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A Causation Investigation for Observed Casing Failures Occurring During Fracturing Operations

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Abstract

The objective of this paper is to present findings from a causation investigation of casing failures occurring during fracturing operations. The study analyzed case histories and examined post-failure laboratory results. Outcomes from casing failures include blowouts, pollution, injuries/fatalities, and loss of the well with associated costs. This work has not been previously published nor is this type of work available in the public domain literature.

This study cataloged pertinent data from fourteen (14) land-based case histories of casing failures while fracturing. The case histories were analyzed with the use of photographic evidence of recovered casing, well reports, fracturing treatment data, drilling records, and laboratory testing of recovered casing when available. Failure causes were identified. Preliminary guidelines are provided to avoid casing failures and mitigate the damages. Recovery guidelines are presented.

A model was developed to evaluate axial loads under several considerations associated with fracturing. The model accounted for the casing's in-air load, buoyancy effects from wellbore fluids, piston effect, bending, erosion, and temperature decreases. The combined loads were compared to the casing's yield strength.

The failures were not systemic but included cracking related to fatigue, hydrogen and sulfide stress embrittlement, and erosion at ERW weld lines. The failures were observed at various well depths, both in the cemented and uncemented hole sections. Results address common casing sizes and couplings involved with each failure, weight and grade, failure location and causation identification of other factors contributing to the failure. A goal of this investigation and on-going work is to develop a thorough understanding of casing failures and the myriad of contributing factors in order to develop a comprehensive predictive model for land and offshore fracturing operations.

Overview

Fracture/stimulation for enhanced reservoir production has become commonplace. One source (EPA 2015) estimated that 90% of new US land-based wells are hydraulically fractured. The combination of multi-stage fracturing and horizontal drilling technology has opened new frontiers, particularly for oil and/or gas shales. As with many advances in science and technology, hydraulic fracturing has presented new problems and challenges that must be addressed. One of these challenges involves casing failures occurring during fracturing operations.

Incidents of casing failures occurring during fracture stimulation operations are increasing at an alarming rate. Observed outcomes from land-based failure incidents include injuries and fatalities, blowouts, oil pollution and environmental damage, loss of the wellbore and portions of the reservoir that had been fractured. Costs often reach millions of dollars from categories that have included blowout control, pollution cleanup and remediation, post-incident wellbore diagnostics, fishing, reestablishment of wellbore integrity where possible, partial or complete loss of the wellbore, plug and abandonment, and re-drills. These outcomes affect environmental issues with the public scrutiny associated with them. The impact on public perception affects the social license to operate so critical in many US locations. These outcomes and their related costs and environmental impacts warrant further study.

Histories of fourteen (14) land-based casing failures were collected. Public domain information and private files were used to augment the case histories. Failures unrelated to fracturing have been excluded. Also excluded are those incidents reported as casing failures where the pertinent issue involved the cement and its related integrity. The term 'casing failure' will be used herein to address those fracturing-related failures that occur in the pipe body, the coupling or at the pipe body-coupling interface.

Literature Review

The issue of casing failures has been widely recognized and reported in the literature for decades. In the mid-1950s, Texter (1955) covered casing and tubing problems. The publication indicated that casing design should address tension, collapse and burst. At that time, frequency in which wells were fractured was inconsequential such that Texter didn't have an opportunity to observed fracture-related casing failures. It is worthwhile to note that current casing design philosophies show little advancement since the 1950s despite the industry's awareness of many factors that should be addressed.

Texter introduced the failure condition of the *last engaged thread failure*. Causes were reported as shock loading or vibration fatigue. This observation is consistent with the findings identified in this paper although Texter indicated that the magnitude of the problem was small. Texter's observations on the last engaged thread failure follows:

1. All failures occurred above the top of the cement;
2. Straighter holes produced more failures than deviated wells; and
3. The failures involved various grades of pipe and both seamless and ERW types.

Clark (1987) addressed casing design by including considerations for the piston effect, decreasing temperatures, ballooning and bending. He noted that the most common error in casing design under fracture treatments was casing selection on the basis of burst alone. Design and field guidelines were generated that proved successful in avoiding failures in the fracture treatment of 26 wells. Clark commented that the burst and tensile ratings for casing could be substantially reduced by partial erosion although his work didn't address the effects from erosion. Buckling was not considered.

Payne (1993) explored fatigue failures of in-service API 8-round casing while drilling through casing. This mode of failure was described as 'unusual, unexpected and difficult to design for', an observation still valid in 2016. Payne recognized the potential for well control issues if such a failure should occur.

Four detailed field cases of 8-round casing failures were presented. The findings, conclusions and recommendations included the following:

1. Minimize the uncemented interval;
2. Use API guidelines for all mill-end make-ups;

3. Vibrations are increased when air drilling; and
4. On-site quality assurance should be provided for both mill and field-end make-ups.

Both Texter and Payne emphasized mill-end failures.

Magill (2013) made a presentation titled "Recent Casing Failures in Horizontal Wells" that reported results from investigations of numerous failures. Focus was given to (1) P110 pipe and coupling failures, (2) split failures near the heel after multiple stages were pumped, (3) vibration failures at the wellhead-casing interface (Fig. 1), (4) pin fatigue and (5) sulfide stress cracking (SSC). Causes for the SSC embrittlement included (1) increased hardness noted with high strength casing such as P110 grade steel (2) increased tensile stresses from coupling make-up and (3) reductions in pH and temperature. Although the API's range of acceptable strengths for P110 are 110 to 140 ksi, Magill recommended to set a maximum tensile limit of 133 ksi for P110 pipe due to its susceptibility to environmentally assisted cracking and that efforts should be made to maintain reasonable limits on the pipe's hardness.

Figure 1—A fatigue crack at the wellhead-casing interface resulted in a blowout. The fatigue was vibration-induced.

O'Brien (1984) used two case histories to describe buckled casing failures in an uncemented interval between two cemented segments. This scenario is applicable while fracturing uncemented or poorly cemented casing in the lateral section of horizontal wells. O'Brien concluded that effective cementing was the only method available to maintain casing in a stable condition which should avoid buckling.

Case History Analysis

A substantial effort was made to gather case histories and other relevant data. The intent was (1) to identify wells that experienced casing failures and (2) acquire data from available sources that included well files, public databases, publications and private files. Well files maintained by individual states were accessed and downloaded if pertinent well identifiers such as the well's API number were available. Information sources included (1) drilling and completion plans/prognosis including the fracturing program, (2) daily operations reports for drilling and completion, (3) directional surveys, (4) cementing records for each casing string, (5) post-fracture treatment reports for each stage, (6) drilling fluids daily or end-of-well reports, (7) bit records, (8) geological reports, (9) scout tickets, (10) post-incident production data, (11) logs and reports generated during diagnostic work, (12) metallurgical laboratory testing reports and (13) the well's current status. In a few cases, offset well data was acquired to determine if the fractured well had demonstrable influences on surrounding wells. Commercial information sources such as log libraries were utilized in some instances. The search for additional case histories and supplemental information is on-going.

Land-based fracturing candidates and field operations typically have shared failure characteristics pertinent to this investigation. Most unconventional wells encounter normal or slightly sub normal formation pressures although a few over-pressured exceptions exist. Horizontal drilling through oil/gas shales appears to be more common than with vertical wells. Length of the lateral section often exceeds the vertical depth. True vertical depths rarely exceed 10,000 ft. Directional drilling through the build section often created dog-legs exceeding 15-20°, values that were considered unacceptable a few years ago. Cementing faced several challenges that included (1) cement displacement efficiency in hole/casing sizes observed with the recent failures and (2) incidents of loss of circulation experienced while drilling, running casing or cementing.

