Structural Integrity Management of Fixed Offshore Structures

API RECOMMENDED PRACTICE 2SIM
FIRST EDITION, NOVEMBER 2014

AMERICAN PETROLEUM INSTITUTE

Special Notes

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to assure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

Foreword

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

The verbal forms used to express the provisions in this specification are as follows:

— the term “shall” denotes a minimum requirement in order to conform to the specification,

— the term “should” denotes a recommendation or that which is advised but not required in order to conform to the specification,

— the term “may” is used to express permission or a provision that is optional,

— the term “can” is used to express possibility or capability.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 1220 L Street, NW, Washington, DC 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 1220 L Street, NW, Washington, DC 20005.

Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

Contents

Contents

Contents

Introduction

The purpose of this recommended practice is to provide guidance to owner/operators and engineers in the implementation and delivery of a process to manage the structural integrity of existing fixed offshore platforms. This process is called structural integrity management (SIM).

The SIM process described in this recommended practice is based on internationally recognized industry standards, including API 2A-WSD, 22nd Edition and ISO 19902:2007, and on global industry best practices. This recommended practice details engineering practices for the evaluation, assessment, and inspection of existing fixed offshore structures to demonstrate their fitness-for-purpose. This recommended practice incorporates and expands on the recommendations of Section 14, “Surveys” and Section 17, “Assessment of Existing Platforms” as previously provided in API 2A, 21st Edition.

The principal section describing the recommended SIM process is Section 5. It contains details of each aspect of the SIM process and provides a roadmap for using the recommended practice. Each of the remaining sections provides self-contained detailed guidance on performing the relevant SIM task.

Section 6 contains guidance on underwater surveys of fixed platforms. Two approaches are provided: a risk-based underwater survey (6.5.2) and an exposure-based underwater survey (6.5.3). When the owner/operator has not adopted a risk-based SIM strategy, an exposure-based (default) inspection program should be used.

In particular, Section 9 contains guidance on the selection of calibrated metocean criteria used for the fitness-for-purpose assessment of platforms designed and constructed to API 2A-WSD, 19th Edition and earlier editions that are located in the U.S. waters of the Gulf of Mexico or West Coast. In addition, Section 9 contains guidance on the selection of appropriate metocean criteria used for the fitness-for-purpose assessment of platforms designed and constructed to API 2A-WSD, 20th Edition and later for platforms located in the waters of the U.S. Gulf of Mexico or U.S. West Coast.

Structural Integrity Management of Fixed Offshore Structures

1 Scope

This recommended practice provides guidance for the structural integrity management (SIM) of existing fixed offshore structures used for the drilling, development, production, and storage of hydrocarbons in offshore areas. However, the general principles of SIM apply to any structure.

Specific guidance is provided for the evaluation of structural damage, above- and below-water structural inspection, fitness-for-purpose assessment, risk reduction, mitigation planning, and the process of decommissioning. This recommended practice incorporates and expands on the recommendations of Section 14, "Surveys" and Section 17, "Assessment of Existing Platforms" as previously provided in API 2A-WSD, 21st Edition. See Annex A for additional information and guidelines on the provisions stated in the numbered sections of this document.

The SIM process provided in this recommended practice is applicable to existing platforms installed at any location worldwide. However, the recommended practice provides specific metocean criteria, which are only applicable for use in fitness-for-purpose assessments of platforms located in the U.S. Gulf of Mexico and the U.S. West Coast.

For guidelines, recommended practices, and other requirements relating to planning, designing, and constructing new fixed offshore platforms, including reuse and change-in-use of existing platforms, reference should be made to the latest edition of API 2A-WSD.

For guidelines, recommended practices, and other requirements relating to planning, designing, and constructing new offshore floating production systems, including reuse and change-in-use of existing floating production systems, reference should be made to the latest edition of API 2FPS.

2 Normative References

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

API Recommended Practice 2A-WSD, *Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design*, 22nd Edition

API Recommended Practice 2EQ, *Recommended Practice for Seismic Design Procedures and Criteria for Offshore Structures*

API Recommended Practice 2MET, *Recommended Practice for Derivation of Metocean Design and Operation Conditions*

API Recommended Practice 2N, *Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1
air gap
The clearance between the highest water surface that occurs during the extreme metocean conditions and the underside of the cellar deck.

3.1.2
anomaly
An in-service survey measurement that is outside the threshold considered acceptable from the design or most recent fitness-for-purpose assessment.

3.1.3
assessment initiators
Changes in platform condition or operating experience, such as storms, which require an existing platform to undergo an assessment to demonstrate fitness-for-purpose.

3.1.4
collapse
The ultimate load bearing capacity of the platform at which the jacket structure or deck columns are no longer able to support vertical loads.

3.1.5
condition assessment
The process of gathering the information on the platform's present condition needed in order to perform a fitness-for-purpose assessment.

3.1.6
consequence
The adverse effects of an extreme event, such as metocean, seismic, ice, or accidental, on personnel, the environment, or property.

3.1.7
consequence of failure category
A system applied to categorize the consequences of failure of an existing offshore platform.

3.1.8
corrosion
Degradation of a component or components due to corrosion. Corrosion may be categorized as either general or local and may cause pitting, holes, or crevices.

3.1.9
damage tolerance
The quantity of deterioration or damage that a structure can withstand without failing.

3.1.10
deck elevation
The measured distance from the underside (bottom-of-steel) of the support structure of a topside deck structure to a confirmed datum, such as the mean sea level (MSL).

3.1.11
decommissioning
A process followed to plan, gain approval for, and implement the removal, disposal, or reuse of the platform structure, equipment, and associated pipelines and wells.

3.1.12
defect
An imperfection, fault, or flaw in a component of an existing platform. As used in this recommended practice, the term "defect" does not necessarily denote that the platform is not fit-for-purpose.

3.1.13
design level analysis
A fitness-for-purpose analysis of a platform using linear-elastic methods with an appropriate safety margin, similar to the analysis methods used for new platform designs

3.1.14
design life
The planned time period from initial installation or reuse until permanent decommissioning, which may include extensions justified through the SIM process.

3.1.15
deterioration
The reduction in the ability of a component to provide its intended purpose.

3.1.16
exposure category
The classification used to categorize the platform consequence of failure based on the consideration of life safety, environmental pollution, and business disruption.

3.1.17
extreme event
An extreme metocean, seismic, and/or ice condition that a structure may be subjected to during its operational life.

3.1.18
fitness-for-purpose
A demonstration that an existing structure has adequate strength to resist the imposed assessment loads.

3.1.19
full population hurricane
A population of hurricanes that includes all hurricanes that develop inside or outside of the Gulf of Mexico, used for statistical analysis.

3.1.20
in-service
A platform that has been placed in operation.

3.1.21
inspection
The visit to the platform and the associated survey activities for purposes of collecting data required in evaluating its structural integrity for continued operation.

3.1.22
life extension
The process of extending the operational life of a structure beyond the life considered during the structure's design.

3.1.23
mechanical damage
A defect type that includes dents, bows, gouges, holes, and separated or severed members.

3.1.24
mitigations
Platform strengthening, modification, and/or repairs (SMRs) and/or operational procedures that reduce loads, increase capacities, or reduce the exposure category.

3.1.25
nonredundant platform
A platform for which its global capacity is reached when one of its primary structural elements reaches its maximum capacity.

3.1.26
not normally manned
A platform that does not have facilities to accommodate personnel for overnight or extended stays.

3.1.27
omnidirectional
A criterion that is considered uniform in all directions.

3.1.28
operator
The person, firm, corporation, or other organization employed by the owners to conduct operations.

3.1.29
owner
A party who owns physical infrastructure assets (pipelines, platforms, or terminals) and/or a party who owns capacity rights in those physical assets but does not own the asset itself.

3.1.30
performance criteria
The criteria for which an existing platform should meet to be considered fit-for-purpose.

3.1.31
prior exposure
The historical exposure of a platform to the design metocean, seismic, or ice loading.

3.1.32
redundant platform
A platform for which its global capacity is maintained when one or more of its primary structural elements reaches its maximum capacity.

3.1.33
redundancy
The availability of alternate load paths in a platform following the failure of one or more structural components.

3.1.34
repair
The structural work necessary to restore a platform to a condition deemed fit-for-purpose.

3.1.35
reserve strength ratio
RSR
A measure of the ultimate load carrying capacity of a platform, defined as the ratio of the base shear at ultimate capacity to the base shear from the 100-year reference criteria.

NOTE For the Gulf of Mexico this is the full population hurricane.

3.1.36
residual strength
The ultimate strength of an offshore structure in a damaged condition is expressed as the structure's residual strength and is highly dependent on the inherent robustness of the structure.

3.1.37
risk-based inspection
Inspection strategies developed from an evaluation of the risk associated with a platform or group of similar platforms with the intention of tailoring inspection level to risk magnitude and location.

3.1.38
robustness
The ability of a structure to tolerate damage without failure.

3.1.39
sudden hurricane
A hurricane that develops inside the Gulf of Mexico sufficiently close to the relevant platform such that personnel evacuation is not assured.

3.1.40
splash zone
The area of the structure that is intermittently wet and dry due to wave and tidal action.

3.1.41
survey
A specific visual or nondestructive examination of one or more platform components.

3.1.42
ultimate capacity
The load or action at which a structure will collapse.

3.1.43
ultimate strength analysis
The fitness-for-purpose analysis of a platform using nonlinear methods or equivalent linear methods to determine the platforms global ultimate capacity, often referred to as a "pushover."

3.2 Acronyms and Abbreviations

ALE	abnormal level earthquake
CP	cathodic protection
CFR	*Code of Federal Regulations*
CGF	conductor guide frame
CVI	close visual inspection
ELE	extreme level earthquake
FMD	flooded member detection
HEAT	Hurricane Evaluation and Assessment Team
HLV	heavy lift vessel
LRFD	load and resistance factor design
MLLW	mean lower low water

NDE	nondestructive examination, including visual examination
NDT	nondestructive testing
MSL	mean sea level
OCS	Outer Continental Shelf
ROV	remotely operated vehicle
RSR	reserve strength ratio
SIM	structural integrity management
SMR	strengthening, modification, and/or repair
SSSV	subsurface safety valve
UT	ultrasonic testing
WSD	working stress design

4 Structural Integrity Management Overview

4.1 General

SIM is a continuous process used for demonstrating the fitness-for-purpose of an offshore structure from installation through to decommissioning. SIM provides the process for understanding the effects of deterioration, damage, changes in loading, and accidental overloading. In addition, SIM provides a framework for inspection planning, maintenance, and repair of a platform or group of platforms. The SIM process, shown in Figure 1, consists of four primary elements: data, evaluation, strategy, and program.

Data includes information from the original design of the structure, inspection findings throughout the life of a structure, effects of damage and deterioration found through inspection, overloading, and changes in loading and/or use. Data may also emanate from technology development projects or in-service experience of similar structures within industry. Throughout the life of the platform, new data is collected through periodic inspections, results of accidental events, from planned modifications, or from additions to the platform. This data is subject to qualified engineering evaluation to demonstrate fitness-for-purpose and adjust the SIM strategy, if necessary. The results from the evaluation are used to develop and subsequently implement a topside, above- and below-water inspection strategy. The program is the implementation of the detailed inspection, maintenance, and repair work scopes, as defined from the SIM strategy.

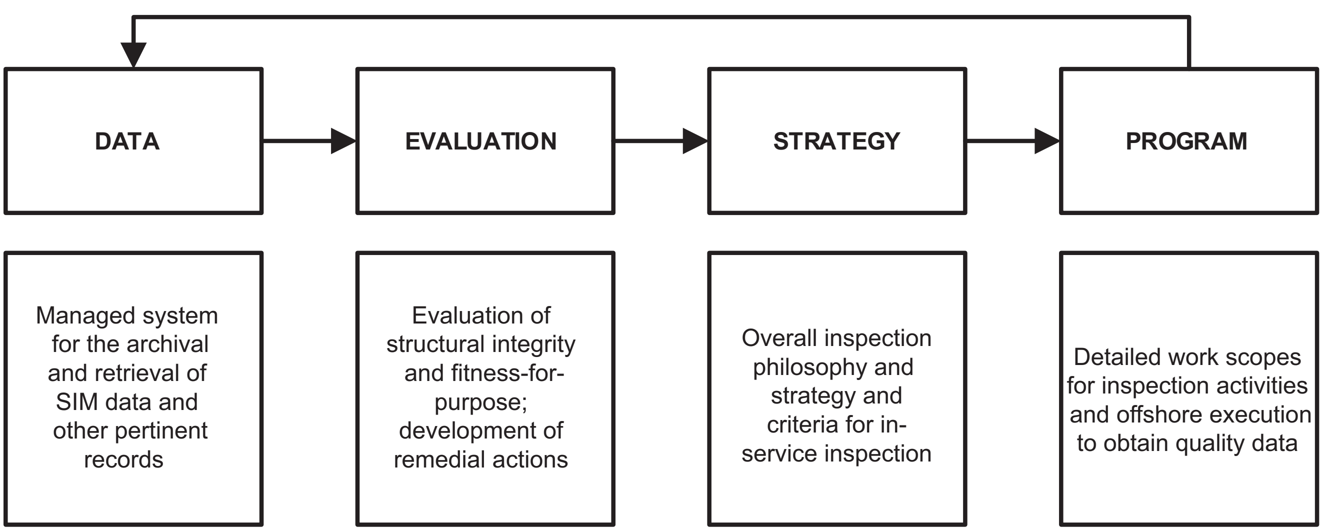

Figure 1—SIM Process

4.2 Competency

Broadly defined, competency is the experience gained through formal education and a combination of training, qualifications, understanding, and practicing skills. The engineer(s) involved in the SIM process should be knowledgeable of the following:

a) offshore structural engineering and with the specific platform(s) under consideration;

b) offshore construction, repair, and installation techniques and technologies;

c) deterioration, damage evaluation, and mitigation;

d) the differences between design and assessment engineering;

e) risks to offshore structures;

f) offshore inspection and construction planning, tools, and techniques;

g) the general inspection findings in the offshore industry;

h) anomalies that may trigger additional inspection or analysis.

Further description of competencies for each aspect of the SIM process is provided in the relevant section.

4.3 Risk

This recommended practice includes a risk-based approach to managing the structural integrity for existing offshore structures. Within this context, risk is defined as the combination of the likelihood of some event occurring during a time period of interest and the consequences (generally negative) associated with the event.

In mathematical terms, risk is expressed as:

$$\text{Risk} = \text{Likelihood} \times \text{Consequence}$$

The primary purpose of developing and implementing a risk-based approach is to highlight to the owner/operator risks from a safety/health/environment perspective and/or from an economic standpoint and appropriately target inspection, maintenance, and repair resources.

4.4 Limitations

4.4.1 Metocean Criteria

Metocean criteria are provided for the different exposure categories consistent with the supplement to the 20th Edition of API 2A-WSD that was subsequently adopted into the 21st Edition of API 2A-WSD. For certain exposure categories, use of the metocean criteria for assessment may leave an owner/operator with a platform that is vulnerable to damage or collapse in a hurricane, particularly for an L-2 or L-3 exposure category platform designed prior to the 20th Edition of API 2A-WSD.

4.4.2 Economic Risk

The assessment approach is structured so that the damage to or collapse of a platform will not increase life safety or environmental risk; however, it may create an economic burden to the owner in terms of facility and production losses. The determination of an acceptable level of economic risk is left to the operator’s discretion. It may be beneficial for an operator to perform explicit cost-benefit risk analyses in addition to using the fitness-for-purpose performance criteria provided in this recommended practice.

4.4.3 Working Stress Design (WSD)

This recommended practice is based on WSD, although there is nothing to preclude the engineer from using load and resistance factor design (LRFD) as an acceptable alternative. However, no further guidance is given on the use of LRFD in this recommended practice.

5 Structural Integrity Management Process

5.1 General

Structural integrity management (SIM) is the process for demonstrating a structure's fitness-for-purpose over its entire life. SIM is a process for managing the effects of deterioration, damage, changes in loading, and accidental overloading.

The SIM process consists of four elements; data, evaluation, strategy, and program, which are described in detail in this section. A flowchart showing the components of the SIM process in relation to the organization of this recommended practice is shown in Figure 2.

The SIM process provides the opportunity for owners/operators and engineers to adopt risk principles for developing SIM strategies. The likelihood of failure during an extreme event such as a hurricane is the likelihood that a hurricane will occur at the platform location and is of sufficient magnitude to collapse or render the structure inoperable. The consequence of failure includes the potential for loss of life, environmental pollution, repairs, cleanup, facility replacement, site restoration, and the economic costs of deferred production. If the field is to be abandoned, then the consequence costs also may include the nonrecovery of hydrocarbon reserves, decommissioning, and restoration of the site. A risk-based approach recognizes that higher risk platforms may warrant more frequent, and more focused, inspection than lower risk platforms. During the development of an inspection strategy, the platform risk category may be used for setting survey intervals and work scopes as part of a risk-based SIM strategy. It is important to note that surveys alone do not guarantee structural integrity.

5.2 Data

5.2.1 General

Up-to-date platform information is required for the SIM process. Information on the original design, fabrication and installation (including results of structural analyses), in-service inspections, engineering evaluations, structural assessments, modifications, strengthening, repairs, and operational incidents all constitute parts of the SIM knowledge base.

SIM data falls into two broad categories: platform "characteristic data" and platform "condition data."

5.2.2 Characteristic Data

The platform's characteristic data is the baseline data that represents the structure at installation. The characteristic data includes:

— general platform data,

— design data,

— fabrication data, and

— installation data.

This data is most easily collated into a data management system at the completion of the platform design/build/install phases of a project. Examples of characteristic data that should be considered for the SIM process are included in A.5.2.

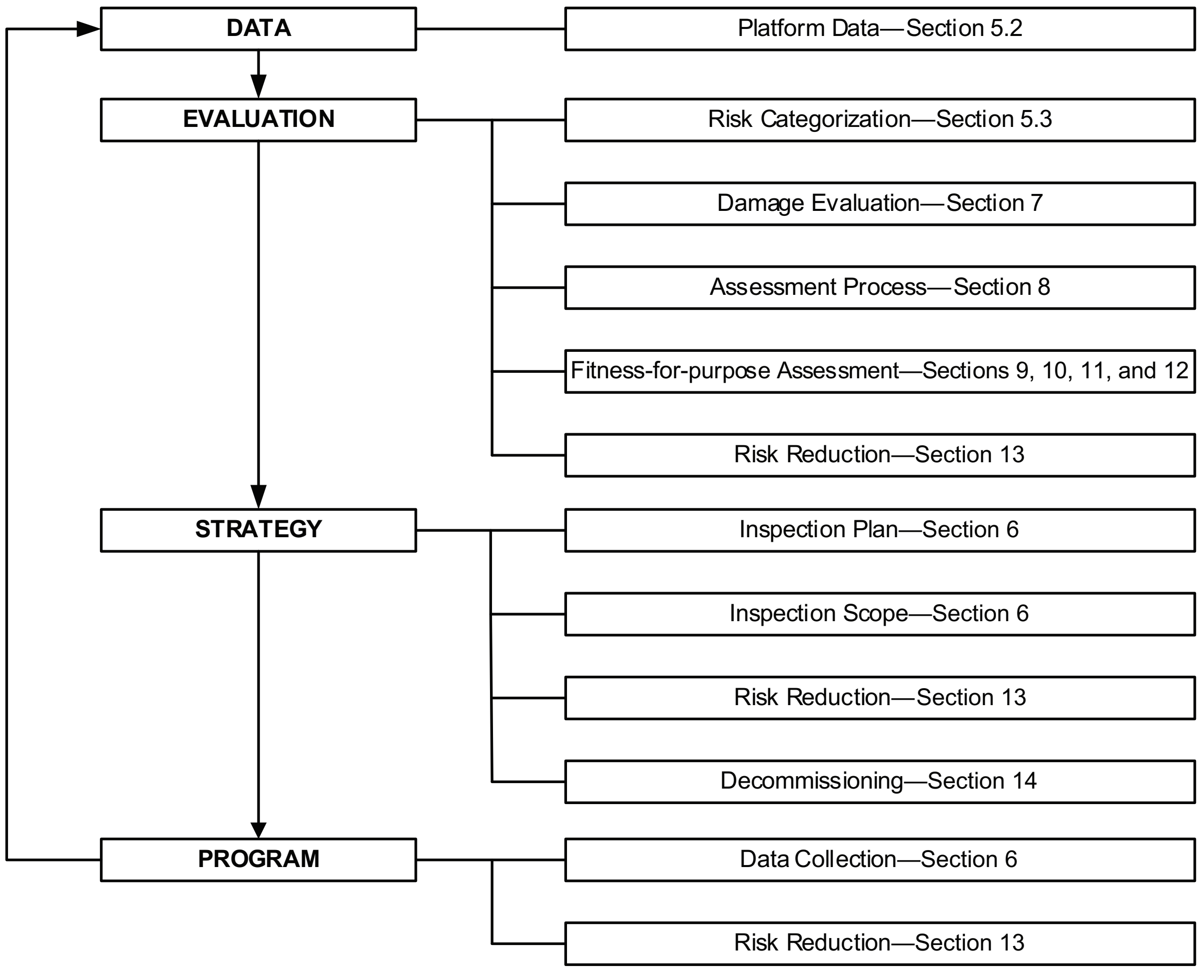

Figure 2—SIM Process and Document Organization

5.2.3 Condition Data

The platform condition data represents the changes to the characteristic data that may occur during the life of the platform. The condition data includes the following:

a) in-service inspection data,

b) damage evaluation data,

c) corrosion protection data,

d) SMR data,

e) platform modifications,

f) condition monitoring data,

g) operational incident data.

5.2.4 Data Management

SIM data collected throughout the life of a platform should be maintained in a data management system. The data should be compiled in a timely manner and be in a form suitable to be retained as a permanent record. Data shall be collected during inspections and shall be defined by the SIM strategy. Examples of typical condition data are included in A.5.2.

The operator shall retain detailed records for the life of the platform. During change of ownership, the operator should transfer all platform data to the new operator.

5.3 Evaluation

5.3.1 General

SIM evaluation is the method of applying competent engineering to assess the impact that new data has on the fitness-for-purpose and the SIM strategy for the platform. Evaluation is routinely performed throughout the life of a platform. As additional data is collected, an evaluation should be performed by a competent structural engineer. The evaluation should consider all relevant SIM data for the platform and similar platforms, where appropriate. Evaluation does not automatically imply a detailed structural analysis; evaluation can include engineering judgment based on specialist knowledge or operational experience, simplified (screening) analysis, or reference to research data, detailed analysis of similar platforms, etc.

Recommendations for performing the data evaluation are provided in the following sections:

a) factors to consider (see 5.3.2),

b) risk categorization (see 5.3.3),

c) the platform exposure category (see 5.3.4),

d) the likelihood of platform failure (see 5.3.5),

e) the requirement for platform assessment (see 5.3.6).

5.3.2 Factors to Consider

Evaluation requires consideration of numerous factors, including:

a) platform age, condition, original design criteria;

b) analysis results and assumptions for original design or subsequent assessment;

c) platform reserve strength and degree of structural redundancy;

d) degree of conservatism or uncertainty in metocean criteria;

e) fabrication quality and occurrence of any rework or rewelding;

f) occurrence of any damage during transportation or installation;

g) extent of inspection during fabrication, transportation, and installation;

h) in-service inspection findings;

i) learning from other similar platforms;

j) platform modifications, additions, and repairs/strengthening;

k) accidental (i.e. fire, blast, vessel impact, dropped object, etc.) or metocean or other design event overload;

l) fatigue sensitivity;

m) past performance of corrosion protection system;

n) criticality of platform to other operations;

o) platform monitoring data.

In many instances much of this data will not be available; however, missing data may impact the evaluation, strategy and program for the ongoing SIM of the platform. Where characteristic data are not available, or are inaccurate, surveys of the structure and facilities should be considered to collect the necessary information. It may be more expedient to proceed with an appropriate premise, recognizing the inherent uncertainties and assumptions.

5.3.3 Risk Categorization

5.3.3.1 General

An owner/operator may choose to adopt a risk-based strategy to better focus inspection resources and optimize inspection planning. If a risk-based SIM strategy is adopted, platforms should be assigned to the risk category based upon the product of their exposure category, as defined in 5.3.4, and their likelihood of failure, as defined in 5.3.5.

5.3.3.2 Risk Matrix

Risk may be presented in a variety of ways to communicate the results of the analysis to decision-makers and inspection planners. One goal of the risk determination is to communicate the results in a common format that all parties can understand. A risk matrix may be helpful in accomplishing this goal.

An example risk matrix is shown in Figure 3. In this figure, the exposure category and likelihood categories are arranged such that the highest risk ranking is toward the upper right-hand corner. Owner/operators may decide to adopt more detailed risk assessment techniques or more complex matrices to further subdivide the platform exposure category and/or likelihood.

Risk categories are typically assigned to the boxes on the risk matrix. For the example matrix, symmetrical risk categories have been assigned. They may also be asymmetrical where for instance the exposure category may be given higher weighting than the likelihood category.

5.3.3.3 Using a Risk Matrix

Risk categories may be used for setting inspection intervals and work scopes as part of a risk-based SIM strategy. For example, a 3 × 3 risk matrix, as shown in Figure 3, can be used to categorize the platforms as follows.

a) Risk Level 1—Platforms that reside in this risk category should be considered for a major focus of resources, which may include an increased inspection frequency and intensity of inspection and/or more detailed engineering.

b) Risk Level 2—Platforms that reside in this risk category may be considered for a moderate focus of resources.

c) Risk Level 3—Platforms that reside in this risk category may be considered for less focus of resources, which may include a reduced inspection frequency and scope of inspection.

Exposure Category	High	Risk Level 2	Risk Level 1	Risk Level 1
	Medium	Risk Level 3	Risk Level 2	Risk Level 1
	Low	Risk Level 3	Risk Level 3	Risk Level 2
		Low	Medium	High
		Likelihood of Failure		

Figure 3—Risk Categorization Matrix Example

5.3.4 Exposure Categories

5.3.4.1 General

Existing platforms are categorized by their life safety and environmental exposure to determine the criteria for fitness-for-purpose assessment and for developing inspection strategies.

Life safety should consider the maximum anticipated environmental event that would be expected to occur while personnel are on the platform.

Categories for life safety are as follows:

— S-1 is manned-nonevacuated,

— S-2 is manned-evacuated,

— S-3 is unmanned.

The consequence of failure should include consideration of the anticipated impact to the environment, and the possible economic impact through losses to the owner (platform and equipment repair or replacement, lost production, etc.), anticipated losses to other operators (lost production through trunk lines), and anticipated losses to industry and government.

Categories for consequence of failure are as follows:

— C-1 is high consequence of failure,

— C-2 is medium consequence of failure,

— C-3 is low consequence of failure.

The platform exposure category to be used is the more restrictive of either life safety or consequence of failure. Platform categorization may be revised over the life of the platform as a result of changes in factors affecting the platform life safety or platform consequence of failure.

The exposure category should be determined using the matrix provided in Table 1.

Table 1—Exposure Category Matrix

Life Safety Category	Consequence Category		
	C-1, High Consequence	C-2, Medium Consequence	C-3, Low Consequence
S-1 manned-nonevacuated	L-1 [a]	L-1 [a]	L-1 [a]
S-2 manned-evacuated	L-1	L-2	L-2
S-3 unmanned	L-1	L-2	L-3

[a] In the U.S. Gulf of Mexico, the S-1 manned-nonevacuated category is applicable to the full population metocean design event. For sudden hurricanes and winter storms, it is possible that the platform will be manned-nonevacuated during these design events; however, for developing assessment criteria and for developing a default inspection program, these platforms should be categorized as S-2.

5.3.4.2 Life Safety

5.3.4.2.1 General

The determination of the applicable category for life safety should be based on the descriptions defined in 5.3.4.2.2 through 5.3.4.2.4.

5.3.4.2.2 S-1 Manned-nonevacuated

The manned-nonevacuated category refers to a platform that is continuously (or nearly continuously) occupied by persons accommodated and living thereon and from which personnel evacuation prior to the design environmental event is either not intended or impractical. Design environmental events for which evacuation is not practical include winter storms, sudden hurricanes, and earthquakes.

A platform shall be categorized as S-1 manned-nonevacuated unless the particular requirements for S-2 or S-3 apply throughout the design service life of the platform.

5.3.4.2.3 S-2 Manned-evacuated

The manned-evacuated category refers to a platform that is normally manned except during a forecast design environmental event. For categorization purposes, a platform shall not be categorized as a manned-evacuated platform unless all of the following apply:

a) reliable forecast of a design environmental event is technically and operationally feasible and the weather between any such forecast and the occurrence of the design environmental event is not likely to inhibit an evacuation;

b) prior to a design environmental event, evacuation is planned;

c) sufficient time and resources exist to safely evacuate all personnel from the platform and all other platforms likely to require evacuation for the same storm.

5.3.4.2.4 S-3 Unmanned

The unmanned category refers to a platform that is not normally manned or a platform that is not classified as either manned-nonevacuated or manned-evacuated. Platforms in this classification may include emergency shelters. However, platforms with permanent quarters are not defined as unmanned and should be classified as manned-nonevacuated or as manned-evacuated as defined in 5.3.4.2.3. An occasionally manned platform could be categorized as unmanned in certain conditions, as discussed in A.5.3.4.2.

5.3.4.3 Consequence of Platform Failure

5.3.4.3.1 General

The consequences of failure should include consideration of anticipated losses to the owner, the other operators, and the industry in general. The following descriptions of relevant factors serve as a basis for determining the appropriate category for the platform consequence of failure. In addition, the consequences of failure should consider the factors discussed in A.5.3.4.3. The consequence definitions for U.S. Gulf of Mexico platforms are contained in API 2A-WSD.

5.3.4.3.2 C-1 High Consequence

The high consequence of failure category refers to major platforms and/or those platforms that have the potential for well flow of either oil or sour gas in the event of platform failure. In addition, it includes platforms where the shut-in of the oil or sour gas production is not planned or not practical prior to the occurrence of the design event (such as areas with high seismic activity). Platforms that support major oil transport lines, as discussed in A.5.3.4.3.2, and/or storage facilities for intermittent oil shipment are also considered to be in the high consequence category.

5.3.4.3.3 C-2 Medium Consequence

The medium consequence of failure category refers to platforms where production would be shut in during the design event. All wells that could flow on their own in the event of platform failure must contain fully functional subsurface safety valves (SSSVs), which are manufactured and tested in accordance with the applicable API specifications. Oil storage is limited to process inventory and “surge” tanks for pipeline transfer.

5.3.4.3.4 C-3 Low Consequence

The low consequence of failure category refers to minimal platforms where production would be shut in during the design event. All wells that could flow on their own in the event of platform failure must contain fully functional SSSVs, which are manufactured and tested in accordance with applicable API specifications. These platforms may support production departing from the platform and low volume infield pipelines. Oil storage is limited to process inventory.

