Specification for Drilling and Well Servicing Structures

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Specification for Drilling and Well Servicing Structures

1 Scope

This specification states requirements and gives recommendations for suitable steel structures for drilling and well servicing operations in the petroleum industry, provides a uniform method of rating the structures, and provides two product specification levels (PSLs).

This specification is applicable to all new steel derricks, masts (including masts with guy lines and service rig masts), substructures, and crown block assemblies with a date of manufacture after the effective date of this specification.

Annex A provides standard supplementary requirements (SRs) that apply only if specified by the purchaser. Annex B is an informative annex to assist in an understanding/application of this API specification. Annex C is an informative annex regarding the API Monogram Program and the API Monogram marking requirements. Annex D is an informative annex providing guidelines to assist the purchaser with purchasing equipment manufactured to the requirements in this API document.

2 Normative References

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any addenda) applies.

API Bulletin 2INT-MET, *Interim Guidance on Hurricane Conditions in the Gulf of Mexico*

API Recommended Practice 2A-WSD, *Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design*

API Recommended Practice 4G, *Recommended Practice for Use and Procedures for Inspection, Maintenance, and Repair of Drilling and Well Servicing Structures*

API Recommended Practice 9B, *Recommended Practice on Application, Care and Use of Wire Rope for Oilfield Service*

API Specification 8C, *Specification for Drilling and Production Hoisting Equipment (PSL 1 and PSL 2)*

API Specification 9A, *Specification for Wire Rope*

ANSI/AISC 360-16, *Specification for Structural Steel Buildings*

ASCE/SEI 7-05,[1] *Minimum Design Loads for Buildings and Other Structures*

ASTM A370,[2] *Standard Test Methods and Definitions for Mechanical Testing of Steel Products*

ASTM A578/A578M, *Standard Specification for Straight-Beam Ultrasonic Examination of Rolled Steel Plates for Special Applications*

AWS D1.1/D1.1M,[3] *Structural Welding Code—Steel*

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1 American Society of Civil Engineers, 1801 Alexander Bell Drive Reston, Virginia 20191, www.asce.org.

2 ASTM International, 100 Barr Harbor Drive, PO Box C700, West Conshohocken, Pennsylvania 19428-2959, www.astm.org.

3 American Welding Society, Incorporated, 8669 NW 36 Street, # 130, Miami, Florida 33166-6672, www.aws.org.

ISO 19901-1, *Part 1, Metocean Design and Operating Considerations*

ISO 9712,[4] *Non-destructive Testing—Qualification and Certification of Personnel*

3 Terms and Definitions

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

3.1
appurtenances
All components attached to but not part of the *bare drilling structure*.

3.2
bare drilling structure
The structural members of the drilling structure including crown, water table, and gin pole as applicable.

3.3
clear height
Minimum vertical distance. For derrick and mast without guy lines, this means from the top of the working floor to the bottom of the crown block support beams. For mast with guy lines, this means from the top of the working floor to the bottom of the crown block support beams. For service rigs with guy lines, this means from the ground to the bottom of the crown block support beams.

3.4
critical component
Component that is necessary to maintain stability of a structure and that resides within the primary load paths of the structure when the structure is loaded under the design loadings of Section 7.

3.5
critical weld
Weld that joins critical components.

3.6
crown block assembly
The set of components including sheave or block assemblies installed at the top of a derrick or mast to support the hook load.

3.7
date of manufacture
Date chosen by the manufacturer occurring between the initiation of manufacture and the delivery to the purchaser.

3.8
derrick
Structural tower, of square or rectangular cross section, having members that are latticed or trussed on all four sides.

NOTE It may or may not be guyed.

3.9
design load
Force or combination of forces that a structure is designed to withstand without exceeding the allowable member strength in any member.

[4] International Organization for Standardization, Chemin de Blandonnet 8, CP 401, 1214 Vernier, Geneva, Switzerland, www.iso.org.

3.10
design reference wind velocity
V_{ref}
The wind velocity of a 3-second gust at a 10 m (33 ft) reference elevation, in knots, for the appropriate return period at the intended drilling location.

3.11
design validation
The process of proving a design to demonstrate conformity of the product to design requirements.

3.12
design verification
The process of examining the result of design and development output to determine conformity with specified requirements.

3.13
dynamic loading
Loading imposed upon a structure as a result of motion.

3.14
erection load
Load produced in the mast and its supporting structure during its raising and lowering, or in the substructure during its raising and lowering.

3.15
guide tracks and dollies
Equipment used to hold the traveling equipment in correct position relative to the derrick during various operations.

NOTE A retractable dolly is used move the traveling equipment horizontally between the drilling position and the retracted position.

3.16
guy line
Wire rope with one end attached to the mast assembly and the other end attached to a suitable anchor to provide structural and/or lateral support for a mast under design loading conditions.

3.17
guying pattern
Plan view showing the manufacturer's recommended locations for guy lines and their distance out to the anchors with respect to the centerline of the well.

3.18
heave
Distance of movement from above or below horizontal.

3.19
impact loading
Loading resulting from near-instantaneous changes of forces.

3.20
mast
Structural latticed tower of rectangular cross section with an open face.

3.21
mast setup distance
Distance from the centerline of the well to a designated point on the mast structure defined by a manufacturer to assist in the setup of the rig.

3.22
maximum rated design wind velocity
V_{des}
The wind velocity after adjustment for SSL by the onshore or offshore factor of a 3-second gust at a 10 m (33 ft) reference elevation, in knots, used to calculate the force that the drilling structure is designed to resist.

3.23
maximum rated static hook load
Load composed of the weight of the traveling equipment and a static load applied to the traveling equipment.

NOTE It is the largest load that can be applied to the structure within the guidelines imposed by this standard with a specified number of lines strung to the traveling block and in the absence of pipe setback, sucker rod, or wind loading. A designated location of the deadline anchor and drawworks is assumed.

3.24
nominal wire rope assembly strength
Nominal strength of the wire rope, multiplied by the efficiency of the end attachment in accordance with API 9B.

3.25
period (of roll, pitch or heave)
τ
Time required for a complete cycle.

3.26
pipe lean
Angle between the vertical and a typical stand of pipe in the setback.

3.27
product specification level
PSL
Level of material and process controls placed upon the primary load-carrying components of the covered equipment.

3.28
racking platform
Platform located at a distance above the working floor for laterally supporting the upper end of racked pipe.

3.29
rated setback
Maximum weight of tubular goods that can be supported by the substructure in the setback area.

3.30
rated static rotary load
Maximum weight that can be supported by the rotary-table support beams.

3.31
rod board
Platform for supporting rods that is located at a distance above the working floor.

3.32
roll
pitch
Angle of movement to one side from vertical.

3.33
service rig mast
A mast designed with ratings for operations with or without setback or rods.

NOTE See Table 3.

3.34
structural safety level
SSL
The classification of a drilling structure application by a purchaser to reflect various degrees of consequence of failure, considering life safety and other issues such as pollution, economic loss, and public concern.

3.35
substructure
Structure(s) through which the mast load, hook load, rotary load, and/or setback load are transmitted.

3.36
wind environment
The combination of rig configuration and load combinations to be considered with a given wind loading.

4 Product Specification Levels

This standard establishes requirements for two PSLs for drilling and well servicing structures that define two levels of technical and quality requirements. These requirements reflect practices currently being implemented by a broad spectrum of the manufacturing industry. PSL 1 includes practices currently being implemented by a broad spectrum of the manufacturing industry. PSL 2 includes all the requirements of PSL 1 plus additional requirements.

5 Marking and Information

5.1 Nameplate

Drilling and well servicing structures manufactured in accordance with this standard shall be identified by a nameplate bearing at least the information specified in 5.2 through 5.5, including the units of measurement where applicable. Markings shall be either raised or stamped. The nameplate shall be securely affixed to the structure in a conspicuous place.

5.2 Derrick and Mast Nameplate Information

NOTE See 5.3 for nameplate information for service rig masts.

The following information shall be provided:

a) manufacturer's name;

b) manufacturer's address;

c) date of manufacture, including month and year;

d) serial number;

e) clear height, m (ft);

f) maximum rated static hook load with guy lines, if applicable, for stated number of lines to traveling block, KN (short tons);

g) maximum rated design wind velocity, V_{des} at reference elevation of 10 m (33 ft) above mean sea level or ground, in knots, for 3-second gust duration with guy lines, if applicable, *with* rated capacity of pipe racked in racking platform, m/s (knots);

h) maximum rated design wind velocity, V_{des}, at reference elevation of 10 m (33 ft) above mean sea level or ground, in knots, for 3-second gust duration with guy lines, if applicable, *without* pipe racked in racking platform, m/s (knots);

i) elevation of base of derrick or mast above mean sea level or ground used in design for wind loading, m (ft);

j) API 4F, Fifth Edition;

k) manufacturer's guying pattern, if applicable;

l) the following text:

CAUTION—Acceleration or impact loading, also setback, rods, and wind loads will reduce the maximum rated static hook load capacity.

m) manufacturer's load distribution diagram (may be placed in mast instructions);

n) graph plotting allowable static hook load for wind velocities varying from zero to maximum design rated wind velocity, V_{des}, with full rated setback and with maximum number of lines to traveling block;

o) mast setup distance for mast with guy lines, m (ft);

p) PSL 2, if applicable; and

q) supplementary information as specified in the particular SR, if applicable (see Annex A).

5.3 Service Rig Mast Nameplate Information

The following information shall be provided:

a) manufacturer's name;

b) manufacturer's address;

c) date of manufacture, including month and year;

d) serial number;

e) clear height, m (ft);

f) maximum rated static hook load with guy lines, if applicable, for stated number of lines to traveling block, KN (short tons);

g) allowable static hook load with guy lines, if applicable, for stated number of lines to traveling block, KN (short tons) in combination with rated capacity of pipe racked and maximum rated capacity of rods hung in mast, KN (short tons), if applicable;

h) maximum rated design wind velocity, V_{des}, at reference elevation of 10 m (33 ft) above mean sea level or ground, in knots, for 3-second gust duration with guy lines, if applicable, *with* rated capacity of pipe racked on racking platform, m/s (knots);

i) maximum rated design wind velocity, V_{des}, at reference elevation of 10 m (33 ft) above mean sea level or ground, in knots, for 3-second gust duration with guy lines, if applicable, *without* pipe racked on racking platform, m/s (knots);

j) elevation of base of derrick or mast above mean sea level or ground used in design for wind loading, m (ft);

k) API 4F, Fifth Edition;

l) manufacturer's guying pattern, if applicable;

m) the following text:

CAUTION—Acceleration or impact loading, also setback, rods, and wind loads will reduce the maximum rated static hook load capacity.

n) manufacturer's load distribution diagram (may be placed in mast instructions);

o) graph plotting allowable static hook load for wind velocities varying from zero to maximum design rated wind velocity, V_{des}, with full rated setback but no rods and with maximum number of lines to traveling block;

p) mast setup distance for mast with guy lines, m (ft);

q) PSL 2, if applicable; and

r) supplementary information as specified in the particular SR, if applicable (see Annex A).

5.4 Substructure Nameplate Information

The following information shall be provided:

a) manufacturer's name;

b) manufacturer's address;

c) date of manufacture, including month and year;

d) serial number;

e) maximum rated static hook load, KN (short tons);

f) maximum rated static rotary capacity, KN (short tons);

g) maximum rated pipe setback capacity, KN (short tons);

h) maximum combined rated static hook and rated setback capacity, KN (short tons);

i) maximum combined rated static rotary and rated setback capacity, KN (short tons);

j) for substructures that support a mast or derrick, the following apply:

— maximum rated design wind velocity, V_{des}, at reference elevation of 10 m (33 ft) above mean sea level or ground, in m/s (knots), for 3-second gust duration with guy lines, if applicable, *with* rated capacity of pipe racked;

— maximum rated design wind velocity, V_{des}, at reference elevation of 10 m (33 ft) above mean sea level or ground, in m/s (knots), for 3-second gust duration with guy lines, if applicable, *without* pipe racked;

— elevation of base of substructure above mean sea level or ground used in design for wind loading, m (ft);

k) API 4F, Fifth Edition;

l) PSL 2, if applicable; and

m) supplementary information as specified in the particular SR, if applicable (see Annex A).

5.5 Crown Block Assembly Nameplate Information (Required Only for Crown Block Assemblies for Use with Derricks)

The following information shall be provided:

a) manufacturer's name;

b) manufacturer's address;

c) date of manufacture, including month and year;

d) serial number;

e) maximum rated static hook load, KN (short tons);

f) API 4F, Fifth Edition;

g) PSL 2, if applicable; and

h) supplementary information as specified in the particular SR, if applicable (see Annex A).

6 Structural Safety Level

Drilling structures are qualified according to their SSL. The selection of the expected or the unexpected SSL (e.g. SSL E2/U1) is, by agreement, between the manufacturer and the purchaser for each specific location. For a given SSL and location, the design environmental conditions may be developed from the guidelines that follow.

The SSL level reflects various degrees of consequence of failure, considering life safety and other concerns such as pollution, economic loss, and public concern. It also reflects the expectation (expected or unexpected) of the environmental event. These SSLs are shown in Table 1 below. Each structure will have two SSLs, the first for the expected environmental event, the second for the unexpected environmental event (e.g. SSL E2/U1).

Table 1—Structural Safety Levels for Drilling Structures

Life Safety	Other Concerns (Pollution, Economic Loss, Public Concern, etc.)		
	High	Medium	Low
High	E1 or U1[a]	E1 or U1[a]	E1 or U1[a]
Medium	E1 or U1[a]	E2 or U2[b]	E2 or U2[b]
Low	E1 or U1[a]	E2 or U2[b]	E3 or U3[c]

[a] Structural Safety Level E1 or U1—Structures with high consequences of failure.
[b] Structural Safety Level E2 or U2—Structures with medium consequences of failure.
[c] Structural Safety Level E3 or U3—Structures with low consequences of failure.

The prefix E refers to an *expected* environmental event, such as a large hurricane or storm, where preparation can be made prior to the event. The prefix U refers to an *unexpected* environmental event, such as a sudden storm or earthquake, which does not allow for sufficient preparations. When a structure is evacuated in advance of an expected severe event, the SSL for the manned event may differ from the SSL for the evacuated severe event.

Transportable Drilling "Nonstationary" Structures—Drilling structures are commonly used in different locations during their lifetime, and the evaluation of their suitability for use in a given location must therefore account for the environmental conditions at that location, installation elevation, and the SSL of the new installation.

For identical SSLs, the design wind load for a *derrick* or *mast* is no different whether it is on a fixed or mobile installation (e.g. platform rig, jack-up, semi-submersible, or drillship).

7 Design Loading

Each drilling structure shall be designed for combinations of loads in accordance with Table 2 or Table 3, as applicable. The structures shall be designed to meet or exceed these conditions in accordance with the applicable design specifications of Section 8.

