Centralizer Placement and Stop-collar Testing

API RECOMMENDED PRACTICE 10D-2 SECOND EDITION,

energy API

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Contents

Introduction

This edition is based on API Recommended Practice 10D-2, 1st edition, August 2004.

Users of this standard should be aware that further or differing requirements may be needed for individual applications. This standard is not intended to inhibit a vendor from offering, or the purchaser from accepting, alternative equipment or engineering solutions for the individual application. This may be particularly applicable where there is innovative or developing technology. Where an alternative is offered, the vendor should identify any variations from this standard and provide details.

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This document uses a format for numbers which follows the examples given in *API Document Format and Style Manual,* October 2020. This numbering format is different than that used in API 10D, Sixth Edition. In this document the decimal mark is a period and separates the whole part from the fractional part of a number. No spaces are used in the numbering format. The thousands separator is a comma and is only used for numbers greater than 10,000 (i.e. 5000 items, 12,500 bags).

This is the draft for API 10D-2, 2nd Edition

Centralizer Placement and Stop-collar Testing

1 Scope

This standard provides calculations for determining centralizer spacing, based on centralizer performance and desired standoff, in deviated and dogleg holes in wells for the petroleum and natural gas industries. It also provides a procedure for testing stop-collars and reporting test results.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Specification 10D*, Casing Bow-spring Centralizers*

ISO 11960 [1], *Petroleum and natural gas industries — Steel pipes for use as casing or tubing for wells*

3 Terms and Definitions, Symbols and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

3.1.1
bow-spring centralizer
An apparatus comprised of a plurality of bow-shaped springs biased outwardly from a tubular body, the outside diameter of which can vary under a change in applied load, and connected by two end collars, which is placed on the outside of a tubular (e.g. casing or tubing), and used to centralize the tubular in a wellbore.

3.1.2
bow-spring centralizer sub
A bow-spring centralizer installed on a tubular body having an integral holding method where the tubular body becomes its own section of the casing string.

3.1.3
holding device
Device employed to limit the axial movement of the stop-collar or bow-spring centralizer on the casing.

EXAMPLE Set screws, nails, machined tubular, mechanical dogs, epoxy resins, or machined features (integral).

3.1.4
holding force
Force required to initiate slippage of a stop-collar on the casing.

3.1.5
hole size
Diameter of the wellbore at the intended centralizer setting depth.

NOTE This includes setting depth in cased hole, open hole, or restriction(s).

3.1.6
limit clamp
Equivalent term for a stop-collar (see 3.1.17).

3.1.7
restoring force
Normal force exerted by a bow-spring centralizer against the casing to keep it away from the wellbore wall, and equal to the load force required to provide the deflection of the bow in given conditions and installation methods.

3.1.8
rigid centralizer
Centralizer manufactured with bows, blades or bars that do not flex.

3.1.9
running force
Average force required to move a bow-spring centralizer through a specified wellbore diameter in given conditions and installation methods.

3.1.10
sag point
Point where the casing deflection is at a maximum.

NOTE 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.

3.1.11
slippage force range
Range of forces required to continue to move a stop-collar after the holding force has been overcome.

3.1.12
solid centralizer
Centralizer manufactured in such a manner as to be a solid device with nonflexible fins or bands.

NOTE These centralizers have solid bodies and solid blades.

3.1.13
Standoff
Smallest distance between the outside diameter of the casing and the wellbore.

3.1.14
standoff ratio (*SOR)*
Ratio of standoff to annular clearance, expressed as a percentage.

NOTE In the field standoff ratio is commonly referred to as “standoff”.

3.1.15
starting force
Maximum force required to insert a bow-spring centralizer into a specified wellbore diameter in given conditions and installation methods.

3.1.16
stop-collar
Device attached to the casing to limit axial movement of a casing bow-spring centralizer.

NOTE Can be either an independent piece of equipment or integral with the bow-spring centralizer.

3.2 Symbols

For the purposes of this document, the symbols hereafter should be used.

D_H wellbore diameter (open hole or outer casing internal diameter), expressed in meters (inches)

E modulus of elasticity of the casing, expressed in pascals (N/m²) (pound-force per square inch)

e_c standoff at the centralizer, expressed in meters (inches)

e_s standoff at the sag point, expressed in meters (inches)

e_{max} annular clearance for perfectly centered casing, expressed in meters (inches)

F_l lateral load, expressed in newtons (pound-force)

$F_{l,dp}$ total lateral load in the dogleg plane, expressed in newtons (pounds-force)

$F_{l,p}$ total lateral load perpendicular to the dogleg plane, expressed in newtons (pounds-force)

F_t axial tension force below the centralizer, expressed in newtons (pound-force)

f_b buoyancy factor (dimensionless)

f_c lateral load force, expressed in Newtons (pounds-force)

f_w wellbore deflection restriction, expressed in meters (inches)

I moment of inertia of the casing, expressed in m^4 (in.^{4})

ID_C inside diameter of the casing, expressed in meters (inches)

ID_c inside diameter of the solid or rigid centralizer, expressed in meters (inches)

L length of curved wellbore section, expressed in meters (inches)

l_c distance between two adjacent centralizers, expressed in meters (inches)

M resultant of the internal moment (torque and drag forces), expressed in Newtons (pounds-force)

M_b torsional load, expressed in Newtons (pounds-force)

m moment due to the contact forces (drag and torque), expressed in Newtons (pounds-force)

OD_C outside casing diameter, expressed in meters (inches)

OD_c outside diameter of the solid or rigid centralizer blades, expressed in meters (inches)

P pipe bending lateral contact force, expressed in newtons (pounds-force per square inch);

R wellbore curvature radius, expressed in meters (inches)

r wellbore clearance, expressed in meters (inches),

SOR standoff ratio, expressed as a percentage

SOR_c standoff ratio at the centralizers, expressed as a percentage

SOR_m minimum standoff ratio, expressed as a percentage

SOR_s standoff ratio at the sag point, expressed as a percentage

s measured depth along the wellbore axis, expressed in meters (inches)

T axial load force, expressed in Newtons (pounds-force per square inches)

t direction of the tangent to the wellbore curvature (see 9.4.5)

u casing displacement, expressed in meters per second (inches per second)

W unit weight of casing in air, expressed in newtons per meter (pound-force per inch)

W_b unit buoyed weight of the casing, expressed in newtons per meter (pound-force per inch)

w casing rotation, expressed in radians per second

β wellbore curvature, expressed in radians per meter

δ casing eccentricity (or bow-spring centralizer deflection), expressed in meters (inches)

δ_{max} maximum deflection of the casing between two (2) centralizers, expressed in meters (inches)

γ_o angle between the gravity vector and the binormal of the wellbore, expressed in degrees

γ_n angle between the gravity vector and the principal normal of the wellbore, expressed in degrees

θ wellbore inclination angle, expressed in degrees

θ_1 wellbore inclination angle at the top of the upper centralizer (i.e. top of l_{cent}), expressed in degrees;

θ_2 wellbore inclination angle at the bottom of the lower centralizer (i.e. bottom of l_{cent}), expressed in degrees;

μ axial load factor (see 9.4.3)

ρ_e density of the fluid outside the casing, expressed in kilograms per cubic meter (pound-mass per gallon).

ρ_i density of the fluid inside the casing, expressed in kilograms per cubic meter (pound-mass per gallon)

ρ_s density of the casing material, expressed in kilograms per cubic meter (pound-mass per gallon)

ϕ_1 wellbore azimuth angle at the top of the upper centralizer, expressed in degrees

ϕ_2 wellbore azimuth angle at the bottom of the lower centralizer, expressed in degrees

3.3 Abbreviations

For the purposes of this document, the following abbreviations are used:

DLS dog leg severity

DwC drilling-with-casing

ECD equivalent circulating density

ERD extended reach drilling

FEM finite element model

ID inside diameter

MD measured depth

OD outside diameter

TD total depth

NOTE Standoff ratio is defined as a variable i.e. SOR.

4 Methods for estimating centralizer placement

4.1 Benefits of Centralization

Casing should be centralized in the wellbore for the following reasons:

a) to help get the casing to bottom (this includes reduction of the potential for sticking of the string, and delaying the onset of buckling);

b) to help pull casing out of the hole;

c) to help rotate and reciprocate casing during drilling fluid conditioning and the cementing operation;

d) to provide an optimal path for fluid flow during drilling fluid conditioning and cementing allowing for effective drilling fluid removal to achieve zonal isolation, and;

e) to reduce potential fluid contamination in the annular space.

Field experiences, numerous large-scale experiments and computer simulations have shown that poor casing centralization can be detrimental to the cement placement, particularly in narrow annuli. Therefore, a good centralization program should aim for adequate levels of standoff, which produces improved drilling fluid removal, particularly across critical areas of the wellbore, that is, those areas where isolation is required. It should be imperative the user investigates the standoff at all points, especially between the centralizers, and at different points in time while running casing and during the cementing operation.

4.2 General Comments on Modeling

The equations presented in Section 9 are based on certain assumptions and are considered sufficiently accurate for general use. More specific calculations based on complete wellbore data may be available but are beyond the scope of this document.

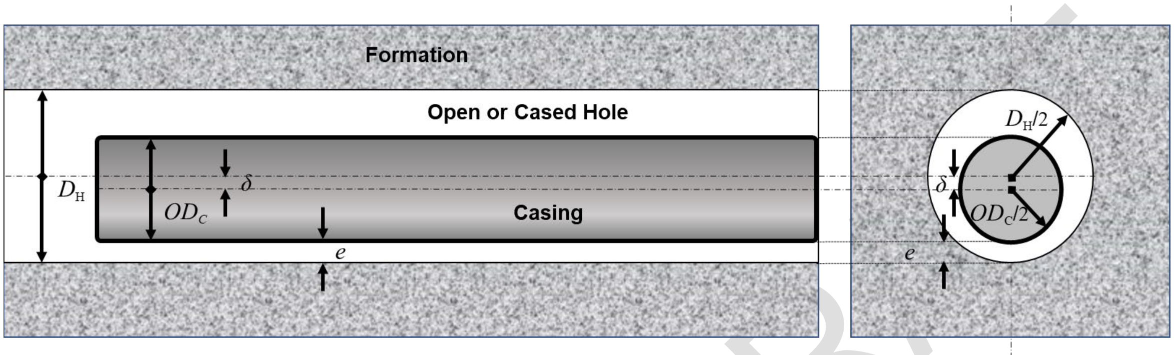
There is no recommendation or requirement for a specific standoff ratio (SOR) for casing centralization. The SOR of 67 % is used in Specification API 10D for the purpose of setting a minimum standard for performance of casing bow-spring centralizers only. This number is used only in API 10D for bow-spring type centralizers and deals with the minimum force for each size of centralizer at that standoff. The 67 % SOR 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 SOR required for specific well conditions based on well requirements and sound engineering judgement.

Even a minor change in inclination and/or azimuth, with the string of casing hanging below it, materially affects the standoff and the requirements for centralizer placement.

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 component exerted by the pipe hanging below the centralizer.

4.3 Definition of Standoff

Standoff is defined as the smallest distance between the outside diameter (OD) of the casing and the wellbore. The SOR (standoff ratio) is defined as the ratio of standoff to the annular clearance for perfectly centered casing expressed as a percentage (%). Annular clearance for perfectly centered casing is the wellbore diameter minus the casing OD divided by two (see 9.2). Figure 1 illustrates standoff and annular clearance.



Key

OD_C	Outside casing diameter	δ	Bow deflection and casing eccentricity
D_H	Wellbore diameter (open hole or outer casing inside diameter)	e	Standoff

Figure 1—Definition of Casing Standoff

4.4 Casing Centralization

Casing centralization often requires centralizers to keep the casing away from the wellbore and/or from the cased sections of the well. Significant considerations for selecting and placing centralizers should include following parameters.

a) Centralizer types, quantities, and installation mode must allow the casing to be run to total depth (TD) of wellbore with minimum problems.

b) Centralizer must provide enough load support to overcome the normal forces tending to lay the casing against the formation wall, particularly in deviated holes, horizontal holes and through doglegs.

c) Enough centralizers should be used to provide required casing centralization over the needed intervals (including at points between the centralizers).

d) Capacity of the formation(s) to provide enough support for the tools to minimize centralizer embedment.

e) Presence of a cuttings bed may decrease the annular gap on the low side of the hole.

f) Presence of a cuttings bed may increase drag forces, hindering casing running.

g) Centralizers must also allow for planned and contingency casing movement.

h) Wellbore quality (tortuosity, washouts, hole enlargement, keyseats, tight spots, collapse, hole geometry, hole cleaning).

i) Flow-by area and equivalent circulating density (ECD) limitations.

j) Cementing objectives.

k) Downhole environment, material compatibility (casing, centralizer, stop-collar, set screws), longevity.

l) Logistics.

m) Field installation limitations.

5 Centralizer Types

5.1 General

The industry has developed the following main types of centralizers: bow-spring, rigid, solid, integral, bonded.