U.S. Gulf of Mexico platforms in this category include caissons and small well protectors with no more than five well completions either located on or connected to the platform and with no more than two pieces of production equipment. Total deck area (excluding helideck) is limited to 37 m^2 (400 ft^2) and contains no more than two pieces of production equipment. In addition, platforms in this category are defined as structures in water depths not exceeding 30 m (100 ft).

5.3.5 Likelihood of Platform Failure

5.3.5.1 General

If the platform owner/operator chooses to adopt a risk-based SIM strategy, the SIM data should be evaluated to determine the likelihood of platform failure. The likelihood that a platform will fail as a result of loading, whether that is an extreme storm load, ice load, earthquake, or some other foreseeable design load, is a function of the robustness of the structure. Additional discussion and definition of robustness and damage tolerance is provided in A.5.3.

Each platform has a likelihood of failure based on key structural characteristics, such as the deck elevation and robustness provided by the number of legs and bracing configuration. Damage or deterioration may indicate that the strength of a platform has reduced, thus increasing the likelihood of failure.

The platform likelihood of failure should be categorized using qualitative, semiquantitative, or fully quantitative methods. The owner/operator may choose to select three or more categories of failure likelihood. General guidelines for three likelihood categories are defined in 5.3.5.2 through 5.3.5.4.

5.3.5.2 High Likelihood

The high likelihood of failure category refers to platforms that are likely to fail in the design event. This implies a reserve strength ratio (RSR) of less than 1.0 for the platform's present condition, including all modifications and known damage, against the 100-year environmental design event. Platforms in this category may have limited tolerance to damage or overload. Overload may result from having deck structure and/or equipment that could be inundated during the metocean event.

5.3.5.3 Medium Likelihood

The medium likelihood of failure category refers to platforms that are not expected to fail during the design event. However, these structures may sustain damage that requires inspection after the design event. These are essentially platforms that do not meet the high likelihood or low likelihood definitions.

5.3.5.4 Low Likelihood

The low likelihood of failure category refers to platforms that are very unlikely to fail under the design environmental event. This implies sufficient reserve strength in the platform's present condition, including all modifications and known damage, for the specified criteria. Such platforms should not suffer damage in the design environmental event, and they are robust and tolerant of any damage and overload that does occur.

5.3.6 Requirement for Platform Assessment

A platform fitness-for-purpose assessment is a detailed evaluation or structural analysis that compares the estimated strength of a structure against performance criteria. An assessment may also consist of comparing an actual proof or overload against the performance criteria. A fitness-for-purpose assessment of the structure shall be performed if the engineering evaluation of relevant SIM data determines that an assessment initiator, as defined in 8.3, has been triggered. This process is shown in Figure 4.

The assessment will determine whether a platform is fit-for-purpose or whether risk reduction measures should be considered. The structural assessment process is defined in Section 8. The fitness-for-purpose performance criteria, which are based on the platform exposure category as defined in 5.3.4, are provided in Section 9 for metocean loading assessments, Section 10 for fatigue loading, Section 11 for seismic loading, and Section 12 for ice loading.

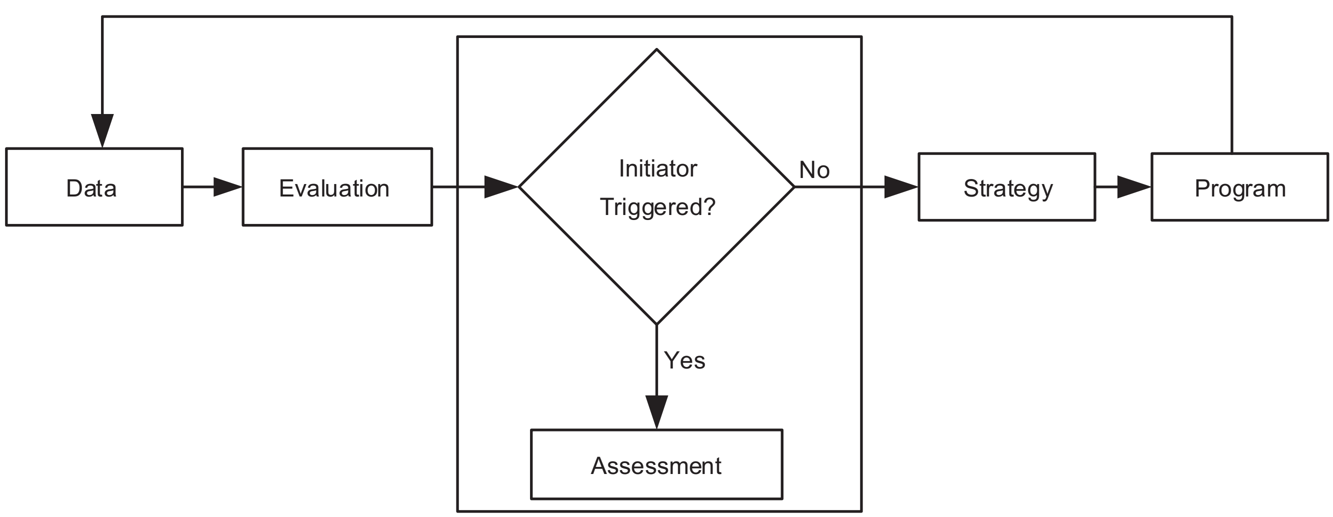

Figure 4—Assessment Within the SIM Process

5.4 Strategy

5.4.1 General

The SIM strategy defines the overall inspection philosophy and mitigation philosophy for the platform or fleet of platforms. This recommended practice provides guidance for the development of a SIM strategy based on the platform risk, as defined in 5.3.3, or platform exposure category, as defined in 5.3.4, with specific recommendations for inspection planning and mitigation and risk reduction options.

5.4.2 Inspection Plan

5.4.2.1 Inspection Scope

The inspection plan defines the frequency and scope of the inspection, the tools/techniques to be used, and the deployment methods. The inspection plan shall be developed for the operated platforms and shall cover a number of years. The plan should be periodically updated throughout the platform's service life following receipt and evaluation of relevant SIM data (e.g. inspection data, results of platform assessments, etc.). The following basic elements should be included in the inspection plan.

a) Routine above-water inspections should be conducted to provide the information necessary to evaluate the condition of the platform topsides and should be conducted on an annual basis. Recommendations for the above-water inspections are provided in 6.3.

b) Baseline underwater inspection should be conducted to determine the as-installed platform condition and as a benchmark for the future SIM of the platform. A baseline inspection shall be conducted prior to implementation of risk-based inspection. Recommendations for the baseline inspections are provided in 6.4.

c) Routine underwater inspections should be conducted to provide the information necessary to evaluate the condition of the platform and appurtenances and should be conducted at an interval consistent with the SIM strategy adopted by the owner/operator. This may be a prescriptive exposure-based strategy with a default frequency and work scope or a more focused risk-based strategy. Recommendations for the routine underwater inspections are provided in 6.5.

d) Special inspections are nonroutine inspections, which should be conducted after events such as a hurricane or collision. Recommendations for special inspections are provided in 6.6.

5.4.2.2 Inspection Strategy

Two contrasting routine inspection strategies can be used as part of the overall SIM strategy. Each approach is valid under different circumstances, and the choice of inspection strategy depends on the characteristics of the owner/operator structures inventory and the recommendations provided in Section 6. The following are two contrasting strategies.

a) A significant commitment to ongoing in-service inspection with the goal of reducing the possibility of major repairs (clamps, member replacements) in the future. This approach relies on early detection of damage and defects with prompt implementation of relatively inexpensive repairs and preventive measures. Early detection of defects typically requires greater use of nondestructive testing (NDT) techniques.

b) Minimization of in-service inspection scope where adequate measures have been taken to reduce the risk of damage, defects, or deterioration that would require major repair efforts in the future. This approach assumes that in-service inspection without the use of NDT techniques will be able to detect damage, defects, or deterioration before structural integrity is threatened. This approach may be appropriate for robust structures that are tolerant to damage and overload.

5.4.3 Risk Reduction

5.4.3.1 General

Exposure mitigation and likelihood reduction options should be considered at all stages of the SIM process.

5.4.3.2 Exposure Mitigation

Exposure mitigation is defined as changes that reduce the exposure of the platform. Mitigation includes measures that reduce the consequence of platform failure through hydrocarbon inventory reduction and by reducing the manning levels, either during a forecast event or permanently. Exposure mitigation recommendations are provided in 13.2.

5.4.3.3 Likelihood Reduction

Likelihood reduction is defined as modifications that reduce the likelihood of structural failure. It includes measures such as load reduction and/or an increase in system strength through global and or local strengthening and/or repairing known damage. Likelihood reduction recommendations are provided in 13.3.

5.5 Program

5.5.1 General

The SIM program represents the execution of the detailed work scope and should be conducted to complete the activities defined in the SIM strategy. The SIM program may include one or more of the following:

— baseline inspections,

— routine above-water inspections,

— routine underwater inspections,

— special inspections,

— SMR activities.

To complete the SIM process, all data collected during the SIM program should be incorporated back into the SIM data management system. Consistency, accuracy, and completeness of inspection records are important since these data form an integral part of the SIM system. Specific requirements for the execution of the work scope for any inspections, including data recording and reporting requirements, are provided in Section 6.

5.6 Decommissioning

Decommissioning is the process followed by the owner/operator of an offshore oil and/or gas facility to plan for, gain approval, and then implement the removal, disposal, or reuse of the platform structure, equipment, and associated pipelines and wells. The decommissioning process involves closing down operations at the end of field life, including permanently abandoning the wells, making the platform safe, removing some or all of the facilities, and reusing or disposing of them as appropriate. The stages of the decommissioning process are defined in Section 14.

Predecommissioning data gathering should be conducted to gain knowledge of the platform and associated facilities, wells, pipelines, risers, and subsea equipment where present. The SIM strategy should integrate with the decommissioning planning process to align late-life structural inspections to collect the condition data as defined in Section 6. In many cases it may be advantageous to permanently abandon wells as they become nonproductive or uneconomic to reduce the potential environmental and life safety exposure from platform failure.

6 Surveys

6.1 Inspection Strategy

The in-service inspection program is developed from the inspection strategy and will include above-water inspections and below-water inspections, as defined in 5.4. Details on the inspection strategy are provided in:

— 6.3 for above-water inspections,

— 6.4 for post-installation baseline below-water inspections,

— 6.5 for routine below-water risk-based (see 6.5.2) or exposure-based (see 6.5.3) inspections,

— 6.6 for nonroutine special inspections.

6.2 Personnel Qualifications

6.2.1 Planning

The work scope for the inspection including the preselection of areas for close visual or NDT should be compiled and approved by a competent structural engineer. The recommended qualifications for personnel employed in developing the inspection plan are provided in A.6.2.

6.2.2 Surveys

Surveys should be performed by qualified personnel. The personnel conducting above-water surveys (see 5.3) should be experienced in performing all surveys and in recognizing situations that could lead to damage, how to take cathodic protection (CP) readings, and how to review coating system conditions and deterioration.

The personnel conducting remotely operated vehicle (ROV) or diver surveys below water (see 5.4 and 5.5) should work with the guidance of personnel experienced in the methods to conduct cathodic potential surveys and/or visual inspection and other surveys of the underwater portion of a platform.

Only personnel trained and experienced in application of the survey method being used should perform NDT examination on the platforms.

6.3 Level I Surveys—Routine Above-water Inspection

6.3.1 General

The Level I survey should be carried out on an annual basis. The purpose of the inspection is to detect or verify the following.

a) Indications of obvious overloading, deteriorating coating systems, excessive corrosion, and bent, missing, or damaged members of the structure in the splash zone and above water. Guidance on the grading of coating systems is provided in NACE SP0108.

b) Damage or deterioration to appurtenances and personnel safety, escape, and evacuation devices.

c) The performance of the platform’s under water CP system using dry operator technique (e.g. a drop cell survey).

6.3.2 Above-water Visual Survey

The Level I survey should include an above-water visual examination of all structural members in the splash zone and above water, concentrating on the condition of the more critical areas such as deck legs, girders, trusses, members, joints, leg/pile shim welds, etc. Components should be inspected for presence of damage, straightness, corrosion, weld integrity, and modifications.

If above-water damage is detected, a complete record of the damage should be made with sufficient detail to allow engineering personnel to determine if repairs or further NDT are required. Damage records should include detailed measurements, photographic documentation, and drawings. If the above-water survey indicates that underwater damage may have occurred, for example, a missing boat landing or previously unrecorded damage, an underwater inspection should be conducted as soon as conditions permit.

6.3.3 Coating Survey

The Level I survey should include a coating survey to assess the effectiveness and condition of the various protective coating systems on the topsides. The inspection should detect deteriorating coating systems and excessive corrosion. The inspection should describe the type of coating systems for the components inspected (i.e. Monel cladding or elastomers on the splash zone members and jacket legs, paint on the conductors, etc.) and record specific locations and extent of coating deterioration.

6.3.4 Underwater CP Survey

The Level I survey should include a below-water measurement over the full water depth of the CP system by silver/silver chloride drop cells or other approved drop cells. The survey should be performed to NACE SP0176 by qualified personnel.

6.3.5 Appurtenance and Personnel Safety Devices Surveys

6.3.5.1 General

The Level I survey should include an inspection of appurtenances and personnel safety devices for damage or deterioration. Appurtenances and personnel safety devices include handrails, grating, stairs, swing ropes, boat landings, helideck, bridges, supports to risers, survival craft supports, crane pedestals, communications tower deck connections, and structural elements supporting evacuation routes and temporary refuge. Crane pedestal support framing should be inspected in accordance with API 2D.

6.3.5.2 Conductor Visual Survey

During the Level I survey, a visual inspection of the overall condition of all conductors from the splash zone area and upward should be performed. The conductors should be inspected for coating condition, extent of corrosion, damage, presence of shims, movement, and operational status (i.e. flowing, shut in, temporarily abandoned, or permanently abandoned).

6.3.5.3 Riser Survey

Level I surveys should include a visual inspection of the overall condition of all risers from the splash zone area and upward. The risers should be inspected for breakdown of coating, the extent of corrosion, the integrity of supporting steelwork and clamps, and operational status (i.e. live, out-of-service, permanently abandoned).

6.3.5.4 Pipeline Flange Isolation

The Level I survey should include a review of the effectiveness of pipeline riser insulation kits. The purpose of this inspection is to assess the condition of pipeline flange insulation kits to determine if the pipeline riser is electrically isolated from the structure. In general, the survey is accomplished by taking measurements on either side of an actual or potential isolation barrier. Identical measurements indicate electric continuity whereas different measurements indicate isolation.

6.3.5.5 Attachment Tie-down Points

Level I surveys should include a walk-down survey to assess the vulnerability of relevant personnel safety equipment and supports to damage from shock loading and strong vibration induced from extreme metocean, seismic events, or accidental loadings. The survey should be performed in accordance with API 2TD. The walk-down is primarily a visual inspection, with special emphasis directed to tie-downs that may have been designed without consideration for lateral loads. The support may be permanent or temporary; however, sufficient data should be recorded to allow a competent engineer to evaluate the ability of the tie-down to resist lateral loads.

6.3.5.6 Escape Routes

During the Level I survey, a visual survey of the personnel escape routes should be performed. Escape routes consist of open decks, walkways, stairs, and landings. The routes should be established and surveyed to confirm clear access to the escape routes is provided from all locations on the structure. Swing ropes and connections should be examined for signs of damage or deterioration. API 54 provides further inspection guidance.

6.3.6 Deck Elevation Survey

In operational areas of known or suspected subsidence, the Level I survey should include a survey of the gap between the cellar deck bottom of steel and the mean water level.

For other areas, consideration should be given to measuring the deck elevation on a periodic basis to provide up-to-date and accurate information. Measurements may be made with a plumb line and should be recorded against the time of measurement to allow later agreement with tidal information or changes. Suspected subsidence or differential settlement of the structure should be recorded and if significant (e.g. the deck is lower than assumed) could trigger an assessment.

6.3.7 Supplemental Surveys

The Level I survey may include supplemental surveys to characterize damage as specified in the scope of work (e.g. NDT, material sampling, wall thickness measurements, etc.).

6.4 Baseline Underwater Inspection

A baseline underwater inspection should be performed to establish the as-installed platform condition. A baseline inspection shall be conducted prior to implementation of a risk-based inspection planning for the platform.

The minimum scope of work should consist of the following, unless the information is available from the installation records:

a) a visual survey of the platform for structural damage, from the mudline to top of jacket, including coating integrity through the splash zone;

b) a visual survey to verify the presence and condition of the anodes;

c) a visual survey to confirm the presence and condition of installed appurtenances;

d) measurement of the as-installed mean water surface elevation, with appropriate correction for tide and sea state conditions;

e) record the as-installed platform orientation;

f) measurement of the as-installed platform level.

6.5 Level II, III, and IV Surveys—Routine Underwater Inspection

6.5.1 General

Routine underwater platform inspections using either Level II, III, or IV surveys should be conducted to detect, properly measure, and record any platform defects, deterioration, or anomalies that affect the structural integrity. Platform deterioration may include excessive corrosion to welds and members, weld/joint damage (including deformation due to overload and cracking due to fatigue damage), and mechanical damage in the form of dents, holes, bows, and gouges. Anomalies may include nonoperating or ineffective corrosion protection system, scour, seafloor instability, hazardous or detrimental debris, and excessive marine growth.

The routine underwater inspection should be carried out at an interval consistent with the SIM strategy adopted by the owner/operator. Inspection intervals are provided based on either the platform risk as recommended in 6.5.2 or based on the platform exposure category as recommended in 6.5.3.

If during the course of an inspection program, anomalies are discovered that could potentially affect the structural integrity of the platform, conductors, risers and J-tubes, or appurtenances, qualified personnel should conduct an evaluation to determine if and when additional inspection and/or remedial measures should be undertaken. Additional inspection may require use of more detailed survey techniques. All damage, anomalies, and any follow-up activities shall be documented, with all records and reports retained.

6.5.2 Risk-based Inspection Program

6.5.2.1 General

Risk, as defined in 5.3.3, may be used as a basis for developing an in-service inspection program. A risk-based approach allows an owner/operator to prioritize and optimize the use of inspection resources. The risk-based strategy for the development of inspection scopes of work requires a thorough understanding of a platform's susceptibility to damage, the tolerance of damage, and the known condition.

For an owner/operator that has adopted a risk-based SIM strategy, surveys included in the inspection program should be consistent with the overall strategy, based on the data evaluation. The SIM strategy should be comprised of a risk-based inspection interval, a risk-based inspection scope, the relevant deployment method (diver versus ROV), and survey technique (general visual versus close visual/NDT).

The underwater inspection in a risk-based program should be a minimum of Level II; however, the risk-based inspection strategy should specify if Level III or Level IV inspections are required. Damage or deterioration found during a risk-based inspection may trigger a Level III or Level IV inspection.

6.5.2.2 Risk-based Inspection Intervals

Where the owner/operator has adopted a risk-based SIM strategy, the inspection intervals shown in Table 2 should be used. Platforms with higher consequence appurtenances may require more frequent inspection than that based on the structure's risk-based interval. In addition, the risk-based interval may require adjustment to account for the design life or present condition of the CP system.

Table 2—Risk-based Inspection Program Intervals

Risk Category	Inspection Interval Ranges
Higher	3 years to 5 years
Medium	6 years to 10 years
Lower	11 years to 15 years

The timing for the first risk-based underwater routine inspection should be determined from the completion date of the baseline inspection.

The setting of intervals between inspections greater than 10 years requires the operator/owner to demonstrate that the platform is unmanned, that risk of platform failure has been quantified through an ultimate strength analysis, that inspection trends are understood, and that annual Level I CP readings are performed and are acceptable. This interval is only applicable to structures designed to API 2A-WSD, 20th Edition and later.

6.5.3 Default Inspection Program

6.5.3.1 General

When the owner/operator has not adopted a risk-based inspection strategy, an exposure-based inspection program should be used. The exposure-based inspection program provides predefined in-service inspection intervals and survey levels.

6.5.3.2 Inspection Intervals

The inspection program intervals and survey requirements are shown in Table 3 and should be established based on the platform exposure category, as defined in 5.3.4.

6.5.4 Level II, III, and IV Surveys

6.5.4.1 Level II Survey

A Level II survey consists of general underwater visual inspection by divers or ROV to detect the presence of any or all of the following:

a) deterioration due to corrosion;

b) deformation or fracture due to accidental or metocean overloading;

c) scour, seafloor instability, etc.;

d) advanced fatigue cracking detectable in a visual swim-around;

e) in-service damage (e.g. dents, holes, bows, cracks, abrasion, etc.);

f) debris, and possible damage caused by the debris;

g) excessive compressed soft or hard marine growth;

h) condition of appurtenances.

The survey should include the measurement of cathodic potentials of preselected locations using divers or ROV. Detection of significant structural damage during a Level II survey should become the basis for the initiation of a Level III survey. The Level III survey, if required, should be conducted as soon as conditions permit.

6.5.4.2 Level III Survey

A Level III survey consists of an underwater visual inspection of preselected locations and/or, based on results of the Level II survey, areas of known or suspected damage. Such locations should be sufficiently cleaned of marine growth to permit thorough inspection (e.g. closure welds for prefabricated or cast nodes). Preselection of areas to be surveyed should be based on an engineering evaluation of areas particularly susceptible to structural damage or areas where repeated inspections are desirable in order to monitor their integrity over time.

Table 3—Default Inspection Program

Interval (Years)	Exposure Category [a]		
	L-3	L-2	L-1
	5–10	5–10	3–5
Level II			
General visual survey	X [b]	X [b]	X [b]
Damage survey	X	X	X
Debris survey	X	X	X
Marine growth survey	X	X	X
Scour survey	X [c]	X [c]	X [c]
Anode survey	X	X	X
Cathodic potential	X	X	X
Riser/J-tubes/caisson	X	X	X
Interval (Years)	**Exposure Category [a]**		
	L-3	**L-2**	**L-1**
	d	**11–15**	**6–10**
Level III			
Visual corrosion survey	X [e]	X [e]	X
Flooded member detection or member close visual inspection	X	X	X
Weld/joint close visual inspection, after cleaning to bright metal	If required	If required	X
Level IV [f]			
Weld/joint NDT	g	g	g
Wall thickness	g	g	g

[a] Exposure category is defined in 5.3.4.

[b] Detection of significant structural damage should form the basis for initiation of a Level III survey in 6.5.1.

[c] If seafloor is conducive (loose sand) or seafloor instability is known/suspected, a scour survey should be performed.

[d] Only required if the results from the Level II survey indicate suspected damage.

[e] Not required if the annual above-water inspection CP survey indicates uninterrupted protection below water.

[f] Only required if the results from the Level III survey indicate suspected damage.

[g] Surveys should be performed as indicated in 5.5.4.3.

Flooded member detection (FMD) can provide an acceptable alternative to close visual inspection (CVI) (Level III) of preselected areas. Engineering judgment should be used to determine optimum use of FMD and/or CVI of joints. For example, FMD cannot detect punching shear or fatigue failure of the chord at the ends of the member being surveyed. CVI of preselected locations for corrosion monitoring should be included as part of the Level III survey.

Detection of significant structural damage during a Level III survey should become the basis for initiation of a Level IV survey in those instances where visual inspection alone cannot determine the extent of damage. The Level IV survey, if required, should be conducted as soon as conditions permit.

6.5.4.3 Level IV Survey

A Level IV survey consists of underwater NDT of preselected locations and/or, based on the results of the Level III survey, areas of known or suspected damage. A Level III and/or Level IV survey of fatigue-sensitive joints and/or locations susceptible to cracking could be used to detect early stage fatigue cracking.

If crack indications are reliably reported, they should be assessed by a competent engineer. Suspected false alarms may be resolved by a second inspection using a different method or by shallow surface grinding.

6.5.4.4 Preselected Survey Locations

It is important to the effectiveness of each survey to select a sufficient number of inspection locations to provide representative condition data on the overall structure. Where the SIM strategy determines that close visual survey is required, the selection of the welded joints to be surveyed should be made by a competent engineer familiar with the SIM strategy for the platform.

Selection of survey locations should include consideration of the following:

a) data collected from the baseline survey,

b) relevant information about the specific platform(s) under consideration,

c) general inspection findings in the offshore industry,

d) the significance of members and joints to the platform system capacity,

e) the platform robustness and damage tolerance,

f) joint and member stresses and stress concentrations,

g) joint fatigue lives.

During platform design and any subsequent assessment, members and joint loading should be recorded and used to define requirements for future platform surveys.

While fatigue has not been a common problem for primary structural members in U.S. Gulf of Mexico platforms, fatigue damage and subsequent structural member failures have occurred in the upper conductor guide framing of some older platforms. This damage can occur if conductor framing is plated, which increases the vertical wave loading area. Conductor guides located at (–) 12 m (40 ft) or shallower are particularly susceptible, although cracking has been seen in water depths up to (–) 43 m (140 ft). This type of fatigue damage is identified by fatigue cracks at the 12 o'clock and/or 6 o'clock positions of the members supporting the conductor tray and is not typically identified by standard structural strength or fatigue analysis. Specific inspection of these areas should be considered for platforms with this type of conductor framing. FMD can be useful in locating this type of damage.

6.6 Special Inspections

6.6.1 General

Special inspections are nonroutine inspections. Data collected during a special inspection is needed to evaluate the structural condition of a platform for a specific purpose. Details on the inspection program for five types of special inspections are provided in:

— 6.6.2 for strengthening, modification, and repair monitoring;

— 6.6.3 for post-event inspections;

— 6.6.4 for inspection for assessment;

— 6.6.5 for inspection for decommissioning; and

— 6.6.6 for inspection for reuse.

Subject to qualified engineering evaluation, the timing of a special inspection may be advanced or delayed to coincide with other planned inspections. The planned routine scope of work should be adjusted to ensure that the special inspection data is also collected. Particular attention should be given to detecting damage and indirect signs of damage, such as localized areas of missing marine growth. Specific details of the work scopes are provided in 6.7.

6.6.2 SMR and Damage Monitoring

Special inspections should be performed to determine the performance of structural or appurtenance repairs, for example, nondestructive examination (NDE) of underwater wet welds and tightness of bolts in stressed clamps or mechanical connectors. Special inspections should also be performed to determine if damage that has been evaluated through the assessment process as not requiring a repair has become more extensive through fatigue, corrosion, or another mechanism.

The integrity of SMRs to areas of the structure that are critical to its structural integrity should be confirmed by visual inspection (with marine growth cleaning as necessary) within a reasonable time frame following the completion of the SMR work. The inspection frequency of the SMR should be determined as part of the overall SIM strategy.

6.6.3 Post-event Inspections

6.6.3.1 General

Post-event inspections are conducted to evaluate the platform's structural condition following a potential overload event (storm, earthquake, mudslide, tsunami, ice) or incident (vessel impact, dropped objects, explosion, abrasion, floating debris, riser damage from anchor drag on pipeline). All post-event inspections should be developed based on an evaluation of the available data, including any event/incident reports.

6.6.3.2 Potential Overload

Above-water inspection should be conducted after direct exposure to the extreme design event (e.g. extreme storm, hurricane, ice movement or earthquake, etc.). A general visual underwater survey should be conducted if the above-water inspection indicates overload or wave-in-deck and/or if underwater damage may have occurred. The minimum scope consists of the following.

a) A visual inspection without marine growth cleaning that provides full coverage from seafloor to top of jacket of the platform structure (members and joints), conductors, risers, and various appurtenances. This inspection includes checking the seabed conditions at the legs/piles and looking for scour, debris, or damage.

b) Visual confirmation of the existence of the CP system (i.e. sacrificial anodes, impressed current, cables, electrodes, etc.).

Particular attention should be given to detecting damage and indirect signs of damage, such as areas of missing marine growth.

6.6.3.3 Accidental Loading

A focused visual underwater survey should be conducted after severe accidental loading that could lead to structural damage (e.g. boat collision, dropped objects, etc.). The inspection should be conducted as soon as practical after the occurrence of the accidental loading event. Sufficient inspection should be conducted to establish the total extent of any damage, with particular attention given to localized areas of missing marine growth.

6.6.4 Inspection for Assessment

Prior to performing a structural assessment, the existing physical condition of the platform and facilities needs to be established. The condition assessment will usually be limited to a review of the most recent inspection and repair reports. However, in certain instances where information is known to be inaccurate or incomplete, surveys of the structure and facilities may be needed to collect the necessary information. Typical information may include baseline inspection data, platform geometry, component dimensions, and wall thickness.

6.6.5 Inspection for Decommissioning

Predecommissioning inspections should be conducted to confirm the condition of the structure prior to decommissioning and assist in demonstrating that the structure is sufficiently robust to sustain the loads imposed during removal. Surveys should confirm the condition of the primary structural components and existing lifting points, cranes, and other topsides structures and accommodation facilities. The primary predecommissioning surveys are as follows:

a) survey of the topsides and substructure to determine the condition of the lifting points and padeyes,

b) survey of the platform to identify suspended debris that may need to accounted for in the decommissioning plan,

c) survey of the seabed surrounding the structure to determine extent of site clearance needed subsequent to platform removal,

d) the condition of the platform cranes and accommodation facilities are also important factors when considering the logistics of offshore decommissioning operations,

e) padeye capacity should be verified for lift and removal loads.

6.6.6 Inspection for Reuse

The reuse inspection program should collect sufficient data to assess the present condition of the platform and meet the specific inspection requirements of API 2A-WSD, 22nd Edition for the reuse of the platform at a new location.

6.7 Survey Work Scope

For each survey identified, a work scope should be developed that specifies the recommendations for data recording and for defect and anomaly reporting. A system for reporting and documenting anomalies and defects should be in place so that sufficient data is collected for subsequent engineering evaluation.

6.8 Inspection Specification

The inspection program should establish specifications for inspection activities and establish procedures for quality assurance, quality control, and data validation. Inspection task example details are provided in A.6.8. The inspection specification should, as a minimum, include the following:

a) anomaly reporting requirements;

b) diver and ROV operator qualifications;

c) NDT technician qualifications;

d) minimum staffing requirements for divers and ROV operators;

e) notification requirements following discovery of an anomaly (e.g. flooded member);

f) measurement procedures (e.g. dents, bows, holes);

g) sensors and instrumentation;

h) reporting formats and procedures;

i) photography and video recording procedures.

6.9 Data Records

Records of above-water and underwater platform inspections shall be maintained by the owner/operator for the life of the platform. The records shall include the inspection level performed and all data obtained during the inspection. The records should be maintained in a managed archival and retrieval system.