Casual conversations with numerous sources indicated a wide-spread awareness of instances involving casing failures. As seemingly abundant as they may be, information on most incidents is not available. The information is under the control of the operator desiring to protect its assets, an insurance company, claims adjustors, or involved in litigation. Two representative case histories were summarized as a means to present and discuss characteristics associated with common failures (Appendix A).

Data items believed to be pertinent to each failure were collected and summarized (Table 1). Several observations were identified as follows:

1. Failures occurred in vertical and horizontal wells;
2. For horizontal wells, failures were observed in the vertical (71.4%) and build (28.6%) sections;
3. Shallow failures above top-of-cement (64.3%);
4. P110 grade pipe was used in 85.7% of the failures;
5. High collapse pressure rated casing (HCP) was common to the failures (85.7%);
6. The typical failure involved the coupling and/or the last engaged thread on either end of the coupling or the pipe tube within 1-2 ft of the coupling;
7. Testing reports identified fatigue in most failures;
8. ERW casing was used on 92.8% of the case histories;
9. Erosion on the ERW weld line (14.3%); and
10. Surface pressures typically exceeded 6,000 psi with pump rates in the range of 50-90 bbl/min at the time of failure.

Table 1—Summary of case history analysis.

No.	Profile[a]	OD/Wt.[b] (in./ppf)	Grade-HCP-Mfg[c]	Cplg[d]	Depth, MD (ft)	Above TOC[e]	Cause/Description
1	H	4.5/11.6	P110-HCP-ERW	LTC	7,550	N	Cause not identified, failure at 7,550 ft in cemented casing, 15th stage.
2	H	5.5/17.0	P110-HCP-ERW	BTC	9,306	N	Failure at 9,306 ft in cemented casing, below KOP.
3	V	5.5/17.0	P110-HCP-ERW	BTC	2,793	Y	Erosion hole on weld line at 2,793 ft, hole located 1 ft from coupling,
4	V	5.5/17.0	P110-HCP-ERW	BTC	2,060	Y	Erosion on cracked coupling in box at 2,060 ft, minor corrosion but not rejected, unable to determine if erosion lead to the crack, or vice versa.
5	H	5.5/17.0	P110-HCP-ERW	BTC	6,000	N	Failure at 6,000 ft, below KOP in cemented section.
6	V	5.5/20.0	L80 – ERW	GB-CD*	700	Y	Erosion hole on weld line-1 ft from coupling at 700 ft.
7	H	7.0/26.0	P110-HCP-ERW	LTC	1,430	Y	Hydrogen stress cracking in coupling at 1,430 ft, fracture originated at tong marks, wellhead blew-off, 2nd failure at 50 ft causing fluids to leak into the cellar.

No.	Profile[a]	OD/Wt.[b] (in./ppf)	Grade-HCP-Mfg[c]	Cplg[d]	Depth, MD (ft)	Above TOC[e]	Cause/Description
8	V	5.5/17.0	P110-HCP-ERW	LTC	3,410	Y	Pressured-up to 8,000 psi to open sleeve for stage 4, wellhead blew off, flowed oil to the cellar, coupling failure at 1,430 ft, fracture origin coincided with tong bite marks.
9	D	5.5/20.0	L80 – ERW	LTC	560	Y	Coupling pull-out at 560 ft, stuck while running casing, pipe did not meet API specs for yield and tensile strength.
10	H	5.5/17.0	P110-HCP-ERW	LTC	4,096	Y	Brittle failure in pipe body at 4,096 ft, failure located 10 ft from coupling, API yield strength is 140,000 psi but failure had 175,000 psi, exceeded API hardness, untempered martensite, HSC[f] cracks observed.
11	H	5.5/20.0	P110-HCP-SMLS	DQX*	8,555	N	¼ in. hole at 8,555 ft, casing not retrieved.
12	H	7.0/–	P110-HCP-ERW	–	100	Y	7 in. casing parted at 100 ft, surface casing also parted just below wellhead, casing-wellhead ejected, minor injuries.
13	H	7.0/29.0	P110-HCP-ERW	GB-CD*	–	–	Failed during 1st or 2nd stage, well flowed oil, gas and water.
14	H	7.0/26.0	P110-HCP-ERW	LTC	2,600	Y	Coupling failure at 2,600 ft.

Key:– = Unknown

[a]Key: V = Vertical, H = Horizontal, D = Directional

[b]OD-Outer Diameter; Wt.-Weight

[c]Manufacturing Process; Key: HCP-High Collapse Pressure; ERW-Electric Resistance Weld; SMLS-Seamless

[d]Coupling; Key:

[*]= Premium coupling

[e]Key: Y = Yes, N = No, – = Unknown

[f]Hydrogen Stress Cracking

Several qualifications should be considered when reviewing this data.

1. ERW pipe was used more often than seamless although this observation may not be meaningful when evaluating casing failures. ERW seems to be preferred by operators because its cost is lower than seamless pipe and its API properties should be the equivalent. The quantities of ERW and seamless casing used as production/fracturing casing were unavailable for comparison purposes.
2. P110 pipe with the commonly used weights has burst ratings greater than 10,000 psi which was sufficient to handle typically observed maximum pump pressures of 7,000-9,000 psi. The cost of this P110 was usually less than other grades with similar properties such as heavy-walled N80 pipe.
3. Pipe diameters of 5.0-5.5 in. were adequate in most cases to satisfy the desired rate objectives while maintaining surface pressures below 10,000 psi.
4. HCP casing was used in several wells. It is typically more brittle than non-HCP pipe. The wells included in this investigation didn't appear to have collapsed conditions that required HCP casing. Well should be analyzed to determine if HCP is required.

Characteristics and Conditions Associated with Failures

Casing failures occur when applied stresses and operating conditions exceeds the pipe's yield properties and fatigue limits. Pipe stresses are affected by surface operations, fluid properties and casing/hole configurations. Pertinent surface operations include pump rate and pressure as well as wellhead vibrations.

Fluid properties include (1) temperature, (2) the type, size and quantity of proppants and (3) the amount, type and concentration of acid. Casing and coupling geometries affect internal fluid velocities, pressures and erosion. Hole configurations include the well's profile, dog-leg severity at depth, hole-to-casing sizes, cement height in the annulus, environmental effects from annular fluids and corrosion. The amount and severity of buckling, ballooning, and bending influences pipe stresses. Fatigue considerations include vibrations, dampening effects of the wellbore and cyclic operations. Some but not all of these parameters will be discussed briefly. Metallurgical laboratory testing on failed specimens often reported the failure cause from one or more of these conditions.

An effective failure analysis requires that stresses associated with each of the characteristics and conditions must be quantified, where possible, and subsequently combined. Calculation procedures and equations currently exist to determine stresses from some factors such as ballooning, bending, buckling and temperature changes. Other conditions such as the effect of vibrations and fatigue with its related contributors are more difficult or impossible to quantify with existing technology. The effect of vibrations will not be presented other than its contributions to cyclical loading. Discussions on these stress sources and other parameters is provided.

Pump rate and pressure. Pump rates associated with hydraulic fracturing are greater than with routine drilling operations. Common rates are in the range of 70-100 bbl/min. Vibrations occur and affect the surface equipment, the wellhead-casing interface and the shallow sections of the casing string. These rates create high fluid velocities inside the casing. Fig. 2 illustrates velocities for typically used casing strings and pump rates. The impact of high velocities on erosion is not well understood.