5.2 Bow-Spring Centralizer

A bow-spring centralizer is composed of flexible spring bows connected by two end collars (see Figure 2). By design the bows are flexible enough to allow passage of the centralizer through restrictions and continue to provide standoff. The springs come in various shapes and dimensions. The OD of a bow-spring centralizer can be larger or equal to the nominal hole (bit) diameter. A larger diameter centralizer can improve stand-off in overgaged hole sections.

Bow-spring centralizers are commonly available in welded, non-welded, or single piece construction. Welded and non-welded centralizers are available in hinged or slip-on designs. Single piece construction centralizers are typically available in slip-on designs. Bow-spring centralizers are sometimes referred to as imperial centralizers or to conventional bow-spring centralizers.

5.3 Double Bow-Spring Centralizer

Double bow-spring centralizers incorporate bows with a reduced bow diameter between the centralizer collars (see Figure 3). Double bow-spring centralizers have a lesser maximum OD than conventional bow-spring centralizers, resulting in lower starting and running forces without sacrificing restoring forces. The rigid OD of double bow-spring centralizers is generally larger than in conventional centralizers, limiting their ability to pass through restrictions or tight areas. Bow geometry also impacts available installation method and location. Double bow-spring centralizers may also be considered as semi-rigid type, as discussed in Section 6.

They are available in similar construction and design options as described above for bow-spring centralizers. Double bow-spring centralizers are sometimes referred to as tandem-rise, dual-bow, or dual-contact spring centralizers.

Figure 2—Example of a Bow-Spring Centralizer

Figure 3—Example of a Double Bow-Spring Centralizer

5.4 Rigid, Semi-rigid and Solids Centralizers

5.4.1 Rigid centralizer

Rigid centralizers incorporate blades or fins with minimum or no flexibility connected by a single or discontinuous body (see Figures 4 and 5).

5.4.2 Semi-Rigid Centralizer

Semi rigid centralizers incorporate solid or hollow blades or fins that are not designed to flex, and therefore, tend to maintain a constant centralizer OD. The centralizers exhibit minimal (or no) flexibility but may have some ability to deform in hole restrictions, depending on their construction. Several types of semi-rigid centralizers are available from manufacturers (see Figure 4).

Figure 4—Examples of Rigid Centralizers

Double bow-spring centralizers are sometimes considered as semi-rigid centralizers. This is because after a small deflection, the bows essentially become rigid.

Semi-rigid centralizers are available in welded, non-welded, or single-piece construction. Welded and non-welded are also available in hinged or slip-on designs. Semi-rigid centralizers can be manufactured with straight or spiral blades or fins.

5.4.3 Solid Centralizer

Solid centralizers are manufactured with completely non-flexible solid blades or fins. They do not flex in hole restrictions. Examples of this type of centralizer include those made of steel and low-friction materials, such as aluminum, zinc alloy, composites, and polymers (see Figure 5). Blades are available either straight or spiraled.

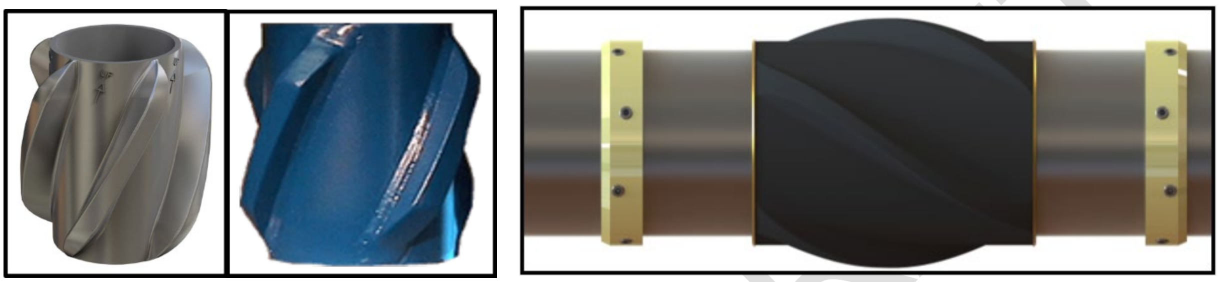


Figure 5—Examples of Solid Centralizers: Low-friction Material and Steel (left), Polymer (right)

Solid centralizers are available in welded or, single-piece construction. Welded are also available in hinged or slip-on designs. Solid centralizers can be manufactured with straight or spiral blades or fins.

Roller centralizers are solid centralizers that incorporate rollers to reduce the drag and torque. Designs of roller centralizers are available for running the casing and for allowing rotation of the string. Figure 6 shows a running-rotating combination. Roller centralizers can assist running the casing in extended-reach wells.

Figure 6—Example of Roller Centralizer for Running and Rotating of the Casing

5.5 Integral Centralizer

Integral centralizers are made up as part of the casing itself (like pup joints). Figure 7 illustrates this type of centralizer. Integral centralizers are mainly used in reduced annular clearance applications, such as deepwater wells. The centralizer blades or fins are commonly machined features on the centralizer sub, eliminating the possibility of slippage. They are also offered with bow-springs for under-reamed applications.

Integral bow-spring centralizers are available in rotating and non-rotating designs. Integral centralizers are also referred to as centralizer subs.

Figure 7—Examples of Integral Centralizers

5.6 Bonded Centralizer

Bonded centralizers are formed and bonded directly onto the pipe. The centralizers are made from a variety of composite materials. Figure 8 illustrates an example of this type of centralizer. Bonded centralizers are commonly used in slim-type well configurations and extended reach drilling (ERD) wells.

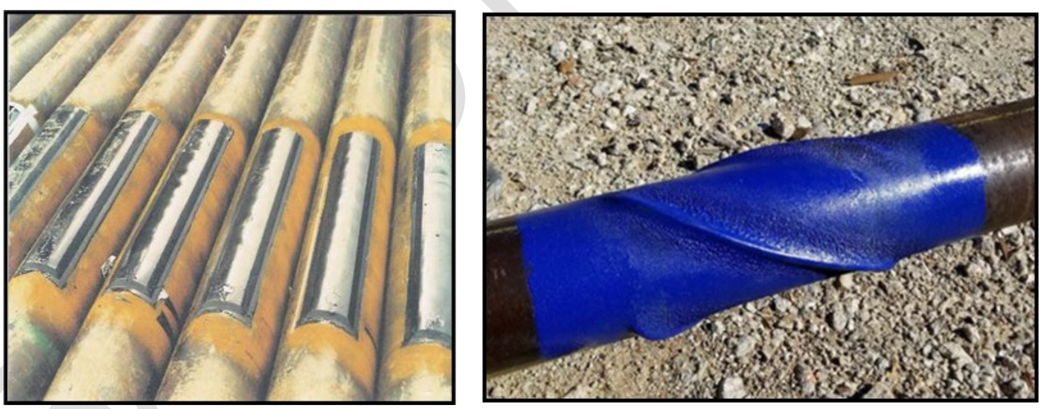


Figure 8—Examples of Centralizers Bonded Directly onto the Pipe

6 Advantages and Limitations of Centralizer Types

This section describes the advantages and limitations of each centralizer type.

6.1 Bow-spring Centralizer

6.1.1 Advantages

Recognized advantages of bow-spring centralizers can be listed.

— Ability (flexibility) of adjusting to varying hole sizes, including passing through smaller diameters (such as in wellheads and casing running equipment). This allows for maintaining standoff even in irregular hole sizes.

— Can be run overgage, increasing the maximum achievable standoff.

— As bow-spring centralizers are typically run at gage or overgage, they can provide better standoff than rigid centralizers.

— With hinged centralizers :

  - May allow installation over casing couplings and external upset connections (associated benefits and risks are discussed later in the document).

  - Greater flexibility for installation, such as multi-joint stands.

  - Efficiency in transportation and storage.

— With single piece construction :

  - Minimizing a potential weak point.

  - Low profile design allowing running through tighter annular clearances.

— Double-bow spring centralizers provide higher restoring forces with minimum increases in starting and running forces.

— May provide larger flow-by area compared to solid body centralizers.

6.1.2 Limitations

For rigid and solid centralizers, their limitations can be as per the following.

— These centralizers generally exhibit starting and running forces.

— Require additional considerations (see Sections 7 and 8) when used in highly deviated and horizontal wells.

— If the centralizers become stuck or encounter excessive drag forces, they may break or the stop-collars may slip, potentially forming a “nest” of centralizers. This can lead to significant problems such as the casing getting stuck, damage to the blow out preventer (BOP) or wellhead, undrillable debris at the bottom of the hole leading to potential sidetracks or loss of hole section, and other problems.

— These devices may not provide desired standoff under high lateral load conditions.

— Require additional considerations and preparation for transportation to avoid damage (when pre-installed offsite).

6.2 Rigid and Solid Centralizers

6.2.1 Advantages

Recognized advantages of rigid and solid centralizers can be listed as per the following.

— Solid centralizers cannot be collapsed by normal forces generated in the hole, they can ensure a minimum standoff in high normal force situations (provided there is minimum embedment in the borehole wall), such as across severe doglegs and high angle or horizontal wells.

— Drag forces are generally lower than for bow-spring centralizers.

— The starting forces are zero.

— Semi-rigid centralizers allow for deformation of the fins to help run the centralizer through hole restrictions (although this will result in lower standoff).

— Available with straight or spiral blades.

— Spiral blades can redirect flow path with the intent of improving drilling fluid removal.

— Provide better stand-off at higher lateral loads compared to bow-spring centralizers.

— Generally, rigid centralizers are more robust than bow-spring centralizers.

— Currently, more options in construction materials.

— Available in roller designs.

— Can be fixed to the casing to rotate to overcome drag, get past ledges and bridging.

6.2.2 Limitations

For rigid and solid centralizers, their limitations can be as per the following.

— By design, solid centralizers have a fixed OD. This can result in reduced standoff or inability to continue running in hole in undergage holes.

— Cannot be run overgage, as the maximum achievable standoff is decreased.

— Centralizer OD is limited by minimum restrictions (including wellhead and casing running equipment) and may not be optimum for open hole.

— Reduced flow-by area.

— Generally, not installed over couplings or upset connections.

6.3 Integral Centralizer

6.3.1 Advantages

Recognized advantages of integral centralizers can be listed as per the following.

— They can be used in applications with lower annular clearances.

— Integral holding mechanism (usually a machined feature) prevents the centralizers from slipping.

— For integral bow spring centralizers, additional mechanical features can offer protection to the bow springs.

— Integral centralizers without a bow spring allow casing rotation to overcome drag.

— Can be made up to the casing off location to save rig time.

6.3.2 Limitations

For integral centralizers, their limitations can be as per the following.

— Additional connections to the string.

— May reduce wall thickness when featured with a bow-spring.

— Require additional casing integrity and manufacturing traceability considerations.

— Cannot rotate the casing independent of the centralizers (for integral centralizers without bow springs)

6.4 Bonded Centralizer

6.4.1 Advantages

Recognized advantages of bonded centralizers can be as listed per the following.

— Manufactured with tight and fit-for-purpose clearances.

— Unlimited configurations (can be spaced over the length of the joint).

— Reduced flow restriction (end rings or stop-collars are not required).

— Can be manufactured with helical blades for improved flow characteristics.

— Available in low friction materials.

— Can reduce casing wear in critical locations.

— Wider blades can reduce stress on the formation and resulting embedment.

— Can be rotated with the casing to overcome drag.

6.4.2 Limitations

For bonded centralizers, their limitations can be as per the following.

— Cannot be installed at the rig site as they require specialized training and materials.

— May require additional casing logistics.

— Cannot be removed.

— Cannot rotate the casing independent of the centralizers.

— Requires evaluating wellbore quality (dog leg severity, wellbore rugosity, etc.).

7 Centralizer Selection

7.1 Principle

The selection of the proper centralizer for a particular well application is a critical engineering consideration. The goal of the centralizer program should be to optimize the centralization of the casing in the wellbore to aid in reaching TD and in proper drilling fluid removal to achieve zonal isolation through cement placement in the wellbore. Depending on several design criteria, the proper centralizer for a particular application may be a bow-spring, rigid, integral, bonded centralizer. In any given well, there can be application for all four types of centralizers, and only by evaluating all available data the proper centralizer(s) can be selected.

Casing centralizers can be selected by identifying and addressing specific well construction challenges and limitations. The following methodology described under 7.2 to 7.7 can be used for this purpose.

7.2 Mechanical Restrictions and Downhole Conditions

Selection of centralizer should consider downhole conditions and potential restrictions.

a) Identify all inside diameters (ID), including restrictions at the well head, casing hanger(s) and casing running equipment. Take note of the smallest ID that the centralizers will be passing through.

b) Identify open hole diameter(s), including potential enlarged or collapsed interval depths.

c) Define the specifications of the casing to be run (where the centralizers will be installed).

d) Future well operations.

e) Maximum downhole temperature.

f) Drilling fluid type.

