Rotating While Packed off May Cause Unexpected Heat-Induced Drill Pipe Tensile Failures

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Abstract

The amount of tensile pull that can be applied to free a stuck drill string is usually restricted by the drill string's minimum margin of overpull (MOP).[1] To free a stuck string, the drill string is often rotated and pulled simultaneously. When this is done, the maximum permitted pull is reduced, depending on the amount of torque applied.

Application of pull, either based on MOP or the decreased tensile rating given the applied torque, has resulted in instances of overload failures of drill pipe. These failures have occurred at loads significantly lower than the drill strings rated capacity. In each of these failures, the formation had packed off around the string and circulation was lost.

This paper presents case studies and lessons learned from the analysis of such drill pipe failures. Metallographic examination of the failed drill pipe has revealed that the frictional forces produced while rotating the string induced sufficient heat to either locally temper the pipe or cause a phase transformation (change in grain structure) of the drill pipe material. As the material gets locally heated (often to temperatures above 1,500°F), the material hardness (and thus strength) decreases. The actual load capacity of the drill string depends on the temperatures reached downhole.

This paper discusses the factors that contribute to these failures and provides test data to support the findings. In addition, this paper presents the limitations of currently available methods used to determine the maximum allowable loads that may be applied when packed off with no circulation.

Cases of Heat-Induced Drill Pipe Tensile Failure

Case 1 – South Texas, Onshore USA: In December 2002, while making a connection at 11,756′ MD, the wellbore packed off around the 5″ 19.50# G-105 drill pipe. The drill string was "worked" by applying torque and tension for approximately forty-five minutes. The drill string moved up the hole with a loss of 60 kips as noted by the rig personnel. The drill string was pulled and a fractured joint of the 5″ 19.50# G-105 drill pipe was found at 9,553′. The down-hole portion of the joint was subsequently recovered during fishing operations. Based on the appearance of the fracture surface, the proximate cause of the failure was readily recognized by the drilling engineer as ductile tensile overload. However, the tensile load applied at the time of failure was well below the calculated tensile capacity (decreased tensile rating based on the measured wall thickness and applied torque) of the 5″ 19.50# G-105 drill pipe.

Case 2 – East Oklahoma, Onshore USA: In April 2003, with the bit near the bottom at 13,930′ TD, the wellbore packed off around the 5″ 19.50# S-135 drill pipe. The drill string was stuck and circulation was lost. To free the stuck drill string, the pipe was rotated and pulled. During these operations, the 5″ 19.50# S-135 drill pipe parted at 11,666′. The tensile loads applied were well below the drill pipe's calculated tensile capacity (decreased tensile rating based on the measured wall thickness and applied torque). The fractured joint was pulled out, and the down-hole portion of the joint was recovered during the fishing operation.

Metallurgical Analysis of Failed Joints

Metallurgical analysis of the fractured 5″ 19.50# G-105 drill pipe "Case 1" and the 5″ 19.50# S-135 drill pipe "Case 2" was performed to evaluate the failure mechanism and the factors contributing to the failure.

To identify as well as to differentiate the fractured joints of drill pipe, the joints will be referred to as:

"*C1*": joint from "Case 1"
"*C2*": joint from "Case 2"

Visual Examination: The overall appearance and fracture morphology of joints *C1* and *C2* were strikingly similar. Both failures were located in drill pipe tube body, close to the pin connection tool joint. Joint *C1* had parted 3′11″ from the pin connection shoulder, while joint *C2* had parted 6′5″ from the pin connection shoulder. The fractured joints are presented in Figures 1 and 2.

