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Geothermal Well Design, Construction and Failures

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ABSTRACT

When a high temperature geothermal well is completed, there is a risk that the well fails on the first heat up or that there is a delayed failure due to the formation environment like the presence of corrosive fluids. When a failure occurs, the loss of production and cost of repair can be quite significant compared with the cost of completing the well. The components in these failures are the casing and cement used in the well. Design and construction techniques have been developed to minimise the risk of catastrophic failure of casing. Also, studies have shown that implementing code design requirements will not necessarily contribute to reducing or eliminating the risk of casing failures due to high temperatures. The use of investigative techniques like down hole video cameras has shown how failures can be categorised. Cement and casing design alone cannot minimise the risk of failure. Construction methods are examined. It is apparent that any oversight or slight deviation in implementing good construction techniques increases the risk of casing failure. Case studies from various geothermal developments in the Pacific – South East Asia region are used to illustrate casing failure mechanisms and causes of such failure. Large and standard diameter wells are compared. In addition, this paper examines two common design and construction options used in geothermal wells, namely, single string design and the use of the tieback liner arrangement. Statistics of successful wells versus failures are assembled to provide risk profiles for each design option and casing failure mechanism.

1. INTRODUCTION

Over several decades, many papers have been published connected with designing and constructing geothermal wells. The primary intent of the design and construction process has been to eliminate or reduce the risk of a well failing to fulfil its long-term function as a conduit between the surface and the underground geothermal reservoir. This paper concentrates on casing failures to see what can be done in the design and construction process to further mitigate the risk of failure. Investigations of casing failures were conducted in geothermal wells in a number of countries within the Pacific – South East Asia region. For commercial reasons, operations and operators are not named in this paper. Specific country references have also been omitted to avoid identifying fields or operators.

For the purposes of this paper, the production casing is defined as the final string of casing cemented in place. The outside diameters of production casing commonly used are 13-3/8", 10-3/4" and 9-5/8". The first two are commonly regarded as "big hole" completions and the latter is referred to as a "standard hole" completion.

The production casing can be run and cemented as a single string from the production shoe to the surface. Alternatively, it can be run and cemented as two segments referred to as a liner and tieback arrangement. The liner is run first and is hung from the inside of the anchor or intermediate casing. It is then cemented. Drilling of the production hole is completed before the tieback is run and cemented.

2. CASING FAILURE MODES

Hoop, radial and axial stresses build up in a casing that is cemented in place as the well heats up. In design, the reference temperature (sometimes called "neutral") is the temperature when the cement sets and locks the casing in place. This reference temperature will vary at points along the casing. It typically increases with depth corresponding to the in-situ ground temperatures. The heat of hydration of cement slurry may affect (increase) the reference temperature. The symbol, ΔT, is defined as the temperature change (increase) relative to the reference temperature.

Table 2.1 summarises failure mechanisms common in geothermal wells. The first two are discussed in more detail in the following subsections.

Table 2.1. Production casing Failure Mechanisms

Casing Failure Mechanism	Conditions	Likely Depth
Casing implosion.	ΔT and casing to casing entrapment of fluids.	Anywhere above shoe of outer casing (s)
Compression failure in casing and/or couplings.	ΔT and rapid heat up. Also an added condition is severe doglegs.	High temperature fields and shallow where ΔT is greatest
Sulfide stress cracking.	Temperatures below 80 ^{o} C and high stress areas.	Shallow with cold shut in conditions
Early (< 2 years) corrosion and/or casing holing (internal).	Sections with worn (thinned) casing or wells with very aggressive (low pH) production fluids.	For aggressive fluids the first sign of problems is corrosion at the well head.
Delayed corrosion (3 - 5 years (internal))	Condensate level in shut-in wells.	At the water gas interface of shut-in wells.
Corrosion evidence after 5 years (external).	Corrosive fluid penetrating along micro-fractures in casing cement.	Any depth on the production casing

Casing implosion can have a marked affect on the productivity of a well immediately after the first discharge. Severe cases can choke the well flow by more than 50 percent. It is unlikely to have an immediate affect on the containment of the full bore pressures. All the other failure mechanisms have the potential of allowing fluid to escape from the well into the surrounding formation or breeching to the surface. However, wells have continued to flow where there have been no outward signs of these types of failure. Generally, there is no sign of change in production rate because, unlike the trapped fluid implosion mode of failure, these casing failure modes do not result in a significant reduction in flow area. However, the loss of pressure containment can pose a serious well control hazard in some cases. It is therefore important to detect cases early and deal with any signs of casing failure appropriately.

