming that the pressure in the tubing is denoted by p_t, by arguments similar to those used for Eq. (C4), we obtain,

$$\frac{dm_{in}}{dt} = \begin{cases} 0, \;\; p_t < p(t) \\ A_l\sqrt{2\rho(p_t - p)}, \;\; p_t > p(t) \end{cases} \tag{C12}$$

Substituting Eq. (C12) in Eq. (C3), and by using the expression for the mass efflux from the nozzle calculated previously, we obtain,

$$\frac{dp}{\left(\frac{dm_{in}}{dt}\right) - A_n\sqrt{p(p - p_{atm})}} = \frac{\sqrt{2RT}}{V_a}dt \tag{C13}$$

Since we are interested in the effect of the leak influx, substituting the expression for the mass flow rate for tubing pressures greater than the annulus pressures, we obtain,

$$\frac{dp}{A_l\sqrt{p(p_t - p)} - A_n\sqrt{p(p - p_{atm})}} = \frac{\sqrt{2RT}}{V_a}dt \tag{C14}$$

By denoting the ratio of the leak path area A_l to the nozzle area A_n by β, we get,

$$dt = \frac{V_a}{A_n\sqrt{2RT}}\frac{d\overline{p}}{\beta\sqrt{\overline{p}(\overline{p}_t - \overline{p})} - \sqrt{\overline{p}(\overline{p} - 1)}} \tag{C15}$$

Integration of both sides of the equation yields the time required to bleed off from an initial annulus pressure pi to a final pressure pf, as described by Eq. (3) in section 5.5.

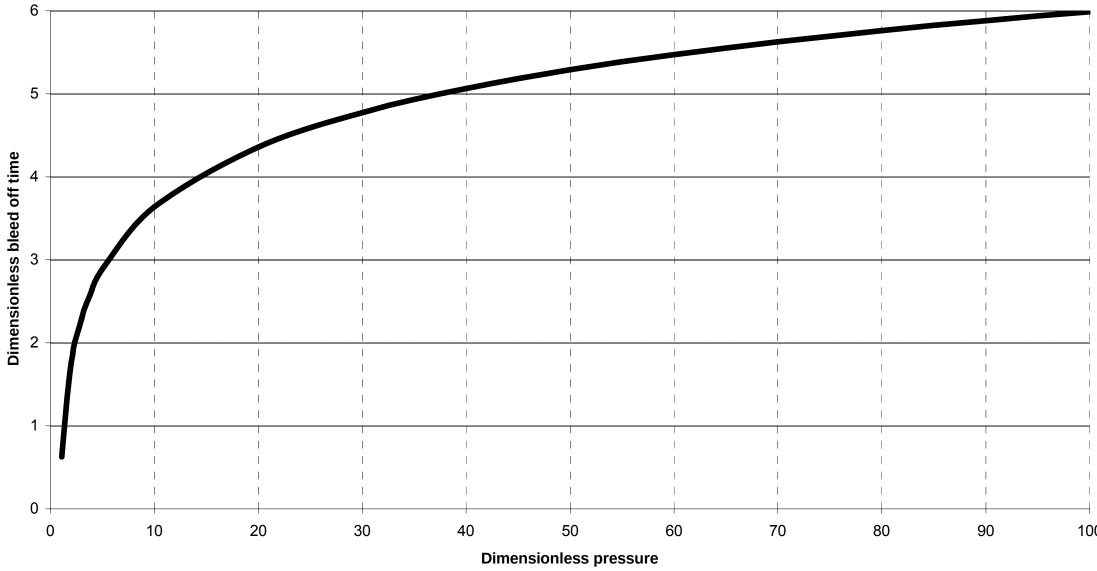


Figure 21 Dimensionless bleed off time for zero mass influx

Appendix D: Conclusions of the LSU Study

Operator experience on the OCS has shown that Sustained Casing Pressure (SCP) problems can lead to blowouts of sufficient flow rate to jeopardize a production platform. However, there has been only minor pollution and no known injuries or fatalities due to problems related to SCP. This study has indicated that further substantial reductions in the regulatory efforts to manage the SCP problem on the OCS are possible without significantly increasing the risk of injury to offshore personnel or the risk of pollution.

Industry experience with problems resulting from sustained casing pressure has shown that the most serious problems have resulted from tubing leaks. When the resulting pressure on the production casing causes a failure of the production casing, the outcome can be catastrophic. The outer casing strings are generally weaker than the production casing and will also fail, resulting in an underground blowout. Flow rates through the tubing leak can quickly escalate if any produced sand is present in the flow stream. Blowouts of sufficient flow rate to jeopardize the production platform are possible.

About 50 % of wells with sustained casing pressure have pressure on the production casing.

The cause of pressure on production casing is generally easier to diagnose than pressure on one of the outer casing strings.

Pressure on production casing is generally easier to correct than pressure on the outer strings.

The magnitude of the leak rate is as important as the magnitude of the pressure when determining the potential hazard posed by sustained casing pressure.

Gas flow or water flow through unset cement in a major cause of sustained casing pressure in the outer casing strings, outside of the production casing.

Channeling of formation fluids through unset cement from high pressure zones to low pressure zones becomes more likely when the casing setting depth is extended by drilling ahead with mud densities approaching the equivalent density for formation fracture in the upper part of the open borehole.

Portland cement is a brittle material and susceptible to cracking when exposed to thermally induced or pressure induced tensile loads. Experimental test results indicated that all cement systems tested exhibited one or more failure modes.

About 10 % of the casing strings exhibiting sustained casing pressure are intermediate casing strings.

About 30 % of the casing strings exhibiting sustained casing pressure are surface casing strings.

About 10 % of the casing strings exhibiting sustained casing pressure are conductor casing strings.

Only about one-third of the casing strings exhibiting sustained casing pressure are in wells that are active and producing.

None of the remedial procedures to stop flow through cement outside of casing have been shown to be effective.

About 90 % of sustained casing pressures observed are less than 1000 psi in magnitude.

More than 90% of all sustained casing pressures observed are less than 30 % of the minimum internal yield pressure (burst pressure) of the casing involved.

The regulatory burden associated with managing the sustained casing pressure problem on the OCS was significantly reduced by a series of LTL's issued since 1991.

Further substantial reductions in the regulatory efforts to manage the sustained casing pressure (SCP) problem on the outer continental shelf (OCS) are possible without significantly increasing the risk of injury to offshore personnel or the risk of pollution.

Appendix E: An Example Tubing Running Procedure

The following is excerpted from Allan and Roberts, (1989).

Adequate thread cleaning to assure removal of all sand, dirt and dried thread dope is the key to proper connection make-up and pressure-tight strings. The following procedure describes a field-proven technique for proper thread cleaning and running practices for high strength tubing with the couplings removed.

Remove the thread protectors.

1. Clean the threads with kerosene and a wire brush; satisfactory cleaning requires complete removal of all dope, dirt, sand and other foreign material to 100 percent bare, shiny steel. The use of kerosene in a compressed air spray gun operating off the rig air system or from a portable unit is also satisfactory method and will accelerate job completion. If steam is available, steam cleaning is an excellent method.
2. Dry the threads with clean rags or compressed air.
3. Re-install clean thread protectors on the dry pin ends.
4. Apply thread compound to the male threads at the box end of the tube.
5. Install and make-up tubing couplings manually with about 300 foot-pounds of torque using special friction-type tongs to eliminate notching. (Installing the couplings before picking up the tubing minimizes the possibility of dropping the string, in the event slippage occurs between the pipe and the elevators as the joint is lowered in the derrick.)
6. Wash all dirt off the ramp and catwalk.
7. Roll one joint of pipe at a time from the upper tiers onto wooden sills placed across the catwalk. Roll pipe slowly and maintain control at all times to prevent colliding of joints.
8. Steel thread protectors should remain on the pin ends of the pipe while picking up pipe from the catwalk.
9. While picking up each joint from the catwalk with a plaited pickup cable and air hoist or cathead, use a snub rope attached to the pin end to enable one man to restrain lateral motion of the joint and minimize contact between the pipe and ramp. Minimizing contact between the pipe and ramp by snubbing should permit the use of clean plastic bucket over the box end as a dirt deflector. A rope hold-back should also be used at the "V" door to catch the lower end of the joint as it swings on to the derrick floor.
10. With the box end of the joint resting on the derrick floor, remove the plastic bucket and use dry compressed air or clean, dry rags to remove sand or other foreign material from the dry box threads.
11. After the traveling block pulls the joint up to a vertical position using a plaited pickup cable, remove the pin-end thread protector. Some new pipe has loose mill scale inside which should be allowed to fall out prior to stabbing to minimize contamination of clean threads. Use dry compressed air or clean, dry rags to remove mill scale or other foreign material which may accumulate on the dry pin-end threads while picking up the joint. Apply a light coat of thread compound to clean pin-end threads and make up the joint.

Appendix F: Attachments 1, 2, 3 & 4

Attachment 1
SPE 23136
The Occurrence of Annulus Pressures in the North West Hutton Field: Problems and Solutions

Attachment 2
Field Trial Results of Annular Pressure Behavior in a High-Pressure/High-Temperature Well

Attachment 3
SPE 21727
Methods of Detecting and Locating Tubing and Packer Leaks in the Western Operating Area of the Prudhoe Bay Field

Attachment 4
Oil & Gas Journal
Designing and Running Pipe

SECTION II: TUBING AND CASING CONNECTION SEALING TECHNOLOGY

1) Tubing and Casing Sealing Technology

The drilling and completion of an oil or gas well requires the use of several sizes of pipe. During the drilling of a well, pipe is used to stabilize the soil through which the well is being drilled and to establish the well. This pipe is referred to as drilling casing and typically can have pipe diameters from 30” to 9-5/8”. As the well is drilled deeper, additional pipe, referred to as production casing, is installed inside the first pipe and is used to protect the well in the event there is a leak in the production tubing. Production casing pipe is typically between 9-5/8” to 5-1/2”. The last string of pipe installed in the well is the production tubing and is the pipeline through which the well is produced. This pipe size is typically between 5-1/2” and 2-3/8”.

All of these pipe sizes are run into the well in lengths of 16 feet to 48 feet. These joints of pipe are joined together with threads that are machined onto the ends of the pipe. Two thread connection designs are used. The most common connection includes a coupling that contains female threads in both ends. The two ends of the pipe are finished with male threads and they screw into the coupling ends. The other connection design has a male thread on one end and a female thread on the other. The pipe is run into the well by simply screwing the male end into the female end.

All tubing and casing connections include threads to structurally hold the pipe string together. All connections also have sealing mechanisms that contain the internal fluid pressure and the external fluid pressure. For tubing, the internal fluid is the oil or gas being produced by the well and the external fluid can be drilling mud, treated fresh water or brine. For casing, the internal and external fluid is typically drilling mud, treated fresh water or brine, or cement if the casing has been cemented into the hole. The threaded connections must be able to provide a pressure barrier between the inside fluid and outside fluid. In some well conditions the inside pressure is greater than the external pressure and in other well conditions the external can be greater.

There are three types of sealing mechanisms used in tubing and casing connections-

- **Thread seal** – typically used in applications below 275°F and pressures up to approximately 4,000 psi
- **Elastomer seal** – same applications as the thread seal
- **Metal-to-metal seal** – typically used for higher temperature and pressure, above approximately 275°F and 4,000 psi

1.1) Thread Seal

The most commonly used connection seal mechanism is the threads themselves. Over the years, the petroleum industry has standardized on two thread sealing connections, 8 Round thread and Buttress thread. Both are coupled designs and are included in the American Petroleum Institute standards and specifications. The 8 Round thread is a tapered thread with 8 threads per inch and a thread height of 0.071”. Thread engagement occurs on the two flanks, which are tightly maintained by connection assembly with a power tong that is used to screw the two pieces tightly together, or “power tight”, to a desired thread interference. The 8 Round thread shape has rounded roots and crests that when engaged have a small clearance that varies between 0.000” and 0.006”. The thread is shown in Figure 1. A lubricant is applied to the threads, referred to as the thread compound, and is required to perform several functions. The compound must (1) serve as a lubricant with a consistent friction factor so that makeup to a specified torque range can be achieved; (2) provide resistance to galling to prevent tearing of the metal thread flanks and (3) plug the root to crest clearance in order to maintain sealing integrity.

API recently included a Supplementary Requirement, SR-22, that improves the sealability of the 8 Round long thread connection (LT&C). This improvement is referred to as "Enhanced Leak Resistance LTC" and while pressure ratings are not given, SR-22 generally included internal pressure equal to the smaller of the API Minimum Internal Yield Pressure or 10,000 psi, and tension loads up to 62.5% of the API connection jumpout strength, with sealing performance to be verified by the user. The SR places many additional requirements on the 8 Round connection, including tighter thread taper tolerances, tin plating, specific application of thread compound, increased number of power tight turns and other requirements.

The API Buttress connection is also a tapered thread design with 5 threads per inch and a 0.062" thread height. The roots and crests are parallel to each other and, similar to the 8 Round connection, are tightly engaged power tight to a desired thread interference. The buttress thread shape and dimensions result in a stab flank clearance of 0.000" to 0.007" and is shown in Figure 2. Similar to the 8 Round connection, a thread compound must be used that provides the same three characteristics, only with the Buttress thread the compound must plug the relatively large stab flank clearance and possibly a small root to crest clearance, depending upon thread height tolerances. Therefore, sealability of both the 8 Round connection and the Buttress connection are highly dependent upon the thread compound.

API is currently reviewing the possibility of improving the sealability of the Buttress connection. A new workgroup has been formed and is evaluating possible improvements that may result in a SR for Buttress improved leak resistance.

1.2) Elastomer Seal

Some connections, including API 8 Round and Buttress, include an optional elastomer seal. This is a secondary seal that is located in a groove machined into the coupling threads. The seal consists of a relatively thin ring that is tightly contained in the threads and provides a separate barrier between internal and external fluid communication. The API seal ring is made from virgin Polytetrafluoroethylene (PTFE) (Teflon™) and is 25% fiberglass filled for added strength. Figure 3 shows the API 8 Round and Buttress connections with the optional seal ring.

1.3) Metal to Metal Seal

The most effective pressure seal is a metal-to-metal, MTM, seal. For threaded connections, most MTM seals are located on the end on the male member, or pin end. As the connection is screwed together, the threads engage first, followed with the meal to metal seal and typically final makeup is provided with a torque shoulder that is usually located at the end of the pin, end of the box (female member) or in the threads. MTM seals usually have a greater radial interference than thread interference. Seal width can be relatively long, about ½", or narrow, about 1/32". Longer seals may require the thread compound to fill in the small grooves machined into the pin surface.

Narrow seals do not rely on thread compound for pressure integrity, but do need the compound for galling resistance. Properly designed MTM seals provide internal pressure sealing equal to the burst pressure of the pipe body at tension loads up to the yield load of the pipe body and in some cases to ultimate failure of the pipe.

MTM seals are used on "premium" connections which are defined as proprietary (non API) connection designs. Figure 4 shows the overall geometry of a typical premium connection and metal seal. One exception to premium connections being proprietary is the API Extreme-Line connection, which is described in API specifications but is rarely used in the Gulf of Mexico.

1.4) Connection Thread Compound Sealing Performance Requirements

ISO 13678, titled "Petroleum and natural gas industries – Evaluation and testing of thread compounds for use with casing, tubing, and line pipe", addresses the performance requirements for threaded connection service. Excerpts from this specification were provided by Mr. Herschel McDonald, a consultant in thread compounds and a member of this workgroup, as follows:

Excerpts from ISO 13678

Thread compound sealing performance requirements

-adequate sealing properties for thread type seal connections and/or not inhibiting the sealing properties of non-thread sealing connections (e.g. metal-to-metal seals, polytetraflouroethylene (PTFE) seals etc.) depending upon service requirements;

Fluid sealing properties

A primary purpose of a thread compound, when used on thread sealing connections, is to provide fluid sealing for thread clearances, such as the helical root-to-crest clearances in ISO/API 8-round threads and the helical stab flank clearance in ISO/API buttress threads. Sealing is typically accomplished in a thread compound with solid particles that agglomerate to plug the thread clearances to prevent the contained fluid from passing through the connection.

Connection sealing also requires that positive contact pressure be maintained along the thread interface in order to ensure the geometric integrity of the helical sealing passages. Contact pressure requirements are established for connection fluid pressure integrity and are found in ISO 10400.

For specific service applications, the total thread compound connection system should be evaluated for fluid sealing integrity on full-size connections. While it is important for a thread compound to provide fluid sealing for thread clearances on ISO/API connections, it is also important that the thread compounds do not inhibit the sealing integrity of proprietary connections that have metal to metal seals. The solid particles that agglomerate may prohibit the designed mechanical seals (metal to metal) from efficiently contacting, resulting in a leakage path. Sealing tests should therefore be conducted on the thread compound/connection system, of which the thread compound is a part.

Additional comments

API modified thread compound and most of the proprietary environmental compounds that are currently marketed, are intended for the lubrication and sealing of API connections, i.e. an open leak path formed by the thread clearances in both 8-round and buttress connections. Typically the volume percent solids of these compounds range from 20 - 30% and the maximum particle sizing of the solids can be as much as .025". A high percentage of solids and relatively large particle sizes are necessary to effect a seal for these connections, especially at high service temperatures and pressures. The buttress thread form presents a particularly difficult problem, not just because of potentially large thread clearances that can be as much as .009" x .063" but because of the opening and closing of the thread flank clearances during stabbing, power make-up and tension as the pipe is run. For these reasons, BTC connections require high-solids, coarse-particle compounds for effective leak resistance.

Conversely, connections designed with a mechanical seal mechanism (premium connections) do not rely on the compound for sealing integrity but rather for galling resistance during make-up and break-out, and for lubrication to allow proper engagement of the connection members. The high-solids compounds required for sealing of API connections can in fact inhibit and restrict the proper make-up of premium connections by effecting a seal in the threaded area of the connection. The hydraulic pressure resistance due to the compound trapped in the threads will prevent proper seal-face contact during initial make-up. During field service at high temperatures, pressures and tension, the trapped compound will eventually be extruded and a leak path will develop. For mechanical seals, a low-solids, small-particle compound should be utilized.

As stated above in the excerpts from ISO 13678, it is critical that the sealing performance be established for the total compound/connection system that is defined in ISO 13678 as follows:

Thread compound/connection system: A system that consists of the various critical connection components including the specific connection geometry, and the individual connection materials and coatings combined with the thread compound.

It is critical that a thread compound is selected that has properties compatible with the geometry and the designed sealing mechanism of the connection in question.

1.5) Connection Testing Procedures and Leak Rates

Over the past 15 or so years several tubing and casing connection testing procedures have been provided by major oil companies and standardization groups. Some of these are summarized in Table 1, with selected pages from each given in the indicated Appendix.

ATT. NO.	CODE	TITLE	ALLOWABLE LEAK RATE	COMMENTS
MAJOR OIL COMPANY CASING TEST PROCEDURES				
1	Britsh Petroleum - Miller approx.1990	Production Tubular Testing Requirements for Miller Development	Any persistent leakage shall constitute specimen failure	Detailed connection test procedure.
2	Statoil - 1991	Qualification Test Procedure for Premium Connection	Any persistent leakage shall constitute specimen failure	Detailed connection test procedure.
3	Shell Europe - 1991	NAM TEO/3 Test Procedure for Tubing & Casing Connections	.001 acc/sec	Detailed connection test procedure.
MAJOR OIL COMPANY CASING TEST PROCEDURES				
4	Exxon Production Research - 1992	Evaluation of Premium Threaded Connections Using Finite Element Analysis and Full-Scale Testing	No criteria	Generic connection test procedure.
5	AGIP approx. 1993	Test Procedure for Connection Evaluation	Successful if no leakage of gas occurs	Detailed connection test procedure.
6	ARCO China - 1993	Performance Test Program for 7" 29 lb/ft L80-13Cr NK3SB Premium Connection Production Tubulars	Leakage will constitute failure of connections	Detailed connection test procedure.
7	Mobil Oil - 1997	Qualification of Coupled Premium Connections	.001 acc/sec	Detailed connection test procedure.
CURRENT INDUSTRY STANDARDIZATION GROUPS				
8	API RP 5C5 - 1991	Evaluation for Casing & Tubing Connections (downhole)	None listed	Detailed connection test procedure.
9	ISO DIS 13679 - 2000	Pet. & Nat. Gas Test Procedures for Casing & Tubing Connections	.001 acc/sec	Detailed connection test procedure.

Table 1 - : Connection Testing Procedures and Leak Rates

All of these procedures are concerned with the structural and sealing integrity of threaded tubing and casing connections. With regard to a leak criteria or leak acceptance guideline, of the nine procedures listed above, two do not give any leak criteria, four require “no leaks” and three list a maximum acceptable leakage limit of 0.001 atmosphere cc/second. The fact that only three procedures give allowable leak rates, and API is not included, shows that there is no industry accepted leak rate. The anticipated acceptance of ISO DIS 13679 will give the first petroleum industry tubular connection test procedure that provides an allowable leak rate. The internal pressures included in these test procedures are related to the internal yield pressure of the pipe and can vary from about 7,500 psi to 20,000+ psi. While these procedures can apply to both oil and gas, in most cases gas is the required internal test fluid. These procedures also include elevated temperatures to 350°F.

ISO DIS 13679 was written over a period of several years that included three to four meetings each year. During one of these meetings, Mr. W. H. P. M. Heijnen, formerly with Royal Dutch Shell The Hague and currently with BEB, a German petroleum operating company, presented information to the ISO workgroup that gave a simplified example of casing annulus pressure build-up over time as a function of leak rate. This example is shown in Figure 5 and shows various pressures in time for a 3000 meter long tubing string. The production casing is assumed to be 7" and 7-5/8". The plot shows that a leak rate of 0.001 standard cc/sec would result in negligible increase in annulus pressure with time. A much larger leak rate of 1 standard cc/sec would produce a greater pressure increase, which in one year could be 3,000 to 4,500 psi if left unattended. This information was instrumental in ISO DIS 13679 specifying a maximum allowable leak rate of 0.001 cc/sec.

Additional information regarding leakage is given in the book "Industrial Sealing Technology" by H. Hugo Buchter, with several pages of this book given in Attachment 10. Mr. Buchter states that "zero leakage …is misleading because an accepted definition of the term is nonexistent. In general practice a zero leakage specification is an indication to use polymeric seats or seals. Metal-to-metal seals generally fail to meet this requirement. An exception is in gaskets for static conditions where metal is plastically deformed to obtain a leakage of less than 10^{-8} atmospheric cm^3/sec helium". He later states that NASA's definition of zero leakage is no more than 1.4×10^{-3} standard cm^3/sec of GN_2 at 300 psig and ambient temperature. This definition is very consistent with the new ISO DIS 13679 accepted leak rate of 1.0×10^{-3} standard cm^3/sec of GN_2 at test pressures much higher than 300 psig, typically 6,000 to 20,000 psig, and temperatures of 275°F to 350°F.

Mr. John Greenip of Hydril Company provided a summary of excerpts to the ARPTD steering committee which is given in Attachment 11. It is dated February 8, 2000 and gives a very good quick overview of seal technology.

A more in-depth discussion of thread seals, metal-to-metal seals and leak rates is given in the 1985 SPE paper 14040, "Sealing Tubular Connections", by C. A. Bollfrass, and is given in Attachment 12.

1.6) Testing of Tubular Connections During Running

Several methods are available for testing tubing and casing threaded connections when running the strings of pipe into the well. One method provides an internal pressure test of the full connection by inserting an internal assembly that seals on the pipe ID on both sides of the connection and then applying internal helium gas pressure to the connection. A helium gas sniffer is used to detect a leak on the outside of the connection.

Another method utilizes a seal assembly that clamps over the tubular connection and seals on the pipe OD and coupling OD of each connection. A version of the same test tool seals just above and below the joint in integral joint connections. A small volume of external water or gas pressure is then applied to the connection and leakage is determined by a decrease in the applied test pressure. This same method is also available for the mill end connection for use in the pipe mill. Because of the small external areas that are exposed to the test pressures using this tool, this test method apparently does not result in the types of radial distortions during testing that can result from pressuring the entire connection and adjacent tubing/casing in the connection area.

A third method detects connection leakage using a device that clamps to the OD of a coupling. When internal pressure is applied to the connection, the radial displacement of the coupling at the metal-to-metal seal is compared to the radial displacement at the threads and a relative difference as determined by experience can detect a connection leak or potential leak.

A fourth method applies to API 8 Round connections only and maintains sealability by monitoring torque and turns to a specified range of makeup. Values of torque and turns past hand tight makeup are recommended for various pipe sizes, weights and grades along with recommended thread compound.

A review of the results of the "Participant Survey" in the "Pressure Testing" section of Appendix A.4 of Section I of this document reveals the following:

1. Testing of Production Casing:
   - Operators participating in this study reported that they always test their completed casing strings, subsequent to running and cementing.
   - MMS requirements apparently call for testing of production casing strings to 70% of their minimum internal yield pressure after running and cementing.

2. Testing of Production Tubing:
   - Some of the operators participating in this study reportedly always test their tubing strings after running.
   - Some of the participating operators reported that they "sometimes" test tubing strings after running.

3. Testing of Individual Connections While Running:
   - Testing of individual tubing/casing connections while running did not appear to be a common practice among the operators in this study.
   - When the participating operators did test while running, they apparently tested primarily using test tools that pressured the inside of the connections.

1.7) Corrective Action for SCP

"Corrective" actions that may be taken in response to SCP include the following:

1. After an appropriate risk analysis, do nothing.
2. Install a mechanical remedial seal across the leak in the tubing or casing.
3. Pull the tubing and replace the failed connection or down-hole tool.
4. Inject a weighted fluid into the annulus experiencing SCP.
5. Inject a down-hole chemical leak sealant.

One of the participants in this study supplied the following information concerning SCP corrective actions:

1. Mechanical remedial seals include:
    - Tubing and casing straddle packers
    - Tubing and casing "patches"
2. Mechanical remedial seals are available from a number of suppliers, including:
    - Halliburton
    - Schlumberger
    - Owens Tools
    - Mesquite Oil Tools
    - PES
    - HPI Tools
3. Manufacturers/suppliers of downhole chemical sealants were identified as:
    - Furmanite
    - Oil Center Research
    - Dow TRV
    - Utex Industries
    - Seal-Tite International.

SES's review of a recent (1998-1999) edition of the Composite Catalog revealed these additional sources of straddle packers and casing/tubing patches:

1. Straddle Packers:
    - Cardium Tool Services
    - Double-E, Inc.
    - Drillflex
    - EVI Oil Tools
    - McAllister Petroleum Services
    - TAM International
2. Patches (Casing & Tubing):
    - Cardium Tool Services
    - Drillflex
    - Gotco International
    - Weatherford.

A short list of published articles dealing with leak remediation is included in Attachment 13 of this Section. Information documented in the "SCP and Corrective Action" section of Appendix A.4 of Section I of this document shows that the Operators participating in this study felt that successful techniques for repair of leaks included:

1. Tubing/casing packers and patches
2. Replacement of tubing strings.

Techniques with which the Operators in this study had had limited success included:

1. Injection of liquid sealants
2. Displacement of weighted fluids into the annulus experiencing SCP.

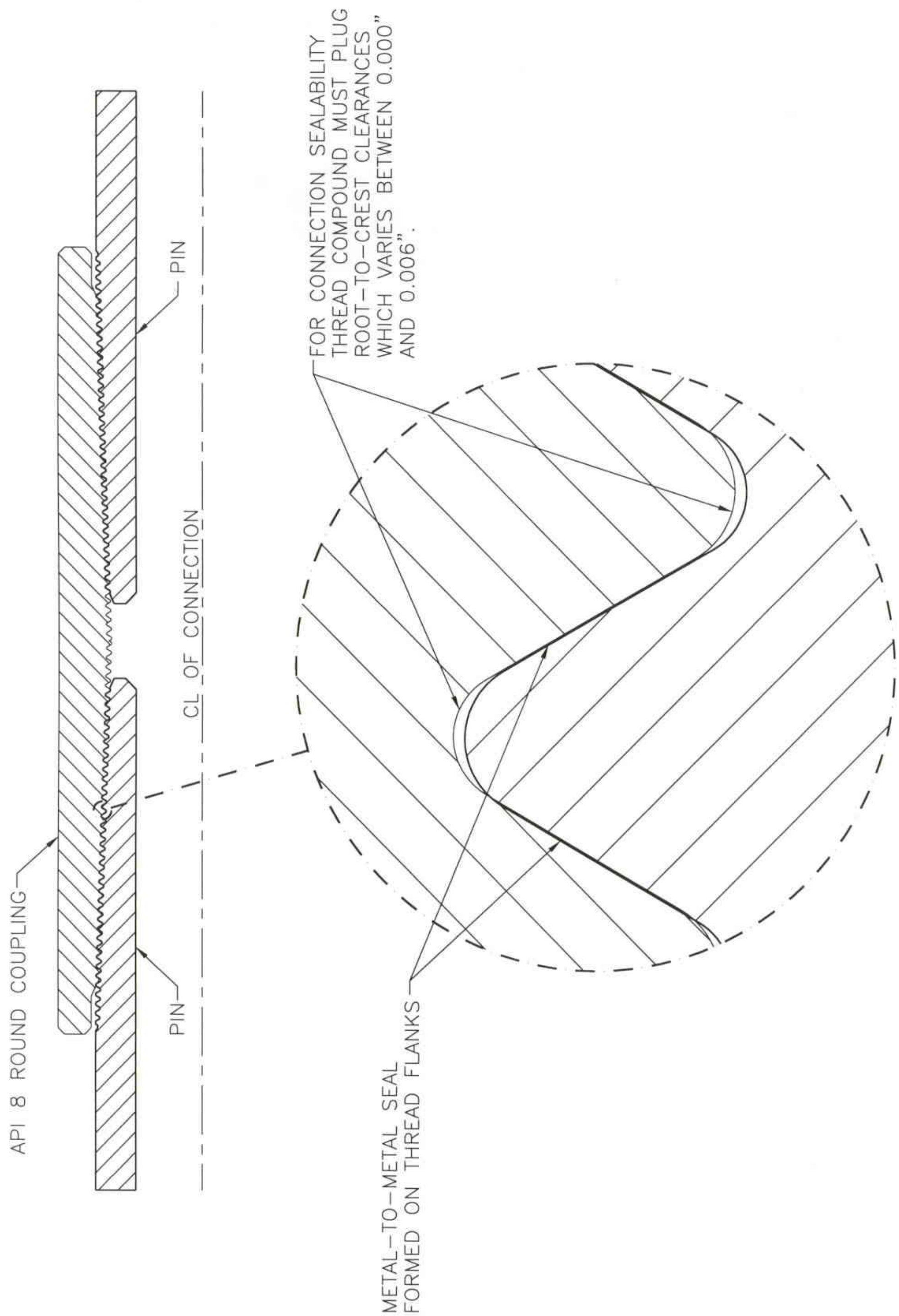


Figure 1: API 8 Round Tubing & Casing connection

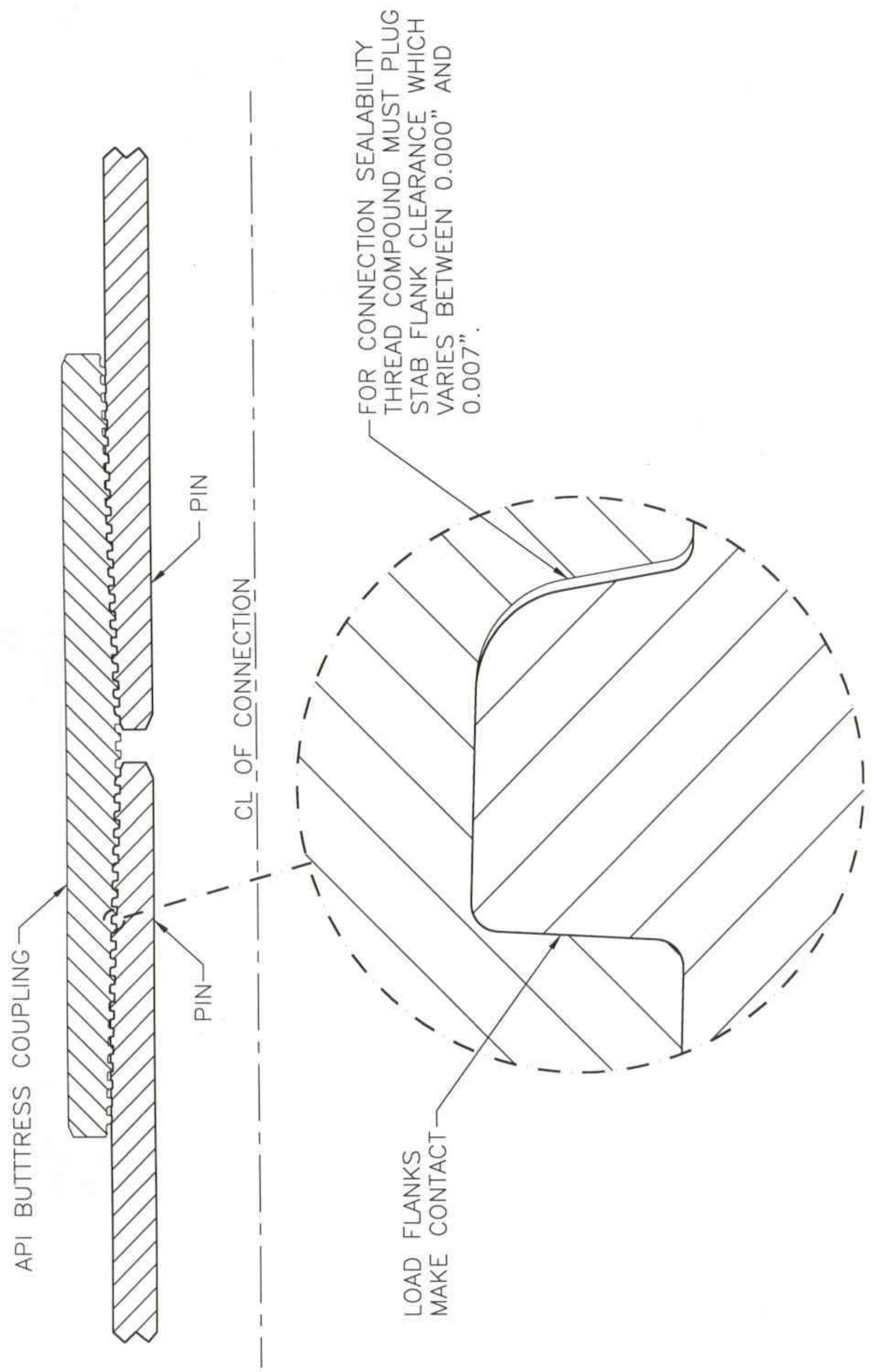


Figure 2: API Casing Buttress Thread Connection

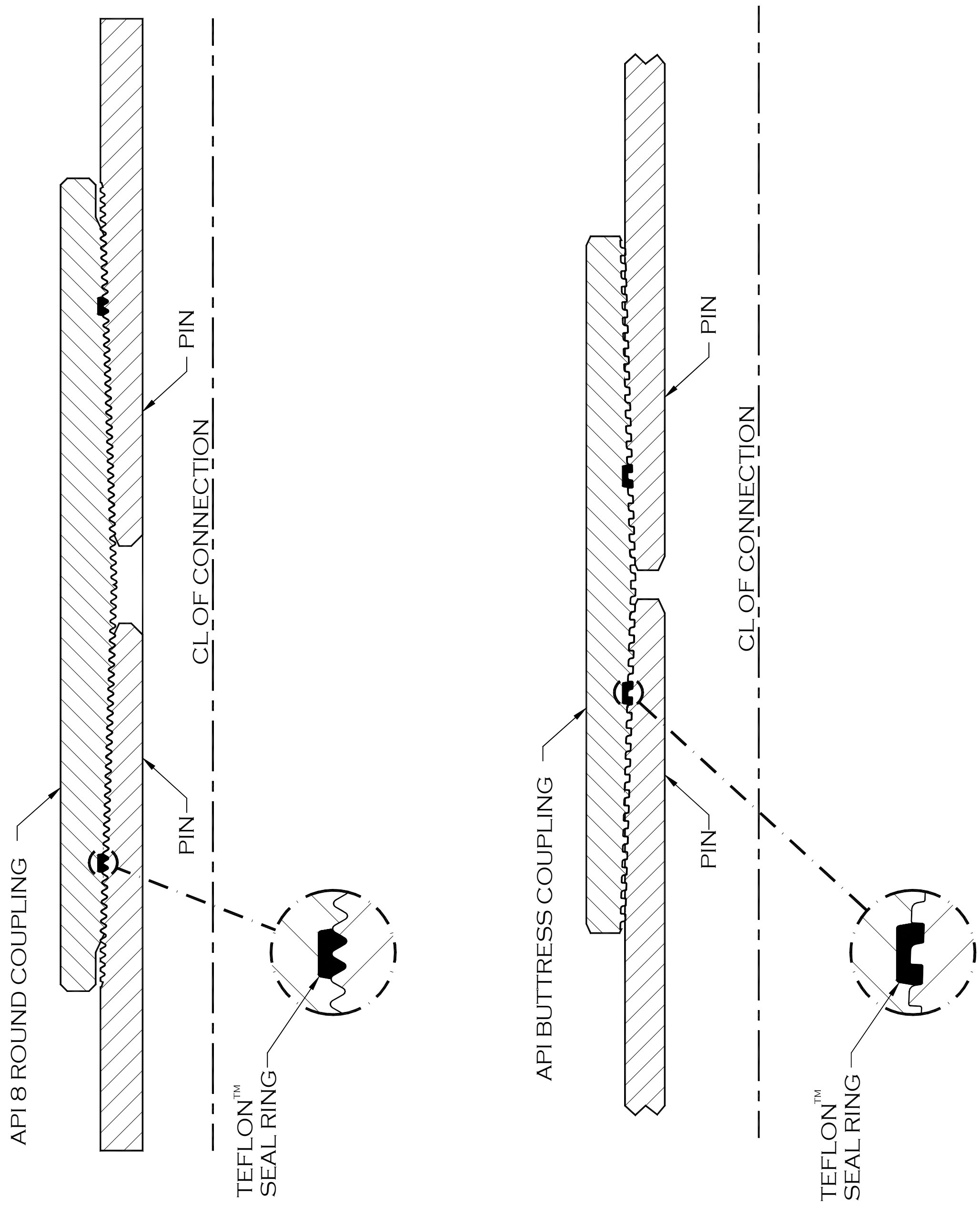


Figure 3: API Connections with Optional Seal Rings

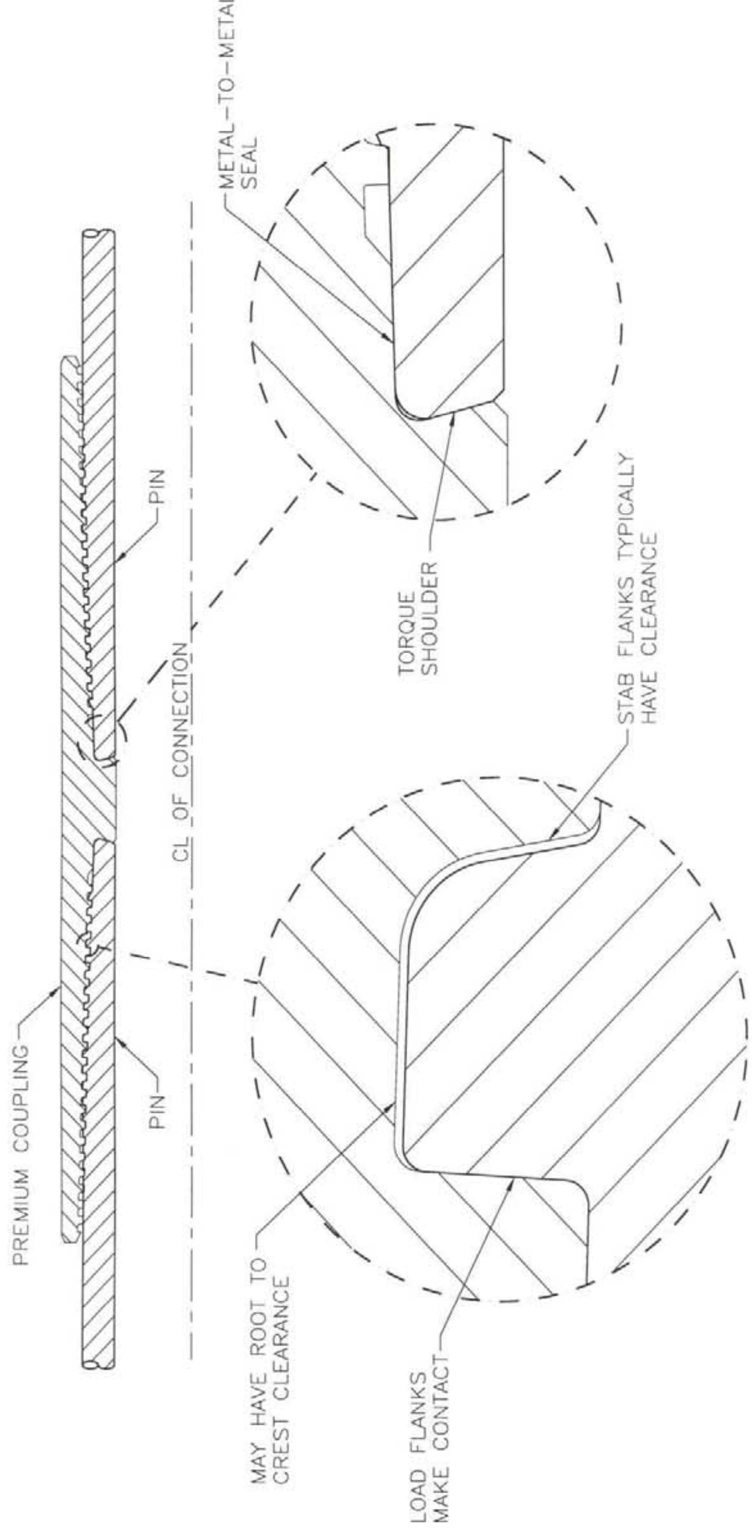
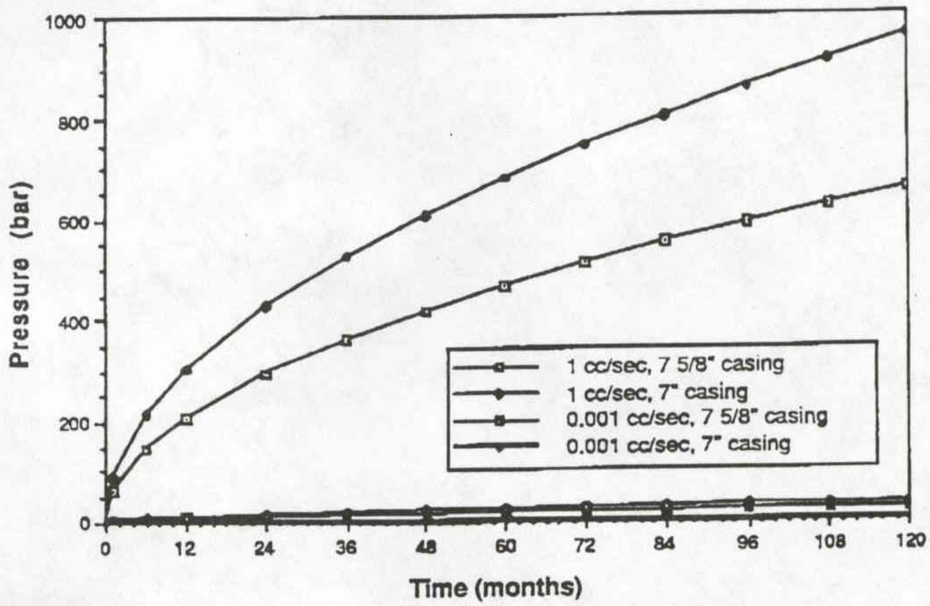


Figure 4: Typical Premium Tubing & Casing Connection



The calculation indicates that a leakage of 1 std cc/sec from one tubing connection would result in an unacceptable rate of pressure increase for both 7 5/8" and 7" casing. Leakage at a rate of 10^{-3} cc/sec would not be detectable in most cases. However, in the somewhat unlikely event that all 400 (pin-box) connections in a 3000m tubing string were leaking at this rate, the increase in annular pressure would be almost as rapid as that resulting from a 1 cc/sec leak from one connection.