7 Damage Evaluation

7.1 General

The objective of the damage evaluation process is to determine whether damage is potentially significant to the structural integrity of the platform and whether a fitness-for-purpose assessment as described in Section 8 is required. Techniques for determining the effects of damage on the strength of individual components are recommended in 7.3. Methods to incorporate reductions in component strength into the evaluation of the structural integrity of the platform are recommended in 7.4. The results of the evaluation may indicate the need for risk reduction as provided in Section 13. In the event that further degradation or damage is detected at some future time, the previous evaluation will form the basis of the reevaluation of the new data.

It is important to recognize that not all damage is structurally significant. Light corrosion or minor bowing of a member are examples of damage that may not be structurally significant to the affected components. A robust platform may be fit-for-purpose throughout its remaining life, even if one or more of its structural components (members and/or joints) have structural damage.

7.2 Degradation Mechanisms

7.2.1 General

This section describes a number of mechanisms that may reduce the structural capacity of the platform.

7.2.2 Dropped Objects

Dropped objects may result in mechanical impact damage to structural components and can cause gouging, denting, bowing, and holing of members. The impact may also cause cracks at the end connections of the member and/or member severance and/or joint deformation or tearing.

Examples of dropped objects include tubular components (e.g. drill strings and piles), drill collars, scaffold poles, and less commonly, larger objects such as link bridges, cranes, drilling derricks, etc. (additional information is provided in API 2A-WSD, 22nd Edition).

7.2.3 Vessel Collision

Impact from vessels may result in mechanical impact damage to structural components in the upper part of the jacket around the splash zone. Vessel impact may cause gouging, denting, and bowing of members. The impact may also cause cracks at the end connections of the member and/or member severance and/or joint deformation or tearing.

The relative magnitude of denting and bowing depends on the impact energy of the vessel, the ductility of the member, the degree of restraint (rotational and axial) provided by the structure, the present condition, and the existence of protective structures such as boat fenders, protection frames, etc.

7.2.4 Corrosion

General uniform corrosion of the underwater structural components may result from a failure of the corrosion protection system or through premature depletion of the system due to excessive debris in contact with the structure. In the splash zone and above-water locations of the structure, similar corrosion damage can result from failure of the protective coating systems.

In either case, thinning and/or perforation of the components may occur. Localized corrosion may develop at areas on the structure not adequately protected by the CP system, for example, dense conductor arrays or appurtenance connections, in particular inside conductor guides and bolted clamps. Localized corrosion may also develop due to galvanic (bimetallic) corrosion, for example, caissons housing stainless steel pump/strainer components.

7.2.5 Fatigue

Cyclic loading causes fatigue that, with time, may result in cracks at welded connections of structural components. Unless crack propagation is arrested, the cracks can eventually lead to member severance at the joint. The propagation of the crack may affect other members at a joint; cracking originally in a secondary brace or appurtenance connection may eventually grow into and affect a primary member.

7.2.6 Installation Damage

Mechanical damage to the platform and appurtenance may occur during load-out, transportation, and installation. This damage is typically discovered during the baseline inspection and may include missing anodes, scrapes, dents, severed components, bows, etc.

7.2.7 Fabrication Flaws

Fabrication flaws may include the use of out-of-specification materials, incorrect member sizes, incorrect member positions, omissions, and incorrect welding procedures. More commonly occurring flaws are weld defects such as defect inclusion, lack of penetration, or excessive undercut. Weld defects beyond normal acceptance standards can lead to premature fatigue cracking at susceptible connections. Omission of vent holes for intended flooded members might result in hydrostatic collapse.

7.2.8 Seabed Scour or Seabed Build-up

Seabed scour may affect both lateral and axial pile performance. Under certain conditions, drill cuttings or fallen hard marine growth (shells) can accumulate and bear onto lower frames or members, with the potential to cause damage.

7.2.9 Overload

Overload of the structure may result from occurrence of an extreme event, for example, a hurricane or earthquake of a greater magnitude than that used for the design or fitness-for-purpose assessment of the platform. Overload may result in member or joint failure with permanent deformation and possible cracking or tearing.

7.3 Component Evaluation

7.3.1 General

The residual capacity of a damaged component may be determined through simplified methods or detailed analytical techniques. The residual capacity of the component can be used in the evaluation of the system capacity.

Overall guidance is provided in 7.3.2 through 7.3.6 for the determination of the residual capacity of certain types of damage for components of offshore structures. Additional guidance for determining the residual capacity of damaged components is contained in Reference [20] and Reference [28].

7.3.2 Dented Tubular Members

The axial capacity of a transversely loaded brace can be significantly reduced due the presence of a dent. In offshore structures, braces are susceptible to wave loadings, particularly near the water surface, where wave slamming during storms can impose significant lateral loading on these members. Tubular members under an impact event may suffer denting and bowing of the member.

Since an analysis is based on information provided from the platform inspection, it is important that the necessary information is obtained. This includes, as a minimum, the location, orientation, and depth of the dent. Possible member out-of-straightness should also be provided. The most significant geometrical parameter affecting residual strength is the dent depth.

The effects of member bowing on the capacity of the member may be considered by taking into account the out-of-straightness of the damaged member. For an initial assessment, the dented member can be assumed to be unable to carry any loading. Further, a theoretical hinge can be assumed at the dent site to model reduced compression axial capacity.

7.3.3 Uniformly Corroded Tubular Members

The simplest way to evaluate the reduction in strength for uniform corrosion is to reduce the thickness for the entire member. This thickness reduction is to be consistent with the amount of material removed due to corrosion. The member may then be evaluated as an undamaged member with reduced wall thickness. Using minimum local thickness (averaged over the worst 60 degree arc) is generally conservative even though the reduction in thickness is not constant throughout the entire member length.

7.3.4 Locally Corroded Tubular Members

Localized corrosion (i.e. pitting and/or holes) may reduce the member capacity. In lieu of any refined analyses, the strength of members with severe localized corrosion may be assessed by treating the corroded part of the cross section as noneffective and using methods similar to those provided in 7.3.2 for dented members.

7.3.5 Cracked Tubular Members

Partially cracked tubular members may reduce member capacity. In lieu of any refined analyses, a partially cracked member with the cracked area loaded in compression can be treated in a similar manner to that of a dented member (i.e. using a reduced capacity). For tensile loads or tensile bending moments, an engineering fracture mechanics assessment may be helpful.

7.3.6 Cracked Tubular Joint

The static tensile strength of a partially cracked tubular joint can be estimated by reducing the affected joint strength by some fraction. Provided the material is ductile under service conditions, the reduced joint strength can be estimated either from simple methods, based on the use of reduced area or section modulus in proportion to the lost area on the failure surface, or from more extensive numerical analysis using finite element analysis models or experimental evidence.

7.4 System Evaluation

The primary objective of the system engineering evaluation is to obtain as best an estimate of the structural strength of the platform components and system as possible, irrespective of the nature of the damage.

If a fitness-for-purpose assessment is required from the engineering evaluation, the damaged components may be included in the assessment model with a representative residual capacity. Alternatively, damaged components may be considered totally ineffective provided that the hydrodynamic loading from these components is included in the assessment.

Post-damage stiffness properties can be specified in a structural model to represent the damaged members. Damage types for which this procedure is typically adopted include dented or buckled members and members with excessive corrosion. Dented member properties may be determined by reference to published data, through finite element analysis or testing.

Corroded or damaged members and joints should be modeled to represent the actual corroded or damaged properties. Strengthened or repaired members and joints should be modeled to represent the actual strengthened or repaired properties.

A simple, conservative approach to determine the effects of localized damage on the system integrity is to remove the stiffness effects of the member from the assessment model. This can be done by either reducing the modulus of elasticity of the member to a small value or replacing the member with an equivalent nonstructural member so as to maintain proper weight, buoyancy, and wave loading on the structure.

8 Structural Assessment Process

8.1 General

Structural assessment is a process by which a structure's fitness-for-purpose is evaluated. The assessment process is stepwise with increasing complexity and is typically accomplished by performing a structural analysis. Assessment may also consist of demonstrating that a platform survived with little or no damage an extreme loading event that is as severe as or more severe, by an appropriate margin, than that required in this section. Other assessment methods are also possible.

An assessment should be conducted if one or more of the assessment initiators defined in 8.3 exist or when the platform owner/operator elects to perform an assessment.

The overall assessment process is shown in Figure 5 and consists of the following:

a) determine the platform assessment category (see 8.2);

b) determine if an assessment initiator exists (see 8.3);

c) gather the assessment information (see 8.4);

d) select the assessment method (see 8.5);

e) determine if the platform meets the fit-for-purpose performance criteria (see 8.6);

f) implement risk reduction measures, if necessary (see 8.7).

The assessment process provided in this recommended practice is applicable for areas outside of the United States, with the exception of the fitness-for-purpose performance criteria. The performance criteria, including in some circumstances reduced metocean criteria from that applicable for new designs, are only applicable for indicated U.S. areas.

8.2 Assessment Category

A platform shall be assessed according to its exposure category, as defined in 5.3.4. The exposure category is used to determine the specific criteria/loadings to be used for the fitness-for-purpose assessment.

8.3 Assessment Initiators

8.3.1 General

A platform should undergo the assessment process if one or more of the assessment initiators defined in 8.3.2 through 8.3.7 are triggered. Any platform that has been totally decommissioned (i.e. an unmanned platform with inactive flowlines and all wells plugged and abandoned) or is in the process of being removed (i.e. wells being plugged and abandoned) is not subject to this assessment process.

8.3.2 Addition of Personnel

If the life safety category as defined in 5.3.4.2 is changed to a more restrictive category, the platform's structural strength shall be assessed.

8.3.3 Addition of Facilities

If the addition of facilities (e.g. additional pipelines, additional wells, or a significant increase in topside hydrocarbon inventory capacity) increases the consequence of failure category, as defined in 5.3.4.3, the platform's structural strength shall be assessed.

8.3.4 Increased Loading on Structure

If the structure is altered such that the new combined environmental/operational loading is significantly increased beyond the combined loadings of the original design using the original design criteria or the level deemed acceptable by the most recent assessments, the platform's structural strength shall be assessed. Increases in platform loading due to changes from the design or most recent assessment are considered to be significant if the total of the cumulative change in loading is greater than 10 %.

8.3.5 Inadequate Deck Height

If the platform has an inadequate deck height and the platform was not designed for the impact of wave loading on the deck, the platform's structural strength shall be assessed. Deck height is measured to the underside of the support structure for the cellar deck. The definition of cellar deck for the purpose of assessment is provided in A.8.3.5.

For the U.S. Gulf of Mexico, the deck height threshold at which an ultimate strength assessment shall be initiated is based on the crest elevation of the ultimate strength metocean conditions determined in relation to the exposure category for the platform as provided in Table 6. If the crest elevation is higher than the cellar deck height then the platform shall be assessed.

For other U.S. areas, a site-specific metocean study to determine the crest elevation representative of the ultimate strength metocean conditions shall be used. The crest elevation shall be determined using an accepted wave theory approach applicable for the platform's water depth. If the crest elevation is higher than the cellar deck height, then the platform shall be assessed.

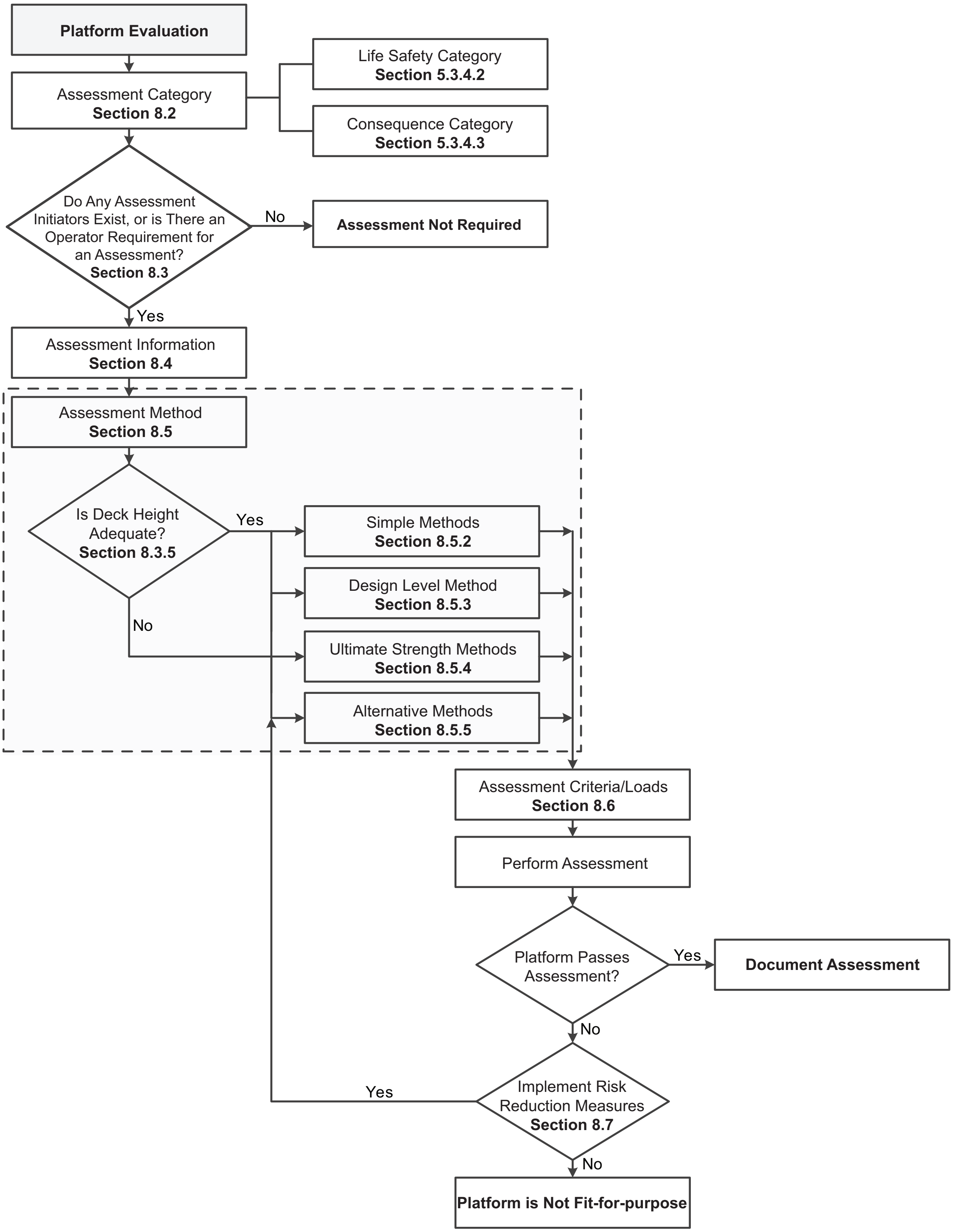

Figure 5—Fitness-for-Purpose Assessment Process

8.3.6 Significant Damage

If the platform has significant structural damage or deterioration, the platform's structural strength shall be assessed. Cumulative damage and/or deterioration data should be evaluated to determine if it is significant.

The combined cumulative damage to the platform is considered to be significant if it results in a decrease in the platform system capacity of 10 % or more. If there is uncertainty in the determination of the percentage reduction in system capacity, it is recommended that an assessment be performed.

Recommended methods for evaluating damage are provided in Section 7. Minor structural damage may be evaluated using engineering judgment or simplified structural analysis without performing a detailed assessment. If the evaluation determines that the cumulative effects of damage are not significant, then the evaluation process and the evaluation results should be documented and retained.

8.3.7 Cumulative Increased Loading and Damage

Cumulative decreases in platform system capacity due to damage or cumulative increases in platform system loading due to changes from the design are considered to be significant if the sum of the cumulative changes is greater than 10 %. For example, if there is a 7 % decrease in system capacity and a 5 % increase in system loading due to changes, then the combined total of 12 % is considered significant.

8.4 Assessment Information

8.4.1 General

This is the data necessary for the assessment and should mostly be available from the platform characteristic data and inspection data. The data should be up-to-date and reflect the condition of the platform at the time of the assessment. This information should be available from the platform database as described in 5.2.

The platform should be assessed based on its present condition, accounting for any damage, repair, scour, or other factors potentially affecting its fitness-for-purpose. The owner/operator should ensure that any assumptions made are reasonable and that the data are accurate and representative of actual conditions at the time of the assessment or for future modifications to the platform.

Additional above-water and underwater information may be required other than that recorded during a routine platform inspection, as defined in 6.6.4. Local soils information may also be required if the platform was designed using offsite or general area soils data.

8.4.2 Above-water Information

Where drawings are unavailable or inaccurate, additional walk-around inspections of the topside structure and facilities should be considered to collect the necessary information; for example, actual topside arrangement and configuration, structural framing details, equipment locations, etc.

8.4.3 Underwater Information

In some instances, engineering judgment may necessitate additional Level III/Level IV inspections, as defined in 6.5, to verify suspected damage, deterioration due to age, lack of joint cans, major modifications, unavailable or inaccurate platform drawings, poor inspection records, or analytical findings.

8.4.4 Geotechnical Information

Available on- or near-site soil borings and geophysical data should be reviewed. Many older platforms were installed based on soil boring information a considerable distance away from the installation site. Interpretation of the soil profile by a geotechnical engineer can be improved based on more recent site investigations with improved sampling techniques and in-place tests performed for other nearby structures. More recent and refined geophysical data might also be available to correlate with soil boring data to develop an improved foundation model.

8.5 Assessment Method

8.5.1 General

Four assessment methods are available for use when performing platform fitness-for-purpose assessments. However, within each method there are several applicable approaches. Details on implementation of the assessment method are provided in:

— 8.5.2 for simple methods,

— 8.5.3 for design level method,

— 8.5.4 for ultimate strength methods, and

— 8.5.4 for alternate assessments methods.

Simple methods provide a method of assessment with minimal effort, for example, comparison to a similar platform. The design level method uses linear (elastic) methods to check the platform member-by-member, similar to the approach used for design of new platforms. The ultimate strength methods use a nonlinear or equivalent linear method to determine platform performance on a global basis. Alternative methods use historical performance of the platform or explicit probabilities of survival of the platform for the assessment.

The methods are presented in order of increasing technical complexity and decreasing ease of implementation, based upon typical applications. While the technical complexity increases with each approach, the conservatism tends to decrease. For example, there is more conservatism inherent in the design level method than in the ultimate strength methods. Generally, any of the methods used are valid to demonstrate that the platform passes assessment. The one exception is that if the assessment initiator as defined in 8.3 is due to inadequate deck height, then an ultimate strength method is required. A platform that does not pass the design level method may pass the ultimate strength method.

8.5.2 Simple Methods

8.5.2.1 General

Simple methods may be used for assessment in lieu of more complex and time-consuming platform-specific analyses. These methods are typically used for a platform that meets a certain class of structure where prior studies are available or when there are existing previous analyses available. If there is any concern that a simplified method does not meet the requirements of this section, then one of the more detailed assessment approaches should be used.

8.5.2.2 Simplified Procedures

Simplified procedures exist for the fitness-for-purpose evaluation of existing platforms. The use of these procedures requires knowledge of the assumptions upon which they were based, as well as a thorough understanding of their application and limitations. The loadings used in a simplified procedure should be validated as being as conservative as used in a more advanced method.

8.5.2.3 Results from a Previous Analysis

A previous assessment of a platform may be used if the analysis accurately reflects the present configuration, condition, and loading of the platform. If an ultimate strength method is required by the initiator, then a previous conducted design level method shall not be used.

8.5.2.4 Comparison with a Similar Platform

Assessment results for one platform can be used for another platform provided that the platforms are substantially similar with respect to framing, steel material, foundation properties, structural condition, loading condition, water depth, and operational history. The assessment results for the similar platform can be based on any of the assessment methods in this section.

8.5.3 Design Level Method

8.5.3.1 General

A design level method is the first level of detailed analysis of the platform if simplified methods are not available or not adequate for the assessment. The design level method is simpler and more conservative than the more complex and less conservative ultimate strength methods.

A design level method analysis is similar to the API 2A-WSD, 22nd Edition method for the design of new platforms where a structure is checked on a component by component basis. The procedure consists of linear analysis and checks of individual structural components using member and joint safety factors in accordance with API 2A-WSD, 22nd Edition to verify that they do not exceed allowable levels.

8.5.3.2 Assessment Model

8.5.3.2.1 General

The platform model should be three-dimensional and include adequate representation of the deck, jacket, and foundation following the procedures for design of new platforms as provided in API 2A-WSD, 22nd Edition. The model should be based on its current condition, accounting for any damage, repair, scour, or other factors affecting its performance or integrity. Special attention should be given to defensible representation of the actual stiffness of damaged or corroded members and joints.

8.5.3.2.2 Effective Length Factors

Studies and tests have indicated that effective length (K) factors are substantially lower for elements of a frame subjected to overload than those specified in API 2A-WSD, 22nd Edition. Lower values may be used if it can be demonstrated that they are both applicable and substantiated.

8.5.3.2.3 Tubular Member Strength Checks

The assessment of structural members should be in accordance with the requirements of API 2A-WSD, 22nd Edition. Effective length (K) factors other than those noted in API 2A-WSD, 22nd Edition may be used when justified. Damaged or repaired members may be evaluated using a rational, defensible engineering approach, including historical exposure or specialized procedures developed for that purpose.

8.5.3.2.4 Tubular Joint Strength Check

The assessment of structural connections should be in accordance with API 2A-WSD, 22nd Edition and should be evaluated for the actual loads derived from the global assessment analysis. The strength of grouted and ungrouted joints may be based on the results of experimental and analytical studies if it can be demonstrated that these results are applicable, valid, and defensible. For assessment purposes, the enhanced properties of API 2H material need not be met for joint cans.

8.5.4 Ultimate Strength Methods

8.5.4.1 General

Ultimate strength methods provide an estimate of a platform's system capacity. This typically involves the use of nonlinear, large deformation analysis to determine the maximum loading that the platform can sustain without collapse. The equivalent strength method, which is similar to a design level method with all safety factors and sources of conservatism removed, is also permitted as this provides a conservative estimate of the platform's ultimate strength.

The ultimate strength assessment should demonstrate that a platform's system capacity is equal to or greater than the ultimate strength performance criteria. Prediction of the local failure of structural members or connections is acceptable provided that the platform system capacity meets or exceeds the performance criteria.

The ultimate strength methods involve an assessment of the global platform capacity, as opposed to the component level check of the platform that is used for a design level method. The ultimate strength assessment shall demonstrate as a minimum that the platform does not collapse at a load equal to that required for assessment.

There are two general types of ultimate strength methods: equivalent linear methods and nonlinear methods.

8.5.4.2 Ultimate Strength Using Equivalent Linear Methods

The equivalent strength method is similar to the design level, except that all safety factors and other sources of conservatism are removed. The safety factors to be removed are as defined in API 2A-WSD, 22nd Edition.

Equivalent linear methods provide a conservative estimate of ultimate strength. The structure passes assessment if no elements have exceeded their equivalent ultimate strength. If there are a few overloaded members and/or joints, local overload considerations may be used to justify that the platform will not collapse.

Other equivalent linear methods can be used, provided that they can be justified to provide conservative or similar results as nonlinear methods.

8.5.4.3 Ultimate Strength Using Nonlinear Methods

Nonlinear methods are intended to demonstrate that a platform has adequate strength and stability to withstand the ultimate strength loading. Local overstress and member or joint failure may be predicted, however, without global collapse. At this level of analysis, stresses have exceeded linear levels and modeling of overstressed members, joints, and foundations should adequately recognize ultimate capacity as well as post-buckling behavior, rather than linear load limits.

The ultimate strength of a platform is typically determined using nonlinear pushover structural analysis software, which applies an incrementally increasing lateral load to the platform model until collapse is predicted. The lateral pushover load should be representative of the loads acting on the platform at the instance of collapse.

The provisions in the recommended practice for the ultimate strength method generally apply to platforms where a static analysis adequately represents structural response. For dynamically sensitive structures, a dynamic, time domain, nonlinear pushover analyses could also be utilized.

8.5.4.4 Assessment Model

8.5.4.4.1 General

The global structural model should be three-dimensional and special attention should be given to a defensible representation of the actual stiffness of damaged or corroded members and joints. The following guidelines should be considered for ultimate strength methods.

8.5.4.4.2 Component Strength Modeling

The strength of undamaged members, joints, and piles can be established using the strength formulas of API 2A-WSD, 22nd Edition, with all safety factors set to 1.0. Nonlinear interaction equations may be utilized as appropriate. Mean yield strength may be used rather than nominal values. Ultimate strength of damaged or repaired elements of the structure may be evaluated using recognized and documented methodology.

8.5.4.4.3 Yield Strength

When adequate data is available, the actual (coupon test or mill certification) or mean yield strength may be used instead of nominal yield strength. However, mean yield strength should not be used when it is greater than actual strength. In most cases, the mean yield strength for 248 MPa (36 ksi) steel is estimated to be 276 MPa (40 ksi) to 317 MPa (46 ksi), with 296 MPa (43 ksi) being a reasonable average. Increased strength due to strain hardening may also be used if the structural section is sufficiently compact, but not for rate effects beyond the normal (fast) mill tension tests. Additional discussion on yield strength modeling is provided in A.8.6.2.

8.5.4.4.4 Pile Foundations

Assessment of existing piled foundations is different than for new design and additional considerations and revised approaches should be used. Similar to new design, pile foundations should be modeled in sufficient detail to adequately simulate their response. However, the pile soil properties and pile modeling may differ in order to obtain a best estimate of foundation response. Some of these changes include the use of static p-y curves to define lateral resistance instead of the cyclic degraded curve typically used for new design.

The piles should use the actual or mean steel strength, as described in 8.5.4.4.3, instead of the nominal steel strength. The foundation of well conductors should be included in the assessment to provide additional lateral foundation capacity to the structural system. Group effects should be included for dense arrays of well conductors. Early plastic deformation of some of the piles is acceptable. If a global collapse mechanism in the foundation controls the platform ultimate strength, then a geotechnical engineer familiar with assessment should be involved in the assessment. Additional discussion on the modeling of the foundations is provided in A.8.6.2.

8.5.5 Alternative Assessment Methods

8.5.5.1 General

Alternative assessment methods can be used in lieu of specific structural analysis of a platform. This involves the use of techniques other than a direct structural evaluation to assess an existing platform. There are two basic types of alternative methods: historical performance and explicit probabilities of survival.

8.5.5.2 Assessment by Prior Exposure

An alternative to a metocean loading assessment is to use prior storm exposure, provided the platform has survived with no significant damage. This may be performed by comparing the expected maximum base shear to which the platform has been exposed, either from measurements or calibrated hindcasts, with the base shear implied in the ultimate strength assessment check. The comparison shall demonstrate that the prior exposure load exceeds the ultimate strength performance criteria as defined in 9.5.2.

The comparison shall also take into account the uncertainty of the prior exposure metocean loads, the uncertainty in the platform ultimate strength, and the degree to which the platform's weakest direction was tested by the prior exposure loads. The comparison shall be substantiated by appropriate calculations to show that it meets the performance requirements.

Analogous procedures may be used to assess existing platforms based on prior exposure to seismic or ice loading.

8.5.5.3 Explicit Probabilities of Survival

This involves assessment using explicit probabilities of survival of the platform for the appropriate assessment criteria. The probabilistic-based performance criteria used in the evaluation should be justified as equal to that of the more direct assessment methods defined in this section.

8.6 Performance Criteria

8.6.1 Design Level Method

The design level method shall demonstrate that the platform's structural members and connections perform in accordance with the API 2A-WSD, 22nd Edition approach, including the application of all safety factors, the use of nominal rather than mean yield stress, etc.

8.6.2 Ultimate Strength Method

The ultimate strength method shall demonstrate that the platform's structural system has sufficient global capacity to resist the imposed loads, using the appropriate ultimate strength criteria (Section 8 or Section 11), without collapse.

Two types of performance criteria are provided.

— Specific assessment metocean loading criteria. The metocean criteria are typically defined in relation to a specific return period.

— A specific assessment RSR.

8.7 Risk Reduction

Structures that do not pass the assessment will need consequence mitigation and/or likelihood reduction. This can include modifications or operational procedures that reduce loads, increase capacities, or reduce the exposure category. Consequence mitigation and likelihood reduction may be considered at any stage of the assessment process.

9 Assessment for Metocean Loading

9.1 General

The metocean criteria/loads to be utilized in the assessment should be in accordance with API 2MET with the exceptions, modifications, and/or additions defined in 9.2 and 9.3. The criteria/loads are related to the platform assessment category, as defined in 5.3.4, and are applied as outlined in 8.5. The metocean criteria/loads are intended for use in platform assessment according to this recommended practice and shall not be used for the design of new platforms, the change-of-use of a platform, or the reuse of a platform.

Demonstrating that a platform located in the U.S. Gulf of Mexico is fit-for-purpose using the metocean criteria/loads provided in this recommended practice may leave an owner/operator with a platform that is vulnerable to damage or collapse in a hurricane, particularly for an L-2 or L-3 exposure category platform designed prior to the 20th Edition of API 2A-WSD.

The assessment approach is structured so that the damage to or collapse of a platform will not increase life safety or environmental risk; however, it may create an economic burden to the owner in terms of facility and/or production losses. The determination of an acceptable level of economic risk is left to the operator's discretion. It can be beneficial for an operator to perform explicit cost-benefit risk analyses in addition to using this recommended practice.

Detailed metocean criteria/loads for a design level method and an ultimate strength method are provided for the U.S. Gulf of Mexico and reflect industry experience of survival and failure of U.S. Gulf of Mexico platforms exposed to significant hurricanes. Industry experience in the U.S. Gulf of Mexico allows the justification for using metocean criteria/loads for assessment that have been reduced below those used in the present design practice. This reduction in the metocean criteria/loads are applicable to the large number of U.S. Gulf of Mexico platforms designed prior to the wave force calculation procedure originally presented in the 20th Edition of API 2A-WSD.

In some shallow water areas, the system strength of platforms with large decks may be governed by wind loads instead of wave and/or current loads. In such cases, the platform system capacity should be assessed against the API 2MET maximum wind criteria in combination with the associated waves, currents, and surge. This is may be of particular concern for platforms located in the U.S. Gulf of Mexico API 2MET Western Region.

9.2 Assessment Criteria

The assessment criteria are specified according to geographical region. Criteria for the U.S. Gulf of Mexico and three regions off the U.S. West Coast are provided. The U.S. West Coast regions are Santa Barbara Channel, San Pedro Channel, and Central California (for platforms off Point Conception and Point Arguello). No metocean criteria are provided for Cook Inlet as ice forces dominate at that location.

The metocean criteria for assessment shall consist of the following items:

— omnidirectional wave height,

— storm tide (storm surge plus astronomical tide),

— crest elevation,

— wave and current direction factors,

— current speed and profile,

— wave period,

— wind speed.