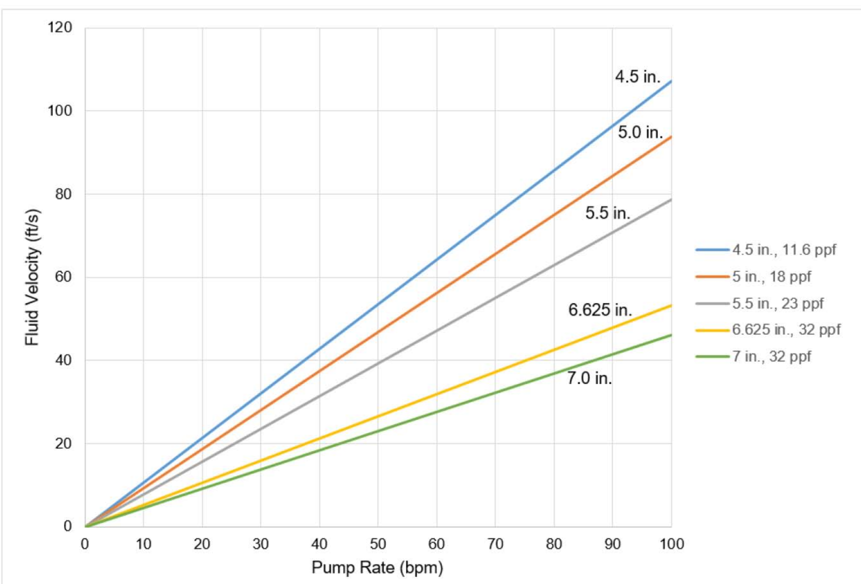

Figure 2—Fluid velocities associated with various pump rates and casing sizes commonly used for fracturing operations. Velocities are shown in ft/sec (ft/s). A pump rate of 86.5 bbl/min (bpm) (Fig A-3) resulted in fluid velocities greater than 90 ft/sec.

A fracture treatment plot of pump rates and pressures is shown in Figure A.3 (Appendix A). The 15th stage was being pumped when a failure occurred. Appendix A should be consulted for details.

Temperature. Fracturing exposes the casing to dynamic temperature loads. Fracturing fluids, often in surface tanks where the atmospheric temperature may be cold, invariably lower than downhole formation temperatures. They are pumped at rates and velocities that can displace the fracturing string in 60-75 seconds. Changes from the fluid's cooling effect can cause substantial stress increases in the casing. Also, rate changes and shut-down periods results in a dynamic temperature scenario that allows cooling and heating phases observed during fracturing operations.

Thermal shock may damage casing. It occurs when thermal gradients cause different parts of casing to expand or contract at different rates. Evaluating a failure for possible thermal shock is a challenge because the generated crack is similar in appearance to fatigue or brittle cracks. Research on thermal shock in casing strings is sparse.

Erosion. An undesired byproduct from fracturing operations is erosion. Fracturing fluids containing proppants, usually some type and size of sand, are pumped at high rates and fluid velocities. As previously shown in Fig. 2, velocities of 70-100 ft/sec are the expected norms. Factors affecting erosion include the roughness of the inner tube wall, hardness and angularity of the proppant, brittle vs ductile pipe, fluid velocity, straightness of the tube and many others. The complexities of the erosion process under stimulation conditions precluded further investigation at this time.

Two case history failures were caused by erosion in similar circumstances. ERW pipe was being used. The seam on the internal weld line was attacked by the proppant (Fig. 3). The erosion-generated hole grew until it had penetrated the tube's outer wall. The failure indicator was lower-than-anticipated pump pressures. In both cases, the operator successfully identified the anomaly prior to complete pipe parting.

Figure 3—Internal erosion on the weld line of ERW pipe penetrated the pipe's wall thickness. Erosion can initiate at physical anomalies such as grind marks. (Case History No. 3)

An attempt was made to evaluate the erosive conditions in the case histories to existing models. The two models selected for this effort were API's RP 14E "Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems" and DNV's "Particle" Impact Erosion Model (DNV-RP O501). In the case of RP 14E, the fluid velocities and sand quantities upon which it was based is orders of magnitude lower than observed during stimulation operations. The DNV model did not contain details and correlations used as its basis so a head-to-head comparison with conditions associated with the casing failures was not possible.

Buckling. Buckling is another condition that affects pipe stresses (Lubinski and Althouse 1962, Mitchell 2008). Buckling severity is a function of several variables including pressure, the section length and external support from cement or the wellbore (Fig. 4). Buckling does not damage the pipe unless the increased stresses exceed the pipe's yield properties. Permanently buckled pipe (Fig. 5) results when the pipe's yield properties are exceeded.

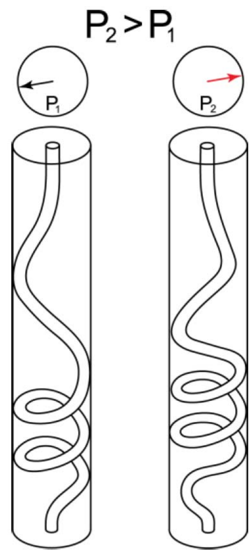

Figure 4—This artist's rendering shows the concept of buckling. A further increase in internal pressures results in a pitch reduction accompanied by stress increases.

Figure 5—A high pressured, fracture treatment allowed the pipe to buckle. A permanent deformation of the pipe occurs when the buckling-induced stresses exceeds the pipe's yield strength. (Photograph courtesy of Dr. Robert Mitchell.)

Ballooning. Ballooning occurs when pump pressures are internally applied to the casing (Fig. 6) (Clark 1987). Mechanics of ballooning and the equations that defined it are found in the literature. In an unrestrained condition, the casing length would shorten as pressure is applied. However, cement restrains the casing's movement which causes stress increases in the pipe. Pressure variations observed during fracturing operations may result in a dynamic ballooning process that increases fatigue wear.

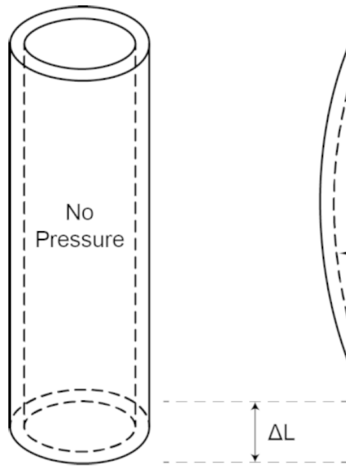

Figure 6—The application of internally-applied treatment pressures forces an outward radial movement of the pipe wall. The pipe's length will shorten if the pipe is not restrained. If annular cement restrains pipe movement, stresses are increased.

Bending. Pipe bending in wellbore dog-legs is inevitable in all wells, including vertical wells. The bending load associated with a dog-leg causes a stress increase on one side of the pipe and an equal decrease on the opposite side of the pipe. The stress magnitude is determined from a square root function resulting in positive and negative solutions (Lubinski 1961). The resulting stress load is the sum of the initial axial stress and the bending-related stress (Fig. 7). Bending doesn't damage the pipe unless yield properties are exceeded.

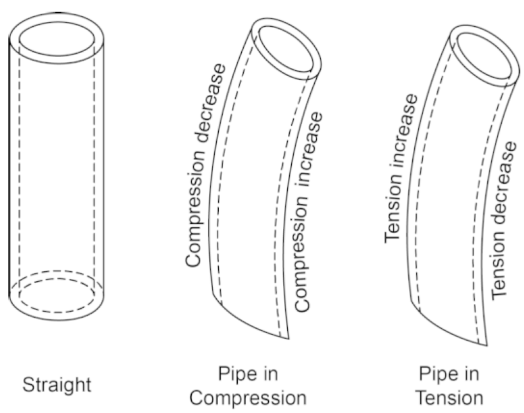

Figure 7—Pipe bending across wellbore dog-legs creates bending stresses that are added to the existing axial stress to arrive at total stresses at that depth. In addition to pipe bending, other conditions will similarly create stresses additive to the existing axial stress.

