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ERRATA

Page 8, Equation 13 in 8.6 should read as follows:

$$N = W_e L \sin \bar{\theta} + 2T \sin \frac{\beta}{2} \qquad (13)$$

Specification for Bow-Spring Casing Centralizers

API SPECIFICATION 10D
FIFTH EDITION, JANUARY 1, 1995

Contains ISO 10427:1993

Petroleum and natural gas industries—Bow-spring casing centralizers—Specification

American Petroleum Institute
1220 L Street, Northwest
Washington, D.C. 20005

Specification for Bow-Spring Casing Centralizers

Exploration and Production Department

API SPECIFICATION 10D
FIFTH EDITION, JANUARY 1, 1995

American
Petroleum
Institute

SPECIAL NOTES

Note: This section is not part of ISO 10427:1993

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FOREWORD

Note: This section is not part of ISO 10427:1993.

API Specification 10D serves as the basis for ISO 10427:1993. The complete text of both the API and ISO standards is contained in this document. Some differences exist between the API version and the ISO version of this standard; for example:

- The Special Notes and Foreword are not part of ISO 10427:1993.
- Text that is shaded is not part of ISO 10427:1993.
- Appendix B is not part of ISO 10427:1993.
- Appendix C is not part of API Specification 10D.

Language that is unique to the ISO version is shown in ***bold oblique type*** in the text or, where extensive, is identified by a note under the title of the section. Language that is unique to the API version is identified by a note under the title of the section or is shaded. The bar notations identify parts of this publication that have been changed from the previous API edition.

This standard shall become effective on the date printed on the cover but may be used voluntarily from the date of distribution.

Specification for Bow-Spring Casing Centralizers

1 Scope

The purpose of this specification is to provide minimum performance standards, test procedures, and marking requirements for bow-spring casing centralizers. The requirements contained herein are limited but are deemed adequate for use in oil field cementing operations.

This specification is under the jurisdiction of the Committee on Standardization of Well Cements.

This specification covers performance requirements for bow-spring centralizers under specified testing procedures. This testing serves (a) as verification testing for manufacturer's design, materials, and process specifications; and (b) as periodic testing to confirm the consistency of product performance. It is not applicable to rigid or solid centralizers. Testing equipment, as well as marking requirements, are included. In addition, calculations for determining centralizer spacing, based on centralizer performance and desired standoff, in deviated and dogleg holes are presented.

2 Definitions

2.1 annular clearance for centered casing: Diameter of borehole minus outside diameter (OD) of casing divided by two.

2.2 centralizer permanent set: Permanent set is the change in centralizer bow height after repeated flexing. A centralizer is considered to have reached permanent set after being flexed 12 times for the purposes of this specification.

2.3 deflection/sag/sag point: Casing that is supported at two points will tend to sag between the support points. This sag is called the casing sag or casing deflection. The point where the deflection is at a maximum is called the sag point. (See Figure 4.)

2.4 DLS: Dogleg severity is a rate of change in deviation of the well bore and is measured in degrees per 100 feet (30.48 meters) (see Equation 31 in Section 8.12).

2.5 flexed: A bow spring is considered flexed when three times the specified minimum restoring force (± 5 percent) has been applied.

2.6 holding device: The device employed to fix the stop collar or centralizer to the casing. Examples of holding devices include set screws, nails, mechanical dogs, and epoxy resins.

2.7 holding force: The maximum force required to initiate slippage of a stop collar on the casing.

2.8 hole size: The diameter of the borehole.

2.9 limit clamp: An equivalent term for a stop collar.

2.10 restoring force: The restoring force is the force exerted by a centralizer against the casing to keep it away from the borehole wall.

2.11 rigid centralizer: A centralizer manufactured with bows that do not flex and maintain a constant OD (see solid centralizer).

2.12 running force: Running force is the maximum force required to move a centralizer through the previously run casing.

Note: Starting, restoring, and running force values can vary based on installation methods.

2.13 slippage force range: The range of forces required to continue to move a stop collar after the holding force has been overcome.

2.14 solid centralizer: A centralizer manufactured in such a manner as to be a solid device with nonflexible fins or bands. These centralizers have solid bodies and solid blades that have a constant blade OD (see rigid centralizer).

2.15 standoff: The smallest distance between the OD of the casing and the diameter of borehole.

2.16 standoff ratio: The standoff ratio is the ratio of standoff to annular clearance, expressed as a percentage. (For an example calculation, see A.2 of Appendix A.)

2.17 starting force: Starting force is the maximum force required to start a centralizer into the casing.

2.18 stop collar: A device attached to the casing to prevent movement of a casing centralizer. It can be either an independent piece of equipment or integral with the centralizer.

3 Requirements

3.1 FUNCTIONS OF A CENTRALIZER

The purpose of a casing centralizer is to facilitate running casing to the desired depth and to assist in centering the casing in the borehole. A centralizer can be constructed in various ways, using various types, shapes, and quantities of bow springs.

3.2 STARTING FORCE

The maximum starting force shall be less than the weight of 40 feet (12.19 meters) of medium weight casing as defined in Table 1. The maximum starting force is to be determined for a centralizer in new, fully assembled condition.

3.3 RESTORING FORCE

The minimum restoring force for 67 percent standoff ratio shall not be less than the values shown in Table 1. See Appendix A for the calculation of how the requirements were derived.

Table 1—Specifications: Casing Centralizers

(1)		(2)		(3)		(4)	
Casing Size		Medium Wt. Casing		Minimum Restoring Force at 67% Standoff Ratio		Maximum Starting Force	
in.	mm	lb/ft	kg/m	lbf	N	lbf	N
3 1/2[a]	89	9.91[a]	14.8	396	1,761	396	1,761
4[a]	102	11.34	16.9	454	2,019	454	2,019
4 1/2	114	11.6	17.3	464	2,064	464	2,064
5	127	13.0	19.4	520	2,313	520	2,313
5 1/2	140	15.5	23.1	620	2,758	620	2,758
6 5/8	168	24.0	35.7	960	4,270	960	4,270
7	178	26.0	38.7	1,040	4,626	1,040	4,626
7 5/8	194	26.4	39.3	1,056	4,697	1,056	4,697
8 5/8	219	36.0	53.6	1,440	6,405	1,440	6,405
9 5/8	244	40.0	59.6	1,600	7,117	1,600	7,117
10 3/4	273	51.0	76.0	1,020	4,537	2,040	9,074
11 3/4	298	54.0	80.4	1,080	4,804	2,160	9,608
13 3/8	340	61.0	90.8	1,220	5,427	2,440	10,853
16	406	65.0	96.8	1,300	5,783	2,600	11,565
18 5/8	473	87.5	130.3	1,750	7,784	3,500	15,569
20	508	94.0	140.0	1,880	8,363	3,760	16,725

Note: The specifications for starting and restoring forces for bow type centralizers are based on the centralizer being installed as per manufacturer recommendations and tested with lugs on the casing. If the centralizer is tested over a casing collar, stop collar, or with an integral stop collar, the actual results obtained from that test can vary from the specifications. It should be noted on the test report how the centralizer was installed and the type of holding device used during the test. If a centralizer is tested in this manner, the test can no longer be considered a specification test and the results may or may not meet the specifications set forth in Table 1.

[a] Liner sizes and plain-end weight.