All of the criteria items in this list are provided in API 2MET for the U.S. Gulf of Mexico. Platform owner/operator may be able to justify different metocean criteria for platform assessment than the recommended criteria specified in API 2MET. However, these alternative criteria shall meet the following conditions:

a) be based on a sufficiently long record of measured data from the storm types that contribute to the most severe wind, wave, and current conditions in the area (e.g. winter storms and hurricanes in the Gulf of Mexico) or on a sufficiently long record of hindcast data from numerical models and procedures that have been thoroughly validated with measured data;

b) extrapolation of measured or hindcast storm data to long return periods and determination of "associated" values of secondary metocean parameters shall be done with defensible methodology;

c) derivation of metocean criteria for platform assessment shall follow the same methodology as used to derive the guideline parameters provided in Reference [16] and Reference [40]. This derivation methodology is further explained in A.9.

The wave and storm surge figures in API 2MET are valid down to water depths of 10 m (33 ft). These figures should not be used for water depths less than this, since metocean conditions are difficult to predict in shallow water due to the effects of coastal storm surge, wave shoaling, bottom soils, the geometric effect of the coastline, and other factors. Development of the appropriate criteria for shallow water depths should be part of a specialist study by suitably qualified metocean personnel.

9.3 Assessment Loading

9.3.1 Metocean Loading

The metocean criteria provided in this recommended practice are to be applied with wave/wind/current force calculation procedures specified in API 2A-WSD, 22nd Edition.

If there is a wave-in-deck loading trigger, then the procedures provided in 9.3.4 should be followed. Alternative wave-in-deck loading methods can be used as long as they are justifiable. Even though there may not be a wave-in-deck loading trigger, wave loads may act on other deck areas such as sump and spider decks and the wave loading should on these areas be determined in an appropriate manner. Special attention should be given to wave loading in areas such as sump decks using the wave-in-deck procedures.

9.3.2 Gravity Loading

Gravity loading should consider the actual loads on the platform as well as future planned or temporary loads (e.g. drill rig). Metocean and/or seismic loading should consider the actual configuration of the structure at the time of the assessment, such as actual number of conductors or risers, drill rig, etc. Future planned or temporary loads should also be considered.

9.3.3 Dynamic Effects

The wave loads on a platform are dynamic in nature. For most design water depths these loads may be adequately represented by their static equivalents. For deeper waters, or where platforms tend to be more flexible or the platform is damaged, the static analysis may not adequately describe the true dynamic loads induced in the platform. Correct analysis of such platforms requires a load analysis involving the dynamic response of the structure.

Dynamic effects should be considered for platforms as appropriate. However, they shall be considered in water depths greater than 122 m (400 ft). Dynamic effects should also be considered for damaged platforms that may sustain higher motions in the damaged condition than in the intact condition.

9.3.4 Wave and Current Loads on Platform Decks

9.3.4.1 General

Platform damage and failure experience in the U.S. Gulf of Mexico clearly demonstrates that platforms are much more susceptible to damage if waves inundate the platform deck; however, calculation of wave forces on a deck and on the deck equipment is not a simple task. The procedure described in 9.3.4.3 is a simplified method for estimating the global horizontal wave/current forces on platform decks. This deck force procedure is calibrated to deck forces measured in wave tank tests in which hurricane and winter storm waves were modeled. The variability of the horizontal deck forces measured in the laboratory tests for a given wave height is rather large. The coefficient of variation (i.e. standard deviation divided by the mean) is approximately 0.35.

The result of applying this procedure is the magnitude and point-of-application of the horizontal deck force for a given wave direction. The horizontal force on the deck should be added to the associated wave/current force on the jacket, with due consideration to phasing.

Other wave/current deck force calculation procedures for static and/or dynamic analyses may be used provided they are validated with reliable and appropriate measurements of global wave/current forces on decks either in the laboratory or in the field.

9.3.4.2 Crest Height Calculation Procedure

The horizontal wave/current deck force criteria provided in 9.3.4.3 rely on a calculated crest height for the specified wave. The crest height should be calculated using the appropriate order of stream function wave theory as recommended in API 2A-WSD, 22nd Edition, the appropriate storm water depth, and the associated wave period. In many cases, Stokes V wave theory will produce acceptable accuracy. Other wave theories, such as extended velocity potential and Chappelear, may be used if an appropriate order of solution is selected, with the ultimate strength analysis directional wave height, associated wave period, and storm tide.

Calculations using the ultimate strength analysis directional wave height, associated wave period, and storm tide are used to determine crest elevation and base case load pattern. It is generally considered preferable to scale up the metocean conditions, rather than the base case load pattern, to find the structural collapse load.

9.3.4.3 Deck Force Calculation Procedure

The steps for computing the deck force and its point of application are as follows.

a) Step 1: Given the crest height calculated using the procedure, given in 9.3.4.2, compute the wetted “silhouette” deck area (A) projected in the wave direction (θ_w).

   The full silhouette area for a deck is defined as the area shown in Figure 6 (i.e. the area between the bottom of the scaffold deck and the top of the “solid” equipment on the main deck).

   The wetted silhouette area for deck force calculations is a subset of the full area, extending up to the “crest elevation.” This is an elevation above mean lower low water (MLLW) that is equal to the sum of the storm tide and the crest height of the wave required for ultimate strength analysis. The wetted silhouette area is therefore equal to the distance between the underside of the cellar deck and the crest elevation, times the maximum deck width between the cellar deck and the crest elevation. As shown in Figure 6, this area may be divided into subsets of areas, with the area of each subset equal to the height of the area times the maximum deck with within that height. For lightly framed subcellar deck sections with no equipment (e.g. a scaffold deck comprised of angle iron), use one-half of the silhouette area for that portion of the full area. The areas of the deck legs and bracing above the cellar deck are to be included in the silhouette area. Deck legs and bracing members below the bottom of the cellar deck should be modeled along with jacket members in the jacket force calculation procedure. Lattice structures, such as drilling derricks, extending above the “solid equipment” on the main deck can be ignored in the silhouette.

   The area, A, is computed as:

   $$A = A_x \cos\theta_w + A_y \sin\theta_w$$

   where

   θ_w, A_x, and A_y are as defined in Figure 7.

b) Step 2: Using the wave theory recommended in API 2A-WSD, 22nd Edition, calculate the maximum wave-induced horizontal fluid velocity, V, at the crest elevation or the top of the main deck silhouette, whichever is lower.

c) Step 3: The wave/current force on the deck, F_{dk}, is computed by:

   $$F_{dk} = \frac{1}{2}\rho C_d (a_{wkf} \times V + a_{cbf} \times U)^2 A$$

where

U is the current speed in-line with the wave;

a_{wkf} is the wave kinematics factor (0.88 for hurricanes and 1.0 for winter storms);

a_{cbf} is the current blockage factor for the jacket;

ρ is the weight density of seawater.

The drag coefficient, C_d, is given in Table 4.

d) Step 4: The force F_{dk} should be applied at an elevation Z_{dk} above the bottom of the cellar deck. Z_{dk} is defined as 50 % of the distance between the lowest point of the silhouette area (the underside of the cellar deck) and the lower of the wave crest or top of the main deck.

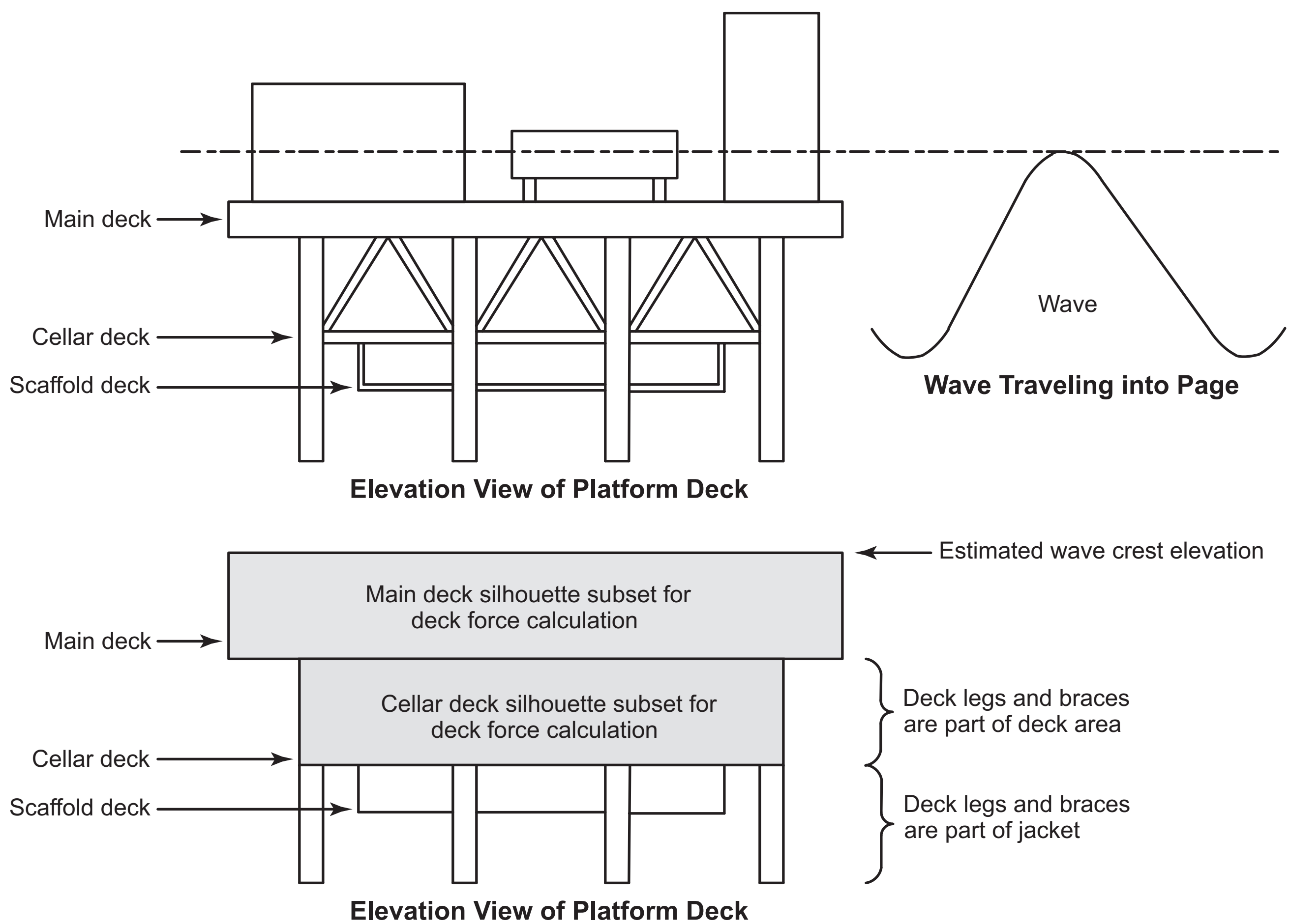

Figure 6—Deck Silhouette Definition

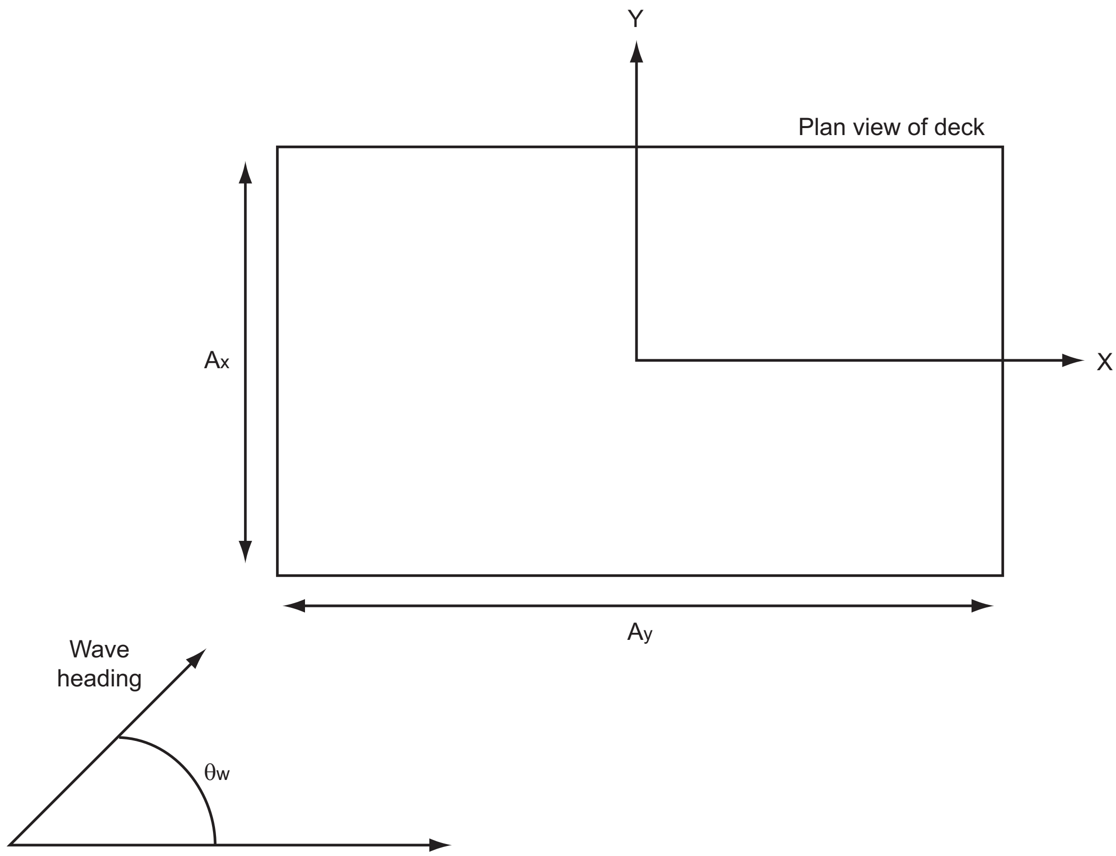

Figure 7—Wave Heading and Direction Convention

Table 4—Drag Coefficient, C_d, for Wave/Current Platform Deck Forces

Deck Type	End-on and Broadside Drag Coefficient C_d	Diagonal (45°) Drag Coefficient C_d
Heavily equipped	2.5	1.9
Moderately equipped	2.0	1.5
Bare (no equipment)	1.6	1.2

9.4 Design Level Method

9.4.1 Assessment Criteria/Loads

9.4.1.1 U.S. Gulf of Mexico

For platforms located in the U.S. Gulf of Mexico, Table 5 shall be used for defining the metocean criteria to be utilized for performing a design level assessment. However, design level assessment of S-2 platforms located in the U.S. Gulf of Mexico is not recommended. Assessment of these platforms should be performed using ultimate strength methods.

9.4.1.2 U.S. West Coast

For platforms located on the U.S. West Coast, the design level assessment shall be performed using site-specific 100-year metocean criteria developed in accordance with the requirements of API 2MET.

Table 5—Design Level Metocean Criteria, U.S. Gulf of Mexico [a c d]

Category	Design Edition		
	API 2A-WSD, 19th Edition and Earlier [b]	API 2A-WSD, 20th or 21st Edition	API 2A-WSD, 22nd and Later
L-1	50-year	100-year	100-year
S-2	Not applicable	Not applicable	Not applicable
C-2	15-year	50-year	50-year
L-3	10-year	25-year	25-year

[a] Metocean criteria to be developed in accordance with the requirements of API 2MET. Site-specific metocean criteria should be used in preference to the indicative criteria provided in API 2MET.

[b] Platforms designed prior to API 2A-WSD, First Edition should be considered as pre-19th Edition.

[c] The selection of the metocean criteria for areas of shallower water or where wind loads are perceived to dominate it may be necessary to consider a different combination of metocean parameters, such as the wind and associated conditions.

[d] All metocean return periods are for full population hurricane conditions.

9.4.1.3 Other U.S. Offshore Areas

For platforms located in other U.S. Offshore Areas, the design level assessment shall be performed using site-specific 100-year metocean criteria developed in accordance with the requirements of API 2MET.

9.4.2 Performance Criteria

9.4.2.1 U.S. Gulf of Mexico

For a design level analysis, the assessment shall demonstrate that the platform withstands the imposed loads from the metocean criteria defined in Table 5 without member or connection overstress, with all of the safety factors as recommended in the 22nd Edition of API 2A-WSD.

9.4.2.2 U.S. West Coast

For a design level analysis, the assessment shall demonstrate that the platform withstands the imposed loads from the metocean criteria defined in 9.4.1.2 without member or connection overstress, with all of the safety factors as recommended in the 22nd Edition of API 2A-WSD.

9.4.2.3 Other U.S. Offshore Areas

For a design level analysis, the assessment shall demonstrate that the platform withstands the imposed loads from the metocean criteria defined in 9.4.1.3 without member or connection overstress, with all of the safety factors as recommended in the 22nd Edition of API 2A-WSD.

9.5 Ultimate Strength Method

9.5.1 Assessment Criteria/Loads

9.5.1.1 U.S. Gulf of Mexico

For platforms located in the U.S. Gulf of Mexico. Table 6 shall be used for defining the metocean criteria to be utilized for performing an ultimate strength assessment. The recommended metocean criteria shall be based on risk considering life safety and consequence of failure, as defined in 5.3.4. In addition, the recommended assessment metocean criteria allow for a reduction in the criteria compared with the criteria required for new designs. This reduction in the metocean criteria are only applicable for platforms designed to the 19th Edition of API 2A-WSD or earlier.

Wave/current forces on platform decks, if applicable, for any exposure category, should be calculated using the procedure defined in 9.3.4.

Table 6—Ultimate Strength Metocean Criteria, U.S. Gulf of Mexico [a e f]

Category	Design Edition		
	API 2A-WSD, 19th Edition and Earlier [c]	API 2A-WSD, 20th or 21st Edition	API 2A-WSD, 22nd and Later
L-1	300-year [b]	300-year [b]	1000-year
S-2 [d]	2500-year sudden hurricane	2500-year sudden hurricane [g]	500-year
C-2	25-year	300-year	500-year
L-3	10-year	100-year	100-year

[a] Metocean criteria to be developed in accordance with the requirements of API 2MET. Site-specific metocean criteria should be used in preference to the indicative criteria provided in API 2MET.

[b] L-1 for the 19th, 20th, or 21st Editions shall use the higher load measured as base shear for L-1 or S-2 conditions.

[c] Platforms designed prior to API 2A-WSD, First Edition should be considered as pre-19th Edition.

[d] The development of metocean criteria for platforms categorized as L-2 with S-2 are dependent on the time required to evacuate personnel from the platform, with relevant definitions provided in API 2MET. Shorter evacuation windows and a relaxation in criteria maybe justifiable if supported with defensible evacuation procedures.

[e] The selection of the metocean criteria for areas of shallower water or where wind loads are perceived to dominate it may be necessary to consider a different combination of metocean parameters, such as the wind and associated conditions.

[f] All metocean return periods are for full population hurricane conditions unless noted otherwise.

9.5.1.2 U.S. West Coast

For platforms located on the U.S. West Coast, the ultimate strength assessment shall be performed using site-specific 2500-year metocean criteria developed in accordance with the requirements of API 2MET.

9.5.1.3 Other U.S. Offshore Areas

For platforms located in other U.S offshore areas, the ultimate strength assessment shall be performed using site-specific 2500-year metocean criteria developed in accordance with the requirements of API 2MET.

9.5.2 Performance Criteria

9.5.2.1 U.S. Gulf of Mexico

For an ultimate strength assessment using an equivalent linear method, the assessment shall demonstrate that the platform withstands the imposed loads from the metocean criteria defined in Table 6 without member overstress. This may be achieved by ignoring all of the safety factors as recommended in the 22nd Edition of API 2A-WSD for a new platform design.

For an ultimate strength assessment using nonlinear methods, the assessment shall show that the platform withstands the imposed loads from the metocean criteria defined in Table 7 without collapse.

9.5.2.2 U.S. West Coast

For platforms located on the U.S. West Coast, recommended acceptable ultimate strength is a RSR of 1.6. The RSR is defined as the ratio of a platform's ultimate lateral load carrying capacity to a reference lateral loading defined in 8.4.1.2 that is computed using API 2A-WSD, 22nd Edition loading methodologies. This RSR is specific to the metocean conditions and types of platforms used in offshore regions on the U.S. West Coast.

The performance criteria for platforms located on the U.S. West Coast are based on the life safety consequence. Economic and environmental consequence may require consideration of higher performance criteria.

9.5.2.3 Other U.S. Offshore Areas

For platforms operating in other U.S. offshore areas, recommended acceptable ultimate strength is a RSR of 1.6. The RSR is defined as the ratio of a platform's ultimate lateral load carrying capacity to a reference lateral loading defined in 8.4.1.3 that is computed using API 2A-WSD, 22nd Edition loading methodologies. This RSR is specific to the metocean conditions and types of platforms used in U.S. offshore regions outside of the U.S. Gulf of Mexico or West Coast and is not applicable for any other worldwide offshore areas.

The performance criteria for platforms located in other U.S. offshore areas are based on the life safety consequence. Economic and environmental consequence may require consideration of higher performance criteria.

9.6 Risk Reduction

Structures that do not meet the metocean loading fitness-for-purpose assessment requirements using the methods recommended will need consequence mitigation and/or likelihood reduction measures. Consequence mitigation and/or likelihood reduction measures should be considered at all stages of a fitness-for-purpose assessment and may be used in lieu of more complex assessment. Detailed recommendations on developing consequence mitigation and likelihood reduction measures are provided in Section 13.

10 Assessment for Fatigue Loading

All offshore structures, regardless of location, are subject to fatigue degradation. In many areas, fatigue is a major design consideration due to relatively high ratios of operational sea states to maximum design metocean events. In the U.S. Gulf of Mexico, however, this ratio is low. Still, fatigue effects should be considered and engineering decisions should include consideration of fatigue analysis results.

In the U.S. Gulf of Mexico, cracking due to fatigue is not generally experienced. If cracks occur, they are most likely found at joints in the first horizontal conductor framing below water, normally resulting from fatigue degradation. Fatigue cracks may also occur at the main brace to leg joints in the vertical framing at the first bay above mudline, normally due to metocean overload (i.e. low cycle fatigue), or at the perimeter members in the vertical framing at the first bay below-water level, normally as a result of boat impact.

As part of the assessment process for future service life, consideration should be given to accumulated fatigue degradation effects. Where Levels III and/or IV inspections are made and any known damage is assessed and/or repaired, no additional analytical demonstration of future fatigue life is required. Alternatively, adequate fatigue life may be demonstrated by means of an analytical procedure compatible with those specified in API 2A-WSD, 22nd Edition.

In some cases, Level IV inspection of the joint can be used to "reset" accumulated fatigue degradation if there is no evidence of surface cracking. Such information can also be used to establish risk-based inspection intervals as discussed in 6.5.2.2. Monitoring fatigue-sensitive joints, and/or reported crack-like indications, is an acceptable alternative to analytical verification.

11 Assessment for Seismic Loading

11.1 General

The assessment of platforms for seismic loading shall follow the analysis procedures and criteria definition for offshore structures as specified in API 2EQ. The basic flow chart shown in Figure 5 is applicable to determine the fitness-for-purpose for seismic loading.

All platforms located in U.S. areas with seismic activity are considered L-1 exposure category.

11.2 Simplified Analysis

A validated simplified analysis may be used for seismic assessment as defined in 8.5.2. However, the simplified analysis should be demonstrated to be more conservative than a detailed seismic strength analysis.

11.3 Design Basis Check

The design basis check procedures noted in 8.5.1 are appropriate provided no significant new faults in the local area have been discovered, or any other information regarding site seismic hazard characterization has been developed that significantly increases the level of seismic loading used in the platform's original design.

For all exposure categories defined in 5.3.4, platforms designed or recently assessed in accordance with the requirements of API 2A-WSD, Seventh Edition, which required safety level analysis (referred to as "ductility level analysis" in subsequent editions), are considered to be acceptable for seismic loading, provided the following:

a) no new significant fault has been discovered in the area;

b) no new data indicate that a current estimate of strength level ground motion for the site would be significantly more severe than the strength level ground motion used for the original design;

c) proper measures have been made to limit the life safety risks associated with platform appurtenances as noted in API 2A-WSD, 22nd Edition;

d) the platforms have no significant unrepaired damage;

e) the platforms have been inspected;

f) the present and/or anticipated payload levels are less than or equal to those used in the original design.

11.4 Extreme Level Earthquake

For seismic fitness-for-purpose assessments, the extreme level earthquake (ELE) analysis is not applicable. An abnormal level earthquake (ALE) analysis is required if the platform does not pass the design basis check or screening.

11.5 Abnormal Level Earthquake

11.5.1 Assessment Criteria/Loads

The assessment criteria and procedure for performing an ALE assessment shall be based on the recommendations in API 2EQ.

11.5.2 Performance Criteria

Assessments of platforms may be considered adequate for seismic loading provided it can be demonstrated that the platforms meets the performance criteria for an ALE as defined in API 2EQ. For platforms designed to the 19th Edition or earlier, 1000-year return period conditions can be used for the ALE assessment. In addition, the life safety requirements associated with platform appurtenances as provided in API 2A-WSD, 22nd Edition shall be met.

11.6 Risk Reduction

Structures that do not meet the seismic loading fitness-for-purpose assessment requirements using the methods recommended will need consequence mitigation and/or likelihood reduction measures. Consequence mitigation and/or likelihood reduction measures should be considered at all stages of a fitness-for-purpose assessment and may be used in lieu of more complex assessment. Detailed recommendations on developing consequence mitigation and likelihood reduction measures are provided in Section 13.

12 Assessment for Ice Loading

12.1 General

For all platforms which may be subject to ice loading, the assessment shall follow the procedure provided in API 2N. The loads used for the assessment shall be identical to those used for design unless reevaluation of ice loading data results in a justifiable change in criteria. The selection of the appropriate ice criteria and loadings are provided in API 2N. However, it is noted that the ice feature geometries provided in API 2N are not associated with any return period as no encounter statistics are presented.

All references to simple, design level, and ultimate strength analyses in Section 8 assume the use of the values noted in API 2N. Where ranges of loads are recommended, the smaller number can be used for a design level assessment and the larger number can be used for an ultimate strength assessment. Additional details can be found in Reference [17]. Special attention should be given to exposed critical connections where steel was used that were not specifically specified for low temperature service.

12.2 Design Basis Check

A design basis check may be used to demonstrate the fitness-for-purpose of a platform for ice loading, provided that it has been maintained and inspected, has had no increase in design level loading, is undamaged, and was designed or previously assessed in accordance with API 2N. The design basis check is applicable for all platform exposure categories defined in 5.3.4.

12.3 Simplified Analysis

A validated simplified analysis may be used for the assessment of ice loading. It shall be demonstrated that the simplified analysis will be as or more conservative than the design level analysis.

12.4 Design Level Method

L-1 exposure category platforms that do not meet the screening criteria may be considered adequate for ice loading if they meet the provision of API 2N, using a linear analysis with the basic allowable stresses referred to in API 2A-WSD, 22nd Edition, increased by 50 %.

C-2 exposure category and C-3 exposure category platforms that do not meet the screening criteria may be considered adequate for ice loading if they meet the provisions of API 2N using a linear analysis with the basic allowable stresses referred to in API 2A-WSD, 22nd Edition, increased by 70 %.

12.5 Ultimate Strength Method

Platforms that do not meet the design level analysis requirements may be considered adequate for ice loading if an ultimate strength analysis is performed using best estimate resistances and the platform is shown to have a RSR equal to or greater than 1.6 in the case of L-1 exposure category platforms and a RSR equal to or greater than 0.8 in the case of C-2 exposure category and C-3 exposure category platforms. RSR is defined as the ratio of platform ultimate lateral capacity to the lateral loading computed with API 2N.

12.6 Risk Reduction

Structures that do not meet the ice loading fitness-for-purpose assessment requirements using the methods recommended will need consequence mitigation and/or likelihood reduction measures. Consequence mitigation and/or likelihood reduction measures should be considered at all stages of a fitness-for-purpose assessment and may be used in lieu of more complex assessment. Detailed recommendations on developing consequence mitigation and likelihood reduction measures are provided in Section 13.

13 Risk Reduction

13.1 General

Risk reduction measures should be considered if a structure does not meet the fitness-for-purpose performance criteria, as defined in Section 9 for metocean loading, Section 9 for fatigue loading, Section 11 for seismic loading, and Section 12 for ice loading. Risk reduction should be considered at all stages of assessment and may be used in lieu of more complex assessment.

Risk reduction may include consequence mitigation through measures that reduce the exposure of the platform or may include likelihood reduction through measures that reduce the likelihood of platform failure.

13.2 Exposure Reduction

13.2.1 Life Safety

Life safety mitigation measures involve demanning the platform either permanently or temporarily during a forecasted extreme event.

13.2.2 Consequence of Failure

Consequence of failure mitigation measures should include one or more of the following:

a) installation of subsurface safety valves that are manufactured and tested in accordance with applicable API standards,

b) removal or reduction of hydrocarbon storage or inventory volume,

c) removal or rerouting of major oil lines,

d) removal or rerouting large volume gas flow lines,

e) permanent abandonment or temporary abandonment of nonproducing wells,

f) isolation of the pipeline to reduce the potential volume of hydrocarbon release.

13.2.3 Hurricane Preparedness

Advanced planning can reduce hurricane risks as well as improve post-hurricane response. Written hurricane preparedness plans should be developed covering both general hurricane preparedness activities and structure-specific response activities. Checklists and platform-specific guides can assist during the evacuation process. Platforms with higher life safety, environmental, and/or economic risk may require additional considerations.

Examples of hurricane preparedness are as follows.

a) Evacuation planning for major hurricanes, including priority evacuation of platforms that are at greater risk of failure and those that are furthest from shore. Initial evacuation of nonessential personnel should begin early.

b) Evacuation planning for sudden hurricanes that occur with short notice should be given special consideration, including evacuation from S-2 and C-2 offshore platforms to more robust L-1 platforms.

c) Begin preparing structure operations for safe shut-in as early as possible including system pump down, securing equipment and control panels, reducing liquid inventories, etc.

d) Secure loose objects and equipment that can become airborne projectiles. Store movable equipment in safe and dry areas (e.g. generators).

e) Develop advance plans for accessing the structure post-hurricane should normal access and safety systems such as boat landings, walkways, power, etc. not be available due to damage.

f) Establish evaluation guidelines and procedures for the eventual safe reboarding of a damaged structure in terms of whom, how, and when. Minimum acceptance criteria for platform access should be established.

g) Identify critical members and joints for structural integrity for post-hurricane inspections.

13.3 Likelihood Reduction

13.3.1 General

Several likelihood reduction methods are available, with details on their implementation provided in:

— 13.3.3 for removal of a known damaged component,

— 13.3.4 for load reduction,

— 13.3.5 for localized strengthening or repair, and

— 13.3.6 for global strengthening or repair.

Strengthening of the jacket structure can be an effective means of reducing the likelihood of failure of the platform. The strengthening scheme should be designed to increase the system capacity of the platform to the level necessary to meet the appropriate performance criteria, for the exposure category of the platform as defined in 5.3.4. Alternatively, it is possible to modify the structure to reduce the loading.