Up-hole portion of failed joint

Down-hole portion of failed joint

Figure 1 – As received condition of the failed 5″ 19.50# G-105 drill pipe *C1*

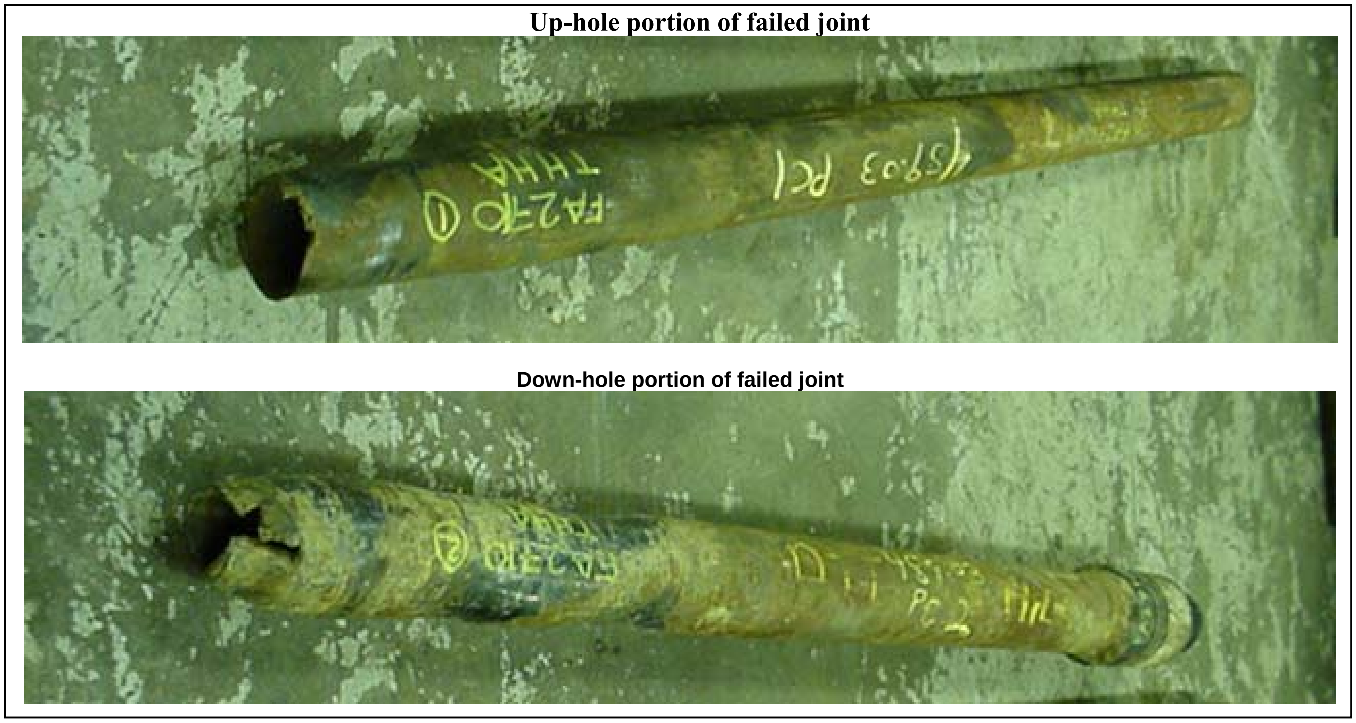

Figure 2 – As received condition of the failed 5″ 19.50# S-135 drill pipe *C2*

The fracture surfaces displayed evidence of a ductile separation under tensile loading. As shown in Figure 3, the fractures propagated along a 45 degree plane relative to the axis of the pipe. The fracture regions also exhibited significant necking and extensive plastic deformation. However, the necking was different from that observed on classic ductile overload failures. Joints *C1* and *C2* presented multiple closely spaced necked areas near the fractured ends. Figure 4 presents the necking and the plastic deformation. Overall, the fracture morphology was indicative of a ductile tensile overload.

As shown in Figure 5, the outer surface of the joints near the fractured ends appeared “smooth” and “polished.” Formation cuts and abrasion marks were also visible. It is likely that this damage resulted from rotation of the drill pipe against the formation.

To evaluate the internal surface, the fractured joints were saw-cut longitudinally and split open. Figure 6 presents the condition of joint *C1’s* internal coating. The internal plastic coating was damaged close to the fractured end. The color and texture of the internal plastic coating also changed towards the fractured end. The damage appeared to have been caused by exposure to unusually high operating temperatures.

Figure 3 – 45 degree fracture surface of joint *C2*

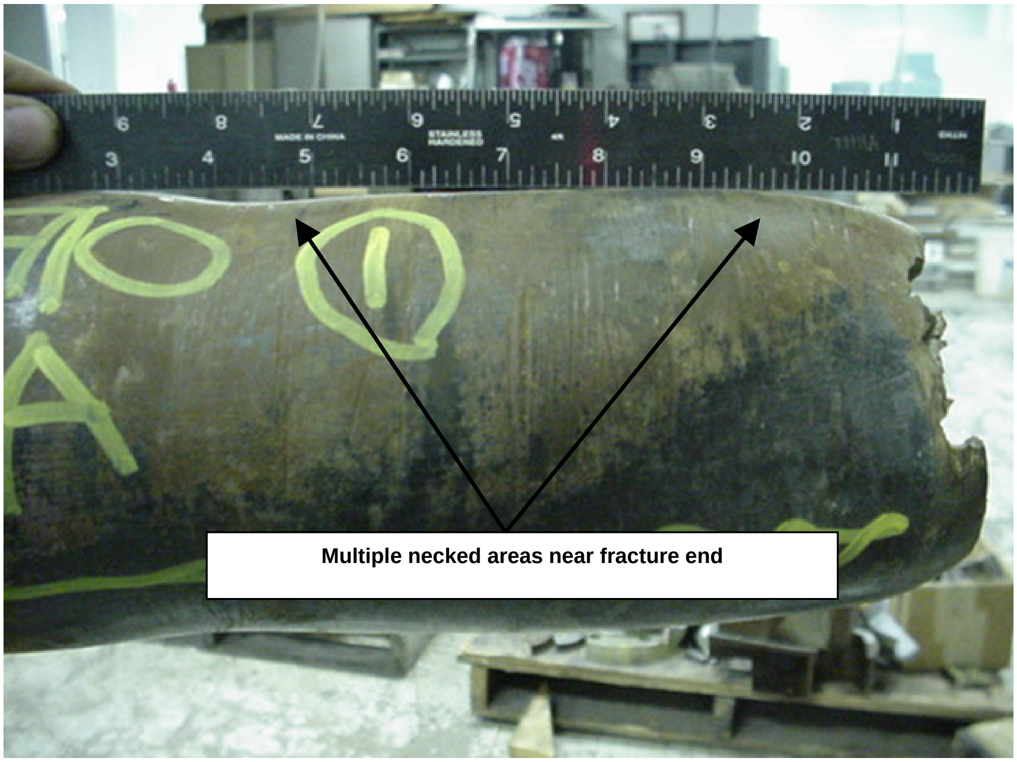

Figure 4 – Necking and plastic deformation observed near the fractured end of joint *C2*