3.4 FREQUENCY OF TESTING

3.4.1 Tests for design and process verification must be performed for a minimum of six prototype centralizers. All of the tested centralizers must conform to the performance requirements of Table 1.

3.4.2 For confirmation of the consistency of product performance, tests must be performed at least annually for each centralizer size manufactured to this specification in quantities greater than 500 per year. Corrective action must be implemented and documented for the centralizer size in question if the tested centralizer does not conform to the performance requirements of Table 1.

4 Testing Equipment

4.1 TEST STAND

The test stand allows application of vertical loads and is capable of measuring these loads and vertical displacements. Examples of typical equipment are shown in Figures 1 and 2.

4.2 INSTRUMENTATION

Displacement: The test stand shall be instrumented to allow reading of 1/16 inch (1.6 millimeters) or smaller.

4.3 ACCURACY

4.3.1 Load measurements: Accuracy shall be within 5 percent of measured value.

4.3.2 Displacement: Accuracy shall be within 1/32 inch (0.8 millimeter) within the range of measurements.

4.3.3 Calibration of all measuring equipment must be performed at least annually.

4.4 TEST PIPE

4.4.1 Inner pipe (A, Figures 1 and 2): The length of the inner pipe shall be greater than a centralizer in the flexed condition and the outer pipe (B). The OD of the inner pipe A shall be within the tolerances shown in API Specification 5CT ***[ISO 11960, at present under study]*** for nonupset pipe. Burrs or similar defects shall be removed.

Surfaces on the ends of inner pipe A, outside the length to be covered by the centralizer and other test components, are exempted from the above specifications.

4.4.2 Outer pipe (B, Figures 1 and 2): The length of the outer pipe shall be greater than a centralizer bow spring in the flexed condition. The ID of the outer pipe shall be the borehole diameter for which the centralizer is designed. Tolerances shall be within +1/8 inch (3.2 millimeters), −1/32 inch (0.8 millimeter). Burrs or similar defects shall be removed. The upper end of the outer pipe used for the starting force test may be beveled on the inside to a maximum of 45 degrees with a maximum larger pipe ID of +1/8 inch (3.2 millimeters).

The end of the outer pipe (other than the upper end used for starting force tests) beyond the length covered by the centralizer when flexed during the restoring force test is exempted from the above specifications.

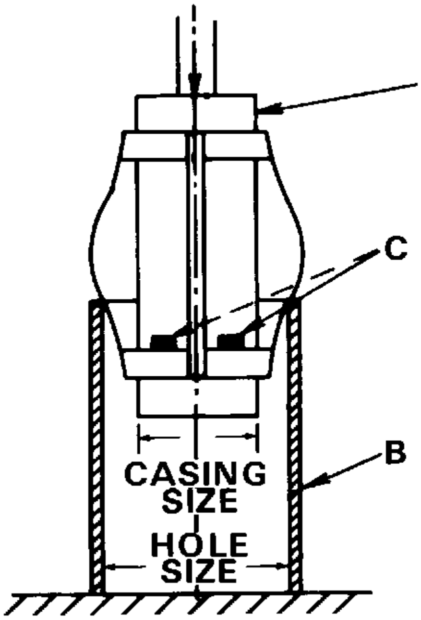


Figure 1—Example Casing Centralizer Starting Force Test Equipment

5 Procedure for Starting Force and Running Force Tests

5.1 STARTING FORCE TEST

5.1.1 A centralizer in new, fully assembled condition shall be installed as shown in Figure 1 on the inner pipe (A) over four equally spaced lugs (C) with each lug having not more than 1/4 inch (6.4 millimeters) height over the outer surface of the inner pipe.

Note: Under field conditions, there are many different methods of attaching a centralizer to the casing. The starting and restoring forces will not be the same as the test results obtained using this procedure for all types of holding devices.

5.1.2 The test assembly shall be within 5 degrees of vertical.

5.1.3 The contacting surfaces shall be lubricated with a petroleum base grease before running the test. API modified type grease is recommended but other greases are allowable.

5.1.4 With the centralizer resting on the edge of the outer pipe B, apply load to the inner pipe A to pull the centralizer into outer pipe B.

5.1.5 Readings of force shall be taken from the time the load is first applied until the centralizer is completely inside pipe B.

5.1.6 Starting force equals the maximum force required to start pipe A inside pipe B (after compensating for the weight of pipe A and attachments).

5.2 RUNNING FORCE TEST

5.2.1 This test is not required to conform to a maximum value, however, it is required to be performed and the results recorded.

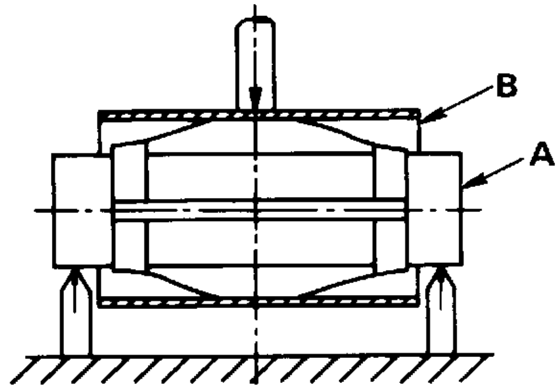


Figure 2—Example Casing Centralizer Restoring Force Test Equipment

5.2.2 The running force test may be performed with the starting force test, or tested separately.

5.2.3 Readings of force shall be taken from the time the centralizer is inside the outer pipe.

5.2.4 Running force equals the maximum force required to slide pipe A inside pipe B once the force reading has become steady (after compensating for the weight of pipe A and attachments).

6 Restoring Force Test

6.1 The test shall be performed with pipe A and pipe B within 5 degrees of horizontal (Figure 2).

6.2 The external force shall be applied to the outer pipe B so that it will be transferred vertically through the point of contact of the centralizer with the pipe (Figure 2).

6.3 Prior to collecting the force data for the test, all bow springs shall be flexed 12 times.

6.4 Apply load and record load-deflection readings at a minimum of 1/16-inch (1.6-millimeter) increments until 3 times (± 5 percent) the minimum restoring force has been obtained (see Table 1). The travel distance to obtain 67 percent standoff shall be determined for each test position.

6.5 Repeat the process, testing the centralizer until each spring and each set of springs has been tested as shown in positions I and II in Figure 3.

6.6 Calculate the total load at each deflection by compensating for the weight of the traveling pipe and attachments.

6.7 The final load-deflection curve shall be prepared using the arithmetic average of the force readings at corresponding deflections. Restoring force shall be determined from this curve at 67 percent standoff ratio. (See Appendix A.)

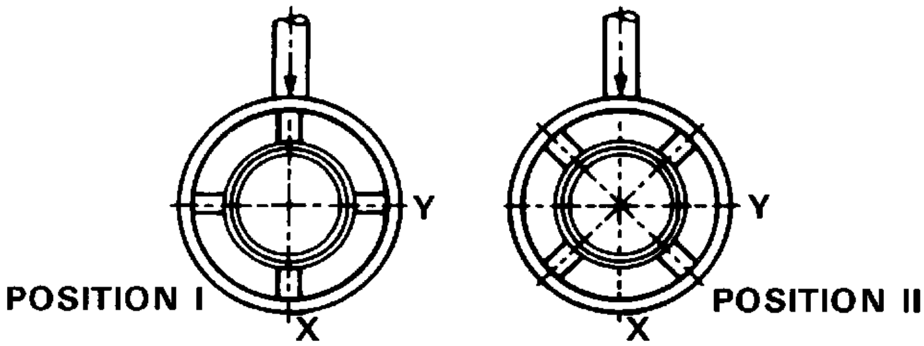


Figure 3—Casing Centralizer Test Positions

7 Marking

7.1 Casing centralizers performing in conformance with this specification shall be marked by the manufacturer as specified hereinafter.