Table 2—Design Loadings for Drilling Structures [a]

Case	Design Loading Condition	Dead Load [b] (%)	Hook Load [c d] (%)	Rotary Load (%)	Setback Load [d e] (%)	Environmental Loads [f]
1a	Operating	100	100	0	100	100 % operating environment
1b	Operating	100	TE	100	100	100 % operating environment
2	Expected	100	TE	100	0	100 % expected storm environment
3a	Unexpected	100	TE	100	100	100 % unexpected storm environment
3b	Unexpected	100	As applicable	As applicable	As applicable	100 % earthquake
4	Erection	100	As applicable	As applicable	0	100 % erection environment
5	Transportation	100	As applicable	As applicable	As applicable	100 % transportation environment

[a] Excludes service rig masts (see Table 3).
[b] For stability calculations, lower values of dead load shall be considered as in 8.10.
[c] For nonoperating wind environments, the weight of all traveling equipment and drill lines suspended from the crown (TE) shall be considered in all load cases, as applicable.
[d] Substructures that do not support a mast or derrick need not be designed for hook load. Similarly, substructures that do not support setback need not be designed for setback load.
[e] Pipe lean is a component of setback loading that shall be considered.
[f] Environmental loads include the full design sail area for setback in racking platform, if applicable.

Table 3—Design Loadings for Service Rig Masts

Case	Design Loading Condition	Dead Load [a] (%)	Hook Load [b] (%)	Rod Load (%)	Setback Load (%)	Environmental Loads [c]
1a	Operating	100	100	0	0	100 % operating environment
1b	Operating	100	TBD	100	0	100 % operating environment
1c	Operating	100	TBD	100	100	100 % operating environment
2	Expected	100	TE	0	0	100 % expected storm environment
3a	Unexpected	100	TE	100	100	100 % unexpected storm environment
3b	Unexpected	100	As applicable	As applicable	As applicable	100 % earthquake
4	Erection	100	As applicable	0	0	100 % erection environment
5	Transportation	100	As applicable	As applicable	As applicable	100 % transportation environment

[a] For stability calculations, lower values of dead load shall be considered as in 8.10.
[b] For nonoperating wind environments, the weight of all traveling equipment and drill lines suspended from the crown (TE) shall be considered in all load cases, as applicable.
[c] Environmental loads include the full design sail area for setback and rods in the racking platform or rod board, if applicable.

8 Design Specification

8.1 Allowable Strength

8.1.1 General

The steel structures shall be designed in accordance with the Allowable Strength Design code in ANSI/AISC 360-16, except as further specified in this standard. ANSI/AISC 360-16 shall be used in determining allowable member strength. Use of load factor and resistance design (LFRD) is not allowed. ANSI/AISC 360-16 shall be used for determination of allowable member strength except that current practice and experience do not dictate the need to follow ANSI/AISC 360-16 for "members and their connections subject to fatigue loading" (Section B3.11) unless specified by the purchaser and for the consideration of secondary loads.

NOTE Derricks, masts, and substructures for drilling rigs fall outside the defined scope of the ANSI/AISC 360-16 specification. AISC recognizes this and recommends that the use of the AISC specification outside of the defined scope be used with engineering judgement as it relates to the specific industry.

For the purposes of this standard, axial loads (tension or compression) are defined as primary loads in individual members of a latticed or trussed structure. Moments in the individual members of a latticed or trussed structure resulting from elastic deformations and rigidity of joints are defined as secondary loads. These secondary loads may be taken to be the differences between loads from an analysis assuming fully rigid joints, with loads applied only at the joints, and those loads from a similar analysis with pinned joints.

Loads arising from eccentric joint connection, or from transverse loading of members between joints, or from applied moments shall be considered primary loads.

When axial loads are the intended primary loads, allowable member strength may be increased by 10 %. This shall apply to members that have a plastic section modulus/elastic section modulus (Z/S) ratio of 1.2 or less when secondary loads are computed and added to the primary loads in individual members, for all loadings except earthquake. The 10 % increase in allowable member strength shall not be used when the Z/S ratio exceeds 1.2. The Z/S ratio is taken about either the major or minor member axis for the direction of the applied moment. Required strength due to primary loads shall not exceed the maximum allowable member strength. The increase in allowable member strength when secondary loads are considered may be taken in addition to the increases allowed in 8.1.2.

The allowable member strength is defined in ANSI/AISC 360–16 as the nominal strength (R_n) of the member divided by a safety factor (Ω). Allowable Strength= R_n/Ω. ANSI/AISC 360-16, Chapters D through K give further definition of the nominal strength and safety factor for the applicable limit states.

Earthquake loading and the related allowable strength are addressed specifically in 8.6. Ice Loading and related allowable strength are addressed specifically in 8.7.

8.1.2 Wind and Dynamic Allowable Strength Increases

For operating and erection conditions, allowable member strength shall not be increased (strength modifier = 1.0) over the basic allowable member strength defined in 8.1.1.

For transportation conditions, allowable member strength may be increased one-third (strength modifier = 1.33) over the basic allowable member strength defined in 8.1.1.

For the unexpected and expected design storm conditions, allowable member strength may be increased one-third (strength modifier = 1.33) over basic allowable member strength defined in 8.1.1.

For purposes of defining the nameplate graph of allowable static hook load vs wind velocity required by 5.2 n) or 5.3 o), a linear transition from a strength modifier of 1.0 for operating cases to 1.33 for the unexpected storm case may be used.

8.1.3 Wire Rope

The size and type of wire shall be as specified in API 9A and by API 9B.

A drilling structure raised and lowered by means of a wire rope assembly shall have the wire rope assembly designed to have a nominal strength of at least 2.5 times the maximum design load on the assembly during erection.

Guy lines shall be designed to have a nominal wire rope assembly strength of at least 2.5 times the maximum guy load resulting from a loading condition.

The strength of a wire rope assembly shall be derated for end connection efficiencies and for D/d ratios less than 18 in accordance with API 9B.

8.1.4 Crown Shafting

Crown shafts, including fastline and deadline sheave support shafts, shall be designed using an allowable stress method with a maximum allowed bending moment as in Equation (1).

$$Maximum\ allowed\ bending\ moment\ =\ 0.60\ F_y S \tag{1}$$

where

F_y = Specified Minimum Yield Strength of shaft material, psi

S = Elastic Section Modulus, in^3

Wire rope sheaves and bearings shall be specified in accordance with API 8C.

8.1.5 Hydraulic Cylinders for Mast and Substructure Erection

To design for combined bending and buckling of the hydraulic cylinders for mast and substructure erection for the expected raising loads over the entire raising envelope, ANSI/AISC 360-16, Chapter H shall be used as minimum criteria. This design shall account for cylinder mounting conditions and initial imperfections due to cylinder bearing tolerances.

8.2 Design for Stability

The stability analysis shall be performed for the drilling structure using any rational method that considers the following:

a) all member deformations;

b) second order effects;

c) geometric imperfections;

d) stiffness reduction due to inelasticity;

e) uncertainty in strength and stiffness.

NOTE There are various methods available for stability analysis. See Annex B Commentary for some of the acceptable methods.

8.3 Operating Loads

Operating loads shall consist of the following, alone or in combination per Table 2 and as specified by the purchaser:

a) maximum rated static hook load, in combination with fastline and deadline loads, for each applicable string up condition;

b) maximum rated static rotary load;

c) maximum rated setback load;

d) dead load of drilling structure assembly;

e) fluid loads in all piping and tanks incorporated in drilling structures (consideration shall be given to both full and empty tank conditions for stability calculations per 8.10);

f) additional simultaneous or independent loadings as agreed upon by the purchaser and the manufacturer due to ancillary equipment.

For all drilling structures, the manufacturer shall include in the rig manual a listing of all items with their total dry and wet weights used in the design. Additionally, the manufacturer shall state the total summation of weights and the first moment of these weights about the base of the drilling structure for both the dry and wet condition.

8.4 Wind Loads

8.4.1 Design Wind

8.4.1.1 General

Each drilling structure shall be designed for the applicable values of design wind as per 8.4. Substructures shall be designed for the same wind speeds as the structures they support.

Drilling structures are to be classified according to their SSL and according to their location: onshore or offshore. The SSLs for drilling structures reflect various degrees of consequence of failure and consider life safety and other issues such as pollution, economic loss, and public concern.

The configuration of the drilling structure during a given wind environment shall be considered. The following wind environments are defined:

a) operational wind—the wind below which unrestricted drilling operations may be continued;

b) erection wind—the wind below which normal rig erection operations may be continued;

c) transportation wind—the wind below which special transportation operations as specified by the purchaser may be continued;

d) unexpected wind—the wind from a sudden hurricane or storm where time for all preparations is insufficient and setback therefore needs to be considered in the computation of the wind loading;

e) expected wind—the wind from a known hurricane or storm where time is sufficient for preparations, such as lowering the setback.

8.4.1.2 Onshore Wind

The design reference wind velocity, V_{ref}, for the operating, erection, and transportation environments shall be as specified by the purchaser.

For nonoperating design environments on land in the United States, V_{ref} for expected storm conditions shall be obtained from the ASCE/SEI 7–05 wind speed map. For other onshore locations, V_{ref} shall be taken from a source such as a recognized standards agency or a governmental meteorological agency. The wind velocity chosen shall be a 3-second gust wind, in knots (1 knot = 1.15 mph), measured at 10 m (33 ft) in open terrain with an associated return period of 50 years.

For the unexpected wind condition where pipe setback might be racked in the drilling structure, V_{ref} shall be taken as no less than 75 % of the expected storm V_{ref}.

For each wind environment, the maximum rated design wind velocity, V_{des}, for various SSLs is then determined by Equation (2), multiplying the design reference wind velocity, V_{ref}, by an onshore multiplier, $\alpha_{onshore}$, as listed in Table 4 but not less than as specified in Table 6.

$$V_{des} = V_{ref} \times \alpha_{onshore} \tag{2}$$

The direction of the wind in all cases may be from any azimuth. The methodology for determining the local wind velocity to be used in the design is discussed in 8.4.1.4.

Table 4—Onshore Structural Safety Level Multiplier, $\alpha_{onshore}$

Case	Design Loading Condition	Structural Safety Level	SSL Multiplier $\alpha_{onshore}$	Approximate Return Period (years)
1a	Operating	All	1.00	—
1b	Operating	All	1.00	—
2	Expected	E1	1.07	100
2	Expected	E2	1.00	50
2	Expected	E3	0.93	25
3	Unexpected	U1	1.07	—
3	Unexpected	U2	1.00	—
3	Unexpected	U3	0.93	—
4	Erection	All	1.00	—
5	Transportation	All	1.00	—

Table 5—Offshore Structural Safety Level Multiplier, $\alpha_{offshore}$

Case	Design Loading Condition	Structural Safety Level	SSL Multiplier $\alpha_{offshore}$	Approximate Return Period (years)
1a	Operating	All	1.00	—
1b	Operating	All	1.00	—
2	Expected	E1	1.09	200
2	Expected	E2	1.00	100
2	Expected	E3	0.91	50
3	Unexpected	U1	1.09	—
3	Unexpected	U2	1.00	—
3	Unexpected	U3	0.91	—
4	Erection	All	1.00	—
5	Transportation	All	1.00	—

Table 6—Minimum Design Wind Speed m/s (knots), V_{des}

Structure	Onshore			Offshore		
	Operating and Erection	Unexpected	Expected	Operating and Erection	Unexpected	Expected
Guyed Masts	12.7 (25)	30.7 (60)	38.6 (75)	21.6 (42)	36 (70)	47.8 (93)
Unguyed Masts	16.5 (32)	30.7 (60)	38.6 (75)	21.6 (42)	36 (70)	47.8 (93)
Derricks	16.5 (32)	30.7 (60)	38.6 (75)	24.7 (48)	36 (70)	47.8 (93)

8.4.1.3 Offshore Wind

The design reference wind velocity, V_{ref}, for the operating, erection, and transportation environments shall be as specified by the purchaser.

For the expected wind design environment, V_{ref} for offshore drilling structures shall be taken from ISO 19901–1, except that velocities for structures to be used in the Gulf of Mexico shall be obtained from API Bulletin 2INT-MET. This value shall represent a 3-second gust wind, in knots (1.15 mph = 1 knot = 0.514 m/s), measured at 10 m (33 ft) in open water with an associated return period of 100 years. For areas not specifically covered by these specifications, V_{ref} shall be taken from a source such as a recognized standards agency or a governmental meteorological agency, or a site-specific study in accordance with ISO guidelines may be used.

For the unexpected wind condition where pipe setback might be racked in the drilling structure, V_{ref} shall be taken as 100 % of the expected storm V_{ref}, unless storm warning systems and rig operating procedures allow sufficient time for the laying down of setback before the expected wind storm event. In the Gulf of Mexico, V_{ref} for the unexpected wind condition shall be no less than 40.1 m/s (78 knots). For other tropical storm areas, site specific studies in accordance with ISO guidelines may be used to determine V_{ref} for the unexpected wind condition. This value shall represent a 3-second gust wind, in m/s (knots), measured at 10 m (33 ft) in open water with an associated return period of 100 years for the population of storms whose speed of formation and intensification allows sufficient warning to meet the operational window required for the safe laydown of a full setback.

For each wind environment, the maximum rated design wind velocity, V_{des}, for various SSLs is then determined using Equation (3) by multiplying the design reference wind velocity, V_{ref}, by an offshore multiplier, $\alpha_{offshore}$, as listed in Table 5 but not less than as specified in Table 6.

$$V_{des} = V_{ref} \times \alpha_{offshore} \tag{3}$$

The direction of the wind in all cases may be from any azimuth. The methodology for determining the local wind velocity to be used in the design is discussed in 8.4.1.4.

8.4.1.4 Local Wind Velocity

Using Equation 4, the maximum rated design wind velocity, V_{des}, is to be scaled by the appropriate elevation factor β from Table 7 to obtain the velocity, V_z, to be used to estimate wind forces per 8.4.3.

$$V_z = V_{des} \times \beta \tag{4}$$

where

β is $\sqrt{0.85}$ for heights up to 4.6 m (15 ft);

β is $\sqrt{2.01 \times (z/900)^{0.211}}$ for heights > 4.6 m (15 ft) with z = height above ground level or mean sea level (ft);

β is tabulated in Table 7.

Table 7—Elevation Factor, β Location: All [a] [b]

Height Above Ground or MSL (m)	Height Above Ground or MSL (ft)	Elevation Factor
0–4.6	0–15	0.92
6	20	0.95
7.6	25	0.97
9	30	0.99
12.2	40	1.02
15.2	50	1.05
18.3	60	1.07
21.3	70	1.08
24.4	80	1.10
27.4	90	1.11
30.5	100	1.12
36.6	120	1.15
42.7	140	1.17
48.8	160	1.18
54.9	180	1.20
61	200	1.21
76.2	250	1.24
91.4	300	1.26
106.7	350	1.28
121.9	400	1.30
137.2	450	1.32
152.4	500	1.33

[a] Linear interpolation for intermediate values of height is acceptable.
[b] At 10 m (33 ft), value equals 1.00.

8.4.2 Wind Loading

Wind forces shall be applied to the entire structure, except that members directly behind or in front of wind walls may be excluded. Wind area calculations shall include all known or anticipated structures and appurtenances, e.g. equipment, wind walls, and appendages installed in or attached to the drilling structure. The total wind force on the structure shall be estimated by the method described in 8.4.3.