Corrosion. All casing used in wells is susceptible to corrosion (Craig 2014). Laboratory reports on some of the failed specimens indicates that corrosion played a role in the pipe failure during its design service life. Most hydraulic fracturing fluid systems contain a stage(s) where large volumes of acid are pumped down the casing string. The relationship between sources of corrosion and the role corrosion plays in casing failures needs further investigation.

An additional consideration is the wellbore environment in which the casing is run and cemented. Drilling fluids and additives may pose long-term threats. Hydrogen and/or sulfides from various sources can embrittle the casing. Environmental failures have been difficult to diagnose as to a specific cause or source.

Fatigue. Fatigue in the coupling area appears to be associated with most casing failures even though new casing was run in the wells (Fig. 8). Loads or deformations which will not cause fracture in a single application can result in fracture when applied repeatedly. Fracture may occur after a few cycles or after millions of cycles. This process of fracture under repeated loading is called *fatigue*. The mechanisms of fatigue failure in downhole casing strings are not well understood. Experiments show that the alternating stress component is the most important factor in determining the number of cycles of load a material can withstand before fracture, while the average stress level is less important. Steels have the property that there is a stress level where the material can withstand unlimited cycles without failure. This stress level is called the *endurance limit*. Fatigue life is strongly influenced by the quality of the surface finish, residual stress, surface or subsurface cracks, stress concentrations, the chemical environment, and the material toughness.

Figure 8—The crack observed in this photograph resulted from coupling fatigue. (Case History No. 7)

Brittle Failures. The laboratory test reports often noted brittleness when discussing failures (Fig. 9). Resistance to brittle failure is called *toughness*. The toughness of a material is its ability to absorb energy and resist brittle fracture. Brittle fracture is catastrophic and can be manifested at stresses below the yield strength of the material. Brittle materials have low toughness because they experience only small plastic deformations before fracture. Generally, toughness decreases with increasing yield strength. Temperature can have a significant impact on the toughness of carbon and low-alloy steels. Toughness is usually measured using the Charpy impact test at a specified temperature. Elongation requirements are also a measure of ductility and are used to ensure adequate toughness. Texter (1955) and Payne (1993) identified brittle failures during their investigations.

Figure 9—A visual examination of the failed casing showed a brittle fracture. Lab testing indicated that the failed specimen's yield strength exceeded the API's acceptable ranges. The pipe was improperly tempered during the manufacturing, as shown by harness testing. (Case History No. 10)

Crack propagation due to internal pressures can occur at less than plastic stress when an imperfection or crack in the steel propagates to the point that the material fails. The service environment, defined by temperature, presence of corrosive gases or fluids, pH, material properties and other factors affects when this type of failure occurs.

Manufacturing issues. A laboratory analysis on a failed casing specimen usually includes a visual inspection and metallurgical testing. API standards such as API's Specification 5CT "Specification for Casing and Tubing" usually provides the basis for comparison with the specimen's test-derived properties. Results from the available case histories identified several failure causes including the following:

1. The specimen's tensile measurement was outside API's acceptable range. Low tensile ratings can cause overload failures although none were reported in the available case histories. Increases in the pipe's brittleness are associated with tested tensile values that exceed API's recommendations. Hardness values exceeded API ranges.
2. The pipe was improperly quenched and tempered when manufacturing. Tempering may have used incorrect temperatures. Water sprayed on the pipe during the quench process may not have been evenly distributed.

Manufacture-related issues may not share characteristics but rather differ with each incident.

Post-Failure Outcomes

Casing failures and subsequent recovery operations observed with the case history data have outcomes that fall in several categories including (1) damage resulting from the failure both downhole and at the surface including blowouts, pollution and fatalities, (2) an assessment of downhole conditions affecting the viability of recovery operations, and (3) the recovery operations. With respect to potential recovery operations, observed outcomes fell in two categories (1) well integrity in some form was reestablished and completion operations were completed, (2) wells requiring abandonment operations when well integrity could not be established. Well control and blowouts have been experienced in both categories. Significant costs are associated with most failure incidents.

An overview of the typical steps and conditions for a successful recovery follow:

1. The incident is quickly detected;
2. Contingency plans for fracture-related casing failures including well control, blowouts, and pollution are initiated;
3. Diagnostic operations are conducted to locate and assess the failure. Caliper logs should be included in the diagnostics program. Determine if the failure is a hole or the casing parted;
4. Initiate recovery operations;

    a. Pull the upper casing section out of the well;
    b. Retrieve several joints at the top of the casing that remained in the well;
    c. Make-up and run replacement casing; and
    d. Establish integrity by pressure testing or other means.

Pre-planning is essential for successful recoveries.

Recovery may not be possible for several reasons. The failed pipe could not be retrieved and replaced. This case is typically associated where the failures are located in the cemented casing sections. In several incidents, hole/casing misalignment prevented access to the lower sections of the well. Casing patches have been attempted but rarely were successful. A casing patch may cause additional diameter restrictions such that the completion operations can't be continued. Expandable casing has been used successfully in one incident.

Blowouts have resulted from casing failures and they remain an on-going threat to future fracturing operations both on land and offshore. Certified well control training is based on the premise that a competent casing string is in place. This premise is not valid with casing failures. Conventional blowout control practices are applicable if the failure was in the equipment immediately above ground. Relief wells are implemented where the failure was in the deep section of the vertical hole or in the lateral. As the results of this study have shown, most failures occur in the vertical section of the well above the top of cement. Failures observed in this section tend to be closer to the surface than the top of cement. Currently existing blowout control techniques are not immediately applicable in these cases.

A comparison was made of the number of blowouts associated with fracturing against the context of all blowouts. The data for comparison was taken from the Texas Railroad Commission's Blowout database (Texas RRC 2016). It contains blowout information from the early 1950s. The time period selected for the analysis was 2011-2016. For each incident, the report had a 'Remarks' section that provided a brief description of the incident including causation for some cases. The database included 114 blowouts for the selected study period. Of the 114 blowouts, 20 incidents or 17.5% were related to various aspects of fracturing operations. Each fracture-related blowout was examined to determine if it occurred as a result of a casing failure during pumping operations. Blowouts occurring during flowback and plug drill-out were excluded (Table 2). Casing failures were identified in 8, or 40%, of the 20 incidents and 7% of all blowouts during the time period. Twelve (12) of the 20 blowouts were excluded because the 'Remarks' section did not explicitly identify the cause as a casing failure. Nine (9) of the excluded incidents appeared to have resulted from casing failures but was not explicitly identified as a casing failure. The case histories identified in Table 1 do not include the blowouts shown in Table 2. Fig. 10 is from a casing failure where the wellhead was ejected and damaged a pump truck.

Table 2—Summary of blowouts from casing failures (Texas 2011-2016).

No.	Year	RRC Comments
1	2015	During frac stimulation, intermediate casing ruptured and possibly surface casing.
2	2015	Well casing parted during fracture operation.
3	2014	During hydraulic fracturing on the 19^{th} stage of 25 stages, fluid was observed flowing from the cellar at a rate of approximately 10-12 bbl/min, wellhead-casing interface cracked.
4	2014	While on the fourth stage of fracking, the 7 in. casing parted approximately 10 ft below the frac tree and brought the tree and the 7 in. casing out of the hole, where it landed next to the well.
5	2013	During a fracture treatment the casing parted.
6	2013	Production casing parted during fracking.
7	2011	Casing parted during frac job, which caused the wellhead to separate from the well.
8	2011	Casing ruptured during fracture stimulation operations.