Additional markings as desired by the manufacturer or as required by the purchaser are not prohibited. The marking shall be die stamped or paint stenciled. Markings shall be applied on the collars or the bow springs.

7.2 The following is the API specification for sequence of markings:

a. Centralizer size: The centralizer size shall be marked for the casing OD on which to run the centralizer.
b. Hole size: The hole size for which the centralizer was tested to API specifications shall be marked.
c. For centralizers shipped preassembled, size marking may be applied to one bow or collar only. For centralizers shipped disassembled or separate shipments of bows and collars, conformance with this specification shall be indicated on shipping documents; in this case, shipping documents shall indicate physical identification of respective components.
d. Example: A 5 1/2 in. (140 mm) centralizer meeting specifications in a hole size of 7 7/8 in. (200 mm) shall be marked with the following:

5 1/2" × 7 7/8" or 140 mm x 200 mm

8 Recommended Methods for Estimating Restoring Force Requirements in Deviated and Dogleg Holes

8.1 GENERAL

8.1.1 This document has been prepared to give the user a set of guidelines for the use of casing centralizers. The document should be considered as a recommended practice only, and is not intended to replace the user's individual calculational procedures or preferences. The equations presented are based on certain assumptions and are considered sufficiently accurate for general use. More specific calculations based on complete well-bore data may be available but are beyond the scope of this document.

API neither recommends nor requires a specific standoff ratio for casing centralization. The standoff ratio of 67 percent is used in the specifications for the purposes of setting minimum standards for performance. This number is used only in the specifications for bow-spring type centralizers and deals with the minimum forces for each size of centralizer at that standoff. The 67 percent standoff ratio is not intended to represent the minimum acceptable amount of standoff required to obtain successful centralization of the casing. The user is encouraged to apply the standoff ratio required for each individual well condition based on individual well requirements and sound engineering judgement.

8.1.2 Section 8 is a recommended method; it is not a specification. The primary purpose of this section is to give background material related to estimating the lateral load a casing centralizer will be expected to support. These equations are based on certain assumptions and are considered accurate enough for determining engineering values.

8.1.3 Even a minor dogleg (change in hole angle), with the string of casing hanging below it, materially affects centralizer restoring force requirements. To counteract these unusually large forces, centralizers on intermediate and production casing strings must exert a proportionately larger restoring force.

8.1.4 The lateral load (force) on a centralizer is composed of two components. The first is the weight component of the section of pipe supported by the centralizer, and the second is the tension exerted by the pipe hanging below it.

8.1.5 Tables 2 and 3 contain two different sets of well data: weight components and tension components, and resulting total lateral loads for nine sizes and weights of casing.

Table 2—Centralizer Loads for Specific Well Conditions A

Note: This table is not part of API Specification 10D.

6200 feet (1890 meters) casing hanging below centralizer
Centralizer spacing: 33 feet (10 meters)

Hole angle: 31.5 degrees
Dogleg: 2.5 degrees/100 feet (30.5 meters)

(1)		(2)		(3)		(4)		(5)		(6)	
Casing Size		Casing Weight		Tension T_{i-1}		Weight Component		Tension Component		Lateral Load	
in.	mm	lb/ft	kg/m	lbf	kgf	lbf	kgf	lbf	kgf	lbf	kgf
$4^1/_2$	114	11.6	17.3	71,920	32,652	200	91	1040	472	1240	563
5	127	13.0	19.4	80,600	36,592	224	102	1166	529	1390	631
$5^1/_2$	140	15.5	23.1	96,100	43,629	267	121	1390	631	1657	752
6	152	20.0	29 8	124,000	56,296	345	157	1794	814	2139	971
$6^5/_8$	168	24.0	35.7	148,800	67,555	414	188	2152	977	2566	1165
7	178	26.0	38.7	161,200	73,185	448	203	2332	1059	2780	1262
$7^5/_8$	194	26.4	39.3	163,680	74,311	455	207	2368	1075	2823	1282
$8^5/_8$	219	36.0	53 6	223,200	101,333	621	282	3229	1466	3850	1748
$9^5/_8$	244	40.0	59.6	248,000	112,592	690	313	3587	1628	4277	1942

Notes:
1. Tension, T_{i-1} = casing weight, lb/ft. multiplied by length of casing hanging below centralizer (column 3); weight component = $W_e L \sin\theta$ (column 4); tension component = $2T_i \sin\propto_i = 2(T_{i-1} + W_e L_i \cos\theta_i) \sin\propto_i$ (column 5), and lateral load = weight component plus tension component (column 6).

2. Table 2 values are determined to the nearest unit to allow a given calculation to be followed. It does not imply that anything greater than engineering accuracy should be used for final application.

Table 3—Centralizer Loads for Specific Well Conditions B

Note: This table is not part of API Specification 10D.

916 feet (279 meters) casing hanging below centralizer
Centralizer spacing: 45 feet (13.7 meters)

Hole angle: 25 degrees
Dogleg: 2 degrees/100 feet (30 5 meters)

(1)		(2)		(3)		(4)		(5)		(6)	
Casing Size		Casing Weight		Tension, T_{i-1}		Weight Component		Tension Component		Lateral Load	
in	mm	lb/ft	kg/m	lbf	kgf	lbf	kgf	lbf	kgf	lbf	kgf
$4^1/_2$	114	11.6	17.3	10,626	4,824	221	100	174	79	395	179
5	127	13.0	19.4	11,908	5,406	247	112	195	89	442	201
$5^1/_2$	140	15.5	23.1	14,198	6,446	295	134	233	106	528	240
6	152	20.0	29.8	18,320	8,317	380	173	300	136	680	309
$6^5/_8$	168	24.0	35.7	21,984	9,981	456	207	361	164	817	371
7	178	26 0	38.7	23,816	10,812	494	224	391	178	885	402
$7^5/_8$	194	26.4	39.3	24,182	10,979	502	228	397	180	899	408
$8^5/_8$	219	36.0	53.6	32,976	14,971	685	311	541	246	1226	557
$9^5/_8$[a]	244	40.0	59.6	36,640	16,635	761	345	601	273	1362	618

Notes:
1 Tension, T_{i-1} = casing weight, lb per ft. multiplied by length of casing hanging below centralizer (column 3); weight component = $W_e L \sin\theta$ (column 4); tension component = $2T_i \sin\propto_i = 2(T_{i-1} + W_e L_i \cos\theta_i) \sin\propto_i$ (column 5); and lateral load = weight component plus tension component (column 6).
2. Table 3 values are determined to the nearest unit to allow a given calculation to be followed. It does not imply that anything greater than engineering accuracy should be used for final application.

[a] Example: 916 feet of $9^5/_8$-inch casing hanging below centralizer; 25 degree hole angle; 45 feet between centralizers; 2 degrees/100 feet dogleg:
$T_{i-1} = (40)(916) = 36{,}640$ lb;
weight component = (40)(45)(0.4226) = 761 lb;
tension component = 2[36,640 + (40)(45)(0.9063)] 0.00785 = 601 lb;
lateral load = 761 + 601 = 1362 lb.

