Addendum 1
November 2003
Addendum Effective Date: May 1, 2004

Recommended Practice for Drill Stem Design and Operating Limits

API RECOMMENDED PRACTICE 7G
SIXTEENTH EDITION, AUGUST 1998

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Addendum 1 to Recommended Practice for Drill Stem Design and Operating Limits

Page 3, 4.5:
Change “A.8” to “A.9”

Page 5, Table 2, Footnote :
Change “A.15” to “A.16”

Page 12, Table 8 and Page 14, Table 9, Note 4:
Change “$^{5}/_{8}$ inch” to “$^{3}/_{4}$ inch” in Note 4

For Pages 15 – 17, most corrections for Table 10 are in Column 7. Additional corrections in Table 10:

Page 15:
$2^{3}/_{8}$ in, 4.85 lb/ft, E75 drill pipe with $2^{3}/_{8}$ OHLW connections the makeup torque for premium class (Column 10) should be “1,723”
$2^{3}/_{8}$ in, 4.85 lb/ft, E75 drill pipe with $2^{3}/_{8}$ OHLW connections the makeup torque for Class 2 (Column 13) should be “1,481”
$2^{3}/_{8}$ in, 6.65 lb/ft, E75 drill pipe with $2^{3}/_{8}$ OHSW connections the makeup torque for premium class (Column 10) should be “2,216”
$2^{3}/_{8}$ in, 6.65 lb/ft, E75 drill pipe with $2^{3}/_{8}$ OHSW connections the makeup torque for Class 2 (Column 13) should be “1,967”
$2^{7}/_{8}$ in, 6.85 lb/ft, E75 drill pipe with $2^{7}/_{8}$ OHLW connections the makeup torque for premium class (Column 10) should be “3,290”
$2^{7}/_{8}$ in, 6.85 lb/ft, E75 drill pipe with $2^{7}/_{8}$ OHLW connections the makeup torque for Class 2 (Column 13) should be “2,804”
$2^{7}/_{8}$ in, 10.40 lb/ft, E75 drill pipe with $2^{7}/_{8}$ OHSW connections the makeup torque for premium class (Column 10) should be “4,411”
$2^{7}/_{8}$ in, 10.40 lb/ft, E75 drill pipe with $2^{7}/_{8}$ OHSW connections the makeup torque for Class 2 (Column 13) should be “4,079”
$2^{7}/_{8}$ in, 10.40 lb/ft, E75 drill pipe with $2^{7}/_{8}$ PAC connections the makeup torque for premium class (Column 10) should be “3,424”
$2^{7}/_{8}$ in, 10.40 lb/ft, E75 drill pipe with $2^{7}/_{8}$ PAC connections the makeup torque for Class 2 (Column 13) should be “3,424”

Page 16:
$4^{1}/_{2}$ IEU-X95, NC46, Column 6, change “$3^{1}/_{4}$” to “3”

Page 17:
Last line, Column 11, minimum OD for $6^{5}/_{8}$ in, 27.70 lb/ft S135 drill pipe, Class 2, change “$7^{27}/_{64}$” to “$7^{27}/_{32}$”

Table 10—Recommended Minimum OD* and Make-up Torque of Weld-on Type Tool Joints Based on Torsional Strength of Box and Drill Pipe

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
								Premium Class			Class 2		
	Drill Pipe			New Tool Joint Data				Min. OD Tool Joint in.	Min. Box Shoulder with Eccentric Wear in.	Make-up Torque for Min. OD Tool Joint ft-lb	Min. OD Tool Joint in.	Min. Box Shoulder with Eccentric Wear in.	Make-up Torque for Min. OD Tool Joint ft-lb
	Nominal Size in.	Nom Weight lb/ft	Type Upset and Grade	Conn.	New OD in.	New ID in.	Make-up Torque[6] ft-lb						
	$2\frac{3}{8}$	4.85	EU-E75	NC26	$3\frac{3}{8}$	$1\frac{3}{4}$	4,125 B	$3\frac{1}{8}$	$\frac{3}{64}$	1,945	$3\frac{3}{32}$	$\frac{1}{32}$	1,689
		4.85	EU-E75	W.O.	$3\frac{3}{8}$	2	2,541 P	$3\frac{1}{16}$	$\frac{1}{16}$	1,994	$3\frac{1}{32}$	$\frac{3}{64}$	1,746
		4.85	EU-E75	$2\frac{3}{8}$ OHLW	$3\frac{1}{8}$	2	2,716 P	3	$\frac{1}{16}$	1,723	$2\frac{31}{32}$	$\frac{3}{64}$	1,481
03		4.85	EU-E75	$2\frac{3}{8}$ SL-H90	$3\frac{1}{4}$	2	3,042 P	$2\frac{31}{32}$	$\frac{1}{16}$	1,996	$2\frac{15}{16}$	$\frac{3}{64}$	1,726
	$2\frac{3}{8}$	6.65	IU-E75	$2\frac{3}{8}$ PAC[2]	$2\frac{7}{8}$	$1\frac{3}{8}$	2,803 P	$2\frac{25}{32}$	$\frac{9}{64}$	2,455	$2\frac{23}{32}$	$\frac{7}{64}$	2,055
		6.65	EU-E75	NC26	$3\frac{3}{8}$	$1\frac{3}{4}$	4,125 B	$3\frac{3}{16}$	$\frac{5}{64}$	2,467	$3\frac{5}{32}$	$\frac{1}{16}$	2,204
		6.65	EU-E75	$2\frac{3}{8}$ SL-H90	$3\frac{1}{4}$	2	3,042 P	$3\frac{1}{32}$	$\frac{3}{32}$	2,549	$2\frac{31}{32}$	$\frac{1}{16}$	1,996
03		6.65	EU-E75	$2\frac{3}{8}$ OHSW	$3\frac{1}{4}$	$1\frac{3}{4}$	3,783 B	$3\frac{1}{16}$	$\frac{3}{32}$	2,216	$3\frac{1}{32}$	$\frac{5}{64}$	1,967
	$2\frac{3}{8}$	6.65	EU-X95	NC26	$3\frac{3}{8}$	$1\frac{3}{4}$	4,125 B	$3\frac{1}{4}$	$\frac{7}{64}$	3,005	$3\frac{7}{32}$	$\frac{3}{32}$	2,734
	$2\frac{3}{8}$	6.65	EU-G105	NC26[2]	$3\frac{3}{8}$	$1\frac{3}{4}$	4,125 B	$3\frac{9}{32}$	$\frac{1}{8}$	3,279	$3\frac{1}{4}$	$\frac{7}{64}$	3,005
	$2\frac{7}{8}$	6.85	EU-E75	NC31	$4\frac{1}{8}$	$2\frac{1}{8}$	7,074 P	$3\frac{11}{16}$	$\frac{5}{64}$	3,154	$3\frac{21}{32}$	$\frac{1}{16}$	2,804
		6.85	EU-E75	$2\frac{7}{8}$ WO	$4\frac{1}{8}$	$2\frac{7}{16}$	4,209 P	$3\frac{5}{8}$	$\frac{5}{64}$	3,216	$3\frac{19}{32}$	$\frac{1}{16}$	2,876
		6.85	EU-E75	$2\frac{7}{8}$ OHLW[2]	$3\frac{3}{4}$	$2\frac{7}{16}$	3,290 P	$3\frac{1}{2}$	$\frac{7}{64}$	3,290	$3\frac{7}{16}$	$\frac{5}{64}$	2,804
03		6.85	EU-E75	$2\frac{7}{8}$ SL-H90	$3\frac{7}{8}$	$2\frac{7}{16}$	4,504 P	$3\frac{1}{2}$	$\frac{3}{32}$	3,397	$3\frac{7}{16}$	$\frac{1}{16}$	2,666
	$2\frac{7}{8}$	10.40	EU-E75	NC31	$4\frac{1}{8}$	$2\frac{1}{8}$	7,074 P	$3\frac{13}{16}$	$\frac{9}{64}$	4,597	$3\frac{3}{4}$	$\frac{7}{64}$	3,867
		10.40	IU-E75	$2\frac{7}{8}$ XH	$4\frac{1}{4}$	$1\frac{7}{8}$	7,853 P	$3\frac{23}{32}$	$\frac{9}{64}$	4,357	$3\frac{21}{32}$	$\frac{7}{64}$	3,664
		10.40	IU-E75	NC26[2]	$3\frac{3}{8}$	$1\frac{3}{4}$	4,125 B	$3\frac{3}{8}$	$\frac{11}{64}$	4,125	$3\frac{11}{32}$	$\frac{5}{32}$	3,839
		10.40	EU-E75	$2\frac{7}{8}$ OHSW[2]	$3\frac{7}{8}$	$2\frac{5}{32}$	5,194 P	$3\frac{19}{32}$	$\frac{5}{32}$	4,411	$3\frac{9}{16}$	$\frac{7}{64}$	4,079
		10.40	EU-E75	$2\frac{7}{8}$ SL-H90	$3\frac{7}{8}$	$2\frac{5}{32}$	6,732 P	$3\frac{19}{32}$	$\frac{9}{64}$	4,529	$3\frac{17}{32}$	$\frac{7}{64}$	3,770
		10.40	IU-E75	$2\frac{7}{8}$ PAC[2]	$3\frac{1}{8}$	$1\frac{1}{2}$	3,424 P	$3\frac{1}{8}$	$\frac{15}{64}$	3,424	$3\frac{1}{8}$	$\frac{15}{64}$	3,424
	$2\frac{7}{8}$	10.40	EU-X95	NC31	$4\frac{1}{8}$	2	7,895 P	$3\frac{29}{32}$	$\frac{3}{16}$	5,726	$3\frac{27}{32}$	$\frac{5}{32}$	4,969
		10.40	EU-X95	$2\frac{7}{8}$ SL-H90[2]	$3\frac{7}{8}$	$2\frac{5}{32}$	6,732 P	$3\frac{11}{16}$	$\frac{3}{16}$	5,702	$3\frac{5}{8}$	$\frac{5}{32}$	4,915
	$2\frac{7}{8}$	10.40	EU-G105	NC31	$4\frac{1}{8}$	2	7,895 P	$3\frac{15}{16}$	$\frac{13}{64}$	6,110	$3\frac{7}{8}$	$\frac{11}{64}$	5,345
	$2\frac{7}{8}$	10.40	EU-S135	NC31	$4\frac{3}{8}$	$1\frac{5}{8}$	10,086 P	$4\frac{1}{16}$	$\frac{17}{64}$	7,694	4	$\frac{15}{64}$	6,893
	$3\frac{1}{2}$	9.50	EU-E75	NC38	$4\frac{3}{4}$	3	7,595 P	$4\frac{13}{32}$	$\frac{1}{8}$	5,773	$4\frac{11}{32}$	$\frac{3}{32}$	4,797
		9.50	EU-E75	NC38	$4\frac{3}{4}$	$2\frac{11}{16}$	10,843 P	$4\frac{13}{32}$	$\frac{1}{8}$	5,773	$4\frac{11}{32}$	$\frac{3}{32}$	4,797
		9.50	EU-E75	$3\frac{1}{2}$ OHLW	$4\frac{3}{4}$	3	7,082 P	$4\frac{9}{32}$	$\frac{1}{8}$	5,340	$4\frac{1}{4}$	$\frac{7}{64}$	4,868
		9.50	EU-E75	$3\frac{1}{2}$ SL-H90	$4\frac{5}{8}$	3	7,469 P	$4\frac{3}{16}$	$\frac{7}{64}$	5,521	$4\frac{5}{32}$	$\frac{3}{32}$	5,003
	$3\frac{1}{2}$	13.30	EU-E75	NC38	$4\frac{3}{4}$	$2\frac{11}{16}$	10,843 P	$4\frac{1}{2}$	$\frac{11}{64}$	7,274	$4\frac{7}{16}$	$\frac{9}{64}$	6,268
		13.30	IU-E75	NC31[2]	$4\frac{1}{8}$	$2\frac{1}{8}$	7,074 P	4	$\frac{15}{64}$	6,893	$3\frac{15}{16}$	$\frac{13}{64}$	6,110
03		13.30	EU-E75	$3\frac{1}{2}$ OHSW	$4\frac{3}{4}$	$2\frac{11}{16}$	10,300 P	$4\frac{13}{32}$	$\frac{3}{16}$	7,278	$4\frac{11}{32}$	$\frac{5}{32}$	6,299
		13.30	EU-E75	$3\frac{1}{2}$ H90	$5\frac{1}{4}$	$2\frac{3}{4}$	14,043 P	$4\frac{17}{32}$	$\frac{1}{8}$	7,064	$4\frac{1}{2}$	$\frac{7}{64}$	6,487
		13.30	EU-X95	NC38	5	$2\frac{9}{16}$	12,057 P	$4\frac{19}{32}$	$\frac{7}{32}$	8,822	$4\frac{17}{32}$	$\frac{3}{16}$	7,785
		13.30	EU-X95	$3\frac{1}{2}$ SL-H90[2]	$4\frac{5}{8}$	$2\frac{11}{16}$	11,073 P	$4\frac{3}{8}$	$\frac{13}{64}$	8,742	$4\frac{5}{16}$	$\frac{11}{64}$	7,647
		13.30	EU-X95	$3\frac{1}{2}$ H90	$5\frac{1}{4}$	$2\frac{3}{4}$	14,043 P	$4\frac{5}{8}$	$\frac{11}{64}$	8,826	$4\frac{9}{16}$	$\frac{9}{64}$	7,646
	$3\frac{1}{2}$	13.30	EU-G105	NC38	5	$2\frac{7}{16}$	13,221 P	$4\frac{21}{32}$	$\frac{1}{4}$	9,879	$4\frac{19}{32}$	$\frac{7}{32}$	8,822
	$3\frac{1}{2}$	13.30	EU-S135	NC40	$5\frac{3}{8}$	$2\frac{7}{16}$	17,858 P	5	$\frac{9}{32}$	12,569	$4\frac{29}{32}$	$\frac{15}{64}$	10,768
		13.30	EU-S135	NC38	5	$2\frac{1}{8}$	15,902 P	$4\frac{13}{16}$	$\frac{21}{64}$	12,614	$4\frac{23}{32}$	$\frac{9}{32}$	10,957
	$3\frac{1}{2}$	15.50	EU-E75	NC38	5	$2\frac{9}{16}$	12,057 P	$4\frac{17}{32}$	$\frac{3}{16}$	7,785	$4\frac{15}{32}$	$\frac{5}{32}$	6,769
	$3\frac{1}{2}$	15.50	EU-X95	NC38	5	$2\frac{7}{16}$	13,221 P	$4\frac{21}{32}$	$\frac{1}{4}$	9,879	$4\frac{19}{32}$	$\frac{7}{32}$	8,822
	$3\frac{1}{2}$	15.50	EU-G105	NC38	5	$2\frac{1}{8}$	15,902 P	$4\frac{23}{32}$	$\frac{9}{32}$	10,957	$4\frac{5}{8}$	$\frac{15}{64}$	9,348
		15.50	EU-G105	NC40	$5\frac{1}{4}$	$2\frac{9}{16}$	16,616 P	$4\frac{15}{16}$	$\frac{1}{4}$	11,363	$4\frac{27}{32}$	$\frac{13}{64}$	9,595
	$3\frac{1}{2}$	15.50	EU-S135	NC40	$5\frac{1}{2}$	$2\frac{1}{4}$	19,616 P	$5\frac{3}{32}$	$\frac{21}{64}$	14,419	$4\frac{31}{32}$	$\frac{17}{64}$	11,963
	4	11.85	EU-E75	NC46	6	$3\frac{1}{4}$	19,937 P	$5\frac{7}{32}$	$\frac{7}{64}$	7,843	$5\frac{5}{32}$	$\frac{5}{64}$	6,476
		11.85	EU-E75	4 WO	$5\frac{3}{4}$	$3\frac{7}{16}$	17,186 P	$5\frac{7}{32}$	$\frac{7}{64}$	7,843	$5\frac{5}{32}$	$\frac{5}{64}$	6,476

(Table continued on next page.)