Figure 5: Effect of leakage rates of 1 cc/sec and 0.001 cc/sec on the rate of increase of annular pressure

Appendix A, Attachments 1 through 13

Attachment 1
Production Tubular Testing Requirements for Miller Development

Attachment 2
STATOIL Technical Standard
Qualification Test Procedure for Premium Connection

Attachment 3
NAM TEO/3
Test Procedure for Tubing and Production Casing Connections

Attachment 4
ADC/SPE 23904
Evaluation of Premium Threaded Connections Using Finite-Element Analysis and Full-Scale Testing

Attachment 5
Agip S.p.A.
TEPR 708307 S 206

Attachment 6
Arco International Oil and Gas Company (AIOGC)
ARCO China, Yacheng Field Development
Performance Test Program for 7" 29lb/ft L80-13Cr NK3SB Premium Connection Production Tubulars

Attachment 7
Qualification of Coupled Premium Connections for Mobil Oil, Rev. 5.2, July 8, 1997

Attachment 8
API Recommended Practice 5C5, Second Edition, November 1996
Recommended Practice for Evaluation Procedures for Casing and Tubing Connections

Attachment 9
ISO TC 67/SC 5
Petroleum and natural gas industries – Testing procedures for casing and tubing connections – Recommended practice

Attachment 10
Industrial Sealing Technology
by H. Hugo Buchter
Excerpts from Chapter 1: Gaskets and Devices for Static Sealing

Attachment 11
Excerpts from Papers on Pressure Sealing Technology
Compiled for ARPTD JIP

Attachment 12
Journal of Petroleum Technology
Sealing Tubular Connections
by C. A. Bollfrass, SPE

Attachment 13
Articles Dealing with SCP Remediation

1. SPE Paper No. 23136

   "The Occurrence of Annulus Pressures in the North West Hutton Field: Problems and Solutions"

2. SPE Paper No. 24986

   "Through Tubing Remedial Treatments Using a Novel Epoxy Resin System"

3. SPE Paper No. 55996

   "Use of Pressure Activated Sealants to Cure Sources of Casing Pressure"

4. SPE Paper No. 59026

   "Leak Sealant in Hydraulic Systems Minimizes Maintenance Costs in Offshore Wells"

5. OTC Paper No. 11029

   "Sustained Casing Pressure in Offshore Producing Wells"

SECTION III: BASICS OF STRING DESIGN AND MORE ON SEALING TECHNOLOGY

1) Introduction

The intent of this section is to provide a practical discussion of SCP that results from downhole equipment malfunction and/or failures. The preparer of this section, Magnolia Global Energy (MGE), was asked to focus on components of the production string, other than the connections, that can (and do) sometimes cause leakage into or out of the primary annulus. This paper is a part of a composite document being prepared to address the causes, remedies, and issues of sustained casing pressure.

Beyond the scope of our paper is the risk associated with SCP. Every operator will have unique approaches to dealing with SCP and the assessment of risk. MGE recommends that further work be done to provide the framework for a uniform approach to risk assessment and the decision making process. Analysis, such as decision trees could be developed for the most common types of well construction equipment. Decisions on how to deal with SCP and equipment malfunctions often result in the decision to operate and maintain acceptable limits of SCP or well intervention to remove and replace or isolate the troubled equipment and leak sources.

This paper will describe the typical sources of SCP with regard to the more common well construction equipment. The well construction basis of design for tubulars and equipment vary in approach and operator protocol. Our experience is that most all GOM operators ascribe to the American Petroleum Institute's (API) product specifications as a "basis of design" in well construction. These include the more common specifications for wellhead/tree, subsurface safety valve, and tubular products.

A more thorough examination of the API product specs is offered in the section "Basis of design".

Product workmanship and materials, as well as wellsite operational techniques are all key variables to the issue of SCP.

2) Scope, Objectives, Approach

This paper provides a discussion on the issues of SCP as a result of equipment malfunction and/or failure; the end result being a leak path to the primary or secondary annuli.

2.1) Scope

Our discussion will be limited in scope to that equipment typically found in a Gulf of Mexico (GOM) producing well. Both near surface and downhole equipment are addressed. The basis of design for equipment is provided as found in both industry standards and the equipment manufacture's proprietary methods. In particular we have focused on the proprietary analytical methods to address internal/external pressure ratings for equipment capacity determination.

Elastomer materials are found through out the design of well construction equipment. The basis of design for equipment using elastomers as a pressure barrier is discussed further in the section "Basis of Design".

2.2) Objectives

The objective of this paper is to identify the potential sources of equipment leaks. By examining the basis of design for this equipment, an appreciation is gained as to the importance of design verification and validation prior to equipment installation.

2.3) Approach

We first met with principals of Stress Engineering Services to gain insight into the project objectives. Drawing upon our experience and reviewing the literature became the basis of our approach, with a focus on the analytical and design aspects of each equipment examined.

3) Annuli in the Well Construction Process

Oil and gas well construction involves design, materials, and operational aspects. Equipment and tubulars typically make up close to thirty percent of the authorized field expenditure (AFE) in the construction process. Equipment reliability is of paramount concern to the return on capital expended by the operator. Pressure integrity of the primary annulus is a function of:

- tubing and connections
- tubing hanger, connections, seals
- tubing head; hanger seal area
- downhole tubing accessories
- production head; hanger seal area
- production casing hanger, connection, seals
- production casing and connections
- production liner, connections
- production liner hanger equipment, connections, and sealing accessories
- production packer, connections, and sealing accessories

A host of downhole equipment can be used in the well construction process depending on production objectives. Several pieces of the equipment are illustrated in the accompanying pictorial.

By definition, an annulus is "the space between two concentric circles on a plane". For oilfield purposes, we will consider the annulus as the volume of space between tubulars sealed at the top and bottom. There are many potential leak paths in the annulus. Pressure integrity in the annulus is dependent upon:

- equipment design and function
- human competency during equipment installation
- tubular design and function- during drilling, completion and production
- tubular connection make-up
- tubular's running and handling
- primary cementing of annulus (where applicable)

Annulus mechanical integrity differs from pressure integrity. The physical loads imposed upon equipment and tubulars must be evaluated in the well construction design process.

Thermal expansion and contraction of tubulars and equipment during the life of the well produce pressure/loading variances, which can lead to abnormal pressures in the annuli. Often annular pressure buildup can be relieved by bleeding off operations at the wellhead. When or if the pressure returns the well is characterized with sustained casing pressure.

4) Basis of Design

In general, most oilfield equipment is designed by their manufacturers according to proprietary means. In a few commodities, industry standards exist such as API (American Petroleum Institute) product specifications that have been developed jointly among manufacturers and end-users. The use of these standards is optional by the manufacturer. API product standards, such as API 6A (wellhead and trees), 17D (subsea wellheads), 14A (subsurface safety valves), etc. have established safety (design) factors. Based on working stress design (WSD) these product specifications have established working pressure ratings which are less than the "test" pressure requirement; a safety factor such as 2.0:1.0 for wellhead /trees and 1.5:1.0 for subsurface safety valves.

It is well recognized among knowledgeable consumers that these safety factors are not based upon minimum material conditions (MMC). MMC represents the worst case manufacturing physicals, such as, minimum material strength and machined tolerances.

4.1) Connections

Equally important in consideration of the basis of design in oilfield equipment is the use of non-API connections, so-called proprietary and premium connections (thread form design). A common connection in downhole tools design is the API 8 and 10 rd EUE and buttress thread forms. Very often these same manufacturers will have to resort to the use of other thread forms in order to meet geometry limitations, such as "stub acme: with an elastomer 0-ring. The demonstrated performances of these non-API standard thread forms (e.g. proprietary) are left to the manufacturer, with safety factors being proprietary in nature.

4.2) Quality

API product specifications generally advocate certain minimum quality controls to ensure the basis of design has been demonstrated on production units; that is in the manufacturing cycle. The so-called non-standardized (e.g. non-API) products will have varying degrees of quality controls among manufacturers. Quality control is the "conformance to specifications". The specifications for design, materials, quality, etc., are usually found in the "quality plan" (or manufacturing inspections plan) generated by the manufacturer.

In attempting to meet API product specifications, a manufacturer attaches the appropriate API "monogram" (e.g. symbol of quality). The use of the monogram is entirely optional, and its use has been historically market driven by the major E & P companies. All too often the end-user is told that the "use of the monogram" will cost him more than if he were to accept the product without it. This is patently false. The prudent product manufacturer adheres to accepted industry practices and standards with regard to the documentation (e.g. so called paper trail) during process of manufacture. Thus, the applications of the "monogram"; the API licensing fee paid and quality audit having been met; costs nothing more.

4.3) Verification of Design Basis

API product specifications have established demonstration criteria (e.g. tests) as verifiable means to establish and record equipment performance ratings. These test criteria will vary according to the standard (product specifications) in terms of basis of design verification.

Pertinent to the study of oilfield equipment and sustained casing pressure (SCP), and with attention to wellhead components, the API 6A states, "casing hangers, tubing hangers, lock screws, and stems shall be designed to satisfy the manufacturer's documented performance characteristics and service conditions. (Ref. API 6A, 17th Edition, Nov. 1999, Sec. 4.3.2). The manufacturer shall specify methods to be used in design, which are consistent with accepted engineering practices".

We will revisit the subject of "accepted engineering practices" later in this section. API 6A further advocates the use of distortion energy theory method for design calculations for pressure containing equipment. "Rules for the consideration of discontinuities and stress concentrates are beyond the scope of the paragraph:" (ibid, Section 4.3.32) Upon examination of any oilfield equipment design, it is often discontinuity and/or stress concentration that can be attributed to a product's failure to meet its intended function. It is generally accepted that the higher the state of stress the lower the reliability. Mobil E & P Services Inc, (MEPSI) conducted a pilot study (1985-90) of equipment failures in the GOM over a five-year period. Failures were categorized by commodity and either design, material/workmanship, and/or human error. Over thirty five percent of equipment failures were attributable to design errors. It should also be pointed out that most of the recorded failures were in the non-API equipment variety. A Shell International E & P (The Hague) study by W. Wilhem, as presented to the ISO TC67 stated similar findings with 30% failures attributable to design aspects of oilfield equipment. In fact, it was this study and Shell's presence in the promotion of ISO equipment standardization that led to the formation of a work group (WG4) to address the development of accepted industry practices for design verification in the non-API equipment categories. Design verification methods and their use vary greatly in our industry among the manufacturing community.

Accepted alternatives to analytical design verification are empirical methods, i.e. physical testing. Common to most testing criteria is the use of test specimens manufactured at "as built" tolerances. One can appreciate that the inherent performance of any equipment is dependent upon its final geometric state and physical properties. It is reasonable that an end-user could expect to consume goods at minimum, nominal, or maximum manufacturing state. To test at minimum material conditions would be a costly and time consuming effort. However, some manufacturers do precisely that in their testing programs. Others achieve similar results by adjusting the test pressure conditions to compensate for "as built" tolerancing (e.g. API-RP-43, 6th Ed., Sec. III).

The API 6A specification for wellheads and christmas trees does not specify that test conditions be at any specified state; minimum, nominal, or maximum, with generous safety factors (i.e. 2.0:1.0 and 1.5:1.0) specified.

This issue of non-standardized products with propriety design verification methods should be of concern to the consumer attempting to characterize equipment performance.

Meeting the consumers intended well conditions may or may not be achievable in the products current design. Often safety factors do not address combined loading conditions. API 6A states “the effects of external loads on the assembly of components are not within the scope of this document” (ibid, Sept. 44.2.1c).

A good example of the relationship of combined pressure (load) and mechanical induced loading (tension/compression) is illustrated in the graphical representation of a production packer (see the figure in the appendix).

It is appreciated that external loading can affect the packer’s pressure rating. Much too often equipment ratings are advertised without the consumers full knowledge of the true performance limitations. This has been recognized in the new emerging International Standard for oilfield packer and plugs (ISO 14310) with a requirement that a “performance envelope” (e.g. graph) be furnished to the end-user by the manufacturer. This represents an industry first in standardization, as this data is to be included within the packaging of these products. The performance envelope is a graphical representation of the test results as specified in the “validation level”. The consumer can easily plot these loading conditions within or outside of the performance boundaries of the graph.

4.4) Elastomer Design

4.4.1) General Comments on Designing Elastomer Systems

Design of elastomeric sealing systems offers a unique technical opportunity. Polymer science is as intriguing as it is confusing. As engineers, we constantly seek a mathematic model to predict performance. A number of formulae have been used with questionable success. The state of the industry is that there exists no set of performance prediction equations that can be used to accurately predict the performance of an elastomer system operating under downhole tool conditions.

Unlike steel, engineers do not have analytic means to predict elastomer performance. This is true for simple single element packers as well as complex multi-element packing systems found in today’s packers. Elastomers are unique in their ability to simultaneously store and dissipate energy via characteristic large strain behavior.

Without digressing too far into the physics and chemistry of elastomers, the following discussion is needed to understand why elastomers work and why they fail. The primary structure of any polymer is a long-chain molecule. The typical elastomer has ”spaghetti” like structure with branch groups. Cross-linking (vulcanization) of two adjacent structures produces the three-dimensional structure. There is a relation between cross-link density and physical properties. Consider a random chain; fill the open spaces around the chain with numerous other random chains, then cross-link the chains to form a matrix. When deformed, the matrix behaves much as a deck of cards when one card slides. In a lightly strained mode, the deformed matrix has sufficient stored energy to return to its original state.

An elastomer is defined (by ASTM D1566) as "a macromolecular material, which at room temperature, is capable of recovering substantially in shape and size after removal of a deforming force."

ASTM D1566 defines rubber as "a material that is capable of recovering from large deformations quickly and forcibly ... (and which), in its modified state, free of diluents, retracts within one minute to less than 1.5 times its original length after being stretched at room temperature to twice its length and held for one minute before release."

Consequently, by these definitions, all rubbers are elastomers, but not all elastomers are rubbers. Further, some plastics qualify as elastomers.

4.4.2) Vulcanized, or Thermoset, Elastomers

- Vulcanized rubber is the most common sealing materials used in the oil industry.
- Prior to vulcanization, the long chained molecules (polymers) making up the rubber are tangled together, but not linked.
- Vulcanization introduces cross-links between the polymer chains yielding structural integrity to the material.

4.4.3) Thermoplastics (or Plastics)

- Thermoplastics are formed by building very long chains of organic polymer. The longer the chains, the heavier and stiffer become the thermoplastic.
- Thermoplastic materials are generally fabricated into their final shape by heating until the material is liquid, and then injecting it into a mold.

4.4.4) Performance Prediction/Design

Classical engineering design and analysis technique allow the straightforward design of structural parts manufactured from steel, iron, aluminum, alloys and plastics. With knowledge of the physical properties of the material, a reasonable prediction of the performance can be determined when the part is subjected to tensile, compressive, burst or collapse forces.

There does not presently exist a recognized, industry accepted, systematic approach to predicting the performance of elastomeric seals, even at ambient conditions, and when the physical properties of the elastomer are known. The process gets further complicated with the introduction of the environmental variables encountered in the oil industry, such as elevated temperatures, reactive fluids, gases, hydrocarbons, corrosion inhibitors, CO_2, and H_2S.

Because of these limitations, the best method to determine the suitability of an elastomeric seal is some form of **qualification testing** in its proposed configuration **at the rated temperature, pressure and environment.** A documented result of elastomeric testing, therefore, forms the basis of supplier confidence in the applicability of an elastomeric material and configuration for a particular use.

API **Bulletin** 6J "API Bulletin on Testing of Oilfield Elastomers - A Tutorial" was first issued in February 1992 and is a useful reference on this topic as is the guidelines for testing elastomers in API 6A Appendix F.

4.4.5) Elastomer Hardness

In the oil industry, elastomer hardness is measured on the Shore A Durometer scale. By definition, Durometer gauges are calibrated to read 100 Shore A when pressed against glass.

- Soft elastomers are generally considered to be 70D (Durometer) or lower.
- Hard elastomers are 90 Durometer and above.

4.4.6) Hardness Selection

As a rule, soft elastomers are used to achieve low pressure and low temperature sealing, with harder elastomers being used as the temperature and pressure rise.

- At lower temperatures and pressures, the elastomer needs to provide its own sealing energy (i.e. it needs to be resilient), and consequently a softer elastomer is used.
- Softer elastomers (< 70D) have comparatively lower physical property ratings (shear strength and modulus), so they are better suited for low-pressure applications.
- As temperature is elevated, elastomers soften with accompanying reductions in their physical properties. Consequently, harder elastomers with higher physical property ratings (shear strength and modulus) are preferred for higher temperature applications.
- As differential pressure increases, higher hardness and physical properties are needed to maintain seal integrity. The higher differential pressure also provides seal energy to the material, so that it can affect a seal.
- The harder elements need more compression to achieve a seal, and consequently are difficult to use with retrievable packers at shallow depths.
- Frequently, in seal stacks and multi Durometer packer element systems, a softer Durometer element (70 Durometer) is used in the center, with harder (90 Durometer) elements on each side of the softer element.
- At higher temperatures and pressures, plastics, Teflon and metals will often be used as backup rings to the seals and o-rings. Metal backup devices are frequently used as packer element backup systems on permanent packers.

4.4.7) Effect of Temperature and Pressure on Seals

4.4.7.1) Temperature

As temperature increases, elastomer mechanical strength decreases.

The modulus of most rubber compounds decreases as much as 90% from ambient temperature to temperature values of 250° F and higher.

As a result of these decreased properties, an elastomer is more susceptible at high temperature to:

- extrusion
- fluid/gas permeation
- blistering
- physical degradation
- abrasion or mechanical damage

At low temperatures, elastomers become stiff and brittle and may lose their sealing capability at their Glass Transition Temperature (Tg). Special elastomer formulations are, therefore, used for arctic conditions.

The following temperature classifications are generally recognized:

Standard:	0° F to 250° F

High Temperature:	250° F to 350° F
Very High Temperature:	> 350° F
Arctic:	-75° F to 180° F

Geothermal and steam injection equipment is rated to 650° F.

4.4.7.2) Pressure

The higher the pressure, the greater the likelihood of rubber extrusion taking place.

Extrusion potential also depends on the seal extrusion gap; elastomer type and strength (modulus); the design of the seal and accompanying tool; and the presence of backup materials or devices.

Increased pressure also causes increased fluid and gas permeation.

Four pressure regimes are generally recognized:

Low Pressure	< 2000 psi
Moderate Pressure	2000 - 5000 psi
High Pressure	5000 - 10000 psi
Very High Pressure	> 10000 psi

Gas permeation will cause blistering and general physical degradation when the applied pressure is released rapidly (especially with explosive decompression below 1000 PSI).

Very low differentials and varying differential directions also pose seal design and selection problems.

In defining the operating conditions for an elastomer, both the expected range of differential pressures and the maximum absolute pressure should be specified.

4.4.8) Effect of Chemical Environment on Seals

The chemical environment effects may include:

- chemical attack
- physical change
- short term or long term swelling
- increase/decrease in hardness
- increase/decrease in physical properties

The effects of short and long-term exposure, as well as the specific application, need to be considered.

The rate of change of specific seal material properties may be significant.

Implications of seal alteration will often depend on the specific application. For example, a material with long-term chemical stability but a rapid short-term swell could be detrimental in a seal bore configuration due to possible physical interference during stab-in (the small cross-section of the seals would add to the swell problem). Whereas, in packer applications, where there are large seal cross sections and larger gaps during run-in and setting, short term swell would not be such a problem. Further, if the application is static, as in a permanent packer,swelling is even less of a problem.

Of particular concern for elastomer selection are:

- Primary Hydrocarbon Type (Oil or Gas)
- Aromatic Oils
- Organic Solvents (Kerosene, Methanol, Trichloroethene, etc.)
- Corrosion Inhibitors, especially amines
- Hydrogen Sulfide (H_2S) (> 5% at temperatures < 200°F)
- Carbon Dioxide (CO2) (> 5%)
- Steam and Geothermal Brines
- High Density Brines, especially those containing Zinc and/or Bromide
- Acids and their associated inhibitors
- Scale Inhibitors
- Hydraulic Control Fluids
- Diesel Oil, especially Arctic Diesel

4.4.9) Effect of Seal Movement and Service Life

4.4.9.1) Seal Movement

Intended or expected seal movement can affect material selection; consideration must be given to whether the seal movement will be **static, intermittent, dynamic, or entirely dynamic.**

Static seals, such as packer elements on a permanent packer, are less affected by changes in physical properties than seals that move. Most permanent packer elements used in hostile environments are mechanically backed-up with continual energizing force, yielding little effect on sealing with changes in material physical properties.

An example of **intermittent seal movement** could be an O-ring in a standard O-ring groove. Quite often, these seals are subjected to pressure reversals or repeated pressure applications. These pressure reversals cause the O-ring to move from one side of the groove to the other. In this situation, elastomeric materials that do not retain resiliency and their original physical properties can eventually lose their sealing capability and start to leak.

An example **of dynamic seals** is the v-packing used on seal mandrels that are stabbed into polished bore receptacles (PBR's) or permanent packers. If the seal mandrel is allowed to "float," the seals need to continually provide their own initial sealing force. Of course, after initial sealing occurs, the hydraulic boost coming from the pressure differential will enhance the sealing capability of the v-packing.

Compression set can also affect sealability, particularly in the case of cyclic loading. Both material properties and the environment can affect compression set.

4.4.9.2) Service Life

The expected service life of an elastomeric seal is a prime elastomer selection consideration.

If the application is of short term, in the range of days or hours, the material selected does not necessarily need to have as high a chemical resistance as that of a seal that must withstand an environment for longer periods of time. A prime example is the use of Nitrile elastomers in low sour gas concentration applications at lower temperatures.

4.4.9.3) Shelf Life and Storage Procedures

Some elastomers, such as Nitrile, are very susceptible to storage degradation and have a limited shelf life. While others, such as some fluoroelastomers, may have a shelf life exceeding 20 years if properly stored.

Seal materials can be damaged prior to use by prolonged exposure to:

- UV radiation (e.g. sunlight)
- Ozone (e.g. produced by welding or high-voltage equipment)
- Excessive heat (> 100° F) in the store room
- Excessive cold (< 0°F) in the store room

Elastomers should be stored in proper packaging (e.g. a plastic bag or wrapping); in a cool warehouse if in sub-tropical areas, or a heated warehouse in sub-arctic areas; and away from high voltage equipment.

4.4.10) Selection and Testing of Elastomers

4.4.10.1) Seal Material and Configuration Selection

Seal selection involves developing the best compromise in material properties and configuration with consideration of the operating environment. The five criteria for seal material selection are:

- Temperature (handling; maximum and minimum operating)
- Pressure (maximum absolute; range of operating differentials)
- Chemical Environment
- Seal Movement
- Service Life

The information presented in **the "Elastomeric Guidelines Section " is a general guideline only** for the listed environments and applications. The engineer approving equipment with elastomeric seals needs to consider elastomer testing, engineering qualification, and quality control; and seek expert advice from an elastomer specialist.

4.4.10.2) Elastomer Testing, Engineering Qualification and Quality Control

Because of the limitations on theoretical design methods, some methodology needs to be followed to determine the suitability and assure performance of an elastomeric seal for a given set of conditions. To date, **the best method to assure performance is some form of qualification testing of the elastomeric part in its proposed configuration, exposed to the rated temperature, pressure, and environment.**

Documented results of elastomeric testing should form the basis for supplier confidence in the applicability of an elastomeric material and configuration for a particular use. Acceptable data can include environmental or life prediction testing for the elastomeric material, along with performance testing at temperature and pressure.

An identifiable path must exist from manufacture of the qualified compound to the seal being used in a Company application.

4.4.11) Standard Elastomers

4.4.11.1) Nitrile (Buna-N) Seals - Polybutadiene Acrylonitrile

Nitrile is the standard oil industry elastomer seal material for standard temperatures and little or no H_2S. Nitrile has a temperature limit of 250-275°F as an O-ring or v- packing, 275°F as a retrievable packer element and 300-325°F in a permanent packer element. Nitrile should not be exposed to bromide completion fluids at temperatures above 175°F.

Nitrile rubber is usually cured with sulfur, and consequently **becomes harder, losing elasticity, resiliency, and flexibility during exposure to H_2S.** This reaction is accelerated with higher temperatures and is time dependent, with the Nitrile seal getting progressively harder with continued H_2S exposure time. The eventual state and hardness of a Nitrile seal exposed to H_2S for a long period of time is often similar to that of glass. Nitrile, therefore, will function acceptably as a static seal, such as permanent packer, in sour environments, but is not acceptable in applications with movement or changing differential pressures. Nitrile retrievable packer elements will tolerate small amounts of H_2S (<5%) at temperatures below 200°F. A lesser degree of hardening can also be expected with some amine inhibitors.

Hard Nitrile rubbers (>90 D) are reasonably resistant to CO_2 impregnation. However, they cannot be used in shallow well retrievable packers. With softer Nitriles, high levels of CO_2 (>5%) cause blistering of seal materials during retrieval. Nitrile seals are, consequently, not recommended for use in shallow CO_2 injection wells.

Some Nitrile rubbers can exhibit severe swell when exposed to some highly aromatic oils, or during prolonged exposure to high concentrations of organic solvents. Severe swelling can pose problems with moving seals (such as in SSV's, sleeves, and slip joints), but is rarely a problem with packers. In these conditions, a composite seal stack can often be used to isolate the nitrile from direct contact with the oil or solvent; alternatively the seal area can be flushed after solvent treatments.

Swelling of Nitrile also occurs in bromide completion fluids at temperatures above 175°F.

4.4.11.2) Highly Saturated Nitrile (HSN) Seals

Highly saturated Nitrile, "HSN's," or hydrogenated Nitrile rubber, HNBR, have been presented to the oil industry as an answer to the continued search for a hostile environment, or severe service rubber. These claims have often been oversold. The published literature and the elastomer manufacturers' sales literature indicate with laboratory tests that HSN, or HNBR; has performance advantages over Nitrile rubber. The performance advantages stated are (35° to 80° F) higher temperature resistance; higher tensile properties; improved low temperature performance; and higher resistance to CO_2 and H_2S. **However, rubber processors and molders have difficulty molding with HSN because of its sensitivity to formulation and process variations; and molded products do not show the increased performance that had been expected under field use, or simulated field usage testing conditions. Often, the HSN materials will not perform mechanically as well as common generic Nitrile.**

When presented with the potential use of HSN or HNBR, it is recommended that the engineer examine documented test data looking for verifiable references in the proposed configuration. Also, the parts must be molded under strict quality control; a variation of mold temperature of 10 - 20°F can make the difference between a part that will perform acceptably and one that could fail.

4.4.11.3) Viton and Fluorel Seals - Fluoroelastomers

Viton and Fluorel are the prime high temperature (<350°F) sour gas elastomers.

However, the performance rating of these Fluoroelastomers in dry gas and water is not as good as that in oil. In gas service, an H_2S limit of 5%-15% is often applied at temperatures in excess of 250°F, unless a special formulation or a composite seal stack is used.

Fluoroelastomers are amine cured and consequently become harder with exposure to large quantities of amine-based inhibitors. This is the main problem with their use in gas wells where CO_2 corrosion is prevented with inhibitors. The primary risk is with small o-rings and v-packing rather than packer elements. Without the presence of inhibitors, their resistance to high pressure CO_2 is good at higher hardness levels. However, they are not suitable for use in CO_2 injection schemes.

Properly formulated, Fluoroelastomers have excellent resistance to organic fluids.

4.4.12) Premium and Special Service Elastomers

4.4.12.1) Application and Limitations

Premium elastomers are primarily used in high pressure and sour gas wells, generally classified by exploration companies as "hostile conditions."

With the exception of Kalrez and a more recent grade of Aflas, **the principal limitation of these premium elastomers has been sealing at temperatures below** 100°F. This sealing problem is especially pronounced **in low-pressure applications** where the seals are not energized with a significant pressure differential.

4.4.12.2) Aflas - Tetraflouroethylene-propylene copolymer

Aflas is used for high temperature (250°-400°F) sour service gas wells and high-pressure wells completed in bromide type fluids.

Aflas is a half-fluorinated elastomer, and is sometimes designated a "fluoroelastomer". Aflas has a greater heat and oil resistance than EPDM. Oil resistance is obtained from the polar tetraflouroethylene component.

To date, Aflas compounds have exhibited poor low temperature performance properties at 100°F and below. The material becomes less resilient at low temperatures and will have a tendency to leak. This shortcoming is particularly evident with low differential pressures. In applications where an Aflas seal needs to seal at both high and low temperatures, such as a production well with the possibility of fracturing or dynamic kill with lower temperature fluids, it is suggested that a representative seal be tested simulating the expected service conditions. To get around this problem, the service company might use one stack of v-seals that include some Kalrez v-rings as a contingency for possible low temperature transients.

In the early 1990's, there were some developments on a grade of Aflas with improved low temperature properties. The engineer is encouraged to inquire whether the material being used is of the low temperature resistant variety and to request verifiable evidence of the claimed performance.

4.4.12.3) Kalrez - Tetraflouroethylene-perfluorovinylmethylether (sometimes designated a "perfluoroelastomer")

Kalrez is used for very high temperature applications (550°F) and sour crude service.

Kalrez has the best overall heat and fluid resistance of any elastomer presently available. The fact that it is difficult to mold in thick cross sections and is very costly limits its use to O-rings and v-rings in seal stacks.

4.4.12.4) Epichlorohydrin

Epichlorohydrin has low resilience and moderate tensile strength, but has good resistance to swelling from oil, intermediate temperature resistance, and low permeability to gases, including CO_2. At standard temperature ranges, up to 250°F, and low levels of H_2S, **it is the elastomer of choice for low pressure, shallow CO2 injection wells.** Special testing is recommended in cases where amine inhibitors are being used.

4.4.12.5) EPDM - Ethylene Propylene Diene Monomer

EPDM has a broad chemical resistance, as well as being resistant to exposure to heat, oxidation, ozone and bromide completion fluids but **swells severely in crude oil and diesel.** EPDM has very little interaction with methane, even at high temperatures. Consequently, **EPDM can be used in dry gas wells with little or no condensate and in continuous steam injection wells with steam temperatures below** 550 °F. It is also commonly used as an insulator in ESP cables, especially in ESP wells completed with a packer.

4.4.13) Thermoplastics and Composite Seal Stacks

4.4.13.1) Ryton - Polypheynylene Sulfide

Ryton is a crystalline, high performance thermoplastic with very high heat resistance, heat stability and chemical resistance. The amount of crystallinity can be controlled in the manufacturing process that in turn can control the hardness of the material. Ryton has excellent chemical resistance over a wide range of temperatures, and has no known solvent below 400°F. Ryton has excellent thermal stability at temperatures of 400°F to 450°F depending upon the material grade. Various grades of Ryton are available with varying levels of glass reinforcement, as well as mineral and carbon fiber filled grades.

A softer form of Ryton is used as a premium seal in vee-ring seal stacks; and harder grades of Ryton, and glass reinforced Ryton, are used as backup rings.

4.4.13.2) PEEK - Polyetherertherketone

PEEK is a high temperature, crystalline thermoplastic with very high heat resistance, and resistance to organic solvents, dynamic fatigue, and short-term heat aging. PEEK has a resistance to attack over a wide pH range ranging from 60% sulfuric acid to 40% sodium hydroxide at elevated temperatures. PEEK has shown long term stability of up to 50,000 hours at 475°F, and has shown good resistance to water environments at temperatures to 500°F. On a short-term basis, PEEK is suitable for service temperatures of up to 570°F. PEEK is available in the non-reinforced state, 20 and 30% glass fiber reinforced, and 30% carbon fiber reinforced.

PEEK is most commonly used for backup rings for o-rings and in v-ring seal stacks. PEEK is routinely used in highly aggressive hostile environments with high concentrations of H_2S and CO_2.

4.4.13.3) Teflon

Teflon is the primary sealing material for very high temperatures (T> 500°F). It is also used extensively as a backup ring for softer elastomers.

For the higher temperature service and higher strength applications, Teflon is reinforced with glass fiber. The amount of reinforcement commonly used will start at a minimum of 15% and may go up to 40% by weight of glass fiber.

Teflon, with or without glass reinforcement, has very little resilience and has a tendency to creep (more so without reinforcement); therefore, Teflon seals need very small extrusion gaps, and are often provided with metal backup rings. Because of its lack of resilience, Teflon will have a greater tendency to leak due to small defects in the mating sealing surface when used as a seal. Sometimes the leak-causing defects are difficult to detect by visual examination. Teflon seals are generally replaced if pulled from the well (e.g. a retrievable steam packer is redressed after each run).

4.4.13.4) Composite Seal Stacks

Seal assemblies for permanent packers and PBR's will often use a combination of the above elastomers and plastics to achieve a wide range of operating conditions.