8.2 EXAMPLE STANDOFF RATIO CALCULATION

For a 7-inch (178 mm) centralizer run in an 8½-inch (216 mm) hole, which is intended to maintain a standoff of 0.5 inch (12.7 mm), the standoff ratio is calculated as follows:

Annular clearance for perfectly centered casing =

$$\frac{8.5-7}{2} = 0.750 \text{ inches}$$

Standoff to annular clearance ratio =

$$\frac{0.5}{0.750} = 0.67 = 67 \text{ percent}$$

8.2.1 Standoff ratio for solid or rigid casing centralizers

Note: This section is not part of ISO 10427:1993.

Standoff at the centralizer:

$$W = R_c - R_P \quad (1)$$

$$\text{Percent standoff} = \frac{W}{R_B - R_P} \times 100 \quad (2)$$

Where:

R_B = radius of the borehole or previous casing, inches (millimeters).
R_P = outside radius of the casing, inches (millimeters).
R_c = radius of the solid or rigid centralizer blade, inches (millimeters).
W = casing/well-bore standoff.

Standoff between the centralizers considering casing deflection: (See Figure 4.)

$$W_s = R_c - R_P - D \quad (3)$$

$$\text{Percent standoff} = \frac{W_s}{R_B - R_P} \times 100 \quad (4)$$

Where:

R_B = radius of the borehole or previous casing, inches (millimeters).
R_P = radius of the casing, inches (millimeters).
R_c = radius of the solid or rigid centralizer blade, inches (millimeters).
D = deflection or sag of the casing between centralizers (number can be either positive or negative), inches (millimeters).
W_s = casing/well-bore standoff with casing deflection or sag.

8.2.2 Discussion

Note: This section is not part of ISO 10427:1993.

With solid or rigid centralizers, the calculation for standoff at the centralizer is a direct function of the OD of the

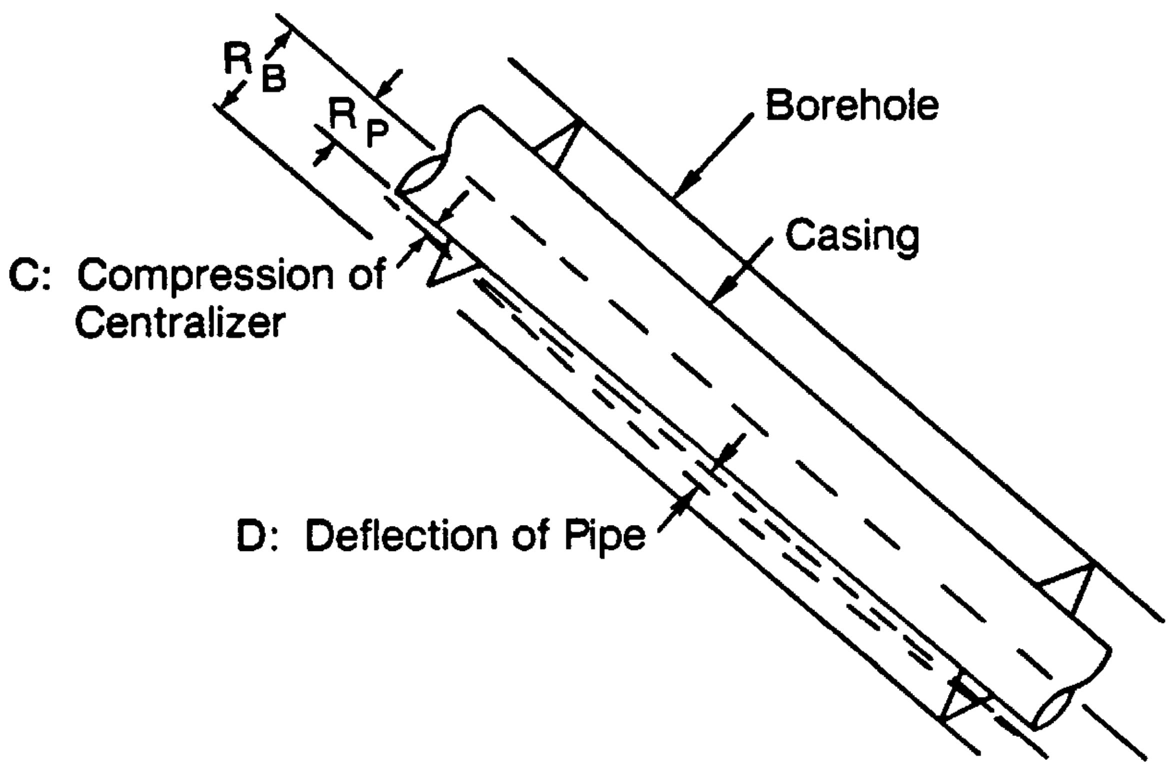


Figure 4—Calculation of Standoff in Borehole

centralizer and the diameter of the well bore. There is no blade deflection in a solid or rigid centralizer. For the same reason, there are no specifications for starting, running, or restoring forces for solid and rigid centralizers. It should be noted that by definition, 100 percent standoff ratio cannot be obtained with a solid or rigid centralizer.

8.3 BUOYED WEIGHT OF CASING

Note. This section is not part of ISO 10427 1993.

The buoyed weight of casing is the effective weight of the casing in the well. Consideration is given to the densities of the fluids in the well and the weight in air of the casing. The following is a generalization of the treatment of effective weight to accommodate differing internal and external fluids.

8.3.1 Generalized Equation

$$W_f = \frac{\left[1-\frac{\rho_o}{\rho_c}\right]-\left[\frac{ID}{OD}\right]^2 \times \left[1-\frac{\rho_i}{\rho_c}\right]}{1-\left[\frac{ID}{OD}\right]^2} \qquad (5)$$

Where:

W_f = buoyancy factor.
ID = inside diameter of casing.
OD = outside diameter of casing.
ρ_i = density of fluid inside the casing.
ρ_o = density of fluid outside the casing.
ρ_c = density, in air, of the casing material.

Simplified equation for steel casing:

$$Wt_b = Wt_c + 0.0408 \times [(ID^2 \times \rho_i - (OD^2 \times \rho_o)] \qquad (6)$$

Where:

Wt_b = buoyed weight of casing in pounds per foot.
Wt_c = weight of casing in air in pounds per foot.
ID = inside diameter of casing, inches.
OD = outside diameter of casing, inches.
ρ_i = density of fluid inside the casing, lb/gal.
ρ_o = density of fluid outside the casing, lb/gal.

8.3.2 Discussion

The buoyed weight of the casing being cemented will change during a cementing operation. As the densities of the fluids inside the casing and the annulus change, the relative buoyed weight will tend to reach a maximum as highest density fluid is inside the casing, and a minimum when the highest density fluid is in the annulus. In the calculation of buoyed weight for centralizer spacing, the densities of the fluids both inside the casing and in the annulus may be considered. The centralizer spacing can vary depending on the selection of fluid densities present during the cement job. The variation in the centralizer spacing will change throughout the cement job, and the user should note at what point during the cement job the required centralization standoff ratio needs to be met and the appropriate buoyancy factor used in the calculations.