Figure 5 – Formation cuts and polished outer surface on the tube body of joint *C1*

Figure 6 – Damage to internal plastic coating of joint *C1* from exposure to high temperatures

Material Testing: The fracture mechanism was identified as ductile tensile overload. For a typical tensile overload failure, either (a) the operating load is greater than the rated tensile capacity of the pipe (accounting for applied torque and measured wall thickness) or (b) the material does not meet the minimum specification requirements. As the operating loads were well below the drill pipe's calculated tensile capacity, the material properties had to be below the minimum requirements at the time of the failure.

Material Away From Heat Affected Area: To verify the pipe's inherent material properties, specimens were machined from joints *C1* and *C2*. These specimens were removed from a location on the pipe at least five feet away from the heat affected area. The heat affected area is considered to be anywhere along the pipe where necking or damage to internal plastic coating is present. Chemical analysis, tensile tests, Charpy V-notch impact tests, and microstructural examination were performed on these specimens.

The test results are summarized in Table 1. The material met the minimum requirements specified in API Specification 5D[2] for the respective grade of drill pipe. Material outside the heat affected area was identified as having a tempered martensitic grain structure, which is characteristic of quenched and tempered steel. S-135 and G-105 grade drill pipe is required to be quenched and tempered. This indicated that the failure was not caused by an inherent lack of strength or improperly heat treated drill pipe material.

Table 1 – Material properties of the tube of joints *C1* and *C2*, outside the heat affected area

Material Properties		Joint *C1* Values		Joint *C2* Values	
		G-105 Grade Requirements	Test Results	S-135 Grade Requirements	Test Results
Tensile Test	Yield Strength (ksi)	105 (Min)	129.5	135 (Min)	150.7
		135 (Max)		165 (Max)	
	Ultimate Tensile Strength (ksi)	115 (Min)	142.1	145 (Min)	166.1
	Elongation (%)	14% (Min)	22.95	12.5% (Min)	18
Chemical Analysis	Phosphorous (%)	.030 (Max)	0.012	.030 (Max)	0.012
	Sulfur (%)	.030 (Max)	0.005	.030 (Max)	0.005
Charpy V-notch Impact Test	Average (ft-lbs)	32 (Min)	62	32 (Min)	36
	Minimum (ft-lbs)	28 (Min)	61	28 (Min)	34

Material Close To Fractured End: To examine the material properties near the fractured end, a longitudinal section was removed form the pipe that extended from inside the heat affected area near the fractured end to outside the heat affected area. A hardness survey at 1/4″ spacing was performed at mid wall along the length of this longitudinal section. The hardness values for joints *C1* and *C2* are presented in Figures 7 and 8 respectively.

For joint *C1* (G-105 drill pipe, typical Rockwell "C" hardness = 30 HRC), the average hardness reading outside the heat affected area was about 30 HRC. This hardness correlates to a tensile strength of about 136,000 psi. However, a drop in hardness to values as low as 15 HRC, which correlates to a tensile strength of about 100,000 psi, was observed near the fracture.

Similar to joint *C1*, a drop in hardness close to the fracture was observed on joint *C2* (S-135 drill pipe, typical Rockwell "C" hardness = 35 HRC). The hardness values reduced from an average close to 35 HRC, which correlates to a tensile strength of about 157,000 psi, to values as low as 17.5 HRC near the fracture, which correlates to a tensile strength of about 104,000 psi.