Temperature Limits (° F)

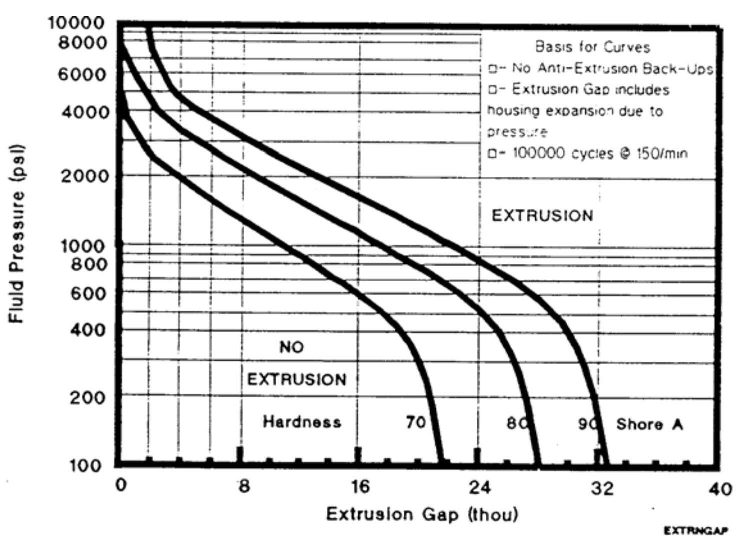
		Oil	**Gas**	**Steam**
NTR	Nitrile Teflon Ryton	250	175	N/A
VTR	Viton Teflon Ryton	350	250	N/A
ATR	Aflas Teflon Ryton	400	375	450
ATP	Aflas Teflon PEEK	450	400	450
RTR	Ryton Teflon Ryton	450	450	450
KTR	Kalrez Teflon Ryton	450	375	550
KTP	Kalrez Teflon PEEK	550	450	550
TMM	Teflon Metal to Metal	650	650	650
KTM	Kalrez Teflon Metal to Metal	550	500	650

4.4.14) Elastomer Failure Mechanisms

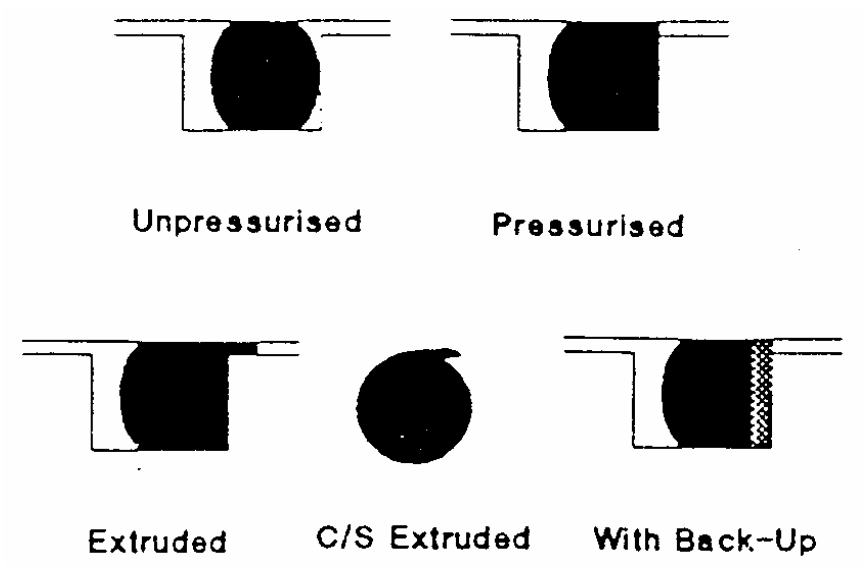
This section outlines some of the failure modes that can occur in seals, how they are caused and how they can be corrected to prevent future failures.

4.4.14.1) Extrusion Damage

The pressure ranges, given in the extrusion diagram below, show allowable pressures for various degrees of elastomer hardness. Increased temperature reduces hardness and these data refer to the hardness maintained at the operating temperature.



In it's housing before pressurizing, an unsupported seal sits slightly deformed between the gland and sealing surface. On pressurizing (100 - 1500 PSI), the seal acts like an incompressible fluid, exerting a pressure on the gland proportional to the system pressure and so forms a closure. At higher pressures (1500-3000psi), if the system pressure exceeds the seal strength, then a small volume of material will be forced into the clearance gap and may be cut off by the retracting low-pressure side of the O-ring trying to resist the tendency of the O-ring to extrude into the clearance gap. Seal failure and leakage follows rapidly.



Extrusion is characterized by a "peeling" or "nibbling" of the O-ring surface and is the most common cause of O-ring failure

This type of failure is exaggerated in dynamic applications where material is clamped in the clearance gap and sheared off completely. However, it must be remembered that in static applications extrusion will occur at high pressures and is accentuated when pressures fluctuate and the seal housing components stretch under load.

Using modulus values at 100 percent elongation may compare resistance to extrusion for differing materials. Alternately, hardness may be used to select appropriate maximum pressure levels.

For pressures above 1500-3000 PSI in critical applications, back up rings should be used. T-seals and V-seals always have back up rings associated with them and extrusion is not such a problem as with unsupported O-rings.

Causes of Extrusion Failure:

- unnecessarily large clearances
- high pressure
- soft seal material
- physical or chemical changes which weaken/soften seal

- eccentricity. sharp edges on seal gland
- wrong size seal

Corrective Action:

- tighten tolerances
- use a back-up ring
- increase seal material hardness
- check medium compatibility
- prevent eccentricity
- strengthen machine parts to prevent "breathing"
- gland radii from 0.10 to 0.40 mm
- select T-seal or V-seal geometry with suitable back up

4.4.14.2) Compression Set Failure

Compression set, the partial or total loss of elastic memory of an elastomer, is a common failure mode. It is characterized by a double sided flattening of a seal (radial or axial according to application) and can be clearly seen after disassembly.

The problem is usually caused by selection of the wrong compound. The elasticity of a seal depends not only on the formulation, but also on the working temperature, type and length of deformation and aging caused by a medium e.g. air, steam, acid, petroleum etc.

Compression set damage can be described as the loss of cross-link sites between the molecular chains or as the creation of new sites, brought about by temperature or chemical changes.

Compression set damage clearly visible at low temperatures is generally reversible and at higher temperatures the elasticity may return to affect a seal again.

The causes of high temperature compression set and loss in sealing power are connected and can be described as follows:

Causes of Compression Set Failure:

- seal compound has poor compression set
- wrong gland dimensions
- working temperature higher than expected
- higher deformation through tight gland area

Corrective Actions:

- select elastomer with low compression set
- select elastomer according to working conditions

- reduce system temperature at seal
- check compatibility of seal with environment
- use correct gland dimensions

4.4.14.3) Explosive Decompression Damage

Under high pressure, gases will diffuse into elastomers. On rapid decompression the absorbed gases expand quickly causing high levels of internal stress, which may cause internal rupture and blistering to occur on the sealing surface. A seal may also swell on decompression but with time may return to its original shape without leaving any external evidence of decompression damage. This is potentially dangerous since it has been noted that serious internal fissures can be present, but remain undetected, which will affect the sealing performance.

This problem may be solved or at least reduced in the following ways:

- lengthen the time for decompression
- reduce working pressure at seal
- design for smaller seal cross-section
- select a seal material with higher strength, higher modulus and higher hardness
- use specially compounded grades having known resistance to explosive decompression

Blister damage has been reported for a wide range of elastomers under hydrocarbon duties, particularly under gas alone but also in gas/oil mixtures. The presence of carbon dioxide and hydrogen sulphide are especially prone to causing problems on rapid decompression (they are both easily liquefiable gases and have solubility limits approaching those of the elastomer seal materials).

4.4.14.4) Wear Failure

Wear is probably the most understandable form of seal failure in dynamic seals. In this type of failure, which is typified by a flattening on one side of the seal only, it is important to note that friction is proportional to deformation, and that applied pressure and wear are proportional to friction and further, that the temperature increase of the seal is proportional to friction.

The seal parameters must be considered along with the medium to achieve an optimum compromise. In a static application, damage through wear is caused by pulsating pressure, which induces the seal to abrade on relatively rough surfaces or edges of the gland.

Causes of Wear Failure:

- incorrect surface finish
- poor lubrication
- high temperature
- too high a deformation
- impurities in system fluid

- high or pulsating pressure

Corrective Actions:

- correct surface finish
- use a hard coated surface
- select an improved machining process
- change system fluid to one with better lubricity
- select a compound with higher wear resistance e.g. PTFE
- select a material with internal lubrication or design lubrication pockets
- clean system and filter fluid

4.4.14.5) Chemical Degradation

Chemical degradation depends on a number of factors, which include temperature, concentration, and duration of exposure. Mechanical properties of a seal material can be seriously changed by a chemical reaction. The timescale for the change is ultimately a function of the severity of service conditions and may be slowly progressive to catastrophically fast.

Two different processes can occur when a seal is exposed to chemical environment:

1. **Bond Scission** - results in chemical bonds being broken in the elastomer causing softening, weakness and a gummy seal material.
2. **Cross linking** - results in bond formation causing a harder, more brittle, often cracked or crazed seal. The elastic properties are lost often beyond a point where the seal ceases to function. Leak paths through a cracked seal can lead to failure.

The effects of chemicals may lead to competing reactions occurring simultaneously and a simple swelling reaction may eventually turn into one of contraction where absorption is overtaken by the dissolution of particular components.

The effect of increased temperature will be to speed up the reaction rates, but more than this the mechanical properties of an elastomer are normally reduced with increasing temperature so it is important to select materials with both sufficiently high chemical and thermal resistance.

4.4.14.6) Assembly Failure

Even if all the above hints and rules are observed, failure can still occur due to poor workmanship practices adopted on assembly of the seal into its housing. A seal is a precision product and should be treated with respect. Careful assembly will repay the user in trouble free operation. The alternative is an expensive and possibly dangerous failure.

Causes of Assembly Failures:

- using undersized seal
- twisting, cutting or shearing of seal

- assembly without the correct tool
- assembly without lubrication (care - compatibility)
- assembly in dirty conditions

<u>Corrective Action</u>:

- breaking all sharp edges
- leading edge chamfer of between 15 to 20 degrees
- cleanliness
- check seal size before assembly
- assembly as a stack of seals where possible

4.4.15) Practical Guidelines with Elastomers (Do's &, Don'ts, Rules of Thumb)

1. If you have a problem, define service history and material and ask for help (Company engineering group or the Supplier).
2. The effect of a chemical reaction doubles for every 20°F temp rise so watch out for high temps. The lifetime roughly doubles for every 20°F drop.
3. Do make sure that the upper temp is within the capability of the seal material.
4. The seal material must be compatible with the fluid environments or the design afford the best shield to the seal to protect the elastomer from chemical exposure.
5. Don't use Zinc Bromide (ZnBr) brine with Nitriles. It causes severe hardening.
6. Nitrile packers may be less affected in amines than other types of seal geometry simply because of the large bulky nature of packer elements.
7. Methanol can affect Vitons, use Aflas or nitrile if possible.
8. Don't use EPDM where hydrocarbons are present.
9. For really aggressive hot, sour conditions - best bet is the expensive Kalrez (to 260°C) or Chemraz (20% cheaper better properties over -20° to 230°C).
10. Pressure level dictates mechanical properties required.
11. Critical Pressure for blistering is $Pb \sim 5E/6$ where $E \sim$ Youngs Modulus (at service temperature).
12. Critical Pressure for Rupture is $Pr = 4(Lb*Sb)/3$ where Lb = extension ratio at break (length of stretched material per unit initial length), $Sb \sim$ stress at break (at service temperature).
13. Think whether there is likely to be gas dissolved into the seal, which may be subjected to rapid decompression; there are special grades with improved decompression resistance.
14. Seal stacks form good solutions to wide ranging service. They allow use of varying hardness or differing materials in the stack and the outer rings may be sacrificial for the sake of the main inner seal.
15. Do not pull seal stacks from a seal bore under pressure, the last seal will suffer decompression damage. If the seal is then reinserted, the damaged seals may roll or break off causing yet further damage to the other seals following into the bore.

16. Ryton is relatively brittle compared with PEEK or reinforced Teflon. Fracture debris could cause tearing in the elastomer seal, especially in the less mechanical strong Kalrez & Chemraz perfluoroelastomers. Use PEEK or Teflon in preference to Ryton.
17. Cyclic temperatures could cause *loss* of sealing by compression set especially at lower temperatures near to the Glass Transition temperature. Aflas is prone to this.
18. Increase in molecular weight and cross-link density improves the tensile strength, elongation, modulus and compression set. Hardness can be improved by increasing cross-link density and/or by using certain fillers, thus specifying hardness alone will not necessarily give good extrusion resistance at elevated temperature. Tensile modulus should also be included in the specification.
19. $C0_2$ and H_2S often occur together. $C0_2$ has no chemical effect on elastomers but is more soluble in fluoroelastomers than in nitrites, it may also be easily compressed and can give rise to decompression damage in seals. H_2S can affect elastomers chemically by acting as a curing agent which causes embrittlement**.** It also is easily compressible and may lead to decompression damage.
20. Seal swell in highly aromatic asphaltene dissolving solvents may cause sealing problems in Aflas and Vitons.

4.5) Performance Verification Test Procedure:

4.5.1) General Comments

As consultants, we have the opportunity to witness a wide variety of tests and test methods. We have also witnessed the ruin of many a test for lack of proper planning and record keeping. The intent of this discussion is to outline the elements of what would be considered an ideal test. Much of the procedural information comes from API 6A Appendix F Testing for Wellheads and Trees.

While conducting a test in this manner may seem overly concerned with minutia, the result is well worth the effort. The intent is to assure the client gets the most value for his test dollar, and results reported in a way that would pass scrutiny from the most demanding customer or regulatory body.

At the beginning of every test program, there is a product and an application for which the product is to be qualified. Based on this information, test objectives should be clearly and concisely stated, as well as their relation to operating or rated conditions. If there are specific API or regulatory requirements, those should be identified. If the specimen and fixture, or components such as casing, require full traceability, that requirement should be stated. Another often-overlooked objective is the requirement for instrumentation and accuracy. To achieve the objective, certain data must be measured and recorded. Parameters to be measured, their range, and accuracy should be clearly stated.

Criteria should be established for acceptance or rejection (pass or fail) of the specimen. Recorded values rarely result in *perfectly flat* pressure traces to indicate no leakage. For objective results, criteria should be capable of being measured; for subjective results, the method of documentation (such as photograph) should be stated.

In many cases, it is not practical to manufacture test specimens to actual production conditions. Long seal bores and long strings of tubing or casing are often not practical when designing test fixtures. Specimens should contain all critical components of the production piece and be compatible with the test fixture. Fixture design should allow application of test parameters, such as heat, pressure and load, in the same manner as production operations.

Special consideration should be given to evaluation of fixture-induced loads in the specimen. Closed end containers introduce high axial loads that may not represent actual operating conditions. All loads, induced and applied must be taken into consideration at this point.

Once we have the specimen and fixture defined, a comprehensive test procedure should be written. This document will include a step-by-step list of exactly what operations are to be performed and in what order. An example of an inadequate step would *be "Pressure down tubing to set the packer".* More accurately stated, the procedure would state, *"While allowing tubing to move in the axial direction, and with upper and lower annulus ports open, increase tubing pressure to X PSI and hold five minutes; increase tubing pressure to Y PSI to shear ball seat. If ball seat does not shear, increase to Z PSI, release pressure, and rotate out taking right hand torque. Expect three shear events at D, E, and F PSI."* Stated in this manner, packer setting procedure is clearly and concisely defined. Quality is defined as conformance to specification. In the case of performing a product test, the specification is the procedure.

Once the procedure is defined, design of the test specimen and fixture should be reviewed to assure all test steps could be performed (are sufficient ports available in the fixture, does the fixture allow for axial movement of the tubing). Instrumentation should be reviewed to assure proper ports or connections are provided and that the acceptance or rejection criteria are properly instrumented. Instruments are assigned (by serial number) and an instrumentation plan recorded for traceability.

At this point, we are ready to manufacture the test specimen and fixture. During this process, care should be taken to characterize each component under test. Ideal conditions would find test components manufactured of material at the minimum physical property and dimension. If minimum material and physical property conditions cannot be met, testing should be done to equivalent stress levels as defined in API 6A. To adequately characterize the specimen, material certification and physical dimension (compared to print dimension) should be recorded and included with the test report. From evaluating existing product tests, the most common fault is incomplete characterization of the product being tested. If you don't know *what* you tested, the entire test can be considered invalid. Test fixtures are often exempt for this requirement, however casing should always be identified.

When both specimen and fixture manufacturing is complete, all should be shipped to arrive at the test facility at least one week prior to the onset of testing. This allows for review of documentation and assured adequate time to address "fit" problems. It also allows the test company time to have everything ready to test on the designated test day.

Rigging the test occurs from one day to one week prior to testing. Heat systems are rigged, connections are located, cleaned and dressed, and select test facility equipment prepared for operation. Heat systems are often brought to temperature (without the specimen), pumps primed, hoses flushed, and instruments checked out prior to test day.

On test day, the procedure is performed as written. Should the test not proceed as planned (stated in the procedure), each operation must be documented and time stamped. It is imperative to record observations (seen or heard) and decisions as they occur. Should there be an occurrence that prematurely ends the test, acceptance or rejection criteria establish whether the test is valid; for example a performance test to 10,000-PSI (acceptance criteria) passes while a subsequent pressure test to 12,000-PSI results in a leak.

4.5.2) Test Reports

Upon completion of the procedure, raw data from the manufacturing, quality and test are gathered into a written report. While good test reports contain a wide variety of data and are written in a variety of formats, there are basic ingredients that must be present. In the most comprehensive test, additional data should be present. While this list may seem like a repeat of requirements previously covered, this list includes the method by which they should be documented.

4.5.2.1) Purpose of the test

What specific requirement will completing this test satisfy, state clearly and concisely.

4.5.2.2) What was tested

The test specimen should be accurately and completely identified, to the point that no other product could be confused with this particular product. Again, failure to meet this requirement is the primary reason existing tests are not accepted.

4.5.2.3) Test procedure

What was done, step-by-step, using the test specimen to achieve the objective. This would include test conditions of temperature, pressure, load, fluid, flow rate, etc.. Steps should be specific as to what was done and in what order; for example, if pressure and load were to be increased, which was increased first and which was decreased first? In conjunction, a test report would list the actual steps performed as opposed to those of the procedure (they may or may not be identical).

4.5.2.4) Test fixture and equipment used to perform the test

In order to evaluate test results, we have to know something about the equipment used to perform the test. A comprehensive list of equipment and instrumentation used to perform the test steps listed above should be included. The test fixture may have consisted of a joint of casing, however a much larger assembly of test equipment was required to perform the entire test. There may have been a heating system that applied heat in a specific manner. Method of heating and method of temperature measurement and control should be included. Application of load and pressure can be handled in much the same manner, considering how loads were applied and at what rate. Instrumentation used in data gathering should be identified. Certain instruments were used in obtaining test results. It is important to identify what kind of instruments were used in data gathering. It is preferred to present data in “hard copy” format in the form of strip chart recordings. Personal observation of quantitative data is not recommended. The charting instrument should be identified.

4.5.2.5) Acceptance or rejection criteria

Statement of qualitative or quantitative criteria used to determine if the test was a success or failure. When qualitative criteria are specified, visual documentation, such as photo or video, must be supplied as evidence.

4.5.2.6) Test data (objective)

Usually found in the form of strip charts or tabular data from a computer based data acquisition system. Data should be presented in a manner that clearly verifies compliance to the test procedure. All anomalies (such as a pump that lost prime, or a line failure) should be recorded and noted. All occurrences, whether part of the procedure or not, are part of the test.

4.5.2.7) Test data (subjective)

Photographs best convey subjective results. Whether an elastomer or a slip is damaged is a subjective judgment and can only be documented by visual means. Photographs are preferable to video as they are a more permanent means of documentation, and personal observations are subjective in themselves.

4.5.2.8) Supporting data

This category is optional and contains data about the test facility, test specimen, and/or test fixture. Material certification and quality inspection data would be included.

Following completion of the test, specimens should be labeled and stored to preclude disruption of test evidence. Both the specimen and the report should be readily available and easily retrievable.

As stated at the beginning of this article, this is an ideal test. Should the test be conducted in this manner, results should satisfy any customer or regulatory body. There are instances when the customer or the testing party does not require this level of documentation.

4.6) Engineering Design Practices:

4.6.1) General Comments on Stress in Pressure Vessels

The main purpose of a pressure vessel is to contain fluid under conditions of pressure, temperature, and applied load. In doing so, they are subjected to the action of steady and dynamic support loads, tubing reactions, thermal shocks, and a host of other outside influences. To accurately predict performance, an overall knowledge of the stresses imposed by these conditions on various component shapes is required.

Two basic configurations of a cylindrical component are considered. When components have walls that are “thin” in relation to other dimensions (particularly diameter), the wall offers little resistance to bending perpendicular to its surface. The wall is considered a “membrane” and features essentially no stress gradient through the wall. When the wall is “thick” in relation to other dimensions, the variation in stress between the inner and outer surface becomes appreciable. Even though wall thickness may seem small in relation to diameter, downhole tools almost always fall into the latter category.

In the case of a cylindrical vessel under internal pressure, both radial and tangential stresses are maximum at the inner surface. Radial stress is always compressive and equal to the applied or induced pressure, and tangential stress is always tensile. Tangential stress is always numerically greater than internal pressure at the inner fiber. Tangential stress at the outer fiber is less than that at the inner fiber by the amount of applied or induced internal pressure. Shear stress is maximum at the inner fiber and correlates well with the actual rupture of thick cylinders.

In the case of a cylindrical vessel under external pressure, both radial and tangential stresses are compressive at the inner fiber with tangential stress numerically greater. Maximum tangential stress occurs at the inside fiber while maximum radial stress is present at the outer fiber.

4.6.2) Collapse

4.6.2.1) Mechanism of Collapse

Collapse pressure prediction is the most difficult and least understood calculation for tubulars. Collapse tends to be an *instability* failure, meaning that the onset of collapse and complete failure in collapse often occur at almost the same load. Collapse failure prediction is not unlike buckling failure prediction in this sense.

Collapse of tubulars results from either tangential stress exceeding material strength (referred to as yield-strength collapse) or geometric instability (elastic collapse). Different equations govern the calculation of collapse for different mechanisms. Yield strength collapse applies when the D/t (outside diameter divided by wall thickness) ratio is small (small diameter, thick walled tubes). Elastic collapse applies for higher D/t ratio (larger diameter, thin walled tubes). There are additional geometric constraints that govern the analysis of tubulars in collapse.

Almost all (unless specified otherwise) formulae for collapse pressure prediction assume an infinitely long tube. In engineering terms, this means the section under analysis is long enough such that anything “happening” at either end of that section does not materially contribute to change the section’s propensity to collapse. In the case of some equipment used in completions, this criterion has *not* been met. A basic criterion for a short section is length less than seven times outside diameter. Short sections are more resistant to collapse than long sections.

Classic collapse theory (the basis for classic formulae) assumes no radial support about the collapsing section. In order to collapse, the cross section of the tube collapses inward, significantly decreasing the inside diameter at the collapsed section. Perpendicular to the decrease in diameter, there is an increase in outside diameter. Any support about the inside or outside of the tube tends to increase collapse resistance (prevent the section from collapsing). In the case of most completion equipment, there is radial support outside the component (casing) and possibly inside the component (seal assembly) when performing the collapse analysis.

To complicate the analysis, most equipment features a short-section analysis at the bottom of the section under scrutiny followed by a composite section. The mechanism for this specific collapse is complex and is *not* described in classic theory.

Most classic collapse theory defines the condition of two-lobe collapse, resulting in the familiar “smiling face” cross-section of the collapsed section. When some means of support is provided, results may show multiple-lobe collapse. If a TBR collapses about a seal nipple, and the nipple does not collapse, we may see this phenomenon.

4.6.2.2) Collapse Pressure Calculation

The assumption that a completion equipment manufacturer uses an improper or incorrect formula for collapse pressure prediction implies there is a proper and correct formula. There are a number of collapse prediction formulae circulating the engineering community. What's confusing for the engineer is the variance in predicted collapse pressure using these formulae.

The following is a brief discussion of collapse pressure prediction as presented by the API (American Petroleum Institute), SPE (Society of Petroleum Engineers), and a consortium of industry specialists.

4.6.2.3) API Bulletin 5C3 Collapse Formulae

Most widely used collapse prediction formulae can be found in the API Bulletin 5C3 ***Bulletin on Performance and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties*** (5^{th} Ed.). The key phrase in the bulletin title is "Casing, Tubing, Drill Pipe and Line Pipe" and the admonition on the introduction page that the document is intended to supplement rather than replace individual engineering judgment. There is also a phrase found in the foreword (p.3 c.) that states "API bulletins are published to provide information for which there is a broad industry need but which does not constitute either Specifications or Recommended Practices". Four distinct minimum collapse pressures are calculated as follows:

1. *Yield Strength Collapse:* not a true collapse, but rather that value of external pressure that results in yield stress at the inside wall of the tube. Derived from theoretical analysis. Experimental results indicated this formula to be somewhat conservative, however it was thought unsafe to use a pressure exceeding the value that would cause yield at the inner wall. Basis for this formula is the Lame formula.
2. *Plastic Collapse:* Derived empirically from 2488 collapse tests on K55, N80, and P110. Formulae developed from the modified elastic collapse formulae.
3. *Transition Collapse:* Determined on an arbitrary basis. Formulae developed from the modified elastic collapse formulae. Curves for plastic and elastic collapse pressure (plotted against D/t) do not intersect until pressure falls below the minimum elastic collapse value. Transition collapse was developed to overcome this anomaly.
4. *Elastic Collapse*: Derived from theoretical analysis by W.O. Clinedinst for the API.

API 5C3 collapse pressure is determined by choosing the appropriate formula based on D/t for the tubular under analysis.

API 5C3 has been the standard of the industry for calculating collapse pressure. If your equipment operates at pressure at or less than the calculated API 5C3 collapse pressure, it's extremely unlikely your product will ever collapse. Calculations using the 5C3 formulae are shown (see appendix) to be quite conservative when compared to other methods. API 5C3 identifies performance "modifiers" that effect calculated collapse pressure. The addition of compressive load increases collapse resistance as defined in equation 1.1.5.1. There is also a modifier for the presence of internal along with external pressure as defined by equation 1.1.6.1.

4.6.2.4) Other Collapse Design Methods

In 1993, an SPE paper, ***An Improved Design Equation for Tubular Collapse,*** was presented by Issa (Exxon) and Crawford (Stanford Univ.) with an improved method of evaluating tubular collapse. A collapsing tubular is a system governed by a large number of highly non-linear equations resulting from large displacements and material non-linearity. The basis for their formulae is a large number of non-linear finite element analyses using different geometric tolerances and mechanical properties. Full scale testing was conducted to verify results of the FEA, both for magnitude and tubular shape. Testing verified FEA within 6%, a value judged to be acceptable due to assumptions made concerning material properties.

In May 1998, Shell hosted an SPE Applied Technology Workshop at their facility in The Woodlands on the subject of ***Risk Based Design of Casing and Tubing***. Risk based design assumes there is a statistical distribution of known loads and a similar distribution of load capacity. These distributions can be noted by two "bell curves" with probability density on the y-axis and load on the x-axis. The two curves intersect to form an area defined as probability of failure. The concept of "risk based" design assumes an acceptable level of probability of failure.

At this workshop, it was recognized that the API 5C3 formulae are in need of examination and update. There were a number of technical papers presented on the subject of collapse listed below:

- *On the Development of Reliability-based Design Rules for Casing Collapse*
- *Determination of Casing and Tubing Burst and Collapse Design factors to Achieve Target Level of Risk, Including Influence of Mill Source*
- *A Reliability Approach to the Design of OCTG Tubulars Against Collapse*
- *Collapse Behavior of Casings: Measurement Techniques, Numerical Analysis and Full Scale Testing*

The papers listed above provide a qualitative as well as quantitative approach to the subject of collapse. Remember that the topic of the group was *risk-based* design of tubulars. Formulae presented in these papers have not been "generally accepted" by the engineering community. Diversity of approach and result is presented to show that there is no single correct equation for the prediction of collapse pressure in a simple joint of casing. Remember that these papers attempt to define collapse for a mill-finish joint of casing and not a short, supported, machined piece.

4.6.3) Burst

4.6.3.1) Mechanism of Internal Pressure Failure

There have been a multitude of formulae used or proposed for establishing internal pressure performance. These have ranged from entirely empirical to completely theoretical based on theories of plasticity and true strain behavior of the material.

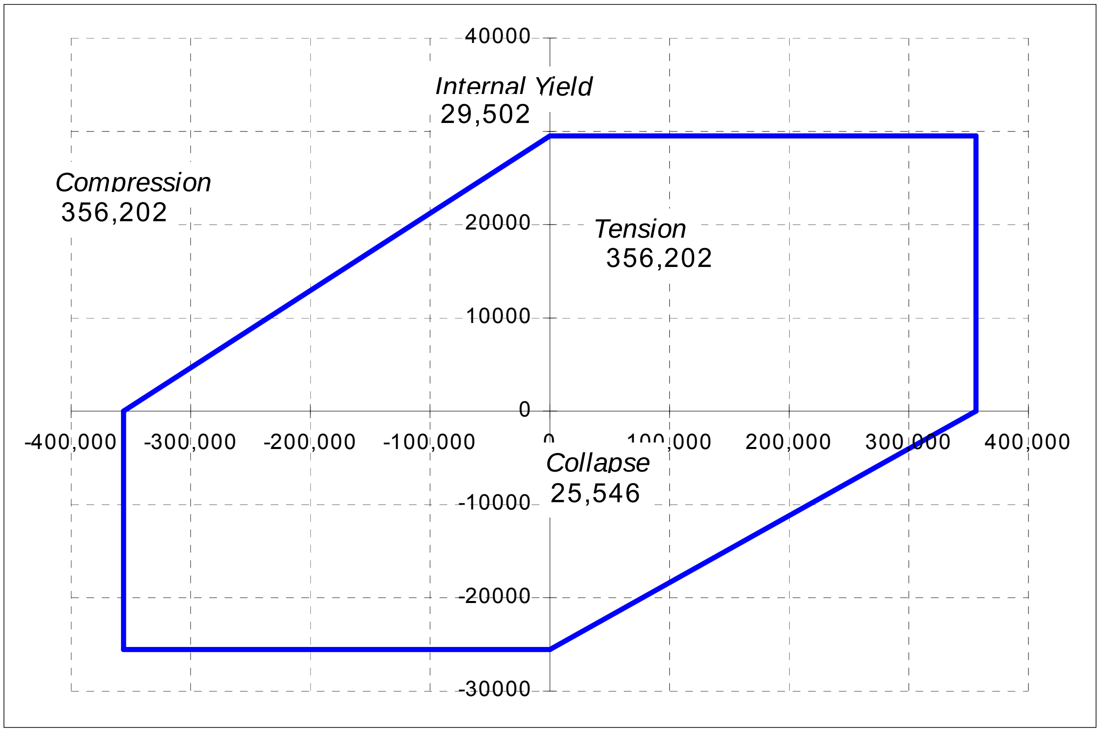
When maximum stresses exceed yield strength of the material, it is assumed that failure either occurs or is eminent. There are a number of failure theories that describe this condition.

The most elementary theory is the Maximum Stress theory. Failure is predicted when the maximum (or minimum) principal stress exceeds yield strength of the material. Represented graphically, this theory of failure would be a square box with x and y limits at the yield strength of the material.

The Maximum Shear Stress or Tresca theory postulates that yield in a component subject to combined stress will occur when maximum shear stress becomes equal to the maximum shear stress at yield point in a simple tension test. This theory illustrates the fact that components subject to tension will support less external pressure and components in compression will support less internal pressure. Represented graphically, the square box would have two corners truncated to illustrate the previous statement.

The Distortion Energy or Von-Mises theory is based on observations that materials do not become inelastic under a triaxial state of stress produced by high hydrostatic pressure. Represented graphically, the truncated box expands slightly to form an ellipse with its major axis at the corners of the box not truncated in the Tresca theory.

The graph below illustrates the Tresca theory.



4.6.3.2) "Burst" Pressure Calculation

Performance of a tubular shape under internal pressure is commonly referred to as "burst" rating. Calculations to represent the "burst" rating are most often represented to be the Lame formula. This is a very common and very incorrect nomenclature. Following convention used in API 5C3, the proper title would be "Internal Yield Pressure" rating.

API 5C3 uses a modified form of the Lame equation in that a safety factor of 12-½% is applied to account for variations in wall thickness and in manufacture. When used with manufactured goods having a machined inside and outside diameter with tolerances common to machining operations, the 12-½% safety factor would not be appropriate.

Calculation of internal yield pressure in downhole equipment is effected by the presence of end conditions. Often a plugged bore, such as a packer with plugged tailpipe or a service tool experiencing plugged workstring adds the end effect of a closed chamber. This condition favors capped-end conditions. Capped end conditions change the state of stress from the simple “maximum stress” calculation to a combined stress calculations similar to the Tresca or Von-Mises theories.

Capturing the state of stress for combined load is best done by generating an operating envelope described in the “theories of failure” section above.

From the SPE Applied Technology Workshop held in May 1998, there are a number of papers that advance certain theories of failure prediction for tubular goods under internal pressure:

- *The Development of Risk-Based Burst Design for Well Casing and Tubing*
- *Burst Pressure Prediction of Thin Walled, Ductile Tubulars Subjected to Axial Load*
- *Analytical Burst Strength Prediction of OCTG With and Without Defects*

4.6.4) Specifications

To clarify the state of the industry, there is no industry standard specification (API or otherwise) for downhole completion equipment (other than safety valves). There is also no industry standard for the performance prediction (equation or test) of these products.

Major E&P companies understand that completion equipment and accessories are “un-regulated” products. Users must specify what the equipment is expected to do and under what conditions it is expected to perform. It is incumbent on the user to carefully evaluate every piece of equipment that passes through the rotary.

There has been some question as to the implication of specifying “grade” and “size” as part of the completion equipment specification, such as use of the “P-110” specification as set forth by API. Specification 5CT ***Specification for Casing and Tubing***, identifies the requirements for P-110 material, none of which include pressure or load rating for products other than casing or tubing. The designation P-110 covers material and process of manufacture for casing or tubing. When the designation P-110 is used in completion equipment and accessories, it implies the material used has performance properties identical to P-110 material used in casing or tubing. Equipment manufacturer’s specification of P-110 accompanied by a size and weight, does not imply that the completion equipment has the same performance properties of casing in that size and weight. Such a specification implies that furnished completion equipment is compatible in size and material of manufacture with specified casing or tubing.

4.6.5) Equipment Rating

If there exists all this divergent technology on the calculation of rated pressure, what’s an equipment manufacturer to do about rating his product? General and accepted practice for critical well application is performance verification testing.

Equipment manufacturers likely have test data that supports use of a particular formula under specific conditions identified in their Engineering Manual for their product line. This is a very specific (geometric) application and applies only to a specific product or combination of products.

So, what good are all these calculations? They allow us to *estimate* the pressure at which collapse will occur. We use that engineering judgment referred to in the cover of API 5C3 to decide which equations most likely apply and what margin of error should be used. We can predict the magnitude of external pressure that can be exerted without risk of burst or collapse with a healthy safety margin, then we test to refine.

4.6.6) How can pressure failure problems be prevented?

1. The first rule in running downhole tools is to characterize all equipment in the string. This means that performance properties of all equipment that's run in the well is known and understood by the operator. For the drill string, this is usually done on the rig or in the completion plan. For the production string, this is done well ahead of actually drilling the well.
2. During the planning phase, and almost always prior to the funding phase, there is a completion schematic of the proposed wellbore. This schematic pictorially and verbally describes all components required for a "trouble-free" completion and contingency completions. The amount of contingency work is directly proportional to the perceived risk in completing the well trouble-free.
3. From this completion schematic, an equipment list is drawn along with operational and performance criteria. We now have the foundation for an equipment specification. From this specification, completion equipment manufacturers are considered and evaluated for technical merit, cost, and service quality. Specific pieces of equipment are qualified (technically) and selected for quotation. Vendors are ranked and a supplier chosen. The equipment is ordered well in advance of delivery to assure the proper weight, grade, and size are used. The supplier and operator mutually draft an operations plan that defines how the equipment will be run and operated.
4. Now, does all this prevent completion equipment from failing? Certainly not. What it *does* is assure the equipment is the best possible for the job (technically) and that all parties understand the performance limits.
5. Dynamic conditions such as those resulting from surging the formation are brutal on downhole tubulars. Actual forces are unknown and, for the most part unpredictable. Dynamic loads can be considerably higher than the static loads we use in formulae. We identify this operation in the completion plan under contingency operations. If the well doesn't come in by swabbing or jetting the fluid level down, the contingency plan may be to pump into the formation and surge fluid back. The next question would be the pressure limit on tubing prior to surging, and that limit would be an operational parameter of the downhole tools.

4.6.7) Example Calculations

Following is a sample calculation sheet used to compare and contrast different theories of performance prediction. Engineering judgment is used to determine which calculation best represents the actual operating conditions.

Burst / Collapse .. Tension / Compression / Torsion Analysis

Identification:

Example Product
Load Case defined below

Input Data:

$OD := 12.000$ min $ID := 10.975$ max $E := 2.9 \cdot 10^{7}$ $mu := 0.29$

Design Load: $Fd := 250000$ lbs (tension is positive) Yield Strength: $Sy := 120000$ psi

Load = Compressive specified by customer Length: $L := 10.00$ inches

Operating Pressure: Internal: $Pin := 5000$ psi Length of component not supported.

External: $Pout := 4500$ psi

Basic Calculations

Cross Sectional Area: Ax $Ax := \pi \cdot \dfrac{\left(OD^{2} - ID^{2}\right)}{4}$ $Ax = 18.496$ sq. inches

Polar Moment of Inertia: J $J := \pi \cdot \dfrac{OD^{4} - ID^{4}}{32}$ $J = 611.398$ inches^4

Inner radius: $a := \dfrac{ID}{2}$ Outer radius: $b := \dfrac{OD}{2}$

Tension/Compression Load Rating Calculations

$F := Ax \cdot Sy$ $F = 2219476$ pounds

Torsion Rating Calculations

$Tq := Sy \cdot \dfrac{J}{OD \cdot 12}$ $Tq = 509498$ ft-lbs

Safety Factor Calculations

$SFt := \dfrac{F}{Fd}$ $SFta := \sqrt{SFt^{2}}$ $SFta = 8.88$ Tension Compression

Burst & Collapse Calculations

Minimum Wall: $t := \dfrac{OD - ID}{2}$ $t = 1$ inches

D/t: $Dt := \dfrac{OD}{t}$ $Dt = 23.41$

Equivalent Collapse Yield Strength Under Axial Stress (API 5C3 1.1.5.1)

$$Syc := \left[\left[1 - 0.75 \cdot \left(\frac{Fd}{Ax \cdot Sy}\right)^{2}\right]^{0.5} - 0.5 \cdot \frac{Fd}{Ax \cdot Sy}\right] \cdot Sy$$

$Syc = 112669$ psi

Internal Pressure Calculations:

Internal Yield (API 5C3): Based on the Barlow equation

$Py := 0.875 \cdot Sy \cdot \left(2 \cdot \dfrac{t}{OD}\right)$ $SFpy := \dfrac{Py}{Pin}$

$Py = 8969$ psi for tubulars subject to wall thickness variations

$SFpy = 1.79$

$Pym := \dfrac{Py}{0.875}$ $SFpym := \dfrac{Pym}{Pin}$

$Pym = 10250$ psi for tubulars where minimum wall is used

$SFpym = 2.05$

Capped End Yield:

$$Pcey := \left(\frac{4 \cdot Sy}{\sqrt{3}}\right) \cdot \left(\left(\frac{t}{OD}\right)\right) \cdot \left[1 - \left(\frac{t}{OD}\right)\right]$$

$SFpcey := \dfrac{Pcey}{Pin}$

$Pcey = 11330$ psi

$SFpcey = 2.27$

Capped End Burst:

$$Pceb := \frac{2 \cdot Sy}{\sqrt{3}} \cdot \ln\left[\frac{1}{1 - \left(\frac{2 \cdot t}{OD}\right)}\right]$$

$SFpceb := \dfrac{Pceb}{Pin}$

$Pceb = 12372$ psi

$SFpceb = 2.47$

Open End Internal Yield:

$$Poey := 2 \cdot Sy \cdot \left(\frac{t}{OD}\right) \cdot \left[1 - \left(\frac{t}{OD}\right)\right]$$

$SFpoey := \dfrac{Poey}{Pin}$

$Poey = 9812$ psi

$SFpoey = 1.96$ Calculation...