3. CASING COLLAPSE OR IMPLOSION - TRAPPED FLUID IN CASING TO CASING ANNULUS

3.1 Video Record

Casing collapse in geothermal wells is normally due to the thermal expansion of trapped fluid in the casing to casing annulus. With the use of downhole video cameras, this type of failure is readily identified by the deformation being segmented to one side of the casing circumference. No evidence has been seen of a complete necking or symmetrical collapse of the casing. This non-symmetric collapse tendency is probably a reflection that fluid is trapped in "lineal streaks" rather than as a full annular slug of fluid during cement placement. Collapse is normally located in the body of the casing and not near the couplings. At couplings (ie. couplings on the production casing), trapped fluid occupies lesser annular space. In addition, any yielding of the coupling may allow the loss of sealing capacity, thus providing a pressure relief for the expanding trapped fluid. The visual absence of alternative collapse behaviour does not necessarily mean that collapse at couplings and collapse over the entire 360 degree circumference does not exist. The observations suggest that casing collapse is determined by the geometry of the trapped fluid.

Downhole video images has revealed the different degrees of severity with collapsed casing.

In one big hole well, video showed a 13-3/8" OD (L80 72 lb/ft., BTC) casing collapse at the depth of 338.8 m where several sinker bars were stuck. The collapse appeared to have been violent with the casing wall on one side being torn and folded in on itself over a depth of about 3 meters. The sinker bars had lodged in the folded over section. It was apparent that mineral deposition occurred as a result of and after the collapse incident. Heavy scale build-up was found at the casing break, thinning out over a 10-20 m interval above the break. This was possibly the reason for the steady decline in output during the few days of well testing. Higher in the well there appeared to be a thin layer of scale over much of the casing string (recognizable in areas where chips had broken off). About 1.3 m below where the sinker bars became lodged, formation water could be seen flowing into the well. No samples were obtained and the chemistry of this water was not known. At about this point was located a coupling on the 20" OD, 106 lb/ft; K55, outer casing. It was surmised that this coupling was distorted during the implosion allowing small amounts of formation, gas and fluids to enter the imploded section.

Some videos of casing collapse have revealed relatively minor inward bulging of the casing wall compared with that described above. This may probably be indicative of the relatively small size of the pocket of trapped fluid.

3.2 Implications for Standard Design

The Code of Practice for Deep Geothermal Wells NZS 2403:1991 (reference 3) is a standard commonly used as the basis for designing geothermal wells. This standard stipulates that the ratio of the collapse resistance of the inner casing to the internal yield of the outer should not be less than 1.2. The ratio was 1.11 for the collapse observed and described in the previous section. Generally for big hole completions, achieving the 1.2 ratio is far more difficult than with the smaller diameter casings used in standard hole completions (9-5/8" OD production casing inside 13-3/8" OD outer casing). Evidence of casing collapse has been found in several wells where there has been compliance with the 1.2 ratio. In one well, the 9-5/8" OD, K55, 47 lb/ft production casing was cemented inside 13-3/8" OD, K55, 54.5 lb/ft casing which in turn was cemented into a 17-1/2" hole, ie. there was no other outer casing at the depth where collapse took place (279.5 m). Samples of very hard cement and very soft cement were recovered from the collapsed section during repair operations conducted on the collapsed production casing. These failures suggest that the confinement of the outer casing by the cement and the surrounding rock reinforces the outer casing from the casing to casing annular pressures to an extent that bursting of this outer casing is unlikely to, or will not, occur during the trapped fluid expansion. The observation that the inner casing will collapse preferentially to the yielding of the outer confined casing suggests that

a) the 1.2 minimum ratio appears to be far too low, and

b) the prevention of casing collapse due to trapped fluid cannot be readily dealt with or guaranteed by designing for thicker inner casing.

Work outlined in reference 2 tends to support the second conclusion. The author has not seen any trapped fluid type of casing failures in geothermal wells completed with 7" production casing cemented inside 9-5/8" OD casing. Compared with the standard and big hole completions, this type of completion are not so common. Apart from more favourable ratios, the other possible reason for the absence of this type of failure is the smaller annular space.

The challenge is to find alternative design measures that are practical and economical to implement. In the meantime, a practical strategy is to concentrate on the construction methods as a way to mitigate the risk of this type of failure. These measures should include

1) the use of tieback casing strings and

2) implementing a high standard of quality assurance and control during

   - the cement slurry preparation, and

   - placement of cement.