7.3 Anticipated Casing Running Challenges

Selection of centralizer should anticipate casing running challenges related to the wellbore and operations.

a) Define actual dog leg severity (DLS) and overall directional survey, in cased hole and open-hole sections:

   1. The selection of centralizer type (or combination of centralizers) should be made using a centralizer placement simulator for the actual condition of the well. Torque forces and drag (total running forces) should be calculated, as well as the standoff, throughout the entire wellbore using the actual hole deviation and caliper data. The properties (start and running forces, and stand-off) of the centralizers being considered should be used in the calculations.

   2. There may be situations where bow-spring centralizers will not perform as required because of large normal and/or running forces, such as found in high DLS. For these circumstances and for complicated well paths (high deviations, high angle change, severe doglegs, ERD, S-shapes, etc.) the use of solid or rigid centralizers may be required.

b) Rig capacity (maximum hook load and surface torque).

c) Review wellbore quality based on data from offset wells to identify ledges, hole cleaning, borehole stability, depleted or low-pressure zones.

d) Surge and swab limitations.

e) Casing buckling.

f) Casing rotation requirements.

7.4 Cementing Challenges and Objectives

While it is common to emphasize stand-off between centralizers as a critical point, stand-off throughout the entire casing string and throughout the entire casing running and cementing should be considered for its effect on the ability to run casing and provide drilling fluid displacement efficiency to achieve cementing challenges and objectives. These include following parameters.

a) Critical cemented intervals.

b) Anticipated hole size variations.

   Rigid and solid centralizers have lower running forces than bow-spring centralizers, but their fixed OD limits the ability to maintain high standoff in enlarged holes. In addition, the previous casing drift ID often limits the OD of the centralizer that can be run to centralize the casing in the open hole. Under these circumstances, the OD of the rigid or solid centralizer that can be used in a given case may be too small to provide the desired degree of standoff in the open hole section.

   This condition becomes more severe in cases where the open hole has been under-reamed, has washouts, or ovality. The location and magnitude of the washouts or restrictions should be considered in determining the geometry and placement of the centralizer. The effect of hole diameter variations on standoff can be appreciated in the following example, a 7 in. casing centralized with solid or rigid centralizers in a nominal 8.5 in. open hole.

EXAMPLE — Casing size: 7 in.

— Solid or rigid centralizer OD: 8.25 in.

— Centralizer ID: 7.125 in.

— Installation method: free to rotate (no set screws)

Table 1—Example of Rigid or Solid Centralizers Standoff Ratio vs Hole Size

Hole OD (in.)	*SOR* at the Centralizer %
8.50	75
8.75	64
9.00	56
9.25	50
10 (washout)	38

The best standoff that can be obtained with a solid or rigid centralizer for this example well is seventy five percent. It assumes that the hole is equal to the bit size, which is normally not the case. In a situation where the hole size is larger than the bit size, it is possible to see a limitation (from a standoff point of view) with fixed OD centralizers as shown in the example Table 1.

It is also noted that in all the example cases, Table 1, the minimum gap between the casing and the wellbore at the centralizer is 0.25 in., assuming embedment of the centralizer at the wellbore is negligible.

Another important point is whether the centralizers are installed on the casing before the actual size (caliper) of the open hole is known (hole size is often estimated from offset wells). In this situation, if the actual hole turns out to be enlarged, it might be too late to change the previously selected centralizer type.

c) Casing rotation and reciprocation objectives.

d) Required centralization to achieve proper drilling fluid displacement.

7.5 Long-term Wellbore Integrity

Long-term wellbore integrity should include following parameters:

a) Casing corrosion protection.

b) Offset well data to inform future jobs, such as challenges during hydraulic fracturing (communication between stages, plug slippage, or other).

7.6 Logistics and Installation

Logistics related to centralizer program and their installation should take in account following considerations.

a) Installation location.

b) Handling and transportation requirements and limitations.

c) Position on the casing where the centralizers will be installed: over coupling vs. midspan.

NOTE Installation over coupling is not possible with flush connections and some semi-flush connections.

Benefits associated with limitations and risks for installation over couplings can be identified and listed as hereafter.

1) Benefits of installation over couplings.

   - Reduce drag from couplings.
   - Eliminate the need to use stop-collars.
   - Eliminate the risk of the centralizers slipping.
   - Efficiency in centralizer installation.
   - Depending on design, pulling the centralizer through tight spots.

2) Risks and limitations of installation over couplings.

   - Damage to the bow spring due to the coupling profile.
   - Limited bow deflection.
   - Increased maximum rigid OD.
   - Reduced overall stand-off due to increased effective stiffness.
   - Loss of stand-off provided by the coupling compared to placing the centralizer at mid-joint.
   - Risk of dropping tools in the well when installing on the rig floor.

3) Additional considerations for deepwater rigs

Modern rigs used in deepwater applications typically have dual derricks and advanced automated pipe handling systems. This may lead to certain limitations and challenges when it comes to centralization spacing and installation. For example, if building stands of three (3) full length casing joints offline, and racking entire stands back, the following limitations should be considered.

- Mouse hole on the offline side very often has quite a small ID and therefore limits the centralizer and stop-collar maximum OD.
- Centralizer placement is dictated by the finger/belly boards and, also by the pipe handling system. This may interfere with the simulated spacing and require alternating spacing lengths.

7.7 Quality

Failure of casing centralizers may affect casing running and well cementing. The quality of centralizers available to operators may vary, and construction quality of the device shall be considered by the user when selecting a centralizer. Quality control of centralizers should include: properties of the construction materials, welds, type and properties of set screws and hinges, hinge pins, length and ID/OD of the centralizer, storage and handling, etc. It is important that centralizers should be manufactured under a Quality Management System, such as those described in API Q1 or ISO 9001. Specification API 10D as ISO 10427-1 include methods to test the performance of bow-spring centralizers. Similarly, API 10TR5 [4] defines additional methods to test the quality and performance of rigid or solid centralizers.

8 Operational Considerations

8.1 Drag Force vs Standoff Considerations

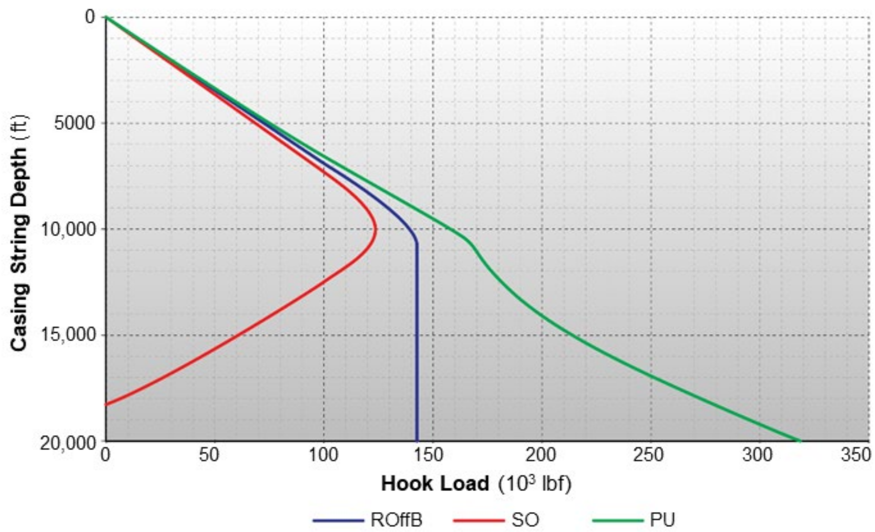
In highly deviated, ERD and horizontal wells, it often becomes necessary to design the centralizer program considering the need for both high standoff and low drag (total running) forces. Under these conditions, the problem becomes not just one of generating good centralization for good cement placement, but one of being able to run the casing to the target depth.

Table 2 gives parameters used in Figures 9 and 10, examples of computer-generated simulations.

Table 2—Parameters Used in Figure 9 and 10 Generated Simulations Example

Parameter	Value
Casing size and mass	5.5 in., 17 lbm/ft
Hole size	8.5 in.
Drilling fluid	10 lbm/gal
Horizontal hole section	9000 ft

The first example, Figure 9, shows a case in which the pipe could not be run to bottom because of the elevated drag generated by bow-spring centralizers.

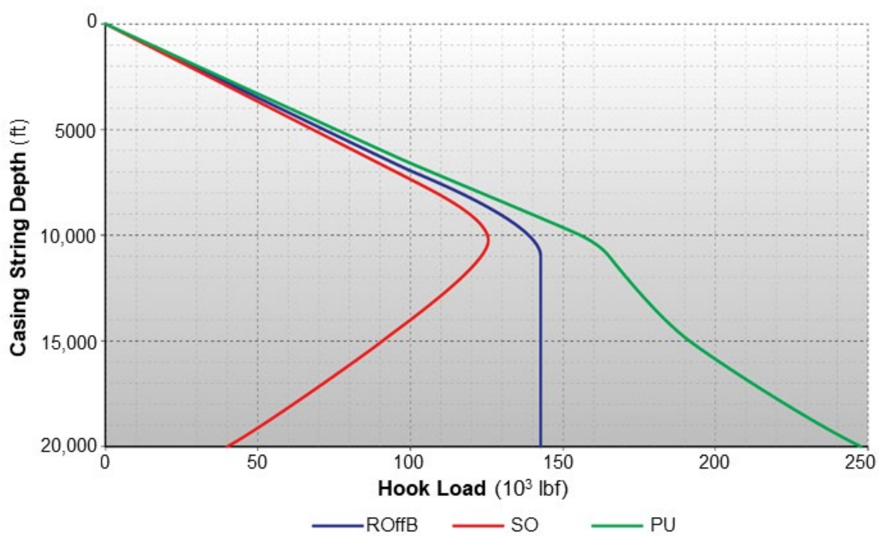


Key

ROffB	rotating off bottom	SO	slack-off weight	PU	pick up string

Figure 9—Overgage Bow-spring Centralizers Simulation Case: Casing Cannot be Run to Bottom

The second example, figure 10, shows that a rigid centralizer would allow the pipe to get to bottom. The centralizer of choice to use in this case is a rigid centralizer (OD 8.25 in.).

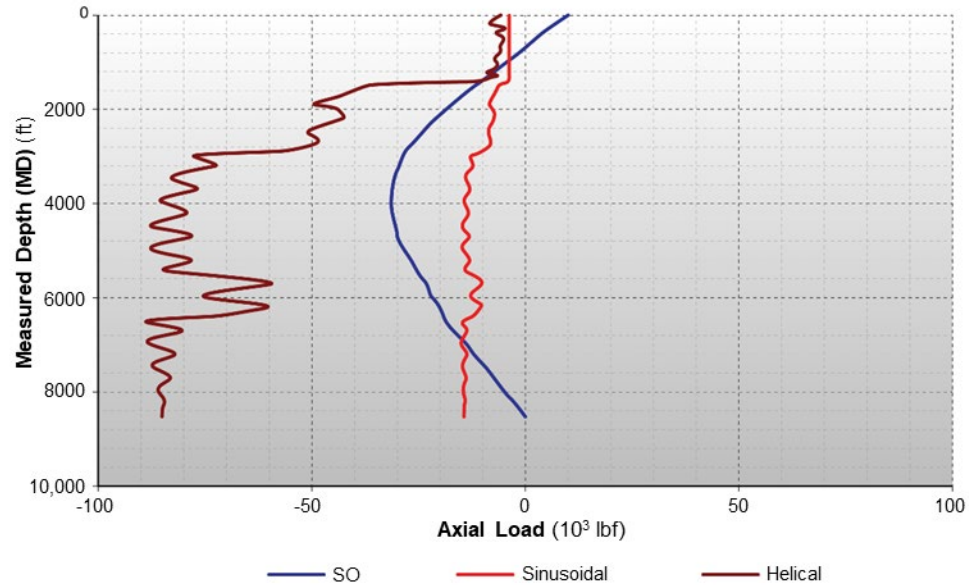


Key

ROffB	rotating off bottom	SO	slack-off weight	PU	pick up string

Figure 10—Rigid Centralizers Simulation Case: Casing Can be Run to Bottom

In addition to hookload vs measured depth (MD) curves, one should also consider the axial load profile at different depths to assess sinusoidal and helical pipe buckling, and the possibility of locking up the casing. An example of an axial load curve is shown in Figure 11.



Key

SO	slack-off weight
Sinusoidal	sinusoidal pipe buckling axial load
Helical	helical pipe buckling axial load

Figure 11—Example of Axial Load Curve

The axial load profile will be impacted by most of the factors mentioned in 8.2, including the centralizers used.

It is also important to consider the magnitude and development or change of side forces throughout the casing run. As the casing is run in hole, side forces can change significantly in magnitude and direction. One should determine the maximum expected side forces and confirm the selected centralizers are appropriate.