The manufacturer shall include in the rig manual a listing of all items with their unshielded projected area used in the design. This list shall include areas for at least two orthogonal directions. Additionally, the manufacturer shall state the total summation of areas and the first moment of areas about the base of the drilling structure in question for the chosen directions. For purposes of calculating the first moment of wind areas, the traveling equipment shall be assumed to be located at 0.7 times the clear height of the structure from the base.

8.4.3 Member-by-Member Method

8.4.3.1 General

The total wind force on the structure shall be estimated by taking the vector sum of wind forces acting on individual members and appurtenances. The wind directions that result in stresses having the highest magnitude for each component part of the structure must be determined and considered. Wind forces for the various design wind speeds shall be calculated using Equation (5) and Equation (6):

$$F_m = 0.00338 \times K_i \times V_z^2 \times C_s \times A \tag{5}$$

$$F_t = G_f \times K_{sh} \times \Sigma F_m \tag{6}$$

where

F_m	is wind force normal to longitudinal axis of an individual member, or normal to the surface of a wind wall, or normal to the projected area of an appurtenance, lb;
K_i	is a factor to account for the angle of inclination ϕ between the longitudinal axis of an individual member and the wind;
	is 1.0, when the wind is normal to member ($\phi = 90°$), or for appurtenances including wind walls;
	is $sin^2\phi$, when the wind is at an angle ϕ (in degrees) to the longitudinal axis of an individual member per 8.4.3.3;
V_z	is local wind velocity in knots at height z per 8.4.1.4;
C_s	is shape coefficient per 8.4.3.5;
A	is projected area of an individual member equal to the member length times its *projected width* with respect to the normal wind component per 8.4.3.6, or the normal surface area for a wind wall, or the projected area for an appurtenance other than a wind wall per 8.4.3.7, ft^2;
F_t	is vector sum of wind forces acting on each individual member or appurtenance of the entire drilling structure factored by K_{sh} and G_f. F_t shall not be less than the vector sum of wind forces calculated for each individual member of the bare drilling structure;
G_f	is gust effect factor to account for spatial coherence, per 8.4.3.4;
K_{sh}	is a reduction factor to account for global shielding by members or appurtenances, and for changes in airflow around member or appurtenance ends, per 8.4.3.2.

The designer shall give consideration to the fact that shielding is not uniform over the entire drilling structure and that any individual member or local assemblage of members may not be shielded. This consideration shall be documented. As a minimum, the designer shall calculate interaction ratios for individual members using member forces from analyses using global wind loads F_t, with additional superimposed member loading attributable to the member itself or a local assemblage of members being unshielded. The additional loading on a member that is unshielded is calculated using Equation (7) as follows:

$$F_m \times (1 - K_{sh} \times G_f) \tag{7}$$

8.4.3.2 Shielding and Aspect Ratio Correction Factor

A correction factor K_{sh} is used to account for global shielding effects and for changes in airflow around member or appurtenance ends. K_{sh} shall be applied only when calculating F_t.

For a derrick, K_{sh} is calculated using Equation (8) based on the solidity ratio, ρ, and is applied to all structural members within the derrick frame.

$$K_{sh} = 1.11\rho^2 - 1.64\rho + 1.14 \quad 0.5 \le K_{sh} \le 1.0 \tag{8}$$

When calculating K_{sh} for structural members, the solidity ratio ρ is defined as the projected area of all members in the front face of the bare frame divided by the projected area enclosed by the outer frame members, with projections normal to the wind direction.

When calculating global shielding effects for other derrick components including, but not limited to, wind walls, setback, guide tracks and dollies, crown, vent pipe, top drive, and gin pole, K_{sh} shall not be less than 0.85.

For a mast, the shielding and aspect ratio correction factor K_{sh} for all structural members or appurtenances shall not be less than 0.9 for all wind directions.

8.4.3.3 Member Angle of Inclination

The angle of inclination, ϕ, is defined as the angle in degrees between the *longitudinal* axis of a member and the wind direction (see Figure 1).

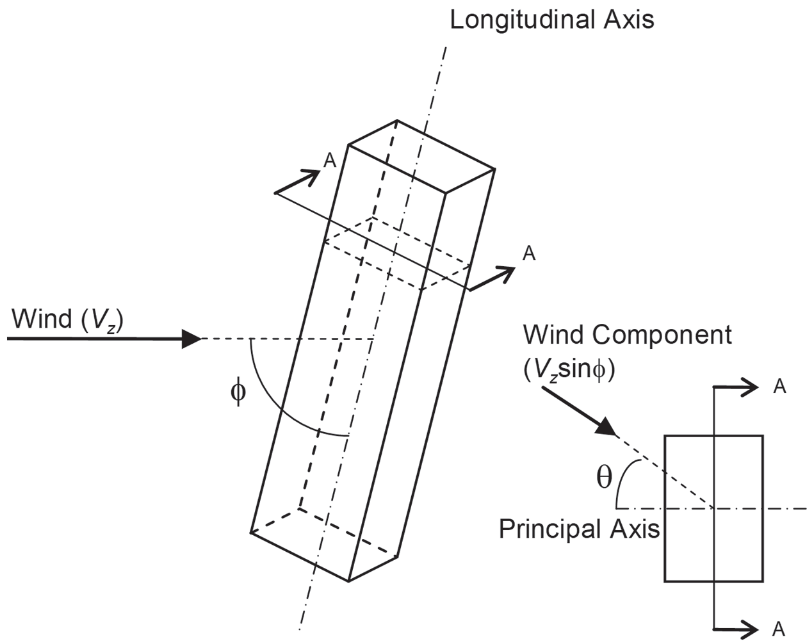


Figure 1—Member Angle of Inclination

The member orientation angle, θ, is defined as the angle in degrees between the wind component acting perpendicular to the longitudinal axis and the principal axis of the member, with the principal axis normal to the longitudinal axis. The angle θ lies in a plane normal to the longitudinal axis and is used to select a shape coefficient per 8.4.3.5. For wind walls, K_i equals 1.0.

8.4.3.4 Gust Effect Factor

A gust effect factor shall be applied as listed in Table 8. Selection of G_f shall be made based on the gross projected area of the drilling mast or derrick, defined as the area enclosed by the outer bay members with the projection normal to the wind direction. G_f is applied only when calculating the total wind force acting on the structure. It is not applied when calculating wind forces acting on individual members or appurtenances.

Table 8—Gust Effect Factor

Gross Projected Area (m^2)	Gross Projected Area (ft^2)	Factor
>65	>700	0.85
37.2–65	400–700	0.90
9.3–37.1	100–399	0.95
<9.3	<100	1.00

8.4.3.5 Member or Appurtenance Shape Coefficient

Representative coefficients for various shapes are provided in Figure 2 (which comprises Figure 2a and Figure 2b).

In portions of structures where large numbers of members are in close proximity, such as within a drill floor assembly, the member-by-member approach will overestimate wind forces on the assemblage. In such areas, the assemblage may be replaced by a blocked area with a corresponding shape factor of 1.5.

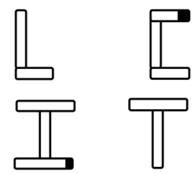
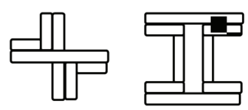
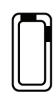
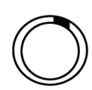
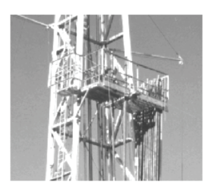
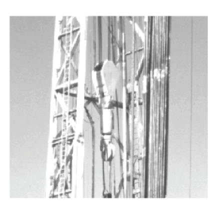
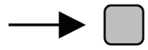
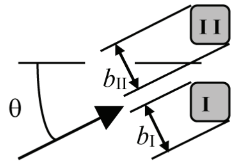
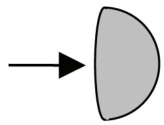
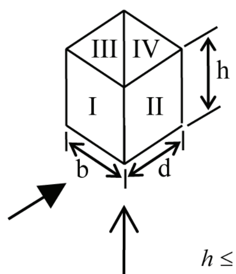
Section			Wind Orientation (θ): All Directions
Type	Shape		
Structural	Angles, Channels, Beams, Tees		1.8
	Built-up Members		2.0
	Square		1.5
Tubular	Rectangular		1.5
	Round		0.8
Attachments	Any member, other than a structural member, with flat edges (e.g. crown cluster, ducs, traveling block, hook, top drive)		1.2
	Any member, other than a tubular member, with a continuous surface, i.e. no flat edges (e.g. stand pipes, hoses, collars, cables)		0.8

Figure 2a—Shape Coefficients

<table>
<tr><th colspan="3">Section</th><th colspan="4" rowspan="2">Wind Orientation (θ):
All Directions</th></tr>
<tr><th>Type</th><th colspan="2">Shape</th></tr>
<tr><td rowspan="2">Setback Pipes and Rods</td><td rowspan="2">Square or Rectangular</td><td></td><td colspan="4">1.2</td></tr>
<tr><td>
θ b_{II} b_I I II</td><td colspan="4">I and II: 1.2
except for 70° ≤ θ ≤ 90°
I: 1.2 II: 0.3</td></tr>
<tr><td></td><td>Semicircular</td><td></td><td colspan="4">1.2</td></tr>
<tr><td colspan="3"></td><td colspan="2">0° ± 20° to Normal</td><td colspan="2">45° ± 25° to Diagonal</td></tr>
<tr><td></td><td>Four-sided:
airflow permitted into enclosure</td><td>
III IV I II h b d
h ≤ b
b/d ≅ 1</td><td colspan="2">I: 0.8
II: –0.5
III: –0.5
IV: –0.3</td><td colspan="2">I: 0.5
II: 0.5
III: –0.5
IV: –0.5</td></tr>
<tr><td rowspan="3">Wind Walls

NOTE
+ toward inside of enclosure
– toward outside of enclosure

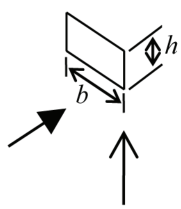
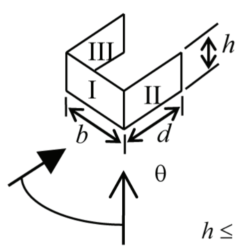
NOTE
Round value of θ to nearest table value</td><td>Single-sided</td><td>
h b
h ≤ b</td><td colspan="2">1.1</td><td colspan="2">0.6</td></tr>
<tr><td rowspan="2">Three-sided:
airflow permitted into enclosure</td><td rowspan="2">
III I II h b d θ
h ≤ b
b/d ≅ 1</td><td>θ</td><td>I</td><td>II</td><td>III</td></tr>
<tr><td>0°
45°
90°
135°
180°</td><td>0.8
0.5
–0.5
–0.5
–1.2</td><td>–0.5
0.5
0.8
0.5
–0.2</td><td>–0.5
–0.5
–0.3
–0.9
–0.2</td></tr>
</table>

Figure 2b—Shape Coefficients (Continued)

8.4.3.6 Member Projected Area

Calculation of the projected area, A, for an individual member is with respect to the wind component *normal to the longitudinal axis* ($V_z sin\phi$). Thus, for all values of ϕ, the projected area for a member will equal the member length

L times its projected width *w* with respect to the normal wind component. Moreover, the calculated wind force will act *normal to the longitudinal axis* (i.e. normal to the projected area) of the member (see Figure 3).

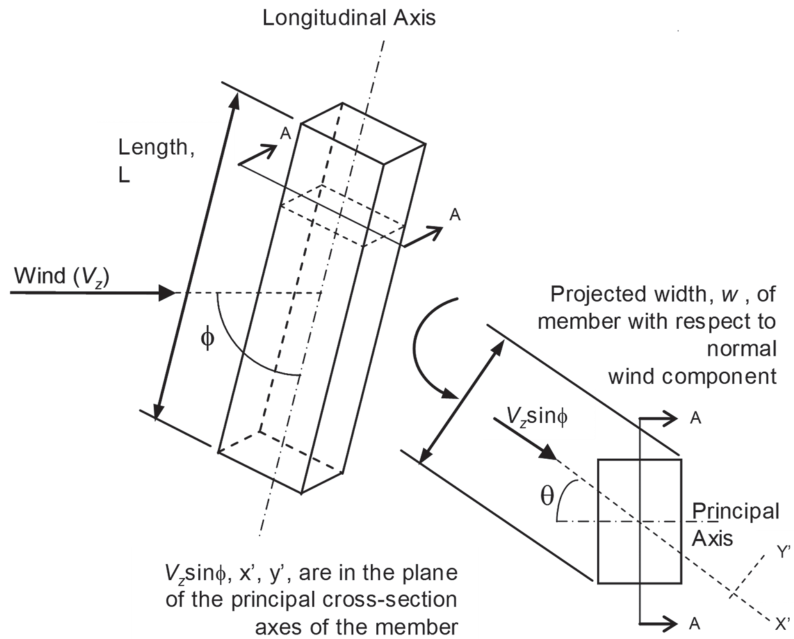


Figure 3—Member Projected Area

8.4.3.7 Appurtenance Projected Area

The projected area, *A*, for appurtenances other than wind walls shall be that area that projects onto a plane normal to the wind direction. Moreover, the calculated wind force will act in the same direction as the wind direction.

For wind walls, the area *A* for a given wall section equals its surface area. A positive sign for the shape coefficient means the resultant wind force acts toward the wall, while a negative sign means the resultant wind force acts away from the wall, with the resultant force acting normal to the wall. The shape coefficients for wind walls as shown in Figure 2 apply only to a partially clad drilling *mast* or *derrick*. For cases where a drilling *mast* or *derrick* is completely covered with cladding (e.g. a rig mounted on an arctic drilling ship), other wind loading standards, specifically ASCE/SEI 7–05, are available and should be used to estimate wind loadings for such cases.

8.4.4 Wind Tunnel Tests

Wind tunnel tests or similar tests using a fluid other than air shall be considered acceptable for the purposes of determining forces and pressures, assuming Reynold's number is properly modeled.

8.4.5 Wind Dynamics

A dynamic analysis procedure shall be performed for wind-sensitive structures likely to experience additional loads due to the dynamic interaction between wind and structure. Detailed procedures for dynamic analysis of all classes of structures can be found in other published standards.

8.5 Dynamic Loads

8.5.1 Inertial Loads

The purchaser shall supply all motion information required for analysis of the drilling structures for dynamic loads due to motions of supporting vessel, compliant platform, or deepwater fixed structure. Forces due to motions shall be calculated by rational methods as appropriate to the form of the motion data.

As a minimum, dynamic forces shall be combined as follows:

a) longitudinal dynamic forces, to include surge and pitch, with heave;

b) transverse dynamic forces, to include sway and roll, with heave;

c) diagonal dynamic forces combined with heave (diagonal dynamic forces shall be determined as the square root of the sum of squares of longitudinal and transverse forces unless otherwise specified by the purchaser).

A static analysis of the drilling structure may be made using the motions of the supporting structure as defined above, provided that the drilling structure is sufficiently stiff to be treated as a rigid body.

8.5.2 Dynamic Amplification

A dynamic analysis procedure shall be performed for drilling structures likely to experience additional loads due to dynamic amplification caused by motions of the foundation support structure. Detailed procedures for dynamic analysis of all classes of structures can be found in other published references. The purchaser shall be responsible for supplying the necessary motion information for the supporting structure.