API 5C3 Collapse Calculations:

Intermediate Calculations :

$$A := 2.8762 + 0.10679\cdot 10^{-5}\cdot Syc + 0.21301\cdot 10^{-10}\cdot Syc^2 - 0.53132\cdot 10^{-16}\cdot Syc^3$$

$$B := 0.026233 + 0.50609\cdot 10^{-6}\cdot Syc$$

$$C := -465.93 + 0.030867\cdot Syc - 0.10483\cdot 10^{-7}\cdot Syc^2 + 0.36989\cdot 10^{-13}\cdot Syc^3$$

$$K := \frac{3\cdot\left(\frac{B}{A}\right)}{2+\left(\frac{B}{A}\right)} \qquad F := \frac{46.95\cdot 10^6\cdot K^3}{Sy\cdot\left[K-\left(\frac{B}{A}\right)\right]\cdot(1-K)^2} \qquad G := \frac{F\cdot B}{A}$$

$A = 3$ $B = 0$ $C = 2932$

$K = 0$ $F = 2$ $G = 0$

Yield Point Collapse:

Not a true collapse, but rather that value of external pressure that results un tubular yield stress at the inside wall of the tube. Derived from theoretical analysis, experimental results indicate this formula to be somewhat conservative. Basis for this formula is Lame.

$$Dyp := \frac{\left[\sqrt{(A-2)^2 + 8\cdot\left[B+\left(\frac{C}{Syc}\right)\right]} + (A-2)\right]}{2\cdot\left[B+\left(\frac{C}{Syc}\right)\right]} \qquad Pyp := 2\cdot Syc\cdot\frac{\left(\frac{OD}{t}\right)-1}{\left(\frac{OD}{t}\right)^2}$$

$Dt = 23$

$Dyp = 12$

$Pyp = 9213$ psi

Plastic Collapse:

Derived empirically from 2488 collapse tests on K55, N80, and P110. Formula developed from the modified elastic collapse formula.

$$Dp := \left[Syc\cdot\frac{A-F}{(C+Syc\cdot(B-G))}\right] \qquad Pcp := Syc\cdot\left[\left[\frac{A}{\left(\frac{OD}{t}\right)}\right]-B\right]-C$$

$Dt = 23$

$Dp = 21$

$Pcp = 3043$ psi

Transition Collapse:

Arbitrarily determined, developed from elastic collapse formula. Curves for elastic and plastic collapse pressure do not intersect until pressure falls below minimum elastic collapse. Transition collapse was developed to overcome this anomaly.

$$Dtr := \frac{2+\left(\frac{B}{A}\right)}{\left(\frac{3\cdot B}{A}\right)} \qquad Ptr := Syc\cdot\left[\frac{F}{\left(\frac{OD}{t}\right)}-G\right]$$

$Dt = 23$

$Dtr = 26$

$Ptr = 3644$ psi

Elastic Collapse :

Derived from theoretical work by W.O. Clinedinst for the API.

$$Pec := \frac{46.95\cdot 10^6}{\left(\frac{OD}{t}\right)\cdot\left(\frac{OD}{t}-1\right)^2}$$

$Pec = 3991$ psi

Using API 5C3 Collapse Formulae :

If (D/t) < Dyp then use Pyp, Yield Strength Collapse
If (D/t) < Dp then use Pp, Plastic Collapse
If (D/t) < Dtr then use Ptr, Transition Collapse
Otherwise use Elastic Collapse

Calculation...

Collapse of Tubulars (SPE 26317)

SPE paper #26317 presented in 1993 by Issa (Exxon) and Crawford (Stanford U.) features an improved method of calculating tubular collapse. The basis for their formula is a large number of non-linear finite element analyses using differing geometric tolerances and mechanical properties. Full scale testing was done to verify results of the FEA, both for magnitude and tubular shape. Testing verified analysis within 6%, a value judged to be acceptable based on assumptions.

Elastic Collapse Pressure

$$Pe := \left[2 \cdot \frac{E}{\left(1 - mu^2\right)}\right] \cdot \left[\frac{1}{\left[Dt \cdot (Dt - 1)^2\right]}\right] \qquad Pe = 5383 \quad \text{PSI}$$

Elastic-Plastic Collapse Pressure

$$Pec := \left(Syc \cdot \frac{Dt - 1}{Dt^2}\right) \cdot \left[\frac{7.0333}{1 + \left[0.1295 + 12.3298 \cdot \left(\frac{Syc}{E}\right)\right] \cdot Dt}\right] \qquad Pec = 6286 \quad \text{PSI}$$

Tubular Collapse for Near Perfect Tubulars : (often the case with machined parts)

$$Po := \frac{Pe + Pec}{2} - \frac{\sqrt{(Pe - Pec)^2}}{2} \qquad Po = 5383 \quad \text{PSI}$$

ASME Design Criteria for Collapse:

Reference: The New Type Code Chart for the Design of Vessels Under External Pressure;ASME Pressure Vessel and Piping Design, Collected Papers; E.O. Bergman; 1960... and ... Theory and Design of Pressure Vessels, 2nd Ed.; John F. Harvey; Van Nostrand, Reinhold; 1991; p.604

Long Cylinders:

Cylinders are considered long if length is greater than lc as given by the equation below. This equation is considered valid provided the corresponding compressive stress does not exceed the proportional limit (yield strength).

$$lc := 1.11 \cdot OD \cdot \sqrt{\frac{OD}{t}} \qquad lc = 64 \quad \text{and} \quad L = 10 \quad \text{inches}$$

$$PcASME := \frac{2 \cdot E}{\left(1 - mu^2\right)} \cdot \left(\frac{t}{OD}\right)^3 \qquad PcASME = 4933 \quad \text{PSI}$$

$$\sigma cASME := \frac{E}{\left(1 - mu^2\right)} \cdot \left(\frac{t}{OD}\right)^2 \qquad \sigma cASME = 57753$$

If $\sigma c > SY$, then use short cyl. formula;

Intermediate Cylinders:

For two lobe failure mode with L~lc:

$$Pc1ASME := \left[\frac{\left[2.6 \cdot E \cdot \left(\frac{t}{OD}\right)^{2.5}\right]}{\left(\frac{L}{OD}\right) - 0.45 \cdot \sqrt{\left(\frac{t}{OD}\right)}}\right] \qquad Pc1ASME = 38391 \quad \text{PSI}$$

Short Cylinders:

Failure is by plastic yielding at the yield strength of the material; characteristic of thick walled cylinders in which the influence of length is negligible.

$$Pc2ASME := 2 \cdot Sy \cdot \left(\frac{t}{OD}\right) \qquad Pc2ASME = 10250 \quad \text{PSI}$$

Lame Formulae for Stress in Thick Walled Vessels:

In thick walled vessels, stress varies widely from inside to outside wall, and ordinary membrane forumae are not satisfactory for indication of state of stress.

For Internal Pressure *Only*
Conditions:

Under this loading condition, tangential stress is always numerically greater than radial stress, and is at its maximum at the inner fibers. Maximum stress under given operating conditions is presented below:

$$\sigma ti := \frac{Pin \cdot (a^2 + b^2)}{b^2 - a^2} \qquad SF\sigma ti := \frac{Sy}{\sigma ti}$$

$\sigma ti = 56148$ psi tensile stress

$SF\sigma ti = 2.14$

Deformation of the cylinder under internal pressure:

Under certain conditions, as in a packer mandrel, PBR, or seal mandrel, deformation of the inner and outer wall under applied pressure effects performance.

Inner fiber:

$$\delta ii := \frac{Pin \cdot a}{E} \cdot \left(\frac{a^2 + b^2}{b^2 - a^2} + mu\right)$$

$\delta ii = 0.0109$ inches radial

Outer fiber:

$$\delta oi := \frac{2 \cdot Pin \cdot a^2 \cdot b}{E \cdot (b^2 - a^2)}$$

$\delta oi = 0.0106$ inches radial

For External Pressure *Only* Conditions:

Under this loading condition, tangential and radial stress are both compressive, with tangential always numerically greater. maximum stress occurs at the inner fiber. Maximum radial stress occurs at the outer fiber and is equal to the applied external pressure. Maximum stress under given operating conditions is shown below:

$$\sigma to := 2 \cdot Pout \cdot \frac{b^2}{b^2 - a^2} \qquad SF\sigma to := \frac{Sy}{\sigma to}$$

$\sigma to = 55033$ psi compressive stress

$SF\sigma to = 2.18$

prediction of collapse pressure using the Lame formula would be as follows:

$$Plame := \frac{(b^2 - a^2)}{2 \cdot b^2} \cdot Syc$$

$Plame = 9213$ psi external pressure

Deformation of the cylinder under external pressure:

Under certain conditions, as in a packer mandrel, PBR, or seal mandrel, deformation of the inner and outer wall under applied pressure effects performance.

Inner fiber:

$$\delta io := \frac{-2 \cdot Pout \cdot a \cdot b^2}{E \cdot (b^2 - a^2)}$$

$\delta io = -0.0104$ inches radial

Outer fiber:

$$\delta oo := \frac{-Pout \cdot b}{E} \cdot \left(\frac{a^2 + b^2}{b^2 - a^2} - mu\right)$$

$\delta oo = -0.0102$ inches radial

Roark & Young Collapse Formulae:

For thin walled vessels:

Reference:
Southwell, R.V.; On the Collapse of Tubes by External Pressure; Philos. Mag.; vol 29; p.67, 1915
Saunders, H.E. and Windenburg, D.F.; Strength of Thin Cylindrical Shells Under External Pressure; Trans. ASME vol 53, p.207, 1931
Jasper T.M. and Sullivan, J.W.W.; The Collapsing Strength of Steel Tubes; Trans. ASME vol.53, p.219, 1931

$$PcR := \left(2\cdot\frac{t}{OD}\right)\cdot\left[\frac{Sy}{1+\left(4\cdot\frac{Sy}{E}\right)\cdot\left(\frac{OD}{2\cdot t}\right)^2}\right]$$

$PcR = 3136$ psi

Tamano Equations for ultimate collapse strength :

For reference only; applicability remains under study .

Elastic Collapse:

$$Pe := \left[\frac{(2\cdot E)}{\left(1-mu^2\right)}\right]\cdot\frac{1}{\left(\frac{OD}{t}\right)\cdot\left[\left(\frac{OD}{t}\right)-1\right]^2}$$

$Pe = 5383$ psi

Yield Collpase:

$$Py := 2\cdot Sy\cdot\left[\left(\frac{OD}{t}\right)-1\right]\cdot\left(\frac{t}{OD}\right)^2\cdot\left[1+\left[\frac{1.47}{\left(\frac{OD}{t}\right)-1}\right]\right]$$

$Py = 10456$ psi

Sir William Fairbairn's Formula for Short Tubes with External Pressure:

$\beta := \frac{L}{OD}$

Reference: Machine Design Data Handbook; p-7.12; McGraw Hill; 1994

$Lm := L\cdot 25.4 \quad ODm := OD\cdot 25.4$ (metric conversion for use with formula as stated in text)

$tm := t\cdot 25.4$

$$Pcwf := 9657600\cdot\left(\frac{tm^{2.19}}{Lm\cdot ODm}\right)$$

To be valid, $\beta < 6$: $\beta = 0.8$

$Pcwf = 34422$ psi

Harvey - Theory and Design of Pressure Vessels 2nd Ed :

For reference only; applicability remains under study.

Two Lobe Short Section (eq. 8.2.2):

Refernce: Seely and Smith; Advanced Mechanics of Materials; Wiley & Sons; 1960

Assumes thin walled vessel (i.e. stress at ID = stress at OD)

$$P822 := \left(\frac{8}{3}\right)\cdot E\cdot\left(\frac{t}{OD}\right)^3$$

$P822 = 6024$ PSI

Elastic Collapse of Long Cylinders or Tubes (eq. 8.2.37 and 8.2.38):

Equation is considered valid unless compressive stress exceeds yield strength:

$$P8237 := \left[\frac{(2\cdot E)}{\left(1-mu^2\right)}\right]\cdot\left(\frac{t}{OD}\right)^3$$

$P8237 = 4933$ psi

Compressive Stress:

$$\sigma 8238 := \left[\frac{E}{\left(1-mu^2\right)}\right]\cdot\left(\frac{t}{OD}\right)^2$$

$\sigma 8238 = 57753$ psi

and $Sy = 120000$ psi

Collapse of Thick Walled Cylinders Under External Pressure (Tresca & VonMises):
For reference only:

Conditions of the Fully Plastic Wall:
Equations for the average stress through the cylinder wall are:

Tangential (8.4.1):

$$\sigma 841 := \frac{-(Pout \cdot OD)}{2 \cdot t} \qquad \sigma 841 = -52683$$

Radial (8.4.2):

$$\sigma 842 := \frac{-Pout}{2} \qquad \sigma 842 = -2250$$

Longitudinal (8.4.3):

$$\sigma 843 := -\left[\frac{\left[Pout \cdot \left(\frac{OD}{2}\right)^2\right]}{\left(\frac{OD}{2}\right)^2 - \left(\frac{ID}{2}\right)^2}\right] \qquad \sigma 843 = -27517$$

Full yielding occurs when the pressure is sufficient to increase effective stress to material yield strength.

Tresca failure theory (8.4.4):

$$\sigma Tresca := \sigma 842 - \sigma 841 \qquad \sigma Tresca = 50433$$

VonMises failure theory (8.4.5):

$$\sigma VM := \sqrt{\frac{\left[(\sigma 842 - \sigma 841)^2 + (\sigma 842 - \sigma 843)^2 + (\sigma 841 - \sigma 843)^2\right]}{2}} \qquad \sigma VM = 43676$$

and $Sy = 120000$ psi

Tests of thick walled cylinders show much lower results than predicted by these theories. When the highest triaxial stress is used, good agreement with experimental results is obtained.

5) Wellheads

5.1) Product Description

The 'wellhead' is oilfield terminology for the upper end of a structural pressure vessel that is used to drill and case the wellbore. All casing strings are suspended from the wellhead. The wellhead is comprised of a series of 'housings or spools ", which allow the casing string (s) to 'hung-off', "sealed", and "suspended". Wellheads are categorized as either 'surface' or 'subsea'. This paper will address the surface platform type wellhead (see attached illustration).

A typical wellhead is described from bottom upward, as follows:

a) 'A Section' Casing Head Housing: 20" Assy Housing, f/ 18-5/8" Casing

b) 'B Section' Casing Spool Assembly: f/ 13-5/8", 9-5/8", and 7" Casing

c) 'C Section' Tubing Spool Assembly: f/ 2-7/8" tubing and tubing hanger

d) A typical tree is described as: 'D Section' Christmas Tree stacked gate valves

5.2) Functional Requirements

The functional requirements of the wellhead are as follows:

a) Hang, seal, and suspend casing (s); per drilling program

b) Provide surface well control:

1. Contain drilling / reservoir fluid pressures with the wellhead at the surface
2. Injection capability; for killing the well; casing (s) annuli's
3. Flowing the well during the DST (well test).
4. Maintain pressure integrity of casing strings via casing hangers / pack-off's

c) Facilitate 'bleeding-off' wellbore pressure; casing (s) annuli

d.) Adaptable to the surface BOP (blow out preventor)

5.3) Technical Requirements

Typical technical requirements of the wellhead are:

a) Meets the operator's purchase order specification for Wellhead and Production Tree.

b) Design per API 6A 17th edition; Monogram Typically Required.

c) Typical Test per API 6A 17th Ed.

'A Section' = PSL3

'B Section' = PSL3

'C Section' = PSL3G

'D Section' = PSL3G

d) Typical Temperature rated per API 6A 17th Ed.

‘A Section’ = P, U

‘B Section’ = P, U

‘C Section’ = P, U

‘D Section’ = P, U

e) Typical Material Class per API 6A 17th Ed.

‘A Section’ = DD, EE

‘B Section’ = DD

‘C Section’ = DD, EE

‘D Section’ = DD, EE

f) Quality Plan:

Unique to Project

Supplier designator: Quality Plan Number

Factory Acceptance Test required; third party witness

Meets ‘NACE MR-01-75’,”Sulfide Stress Cracking Resistant Metallic Material for Oilfield Equipment”

5.4) Supplier Equipment Ratings

Typical manufacturer’s rating: Standard API 6A 17th Edition “Standard for Wellhead and Trees”.

a) Casing Head and Spool Housing: 5,000 psi working pressure

b) Tubing Spool: 5,000 psi working pressure

c) Tree: 5,000 psi working pressure

5.5) Ratings Validation

The wellhead manufacturer should have verified the equipment ratings by both analytical and empirical means in accordance to API 6A “ Standard for Welleads and Tress” 17th Edition. A design file is established to document the equipment design, manufacture, test, and performance verification

5.6) Performance Demonstration

The wellhead manufacturer should have demonstrated the compliance of their equipment via demonstrated performance tests to API 6A 17th Edition, per product specification level (PSL level specified by the operator). Test results are on file.

5.7) Wellhead and Accessories Leak Path

The wellhead is further described as consisting of pressure containing/load bearing components used to suspend casing and tubing. These components are casing head housings/spools, tubing head spool, crossover spools, etc. (API 6A, 17th Edition) There are two principle types of wellheads; the standard or compact. Compact wellheads are differentiated by their functions of suspending casing loads. The standard version is illustrated in the appendix. Note how the load paths are transferred into the wellhead.

In either version, isolation of individual casing strings is provided by either elastomers or metal-to-metal (MTM) seals. Pressure containment is also provided by ring gaskets and bolted flanges or by proprietary connectors and seals. The tubing is likewise suspended at the wellhead by a tubing hanger. Tubing pressure is isolated at the tubing hanger forcing produced fluids into the surface production tree.

5.7.1) Drilling

Drilling operations are simply described as providing a "bore hole" to place casing tubulars to be suspended at the wellhead. As the progression of placing the various sizes of the tubular (casing) into the well, cementing the casing annuli is routinely done to isolate formation pressures and fluids. A blow out preventor (BOP) provides the surface well control needed during drilling of the boreholes. As the casing strings are placed and landed at the wellhead, two types of suspension means are typically explored; slip or "wrap around" hangers or mandrel type hangers.

Both the slip type or mandrel casing hanger employ various sealing technologies. The mandrel type casing hanger typically uses metal-to-metal (MTM) sealing technology of proprietary design by the wellhead manufacturer. In contrast, the elastomer seals are usually an "off-the-shelf" design by various seal manufacturers. The wellhead manufacturer consults the seal supplier for design data to construct the sealing components. The use of elastomer seals during casing operating requires the determinations (measurements) of exact dimensions (outside diameter), in order to achieve sealing integrity. Wellhead operations personnel make these determinations on site and select from an array of various sizes of elastomers. A more in depth discussion of elastomer sealing technology in offered in this report.

MTM seals have recessed or non-recessed polished bore receptacles in the casing head housing. Non-recessed bores are susceptible to damage. Setting tools are used to energize the MTM into the polished bore. These tools are either mechanical torque set or hydraulic set. A pre-determined compression of the MTM seals is necessary during installation.

5.7.2) Production

With all casing strings in place, the tubing is run, suspended and sealed. Produced fluids are restricted to the tubing string (flow conduit) from downhole to the surface tree. Since the tubing is replaceable by nature, the dynamics of pressure, loads, and temperature play a significant role in sealing integrity. Various means and materials achieve a seal between the tubing and production casing. At the surface, the casing tubing annulus is usually sealed by either elastomers or MTM sealing technology. Whereas downhole casing/tubing annulus sealing is achieved with a packer (see discussion on packers in this report).

6) Liner Hangers

6.1) Description

Liner hangers are used to suspend liners inside of larger ID casing. Liners can be used as drilling liner, or a production liner. Hangers can be set either mechanically or hydraulically. Liner hangers employ the use of slips to suspend or hang the liner. A liner hanger's slips are usually longer and have a "shallower" angle than a production packer slip. This feature allows for more contact area between the slip and the production casing so as to reduce stress and allow a higher load capacity. When used by themselves, liner hangers are not always designed as a pressure vessel, as some designs do not have a solid body. The pressure seal is obtained by the cement sheath in the casing/liner overlap.

Frequently a liner top packer is utilized to prevent pressure communication with the liner/casing annulus in the event of an uncemented or poorly cemented liner. A liner top packer can also be used instead of a production packer in a monobore type completion. Liner top packers may be run integral to the liner hanger, or when equipped with a seal assembly them can be run on an additional trip. This "second trip" packer's seal assembly then seals into an extension sleeve above the hanger, or a PBR below the hanger.

Liners can be used for several reasons such as

1. Cover a lost circulation or weaker upper zone
2. Repair corroded production casing
3. Reduce cost over a full string of casing
4. Case off a normal pressured zone prior to drilling into a depleted reservoir
5. Provide a PBR completion
6. Allow test of deeper interval prior to plugging back to primary pay interval

6.2) Design Basis

Service Company manufacturer's proprietary or internal design.

6.3) Potential Leak Paths

1. In the liner / casing annulus
2. Liner hanger thread connection
3. Past the elastomer in a hydraulic set hanger
4. Liner Top packer Seal (if used)
5. Liner top packer and hanger connection (if integral)
6. Liner top packer seal assembly (if "second trip")

6.4) Leak Prevention

1. Properly validated design

2. Adequate manufacturing QC
3. Good cement job
4. Proper installation procedure
5. Sufficient liner/casing overlap

6.5) Remediation Options

1. Continue to use as is after assessing risk
2. Attempt to cement squeeze liner top
3. If hanger is so equipped install a liner top packer
4. Install a production packer above leaking liner top

7) Stage Cementing Tools

7.1) Description

Stage Cement Tools (SCT) or "DV" tools (differential fill) are used to divert the flow of cement during primary cementing of casing strings. SCT are used where "full sting" cementing is undesirable. The SCT is placed in the casing string during casing makeup and conveyed downhole to the pre-determined location.

A SCT is best described as a sliding sleeve. The sleeve is opened to direct the flow of cement into the annuli. Once a predetermined volume of cement is pumped the sleeve can be closed. Long-term pressure integrity of the SCT is based on the longevity of the SCT's elastomer seals that effectively seal the sliding sleeve. SCT's are not normally used in the production casing string as elastomer degradation and loss of pressure integrity would be intolerable.

SCT's are normally found in use in intermediate casing strings, and are considered a potential leak source of annuli pressure should the cement sheath fail (micro annuli).

8) Sub Surface Safety Systems

8.1) Description

The subsurface safety valve is the main component of the downhole safety system. However there are other components of the system, which should be discussed. The usual components of a subsurface safety system are:

1. Control System (SCSSV only)
2. Communication System (SCSSV only)
3. Subsurface Safety Valve

The focus of this topic discussion will be on downhole safety systems as it pertains to sustained casing pressure. Therefore only the communication system and subsurface safety valve will be discussed in this section.

8.1.1) Communication System

The communication system provides the means of transmitting energy, usually hydraulic pressure, via a control line from surface down to the subsurface safety valve, if required, to keep the valve open.

8.1.2) Subsurface Safety Valve

The subsurface safety valve is the heart of the subsurface safety system. In the event of a catastrophe on the surface, the subsurface valve can shut the well in below the surface. This relieves the surface equipment from the pressure load in case of a fire or when an impact renders the wellhead equipment incapable of holding pressure. Surface safety equipment should react to routine alarm conditions, while the subsurface valve should react to catastrophes.

8.1.2.1) Types of Subsurface Safety Valves

There are generally three criteria used to define the types of subsurface safety valves. These are:

1. Type of Control
2. Type of Closure
3. Retrievability.

8.1.2.2) Subsurface Control

There are two main types of control of subsurface safety valves: direct and remote. These are often referred to as Subsurface Controlled Subsurface Safety Valve (SSCSVS) and Surface Controlled Subsurface Safety Valves (SCSSVs).

Direct (subsurface) controlled safety valves, also called "storm chokes", sense downhole conditions. Whenever the conditions at the valve depth exceed a preset parameter, the valve closes. The parameter usually measured is either flow rate or ambient pressure, either of which is affected by the failure of the wellhead or surface equipment. Those SSCSVs closed by flow rate detect failure by measuring increased pressure differences across the valve due to increases in flow rate. Usually a choke bean creates restriction in the flow stream. The valve shuts when a pressure drop across the valve exceeds a preset valve. This valve is called a "differential pressure" valve, or a velocity valve. Another type of SSCSV is the ambient pressure valve. This type of SSCSV utilizes the production pressure in the tubing at the valve to determine when closure should occur. It has a charged chamber containing gas at a preset pressure. When tubing pressure at the valve depth drops below this charged pressure, the valve closes.

8.1.2.3) Surface Control

Remote control subsurface safety valves are relatively insensitive to changes in operating conditions. They rely on the loss of operating energy to cause them to "fail" in the closed (or "safe") position. This loss of operating energy can be created by the surface control system or by physical breakage of the communication system (i.e., loss of a Christmas tree).

An SCSSV is opened when energy (usually pressurized hydraulic fluid) is applied to the topside of a piston area. The backside of the piston area is usually exposed to tubing pressure. When the control line pressure (applied plus hydrostatic) is great enough to overcome tubing pressure the SCSSV will open.

8.1.2.3.1) Valve Operation

The opening and closing mechanism of this valve is dependent on several forces produced by either the hydraulic pressure or production pressure in the tubing string. There are two operating pressures acting on these valves. Production pressure (Pl) at the valve and hydraulic control line pressure (P2). P2 is created both by the hydrostatic head of the control fluid in the line and pressure generated by the control system.

8.1.2.3.2) SCSSV-Special Features

Many Surface Controlled Subsurface Safety Valves can have special features which may be advantageous in certain installations. Among these are deep service valves, self-equalizing valves, temporary and permanent abandon, wireline valve backup, flapper protection, and special service (corrosion) valves. Most of these features do not have an effect on whether or not the equipment may be the cause of sustained casing pressure.

8.1.3) Permanent Abandonment

Most tubing retrievable safety valves have a permanent lock open feature, which allows it to be permanently locked open using a "permanent lock open tool." This feature keeps the safety valve in the open position without hydraulic control pressure. It is used when the tubing is pulled, permitting pulling a dry string. The permanent lock open feature is also used in the event of safety valve malfunction. When the safety valve has been permanently locked open, it may accept a separation sleeve or a wireline insert valve.

8.1.4) Types of Closure

Subsurface safety valves are closed by one of three major types of closing mechanisms:

1. The first subsurface safety valves were Poppet Valves. Poppet Valves close off flow by a valve member moving in the same direction as the flow, which produces a seal with a seat. This closing mechanism is currently used primarily in direct controlled safety valves (SSCSVs).
2. The Flapper Valve is a modified poppet valve that is hinged on one side. When the valve is open, flow is relatively unrestricted. Most flapper valves are equipped with a flow tube which opens the flapper. A torsion spring acting on the flapper forces the flapper to swing upward and engage the valve seat. Once the flapper valve has engaged the valve seat, increased pressure below the flapper valve increases the sealing forces between the flapper and seat.
3. The third type of subsurface safety valve closing mechanism is the Ball. Ball Valves have the protected seal and the smooth straight conduit features of the Flapper Valve. The ball is actuated by a cam and the linkage to the flow tube.

8.1.5) Retrievability

The third way to describe downhole safety valves is by their retrievability, that is, how they are retrieved and brought to the surface for repair or replacement. Subsurface controlled subsurface safety valves are wireline retrievable. Surface controlled subsurface safety valves can be either wireline retrievable or tubing retrievable.

"Wireline Retrievable" safety valves are run and pulled on wireline (slickline). They are attached to "locking mandrels" which lock them into a "landing nipple" in the tubing string. Landing nipples are short pieces of tubing with special profiles cut internally, which match the profiles of the locking mandrel keys. When installing a subsurface safety valve which utilizes nipples and lock mandrels, the pressure limitations of each component must be considered. Wireline Retrievable valves are selected because of the ease with which they can be retrieved. Their major disadvantages are their restricted flow area and that they must be pulled in order to perform certain wireline operations below the valve.

Tubing retrievable safety valves have a much larger flow area, which reduces the restriction of flow through the tubing. These larger valves also permit wireline equipment to be run through them without disturbing the safety valve. Tubing Retrievable valves are run as an integral part of the tubing string. If a valve failure occurs (failure to open, failure to close, or failure to seal) the tubing must be pulled to replace the valve. Another option would be to install a direct-controlled valve in the well, or to install a secondary wireline retrievable safety valve into a profile which most tubing retrievable valves possess.

8.1.6) Wireline

In the event of a tubing retrievable safety valve malfunction, a wireline retrievable insert valve can be run into the nipple profile in the I.D. (of most tubing retrievable safety valves) after it has been permanently locked open.

The packing of the wireline retrievable insert safety valve straddles the tubing retrievable SCSSV from top to bottom. It uses the same control line which previously operated the tubing retrievable SCSSV. Therefore, if a tubing retrievable safety valve malfunctions, an insert safety valve can be run inside it. This feature can prevent costly workovers.

A separation sleeve may be used while troubleshooting. It may be installed in a permanently locked open safety valve to test the integrity of the control line. The packing on the separation sleeve straddles the safety valve from top to bottom. It is installed and retrieved by wireline.

8.2) Functional Requirements

8.2.1) Tubing Retrievable

1. Connect to tubing string
2. Withstand internal pressure
3. Withstand collapse pressure
4. Subject to temperature cycling
5. Stop well flow when closed
6. Failsafe close
7. Subjected to various fluids and gases
8. Subjected to tension and compression loads
9. Ability to reopen valve

8.2.2) Wireline Retrievable

1. Installed and retrieved by wireline
2. Lands and seals in profile nipples
3. Contain internal pressure
4. Stop well production when closed
5. Failsafe close
6. Subjected to various fluids
7. Ability to reopen valve

8.2.3) Desirable Characteristics of Subsurface Safety Valves

In order for a subsurface safety valve to operate properly and in a reliable fashion, its design should include the following features:

1. It should include sensors that measure abnormal conditions as quickly and directly as possible. When possible, the system should detect an abnormally before a catastrophic failure occurs.
2. It should be highly reliable.
3. It should be simple. Only when it is an operational necessity should components be added to the system. Reliability worsens rapidly as the number of components increases.
4. It should be durable. This is particularly true of surface equipment since it represents the final barrier to a complete catastrophe; it is also true for subsurface safety valves.
5. It must be designed to give years of service in the expected downhole environment (pressure, temperature, loading, corrosion, erosion, etc.).

8.3) Design Basis

Industry standards used are API 14A / ISO 10432.

8.4) Potential Leak Paths

8.4.1) Material failure

For purposes of this document only the failures that could cause sustained casing pressure will be discussed. There are numerous components that could fail. While this would cause valve failure, it would not necessarily be a cause of sustained casing pressure. This type of failure would occur due to induced stress exceeding the allowable yield stress of the metallic components. Failure could be brought on by poor design, erosion, corrosion, material and/or manufacturing lacking proper QC, installation damage, or changes in operational conditions that exceed original design criteria. This would generally be a catastrophic failure.

8.4.2) Connection leakage.

Due to the nature of subsurface safety systems there are numerous connections with leak potential.

1. Control line connections/bushings from the tubing hanger to the SCSSV
2. Tubing joint connections where the SCSSV connects to the tubing string
3. SCSSV body joint connections: Due to the requirements for assembly an SCSSV usually contains two or more body joint connections. These are usually manufacturer proprietary.

Depending on the design, the sealing mechanism of these connections can be proprietary metal to metal, elastomer, interference, or a combination.

8.5) Leak Prevention

As previously discussed much can be done early in the design stages to reduce the potential for problems. These actions include proper material selection to withstand the environmental requirements, proper design and review, and proper validation testing. Validation testing is especially critical for elastomers and determining the combined load capabilities of the body joint connection.

8.6) Remediation Options

After determining through diagnostic means that the cause of casing pressure is due to a pressure integrity failure of the subsurface safety system, there are some options.

1. Continue to use as is, after risk assessment.
2. Sealant could be pumped in an attempt to plug a control line leak. The only control line leakage we are concerned with here is in the control line itself or the connections/bushings. Any leakage through the operating system of the SCSSV (i.e. past the piston) generally will leak internally into the flow stream and not to the annulus.

3. SCSSV Body joints, might be isolated out by locking the valve open and installing a wireline retrievable valve if the TRSCSSV is so equipped to receive one.
4. Pull the equipment and repair or replace.

9) Expansion Joint

9.1) Description

An expansion joint is used to compensate for tubing movement caused primarily by changes in temperature. It is run on the tubing string and can be splined to transmit torque or can rotate unless in the full open or closed position. The sealing of moving parts is by elastomer seals.

9.2) Design Basis

Manufacturer's proprietary basis of design.

9.3) Potential Leak Paths

1. Body Failure
2. Tubing End connections
3. Internal Body connections
4. Seal Failure

9.4) Leak Prevention

1. A properly validated design
2. Attempt to reduced the frequency of seal movement

9.5) Remediation Options

1. Continue to use as is, after risk assessment.
2. Attempt to re-space and reduce tubing movement thereby exposing the seals to different seal surface.
3. Pull tubing to repair or replace.

10) Seating Nipples

10.1) Description

There are three types of seating nipples used as an integral part of the tubing string.

1. pump seating nipples
2. selective landing nipples
3. nonselective or No-Go landing nipples

Seating nipples, which are used to accommodate a pump, plug, hanger, or flow control device, consist of a polished bore with an internal diameter marginally less than the tubing drift diameter. Usually a lock profile is also required, especially for landing nipples.

Seating nipples and the devices that are set inside them can be used for the following purposes:

1. to facilitate pressure testing of the bottomhole assembly and tubing couplings, and the setting of hydraulic packers
2. to land and seal off a bottomhole pump (pump seating nipple)
3. to isolate the tubing if it is to be run dry for high drawdown perforating
4. to land wireline retrievable flow controls, such as plugs, tubing safety valves, bottom hole chokes, and regulators
5. to plug the well if the tree must be removed
6. to land bottomhole pressure bombs
7. to pack-off across blast joints
8. to install a standing valve for intermittent gas lift
9. to plug the tailpipe below packer in order to pull the tubing without killing the well
10. to temporarily plug the well while the rig is moved on or off the well

10.1.1) Selective Landing Nipples

Selective Landing Nipples are nipples with a common internal diameter. In some, the lock profile is varied for easy identification. Others are accessed by tripping the lock mechanism at the selected depth. Selective nipples are used when more than one nipple is required within a single string of tubing, and the designer wishes to maintain maximum through bore.

10.1.2) No-Go Landing Nipples

No-Go Landing Nipples are designed with an ID that is slightly restricted to provide a positive shoulder to locate a locking mandrel. At least one No-Go nipple is usually located at the bottom of the tubing string or tailpipe to prevent loss of swabbing or other wireline tools into the sump.

10.2) Design Basis

Service company manufacturer’s proprietary design.

10.3) Potential Leak Paths

1. Body Failure
2. Tubing Connection leak

10.4) Leak Prevention

1. Proper design validation
2. Proper installation procedure

10.5) Remediation Options

1. Continue to use as is after risk assessment.
2. Pull tubing and replace

11) Flow Couplings

11.1) Description

Flow couplings are special joints having tubing ID and collar or coupling OD dimensions. They are usually manufactured from special heat-treated steel.

Since most flow controls restrict the ID, the tubing above and below the controls can be protected against internal erosion by use of a flow coupling. Flow couplings should be run immediately above and below any landing nipple which maybe used to install a downhole choke, or retrievable SCSSV or SSCSSV. In high rate or corrosive gas wells, flow couplings should be used above and below all upsets or profile changes to reduce erosion, especially if the turbulent fluid contains abrasive particles.

The length of the flow couplings vary. The length depends on several factors, depending on flow rate, fluid composition, and or individual company policy.

11.2) Design Basis

Service company manufacturer's proprietary design

11.3) Potential Leak Paths

1. Body failure
2. Tubing connection leak

11.4) Leak Prevention

1. Properly validated design
2. Proper installation procedures

11.5) Remediation Options

1. Continue to use as is after risk assessment
2. Pull tubing and repair or replace

12) Side Pocket Mandrels

12.1) Description

Side pocket mandrels (SPM) are a special eccentric nipple that can accommodate a valve parallel to the tubing to control access to the annulus. They can be used to install wireline retrievable gas-lift valves, circulation devices, flow control valves, and injection valves. The location of the side pocket mandrels for gas-lift valves will be determined by the lift gas pressure available, kickoff requirements and the density of the fluid to be lifted. If high density brines and kill fluids are to be kicked out with gas, a closer spacing is needed than on dead oil wells that will be swabbed-in and only have to kick-off from the free-standing liquid level.

It is sometimes desirable to have an SPM located just above the top packer in high pressure gas well completions for installation of a shear-open kill valve and/or injection valve. These are used to facilitate a controlled circulation kill in the event the upper tubing becomes obstructed. They are also used as a connection point for corrosion-inhibitor lines. Some operators use side pocket mandrels to install a pressure and temperature sensor that can transmit data to the surface via a cable attached to the outside of the tubing.

Some engineers prefer to use a side pocket mandrel instead of a sliding sleeve above the top packer. The elastomer seals on a side pocket circulation valve are easily retrieved and redressed using wireline, while repair of those in a sliding sleeve requires a workover. However, most side pocket circulation valves have a limited throughput capacity. Using a side pocket mandrel without using a seat protector runs a risk of cutting out the valve seat in the mandrel, which would inevitably require a workover to replace the mandrel.

Conventional Gas lift Valves: Conventional gas lift valves are not discussed here as there will always be pressure on the casing during gas lift.

12.2) Design Basis

Service company manufacturers proprietary design

12.3) Potential Leak Path

1. Body failure
2. Tubing connections
3. Seals on flow control device
4. Through the side pocket device (i.e. valve)

12.4) Leak Prevention

1. Properly validated design
2. Proper manufacturing QC
3. Proper installation procedures
4. Avoid excessive circulation rate through an empty side pocket

12.5) Remediation Options

1. Use as is after assessing the risks
2. Pull and repair or replace valve or flow control device
3. Pull tubing and repair or replace mandrel

13) Sliding Sleeve

13.1) Description

Also referred to as sliding side doors or circulating sleeves, these tubing components are used to obtain access from the tubing to the tubing/casing annulus either for fluid circulation or to permit a previously isolated zone to be produced. They are opened and closed with a wireline tool that has a locating key that engages the profile in the sleeve.

These devices are typically placed above each packer in the well. Obviously, they are an essential requirement of mufti-zone completions scheduled for selective production. Many producers run sliding sleeves in each string of a multi-string completion to increase production flexibility.

A sleeve is sometimes run above the upper packer and can be useful for the following operations:

1. kick-off by displacing the tubing contents with a low-density fluid and avoiding use of coiled tubing or circulation of low-density fluids before the packer is set
2. minimizing the cost of well killing prior to a tubing pulling job or workover
3. circulating out completion fluid with a packer fluid (e.g. from mud to brine or from water to inhibited brine) or changing packer fluid types (e.g. spotting corrosion inhibitor or thermal insulating fluid)
4. testing of subsurface safety valve (SSSV)
5. spotting treatment fluids

13.2) Design Basis

Service company manufacturer's proprietary design basis

13.3) Potential Leak Paths

1. Body Failure
2. Tubing Connections
3. Body Joint Connections
4. Sealing failure at the elastomer sleeve seal

13.4) Leak Prevention

1. Properly validated design
2. Proper manufacturing QC
3. Proper installation procedure
4. Reduce frequency of operation
5. Use of molded/bonded seals
6. Reduce differential across seal when opening

13.5) Remediation Options

1. Continue to use as is after risk assessment
2. Open and close to attempt to reestablish pressure containment of seal
3. If sliding sleeve is equipped with profile and polished bore: run isolation sleeve
4. Pull tubing to repair or replace

14) On Off Tool

14.1) Description

An on/off tool is usually a short compact, overshot type tubing disconnector, with a jay that automatically engages and releases with rotation. The On-Off Seal Unit is used with double-grip retrievable packers, or with latch type seal assemblies.