8.2 Required Torque Considerations

Casing centralizers should have an impact of the amount of torque required to rotate the casing and the torque profile along the string. This torque is a function of many factors, including the following parameters.

a) Rotating speed

b) Casing diameter

c) Friction factors

d) Fluid properties

e) Buoyed weight (see 9.3)

f) Number, type, size, and position of centralizers

g) Length of the centralized interval

h) How the centralizers are installed (fixed vs rotating)

i) Wellbore profile

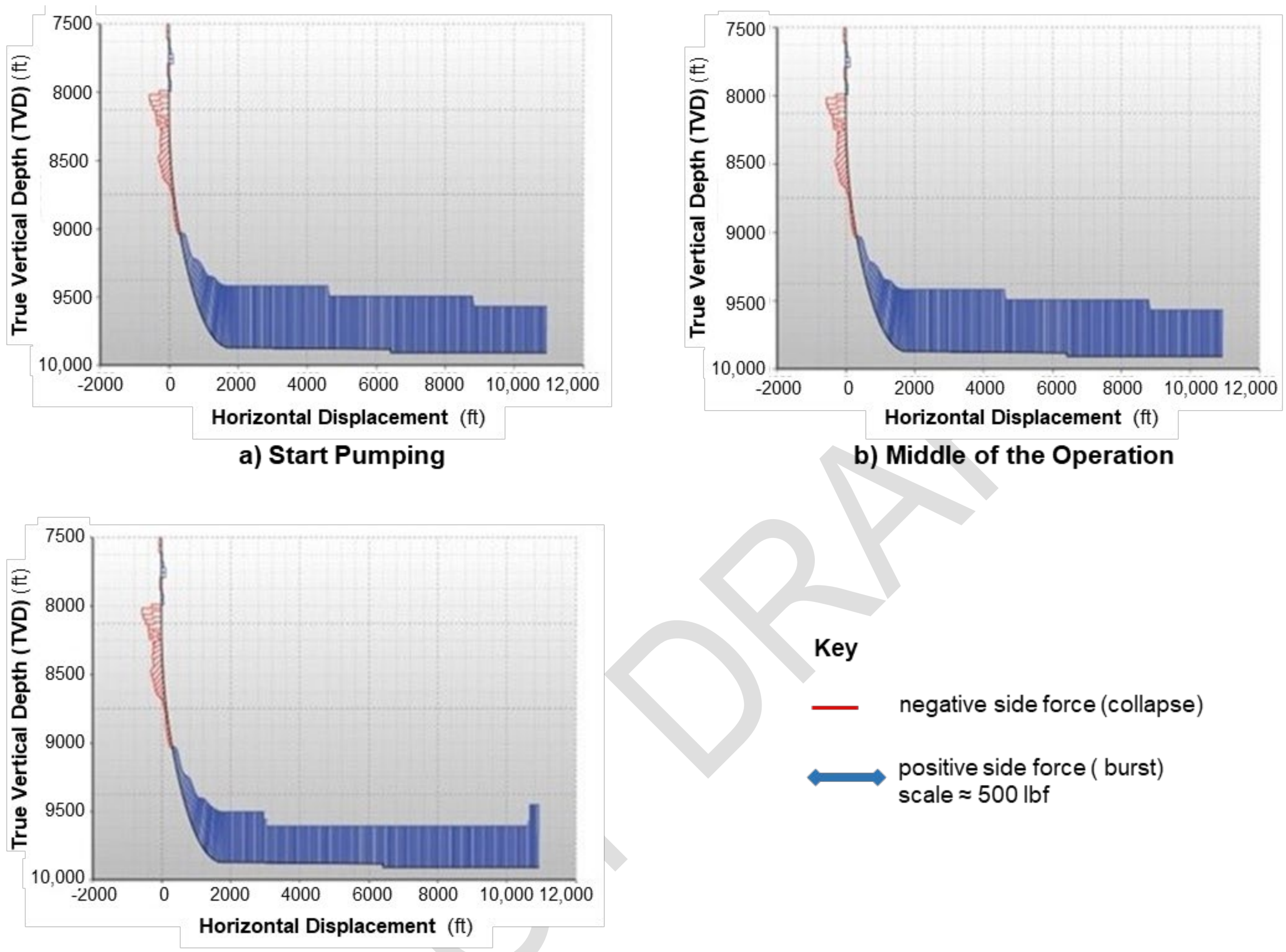
j) Standoff

k) Effective stiffness.

When planning to rotate while cementing, one should consider the effect of centralizer material on rotating friction factor, both between the casing and the centralizers (when the centralizers are free to rotate) and between the centralizers and the formation or previous casing (when the centralizers are fixed to the casing). The change in rotational friction factor as cement is displaced should also be considered. In general, fixing the centralizer to the casing will increase required torque.

In addition to required surface torque, one should consider the torque profile along the string while rotating the casing to ensure connection limitations and pipe strength are not exceeded.

In a horizontal well, Figure 12 shows an example of the progression of side forces on the casing string as the cementing operation is executed.



a) Start Pumping

b) Middle of the Operation

c) End of the Operation

Figure 12—Change of Side Forces during the Cementing Operation

A practical use of these graphs shall be to estimate standoff based on the centralizer load-deflection force curve generated under API 10D. An example such curve is given in Figure 13:

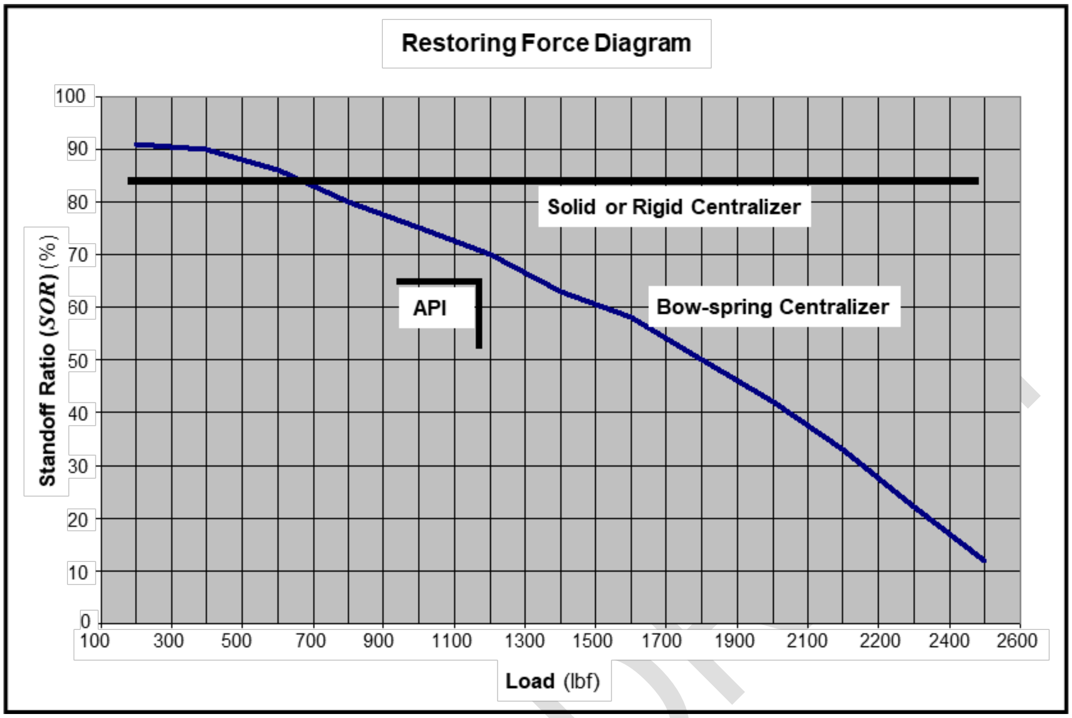


Figure 13—Sample Centralizer Load-deflection Force Curve Generated under Specification API 10D

For example, referring to Figure 12, the side force at 10,000 ft is approximately 400 lbs. Using this number, one can enter the horizontal axis in Figure 13 at 400 lbs and move up to intersect the deflection curve, where the standoff (bow-spring centralizer) would be approximately 90%.

As side forces change, surface torque while cementing will also change. This is illustrated in Figure 14.

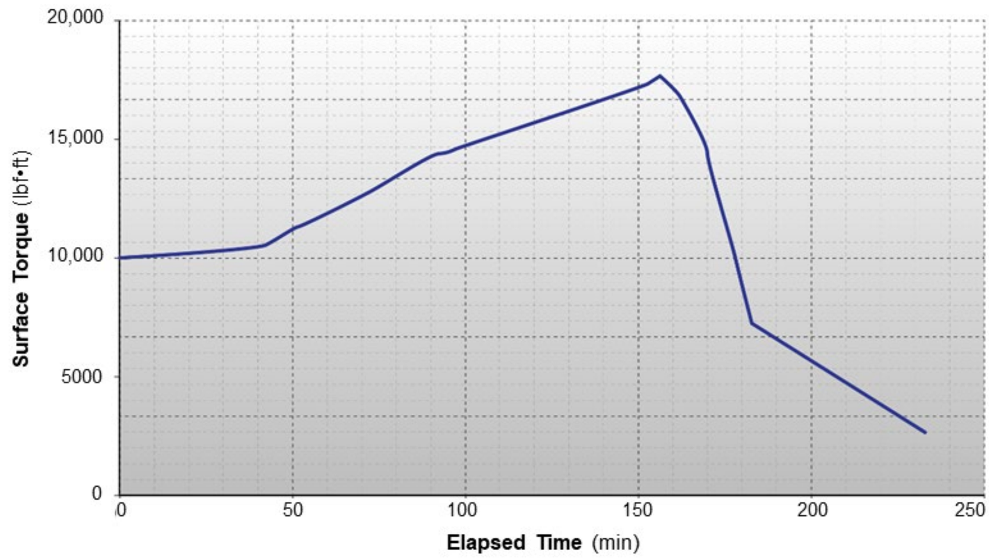


Figure 14—Example of Surface Torque While Cementing

8.3 Location and Number of Centralizers to Obtain a Desired Standoff

For solid and rigid centralizers, the standoff at the centralizer shall be calculated using Equation (2) (see Section 9). This equation assumes that the centralizer is in contact with the formation at some point and that there is no embedment of the centralizer into the formation. For bow-spring centralizers, the restoring force of the centralizer shall be also considered. Between centralizers, the casing sag point shall be estimated using the equations given by API document dealing with recommended practices for the use of bow-spring centralizers (see API 10D). For calculations of casing sag the equations used for bow-spring centralizers shall apply (see Section 9), with the exception that solid and rigid centralizers do not flex due to the normal forces.

8.4 Estimating Drag and Torque when Using Rigid and Solid Centralizers

Factors affecting the calculations include casing size and weight, drilling fluid and cement slurry densities, drilling fluid type, well inclination, DLS, friction reduction additives and devices, wellbore quality, and axial load. Section 9 contains the formulas required to calculate the normal forces for a given hole-casing geometry. The normal forces should be calculated up and down the casing for the given well configuration, then friction forces can be calculated by multiplying the normal forces by the estimated dimensionless friction factor. The total drag can then be estimated by adding up the calculated localized friction forces.

Similarly, assuming the casing rotates inside the centralizer (centralizer is fixed against the formation) localized torque components should be estimated using the calculated normal forces and the estimated rotating friction factor. Total torque at the surface can be estimated by adding up all the torque components. These calculations require a computer simulator, particularly for complicated well trajectories and severe dogleg sections.

If the centralizers are rotating with the casing, a larger effective casing diameter should be considered. Also, the applicable friction factor is now between the centralizers and the wellbore. It should be noted that casing running friction factor may be different from friction coefficient. Additional information on this topic can be found in Mason and Chen [5].

8.5 Friction Coefficients

The value of the friction coefficient for a centralizer is influenced by the material used to manufacture the centralizer, the type of centralizer (bow-spring, rigid and/or solid), the blade orientation, the drilling fluid system used (level of lubricity) and the formation. Friction coefficients are dependent on the drilling fluid type (water-based or non-aqueous drilling fluid) and its additives (including lubricants).

Laboratory testing methods have been developed to measure friction coefficients for different construction materials and drilling fluid systems. A test method that can be used for comparison among different centralizer materials and drilling fluid systems is given and discussed in API 10TR5 [4].

8.6 Centralizer-induced Swirl

Many centralizers are configured in such a way as to induce swirl during pumping. Swirl can be beneficial to the displacement process. However, swirl alone may not completely remove the dehydrated drilling fluid and solids beds in the hole.

8.7 Centralizer Installation

8.7.1 General

Centralizer installation can have an impact on the effectiveness of the centralizers, the ability to run casing in hole, and the ability to rotate or reciprocate casing. Centralizer installation can also impact the decision on using centralizers or not, and the type, quantity and spacing or both, of centralizers.

If appropriately designed centralizers and stop-collars (or holding devices) are used, the likelihood of damage running in hole and during pipe movement can be reduced. The correct installation of the centralizers should be also critical. If the centralizer becomes stuck, it may break or the stop-collar may slip, potentially forming a “nest” of centralizers. For example, there are applications where installation of the centralizers over casing collars is appropriate. However, there are situations where this practice should be avoided. Compatibility of the centralizer and stop-collar or casing collar must be checked and evaluated against well conditions and desired performance in the well.