8.6 Earthquake Loads

Earthquake consideration is a special loading condition to be addressed if specified by the user. The user is responsible for furnishing the design criteria, which include design loading, the design analysis method, and allowable response.

The design criteria for land-based units may be in accordance with local building codes, using equivalent static design methods.

For a unit based on a fixed offshore platform or jack-up, the design method for earthquake loading shall follow the strength level analysis guidelines outlined in API RP 2A-WSD. The drilling and well servicing units shall be designed to resist the movement of the deck on which they are founded, i.e. the response of the deck to the ground motion prescribed for the design of the offshore platform. The allowable member strength for the combined earthquake, gravity and operational loading may be increased one-third (strength modifier = 1.33) over basic allowable member strength defined in 8.1.1. The computed member strength should include both the primary and the secondary load components.

8.7 Ice Loads

Ice loading is a special loading condition to be addressed if specified by the user. The user is responsible for furnishing the design criteria, which include design loading and load combinations and allowable strength modifier.

8.8 Erection Loads

Each drilling structure and its supporting structure shall be designed for erection loads in combination with dead loads and erection environment wind, or alternatively, for wind and inertial loads as specified by the purchaser.

Fluid loads or added dead loads such as counterweights specifically required to provide overturning stability during erection shall be clearly specified on the drilling structure nameplate and in rig operating instructions.

Drilling structures designed to be crane erected shall be designed in accordance with the guidelines for lifting in API RP 2A-WSD, including dynamic factors as specified therein.

8.9 Transportation Loads

Each drilling structure shall be designed for transportation loads in combination with dead loads and transportation environment wind, or alternatively, for wind and inertial loads, as specified by the purchaser.

8.10 Overturning and Sliding

The maximum allowable static coefficient of friction to be used in overturning or inadvertent rig sliding calculations of drilling structures supported by soil, concrete, or wood matting foundations shall be limited to 0.15, and to 0.12 for those supported by steel foundations, except as follows: alternative values for the maximum design coefficient of friction may be used, provided such values have been validated through testing and are consistent with rig operating procedures (e.g. an offshore skiddable rig design incorporating a coefficient of friction consistent with ungreased surfaces would require that the owner/operator maintain and inspect the beams to ensure that they are not inadvertently greased).

For all stability and sliding calculations, dead weights providing resistance to overturning or sliding shall be limited to a maximum of 90 % of their expected minimum weight. The calculation of minimum weight shall assume the removal of all optional structures and equipment, and fluid tanks shall be considered empty, unless otherwise specified in the rig instructions for storm preparations or rig erection. For drilling structures subject to vertical heave, the stabilizing weights shall be further reduced by the magnitude of the negative heave acceleration.

Freestanding structures on land shall have a minimum factor-of-safety against overturning of 1.25, calculated as the ratio of the minimum stabilizing moment of the dead weight of the structure, taken about a tipping line, divided by the overturning moment of the sum of any overhanging vertical live loads plus environmental loads, including wind or earthquake, taken about the same tipping line or axis. The designer shall consider suitable tipping lines so as to determine the minimum factor-of-safety and shall consider the possibility of overturning loads from any possible direction of application. Determination of the location of a tipping line shall be such that the tipping line shall lie along the centroid of the nominal vertical ground support reactions for the case considered; the distribution of ground support reactions shall be limited to comply with design allowable ground bearing pressures for the structures under consideration. The manufacturer shall include foundation loading diagrams and the required safe ground bearing pressure allowables for erection and operating conditions in the rig manual. Freestanding land drilling structures shall have a minimum factor-of-safety against inadvertent sliding of 1.25, calculated as the ratio of the minimum sliding resistance at the design maximum allowable static coefficient of friction, divided by the total applied shear loads due to environmental loads.

Freestanding offshore drilling structures shall have a minimum factor-of-safety against overturning of 1.50, calculated as the ratio of the minimum stabilizing moment of the dead weight of the structure, taken about a tipping line, divided by the overturning moment of the sum of any overhanging vertical live loads plus environmental loads, including wind, earthquake, or dynamic loads due to vessel motion, taken about the same tipping line or axis. The designer shall consider suitable tipping lines so as to determine the minimum factor-of-safety and shall consider the possibility of overturning loads from any possible direction of application. Determination of the location of a tipping line shall be such that the tipping line shall lie along the centroid of the nominal foundation support reactions for the case considered. The distribution of foundation support reactions shall be limited to comply with allowable design loadings of the supporting structures foundations, if so specified by the purchaser. The manufacturer shall include diagrams defining the maximum foundation support loads based on the factored lateral loads with the rig instructions. Freestanding offshore drilling structures shall have a minimum factor-of-safety against inadvertent sliding of 1.5, calculated as the ratio of the minimum sliding resistance at the design maximum allowable static coefficient of friction, divided by the total applied shear loads due to environmental loads.

Structures unable to meet the requirements for freestanding structures shall incorporate suitable devices to prevent such movements, to include the following:

a) Such components, when used on skiddable drilling structures shall be termed “tie-down clamps” and shall be rated to resist overturning and sliding loads in all load combinations calculated using overhanging vertical live loads, design lateral wind, seismic and dynamic forces due to vessel motion factored by a value of 1.25, at ANSI/AISC 360-16 allowable strength levels without the $^1/_3$ increase for wind or dynamic loading.

b) Structural components other than tie-down clamps shall be rated in accordance with 8.1.

Some structural connections provide two methods or paths for carrying loads. Examples of such a dual- load path connection are a derrick leg splice or derrick base plate connection with flange connections, where compression is carried by the bearing of one flange plate on the other and tension is carried by bolts in tension. Mast legs designed to carry compression loads by contact bearing and tension loads through pin connections are another example.

In addition to meeting the requirements of 8.1, dual-load path connections other than tie-down clamps shall also be designed to resist primary loads calculated using overhanging vertical live loads, design lateral wind, seismic and dynamic forces due to vessel motion, as appropriate, factored by a value of 1.25:

— in all operating and erection load combinations with a $^{1}/_{3}$ increase in allowable strength;

— in expected and unexpected wind load combinations with a $^{2}/_{3}$ increase in allowable strength;

— in transportation load combinations with a $^{1}/_{3}$ increase in allowable strength, or $^{2}/_{3}$ increase in allowable strength if so specified by the purchaser.

In no case shall the absolute value of the design loadings for one load path of a dual-load path connection be less than 20 % of those of the alternate load path.

The manufacturer shall provide suitable instructions in the drilling structure documentation to be delivered with the unit regarding the proper installation of clamps, pins, and bolts used for tie downs. Tie-down components incorporating bolts that are expected to be tensioned multiple times shall be designed with specified preloads of bolts no greater than 50 % of the bolt material minimum ultimate strength times its nominal cross-sectional area, so as to allow reuse of the bolts. Clamp installation instructions shall include pretension values and tolerances. Bolt tensioning shall be achieved using calibrated tensioning methods. Bolts that are specified to be pretensioned to higher values shall only be used once.

The rig owner/operator shall develop procedures to include storm preparation information, including proper clamp installation, based on the manufacturer's recommendations.

8.11 Design Verification

See 11.8.2 for requirements.

8.12 Design Validation

Design validation shall be performed in accordance with a design and development plan of the manufacturer to ensure that the resulting product is capable of meeting the specified design requirements. Validation should be completed prior to the delivery of the product.

9 Materials

9.1 General

This section describes the various material qualifications, property, and processing requirements for critical components, unless otherwise specified.

All materials used in the manufacture of equipment furnished under this standard shall be suitable for the intended service.

9.2 Written Specifications

Material shall be produced to a written material specification. The specification requirements shall define at least the following parameters and limitations:

a) mechanical property requirements;

b) chemical composition and tolerances;

c) material qualification.

9.3 Mechanical Properties

Materials shall meet the property requirements specified in the manufacturer's material specification.

If specified by the purchaser, the supplementary impact toughness requirements in A.1 shall apply.

9.4 Material Qualification

The mechanical tests required by this standard shall be performed on qualification test coupons representing the heat and heat-treatment lot used in the manufacture of the component. Tests shall be performed in accordance with the requirements of ASTM A370 or equivalent standards, using material in the final heat-treated condition.

Qualification test coupons shall be either integral with the components they represent, separate from the components, or a sacrificial product part. In all cases, test coupons shall be from the same heat as the components that they qualify, given the same working operations, and shall be heat treated with the components.

9.5 Material Manufacture

All wrought materials shall be manufactured using processes that produce a wrought structure throughout the component.

For PSL 2, all heat-treatment operations shall be performed using equipment qualified in accordance with the requirements specified by the manufacturer or processor. The loading of the material within heat-treatment furnaces shall be such that the presence of any one part does not adversely affect the heat-treatment lot. The temperature and time requirements for heat-treatment cycles shall be determined in accordance with the manufacturer's or processor's written specification. Actual heat-treatment temperature and times shall be recorded, and heat treatment records shall be traceable to relevant components.

9.6 Bolts

Bolts that conform to a recognized industry standard shall be marked in accordance with such standard. Other bolts may be used, provided the chemical, mechanical, and physical properties conform to the limits guaranteed by the bolt manufacturer.

9.7 Wire Rope

Wire rope for guy line or erection purposes shall conform to API 9A.

10 Welding Requirements

10.1 General

This section describes requirements for the welding of critical components.

10.2 Welding Qualifications

All welding undertaken on components shall be performed using welding procedures that are in accordance with AWS D1.1/D1.1M or similarly recognized industry standard.

This welding shall only be performed by welders or welding operators who are qualified in accordance with aforementioned standards. Workmanship and technique shall be in accordance with the same standard.

10.3 Written Documentation

Welding shall be performed in accordance with welding procedure specifications (WPS) written in accordance with the applicable standard. The WPS shall describe all the essential variables as listed in the applicable standard.

The use of prequalified joint details as specified in AWS D1.1/D1.1M is acceptable. The manufacturer shall have a written WPS for prequalified joints.

Weld joints and/or process not meeting AWS D1.1/D1.1M requirements for prequalification shall be qualified in accordance with the applicable standard. The procedure qualification record (PQR) shall record all essential and supplementary essential (when required) variables of the weld procedure used for the qualification tests. Both WPS and the PQR shall be maintained as records in accordance with the requirements of Section 12 of this standard.

10.4 Control of Consumables

Welding consumables shall conform to American Welding Society (AWS) or consumable manufacturers' specifications.

The manufacturer shall have a written procedure for storage and control of weld consumables. Materials of low hydrogen type shall be stored and used as recommended by the consumable manufacturer to retain their original low hydrogen properties.

10.5 Weld Properties

For all procedures requiring qualification, the mechanical properties of the weld as determined by the procedure qualification test shall at least meet the minimum specified mechanical properties required by the design. If impact testing is required for the base material, it shall also be a procedure qualification requirement. Results of testing in the weld and base material heat-affected zone (HAZ) shall be in accordance with contractual requirements and AWS D1.1/D1.1M. In the case of attachment welds, only the HAZ of materials requiring impact testing must meet the above requirements.

All weld testing shall be undertaken with the test weldment in the applicable postweld heat treated condition.

10.6 Postweld Heat Treatment

Postweld heat treatment of components shall be in accordance with the applicable qualified WPS.

10.7 Quality Control Requirements

Requirements for quality control of permitted welds shall be in accordance with Section 11.

10.8 Specific Requirement—Repair Welds

10.8.1 Access

There shall be adequate access to evaluate, remove, and inspect the nonconforming condition that is the cause of the repair.

10.8.2 Fusion

The selected WPS and the available access for repair shall be such as to ensure complete fusion with the base material.

10.8.3 Heat Treatment

The welding procedure specification used for qualifying a repair shall reflect the actual sequence of weld repair and heat treatment imparted to the repaired item.

11 Quality Control

11.1 General

This section specifies the quality control requirements for equipment and material. All quality control work shall be controlled by the manufacturer's documented instructions, which shall include appropriate methodology—quantitative and qualitative acceptance criteria.

The manufacturer shall have a program to ensure that the quality of products is planned, implemented, and maintained. The quality program shall be described in a quality manual, the issuance and revision of which shall be controlled and shall include a method to identify the latest revisions in the manual.

The acceptance status of all equipment, parts, and materials shall be indicated either on the item or in the records related to the equipment, parts, or materials.

11.2 Quality Control Personnel Qualifications

11.2.1 Nondestructive examination (NDE) personnel shall be qualified and/or certified in accordance with ISO 9712.

NOTE For the purposes of this provision, ASNT TC-1A is equivalent to ISO 9712.

11.2.2 Personnel performing visual inspection of welding operations and completed welds shall be qualified and certified as follows:

a) AWS certified welding inspector;

b) AWS certified associate welding inspector; or

c) a welding inspector certified by the manufacturer's documented requirements.

11.2.3 All personnel performing other quality control activities directly affecting material and product quality shall be qualified in accordance with the manufacturer's documented procedures.

11.3 Measuring and Test Equipment

Equipment used to inspect, test, or examine material or other equipment shall be identified, controlled, calibrated, and adjusted at specific intervals in accordance with the manufacturer's documented procedures and consistent with a recognized industry standard to maintain the required level of accuracy.

11.4 Nondestructive Examination

11.4.1 General

Instructions for NDE activities shall be detailed regarding the requirements of this standard and those of all applicable referenced specifications. All NDE instructions shall be approved by an examiner qualified to ISO 9712, Level 3.

NOTE For the purposes of this provision, ASNT SNT-TC-1A Level III is equivalent to ISO 9712, Level 3.

If examination is required, it shall be done after final heat treatment.

The requirements of 11.4 shall apply to all critical components as designated by the manufacturer's design engineering department unless specified otherwise.

11.4.2 Visual Examination

All critical welds shall be 100 % visually examined.

11.4.3 Surface NDE

Twenty percent (20 %) of critical welds shall be inspected using magnetic particle (MP) or liquid penetrant (LP) method in accordance with AWS D1.1/D1.1M. The manufacturer's inspector shall choose areas for random inspection coverage.

11.4.4 Volumetric NDE

11.4.4.1 General

All full- or partial-penetration welds loaded in tension to 70 % or greater of their allowable stress, as determined by design, shall be ultrasonically or radiographically inspected in accordance with AWS D1.1/D1.1M. The manufacturer's design engineering department shall document the welds that require volumetric NDE.

11.4.4.2 PSL 2 Through-thickness NDE

Connections in critical components with through-thickness tensile stresses greater than 70 % of allowable stress, as determined by design, shall be ultrasonically inspected for laminations and internal discontinuities in accordance with ASTM A578/A578M, with the following changes:

a) The area to be examined shall include the weld area and adjacent areas up to 76 mm (3 in.) from the weld. The area shall be 100 % scanned.

b) The following discontinuities shall be recorded and referred to the manufacturer's design engineering department for disposition:

— all discontinuities causing a 50 % loss of initial backwall regardless of size;

— all discontinuities with amplitudes greater than 50 % of initial backwall that cannot be contained in a 25 mm circle (1 in.); and

— any discontinuities that in the technician's judgment would interfere with the ultrasonic inspection of the completed weldment.

The manufacturer's design engineering department shall review all recordings and determine repair requirements, if any.

All recordings and dispositions shall be documented and records retained in accordance with Section 12.