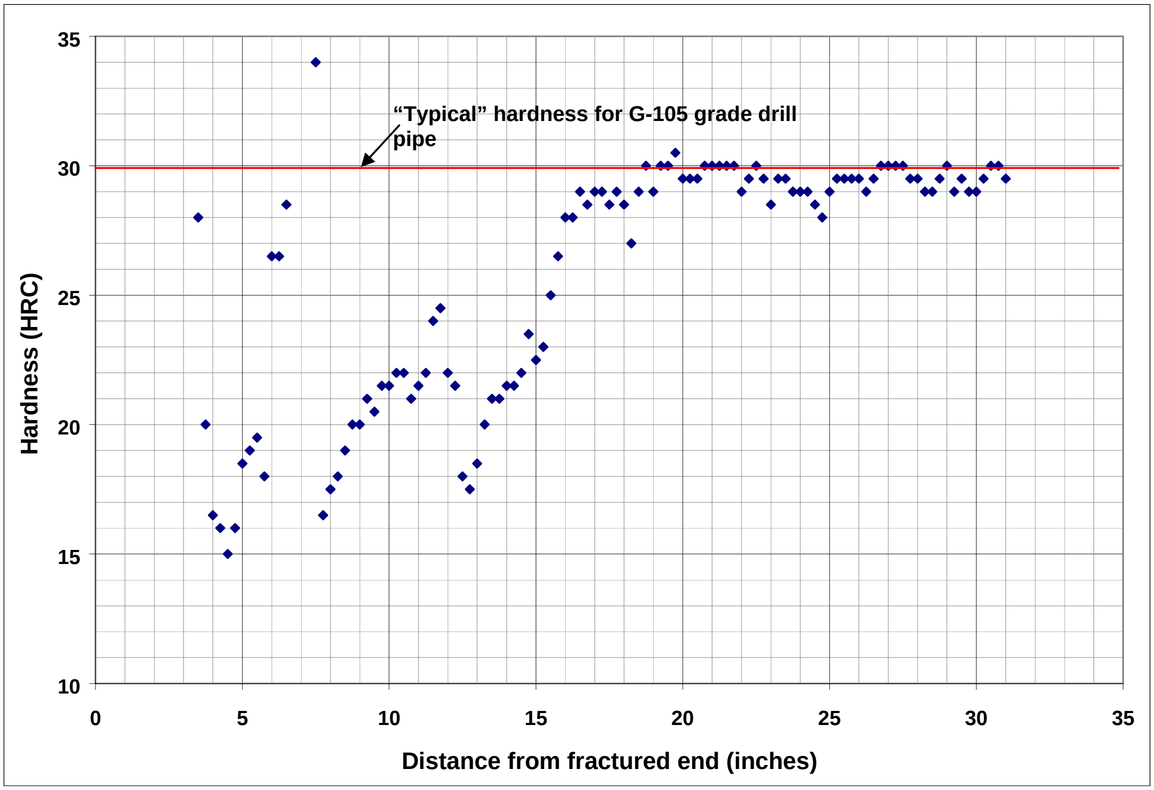

Figure 7 – Hardness (HRC) readings along the length of longitudinal section removed from joint *C1*

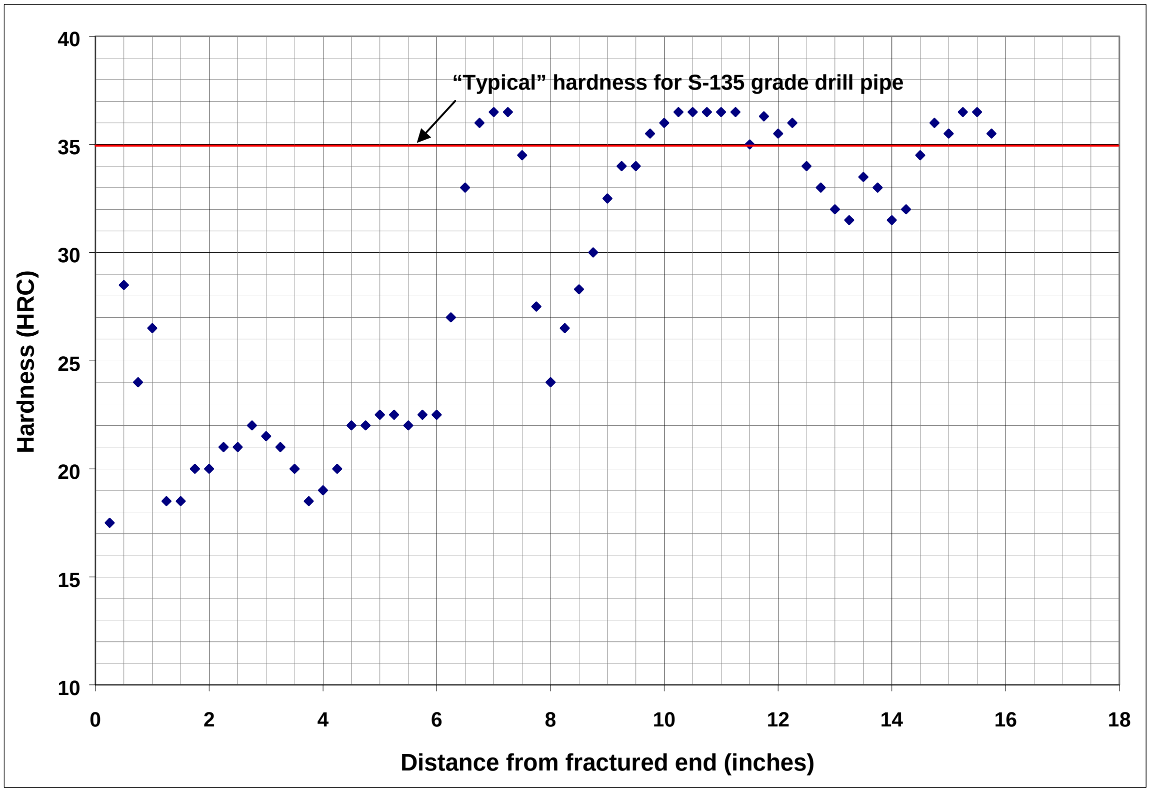

Figure 8 – Hardness (HRC) readings along the length of longitudinal section removed from joint *C2*

In cases of ductile overload failures, the hardness in the necked region is greater than the inherent material hardness due to strain hardening. However, in the case of the failed drill pipe joints *C1* and *C2*, the hardness in the heat affected area was significantly lower than the inherent material hardness. This reduction in hardness was indicative of localized heating near the fractured end to at least the tempering temperature.