3.3 Options for Construction

The practical solution to the problem of casing implosion is to take all necessary measures to avoid fluids (including un-set cement) being trapped in the casing to casing annulus. The key measures for achieving this are:

- use of tieback or external casing packers to provide a higher degree of certainty of filling the casing to casing annulus with quality cement.

- ensuring that the slurry free water value is zero under all pumping conditions and slurry temperature variations.
- for single strings, ensuring strict adherence to sound cement top job procedures.

Each one of these measures requires attention to detail in the laboratory and in the execution of the cement job.

Free water in the cement slurry is seen as a possible source of trapped fluid. Commonly, slurries are tested for one or two temperatures (normally anticipated bottom hole circulating temperatures) and free water measured for these temperatures. Free water has been found to exist in the same slurries when tested at lower temperatures. Therefore, slurry designs should be tested for (zero) free water at all temperatures that the slurry will approach during its journey from mixing until it sets up.

In a plain single string design, it is highly likely that a cement top job will be required. This involves the addition of cement slurry to the top of the annulus due to fall back of the primary cement slurry or the total lack of returns during the primary cement job. Conducting top jobs can be a source of water entrapment if the procedures are not carried out properly or if the top job slurry is poorly designed with free water values greater than zero. Often, top jobs require a waiting period. During this waiting period, personnel may forget that they have water in the cementing lines when reconnecting to the side valve to re-commence filling the annulus.

The use of small diameter tubing is an alternative means of doing top jobs. This method is satisfactory when the primary slurry has fallen back by no more than several joints of casing. The risk of fluid entrapment is increased when more severe fall back or complete losses occur with the primary cement job.

Inflatable external casing packer (ECP) just above the shoe of the anchor casing can eliminate this problem in a single string design. However, it is not as commonly used as the tieback system to eliminate cement fall back. The relative complexity and mixed reliability of ECPs to function properly, is probably the reason why operators prefer the simpler tieback – liner system. The tieback system eliminates this fall back if the lap has an adequate seal. However, in spite of the use of tiebacks, it has not eliminated the type of failure that it is designed to eliminate. Major geothermal operators have had tieback casing implosion type of failure suggesting that fluids (or over retarded cement) can still be entrained in the slurry during the placement of the slurry. Further discussion on this is provided in the tieback design and construction section of this paper.

3.4 Heatup and first discharge of the Well

In the event that trapped water is suspected to be present, it may still be possible to prevent the implosion of the inner casing. If the well is allowed to heat sufficiently slowly, it is possible that the slight leakage of this water through micro-annuli, casing couplings, etc; will be enough to prevent the pressure from reaching critical levels (only small volumes are required to be vented to reduce the pressure considerably). In addition, slow heating can break the cement – casing bond before the stresses in the casing peak. There is anecdotal evidence that casing that have been through thermal cycling during drilling of the production hole are less susceptible to casing failure during the first discharge of the well after completion. Thermal cycling includes wells drilled with occasional steam kicks, under balanced drilling or with aerated water.

Large step increases in temperature (which sometimes occur when the well is gas lifted) have resulted in severe casing failures (casing implosion or compression failure, or both). Two such wells suffered this fate when 150+ ^{0}C water was lifted across casing that was originally at ambient temperature (30 to 40 ^{0}C) within the space of 30 minutes.

In practice, for a self discharging well, this can be achieved by placing the well on increasing bleed rates or using a connected well to heat the well. This option is not available where wells are not self discharging. Steam heating using a mobile oil fired boiler was used in the early days of development in the Philippines. This is a preferred option to using cold gas lifting techniques.

4. COMPRESSION FAILURE

4.1 Mechanism

This mode is sometimes mistakenly put down to a tension failure of the casing at the coupling due to quenching of a hot well. Basic analysis will show that tensile stresses during cool down to or below the reference temperature are well below the yield stresses for the casing or the coupling. When the casing is examined using casing calipers or video, it is in a quenched state and the couplings appear to be pulled apart. This "pulled" effect, common when buttress threaded couplings (BTC) are used, is due to the loss of mechanical integrity of the coupling during compression yielding under hot conditions (thereby reducing the capacity for the coupling to withstand tensile loading under cold conditions).