11.4.5 Acceptance Criteria

The acceptance criteria of AWS D1.1/D1.1M for statically loaded structures shall be used for the visual, surface, and volumetric NDE examination.

PSL 2—The acceptance criteria of AWS D1.1/D1.1M for cyclically loaded structures shall be applied to critical welds of masts and derricks.

11.5 Dimensional Verification

Verification of dimensions shall be performed on a sample basis as defined and documented by the manufacturer.

11.6 Workmanship and Finishing

11.6.1 Structural Steel

Structures and products produced shall conform to applicable sections of the ANSI/AISC 360-16 concerning fabrication.

11.6.2 Castings

All castings shall be thoroughly cleaned, and all cored holes shall be drifted to ensure free passage of proper size bolt.

11.6.3 Protection

All forged, rolled structural steel shapes and plates, and castings shall be cleaned, primed, and painted with a good grade of commercial paint or other specified coating before shipment. Machined surfaces shall be protected with a suitable lubricant or compound.

11.6.4 Socketing

Socketing of raising, erection, or telescoping mast wire ropes shall be performed in accordance with practices outlined by API 9B. Socketed connections shall be proof tested in accordance with 11.8.3.

11.7 Purchaser's Inspection and Rejection

11.7.1 Inspection Notice

If the inspector representing the purchaser requests to inspect the product, the product at the works, or the witness test, the manufacturer shall give the inspector reasonable notice as to available inspection dates.

11.7.2 Records

Full records of all calculations and tests shall be maintained by the manufacturer. If requested by an actual purchaser of the equipment for his/her use or by a user of the equipment, the manufacturer shall make available for examination details of computations, drawings, tests, or other supporting data as may be necessary to demonstrate compliance with this standard. It shall be understood that such information is for the sole use of the user or prospective purchaser for the purpose of checking the equipment rating for compliance with this standard and that the manufacturer shall not be required to release the information from his/her custody.

11.7.3 Supply of Crown Block Assembly

The scope of what is supplied with crown block assemblies shall be as agreed to by the purchaser and manufacturer.

11.8 Testing

11.8.1 Proof Load Testing

Proof load testing of products manufactured to this standard is not a requirement of this standard. If specified by the purchaser, proof load testing shall be in accordance with A.2.

11.8.2 Design Verification

The accuracy of the standard design ratings of each structure shall be tested by proof loading or by a computer model such as finite element analysis (FEA). The intent of such testing shall be to verify the structure for the design loadings specified in Section 7.

Testing methods and assumptions shall be documented. Computer modeling documentation shall include loads, member properties, model geometry and connectivity, member effective-length factors and unbraced lengths, support conditions, member end fixities, and analysis results demonstrating compliance with Section 8. Documentation shall be verified by a qualified individual other than the designer of the test or computer model.

11.8.3 Wire Rope Connections

Wire rope end connections used for erection purposes shall be proof tested to 50 % of nominal wire rope assembly strength.

11.8.4 Cylinders and Winches

Cylinders and winches used for erection of masts or substructures shall be pressure tested to 1.5 times the system design working pressure. The test pressure shall be maintained for a duration of 10 min.

11.9 Traceability

The manufacturer shall obtain and retain a material test report on all steel material received having a specified yield strength greater than the following:

— structural shapes or plate 248 MPa (36 ksi);

— tubing 317 MPa (46 ksi);

— solid round bars 414 MPa (60 ksi).

Any substitution of an alternative material to that called out in the engineering drawing or instructions should be documented and traceable to the specific unit by serial number or similar specific identification.

For PSL 2, critical components shall be traceable by heat and heat-treatment lot identification. Identification shall be maintained through all stages of manufacturing, traceable to the specific unit by a serial number.

For PSL 2, certified reports shall constitute sufficient evidence of conformity for nonferrous materials and bearings.

For PSL 2, bolts shall be exempt from the traceability requirements, provided they are manufactured and marked in accordance with recognized industry standards.

11.10 Processes Requiring Validation

11.10.1 General

The following processes shall require validation when the specified properties of the final product cannot be verified after the process completion:

— NDE;

— welding; and

— heat treating.

11.10.2 Heat Treating

Where the properties required are specified in the design, no further validation is required if production material qualification (e.g. material test reports, testing of qualification test coupons, etc.) is performed to verify that the required properties are achieved in each production heat/heat treatment lot. Where a heat treatment process is specified but the results are not verified by testing of each production heat/heat treatment lot of material subjected to the process(es), the process(es) shall be validated by testing of samples, which demonstrate that the process will consistently produce the properties required by the design.

The validation method and results shall be documented.

11.10.3 Bolt Pretensioning

When a preload is specified by the design, bolt pretensioning shall be considered a process requiring validation.

When such values are as specified in accordance with the values in ANSI/AISC 360-16, process validation in accordance with the turn-of-the-nut method per AISC's Research Council on Structural Connections document *Specification for Structural Joints Using High-Strength Bolts* is acceptable.

12 Documentation

12.1 General

Full records of any documentation referenced in this standard shall be kept by the manufacturer for a period of five years after the equipment has been manufactured and sold. Documentation shall be clear, legible, reproducible, retrievable, and protected from damage, deterioration, or loss.

All quality control records required by this standard shall be signed and dated. Computer-sorted records shall contain originator's personal code.

If requested by a purchaser of the equipment, authorities, or certifying agencies, the manufacturer shall make available all records and documentation for examination to demonstrate compliance with this standard.

12.2 Documentation to Be Kept by the Manufacturer

The following documentation shall be kept by the manufacturer:

a) design verification documentation (see 11.8.2);

b) written specifications (see Sections 9 through 11);

c) qualification records such as:

   1) weld procedure qualification records;

   2) welder qualification records;

   3) NDE personnel qualification records;

   4) measuring and test equipment calibration records;

d) inspection and test reports covering the following tests, as applicable:

   1) material test reports covering the following tests, as applicable:

      a) chemical analysis;

      b) tensile tests;

      c) impact tests;

      d) hardness tests;

e) NDE records covering the surface and/or volumetric NDE requirements of Section 11;

f) performance test records, where applicable, including:

   1) proof load-testing records;

   2) hydrostatic pressure-testing records;

   3) slingline socket proof-testing records;

g) special process records, where applicable.

12.3 Documentation to Be Delivered with Equipment

12.3.1 Instructions

The manufacturer shall furnish to the purchaser one set of instructions that covers operational features, block reeving diagram, foundation loading diagrams, and the required safe ground bearing pressure or maximum foundation support loads as appropriate (see 8.10), suitable instructions regarding the proper installation of clamps, pins, and bolts used for tie downs (see 8.10), and lubrication points for each drilling or well servicing structure. Instructions shall be included to include erection and lowering of the mast and/or substructure. A facsimile of the nameplate shall be included in the instructions.

Tables summarizing wet and dry dead weights of the drilling structure and all appurtenances and their first moments about the base of the drilling structure used in design shall be included per 8.3.

Tables summarizing wind areas and their first moment about the base of the drilling structure used in design shall be included per 8.4.2.

12.3.2 Data Book

If specified by the purchaser, a comprehensive data book shall be provided in accordance with A.3.

Annex A
(normative)

Supplementary Requirements

A.1 SR1—Low-temperature Testing

This SR shall apply when specified by the purchaser. In all cases, the purchaser and the manufacturer shall agree upon the minimum design temperature and required testing temperatures.

Critical components shall be fabricated from materials possessing the specified notch toughness at the required minimum design temperature. Impact testing shall be performed in accordance with the requirements of ASTM A370.

If it is necessary for subsize impact test pieces to be used, the acceptance criteria shall be multiplied by the appropriate adjustment factor listed in Table A.1. Subsize test pieces of width less than 5 mm (0.2 in.) are not permitted.

Table A.1—Adjustment Factors for Subsize Impact Specimens

Specimen Dimensions mm × mm	Adjustment Factor
10.0 × 7.5	0.833
10.0 × 5.0	0.667

Weldment qualification by impact testing shall be performed in accordance with AWS D1.1/D1.1M.

Products meeting this SR shall have their nameplate stamped with SR1 and with the design minimum temperature, in degrees Celsius. Impact value requirements for the various base metals shall be stated in the rig instructions.

A.2 SR2—Proof Load Test

The equipment shall be load tested to a load agreed by the purchaser and the manufacturer. After load testing, the equipment shall be visually examined in accordance with 11.4.2 of this standard.

The equipment shall have its nameplate stamped with SR2 and the ratio of load test to design load (load test/design load), e.g. SR2-1.0.

A.3 SR3—Data Book

If specified by the purchaser, records shall be prepared, gathered, and properly collated in a data book by the manufacturer. The data book shall include for each unit at least a:

a) statement of compliance;

b) equipment designation/serial number;

c) assembly and critical-area drawings;

d) nominal capacities and ratings;

e) list of components;

f) traceability codes and systems (marking on parts/records on file);

g) steel grades;

h) heat-treatment records;

i) material test reports;

j) NDE records;

k) performance test records, including functional hydrostatic and load-testing certificates (when applicable);

l) SR certificates as required;

m) WPS and qualification records; and

n) instructions.

Annex B
(informative)

Commentary

NOTE Paragraph numbering aligns with the body of this document. Not all sections have commentary.

B.1 Scope

Products manufactured according to API 4A, API 4D, API 4E, and previous revisions of API 4F may not necessarily comply with all the requirements of this specification. It is the committee's intention that this standard be written to meet the requirements of present and future operating conditions, such as deeper drilling, offshore drilling from floating devices, and the effect of earthquakes, storms, and other adverse operating conditions.

This standard is written to serve as a guide by which the manufacturer and the user will have a common understanding of the capacities and ratings of the various structures for drilling and well servicing operations.

B.6 Structural Safety Level

Prior editions of this specification differentiated between derricks and masts, with the implicit assumption that masts had either lower consequences of failure or lower probability of failure (a mast might be laid down in preparation for a large storm). Specifying lower design wind speeds for masts relative to derricks reflected this assumption. The present specification eliminates this distinction.

A given mast or derrick is usually designed with the following set of parameters (to simplify this discussion, the earthquake condition is excluded):

— rated hook load;

— rated setback;

— operational wind;

— design expected wind;

— design unexpected wind.

If the mast or derrick were designed for an SSL E3/U2 for an area of severe environmental conditions, then it might be utilized for SSL E2/U1 operations in a region with a less severe environment. In other words, the classification of a rig by its SSL has meaning only when it is operating within a region of similar environmental conditions. A shift in qualification of SSLs is not anticipated to occur within a given geographical location, such as the Gulf of Mexico if the operational strategy is unchanged.

By defining the SSL as a dual parameter, the operator/lessee has more latitude in assessing the consequences of the expected or survival condition when the rig is often unmanned. The following six SSLs are considered possible:

— SSL E1/U1;

— SSL E2/U1;

— SSL E3/U1;

— SSL E2/U2;

— SSL E3/U2; and

— SSL E3/U3;

whereas

— SSL E1/U2;

— SSL E1/U3; and

— SSL E2/U3

are considered to be unrealistic. That is, rig overload is always equal or more consequential for the unexpected condition than for the expected condition.

In some areas, such as in tropical revolving storm areas like the Gulf of Mexico, structures are evacuated in advance of an extreme environmental event. In such cases, an SSL for the manned event may be a higher order when personnel are not present during to the severe event. In these cases, the unmanned SSL may be lower than the higher extreme event.

When specifying dynamic load conditions due to platform or vessel motion, the user might consider use of motions for the same approximate return period as is used for the design wind loads, as this would presumably be consistent with the chosen SSL for the drilling structure.

B.6.1 Existing Onshore Structures

Qualification of an existing rig shall reflect the results of inspections such as that required in API 4G.

The selection of the onshore SSL multipliers in Table 4 is based on a target of equivalence between the expected wind loading as specified by API 4F, Second Edition and the wind loading in this specification. It is thought that guyed masts properly designed to API 4F, Second Edition would likely meet the requirements of this specification for use in the noncoastal areas of the United States for SSL E3/U3. Similarly, it is thought that unguyed masts properly designed to API 4F, Second Edition would likely meet the requirements of this specification for use in the noncoastal areas of the United States for SSL E1/U1.

The degree to which that target is met has been biased by experience and judgment.

B.6.2 Existing Offshore Platforms

Qualification of an existing rig shall reflect the results of inspections, such as that required in API 4G.

The selection of the SSLs of existing derricks and masts for offshore operations is based on a target of equivalence between the wind loading as specified by API 4F, First Edition and the wind loading in this specification. It is thought that masts properly designed to API 4F, Second Edition would likely meet the requirements of this specification for use in all but the central region of the Gulf of Mexico for SSL E3/U3. Similarly, it is thought that derricks properly designed to API 4F, Second Edition would likely meet the requirements of this specification for use in all but the central region of the Gulf of Mexico for SSL E2/U2.

The degree to which that target is met has been biased by experience and judgment.

B.6.3 Transportable Drilling "Nonstationary" Structures

When a drilling structure is considered for use in a new location, the new base elevation of the drilling structure may be different than the nameplate base elevation. This difference must be considered in the evaluation of the suitability of the structure for use at the new location.

The design wind loads for a drilling structure per this specification are typically greater than the wind loads used in the global response analysis of a mobile or floating platform where spatial and combined loads are used. The appropriate global wind loading of mobile, floating, or fixed platforms is beyond the scope of this document. The user should consult with appropriate design documents for these conditions.

B.7 Design Loading

Operating, erection, and transportation load cases include a purchaser-defined wind velocity, to be not less than a specified minimum, depending on type of structure and application (onshore or offshore).

No increase in allowable strength is allowed for operating or erection cases with wind or inertia forces. The nameplate curve of hook load vs wind velocity is made using a linear transition from a strength modifier of 1.0 for operating cases to 1.33 for the unexpected storm case.

The choice of the wind velocity for operating cases is not considered a structural safety concern as it is generally trivial to reduce hook load by setting the pipe string off in the rotary slips; rather, the level chosen represents a tradeoff of costs and benefits to the user—higher costs for higher wind speed ratings vs reduced operational window for lower wind speed ratings. Arbitrarily, the specification minimums for operating wind velocity are set to a level that generates about 20 % of the unity checks (UCs) from unexpected (setback) wind load case UCs on land rigs and 20 % of maximum expected wind load case UCs on offshore structures. Because the nameplate also includes the curve of allowable hook load vs wind loads, the user will have the necessary information to develop suitable rig operating procedures and to plan rig operations to mitigate the effects of weather conditions on operations for wind conditions in excess of the operating case design wind velocity.

B.8.1.1 General

Per ANSI/AISC 360-16, Chapter F, Section 2; Nominal Flexural Strength, M_n, shall be the lower value obtained from Equation (B.1) according to the limit states of yielding (plastic moment) and lateral-torsional buckling.