When mounted above a double grip retrievable type packer, this tool provides a means of disconnecting the tubing string without unseating the packer. The overshot portion connected to the tubing usually contains the elastomer seals. These seals can be pulled with the tubing and inspected without removing the packer or seal assembly.

The mandrel OD has a sealing finish and a wireline profile is sometimes machined into the mandrel to allow the ability of blanking off the zone below the packer with a wireline retrievable plug.

14.2) Functional Requirements

1. Provide pressure containment (internal/external)
2. Withstand tension and compression loads
3. Ability to transmit torque through the tool
4. Wireline profile for plugging
5. Able to engage and disengage multiple times
6. Connect to tubing and packer or latch type seal assembly
7. Capable of withstanding well fluids and operating temperatures

14.3) Design Basis

Service company manufacturer's design criteria

14.4) Potential Leak Paths

1. Body failure
2. Tubing/Packer connection leak
3. Leak past elastomer seals

14.5) Leak Prevention

1. Eliminate or minimize tubing movement that would cause seal wear
2. Proper selection of materials (metallic and elastomers)
3. Properly validated design

14.6) Remediation Options

1. Continue to use as is after risk assessment

2. Set plug in wireline profile if well is to be temporarily abandoned
3. Pull tubing and overshot and replace the seals
4. Pull Packer or seal assembly to repair or replace

15) Safety Joint

15.1) Description

A Tubing Safety joint is commonly used above packers when some type of emergency tubing string separation is required because of the likelihood of a stuck packer or seal assembly. Safety joints are usually operated by either rotation or straight pull shear release. Rotation type safety joints are usually best when large tension loads are expected.

15.2) Design Basis

Service company manufacturer's proprietary design basis

15.3) Potential Leak Path

1. Body Failure
2. Tubing/Packer connections
3. Safety Joint connections

15.4) Leak Prevention

1. Properly validated design
2. Proper manufacturing QC
3. Proper installation procedures

15.5) Remediation Options

1. Continue to use as is after risk assessment
2. Pull and repair or replace

16) Packers

16.1) Description

Packers are used in wells to provide a pressure tight barrier. The barrier may be intended to separate a tubing space from an annular space or to divide a well into compartments above and below the packer.

The strategic uses of packers include the following:

1. Protection as it allows use of kill and / or inhibited fluid in the annulus. It allows diversion of corrosive fluids into the tubing.
2. Isolation Between Zones in multi-zone completions
3. Gas Lift to confine gas to the annulus so that gas can be injected into the tubing in a controlled amount
4. Control of Slugging by diverting all produced fluids into the tubing which prevents gas and liquids from building up in the annulus and periodically kicking liquid slugs up the tubing
5. Pressure Containment by diverting high-pressure well fluids into the tubing reducing the risk of casing failure

Packers can be categorized in several ways.

1. Setting method:

   a. Mechanically Controlled Tools. Tools are set and released mechanically by manipulation of the drill string or tubing

   b. Hydraulic Controlled Tools intended for hydraulic manipulation can be designed to function off surface induced pressure in the drill pipe/tubing pressure or exposed to the well's hydrostatic pressure

   c. Wireline Controlled Tools

      1. Electric Conductor Line using a pressure setting assembly
      2. Slickline - This is a nonconductor line; in other words. no electrical current is passed through the wireline. A set of downhole jars and weight bars are used to develop the setting/unsetting force.
      3. Sandline - This type of line is the strongest type wireline commonly used in the field. It is employed when the well is not under significant pressure.

2. Retrievability:

   a. Permanents which are sometimes called drillable or seal bore packers: The typical packer in the group is permanently installed in a well until it is drilled/milled out. This group includes some packers that are retrievable but their construction is similar to permanents.

   b. Retrievables: The typical packer in this class is run and retrieved on tubing. Some types of this group have opposing lockable slips and can be run with on off tools that allow the tubing to detach from the packer after it is set.

16.2) Permanent Packers

16.2.1) Description

The term permanent refers to the packer's attachment to the casing wall by opposite acting slips. Permanent packers are called permanent because they cannot be retrieved on the production string. The most commonly used permanent packers are designed to be drilled out or milled out rather than recovered.

A few permanent packers are actually made to be retrievable. They may have either a shear release or they may have an unlocking mechanism. Many of the retrievable permanents can only be retrieved with a special service tool that must be run in after the production string is recovered.

Permanent packers have obtained a reputation for dependability in hostile environments due to their simple design, construction and operation.

The principal features of a permanent packer are the central rubber packing element, the seal bore and the external opposing slips.

16.2.2) Setting Methods for Permanent Production Packers

16.2.2.1) Wireline set

A wireline set permanent production packer (with or without an expendable plug) is run to the desired setting depth and set with the appropriate size wireline pressure setting assembly (PSA) and adapter kit.

Once the packer is set and the pressure setting assembly is retrieved, the tubing, seal assemblies, and production tube are lowered into the well.

An electrical impulse triggers an explosion within the pressure setting tools piston chamber to set the packer. Ensuring the proper oil level in the setting tool as well as the correct power charge will help ensure that the packer is set properly by applying the correct force and time to set. Too little oil in the setting tool will cause a lack of driving force and too quick a power charge burn will result in an improperly set packer.

16.2.2.2) Mechanical Setting Tool

Mechanical set permanent production packers have drag springs that allow torque to be transmitted to the packer for setting. Rotation of the tubing string will release the upper slips of the packer. An upward pull is then initiated at the tool to set the lower slips and compress the sealing elements. Once the packer has been set the setting assembly is retrieved from the well and replaced by a locator seal assembly and the well is placed on production.

16.2.2.3) Hydraulic Setting Tool

A hydraulic setting tool is available for setting permanent packers on drill pipe or tubing. It is similar to the mechanical setting tool in that the tool is used only for setting the permanent packer, and must be retrieved after the packer is set. The hydraulic setting tool must be released from the packer and tripped out of the well. The final tubing string with a seal assembly on bottom would be run in and landed to complete the hook up.

The setting procedure starts with making up the packer on the setting tool. The packer is run down to setting depth. A ball is dropped from surface, which lands in a seat in the setting tool. Applying tubing pressure causes the upper slips to set. Pulling tension can then set the lower slips. The set of the packer should be checked by slacking off weight and pulling weight. The packer manufacturer should recommend the amount of weight to pull and set down to ensure that the rubber elements are fully set and that this will hold their rated pressure differential. The setting tool can then be released from the packer.

The hydraulic and mechanical setting tools are also useful when there are severe doglegs in a well which would cause a packer run on wireline setting assembly to hang up.

16.2.2.4) Self Setting Permanent Packers

Special one trip hydraulically set permanent packers are used in many deviated wells. This "hydro-set" packer has a packer setting mechanism attached to the bottom of the packer body. The seal assembly is pinned or latched to the packer so that all components: tailpipe, packer, seal assembly, and final string can be run together.

Once the tool is "on depth" a ball is dropped into the production tubing allowing it to fall into a seat in the packer. After pressure is applied to set the packer, a further elevation in tubing pressures will shear the ball seat loose, allowing it to fail to bottom.

16.2.3) Seal Assemblies

The second half of a permanent packer is the seal assembly that lands in the bore of the packer. The seat assembly may have a latching device or it may be run without a latch so that the seal assembly can move within the packer in response to tubing stress and movement. Seal assemblies typically have chevron type packing rings.

The seal assembly can be landed in three modes as discussed

16.2.3.1) Unlimited or Free Motion

The tubing movement is accommodated by sufficient seal bore extensions under the packer, by a PBR (Packer Bore Receptacle), or an Overshot Seal Assembly above the packer. The seal assembly is stabbed into the seal bore without latching or locking. Free vertical travel is possible.

16.2.3.2) Limited Motion

To aid the space out of seal assemblies, a Location Shoulder is often used so that the seal assembly will bottom-out on the packer or receptacle. This provides the option of landing the tubing such that the seals will not move downward during normal production operations, but are free to move up if the well is cooled.

16.2.3.3) Latched or Fixed

The tubing is latched or fixed on the packer allowing no movement

16.2.4) Design Basis

ISO 14310 and manufacturer’s proprietary design

16.2.5) Potential Leak Paths

1. Packing Element System leak can be caused by:
    a. Elastomer extrusion
    b. Thermal/Chemical effects on the packer elastomer element
    c. Damage upon installation
    d. Failure of the packer element back ups
    e. Packer body loc ring failure

    All of which can cause the packer element to lose pressure sealing capability

2. Body to seal bore extension connection leak can be caused by differential pressure below the packer-to-packer ID. Since the pin connection is generally a thinner cross section. Excessive differential can cause pin deflection and loss of pressure integrity from the production casing annulus, especially if seal assembly is located in seal bore extension below this pin.
    2. Left Hand Square Thread failure only occurs when tubing is anchored as tensile load is taken through a thread relief and internal pressure results in swelling. Failure causes loss of seal integrity and is catastrophic.
    3. Seal assembly seal leak can be caused by damaged seals during installation, seal bore damage, seal movement out of the seal bore, wear on seals due to excessive seal movement, adverse reaction to well fluids/temperature/or excessive pressure.
3. Seal Assembly mandrel connections (if any): Generally referring to a failure of mandrel connection. Usually caused by loss of pressure integrity, due to combined loading effect and design of connection.
4. Tubing to seal assembly connection: could be caused by improper makeup, damage, or improper type connection for the combined loads of tension, compression, burst, collapse encountered.

16.2.6) Leak Prevention

1. Properly validated design
2. Proper manufacturing QC
3. Proper installation procedure
4. Design for no seal movement, if possible

16.2.7) Remediation Options

1. Continue to use is, after risk assessment
2. Check space out to ensure seal assembly fully landed
3. Pull seal assembly and repair/ replace seal assembly
4. Run another production packer above packer in question
5. Drill/Mill out packer and replace

16.3) Retrievable Packers

16.31) Description

Packers of the retrievable design usually include a manual or automatic jay ("J") and/or a hi/lo cam. Basically these mechanisms allow the tool to be run into the wellbore in a "safety position" Retrievable packers may also have a rotation or hydraulic setting mechanism.

With a mechanical set retrievable, upon reaching the intended setting depth, a manipulation of the work string will un-jay the tool and allow weight or tension to pack off the rubber sealing elements.

The main components of a retrievable packer are

1. Slips or holding devices: Which are either mechanically operated (Slips) or hydraulically operated (holddown buttons). Slips and hold downs keep the tool in place and maintain compression loads on the packing element.
2. Packing element made from various elastomer compounds and when compressed seals against the casing wall.
3. Gauge rings on either side of the packing element. They are the largest OD of the retrievable packer also act as an extrusion barrier when the packing element is compressed. In permanent packers, back up rings or shoes that expand to the casing ID are used instead of gauge rings.
4. Mandrel is the basic strength member of the packer. It provides the flow path through the packer. The strength of the mandrel and the elastomer rating determine the pressure rating of the packer.
5. Bypass valve or unloaders are often found on retrievable packers. They allow communication of pressure around the packing elements. This helps prevent swabbing off the elements while running and also helps to equalize pressure when unsetting the packer.

16.3.2) Design Basis

ISO 14310 and service company manufacturer’s proprietary design.

16.3.3) Potential Leak Paths

1. Packing element failure. Can be caused by:
   a. Damage or abrasion to the elements either during installation or while in operation
   b. Improper gauge ring size (i.e. extrusion gap)
   c. Insufficient force applied to pack off against the casing
   d. Thermal or chemical reaction from the environment
2. Mandrel Failure. Mandrel failure could be caused by erosion, corrosion or induced stresses exceeding the yield stress.
3. Mandrel connection failure or
4. End connection failure. Leakage through the threaded connection for a number of potential reasons. End connections are typically EUE type connections of limited pressure ratings while the mandrel connection is usually a proprietary thread that incorporates an elastomer o-ring for sealing.

5. Bypass failure. Bypass leakage could be caused by damage to either the elastomer or metal lip. Leakage could occur because of damage caused by opening under higher than recommended differential pressure. Elastomer could be damaged by thermal or chemical reactions.

16.3.4) Leak Prevention

1. Proper installation procedure
2. Utilize proper class of retrievable packer for the application
3. Properly validated design
4. Proper manufacturing QC

16.3.5) Remediation Options

1. Continue to use as is after risk assessment
2. Attempt to reset or reposition packer
3. Pull tubing and repair or replace packer

17) Polished Bore Receptacles

17.1) Description

The Polished Bore Receptacle (PBR) was introduced to the industry as an alternative to the packer type completion. Its main attribute is an integral sealing mechanism between the tubing and the casing string requiring no secondary tools or setting. PBR's can be installed (a) directly in the casing string, (b) as a part of the liner hanger, or (c) on top of a production packer.

The PBR is simply a section of heavy wall pipe with a honed inner surface into which a seal assembly is run.

As with a permanent packer seal assembly, the tubing can be anchored, have limited motion, or be free to lengthen and contract in response to pressure and temperature change.

Where PBR's are installed as part of the casing or liner, they provide the greatest possible through bore across the tubing to casing pack-off. Therefore, they are common on deep high pressure wells completed with small liners and on very high rate wells.

PBR Type Seal Receptacles are sometimes used on top of packers in place of an overshot seal receptacle or seal bore extension. Redundant seals are less exposed to the produced fluid in this configuration, but more liable to damage during installation than with an overshot arrangement.

17.2) Design Basis

Service company manufacturer's proprietary design basis

17.3) Potential Leak Paths

1. Body failure
2. Lower PBR connection leak (for liner top or packer installations only)
3. PBR connection leak (for long PBRs)
4. Past the elastomer seals of a seal assembly

17.4) Leak Prevention

1. Properly Validated Design
2. Properly qualified connections
3. Elastomer seals on Seal assembly validated
4. Proper manufacturing QC
5. Proper installation procedure

17.5) Remediation Options

1. Continue to use as is after risk assessment

2. Respace to ensure full seal engagement
3. Pull and replace seal assembly
4. Install (stack) a packer if PBR is on a liner hanger or production packer PBR
5. Install a production packer if PBR is installed in the casing

18) Conclusions

As referenced throughout the previous discussion, the elimination of sustained casing pressure due to improper design or equipment application is best handled early in the well construction process. Many problems could be eliminated before the equipment is installed by proper design verification, equipment validation, and manufacturing quality controls.

Once the equipment is installed there are a limited number of options available to eliminate the sustained casing pressure problem. Generally the two options are:

1. Isolate across the leak if possible, such as installing an isolation sleeve in a leaking sliding sleeve, or installing a wireline retrievable safety valve inside a tubing retrievable valve with a leaking body joint connection.
2. Remove and repair or replace the component.

Both of these require well intervention to repair subsurface equipment.

A third option previously discussed would not eliminate the casing pressure, but the option is to continue to operate after performing a risk assessment.

19) Recommendations

Further study in the form of a separate project is needed to determine the risk of sustained casing pressure occurrence and also the risk danger to the environment. The risk would be determined by developing quantitative risk analysis, HAZOP's. Additional "tools" should be developed such as "fish bone" diagrams of failure modes and decision trees for the most common types of equipment. This would aid by developing steps for corrective action to reduce possibility of SCP in future installations and how to deal with it when it occurs.

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20.2) Engineering Design Practices

20.2.1) API Publications

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20. *Specification for Casing and Tubing*

20.2.2) Risk Based Design of Well Casing and Tubing (SPE Seminar)

5. *A Reliability Approach to the Design of OCTG Tubulars Against Collapse*
6. *Analytical Burst Strength Prediction of OCTG With and Without Defects*
7. *Burst Pressure Prediction of Thin Walled, Ductile Tubulars Subjected to Axial Load*
8. *Collapse Behavior of Casings: Measurement Techniques, Numerical Analysis and Full Scale Testing*

21. *Determination of Casing and Tubing Burst and Collapse Design factors to Achieve Target Level of Risk, Including Influence of Mill Source*

22. *On the Development of Reliability-based Design Rules for Casing Collapse*

23. *The Development of Risk-Based Burst Design for Well Casing and Tubing*

20.3) Misc. Papers and Publications

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35. *Mobil Well Equipment Design Manual*

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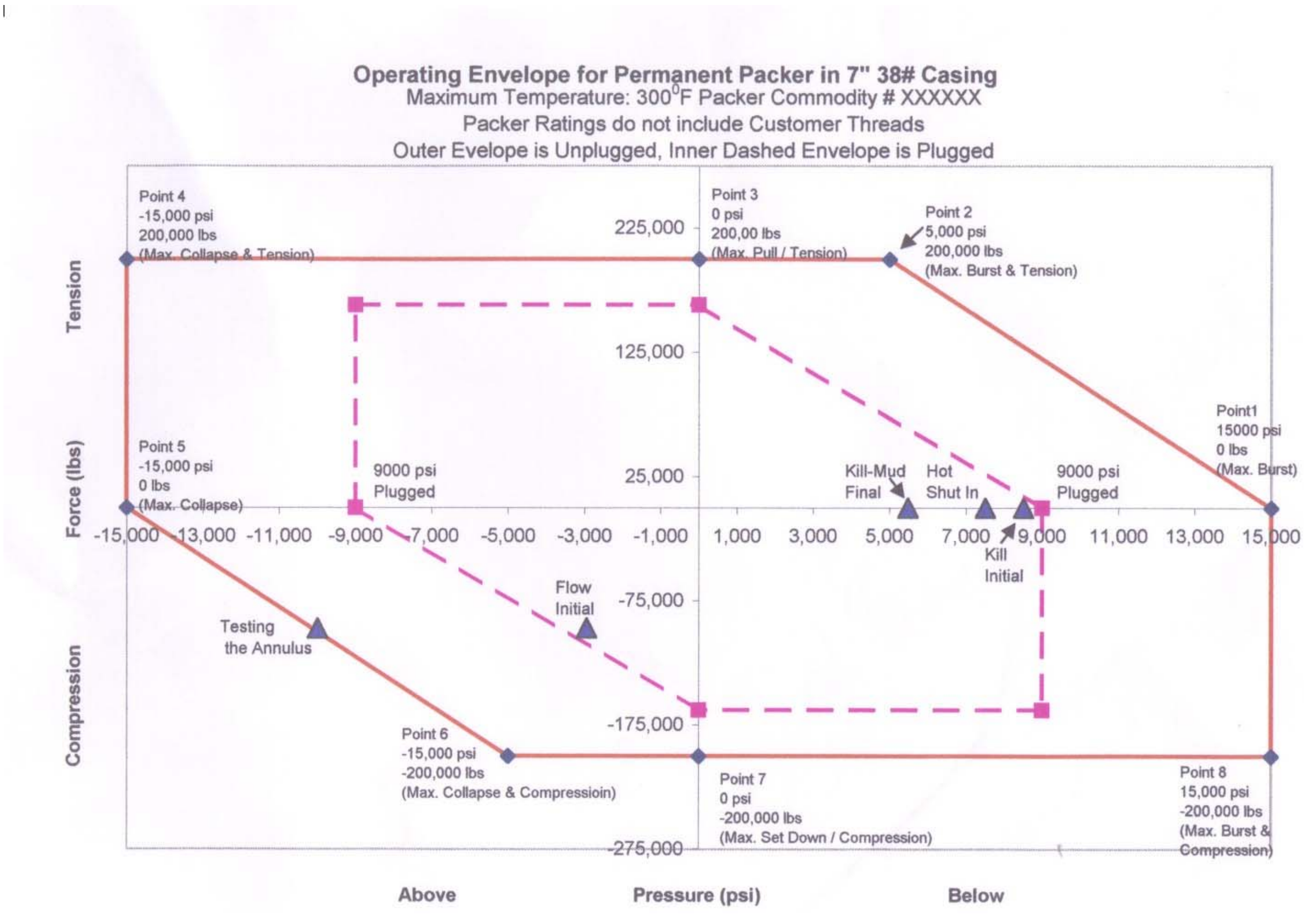
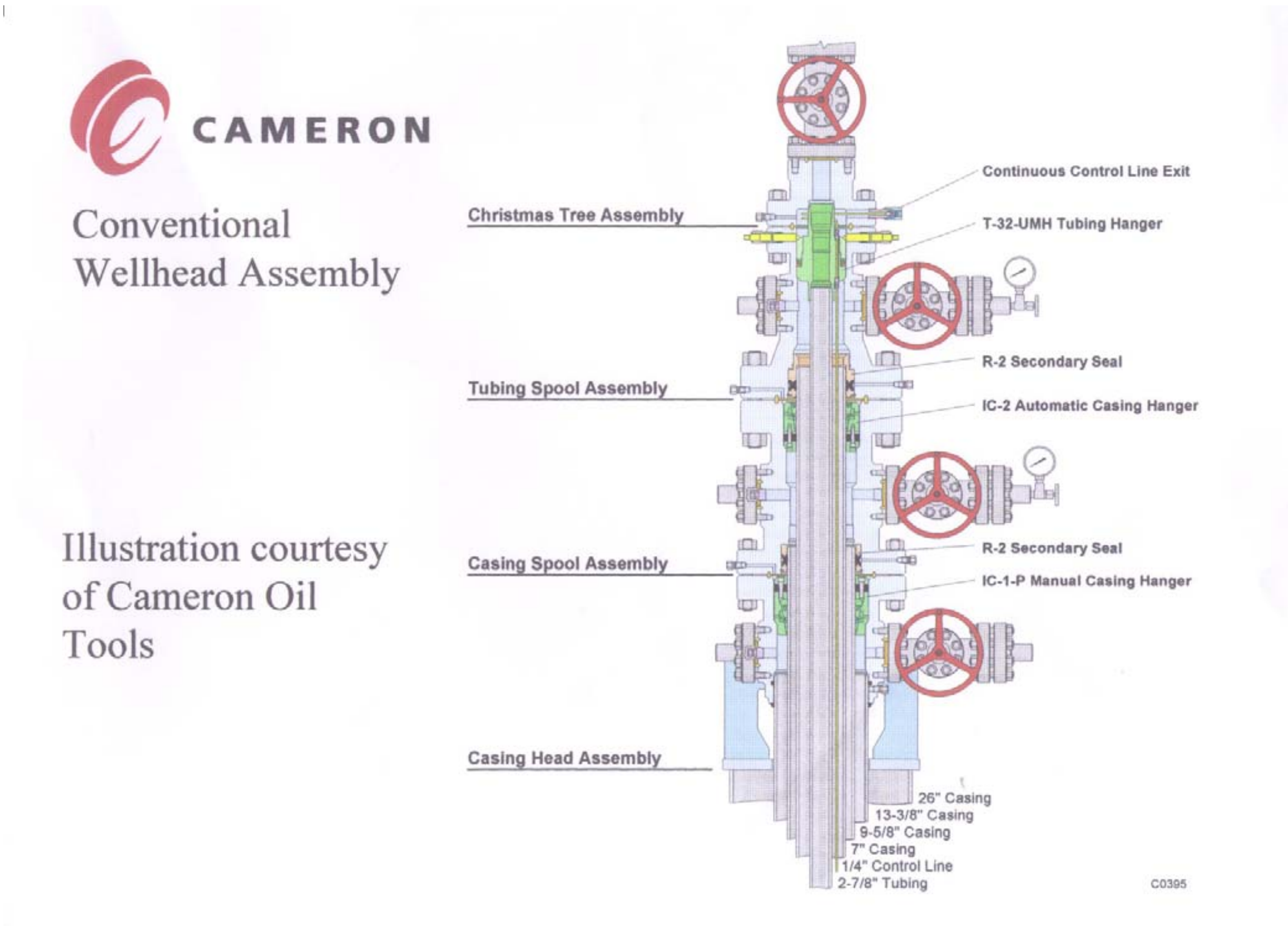
Appendix A: Diagrams

A.1) Packer Performance Envelope



A.2) Wellhead schematic



A.3) Wellbore sketch with casing and wellhead

EXAMPLE WELL

	Depth	Length	O.D.	I.D.	Description
14	0.00	0.00	0.00	0.00	Tree Cap
13	0.00	0.00	0.00	0.00	Flow Tee
12	0.00	0.00	0.00	0.00	Manual Gate Valve
11	0.00	0.00	0.00	0.00	Master Valve
10	0.00	0.00	0.00	0.00	Base
9	0.00	0.00	0.00	0.00	Casing 9-5/8"
8	0.00	0.00	0.00	0.00	Casing 9 5/8"
7	0.00	0.00	0.00	0.00	Casing 9 5/8"
6	0.00	0.00	0.00	0.00	Casing 9 5/8"
5	0.00	0.00	0.00	0.00	Liner Hanger
4	0.00	0.00	0.00	0.00	Liner 7"
3	0.00	0.00	0.00	0.00	Liner 7"
2	0.00	0.00	0.00	0.00	Perforated Liner 7"
1	0.00	0.00	0.00	0.00	Liner Shoe

A.4) Wellbore diagram with downhole equipment

WELL STATUS RECORD	FIELD:	PLATFORM:	WELL NO. DWG 1a

Well Type: Oil Producer	RTE:	Max. Dogleg:
First Completed:	Tubing Hanger:	Max. Deviation:
Workover Date:	KOP:	Av. Angle Thru. Pay:
Workover No.:	HUD:	Minimum ID:
Ann. Fluid:	Depth Units:Feet	
Fluid Wt.:	Ref. Log:	

Casing Data

Size (in)	WT (lb/ft)	Grade	Conn.	MD	TVD
10-3/4"	60.7	L80			
9-5/8"	53.5	L80			

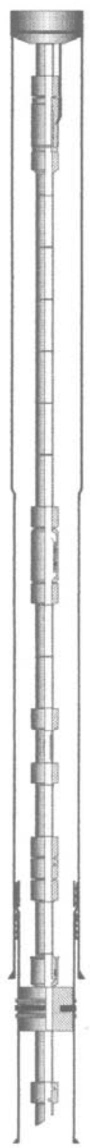
Wellhead Data

	Maker	Type	Bore (in)	Flanges (in)	Rating (psi)
Xmas Tree			5- 1/8"		5000
Wellhead			13.625		5000
Tubing Spool			13.625		5000
Tubing Hanger			5		5000

Liner Data

Size (in)	WT (lb/ft)	Grade	Conn.	MD	TVD
7"	29	L80			

MD BRT	TVD BRT



Description	Maker	MIN. I.D.	MAX. O.D.	Drift	Length	Material	Threads
Tubing Hanger 3 1/2"	0.	0.000	8.50	0.00	10.00		
Tubing 3-1/2"		0.000	0.00	0.00	29.99		
Flow Coupling	0.	0.000	0.00	0.00	6.00	Super 13CR	
T.R.S.C.S.S.V 3-1/2"	0.	2.992	5.75	0.00	2.40	0.	
Flow Coupling	0.	2.992	3.92	0.00	6.00	Super 13CR	
Tubing 3 1/2"	0.	0.000	0.00	0.00	30.00	0.	
Tubing 3 1/2"	0.	2.992	3.50	0.00	30.00	0.	
Tubing 3 1/2"	0.	2.992	3.50	0.00	30.00	0.	
Tubing 3 1/2"	0.	2.992	3.50	0.00	30.00	0.	
Tubing 3 1/2"	0.	0.000	0.00	0.00	30.00	0.	
Tubing 3 1/2"	0.	0.000	0.00	0.00	30.00	0.	
Flow Coupling	0.	0.000	0.00	0.00	6.00	L80 13 CR	
Sidepocket Mandrel 5-1/2" Latch T2 Valve Dummy		0.000	0.00	0.00	29.99		
Flow Coupling	0.	0.000	0.00	0.00	6.00	L80 13 CR	
Tubing 3 1/2"	0.	0.000	0.00	0.00	30.00	0.	
Tubing 3 1/2"	0.	0.000	0.00	0.00	30.00	0.	
Flow Coupling	0.	0.000	0.00	0.00	6.00	L80 13 CR	
Sliding Sleeve	0.	2.750	4.00	0.00	4.00	0.	
Flow Coupling	0.	0.000	0.00	0.00	6.00	L80 13 CR	
Tubing 3 1/2"	0.	0.000	0.00	0.00	30.00	0.	
Flow Coupling	0.	0.000	0.00	0.00	1.97	L80 13 CR	
Selective Nipple	0.	2.750	4.00	0.00	2.50	L80	
Flow Coupling	0.	0.000	0.00	0.00	1.97	L80 13 CR	
Tubing 3 1/2"	0.	0.000	0.00	0.00	30.00	0.	
P.B.R. 20 ft long	0.	0.000	0.00	0.00	0.00	L-80 13 Cr	
Permanent packer	0.	0.000	0.00	0.00	14.78	L-80 13 Cr	
Tubing 3 1/2"	0.	0.000	0.00	0.00	30.00	0.	
Seating Nipple	0.	2.625	4.00	0.00	2.50	L80	
Wireline Entry Guide		0.000	0.00	0.00	24.00	L80	

SECTION IV: CORROSION CONSIDERATIONS IN SCP

1) Introduction

Despite efforts by Oil & Gas Operating Companies to design and install production tubing and casing strings that will remain leak-free for the operational life of their wells, there are a number of time dependent degradation mechanisms that may result in leakage into the production tubing-by-production casing annulus. The most significant (or certainly the most publicized) of these degradation mechanisms appears to be corrosion and/or environmentally induced cracking of the tubing and casing strings and their associated completion hardware.

The inner surface of the production tubing string is, of course, susceptible to the corrosive effects of the produced well fluids. The most significant active corrosive species found in the primary production from Gulf of Mexico (GOM) oil and/or gas wells appears to be the acid gases, carbon dioxide and hydrogen sulfide. When these acid gases dissolve in the formation brine or condensed water that is usually produced from the well, low pH, aqueous solutions result. These solutions, in turn, may produce corrosion and/or environmentally induced cracking (sulfide stress cracking or chloride stress cracking) of the alloys used in the production tubing and production casing strings.

There appears to be a growing body of recent evidence that traces of organic acids (sometimes present in produced well fluids) may also play a significant role in lowering the pH, and thus increasing the corrosivity, of the produced water or brine. Also, in gas lift wells and water injection wells (used for reservoir pressure maintenance), oxygen can be accidentally introduced into the well tubing or into the tubing-by-production casing annulus. At comparable concentrations, it is known that oxygen is much more corrosive than either CO_2 or H_2S to carbon and low alloy steels. Experience has thus shown that even very small concentrations of oxygen in hot salt water can result in very high corrosion and pitting rates in carbon and low alloy steels.

The exterior of the production casing string (below the outer, surface and/or intermediate strings) may also be exposed to the action of corrosive formation fluids. The extent that the formation fluids attack the exterior of the production casing will, of course, depend upon the quality and the height of the cement used to install the production casing. In addition, the "exposed" exterior of the production casing string may suffer corrosion due to the action of any "stray DC currents" that may "go to ground" over this section of casing.

The outer surface of the production tubing and the inner surface of the production casing may also suffer corrosive attack by the "packer" or well completion fluids that are usually left in the annulus for well control purposes. These completion fluids are commonly high salinity brines that may become very aggressive if they are contaminated by small leaks of carbon dioxide or hydrogen sulfide (from the production stream) or by small concentrations of dissolved oxygen (air).

1.1) CO_2 Corrosion

As detailed below, the severity of corrosion due to carbon dioxide in "sweet" oil and gas wells depends upon a number of environmental conditions. These include (but are not limited to): the partial pressure of carbon dioxide in the produced gas, the well temperature, the composition of the produced water, the amount and characteristics of any liquid hydrocarbons produced from the well, the velocity and flow regime of the production stream, the in-situ or down-hole pH of the produced water and the tendency for stable iron carbonate scale to form on the corroded tubing surface.

Corrosion due to carbon dioxide can occur as general weight-loss corrosion, as pitting and as localized corrosion in areas of turbulence and changes in flow direction. Pieces of equipment in the production tubing string that contain changes or restrictions in the flow path are thus particularly susceptible to corrosion attack. For example, accelerated attack has been observed in landing nipples, in elbows at the wellhead, and in the “J-areas” of API connections.

Numerous models that purport to predict the rate of corrosion due to carbon dioxide have been described in the literature. These models are based both on considerations of basic electrochemical and hydrodynamic effects and upon expert systems developed from field observations. Several of the domestic model developers also offer commercially available technical support to operators that may need to investigate the anticipated severity of corrosion for specific applications.

In using the corrosion rates predicted by a model (for assessing the anticipated life of a tubing string or in performing economic evaluations of alternative corrosion mitigation schemes), it is important to determine the extent to which the model incorporates all the important aspects of the specific well under consideration. It should also be remembered that the conditions in the well (e.g., total well pressure and thus partial pressure of carbon dioxide, composition of the produced brine, concentration of hydrogen sulfide, flow rate and flow regime of the produced well stream, etc.) may undergo substantial changes during the life of the well. The predicted corrosion rates over the total anticipated range of operating conditions that may be experienced during the life of the well should thus be investigated.

Before using a particular model, the user should also understand the basic philosophy used in developing the model. It is our understanding that some of the models are intended to give conservative, worst case corrosion predictions while other models reportedly use correlations with field data to produce more realistic, representative predictions.

1.2) H_2S, Sulfide Stress Cracking

Tubing and casing strings are typically “designed” for resistance to sulfide stress cracking (SSC) by limiting the selection of materials for sour service to those that are essentially immune to SSC (regardless of exposure time) at stress levels up to some useful percentage of their yield strengths. The concentrations of hydrogen sulfide above which the production stream is considered “sour” (and which will thus probably cause SSC) are defined in NACE Standard MR0175-2000, “Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment”, Figures 1 and 2 [1]. Other important variables that, according to MR0175, have an effect upon the tendency for alloys to exhibit SSC include:

1. Alloy hardness,
2. Alloy chemistry and heat treatment,
3. Water/brine pH,
4. Temperature,

5. Time,
6. Total stress.

A careful reading of MR0175 indicates that other variables may also have an effect upon the tendency of an alloy to exhibit SSC. These include:

1. Water/brine composition (salinity and buffering capacity),
2. Presence/absence of cold work in the alloy,
3. Presence/absence of elemental sulfur in the well environment,
4. The manufacturing process used to produce the alloy.

Alloys were originally added to MR0175 based upon their successful use in sour service in the field. MR0175 has, however, since been accepted as a mandatory requirement by several regulatory bodies. New alloys are thus presently added to MR0175 based upon the results of laboratory testing. The testing procedures given in NACE Standard Test Method, TM0177, "Laboratory Testing of Metals for Resistance to Specific Forms of Environmental Cracking in H_2S Environments" [2], are typically used as the vehicle to add new materials to MR0175.

Materials that have been found to be acceptable (from the standpoint of SSC) for specific equipment and components used in oil & gas production are discussed in Sections 6 through 11 of MR0175. Section 10, in particular, discusses tubulars and subsurface equipment for use in oil & gas production.

1.3) Other Damage/Degradation Mechanisms

In addition to CO_2 corrosion and sulfide stress cracking, other time dependent damage mechanisms that may lead to leakage into the "primary", production tubing-by-production casing, annulus include the following:

1. Stress Corrosion Cracking (SCC or Chloride Stress Cracking) of austenitic stainless steels and similar alloys,
2. Erosion,
3. Galvanic corrosion effects caused (for example) by coupling more corrosion resistant alloy completion hardware (e.g., packers, etc.) to carbon steel tubulars,
4. Environmentally and/or stress induced degradation of elastomeric seals,
5. Wear/abrasion of "movable" seal areas due to accumulation of debris and/or corrosion products,
6. High or low cycle metal fatigue due to temperature and/or pressure cycles,
7. Gradual penetration of the thread dope used to seal API connections by the combined effects of temperature/pressure cycles and attack of the thread dope by high pressure gas,
8. Crevice corrosion in tubing or casing connections, seal areas, etc.,
9. Corrosion initiated by improperly executed acidizing operations,
10. Corrosion caused by contamination of the well by oxygen (accidental introduction of air into the well),
11. Corrosion in the well annulus due to the action of bacteria and/or algae (MIC),
12. Damage caused by running wire lines and/or coiled tubing in the well.

These latter potential damage mechanisms are outside the scope of the present discussion but should, of course, be considered during well design considerations.

1.4) CO_2 Corrosion Models

A listing and review of several of the existing CO_2 corrosion models has recently been published in the European Federation of Corrosion (EFC) Publication Number 23, "CO_2 Corrosion Control in Oil and Gas Production", [3]. Table 1 was taken from EFC Publication Number 23. The models listed in Table 1 include proprietary (in-house) models, models that have been more or less fully documented in the literature and models that have been privately developed but which are currently commercially available for use.

We have included detailed information describing models 5, 6 and 7 in Attachment A. The information given in Attachment A was retrieved from the internet at the internet locations identified. Models 6 and 7 were developed in the U.S. and are currently commercially available for either purchase or for performing individual assessments of well environments of potential interest.

The early work of de Waard and coworkers that ultimately resulted in the "Shell" model (model 1 of Table 1) revealed many of the significant characteristics of CO_2 corrosion of carbon and low alloy steels. For example, the Shell "Nomogram for CO_2 Corrosion" that allows easy estimation of the predicted corrosion rate at various temperatures and CO_2 partial pressures is given Figure 1. The combined effects of temperature and CO_2 partial pressure on the anticipated corrosion rates are shown in Figure 2. A listing of factors (see Table 1) that are known to affect the rate of CO_2 corrosion of carbon and alloy steel tubulars include the following:

1. CO_2 partial pressure,
2. Temperature,
3. Water/brine pH,
4. Flow rate of produced fluids and gas,
5. Flow regime of produced fluids and gas,
6. Tendency for protective scales to form on tubing surfaces,
7. The tendency for the steel surface to be oil or water wet,
8. The Ca and HCO_3 contents of the produced water,
9. The H_2S content of the produced gas,
10. The presence of organic acids in the produced water.

In using any of the predictive models listed in Table 1, the user should, of course, review the details of the model (with its developer) so that he or she understands the assumptions and limitations built into the model. The user should also investigate if the model is designed to estimate a "worst case" (highest) corrosion rate or if it is designed to predict average corrosion rates.

In addition to the parameters listed immediately above (and in Table1), the ability of each model to include the effects of the following well parameters should also be investigated. If these additional well parameters are not included in the analyses, methods to quantify and include their effects should be considered.

1. Local hole angle and its effect upon flow regime,
2. The effects of local turbulence (due to changes in flow cross section or direction),
3. Erosion,
4. The tendency for pitting and/or crevice corrosion to occur in the well environment,
5. The anticipated effectiveness of the corrosion inhibitors and inhibition programs that may be used in the well,
6. The anticipated effectiveness of internal plastic coatings (if they are to be used in the well).
7. The volume and nature of oil produced by the well (e.g., does the oil have a tendency to deposit paraffin?).

It should also be recognized that the well conditions will probably vary considerably over the life of a well. For example, the total well pressure and thus the partial pressure of CO_2 will probably change significantly. The relative volumes of water, oil and gas will probably also change. The composition of any produced water (representing the mixture of formation brine and condensed water) could change significantly during the life of the well. It is also not unusual for the H_2S content of the reservoir, and thus the produced well fluids, to increase during the life of the reservoir. Finally, if wells are converted to gas lift, gas injection or water injection wells at some time during their life, the accidental inclusion of oxygen (air) into the annulus and/or tubing of the well may result in significant increases in the corrosion rates in the well. In using predictive corrosion rate models, the anticipated well conditions at various times in the life of the well must thus be taken into consideration.