When properly cemented casing is subjected to heating, the casing will be restrained from expanding longitudinally by the cement. This will induce compressive stresses in the casing and tensile stresses in the cement. These stresses are directly proportional to the ΔT temperature change. If the temperature change is greater than 230 ^{o}C the compressive stresses can exceed the point where permanent (plastic) deformation occurs.

Failure normally occurs in

1) high temperature fields,
2) high temperature production conditions (where well head temperatures exceed 260 ^{o}C),
3) production casing completed with good cement jobs.

High temperature well head conditions can occur when the well is on high pressure hot bleed (ie. at maximum discharge pressure).

4.2 Performance of Threaded Casing Connections in Compression

For buttress threaded connections, tests have demonstrated that thread jump will occur after the pipe body begins yielding in compression. Furthermore, this phenomenon has been confirmed with downhole video and casing calipers run into wells in several high temperature fields (with reservoir feed temperatures in excess of 300 ^{o}C). In one well that was surveyed, the video (run in cold quenched conditions) clearly showed couplings parted (failed in compression) at depths of 224.6 m, 249.5 m, 310.5 m and 372.0 m (approximately every third joint). Close to the (pulled) threads, it was observed that the casing body was deformed slightly. The failed production casing consisted of 13-3/8” OD, K55, 68 lb/ft, BTC. This casing was run as a single string to 1554.6 m with an external casing packer - stage cementing collar arrangement at 679.5 m (directional well with kick off at 700 m). The records showed that the casing was slackened off during second stage cementing and while waiting on cement.

Buttress threaded couplings are susceptible to thread jumping in compression because of the lack of positive pressure contact at the pin ends after it is torqued up (reference 1). Tests have also shown that buttress threads lose their ability to seal when heated above 200 ^{0} C (reference 5). Thread jumping and sealing failure is less likely to occur with premium connections consisting of positive contact or metal to metal sealing at the pin ends. Confined compression tests on a premium connection with metal to metal sealing connection have shown that casing joint pressure integrity will remain, even after the body has yielded (reference 5). This should negate the need for pre-tensioning of production casing strings when using such premium connections.

When using buttress threaded connections, one can prevent compressive yielding by ensuring that the initial tensile stress in the casing (when the cement sets) is sufficient to offset the effects of severe stress reversals at heat up. Relatively short production casing strings and tiebacks using buttress threaded couplings, suffered this mode of failure. In contrast, a longer single string of casing has greater initial tensile stress (due to casing weight) locked in at the critical area near the top of the string (where ΔT is greatest). Pre-tensioning is an option for tie back and single string casing when cemented in two stages. This should reduce the risk of compression type casing failures described in this section.

Failure at buttress threaded couplings can also occur if the well heats up suddenly. Such failures have been seen when using nitrogen to stimulate flow in a well. This reinforces the case for slow heating of wells prior to full output testing as advocated in section 3.4 of this paper.

5. CORROSION AND SULFIDE STRESS CRACKING

5.1 Reduction in Casing wall thickness

Shallow CO_2 rich environment in shallow reservoir fluids has resulted in casing being attacked from the outside. It is a problem in only a few fields. Installing additional strings of casing as a sacrificial layer of steel adjacent to the zone producing corrosion fluids is one measure that is being implemented.

In the early 1990’s, CR22 (steel with 22% chromium) casing was used by an operator in several geothermal fields to combat external corrosive attack from formations known to be conduits for corrosive fluids associated with sulfide rich fluids which form sulfuric acid. The casing was used to cover the formation and at least 30 m either side of the formation. Since the use of this CR22 casing, it has been reported that the ordinary casing below the CR22 has corroded indicating that the corrosive fluids have migrated down the cemented annular space. It should be noted that these wells used API Class G high sulfate resistant (HSR) cement with 30 to 40 percent silica flour.

Internal casing corrosion is not normally a problem with wells in the geothermal fields that were investigated.

5.2 Sulfide Stress cracking

Sulfide stress cracking is not common in geothermal wells. This is possibly due to either the common use of K55 and L80 grade of casing for production and well head anchoring strings, or to fact that some operators maintain wells hot, even when not connected to the steam gathering system.

A video survey of one geothermal well possibly indicated casing failure due to sulfide stress cracking. The well was completed with 1272 m of 9-5/8” API grade C95, 43.5 lb/ft production casing. The video showed extensive longitudinal splitting of the casing from 79 m to 180 m. Also shown was a parting of the casing at 79.36 m GL. The well was blocked at 180 m. The cracking of the casing indicated a brittle failure.