Chapter F, Section 2 applies to doubly symmetric compact I-shaped members and channels bent about their major axis. For other shapes bent about their major axis or minor axis, refer to other applicable sections in Chapter F.

$$M_n \text{ for Yielding} = M_p = F_y Z_x \tag{B.1}$$

where

F_y = specified minimum yield stress of the type of steel being used, ksi (MPa)

Z_x = plastic section modulus about the x-axis, in.^{3} (mm^3)

NOTE ANSI/AISC 360-16, Equation F2–1 (for simplicity only the yielding equation and not the Lateral-Torsional Buckling Equation F2–2 is illustrated)

$$F_y Z_x / \Omega_b = F_y Z_x / 1.67 = 0.60\ F_y Z_x \text{ (Allowable Flexural Strength per ANSI/AISC 360-16)}$$

$$F_b \approx 0.66\ F_y S_x \text{ (Allowable Stress per AISC 335-89)}$$

$$0.66/0.60 = 1.10 \text{ (Shape Factor per ANSI/AISC 360-16)}$$

Regarding the Z/S limit of 1.2, AISC 335-89 already included a shape factor of 1.1 (Z/S) for all compact sections. Therefore, the results emerged as $0.66 * F_y (1.1 * 0.6 F_y)$ and previous API 4F Editions allowed an increase of 20 % for secondary stresses. Therefore, taking both into account, 1.2 × 1.1 = 1.32 total.

Using the AISC 360 code, the plastic modulus gives the design engineer an advantage equal to the shape factor (Z/S). If the shape factor advantage is limited to 1.2 and only allows an extra allowable strength of 10 %, the results for the allowable increase is the same as AISC 335-89. The total allowable increase is $1.2 \times 1.1 = 1.32$. However, this could be even less if the shape factor is less than 1.2. Therefore, this is conservative in the new code, AISC 360, if using the secondary stress increase.

When attempting to apply the 10 % allowable strength increase for other members not shown in Chapter F, Section 2, whether they bend about their strong axis or weak axis, the design engineer should make sure not to exceed the Z/S values as expressed in the specific Chapter F equations that give an equated Z/S relationship such as mentioned in Equations F6-1 and F11-1.

B.8.2 Design for Stability

The Allowable Strength Design code in ANSI/AISC 360-16 offers methods to design for stability for building design in Chapter C, Design for Stability, such as the direct analysis method. The direct analysis method requires an adjustment to the structure stiffness by a factor of 0.80 along with increasing the load by a factor of 1.6 ($\alpha = 1.6$) and the results divided by 1.6 to obtain the required strength of the components.

ANSI/AISC 360-16 Commentary in Chapter C, Section C2.1, page 16.1-294 also allows an alternate direct analysis method that allows the adjustment to the structure stiffness by a factor of 0.50 while keeping $\alpha = 1.0$, thereby eliminating the need of a load increase by a factor or division of the results by a factor.

ANSI/AISC 360-16 Commentary in Chapter C, Section C2.3, page 16.1-296 also states that for computer programs that do semi-automated design, one should ensure that the reduced E is applied only for second-order analysis. The elastic modulus should not be reduced in nominal strength equations that include E.

Given that the design for stability methods as written in ANSI/AISC 360-16 are specifically intended for building structures, they may be overly conservative in some cases for drilling structures. Commentary in Chapter A, Section A1, page 16.1-258 states that “It is not the intent that this Specification address steel structures with vertical and lateral force resisting systems that are not similar to buildings” and “Engineering judgement must be applied to the specification requirements when structural steel elements are exposed to environmental or service conditions and/or loads not usually applicable to building structures.”

Any rational method of design for stability that considers all the listed effects in Section 8.2 is permitted.

B.8.3 Operating Loads

Operating loads have been defined to include both drilling loads and gravity loads. Drilling loads include hook, rotary, and setback loading. Gravity loads include both dead loads and fluid loads. The specification requirement for the inclusion of dry and wet weights and their first moments about the base of the drilling structure was included to allow users to monitor any growth of weights during the life of the structure due to additions of structure and appurtenances and to establish a threshold for added weights beyond which requalification of the structure would be required.

B.8.4 Wind Loads

This edition differs from previous API 4 specifications in that it no longer specifies the minimum design wind ratings solely based upon the type of structure (e.g. mast vs derrick). Instead, the specification requires the use of regional wind data from recognized national and international specifications to determine the design wind ratings, which are independent of the type of structure.

The wind force determination for design in this specification is based, in part, on a 2001 Joint Industry Project (JIP) titled *Measurements of Wind Load Resistance on Drilling Structures*. The methodology proposed in the JIP was calibrated against a square derrick structure and has been modified within this specification for use with other types of drilling structures with caution, particularly with respect to shielding of masts that have an open face.

The specification for wind is intended for the design of drilling structures and developed for this purpose. The underlying technology is valid for prediction of wind forces on drilling structures. The wind velocity used in this specification is a 3-second gust. However, the averaging time for wind velocity as cited in other specifications may differ. Caution should therefore be exercised in making sure the appropriate averaging time is used as cited by a particular design specification.

B.8.4.1 Design Wind

Structural Safety Level—The SSL for masts and derricks is to be selected with due concern of the consequence of failure. Onshore masts with guylines are usually less consequential than are unguyed masts. Derricks are usually the most consequential. Offshore consequences of failure are often dominated by the support structure of the drill rig system.

Wind Environment—The operational wind is not related to a return period, but to the expected conditions during which normal operations would continue and is specified by the purchaser.

The expected wind environment is sometimes known as the survival wind, and the unexpected wind as the storm wind.

Purchaser-specified wind environments are defined for erection and transportation.

B.8.4.1.2 Onshore Wind

For the onshore wind, the ASCE/SEI 7-05 Standard, *Minimum Design Load for Buildings and Other Structures*, 7-05, has been considered in the selection of the wind velocities. The ASCE 7-05 Basic Wind Speed Map provides 3-second gust speeds at a 10 m (33 ft) reference elevation associated with an annual probability of 0.02 or a 50-year return period for the United States. The SSL multipliers of Table 4 are used to determine the maximum design wind speed rating from the reference wind speed; for an E1, E2 or E3 structure, the specified SSI multipliers correspond approximately to 100-year, 50-year, and 25-year return periods, respectively.

The design wind criteria for masts and derricks operating outside the United States should appropriately consider and implement the local equivalent of ASCE/SEI 7-05, if available, or other recognized source.

B.8.4.1.3 Offshore Wind

For the offshore wind, ISO 19901-1 is used to provide reference wind speed data, or the API Bulletin 2INT-MET document for the Gulf of Mexico. The SSL multipliers of Table 5 are used to determine the maximum design wind speed rating from the reference wind speed; for an E1, E2, or E3 structure, the associated return periods correspond approximately to 200-year, 100-year, and 50-year return periods, respectively.

B.8.4.1.4 Local Wind Velocity

The elevation factors for the onshore masts and derricks are consistent with the pressure coefficient, K_z, recommended in ASCE/SEI 7-05 for exposure Category C: “Exposure C. Open terrain with scattered obstructions having heights generally less that 30 ft.”

The elevation factors for offshore masts and derricks are consistent with the values proposed for offshore platforms in API RP 2A-WSD, 21st Edition, December 2000.

B.8.4.2 Wind Loading

Appurtenances contribute significantly to total wind loads on drilling structures. This fact is well-documented in the JIP wind tunnel test results, and a number of international wind codes (including ASCE 7, Australian, and British codes) require that wind loads from appurtenances be included in force calculations; however, the codes generally do not provide rigorous methods for estimating the wind on such items.

The specification requirement for the inclusion of wind areas and their first moments about the base of the drilling structure was included to allow users to monitor any growth of sail areas during the life of the structure due to additions of structure and appurtenances and to establish a threshold for added sail area beyond which requalification of the structure would be required.

B.8.4.3 Member-by-Member Method

The process of estimating total wind force by summing the wind forces acting on individual members and adjoining components of a drilling *mast* or *derrick* is similar to the methods of other published wind standards for estimating total wind force on an open frame truss. When determining the critical wind direction, as a general rule the total wind force for a *diagonal* wind is greater than a broad face wind due to the greater projected area of a diagonal face when compared to a broad face. This rule is recognized in other wind specifications as ASCE/SEI 7-05 and the Australian Specification AS 1170.2.

Determining the direction of the resultant wind force on a member subject to an inclined wind ($\phi < 90°$) is generally done in one of three ways. For the purpose of discussion, let F_I equal the in-line wind force, F_C equal the cross-wind force (normal to F_I), F_N equal the wind force normal to the longitudinal axis of a member, and F_T equal the tangential force parallel to the longitudinal axis (normal to F_N). Using Bernoulli's equation with a shape coefficient equal to one and a member area equal to A (width times length), the wind force acting on the member will vary as a function of wind velocity V and angle of inclination ϕ.

As illustrated below, one approach (see Figure B.1) is to calculate the in-line wind force by projecting the area of the member onto a plane normal to the wind. For this "projected area approach," F_I will be a function of $V^2 A sin\phi$ while $F_C = 0$. Similarly, $F_N = f(V^2 A sin^2\phi)$ and $F_T = f(V^2 A sin\phi\ cos\phi)$.

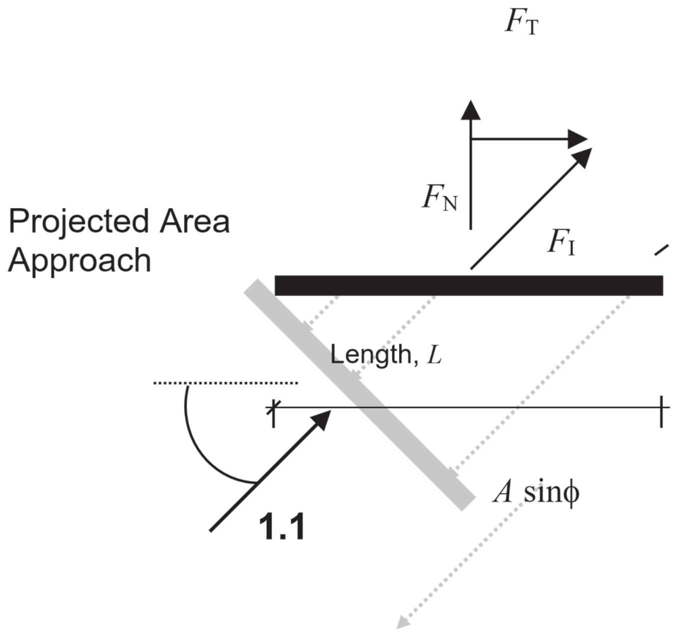


Figure B.1—Projected Area Approach

A second approach (see Figure B.2) is to calculate the wind force normal to the member, F_N, using the normal component of wind pressure, $½\rho V^2$, projected along the length of the member. For this "projected pressure approach," F_N will be a function of $V^2 A sin\phi$ while $F_T \cong 0$. Hence, $F_I = f(V^2 A sin^2\phi)$ and $F_C = f(V^2 A sin\phi\ cos\phi)$.

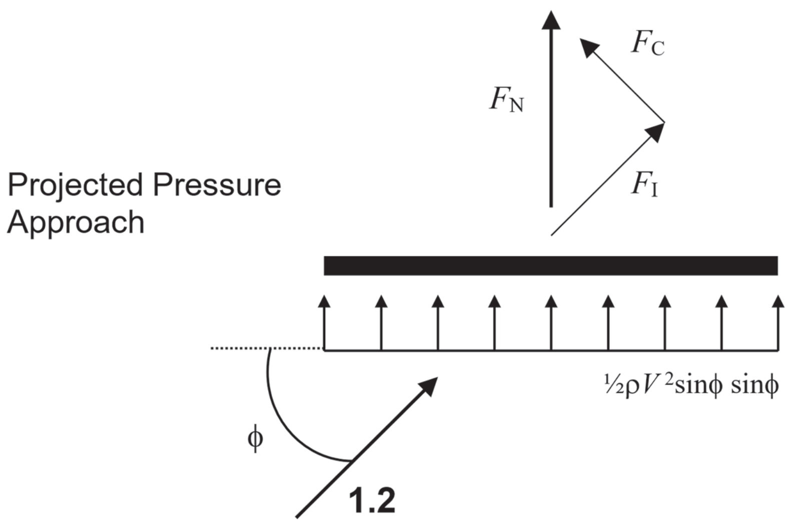


Figure B.2—Projected Pressure Approach

A third approach (see Figure B.3) is to calculate the wind force normal to the longitudinal axis of the member, F_N, by using the normal component of wind velocity, $V sin\phi$. For this "velocity component approach," F_N will be a function of $V^2 A sin^2\phi$ (note that $sin^2\phi$ results from squaring $V sin\phi$ via Bernoulli's equation) while $F_T \cong 0$. Hence, $F_I = f(V^2 A sin^3\phi)$ and $F_C = f(V^2 A sin^2\phi\ cos\phi)$.

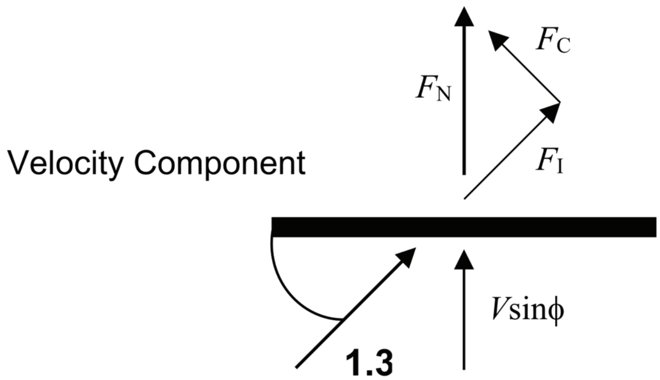


Figure B.3—Velocity Component Approach

Table B.1 below summarizes the variable terms for each of the three approaches ($V^2 A$ is omitted).

Table B.1—Wind Force Components Using Three Approaches

Approach	Wind Force Components			
	With Respect to Member		With Respect to Wind Direction	
	F_N (normal)	F_T (tangential)	F_I (in-line)	F_C (cross-wind)
Projected Area	$\sin^2\phi$	$\sin\phi\cos\phi$	$\sin\phi$	0
Projected Pressure	$\sin\phi$	0	$\sin^2\phi$	$\sin\phi\cos\phi$
Velocity Component	$\sin^2\phi$	0	$\sin^3\phi$	$\sin^2\phi\cos\phi$

Measurements of wind and current forces on structural and tubular members at an incline to the flow indicate that, to a first approximation, normal forces are dominant while tangential forces are negligible. The "projected area approach" implies that the in-line wind force is dominant with a notable tangential force present. By contrast, the "projected pressure approach" and the "velocity component approach" imply that the normal force dominates while the tangential force is negligible. Moreover, these two approaches also use shape coefficients in a manner that is consistent with their derivation. However, the "projected pressure approach" uses components of pressure, which is inconsistent with the definition of pressure as a scalar quantity. By contrast, the "velocity component approach" uses a velocity vector component to calculate fluid (i.e. wind) forces. This approach is consistent with information presented in fluid mechanics references.

The "velocity component approach" is used when estimating the wind force per 8.4.3 for the bare structure and for wind walls. Hence, it is assumed that the tangential component of the wind acting parallel to the longitudinal axis of a member or wind wall contributes nominally to the total wind force. Only the normal wind component acting perpendicular to the longitudinal axis ($V_z \sin\phi$) is considered when estimating the total wind force on a member of the bare structure per 8.4.3. For wind walls, the shape factors of Figure 2 approximately include the $\sin^2\phi$ term, so that $K_i = 1.0$.