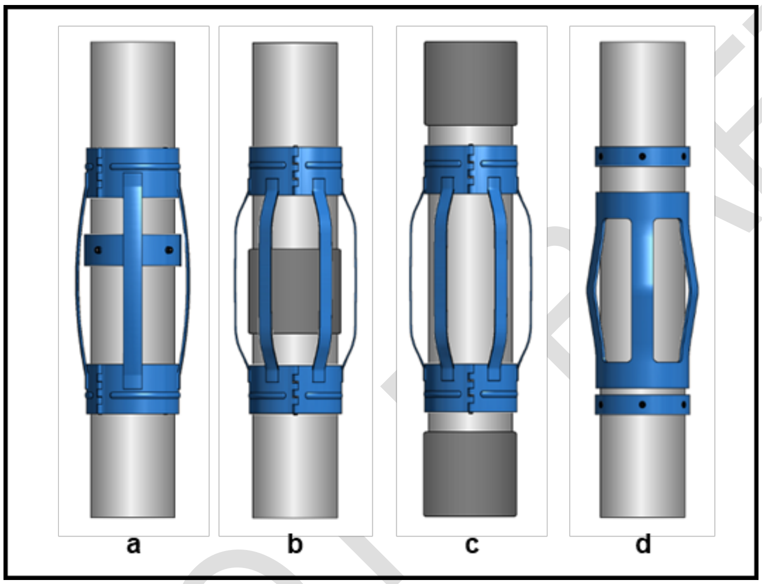
To help optimize drilling fluid displacement, centralizers must be properly installed on the casing. The type and timing of required pipe movement should be considered when installing centralizers. If the casing will have to be rotated while running in hole to overcome drag, spiral solid body centralizers fixed to the casing may be needed. If the casing will only be rotated while cementing, the centralizers should be installed so that casing can rotate inside of them.

8.7.2 Casing rotation and centralizer

If the casing will be rotated inside of the bow-spring centralizers, large clamp screws in the stop-collars should be avoided since they may tend to “lock” the centralizer onto the collar when attempting to rotate the casing.

Figures 15 and 16 illustrate possible centralizer installations for casing rotation. When casing will be rotated, it is important to place the centralizers over stop-collars, over the casing collars (if allowed by well conditions), between casing collars, or between stop-collars, so that centralizers can allow rotation of the casing without having to move after the casing is in place (see Figure 15).

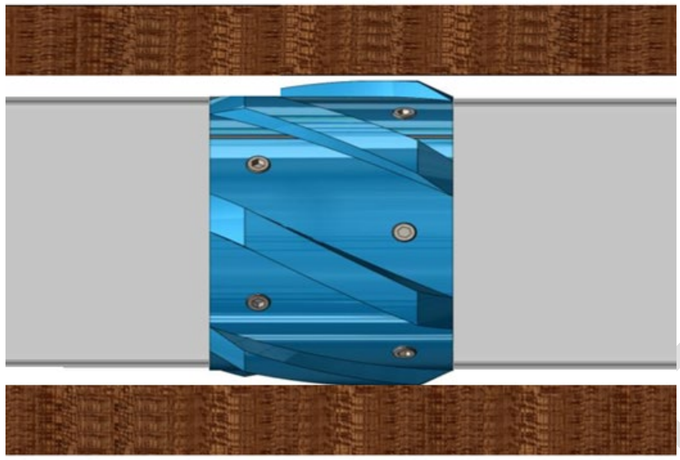
Figure 16 illustrates the installation of a spiral solid centralizer fixed to the casing to allow casing rotation to overcome drag while running in hole (RIH). In this case, the rotational holding force of the set screws or holding mechanism should be compared to the anticipated required torque to ensure the centralizer will rotate with the casing.



Key

- **a** over stop-collar
- **b** over casing collar
- **c** between casing collars
- **d** between stop-collars

Figure 15—Centralizer Installations for Casing Rotation



NOTE Solid body centralizer with spiral vanes and fixed to the casing with set screws.

Figure 16—Example of Rigid Centralizer Installed for Casing Rotation to Overcome Drag

8.7.3 Casing reciprocation and centralizer

If the casing is to be reciprocated, it is again important to have the centralizers static while the pipe is being moved. For this application, it is best to "float" the centralizers between casing collars or stop-collars, and to limit the reciprocation stroke to lengths such that the centralizers will not be forced to move once the casing is in place. When reciprocating casing, "floating" the centralizers between casing collars or stop-collars and limiting the reciprocation stroke so that the centralizers remain static, may reduce the risk of damage.

However, installing the centralizers so that they reciprocate with the casing may improve standoff during reciprocation. In this case, the suitability of the centralizer to reciprocate with the casing should be discussed with the manufacturer.

8.7.4 Possible centralizer installation methods

There are five possible installation methods for centralizers which are illustrated by Figure 17.

a) Case 1: over stop-collars, for casing rotation, often not used for reciprocation, not for close tolerances, will result in centralizer being "pulled" into the wellbore, easy to install on the racks.

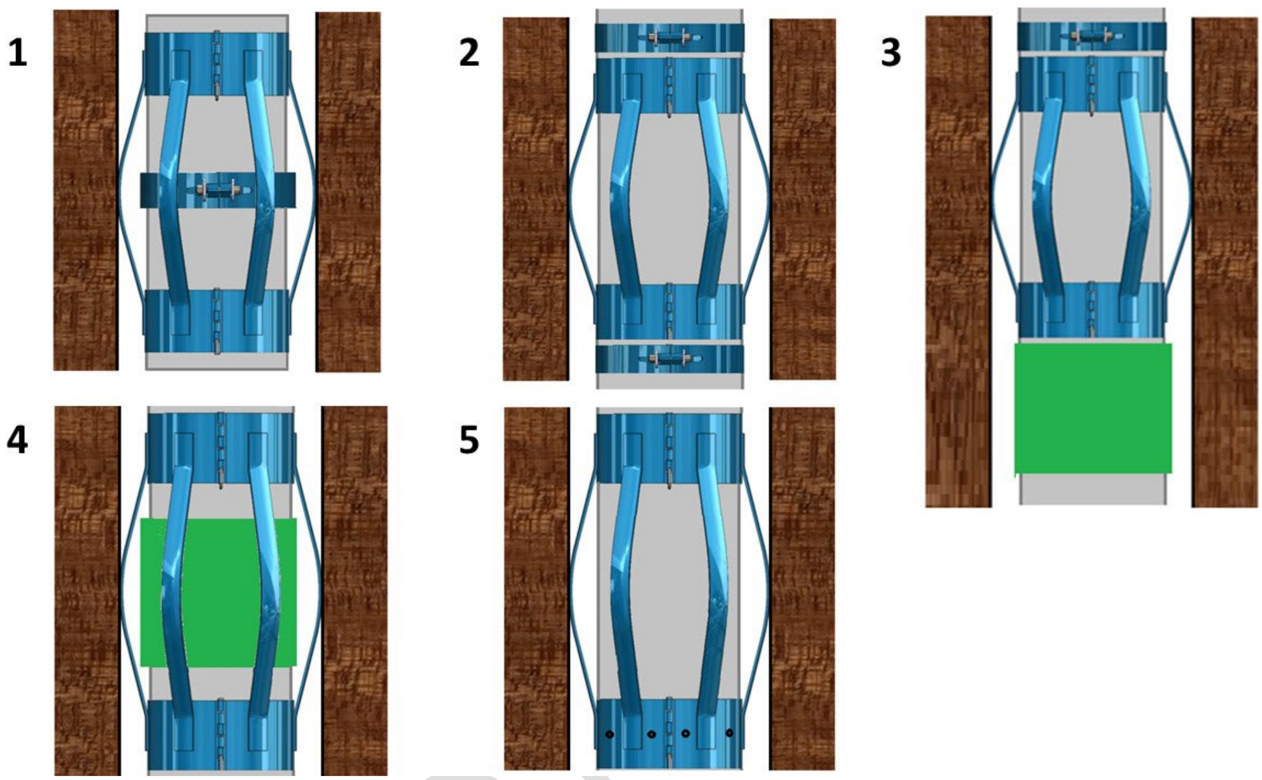
b) Case 2: between stop-collars, for rotation or reciprocation, for close tolerance situations, easy to install on the racks, will result in the centralizer being pushed into the hole.

c) Case 3: between couplings and stop-collars, for rotation or reciprocation, for close tolerances, will result in the centralizer being pushed into the hole.

d) Case 4: over casing couplings, for rotation, not for close tolerances, reduces annular flow area, cannot be installed on the pipe rack, may reduce overall stand-off.

e) Case 5: set screws or other integral holding mechanisms that fix the centralizers to the casing are not suitable for casing rotation, but they eliminate the need for stop-collars or installation over coupling.

This will also result in the centralizers being pulled into the wellbore as the casing is run in and pushed out if the casing is retrieved. This installation method is typically not performed on the pipe rack.



Key

1	over stop-collar	**3**	between stop-collars and casing couplings
2	between stop-collar	**4**	over casing coupling
(green)	casing coupling	**5**	Integral stop or holding mechanism

Figure 17— Centralizer Installation Patterns

8.8 Use of Dissimilar Materials: Casing— Centralizer

Some in the industry have expressed concern regarding the use of centralizers constructed from metals other than iron (steel). An example of these type centralizers are solids and/or rigids made from aluminum and/or zinc. The concern is based on the potential for long-term corrosion effects of the casing string generated using dissimilar materials. It should be noted that zinc and aluminum are commonly used for the protection of steel in pre-stressed concrete structures.

8.9 Hole Cleaning

Inadequate hole cleaning practices can result in a cuttings bed being left in the hole. This situation may have an impact on:

a) the ability to run casing to bottom;

b) actual standoff while cementing due to embedment of the centralizers in the cuttings bed;

c) the ability to rotate and reciprocate casing while cementing;

d) increase ECD and ability to maintain returns.

8.10 Stop-collar and Integral Collar Holding Forces

When one considers the complex subject of casing centralization, stop-collars and their holding forces should not be neglected. Stop-collars are extremely important to the success of the centralization program. If the collars are damaged or if they move, even the running of the casing in the hole can be jeopardized (formation of centralizer "nests").

NOTE Holding forces for integral collar, i.e. holding mechanism associated to the centralizer, are also extremely important for the centralization success.

When hole conditions allow, centralizers are often placed over casing collars. This type of installation eliminates stop-collar concerns and may be used in both casing rotation and reciprocation applications. This technique may not be appropriate for use in tight annuli, where the centralizer may bend if it flexes against the shoulder of a collar. The compatibility of centralizers with casing collars must be verified.

Different hole configurations require different stop-collar designs. The stop-collars must provide adequate holding force according to the drag forces anticipated on the centralizers to prevent slippage.

Stop-collars should be tested to measure their performance characteristics. Section 10 provides a method to test the holding and slippage forces of stop-collars. Depth of the gouge (indentation) on the casing after the collar moves should be measured. It is critical that the holding force tests should be conducted using the same grade of pipe to be used in the actual well, as this will have an impact on the results.

No stop-collar or holding device will function if improperly installed. Manufacturer's installation procedures must be followed precisely for stop-collars to hold centralizers in place as desired. Some centralizers have built-in holding mechanisms. These should also be applied according to the manufacturer's recommendations.

It should be noted that the holding forces as measured in the above tests are only approximations. Actual downhole performance may vary significantly with downhole conditions.

8.11 Potential Impact of Centralizers on Effective Casing String Stiffness

The spacing of centralizers as well as the type chosen can have an impact on the lateral loads on the casing and therefore the drag forces. The equations for soft string modeling for calculating lateral loads do not take into account the stiffness of the casing string or the tortuosity of the wellbore path between survey points. If the wellbore is relatively straight with low DLS, the stiffness of the casing will have little effect on the lateral loads generated. However, severe doglegs can induce high lateral loads (and therefore increased drag) from bending moments in proportion to the casing string stiffness, in addition to the tensional component of the lateral load produced by a geometric obstruction within the wellbore.

Stiffness increases with increasing casing diameter and wall thickness. Centralizers have the effect of increasing the apparent casing diameter where contact is made with the wellbore, causing the casing to follow the curvature of the wellbore more closely. Increased curvature of the casing results in higher bending moments of the casing and higher lateral loads at the centralizers. If centralizers are spaced too closely, and if there is little clearance between the centralizer's rigid OD and the borehole diameter, the casing may be difficult to run through changing wellbore curvatures. Examples of this situation in a wellbore with a short offset length are illustrated in Figure 18 Whereas casing with no centralizers may run through this particular short offset section without bending, rigid centralizers may force the casing to follow the wellbore curvature more closely. By spacing the rigid centralizers further apart as illustrated, the casing may not follow the wellbore path as closely and bending moments in the casing may be reduced. Bow-spring centralizers flex in proportion to the lateral load, allowing less casing curvature and therefore less bending moments when running through offset sections. On the other hand, bow-spring centralizers may not provide adequate standoff across hole sections of high lateral loads because of deflection of the bows.