"Tempering of steel is a process in which previously hardened steel is heated to a temperature below the transformation range and cooled at a suitable rate, primarily to increase ductility and toughness.[3]" Tempering usually results in a decrease in hardness, tensile strength and yield strength, but an increase in ductility and toughness. Figure 9 shows the effect of tempering temperature on the hardness of 4130 alloy steel (this is the same material from which joints *C1* and *C2* were made).

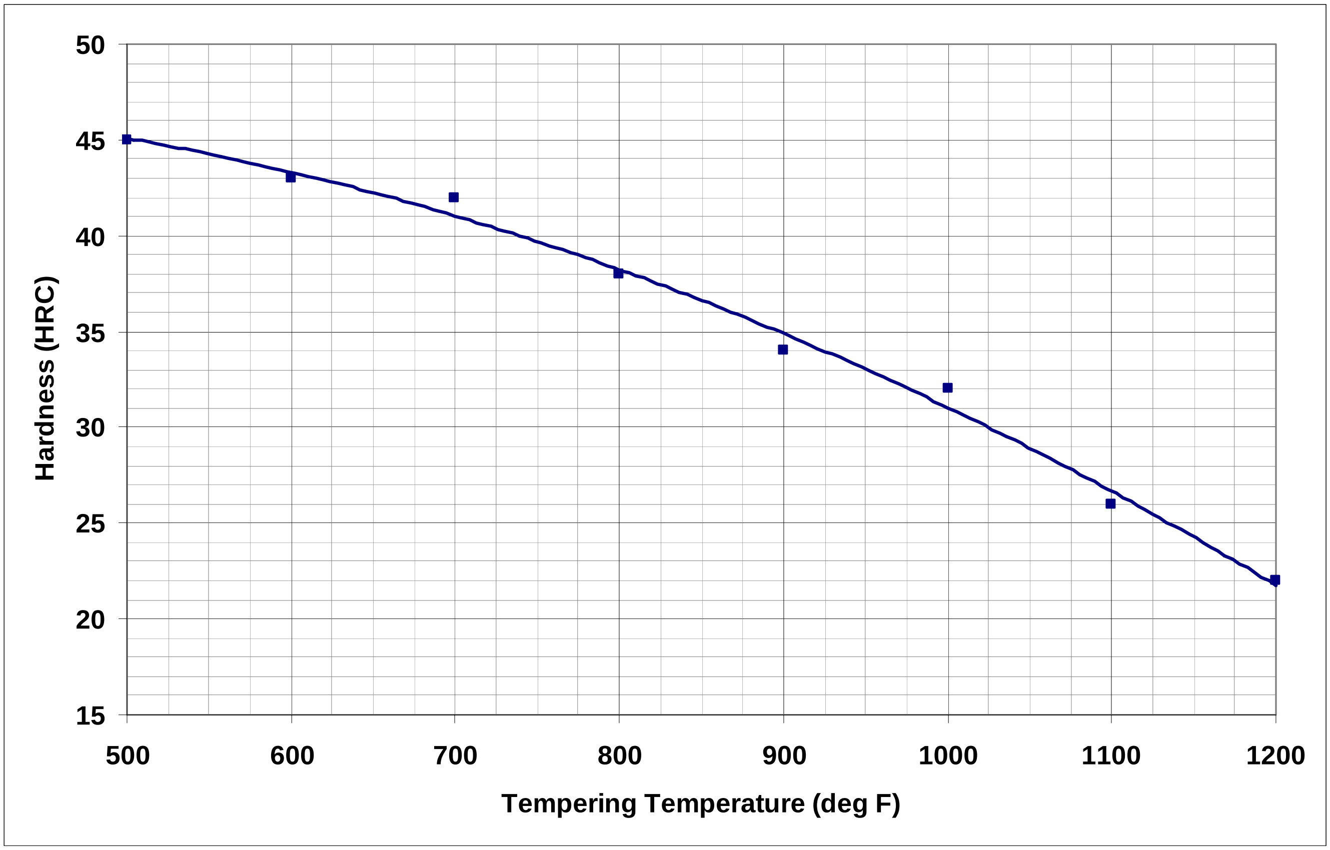

Figure 9 – Hardness of 4130 Alloy Steel After Tempering[4]

Increased temperatures reduces the strength of steel. Yield strength decreases to zero when the material reaches the melting point. As joints *C1 & C2* were locally heated near their fracture locations to temperatures greater than or equal to their tempering temperatures, their material hardness (and thus strength) decreased. The load capacities of the drill pipe tubes were reduced resulting in the ductile tensile overload failures. The hardness values and corresponding tensile strengths reported for joints *C1* and *C2* were measured after the joints had been cooled. The actual hardness and corresponding tensile strength values at the time of the failures would have been much lower. However, because there is no way of knowing what temperatures the drill pipe joints reached when rotated while packed off, the tensile strength at the time of failure is unknown.

Microstructural Examination: The drop in hardness in the heat affected area indicates that the drill pipe was locally heated to a temperature equal to or greater than the tempering temperature. One way to determine the approximate temperature range to which the pipe was heated is to examine the microstructure in the heat affected area and compare it with the microstructure outside the heat affected area. A change in the microstructure (from the inherent structure) in the heat affected area would mean that the temperatures reached were greater than the austenitic transformation temperature. This minimum phase transformation temperature is represented by line "*AC3*" on the Carbon-Iron phase diagram shown in Figure 10.