The parting of the casing at 79.36 m was unlikely to be the result of a thermo-compressive failure as described in section 4. A stress analysis of this casing configuration shows that there was an adequate margin between the calculated maximum compression stress (assuming a 290 ^{o} C fluid passing up the casing) and the compressive strength of the C95 grade casing. The evidence indicated that the buttress coupling parted as a result of the cracking up to and across the pin.

The history of this well was that there were numerous incidents of jarring during the drilling. It appeared that the casing failures were not evident then or immediately following the completion of the well. In the early life of this well, the well was maintained in hot condition by bleeding. This practice ceased with a change of operator and the well remained shut in.

As a precursor to discharging this well, gas (presumably cold) was bled from the well over a 9 day period at various wellhead pressures ranging up to 1400 psig. This indicated a large volume of gas in the well extending from the well head to the liquid or two phase zone below the 180 m blockage point. It is uncertain when these failures occurred. However, all the evidence pointed to the production casing splitting due to sulfide stress cracking. It is worth noting that the outer 13-3/8” (61 lb/ft and also C95 grade) casing contained the pressure. A possible reason why this string did not suffer the same fate was the relatively lower axial and hoop stresses locked into this shorter string of casing. It was also noted that at least 4 other wells (in the same field), with similar casing profiles, produced video images of longitudinally split production casing.

6. TIEBACK DESIGN AND CONSTRUCTION

6.1 Advantages

Tieback casing design has some advantages when applied to geothermal wells. The primary ones are:

1) Casing worn thin due to drill pipe rotation can be covered over with new casing (tieback) at the end of drilling a well,

2) It provides the opportunity for a perfect cement job in the critical casing to casing section of the well.

Casing wear is more concentrated on build up sections of a deviated well. A number of wells covered by this paper, did not utilise this advantage. Many tiebacks were run in vertical sections of the well only. However, thinned casing in the liner section will not have well control implications if the anchor casing shoe is already deep enough to contain production pressures.

The second advantage is the primary reason for operators using the tieback option. However, the advantage can be lost if there is a failing in the cement design or cement placement procedures. A few casing collapses in the tieback due to trapped fluids have occurred and are addressed below.

6.2 Tieback Design Issues

The tieback system has some drawbacks for which solutions can be engineered to overcome or mitigate these drawbacks.

The first is that the connection between the tieback and the liner will invariably leak down the lap during the productive life of the well. This is discussed in more detail in section 6.4.

The second is the fact that the tieback string is short and therefore much lighter than a single production casing string. If pre-tensioning is not imparted to the tieback, the tieback will yield in compression if ΔT is sufficiently large. For tiebacks with buttress connections, this yielding will result in a loss of pressure containment and “pulled” joints (refer section 4.2). This yielding can be prevented if the maximum heat up temperatures are known beforehand and the tieback pre-tensioned before the cement sets. This will necessitate the use of latch down slip assemblies in the tieback receptacle or immediately above the receptacle. Alternatively, yielding can be permitted providing the connections remain gas tight. To this extent, use should be made of a premium connection that has been tested for gas tightness when it is loaded past compression yielding occurs.

6.3 Tieback “Perfect Cement Jobs”

Before a tieback is run, a drillable bridge plug is required to be set in the liner to isolate the newly drilled production hole. This bridge plug should be located immediately below or close to the tieback receptacle to avoid any fluid contamination of slurry. In at least two tieback failure incidents that have been attributed to trapped fluid expansion, the bridge plug was set at least 117 m below the tieback receptacle. In one case, water occupied the space between the bridge plug and the receptacle. A thick gel with a relatively high density should have been used to prevent the heavy tieback cement slurry from falling through the liquid column.

Other sources of trapped fluid in tie back cement jobs is

a) the presence of free water in the slurry and

b) insufficient “excess” slurry volume to ensure complete displacement of the pre-flush fluids. This is particularly important with the larger diameter tiebacks where there is more mixing and channelling between the slurry front and the pre-flush fluids.

One other issue, commonly overlooked with tieback design, is the quality of cement job in any casing to casing annular space beyond the two inner strings associated with the tieback. If this has trapped fluid in the casing to casing annulus, this may still cause an implosion of the two inner strings of casing (anchor and tieback). A desk study has shown that this type of two or composite casing string failure is possible when subjected to trapped fluid pressures. A solution to minimise this risk is to run a tieback arrangement for the anchor casing instead of running a single string as is commonly done.