The platform fitness-for-purpose shall be demonstrated for the selected likelihood of failure reduction method.

13.3.2 Factors to Consider

There are a large number of SMR techniques available for consideration as shown in Figure 8. The platform fitness-for-purpose assessment, as defined in Section 8, will determine whether platform strengthening or repair is required to meet the assessment performance criteria. If strengthening and repair are to be considered, the assessment model should be used to develop strengthening options. Global and local SMR schemes should be considered in terms of their effects on the structure as a whole.

Once a decision has been made in favor of SMR, an appraisal should be completed of all available SMR techniques. Subsequently, the most appropriate scheme from technical, cost, and safety standpoints should be selected. Considerations for selecting and designing a SMR technique include, but are not limited to, the following:

a) safety of diving, diving support, construction, and operations personnel;

b) potential for use of diverless techniques;

c) difficulty of fabrication, handling, and installation;

d) rigging complexity and layout;

e) list support vessel type, availability, and access;

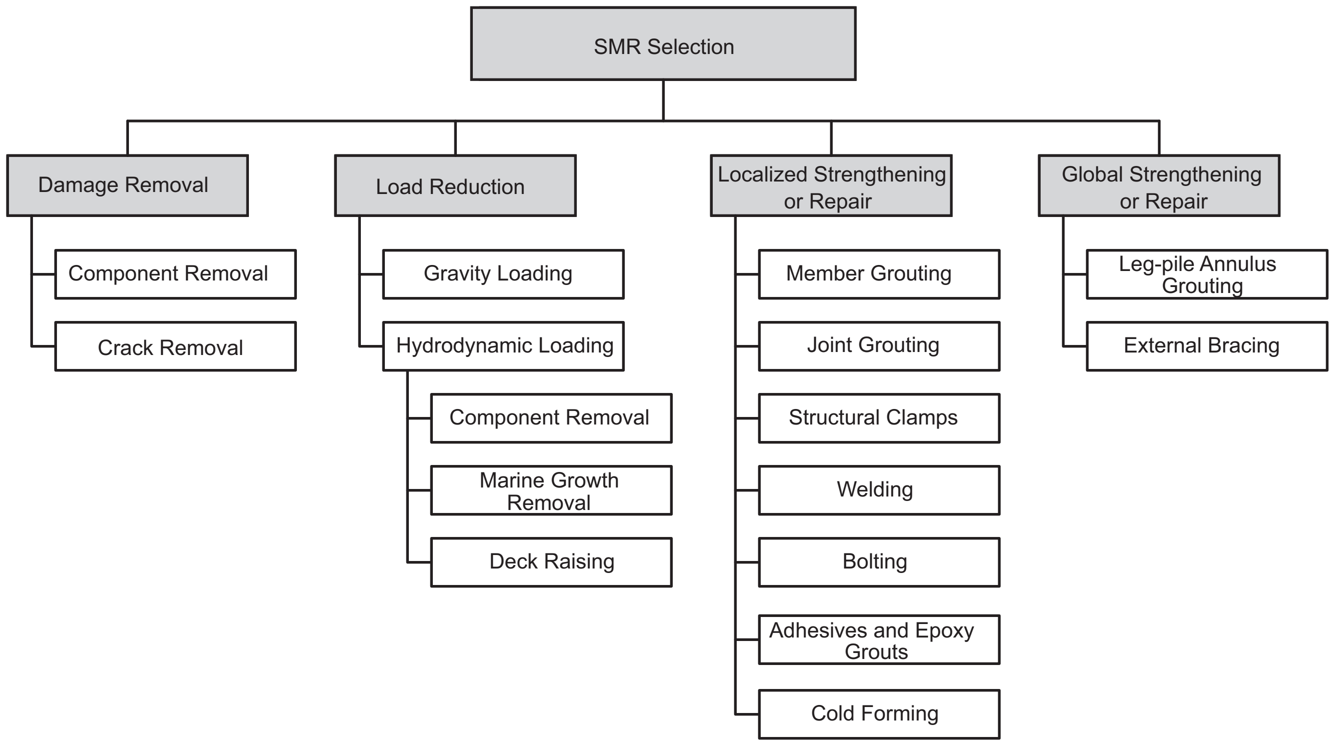

Figure 8—SMR Techniques

f) fit-up tolerance (clamps and members);

g) interference with conductors, jacket members, and appurtenances (sumps, caissons, anodes, etc.);

h) potential for collision with existing risers and control bundles;

i) requirements for predesign inspection, field measurements, and materials samples;

j) outfitting with well-designed installation aids;

k) required weather windows.

The design practices for platform SMR are usually outside the scope of recognized codes of practice, standards, and regulations. Competent assessment engineering should determine the need for and appropriate selection of either, or both, load reduction or strengthening options. Strengthening and repair of existing platforms requires specialist engineers to provide reliable and economical solutions that can be efficiently and safely installed.

13.3.3 Damage Removal

13.3.3.1 General

An approach to the SMR of damaged structures is to completely remove the damage.

13.3.3.2 Member Removal

The removal of damage by cutting out the affected member should only be considered if it can be demonstrated during the assessment phase that the member is no longer required for the structure’s in-place condition.

13.3.3.3 Crack Removal

The removal of cracks may be achieved by remedial grinding. In the case of cracks caused solely by fatigue loads (i.e. not in combination with a fabrication defect), other SMR techniques may be considered in addition to grinding.

13.3.4 Load Reduction

13.3.4.1 Gravity Loading

During the operation of the platform the actual topsides loading may be significantly lower than the loads assumed for the design of the platform. Operational procedures can be implemented to reduce and control topsides loads, for example by:

— removal of unnecessary equipment and/or structures,

— effective weight management procedures with defined weight limits,

— use of lightweight drilling rigs or rigless operations, and

— use of cantilever jack-up drilling operations.

The major impact of load reductions will be to reduce leg and pile stresses and pile reactions. Reduced mass generally has a beneficial effect on platform dynamics (although not necessarily for earthquake response) although in most instances, this effect will generally be small. On platforms with pile tips founded in sand layers, tensile pile capacities may need to be checked. One potential benefit of removing equipment is a possible associated reduction of wind area.

13.3.4.2 Hydrodynamic Loading

13.3.4.2.1 General

Several methods are available for reducing hydrodynamic loads on existing platforms.

13.3.4.2.2 Component Removal

Load reduction may be achieved by removing items that attract metocean loading; this will be most beneficial in the upper water column where wave kinematics is highest.

Removal of nonessential or out-of service components such as barge bumpers, boat landings, walkways, stairs, or risers can reduce load. Boat landings, walkways, stairs, and ladders can be removed only after verifying that they are no longer part of the platform escape routes (see 6.3.5.6).

Removal of conductors can reduce load; however, conductors may also contribute to the capacity of the platform foundation. This should be confirmed during the assessment process. If the conductors increase the foundation capacity of the platform, consideration may be given to removal of the upper portion in order to reduce the hydrodynamic loads.

Removal, or relocation, of equipment on lower deck elevations can reduce loads on the platform in the event of wave inundation of the deck.

13.3.4.2.3 Marine Growth Removal

Load reduction may be achieved by the removal of areas of excessive marine growth. However, the amount of load reduction to be achieved should be evaluated prior to implementation. The load reduction to be achieved will need to be sufficient (in combination with any other load reduction measures) to enable the platform to meet assessment criteria. Measures shall be taken to ensure that returning growth does not cause the hydrodynamic loading to exceed the level required to pass assessment. Such measures may include installation of sliding marine growth preventers and/or adding periodic removal to the SIM program for the platform.

13.3.4.2.4 Raise Deck

For platforms where the wave crest is expected to inundate the deck, raising the deck out of the wave crest will significantly reduce global hydrodynamic loading. However, the structural stability of increased deck legs lengths shall be evaluated.

Due to the high cost and operational impact of raising the deck the cost-benefit should be considered on a case-by-case basis. An alternative to raising the deck is to remove or relocate equipment and nonessential structures from the lower deck elevations; this results in lower hydrodynamic forces and will reduce equipment damage from direct wave loads.

Deck grating instead of plating can be beneficial in reducing vertical loads on the underside of the deck by allowing encroaching water and trapped air to dissipate more easily.

In some locations, field subsidence has caused a general settling of the seafloor. Mitigation alternatives for this case often rely on reservoir pressure techniques such as water or gas injection. This approach, however, does not recover lost height but can be used to slow future subsidence.

Some platforms with low decks have been strengthened by direct bracing to a modern structure. This allows for the placement of the process and control equipment on the new, acceptably high, deck. The affected structure may then be reduced to a wellhead platform.

13.3.4.2.5 Hydrodynamic Blockage and Shielding

In special situations, in particular for structures having dense framing, hydrodynamic studies may be able to justify lower hydrodynamic forces than used in the original design. Dense framing has the effect of developing internal shielding of the members and may result in lower overall global loads.

13.3.5 Localized Strengthening or Repair

13.3.5.1 General

Localized strengthening or repair can be used to directly strengthen or repair a component without altering load paths within the structure. For damaged structures, the damage will normally be left in place. The designer should recognize that additional load may be attracted to the component, either by virtue of its increased stiffness following SMR or due to increased hydrodynamic loads. Localized strengthening or repair options include the following:

a) grout filling—members and joints;

b) clamps—unstressed grouted, stress grouted, mechanical, and elastomer lined;

c) welding, one atmosphere, wet welding, and hyperbaric techniques;

d) weld improvement, grinding, shot peening, and toe dressing;

e) member removal as a standalone repair technique;

f) mechanical repair system such as bolts and swaging;

g) composite materials.

13.3.5.2 Member Grouting

Member grouting, which involves completely filling the tubular member with grout, can be used as an effective means to enhance their axial compressive capacity. This procedure will not be fully reliable unless complete grouting along the member length can be assured (i.e. avoiding voids at the member end). For bending strength increases near midspan, the presence of small voids at member ends is less critical.

Additionally, tests have shown that significant capacity (up to the original capacity) can be obtained by grouting all or only the dented portion of dented members.

The impact of the increased gravity loads and dynamic mass as well as possible decommissioning implications should be considered before grouting.

13.3.5.3 Joint Grouting

Grout filling of tubular chord elements can be used to improve the static strength of the joint and if needed increase the fatigue life of the connections at the joint. The repair method has the advantage of introducing no additional metocean loads on the platform; however, the increased chord rigidity restricts joint ovalization thereby significantly increasing joint capacity for both compression and tension loads. In some cases, grouting may also increase the moment at the joints and this should be considered.

Grouting may be counterproductive for seismically loaded structures, where the grouting leads to an increase in joint stiffness and a reduction in joint ductility. In addition, the impact of the increased gravity loads and dynamic mass as well as possible decommissioning implications should be considered before grouting.

13.3.5.4 Structural Clamps

Structural clamps can be an effective means to repair brace members or joints of jacket structures. They can also be used to connect external bracing to additional piles in a global strengthening scheme, to add new members into a structure to increase redundancy, to increase the capacity of existing members or joints, and/or to reinstate the capacity of damaged members of joints.

Stressed clamps rely on bolt tension to induce hoop stress around the member or joint to resist axial and bending loads in the structure. In many cases, the clamp is made oversized in order to accommodate lack-of-fit tolerances and the annulus between the clamp and the structure is grout filled prior to bolt tensioning—the grout acts a load transfer medium. Unstressed grouted clamps can be applied to intact or damaged brace members to increase the axial and bending capacity of the member.

Reliable structural clamp design is a specialized activity that requires careful control of bolt strength, bolt length, fatigue design, and detailing to avoid loss of prestress over the life of the repair. Tight fabrication tolerances are required to avoid fit-up problems during fabrication and suitable installation procedures are essential to effective long-term performance.

13.3.5.5 Underwater Welding

Welding is often regarded as the best strengthening or repair technique and would be used even more often if it were not for certain operational difficulties in its execution. There are several underwater welding techniques that can be considered, such as

— dry welding at or below sea surface at one atmosphere using a cofferdam or pressure-resisting chamber,

— hyperbaric welding using habitats, or

— underwater wet welding.

Repairs by both cofferdam and hyperbaric habitat welding techniques have proven track records and can produce high quality welded connections. The disadvantages to both are the high cost and extended schedules associated with cofferdam or habitat design, fabrication and deployment, and the associated hazardous diving operations.

Wet welding is underwater welding, when the arc is operated in direct contact with the water. The principal advantage over conventional welding is the ability to weld below the water surface without the need for a welding habitat or chamber. Provided the weld is suitably designed for low stress, good fit-up can be assured, and the parent material is tested to ensure compatibility, wet welding can be a viable solution.

13.3.5.6 Bolting

Bolts are an integral part of steel repair clamps and are found in riser and other pipe supports throughout a platform. They are used for topsides repair where a bolted joint can be made in a hazardous area without the need to shut down the platform operations.

Maintaining the long-term bolt tension is critical to a safe bolt design. Proof of the applied tension at the time of bolt installation is the normal standard for acceptance and should be indicated by the pressure applied through hydraulic equipment. Good engineering practice demands that the loss of bolt tension through load transfer and elastic relaxation be calculated. Additional long-term bolt tension losses can occur by creep in stressed grouted and elastomer-lined clamps.

There are physical limits placed on bolt sizing, spacing, and group number when tensioning devices are used. Also, corrosion of bolting materials has been a problem and particular attention should be given to material selection of bolts on any part of an offshore installation.

13.3.5.7 Member Removal

Structural member removal may be a staged development in a larger repair scheme or may constitute a repair in its own right. In either event the structural framework will need to be checked to ensure adequacy under the proposed loading and revised framing configuration.

13.3.5.8 Member Flooding

The intentional flooding of structural members that are subjected to a combination of structural and hydrostatic loading can be used as a method for increasing the load carrying capacity of the member. The impact of the increased gravity loads and dynamic mass as well as possible decommissioning implications should be considered before flooding members.

13.3.5.9 Adhesives and Epoxy Grouts

There are three main structural uses of resins offshore: as adhesives, as grout, and as the matrix in composite materials.

13.3.5.10 Cold Forming

Two broad categories of cold forming techniques are available: mechanical connectors and swaging.

A swaged connection between two concentric tubular members is formed when the inner one is expanded (by internal pressure) and is plastically deformed into grooves machined in the other member. The technique has been used to successfully make pile-sleeve connections offshore.

The advantages of swaged or mechanical connectors, which can potentially be exploited in SMR applications, are

— the connection can be made quickly,

— full strength is obtained immediately on installation,

— their suitability for permanent or temporary SMR (some connectors are reusable), and

— can be installed by ROV.

13.3.6 Global Strengthening or Repair

13.3.6.1 General

The design of a global strengthening or repair scheme should ensure that load is diverted away from the damaged or under-strength component. To achieve this, the strengthening or repair scheme shall be sufficiently stiff to attract a suitable portion of the load that would otherwise have been applied to the defective part of the structure.

13.3.6.2 Leg-pile Annulus Grouting

Grouting of the annulus between the jacket legs and piles is a reliable and cost-effective method of increasing the global capacity of the structure. The grout causes the pile and jacket leg to act compositely. The effect can be especially pronounced on jackets that have skirt piles, as the increased leg stiffness will tend to take load from the skirt piles and move it to the jacket main piles.

The grouting of the annulus between the jacket legs and piles has the added benefit of locally strengthening the jacket joints for bracing loads. The grout, in effect, mobilizes the pile cross section and forces the jacket leg and pile to act in composite behavior against joint ovalization, thereby increasing joint capacity for both compression and tension loads.

Installation can be difficult if the area between the jacket leg and pile is not properly sealed. Additionally, grout nipples must be properly sealed to prevent leakage.

Three issues that should be considered before grouting main piles are: the impact on platform decommissioning, impact of increased weight, and the increase in dynamic mass.

13.3.6.3 External Bracing

Small platforms, particularly cantilevered wellhead caissons, may be globally strengthened by the addition of external bracing to additional piles. External braces may be attached to the structure using either welded or clamped connections. This method can be extended for larger structures using additional external braces and piles or sometimes by the installation of a new adjacent structure with its own piled foundation to brace the existing structure.

14 Platform Decommissioning

14.1 General

Decommissioning is a process followed by an owner/operator of an offshore oil and/or gas facility to plan, gain approval for, and implement the removal, disposal, or reuse of the platform structure, equipment, and associated pipelines and wells.

14.2 Decommissioning Process

14.2.1 General

The decommissioning process involves closing down operations at the end of field life including permanently abandoning wells, properly disposing of hydrocarbons and chemicals, making the platform safe, and removing some or all of the facilities and reusing or disposing of them as appropriate. The stages of the decommissioning process are described in 14.2.2 through 14.2.10, and the link to the SIM process is emphasized. Additional background to each stage in the process and further discussion is provided in A.14.

14.2.2 Predecommissioning Data Gathering

Predecommissioning data gathering should be conducted to gain knowledge of the platform and associated facilities, wells, pipelines, risers, and subsea equipment where present. The SIM strategy should integrate with the decommissioning planning process to align late life structural inspections to collect the condition data, as recommended in 6.6.5.

14.2.3 Planning and Engineering

Data collected from the predecommissioning activities is used to develop the decommissioning plan. Sufficient engineering should be conducted to allow selection of the preferred execution plan to verify that environmental and life safety risk considerations are adequately addressed.

14.2.4 Permitting and Regulations

Decommissioning a platform, well or pipeline is a regulatory requirement in U.S. Outer Continental Shelf (OCS) waters and must be in compliance with the relevant *Code of Federal Regulations* (*CFR*). The execution plan should be permitted and approved accordingly. Outside U.S. OCS waters, applicable national, state, and/or regional environmental, health, and safety standards and codes of practice must be adhered to.

14.2.5 Well Decommissioning

Well decommissioning involves the permanent plugging and abandonment of the wellbores and eventual removal of the conductor. In many cases it can be advantageous to plug and abandon wells as they become nonproductive or uneconomic to reduce the potential environmental, life safety, or economic consequence of platform failure.

14.2.6 Facilities Decommissioning

Facilities decommissioning involves the flushing, cleaning, and removal of process equipment and facilities as well as the removal and environmentally sound disposal of waste streams.

14.2.7 Pipeline Decommissioning

The pipeline decommissioning plan depends on geographic location and/or national or regional regulations. Pipelines may be decommissioned in situ or completely removed. For in situ decommissioning, the pipeline may be disconnected from the platform and left in place following cleaning, plugging, and burying at both ends.

14.2.8 Conductor Removal

The conductors from the well tree to below the mudline will usually be severed at a suitable distance below the mudline and the upper portion removed prior to the substructure (jacket) decommissioning. Planning for conductor removal should be integrated with the overall SIM strategy as complete or partial removal of conductors can be effective in reducing the likelihood of platform failure, as defined in 13.3.

14.2.9 Structure Decommissioning

The deck and topsides structure is usually removed in one or more lifts and transported to shore for disposal or reuse. Before decommissioning of the substructure (jacket), the foundation piles should be severed at a suitable distance below the mudline. The jacket is typically removed in one or more lifting operations and recovered to shore for disposal or reuse.

Subject to national and regional regulations, the structure may be toppled in place to form an artificial reef or transported and placed at a designated reef site. Consideration may be given to leaving the lower part of the jacket in place if it is to be part of a reef.

Structural decommissioning activities should be integrated with the late life SIM strategy for the platform to ensure the structural integrity of the platform is consistent with safe access for decommissioning operations.

14.2.10 Site Clearance

After the platform is removed, the area should be cleared of debris in accordance with the execution plan and with due account of national and regional regulatory requirements.

Annex A
(informative)

Commentary on Structural Integrity Management

NOTE The sections in this annex provide additional information and guidance on the main text of this recommended practice. The title of each subsection identifies the subsection of this recommended practice.

A.4 Commentary on Structural Integrity Management Process

A.4.1 General

Background

The evolution of the design process has resulted in a varied assortment of structures since platforms were first installed offshore in the late 1940s. Platforms built prior to the late 1970s exhibit a wide diversity in design criteria and fabrication techniques. Much of the assessment effort of the offshore industry has been focused on the historical response of these structures to the environment and their structural adequacy as they have aged. Platforms installed since the late 1970s provide a much more uniform design basis and have incorporated many of the lessons learned during the design, installation, and operation of earlier generation platforms.

The focus for design and operation of offshore platforms is preservation of life safety, environmental protection, and economics. As the offshore industry has matured, the implicit levels of risk associated with each of the areas have changed. In addition, as structures age, the original safety margins may be altered due to damage, deterioration, or changes in use from the original design.

The SIM process, when properly followed, provides a means for an operator to predict how a structure performs when damaged and/or overloaded by application of appropriate techniques including analysis, testing, monitoring, etc. Once this structural behavior is known and understood, an inspection program tailored to the entire life cycle can be designed and implemented. All aspects of SIM require competent persons involved for a successful program that is a key means for fitness-for-purpose.

Further to maintaining fitness-for-purpose, SIM provides critical insight into how structural integrity should impact decision-making regarding adding personnel, equipment, wells, and/or risers. SIM also provides critical insight into when consideration should be given to reducing personnel, permanently or temporarily abandoning wells, and removing equipment, risers, and other appurtenances in order to reduce risk and/or the consequence associated with damaged platforms and wells.

Application of SIM Outside of the United States

The assessment process is generic and applicable for existing platforms in all offshore areas in terms of the overall approach and the use of a stepwise procedure for demonstrating fitness-for-purpose. The exception is the use of reduced criteria, which was developed specifically for the U.S. areas indicated in Section 9. The use of reduced criteria for assessment is not applicable in other offshore areas, unless special studies indicate otherwise. These studies should be in depth and consider platform design, fabrication, installation, and operation specific for the region as well as the local environmental conditions. The studies should be similar to those that support the application of the reduced criteria for U.S. areas, as described in Reference [18].

Change-in-use Platforms

Examples of platform change-in-use include the addition of a significant pipeline crossing to an existing platform, the use of an existing platform as a tie-back for a deepwater facility, and the conversion of an existing platform into a receiving terminal for LNG or other nonexploration and production activity. In these cases, the use of the offshore structure has changed since the platform may now have a different function, expected life, and consequence of failure. For example, fatigue may have to be reevaluated in detail since the structure now has a significantly longer-term use under perhaps different loading conditions compared to its original design. The use of the reduced metocean criteria for assessment, as provided in Section 9, is not applicable for demonstrating the fitness-for-purpose for platforms that are undergoing a change-in-use.

A.5 Commentary on Structural Integrity Management Process

A.5.2 Data

Evaluations and assessments are only as accurate as the engineering methodology and the data used therein. In other words, missing or incorrectly measured data may force conservative assumptions to be made during an engineering assessment, which may prevent upgrades and hence unjustly prevent potential development. A specific example is when a dent location is not correctly measured. In this case, the engineer has to assume that the dent is located where it will cause the highest strength reduction. In some instances, this error could prevent modification to the platform or erroneously trigger a more detailed assessment. The owner/operator may develop specifications that detail underwater measurement techniques, personnel qualifications, survey limits, anomaly criteria, etc.

The design and construction processes produce a vast amount of information regarding the design of an offshore platform and its predicted response to loading. From this information, the key inspection areas can be identified and the nature of their criticality highlighted.

The first stage in the assessment process is to collate the data required for the assessment; of particular importance is the design report (or most recent assessment report). This provides an important validation point for the assessment engineering. Any differences between the design and the assessment should be clearly identified and understood before more complex analyses are carried out.

It should be recognized that an assessment might not involve the evaluation of all available data once an initiator has been triggered. In many instances data may not be available or be significant, and it may be more expedient to proceed with an appropriately conservative premise that recognizes the uncertainties and assumptions. The quantity of data utilized in an assessment should be tailored to meet the specific circumstances of the assessment.

The following is a summary of data that should be included.

a) Characteristic data.

   1) General information:

   — original and current owner/operator;

   — original and current platform use and function;

   — location, water depth, and orientation;

   — platform type—caisson, tripod, 4/6/8-leg, etc.;

   — number of wells, risers, and production rate;

   — other site-specific information, manning level, etc.

   2) Original design:

   — design contractor and date of design;

   — design drawings and material specifications;

— design code (i.e. edition of API 2A-WSD used in the platform design);

— metocean criteria—wind, wave, current, seismic, ice, etc.;

— deck clearance elevation (underside of cellar deck steel);

— operational criteria—deck loading and equipment arrangement;

— foundation/soil data;

— number, size, and design penetration of piles and conductors;

— appurtenances—list and location as designed.

3) Construction:

— fabrication and installation contractors and date of installation;

— approved for construction drawings or as-built drawings;

— fabrication, welding, and construction specifications;

— material documents, such as construction specifications and/or mill certificates and material traceability;

— pile and conductor driving records;

— pile grouting records, (if applicable).

b) Condition data.

1) Platform history:

— metocean loading history—hurricanes, earthquakes, etc.;

— operational loading history—collisions and accidental loads;

— performance during past metocean events;

— survey and maintenance records;

— repairs—descriptions, analyses, drawings, and dates;

— modifications—descriptions, analyses, drawings, and dates;

2) Present condition:

— all decks—actual size, location, and elevation;

— all decks—existing loading and equipment arrangement;

— field measured deck clearance elevation (bottom of steel);

— production and storage inventory;

— appurtenances—current list, sizes, and locations;

— wells—number, size, and location of existing conductors;

— recent above-water survey results;

— recent underwater platform survey results.

If the original design data or as-built drawings are not available, assessment data may be obtained by field measurements of dimensions and sizes of structural members and appurtenances. The thickness of tubular members can be determined by ultrasonic procedures, both above and below water, for all members except piles. When the wall thickness of piles cannot be determined and the foundation is a critical element in the structural adequacy, it may not be possible to perform an assessment. In this case, it may be necessary to downgrade the use of the platform to a lower exposure category by reducing the risk or to demonstrate adequacy by prior exposure.

Soil Data

Many sampling techniques and laboratory testing procedures have been used over the years to develop soil strength parameters. With good engineering judgment, parameters developed with earlier techniques may be upgraded based on published correlations. For example, design undrained shear strength profiles developed for many platforms installed prior to the 1970s were based on unconfined compression tests on 57 mm (2.25 in.) diameter driven wireline samples. Generally, unconfined compression tests give lower strength values and greater scatter than unconsolidated undrained compression tests, which are now considered the standard (additional information is provided in API 2GEO).

Pile-driving data may be used to provide additional insight on the soil profiles at each pile location and to infer the elevations of pile end bearing strata.

Structural Integrity Monitoring Systems

Structural integrity of certain types of fixed offshore jackets can be inferred from measurements of its structural response characteristics. Such measurements should identify and quantify the natural frequencies and associated mode shapes of the fundamental normal modes of the structure (i.e. at least two orthogonal sway modes and one torsion mode).

The response characteristics can be monitored on a continuous basis or by repeat measurements at regular intervals. Changes in the response characteristics over time may indicate a degradation of structural integrity as such changes arise from the following:

— severance (or severe cracking in low redundancy jackets) of a jacket member;

— reduction in foundation stiffness (e.g. due to scour);

— changes in the mass or distribution of mass on the platform deck.

The response of a structure can be measured using sensors that respond to dynamic force or motions, most commonly accelerometers or strain gauges. With the suitable conditioning of analogue signals, the signals can be recorded and stored by a computer for data analysis and processing. Due consideration should be given to noise performance, synchronization, and calibration of the signals. The sample rate at which signals are converted to digital format must be such that all relevant frequencies are adequately captured. Good practice is required for avoidance of aliasing and interference pickup. Since wave action on the jacket is normally the dominant loading source, consideration should be given to recording wave height data in conjunction with the response data. This provides a further benefit in that platform subsidence can also be detected, along with deck displacement per-unit wave.

The response characteristics should be compared over time to determine if any of the natural frequencies have decreased or if any of the mode shapes have changed. It should be recognized that changes in platform mass and the distribution of mass on the deck are a normal part of platform operations. These (and other effects) provide a background variation in response characteristics. If any of the response characteristics have changed significantly, this may be attributed to some form of structural failure.

The following stages outline the recommended steps to deploy a structural monitoring system.

a) An inspection plan in accordance with this recommended practice should be in place.

b) Preliminary evaluation of jacket member severance detection using an appropriate structural analysis model of the platform. The objective of this stage is to confirm that the changes to natural frequency and mode shape following a member severance can, in fact, be measured.

c) Risk-based analysis of jacket integrity following the failure of each relevant jacket member.

d) Baseline measurements of as-built platform response. These are conducted on the platform to determine the baseline intact structural response.

e) Configuration of automated, continuous monitoring system, with regular review of response data or commencement of regular and event-driven measurement campaigns with subsequent data analysis and review.

Further information on structural monitoring may be found in Reference [23] and Reference [24].

A.5.3 Evaluation

A.5.3.1 General

Assessment

Assessment forms one part of the life cycle SIM process for existing platforms. The SIM process is continuous and is used as a means of determining whether an existing platform is capable of fulfilling its required function, based upon a fitness-for-purpose philosophy. The essence of the approach is based upon a realistic appraisal of the structure in conjunction with an effective topside and underwater survey and planned maintenance program. Assessment involves gathering all the known facts about a structure's configuration, condition, and loading; analyzing the structure using realistic techniques, comparing analysis results with the evidence from survey of the structure; and correlating and refining both analysis and survey. This information is then used to make an engineering judgment on the structure's integrity and fitness-for-purpose. As the definition implies, assessment is concerned with real situations as opposed to the process of new design, which is concerned with future facilities yet to be built.

Assessment Criteria

In engineering practice, it is widely recognized that although an existing platform does not meet present-day design standards, the structure may still be adequate or serviceable. Examples of this not only include fixed offshore platforms but also buildings, bridges, dams, and onshore processing plants. The application of reduced criteria for assessing existing platforms is also recognized in risk management literature, justified on both cost-benefit and societal grounds.

The metocean criteria in Section 9 results in platforms that may not withstand the same level of metocean loading as newly designed platforms. The result is that the risk of the facility to damage or failure from metocean events is increased. A platform owner/operator should take into account the higher risk of platform failure in extreme hurricanes, in comparison to new design, when using the metocean criteria in Section 9.

A.5.3.3 Risk Categorization

Risk Ranking

In developing an inspection strategy for a fleet of platforms, one approach is to categorize the platforms according to the risk posed to the owner/operator by each platform. The likelihood of failure is a function of specific structural characteristics of the platform, while consequence of failure is a function of the impact to life safety, the environment, and/or business interruption.

In a qualitative approach, the determination of the likelihood of failure requires information on a platform's structural configuration in order to determine its "baseline" susceptibility to failure (e.g. tripod versus four legs versus eight legs), as well as its present condition, based on inspection that may influence the baseline likelihood (e.g. damaged members). As an example, a 1960s vintage six-leg, K-braced platform has a higher likelihood of failure than a 1980s vintage eight-leg, X-braced platform. The newer platform is designed to better standards, such as incorporating joint cans, and has an inherently more redundant structural configuration since it has eight legs and is X-braced. However, if the SIM program reveals that a newer platform has a track record of damage such as corrosion or fatigue cracking, then the platform should be recategorized as a high likelihood of failure platform.