8.3.3 Example of Buoyed Weight Calculation

Casing = 7 inch, 35 lb/ft casing
Mud density = 13.5 lb/gal
Cement density = 15.6 lb/gal

Buoyed weight with mud in casing and annulus:

$$Wt_b = 35 + 0.0408 \times [(6.004^2 \times 13.5) - (7^2 \times 13.5)]$$
$$Wt_b = 27.87 \text{ lb/ft}$$

Buoyed weight with cement inside pipe and mud in annulus:

$$Wt_b = 35 + 0.0408 \times [(6.004^2 \times 15.6) - (7^2 \times 13.5)]$$
$$Wt_b = 30.95 \text{ lb/ft}$$

Buoyed weight with cement in annulus and mud inside casing:

$$Wt_b = 35 + 0.0408 \times [(6.004^2 \times 13.5) - (7^2 \times 15.6)]$$
$$Wt_b = 23.67 \text{ lb/ft}$$

8.4 CALCULATIONS FOR CENTRALIZER SPACING

Note: This section is not part of ISO 10427:1993.

Note: The equations are valid only for a string with axial tension and will not apply for strings under compression. The equations do not consider end effects, such as at the shoe, the wellhead, or at the linear hanger. The equations are valid only for calculating the casing deflection between two identical centralizers.

In an inclined well bore with no doglegs and negligible axial tension or compression in the casing, the deflection at the midpoint between two centralizers is given by the following:

$$\delta = \left(\frac{(W_e \sin \bar{\theta})\, L^4}{384\, EI}\right) \qquad (7)$$

Given that there will be cases where the tension factor may be zero (the casing shoe is one example), the above equation can be changed to allow for the incorporation of the tension component.

8.5 CASING DEFLECTION IN A 1-D STRAIGHT, INCLINED WELL BORE WITH AXIAL TENSION

Note: This section is not part of ISO 10427:1993.

$$\delta = \left(\frac{(W_e \sin\bar{\theta})\, L^4}{384\, EI}\right)\left(\frac{24}{u^4}\right)\left[\frac{u^2}{2} - \frac{u \cosh u - u}{\sinh u}\right] \qquad (8)$$

Where:

$$u = \sqrt{\left(\frac{TL^2}{4\,EI}\right)} \quad (9)$$

$$T = T_t - (p_i A_i - p_o A_o) \quad (10)$$

This equation can be used to determine the maximum casing deflection in a well bore that is inclined, but has no doglegs.

8.6 CASING DEFLECTION IN A 2-D DROPOFF WELL BORE (SEE FIGURE 5)

Note: This section is not part of ISO 10427:1993.

$$\delta = \left[\frac{\left(W_e \sin\bar{\theta} + \frac{T}{R}\right)L^4}{384\,EI}\right]\left(\frac{24}{u^4}\right)\left[\frac{u^2}{2} - \frac{u\cosh u - u}{\sinh u}\right] \quad (11)$$

or

$$\delta = \left(\frac{NL^3}{384\,EI}\right)\left(\frac{24}{u^4}\right)\left(\frac{u^2}{2} - \frac{u\cosh u - u}{\sinh u}\right) \quad (12)$$

Where:

$$N = W_e L \sin\bar{\theta} - 2T\sin\frac{\beta}{2} \quad (13)$$

8.7 CASING DEFLECTION IN A 2-D BUILDUP WELL BORE (SEE FIGURE 5)

Note: This section is not part of ISO 10427:1993.

$$\delta = \left[\frac{\left(W_e \sin\bar{\theta} - \frac{T}{R}\right)L^4}{384\,EI}\right]\left(\frac{24}{u^4}\right)\left[\frac{u^2}{2} - \frac{u\cosh u - u}{\sinh u}\right] \quad (14)$$

or

$$\delta = \left(\frac{NL^3}{384\,EI}\right)\left(\frac{24}{u^4}\right)\left[\frac{u^2}{2} - \frac{u\cosh u - u}{\sinh u}\right] \quad (15)$$

Where:

$$N = W_e L \sin\bar{\theta} - 2T\sin\frac{\beta}{2} \quad (16)$$

Note that the equations for the 2-D well bores vary only in the addition or subtraction of the $2T\sin{}^{\beta}/_{2}$ term depending on if there is a buildup or a dropoff in the well bore.

8.8 CASING DEFLECTION IN 3-D WELL BORE (SEE FIGURE 6)

Note: This section is not part of ISO 10427:1993.

$$N_s = W_e L\cos\gamma_n + 2T\sin\frac{\beta}{2} \quad (17)$$

$$\cos\gamma_n = \frac{\sin\bar{\theta}}{\sin\beta}\cos\left(\frac{\phi_1 - \phi_2}{2}\right)\sin(\theta_1 - \theta_2) \quad (18)$$

$$N_p = W_e L\cos\gamma_m \quad (19)$$

$$\cos\gamma_m = \frac{\sin\theta_1\sin\theta_2\sin(\phi_2 - \phi_1)}{\sin\beta} \quad (20)$$

$$\delta = \left[\frac{NL^3}{348\,EI}\right]\left(\frac{24}{u^4}\right)\left[\frac{u^2}{2} - \frac{u\cosh u - u}{\sinh u}\right] \quad (21)$$

Where:

$$N = \sqrt{N_s^2 + N_p^2} \quad (22)$$

When there is no azimuth change, $\phi_1 = \phi_2 = \phi$, the above equations reduce to those of the 2-D well bore.

Nomenclature:

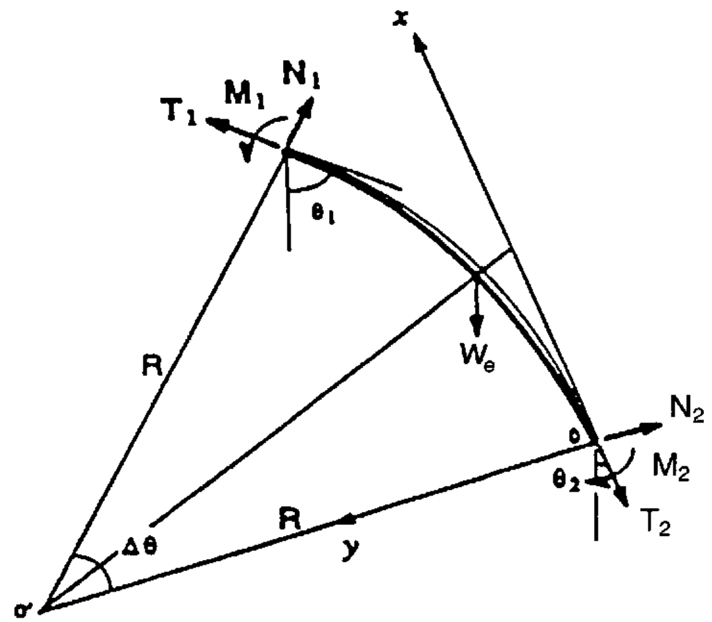
E = modulus of elasticity, lbf/in.^{2}
I = moment of inertia of casing, in.^{4}
L = centralizer spacing, inches.
N = lateral load, lbf.
R = radius of the well bore, inches.
T = effective tension below the centralizer, lbf. Between adjacent centralizers, T varies by the term $W_e L\cos\theta$
T_t = true tension below the centralizer, lbf.
p_i = internal pressure, lbf/in.^{2}
p_o = external pressure, lbf/in.^{2}
A_i = internal cross-sectional area of casing, in.^{2}
A_o = external cross-sectional area of casing, in.^{2}
W_e = effective buoyed casing weight, lbf/in.
β = total angle change between centralizers, degrees.
γ_m = angle between gravity vector and the binormal of the well bore.
γ_n = angle between gravity vector and the principal-normal of the well bore.
δ = maximum casing deflection, inches.
θ = inclination angle, degrees.
$\bar{\theta}$ = average inclination angle, degrees.
ϕ = azimuth angle, degrees.