Finally, the user should determine, if possible, the accuracy with which each model has been able to predict observed field corrosion rates. Ideally, the user will have field corrosion data for reservoirs similar to the one being investigated for this comparison.

1.5) Sulfide Stress Cracking

As discussed above, tubing and casing strings are typically designed for SSC resistance by selecting materials for their construction that are basically immune to H_2S cracking. Guidelines for selection of candidate materials for sour service are presented in NACE Standard MR0175-2000. Many of the materials that were originally included in MR0175 were included based upon successful field service. For new candidate materials that users and/or manufacturers may want to add to the Standard, however, the testing procedures described in NACE Standard TM0177 are typically used.

An extensive list of the material and environmental variables that may play a role in sulfide stress cracking was given above. One of the most important variables identified earlier was the total stress (active plus residual) that the component may experience while in service. Unfortunately, a careful examination of MR0175 reveals that there are only limited guidelines in that document concerning the stress levels at which an “acceptable” material may be successfully used. In addition, although the stress levels used for testing per TM0177 must be determined and reported for an acceptable test, there are also no recommendations in TM0177 as to the stress levels that should be considered for use in qualification testing programs.

Discussions with current MR0175 committee members revealed that the stress levels at which candidate materials are presently usually tested (per NACE TM0177) and approved for use (per NACE MR0175) are 80% to

100% of their minimum specified yield strengths. It is our understanding, however, that a material that may have been tested at lower stress levels might be accepted for use in a specific, low stress application, if the voting MR0175 committee members felt that the stresses in service would always be low enough to result in an acceptable level of safety. Again, unfortunately, this level of subtlety in the material selection and approval process is not obvious from simply reading the two applicable NACE documents.

In comparison, the document EFC Publication Number 16 "Guidelines on Materials Requirements for Carbon and Low Alloy Steels for H_2S-Containing Environments in Oil and Gas Production" [26], lists suggested acceptance stress levels of 90% or more of the actual yield stress for use in SSC testing of tubing, casing, welded piping and pressure vessels. For SSC testing of materials for use in "low-pressure containing equipment" and "heavy section/complex shape components", the EFC document suggests that an acceptance stress level equal to or greater than the actual service stress be used during SSC acceptance testing.

A review of API 5CT, "Specification for Casing and Tubing" [27], on the other hand, shows that the API Grades C90 and T95 must be successfully tested to only 80% of the specified minimum yield strength for these grades using the procedures of NACE TM0177 in order to meet the requirements of API 5CT for SSC resistance.

Despite its lack of specific guidelines on minimum recommended test stresses for many materials, MR0175 does offer many specific recommendations concerning the material and environmental conditions required for resistance to SSC. For example, the maximum acceptable hardness levels (and thus, by inference, the maximum strengths) of a large number of materials are given in the specification. There are also admonitions that specific heat treatments must be performed on some alloys. There are specific limitations on the chemical composition and metallurgical microstructure of several alloys. There are also requirements that specific manufacturing processes must be used in the production of various alloys.

Several sections of MR0175 deal specifically with materials for use in tubulars and down hole equipment. Section 10.2, for example, covers materials for use in tubulars and tubular components. Section 10.3, on the other hand, covers materials for use in other subsurface equipment (e.g., gas lift equipment and packers). Table 5 of the specification lists "Acceptable API and ASTM Specifications for Tubular Goods" while Table 6 lists "Acceptable Materials for Subsurface Equipment".

1.6) Corrosion and Cracking in Environments Containing Both H_2S and CO_2

For service environments that contain appreciable levels of both H_2S and CO_2, test environments defined in NACE MR0175 can be used to generate data concerning resistance to corrosion as well as environmental cracking. For example, Table 1 of MR0175 lists test environments containing partial pressures of H_2S and CO_2 of up to 508 psi at temperatures of up to 410^0 F.

For production environments containing more than 20 to 30 psi CO_2 and more than 1 to 2 psi H_2S, it is common for high alloy materials to be considered for use in the production tubing and casing strings. A listing of corrosion resistant materials that have been used in oil and gas production environments is presented in the NACE Publication 1F192, "Use of Corrosion-Resistant Alloys in Oilfield Environments" [28]. Included in Publication 1F192 (in Sections 5, 6 and 7) are a list of environments in which various alloys have been successfully used. For example, as discussed in Sections 6.3.1.2 and 6.3.1.3, there appears to be a growing consensus that 9Cr-1Mo and 13 Cr materials (when properly heat treated) can be used for tubulars in handling environments containing H_2S partial pressures as high as 0.5 to 1.5 psi.

Another NACE publication, 1F196, "Survey of CRA Tubular Usage" [29], presents a survey and history of the use of high alloy materials for oil and gas production tubing and casing. The data presented in 1F196 represents information from both U.S. domestic as well as international operations. Information presented below in Table 2 compares the footage of various alloy tubulars that have been used in world-wide operations with the footage that has been used in Gulf of Mexico (GOM) operations. It is interesting to note that while GOM operations accounted for only approximately 14% of total world-wide CRA tubular footage (at the time of the survey), the use of the more highly alloyed tubulars (Alloy 28 through C276 in Table 2) in GOM operations accounted for approximately 57% of the world-wide use of these higher alloy materials. These data appear to indicate that either domestic U.S. well designers are more conservative (specify higher alloy materials) than engineers that design international wells or that GOM operations include production environments that are significantly more aggressive than those encountered in international operations.

Recommendations for test procedures to be used in evaluating the corrosion and environmental cracking resistance of candidate corrosion resistant alloys can also be found in EFC (European Federation of Corrosion) Publication Number 17, "Corrosion Resistant Alloys for Oil and Gas Production: General Requirements and Test Methods for H_2S Service" [30]. As in NACE TM0177, EFC Publication Number 17 discusses specimens that consist of smooth uniaxial tensile samples, 4-point bent beam samples, and C-ring samples. EFC Publication Number 17, however, also discusses the use and interpretation of slow strain testing in evaluating the resistance of alloys to sulfide stress cracking. In addition, EFC Publication Number 17 discusses test methods to be used for evaluating the resistance of alloys to environments that contain both H_2S and elemental sulfur. Laboratory data and field experience have both shown that the presence of elemental sulfur may result in very aggressive corrosion of alloys used for production tubing and casing.

Information of the type presented in the NACE publications MR0175, 1F192 and 1F196 has been used by the manufacturers and suppliers of alloy tubulars (along with what appears to be the results of their own extensive, in-house testing programs) in developing simple guidelines for the use of various alloys in down-hole environments. The alloy selection guides from several manufacturers of CRA tubulars are presented in Attachment B. The selection guides that cover the full range of environmental conditions typically use a threshold CO_2 concentration (in the range of ~3 to 30 psi partial pressure in the gas) to switch from carbon and low alloy steels to higher alloys. The higher alloys then initially considered generally consist of 13 Cr and or one of the duplex stainless steels (e.g., 2205 or 2507). At even higher temperatures and higher H_2S partial pressures, austenitic Fe-Cr-Ni alloys (e.g., Alloy 28 and Alloy 825) and other high alloy, proprietary alloys are typically recommended.

It is our understanding that the test data used to generate the selection guides presented in Attachment B include possible effects due to sulfide stress cracking (SCC), chloride stress cracking (SCC), general weight loss corrosion as well as pitting and crevice corrosion. It is recommended that detailed discussions with the manufacturers be conducted prior to selection and use of a material based upon one of the guides. If the anticipated use environment is significantly different than the range of environments used to generate the selection guides, it may be necessary to perform high temperature, high pressure autoclave and/or flow loop testing to investigate the suitability of any of the various candidate alloys.

A commercially available, computer based “Expert System” is available that, according to its developer, allows the user to “select applicable materials (CRAs) for all types of oil and gas production and non-production environments”. The expert system is apparently based on data of the type discussed above, as well as laboratory data generated by the developer of the system itself. It is our understanding that the expert system, which uses a PC based Windows environment, can either be purchased or may be used by its developer to supply analyses on a case-by-case basis. Information concerning the expert system (called “Socrates” by its developer) is included below in Attachment C.

2) Corrosion Prevention

Methods that have commonly been used to successfully combat corrosion (and cracking) of production casing, tubing and completion hardware include:

- Selection and Use of High Alloy Tubulars (as discussed above),
- Use of Corrosion Inhibitors,
- Use of Internal Plastic Coatings.

The use of production operation changes (such as reduction of the production rate of high temperature, high pressure gas wells) that might also reduce the corrosion and erosion rates in the well are outside the scope of this presentation.

2.1) Corrosion Inhibitors

Discussions of corrosion inhibitors and their use in production applications are available in several sources [31,32,33]. The inhibitors typically used for down-hole applications consist of high molecular weight, polar, organic molecules. The active portion of the inhibitor molecule generally consists of or contains a monoamine, a diamine or an amide. The inhibitor apparently functions when the active end of the inhibitor molecule forms a weak "bond" to the metal surface. The organic end of the inhibitor molecule then forms an oily, water repellant film over the protected surface.

The amount of inhibitor attached to the surface (and thus the level of corrosion protection) apparently depends primarily upon the concentration of inhibitor in the produced fluids as well as the temperature. There are also temperature limits above which the inhibitors change composition and thus lose most of their effectiveness. Comparative testing of various candidate inhibitors in test environments similar to those anticipated in the field should be considered prior to initiating an inhibition program. Consideration should also be given to closely monitoring the on-going performance of inhibitors after the start of production operations.

Methods of inhibitor application include both continuous and intermittent (or batch) treatments. The method of application usually depends upon the well configuration.

In continuous inhibitor injection, a chemical displacement pump at the surface may be used, in conjunction with small diameter concentric or non-concentric tubing strings, to pump inhibitor to the bottom of the well on a more-or-less continuous basis. The use of a concentric string may not require that the well be completed with a packer between the production tubing and the production casing. A non-concentric inhibitor injection string, on the other hand, can be used to introduce the inhibitor below a packer or through a side pocket mandrel.

Intermittent or batch inhibitor treatments can be done in wells that have been completed with or without a bottom-hole packer. For wells completed without a packer, a common treatment procedure consists of injecting a "batch" of inhibitor into the production tubing-by-production casing annulus and then by-passing production from the well into the annulus. The inhibitor batch may be simply displaced into the bottom of the tubing from the annulus and then produced with the well fluids/gas after one pass through the tubing. Alternatively, the produced inhibitor batch may subsequently be circulated back into the annulus (for re-circulation again at a later date).

For wells with a packer, the "tubing displacement" technique is often used. In this method, an appropriately diluted batch of inhibitor is displaced to the bottom of the tubing string. After what is judged an appropriate shut-in period, the well is put back into normal operation, thus coating the inner surface of the production tubing with inhibitor as the inhibitor is produced from the well.

For areas where experience has shown that the inhibitor will not "damage" (significantly reduce the production capacity of) the producing formation, an inhibitor "squeeze" technique might be considered in wells that are completed with a packer. In this method, the inhibitor "batch" is displaced to the bottom of the well and is then displaced or "squeezed" into the surrounding producing formation. The inhibitor is thus adsorbed onto the internal surfaces of the formation and is slowly produced back up the production tubing when the well is put back into normal operation.

In wells with a packer, a down-hole injector valve can also be used to periodically or continuously inject inhibitor solution into the production tubing. In this method, the annulus is typically kept full of inhibitor solution. The inhibitor treatment then consists of displacing inhibitor into the tubing by injecting additional inhibitor into the annulus at the surface.

Despite the application technique employed, it is recommended that candidate corrosion inhibitors be subjected to comparative testing prior to final selection for use in a well. This testing might simply consist of static exposures of steel coupons to simulated produced brines to which inhibitors have been added. Slightly more sophisticated testing might include "wheel" testing in which coupons are mounted on a wheel that is rotated such that the coupons spend part of their exposure submerged in the brine and part of their exposure in the gas phase of the simulated production environment. Finally, a re-circulating flow loop (in which the anticipated down-hole flow conditions of the well are duplicated as closely as possible) could be used to give even more realistic predictions of inhibitor performance.

2.2) Plastic Coatings

Discussions of plastic coatings for use in production tubing are available [32,33]. These sources indicate that the coating systems normally used to internally coat production tubing consist of either phenolics or fusion bonded epoxies. Information concerning plastic coating systems from two of the major suppliers of these systems is given in Attachment D. A review of the information in Attachment D reveals that the upper temperature limit of the coating systems ranges from approximately 200^0F to approximately 400^0F, depending upon the coating. The information also indicates, however, that the coating systems may exhibit substantially lower temperature limits when exposed to significant concentrations of H_2S.

Adequate care must be exercised by the coating manufacturers during the application of internal plastic coatings. In particular, the inner surface of the tubing is usually given an initial cleaning by acid pickling and water washing. After the initial cleaning, the inner surface is then sandblasted in order to remove any surface oxidation or remaining solids. The coating should then be applied as soon as possible following the cleaning, before a fresh layer of rust can form on the cleaned surface. The coatings are then checked for pin-holes (or "holidays") using an electrical detector that is sensitive to high conductivity paths through the coating.

A NACE document, Standard RP0191, Standard Recommended Practice, "The Application of Internal Plastic Coatings for Oilfield Tubular Goods and Accessories" [34], discusses, in detail, the points mentioned above.

Finally, it should be realized that internal coating systems are susceptible to mechanical damage due to flexing and/or mechanical impacts of the pipe during transportation and running of the tubing. The coatings near the ends of the pipe are particularly susceptible to handling and "stabbing" damage while the pipe is being run in the well.

3) Corrosion Monitoring

What appears to be a more or less complete compilation of the possible techniques for monitoring corrosion in general industrial applications has recently been published by NACE in the NACE Publication 3T199, "Techniques for Monitoring Corrosion and Related Parameters in Field Applications", [35]. In Publication 3T199, the monitoring techniques are divided into the following categories:

- Direct methods
  Intrusive & Non-intrusive,
- Indirect techniques
  On-line & Off-line.

Direct, intrusive monitoring methods include (for example): coupons, and electrical probes that are inserted through the wall (pressure boundary) of the equipment. Direct, non-intrusive methods, on the other hand, include measurement techniques that can be performed without penetrating the wall of the equipment. These techniques include: ultrasonics, magnetic flux leakage, eddy current techniques, radiography and acoustic emission.

Indirect, on-line techniques consist of measurements of some characteristic of the active corrosion environment. These include (for example): pH, solution conductivity, and dissolved oxygen content of the brine, as well as flow velocity, pressure and temperature of the produced fluids/gas. Indirect, off-line methods consist primarily of measurements of the corrosion environment that are made on samples that have been removed from the system under investigation. These indirect, off-line measurements include measurements of: alkalinity, metal ion concentrations (e.g., iron and manganese), dissolved solids, dissolved gases and residual inhibitor concentrations in the produced water/brine.

Our review of the literature revealed that the techniques that are most commonly used to successfully monitor on-going, active corrosion of down-hole tubulars include: measurements of iron and manganese contents in the produced brines and measurements of residual inhibitor concentrations. Unfortunately, the areas of primary interest in the tubing strings may be remote from the surface and significant changes in the corrosion environment may thus occur as the production stream is brought to the surface. The direct, intrusive techniques and the remainder of the indirect techniques (other than the measurements of iron and manganese and residual inhibitor concentrations) have thus not proven to be very useful in tracking down-hole corrosion rates. Also, while dissolved iron and manganese concentrations and residual inhibitor concentrations can apparently be successfully correlated with over-all average corrosion rates in production tubing strings, these measurements cannot predict where the corrosion is taking place and whether or not it may be concentrated over some relatively small portion of the total well depth.

NACE publications describing the use of coupons [36], hydrogen probes [37], and galvanic probes [38] for monitoring corrosion in oil and gas operations are available. There is also an NACE publication [39] that describes the use of "iron counts" (dissolved iron concentrations in the produced water) for monitoring down-hole corrosion processes.

Fortunately, down-hole casing and tubing logging tools have been developed that use most of the measurement techniques described above as the "direct, non-intrusive techniques". Although the individual measurement techniques used in these tools may be described as "non-intrusive", for the well taken as a whole, the tools actually are intrusive since the well flow must be shut-in in order to allow the introduction of the logging tools into the top of the well.

Another NACE document is available [40] that describes the logging tools that have been developed for evaluating down-hole corrosion in casing and tubing strings. The down-hole casing and tubing logging tools described in the NACE document include the following:

- Multi-finger, mechanical calipers,
- Ultrasonic tools,
- Electromagnetic tools
  - DC flux leakage tools
  - AC tools.

The NACE document also includes discussions of casing potential profile tools, temperature measuring tools and optical (TV camera) inspections. The measurements of these latter tools, however, do not depend upon the remaining wall thickness of the casing or tubing and their results are thus only indirect or qualitative indicators of the condition of the tubulars at the time of the inspection.

3.1) Mechanical Calipers

Mechanical calipers detect the internal radius at a number of circumferential locations in the tubular being inspected. The "single-stylus" type mechanical caliper records data only from the feeler that is detecting the maximum internal radius at any depth. In the "maximum-minimum" monitoring tool, the outputs of the two feelers that are sensing the maximum and minimum internal radius of the tubular at any depth are recorded. The "complete monitoring" mechanical caliper tools, on the other hand, record the internal radii from all of the feelers of these tools.

One of the "complete monitoring" mechanical caliper tools (available from Schlumberger) is run on wire line and the results from each of the feelers are sent back to the surface and are recorded as the tool is run. The only other "complete monitoring" tool (that we are aware of) is available from the Kinley Corporation. The Kinley tool is completely mechanical and records the information from each feeler on a down-hole chart drum. The Kinley tool thus contains no electronics and is reportedly capable of operating at temperatures above 500^0 F and in very aggressive (high H_2S) environments.

<u>3.2) Ultrasonic Tools</u>

The ultrasonic tools use pulsed, normal wave ultrasonic transducers to measure the internal diameter and wall thickness of the tubular being examined. There are two types of ultrasonic tool available. The single transducer type tool uses a single transducer to send and receive the ultrasonic signal. In this type of tool, either the transducer itself rotates or there may be a rotating "prism" that directs the sonic pulse to and from the inner tubular surface from a stationary transducer. The multiple transducer type ultrasonic tools, on the other hand, typically use eight stationary, radially focused transducers to send and receive the ultrasonic pulses.

3.3) Electromagnetic Tools

The DC flux leakage tools use an electromagnet to establish a high DC magnetic field parallel to the axis of the tubular being examined. As the tool is pulled upward through the tubular, sensitive "pad mounted" search coils (or solid state detectors) sense the "flux leakage" generated by both internal and external corrosion pitting and surface roughness of the pipe. The pads of the tool also contain coils that use high frequency AC signals to generate eddy currents on the adjacent internal surface of the tubular. Signals from these eddy current coils can thus be used to determine if a matching flux leakage indication has come from an internal or an external imperfection. Information collected from prior calibration of the tool (using simulated corrosion defects) is then used to estimate the depth and areal extent of corrosion damage.

The AC electromagnetic tools include: 1) a high frequency "electromagnetic caliper" that measures the average internal circumference (and thus the average internal diameter) of the tubular being examined and 2) a low frequency "far-field eddy current" tool that senses the average wall thickness of the tubular. The electromagnetic caliper uses relatively high frequency signals to determine the average internal circumference over a one to two inch long axial section of the tubular being examined. The "far-field eddy current" tool, on the other hand, uses the phase shift and attenuation of low frequency signals induced in the pipe wall between a set of transmitter and receiver coils to estimate the average wall thickness of the pipe between the coils.

Of the corrosion monitoring tools discussed above, the DC flux leakage tools appear to be the most sensitive to small, isolated corrosion pits and surface "roughening" due to corrosion. The results of the flux leakage tools do not, however, appear to be as accurate as those of the other tools.

For measuring the effects of internal corrosion, the multi-finger mechanical calipers are clearly the most reliable and most accurate of the tools presented above. The mechanical calipers do not, however, give any information concerning wall losses that may have occurred on the outside surface of the pipe.

Because they only respond to the average values of the inner diameter or average wall thickness of the tubulars, the AC electromagnetic tools, while apparently reasonably accurate (on a percentage basis) for very large defects, are almost totally insensitive to small, isolated defects.

The ultrasonic tools, while inherently very accurate, may be susceptible to significant loss of signal when the inner and/or outer surfaces of the pipe are "rough" or are not oriented perpendicular to the sound beam. In addition, with the ultrasonic tools, the tubing or casing under examination must be fluid filled in order for the tools to function.

When tubing (and/or casing) can be retrieved from the well, it can be inspected on the surface with inspection systems having expanded and improved inspection capabilities. These surface inspection systems have typically included DC flux leakage devices capable of detecting both circumferential and longitudinal imperfections and gamma ray inspection devices capable of determining remaining wall thickness.

More recent surface inspection systems have included ultrasonic inspection devices with multiple heads, each containing multiple transducers. Depending upon the surface roughness of the tubing or casing, these ultrasonic inspection tools (e.g., Tuboscope-Vetco's "Truscope" inspection system) should do an acceptable job of finding both crack-like defects and in measuring remaining wall thickness.

4) Economic Considerations

Several sources of information dealing specifically with the economic aspects of corrosion are available [32,41,42]. The NACE document, Publication 3C194 [41], for example, is a very good source of information on the subject. Although several methods of economic analysis are presented in Publication 3C194, the present worth (PW) or net present value (NPV) method is recommended, since the PW method is both relatively easy to apply and is apparently the method normally used in most evaluations of engineering economy.

Generalized equations for performing PW evaluations are presented in Publication 3C194, along with a number of worked examples. The equations in Publication 3C194 allow the inclusion of the following considerations in the PW analysis of corrosion related items:

- Calculation of the present values of capital expenditures as well as all expense items that may be incurred during the life of the project,
- The effects of equipment depreciation,
- The effects of federal and state income taxes,
- Effects of the salvage value of equipment at the end of the project.

In order to perform meaningful comparative PW evaluations of several alternatives, the analyst must have reasonably accurate information concerning the capital, expense and operating costs associated with each alternative. Accurate information for the anticipated service life of the equipment (tubing, casing and down-hole completion equipment) in each alternative must also be available or must be estimated. For tubulars and other down-hole equipment, information concerning the anticipated service life must therefore be available or must be estimated using one or more of the methods given above. The effects of internal plastic coatings and corrosion inhibitors can also be included in the PW evaluations if reliable information concerning the effects of these corrosion "prevention/reduction" methods on the expected useful life of the equipment is available.

As discussed above, it should be remembered that the corrosivity of the produced gas and fluids from a well may change significantly during the life of the well. The location(s) of the maximum corrosion rates within the well may also change significantly during the life of the well. These observations should, of course, be considered during life predictions and PW evaluations of alternative completion schemes.

A listing of the abstracts of a number of published articles dealing with "case studies" of field corrosion assessments and economic evaluations of alternative completion schemes is given in Attachment E.

5) Conclusions

The rate of general corrosion of carbon and low alloy steels by CO_2 has been shown to be a complex function of many well parameters. The most important of these probably include the following:

- CO_2 partial pressure,
- Temperature,
- Down-hole (in-situ) water/brine pH,
- Flow rate and flow regime of the produced fluids and gas.

A number of "models" have been developed for predicting the corrosion rates of carbon and low alloy steels due to CO_2. In order to effectively utilize the results of these models, the user should have an understanding of the basic assumptions employed in developing each model as well as well as a knowledge of which well parameters have been included in each model.

At exposure temperatures of less than approximately 225^0 F, carbon and low alloy steels used in API tubulars may be susceptible to sulfide stress cracking (see Table 5 of NACE MR0175). As in the case of CO_2 corrosion, there are numerous well (and material) parameters that may have a significant influence on the SSC resistance of the steels. The most important of these apparently include the following:

- H_2S partial pressure,
- Temperature,
- Exposure time,
- Hardness (or strength) of the alloy,
- Stress level,
- Water/brine pH.

Information given in several NACE documents [1,2] can be used to minimize the probability of SSC of any carbon or low alloy steel components that are considered for use in a well.

When significant concentrations of both CO_2 and H_2S are present in the produced gas from high temperature, high pressure wells, high alloy tubulars are often considered for use in the wells. Alloy selection guides (see Attachment B), as supplied by various manufacturers of casing and tubing, are convenient sources of information for selecting candidate corrosion resistant alloys (CRA's) for tubing and casing. Several NACE documents [28,29] also contain applicable information concerning the use of CRA's for down-hole tubulars.

Our review of the corrosion literature indicated that measurements of iron concentrations and residual inhibitor concentrations in the produced water/brine from oil and/or gas wells are apparently the currently preferred methods for "on-line" monitoring of the active corrosion processes in the wells. Unfortunately, these techniques cannot yield any information concerning the location(s) and distribution of the corrosion that is detected.

When production from a well can be "shut-in", down-hole logging tools are available for monitoring the condition of the tubulars in the well. Our experience indicates that the DC flux leakage type tools are the most sensitive of the available tools for detecting small, isolated corrosion pits and the initial stages of general surface roughening due to corrosion. The size of the DC flux leakage tools generally limits their use to pipe that is approximately 3-1/2 inches (and larger) in diameter. In cases where internal corrosion of the production tubing is of sole or primary interest, one of the multi-finger mechanical calipers is clearly the preferred logging tool for quantifying the extent of the problem. The fully mechanical tool (supplied by the Kinley Corporation) can reportedly operate at higher temperatures and in more aggressive environments than competitive, electromechanical tools.

When several technically feasible solutions are available to a corrosion problem, an economic evaluation of the alternatives should be considered. Information on performing present worth (PW) evaluations of such alternative solutions to corrosion problems is available in the literature. In performing these PW evaluations, the analyst needs accurate estimates of the anticipated life of the equipment to be used in the well. In addition, accurate data for the anticipated capital expenditures and operating costs for the well must be available. A listing of the abstracts of a number of "case studies" of field corrosion assessments has been included as an attachment to this report.

Finally, a "General Information" section has been added to the Bibliography, in which a number of papers that contain useful information are referenced by groupings.

TABLES

Table 1: Models

PARAMETER	1	2	3	4	5-NORSOK	6-USL	7-PREDICT
CO_2 PAR. PRESS.	•	•	•	•	•	•	•
TEMP	•	•	•	•	•	•	•
PH	•	•	•	•	•	•	•
FLOW RATE	•	•	•	•	•	•	•
FLOW REGIME	•	□	•	•	•	•	•
$FeCO_3$ SCALE	•	□	•	•	•		•
TOT. PRESS.	•	□	•	•	•	•	•
STEEL COMP.	•	□	•	•	-	-	-
WATER WETTING	□	□	•	-	-	•	•
Ca/HCO_3	-	•	-	-	-	-	•
H_2S	-	•	•	-	-	•	•
ORGANIC ACIDS	-	•	-	-	-	•	•
FIELD DATA	-	•	•	-	-	•	•
REFERENCES	4,5,6,7	8	9	10	11	12-24	25

• = Considered directly
□ = Considered indirectly, effect assumed small
\- = Not considered

Table 2: Use of CRA (THOUSANDS OF METERS)

	CASING		TUBING	
ALLOY	WORLD	GOM	WORLD	GOM
9cr	63.6	0	191.6	0
13cr	38.1	0	2,525.2	202.9
22cr	0	0	371.5	78.7
Alloy 28	0	0	10.7	10.7
825	0	0	68.4	40.1
2550	1.6	1.6	174.9	61.4
G3	0.9	0	10.5	6.1
G50	0	0	38.4	38.4
C276	9.7	3.1	68.8	59.1

FIGURES

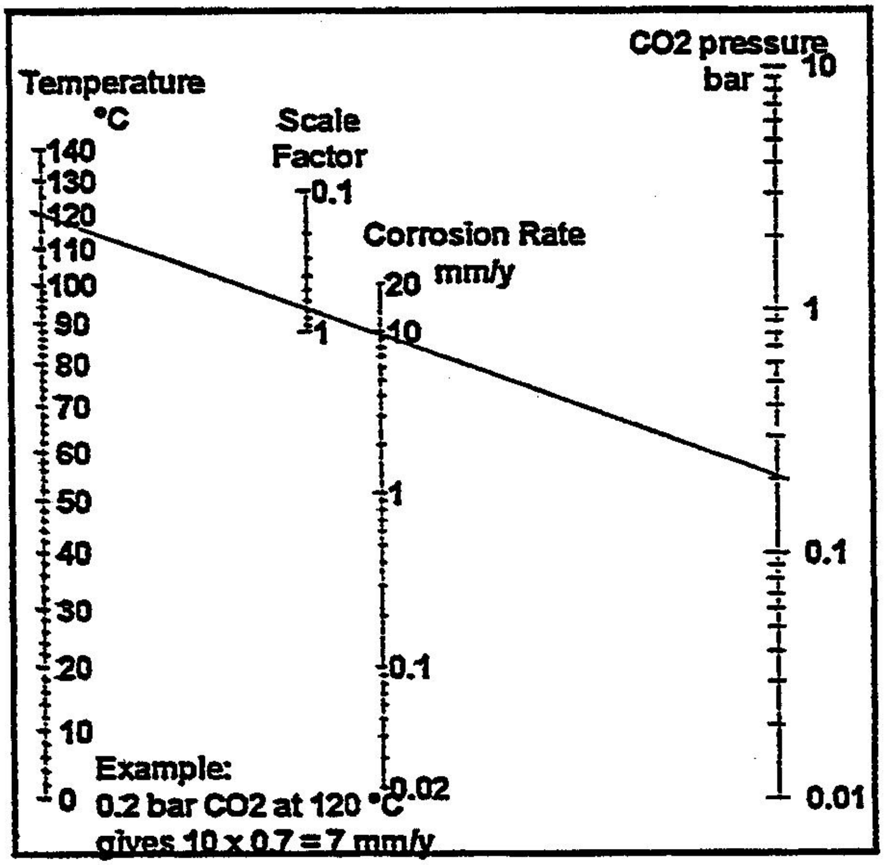


FIGURE 1. CO_2 corrosion nomogram.

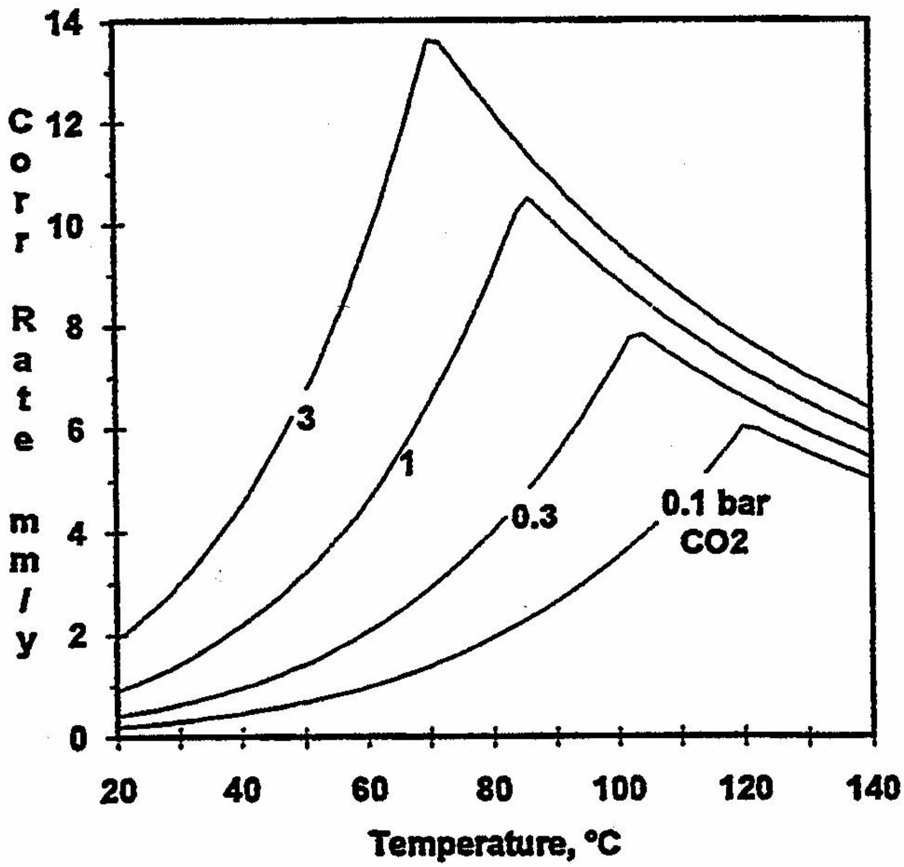


FIGURE 2. Effect of temperature on CO_2 corrosion.

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Attachment A: Internet Information for CO_2 Corrosion Models

Model #5

NORSOK Model

The NORSOK model, "CO_2 Corrosion Rate Calculation Model", M506, is described at the internet website:

http://www.nts.no/norsok/m/m50601/m50601.htm.

The first two pages of information from this website are attached immediately below.

Information concerning the NORSOK standard, "Material Selection", M001, (that is referred to in the corrosion rate model) is presented at the website:

http://www.nts.no.norsok/m/m00102/m00102.htm.

NORSOK STANDARD

CO_2 CORROSION RATE CALCULATION MODEL

M-506

Rev. 1, June 1998

This NORSOK standard is developed by NTS with broad industry participation. Please note that whilst every effort has been made to ensure the accuracy of this standard, neither OLF nor TBL or any of their members will assume liability for any use thereof. NTS is responsible for the administration and publication of this standard.

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FOREWORD

NORSOK (The competitive standing of the Norwegian offshore sector) is the industry initiative to add value, reduce cost and lead time and eliminate unnecessary activities in offshore field developments and operations.

The NORSOK standards are developed by the Norwegian petroleum industry as a part of the NORSOK initiative and supported by OLF (The Norwegian Oil Industry Association) and TBL (Federation of Norwegian Engineering Industries). NORSOK standards are administered and issued by NTS (Norwegian Technology Standards Institution).

The purpose of NORSOK standards is to contribute to meet the NORSOK goals, e.g. by replacing individual oil company specifications and other industry guidelines and documents for use in existing and future petroleum industry developments.

The NORSOK standards make extensive references to international standards. Where relevant, the contents of a NORSOK standard will be used to provide input to the international standardisation process. Subject to implementation into international standards, the NORSOK standard will be withdrawn.

The computer program is informative.

INTRODUCTION

This standard contains two parts as described below:

1. The Clauses 4, 5, 6, 7 and 8 in this standard acts as the user manual for the computer program. A description of the calculation model, the algorithms and the conditions for the corrosion rate calculations are given. In additions, methods and algorithms for calculation of essential input parameters to the corrosion rate calculations are given.
2. The computer program for corrosion rate calculations is available for downloading free of charge from the NTS/NORSOK Internet website (http://www.nts.no/norsok) or it may be procured from NTS, Oslo.

1 SCOPE

The scope of this standard is to present a method for calculation of corrosion rates in hydrocarbon production and process systems where the corrosive agent is CO_2.

The standard has primarily been developed for calculation of corrosion rates in topside piping systems and vessels, but the program may also be used for calculation of corrosion rates in pipeline systems and subsea production facilities.

2 NORMATIVE REFERENCES

The following standard includes provisions which, through reference in this text, constitute provisions of this NORSOK standard. Latest issue of the reference shall be used unless otherwise agreed. Other recognised standards may be used provided it can be shown that they meet or exceed the requirements of the standard referenced below.

NORSOK standard M-001 "Material Selection".

Model #6

USL Model

A brief description of the USL model that has been developed for predicting corrosion in gas condensate wells is presented below. This information was downloaded from the website:

http://engr.louisiana.edu/crc/model/model.htm.

Detailed descriptions of the USL corrosion model for gas condensate wells are available in the literature[12 through 24].

The Corrosion Research Center at USL currently has another joint industry program underway that is aimed at developing a comparable corrosion prediction model for oil wells. Information concerning this JIP can be found at:

http://engr.louisiana.edu/crc/research/oil-pro.htm.

Corrosion Research Center
UL Lafayette Corrosion Model for Gas-Condensate Wells

The Model

The UL Lafayette Corrosion Model for Gas-Condensate Wells has been designed to provide the user with a physical description of conditions inside a gas-condensate well and an estimate of the tubing life. The model which has been under development since 1984 is in Phase 5 - Version 2. This is both a Windows and DOS Version which allows both speed and availability to the eight individual models which make up the main program.

The input data required for the program can be simplified to require as few as 28 data points. If the Windows Version is used, the total time to input data and obtain results is less that five minutes for a 15,000 foot well. The list of 25 variables calculated by the program can be obtained in the form of tabulated data or graphs. Output data can be accessed directly by a preferred graphics program such as Excel, Harvard Graphics, Lotus, etc., if the company desires.

Current Consortium Members and Contact Person

Baker Petrolite, Dr. Sunder Ramachandran, Sugar Land, TX
British Gas, Mr. Tesh Kokoszka, United Kingdom
Champion Technologies, Mr. Nick Grahmann, Houston, TX
Chevron USA, Mr. Jim Skogsberg, Houston, TX
NALCO/Exxon Energy Chemical, Dr. Milan Bartos, Sugarland, TX
Exxon Mobil E & P, Mr. Tim Martin, Houston, TX
Phillips, Mr. George Harris, Bartlesville, OK
Shell Offshore, Mr. Blake Hebert, New Orleans, LA
Texaco, Mr. Russell Louis, Houston, TX
UNOCAL, Mr. Joe Clemens, Lafayette, LA

Demo Disk

The demo disk of the UL Lafayette Corrosion Model for Gas-Condensate Wells is available for examination. Information on the installation and running of the demo is provided to help the user view the contents and capability of the model. Three different wells are described in the demo.

View Installation Instructions ~ Download Demo

Individual Model Run

The Corrosion Research Center provides an opportunity for a company not in the UL Lafayette Corrosion Model Consortium to model a gas-condensate well at a cost of $500. Our University Model Consultant, Cedric Adams, will run the well and provide a detailed report. The report will give a complete physical description of the well as well as the predicted tubing life. If a well is highly corrosive, it will be possible to determine the best method of solving your corrosion problem.

For more information, please call Cedric Adams at CDA and Associates, Lafayette, LA, (337) 237-2342. He will provide you with the necessary data sheet.

Purchase Information

The cost of the model is a one time price of $30,000 for an unlimited number of copies to be used throughout all company locations. There is no annual maintenance fee for the program. There have been periodic version releases which are mainly cosmetic upgrades at no extra charge. A version release to Phase 5, Version 3S was recently completed. A new phase release has historically cost $5,000, but none are planned at the present time.

Training Classes

Training classes for using both the Windows and DOS versions of the UL Lafayette Corrosion Model for Gas-Condensate Wells have been offered by the University's Petroleum Training Service. Mr. Cedric Adams, University Model Consultant, conducts the one-day class at the University for a $100 fee.

View Course Description

Return to: Corrosion Research Center Home Page

This page designed and maintained by the Chemical Engineering Department.
Comments or questions to: garber@louisiana.edu

Model #7

‘Predict’ Model

The “Predict” corrosion model was developed by Intercorr International, of Houston, Texas. The information for the model presented immediately below was retrieved from the Intercorr website:

http://www.intercorr.com/software/predict.htm.