The consequence of failure corresponds to the safety, environmental, and financial issues that would arise should the platform fail at a future date. These are the standard consequence issues addressed in risk assessments for any type of facility, either onshore or offshore. As an example, a manned drilling and production platform would have a higher consequence of failure than an unmanned wellhead platform.

A.5.3.4 Exposure Categories

A.5.3.4.2 Life Safety

A.5.3.4.2.2 S-1 Manned-nonevacuated

The manned-nonevacuated condition is not normally applicable to the U.S. Gulf of Mexico. Present industry practice is to evacuate platforms prior to the arrival of hurricanes.

A.5.3.4.2.3 S-2 Manned-evacuated

In determining the length of time required for evacuation, consideration should be given to the distances involved; the number of personnel to be evacuated; the capacity and operating limitations of the evacuating equipment; the type and size of docking/landings, refueling, egress facilities on the platform; and the environmental conditions anticipated to occur throughout the evacuation effort.

A.5.3.4.2.4 S-3 Unmanned

An occasionally manned platform (i.e. manned for only short duration such as maintenance, construction, workover operations, drilling, and decommissioning) may be classified as unmanned. However, manning for short duration should be scheduled to minimize the exposure of personnel to any design environmental event.

A.5.3.4.3 Consequence of Platform Failure

A.5.3.4.3.1 General

The degree to which negative consequences could result from platform collapse is a judgment that should be based on the importance of the structure to the owner's overall operation and to the level of economic losses that could be sustained as a result of the collapse. In addition to loss of the platform and associated equipment and damage to connecting pipelines, the loss of reserves should be considered if the site is subsequently abandoned. Removal costs include the salvage of the collapsed structure, reentering and plugging damaged wells, and cleanup of the seafloor at the site. If the site is not to be abandoned, restoration costs should be considered, such as replacing the structure and equipment and reentering the wells. Other costs include repair, rerouting, or reconnecting pipelines to the new structure. In addition, the cost of mitigating pollution and/or environmental damage should be considered in those cases where the probability of release of hydrocarbons or sour gas is high.

When considering the cost of mitigating of pollution and environmental damage, particular attention should be given to the hydrocarbons stored in the topside process inventory, possible leakage of damaged wells or pipelines, and the proximity of the platform to the shoreline or to environmentally sensitive areas such as coral reefs, estuaries, and wildlife refuges. The potential amount of liquid hydrocarbons or sour gas released from these sources should be considerably less than the available inventory from each source. The factors affecting the release from each source are further discussed as follows.

Topsides Inventory

At the time of a platform collapse, liquid hydrocarbon in the vessels and piping is not likely to be suddenly released. Due to the continuing integrity of most of the vessels, piping, and valves, it is most likely that very little of the inventory will be released. Thus, it is judged that significant liquid hydrocarbon release is a concern only in those cases where the topsides inventory includes large capacity containment vessels.

Wells

The liquid hydrocarbon or sour gas release from wells depends on several variables. The primary variable is the reliability of the SSSVs, which are fail-safe closed or otherwise activated when an abnormal flow situation is sensed. Where regulations require the use and maintenance of SSSVs, it is judged that uncontrolled flow from wells may not be a concern for the platform assessment. Where SSSVs are not used and the wells can freely flow (i.e. are not pumped), the flow from wells is a significant concern. The liquid hydrocarbon or sour gas above the SSSV could be lost over time in a manner similar to a ruptured pipeline; however, the quantity will be small and may not have significant impact.

Pipelines

The potential for liquid hydrocarbon or sour gas release from pipelines or risers is a major concern because of the many possible causes of rupture, (e.g. platform collapse, soil bottom movement, intolerable unsupported span lengths, and anchor snag). Only platform collapse is addressed in this recommended practice. Platform collapse is likely to rupture the pipelines or risers near or within the structure. For the design environmental event where the lines are not flowing, the maximum liquid hydrocarbon or sour gas release will likely be substantially less than the inventory of the line. The amount of product released will depend on several variables such as the line size, the residual pressure in the line, the gas content of the liquid hydrocarbon, the undulations of the pipeline along its route, and other secondary parameters.

Of significant concern are major oil transport lines that are large in diameter, longer in length, and have a large inventory. In-field lines, which are much smaller and have much less inventory, may not be a concern.

A.5.3.4.3.2 C-1 High Consequence

This consequence of failure category includes drilling and/or production, storage, or other platforms without restrictions on type of facility. Large deepwater platforms as well as platforms that support major facilities or pipelines with high flow rates usually fall into this category. Also included in the L-1 classification are platforms located where it is not possible or practical to shut-in wells prior to the occurrence of the design event, such as in areas with high seismic activity.

A.5.3.4.3.3 C-2 Medium Consequence

This consequence of failure category includes conventional midsized drilling and/or production, quarters, or other platforms. This category is typical of most platforms used in the U.S. Gulf of Mexico and may support full production facilities for handling medium flow rates. Storage is limited to process inventory and “surge” tanks for pipeline transfer. Platforms in this category have a very low potential for well flow in the event of a failure since subsurface safety valves are required and the wells are to be shut in prior to the design event.

A.5.3.4.3.4 C-3 Low Consequence

This consequence of failure category generally includes only caissons and small well protectors. Similar to Category C-2, platforms in this category have a very low potential for well flow in the event of a failure. Also, due to the small size and limited facilities, the damage resulting from platform failure and the resulting economic losses would be very low. New U.S. Gulf of Mexico platforms qualifying for this category are limited to shallow water consistent with the industry's demonstrated satisfactory experience. Also, new platforms are limited to no more than five well completions and no more than two pieces of production equipment. To qualify for this category, pressure vessels are considered to be individual pieces of equipment if used continuously for production. However, a unit consisting of a test separator, sump, and flare scrubber is to be considered as only one piece of equipment.

A.5.3.5 Likelihood of Failure

SIM is a process for demonstrating the fitness-for-purpose of an offshore structure from installation through commissioning. The structural configuration is an important factor in the ability of a platform to sustain component damage without loss of system structural capacity, as described in Reference [19]. Tolerance to damage is an important factor in developing a SIM strategy and the associated inspection program.

This type of framing configuration typically provides robustness to component damage and overload, as indicated in Figure A.1, through many alternate paths to transmit loading to the foundation. In the absence of accidental loading, this configuration can often allow the operator more flexibility in developing and implementing an inspection program due to the significant tolerability to component damage and/or overload.

Conversely, Figure A.2 shows a schematic diagram of the load versus deformation of a diagonal braced platform. This framing pattern does not provide alternate load paths and is less ductile when overloaded. As such, this platform framing does not provide as much flexibility in developing and implementing an inspection program.

Figure A.1 and Figure A.2 show the schematic representation of two jacket-type platforms of different configuration.

A.5.4 Strategy

Damage Tolerance

Each structure has an inherent reserve and/or residual strength, which is directly related to the ability of the structure to provide alternate load paths after failure of a member. This redundancy in the structural system (or robustness) is primarily associated with the arrangement of the braces within the system. A reduction of component capacity does not necessarily imply that the system strength is compromised. This will depend on whether or not the component is participating in the failure sequence that produces the system collapse mechanism or whether the member's integrity is required to realize that particular mechanism.

For a robust structure, damage may result in little immediate risk to the facility. For other less robust structures, even a small damage event may significantly degrade the platform's global structural capacity resulting in a high-risk situation, justifying immediate response such as platform demanning, platform shutdown, or emergency repair. Robustness is also useful for inspection planning. Robust structures may not need as much inspection as other structures since they are more damage tolerant. Information on platform robustness can also be used to identify key local regions of a platform system that are crucial in terms of critical and secondary load paths. These regions should be the focus of inspections.

During the life cycle of the structure, the operational costs and risk levels can be significantly influenced by the framing configuration adopted at the outset. For example, a minimally braced structure may not have alternative load paths to redistribute forces if a component is damaged or if applied loads are higher than initially anticipated. As a consequence, failure of a single component may be critical to overall integrity—relatively intense inspection activity may be required to monitor the structural condition of key load paths and there may be little scope to modify the installation for enhanced facilities at a later stage without adversely affecting safety levels. Conversely, a robust structure with alternative load paths may be more tolerant of damage or increased loads, offering greater operational flexibility and a much-reduced need for inspection activity to provide the same assurance of safety. Framing arrangements therefore impact directly on the safety and economic considerations through the life cycle of jacket structures.

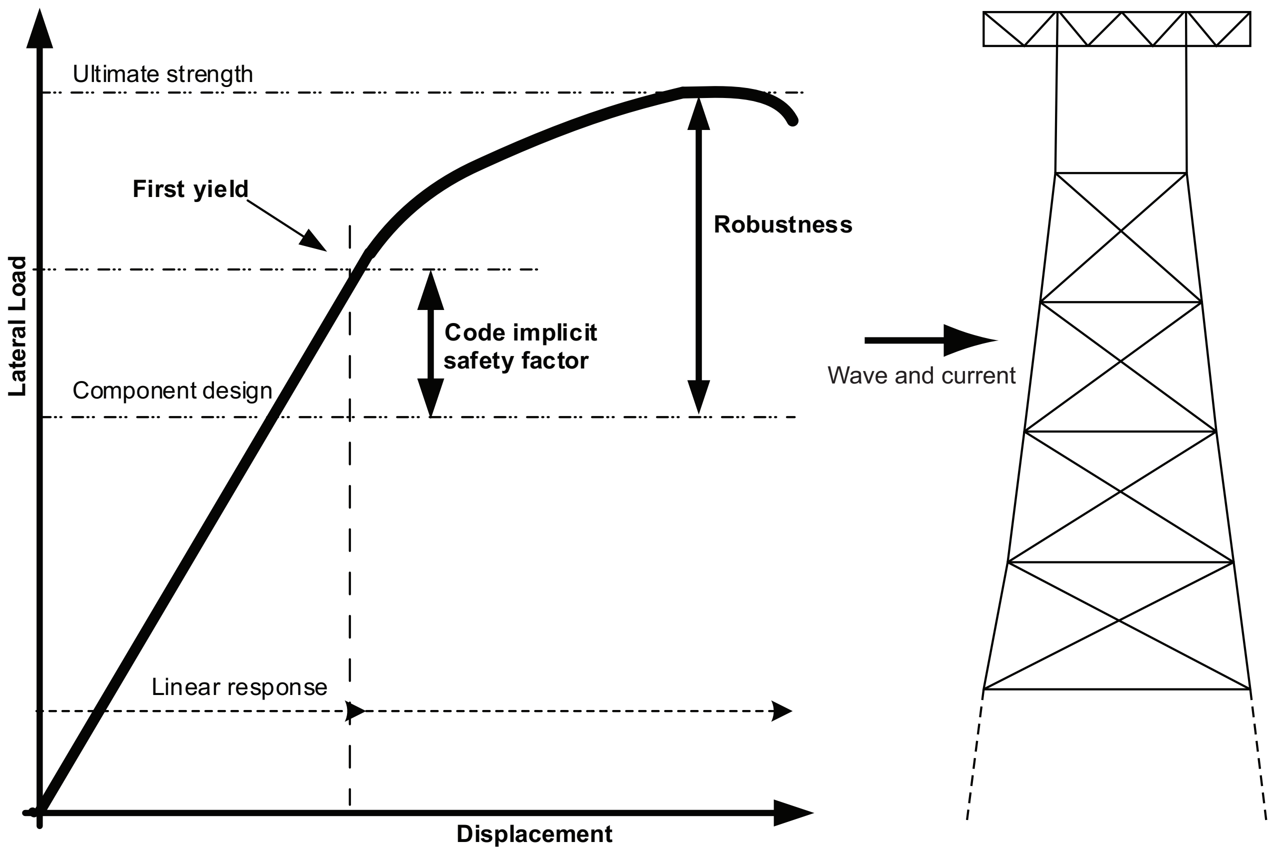

Figure A.1—Schematic Load vs Deformation Diagram of an X-braced Platform

Platform Appurtenances

The SIM process is applicable to all components of the platform needed to operate the platform. These appurtenances include such items as the corrosion protection system, firewater caissons, export risers, and conductors. Evidence from surveys or analytical studies on these components may suggest a different SIM strategy for the platform. For example, in-service performance of a firewater caisson may reveal a fatigue weakness in the component that requires more frequent monitoring and necessitate a change in the SIM strategy for the platform or fleet of platforms.

Platform Surveys

An effective SIM strategy will make use of both the above-water and below-water survey findings. Damage to above-water components may be an indicator of structural damage below water. Also, the above-water survey can be used to determine the effectiveness of the below-water corrosion protection system.

Fatigue Issues

With the growth of platform operating experience with time, it has become clear that the number of occurrences of fatigue cracks discovered in offshore platforms is not as high as would be expected based upon analysis results. Recent projects looking at both North Sea and U.S. Gulf of Mexico experience have documented the results of over 3200 underwater inspections. Results show that fatigue damage that exists is isolated to known susceptible details. The reason for the lack of correlation between the predicted and observed fatigue performance of offshore structures

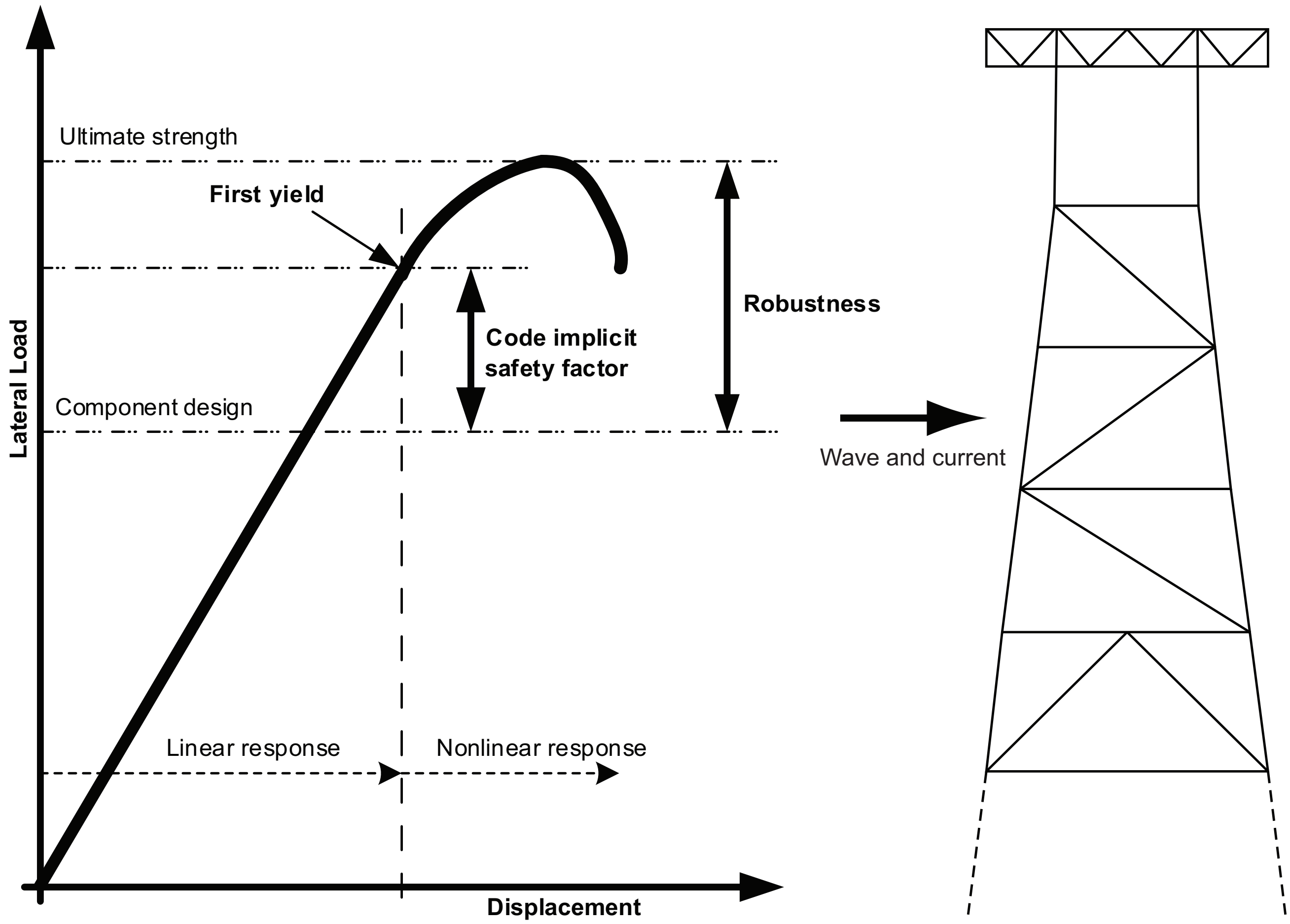

Figure A.2—Schematic Load vs Deformation Diagram of a Diagonally Braced Platform

is the degree of conservatism in the conventional fatigue design procedure. It should be noted that the conservatism has served industry well, allowing many platforms to continue to operate safely well past their initial design lives.

Conventional fatigue design methods under-predict the life of structures in comparison to the experience gained from inspections. Historically, this has meant that structures are more tolerant to damage, life extension, and changes of use or reuse than might have been expected at the outset.

Fatigue damage results primarily from the oscillatory metocean loads due to waves that impact the platform and secondarily from crane and rotating equipment loads. Stresses resulting from wave loading and corresponding structural dynamic response are typically random. The metal fatigue strength in the structural members also shows random characteristics. Therefore, fatigue prediction in offshore structures is a very complex task involving many factors:

— uncertainties associated with the statistical scatter relevant to the metocean data (sea state description);

— uncertainties associated with the wave load prediction (wave theory, Morison's formulae);

— uncertainties associated with the nominal member load stress response prediction in the structural elements (finite element model description);

— uncertainties associated with the estimation of the hot spot stress concentration factors in the welded connections;

— uncertainties associated with the fabrication and assembly operations;

— uncertainties associated with the fatigue damage and crack growth models (Miner-Palmgren rule, Paris' law, S-N fatigue curves).

Therefore, during the platform engineering design stage, to account for all the uncertainties, some conservative choices are customarily made. The “nominal” fatigue design life is computed on the basis of the “design” S-N fatigue curves that predict on the safe side the characteristic fatigue strength that is evaluated as the “mean” strength based on laboratory tests minus 2 standard deviations.

The use of theoretical fatigue life in establishing the extent and frequency of detailed joint inspection should consider the actual in-service performance of the surveyed member/joint connections, the effects of joint flexibility on fatigue life, and the relevant influence of each connection on the overall platform safety. Historical inspection data indicates that joint fatigue is not a common occurrence in complex multi-planar connections of older platforms. However, fatigue may be more common in fixed platforms having stiffer joint connections.

A.6 Commentary on Surveys

A.6.1 Inspection Strategy

An inspection strategy considers the condition of the structure through evaluation of existing inspection data and trend analyses, together with strength and fatigue analysis results. Additional information on existing inspection trends is provided in Reference [26]. The strategy should be sufficiently broad in scope to capture unpredictable anomalies, such as damage from dropped objects or other accidental loading. The inspection strategy should consider the range of inspection techniques, the methods of deployment, and the purpose of each inspection. Additionally the inspection strategy should consider factors such as the following:

a) scheduling flexibility;

b) intervals between routine inspections;

c) promptness of post-event and post-incident inspections;

d) cost and availability of inspection equipment/services;

e) support vessels and specialized equipment;

f) seasonal weather windows;

g) regional differences;

NOTE Regional differences in loading result from differences in the level and frequency of extreme and fatigue wave environment, seismicity levels, wind speeds, and/or the presence of ice. These differences may lead to a different inspection strategy depending on the actual or perceived influence of these factors.

h) consideration of reliability of inspection technique(s).

NOTE The reliability of the inspection technique (e.g. probability of detection, accuracy of sizing) should be considered with due regard to the type of data needed or the sensitivity of the structure to a damaged component. Moreover, the sensitivity of the technique compared to the application should be considered (i.e. there is no need to use a highly sensitive inspection technique when only through-wall defects are required to be detected).

Since observations and measurements from the in-service inspection are often the only data available to make an engineering assessment, the reliability of such data is important. To provide suitable information for subsequent engineering evaluation and possible assessment engineering, it is recommended that quality control and quality assurance procedures are in-place during the inspection.

Improvements in quality through familiarity and efficiencies may be achieved when the periodic inspection strategy is developed for a group of structures together, if such a grouping is appropriate. When the group of structures has similar characteristics, good inspection history, good maintenance history, and similar operational usage, reduced scopes of work can generally be justified (compared to those required if the structures were considered individually). The greatest benefit is realized when the inspection intervals and scopes of work are periodically reviewed and adjusted based on the latest inspection findings for the group of structures, as well as general industry learning.

A.6.2 Personnel Qualifications

Personnel responsible for conducting the evaluation and developing the inspection strategy should have the following qualifications.

a) Familiarity with relevant information about the specific structure(s) under consideration, including the following:

  — metocean conditions,

  — design situations and criteria,

  — structural drawings,

  — structural analyses,

  — fabrication and installation history,

  — past inspection results (scope and findings),

  — operational history.

b) Knowledgeable about underwater corrosion processes and prevention, including:

  — general design principles and functional requirements for the common protection systems, and

  — typical problems encountered in the field.

c) Competent in offshore structural engineering with an understanding of:

  — component failure modes,

  — system failure modes,

  — likelihood of failure,

  — consequences of failure, and

  — system strength sensitivity to component damage of various structural configurations.

d) Experienced in offshore inspection planning with the judgment needed to:

  — establish prudent and practical work scopes,

  — identify components that can serve as good indicators of overall structure performance,

  — select representative components/joints for inspection.

e) Knowledgeable about inspection tools, techniques and their deployment systems including their:

— capabilities,

— limitations,

— cost,

— expertise required,

— local availability, and

— interpretation.

f) Familiar with general inspection findings in the offshore industry (especially for the particular geographic region) and associated structural and corrosion performance

A.6.4 Baseline Underwater Inspection

In order to facilitate monitoring of structural condition trends, the baseline inspection may be used to establish the following for subsequent inspections:

— monitoring locations of installation damage (if any),

— cathodic potential measurement locations,

— scour measurement locations,

— marine growth measurement locations.

A.6.5 Level II, III, and IV Surveys—Routine Underwater Inspection

The objective of the routine inspection is to detect degradation that may significantly reduce the reserve capacity of the structure in the interval between inspections. Industry experience shows that general visual survey techniques are adequate for conventional multi-leg fixed steel platforms that are inspected within the risk-based intervals. The general visual approach should confirm that the platform has not suffered any gross structural damage, for example, heavily deformed or missing structural elements. The general visual strategy should include surveys to confirm that the CP system is operating effectively, the extent of any corrosion, the extent of marine growth, and in predisposed regions the extent of any scour or seafloor instability.

Structures that are not suitable for the general visual approach may include those determined to be susceptible to fatigue damage and/or are not sufficiently robust to safely tolerate minor damage. In this case, the inspection strategy needs to reliably detect the existence of such minor damage through close visual surveys concurrent with suitable NDE techniques. In some cases, FMD can provide an alternative to close-visual surveys, especially at known fatigue sensitive connections such as conductor guide framing and appurtenance connections. Reliance on more widespread use of FMD in lieu of close visual surveys, however, can be of questionable value for some structures, such as those having single diagonal bracing framing into the legs or structures with members intentionally flooded. In the former, fatigue cracks that occur often do so on the chord (leg) side of the connection. In-service experience shows these members usually do not flood the brace even after total severance of the brace and thus will test as dry by FMD.

The main mechanisms for degradation and deterioration in offshore jackets are corrosion and accidental damage. Industry experience indicates that for multi-planar joints in multi-leg jackets, in-service (actual) fatigue cracking is not well predicted by analytical techniques. Fatigue cracking has occurred in older jackets mainly due to plated horizontal conductor bays but may also occur in platforms of any vintage due to fabrication defects, installation damage, and at improperly designed appurtenance connections (caissons, sumps, J-tubes, etc.). As such, fatigue-based probabilistic methods can provide an additional means to determine the inspection frequency and the location of weld inspection requirements but can be very conservative in predicting cracks at end connections of primary members in newer structures.

Subsea corrosion is not generally a problem provided the CP system is adequately designed and is maintained. Special attention needs to be given to impressed current systems since these active systems rely on external power to provide protection. Splash zone corrosion is very common as paint or other protective coatings wear over time and/or are damaged or abraded.

A.6.6 Special Inspections

A.6.6.1 General

Special inspections should be considered to monitor repairs, remediation programs, known damage/defects, or known areas of vulnerability (under-design, scour, etc.). Special inspection may also be needed for platform reuse, platform modification, well additions, decommissioning, assessment, after an incident, or after an extreme loading event.

A special inspection may also be used to monitor known defects, damage, local corrosion, scour, or other conditions that could potentially affect the fitness-for-purpose of the platform structure, risers and J-tubes, conductors, or various appurtenances.

The key feature of special inspections is definition of the goals/objectives, which leads to selection of appropriate tools/techniques, work scope, and inspection intervals. Special inspections may be planned to coincide with the periodic inspection with the scope adjusted accordingly. If possible, the inspections should be developed based on evaluation of all available data.

A.6.6.3 Post-event Inspection

A.6.6.3.1 General

Post-event inspections are performed to look for damage that could significantly lower the capacity of the platform. These inspections are also performed to locate potential damage to risers, conductors, and other appurtenances and to confirm that the CP system is working adequately. Damage inspection is typically completed by a general visual inspection unless the structure has known prior damage or is a nonrobust platform (i.e. susceptible to significant capacity degradation from minor damage). If missing members are discovered, adjacent areas and appurtenances should be inspected for collateral damage. The extent of damage to connections should be quantified using appropriate close visual or NDT methods. Where damage has occurred to a specific component, all connections to the component and to successive components should be inspected. Damage can sometimes be indicated by isolated submerged areas of little or no marine growth indicating possible overload.

The post-event inspection strategy should:

— establish a threshold for triggering inspection;

— define a nominal or default inspection scope of work (subject to modification, based on initial evaluation, when an event occurs); and

— specify a method for measuring or estimating the magnitude and severity of a metocean event, based on consideration of the required accuracy and speed of provision of the information.

These items should be addressed before commencement of platform operations and should be based on an evaluation of all available data, as defined in 5.2.

While the timing of a post-event inspection may, subject to evaluation, be advanced or delayed to coincide with a routine inspection, a separate inspection program should be considered to provide data to confirm adequate structural integrity or to allow repair/strengthening work to be designed and planned to fit available seasonal weather.

A.6.6.3.2 Potential Overload

Typical methods for estimating the magnitude or severity of a potential overload event include the following.

a) General—from observations by personnel on the platform or on nearby platforms and from results of hindcast studies.

b) Waves—from high water marks, wave gauges, ship observations, observable topsides or splash zone damage, and hindcast studies.

c) Wind—from anemometers and observable topsides damage.

d) Earthquake—from accelerometers, reported Richter magnitude, and distance from epicenter to platform.

e) Current—current meters.

A.6.6.3.3 Accidental Loading

Post-incident inspection should focus on areas local to the actual or possible impact location(s) and should include inspection of members in the path of a dropped object or areas above and below water in the area of an impact. In the case of boat impact, hidden damage can also occur on the underside of members when a boat is lifted by a wave or swells.

A.6.7 Survey Work Scope

Structure-specific event and incident thresholds and survey scope of work should be established in advance (preferably during the design) to avoid unnecessary inspection and to enable inspection to be undertaken quickly, if required. The inspection strategy should allow the flexibility to combine post-event and periodic inspection scopes of work and adjust the interval for the next routine inspection if appropriate. Important features of a post-incident inspection strategy include the following.

a) Prompt and reliable reporting of incidents as required by company policy and regulations. Owner/operator should consider establishing protocols and notification procedures.

b) Early involvement of qualified personnel to judge the potential significance of the incident and develop an appropriate inspection scope of work.

c) Close consultation with qualified personnel during offshore execution, review of findings, and assessment of need for any repairs, mitigation, future monitoring, etc.

For manned platforms, significant incidents will usually be noted and reported; however, for unmanned platforms, incidents will sometimes not be immediately noted or reported. Thus, different strategies should be considered, such as installation of sensors with automatic reporting or more performing more regular periodic inspections.

Inspection is more efficient and more likely to produce the data required for analysis if the SIM personnel are familiar with the structure and able to integrate the post-incident work scope, schedule, and/or findings with other inspection activities for the structure or group of similar structures.

A.6.8 Inspection Specification

Inspection activities may be performed by many different methods. The following are some of the more common methods for the activities used in underwater surveys.

Visual Survey

The general visual survey consists of a swim-around by diver or ROV over the entire underwater structure and its appurtenances. It does not involve cleaning of structural elements. The visual survey should:

a) confirm structural geometry, compared to drawings;

b) detect obvious signs of mechanical damage such as missing or separated members, dents, gouges, bows, out-of-roundness, and major joint/weld defects (including large cracks, separation, and distortion) that are visible without marine growth removal;

c) detect obvious signs of corrosion;

d) detect loose or missing items and/or other obvious signs of deterioration on the platform appurtenances;

e) search for debris that is either hazardous to personnel or potentially detrimental to platform structural integrity;

f) locate, count, and assess the type and grade of anode;

g) inspect caissons/sumps for any damage, movement, or blockage; supports and clamps are inspected for damage or deterioration;

h) check the risers, J-tubes, and clamps for any damage, coating loss, signs of corrosion, and leakage; and

i) if visibility permits, check the mudline for scour.

The general visual survey should also include a survey of all splash zone members including the top of jacket framing, barge bumpers, and boat landings. These items should also be inspected below the waterline for damage and proper attachment to the jacket.

The extent of the survey coverage should include all faces, rows, and elevations. All legs, nodes, and members should be inspected when divers perform this survey. The survey extent may be reduced to only legs, nodes, and members external to the structure if the survey is performed by an ROV unless appropriate safety and contractual provisions are made for ROV penetration into the jacket.

During the survey, close attention should be given to confirming or providing information to update available platform drawings and condition evaluations. Indications of missing marine growth or coating scuffing may be evidence of impact damage. Such indications should be closely investigated for both primary and collateral damage. Close attention should also be given to platform nodes to identify large cracks or visible distortion.

Damage Survey

If damage is found during the visual survey, a follow-up survey should be performed to obtain sufficient data for the damage to be adequately evaluated. The survey should clearly identify the location and should include dimensional measurements to measure such quantities as dent size, member out-of-straightness, crack length, and corrosion pit size. The survey should extend to check for collateral damage, for example, a heavily dent-bowed member, bulging or buckled, may have cracks at the member ends.

If a dropped object is suspected as the cause of the damage, the survey should extend down to the seafloor to confirm the object caused no additional damage.