6.4 Lap Leaks

The connection between the tieback and the liner will invariably leak down the lap during the productive life of the well. Increasing the lap to anything over 50 m increases the chance of entraining and trapping liquids during lap squeezes (the equivalent of a top cement job). This leakage can be tolerated if the shoe of the anchor casing is designed to take the pressures that are seen inside the production string. In one tieback system, the well was surveyed with temperature and pressure instruments after evidence was seen of steam leakage to the surface. This well indicated that well bore fluid was exiting the well at or above the connection between the tieback and the liner. The losses above the tieback-liner connection was possibly due to the loss of gas tight integrity of the buttress coupling. One can assume that the fluid exiting the well was finding its way down the lap to the shoe of the anchor casing and then tracking its way back to the surface through the external cement jacket.

Video film of another well indicated that the tieback had not been completely stabbed into the receptacle. Cement was exposed and water was seen entering the well through this exposed cement. Presumably, this was formation water tracking up the lap.

7. CASING FAILURE FREQUENCY

7.1 Big holes

In the South East Asia – Pacific region, big hole completions proliferated in the 1990s with the expectation of gaining greater production flows for each well. A number of investigations into casing failures was prompted by the perception that failures were more frequent with big hole completions, ie. with the larger diameter production casings (reference 4).

Table 7.1 summarises the numbers of the various types of wells in various South East Asia – Pacific geothermal fields where casing failure investigations were carried out.

The numbers are much larger for the single string standard holes as this was a common form of well completion in the prior to the 1990s. Also, tieback and liner use was not common in the region during this earlier period. The numbers reflect the relatively recent introduction of tieback - liner systems in parallel with the use of big hole completions. This smaller number of big holes tends to magnify the proportion of bighole failures. However, it is still considered that the big hole failure rate is real and not surprising. It is due to the relative weakness of the larger diameter casings and the larger annular spaces in some designs (e.g. 13-3/8” inside 20” OD casing).

Table 7.1 Well numbers and completion profile

Production casing string profile	No. of Wells
Single string casing	
Big holes	42
Standard holes	577
Tieback and Liner	
Big holes	18
Standard holes	11

7.2 Mechanical Casing Failures

For a known case of casing failure, the mode of failure was categorised where adequate information was available. The data was collected from down hole logging (including casing calipers), down hole video, workovers or from surface discharges. Some of the earlier wells, making up the numbers in the single string standard hole of Table 7.1, had casing failures. Due to the lack of information, these were not included in the statistics covered by Table 7.2. Table 7.2 therefore underestimates the percentage of failures.

Table 7.2 lists only those wells that have had casing failure due to thermally induced stresses. Failures due to casing wear, corrosion and sulfide stress cracking are not covered. In all cases of parted casing, buttress threaded couplings were used.

Table 7.2 Frequency of Specific Casing Failure Modes

	Confirmed failure incidents (%)		
Production casing string profile	Total Trapped fluid	Parted Casing	Lap Leaks
Single string casing ()			
Big holes	7.1%	2.4%	N/A
Standard holes	1.0%	2.6%	N/A
Tieback and Liner			
Big holes	11.1%	5.6%	5.6%
Standard holes	0	9.1%	0

As noted in the table, two failures (= 11.1%) due to the expansion of trapped fluids were found in two tieback and liner type wells. Normally, this system provides a better opportunity of eliminating trapped fluid type of failures compared with the use of the single production string type of profile. The relatively high frequency is a reflection of the small numbers of wells with this type of production casing completion. It should not be a reason for not using this system. It remains the best system for eliminating the risk of failure due to the expansion of trapped fluids.

8. CONCLUSIONS

Trapped fluids in the casing to casing annulus remains a challenge for designers to combat. The tieback system reduces the risk of casing failure due to trapped fluids. This system and designing for greater collapse resistance of the production casing string, is not a guarantee that this failure mode can be eliminated. The best practical solution to mitigate this risk is to ensure construction techniques are sound and carefully implemented. In contrast, design is important in preventing other forms of casing failure. Measures can, and should, be taken to avoid loss of pressure containment in production casing during the design phase. For example, pre-tension loads and systems need to be determined to avoid compression yielding when using buttress threaded couplings. Alternatively, the tensile stress requirement can be ignored if one uses premium connections that remain gas tight when the pipe body – coupling yields in compression. Statistics show that the move to larger diameter wells has increased the frequency of casing failures.

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