Table 10—Recommended Minimum OD* and Make-up Torque of Weld-on Type Tool Joints Based on Torsional Strength of Box and Drill Pipe (Continued)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	
							Premium Class			Class 2			
Drill Pipe			New Tool Joint Data				Min. OD Tool Joint in.	Min. Box Shoulder with Eccentric Wear in.	Make-up Torque for Min. OD Tool Joint ft-lb	Min. OD Tool Joint in.	Min. Box Shoulder with Eccentric Wear in.	Make-up Torque for Min. OD Tool Joint ft-lb	
Nominal Size in.	Nom Weight lb/ft	Type Upset and Grade	Conn.	New OD in.	New ID in.	Make-up Torque[6] ft-lb							
	11.85	EU-E75	4 OHLW	5 1/4	3 15/32	13,186 P	5	9/64	7,866	4 15/16	7/64	6,593	
	11.85	IU-E75	4 H90	5 1/2	2 13/16	21,185 P	4 7/8	7/64	7,630	4 27/32	3/32	6,962	
4	14.00	IU-E75	NC40	5 1/4	2 13/16	13,968 P	4 13/16	3/16	9,017	4 3/4	5/32	7,877	
	14.00	EU-E75	NC46	6	3 1/4	19,937 P	5 9/32	9/64	9,233	5 7/32	7/64	7,843	
	14.00	IU-E75	4 SH[2]	4 5/8	2 9/16	9,016 P	4 7/16	15/64	8,782	4 3/8	13/64	7,817	
	14.00	EU-E75	4 OHSW	5 1/2	3 1/4	16,236 P	5 1/16	11/64	9,131	5	9/64	7,839	
	14.00	IU-E75	4 H90	5 1/2	2 13/16	21,185 P	4 15/16	9/64	8,986	4 7/8	7/64	7,630	
4	14.00	IU-X95	NC40	5 1/4	2 11/16	15,319 P	4 15/16	1/4	11,363	4 27/32	13/64	9,595	
	14.00	EU-X95	NC46	6	3 1/4	19,937 P	5 3/8	3/16	11,363	5 5/16	5/32	9,937	
	14.00	IU-X95	4 H90	5 1/2	2 13/16	21,185 P	5 1/32	3/16	11,065	4 31/32	5/32	9,673	
4	14.00	IU-G105	NC40	5 1/2	2 7/16	17,858 P	5	9/32	12,569	4 29/32	15/64	10,768	
	14.00	EU-G105	NC46	6	3 1/4	19,937 P	5 7/16	7/32	12,813	5 11/32	11/64	10,647	03
	14.00	IU-G105	4 H90	5 1/2	2 13/16	21,185 P	5 3/32	7/32	12,481	5 1/32	3/16	11,065	
4	14.00	EU-S135	NC46	6	3	23,399 P	5 9/16	9/32	15,787	5 1/2	1/4	14,288	
4	15.70	IU-E75	NC40	5 1/4	2 11/16	15,319 P	4 7/8	7/32	10,179	4 25/32	11/64	8,444	
	15.70	EU-E75	NC46	6	3 1/4	19,937 P	5 5/16	5/32	9,937	5 1/4	1/8	8,535	
	15.70	IU-E75	4 H90	5 1/2	2 13/16	21,185 P	4 31/32	5/32	9,673	4 29/32	1/8	8,305	
4	15.70	IU-X95	NC40	5 1/2	2 7/16	17,858 P	5	9/32	12,569	4 29/32	15/64	10,768	
	15.70	EU-X95	NC46	6	3	23,399 P	5 7/16	7/32	12,813	5 11/32	11/64	10,647	
	15.70	IU-X95	4 H90	5 1/2	2 13/16	21,185 P	5 3/32	7/32	12,481	5 1/32	3/16	11,065	
4	15.70	EU-G105	NC46	6	3	23,399 P	5 15/32	15/64	13,547	5 13/32	13/64	12,085	
	15.70	IU-G105	4 H90	5 1/2	2 13/16	21,185 P	5 5/32	1/4	13,922	5 1/16	13/64	11,770	
4	15.70	IU-S135	NC46	6	2 5/8	26,982 B	5 21/32	21/64	18,083	5 17/32	17/64	15,035	
	15.70	EU-S135	NC46	6	2 7/8	25,038 P	5 21/32	21/64	18,083	5 17/32	17/64	15,035	
4 1/2	16.60	IEU-E75	4 1/2 FH	6	3	20,620 P	5 3/8	13/64	12,125	5 9/32	5/32	10,072	
	16.60	IEU-E75	NC46	6 1/4	3 1/4	19,937 P	5 13/32	13/64	12,085	5 11/32	11/64	10,647	
	16.60	IEU-E75	4 1/2 OHSW	5 7/8	3 3/4	16,162 P	5 7/16	13/64	11,862	5 3/8	11/64	10,375	
	16.60	EU-E75	NC50	6 5/8	3 3/4	22,361 P	5 23/32	5/32	11,590	5 11/16	9/64	10,773	
	16.60	IEU-E75	4 1/2 H-90	6	3 1/4	23,126 P	5 11/32	3/16	12,215	5 9/32	5/32	10,642	
4 1/2	16.60	IEU-X95	4 1/2 FH	6	2 3/4	23,695 P	5 1/2	17/64	14,945	5 13/32	7/32	12,821	
	16.60	IEU-X95	NC46	6 1/4	3	19,937 P	5 17/32	17/64	15,035	5 7/16	7/32	12,813	
	16.60	EU-X95	NC50	6 5/8	3 3/4	22,361 P	5 27/32	7/32	14,926	5 25/32	3/16	13,245	
	16.60	IEU-X95	4 1/2 H-90	6	3	26,969 P	5 15/32	1/4	15,441	5 3/8	13/64	13,013	
4 1/2	16.60	IEU-G105	4 1/2 FH	6	2 3/4	23,695 P	5 9/16	19/64	16,391	5 15/32	1/4	14,231	
	16.60	IEU-G105	NC46	6 1/4	3	23,399 P	5 19/32	19/64	16,546	5 1/2	1/4	14,288	03
	16.60	EU-G105	NC50	6 5/8	3 3/4	22,361 P	5 29/32	1/4	16,633	5 13/16	13/64	14,082	
	16.60	IEU-G105	4 1/2 H-90	6	3	26,969 P	5 1/2	17/64	16,264	5 7/16	15/64	14,625	
4 1/2	16.60	IEU-S135	NC46	6 1/4	2 3/4	26,615 P	5 25/32	25/64	21,230	5 21/32	21/64	18,083	
	16.60	EU-S135	NC50	6 5/8	3 1/2	26,674 P	6 1/16	21/64	21,017	5 31/32	9/32	18,367	
4 1/2	20.00	IEU-E75	4 1/2 FH	6	3	20,620 P	5 15/32	1/4	14,231	5 3/8	13/64	12,125	
	20.00	IEU-E75	NC46	6 1/4	3	23,399 P	5 1/2	1/4	14,288	5 13/32	13/64	12,085	
	20.00	EU-E75	NC50	6 5/8	3 5/8	24,549 P	5 13/16	13/64	14,082	5 3/4	12/64	12,415	
	20.00	IEU-E75	4 1/2 H-90	6	3	26,969 P	5 13/32	7/32	13,815	5 11/32	3/16	12,215	
4 1/2	20.00	IEU-X95	4 1/2 FH	6	2 1/2	26,528 P	5 5/8	21/64	17,861	5 17/32	9/32	15,665	
	20.00	IEU-X95	NC46	6 1/4	2 3/4	26,615 P	5 21/32	21/64	18,083	5 9/16	9/32	15,787	
	20.00	EU-X95	NC50	6 5/8	3 1/2	26,674 P	5 15/16	17/64	17,497	5 7/8	15/64	15,776	
	20.00	IEU-X95	4 1/2 H-90	6	3	26,969 P	5 9/16	19/64	17,929	5 15/32	1/4	15,441	

(Table continued on next page.)

Table 10—Recommended Minimum OD* and Make-up Torque of Weld-on Type Tool Joints Based on Torsional Strength of Box and Drill Pipe (Continued)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
								Premium Class			Class 2		
	Drill Pipe			New Tool Joint Data				Min. OD Tool Joint in.	Min. Box Shoulder with Eccentric Wear in.	Make-up Torque for Min. OD Tool Joint ft-lb	Min. OD Tool Joint in.	Min. Box Shoulder with Eccentric Wear in.	Make-up Torque for Min. OD Tool Joint ft-lb
	Nominal Size in.	Nom Weight lb/ft	Type Upset and Grade	Conn.	New OD in.	New ID in.	Make-up Torque[6] ft-lb						
	$4^1/_2$	20.00	IEU-G105	NC46	$6^1/_4$	$2^1/_2$	29,578 P	$5^{23}/_{32}$	$^{23}/_{64}$	19,644	$5^5/_8$	$^5/_{16}$	17,311
		20.00	EU-G105	NC50	$6^5/_8$	$3^1/_2$	26,674 P	$6^1/_{32}$	$^5/_{16}$	20,127	$5^{29}/_{32}$	$^1/_4$	16,633
	$4^1/_2$	20.00	EU-S135	NC50	$6^5/_8$	3	34,520 P	$6^7/_{32}$	$^{13}/_{32}$	25,569	$6^3/_{32}$	$^{11}/_{32}$	21,914
	5	19.50	IEU-E75	NC50	$6^5/_8$	$3^3/_4$	22,361 P	$5^7/_8$	$^{15}/_{64}$	15,776	$5^{13}/_{16}$	$^{13}/_{64}$	14,082
	5	19.50	IEU-X95	NC50	$6^5/_8$	$3^1/_2$	26,674 P	$6^1/_{32}$	$^5/_{16}$	20,127	$5^{15}/_{16}$	$^{17}/_{64}$	17,497
03		19.50	IEU-X95	5 H-90	$6^1/_2$	$3^1/_4$	30,732 P	$5^{27}/_{32}$	$^{19}/_{64}$	19,862	$5^3/_4$	$^1/_4$	17,116
	5	19.50	IEU-G105	NC50	$6^5/_8$	$3^1/_4$	30,730 P	$6^3/_{32}$	$^{11}/_{32}$	21,914	6	$^{19}/_{64}$	19,244
		19.50	IEU-G105	5 H-90	$6^1/_2$	3	34,805 P	$5^{29}/_{32}$	$^{21}/_{64}$	21,727	$5^{13}/_{16}$	$^9/_{32}$	18,940
	5	19.50	IEU-S135	NC50	$6^5/_8$	$2^3/_4$	38,036 P	$6^5/_{16}$	$^{29}/_{64}$	28,381	$6^3/_{16}$	$^{25}/_{64}$	24,645
		19.50	IEU-S135	$5^1/_2$ FH	$7^1/_4$	$3^1/_2$	43,328 P	$6^3/_4$	$^3/_8$	28,737	$6^5/_8$	$^5/_{16}$	24,412
	5	25.60	IEU-E75	NC50	$6^5/_8$	$3^1/_2$	26,674 P	$6^1/_{32}$	$^5/_{16}$	20,127	$5^{15}/_{16}$	$^{17}/_{64}$	17,497
		25.60	IEU-E75	$5^1/_2$ FH	7	$3^1/_2$	37,742 B	$6^1/_2$	$^1/_4$	20,205	$6^{13}/_{32}$	$^{13}/_{64}$	17,127
03	5	25.60	IEU-X95	NC50	$6^5/_8$	3	34,520 P	$6^7/_{32}$	$^{13}/_{32}$	25,569	$6^3/_{32}$	$^{11}/_{32}$	21,914
		25.60	IEU-X95	$5^1/_2$ FH	7	$3^1/_2$	37,742 B	$6^{21}/_{32}$	$^{21}/_{64}$	25,483	$6^9/_{16}$	$^9/_{32}$	22,294
	5	25.60	IEU-G105	NC50	$6^5/_8$	$2^3/_4$	38,036 P	$6^9/_{32}$	$^7/_{16}$	27,437	$6^5/_{32}$	$^3/_8$	23,728
03		25.60	IEU-G105	$5^1/_2$ FH	$7^1/_4$	$3^1/_2$	43,328 P	$6^{23}/_{32}$	$^{23}/_{64}$	27,645	$6^5/_8$	$^5/_{16}$	24,412
	5	25.60	IEU-S135	$5^1/_2$ FH	$7^1/_4$	$3^1/_4$	47,230 B	$6^{15}/_{16}$	$^{15}/_{32}$	35,446	$6^{13}/_{16}$	$^{13}/_{32}$	30,943
03	$5^1/_2$	21.90	IEU-E75	$5^1/_2$ FH	7	4	33,412 P	$6^{15}/_{32}$	$^{15}/_{64}$	19,172	$6^{13}/_{32}$	$^{13}/_{64}$	17,127
	$5^1/_2$	21.90	IEU-X95	$5^1/_2$ FH	7	$3^3/_4$	37,742 B	$6^5/_8$	$^5/_{16}$	24,412	$6^{17}/_{32}$	$^{17}/_{64}$	21,246
		21.90	IEU-X95	$5^1/_2$ H-90	7	$3^1/_2$	34,820 P	$6^3/_{16}$	$^{21}/_{64}$	24,414	$6^3/_{32}$	$^9/_{32}$	21,349
	$5^1/_2$	21.90	IEU-G105	$5^1/_2$ FH	$7^1/_4$	$3^1/_2$	43,328 P	$6^{23}/_{32}$	$^{23}/_{64}$	27,645	$6^{19}/_{32}$	$^{19}/_{64}$	23,350
	$5^1/_2$	21.90	IEU-S135	$5^1/_2$ FH	$7^1/_2$	3	52,059 P	$6^{15}/_{16}$	$^{15}/_{32}$	35,446	$6^{13}/_{16}$	$^{13}/_{32}$	30,943
	$5^1/_2$	24.70	IEU-E75	$5^1/_2$ FH	7	4	33,412 P	$6^9/_{16}$	$^9/_{32}$	22,294	$6^{15}/_{32}$	$^{15}/_{64}$	19,172
	$5^1/_2$	24.70	IEU-X95	$5^1/_2$ FH	$7^1/_4$	$3^1/_2$	43,328 P	$6^{23}/_{32}$	$^{23}/_{64}$	27,645	$6^{19}/_{32}$	$^{19}/_{64}$	23,350
	$5^1/_2$	24.70	IEU-G105	$5^1/_2$ FH	$7^1/_4$	$3^1/_2$	43,328 P	$6^{25}/_{32}$	$^{25}/_{64}$	29,836	$6^{11}/_{16}$	$^{11}/_{32}$	26,560
03	$5^1/_2$	24.70	IEU-S135	$5^1/_2$ FH	$7^1/_2$	3	52,059 P	$7^1/_{32}$	$^{33}/_{64}$	38,901	$6^7/_8$	$^7/_{16}$	33,180
	$6^5/_8$	25.20	IEU-E75	$6^5/_8$ FH	8	5	43,934 P	$7^7/_{16}$	$^1/_4$	26,810	$7^3/_8$	$^7/_{32}$	24,100
			IEU-X95	$6^5/_8$ FH	8	5	43,934 P	$7^5/_8$	$^{11}/_{32}$	35,139	$7^1/_2$	$^9/_{32}$	29,552
			IEU-G105	$6^5/_8$ FH	$8^1/_4$	$4^3/_4$	51,280 P	$7^{11}/_{16}$	$^5/_8$	37,983	$7^{19}/_{32}$	$^{21}/_{64}$	33,730
			IEU-S135	$6^5/_8$ FH	$8^1/_2$	$4^1/_4$	65,012 P	$7^{29}/_{32}$	$^{31}/_{64}$	48,204	$7^{25}/_{32}$	$^{27}/_{64}$	42,312
	$6^5/_8$	27.70	IEU-E75	$6^5/_8$ FH	8	5	43,934 P	$7^1/_2$	$^9/_{32}$	29,552	$7^{13}/_{32}$	$^{15}/_{64}$	25,451
			IEU-X95	$6^5/_8$ FH	$8^1/_4$	$4^3/_4$	51,280 P	$7^{11}/_{16}$	$^3/_8$	37,983	$7^9/_{16}$	$^5/_{16}$	32,329
			IEU-G105	$6^5/_8$ FH	$8^1/_4$	$4^3/_4$	51,280 P	$7^3/_4$	$^{13}/_{32}$	40,860	$7^{21}/_{32}$	$^{23}/_{64}$	36,556
			IEU-S135	$6^5/_8$ FH	$8^1/_2$	$4^1/_4$	65,012 P	8	$^{17}/_{32}$	52,714	$7^{27}/_{32}$	$^{29}/_{64}$	45,241