Debris Surveys

A debris survey consists of an underwater visual search of the platform to locate debris that is either hazardous to personnel or potentially detrimental to platform structural integrity. Small debris items should be removed from contact with the platform if it is hazardous to personnel, metallic, or obstructs inspection activities. Large items that cannot be moved should be recorded. When large or heavy items of debris are discovered, the structure above should be checked for mechanical damage. The structure should be checked for fretting or abrasion damage where debris is found in contact with the platform.

Significant debris in contact with the structure has the potential to increase the load on the CP system and should be cleared. Also, debris recording may be useful for future decommissioning planning.

Marine Growth Surveys

The marine growth survey should be performed to measure and record the thickness of marine growth on the structure. The marine growth survey should consist of the measurement of the compressed marine growth thickness, or approved alternative, at preselected locations. Compressed marine growth thickness can be determined by wrapping a broad tape [7.6 cm to 10.2 cm wide (3 in. to 4 in. wide)] around member growth and pulling it tight to record the measurement. When the growth is soft or a combination of hard and soft, the marine growth thickness to be measured is the compressed growth thickness and the length of weed or the height of clumps of sponges.

Care should be taken to avoid hang-ups with the measuring tape so that an accurate reading is achieved. When taking measurements in a specified area, a representative zone of marine growth thickness should be chosen.

Scour Surveys

Two types of scour can be identified: global scour and local scour. Global scour consists of shallow scoured basins of large extent around the structure. Local scour is usually seen as steep-sided scour pits around structural elements such as piles and legs. In the U.S. Gulf of Mexico, scour is not generally found due to the cohesive nature of the soils. It may however be a concern if the platform is located on loose sandy soils or where seabed movements are possible during severe storm events.

The global scour survey should consist of taking measurements of the seafloor relative to a fixed reference point on the platform (bottom of jacket, skirt pile, pile cap, or the lowest exposed horizontal bracing). The local scour survey may include taking measurements around platform legs/piles relative to the seabed surrounding the platform. Physical measurements (i.e. measuring ruler) are preferred to diver depth-gauge readings. If the depth gauge is used it should be calibrated to some platform datum with the calibration recorded. Diver pnuemo-gauge readings may be used in areas of low visibility with low or minimal tide variation.

Sometimes a scour survey may identify accumulations (e.g. drill cuttings sedimentations) or turbidity flow. This should also be reported as it can result in unintended loads or reactions on newly buried structural elements.

Corrosion Protection Surveys

CP and anode surveys should be conducted to determine that the structure is adequately protected against corrosion at the time of the survey and for some period based on future anode (impressed current or sacrificial) performance. The CP and anode survey should be complimented by an annual above-water (dropped cell) confirmation of the system.

Anode Surveys

The anode survey should consist of an underwater visual examination of a representative sampling of the platform sacrificial anodes. Guidance on grading anodes is helpful in achieving consistency of reporting and for planning retrofits. The survey should locate, count, and estimate depletion of platform anodes.

For platforms with impressed current systems the survey should consist of confirming that:

— the conduit to the anode is secure,

— insulating boots are in good condition, and

— the anode is not deformed or otherwise damaged.

For diver safety, impressed current anode systems should be turned off when there is risk that the diver may come in contact with the anode.

Cathodic Potential Survey

The CP surveys consist of underwater measurements of the electrical potential of elements at selected locations. The cathodic potential survey should be performed to confirm or otherwise correct operation of the platform corrosion protection system.

The survey may be required depending on the results of the annual above-water survey and other underwater surveys such as the visual corrosion survey and the anode survey. These other indicators of the effectiveness of the corrosion protection system may also be used to define the extent of the underwater CP survey.

Close Visual Inspection (CVI)

The CVI consists of an underwater inspection of preselected member areas and/or welds. Preselection of inspection areas should be based on results of an engineering evaluation of areas particularly susceptible to structural damage or to areas where subsequent inspections are desirable in order to monitor integrity over time.

Inspection areas should be sufficiently cleaned of marine growth to permit thorough inspection. CVI of preselected areas may also be used for corrosion monitoring.

Detection of significant structural damage during CVI should initiate a NDE in those instances where visual inspection alone cannot determine the extent of damage.

Close Visual Corrosion Survey

Close visual corrosion surveys are used to supplement CP and anode surveys. The visual corrosion survey should consist of localized cleaning and close visual examination of the steel surface of a platform element to assess the extent of corrosion.

The visual corrosion survey should consist of local manual cleaning (brush/scraping tool or similar) of the steel surface and close visual examination to determine the level of corrosion. The cleaning needs to expose no more than a 6-in. square. The selected location/s for the survey should be continuously submerged (i.e. not within the splash zone).

The choice of location and number of close visual corrosion survey areas can depend on the water depth of the jacket and the measured CP profile of the platform. Where CP is discovered to be inadequate, a greater number of close visual survey areas may be necessary. Generally, two locations are sufficient to establish the overall level of corrosion: one location at a member end weld and the other at a convenient location along a primary member. If the extent of corrosion is not established visually, then it is recommended that the close visual surveys for corrosion be combined with ultrasonic testing (UT) measurements, pit gauges, or stereo-photography.

Close Visual Weld/Joint Survey

The close visual weld/joint survey consists of a thorough visual examination of the selected weld/joint in the jacket. The close visual weld/joint survey is used to:

— detect and size visual cracks in or adjacent to the weld, and

— confirm the extent of corrosion of the steel surface and areas adjacent to the weld.

The weld/joint selection strategy should be consistent with the overall SIM philosophy adopted. Welds/joints may be selected in a number of ways, including:

— the known historic susceptibility of similar welds/joints on similar platforms to fatigue or overload damage;

— knowledge of existing damage at, or adjacent to, the weld/joint (includes damage monitoring); and

— the criticality of the weld/joint to the platform's integrity during occurrence of the extreme event.

Flooded Member Detection (FMD) Survey

The FMD survey detects flooded tubular members on underwater hollow tubular components or compartments. FMD may provide an acceptable alternative to CVI of preselected areas. The FMD survey should employ appropriate underwater NDE equipment to assess whether a platform member is "dry," "flooded," or "partially flooded."

Engineering judgment should be used to determine optimum use of FMD and/or CVI of welded joints. The amount of flooded member checks should be determined from a consideration of platform condition, experimental data, redundancy, strength, reliability, and experience with other platforms.

Flooding of members may be indicative of through-wall fatigue cracking in welded joints or attachments. Flooding may also result from other through-wall defects associated with fabrication, mechanical damage, or corrosion. FMD provides a useful screening of members considered prone to such damage, in particular, members in or supporting the conductor guide frame (CGF) down to approximately 30 m (100 ft) below the water surface.

Caution is advised in the application of the technique to primary structural members framing into platform legs. These connections are not prone to fatigue damage in most platforms; however, if fatigue cracks do occur they are more likely to develop on the chord-side of the weld and may not result in flooding of the brace. In this case, the FMD may not be a reliable method to detect fatigue cracks.

Nondestructive Examination (NDE)

The NDE consists of underwater inspection of preselected areas and/or areas from the results of a CVI or from known or suspected damage. A NDE survey may also be included in the detailed inspection and measurement of damaged areas.

NDE of fatigue sensitive joints and/or areas that are susceptible to cracking may be necessary to determine if damage has occurred. Monitoring fatigue sensitive joints, and/or reported crack-like indications, may be an acceptable alternative to analytical verification.

The examination will normally require prior cleaning. In some cases, NDE will require the use of partially destructive techniques. Where NDE techniques are used, detailed specifications should be provided and the testing undertaken by suitably qualified and experienced personnel. The training, cleaning, and testing requirements will vary depending on the type of damage/defect that is to be investigated and the type of inspection equipment to be used. Procedures should include guidance for the confirmatory grinding of indications and remedial grinding and crack-arrest drilling for confirmed cracks.

NDE Weld/Joint Survey

The NDE weld/joint survey is used to detect surface breaking discontinuities, mainly fatigue cracks that are not visually detectable. These discontinuities typically initiate in the toe of the weld on the external surface making them ideal for detection by magnetic testing.

The weld/joint survey should consist of a thorough underwater examination of the weld/joint. The location should be sufficiently cleaned of marine growth to permit thorough examination. Welds/joints may be selected in a number of ways, including:

— the known historic susceptibility of similar welds/joints on similar platforms to fatigue or overload damage,

— knowledge of existing damage at, or adjacent to, the joint (includes damage monitoring), and

— the criticality of the weld/joint to the platform integrity during occurrence of the extreme event.

Wall Thickness Survey

Ultrasonic thickness measurements of structural members should be considered if excessive corrosion is suspected for corroded structural members or appurtenances in the splash zone. The technique may also be used to provide member thicknesses for subsequent assessment engineering in the case that drawings are not available. The surface should be adequately prepared to ensure the reliability of the reading.

Appurtenance Inspections

Nonstructural platform appurtenances including risers and J-tubes, caissons, conductors, boat landings, and barge bumpers should be included within other platform surveys as appropriate. Appurtenance inspections should include the following.

a) Riser coating—The riser coating should be examined to determine type, integrity, and depth of termination. At damage locations, UT wall thickness readings should be taken.

b) Support clamps—Support clamps and guides should be sufficiently cleaned and visually examined to determine their integrity and that of their fasteners. Loose or missing fasteners should be tightened or replaced.

c) Caisson intakes—The lower section of the caisson around the intake should be cleaned and any blockages removed.

d) Pipeline spans—The riser inspection should extend to the bury point or anchor point or to a reasonable alternative distance from the platform [e.g. 15 m (50 ft)]. Any suspension of the pipeline should be measured and recorded.

Typical appurtenance anomalies found on offshore structures may include loose or missing bolts at clamped attachments, fatigue cracking of J-tube or caisson welded connections, etc.

A.7 Commentary on Damage Evaluation

A.7.1 General

In general terms, significant damage is defined as that causing the main framing capacity of the structure to be reduced by members that are dented, buckled, or have reduced area and section modulus due to cracks and/or tears and joint nodes that have been deformed to excess or accidental loading. Procedures to evaluate the significance of damage can be found in Reference [28]. These procedures were discussed in a public forum hosted by the U.S.

Minerals Management Service [27]. These guidelines have been developed to aid in determining significant damage for a wide range of structures; however, the results should be reviewed and approved by a qualified engineer.

A.7.3 Component Evaluation

A.7.3.2 Dented Tubular Members

Primary tubular members that have been deformed by accidental loading and that are to remain in place can be evaluated by D/t ratios versus reduction in ultimate capacity for jacket leg members. Additional information for this type of evaluation can be found in API 2A-WSD, 22nd Edition.

A.8 Commentary on Structural Assessment Process

A.8.1 General

There are available numerous simple methods as well as rigorous approaches for the design level and ultimate strength methods in Reference [29] and Reference [31]. However, care should be taken when using such methods, including prior testing and verification of the method to confirm the approach and the applicability of the method to the assessment case. In particular, the results of such methods should be reviewed and approved by a qualified engineer.

A.8.3 Assessment Initiators

A.8.3.5 Inadequate Deck Elevation

Inadequate cellar deck height is considered an initiator, as many historical platform failures in the U.S. Gulf of Mexico have been attributed to waves impacting the platform cellar deck, resulting in a large stepwise increase in loading. In a number of these cases this conclusion is based on hurricane wave and storm surge hindcast results, which indicate conditions at the platform location that include estimated wave crest elevations being higher than the underside (bottom elevation) of the platform's cellar deck main beams.

A cellar deck is defined as a deck that has substantial deck structure and/or equipment that cause the wave loading to increase dramatically in a stepwise manner once the wave reaches the deck. Figure 6 provides a schematic representation of typical deck configurations for U.S. Gulf of Mexico platforms and should be used as guidance in defining the cellar deck.

Inadequate cellar deck height may result from one or more of the following circumstances:

— platform cellar deck elevation set by equipment limitations,

— platform cellar deck elevation set to only clear a lower design wave height,

— field installed cellar deck,

— platform installed in deeper water than its original design specified,

— subsidence of the foundation.

In some cases, the cellar deck elevation may be greater than the criteria specified in 8.3.5 as an inadequate deck height trigger; however, there may still be one or more smaller decks below the cellar deck, such as a scaffold, sump, or spider deck, that will be impacted by waves. These decks will have a small profile and the anticipated wave loading is not expected to be sufficient to cause failure of the platform. However, the assessment should consider the appropriate hydrodynamic loads on these decks and associated equipment, as described in 9.3.4, for either a design level assessment or an ultimate strength assessment as may be required for the structure.

A.8.3.6 Significant Damage

Offshore steel structures are designed on the basis of traditional structural engineering practice. A combination of loads is applied to the structure and the internal forces in each brace member are established. Each member and joint is checked against allowable strengths given in design codes. The structure is considered to meet the selected code standards if all the individual components satisfy the code requirements. All codes, whether they are based on permissible stress design or limit state design, address the design of individual members and joints; the allowable strengths are essentially derived from the large database of tests on isolated joints and tubular beam-column members. Implicit within this design procedure is the premise that failure of one member or joint to satisfy code requirements constitutes noncompliance with the relevant code. However, it is recognized that fixed offshore structures are usually redundant and have a number of different load paths. Therefore, failure of one member is unlikely to lead to catastrophic structural collapse provided that adequate redundancy is available.

When damage occurs, a new loading distribution is produced in the structure. Depending on the altered form, dimensions and degree of yielding (and hence stiffness) of the damaged area, and also on its relationship to the remaining (undamaged) structure, the load path across the damaged area may be partially or completely disrupted. The additional load transferred from the damaged area will act as new loadings across the undamaged structure; reducing the margin of safety of undamaged components. This in turn may reduce the ultimate capacity of the structural system and potentially a decrease in the fatigue life of the structure.

Damage, depending on its cause, may manifest itself as dents, bows, permanent deformations, loss of thickness, gouges, cracks, tears, holes, and severance of members. These forms of damage can occur singly or in combination. The damage may or may not be important to the integrity of the platform. This depends on the severity of the damage, the loads carried by the damaged component, and the degree of structural redundancy. Each situation should be assessed individually to enable rational decisions to be made on whether to repair and/or strengthen.

A.8.4 Assessment Information

A.8.4.4 Geotechnical Information

Many sampling techniques and laboratory testing procedures have been used over the years to develop soil strength parameters. With good engineering judgment, parameters developed with earlier techniques may be upgraded based on published correlations. For example, design undrained shear strength profiles developed for many platforms installed prior to the 1970s were based on unconfined compression tests on 57-mm (2.25-in.) diameter driven wireline samples. Generally speaking, unconfined compression tests give lower strength values and greater scatter than unconsolidated undrained compression tests, which are now considered industry standard. Studies have also shown that a 57-mm (2.25-in.) sampler produces greater disturbance than the 76-mm (3-in.) diameter thin-walled push samplers now typically used offshore. Therefore, depending on the type of sampling and testing associated with the available data, it may be appropriate to adjust the undrained shear strength values accordingly.

Pile-driving data may be used to provide additional insight on the soil profiles at each pile location and to infer the elevations of pile end bearing strata.

A.8.5 Assessment Method

Structural evaluation can be performed in consecutive order of increasing complexity, which also results in decreasing levels of conservatism, with the simple methods being the most conservative and the ultimate strength method and alternative method being the least conservative. Should a structure not pass using simple methods, it should be assessed using the design level method, and similarly if the structure does not pass the design level method, ultimate strength methods should be used. Conversely, should a structure pass using simple methods, no further assessment is required and similarly for the other levels. In most cases, it is not necessary to initiate the structural assessment process at the lowest level assessment method. Based upon experience, it may be evident that the platform will not pass the more conservative design level method and an ultimate strength method may be performed from the onset.

For example, an owner/operator may want to start the process with ultimate strength methods when it is clear that the platform may not pass the other more conservative approaches.

A.8.5.3 Design Level Method

A.8.5.3.1 General

The design level method metocean criteria provided in Section 9 were calibrated for structures that did not have wave loading on their decks. It is therefore unconservative to consider wave loading on decks for assessments using design level analysis. The ultimate strength method is required instead.

It is generally more efficient to begin with a design level method since it is usually simpler to implement than the ultimate strength method. There may also be an existing computer model of the platform that was used for design of upgrades or other modifications that can be readily updated for platform assessment.

Analysis Procedures

Should ongoing research be used to determine the strength of members, the research results should be carefully evaluated to assure applicability to the type of member and the actual in situ condition, its level of stress, and the level of confidence in the results. For example, the use of smaller values for effective length (K) factors might be appropriate for members developing large end moments and high levels of stress but might not be appropriate for lower levels of stress.

As a result of steel availability during construction and possibly other nonstructural reasons, tubular members could have steel with yield stress higher than the specified minimum. If no such data exist, coupon tensile tests can be used to determine the actual yield stress. Joint industry studies have indicated that higher yield stresses can be justified statistically; however, this should be justified on a case-by-case basis for a particular platform or for a fleet of platforms with similar fabrication histories. The use of indentation tests to determine yield strength is not considered acceptable due to the large scatter in correlation with yield strength from coupon tests.

Joints are usually assumed rigid in the global structural model. Significant redistribution of member forces can result if joint flexibility is accounted for, especially for short bracing with small length-to-depth ratios, and for large leg can diameters where skirt piles are used. Joint flexibility may be determined using finite element methods. Steel joints can have higher strength than currently accounted for in design. Similarly, the evaluation of strength for grouted joints, as well as the assessment of grout stiffness and strength, may consider higher values than normally used for design. Validated methods should be used to determine higher joint strengths.

A.8.5.5 Alternative Assessment Methods

A.8.5.5.2 Assessment by Prior Exposure

Hurricanes Ivan (2004), Katrina (2005), Rita (2005), and Ike (2008) exposed thousands of U.S. Gulf of Mexico platforms to extreme hurricane conditions. Many of these structures experienced metocean conditions close to or larger than API 2A-WSD, 22nd Edition 100-year conditions. Some waves reached 23 m to 27 m (75 ft to 90 ft) in height and in some cases higher, in particular the Central Region due to Ivan and Katrina. This provides an opportunity to use prior exposure, otherwise known as “proof testing,” to assess the structure. Prior exposure means that the platform was subjected to and survived, without significant damage, metocean conditions greater than or equal to the assessment criteria, either in the form of specific wave heights or target RSR.

When performing an assessment by prior exposure, careful attention should be paid to the specific metocean conditions during the hurricane, typically determined through a hindcast study, and how these compare to the assessment criteria. Directionality of the waves, winds, and currents and how these align with each of the structure’s primary strength directions need to be considered. For example, if a platform experienced a wave greater than the API 2SIM L-1 ultimate strength wave in one of the orthogonal directions, this does not mean that the platform has been fully “proof tested” via prior exposure. The direction of loading needs to have aligned with the weakest of a platform's strength directions. Also, currents and winds should be properly accounted for in the prior exposure assessment.

Alternatively, the combined wave/wind/current can be measured as total base shear acting on the structure, and this is a more convenient method to compare to the base shear representative of an L-1 ultimate strength wave in that direction for the structure. When the assessment is using a target RSR approach, such as 1.2 in the Central Region, the prior exposure base shear needs to be shown to be 1.2 times the 100-year condition for the platform's location. In addition, deeper water depth platforms, in say 91 m (300 ft) or greater, should consider a dynamic amplification factor that needs to be included in the target base shear. As an example, a 122-m (400-ft) water depth platform located in the Central Region would need to have experienced a base shear equal to the 100-year API 2MET condition [about 24 m (80 ft) in this water depth], multiplied by 1.2 for the L-1 target and then increased further by say 15 % for the dynamic amplification factor. The resultant base shear would be 1.38 times that of a 24 m (80 ft) wave and its associated wind and current. Few U.S. Gulf of Mexico fixed platforms have been exposed to this level of loading.

Study of these hurricanes by the API Hurricane Evaluation and Assessment Team (HEAT) and published in Reference [32] and Reference [33] indicate that while 100-year API conditions may have been exceeded at many offshore platform locations, these conditions may not have been sufficient to load, and therefore not adequately proof load, most offshore structure's beyond their ultimate strength level, especially L-1 platforms. Hurricanes Ivan and Katrina resulted in the largest waves of 27 m to 30 m (90 ft to 100 ft), which is close to ultimate strength waves; however, they also passed though portions of the U.S. Gulf of Mexico with the fewest number of platforms. In contrast, Rita and Ike had maximum wave heights in the range of range of 21 m to 24 m (70 ft to 80 ft). These loadings may also have not been in the weakest direction of the platform.

In summary, prior exposure can be a useful method that can be used for assessment if performed in a careful and precise manner taking into account the specific loading acting on the platform during the hurricane as well as the particular characteristics of the platform's strength, including orientation.

A.8.6.2 Ultimate Strength Method

General

In ultimate strength analysis, structural elements are modeled to carry loads up to their ultimate capacities and possibly beyond depending on their ductility and post-elastic behavior. Such elements may exhibit signs of damage, having reached or exceeded buckling, yielding, or tensile limits. In this context, simulated damage may be considered acceptable as long as the structure's global strength is not compromised.

Ultimate Strength Using Equivalent Linear Methods

As an alternative to a nonlinear assessment such as a pushover analysis, it may be possible to demonstrate that the platform will pass the ultimate strength assessment by using a linear elastic analysis, similar to a design level analysis, with the exception that the typical factors of safety associated with axial, bending, shear, and other loading conditions have been removed. Other known sources of conservatism such as the use of mean yield strength instead of nominal yield strength may also be taken into account. The intent is to approximate performance of the platform members when loads are above allowable stress and below yield. If all of the platform members can be shown to have a load that is less than yield, considering all combined stress states, then the platform passes the ultimate strength assessment. If the load in a platform member or members exceeds yield, then a nonlinear ultimate strength analysis should be utilized.

Ultimate Strength Using Nonlinear Methods

It should be recognized that calculation of the ultimate strength of structural elements is a complex task. The effects of strength degradation due to cyclic loading and the effects of damping in both the structural elements and the supporting foundation soils should be considered. Strength increases due to soil consolidation may be used if justified.

Several nonlinear methods have been proposed for ultimate strength evaluation of structural systems. Two methods that have been widely used for offshore platform analysis are the pushover and the time domain methods. It is important to note that regardless of the method used, no further analysis is required if an analysis indicates that a structures reaches the specified extreme metocean loading (i.e. analysis up to collapse is not required).

The pushover method is well suited for static loading, ductility analysis, or dynamic loading that can be reasonably represented by equivalent static loading. Examples of such loading would be waves acting on stiff structures with natural periods under three seconds, having negligible dynamic effects, or ice loading that is not amplified by exciting the resonance of the structure. The analysis tracks the performance of the structure as the level of force is increased until it reaches the extreme load specified. As the load is incrementally increased, structural elements such as members, joints, or piles are checked for inelastic behavior in order to ensure proper modeling. This method has also been widely used for ductility level earthquake analysis by evaluating the reserve ductility of a platform or by demonstrating that a platform's strength exceeds the maximum loading for the extreme earthquake events. Although cyclic and hysteretic effects cannot be explicitly modeled using this method, their effects can be recognized in the model in much the same way that these effects are evaluated for pile head response to inelastic soil resistance. The structural model should recognize loss of strength and stiffness past ultimate.

The time domain method is well suited for detailed dynamic analysis in which the cyclic loading function can be matched with the cyclic resistance-deformation behavior of the elements step by step. Examples of dynamic loading appropriate for consideration using the time domain method are earthquakes or waves acting on platforms with fundamental periods of three seconds or greater. This method allows for explicit incorporation of nonlinear parameters such as drag and damping into the analysis model. The identification of a collapse mechanism, or the confirmation that one does exist, can require significant judgment using this method.

Regardless of the analysis method, it is necessary to accurately model all structural elements. Before selection of element types, detailed review of the working strength analysis results is recommended to identify those elements with very high stress ratios that are expected to be overloaded. Since elements usually carry axial forces and biaxial bending moments, the element type should be based on the dominant stresses. Some software will track the member stresses as the pushover load increases and will automatically convert the member to a nonlinear member in order to reflect nonlinear performance at high loads.

Assessment Model

General guidance about ultimate strength platform modeling is as follows.

Steel Yield Strength

An API study [38] investigated how other offshore and onshore codes and standards address the use of mean yield strength for assessment of existing platforms. The work also included the collection of steel strength test data from several U.S. Gulf of Mexico platforms to establish a dataset and corresponding steel yield strength. The work showed that other codes and standards commonly recommend the use of mean steel strength for assessment of existing platforms. The U.S. Gulf of Mexico platform data showed a clear mean strength of about 317 MPa (46 ksi) for 248 MPa (36 ksi) nominal strength steel. The principal recommendations of the study are summarized as follows and should be used for ultimate strength assessments.

a) If available, actual tested yield strength should be used for assessment when using the ultimate strength method. The best approach for assessment is to use the actual yield strength of each member since it ensures the correct load path that determines the platform's ultimate strength. Many newer platforms, or older platforms that have well-documented fabrication records, have this data available and it should be utilized.

b) If actual strengths are not available, then they can be approximated by using estimated mean yield strength. The suggested range for steel with a nominal strength of 248 MPa (36 ksi) is 276 MPa to 317 MPa (40 ksi to 46 ksi). The lower 276 MPa (40 ksi) value represents about a 10 % increase, similar to what some onshore codes suggest as the minimal increase, and is equal to about the mean minus one standard deviation of the platform test data, or about

85 % of all steel in the platform should have a strength of 276 MPa (40 ksi) or larger. The higher 317 MPa (46 ksi) value represents the mean of the platform test data, or 50 % of all steel in the platform should have a larger strength. This is also approximately the upper value suggested by some standards. An average 296 MPa (43 ksi) value for mean yield strength provides a reasonable approximation of this range. Data were not available for 345 MPa (50 ksi) material and no specific guidance is provided; however, it is generally known that the percentage increase from nominal to mean for higher strength steel is much less than for 248 MPa (36 ksi) material.

c) In some structural assessments, the platform's ultimate strength may be dependent on the yield strength of a few critical members, for example, the deck legs. In these cases, it is recommended that a steel sample be taken and the yield strength determined provided the sample can be taken in an efficient and safe manner.

Elastic Members

A majority of the platform members are expected to have stresses below yield and would not be expected to reach their capacity during ultimate strength analysis. These elements should be modeled the same as in the design level method and tracked to ensure their stresses remain in the elastic range. Examples of such members are deck beams and girders that are controlled by gravity loading and with low stress for metocean loading, allowing for significant increase in the latter before reaching capacity. Other examples may be jacket main framing controlled by installation forces, as well as plated conductor guide framing, secondary bracing, and appurtenances.

Axially Loaded Members

These are undamaged members with high Kl/r ratios and dominant high axial loads that are expected to reach their capacity as the platform is loaded to its ultimate strength. These members should be modeled using strut elements. Examples of such members are primary bracing in the horizontal levels and vertical faces of the jacket and primary deck bracing. The strut element should recognize reductions in buckling and post-buckling resistance due to applied inertia or hydrodynamic transverse loads. Effects of secondary (frame-induced) moments may be ignored when this type of element is selected. Some jacket members, such as horizontals, may not carry high axial loads until after buckling or substantial loss of strength of the primary vertical frame bracing.

Moment Resisting Members

Members with low Kl/r ratios and dominant high-bending stresses are expected to form plastic hinges under extreme loading. Examples are piles and unbraced sections of the deck and jacket legs.

Joints

The joint model should recognize whether the joint can form a hinge or not, depending on its D/t ratio and geometry, and should define its load deformation characteristics after hinge formation. The API 2A-WSD, 22nd Edition joint design equations with the factors of safety removed are a reasonable estimate of joint ultimate capacity. Other evaluations of joint strength may be acceptable if applicable and if substantiated with appropriate documentation.

Damaged Members

The type of damage encountered in platforms ranges from dents, bows, holes, tears, and cracks to severely corroded or missing members and collapsed joints. Theoretical as well as experimental work has been ongoing to evaluate the effects of damage on structural strength and stiffness. Modeling of such members should provide a conservative estimate of their strength up to and beyond capacity.

Repaired and Strengthened Elements

The type of repairs usually used on platforms ranges from wet or hyperbaric welding, grouting, and clamps to grinding and relief of hydrostatic pressure. Grouting is used to stiffen members and joints and to preclude local buckling due to dents and holes. Grinding is commonly used to improve fatigue life and to remove cracks. Several types of clamps have been successfully used, such as friction, grouted, and long-bolted clamps. Platform strengthening can be accomplished by adding lateral struts to improve the buckling capacity of primary members and by adding insert or outrigger piles to improve foundation capacity. Members and joints element properties can often be modified by the qualified engineer to account for the local or global effects of repair/strengthening.

Foundation

Piled foundations are typically modeled using the lateral and axial nonlinear pile-soil methods described in API 2A-WSD, 22nd Edition. However, some aspects of the approach should be revised for existing piled foundations. An API study [39] on the performance of U.S. Gulf of Mexico platforms in hurricanes developed specific guidance for the assessment of existing piled foundations and is summarized as follows.

a) When the foundation controls the assessment, include a geotechnical engineer familiar with platform assessments. There are aspects of geotechnical engineering that cannot be fully captured in a recommended practice and additional guidance is often needed. An assessment is different from new design, so the geotechnical engineer needs to be familiar with assessment technology.

b) Include well conductors in the structural analyses. The conductors provide additional lateral foundation support to the platform system. Ensure the conductor guide framing is sufficiently modeled to account for conductor loading to the jacket.

c) Use the mean steel yield strength for the piles and conductors. The steel yield strength is an important factor in determining lateral foundation resistance and the best estimate value should be used. See additional discussion in this section regarding steel yield strength.

d) Use static versus cyclic p-y curves for lateral soil resistance for ultimate strength assessments. The ultimate lateral capacity of the foundation system is reached as the piles push laterally into undisturbed soils. This differs from the design of new platforms where degraded cyclic curves are used.

e) Be careful when relying on a soil boring that was not drilled at the location of the platform or was not drilled using modern methods of sampling and testing. A geotechnical engineer can help determine if a nearby boring is appropriate for the platform location, otherwise a site-specific boring should be used.

f) Try to obtain pile driving records as well as soil boring logs to help estimate the axial pile capacities. Although not always available, these records are particularly useful where there are questions about the soil stratigraphy or the final pile penetration.

g) When the pile foundation system is governing the capacity of the platform in a pushover analysis, check the sensitivity of the foundation system capacity to the lateral and axial (overturning) capacities of the piles independently. If the failure mode is in the lateral direction, then there are a variety of structural factors that become important, such as steel yield strength, horizontal bracing, and conductor guide framing. If the failure mode is axial, then geotechnical factors such as the soil stratigraphy become important.