Specimens were removed from both inside and outside of the heat affected area of joint *C2*. Material from outside the heat affected area presented a tempered martensitic structure, which is characteristic of quenched and tempered (Q&T) steel, as required for S-135 grade drill pipe. This was the inherent drill pipe material structure. Material inside the heat affected area presented a mixed ferritic and pearlitic structure. Figures 11 and 12 present the two microstructures. Transformation of the grain structure in the heat affected area indicated that localized heating resulted in temperatures above 1,500°F (austenitic transformation temperature for joint *C2* material, as shown in Figure 10).

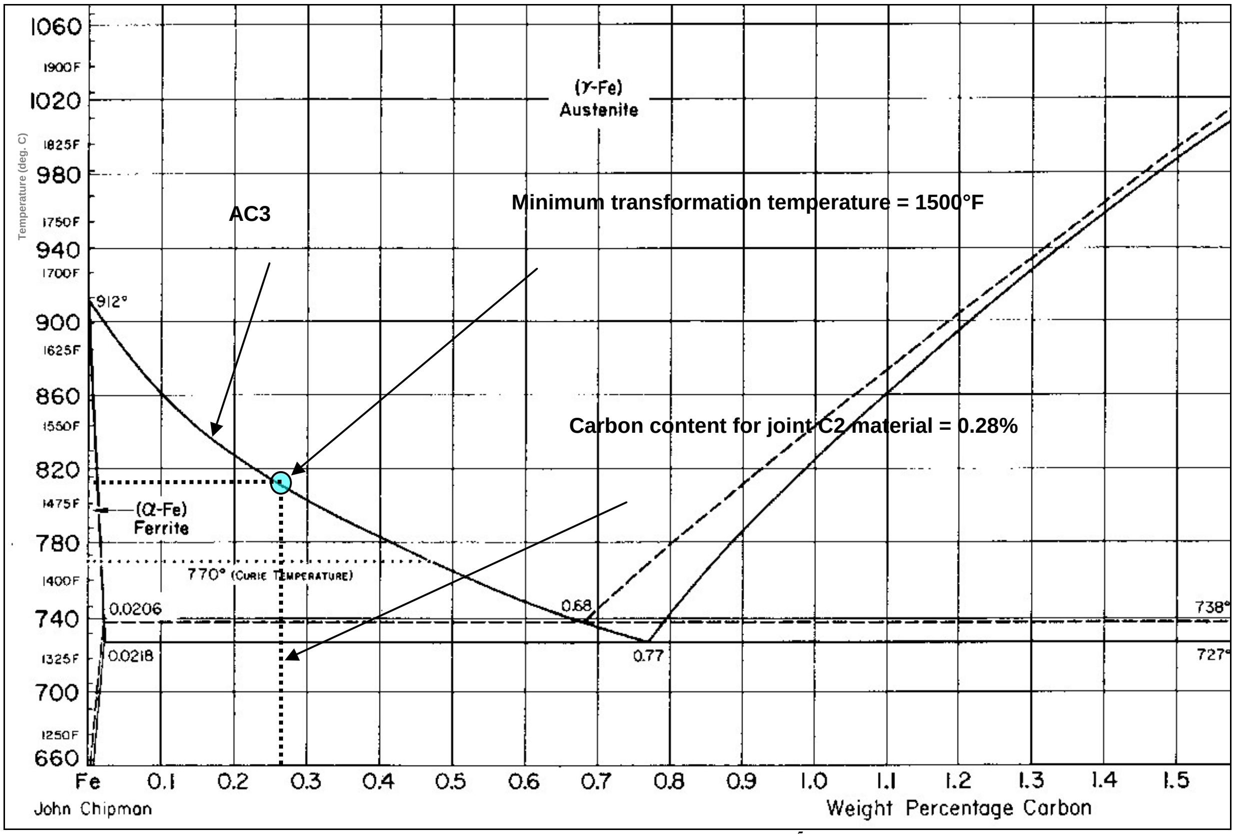

Figure 10 – Carbon-Iron phase diagram[5]

Figure 11 – Inherent microstructure of joint *C2* (200X)