[1]The use of outside diameters (OD) smaller than those listed in the table may be acceptable due to special service requirements.
[2]Tool joint with dimensions shown has lower torsional yield ratio than the 0.80 which is generally used.
[3]Recommended make-up torque is based on 72,000 psi stress.
[4]In calculation of torsional strengths of tool joints, both new and worn, the bevels of the tool joint shoulders are disregarded. This thickness measurement should be made in the plane of the face from the I.D. of the counter bore to the outside diameter of the box, disregarding the bevels.
[5]Any tool joint with an outside diameter less than API bevel diameter should be provided with a minimum $^1/_{32}$ inch depth x 45 degree bevel on the outside and inside diameter of the box shoulder and outside diameter of the pin shoulder.
00 [6] P = Pin limit; B = Box limit.
*Tool joint diameters specified are required to retain torsional strength in the tool joint comparable to the torsional strength of the attached drill pipe. These should be adequate for all service. Tool joints with torsional strengths considerably below that of the drill pipe may be adequate for much drilling service.

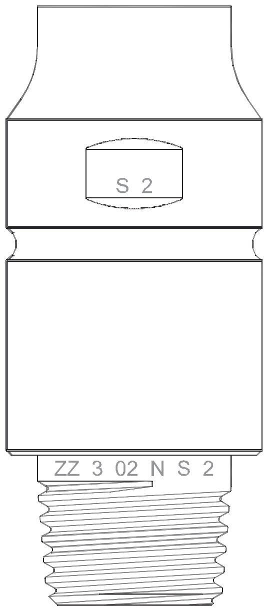
Page 38, Table 14, Footnote 1:
Change “A.8” to “A.9”

Page 112, replace 13.1 with the following:

13.1 DRILL STRING MARKING AND IDENTIFICATION

Sections of drill string manufactured in accordance with API Specification 7 are identified with markings on the base of the pin connection. An additional pin base marking, representing the drill pipe weight code, is recommended as shown in Figure 82. The recommended weight codes are shown in Figure 83. It is recommended that drill string members not covered by API Specification 7 also be stenciled at the base of the pin as shown in Figure 82. It is also recommended that drill string members be marked using the mill slot and groove method as shown in Figure 83.

Page 113 and 114, replace Figures 82 and 83 with the following:



Sample markings at base of pin[1,2]

1	2	3	4	5	6
ZZ	3	02	N	S	2

1 Tool Joint Manufacturer's Symbol:
ZZ Company (fictional for example only)

2 Month Welded:
3 – March

3 Year Welded
02 – 2002

4 Pipe Manufacturer's Symbol:
N – United States Steel Company

5 Drill Pipe Grade
S – Grade S135 drill pipe

6 Drill Pipe Weight Code[2]

Notes:

1. Tool Joint manufacturer's symbol, month welded, year welded, pipe manufacturer and drill pipe grade symbol shall be stenciled at the base of the pin as shown above. Pipe manufacturer symbol and drill pipe grade symbol applied shall be as represented by manufacturer. Supplier, owner, or user shall be indicated on documents such as mill certification papers or purchase orders.
2. Stamping the drill pipe weight code on the pin base and milled slot is recommended, in addition to the marking requirements of API Specification 7.

TOOL JOINT MANUFACTURER'S SYMBOL

Refer to the current edition of the IADC Drilling Manual* for a list of Tool Joint Manufacturer's symbols.

*Available from: International Association of Drilling Contractors (IADC) P.O. Box 4287, Houston, TX 77210.

Month and Year Welded

Month	Year
1 through 12	Last two digits of year

Drill Pipe Grade

Grade	Symbol
E75	E
X95	X
G105	G
S135	S

The "manufacturer" may be either a pipe mill or processor. See API Specification 5D, *Specification for Drill Pipe.*

These symbols are provided for pipe manufacturer identification and have been assigned at pipe manufacturer's requests. Manufacturers included in this list may not be current API Specification 5D licensed pipe manufacturers. A list of current licensed pipe manufacturers is available in the *Composite List of Manufacturers. (Licensed for Use of the API Monogram).*

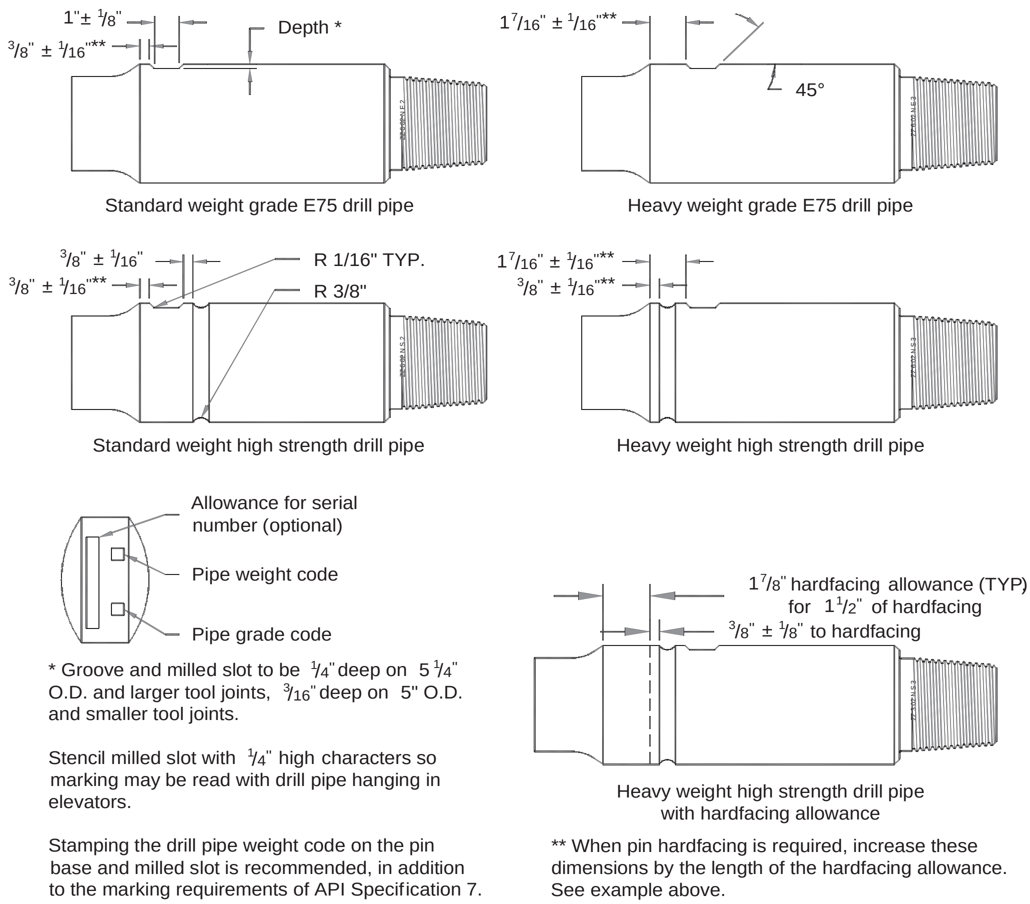
Pipe mills may upset and heat treat their own drill pipe, or they may have this done according to their own specifications. In either case, the mill's assigned symbol should be used on each drill string assembly since they are the pipe manufacturer.

Pipe processors may buy "green" tubes and upset and heat treat these according to their own specifications. In this case, the processor's assigned symbol should be used on each drill string assembly since they are the pipe manufacturer.

Pipe Manufacturers (Pipe Mills or Processors)

Active		Inactive	
Mill	Symbol	Mill	Symbol
Algoma	X	Armco	A
British Steel		American Seamless	AI
Seamless Tubes LTD	B	B&W	W
Dalmine	D	CF&I	C
Kawasaki	H	J&L	J
Nippon	I	Lone Star	L
NKK	K	Ohio	O
Mannesmann	M	Republic	R
Reynolds Aluminum	RA	TI	Z
Sumitomo	S	Tubemuse	TU
Siderca	SD	Voest	VA
Tamsa	T	Wheeling Pittsburgh	P
US Steel	N	Youngstown	Y
Vallourec	V		
Used	U		
Processor	Symbol		
Grant TFW	TFW		
Omsco	OMS		
Prideco	PI		
Texas Steel Conversion	TSC		

Figure 82—Marking on Tool Joints for Identification of Drill String Components



Drill Pipe Weight Code

(1) Size OD inches	(2) Nominal Weight lb per ft	(3) Wall Thickness inches	(4) Weight Code Number
2 3/8	4.85	.190	1
	6.65*	.280	2
2 7/8	6.85	.217	1
	10.40*	.362	2
3 1/2	9.50	.254	1
	13.30*	.368	2
	15.50	.449	3
4	11.85	.262	1
	14.00*	.330	2
	15.70	.380	3
4 1/2	13.75	.271	1
	16.60*	.337	2

(1) Size OD inches	(2) Nominal Weight lb per ft	(3) Wall Thickness inches	(4) Weight Code Number
4 1/2	20.00	.430	3
	22.82	.500	4
	24.66	.550	5
	25.50	.575	6
5	16.25	.296	1
	19.50*	.362	2
	25.60	.500	3
5 1/2	19.20	.304	1
	21.90*	.361	2
	24.70	.415	3
6 5/8	25.20*	.330	2
	27.70	.362	3

*Designates standard weight for drill pipe size.

Figure 83—Recommended Practice for Mill Slot and Groove Method of Drill String Identification

Page 127, replace Section 14 with the following:

14 Special Processes

14.1 DRILL STEM SPECIAL PROCESSES

14.1.1 Usually the materials used in the manufacture of down hole drilling equipment (tool joints, drill collars, stabilizers and subs) are AISI–4135, 4137, 4140, or 4145 steels.

14.1.2 These are alloy steels and are normally in the heat treated state, these materials are not weldable unless proper procedures are used to prevent cracking and to recondition the sections where welding has been performed.

14.1.3 It should be emphasized that areas welded can only be reconditioned and cannot be restored to their original state free of metallurgical change unless a complete heat treatment is performed after welding, which cannot be done in the field.

14.2 CONNECTION BREAK-IN

Based on field experience, it has been observed that used rotary shouldered connections are less likely to gall than new connections. It is believed that this is due to work hardening the connection surfaces. The process of Connection Break-In is a make-up and break-out of the connection under controlled conditions in order to provide surface work hardening prior to use. Connection Break-In may be done on the rig, as an optional manufacturing step, or at a service facility.

Since many factors effect connection galling, Connection Break-In does not eliminate the possibility of galling.

14.2.1 Preparation for Connection Break-In

Remove any storage or rust preventative coatings. Make sure that the connections are free of dirt or other debris. Thoroughly coat the threads and shoulders of both pin and box connections with a thread compound suitable for rotary shouldered connections. Determine the recommended make-up torque of the connection. Make note of the friction factor of the thread compound and any adjustment required to the applied make up torque. See API Specification 7, Appendix G and API Recommended Practice 7A1 for further information on thread compounds and friction factor.