The length and method of attachment of rigid centralizers can also impact the effective stiffness of the casing string. If the rigid centralizer is secured to the casing with no clearance over its length, the stiffness of the casing increases. Increased stiffness results in higher lateral loads in a curved wellbore. Clearance between the rigid centralizer and the casing allows the casing to bend in proportion to this clearance without interference. It also has the effect of reducing the standoff dimension. An increase in the length of a rigid centralizer reduces the allowable bending of the casing without interference from the centralizer. The stiffness of the casing section is increased after centralizer interference is established.

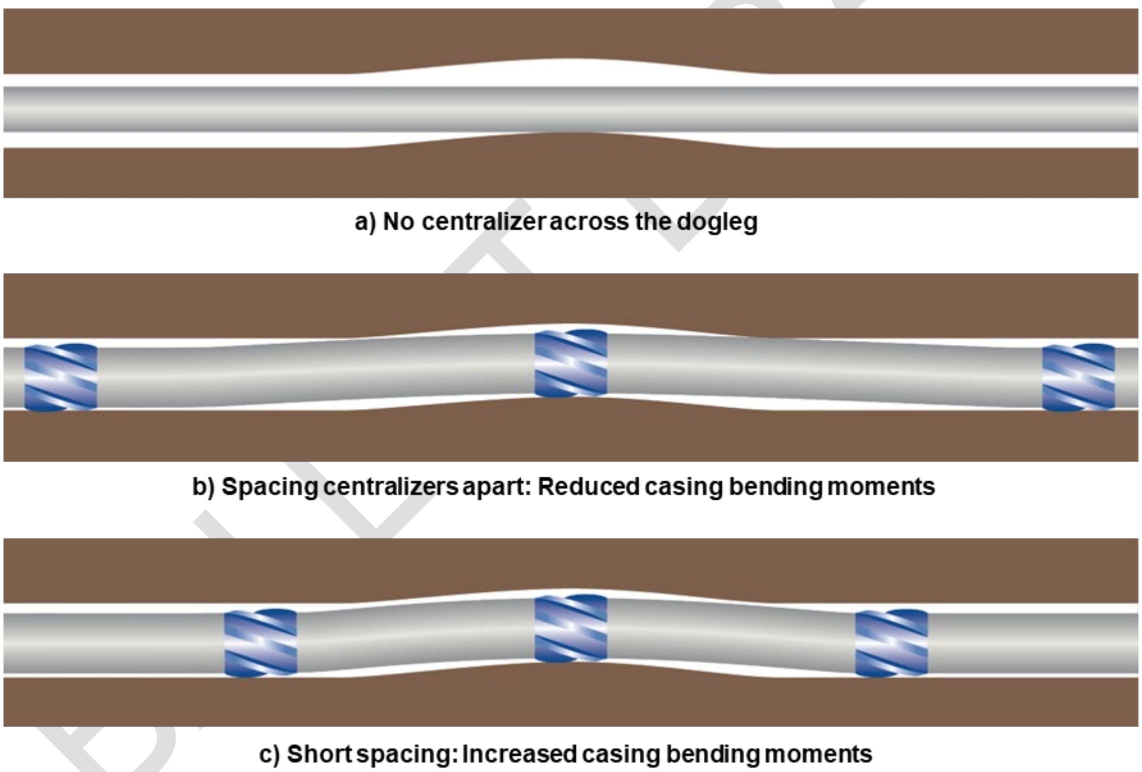


Figure 18—Impact of Rigid Centralizers and Centralizer Spacing on Effective Casing String Stiffness

8.12 Compatibility of the Centralizers with Wellbore Fluids

Centralizer and stop-collar construction materials must be fully compatible with wellbore fluids (drilling fluid and cementing spacers, flushes, and slurries) under downhole conditions. For materials other than steel, it is important for the user to consult with the manufacturer any deleterious effects (i.e. degradation, softening, decomposition, etc..) due to interaction of the material with the wellbore fluids.

8.13 Potential Generation of Gases from Materials Under Downhole Conditions

While the potential exists for chemical reactions of the cement slurries with, for example, zinc or aluminum, the centralizer surface areas exposed to cement slurries are normally not sufficient to generate substantial volumes of gas. Furthermore, possible generation of small amounts of gas is normally not considered a problem under the high hydrostatic pressures encountered in typical wells. Finally, once cement is set, the amount of gas which can be produced is very small and of little significance.

8.14 Centralizer Wear (Durability) during Running in the Hole

When using centralizers made from low-friction materials, such as aluminum, zinc alloy, composites and polymers, the potential trade-off between reduced friction and loss of standoff due to wear should be considered. API 10TR5 [4] defines additional methods to test wear resistance of rigid or solid centralizers.

8.15 Centralizers for Drilling-with-Casing (DwC) applications

In DwC applications casing is used as a conduit for drilling, attached to a bottomhole assembly that enables the simultaneous capability to drill the hole and run in the casing. This application has been applied in challenging wells dealing with losses and formation challenges such as wellbore instability, fractured formations, faults etc.

Centralizers for DwC applications can be subjected to continuous rotation of the casing and high axial and lateral loads. Rigid centralizers should be used. The centralizers should have spiral vanes with adequate flow area for cuttings passage between them, and high circumferential coverage for optimum standoff. In some applications, a wear resistant coating (e.g. tungsten carbide hard facing) might be required for high wear resistance and durability.

The centralizer placement scheme may influence the efficacy of a phenomenon known as the smear effect during DwC due to the casing standoff. The smear effect is generally thought to enhance wellbore stability and help protect against lost circulation.

Fixing the centralizers to the casing string allow the centralizer to act as an integral part of the casing string. If the centralizers are not fixed to the casing, the friction between the centralizer ID and the casing OD over lengthy periods of rotation during drilling (especially without cooling/lubricating circulating fluid if there is lost circulation) can lead to wear and damage of the centralizer or casing. When centralizers are fixed rotationally on the casing, casing rotation when running in hole can reduce drag. When centralizers are not fixed to the casing, axial drag may not be reduced significantly during casing rotation as the casing could spin within the centralizers. As such, fixing the centralizers to the casing can be beneficial in ERD casing and liner runs to enhance the ability to reach TD.

9 Methods for Estimating Centralizer Placement

9.1 General

The equations presented Section 9, are based on certain assumptions and are considered sufficiently accurate for general use. More specific calculations based on complete wellbore data may be available but are beyond the scope of this document.

There is no recommendation or requirement for a specific *SOR* for casing centralization. The *SOR* of 67 % is used in API 10D for the purpose of setting a minimum standard for performance of casing bow-spring centralizers only. This number is used only in the standard for bow-spring centralizers and deals with the minimum force for each size of centralizer at that standoff. The 67 % *SOR* 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 *SOR* required for specific well conditions based on well requirements and sound engineering judgement.

Even a minor change in inclination and/or azimuth, with the string of casing hanging below it, materially affects the standoff and the requirements for centralizer placement.

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

9.2 Standoff and *SOR* Calculations

9.2.1 Standoff at the centralizer

For perfectly centered casing in a wellbore, the maximum annular clearance (i.e. the maximum standoff, see Figure 21) shall be calculated using Equation (1).

$$e_{\mathrm{max}} = \frac{D_{\mathrm{H}} - OD_{\mathrm{C}}}{2} \tag{1}$$

where:

e_{max} is the annular clearance for perfectly centered casing, expressed in meters (inches);

D_{H} is the wellbore diameter (open hole or outer casing internal diameter), expressed in meters (inches);

OD_{C} is the casing outside diameter, expressed in meters (inches).

The standoff at the centralizer in a given hole size is represented by the symbol e_{c} (see Figure 21).

The standoff at a bow-spring centralizer shall be taken from the load deflection curve of the centralizer, tested in that hole size, based upon the lateral load applied (see API 10D).

NOTE Differences in hole size alter the load-deflection curve of a bow-spring centralizer.

In case of solid or rigid centralizer since the bows or blades do not deflect, the standoff shall be calculated using Equation (2) and the rigid or solid blade centralizer diameters.

$$e_{\mathrm{c}} = \frac{OD_{\mathrm{c}} - ID_{\mathrm{c}}}{2} \tag{2}$$

where:

e_c is the standoff at the centralizer, expressed in meters (inches);

OD_c is the outside diameter of the solid or rigid centralizer blades, expressed in meters (inches);

ID_c is the inside diameter of the solid or rigid centralizer, expressed in meters (inches).

9.2.2 Standoff at the casing sag point

Standoff at the sag point may be determined by Equation (3), which considers the deflection (δ_{max}) of the casing string and, in case of centralization with bow-spring centralizer compression of the centralizers due to lateral load (see Figure 19, centralization with solid or rigid type).

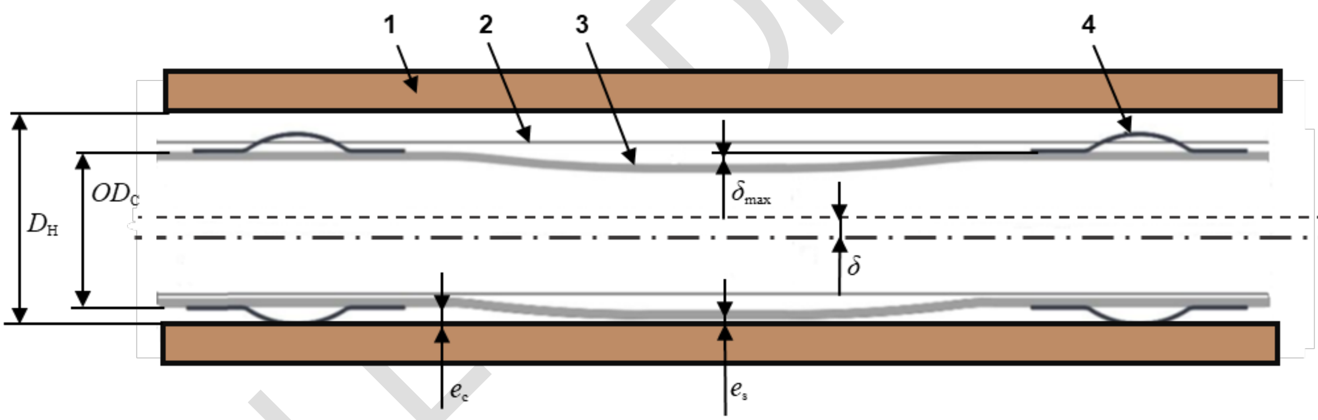
$$e_s = e_c - \delta_{max} \tag{3}$$

where

e_s is the standoff at the sag point, expressed in meters (inches);

e_c is the standoff at the centralizer, expressed in meters (inches);

δ_{max} is the maximum deflection of the casing between 2 centralizers, expressed in meters (inches).



Key

1	wellbore	D_H	open hole diameter (or outer casing inside diameter (ID_C)
2	perfectly centered casing axis	OD_C	casing outside (nominal) diameter
3	deflected casing axis (no deflection)	δ	casing eccentricity (and bow deflection, case of bow-spring centralizer)
		δ_{max}	casing deflection between two (2) adjacent centralizers
4	centralizer	e_c	standoff (minimum clearance) at centralizer
		e_s	standoff (minimum clearance) at sag point between two (2) centralizers

Figure 19 — Calculation of Casing Standoff in a Wellbore

Standoff ratio (SOR)The minimum standoff may occur at the location between centralizers where the deflection of the casing is at its maximum (δ_{max}) or at the centralizers. Therefore, standoff (e) of a section of casing is the minimum value of standoff at the centralizers (e_c) or standoff at the sag point (e_S). For these locations along the casing, the SOR shall be calculated using Equations (4) to (6).

$$SOR_c = 100 \times \frac{e_c}{e_{max}} \tag{4}$$

$$SOR_s = 100 \times \frac{e_s}{e_{max}} \tag{5}$$

$$SOR_m = \text{mini}\ \left(SOR_c, SOR_s\right) \tag{6}$$

where

SOR_c	is the standoff ratio at the centralizers, expressed as a percentage;
SOR_s	is the standoff ratio at the sag point, expressed as a percentage;
SOR_m	is the minimum standoff ratio, expressed as a percentage;
e_c	is the standoff at the centralizers, expressed in meters (inches);
e_s	is the standoff at the sag point, expressed in meters (inches);
e_{max}	is the annular clearance for perfectly centered casing, expressed in meters (inches).

9.3 Buoyed weight of casing

9.3.1 General

The buoyed weight of casing is the effective weight of the casing in the well. Consideration is given to the densities of the fluids inside and outside the casing, and the weight of the casing in air.