8.9 HOW RESTORING FORCE REQUIREMENTS WERE DETERMINED

Field observations indicate hole deviation on an average varies from zero to approximately 60 degrees; therefore, an average deviation of 30 degrees is used to calculate restoring force requirements.

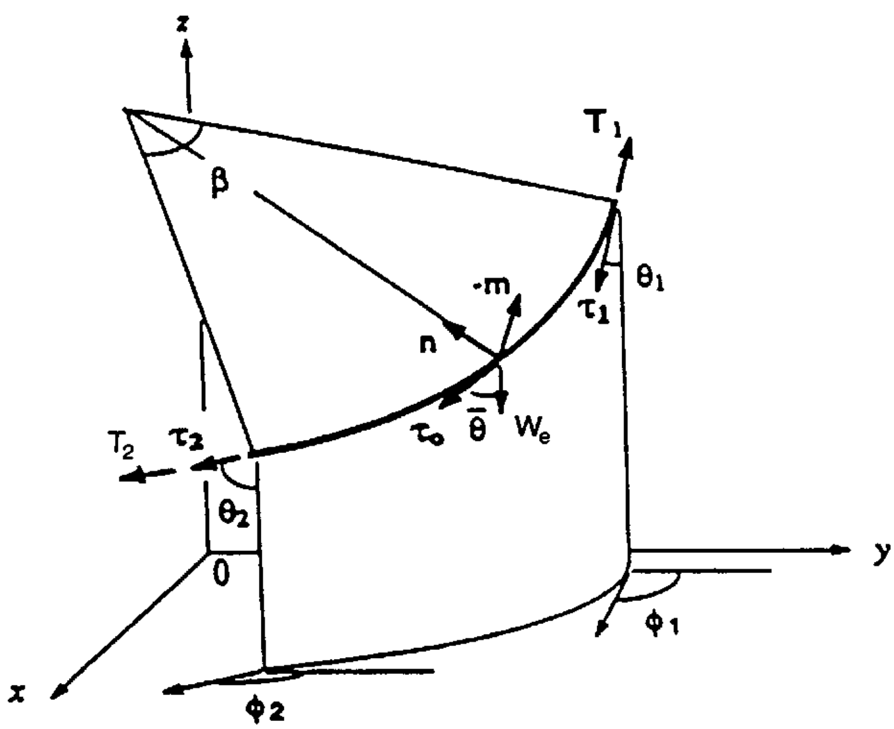
For casing sizes 10³/₄ inches (273 mm) through 20 inches (508 mm), casing strings generally placed in relatively vertical hole sections, the minimum restoring force shall be not less than:

$$RF = W\ \sin 30 = 0.5 \times W \quad (23)$$



Source: SPE 21282, "Casing Deflection and Centralizer Spacing Calculations," by Hans C. Juvkan-wold, et al.

Figure 5—Model of Casing Segment in a 2-D Dropoff Well Bore



Source: SPE 21282, "Casing Deflection and Centralizer Spacing Calculations," by Hans C. Juvkan-wold, et al.

Figure 6—Casing Segment in a 3-D Well Bore

Where:

RF = minimum restoring force.

W = weight of 40 ft (12.19 m) of medium weight casing.

For casing sizes 4½ inches (114 mm) through 9⅝ inches (244 mm), casing strings generally placed in the deviated hole sections, the minimum restoring force shall be not less than:

$$RF = 2\ W\ \sin 30 = W \tag{24}$$

The factor of 2 is established as a compensating factor for the effect of doglegs.

8.10 SIXTY-SEVEN PERCENT STANDOFF FOR FIELD APPLICATIONS

Sixty-seven percent standoff may or may not give adequate centralization of casing in field applications. Sixty-seven percent standoff is used merely for the purpose of specifying minimum performance standards that centralizers must meet.

8.11 DETERMINATION OF THE FORCES ACTING ON A CENTRALIZER[1, 2]

Note: This section is not part of API Specification 10D.

$$N_i = \frac{\dfrac{W_e L_i \sin \theta_i + W_e L_{i+1} \sin \theta_i + 1}{2} + 2T_i \sin \propto_i}{\cos \propto_i} \tag{25}$$

and

$$T_i = \cos \propto_i \frac{T_{i-1}}{\cos \propto_{i-1}} + W_e L_i \cos \theta_i + W_e \left(\frac{L_i \sin \theta_i}{2} \right) (\tan \propto_i - \tan \propto_{i-1}) \tag{26}$$

Where:

$$W_e = W \left(1 - \frac{\rho_{\text{fluid}}}{\rho_{\text{steel}}} \right) \tag{27}$$

and

N = force on a centralizer.

T = tension of pipe hanging below the centralizer.

$\propto$ = one-half the change in angle between centralizers.

θ = angle of hole deviation at the centralizer.

ρ_{fluid} = density of fluid.

ρ_{steel} = density of steel.

W_e = effective casing weight considering buoyancy factor.

W = casing weight in air.

L = centralizer spacing.

at $\propto$

$$N_i = W_e L \sin\theta + 2T_i \sin\propto_i \tag{28}$$

$$T_i = T_{i-1} + W_e L_i \cos \theta_i \tag{29}$$

8.12 DOGLEG SEVERITY ANALYSIS IN A DEVIATED BOREHOLE

In a three-dimensional borehole trajectory, Lubinski's formula[3] can be used to determine the borehole curvature.

$2\propto$ =

$$2 \arcsin [\sin^2 (\Delta\theta/2) + \sin^2 (\Delta\phi/2) \times \sin \theta_i \times \sin \theta_{i-1}]^{1/2} \tag{30}$$

and

$$DLS = \frac{(100\text{ ft})\ (2\propto)}{L} \tag{31}$$

$$\propto = \frac{(DLS)(L)}{200\text{ ft}} \tag{32}$$

Where:

L = length of borehole section between two centralizers, ft.

DLS = dogleg severity, degree per 100 ft.

$\propto$ = one-half the change in angle in borehole, degrees.

$\Delta\phi$ = change of hole direction (azimuth) between two centralizers, degree.

$\Delta\theta$ = change of hole inclination between two centralizers, degree.

8.13 CALCULATION OF STANDOFF IN A BOREHOLE

The standoff in the borehole may be determined by the following equation, which considers the deflection of a casing string and compression of centralizer due to the lateral load. Using this definition, the standoff distance is considered to be at the location between centralizers where the sag deflection of the casing is at its maximum (see Figure 4):

$$\text{Standoff at sag point} = (R_B - R_P - C - \delta) \tag{33}$$

---

[1] "The Development and Application of a Method for Calculating the Forces on Casing Centralizers," by Myers and Sutko, presented at the API Mid-Continent Meeting, Amarillo, Texas, April 3–5, 1968. In the equation solving for N_i, the plus sign is used before the term $2T_i \sin\propto_i$. In the Myers and Sutko paper, this sign is negative for the same equation. Use of the positive or negative sign before the term depends upon the direction of the dogleg. The positive sign is used in this publication to arrive at a slightly more conservative figure for the force on a centralizer because of the various unknowns in a typical deviated hole.