14.2.2 Connection Break-In at the Rig

Taking care to align the connection, stab and make-up the connection slowly. Spinning in with a chain or high speed power spinner may cause galling. Using a calibrated torque gage or line pull indicator, slowly make-up to the recommended make-up torque. With manual tongs, use both sets of tongs and keep lines at 90 degrees for the final torque. Slowly break-out the connection. During both make-up and break-out, watch for excessive resistance or other signs that could indicate the possibility of galling. Wipe clean the pin and box connections and visually inspect for evidence of galling in the threads or sealing shoulders. If galling occurs, rework the connection prior to use.

14.2.3 Connection Break-In During Manufacturing

When performing break-in at the factory or service facility, the connection should be finished machined, inspected, cold rolled (if specified) and preferably coated with an anti-gall material such as a phosphate or copper.

Note: Break-in will change thread gage standoff.

Slowly make-up three times to the recommended torque. Between each make-up, break-out only far enough to apply additional thread compound to the shoulders and last engaged threads. Break out the connection after final make-up. Wipe clean the pin and box and visually inspect for galling on the threads or shoulder. If galling occurs, the connection is rejected.

Page 130, Table 33, add the following sizes:

Connection	Maximum Pin ID in.	Bit Sub OD in.	Minimum Make-up Torque ft-lb
1 API REG	0.75	1.56	185
1$^{1}/2$ API REG	1.00	2.00	665

Page 130, Table 33, Note:

Change “A.8” to “A.9”

Replace Appendix A with the following:

APPENDIX A—STRENGTH AND DESIGN FORMULAS

A.1 Torsional Strength of Eccentrically Worn Drill Pipe

Assume 1: Eccentric hollow circular section (see Figure A-1).
Reference: *Formulas for Stress & Strain*, Roark, 3rd Edition.

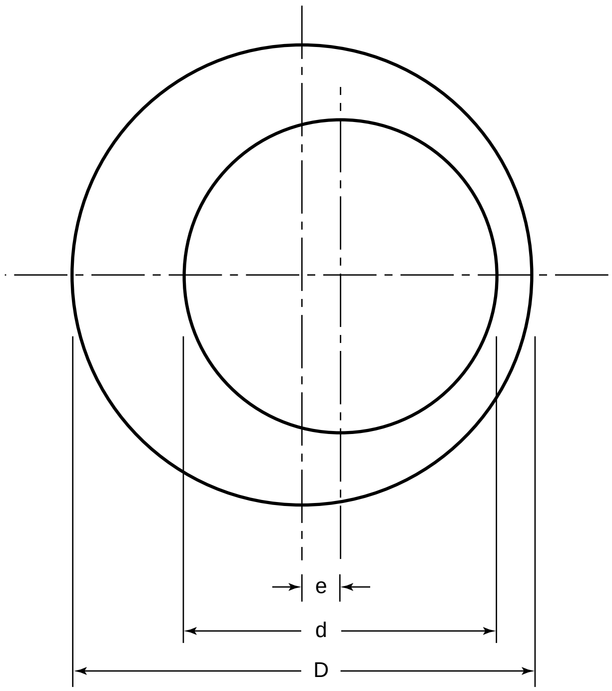


Figure A-1—Eccentric Hollow Section of Drill Pipe

$$T = \frac{\pi S_s (D^4 - d^4)}{12 \times 16 \times D \times F}, \tag{A.1}$$

where

$$F = 1 + \frac{4N^2\phi}{(1-N^2)} + \frac{32N^2\phi^2}{(1-N^2)\ (1-N^4)} + \frac{48N^2(1+2N^2+3N^4+2N^6)\phi^3}{(1-N^2)\ (1-N^4)\ (1-N^6)},$$

N = d/D,

$\phi = \frac{e}{D}$,

T = torque, ft-lbs.,

S_s = minimum shear strength, psi,

D = outside diameter, in.,

d = inside diameter, in.

Assume 2: The internal diameter, d, remains constant and at the nominal ID of the pipe throughout its life.

Assume 3: The external diameter D is d + t nominal + t minimum; i.e., all wear occurs on one side. This diameter is not the same as diameter for uniform wear.

Note: Torsional yield strengths for Premium Class, Table 4, and Class 2, Table 6 were calculated from Equation A.1, using the assumption that wear is uniform on the external surface.

A.2 Safety Factors

Values for various performance properties of drill pipe are given in Tables 2 through 7. The values shown are minimum values and do not include factors of safety. In the design of drill pipe strings, factors of safety should be used as are considered necessary for the particular application.

A.3 Collapse Pressure for Drill Pipe

Note: See API Bulletin 5C3 for derivation of equations in A.3.

The minimum collapse pressures given in Tables 3, 5, and 7 are calculated values determined from equations in API Bulletin 5C3. Equations A.2 through A.5 are simplified equations that yield similar results. The D/t ratio determines the applicable formula, since each formula is based on a specific D/t ratio range.

For minimum collapse failure in the plastic range with minimum yield stress limitations: the external pressure that generates minimum yield stress on the inside wall of a tube.

$$P_c = 2Y_m\left[\frac{(D/t)-1}{(D/t)^2}\right] \tag{A.2}$$

Applicable D/t ratios for application of Equation A.2 are as follows:

Grade	D/t Ratio
E75	13.60 and less
X95	12.85 and less
G105	12.57 and less
S135	11.92 and less

For minimum collapse failure in the plastic range:

$$P_c = Y_m\left[\left(\frac{A'}{D/t}\right) - B'\right] - C \tag{A.3}$$

Factors and applicable D/t ratios for application of Equation A.3 are as follows:

	Formula Factors			
Grade	A'	B'	C	D/t Ratio
E75	3.054	0.0642	1806	13.60 to 22.91
X95	3.124	0.0743	2404	12.85 to 21.33
G105	3.162	0.0794	2702	12.57 to 20.70
S135	3.278	0.0946	3601	11.92 to 19.18

For minimum collapse failure in conversion or transition zone between elastic and plastic range:

$$P_c = Y_m\left[\left(\frac{A}{D/t}\right) - B\right] \qquad \text{(A.4)}$$

Factors and applicable D/t ratios for application of Equation A.4 are as follows:

	Formula Factors		
Grade	A	B	D/t Ratio
E75	1.990	0.0418	22.91 to 32.05
X95	2.029	0.0482	21.33 to 28.36
G105	2.053	0.0515	20.70 to 26.89
S135	2.133	0.0615	19.18 to 23.44

For minimum collapse failure in the elastic range:

$$P_c = \frac{46.95 \times 10^6}{(D/t)[(D/t) - 1]^2} \qquad \text{(A.5)}$$

Applicable D/t ratios for application of Equation A.5 are as follows:

Grade	D/t Ratio
E75	32.05 and greater
X95	28.36 and greater
G105	26.89 and greater
S135	23.44 and greater

where
P_c = minimum collapse pressure, psi,
*D = nominal outside diameter, in.,
*t = nominal wall thickness, in.,
Y_m = material minimum yield strength, psi.

Notes:
*Collapse pressures for used drill pipe are determined by adjusting the nominal outside diameter, D, and wall thickness, t, as if the wear is uniform on the outside of the pipe body and the inside diameter remains constant. Values of D and t for each class of used drill pipe follow. These values are to be used in applicable Equation A.2, A.3, A.4, or A.5, depending on the D/t ratio, to determine collapse pressure.
Premium Class: t = (0.80) (nominal wall), D = nominal OD – (0.40) (nominal wall)
Class 2: t = (0.70) (nominal wall), D = nominal OD – (0.60) (nominal wall)

A.4 Free Length of Stuck Pipe

The relation between differential stretch and free length of
98 a stuck string of steel pipe due to a differential pull is:

$$L_1 = \frac{E \times e \times W_{dp}}{40.8\ P}, \qquad \text{(A.6)}$$

where
L_1 = length of free drill pipe, ft.,
E = modulus of elasticity, lb/in.,^{2}
e = differential stretch, in.,
W_{dP} = weight per foot of pipe, lbs/ft.,
P = differential pull, lbs.

Where $E = 30 \times 10^6$, this formula becomes:

$$L_1 = \frac{735{,}294 \times e \times W_{dP}}{P} \qquad \text{(A.7)}$$

A.5 Internal Pressure

A.5.1 DRILL PIPE

$$P_i = \frac{2Y_m t}{D}, \qquad \text{(A.8)}$$ 98

where
P_i = internal pressure, psi,
Y_m = material minimum yield strength, psi,
t = remaining wall thickness of tube, in.,
D = nominal outside diameter of tube, in.

Notes:
1. Internal pressures for new drill pipe in Table 3 were determined by using the nominal wall thickness for t in the above equation and multiplying by the factor 0.875 due to permissible wall thickness tolerance of minus $12^1/_2$ percent.
2. Internal pressures for used drill pipe were determined by adjusting the nominal wall thickness according to footnotes below Table 5 and 7 and using the nominal outside diameter, in the above Equation A.8.

A.5.2 KELLYS

$$P_i = \frac{Y_m[D_{FL}^{\ 2} - (D_{FL} - 2t)^2]}{\sqrt{3(D_{FL})^4 + (D_{FL} - 2t)^4}}, \qquad \text{(A.9)}$$ 98

where
P_i = internal pressure, psi,
Y_m = material minimum yield strength, psi,
D_{FL} = distance across drive section flats, in.,
t = minimum wall, in.

Note: The dimension t is the minimum wall thickness of the drive section and must be determined in each case through the use of an ultrasonic thickness gauge or similar device.

A.6 Stretch of Suspended Drill Pipe

When pipe is freely suspended in a fluid, the stretch due to its own weight is:

$$e = \frac{L_1^{\ 2}}{24E}\ [W_a - 2W_f(1 - \mu)], \qquad \text{(A.10)}$$

where
e = stretch, in.,
L_1 = length of free drill pipe, ft., 98

E = modulus of elasticity, psi,
W_a = weight of pipe material, lb/cu ft.,
W_f = weight of fluid, lb/cu ft.,
00 μ = Poisson's ratio.

For steel pipe where W_s = 489.5 lb/cu ft, $E = 30 \times 10^6$ psi and μ = 0.28, this formula will be:

$$e = \frac{L_1^{\ 2}}{72 \times 10^7} \left[489.5 - 1.44 W_f\right], \qquad \text{(A.11)}$$

or

$$e = \frac{L_1^{\ 2}}{9.625 \times 10^7} \left[65.44 - 1.44 W_g\right], \qquad \text{(A.12)}$$

where
W_f = weight of fluid, lb/cu ft.,
W_g = weight of fluid, lb/gal.

03 A.7 Tensile Strength of Drill Pipe Body

$$P = Y_m A, \qquad \text{(A.13)}$$

where
P = minimum tensile strength, lbs.,
Y_m = material minimum yield strength, psi,
A = cross-section area, sq. in. (Table 1, Column 6, for drill pipe).

A.8 Torsional Yield Strength of Drill Pipe Body

A.8.1 PURE TORSION 03

$$Q = \frac{0.096167 J Y_m}{D}, \qquad \text{(A.14)}$$

where
Q = minimum torsional yield strength, ft-lb.,
Y_m = material minimum yield strength, psi,
J = polar moment of inertia
$= \frac{\pi}{32}(D^4 - d^4)$ for tubes
$= 0.098175\,(D^4 - d^4)$,
D = outside diameter, in.,
d = inside diameter, in.

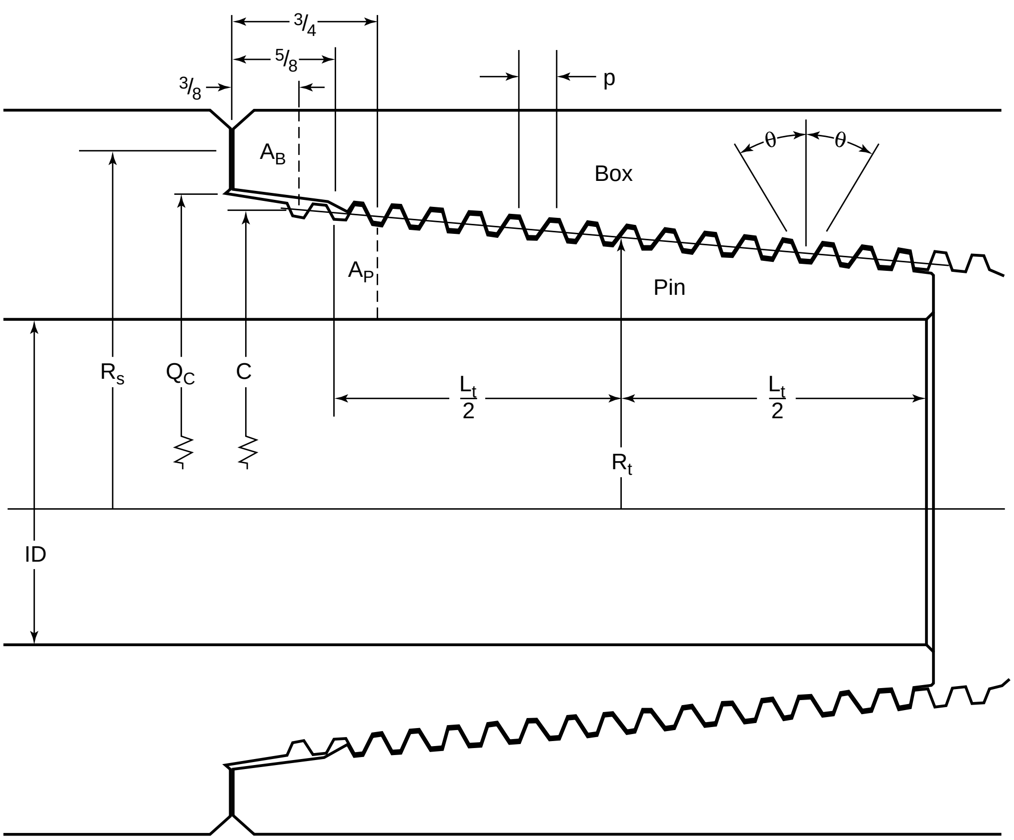


Figure A-2—Rotary Shouldered Connection

A.8.2 TORSION AND TENSION

$$Q_T = \frac{0.096167J}{D}\sqrt{Y_m^2 - \frac{P^2}{A^2}} \qquad \text{(A.15)}$$

where

Q_T = minimum torsional yield strength under tension, ft-lb.,

J = polar moment of inertia

$= \frac{\pi}{32}(D^4 - d^4)$ for tubes

$= 0.098175\ (D^4 - d^4)$,

D = outside diameter, in.,

d = inside diameter, in.,

Y_m = material minimum yield strength, psi,

P = total load in tension, lbs.,

A = cross section area, sq. in.