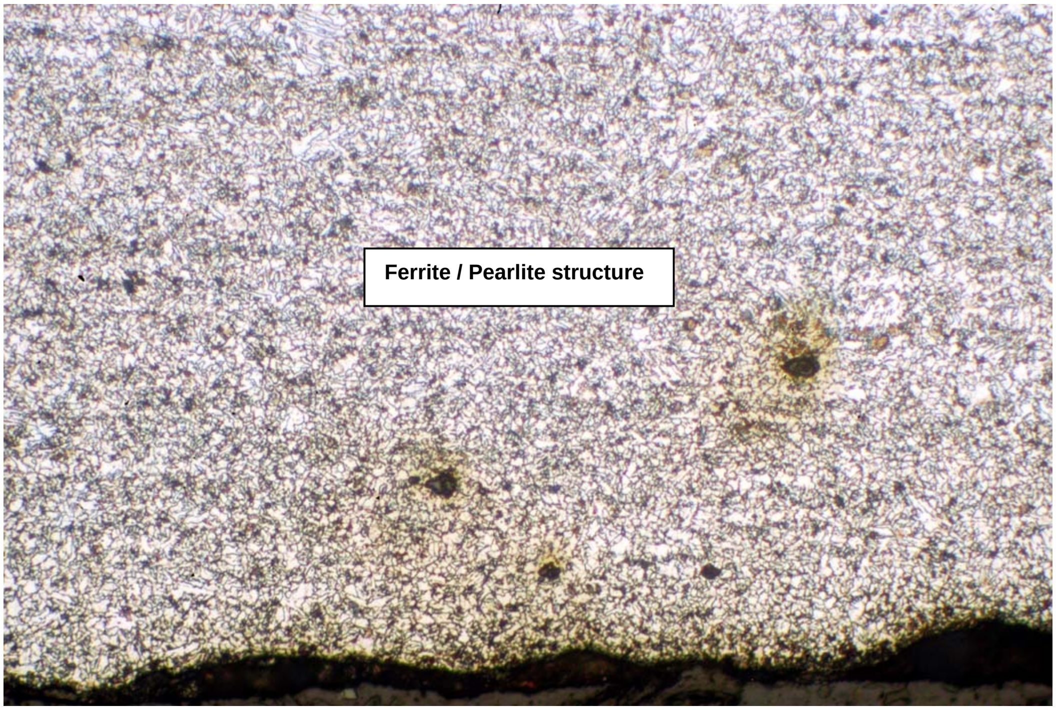

Figure 12 – Microstructure near fractured end of joint *C2* (200X)

Specimens for microstructural examination were also removed from both inside and outside of the heat affected area of joint *C1*. However, unlike the change in structure observed on joint *C2*, both specimens removed from joint *C1* presented a tempered martensitic structure. This is shown in Figures 13 and 14. Presence of a similar structure meant that the temperatures reached in the heat affected area of joint *C1* did not exceed the austenitic transformation temperature (~ 1,500°F). Instead the temperatures reached were closer to the typical tempering temperature for G-105 grade drill pipe material (~ 1,000°F).

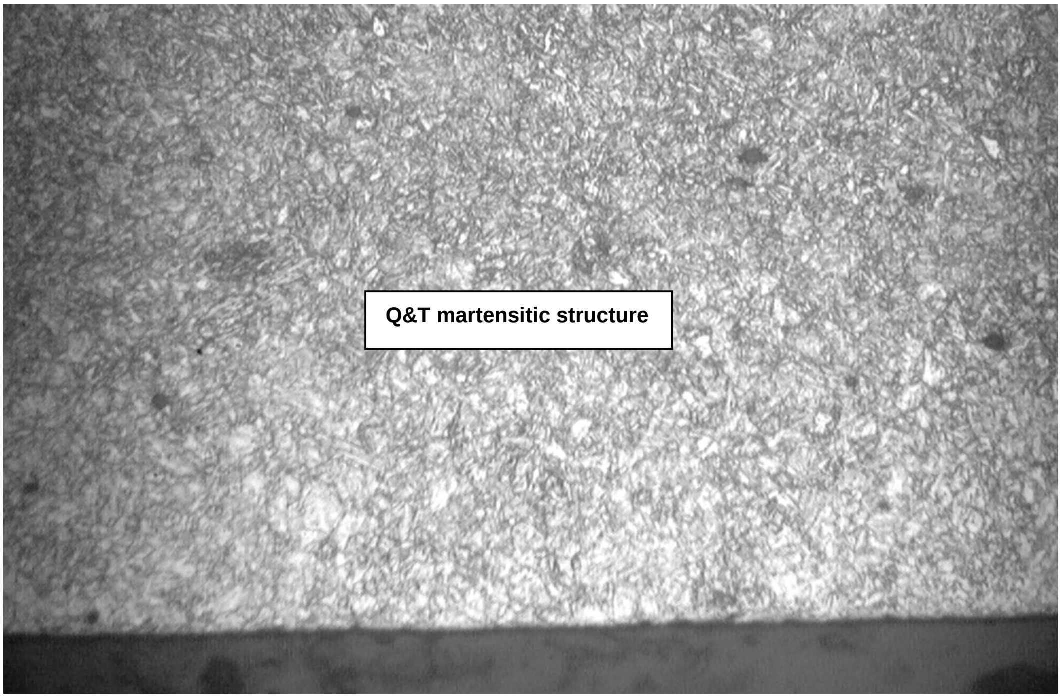

Figure 13 – Inherent microstructure of joint *C1* (200X)