Additional information concerning the model is available at the websites:

http://www.intercorr.com/software/predintrfc.htm,

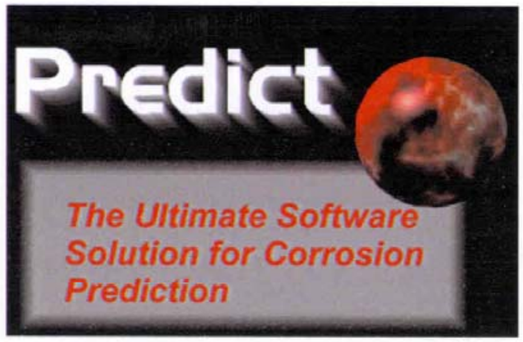
http://www.intercorr.com/software/predsysdesc.htm,

http://www.intercorr.com/software/preddataconv.htm,

http://www.intercorr.com/software/predcstanal.htm,

http://www.intercorr.com/software/predflowmdl.htm,

http://www.intercorr.com/software/pred_up.htm.



Predict is a new generation software tool that addresses one of the most significant issues in corrosion evaluation, i.e., ***assessment and prediction of corrosion rates*** for steels exposed to corrosive environments. Predict, a by-product of years of corrosion research and modeling, puts to good use application of state-of-the-art software technology to provide access to a comprehensive knowledge on corrosion decision-making. It's easy-to-use graphical tool integrates the effects of a complex set of environmental parameters to provide a corrosion rate assessment based on extensive literature data, lab testing and field experience.

Characteristics

- Predict performs a rigorous evaluation of corrosive environments and provides a prediction of maximum potential corrosion rate of steels.
- Incorporates comprehensive and accurate corrosion modeling to account for the effects of a number of critical parameters.
- Helps in the determination of system pH for typical oil and gas production environments.
- Provides decision-making rules for corrosion characterization on the basis of a corrosion model that accounts for the interaction of different critical parameters.
- Determines annualized and present worth cost as a means to conducting cost analyses to compare different material choices.
- Includes an intuitive, graphical, easy-to-use interface.

Benefits

- Microsoft® Windows based tool that can run on most common personal computers.
- Easy to use graphical interface makes using the system a simple task.
- Extensive on-line help assists the user in understanding the significance of different corrosion evaluation parameters.
- Cost analysis module facilitates comparison of project cost when using different materials.
- Can be easily installed on any stand-alone or network system compatible with Windows/Windows NT/Windows for Work groups/Windows-95, 98 operating system.
- Can lead to significant reduction in time spent assessing corrosion and can be a means for obtaining cost-effective automated solutions.
- Access to extensive consulting and development support from InterCorr in using/customizing Predict.

Attachment B: CRA Selection Guides

GENERAL GUIDELINE FOR MATERIAL SELECTION FOR OCTG

Given

- CO_2 content in the gas by mol fraction (%)
- H_2S content in the gas by mole fraction (ppm)
- Bottom hole pressure (BHP) (psi)
- Bottom hole temperature(BHT) (°C)
- pH of the water in the well

Calculate

Partial pressure of CO_2:

$$P_{CO_2}(\text{psi}) = \text{BHP} \times \frac{CO_2 \text{ content (\%)}}{100}$$

Partial pressure of H_2S:

$$P_{H_2S}(\text{psi}) = \text{BHP} \times \frac{H_2S \text{ content (ppm)}}{1\,000\,000}$$

$P_{CO_2} \geqq 10$ psi — YES → Higher CRA in the two alloys selected by Fig. 1 and 2

NO ↓

$P_{H_2S} \leqq 0.05$ psi — YES → Any grade up to V150

NO ↓

Temp. ≧ 80 °C — YES → API: N80, P110

NO ↓

Temp. ≧ 65 °C — YES → API: N80(QT), C95

NO ↓

API	J55, K55, L80-I, C90, T95
KSC	80S, 85S, 90S, 95S, 85SS, 90SS, 95SS, 100SS, 105SS, 110SS

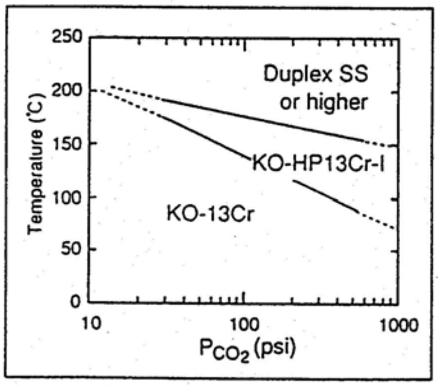


Fig. 1

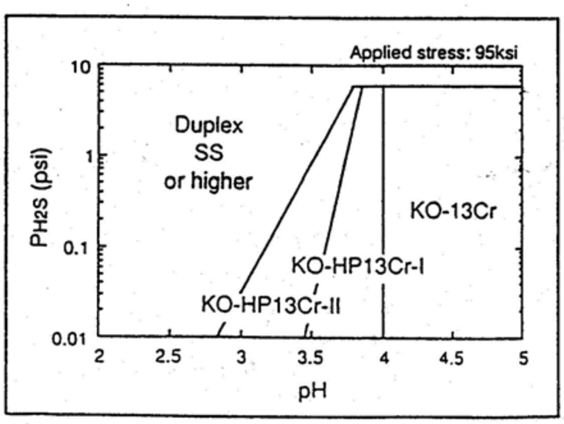
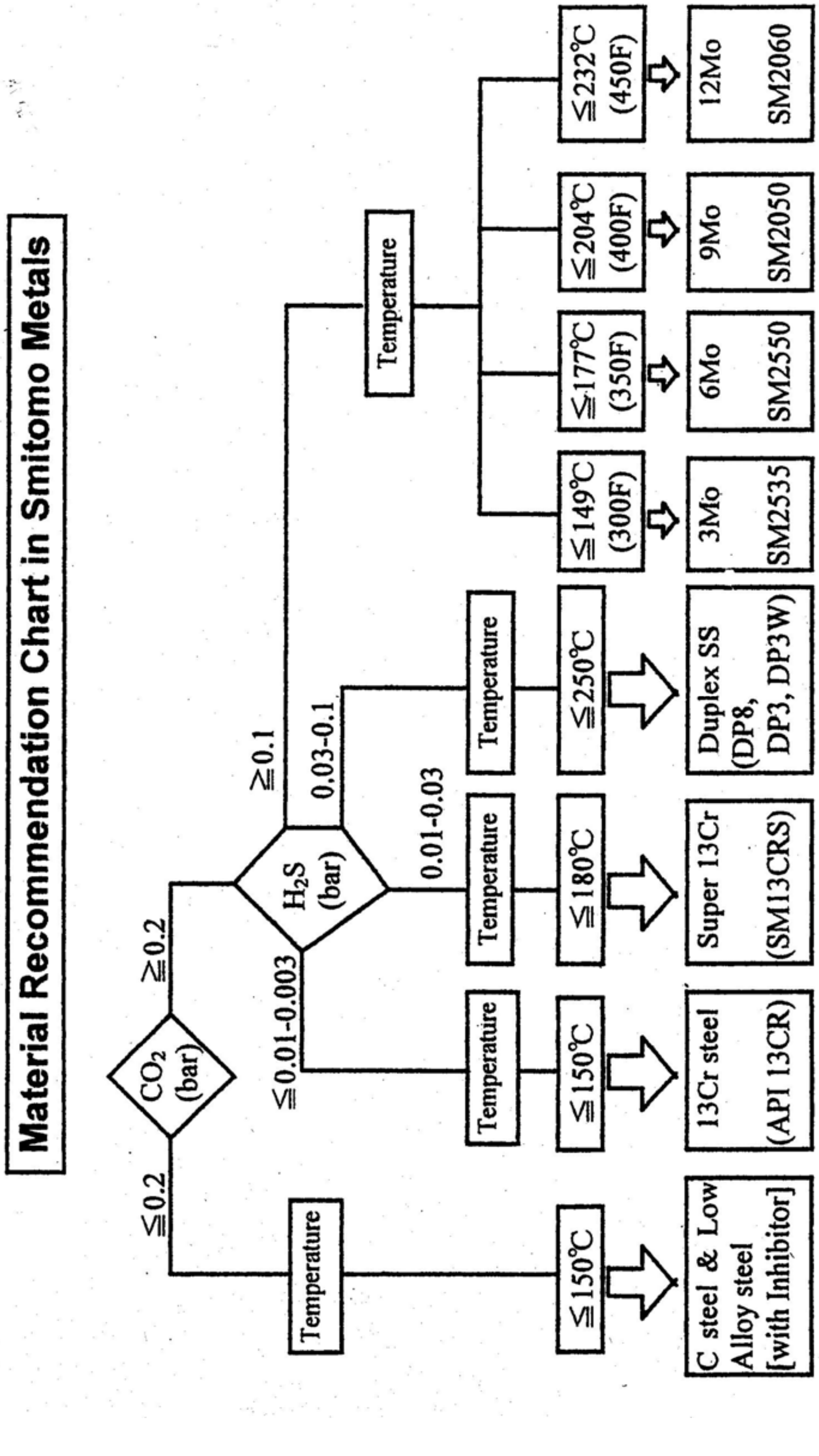


Fig. 2

Legal Notice

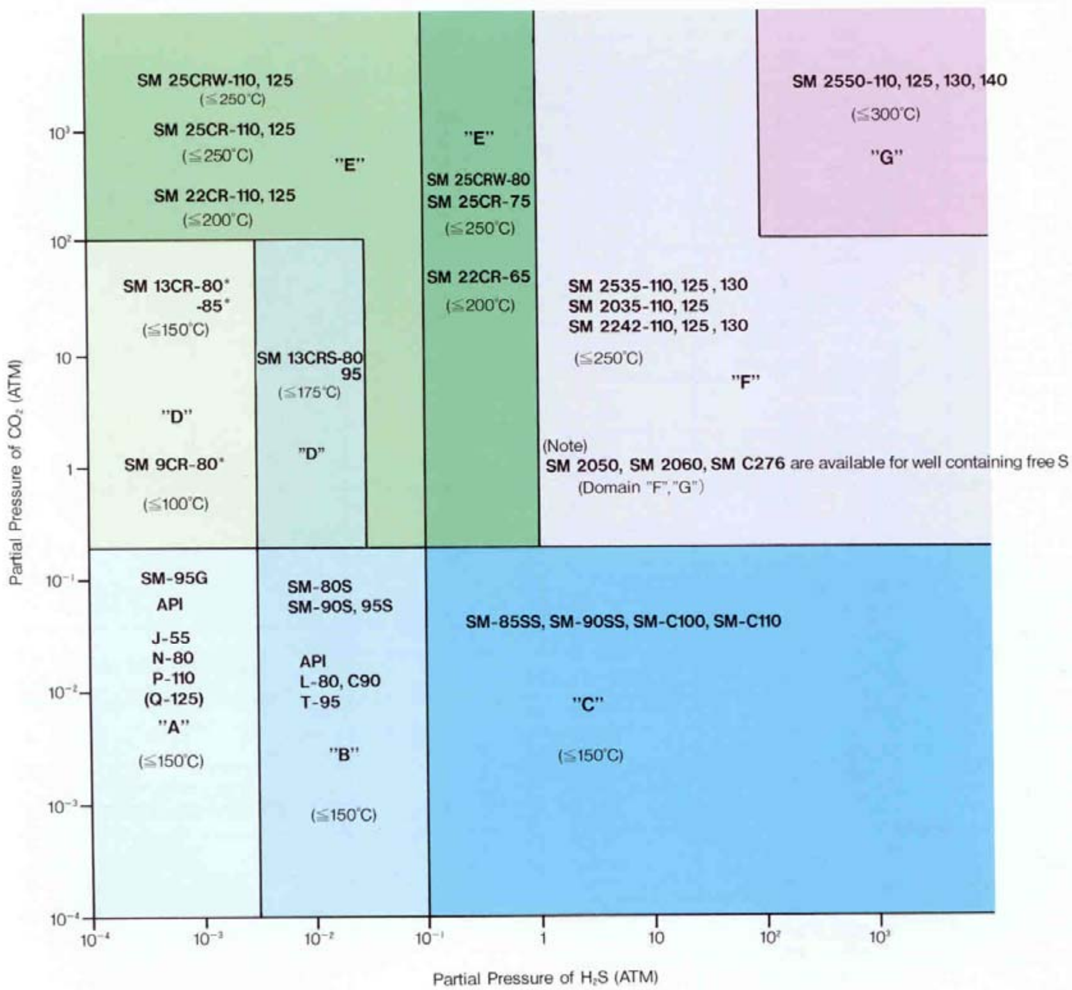
This guideline is edited for general information only. Kawasaki Steel Corporation in no way assumes liability or responsibility for any loss, damage or injury resulting from the use of the information and data contained herein. It is requested that all applications for the material described are to be undertaken solely

Sumitomo Guidelines



● THE NEW SM-SERIES AND THEIR APPLICATIONS TO CORROSIVE WELLS

Concept of Material Selection according to Gas (CO_2 and H_2S) Partial Pressure



(Note) * $C\ell^-$ content is less than 50,000ppm for SM 9CR and SM 13CR

Special Application for Corrosive Well Environment

Special Application	Materials	Sumitomo's Designation	Remarks
Mild Environment Domain "A"	API Specification	J-55 SM-95G N-80 (SM-125G) P-110 (Q-125)	
Sulfide Stress Corrosion Cracking (Medium Pressure and Medium Temperature) Domain "B"	Cr or Cr-Mo Steel	API SM-80S L-80, C-90, SM-90S T-95 SM-95S	
Sulfide Stress Corrosion Cracking (High Pressure and High Temperature) Domain "C"	1Cr-0.5Mo Steel Modified AISI 4130	SM-85SS SM-90SS SM-C100 SM-C110	Higher Yield Strength for Sour Service
Wet CO_2 Corrosion	9Cr-1Mo	SM 9CR-75 SM 9CR-80 SM 9CR-95	Quench and Tempered
Domain "D"	13Cr(Mod.AISI 420) 13Cr-5Ni-2Mo	SM 13CR-75 SM 13CR-80 SM 13CR-95 SM 13CRS-80 SM 13CRS-95 SM 13CRS-110 *1	Quench and Tempered
Wet CO_2 with a little H_2S Corrosion Domain "E"	22Cr-5Ni-3Mo 25Cr-6Ni-3Mo 25CR-7Ni-3Mo-2W	SM 22CR-65 *2 SM 22CR-110,-125 *3 SM 25CR-75 *2 SM 25CR-110,-125, *3 SM 25CRW-80 *2 SM 25CRW-110,-125 *3	Duplex Phase Stainless Steel *2 Solution Treated *3 As Cold Drawn
Wet CO_2 and H_2S Corrosion Domain "F"	25Cr-35Ni-3Mo 22Cr-42Ni-3Mo 20Cr-35Ni-5Mo	SM 2535-110,-125,-130 SM 2242-110,-125,-130 SM 2035-110,-125	As Cold Drawn
Most Corrosive Environment Domain "G"	25Cr-50Ni-6Mo 20CR-50Ni-11Mo 20Cr-58Ni-13Mo 16Cr-54Ni-16Mo-W	SM 2550-110,-125,-130,-140 SM 2050-110,-125,-130,-140 *4 SM 2060-110,-125,-130,-140,-150,-155 *4 SM C276-110,-125,-130,-140,-150 *4	As Cold Drawn *4 Environment with Free Sulphur

*1 Grade SM-13CRS-110 is not suitable for H_2S condition.
Please consult us when a small amount of H_2S is existing in your application.

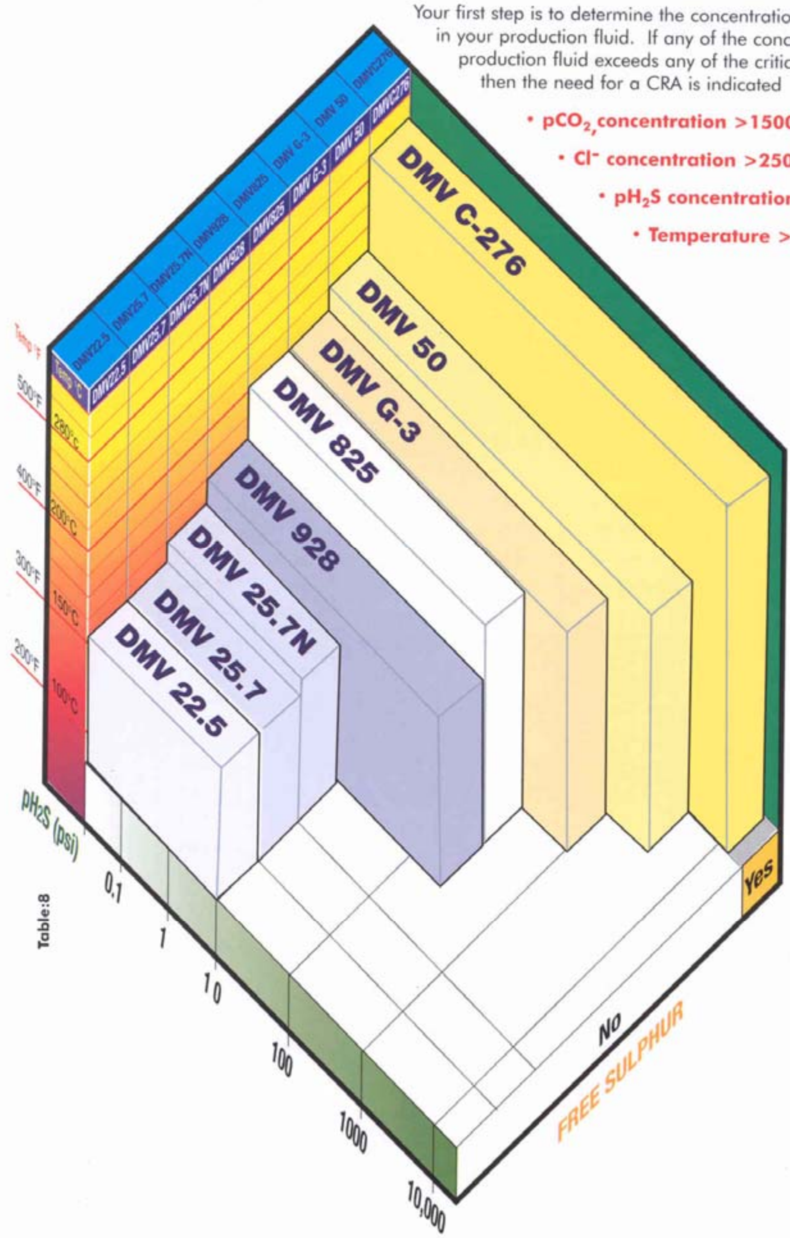
CRA grade selection diagram

... for severe corrosive conditions

The appropriate alloy for your application can be selected using the diagram below.

Your first step is to determine the concentration of certain corrosive media in your production fluid. If any of the concentrations in your production fluid exceeds any of the critical conditions shown below, then the need for a CRA is indicated

- pCO_2 concentration >1500psi
- Cl^- concentration >250 g/l
- pH_2S concentration >10 psi
- Temperature > 390°F



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DMV CRA GRADE SELECTION GUIDE

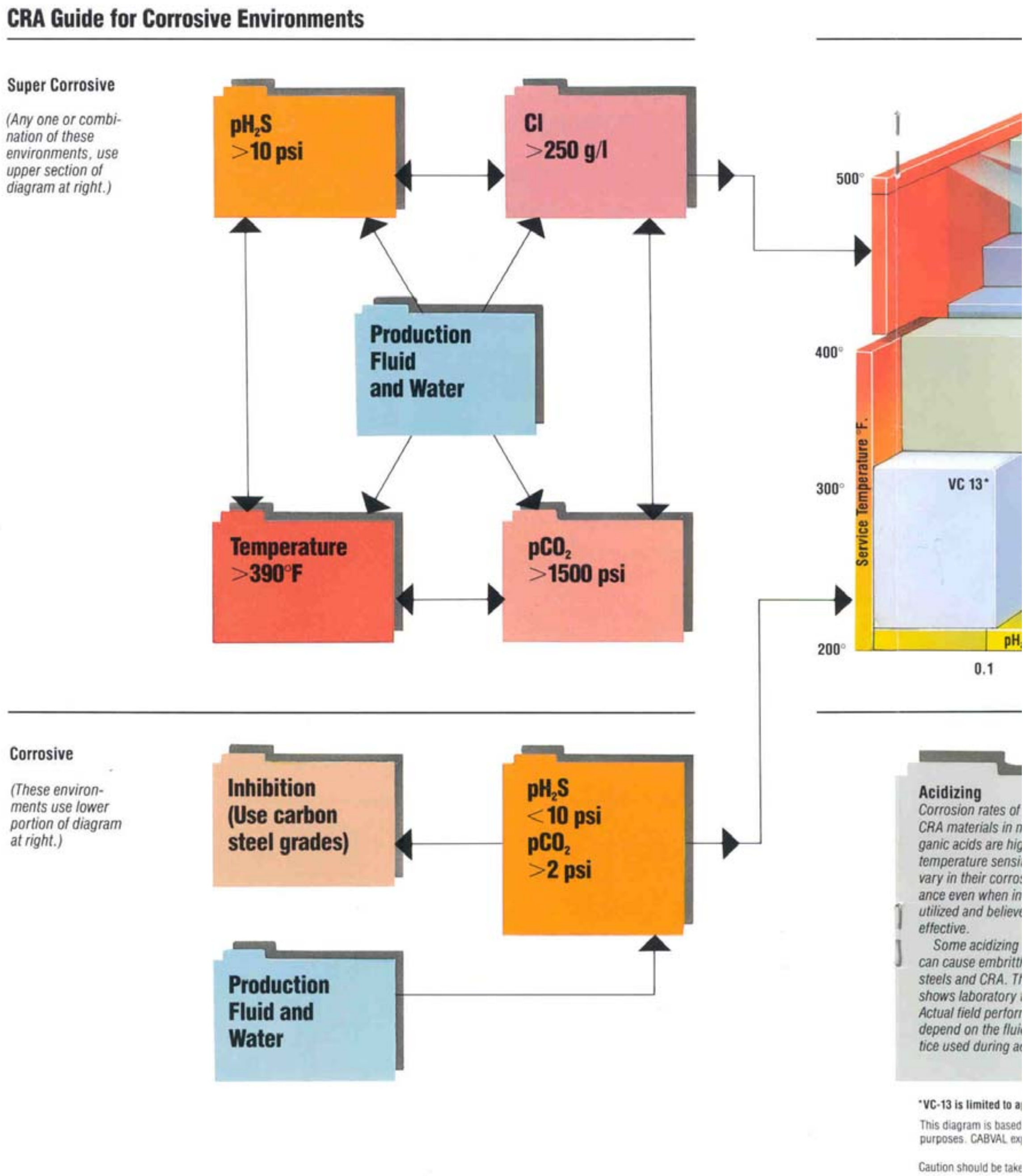
Materials Selection

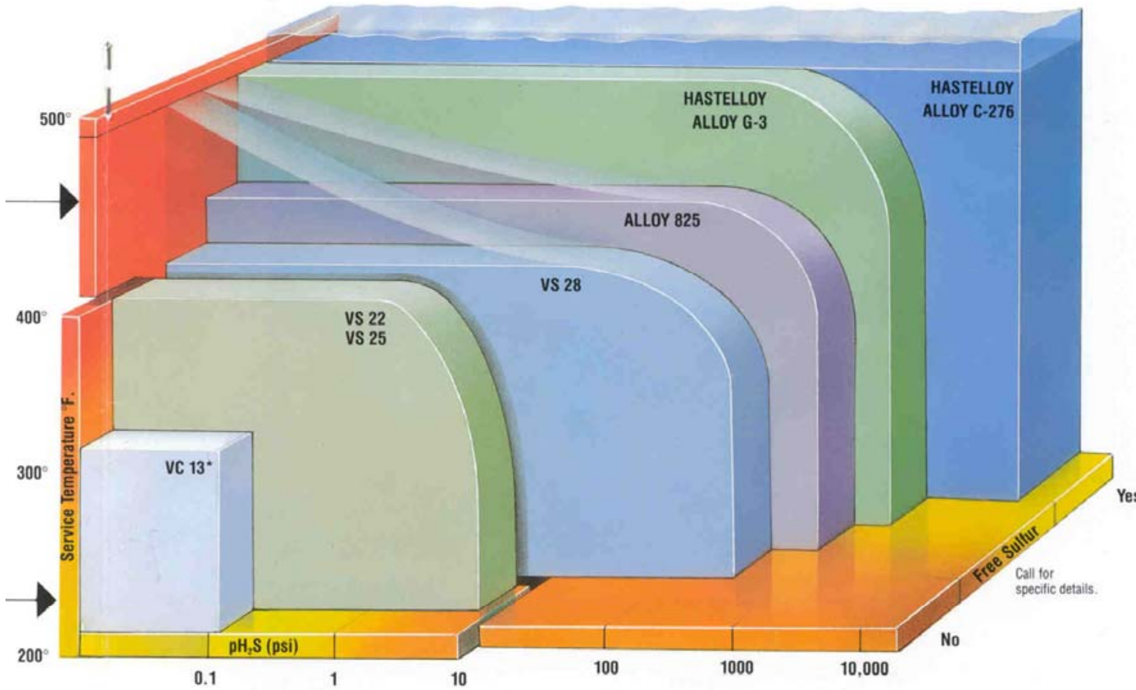
The alloy compositions described in this brochure have been designed to provide the optimum performance under a certain set of conditions. Correct material selection combines the best performance with the lowest cost. Generally the higher the alloy content, the better the performance but the higher the cost. The CRA SELECTION GUIDE below and the CRA GRADE SELECTION DIAGRAM on the next page will help the completion engineer in making the proper selection.

Table:7

WELL CONDITIONS	ALLOY TYPE	REMARKS/GRADES	DMV DESIGNATION	OTHER ALLOY DESIGNATIONS
		$CO_2 + H_2O + Cl^-$		
Temperature < 350°F pH_2S < 10 psi	Duplex			
	22 Cr - 5 Ni	Solution Annealed (65ksi) Cold Worked Grades: 110, 125, 140	DMV 22.5	Duplex 22 Cr; VM 22; D 22.5
	25 Cr - 7 Ni	Solution Annealed (75 ksi) Cold Worked Grades: 110, 125, 140	DMV 25.7	Duplex 25 Cr; VM 25; D 25 Cr 7 Ni
	Super Duplex			
	25 Cr - 7 Ni -N	Solution Annealed (80 ksi) Cold Worked Grades: 110, 125, 140	DMV 25.7N	Super Duplex 25Cr; VM 25 S; ZERON 100
		$CO_2 + H_2O + H_2S + Cl^-$		
Temperature < 350°F pH_2S < 400 psi	Austenitic			
	Alloy 28 28 Cr - 32 Ni	Cold Worked Grades: 110, 125, 140	DMV 928	28 Cr; Alloy 28; VM 28; D 28-32
		$CO_2 + H_2O + H_2S + Cl^-$		
Temperature < 400°F pH_2S < 400 psi	Nickel Base			
	Alloy 825 42 Ni - 21 Cr - 3 Mo	Cold Worked Grades: 110, 120	DMV 825	Alloy 825; VM 825
		$CO_2 + H_2O + H_2S + Cl^-$		
Temperature < 400°F pH_2S < 1000 psi	Nickel Base			
	Alloy G-3 50 Ni - 22 Cr - 7 Mo	Cold Worked Grades: 110, 125, 140	DMV G-3	G-3; Alloy G-3; VM G-3
		$CO_2 + H_2O + H_2S + Cl^-$		
Temperature < 425°F pH_2S < 1200 psi	Nickel Base			
	Alloy 50 54 Ni - 20 Cr - 9 Mo	Cold Worked Grades: 110, 120, 125	DMV 50	50; Alloy 50; VM 50
		$CO_2 + H_2O + H_2S + Cl^-$		
Temperature < 550°F pH_2S < 10,000 psi Elemental Sulphur	Nickel Base			
	Alloy C-276 60 Ni - 16 Cr - 16 Mo	Cold Worked Grades: 110, 125, 140,	DMV C-276	C-276; Alloy C-276

Cabval Guidelines





Acidizing

Corrosion rates of steels and CRA materials in many inorganic acids are highly temperature sensitive. They can vary in their corrosion resistance even when inhibitors are utilized and believed to be 99% effective.

Some acidizing environments can cause embrittlement of steels and CRA. The table shows laboratory test values. Actual field performance will depend on the fluids and practice used during acidizing.

	CORROSION RESISTANCE OF ALLOYS in 15% HCl + 5% NaCl	EFFECTS OF GASES ON CORROSION RATES IN ACIDIZING ENVIRONMENTS 15% HCl + 5% NaCl		STRESS CORROSION CRACKING OF ALLOYS C-shaped Samples, 24 hour Tests CO_2 Cover Gas			
	0.2 vol% inhibitor 300°F	0.1 vol% inhibitor 350°F		0.1 vol% inhibitor 300°F			
	Corrosion Rate (mpy)	Corrosion Rate (mpy)		ENVIRONMENT			
		CO_2	CO_2 + H_2S	20% $MgCl_2$ + 5% NaCl	15% HCl + 5% NaCl	15% HCl + 2% Formic Acid	3% HF + 5% NaCl
1020 Steel	5500	—	—	—	—	—	—
alloy 825	1000	1400	5000	NC	NC	NC	NC
HASTELLOY alloy G-3	380	600	2900	NC	NC	NC	NC
HASTELLOY alloy C-276	78	860	1100	NC	NC	NC	NC

NC = No Cracking

***VC-13 is limited to approximately 60,000 ppm Cl^- at 300°F.**

This diagram is based on a combination of laboratory test results and current state-of-the-art field application experience. It is to be used only for information purposes. CABVAL expresses no guarantee as to its use and expressly denies any liability in case of damage arising from the use of such information.

Caution should be taken in using duplex stainless steels during HCl acidizing.

Attachment C: Internet Information on "Socrates" Expert System

“Socrates” Expert System

The “Socrates” expert system was developed by Intercorr International, of Houston, Texas. The information describing the system that is attached immediately below was retrieved from the Intercorr website at:

http://www.intercorr.com/software/soc.htm

Additional information concerning the system is available at the Intercorr websites:

http://www.intercorr.com/software/socintrfc.htm

http://www.intercorr.com/software/socsysdec.htm

http://www.intercorr.com/software/socenveval.htm

http://www.intercorr.com/software/socstanal.htm

http://www.intercorr.com/software/socstleval.htm

http://www.intercorr.com/software/socdbhlp.htm

http://www.intercorr.com/software/soc_up.htm

http://www.intercorr.com/software/socapndx1.htm

http://www.intercorr.com/software/socapndx2.htm

http://www.intercorr.com/software/socapndx3.htm

Socrates
- Interface
- System Description
- Environment Eval.
- Cost Analysis
- Steel Evaluation
- Database and Help
- Features and Benefits
- Appendix-I
- Appendix-II
- Appendix-III

What's New in v6.0?

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System Requirements
Y2K Compliance

Selection of Corrosion Resistant Alloys Through Environment Specifications

The **Socrates** system is a *comprehensive material selection tool for oil and gas applications* and provides the user access to the material selection decisions and decision logic of a domain expert and the pooled expertise of a distinguished group of oil companies, equipment manufacturers and materials suppliers in selection of CRA. The system also embodies information from other sources such as published literature on lab and field experience related to oil and gas field service as well as proprietary test data on evaluation of specific CRA material classes. The software system is integrated with a database containing information about lab/field experience of several classes of CRA as well as a database on CRA material compositions.

The SOCRATES system selects CRAs through material evaluation at five hierarchical levels:

- CRA evaluation based on mechanical strength parameters, heat treatment/cold work and hardness limitations
- Material selection based on characterization of the environment in terms of operating pressure, temperature, pH, H2S, Chlorides, Elemental Sulfur, aeration, Gas to Oil Ratio and Water to Gas Ratio/water cut
- CRA evaluation for stress corrosion cracking (SCC), hydrogen embrittlement cracking (HEC) and sulfide stress cracking (SSC)
- CRA evaluation for resistance to pitting corrosion
- Selection of final set of materials based on application related constraints.

The system also facilitates a database search for the conditions specified by the user. The database contains information from literature relevant to applications of CRA. Further, the system comes with a cost analysis module that allows the user to compare costs of utilization of different alloys.

Attachment D: Coating Information

Tuboscope: TUBE-KOTE Coatings General Descriptions

	TK-2	TK-7	TK-15	TK-33	TK-34 or TK-34XT	TK-69 or TK-69XT	TK-70	TK-99
Coating Description	Highly corrosion resistant, broad spectrum thin film	High temperature, high pressure corrosive gas	High performance, thick- film with enhanced flexibility	Paraffin control & abrasion resistance	Drill pipe	Alkali resistant, corrosion protective coating	Corrosive water & oil mixture	Super flexible for CO_2 injection & recovery projects
Type	Liquid-Phenolic	Liquid-Modified Phenolic	Powder-Modified Novolac	Liquid-Urethane	Liquid-Epoxy Phenolic	Liquid-Epoxy Modified Phenolic	Powder-Epoxy	Powder-Nylon
Color	Maroon	Tan	Dark Green	Green	Green (XT is Blue)	Green (XT is Blue)	Maroon	Black
Temperature	To 400° F (204° C)	To 400° F (204° C)	To 300° F (149° C)	To 225°F (107°C)	* See Note Below	To 250° F (121° C)	To 175° F (79° C)	To 225° F (107° C)
Applied Thickness	5-8 mils (125 - 200 um)	5-8 mils	10-18 mils	5-9 mils (125 - 225 um)	5-9 mils	5-9 mils	10-20 mils (250 - 500 um)	12-25 mils (300 - 625 um)
Pressure	Up to yield strength of pipe	Up to yield strength of pipe	Up to yield strength of pipe	Up to yield strength of pipe	Up to yield strength of pipe	Up to yield strength of pipe	To 6,000 psi	Up to yield strength of pipe
Primary Service	Oil, fresh & salt water, sweet (CO_2) & organic acids to 400°F (204°C); gas production to 200°F	Oil & gas, CO_2 up to 400°F (204°C) & sour gas to 300°F (149°C) and above depending on CO_2 & H_2S concentration	Oil, natural gas, fresh & salt water, sweet corrosion (CO_2), mild H_2S, and alkaline service to pH 12. Paraffin mitigation	Paraffin, scale & corrosive environments	Natural & synthetic drilling muds	Oil, salt & fresh waterfloods, CO_2 floods, organic acids, strong alkalis including caustic completion fluids and gases of miscible injection systems	Subsurface CO_2 & water handling systems, salt solutions, crude oil & mild mineral acids	CO_2, fresh & salt water, oil & gas service to 225°F (107°C)
Primary Applications	Production tubing, chemical vessels, flowlines, wellheads (christmas trees, chokes), acidic and CO_2 lines, pumps and tools; hydraulic improvement	Production tubing & downhole equipment; hydraulic improvement	Production tubing, water & CO_2 injection, disposal wells & flowlines; hydraulic improvement	Water injection & salt water disposal wells; flowlines, tubing, sucker rods & other equipment subject to paraffin, scale and/or high abrasion	Drill pipe coating for corrosion protection & hydraulic efficiency. TK-34XT formulated for increased wear resistance	Water flood systems, salt water disposal, crude flowlines, chemical and manufacturing vessels. TK-69XT formulated for increased wear resistance; hydraulic improvement	New & used tubular goods & line pipe; hydraulic improvement	Tubing & flow lines; hydraulic improvement
Limited Service	Alkaline (caustic) environments to pH 9; excursions to pH 11.5. (Also see TK-69). Sour service (H_2S) to 200°F (93°C) Also see TK-7	Wells with high water cuts and/or low temperatures (see also TK-2 and TK-69)	Maximum operating temperature and H_2S level will be dependent on total operating environment	N/A	**Note**: * TK-34 will withstand all temperatures commonly encountered during drilling provided circulation is maintained	N/A	N/A	Caution should be used in contact with stimulation acids above 15% and H_2S corrosives
Additional Notes	**Hydraulic Improvement**: All coatings provide a smooth and consistent surface finish allowing for improved flow dynamics that can maximize productivity. **Stimulation Fluids** charged through coating, generally cause little effect if the fluids are flushed completely. TVI representative should be consulted when a stimuation is planned.							

The description of the physical properties of Tuboscope coatings represent typically average values obtained in accordance with accepted test methods and are subject to normal manufacturing variations. These descriptions are supplied as a technical service and are subject to change without notice. Please check with your local Tuboscope Representative.

For more information concerning advantages, limitations, & selection of coatings, contact Tuboscope Coating Technical Services at (713) 799-5339 or your local representative.

Tube-Kote Coating General Descriptions Table 06-20-00 cfs

Internal Protective Coatings

IPC Coating Summary

Coating	Recommended Services	Benefits	Characteristics
IPC 100	Drilling	Temperature Resistance Abrasion Resistance Excellent Acid/Caustic Resistance Hydraulic Efficiency	Generic Type: Modified Epoxy Primer: Phenolic Thickness: 8-13 Mils Temp: To 400° w/ Interrupted Circulation
IPC 200	Drilling	Excellent Adhesion Excellent Flexibility Moderate Acid/Caustic Resistance Hydraulic Efficiency	Generic Type: Epoxy-Phenolic Primer: Phenolic Thickness: 5 - 9 Dry Mils Temp: To 250°F (121°C); 400°F w/ Circulation
IPC 505	CO_2 Injection WAG Oil, Water, Gas Production Brine Injection and Disposal Flow Lines and Line Pipe	Excellent Adhesion Excellent Flexibility Moderate Acid/Caustic Resistance	Generic Type: Epoxy Primer: Phenolic Thickness: 10 - 20 Dry Mils Temp: 250°F (121°C)
IPC 521	Oil and Gas Production Transmission Lines Used Tubular Goods Saltwater Disposal	Excellent Adhesion Excellent Flexibility Moderate Chemical Resistance	Generic Type: Modified Epoxy Primer: Phenolic Thickness: 8 - 15 Dry Mils Temp: 300°F (149°C)
IPC 700	Oil and Gas Production Water Injection	Excellent Adhesion Excellent Acid Resistance Good Flexibility	Generic Type: Phenolic Primer: Phenolic Thickness: 5 - 9 Dry Mils Temp: 400°F (204°C)

C 1.1

	Recommended Services:	Benefits:	Characteristics:
IPC 750P	Rod Pump Wells Gas Lift Oil and Gas Wells	Abrasion Resistance Chemical Resistance	Generic Type: Modified Epoxy Primer: Phenolic Thickness: 10 - 25 Mils
IPC 770	Gas Production Oil Production Sweet Service to 400°F (204°C) Sour Service to 300°F (149°C)	Excellent Adhesion Excellent Chemical Resistance Excellent Acid Resistance Good Wire Line Resistance	Generic Type: Modified Phenolic Primer: Phenolic Thickness: 5 - 9 Mils Temp: 400°F (204°C)
IPC 800	Production Tubing Injection Wells WAG Wells	Abrasion Resistance Paraffin Resistance Excellent Acid Resistance Excellent Wireline Resistance	Generic Type: Modified Epoxy Primer: Phenolic Thickness: 8-13 Mils Temp: 350°F (174°C), Pressure to 8,500 psi
IPC 850	Rod Pump Wells Gas Lift Oil and Gas Wells	Abrasion Resistance Excellent Acid Resistance	Generic Type: Cresol Novolac Primer: Phenolic Thickness: 10 - 20 Mils
IPC 1100	Line Pipe Rod Pump Wells Gas Lift Oil and Gas Wells WAG	Abrasion Resistance Reduce Mechanical Damage Sand Abrasion Resistance	Generic Type: Nylon 11 Primer: Phenolic Thickness: 10 - 30 Mils

ICO
Corrosion Control Services

Corporate Headquarters:
11490 Westheimer, Suite 1000
Houston, Texas 77077
Phone: 281-721-4200
Fax: 281-721-4203

Technical Services:
1-800-922-6126
Fax 713-462-5155

Coating Plants:

Houston, TX
Phone: 713-466-9977
Fax: 713-896-0629

Odessa, TX
Phone: 915-362-0581
Fax: 915-366-9617

Amelia, LA
Phone: 504-631-9591
Fax: 504-631-9596

Attachment E: Abstracts of Economic "Case Studies"

Control of corrosion in oil and gas production tubing
Author: Smith, L.
Source: British Corrosion Journal v 34 n 4 1999. p 247-253

Controlling corrosion in production tubing is essential for maintaining production and for preventing loss of well control. Materials for use downhole have to meet criteria for corrosion resistance and also mechanical requirements. The potential corrosion rate can be estimated and the risks of sulfide stress corrosion cracking assessed on the basis of the anticipated environmental conditions and flow regime. Material options for tubing can then be considered on the basis of published corrosion test data and also field experience. Candidate materials may be tested under the precise field conditions expected in order to ensure that over-conservative choices are not made. Corrosion inhibitors, coated carbon steel, and fiber reinforced plastic tubing have temperature, flow regime, and mechanical limitations. Specific corrosion resistant alloys (CRAs) have environmental limitations with respect to temperature, hydrogen sulfide, and chloride content. Details of field experience with all of these material options are given. There exists a large amount of experience with CRAs for downhole applications. Correctly selected CRAs have a good track record of service, even for hostile, H//2S containing conditions. There are a few limited examples of CRA clad tubing. This product may be one that needs re-evaluation as it offers potential for economic use of costly but effective CRAs. (Author abstract) 33 Refs.