A.9 Torque Calculations for Rotary Shouldered Connections (see Table A-1 and Figure A-2)

A.9.1 TORQUE TO YIELD A ROTARY SHOULDERED CONNECTION

$$T_y = \frac{Y_m A}{12}\left(\frac{p}{2\pi} + \frac{R_t f}{\cos\theta} + R_s f\right) \qquad \text{(A.16)}$$

where

T_y = turning moment or torque required to yield, ft-lbs.,

Y_m = material minimum yield strength, psi,

p = lead of thread, in.,

f = coefficient of friction on mating surfaces, threads and shoulders, assumed 0.08 for thread compounds containing 40 to 60 percent by weight of finely powdered metallic zinc. (Reference the caution regarding the use of hazardous materials in Appendix G of Specification 7.),

00 θ = $^1/_2$ included angle of thread (Figures 21 or 22,
98 Specification 7), degrees,

$$R_t = \frac{C + [C - (L_{pc} - .625) \times tpr \times 1/12\ ]}{4},$$

L_{pc} = length of pin (Specification 7, Table 25, Column 9), in.,

R_s = $^1/_4$ (OD + Q_c), in.
The maximum value of R_s is limited to the value obtained from the calculated OD where $A_p = A_b$,

A = cross-section area A_b or A_p whichever is smaller, sq. in.

where

$$A_p = \frac{\pi}{4}\ [(C-B)^2 - ID^2] = \text{without relief grooves,}$$

or

$$A_p = \frac{\pi}{4}\ [(D_{RG}{}^2 - ID^2] = \text{with relief grooves,}$$

where

D_{RG} = diameter of relief groove (Specification 7, Table 16, Column 5), in.,

C = pitch diameter of thread at gauge point (Specification 7, Table 25, Column 5), in.,

ID = inside diameter, in.,

$B = 2\left(\frac{H}{2} - S_{rs}\right) + tpr \times {}^1/_8 \times {}^1/_{12}$,

H = thread height not truncated (Specification 7, Table 26, Column 3), in.,

S_{rs} = root truncation (Specification 7, Table 26, Column 5), in.,

tpr = taper (Specification 7, Table 25, Column 4), in./ft.,

$$A_b = \frac{\pi}{4}\ [OD^2 - (Q_c - E)^2],$$

where

OD = outside diameter, in.,

Q_c = box counterbore (Specification 7, Table 25, Column 11), in.,

$E = tpr \times {}^3/_8 \times {}^1/_{12}$

A.9.2 MAKE-UP TORQUE FOR ROTARY SHOULDERED CONNECTIONS

$$T = \frac{SA}{12}\left(\frac{p}{2\pi} + \frac{R_t f}{\cos\theta} + R_s f\right) \qquad \text{(A.17)}$$

where

A = A_b or A_P whichever is smaller; A_P shall be based on pin connections without relief grooves, sq. in.,

S = recommended make-up stress level, psi.

Note: For values of S, see 4.8.1 for Tool Joints and 5.2 for Drill Collars.

A.10 Combined Torsion and Tension to Yield Rotary Shouldered Connection and Drill Pipe Body

A.10.1 INTRODUCTION

Field-operating practice should always maintain operating torque below the make-up torque. Since there is no margin of safety applied in these curves, the actual dimensions of the tool joint and tube (inspection classification) must be used in the construction of the curve. Always be aware of the operating limits of the pipe in combination with the tool joint. 03

A.10.2 DRILL PIPE SELECTION AND NORMAL OPERATIONS (SEE FIGURE A.3a)

At torque levels up to the make-up torque of the tool joint, the Make-up Torque THEN Tension curves are used to determine the capacity. These curves are used when the maximum torque a connection will experience is the torque applied before
03 tension is applied. The torque value used in this set of curves is the make-up torque or the applied torque, whichever is greater.

A.10.3 SPECIAL OPERATIONS (SEE FIGURE A.3b)

For operations where the applied downhole torque to the drill string might exceed the tool joint make-up torque (fishing, back-reaming, etc.), use the Tension THEN Torque curves. In these cases, the horizontal axis will represent the torque applied after tension is applied.

CAUTION: The dynamic loads considered in this simplified approach are different than static loads. API recommends staying in safe zone of operations. Going outside this zone or getting close to the boundaries can result in a catastrophic failure. 03

A.10.4 EQUATION DEFINITIONS

The variables used in the equations below are defined in A.9.1.

$$P1 = Y_m A_p \tag{A.18}$$

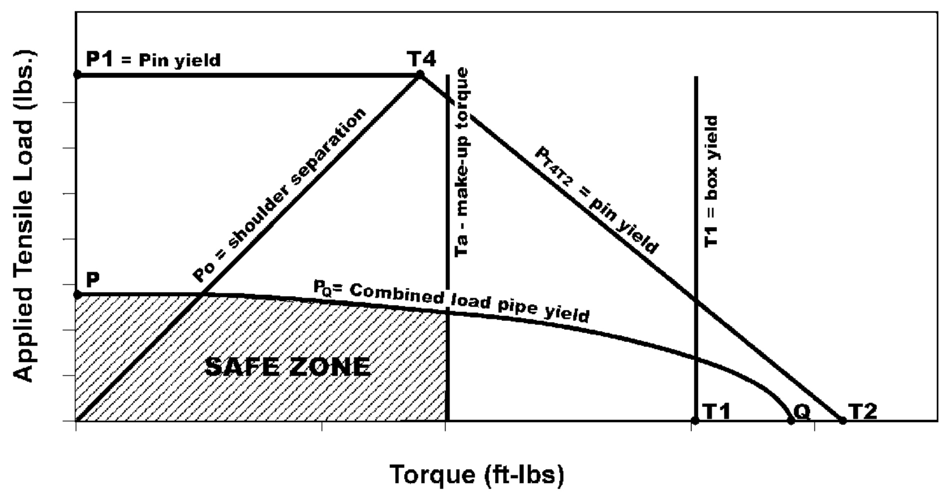


Figure A-3a—Make-up Torque Then Tension 03

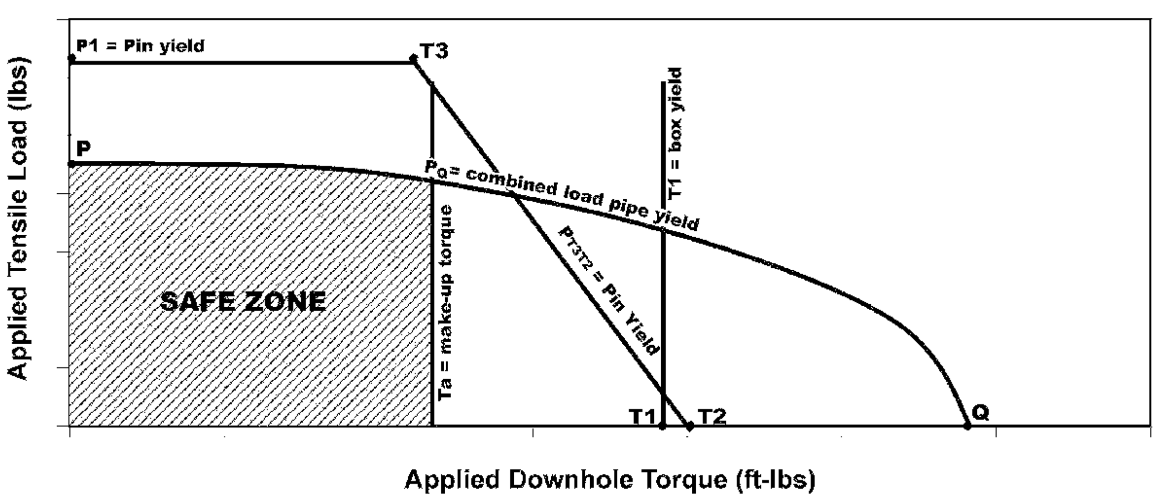


Figure A-3b—Tension Then Torque 03

$$P_o = \frac{12(A_b + A_p)T_a}{A_b\left(\frac{p}{2\pi} + \frac{R_t f}{\cos\theta} + R_s f\right)} \quad (A.19)$$

$$P_{T4T2} = (A_b + A_p)\left(Y_m - \frac{T_a 12}{A_p\left(\frac{p}{2\pi} + \frac{R_t f}{\cos\theta} + R_s f\right)}\right) \quad (A.20)$$

$$P_{T3T2} = \frac{Y_m A_p\left(\frac{p}{2\pi} + \frac{R_t f}{\cos\theta} + R_s f\right) - 12T_{DH}}{R_s f} \quad (A.21)$$

$$T1 = \left(\frac{Y_m}{12}\right)\left[A_b\left(\frac{p}{2\pi} + \frac{R_t f}{\cos\theta} + R_s f\right)\right] \quad (A.22)$$

$$T2 = \left(\frac{Y_m}{12}\right)\left[A_p\left(\frac{p}{2\pi} + \frac{R_t f}{\cos\theta} + R_s f\right)\right] \quad (A.23)$$

$$T3 = \left(\frac{Y_m}{12}\right)\left[A_p\left(\frac{p}{2\pi} + \frac{R_t f}{\cos\theta}\right)\right] \quad (A.24)$$

03 $$T4 = \left(\frac{Y_m}{12}\right)\left[\left(\frac{A_p A_b}{A_p + A_b}\right)\left(\frac{p}{2\pi} + \frac{R_t f}{\cos\theta} + R_s f\right)\right] \quad (A.25)$$

$$P_Q = A\sqrt{Y_m^2 - \left(\frac{Q_t D}{0.096167 \cdot J}\right)^2} \quad (A.26)$$

A description of the values calculated above and those used to plot the curves are:

- T_a = torque that is applied to the tool joint before tension is applied, make-up torque, ft-lbs
- T_{DH} = applied downhole torque, ft-lbs
- $P1$ = yield strength of the tool joint pin at $^5/_8$" from the make-up shoulder, lbs
- P_o = tension required to separate the tool joint shoulders after T_a is applied, lbs. P_o is represented by the line from the origin to the point $T4$. Do not use this formula if T_a is greater than $T4$ since P_o will be greater than $P1$
- P_{T4T2} = tension required to yield pin after T_a is applied, lbs. P_{T4T2} is represented by the line from $T4$ to $T2$
- P_{T3T2} = tension required to yield pin after T_{DH} is applied, lbs. P_{T3T2} is represented by the line from $T3$ to $T2$
- $T1$ = torsional strength of the box of the tool joint and is represented by a vertical line at that value on the *x*-axis, ft-lbs
- $T2$ = torsional strength of the pin of the tool joint, ft-lbs
- $T3$ = torsional load required to produce additional make-up of the connection when the shoulders are separated by an external tensile load on the pipe that produces yield stress in the tool joint pin, ft-lbs
- $T4$ = make-up torque at which pin yield and shoulder separation occur simultaneously with an externally applied tensile load, ft-lbs
- P_Q = yield of the drill pipe tube in the presence of torsion represented by the elliptical curve, lbs. Equation was produced by rearranging Equation A.15

A.10.5 FAILURE MODES

The failure modes under combined torsion/tension loads are:

1. Pin yield.
2. Box yield.
3. Shoulder separation (seal failure).
4. Tube yield.

A.10.6 USING THE CURVES

Calculate the above values using the actual dimensions of the tool joints and tube. Use these values to plot a working curve.

Example 1: Drilling an Extended Reach Well (See Figure A.3c)

Assume:

Anticipated Maximum Drilling Torque = 25,000 ft-lbs 03

Drill Pipe string is 5", 19.50 ppf, Grade S, Premium Class with NC50 tool joints ($6^5/16$" OD × $2^3/4$" ID)

Calculated values:

P = 560,764 lbs
Q = 58,113 ft-lbs
T_a (make-up torque) = 28,381ft-lbs
$P1$ = 1,532,498 lbs
$T1$ = 47,302 ft-lbs
$T2$ = 62,608 ft-lbs
$T4$ = 26,945 ft-lbs

Questions

Is the drill pipe string adequate for the anticipated torque? {{Yes}}

What is the allowable hook load at anticipated maximum drilling torque? {{P = 504,772 lbs at 25,000 ft-lbs}}

Example 2: Fishing Drill Pipe String in Example 1 (See Figure A.3c)

Question:

What is the maximum pull without exceeding yield strength in the absence of torque? {{With a straight pull and no torque, the maximum pull is the tensile capacity of the tube which is P = 560,764 lbs.}}

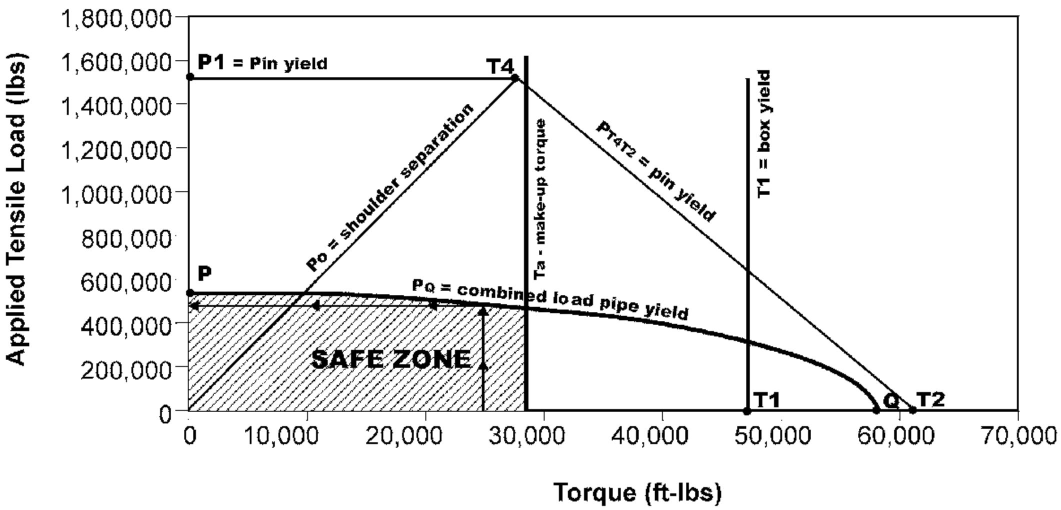


Figure A-3c—Make-up Torque Then Tension 03

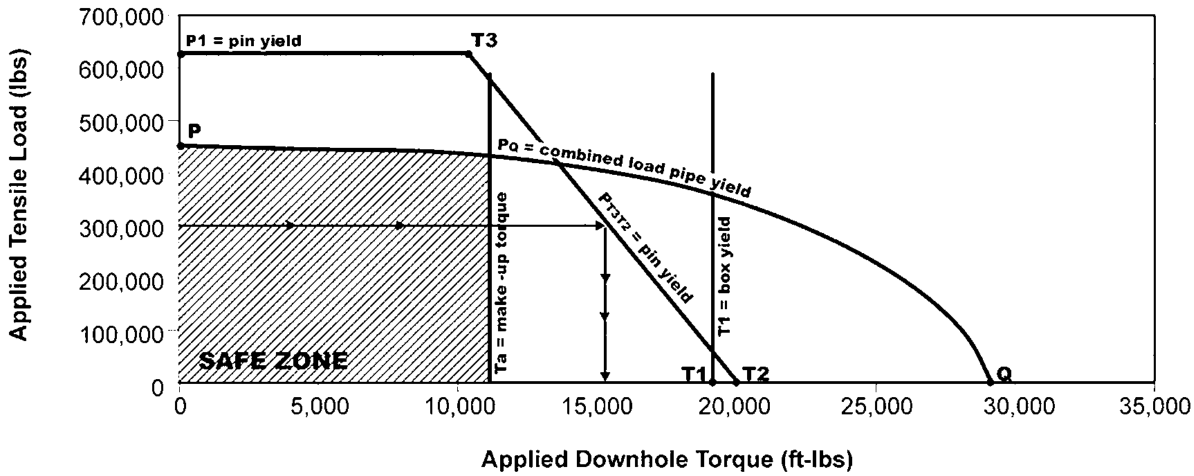


Figure A-3d—Tension Then Torque 03

Example 3: Back-reaming Hole with Drill Pipe Stinger (See Figure A.3d)