Figure 10—A crack at the wellhead-casing interface caused this failure (see Table 2, number 4). The wellhead and short sections of surface and production casing were ejected. The projectile speared the truck's cabin. (The driver was not in the truck.)

Modeling Fracturing Conditions

Clark (1987) suggested that casing design for fracturing considerations should consider stresses from the piston effect, length changes from pressure (ballooning), temperature decreases and bending in addition to burst, collapse and tension. Factors not taken into account by Clark include fatigue, vibrations, corrosion, and cyclic loading. His work was the first step to expand existing casing design practices to include loading conditions associated with fracturing. Admittedly important, casing running loads were excluded in this phase of the investigation but are being considered in a different research phase.

As part of this investigation, a model was developed to evaluate stress increases associated with Clark's suggested considerations. Case History No. 1 (Appendix A) was used to describe modeling results. An adjustment was made to the calculated hook load so it would match the recorded hook load at the site. The calculated hook load was shifted to the observed value. The result was that a negative tension (compression) was observed at the bottom of the casing below 6,681 ft in the build section (Fig. 11a). The accuracy associated with this adjustment can't be tested but is believed to be within an acceptable range for the purposes of these calculations.

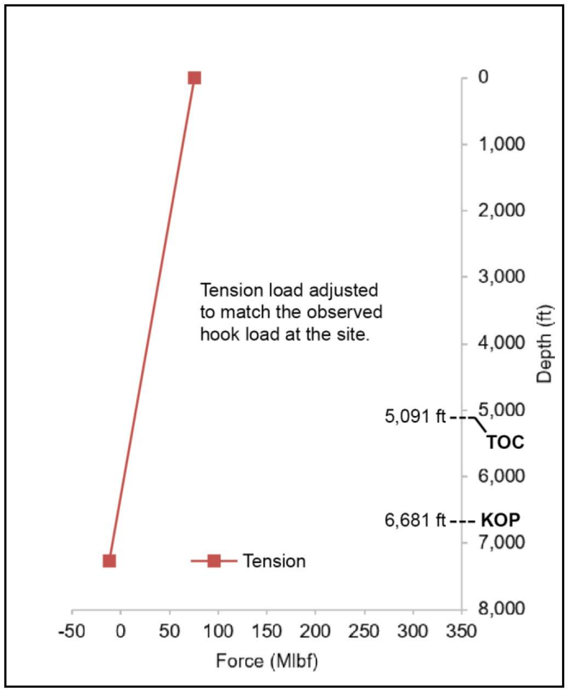

Figure 11a—Tension load adjusted to match the observed hook load.

The bending stresses were calculated with Lubinski's equation. Fig. A-2 shows the dog-legs used for the calculations. The results were added to the initial tension loads (Fig. 11b). As previously indicated, bending stresses typically don't have a significant impact when evaluating the cumulative loads. The combined loads from tension and bending at the bottom of the string are lower than combined loads at the surface.

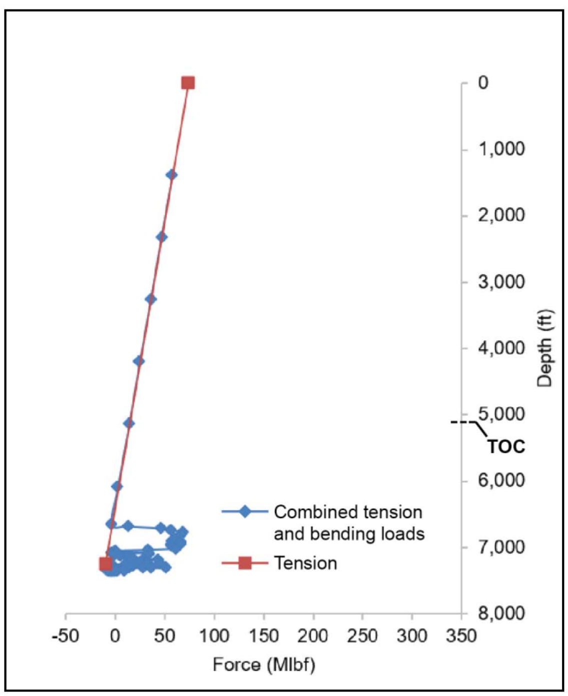

Figure 11b—Combined tension and bending loads.

Loads associated with pressure and temperature changes were determined. An increase in pressure and a temperature decrease results in length changes (shorten) if the casing is not restrained. Since cement prevents pipe movement, additional forces are applied. The combined loads from the initial pipe tension, bending, ballooning and temperature decreases are shown in Fig. 11c. Temperature typically provides the largest stress changes followed by pressure (ballooning).

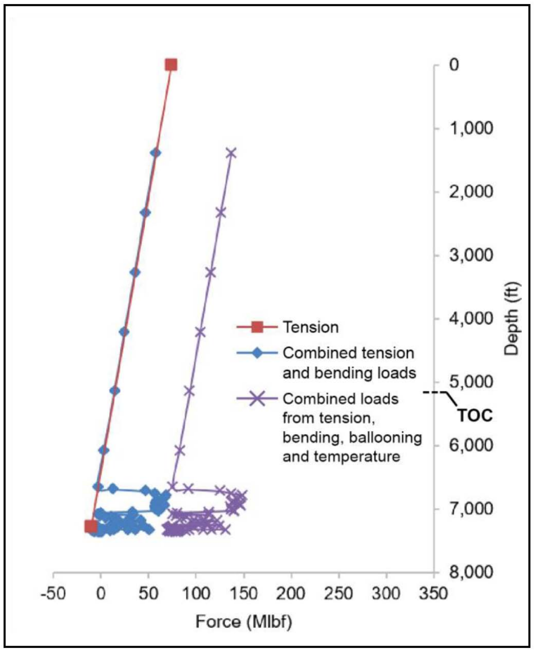

Figure 11c—Combined loads from tenion, bending, ballooning and temperature.

To complete this evaluation, the pipe body's yield strength of 367,000 lbf was compared to the applied loads (Fig. 11d). The pipe's yield strength exceeded the applied load by a factor of 2. This observation is consistent with the modeling results from the other case histories.

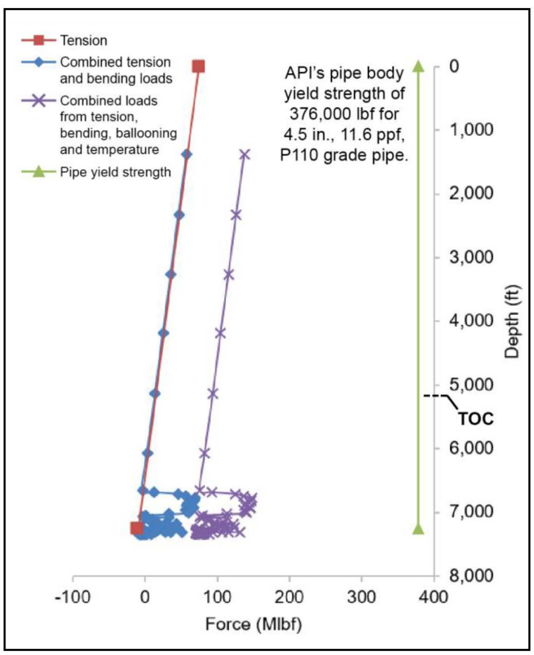

Figure 11d—A comparison of API's pipe body yield strength of 367,000 lbf for 4.5 in., 11.6 ppf, P110 grade pipe and combined loading conditions.