Requirements for corrosion-resistant alloy (CRA) production tubing
Author: Petersen, C.W.; Bluem, M.F.
Source: SPE Reprint Series n 46 1997. p 156-165

The incentive to use corrosion-resistant alloy (CRA) production tubing has grown as bottomhole temperatures have steadily increased above 325 degree F, as corrosion control costs have grown, and as many operations have sprung up in remote sites with limited accessibility. This paper discusses procedures to ensure acceptable manufacture of such tubing and also presents some operational experiences with these alloys. (Author abstract) 1 Refs.

TECHNICAL AND ECONOMIC ASPECTS OF STAINLESS STEELS IN CORROSIVE DOWNHOLE ENVIRONMENTS
Author: Karlsson, S.
Conference Title: Stainless Steels '84.
Conference Location: Goteborg, Swed. Conference Date: 19840903
Source: Published by Inst of Metals (Book n 320), London, Engl. p 438-445
Publication Year: 1985

An economic study demonstrates that the use of stainless production tubing in oil and gas winning is profitable compared with conventional corrosion control methods for shallower and less aggressive wells than earlier anticipated. The study involves methods of selecting an appropriate grade of stainless steel and methods of estimating the conventional corrosion control costs. The economic model is based on the discounted cash flow method and takes into account varying economic conditions and tax regulations for different countries. 3 refs.

Experiences with 13Cr for mitigating CO sub 2 corrosion in the oilfield, case histories: the Gulf of Mexico and inland gas wells.
Baudoin, D A ; Barbin, D K ; Skogsberg, J
Publ: National Association of Corrosion Engineers, P.O. Box 218340,
Houston, TX 77084, USA, 1996
Corrosion-Resistant Alloys in Oil and Gas Production. Vol. I 26-38, 1996

Material selection for downhole completions in the oilfield is one that is critical to the economic success of a project on a long-term basis. In the past, the selection of downhole tubulars has been routine and basic, with most operators selecting carbon steel as standard procedure. Today, a paradigm shift from the use of traditional C steel to 13%Cr is taking place as tools of economics, corrosion engineering, and field data are utilized. Factors to be considered in the decision making process in selecting materials for sweet corrosive environments include: field data (current and historical), corrosion engineering, and economics. This paper takes an objective look at the field experiences, conditions, and economics involved in making a materials selection. Of all elements considered, economics is the main driving force. The paper focuses on four case histories from the Gulf of Mexico and inland Louisiana with various temperatures, pressures, chloride content, CO sub 2 content, and production rates. These case histories, along with proven long term experience will help set the stage for further usage of 13Cr. 6 ref.

Use of Economic Analysis to Select the Most Cost Effective Method of Downhole Corrosion Control.
Tischuk, J L; Huber, D S
Conference: UK Corrosion 1984--Proceedings of the Conference. Vol 1

Economic analysis is a powerful tool for choosing among alternative methods of corrosion control. The factors which are considered include the time value of money, project life, risks of failure and consequential costs of failure in addition to initial capital outlay and estimated operating costs. Although the probability analysis is subjective rather than mathematically rigorous, it is based on field experience and gives good results. One of the strengths of this method is that relatively large changes in the failure scenarios and probabilities of failure result in very small changes in discounted risk costs. As long as the probabilities are reasonable the relative ranking of the alternatives will not be changed if the probabilities are altered. In the case of Esmond Field Development, this work showed that 13Cr stainless steel production tubing was the most cost effective solution to donwhole sweet corrosion. For other projects with different costs and other criteria, other solutions may be most cost effective. 10 ref.--AA

CORROSION MANAGEMENT IN THE ARUN FIELD
RIEKELS L M; SEETHARAM R V; KRISHNAMURTHY R M; KROEN C F; PACHECO J L; HAUSLER R H; SEMERAD V A W; KACZOROWSKI N
51ST ANNU NACE INT CORROSION CONF (CORROSION 96) (DENVER, 3/24-29/96) PAPER NO 24 1996 (16 PP; 19 REFS)

The Arun field, located on the northern coast of the Aceh province in N.
Sumatra, Indon., is a gas condensate reservoir that was discovered in 1971 and has been in production since 1977. The reservoir is a compositionally dynamic system where retrograde condensation, condensate revaporization, water vaporization, mixing of lean injection gas, gas dehydration, and booster compression impact reservoir performance. In order to manage corrosion and its potential impact on gas deliverability, it was necessary to assess the probability that unacceptable down-hole corrosion would occur as the Arun field was depleted. The changes in the well-bore environment over time which could influence corrosion kinetics had to be identified. A risk model has been developed to identify the probability that unacceptable down-hole corrosion would occur as the Arun field was depleted. Using the life expectancy estimates for the carbon steel tubing strings from this model, optimized mitigation strategies could be developed to provide cost-effective alternatives for the management of corrosion.

13CR TUBULARS SOLVE CORROSION PROBLEMS IN THE TUSCALOOSA TREND
COMBES J D; KERR J G; KLEIN L J
PETROL ENG INT V 55, NO 3, PP 50, 52, 56, 58, 60, 64, 66, 68, 70, MARCH
1983

Down-hole corrosion problems in the Tuscaloosa Trend can complicate completion and production practices for the operator. Obviously, the ability to control these corrosion problems can cost the producer considerable time and money. Since becoming one of the first operators in the Tuscaloosa, Chevron has made substantial progress in fighting this tough, corrosive environment, and now, with the help of 13Cr tubulars, appears to be winning the battle. In 1974, Chevron spudded the Alma 1 well, which turned out to be the discovery well for the False River field in the Tuscaloosa Trend which runs across S. Louisiana. The well was completed in 1975. Chevron's Tuscaloosa Trend well completion design is described. A parallel string completion was employed for maximum safety with the kill string available if required. The annulus was packed off and filled with weighted mud above 20,000 ft so that the casing was not exposed to the reservoir fluids, except below the packer. Wellheads and tubing hangers were made of Type 410 stainless steel. (28 refs.)

WELL DESIGN AND EQUIPMENT INSTALLATION FOR MOBILE BAY COMPLETIONS
GORDON J R; JOHNSON D V; HERMAN S R; DARBY J B
26TH ANNU SPE ET AL OFFSHORE TECHNOL CONF (HOUSTON, 5/2-5/94) PROC V 4,
PP 533-542, 1994 (OTC-7571); 4 REFS

Production of sour gas from deep (21,000-ft) reservoirs extended off shore in recent years and has challenged operators to assure equipment integrity and reliability. The high investment in wells and facilities, as well as the high cost of remedial well-bore activities, make quality of initial installations a high priority. Key design and installation topics for a recent 11-well development in the Mobile Bay area are described. Over 50 staff-years of research and development effort were expended in establishing suitability of equipment and procedures for the development. The well design is for extremely corrosive and erosive well conditions (acid gases, 420(deg)F bottom-hole temperature, and 50-Mcfd flow rates). The final well design featured a full CRA flow path and a single mechanical device, the subsurface safety valve (SSSV). The SSSV was a shallow restriction in the well bore (2.56 in. ID) which posed no real operational constraint. Floating seals inside a polished bore receptacle (PBR) eliminated packers and latches and the attendant risk and difficulty of removal during workover operations. The CRA (corrosion resistant alloy) flow path eliminated the need for down-hole chemical injection hardware.

DOWNHOLE MATERIAL SELECTION FOR CLYDE PRODUCTION WELLS: THEORY AND PRACTICE
BLACKBURN N A
SPE EUROPE PROD OPER CONF (ABERDEEN, UK, 3/15-17/94) PROC PP 105-114,
1994 (SPE-27604; 15 REFS)

The Clyde oil field lies within North Sea block 30/17b. First oil was produced from the field in March 1987. Wells drilled during field appraisal indicated a potentially highly corrosive down-hole environment. Although high chromium content (Duplex) steels appeared to be the technically preferred completion material, a decision was made to use carbon steel tubulars. Historical data have shown that carbon steel gives acceptable performance in the majority of production wells. Failures have occurred, but these have been highly specific and related to high fluid velocities and increasing watercuts. A mixed string completion employing carbon steel, 13 Cr and plastic-coated tubing has been successful in controlling down-hole corrosion in these few problem wells. The down-hole corrosion control strategy used on the field and how carbon steel may be used successfully in a severe down-hole environment are shown.

SECTION V: REVIEW OF ARPTD DATABASE

1) The ARPTD Database

As the initial portion of the current joint industry project (JIP), Stress Engineering Services developed a computer-based data acquisition and manipulation system. The system was developed at the request of, and under the direction of, the steering committee of the JIP.

The menu-driven data entry system was structured so as to be accessible by way of the Internet. Each member of the JIP was subsequently given an individual password for the system that allowed data entry into the system. The individual passwords also guaranteed security concerning any data that was entered under that password by the participants.

Information concerning the initial well installation configuration and operating conditions is required for each well entry in the system.. The user of the system can then enter information concerning sustained casing pressure (SCP) events as well as data concerning well workovers and/or recompletions. After the initial well data entry is completed and submitted, the system also allows the user to review and/or edit the data for the well.

The data entry and management system can be accessed on the Internet at http://www.arptd.org. After entering this location in the Internet browser, a small menu screen appears that asks for the users Network user name and password. The information to be entered on this screen is:

- Network user name : arptd
- Network user password: du9chmn

When the above entries are made, the initial screen of the ARPTD database manager will appear. The general appearance and utility of the data input system is illustrated by the menus shown in Attachment A.

Figure 1 of Attachment A is the initial screen of the data management system. As can be seen, the Company identification and company specific password must be entered at this point. Each participant can be identified by way of the "Company" scroll-down bar. When using the system to enter data into their specific part of the data base, each participant is required to use their individual password. The default "Company" entry (intended to be used when doing initial exploration and testing of the system) is "General". The current password for the "General" company I.D. is:

- "ob1knb".

Figures 2 through 8 of Attachment A show the menus that appear as the data of an existing well is reviewed. For the screens shown in the attachment, well # 24 (as identified by the data management system) was used in the review.

The screens shown in Figures 3 through 8 are the result of activating the "Review Well Data" option on the main "Data Management Center" screen, as shown in Figure 2. If the operator had chosen, instead, to use the "Add a Well" or the "Edit/Update Well Data" options on the main "Data Management Center" screen, either of two separate series of similar screens would have been activated. These additional screens are similar in appearance to those shown in Figures 3 through 8. The additional screens, on the other hand, prompt the user to either enter data for a new well to be added to the database, or to edit data previously added for an existing well already in the database (such as well # 24).

The selection of "Review Initial Completion" on the screen shown in Figure 4 results in the appearance of the information shown in Figure 5. Note that the information displayed on this screen is Initial Completion Information. The information shown in Figure 6 is accessed from the Initial Information screen (Figure 5) by hitting the "Review String" button. After reviewing the initial tubing string in Figure 6, the operator returns to the screen in Figure 5 by hitting the Return button on the screen in Figure 6. After reviewing all of the information shown in Figure 5, hitting the Return button at the bottom of the screen returns the operator to the screen shown in Figure 4.

The information shown in Figures 7 and 8 of Attachment A is accessed from the screen shown in Figure 4 by engaging the "Review an SCP Record" or "Review a Workover Record" entries on Figure 4. In the well used in this example, the operator had not entered any information for the "modified" tubing string present in the well following the "workover" activity. It might, therefore, be concluded that essentially the same production string was re-run in the well during the workover, following the SCP event. As can be seen in Figures 5 through 8 of Attachment A, an extensive amount of information concerning the details of the well at the various stages of its life are requested by the database manager.

Unfortunately, only a limited amount of data was collected through the data base manager. Our review of the resulting ARPTD data base revealed the following:

1. Number of well files that contained what appeared to be valid data that could be accessed by the web-site data manager:
   a. "Valid wells" = 73
2. Initial shut-in tubing pressures of "valid" wells:
   a. Range of pressures = 460 psi to 13380 psi
   b. Avg. pressure = 2760 psi
3. Static bottom hole temperatures of wells:
   a. Range of temperatures = 94^0F to 250^0F
   b. Avg. temperature = 175^0F
4. Number of wells identified as containing CO_2:
   a. No. of wells = 17
5. Number of wells identified as containing H_2S:
   a. No. of wells = 0
6. Alloy of production tubing:
   a. 13 Chrome = 7 wells, 8 strings
   b. Carbon steel = 66 wells
7. Connections used on production sting:
   a. 8 Round = 20 wells
   b. 8 Round with seal ring = 10 wells
   c. Hydril = 24 wells

d. Kawasaki = 6 wells

e. AB = 4 wells

f. Benoit = 4 wells

g. Vam = 2 wells

h. Other = 3 wells

8. "Age" of well between SCP event and initial completion or most recent workover or recompletion:

a. Avg. age of all 73 wells = 139 mo.

b. No. of wells that failed in 24 mo. or less = 20

c. Avg. age of wells that survived more than 24 mo. = 187 mo.

9. Number of wells in which "Root Cause of Failure" was identified:

a. Total wells identified = 9

b. Failure due to corrosion = 5

c. Failure due to "component failure" = 3

d. "Not known" = 1

The quantitative information concerning the "age" of the primary annulus at the time of an SCP event is presented in Figure 1 of Attachment B. The information reported for the static bottom hole temperatures of the wells and the information for the initial shut-in pressures of the wells are given in Figures 2 and 3 of Attachment B. These plots illustrate the type of information that might have been available for further evaluation if more information had been entered into the database.

Attachment A: Information Showing the General Structure and Appearance of the Data Base Manager

Figure 1

Figure 2

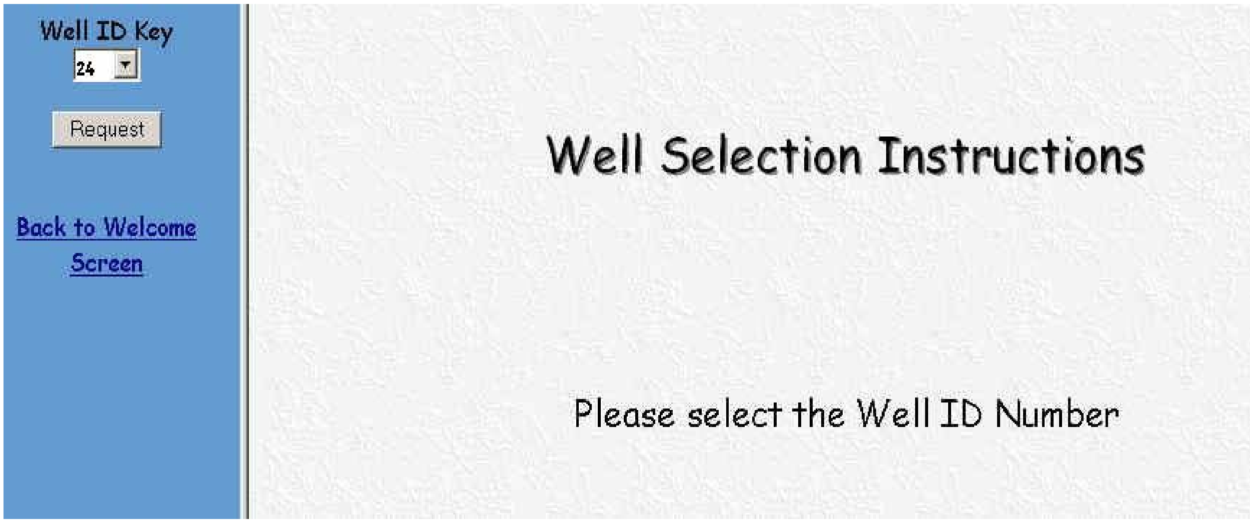


Figure 3

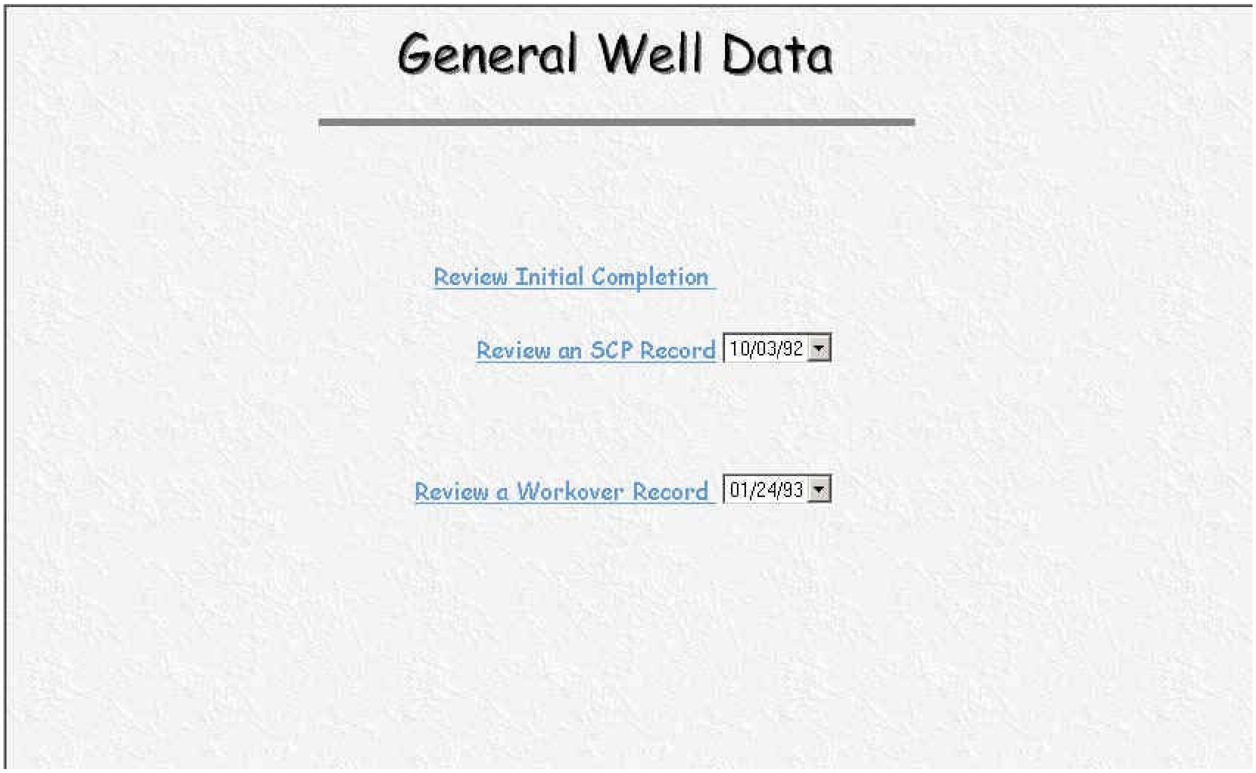

General Well Data
Review Initial Completion
Review an SCP Record
10/03/92
Review a Workover Record
01/24/93

Figure 4

Completion Information

Initial Information

09/08/79	Date (mm/dd/yyyy)
Review String 1 — 1	Number Of Tubing Strings Above Packer
1	Number Of Zones
8244	True Vertical Depth Of Top Perforation
8834	Measured Depth Of Top Perforation
29	Maximum Deviation Angle (degrees)
1000	Vertical Kick-Off Depth (ft)
2	Maximum Build Rate (degrees per 100)
Tubing has DSS-HT connections	Summary Description

Production Casing

If multiple sizes/grades exist, use size at top of casing.

Threaded & Coupled, Upset	Production Casing Type
Other	Connection Manufacturer
Other	Connection Name
10	Production Casing Size (inches)
47	Production Casing Weight
95HC	Production Casing Grade
9252	Measured Depth
	Interval 1 - Top Elevation
	Interval 2 - Top Elevation (MD in ft)
	Interval 3 - Top Elevation (MD in ft)
NaCl	Annulus/Packer Fluid Type
9	Annulus/Packer Fluid Weight

Return

Figure 5

Tubing String Information

String 1

Tubing Connection

Atlas Bradford	Manufacturer
Other	Connection Name
Integral, Upset	Connection Type
Thread, Seal Ring, Metal-to-Metal	Seal Method

Production Tubing

Steel	Type
N80	Grade
4	Size
9	Weight
New	Condition
Yes	Internal Coating

Tubing Make-Up

Torque Gauge	Torque Monitoring Method
2600	Make-Up Torque (ft-lbs)
None	Connection Leak Test
0	Test Pressure (psi)
0	Test Duration (minutes)

Pipe Dope

Undefined	Type
0	Mfg./Number
0	Lubricity Factor

Other Production Equipment

Baker	Production Packer Manufacturer
D	Production Packer Model
No	Gas Lift Mandrel
No	Pressure/Temperature Mandrel
No	Downhole Chemical Inj. Equip.
No	Sliding Sleeve
Undefined	Other
Undefined	Other
Undefined	Other

Well Conditions at Startup

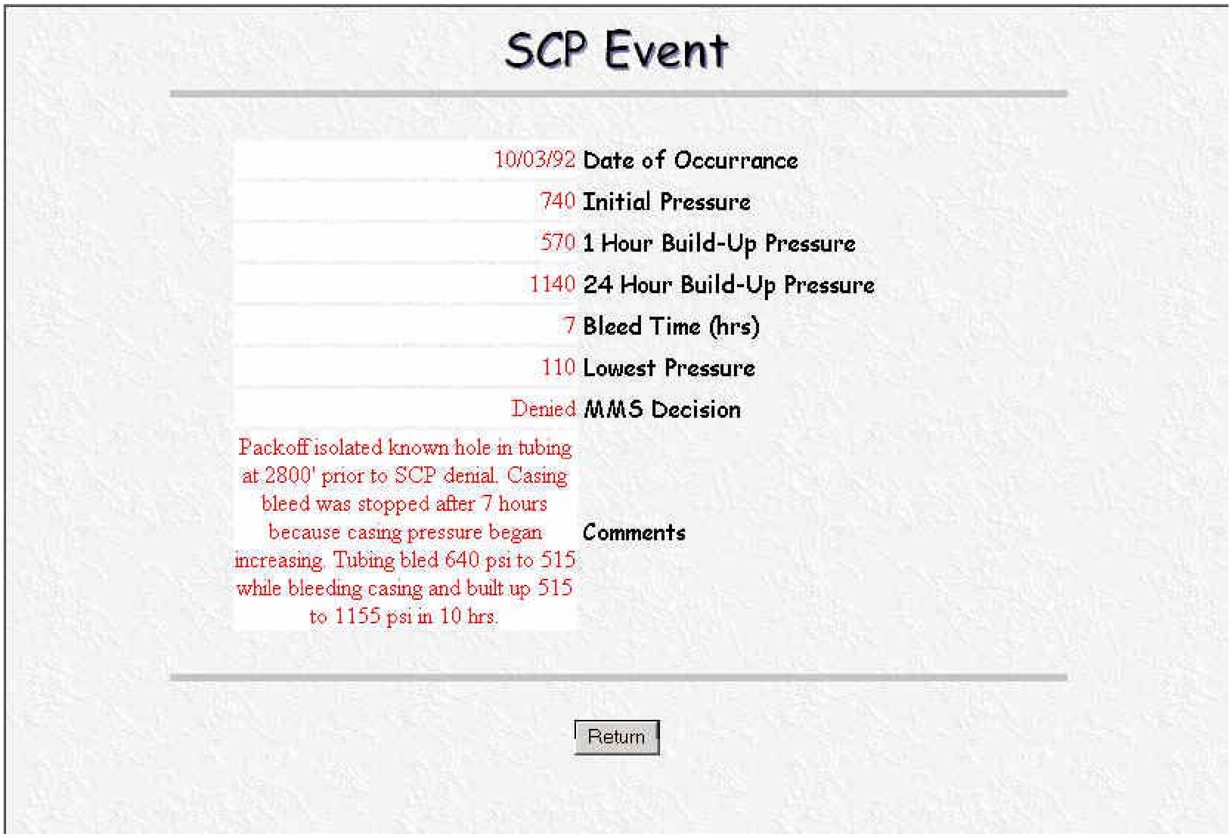
1719	Surface Pressure
2056	BHP (Bottom Hole Pressure)
203	BHT (Bottom Hole Temperature)

Production Information at Startup

6351	Gas
209	Oil
0	Water (barrels/day)
0	Water pH
20000	Chlorides (ppm)
0	H_2S
0	CO_2
No	Sand

Return

Figure 6


SCP Event

10/03/92	Date of Occurrance
740	Initial Pressure
570	1 Hour Build-Up Pressure
1140	24 Hour Build-Up Pressure
7	Bleed Time (hrs)
110	Lowest Pressure
Denied	MMS Decision
Packoff isolated known hole in tubing at 2800' prior to SCP denial. Casing bleed was stopped after 7 hours because casing pressure began increasing. Tubing bled 640 psi to 515 while bleeding casing and built up 515 to 1155 psi in 10 hrs.	Comments

Return

Figure 7

Completion Information

Remedial Action Summary

01/24/93	Remedial Action Date (mm/dd/yyyy)
Other	Remedial Action Taken
Killed well with mud and set tubing plug.	Remedial Action Comments

Failure Mode Summary

Casing	Failure Mode
Corrosion	Root Cause of Failure
Wireline ponytail	Failure Method Of Identifying Failure
Corrission always a concern on this well.	Failure Additional Comments

Workover Information

	01/24/93	Date (mm/dd/yyyy)
Review String 1	1	Number Of Tubing Strings Above Packer
	1	Number Of Zones
	8244	True Vertical Depth Of Top Perforation
	8834	Measured Depth Of Top Perforation
	29	Maximum Deviation Angle (degrees)
	1000	Vertical Kick-Off Depth (ft)
	2	Maximum Build Rate (degrees per 100)
	Well has been killed with mud and is awaiting P&A.	Summary Description

Production Casing

	If multiple sizes/grades exist, use size at top of casing.
Threaded & Coupled, Upset	Production Casing Type
Other	Connection Manufacturer
Other	Connection Name
10	Production Casing Size (inches)
47	Production Casing Weight
95HC	Production Casing Grade
9252	Measured Depth
	Interval 1 - Top Elevation
	Interval 2 - Top Elevation (MD in ft)
	Interval 3 - Top Elevation (MD in ft)
NaCl	Annulus/Packer Fluid Type
9	Annulus/Packer Fluid Weight

Return

Figure 8

Attachment B: Frequency Plots of Well "Age", Static Bottom Hole Temperature and Initial Shut-In Pressure

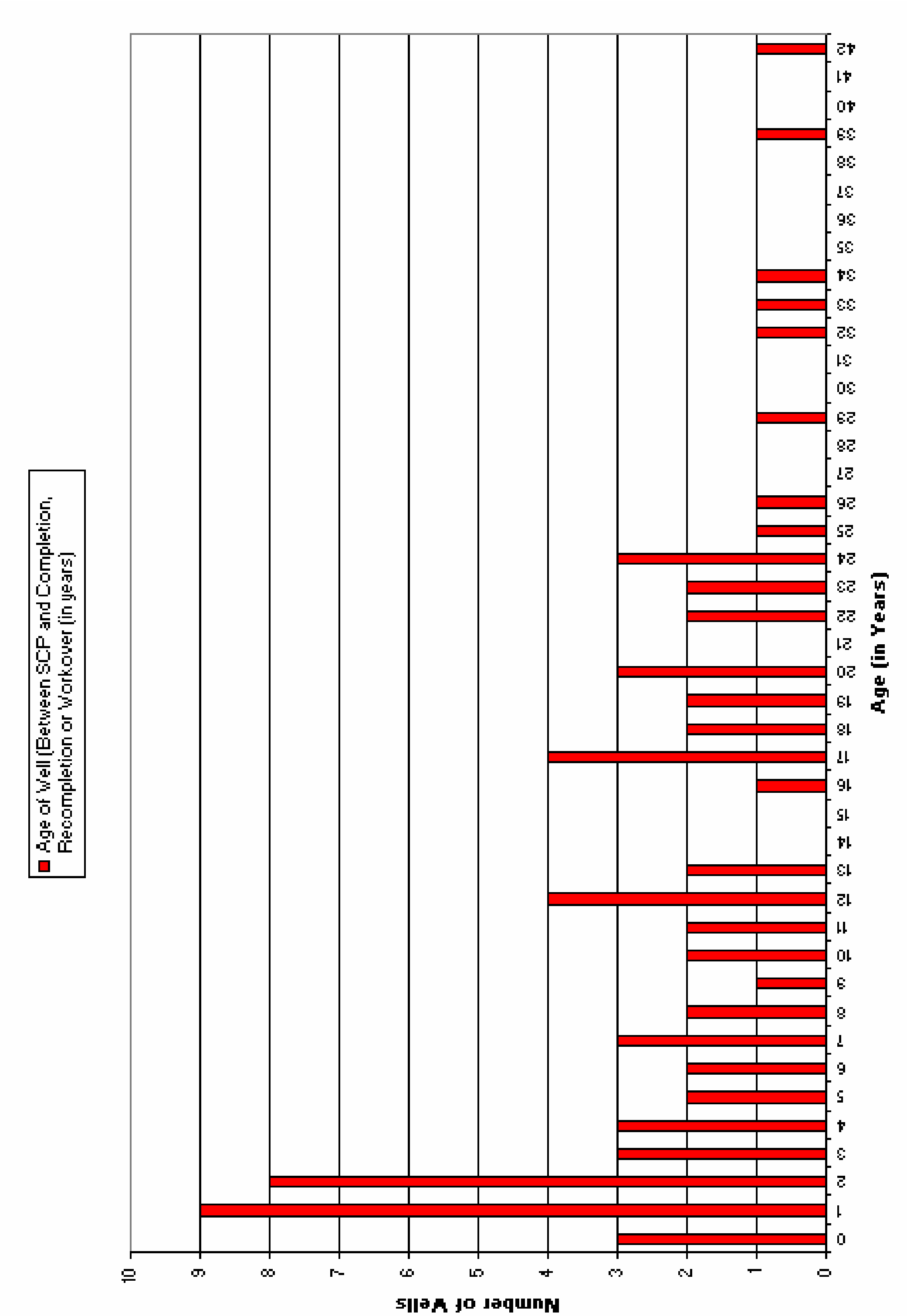


Figure 1: Age of Well Between SCP and Completion, Recompletion or Workover (in years)

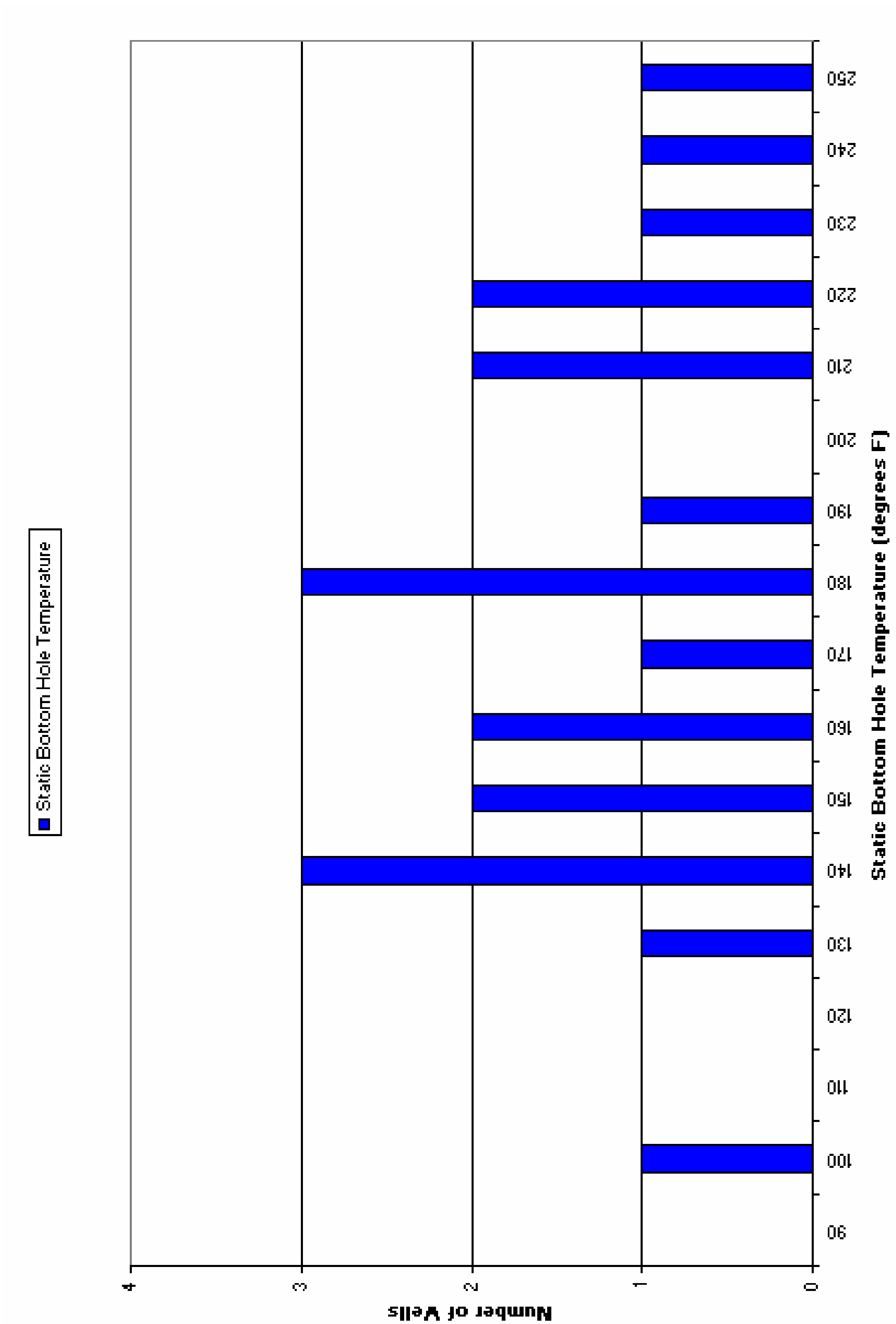


Figure 2: Static Bottom Hole Temperature

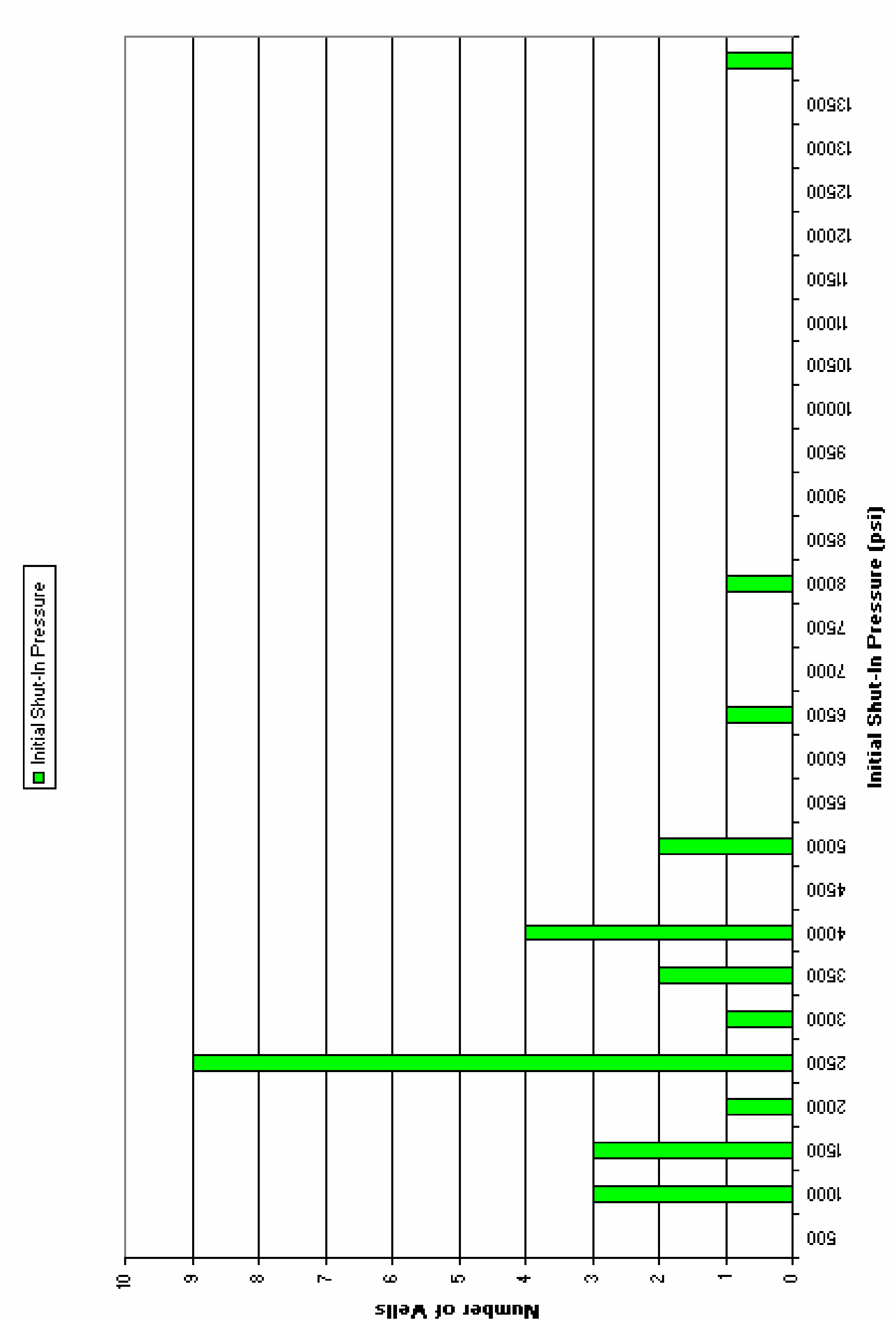


Figure 3: Initial Shut-In Pressure