Assume:

Back-reaming Pull = 300,000 lbs

Drill pipe stinger is $3^1/2$", 15.50 ppf, Grade S, Premium Class with NC38 tool joints ($4^3/4$" OD × $2^9/16$" ID)

03 Calculated values:

P = 451,115 lbs

Q = 29,063 ft-lbs

Make-up Torque = 11,504 ft-lbs

$P1$ = 634,795 lbs

$T1$ = 19,174 ft-lbs

$T2$ = 20,062 ft-lbs

$T3$ = 10,722 ft-lbs

Question:

What is yield torque if back-reaming pull is 300,000 lbs? {T_{DH} = 15,648 ft-lbs}

CAUTION: If a back-reaming pull of 300,000 lbs has a torque exceeding make-up torque (11,054 ft-lbs), the chance of pin failure increases as you approach P_{T3T2}. Always use a safety factor. 03

A.10.7 *CAUTION:* The loads considered in this simplified approach are torsion and tension. These curves are approximations that do not consider the effects of internal pressure or bending. For this reason, the answers from these curves should be derated. A safety factor of one was used.

A.11 Drill Collar Bending Strength Ratio

The bending strength ratios in Figures 26 through 32 were determined by application of Equation A.27. The effect of stress-relief features was disregarded.

$$BSR = \frac{Z_B}{Z_P}$$

03

$$= \frac{0.098\,\dfrac{(OD^4 - b^4)}{OD}}{0.098\,\dfrac{(R^4 - ID^4)}{R}} \qquad \text{(A.27)}$$

$$= \frac{\dfrac{OD^4 - b^4}{OD}}{\dfrac{R^4 - ID^4}{R}},$$

where

BSR = bending strength ratio,
Z_B = box section modulus, cu. in.,
Z_P = pin section modulus, cu. in.,
03 OD = outside diameter of pin and box (Figure A-4), in.,
ID = inside diameter or bore (Figure A-4), in.,
b = thread root diameter of box threads at end of pin (Figure A-4), in.,
R = thread root diameter of pin threads $^3/_4$ inch from shoulder of pin (Figure A-4), in.

To use Equation A.27, first calculate:
Dedendum, *b*, and *R*

$$Dedendum = \frac{H}{2} - f_{rn}, \qquad \text{(A.28)}$$

where

H = thread height not truncated, in.,
f_{rn} = root truncation, in.

00

$$b = C - \frac{tpr(L_{pc} - 0.625)}{12} + (2 \times dedendum) \qquad \text{(A.29)}$$

where

C = pitch diameter at gauge point, in.,
tpr = taper, in./ft.

$$R = C - (2 \times dedendum) - (tpr \times {}^1/_8 \times {}^1/_{12}) \qquad \text{(A.30)}$$

An example of the use of Equation A.27 in determining the bending strength of a typical drill collar connection is as follows:

Determine the bending strength ratio of drill collar NC46-62 ($6^1/_4$ OD x $2^{13}/_{16}$) ID connection.

D = 6.25 (Specification 7, Table 13, Column 2),
d = $2^{13}/_{16}$ = 2.8125 (Specification 7, Table 13, Column 3),
C = 4.626 (Specification 7, Table 25, Column 5),
Taper = 2 (Specification 7, Table 25, Column 4),
L_{pc} = 4.5 (Specification 7, Table 25, Column 9),
H = 0.216005 (Specification 7, Table 26, Column 3),
f_{rn} = 0.038000 (Specification 7, Table 26, Column 5).

First calculate dedendum, *b*, and *R*

$$Dedendum = \frac{H}{2} - f_{rn} = \frac{.216005}{2} - .038000 = .0700025$$

$$b = C - \frac{tpr(L_{pc} - 0.625)}{12} + (2 \times dedendum)$$ 03

$$b = 4.626 - \frac{2(4.5 - .625)}{12} + (2 \times .0700025)$$

$$b = 4.120,$$

$$R = C - (2 \times dedendum) - (tpr \times {}^1/_8 \times {}^1/_{12})$$

$$R = 4.626 - (2 \times .0700025) - (2 \times {}^1/_8 \times {}^1/_{12})$$

$$R = 4.465.$$

Substituting these values in Equation A.27 determines the bending strength ratio as follows:

$$BSR\ (\text{NC46-62}) = \frac{\dfrac{OD^4 - b^4}{OD}}{\dfrac{R^4 - ID^4}{R}}$$ 03

$$= \frac{\dfrac{(6.25)^4 - (4.120)^4}{6.25}}{\dfrac{(4.465)^4 - (2.8125)^4}{4.465}}$$

$$= 2.64:1$$

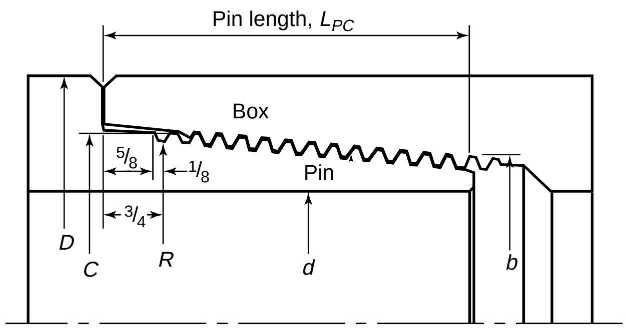


Figure A-4—Rotary Shouldered Connection Location of Dimensions for Bending Strength Ratio Calculations

A.12 Torsional Yield Strength of Kelly Drive Section

The torsional yield strength of the kelly drive section values listed in Tables 15 and 17 were derived from the following equation:

$$Y = \frac{0.577\,Y_m[0.200(a^3 - b^3)]}{12},$$

where

Y_m = tensile yield, psi,

a = distance across flats, in.,

b = kelly bore, in.

A.13 Bending Strength, Kelly Drive Section

The yield in bending values of the kelly drive section listed in Tables 15 and 17 were determined by one of the following equations:

a. Yield in bending through corners of the square drive section, Y_{BC}, ft-lb:

$$Y_{BC} = \frac{Y_m\,(0.118\,a^4 - 0.069\,b^4)}{12a}$$

b. Yield in bending through the faces of the hexagonal drive section Y_{BF}, ft-lb:

$$Y_{BF} = \frac{Y_m\,(0.104\,a^4 - 0.085\,b^4)}{12a}$$

A.14 Approximate Weight of Tool Joint Plus Drill Pipe

Approximate Weight of Tool Joint Plus Drill Pipe Assembly, lb/ft =

$$\frac{\left(\begin{array}{l}\text{Approximate Adjusted} \\ \text{Weight of Drill Pipe} \times 29.4\end{array} + \begin{array}{r}\text{Approximate Weight} \\ \text{of Tool Joint}\end{array}\right)}{\text{Tool Joint Adjusted Length} + 29.4}$$

, (A.31)

where

Approximate Adjusted Weight of Drill Pipe, lb/ft =

$$\text{Plain End Weight} + \frac{\text{Upset Weight}}{29.4} \quad \text{(A.32)}$$ 98

Plain end weight and upset weight are found in API Specification 5D.

Approximate Weight of Tool Joint, lbs =

$$0.222\,L(D^2 - d^2) + 0.167\,(D^3 - D_{TE}{}^3) - 0.501\,d^2(D - D_{TE}) \quad \text{(A.33)}$$ 00

Dimensions for L, D, d, and D_{TE} are in API Specification 7, Figure 6 and Table 7.

Adjusted Length of Tool Joint, ft =

$$\frac{L + 2.253\ (D - D_{TE})}{12} \quad \text{(A.34)}$$

A.15 Critical Buckling Force for Curved Boreholes[27,29,30,31,32]

A.15.1 The following equations define the range of hole curvatures that buckle pipe in a three dimensionally curved borehole. The pipe buckles whenever the hole curvature is between the minimum and maximum curvatures defined by the equations. 98

$$\text{if}\ \ F_b < \frac{4 \times E \times I}{12 \times h_c \times R_L}\ \ \text{pipe not buckled,}$$

$$\text{if}\ \ F_b \geq \frac{4 \times E \times I}{12 \times h_c \times R_L},$$

$$W_{eq} = \frac{12 \times h_c \times F_b^2}{4 \times E \times I},$$

$$B_{Vmin} = \frac{-5730}{F_b}\left[\left(W_{eq}{}^2 - \left(\frac{F_b}{R_L}\right)^2\right)^{1/2} + W_m \times \sin\theta\right],$$

$$B_{Vmax} = \frac{5730}{F_b}\left[\left(W_{eq}{}^2 - \left(\frac{F_b}{R_L}\right)^2\right)^{1/2} - W_m \times \sin\theta\right],$$

where

F_b = critical buckling force (+ compressive) (lb),

B_{Vmin} = minimum vertical curvature rate to cause buckling (+ building, – dropping) (°/100 ft),

B_{Vmax} = maximum vertical curvature rate that buckles pipe (+ building, – dropping) (°/100 ft),
W_{eq} = equivalent pipe weight required to buckle pipe at F_b axial load,
E = 29.6 x 10^6 psi,

$$I = \frac{0.7854(OD^4 - ID^4)}{16},$$

$W_m = W_a\left(\frac{65.5 - MW}{65.5}\right)$ buoyant weight of pipe (lb/ft),
W_a = actual weight in air (lb/ft),
MW = mud density (lb/gal),
$h_c = \left(\frac{D_H - TJOD}{2}\right)$ radial clearance of tool joint to hole (in.),
D_H = diameter of hole (in.),
$TJOD$ = OD tool joints (in.),
$B_L = \sqrt{B_T^2 - B_V^2}$ lateral curvature rate (°/100 ft),
B_T = total curvature rate (°/100 ft),
$R_L = \frac{5730}{B_L}$ lateral build radius (ft),
θ = inclination angle (deg).

A.15.2 If the hole curvature is limited to the vertical plane,
98 the buckling equations simplify to the following:

$$W_{eq} = \frac{12 \times h_c \times F_b^2}{4 \times E \times I},$$

$$B_{Vmin} = \frac{-5730 \times (W_{eq} + W_m \times \sin\theta)}{F_b},$$

$$B_{Vmax} = \frac{5730 \times (W_{eq} - W_m \times \sin\theta)}{F_b},$$

where
B_{Vmin} = minimum vertical curvature rate for buckling (+ building, – dropping) (°/100 ft),
B_{Vmax} = maximum vertical curvature rate for buckling (+ building, – dropping) (°/100 ft),
F_b = buckling force (lb),
E = 29.6 x 10^6 (psi),
$I = \frac{\pi}{64}(OD^4 - ID^4)$,
W_{eq} = buoyant weight equivalent for pipe in curved borehole (lb/ft),
$W_m = W_a\left(\frac{65.5 - MW}{65.5}\right)$ buoyant weight of pipe (lb/ft),
W_a = actual weight of pipe in air (lb/ft),
MW = mud density (lb/gal),
$h_c = \left(\frac{DH - TJOD}{2}\right)$ radial clearance of tool joint to hole (in.),
DH = diameter of hole (in.),
$TJOD$ = OD of tool joint (in.),
θ = inclination angle (deg).

A.15.3 Figures A-5 and A-6 show the effect of hole curvature on the buckling force for 5-inch and 3½-inch drillpipe. Figure A-7 shows the effect of lateral curvatures on the buckling force of 5-inch drillpipe. For lateral and upward curvatures, the critical buckling force increases with the total curvature rate.