9.3.2 Generalized equation

The buoyed weight of a casing shall be calculated using Equations (7) and (8). These Equations are a generalization of the treatment of effective weight of casing to accommodate different internal and external fluids, based upon a model developed by Juvkam-Wold and Baxter [6].

$$W_b = W \times f_b \tag{7}$$

$$f_\mathrm{b} = \frac{\left(1 - \frac{\rho_\mathrm{e}}{\rho_\mathrm{s}}\right) - \left(\frac{ID_\mathrm{C}}{OD_\mathrm{C}}\right)^2 \times \left(1 - \frac{\rho_\mathrm{i}}{\rho_\mathrm{s}}\right)}{1 - \left(\frac{ID_\mathrm{C}}{OD_\mathrm{C}}\right)^2} \tag{8}$$

where

W_b is the unit buoyed weight of the casing, expressed in newtons per meter (pound-force per inch);

W is the unit weight of casing in air, expressed in newtons per meter (pound-force per inch);

f_b is the buoyancy factor (dimensionless);

ID_C is the inside diameter of the casing, expressed in meters (inches);

OD_C is the casing outside diameter, expressed in meters (inches);

ρ_i is the density of the fluid inside the casing, expressed in kilograms per cubic meter (pound-mass per gallon);

ρ_s is the density of the casing (i.e. steel), expressed in kilograms per cubic meter (pound-mass per gallon);

ρ_e is the density of the fluid outside the casing, expressed in kilograms per cubic meter (pound-mass per gallon).

9.3.3 Discussion

The buoyed weight of the casing being cemented changes during a cementing operation. As the densities of the fluids inside the casing and the annulus change, the relative buoyed weight tends to reach a maximum when the casing is full of the highest density fluid (i.e. cement slurries), and a minimum when the highest density fluid is completely 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 should be considered throughout the cementing operation. This is illustrated by the Figure 20 The calculated centralizer spacing can vary depending on the selection of fluid densities present during the cement placement. The *SOR* will change as the fluid densities change, and the user should note at what point during the cement job the required centralization *SOR* needs to be met, and the appropriate buoyed weight for use in the calculations. Figure 20 shows how *SOR* changes throughout the cementing operation, with the lower standoff in the middle of the cement job, where the buoyant weight is the high and the cement slurries inside the casing.

Although these simulations are for a horizontal well, this may also happen with lower inclination wells, leading to pipe-to-wall contact. Surveys should be used when available or additional wellbore tortuosity should be added to the planned survey. The assumption of a vertical well does not obviate the need for centralization.

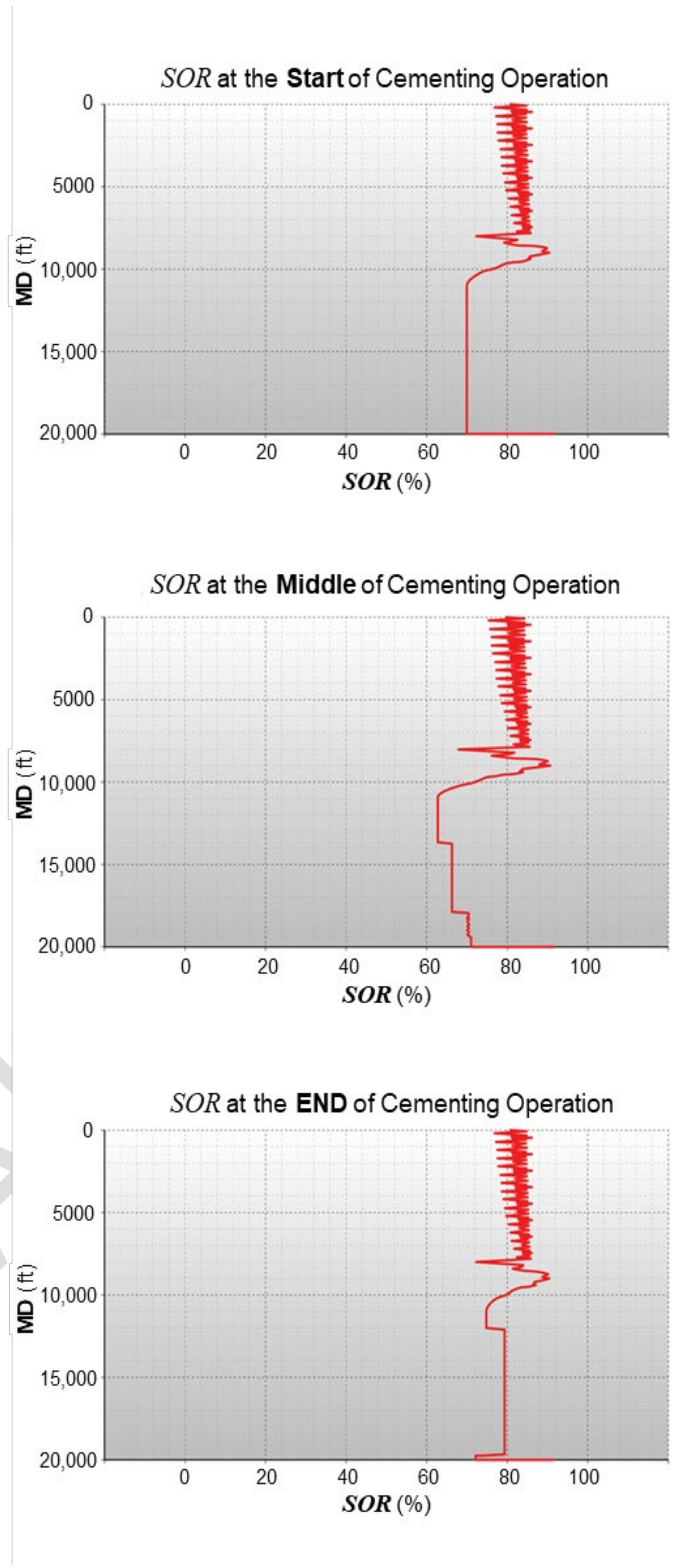


Figure 20 – Change of Standoff Ratio Throughout the Cementing Operation

9.4 Calculations for Centralizer Spacing

9.4.1 General

The equations for soft-string modelling are valid only for casing strings with axial tension and do not apply for casing strings under compression. The equations do not consider end effects, for example at the shoe, the wellhead, or the liner hanger. The equations are valid only for calculating the casing deflection between two identical centralizers. The lateral load calculations are based upon a soft-string model and do not take into effect casing stiffness. Additional models have been developed (Blanco [7]) that consider the effects of compression on the casing standoff and lateral loads. Some of these models are described in 9.8.

9.4.2 Casing deflection in a one-dimensional (1-D) straight, inclined wellbore without axial tension

In an inclined wellbore with no doglegs and negligible axial tension or compression in the casing, the casing deflection at the sag point between two centralizers shall be calculated using Equation (9).

$$\delta_{\max} = \frac{\left(W_{\mathrm{b}} \times \sin\theta\right) \times l_c{}^4}{384\left(E \times I\right)} \tag{9}$$

where

$\delta_{\max}$ is the maximum deflection of the casing between two (2) adjacent centralizers, expressed in meters (inches);

W_{b} is the unit buoyed weight of the casing, expressed in newtons per meter (pound-force per inch);

θ is the wellbore inclination angle, expressed in degrees;

l_{c} is the distance between two adjacent centralizers, expressed in meters (inches);

E is the casing modulus of elasticity (Young's modulus), expressed in pascals, i.e. N / m² (pound-force per square inch);

I is the casing moment of inertia of the casing , expressed in m^4 ($in.^4$).

with $$I = \frac{\pi \times \left(OD_{\mathrm{C}}{}^4 - ID_{\mathrm{C}}{}^4\right)}{64} \tag{10}$$

where OD_{C} and ID_{C} are respectively the casing OD and ID

The lateral load of a length of casing between 2 adjacent centralizers shall be calculated using Equation (11).

$$F_{\mathrm{l}} = w_{\mathrm{b}} \times l_{\mathrm{c}} \times \sin\theta \tag{11}$$

where

F_l is the lateral load of a length of casing between two (2) adjacent centralizers, expressed in newtons (pound-force).

9.4.3 Casing deflection in a 3-D wellbore

Casing deflection in wellbores with changes in inclination and azimuth should be calculated using the following formulae derived by Juvkam-Wold and Wu [8].

Between two (2) adjacent centralizers, the deflection of the casing results from a total lateral force (F_l) which can be decomposed between a lateral load in the dogleg plane ($F_{l,dp}$) and a load perpendicular to the dogleg plane ($F_{l,p}$).

To calculate the total load in the dog leg plane ($F_{l,dp}$) of a length of casing between two (2) centralizers (l_c) in the wellbore dogleg plane:

– Equation (12) shall be used in a drop-off wellbore where the inclination decreases with increasing MD

$$F_{l,dp} = \left(W_b \times l_{cent} \times \cos\gamma_n\right) + \left(2F_t \times \sin\frac{\beta}{2}\right) \tag{12}$$

– Equation (13) shall be used in a build-up wellbore where the inclination increases with increasing MD.

$$F_{l,dp} = \left(W_b \times l_{cent} \times \cos\gamma_n\right) - \left(2F_t \times \sin\frac{\beta}{2}\right) \tag{13}$$

And using Equations (14) and (15) to calculate $\cos\gamma_n$ and β

$$\cos\gamma_n = \frac{\sin\left[(\theta_1 - \theta_2)/2\right]}{\sin(\beta/2)} \times \sin\left(\frac{\theta_1 + \theta_2}{2}\right) \tag{14}$$

$$\beta = \cos^{-1}\left[\cos\theta_1 \cos\theta_2 + \sin\theta_1 \sin\theta_2 \cos(\phi_2 - \phi_1)\right] \tag{15}$$

where

$F_{l,dp}$ is the total lateral load in the dogleg plane, expressed in newtons (pounds-force);

F_t is the axial tension force below the centralizer, expressed in newtons (pound-force).

W_b is the unit buoyed weight of the casing, expressed in newtons per meter (pound-force per inch);

l_c is the distance between two (2) adjacent centralizers, expressed in meters (inches);

θ_1 is the wellbore inclination angle at the top of the upper centralizer (i.e. top of l_c), expressed in degrees;

θ_2 is the wellbore inclination angle at the bottom of the lower centralizer (i.e. bottom of l_c), expressed in degrees;

ϕ_1 is the wellbore azimuth angle at the top of l_c, expressed in degrees;

ϕ_2 is the wellbore azimuth angle at the bottom of l_c , expressed in degrees;

γ_n is the angle between the gravity vector and the principal normal of the wellbore, expressed in degrees;

To calculate the total load ($F_{l,p}$) of a length of casing between two (2) adjacent centralizers (l_c) perpendicular to the wellbore dogleg plane, Equation (16) shall be used.

$$F_{l,p} = W_b \times l_{cent} \times \cos\gamma_0 \tag{16}$$

with

$$\cos\gamma_o = \frac{\sin\theta_1 \sin\theta_2 \sin(\phi_2 - \phi_1)}{\sin\beta} \tag{17}$$

where

$F_{l,p}$ is the total lateral load perpendicular to the dogleg plane, expressed in newtons (pounds-force);

γ_o is the angle between the gravity vector and the binormal of the wellbore, expressed in degrees;

The total lateral load, F_l, of a length of casing between two (2) adjacent centralizers (l_c) in the dogleg plane shall be given using Equation (18).

$$F_l = \sqrt{{F_{l,dp}}^2 + {F_{l,p}}^2} \tag{18}$$

and, the maximum deflection, δ_{max}, between the two (2) adjacent centralizers, expressed in meters (inches), shall be calculated using Equations (19) and (20).

$$\delta_{max} = \left(\frac{F_l \times {l_c}^3}{384 E \times I}\right) \times \left(\frac{24}{\mu^4}\right) \times \left(\frac{\mu^2}{2} - \frac{\mu \times (\cosh\mu - 1)}{\sinh\mu}\right) \tag{19}$$

with μ, axial load factor given using Equation (20):

$$\mu = \left(\frac{F_t \times l_c^2}{4E \times I} \right)^{0.5} = \frac{l_c}{2} \sqrt{\frac{F_t}{E \times I}} \tag{20}$$

where

F_t is the axial tension force below the centralizer, expressed in newtons (pound-force).

9.4.4 Importance of stiff-string models in centralizer design

Due to the simplicity and the fact of being user friendly, soft-string torque & drag models have been extensively utilized in the oilfield well operation. Field experience indicates that the soft-string model generally works well. For example, H-S Ho [9] concluded that soft-string model provides reasonable estimate of force and torque when the trajectory is reasonably smooth. However, the soft-string model does not work well in complex wells because it ignores the effect of pipe stiffness, shear stress, and hole clearance. Consequently, the soft-string model is less sensitive to tortuosity and generally underestimates the contact forces and drag. However, contact and axial forces are important factors in the centralizer placement optimization as they affect casing and centralizer deflection. In general, tensile axial force will make casing behave stiffer, thus there is less deflection when casing is under tension. In addition, there is larger deflection in bow string centralizer when it is exerted by larger contact forces. As a result, centralizer placement optimization and casing deflection calculation requires stiff-string models to better predict axial and contact forces.

9.4.5 Stiff-string torque & drag model

Several stiff-string models have been developed to consider the stiffness effect and to improve the torque & drag calculation. In 9.4.5, three stiff-string torque & drag models which have been applied in the industry are be presented.