A disclaimer for the API pipe body yield strength of 367,000 lbf is warranted. The subject pipe was manufactured to provide a collapse rating greater than the API's rating. Mills use proprietary methods when manufacturing HCP pipe. As such, the API's yield strength may not apply to HCP pipe. Nonetheless, P110 HCP pipe is likely to have a yield strength that exceeds the combined loading.

A finding from this analysis was that the observed casing failures were caused by factors other than previously considered, perhaps acting simultaneously with the axial load and Clark's considerations. Testing reports indicated that fatigue was a contributing cause for most failures. Since fatigue results from cyclic loading, the focus of an on-going investigation is to identify the individual loads involved in cyclic operations and the manner in which they interact.

An ultimate goal is to develop a representative model that will address most or all of the fracturing conditions experienced by casing strings. The model can serve as a predictive aid for field operations, casing design and well planning. After the model has been successfully tested for land-based incidents, its scope should be expanded to handle fracturing conditions associated with deep water, HPHT offshore wells.

Applicability of Current Casing Desing Practices

Failure causes identified during the case history analysis were evaluated in the context of common industry design practices that considers burst, collapse and tension. Causes for the observed failures don't appear to be solely linked to any of these three parameters. With respect to burst, post failure analysis shows the fracture pumping pressures were lower than the casing's API burst rating and the physical characteristics of the failed specimens were different than the longitudinal split often associated with typical burst failures. In similar evaluations, collapse and/or tension failure characteristics were not observed. On-going investigations and research efforts may provide further definition of the variables associated with the failures and the manner in which they interact.

Failures seem to result from many factors, acting individually or in combination. Preliminary work suggests loading conditions that may be in play include axial loading, pipe ballooning, buckling, bending, thermally induced loads, stresses incurred during coupling makeup, fatigue, erosion, environmental effects and cyclic loading. Factors contributing to the fatigue are important. Further discussions on design guidelines for casing used during fracturing operations are premature at this time.

Standards-making organizations such as the American Petroleum Institute and the International Standards Organization (ISO) don't provide design guidelines but focus on items such as specifications for the manufacturing process, care and handling recommendations and formulas/calculations to determine the pipe's performance properties. As an example, API's Specification 5C3 originally considered the following failure criteria for casing design:

1. Initial yield
2. Burst
3. Collapse
4. Axial tension

Following the issuance of the ISO 10400 report, API has revised 5C3 to consider the following failure criteria:

1. Initial yield
2. Ductile rupture
3. Collapse

The burst and axial tension criteria are now considered obsolete.

As previously identified, common failures found during fracturing consist of fractures near connectors, or longitudinal brittle failure of the connectors, with fatigue cracks. The failure modes identified in this investigation aren't addressed by the API or ISO.

Findings and Conclusions

Findings and conclusions arising from this investigation proved to be revealing and unexpected in some cases. This type of failure has the potential for catastrophic outcomes and causation that involves complex issues. Outcomes from a land-based failure are likely to be amplified when fracturing wells located in a deep water HPHT environment. Findings and conclusion presented throughout this paper have been used to develop preliminary considerations for failure avoidance.

Operators and service providers might consider one or more of the following items for failure avoidance, damage mitigation or to aid recovery operations.

1. Larger diameter casing strings than commonly used reduces fluid velocities and surface treatment pressures;
2. Increased attention should be given to thread cutting and coupling installation, particularly on the mill end. Company practices should be established and enforced for the mill- and field-end make-up operations. Record and preserve make-up data;
3. Casing make-up at the rig site often results in the coupling being turned. This occurrence likely invalidates torque-turn analysis for the field end. Ensure that both connections are made-up with the same torque and turn requirements while using the manufacturer's recommended thread lubricant. The affected casing and connector should be taken out of the string;
4. Attention should be given when selecting, sourcing and purchasing couplings. The lowest cost-per-foot for casing with installed couplings may not prove to be the most effective purchasing criterion;
5. Casing providers rarely guarantees their casing to meet API specifications, i.e., buyer be aware. If their casing fails in the field, replacement pipe costs may be reimbursed but other recovery costs becomes the operator's responsibility. Many manufacturers provide a variety of inspection and testing services at the mill on a fee-paying basis. Mag-particle and SEA inspections might be considered over the full length of each joint and particularly the weld seam on ERW casing. Develop a means to ensure that these services are properly performed according strict standards and the results recorded. Special attention should be given to the 3-4 ft length of pipe on each end. Preliminary results from the current investigation has found that non-coupling related failures typically occur within 1-2 ft on either side of the coupling;
6. Determine collapse loads under fracturing conditions. HCP casing may not be required;
7. Most observed failures have occurred in the shallow, uncemented sections of the hole. Increasing cement volumes to move the TOC up the hole as far as reasonably possible should be considered. Low density, filler cements provide support that may assist in failure prevention;
8. Cementing challenges arise when loss of circulation has occurred during the drilling process or while running casing. Further, effective cementing of long laterals with small diameter holes and casing sizes is a problem that may never have a good solution. A good cement job assists in casing failure prevention by providing pipe stabilization;
9. The wellhead-casing interface is subjected to vibrations, particularly when fracturing. Failures have resulted in the ejection of the wellhead and shallow casing sections. Stabilization could assist in vibration reduction. Cementing the top of the casing in the cellar is an option. Heavier walled pipe for the top joints of surface casing provides additional support and stabilization. Install and weld a thick walled, steel plate between the wellhead and the conductor/drive pipe to transfer loads from the wellhead. Top-out the surface casing with a cement capable of providing support for the casing. Consider a second top-out job if the cement level drops out of sight;

10. Coupling design and selection is an important aspect of the well design process. The current study indicates that the coupling and/or the last engaged thread on either side of the coupling have failed. Causes include fatigue that increases the casing's brittleness, i.e., a reduction in the pipe's ductility. Efforts to protect the casing's ductility should be considered;
11. Multiple sizes and types of couplings are available. Make-up stresses should be determined and evaluated as these stresses vary widely among the couplings. Couplings that involve reduced make-up stresses might be favored;
12. Drillers running casing should be cautioned against rapidly lowering the casing and abruptly stopping it to avoid shock; and
13. Running casing for long horizontal wells or crooked holes often demonstrates friction loads that exceed the pipe's hanging weight at the surface. Drillers have resorted to pipe rotation or setting block weight on the top of the casing. These practices should be avoided. Options to address this issue include avoidance of severe dog-legs or reaming the hole if they occur, using a larger bit to drill the section, reduce the drilling fluid's lubricity, lower the fluid loss to develop a thin filter cake, or partially float-in the casing. These options have been used successfully.

The findings from on-going investigations and future research efforts will be used to expand and refine practical guidance to assist operations when planning and drilling wells to be fractured, both on land of offshore.

Acknowledgements
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Appendix A

Discussion of Selected Case Histories

Two case histories (CH) were selected as representative of the observed casing failures in this study and other failures as reported by Magill (2013). They involve horizontal (CH 1) and vertical wells (CH 2). The pipe was recovered and metallurgically tested in CH 2 while the pipe was not recovered in CH1.

Case History No. 1

A 34 stage fracture job was planned for a well to be drilled in Oklahoma (Fig. A-1). Loss of circulation while drilling the 7 in. intermediate hole may have adversely effected the cement job. The estimated top of cement (TOC) for the intermediate casing was 5,620 ft but could be lower due to the prior fluid losses. Logs were not run to identify the cement top. Directional drilling started at 6,681 ft near the bottom of the intermediate section.