A.16 Bending Stresses on Compressively Loaded Drillpipe in Curved Boreholes[33,34]

A.16.1 The type of loading can be determined by comparing the actual hole curvature to calculated values of the critical curvatures that define the transition from no pipe body contact to point contact and from point contact to wrap contact. The two critical curvatures are computed from the following equations.

$$B_c = \frac{57.3 \times 100 \times 12 \times \Delta D}{J \times L\left[\tan\left(\frac{57.3 \times L}{4 \times J}\right) - \frac{L}{4 \times J}\right]},$$

where 98
B_c = the critical hole curvature that defines the transition from no pipe body contact to point contact (°/100 ft),
ΔD = ($TJOD - OD$),
$TJOD$ = tool joint OD (in.),
OD = pipe body OD (in.),
$J = \left(\frac{E \times I}{F}\right)^{1/2}$ (in.),
L = length of one joint of pipe (in.),
E = Young's modulus 30 x 10^6 for steel (psi),
I = moment of inertia of pipe body (in.)
$= \frac{\pi(OD^4 - ID^4)}{64}$,
F = axial compressive load on pipe (lb),
ID = pipe body ID (in.).

$$B_w = \frac{57.3 \times 100 \times 12 \times \Delta D}{J \times L\left[\frac{4J}{L} + \frac{L}{4J \times \tan^2\left(\frac{57.3L}{4J}\right)} - \frac{2}{\tan\left(\frac{57.3L}{4J}\right)}\right]},$$

where
B_w = the critical curvature that defines the transition from point contact to wrap contact (°/100 ft),

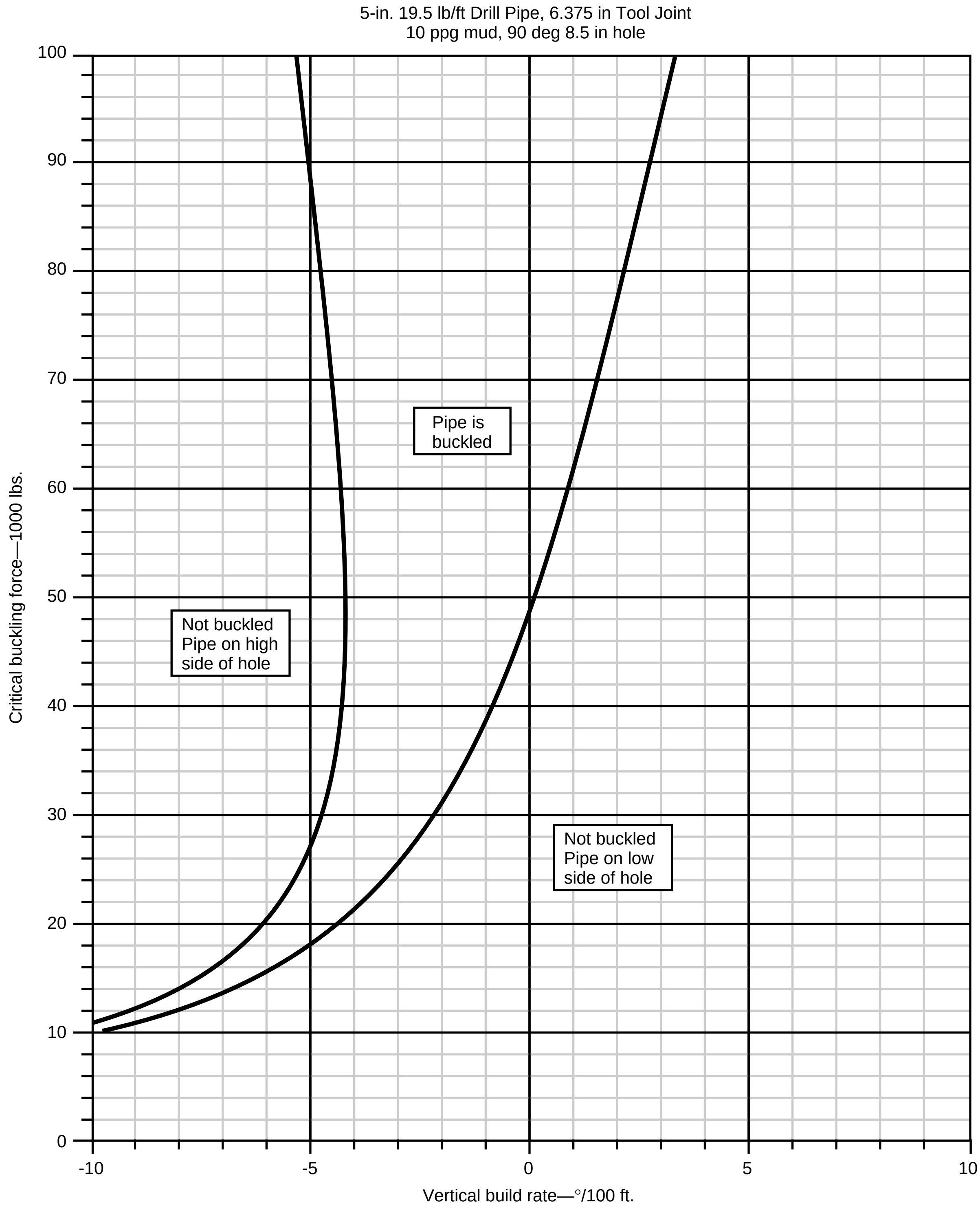


Figure A-5—Buckling Force vs Hole Curvature

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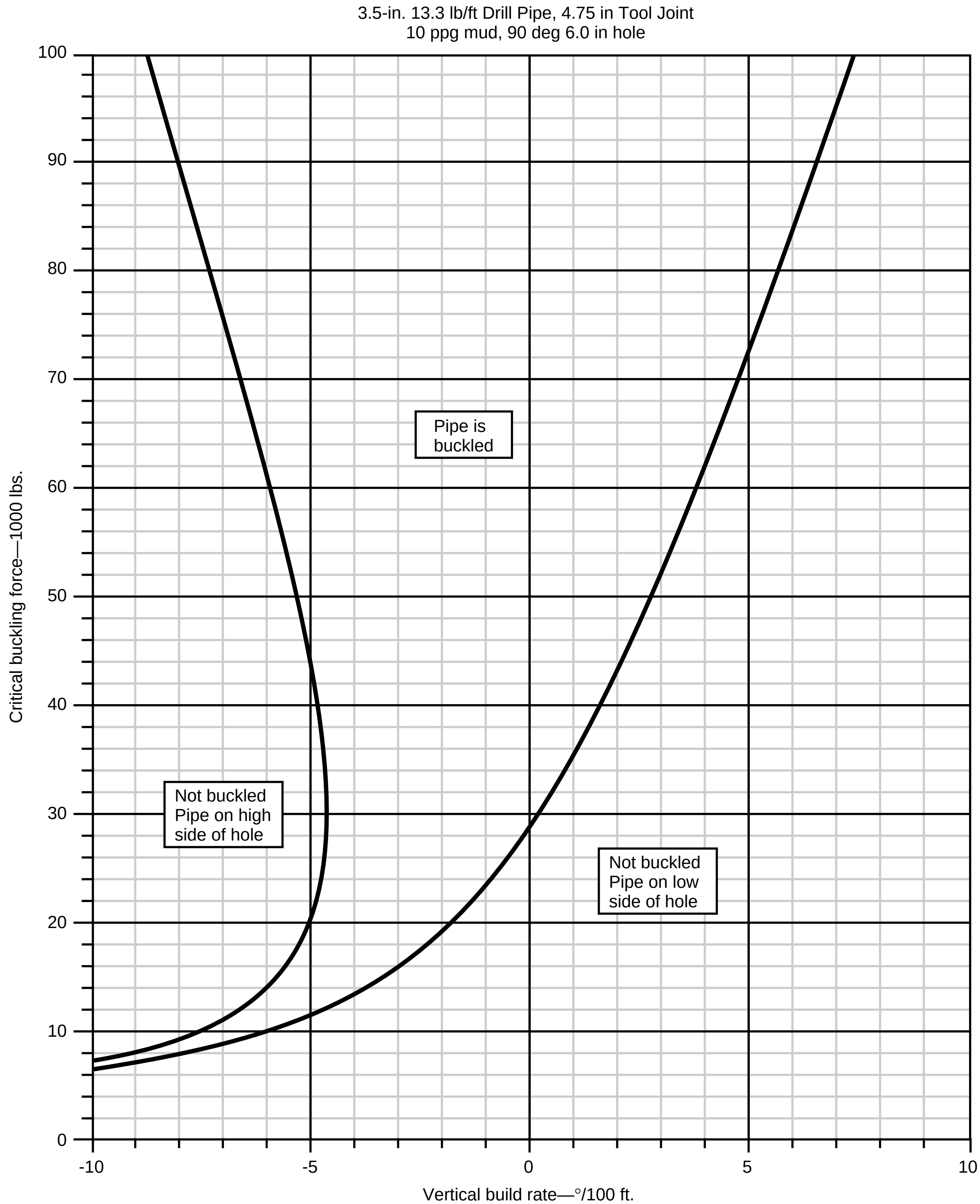

Figure A-6—Buckling Force vs Hole Curvature

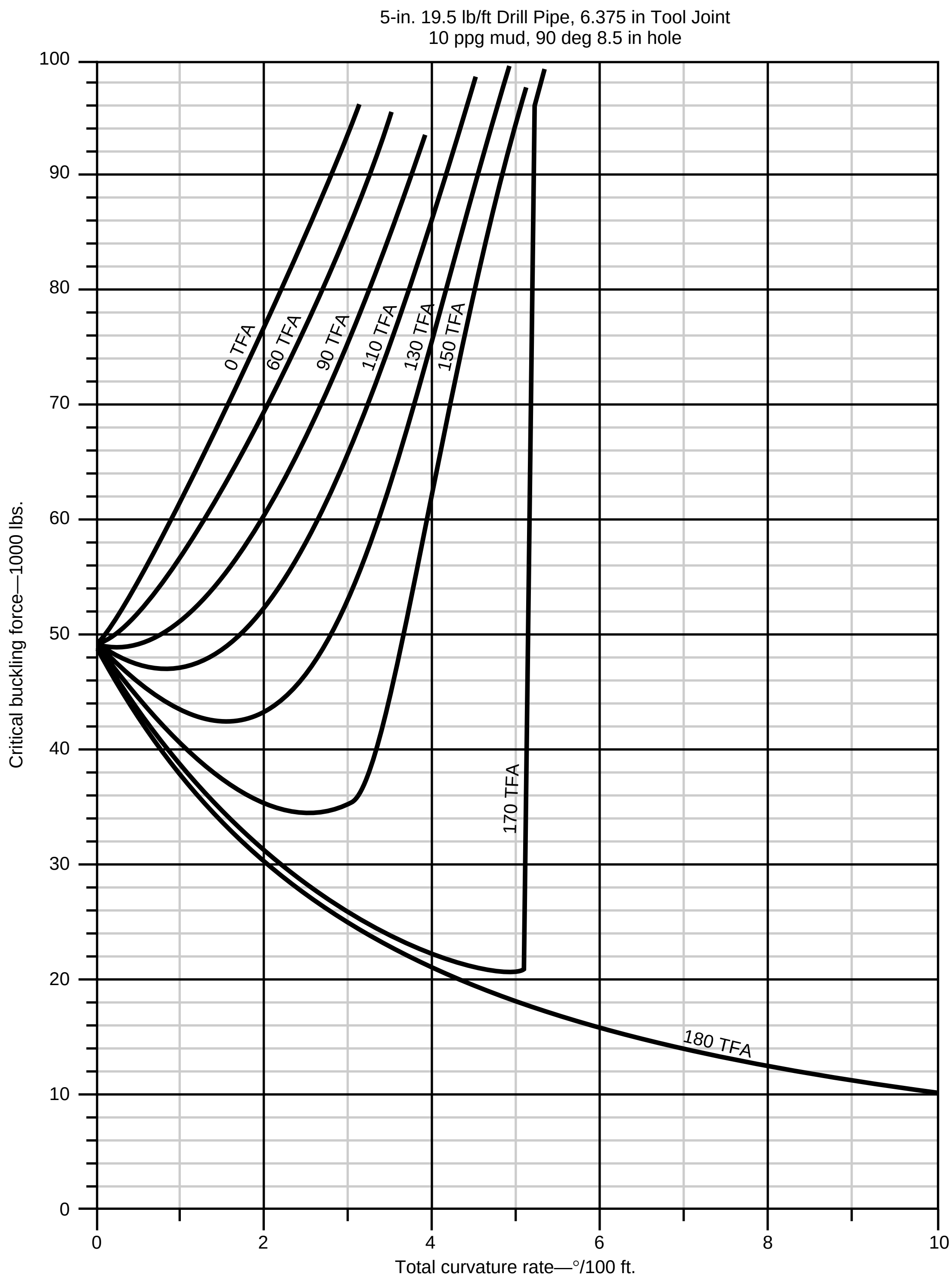

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Figure A-7—Buckling Force vs Hole Curvature

ΔD = $(TJOD - OD)$,
$TJOD$ = tool joint OD (in.),
OD = pipe body OD (in.),

$$J = \left(\frac{E \times I}{F}\right)^{1/2} \quad \text{(in.)},$$

L = length of one joint of pipe (in.),
E = Young's modulus 30 x 10^6 for steel (psi),
I = moment of inertia of pipe (in.^{4})

$$= \frac{\pi(OD^4 - ID^4)}{64},$$

F = axial compressive load on pipe (lb),
ID = pipe body ID (in.).

A.16.2 If the hole curvature is less than the critical curvature required to begin point contact, the maximum bending stress is given by the following:

$$S_b = \frac{B \times OD \times F \times J \times L}{57.3 \times 100 \times 12 \times 4 \times I \times \sin\left(\frac{57.3L}{2J}\right)},$$

where

S_b = maximum bending stress (psi),
B = hole curvature,
F = axial compressive load on pipe (lb),

98 $$J = \left(\frac{E \times I}{F}\right)^{1/2} \quad \text{(in.)},$$

E = Young's modulus 30 x 10^6 for steel (psi),
I = moment of inertia (in.)

$$= \frac{\pi(OD^4 - ID^4)}{64},$$

OD = pipe body OD (in.),
ID = pipe body ID (in.).
L = length of one joint of pipe (in.),

A.16.3 If the hole curvature is between the two critical curvatures calculated, the pipe will have center body point contact and the maximum bending stress is given by the following equation:

$$S_b = \frac{E \times OD \times U^2}{4R}\left[\frac{A \times \sin\theta + B \times \cos\theta}{U \times \sin U - 4 \times \sin^2\left(\frac{U}{2}\right)}\right],$$

where

E = Young's modulus, 29.6 x 10^6 for steel (psi),
OD = pipe body OD (in.),
ID = pipe body ID (in.),

$$U = \frac{L}{2J},$$

L = length of one joint of drillpipe for point contact of pipe body (in.),
L = L_e for wrap contact (in.),

$$A = \left(1 + \frac{4 \times R \times \Delta D}{L^2}\right)\sin U - \frac{4}{U} \times \sin^2\left(\frac{U}{2}\right),$$

$$B = 2\left[1 - \frac{\sin U}{U} - \left(1 + \frac{4 \times R \times \Delta D}{L^2}\right)\sin^2\left(\frac{U}{2}\right)\right],$$

$$\theta = \arctan\left(\frac{A}{B}\right),$$

$$J = \left(\frac{E \times I}{F}\right)^{1/2} \quad \text{(in.)},$$

$$I = \frac{\pi}{64}(OD^4 - ID^4) \quad \text{(in.}^4\text{)},$$

ΔD = diameter difference tool joint minus pipe body OD,
ΔD = $(TJOD - OD)$ (in.),
$TJOD$ = tool joint OD (in.),
R = 57.3 x 100 x 12B,
B = hole curvature (°/100 ft.).