9.4.5.1 Wu and Juvkam-Wold model

Wu and Juvkam-Wold [10] developed a simple model to consider the effect of pipe stiffness in the torque & drag modeling. In this model, the author calculated the additional lateral contact force due to pipe bending based on the beam theory and added it to the soft-string model. The additional lateral contact force shall be calculated using Equations (21) and (22).

$$P = \frac{48 \times E \times I \times \left(f_w - r \right)}{L^3} \tag{21}$$

with

$$f_w = \frac{L^2}{8R} \tag{22}$$

where

P is the pipe bending lateral contact force, expressed in newtons (pounds-force);

E is the modulus of elasticity of the casing, expressed in pascals, i.e. N/m² (pound-force per square inch);

I is the casing moment of inertia, expressed in m^4 ($in.^4$) (see Equation (10)

r is the wellbore clearance, expressed in meters (inches);

L is the length of curved wellbore section, expressed in meters (inches);

f_w is the wellbore deflection restriction, expressed in meters (inches);

R is the wellbore curvature radius, expressed in meters (inches).

This analytical approximation model should be easy to implement and can provide reasonable results in most field case studies.

9.4.5.2 Ho Model

The second stiff-string model was developed by H-S Ho [9]. This model assumes that the drillstring is in continuous contact with wellbore. The author developed the stiff-string torque & drag model by considering the equilibrium condition in 3D well trajectories. The equilibrium equations are derived in Frenet coordinate system ($\vec{t}, \vec{n}, \vec{b}$) and should be shown as given by Equations (23) and (24).

NOTE Frenet coordinate system is a base vector in natural curvilinear system with:

- $\vec{t}$ uphole tangential direction;
- $\vec{n}$ principal normal direction, and
- $\vec{b}$ binormal direction.

$$\frac{d\vec{T}}{ds} + \overrightarrow{f_c} + \overrightarrow{W_b} = 0 \tag{23}$$

$$\frac{d\overrightarrow{M}}{ds} + \left(\vec{t} \times \vec{T}\right) + \vec{m} = 0 \tag{24}$$

where:

T is the axial load force, expressed in newtons (pounds-force per square inches);

M is the resultant internal moment (torque and drag forces), expressed in newtons (pounds-force);

f_c is the lateral load force, expressed in newtons (pounds-force);

W_b is the unit buoyed weight of the casing, expressed in newtons per meter (pound-force per inch);

m is the moment due to the contact force (drag and torque), expressed in newtons (pounds-force);

s is the measured depth along the wellbore axis, expressed in meters (inches);

t is the direction of the tangent to the wellbore curvature.

Because the casing string is assumed in continuous contact with wellbore, the principle component of M in vector $\vec{n}$ is 0 and the component of M in vector $\vec{b}$ (torque load), should be expressed in terms of wellbore curvature as given by Equation (25).

$$M_b = \beta \times E \times I \tag{25}$$

where

M_b is the torsional load, expressed in newtons (pounds-force);

β is the wellbore curvature, expressed in radians per meter.

As a result, the equilibrium equations can be simplified into one moment-equilibrium equation and three force-equilibrium equations. With boundary conditions, the differential system of four equilibrium equations can be solved using integration to obtain axial force, torque, and drag forces.

9.4.5.3 Belaid model

The third stiff-string model was developed by Belaid [11]. Though many stiff-string models have been developed to consider the stiffness effect, most of them assume the drillstring is in continuous contact with the wellbore. The industry has realized that a stiff-string model with a contact algorithm is necessary for more accurate torque & drag calculation. To overcome this shorting coming, Belaid calculates the unknown contact points between the drillstring and wellbore, which simulates more realistic 3D drillstring geometry. In this model, the drillstring is discretized with small and uniform-size beam elements. Besides the equilibrium equations, this model also solves the displacement equations for a casing string which should be shown by Equation (26) and (27).

$$\frac{\mathrm{d}\vec{w}}{\mathrm{d}s} = \frac{1}{E \times I}\left[\vec{M} - \left(\vec{M} \times \vec{t}\right) \times \vec{t}\right] - \left(\vec{t} \times \frac{\mathrm{d}\vec{t}}{\mathrm{d}s}\right) \tag{26}$$

$$\frac{\mathrm{d}\vec{u}}{\mathrm{d}s} = \vec{w} \times \vec{t} \tag{27}$$

where

w is the casing rotation, expressed in radians per second;

u is the casing displacement, expressed in meters per second (inches per second);

M is the resultant of the internal moment, expressed in newtons (pounds-force);

s is the measured depth along the wellbore axis, expressed in meters (inches)

t is the direction of the tangent to the wellbore curvature.

The coupling of equilibrium and displacement equations is generally solved by the finite element method (FEM). To overcome the large computation cost, Belaid also developed a novel numerical algorithm using a direct integration of equilibrium and displacement equations, which runs much faster than FEM.

The torque and drag model used may also have a significant impact of the predicted standoff, both at the centralizers and at midspan. This is illustrated in Figure 23. Figure is showing the predicted SOR with bow spring centralizers, at the centralizers and at midspan and using modified Wu's stiff-string and soft-string models. The side forces predicted with the stiff-string model are higher and in both graphs the resulting SOR is lower than with the soft-string model.

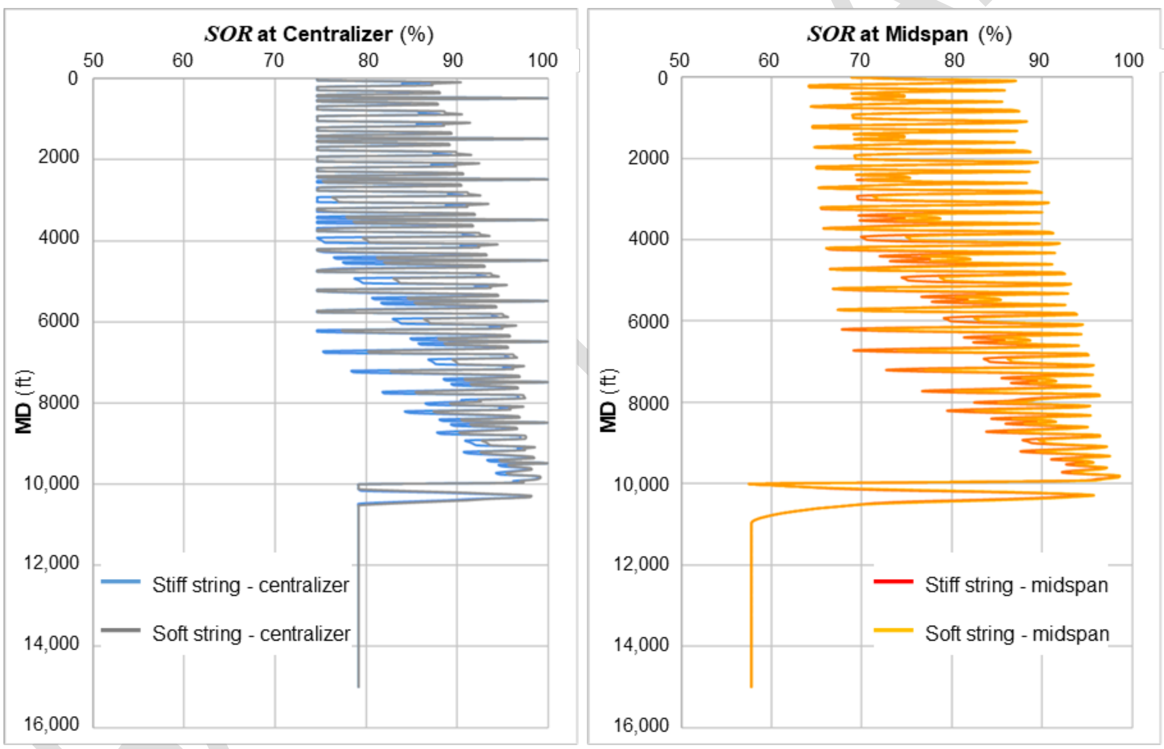


Figure 21—Predicted Standoff Ratio- Effect of Soft-string vs Stiff-string Modeling

10 Testing Stop-collars

10.1 General

For the purposes of this testing procedure, the term "stop-collar" is used to indicate any type of device employed to prevent or limit movement of a centralizer on the casing. This includes stop-collars that are independent of the centralizer and holding devices that are built into the centralizer, as in the case of solid or rigid centralizers. In this section, the principles described for centralizers apply to other casing hardware that incorporate the use of a stop-collar. Examples of these include cement baskets, scratchers, etc.

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 specific holding device.

Regardless of the mechanism used to hold the centralizer in place, the holding device shall 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.

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 have a constant O D . The minimum holding force 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 forces can vary depending on how the centralizer 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 can provide different results for some centralizers.

Further information indicates that the casing grade, mass, and surface finish 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 mass as are to be used for the well.

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 can 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 are insufficient data currently available to make a firm conclusion or recommendation on loading rates. Associated with the loading rate is the way 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 procedure is to provide 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 may require replacement of the test casing and the stop-collar following each test.

10.2 Apparatus

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

10.2.1 Test assembly,

Test assembly shall consist of an inner test casing and an outer sleeve (see Figure 22).

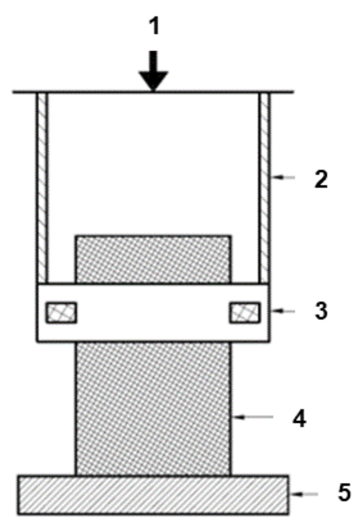
The test casing shall be within the tolerances as indicated in ISO 11960 for non-upset pipe. Burrs or similar defects should be removed prior to testing. The outer sleeve should provide a load surface on which to distribute the load to the stop device. Minor notching of the outer sleeve to allow for concentric loading is acceptable.

10.2.2 Instrumentation

The instrumentation should be capable of recording or otherwise indicating the application of vertical loads, including the maximum load applied during the test as well as the load at initiation of slippage (the holding force) and the slippage force range. The accuracy of load measurements should be within 5 % of the measured value.

The test stand shall be instrumented to allow displacement readings of at least 1,5 mm (or 1/16 in.), or less of displacement, with an accuracy of ±0,8 mm 1/32 in.) within the range of measurement.

Measuring equipment shall be calibrated at least annually.



Key

1	applied force
2	outer sleeve
3	stop-collar
4	test casing
5	Rigid surface

Figure 22 — Typical Stop-collar Test Assembly

10.3 Test Procedure

To test holding performance of stop-collar the following procedure shall be followed.

a) Install the stop-collar on the test casing per manufacturer's recommendations. Installation position should allow for at least 102 mm (4 in.) of travel during the test.

b) The outer sleeve is placed over the test casing. This applies a concentric load to the stop-collar.

c) Load the outer sleeve continuously and slowly. Record the applied load, plus the mass of the outer sleeve.

d) Continue the test by applying continuously load until the stop- collar has been displaced at least 102 mm (4 in.) or completely fails (breaks).

10.4 Reporting of Test Results

The following information shall be reported. A typical form for test results is given in Annex A:

a) size, mass, 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, noting 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) identification of any minor modifications made to the end of the outer sleeve to allow for concentric loading;

i) stop-collar manufacturer, model number, nominal sizes, number and type of attachments, installation torque on attachment device, if applicable.

Annex A
(informative)

Documentation of Stop-collar Test Results

A.1 General

The form in this annex should be intended for free exchange between owners/operators of the equipment or users of API 10D-2.

A.2 Results of Performance Tests on Stop-collar

A.2.1 Stop-collar information

Manufacturer: ________________________

Part Number: ________________________

Model Number: ________________________

Casing size: __________________ mm (in.)   Installation torque (if applicable): _________

A.2.2 Test Data Reference

Specimen Number: ________________________

Date of test: ______________________________

A.2.3 Dimensional data

A.2.3.1 Test assembly characteristics (see API 10 D-2)

Part	OD mm (in.)	ID mm (in.)	Mass kg (lbm)
Test casing			
Outer sleeve			
Stop-collar			

A.2.3.2 Test casing

Diameter : _____________ mm (in.)

Linear mass :___________ kg/m (lbm/ft)

Grade : __________

Surface finish : ___________

A.2.4 Test parameters

Holding force (maximum load prior to slippage):______________________N (lbf)

Time to maximum load:____________________ s

Load rate:_______________________________/_______________= N/s (lbf/s)

Slippage force range: Max. load:_____________________N (lbf)

Min. load:_____________________N (lbf)

A.2.5 Post-test Casing Inspection

Scarring: ________

Scar depth: _________ mm (in.)

Scar length: _________ mm (in.)

Scar width: ________ mm (in.)

A.2.6 Comments

____

____

____

____

____

Tests performed by: _________________ Title: ______________________

Signature: _________________________ Contact Information: _____________________

Date Signed : ______________________

Tests witnessed by : _________________

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