The "projected area approach" is used for appurtenances other than wind walls. By definition, the "projected area approach" means that both the member width *and length* are projected onto a plane normal to the wind. This calculation differs from the calculation made for the projected area A of a member of the bare structure.

When using the normal velocity component (i.e. the "velocity component approach") to estimate wind force, a factor $\sin^2\phi$ is applied ($\sin\phi$ is squared since V_z is squared) to account for the wind angle of inclination with respect to the longitudinal axis. The resulting wind force will act along the length of the member or component, normal to the longitudinal axis. Using this approach means that the *in-line* wind component, calculated from the resultant normal force, will vary as a function of $sin^3\phi$. This variation is consistent with the approach taken for estimating current forces on fixed offshore platforms per API RP 2A-WSD.

The designer should verify that the wind loading methodology of any structural software program used in design is based on this specification.

An initial estimate of the total wind force on a drilling *mast* or *derrick* can be made using the solidity ratio, ρ, of a structural frame. This approach, however, should only be used for *preliminary* analysis. It should not be used in lieu of the specified procedure during final design or analysis. Solidity ratio, ρ, is defined here as the projected area of the front frame face (A_{face}) of the bare structure divided by the gross area enclosed by the frame borders (A_{gross}) of the bare structure. Several references provide shape coefficients for trusses, plate girders, cranes, and derricks as a function of solidity ratio and wind direction. For drilling *masts* and *derricks* with solidity ratios ranging from 0.1 to 0.3, a reasonable estimate of the total wind force may be calculated using Equations (B.2), (B.3), (B.4), and (B.5) below.

For square frames assembled with structural members (e.g. angles, channels, tees) subject to a normal wind:

$$F_{norm,1} = 0.00338 \times V_z^2 \times G_f \times C_f \times A_{face} \tag{B.2}$$

where

$$C_f = (4.0\rho^2 - 5.9\rho + 4.0)$$

For square frames assembled with structural members (e.g. angles, channels, tees) subject to a diagonal wind:

$$F_{diag,1} = F_{norm,1} \times (1.0 + 0.75\rho) \tag{B.3}$$

with

$$F_{diag,1} \text{ no greater than } 1.2 \times F_{norm,1}$$

For square frames assembled with round tubular members subject to a normal wind:

$$F_{norm,2} = F_{norm,1} \times (0.51\rho^2 + 5.7) \tag{B.4}$$

with

$$F_{norm,2} \text{ no greater than } F_{norm,1}$$

For square frames assembled with round tubular members subject to a diagonal wind:

$$F_{diag,2} = F_{norm,2} \times (1.0 + 0.75\rho) \tag{B.5}$$

with

$$F_{diag,2} \text{ no greater than } 1.2 \times F_{norm,2}$$

The equations apply only to open frames. Separate calculations must be made to estimate wind forces on wind walls, setback, and other attachments and equipment per 8.3.

B.8.4.3.2 Shielding and Aspect Ratio Correction Factor

Shielding of members or components of a mast or a derrick by other members or components will depend on member arrangements and shapes, the solidity of the structure, and on the orientation of the mast or of the derrick to the mean wind direction. For derricks, the specification defines a variable shielding factor between 0.5 and 1.0 for the bare structure based on the solidity of the face area. This formula was modified from the shielding equation for square trussed towers in ASCE 7-05 to allow its use with the specification method that considers all members on all faces of the derrick (rather than just the faces of the derrick normal to the wind, as in ASCE 7-05). A uniform shielding factor of 0.85 is defined for appurtenances. These factors are conservatively tuned to the JIP test results.

Because there is no test data or documented code approach for a mast structure, the shielding coefficient for both the bare structure and appurtenances of a mast is limited to 0.9.

For crown cluster, traveling block, hoses, collars, setback, or wind walls, changes in air flow around these shapes are accounted for in the shape coefficients selected for these sections as shown in Figure 2. The shape coefficients for setback pipes and rods in Figure 2 also include an aspect ratio correction.

The application of a global shielding factor means that the load reductions resulting from shielding are averaged over all members within a frame. (Though a small part of the overall correction, the same is true when accounting for airflow around member ends). In reality, only the leeward members will be shielded while the windward members will be exposed entirely to the wind. In most cases, the difference between the actual load and the average load on a windward and leeward (i.e. shielded) member will be about ±10 % to 15 %. Though loads other than wind will likely control the design, individual members are required to meet the allowable stress requirements for the unshielded member wind load superimposed on the global truss loading with shielding considered.

For dual setback, shielding effects are accounted for when the wind direction is within 20° of the vertical plane common to both setbacks (see Figure 2).

B.8.4.3.3 Member or Appurtenance Angle of Inclination

When estimating wind forces using the equation in 8.4.3, the longitudinal axes of the vertical, horizontal, and diagonal members will be oriented in such a manner that $\phi = 90°$ for a drilling mast or derrick exposed to a broadside (i.e. a normal) wind, and applies only to the broadside members. By contrast, for a drilling mast or derrick exposed to a diagonal wind, only the longitudinal axes of the vertical members will be orientated so $\phi = 90°$ while $\phi < 90°$ for the horizontal and diagonal members.

B.8.4.3.4 Gust Effect Factor

Wind gusts have spatial scales relative to their endurance. A 3-second gust is coherent over shorter distances and therefore affects smaller elements of a drilling mast or derrick structure. Given the overall size of drilling structures, a gust effect factor is therefore applied to account for spatial variance of wind speeds over larger areas. The basis for the values as shown in Table 8 are from the Australian Standard AS 1170.2-1989 and are consistent with the application of gust effect factors is presented in current and past editions of the ASCE/SEI 7-05 Standard.

B.8.4.3.5 Member or Appurtenance Shape Coefficient

The shape coefficients (also referred to as drag or force coefficients) in Figure 2 were derived from several sources that listed coefficients as a function of member shape and of wind angle. These sources include the Australian Standard AS 1170.2-1989; *Lattice Towers and Masts* (British Standards Institute); ASCE/SEI 7-05, *Minimum Design Loads for Buildings and Other Structures*; *Wind Effects on Structures* (Simiu and Scanlan); and *Force Coefficients for Transmission Towers* (Mehta and Lou). To simplify coefficient selection for members and adjoining components common to drilling masts and derricks, representative values were derived from these sources for various section types and shapes. Sensitivities to wind orientation (q) were assessed in an effort to provide a representative value for all wind orientations in the plane of a member cross section.

A representative shape coefficient of 1.8 for structural sections like angles, channels, beams, and tees was considered a reasonable value when used in combination with the member projected area. Nominal deviations from this 1.8 value result when comparing coefficients of individual members like angles or I-beams, though greater deviations result with rectangular profiles like channels and tubing. The 1.8 value for structural members is the same value selected by the ASCE Task Committee on Wind-Induced Forces (independent of API 4F) for the structural members of a petrochemical facility.

As a result of viscous flow effects, coefficients are greater for flat edge members but less for rounded members. Moreover, tubular sections have smaller shape coefficients when compared to structural shapes with a similar geometry due to Reynolds number effects.

For attachments like crown cluster, travelling block, hoses, and collars, the shape coefficients represent values similar to values for structural (i.e. flat edge) sections or for tubular (i.e. continuous surfaces) sections, with an adjustment made using an aspect ratio correction of 0.6.

For setback pipes and rods, the cross sections are similar in shape to square or rectangular tubular sections with a representative shape coefficient of 1.5. Hence, a value of 1.2 was selected for setback, reflecting an adjustment for aspect ratio. For dual setback, shielding effects become evident as the wind direction becomes aligned with the two setbacks. Hence, two shape coefficients are provided, one value (1.2) for the windward setback and another value (0.3) for the leeward setback, for wind directions within 20° of the vertical plane common to both setbacks. For a semicircular setback, a shape coefficient value of 1.2 is selected since the corners are rounded instead of flat.

The derivation of representative shape coefficients for wind walls was based on information provided by various standards for estimating wind loads on solid signs or walls. The resulting wind force may act toward or away from the wall surface, depending on the wind direction and wall configuration. Estimating wind forces on a completely cladded drilling mast or derrick involves a more complex process than provided in this specification. Hence, other standards like ASCE Standard 7-95 should be used to estimate wind loadings for such cases.

B.8.4.3.6 Member or Appurtenance Projected Area

Calculations of shape coefficients are made based on the characteristic area of a member, which can either be represented as a constant (e.g. the surface area of the long leg of an unequal-leg angle) or as a variable, often equal to the projected area of a member normal to the given wind direction. Generally considered more intuitive to the designer, the projected area is used to calculate static wind forces on members and adjoining components.

During wind tunnel testing, flow usually occurs normal to the longitudinal axis, i.e. in the plane of the member cross section, with no air flow around the member ends. Hence, most shape coefficients, and the associated characteristic areas, are applicable only to these test conditions. Thus, calculation of the projected area for a member or adjoining component is with respect to a plane normal to the wind component acting perpendicular to the longitudinal axis. The projected area will equal the member length times its width normal to the wind.

For wind walls, the projected area for a given wall section equals its surface area (width times height).

B.8.4.5 Wind Dynamics

Standards are available for estimating wind forces on structures when additional loads are anticipated as a result of dynamic interaction between the wind and the structure. The basis for such an analysis depends on the referenced standard. For example, the Australian Standard AS 1170.2-1989 requires a dynamic analysis for the design of main structural components of any structure if (1) the height or length-to-breadth ratio is greater than five, and (2) the first-mode frequency of vibration is less than 1 Hz. Likewise, ASCE/SEI Standard 7-05 does not apply for dynamic torsional loading or flexible structures with natural frequencies below 1 Hz, or tall slender buildings with height-to-width ratio that exceeds 4.

B.8.5.1 Inertial Loads

The specification broadens inertial force calculations to include surge and sway forces; earlier editions listed only equations for determining inertial forces on the structure for sinusoidally-varying rotational motions such as roll and pitch and heave.

B.8.5.2 Dynamic Amplification

A general requirement in the specification to ensure that the designer gives due consideration concerning dynamic amplification is included, in response to an incident in which a drilling structure incurred dangerous oscillations while on a “fixed” platform; in reality, the platform was installed in more than 305 m (1000 ft) of water and exhibited significant motions in operating sea states with wave periods around five seconds.

B.8.6 Earthquake Loads

As the specification does not address design methodology for earthquake, it is up to the user to specify how the SSL level is to be used for the analysis, if at all.

The document titled *Seismic Assessment Procedures for Drilling Structures on Offshore Platforms*—IADC/SPE 74454-MS, by J. W. Turner, M. Effenberger, and J. Irick provides guidance for assessment and design of drilling structures on offshore platforms and jack-ups. Much of the information presented therein is also applicable to the consideration of seismic design for onshore structures.

B.8.10 Overturning and Sliding

The specification defines allowable maximum values for coefficients of friction for use in overturning and sliding calculations, unless higher values are validated by testing and operational procedures are consistent with such values.

Stabilizing dead weights are limited to 90 % of their expected value, and the added stability against sliding and overturning resulting from fluid loads or temporarily installed equipment is not allowed unless documented in rig instructions by the manufacturer and also on the structure nameplate when required for erection.

The specification defines overturning and sliding factors-of-safety for freestanding structures and requires the calculation of the factor-of-safety in light of the allowable support loadings of the underlying foundation to prevent foundation collapse.

A graph of design loads for tie-down clamps vs increasing overturning and sliding loads may exhibit highly nonlinear or bilinear loading; the clamp sees no load until a load level is reached where the stabilizing effect of gravity loads is overcome. Tie-down clamp loads are calculated using a 1.25 load factor applied to overturning vertical live loads and sliding loads and with “lightship” dead weights; allowable strength may not be increased for tie-down clamps. This requirement ensures a measure of robustness in the event of overload caused by a storm event greater than the design event.

Dual load path components other than tie-down clamps must meet not only the requirements of 8.1 (with an allowable strength multiplier of 1.33 for extreme events) but also the requirements of cases calculated using a 1.25 load factor applied to overturning vertical live loads and sliding loads and with “lightship” dead weights, with an allowable strength multiplier of 1.67. If the nominal factor-of-safety in AISC is taken as 1.67 (that of a bar in tension or a beam in bending), the nominal minimum factor-of-safety for the unfactored cases will be this value reduced by the allowable strength multiplier, or $1.67/1.33 = 1.25$. Similarly, the additional requirement would provide a nominal minimum factor-of-safety for the factored load cases of $1.67/1.67 \times 1.25 = 1.25$. Thus, the additional requirement ensures a consistent factor-of-safety even if these elements exhibit sharply nonlinear or bilinear loading with the level of overturning and sliding loads.

Annex C
(informative)

API Monogram Program Use of the API Monogram by Licensees

C.1 Scope

The API Monogram® is a registered certification mark owned by the American Petroleum Institute (API) and authorized for licensing by the API Board of Directors. Through the API Monogram Program, API licenses product manufacturers to apply the API Monogram to new products which comply with product specifications and have been manufactured under a quality management system that meets the requirements of API Spec Q1. API maintains a complete, searchable list of all Monogram licensees on the API Composite List website (http://compositelist.api.org).

The application of the API Monogram and license number on products constitutes a representation and warranty by the licensee to API and to purchasers of the products that, as of the date indicated, the products were manufactured under a quality management system conforming to the requirements of API Spec Q1 and that the product conforms in every detail with the applicable standard(s) or product specification(s). API Monogram Program licenses are issued only after on-site audits have verified that an organization has implemented and continually maintained a quality management system that meets the requirements of API Spec Q1 and that the resulting products satisfy the requirements of the applicable API product specification(s) and/or standard(s). Although any manufacturer may claim that its products meet API product requirements without monogramming them, only manufacturers with a license from API can apply the API Monogram to their products.

Together with the requirements of the API Monogram license agreement, this annex establishes the requirements for those organizations who wish to voluntarily obtain an API license to provide API monogrammed products that satisfy the requirements of the applicable API product specification(s) and/or standard(s) and API Monogram Program requirements.

For information on becoming an API Monogram Licensee, please contact API, Certification Programs, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001 at Certification@api.org.

C.2 Normative References

For Licensees under the Monogram Program, the latest version of this document shall be used. The requirements identified therein are mandatory.

C.3 Terms and Definitions

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

C.3.1
API monogrammable product
Product that has been newly manufactured by an API Licensee utilizing a fully implemented API Spec Q1 compliant quality management system and that meets all the API-specified requirements of the applicable API product specification(s) and/or standard(s).

C.3.2
API product specification
Prescribed set of rules, conditions, or requirements attributed to a specified product that address the definition of terms; classification of components; delineation of procedures; specified dimensions; manufacturing criteria;

material requirements, performance testing, design of activities; and the measurement of quality and quantity with respect to materials; products, processes, services, and/or practices.

C.3.3
API-specified requirements
Requirements, including performance and Licensee-specified requirements, set forth in API Spec Q1 and the applicable API product specification(s) and/or standard(s).

NOTE Licensee-specified requirements include those activities necessary to satisfy API-specified requirements.

C.3.4
design package
Records and documents required to provide evidence that the applicable product has been designed in accordance with API Spec Q1 and the requirements of the applicable product specification(s) and/or standard(s).

C.3.5
licensee
Organization that has successfully completed the application and audit process, and has been issued a license by API to use the API Monogram Mark.