A.16.4 If the hole curvature exceeds the critical curvature that separates point contact from wrap contact, we need to first compute an effective pipe length in order to calculate the maximum bending stress. The effective pipe span length is calculated from the following equation by trial and error until the calculated curvature matches the actual hole curvature: 98

$$B = \frac{57.3 \times 100 \times 12 \times \Delta D}{J \times L_e\left[\frac{4J}{L_e} + \frac{L_e}{4J \times \tan^2\left(\frac{57.3L_e}{4J}\right)} - \frac{2}{\tan\left(\frac{57.3L_e}{4J}\right)}\right]},$$

where

L_e = effective span length (in.),
B = hole curvature (°/100 ft.),
ΔD = diameter difference between tool joint and pipe body,
ΔD = $TJOD - OD$ (in.),
$TJOD$ = tool joint OD (in.),
OD = pipe body OD (in.),
ID = pipe body ID (in.).

$$J = \left(\frac{E \times I}{F}\right)^{1/2} \quad \text{(in.)},$$

E = Young's modulus 29.6 x 10^6 for steel (psi),

$$I = \frac{\pi}{64}(OD^4 - ID^4),$$

F = axial compressive load (lb),
L_w = length of pipe body touching hole (in.),
L_w = $L - L_e$,
L = length of one joint of pipe (in.).

A.16.5 The maximum bending stresses can then be computed using the equation for point contact and a pipe body length equal to the effective span length.

A.16.6 One of our major concerns when drilling with compressively loaded drillpipe is the magnitude of the lateral contact forces between the tool joints and the wall of the hole and the pipe body and the wall of the hole. Various authors have suggested operating limits in the range of two to three thousand pounds or more for tool joint contact faces. There are no generally accepted operating limits for compressively loaded pipe body contact forces. For loading conditions in which
98 there is no pipe body contact, the lateral force on the tool joints is given by:

$$LF_{TJ} = \frac{F \times L \times B}{57.3 \times 100 \times 12},$$

where

F_{TJ} = lateral force on tool joint (lb),
L = length of one joint of pipe (in.),
B = hole curvature (°/100 ft.).

A.16.7 For loading conditions with point or wrap contact, the following equations give the contact forces for the tool joint and the pipe body:

$$LF_{TJ} = \frac{2 \times E \times I \times U^2}{R \times L_e}\left[\frac{\left(1 - \frac{4R \times \Delta D}{L_e^2}\right)\sin U - \frac{4}{U}\sin^2\left(\frac{U}{2}\right)}{\sin U - \frac{4}{U}\sin^2\left(\frac{U}{2}\right)}\right],$$

where 98

$LF_{pipe} = \frac{F \times L}{R} - LF_{tj}$
LF_{tj} = lateral force on tool joint (lb),
LF_{pipe} = lateral force on pipe body (lb),
$L_w = L - L_e$,
L_w = length of pipe for wrap contact (in.), 00
L_e = L for point contact (in.),
L_e = effective span length for wrap contact,
$R = \frac{57.3 \times 100 \times 12}{B}$
B = hole curvature (°/100 ft.), 98
$U = \frac{L_e}{2J}$
$J = \left(\frac{E \times I}{F}\right)^{1/2}$ (in.), 03
ΔD = diameter difference tool joint minus pipe *OD* (in.),
ΔD = *TJOD* – *OD* (in.), 98
$I = \frac{\pi}{64}(OD^4 - ID^4)$.

Table A-1—Rotary Shouldered Connection Thread Element Information

	(1) Connection Type	(2) Pitch Diameter C	(3) Taper	(4) Pin Length	(5) Thread Height Not Truncated	(6) Root Truncation	(7) Nominal Counterbore	(8) Thread Pitch	(9) Thread Angle θ	(10) Stress Relief Groove Diameter	(11) Bore-Back Cylinder Diameter	(12) Low Torque Counterbore	(13) Low Torque Bevel Diameter
	NC10	1.063000	1.500000	1.500000	0.144100	0.040600	1.204000	.166667	30	—	—	—	—
	NC12	1.265000	1.500000	1.750000	0.144100	0.040600	1.406000	.166667	30	—	—	—	—
	NC13	1.391000	1.500000	1.750000	0.144100	0.040600	1.532000	.166667	30	—	—	—	—
	NC16	1.609000	1.500000	1.750000	0.144100	0.040600	1.751000	.166667	30	—	—	—	—
	NC23	2.355000	2.000000	3.000000	0.216005	0.038000	2.625000	.250000	30	2.140625	2.218750	—	—
	NC26	2.668000	2.000000	3.000000	0.216005	0.038000	2.937500	.250000	30	2.375000	2.531250	—	—
	NC31	3.183000	2.000000	3.500000	0.216005	0.038000	3.453125	.250000	30	2.890625	2.953125	—	—
	NC35	3.531000	2.000000	3.750000	0.216005	0.038000	3.812500	.250000	30	3.231000	3.234375	—	—
	NC38	3.808000	2.000000	4.000000	0.216005	0.038000	4.078125	.250000	30	3.508000	3.468750	—	—
	NC40	4.072000	2.000000	4.500000	0.216005	0.038000	4.343750	.250000	30	3.772000	3.656250	—	—
	NC44	4.417000	2.000000	4.500000	0.216005	0.038000	4.687500	.250000	30	4.117000	4.000000	—	—
	NC46	4.626000	2.000000	4.500000	0.216005	0.038000	4.906250	.250000	30	4.326000	4.203125	—	—
00	NC50	5.041700	2.000000	4.500000	0.216005	0.038000	5.312500	.250000	30	4.742000	4.625000	—	—
	NC56	5.616000	3.000000	5.000000	0.215379	0.038000	5.937500	.250000	30	5.277000	4.796875	—	—
	NC61	6.178000	3.000000	5.500000	0.215379	0.038000	6.500000	.250000	30	5.839000	5.234375	—	—
	NC70	7.053000	3.000000	6.000000	0.215379	0.038000	7.375000	.250000	30	6.714000	5.984375	—	—
	NC77	7.741000	3.000000	6.500000	0.215379	0.038000	8.062500	.250000	30	7.402000	6.546875	—	—
	5 1/2 IF	6.189000	2.000000	5.000000	0.216005	0.038000	6.453125	.250000	30	5.890625	5.687500	—	—
	6 5/8 IF	7.251000	2.000000	5.000000	0.216005	0.038000	7.515625	.250000	30	6.953125	6.750000	—	—
03	1 REG	1.154000	1.500000	1.500000	1.441000	0.040600	1.301000	1.66667	30	—	—	—	—
	1 1/2 REG	1.541000	1.500000	2.000000	1.441000	0.040600	1.688000	1.66667	30	—	—	—	—
	2 3/8 REG	2.365370	3.000000	3.000000	0.172303	0.020000	2.687500	.200000	30	2.015625	2.062500	—	—
	2 7/8 REG	2.740370	3.000000	3.500000	0.172303	0.020000	3.062500	.200000	30	2.390625	2.312500	—	—
	3 1/2 REG	3.239870	3.000000	3.750000	0.172303	0.020000	3.562500	.200000	30	2.906250	2.718750	—	—
	4 1/2 REG	4.364870	3.000000	4.250000	0.172303	0.020000	4.687500	.200000	30	4.013000	3.718750	—	—
	5 1/2 REG	5.234020	3.000000	4.750000	0.215379	0.025000	5.578125	.250000	30	4.869000	4.500000	—	—
00	6 5/8 REG	5.757800	2.000000	5.000000	0.216005	0.025000	6.062500	.250000	30	5.417000	5.281250	—	—
	7 5/8 REG	6.714530	3.000000	5.250000	0.215379	0.025000	7.093750	.250000	30	6.349000	5.859375	7.750000	9.250000
	8 5/8 REG	7.666580	3.000000	5.375000	0.215379	0.025000	8.046875	.250000	30	7.301000	6.781250	9.000000	10.500000
03	2 7/8 FH	3.365400	3.000000	3.500000	0.172303	0.020000	3.687500	.200000	30	—	—	—	—
	3 1/2 FH	3.734000	3.000000	3.750000	0.172303	0.020000	4.046875	.200000	30	3.421875	3.218750	—	—
00	4 1/2 FH	4.532000	3.000000	4.000000	0.172303	0.020000	4.875000	.200000	30	4.180000	3.953125	—	—
	5 1/2 FH	5.591000	2.000000	5.000000	0.216005	0.025000	5.906250	.250000	30	5.250000	5.109375	—	—
	6 5/8 FH	6.519600	2.000000	5.000000	0.216005	0.025000	6.843750.	.250000	30	6.171875	6.046875	—	—
03	2 3/8 SL-H90	2.578000	1.250000	2.812500	0.166215	0.034107	2.765625	.333333	45	2.328125	2.531250	—	—

Table A-1—Rotary Shouldered Connection Thread Element Information

	(1) Connection Type	(2) Pitch Diameter C	(3) Taper	(4) Pin Length	(5) Thread Height Not Truncated	(6) Root Truncation	(7) Nominal Counterbore	(8) Thread Pitch	(9) Thread Angle θ	(10) Stress Relief Groove Diameter	(11) Bore-Back Cylinder Diameter	(12) Low Torque Counterbore	(13) Low Torque Bevel Diameter
03	$2^{7}/_{8}$ SL-H90	3.049000	1.250000	2.937500	0.166215	0.034107	3.234375	.333333	45	2.671875	2.984375	—	—
	$3^{1}/_{2}$ SL-H90	3.688000	1.250000	3.187500	0.166215	0.034107	3.875000	.333333	45	3.312500	3.593750	—	—
	$3^{1}/_{2}$ H-90	3.929860	2.000000	4.000000	0.141865	0.017042	4.187500	.285710	45	3.656250	3.562500	—	—
	4 H-90	4.303600	2.000000	4.250000	0.141865	0.017042	4.562500	.285710	45	4.031250	3.875000	—	—
	$4^{1}/_{2}$ H-90	4.637600	2.000000	4.500000	0.141865	0.017042	4.890625	.285710	45	4.359375	4.187500	—	—
	5 H-90	4.908100	2.000000	4.750000	0.141865	0.017042	5.171875	.285710	45	4.625000	4.406250	—	—
	$5^{1}/_{2}$ H-90	5.178600	2.000000	4.750000	0.141865	0.017042	5.437500	.285710	45	4.906250	4.687500	—	—
	$6^{5}/_{8}$ H-90	5.803600	2.000000	5.000000	0.141865	0.017042	6.062500	.285710	45	5.531250	5.265625	—	—
	7 H-90	6.252300	3.000000	5.500000	0.140625	0.016733	6.562500	.285710	45	6.031250	5.265625	7.125000	8.250000
	$7^{5}/_{8}$ H-90	7.141100	3.000000	6.125000	0.140625	0.016733	7.453125	.285710	45	6.906250	6.000000	8.000000	9.250000
	$8^{5}/_{8}$ H-90	8.016100	3.000000	6.625000	0.140625	0.016733	8.328125	.285710	45	7.781250	6.750000	9.375000	10.500000
	$2^{3}/_{8}$ PAC	2.203000	1.500000	2.375000	0.216224	0.057948	2.406250	.250000	30	1.984375	2.171875	—	—
	$2^{7}/_{8}$ PAC	2.369000	1.500000	2.375000	0.216224	0.057948	2.578125	.250000	30	2.156250	2.343750	—	—
	$3^{1}/_{2}$ PAC	2.884000	1.500000	3.250000	0.216224	0.057948	3.109375	.250000	30	—	—	—	—
	$2^{3}/_{8}$ SH	2.230000	2.000000	2.875000	0.216005	0.038000	2.500000	.250000	30	1.937500	2.093750	—	—
	$2^{7}/_{8}$ SH	2.668000	2.000000	3.000000	0.216005	0.038000	2.937500	.250000	30	2.375000	2.531250	—	—
	$3^{1}/_{2}$ SH	3.183000	2.000000	3.500000	0.216005	0.038000	3.453125	.250000	30	2.890625	2.953125	—	—
	4 SH	3.604000	2.000000	3.500000	0.216005	0.038000	3.875000	.250000	30	3.312500	3.375000	—	—
00	$4^{1}/_{2}$ SH	3.808000	2.000000	4.000000	0.216005	0.038000	4.078125	.250000	30	3.508000	3.468750	—	—
	$2^{7}/_{8}$ XH	3.119000	2.000000	4.000000	0.216005	0.038000	3.359375	.250000	30	2.828125	2.781250	—	—
	$3^{1}/_{2}$ XH	3.604000	2.000000	3.500000	0.216005	0.038000	3.875000	.250000	30	3.312500	3.375000	—	—
00	5 XH	5.041700	2.000000	4.500000	0.216005	0.038000	5.312500	.250000	30	4.742000	4.625000	—	—
	$2^{3}/_{8}$ OH SW	2.588000	1.500000	2.375000	0.216224	0.057948	2.796875	.250000	30	—	—	—	—
	$2^{3}/_{8}$ OH LW	2.588000	1.500000	2.375000	0.216224	0.057948	2.796875	.250000	30	—	—	—	—
	$2^{7}/_{8}$ OH SW	2.984000	1.500000	2.875000	0.216224	0.057948	3.203125	.250000	30	—	—	—	—
	$2^{7}/_{8}$ OH LW	2.984000	1.500000	2.500000	0.216224	0.057948	3.203125	.250000	30	—	—	—	—
	$3^{1}/_{2}$ OH SW	3.728000	1.500000	3.250000	0.216224	0.057948	3.953125	.250000	30	—	—	—	—
	$3^{1}/_{2}$ OH LW	3.728000	1.500000	3.250000	0.216224	0.057948	3.953125	.250000	30	—	—	—	—
	4 OH SW	4.416000	1.500000	4.000000	0.216224	0.057948	4.640625	.250000	30	—	—	—	—
	4 OH LW	4.416000	1.500000	3.500000	0.216224	0.057948	4.640625	.250000	30	—	—	—	—
	$4^{1}/_{2}$ OH SW	4.752000	1.500000	3.750000	0.216224	0.057948	4.953125	.250000	30	—	—	—	—
	$4^{1}/_{2}$ OH LW	4.752000	1.500000	3.750000	0.216224	0.057948	4.953125	.250000	30	—	—	—	—
	$2^{3}/_{8}$ WO	2.605000	2.000000	2.375000	0.216005	0.038000	2.859375	.250000	30	—	—	—	—
	$2^{7}/_{8}$ WO	3.121000	2.000000	3.000000	0.216005	0.038000	3.375000	.250000	30	—	—	—	—
	$3^{1}/_{2}$ WO	3.808000	2.000000	3.500000	0.216005	0.038000	4.078125	.250000	30	—	—	—	—
	4 WO	4.626000	2.000000	4.500000	0.216005	0.038000	4.906250	.250000	30	—	—	—	—
	$4^{1}/_{2}$ WO	5.041700	2.000000	4.500000	0.216005	0.038000	5.312500	.250000	30	—	—	—	—

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