It may be appropriate to consider foundation bearing capacities provided by mudmats and mudline horizontal members, in addition to the foundation capacity due to piles, provided that inspection confirms the integrity of the mudmats and that the soil support underneath the mudmats and horizontals has not been undermined by scour. The mudmats and mudline horizontal members may be treated as shallow foundations using the methods described in API 2GEO. The increase of soil shear strength with time (aging) has been suggested as a source of additional foundation capacity; however, the use of this factor should be substantiated on a case-by-case basis. Assessment of existing piled foundations in seismic and arctic regions may consider some of the issues as well as the special issues associated with the unique loading conditions associated with earthquake and ice loading.

Conductors

Below the mudline, conductors can be modeled using appropriate pile-soil methods similar to piles. A conductor pull test offers an alternative means for estimating the as-installed capacity of a driven pile. In an ultimate strength analysis, well conductors can contribute to the lateral resistance of a platform once the jacket deflects sufficiently to close the gap between the CGFs and the conductors. Consideration should be given to the effects of closely spaced adjacent conductors on the load and deflection characteristics of conductor groups, similar to that of a pile group. Specific guidance can be found in API 2GEO.

A.9 Commentary on Assessment for Metocean Loading

U.S. Gulf of Mexico Platform Exposure Categories

Additional description for each platform exposure category is provided in the following.

L-1 Exposure Category—Platforms in this category have a high risk of significant financial impact, pollution, and/or injury to platform workers in the event of platform damage due to a hurricane. The expectation is that platforms in this category would survive a significant hurricane impact with minimal or no damage leading to no loss of life or significant injury, no significant pollution, and no significant financial impact.

S-2 Exposure Category—Platforms in this category have a very low risk of pollution or significant financial impact in the event of platform damage due to a hurricane. The primary risk is the possibility of personnel being caught offshore due to a storm developing so quickly that the platform cannot be successfully evacuated.

C-2 Exposure Category—Platforms in this category have a very low risk of pollution or significant financial impact in the event of platform damage due to a hurricane. These are essentially unmanned S-2 platforms. The key risk is economic impact to the owner/operator.

L-3 Exposure Category—Platforms in this category have low consequences of failure. Life safety or pollution is not an issue, even if the platform is destroyed in a hurricane; however, the platform should have enough structural integrity to provide life safety during operational storm conditions when personnel may be on board.

Basis of Procedure Used to Develop U.S Gulf of Mexico Assessment Criteria Tables 5 and 6

The approach to determine appropriate assessment criteria as originally defined in API 2A-WSD, 21st Edition, Section 17 and documented in Reference [16] was updated for use in this document using API 2MET conditions for the Central and Western Regions of the Gulf of Mexico. Details are provided in Reference [40]. The critical aspects were return period and load measured as base shear acting on a caisson structure in different water depths in each of the Gulf of Mexico regions. The following provides a brief summary of the basis for the selection of the return periods according to platform category, with the updated conditions called "Section 17 Process 2MET." All of the return periods represent full population metocean conditions unless indicated otherwise.

Table 5—Design Level Metocean Criteria, U.S. Gulf of Mexico

L-1, 19th Edition—Use 50-year conditions, which are a best fit for the Section 17 Process 2MET A-1 Western Region on a load basis. The Central Region uses the same return period for consistency.

S-2, 19th Edition—A design level assessment is not applicable for manned S-2 platforms. An ultimate strength check must be performed for these structures in order to clearly demonstrate they are safe for manning. The ultimate strength assessment provides a more complete understanding of the platform's response to extreme waves than a design level assessment.

C-2, 19th Edition—Use 15-year conditions, which are a best fit for the Section 17 Process 2MET A-1 Western Region on a load basis. The Central Region uses the same return period for consistency.

L-3, 19th Edition—Use 10-year conditions. This is the same concept as for C-2 19th Edition but matches Section 17 A-3 conditions. For both the Western and Central Regions, the best fit on a load basis is a 5-year condition or less. However, this is an exceptionally low return period, and it was decided by the API SIM Task Group to establish a more conservative 10-year minimum. Platform owners can always use an ultimate strength assessment, which will reduce some of this conservatism.

L-1, 20th or 21st Edition—Use 100-year conditions. This is the same as a new design platform.

S-2, 20th or 21st Editions—A design level assessment is not applicable for manned S-2 platforms. An ultimate strength check must be performed for these structures in order to clearly demonstrate they are safe for manning. The ultimate strength assessment provides a more complete understanding of the platform's response to extreme waves than a design level assessment.

C-2, 20th or 21st Edition—Use 50-year conditions. This is the same as a new design platform.

L-3, 20th or 21st Edition—Use 25-year conditions. The original consequence-based design work [10] used 15-year conditions to establish the L-3 design. However, in API 2INT-DG [33] this was reset to a 25-year condition, which is also used in API 2A, 22nd Edition for L-3 platforms.

Table 6—Ultimate Strength Metocean Criteria, U.S. Gulf of Mexico

L-1, 19th Edition—Use 300-year conditions, which are a best fit for the Section 17 Process 2MET A-1 ultimate strength loads for the Western and Central Regions. This return period also closely matches the 1.2 × 100-year condition base shear for the Central Region as required by API 2INT-EX. The original Section 17 showed a 200- to 300-year range for A-1 structures. The Western Region has an added requirement as indicated in the footnotes for water depths where the sudden hurricane is larger than the 300-year conditions. This typically occurs in water depths less than about 200 ft, but can occur in other water depths and therefore should always be checked.

S-2, 19th Edition—Use 2500-year sudden hurricane conditions since these structures are manned-evacuated and at a minimum must survive sudden hurricane conditions. This is a minimum condition and owners/operators may want to consider increased criteria based on specific aspects of their operations, such as platforms that are located further from shore or are very remote.

C-2,19th Edition—Use 25-year conditions. Since these platforms are unmanned, this is an economic consideration. The original Section 17 A-2 metocean conditions were considered a reasonable economic target with a 25-year condition being a match in terms of equivalent base shear acting on a caisson structure for the Western Region and a 10-year condition being a match for the Central Region. The 25-year condition was selected for both regions in order to provide consistency in the Gulf of Mexico, meaning platforms located in the Central Region will have to meet more extreme conditions compared to the original Section 17. This is reasonable given that the Central Region is now known to have more severe metocean conditions than was considered in the development of Section 17. Owners may want to consider increased metocean criteria if these platforms are critical to their operations.

L-3,19th Edition—Use 10-year conditions. This is the same approach as C-2 19th but adjusted to match Section 17 A-3. For the Western Region, the best fit on a load basis is the 10-year conditions and for the Central it is 5-year conditions. Similar to the C-2 category, the higher Western Region return period was selected for consistency in the Gulf of Mexico.

L-1, 20th Edition—Use the same criteria as L-1 for the 19th Edition. API 2INT-EX established that existing L-1 platforms in the Central Region have an assessment acceptance criteria of a base shear of 1.2 × 100-year conditions. Comparison of base shear on a caisson shows this is approximately equal to 300-year return period conditions. The same criteria were selected for the Western Region in order to provide consistency in the Gulf of Mexico.

S-2, 20th Editions—Use 2500-year sudden hurricane conditions since these structures are manned-evacuated and at a minimum must survive sudden hurricane conditions. This is a minimum condition and owners/operators may want to consider increased criteria based on specific aspects of their operations, such as platforms that are located further from shore or are very remote.

C-2, 20th Edition—Use 300-year conditions. The concept is to match the original consequence-based design values for ultimate strength. Reference [18], describing consequence-based design, indicates an L-2 platform has a RSR of 1.3 (or 1.3 × 100-year condition), and this matches a 300- to 400-year condition in the Western Region on a load basis. Since L-1 platforms use a 300-year condition, which is approximately 1.2 × 100-year condition, the C-2 criteria should not be higher and are therefore set as the same as L-1 at 300-year. Since the C-2s are unmanned, the secondary sudden hurricane check indicated in the notes for an L-1 platform is not required.

L-3, 20th Edition—Use 100-year condition. The intent is to match consequence-based design. Reference [18], describing consequence-based design, indicates an L-3 platform has an ultimate strength return period of 100 years.

All Categories, 22nd Edition—Use the robustness metocean conditions for new design platforms contained in API 2A-WSD, 22nd Edition.

All Categories, 22nd Edition: Use the same metocean conditions as contained in API 2A-WSD, 22nd Edition for new design platforms.

Sudden Hurricane

Sudden hurricanes are a small subset of the entire hurricane population; they form locally in the Gulf of Mexico. Due to their speed of formation and proximity to the oil and gas infrastructure, advanced evacuation of manned facilities may not be possible. Therefore, sudden hurricanes and earthquakes have similar life safety consequences for manned platforms, with personnel unable to evacuate prior to the event, and it is reasonable to equate their reliability targets.

The original API 2A-WSD, Section 17 work related to earthquake assessment of existing platforms was based on the THIC study and several industry workshops conducted in 1992 [34] [35] and 1993 [36], which equated offshore platform seismic risks with onshore building seismic risks and established a 1000-year return period condition for the ultimate strength assessment of platforms in seismic regions. This work, along with the latest versions of the onshore building codes for seismic design, was revisited in an API study conducted in 2013 [40]. The study showed that the trend in the life safety target return period has increased for both onshore and offshore structures in the 20 years since the THIC study and workshops and is in the range of about 2500 to 5000 years. Based on this, the API 2SIM Task Group elected to use the 2500-year sudden hurricane condition as the minimum acceptance criteria for manned-evacuated platforms. This return period is approximately the same as recommended by API 2EQ for the ultimate strength of manned platforms in seismic regions.

Associated Wind Speed

The associated 1-hr wind speed, as listed in the metocean criteria, occurs at an elevation of 10 m (33 ft) and applies to all water depths and wave directions. The use of the same speed for all directions is conservative; lower speeds for directions away from the principal wave direction may be justified by special studies. The associated wind speed is intended to be applicable for the assessment of structures where the wind force and/or overturning moment is less than 30 % of the total applied metocean load. If the total wind force or overturning moment on the structure exceeds this amount, then the structure should also be assessed for the 1-minute wind speed concurrently with a wave of 85 % of the height of the assessment wave, acting with the assessment tide and current. As an alternate, the use of wave and current information likely to be associated with the 1-minute wind may be justified by site-specific studies. However, in no case can the resulting total force and/or overturning moment used for the assessment of the platform be less than that calculated using the 1-hour wind with the guideline wave, current, and tide.

A.11 Commentary on Assessment for Seismic Loading

Assessment criteria for the ALE condition are set at the 1000-year return period conditions based on the original work by API 2A-WSD, Section 17 committee as well as the THIC report and industry workshops conducted in the early

1990s [34] [35] [36]. The THIC report established that onshore practice was applicable to offshore practice when evaluating life safety consequences for seismic hazards. The trend in life safety target reliability has increased for both onshore and offshore structures in since the THIC report was published in 1992. However, as discussed in the commentary related to sudden hurricanes and also in Reference [40], more recent onshore building codes for seismic design use approximately a 2500-year return period condition. Onshore building codes use a variety of design factors in the overall approach used to assess an existing building, and it is not apparent if this approach is directly transferable to seismic assessment of an offshore platform. Additional work is required to evaluate how these approaches can be applied to offshore seismic reassessment. Until then, operators should use the 1000-year condition as a minimum, with a better target being the seismic criteria contained in API 2EQ for design of new platforms.

A.14 Commentary on Platform Decommissioning

A.14.2 Decommissioning Process

Further information on decommissioning can be found in the proceedings of an international workshop held in New Orleans by LSU in 1996 [37].

The entire decommissioning process for an offshore platform may broadly be divided into the following discrete activities listed in Table A.1.

Table A.1—Decommissioning Activities

Activity	Description
Predecommissioning surveys/data gathering	Information-gathering phase required to gain knowledge about the existing platform and its condition.
Engineering and planning	Development of a decommissioning plan based on information gathered during predecommissioning surveys.
Well decommissioning	The permanent plugging and abandonment of the nonproductive wellbores.
Facilities decommissioning	The shutdown of all process equipment and facilities, removal of waste streams, and associated activities for a safe and environmentally sound dismantling.
Structure decommissioning	Removal of the deck, followed by removal of the jacket. All or part of the installation is usually removed from the site for disposal, recycle, use as an artificial reef, or reuse of platform components either onshore or offshore.
Site clearance	Final cleanup of seafloor debris.

Planning

A decommissioning plan should be prepared for each installation. This plan should include the method and procedures developed for the well decommissioning, facilities decommissioning, structure removal, and site clearance. This may be in the form of a written description, specifications, computer modeling, and/or drawings. Emphasis should be placed on developing a sound environmental plan and a safe operational approach. Depending on the complexity of the installation, more detailed instructions may be required for special items, such as conductor removal, pipeline flushing, hazardous material handling, toppling, etc. Any restrictions or limitations to operations due to items such as metocean conditions, barge stability, or structural strength (i.e. lifting capacity) should be identified.

Option Assessment

Decommissioning options should be developed, assessed, selected, and put through a detailed planning process that includes engineering and safety preparation. The best decommissioning option may not be the same solution for different special interest groups. The principal spheres of special interest are environmental, health, and safety, besides commercial and political action groups.

Any decommissioning option should contain a precondition that:

— production is shut in,

— the wells abandoned,

— the risers disconnected after flushing through and cleaning the pipeline,

— the process system is decommissioned, and

— inventory materials removed and the platform left in a safe condition.

Risks

The success of safe decommissioning, dismantling, and disposal of offshore installations and pipelines depends on a proper assessment of the risks and by observing safe systems of work. Many hazards and appropriate risk control measures associated with the decommissioning, dismantling, and disposal of offshore installations are similar to those arising from construction or maintenance operations carried out both onshore and offshore.

Safety to persons requires assessment of the risks of injury or death posed by the process of decommissioning. This requires consideration of offshore safety and the risks associated with all marine activity, onshore safety and the risks to personnel arising from associated onshore work, residual risks to safety arising from the end point of the various disposal options, and the risks associated with deviation from the intended plan.

The relative environmental impacts of the different options, including the effects on other users of the sea, should be assessed. This requires consideration of marine impacts, onshore effects, use of energy and release of carbon dioxide, cutting techniques used, movement of drill cuttings, artificial reefs, and recycling and reprocessing effects.

Responsibility

The party responsible for the execution of each phase of the work should prepare the execution plan for that phase, unless otherwise designated by the owner/operator. The owner/operator should establish coordination and approval procedures between all parties.

Personnel Qualifications

Decommissioning and removal or decommissioning in place should be carried out by personnel who have specific knowledge and experience in safety, process flows, platform operations, marine transportation, structural systems, pipeline operations, and decommissioning.

Records and Documentation

At the completion of the decommissioning, each party should compile and deliver to the owner/operator all daily report logs, variation from the procedures, unusual metocean conditions, debris removal, etc. in a form suitable for use as a permanent record. The responsibility for the compilation and retention of these records, with other records related to the construction, installation, and operations of the installation should be in accordance with the requirements of the owner/operator and governing agency.

A.14.2.2 Predecommissioning Data Gathering

All the information on the condition of the facility should be gathered prior to the beginning of the decommissioning. This includes a thorough file/drawing search for information including the topside deck and support structure design, fabrication, and installation, as well as any structural modifications that might have been carried out subsequent to the installation. Installation files should be checked for field notes/logs regarding jacket, deck, and equipment weights.

Frequently, installation data, including pile soundings (depth of soil plug above or below mudline) and actual component lift weights, are documented in the files.

A detailed site inspection should be performed to establish inventories, estimate weights of equipment, prepare weight reports, determine the platform structural integrity and structural condition, and ascertain the state of the seabed and the subsea structure (data for the latter may be found in the latest underwater inspection report). Prior to using any existing lifting eyes, NDT should be used to ascertain their integrity. The inspection should assist in establishing the order of deck dismantling.

A.14.2.3 Planning and Engineering

The engineering should piece together all the previously gathered information to form a logical, planned approach to a safe decommissioning. Technical and engineering aspects of the option, including reuse and recycling and the impacts associated with cleaning or removing hydrocarbons and waste streams from the installation while it is offshore, should be assessed.

Technical feasibility requires an assessment of the likelihood of the proposed decommissioning option being completed successfully, together with the risks and consequences of deviations from the planned course of action.

The technical feasibility should consider the jacket weight, water depth, installation type, number of legs, number of piles, decommissioning date, presence of bridge links, presence of integrated deck, topsides weight, total weight, number and size of modules, maximum module weight, base size, presence of drill cuttings, presence of drilling template/well stubs, feasibility of single vertical emplacement, presence and functioning of buoyancy aids, and number and size of storage tanks.

A.14.2.5 Well Decommissioning

The plugging and abandonment of wells is one of the primary stages of a facility decommissioning program. Generally, well decommissioning requires isolating productive zones of the well with cement, removing some or all of the production tubing, and setting a surface cement plug in the well with the top of the plug a set distance below the mudline. The inner casing string should be checked to ensure that adequate inside diameter and depths are available for lowering of explosives or cutting tools.

An effective plugging and abandonment procedure is critical for the proper sealing of an oil and gas wellbore to safely secure it from future leakage. Techniques used to accomplish this process should be based on industry experience, research, and conformance with applicable regulatory compliance standards and requirements.

A.14.2.6 Facilities Decommissioning

The shutting down and cleaning up of the topside facilities is a major component of the overall decommissioning activity for an offshore platform. This phase is critical to the overall success of the program and involves the final shutdown, purging, and disconnecting of the process equipment including all mechanical and electrical components. This phase should also include any structural or process pipe cutting and moving of equipment to minimize activities required while the heavy lift vessel (HLV) is on site. Topsides can vary significantly in size, functionality, and complexity, and hence a range of decommissioning options should be considered in the project planning. One feature common to all decommissioning projects is the collection and handling of hazardous and nonhazardous wastes in accordance with regulations.

Prior to removal, a detailed plan should be developed on how each material is to be disposed of. The plan should identify recyclable materials such as steel, rubber, aluminum, etc. and include provisions for recycling. For those items not to be recycled, the decommissioning plan should consider the environmental impact of disposal on the dumpsite. Solid wastes should be handled onshore according to acceptable disposal practices.

Process systems throughout the platform should be flushed, purged, and degassed in order to remove any residual pressure and trapped hydrocarbons/fluids. Safe lock-out, tag-out, hot work, and vessel entry procedures should be in place to ensure safety. Hydrocarbon and other residues should be removed to the extent that they do not impact hot work and other operations during cutting and lifting.

A.14.2.7 Pipeline Decommissioning

All pipelines or flowlines connected to the platform should be decommissioned. Decommissioning costs and complexity are affected by pipe diameter, water depth, pipeline burial depth, and whether or not the pipeline is “riser to riser” or “riser to subsea tie-in.” The later will require additional subsea intervention during flushing operations and will increase the costs of decommissioning. Pipeline decommissioning “in situ” includes pipeline flushing (sometimes pigging), cutting and plugging the pipeline ends, and burying the ends to avoid future seafloor obstructions.

A.14.2.8 Conductor Removal

After the wells are P&A, all conductors should be removed up to a specified depth below the mudline as required by local regulations. The conductors may be cut and removed prior to the arrival of the HLV or may be removed by the HLV. Cutting, pulling, removing, and storing the conductor requires detailed planning.

A.14.2.9 Structure Decommissioning

The removal of offshore oil facilities should be accomplished using methodologies, which are efficient while providing for the safety for the workers and minimizing possible impact on the environment. Safety should always be the foremost consideration, with environmental impact and efficiency being weighed on a case-by-case basis.

Disposal issues are complex and are tied to the industrial capacity, environmental factors, and policy affecting the decommissioning area. These variables narrow the available choices for disposal of the deck and jacket materials.

There are three primary methods of disposal:

— refurbish and reuse,

— scrap and recycle,

— dispose in designated landfills.

In practice, a combination of these methods is likely to be employed, consistent with generally accepted waste disposal methods. The decision regarding the disposal and reuse options should be made as part of the overall assessment for decommissioning of the installation.

Structure Removal

The removal of deck and jacket structures is the primary task in the decommissioning of an offshore oil and gas facility. There are many challenges to the decommissioning process created by water depth and mass of the platform structure. There are also limitations of equipment and techniques, which should be assessed in order to choose the best combination of resources and technologies to adhere to the operational and metocean criteria established for the decommissioning site.

Deck and Modules Removal

Deck removal consists of removing the integrated deck or the deck modules and the module support frame. These items should have previously been prepped for lifting during the facilities decommissioning phase. This may be achieved by any of the following methods:

— remove in one piece,

— remove groups of modules together,

— remove in reverse order to installation,

— piece-small removal.

In many cases, the removal of topsides is likely to be the reverse process of the installation. However, the removal process is inherently more complex than the installation process since it has to take into account modifications, both structural and through addition/deletion of equipment during the service life of the platform.

A thorough safety assessment of the removal methods considered should be conducted for each platform. An assessment of the structural integrity of the lifted parts and lifting points is should be conducted to insure safe lifting operations.

Jacket Removal

Jacket removal can be accomplished in various ways and using a number of methodologies. All jacket removal operations should take place following the completion of pipeline decommissioning and deck removal. Available options include the following:

a) total removal (to shore for recycling or disposal as waste, transport to and placement at an artificial reef site, reuse, or other uses);

b) partial removal (to shore for recycling or disposal as waste and leaving the rest of the structure in place as an artificial reef);

c) reuse or other uses;

d) emplacement or toppling on site as part of an artificial reef program;

e) leave in place where permissible.

The structural design, potential reuse, availability of removal equipment, method of disposal, and the legal requirements governing the jurisdiction of the location of the decommissioning should determine the method of jacket removal. All these issues are interrelated and have a direct effect in the overall removal operation. Consideration of the issues will influence the selection of the pile and well conductor severing method. The success of the cutting method whether by explosives, abrasive cutters, or mechanical cutters will dictate the outcome of the jacket removal.

Jackets originally installed by lifting may be removed in a process, which essentially reverses the original installation. Jackets originally installed by launching that cannot be lifted onto barges may be removed by controlled deballasting and skidding the jacket back onto a properly configured barge. Another removal option might involve the underwater cutting of the jacket into smaller, more manageable lifts. Offloading and handling the cut sections should be given special consideration.

Jacket Removal—Partial

Prior to partial removal, the optimum location of the jacket cut points should be identified to minimize diving and cutting tool's onsite duration. The depth at which the jacket is to be severed should be established based upon the requirements of the owner/operator and the governing agency.

For jackets planned for toppling, the forces for each section should be calculated to confirm that the marine equipment selected have the capacity to topple the jacket. Prior to toppling, a diver or ROV can be used to verify that each steel member is completely cut.

Jacket Removal—Remote Reefing

Remote reefing requires the jacket to be lifted/refloated for transportation to a new location. A detailed weight and buoyancy take off should be performed to determine required lifting load or added buoyancy. Care should be taken if the jacket is towed "on the hook" of a HLV. Lifting padeyes can be prewelded to the jacket during the removal preparation phase.

The tow route should be selected to avoid subsea obstructions. A tow route survey can be performed to determine a viable tow route.

A.14.2.10 Site Clearance

The last stage in decommissioning offshore facilities is site clearance. Site clearance should be performed to address potentially adverse impacts from debris and seafloor disturbances due to offshore oil and gas operations. Typical procedures that can be used are:

- side scanning the work area,
- inspecting and cleaning up the work area, and
- trawling the work area.

There are many ways to locate and remove debris; the equipment available in the area and the water depth may affect the choice. A preliminary survey of the site with side scan sonar may be used to provide a target listing and location for existing debris. Debris removal should be performed within a specified radius of the decommissioning site. Any debris that is retrieved from the seafloor will need to be properly disposed.

Bibliography

[1] API Recommended Practice 2A-WSD, *Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design*, First Edition.

[2] API Recommended Practice 2A-WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design, Seventh Edition.

[3] API Recommended Practice 2A-WSD, *Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design*, 19th Edition.

[4] API Recommended Practice 2A-WSD, *Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design*, 20th Edition.

[5] API Recommended Practice 2D, *Operation and Maintenance of Offshore Cranes*

[6] API Recommended Practice 2FPS, *Planning, Designing, and Constructing Floating Production Systems*

[7] API Recommended Practice 2GEO, *Geotechnical and Foundation Design Considerations*

[8] API Specification 2H, *Carbon Manganese Steel Plate for Offshore Platform Tubular Joints*

[9] API Bulletin 2HINS, *Guidance for Post-Hurricane Structural Inspection of Offshore Structures*

[10] API Bulletin 2TD, *Guidelines for Tie-downs on Offshore Production Facilities for Hurricane Season*

[11] API Specification 2W, *Steel Plates for Offshore Structures, Produced by Thermo-Mechanical Control Processing (TMCP)*

[12] API Specification 2Y, *Specification for Steel Plates, Quenched-and-Tempered, for Offshore Structures*

[13] API Bulletin 2INT-DG, *Interim Guidance for Design of Offshore Structures for Hurricane Conditions*, May 2007

[14] API Bulletin 2INT-EX, *Interim Guidance for the Assessment of Existing Offshore Structures for Hurricane Conditions*, May 2007

[15] API Recommended Practice 54, *Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations*

[16] ISO 19902:2007 [1], *Petroleum and natural gas industries—Fixed steel offshore structures*

[17] NACE SP0108 [2], *Corrosion Control of Offshore Structures by Protective Coatings*

[18] NACE SP0176, *Corrosion Control of Submerged Areas of Permanently Installed Steel Offshore Structures Associated with Petroleum Production*

[19] *Metocean Criteria/Loads for Use in Assessment of Existing Offshore Platforms*, Petrauskas, C., Finnigan, T. D., Heideman, J., Santala, M., Vogel, M., and Berek, G., OTC 7484, Offshore Technology Conference Proceedings, May 1994.

---

1 International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, www.iso.org.

2 NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218-8340, www.nace.org.

[20] *Assessments of High Consequence Platforms: Issues and Applications*, Craig, M. J. K., and Digre, K. A., OTC 7485, Offshore Technology Conference Proceedings, May 1994.

[21] *Consequence-Based Criteria for the Gulf of Mexico: Development & Calibration of Criteria*, Ward, E. G., Lee G. C., Hall, R. A., Turner, J. W., Botelho, D. L., and Dyhrkopp, F., OTC 11886, Houston, TX, May 1–4, 2000.

[22] *The Influence of Framing Configuration on the Robustness of Offshore Structures*, Gebara, J., Westlake, H., DeFranco, S., and O'Connor P., OTC 8736, Houston, TX, May 4–7, 1998.

[23] NORSOK, N-004, *Design of Steel Structures*, Rev.1, December 1998.

[24] *API Recommended Practice 2A, Draft Section 17, Assessment of Existing Platforms*, Digre, K. A., Krieger, W. F., Wisch, D., and Petrauskas, C., Proceedings of BOSS '94 Conference, July 1994.

[25] *Process for Assessment of Existing Platforms to Determine Their Fitness for Purpose*, Krieger, W. F., Banon, H., Lloyd, J., De, R., Digre, K. A., Nair, D., Irick, J. T., and Guynes, S., OTC 7482, Offshore Technology Conference Proceedings, May 1994.

[26] *Detection of Jacket Member Severance using Structural Instrumentation*, Killbourn, S., 27th International Conference on Offshore Mechanics & Arctic Engineering, Estoril, Portugal, June 15–20, 2008, OMAE 2008-57391.

[27] *The Applicability of Online Monitoring for the Assurance of Fixed Jacket Structures Structural Integrity*, Sanderson, D., 21st International Conference on Offshore Mechanics & Arctic Engineering, June 23–28, 2002, Oslo, Norway, OMAE 2002-28614.

[28] *An Integrated Approach for Underwater Survey and Damage Assessment of Offshore Platforms*, Kallaby, J., and O'Connor, P., OTC 7487, Offshore Technology Conference Proceedings, May 1994.

[29] *Rationalization and Optimization of Underwater Inspection Planning Consistent with API 2A-WSD Section 14, Final Report*, MSL Services Corporation, Joint Industry Project, December 2000.

[30] *MMS Seminar on the Definition and Reporting of Significant Damage to Offshore Platforms*, June 26, 2003.

[31] *Guidelines for the Definition and Reporting of Significant Damage to Fixed Steel Offshore Platforms*, MSL Services Corporation, Joint Industry Project, January 2003

[32] *Structural Assessment of Existing Platforms*, Kallaby, J., Lee, G., Crawford, C., Light, L., Dolan, D., and Chen, J. H., OTC 7483, Offshore Technology Conference Proceedings, May 1994.

[33] *A Comparison of Analytically Predicted Platform Damage to Actual Platform Damage during Hurricane Andrew*, Puskar, F. J., Aggarwal, R. K., Cornell, C. A., Moses, F., and Petrauskas, C., OTC 7473, Offshore Technology Conference Proceedings, May 1994.

[34] *The Role of Ultimate Strength in the Structural Integrity Management (SIM) of Offshore Structures*, Westlake, H. S., Puskar, F. J., O'Connor, P. E., and Bucknell, J. R., Proceedings, Offshore Technology Conference, Paper No. 18331, May 2006.

[35] *Assessment of Fixed Offshore Platform Performance in Hurricanes Katrina and Rita*, Energo Engineering report for MMS, TAR No. 578, May 2007.

[36] *Reliability vs. Consequence of Failure for of API RP 2A Fixed Platforms Using API Bulletin 2INT-MET*, Energo Engineering report for MMS, TAR No. 609, March 2009.

[37] *Seismic Safety Requalification of Offshore Platforms*, Iwan, W. D., Thiel, C. C., Jr., Housner, G. W., and Cornell, C. A., May 2006, prepared for API, May 1992.

[38] *Proceedings of the International Workshop on Seismic Design and Reassessment of Offshore Structures*, Iwan, W. D., editor, California Institute of Technology, December 1992.

[39] *Proceedings of the Workshop on Public Policy Issues on the Seismic Requalification of Offshore Platforms*, Monahan, L., and Eskijian, M., compilers, November, 1993.

[40] *Proceedings of an International Workshop on Offshore Lease Abandonment and Platform Disposal: Technology, Regulation, and Environmental Effects*, Pulsipher, A., editor, April 1996.

[41] *Determination of Mean Yield Strength of Gulf of Mexico Fixed Steel Platforms for Ultimate Strength Assessment*, Energo Engineering report to API, 2010.

[42] *Comparison of Observed and Predicted Performance for Jacket Pile Foundations in Hurricanes*, Gilbert, R. B., Chen, J-Y, Materek, B., Puskar, F., Verret, S., Carpenter, J., Young, A., and Murff, J. D., Proceedings of the Offshore Technology Conference, Paper No. 20861, May 2010.

[43] *Development of Metocean Return Periods for API RP 2SIM*, Energo Engineering report to API, 2013.

energy API®

AMERICAN PETROLEUM INSTITUTE

1220 L Street, NW
Washington, DC 20005-4070
USA

202-682-8000

Additional copies are available online at www.api.org/pubs

Phone Orders:	1-800-854-7179	(Toll-free in the U.S. and Canada)
	303-397-7956	(Local and International)
Fax Orders:	303-397-2740	

Information about API publications, programs and services is available on the web at www.api.org.

Product No. G2SIM01