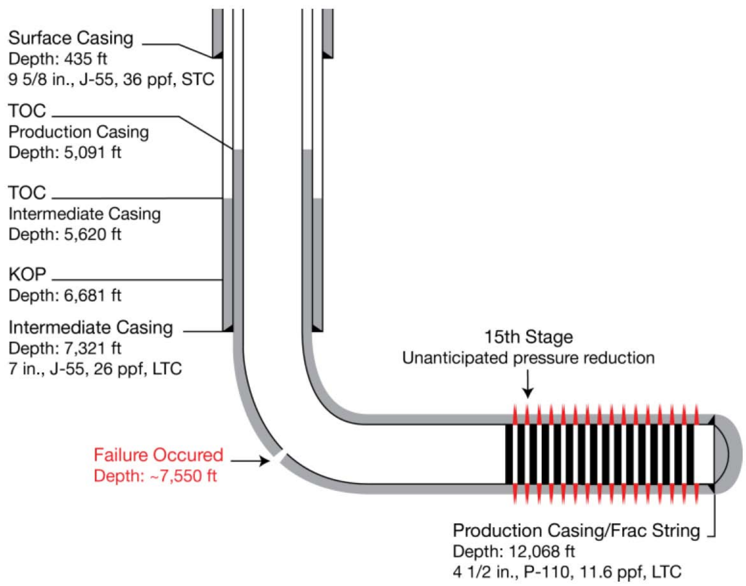

Figure A-1—A failure occurred at ~7,550 ft while pumping the 15th stage. The operator successfully recovered the wellbore and produced the well.

The production section of the well was drilled to 12,068 ft measured depth (md). The 4.5 in. casing string used for fracturing was run to 12,068 ft and cemented. The estimated TOC was 5,091 ft. The casing string included a dual float shoe, 288 joints of 4.5 in. OD, 11.6 pounds per foot (ppf), P110 grade, HCP, LT&C coupled, electric resistance welded (ERW) pipe. Attached to the string as it was being run were 48 solid body, 5-bladed turbolizers with the first being placed 10 ft above the shoe and the remainder placed every third joint.

Drilling operations create dog-legs in the wellbore. Survey data was used to determine the bending severity from the dog-legs (Fig. A-2). The magnitudes of these dog-legs were characteristic of other case histories involving build sections. Although the severities are initially alarming, preliminary conclusions from this investigation indicates that dog-legs may not play a significant role in casing failures.

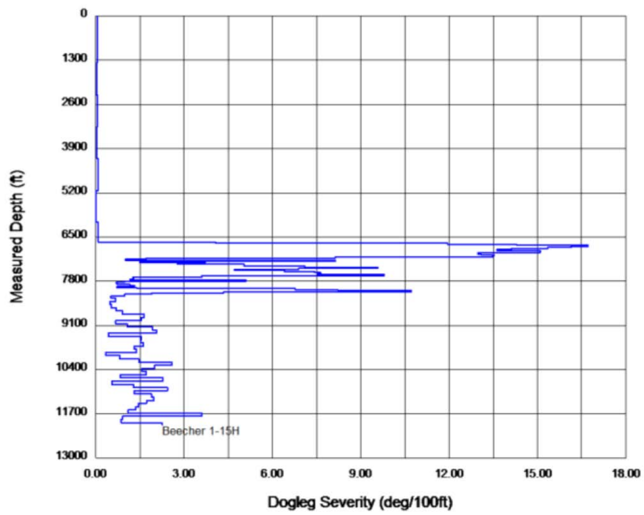

Figure A-2—Dog-legs in the build section exceeded 16.5 degrees. Other case histories had dog-legs greater than 30-35 degrees.

Fig. A-3 shows the surface treating (pump) pressures and slurry rates for the 15th stage in which the failure is believed to have occurred. Pumping operations started at ~2309 hours with a maximum rate of ~86.5 bbl/min and pressure of ~8,550 psi at 0005 hours. It appears the pumps were equipped with an overpressure (auto-stop) feature which was set at 8,500 psi and triggered when surface pressures reached ~8,550 psi. After a short shut down period of 77 seconds, operations continued with a pump rate of ~84 bbl/min accompanied by pump pressure fluctuations.

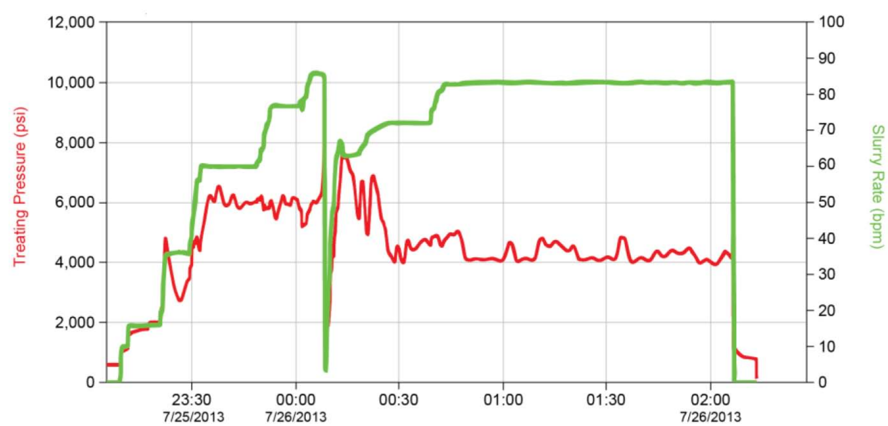

Figure A-3—The fracture treatment report for the 15th stage recorded pump rates and pressures. The failure occurred shortly after midnight. Pressures after the failure were substantially lower than previously estimated.

Fracturing operations were summarized and shown in Table A-1. The cumulative pump time was 2,595 minutes or over 45 hours. Each stage started with a volume of acid. Maximum pump rates routinely exceeded 80 bbl/min while pressures exceeded 8,000 psi.

Table A-1—Summary of fracturing fluids (and sand) through 16 stages.

No.	Pump Time (mins)	Treated Water (gals)	FE Acid (gals)	Sand (lbs)	Max Pressure (psi)	Max. Rate (bbl/min)
1	245	518,054	9,828	137,690	7,926	95.2
2	151	432,739	9,458	167,340	7,367	99.1
3	150	415,783	9,576	172,160	8,177	94.9
4	169	428,875	12,516	173,629	8,289	83.6
5	145	403,156	9,450	170,440	8,239	92.4
6	148	435,813	6,384	160,420	8,128	96.5
7	137	393,589	9,492	165,960	6,939	93.2
8	151	446,221	9,492	181,360	8,223	93.4
9	179	467,599	12,776	122,180	8,376	84.5
10	153	408,611	9,568	170,560	8,381	85.5
11	166	439,982	9,870	170,480	8,430	85.5
12	143	422,267	9,450	88,960	8,205	97.7
13	127	387,161	9,442	170,660	8,172	95.6
14	N/A	435,480	9,350	172,020	8,415	90.5
15	368	472,121	9,526	170,440	8,550	85.6
16	163	387,052	10,568	171,340	8,034	95.2
TOTAL	**2,595**	**6,894,503**	**156,746**	**2,565,639**		
				Avg.	**8,116**	**92**

A summary of the fracturing job through the 16th stage provides insight as to the severity of fracturing operations. Over the 2,595 minutes (43.25 hours) of pumping, the following were pumped:

1. 6,894,503 gallons of treated water;
2. 156,746 gallons of acid; and
3. 2,565,639 pounds of sand.