C.4 Quality Management System Requirements

An organization applying the API Monogram to products shall develop, maintain, and operate at all times a quality management system conforming to API Specification Q1.

C.5 Control of the Application and Removal of the API Monogram

Each licensee shall control the application and removal of the API Monogram in accordance with the following:

a) Products that do not conform to API-specified requirements shall not bear the API Monogram.

b) Each licensee shall develop and maintain an API Monogram marking procedure that documents the marking/monogramming requirements specified by this annex and any applicable API product specification(s) and/or standard(s). The marking procedure shall:

 1) define the authority responsible for application and removal of the API Monogram and license number;

 2) define the method(s) used to apply the Monogram and license number;

 3) identify the location on the product where the API Monogram and license number are to be applied;

 4) require the application of the date of manufacture of the product in conjunction with the use of the API Monogram and license number;

 5) require that the date of manufacture, at a minimum, be two digits representing the month and two digits representing the year (e.g. 05-12 for May 2012) unless otherwise stipulated in the applicable API product specification(s) or standard(s); and

 6) define the application of all other required API product specification(s) and/or standard(s) marking requirements.

c) Only an API licensee shall apply the API Monogram and its designated license number to API monogrammable products.

d) The API Monogram and license number, when issued, are site-specific and subsequently the API Monogram shall only be applied at that site specific licensed facility location.

e) The API Monogram may be applied at any time appropriate during the production process but shall be removed in accordance with the licensee's API Monogram marking procedure if the product is subsequently found to be out of conformance with any of the requirements of the applicable API product specification(s) and/or standard(s) and API Monogram Program.

For certain manufacturing processes or types of products, alternative API Monogram marking procedures may be acceptable. Requirements for alternative API Monogram marking are detailed in the API Alternative Marking Agreement (AMA), which is available on the API Monogram Program website at: https://www.api.org/~/media/Files/Certification/Monogram-APIQR/0_API-Monogram-APIQR/Resources/API-Monogram-Alt-Marking-Agreement_Rev-8_FM-011_Modified-20180601.pdf.

C.6 Design Package Requirements

Each licensee and/or applicant for licensing shall maintain a current design package for all of the applicable products that fall under the scope of each Monogram license. The design package information shall provide objective evidence that the product design meets the requirements of the applicable and most current API product specification(s) and/or standard(s). The design package(s) shall be made available during API audits of the facility.

In specific instances, the exclusion of design activities is allowed under the Monogram Program, as detailed in Advisory # 6, available on the API Monogram Program website at https://www.api.org/products-and-services/api-monogram-and-apiqr/advisories-updates.

C.7 Manufacturing Capability

The API Monogram Program is designed to identify facilities that have demonstrated the ability to manufacture equipment that conforms to API specifications and/or standards. API may refuse initial licensing or suspend current licensing based on a facility's level of manufacturing capability. If API determines that additional review is warranted, API may perform additional audits (at the organization's expense) of any primary subcontractors to ensure their compliance with applicable specifications.

Facilities with capabilities that are limited to the processes or activities defined below do not meet the manufacturing capability requirements to produce new products, and therefore, shall not be licensed or be the basis for licensing under the API Monogram Program:

— Capabilities that are limited to performing final inspection and testing of the product, except for testing agencies as specified in API Spec 14A and/or API Spec 6AV;

— Buying, selling and/or distributing finished products and materials;

— Design and development activities;

— Tearing-down and/or re-assembling of products/components; and,

— Repairing or remanufacturing of existing, used, worn or damaged products.

In all instances where requirements for manufacturing or manufacturing facilities are explicitly identified within the API product specification, those requirements shall take precedence over this advisory.

C.8 Product Marking Requirements

C.8.1 General

These marking requirements shall apply only to those API Licensees wishing to mark applicable products in conjunction with the requirements of the API Monogram Program.

C.8.2 Product Specification Identification

Manufacturers shall mark products as specified by the applicable API specifications or standards. Marking shall include reference to the applicable API specification and/or standard. Unless otherwise specified, reference to the API specifications and/or standards shall be, as a minimum, "API [Document Number]" (e.g. API 6A, or API 600). Unless otherwise specified, when space allows, the marking may include use of "Spec" or "Std", as applicable (e.g. API Spec 6A or API Std 600).

C.8.3 Units

Products shall be marked with units as specified in the API specification and/or standard. If not specified, equipment shall be marked with U.S. customary (USC) units. Use of dual units [USC units and metric (SI) units] may be acceptable, if such units are allowed by the applicable product specification and/or standard.

C.8.4 Nameplates

Nameplates, when applicable, shall be made of a corrosion-resistant material unless otherwise specified by the API specification and/or standard. Nameplate shall be located as specified by the API specification and/or standard. If the location is not specified, then the licensee shall develop and maintain a procedure detailing the location to which the nameplate shall be applied. Nameplates may be attached at any time during the manufacturing process.

The API Monogram and license number shall be marked on the nameplate, in addition to the other product marking requirements specified by the applicable product specification and/or standard.

C.8.5 License Number

The API Monogram license number shall not be used unless it is marked in conjunction with the API Monogram. The license number shall be used in close proximity to the API Monogram.

C.9 API Monogram Program: Nonconformance Reporting

API solicits information on products that are found to be nonconforming with API-specified requirements, as well as field failures (or malfunctions), which are judged to be caused by either specification and/or standard deficiencies or nonconformities against API-specified requirements. Customers are requested to report to API all problems with API monogrammed products. A nonconformance may be reported using the API Nonconformance Reporting System available at http://ncr.api.org/ncr.aspx.

Annex D
(informative)

Purchasing Guidelines

The following information should be provided by the purchaser when making an inquiry or placing an order:

a) Reference to this standard;
b) Reference to any requirement for third party certification, name of the third party agency, and if applicable, the level of certification;
c) Reference to Annex A for optional supplemental requirements (SR) for Low-Temperature Testing, Proof Load Testing, and Data Book requirements.
d) Section numbers represented below are those of API 4F, 5th Edition Specifications

Units Specified:	**Metric**		**Imperial**	

Section 4: Product Specification Levels (PSL)

The level of material and process controls placed upon primary load-carrying components of covered equipment.

PSL 1	
PSL 2	

PSL 1 includes practices implemented by a broad spectrum of the industry.
PSL 2 includes all of PSL 1 plus additional requirements.

Section 5.2, 5.3, 5.4, and 5.5 - API Nameplates Required

API Derrick or Mast Nameplate Required		Yes		No
API Service Rig Mast Nameplate Required		Yes		No
API Substructure Nameplate Required		Yes		No
API Crown Block Nameplate Required		Yes		No

Section 6: Structural Safety Level (SSL) (Refer to Table 1)

Other Concerns
(Pollution, Economic Loss, Public Concern, etc.)

Life Safety	High		Medium		Low	
High	E1[a]	U1[a]	E1[a]	U1[a]	E1[a]	U1[a]
Medium	E1[a]	U1[a]	E2[b]	U2[b]	E2[b]	U2[b]
Low	E1[a]	U1[a]	E2[b]	U2[b]	E3[c]	U3[c]

[a]Structural Safety Level E1 or U1—Structures with high consequences of failure.
[b]Structural Safety Level E2 or U2—Structures with medium consequences of failure.
[c]Structural Safety Level E3 or U3—Structures with low consequences of failure.

E = Expected Environmental Event (Choose Only One)
U = Unexpected Environmental Event (Choose Only One)
Each structure shall have two SSL's, the first for the expected environmental event, and the second for the unexpected environmental event.
Note: SSL E1/U2, E1/U3, E2/U3 are unrealistic. Refer to Annex B.6 for detailed information.

Section 7: Design Loads (Refer to Tables 2 and 3)

Maximum Rated Static Hook Load =	____________	kN (kips)
Maximum Rated Static Rod Load[1] =	____________	kN (kips)
Maximum Rated Static Rotary Load =	____________	kN (kips)
Maximum Rated Setback Load =	____________	kN (kips)

[1]Operating Rod Load required for Service Rig Masts per Table 3.

Section 8.1: Allowable Strength - Fatigue Design Option

Fatigue Design rarely governs in the design of Drilling Structures; Is Fatigue Design required by the purchaser? Yes ☐ No ☐

Section 8.3: Special Operating Loads

Do any special operating loads in excess of Tables 2 or 3 exist as required by the purchaser? Yes ☐ No ☐

If "Yes", list the special operating loads below:

____

____

____

____

Section 8.4.1.2: Onshore Wind

The design reference wind velocity for operating, erection, and transportation shall be specified by the purchaser.

Operating V_{ref} =	____________	knots
Erection V_{ref} =	____________	knots
Transportation V_{ref} =	____________	knots

Note: 1 knot = 1.15 miles per hour = 0.514 meters per second

The expected and unexpected storm wind data may be specified in one of the following manners:

1. Directly specified by the purchaser in knots; The expected wind velocity specified shall be a 3-second gust wind, in knots, measured at 10 m (33 ft) in open terrain with an associated wind return period of 50 years for the land regions where the rig will operate.

   The unexpected wind velocity shall be not less than 75% of the expected wind velocity.

2. Specified by the required Structural Safety Level (SSL; refer to Section 6) and the various regions where the structures shall operate. The manufacturer shall determine the appropriate design wind speeds using data from a recognized standards or governmental meteorological agency for the regions of intended use. Example: ASCE/SEI 7-05 is used for data in the continental United States. Note that for some regions in the world, such meteorological data is not readily available, and the purchaser and manufacturer should agree on appropriate design wind speeds.

Expected V_{ref} =	____________	knots
Unexpected V_{ref} =	____________	knots

Section 8.4.1.3: Offshore Wind

The design reference wind velocity for operating, erection, and transportation shall be specified by the purchaser.

Operating V_{ref} =	_____________	knots
Erection V_{ref} =	_____________	knots
Transportation V_{ref} =	_____________	knots

Note: 1 knot = 1.15 miles per hour = 0.514 meters per second

The expected wind velocity specified shall be a 3-second gust wind, in knots, measured at 10 m (33 ft) in open water with an associated wind return period of 100 years for the location of where the rig will operate.

The unexpected wind velocity specified shall be a 3-second gust wind, in knots, measured at 10 m (33 ft) in open water with an associated wind return period of 100 years for the location of where the rig will operate.

The expected and unexpected storm wind data may be specified in one of the following manners:

1. Directly specified by the purchaser in knots.

2. Specified by the required Structural Safety Level (SSL; refer to Section 6) and the various regions where the structures shall operate. The manufacturer shall determine the appropriate design wind speeds using data from ISO 19901-1. For expected and unexpected offshore storms in the Gulf of Mexico, the wind velocity shall be taken from API Bull 2INT-MET. For any areas not covered by the specifications listed above, the reference wind velocity shall be taken from a recognized standards agency, a governmental meteorological agency, or a site specific study with ISO guidelines. Note that for some regions in the world, such meteorological data is not readily available and the purchaser and manufacturer should agree on appropriate design wind speeds.

Expected V_{ref} =	_____________	knots
Unexpected V_{ref} =	_____________	knots

Section 8.5: Dynamic Loads

Applicable dynamic load combinations shall be specified by purchaser for all types of offshore drilling structures. Two methods of input for offshore dynamics are currently used. The first is commonly specified in naval architecture terms and requires the data listed below:

Surge =	_____________	g			
Sway =	_____________	g			
Pitch =	_____________	degrees	Period =	_____________	seconds
Roll =	_____________	degrees	Period =	_____________	seconds
Heave =	_____________	g			

Longitudinal Metacenter of Vessel =	_____________	m (ft)
Transverse Metacenter of Vessel =	_____________	m (ft)
Vertical Metacenter of Vessel =	_____________	m (ft)

A second method to provide data for offshore dynamics is to provide the accelerations:

Linear X Acceleration =	_____________	m/sec^2 (ft/sec^2)

Linear X Acceleration =	______________	m/sec^2 (ft/sec^2)
Linear X Acceleration =	______________	m/sec^2 (ft/sec^2)
Rotational X Acceleration =	______________	rad/sec^2
Rotational X Acceleration =	______________	rad/sec^2
Rotational X Acceleration =	______________	rad/sec^2
Longitudinal Metacenter of Vessel =	______________	m (ft)
Transverse Metacenter of Vessel =	______________	m (ft)
Vertical Metacenter of Vessel =	______________	m (ft)

Section 8.6: Earthquake Loads

Earthquake consideration is a special loading condition to be specified by the user. The purchaser is responsible to provide all design criteria for the seismic zone in which the drilling unit shall operate.

If the drilling unit is to be designed for earthquakes, the purchaser shall provide design data below.

Section 8.7: Ice Loads

Per API requirements, ice loading is a special loading condition to be specified by the purchaser/user.

If the drilling unit is to be designed for ice loading, the purchaser shall provide design data below.

Section 8.8: Erection Loads

Per API requirements, each drilling structure shall be designed for erection loads in combination with dead loads and erection wind. Any additional erection loads, wind, inertial, or other, shall be specified by purchaser.

If any additional erection loads exist, the purchaser shall provide design data below.

Section 8.9: Transportation Loads

Per API requirements, each drilling structure shall be designed for transportation loads in combination with dead loads and transportation environment wind. Any additional transportation loads, wind, inertial, or other, shall be specified by purchaser.

If any additional transportation loads exist, the purchaser shall provide design data below.

____
____
____
____

Section 8.10: Overturning and Sliding

Distribution of any foundation support reactions shall be limited to comply with allowable design loadings of the supporting structures foundations, if specified by the purchaser. Manufacturer shall include diagrams defining the maximum foundation support loads based on the factored lateral loads with rig instructions. For example, ground supported land drilling structures might be specified to be supported on rig mats with an appropriate limitation on the maximum allowable ground bearing pressure.

Does the drilling unit sit on an additional supporting structure not included in the fabricator's scope of design?	Yes	
	No	

If applicable, the purchaser shall provide data (all allowable loads and conditions, including allowable ground bearing pressure, for foundations) below.

____
____
____
____

Supplementary Requirements

Annex A.1 SR1 - Low-Temperature Testing

The purchaser and manufacturer shall agree on the minimum design temperature and required testing temperatures.

Minimum Design Temperature = ____________ °C (°F)

Impact Test Result Requirements = ____________ N-m (ft-lbs)

Annex A.2 SR2 - Proof Load Testing

Equipment shall be load tested to a load agreed by the purchaser and manufacturer.

Proof Load Test = ____________ kN (lbs)

Annex A.3 SR3 - Data Book

Does the purchaser require a data book per API 4F?	Yes	
	No	

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[1] ABS,[5] *Rules for Building and Classing Offshore Drilling Units*, 1991

[2] ASNT TC-1A,[6] *Recommended Practice for Personnel Qualification and Certification in Non-Destructive Testing (also known as ASNT 2055)*

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[5] American Bureau of Shipping, ABS Plaza, 1701 City Plaza Drive, Spring, Texas 77389, ww2.eagle.org.

[6] American Society for Nondestructive Testing, PO Box 28518, 1711 Arlingate Lane, Columbus, Ohio 43228-0518, www.asnt.org.

[7] American Institute of Steel Construction, One Prudential Plaza, 130 E. Randolph Street, Suite 2000, Chicago, Illinois 60601, www.aisc.org.

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