[2] "Optimal Spacing for Casing Centralizers," by H. K. Lee, R. C. Smith, and R. E. Tighe, presented at SPE Annual Conference in Houston, Texas, 1984. This paper considers the dogleg effects in a three-dimensional borehole trajectory. It also provides a criterion to determine the deflection of a casing string under the lateral load, which is composed of both gravitational and tensile forces.

[3] "How to Spot Dog-Legs Easily," by A. Lubinski, *Oil and Gas Journal*, February 4, 1957.

Standoff ratio at sag point =

$$100\,[(R_B - R_P - C - \delta)/(R_B - R_P)] \tag{34}$$

Where:

R_B =radius of borehole.

R_P =outside radius of casing.

C =compression of centralizers due to the lateral load.

δ =deflection or sagging of the casing string where it is at its maximum deflection.

8.14 DETERMINE THE DEFLECTION/SAG OF CASING

Note: This section is not part of API Specification 10D.

The approximate deflection of the casing between centralizers may be determined by the following equations, which are based on Timoshenko's[4] analysis for a tie-rod under uniform lateral load with tension force:

$$\delta = \left(\frac{5\,NL^4}{384\,EI}\right) \times \left(\frac{\dfrac{1}{\cosh u} - 1 + \dfrac{u^2}{2}}{(5/24)u^4}\right) \tag{35}$$

$$u = \left(\frac{TL^2}{4EI}\right)^{1/2} \tag{36}$$

Where:

δ = maximum deflection, in.
N = lateral load, lb/in.
L = centralizer spacing, in.
E = Young's Modulus, lb/in.^{2}
I = moment of inertia for casing string, in.^{4}
T = tension of pipe below the centralizer, lb.

The magnitude of compression for a centralizer can be obtained based on the load deflection curves (Figure A-1) that are provided by the manufacturers using the API restoring force test procedure.

[4] *Strength of Materials Part II, Advanced Theory and Problems*, by S. Timoshenko, D. Van Nostrand Co., 1956.

APPENDIX A—MISCELLANEOUS INFORMATION

A.1 Load Deflection Information

A typical load deflection curve is shown in Figure A-1. The curves are prepared using the methods described in Section 6. The purpose of the curves is to provide operators with specific information on how a centralizer performs in a given hole size. This information is useful for determining centralizer spacing in deviated wells.

Load deflection curves may be considered to be proprietary information by the centralizer manufacturer. For this reason, the publication of the curves is optional and is not required for compliance with the specification.

A.2 Example Standoff Ratio Calculation

For a 7-inch (178 mm) centralizer run in an $8^1/_2$-inch (216 mm) hole, which is intended to maintain a standoff of 0.5 inch (12.7 mm), the standoff ratio is calculated as follows:

Annular clearance for perfectly centered casing =

$$\frac{8.5-7}{2} = 0.750 \text{ inches}$$

Standoff to annular clearance ratio =

$$\frac{0.5}{0.750} = 0.67 = 67 \text{ percent}$$

A.3 How Restoring Force Requirements Were Determined

Field observations indicate hole deviation on an average varies from zero to approximately 60 degrees; therefore, an average deviation of 30 degrees is used to calculate restoring force requirements.

For casing sizes $10^3/_4$ inches (273 mm) through 20 inches (508 mm), casing strings generally placed in relatively vertical hole sections, the minimum restoring force shall be not less than:

$$RF = W \sin 30 = 0.5 \times W \tag{23}$$

Where:

RF = minimum restoring force.

W = weight of 40 ft (12.19 m) of medium weight casing.

For casing sizes $4^1/_2$ inches (114 mm) through $9^5/_8$ inches (244 mm), casing strings generally placed in the deviated hole sections, the minimum restoring force shall be not less than:

$$RF = 2\,W \sin 30 = W \tag{24}$$

The factor of 2 is established as a compensating factor for the effect of doglegs.

A.4 Sixty-Seven Percent Standoff for Field Applications

Sixty-seven percent standoff may or may not give adequate centralization of casing in field applications. Sixty-seven percent standoff is used merely for the purpose of specifying minimum performance standards that centralizers must meet.

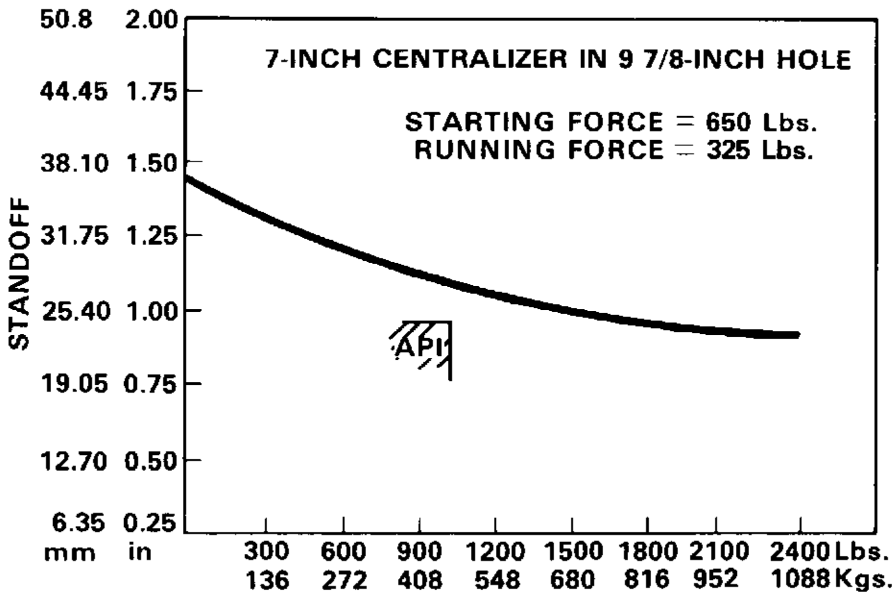


Figure A-1—Load Deflection Curve

APPENDIX B—RECOMMENDED PROCEDURE FOR TESTING STOP COLLARS

Note: This appendix is not part of ISO 10427:1993.

B.1 Introduction

For the purposes of this recommended procedure, the term stop collar will be used to indicate any type of device employed to prevent movement of a centralizer on the casing. This includes stop collars that are independent of the centralizer, integral stop collars, and holding devices that are built into the centralizer as in the case of solid or rigid centralizers. Further the term centralizer shall also apply to other types of casing hardware that incorporate the use of a stop collar. Examples of these include cement baskets, scratchers, etc.

B.2 Discussion

The holding device used to prevent the slippage of a centralizer can be an independent piece of equipment, as in the case of a stop collar, or can be integral within the centralizer itself. Several types are available that include the use of screws, nails, and mechanical dogs. Some manufacturers also recommend the use of resins in conjunction with their particular holding device.

Regardless of the mechanism used to hold the centralizer in place, the holding device must be capable of preventing slippage. While the holding force of the stop collar should be greater than the starting force of the centralizer, some multiplier should be applied depending on the particular well conditions. It is recommended that at least a factor of two times the maximum starting force as defined in Table 1 for the centralizer be applied as a safety factor.

In the case of either solid or rigid centralizers, it is recognized that these types of centralizers do not have a starting force, as they are of constant OD. The minimum holding force that should be applied to these centralizers should follow the same guidelines as a bow type centralizer that would be used in the same hole configuration. This same recommendation also applies to other casing hardware incorporating a stop collar.