This fluid summary clearly indicates that fracturing conditions impose aggressive loading conditions on the casing string that aren't associated with normal, non-fracturing conditions.

Observations from Table A-1 and Fig. A-2 include the following:

1. The maximum treating pressure of ~8,550 psi was lower than the pipe's burst rating of 10,690 psi for the 4.5 in., 11.6 pounds per foot (ppf), P110 grade, LTC pipe;
2. Applied annular collapse pressures were negligible because the annulus valve was left open;
3. The service provider's treatment reports indicate that breakdown occurred at 2309 hours. The pressure drop observed from 2321-2330 hours was not addressed in the available information even though the pump rate was relatively constant at 39 bbl/min; and
4. Although the observed pump rates appeared relatively constant for long periods of time, the associated treating pressures frequently varied.

The failure in the build section was similar to Magill's split failures near the heel of the lateral. This well used P110 pipe as was the case in Magill's publication.

The operator initiated diagnostic operations after it became clear that a failure had occurred. Tubing with a test packer was run in the well, set at various depths and pressures were applied. After several iterations, the failure was located at ~7,550 ft, which is in the build, cemented section of the hole. These conditions prevented the retrieval of the failure specimen for laboratory testing.

The operator was able to produce the well with a pump jack even though the heel failure was not squeezed. Costs associated with the 16 fracture stages were not lost. Drilling costs to the time that fracturing started was estimated to be ~$1,500,000. A replacement well was planned to capture the reserves originally planned for stages 16-34.

Case History No. 2

An existing vertical, plugged well was reentered. The completion plan included five (5) stages designed to fracture the upper and lower Buda, Eagleford Shale and the upper and lower Chalk. An 8.5 in. drill bit was used to drill below the surface casing at 830 ft to 6,010 ft. A cement plug was set from 6,010-8,960 ft to plug the lower section of the original well.

The completion string, inclusive of the 5 stage fracturing and isolation tools, was made up and run in the well. It consisted of 5.5 in. OD, 17 ppf, P110 grade casing manufactured with high collapse pressure (HCP) rating. ERW pipe was used. Isolation was provided by inflatable packers, i.e., the casing was not cemented. A torque-turn system was used to monitor and record connection make up properties. A post-incident review of this data indicated the couplings were properly made up when run.

Subsequent to the release of the drilling rig, the well remained idle for 81 days until surface stimulation equipment became available. The casing and other downhole equipment were subjected to exposure from the water-based drilling fluids and other contaminant and corrosion sources. This condition may be related to other failures where environmental conditions were reported to have caused the incident.

The failure likely occurred in the 2nd stage. Unanticipated pressure drops were observed in stages 2 and 3. An on-site quality assurance representative observed the fracturing operations and provided the comments shown in Table A-2.

Table A-2—Observer's notes for each frac stage.

Stage	Notes/Comments
1	(Lower Buda) Shut down after pumping 44 bbl of 28% HCl acid due to leak on pump suction hole. Flushed lines with 54 bbl of water. Shut down after pumping additional 36 bbl of 28% HCl acid due to coupling on a hose pulling off. Over flushed the casing and shut down for the night. Operations on the next day (10/25) was pumped as designed. Ran 122 bbl of 28% HCl and 110 bbl of 19% HCl acid. (1508-1647 hours)
2	(Upper Buda) Pumped as designed. **Saw a ~1,000 psi drop** during the 1.25 ppg stage.(1648-1827 hours)
3	(Eagle Ford Shale) Pumped as designed, except for the acid volume being short. **Saw a ~1,000 psi drop** during the pad stage. Did not observe pressure increase when Ball 4 should have been on seat. (1828-2007 hours)
4	Pumped as designed, except did not pump acid. Lost prime during the 1.5 ppg stage and had to sweep/flush sand at 45 bbl/min. Stated back sand at 1.5 ppg and pumped remainder of sand. (2008-2147 hours)

Recovery efforts successfully retrieved the upper section of the failed pipe and the top two joints of the lower section. The coupling connector on the top of the lower fish was retrieved. The specimens were tested with standard API testing protocols. All test results indicated the pipe was within satisfactory API ranges. The testing report concluded the failure mode was likely due to initiation and propagation of a fatigue crack near the last engaged thread (first exposed thread) (Fig. A-4 and A-5, Case History No. 8). Other comments contained in the report include the following:

1. The fracture surface is smooth, flat and oriented perpendicular to the axis of the casing which is typical of fatigue cracking;
2. The fracture is located near the last engaged thread of the pin connection on the casing. The last engaged threads of a connection experience higher stresses and stress concentrations compared to the

rest of the connection, making these threads susceptible to the initiation and propagation of fatigue cracks;

3. Washing damage was present on the fracture surface of the pin connection. A fatigue crack (or multiple cracks) likely propagated through the wall thickness of the pin, created a fluid path directly from the string bore to the wellbore annulus. Subsequent erosion of the pin created characteristic "washing" in the pin.
4. The remaining portion of the fracture was oriented 45° to the casing longitudinal axis, which is typical of ductile overload. The fatigue cracks propagated and reduced the cross-sectional area. When the applied load finally exceeded the load carrying capacity of the remaining cross-sectional area after erosion, the connection failed due to ductile overload.

The characteristics observed in this incident are similar to other observed failures. A fatigue crack is observed in the last engaged thread (first exposed thread). Crack propagation leads to a failure. Cracks have been observed in the field and mill ends of the coupling. The failure appears to have occurred without warning signs.

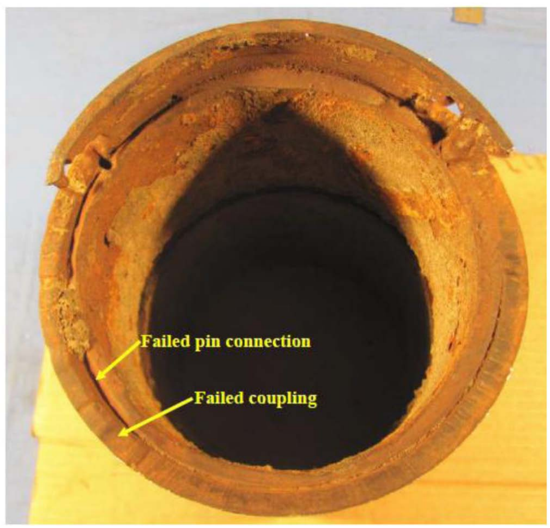

Figure A-4—The failure resulted from a fatigue crack in the last engaged thread (first observed thread). The photograph shows characteristics shared with other failures.

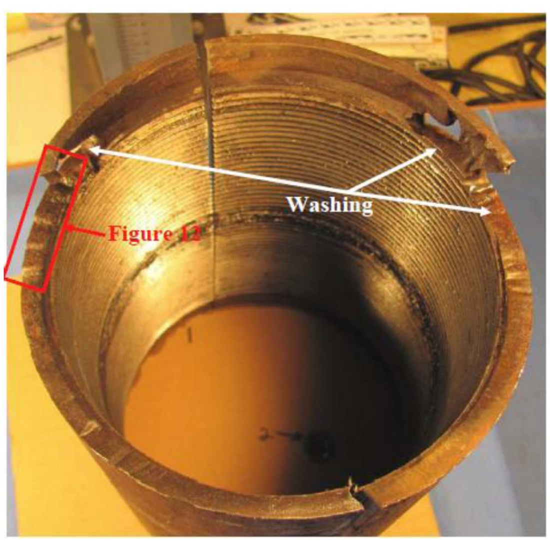

Figure A-5—Erosion occurred as the crack propagated around the casing's circumference. Erosion did not cause the failure.