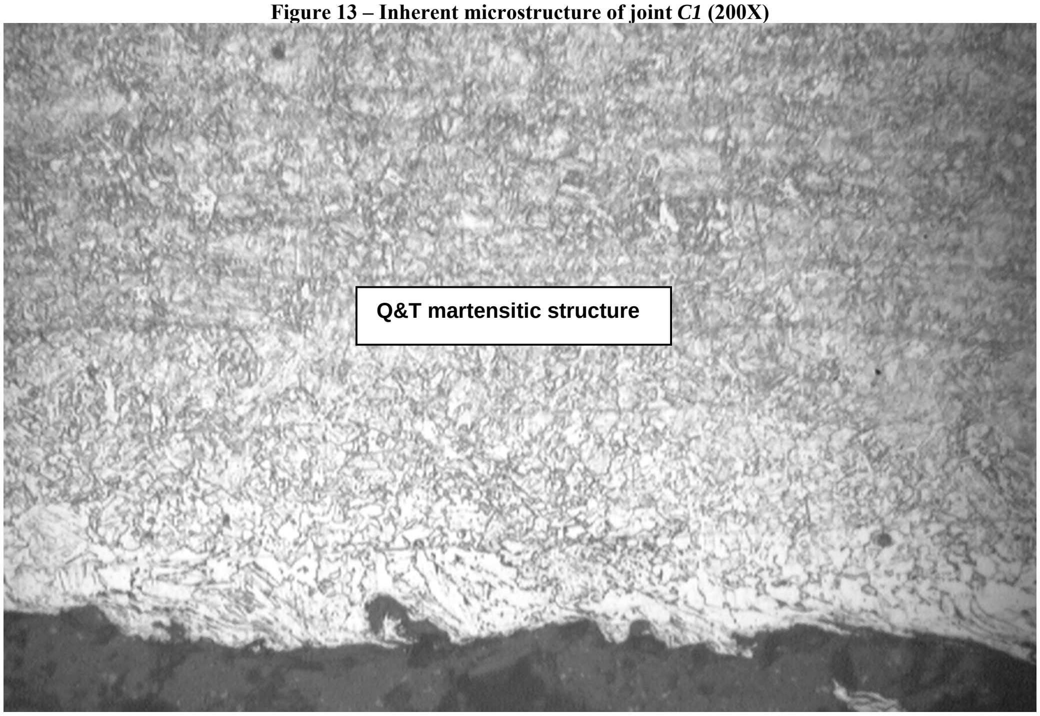

Figure 14 – Microstructure near fractured end of joint *C1* (200X)

Limitations of Stuck Pipe Overload Design Methodology

The standard design practice for preventing tensile overload failures in stuck pipe situations is to design with a margin of overpull (MOP). MOP is the difference between the tensile capacity of the weakest component in the drillstring and the maximum anticipated load that the drillstring will experience. Simply put, MOP is the additional available tensile load that can be safely applied to the drillstring in the case of a stuck pipe situation. Since loads are applied from the surface, the limiting component in the drillstring will almost always be the drill pipe. As seen in the failure cases previously discussed in this paper, if the drill pipe is rotated while packed off and sufficient heat is generated, the designer may not be able to count on the design MOP.

The tensile capacity of a drillstring component is defined as the lower of that component's body or connection tensile capacity, and should always take into account any derating due to pressure and/or torsional loads. Typically in a stuck pipe situation the string is simultaneously pulled and rotated, so there will be both tension and torsion loads applied to the string. For drill pipe tubes, simultaneous torsion will decrease the tube's tensile capacity and vice versa. External pressure will also decrease the tube's tensile capacity. Internal pressure may increase or decrease the tube's tensile capacity depending on how much pressure is applied. However, any gain in tensile capacity due to internal pressure is usually ignored for safety. For tool joints, the effect of torque on tensile capacity depends on whether or not the applied torque is greater than makeup torque (MUT), and in the case where torque is greater than MUT, on whether tension or torque is applied first. See Baryshnikov's, et al paper[6] on combined load capacity of tool joints for more details about determining tool joint tensile capacity. The effects of pressure on tool joint tensile capacity are usually accounted for by applying a safety factor.

Even though the designer may have carefully calculated the tensile capacities of the drillstring accounting for various combined loading scenarios, and has calculated the maximum anticipated loads using torque and drag programs, there is no way to design for these unexpected heat-induced drill pipe failures. The actual capacity of the drillstring depends on the temperatures reached downhole, and there is no way of knowing what temperature the drill pipe will be heated to in situations where the drill pipe is packed off with no circulation.

Conclusions

1. Frictional forces produced while rotating a packed off drillstring with no circulation can induce sufficient heat to either locally temper the drill pipe or cause a phase transformation of the drill pipe material.
2. Localized heating of the drill pipe decreases the material's hardness and can significantly reduce the tensile capacity of the drill pipe depending on the temperature reached.
3. Overload failures have occurred at loads well below the drill pipe's tensile and combined load capacity under these stuck pipe conditions.
4. Characteristic features of this type of failure include, multiple necking sites near the fracture, 45-degree fracture plane, polished outer surface near the fracture, and discolored or burned out internal plastic coating near fracture. The fracture location is characteristically in the drill pipe tube near the pin tool joint.
5. The reduction in tensile capacity of the drill pipe cannot be predicted because there is no method for predicting the downhole temperature of the drill pipe.

References:

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6. Baryshnikov, A., Schenato, A., Ligrone, A., Ferrara, P., "Optimization of Rotary-Shouldered Connection Reliability and Failure Analysis. Part 1: Static Loading," SPE/IADC 27535, paper presented at the Spring Drilling Conference, Dallas, Texas, 1994.