It should be noted that the data obtained for centralizer starting, running, and restoring force can vary depending on how it is installed on the casing. The use of a stop collar either as an integral part of the centralizer or with the centralizer placed over the stop collar may alter the results for some centralizers.

Further information indicates that the casing grade and weight can affect the results obtained from stop collar tests. Changes in the hardness of the casing as well as the casing wall thickness have been shown to cause variations in the results by as much as a factor of four. It is therefore recommended that in a critical situation, the testing be performed using the same casing grade and weight as are to be used for the well.

The test procedure outlined involves evaluation of the stop collar by pushing the stop collar on the test casing. Due to compressional loads and the compression of the test casing during the test, the results obtained from this test may vary from those where the stop collar is evaluated via a pull test rather than a compressional test.

Additionally, the rate at which the load is applied during the test can have a minor effect on the results. While small changes in the loading rate should have minimal effects, shock loading may alter the results. In some instances it may be desirable to equate the loading rate to the anticipated casing running speed, and adjust the rate accordingly. There is insufficient data currently available to make a firm conclusion or recommendation on loading rates. Associated with the loading rate is the manner in which the load is applied. This test procedure incorporates a concentric loading pattern, which may not match precisely the type of loading that can occur during actual field use. The purpose of this recommended practice is to give a consistent method for performing routine tests. If the actual field conditions warrant, individual customized testing may be appropriate. Note that this is a destructive test and will require replacement of the test casing and the stop collar following each test.

B.3 Testing Equipment

B.3.1 The test equipment incorporated in this test shall be capable of the application of vertical loads and capable of measuring those loads and vertical displacement.

B.3.2 The test assembly should consist of an inner test casing and an outer sleeve. The test casing should be within the tolerances as indicated in API Specification 5CT for nonupset pipe. Burrs or similar defects should be removed prior to testing. The outer sleeve should provide a load surface on which to distribute the load to the stop device. Minor notching of the outer sleeve to allow for concentric loading is acceptable.

An example of typical test equipment is shown in Figure B-1.

B.4 Instrumentation

B.4.1 The instrumentation should be capable of recording or otherwise indicating the application of vertical loads and be capable of providing the maximum load during the test as well as the initial and continuous load readings.

B.4.2 The test stand should be instrumented to allow readings of $^1/_{16}$ inch (1.6 millimeters) or less of displacement.

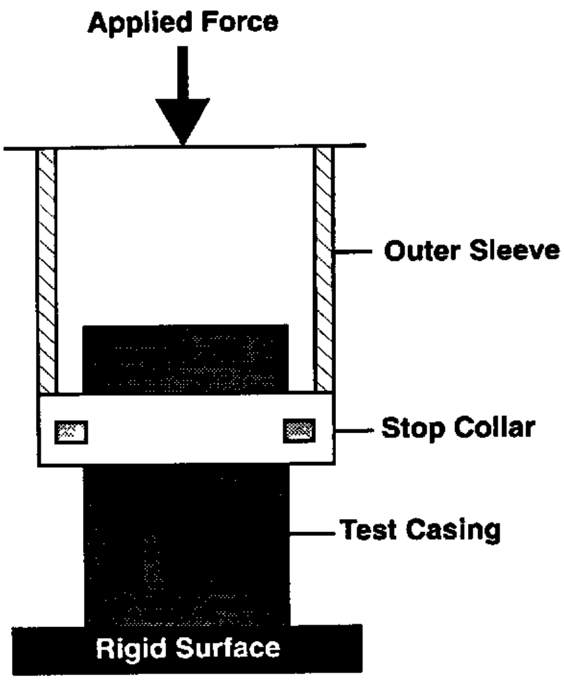


Figure B-1—Typical Test Equipment

B.5 Accuracy

B.5.1 Accuracy of load measurements should be within 5 percent of the measured value.

B.5.2 Accuracy of the displacement measurements should be $\pm 1/32$ inch (0.8 millimeter) within the range of measurement.

B.5.3 Calibration of the measuring equipment should be done at least annually.

B.6 Testing Procedure

B.6.1 The stop collar should be installed on the test casing as per manufacturer's recommendations. Installation position should allow for at least 4 inches (102 millimeters) of displacement during the test.

B.6.2 The outer sleeve should be placed over the test casing. This should apply a concentric load to the stop collar.

B.6.3 The outer sleeve should be continuously and slowly loaded. The applied load, plus the weight of the outer sleeve, should be recorded.

B.6.4 The test should be continued until the stop collar has been displaced at least 4 inches (102 millimeters) or completely fails (breaks).

B.7 Reporting of Test Results

The following information should be reported:

a. Size, weight, grade, and type of surface finish of the test casing.
b. Measured ID and OD of the test casing, outer sleeve, and stop collar.
c. Loading rate and loading technique.
d. Holding force.
e. Slippage force range.
f. Condition of the inner test casing following the test. Note any scarring of the casing and the depth, length, and width of the scarring.
g. Orientation of the stop collar where appropriate (to be reported with stop collars that are to be installed in a particular direction).
h. Identify any minor modifications made to the end of the outer sleeve to allow for concentric loading.
i. Stop collar manufacturer, model number, nominal size, number and type of attachments, and installation torque on attachment device, if applicable.

APPENDIX C—SI UNITS

Note: This appendix is not part of API Specification 10D.

The conversion of English units shall be made in accordance with ISO 31-3.

Table C-1—SI Units

Quantity	U.S. Customary Unit	SI Unit
Area	1 square inch (in.^{2})	645.16 square millimeters (mm^2) (exactly)
Flow rate	1 barrel per day (bbl/d)	0.158987 cubic meters per day (m^3/d)
	1 cubic foot per minute (ft^3/min)	0.02831685 cubic meters per minute (m^3/min) or 40.776192 cubic meters per day (m^3/d)
Force	1 pound-force (lbf)	4.448222 newtons (N)
Impact energy	1 foot pound-force (ft•lbf)	1.355818 Joules (J)
Length	1 inch (in.)	25.4 millimeters (mm) (exactly)
	1 foot (ft)	304.8 millimeters (mm) (exactly)
Mass	1 pound (lb)	0.45359237 kilograms (kg) (exactly)
Pressure	1 pound-force per square inch (lbf/in.^{2}) or 1 pound per square inch (psi) (Note: 1 bar = 10^5 Pa)	6894.757 pascals (Pa)
Strength or stress	1 pound-force per square inch (lbf/in.^{2})	6894.757 pascals (Pa)
Temperature	The following formula was used to convert degrees Fahrenheit (°F) to degrees Celsius (°C):	°C = 5/9 (°F – 32)
Torque	1 inch pound-force (in•lbf)	0.112985 newton meters (N•m)
	1 foot pound-force (ft•lbf)	1.355818 newton meters (N•m)
Velocity	1 foot per second (ft/s)	0.3048 meters per second (m/s) (exactly)
Volume	1 cubic inch (in.^{3})	16.387064•10^{-3} cubic decimeters (dm^3) (exactly)
	1 cubic foot (ft^3)	0.0283168 cubic meters (m^3) or 28 3168 cubic decimeters (dm^3)
	1 gallon (U.S.)	0.0037854 cubic meters (m^3) or 3.7854 cubic decimeters (dm^3)
	1 barrel (U.S.)	0.158987 cubic meters (m^3) or 158.987 cubic decimeters (dm^3)

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