Interim Guidance for Gulf of Mexico MODU Mooring Practice—2006 Hurricane Season

API RECOMMENDED PRACTICE 95F
FIRST EDITION, MAY 2006

Interim Guidance for Gulf of Mexico MODU Mooring Practice—2006 Hurricane Season

Upstream Segment

API RECOMMENDED PRACTICE 95F
FIRST EDITION, MAY 2006

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

This recommended practice is under the jurisdiction of the API Upstream Executive Committee on Drilling and Production Operations (ECDPO).

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.

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, N.W., Washington, D.C. 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

For the purposes of this publication the following definitions apply:

Shall–the term shall indicates that the recommended practice has universal applicability to that specific activity.

Should–the term should denotes a recommended practice a) where a safe comparable alternative practice is available; b) that may be impractical under certain circumstances; or c) that may be unnecessary under certain circumstances or applications. This word indicates that the rule is a recommendation, the advisability of which depends on the facts in each situation.

Neither API nor any of API's employees, subcontractors, consultants, or other assigns make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or utility 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, or represent that its use would not infringe upon privately owned rights.

Users of this Recommeneded Practice should not rely exclusively on the informatoin contained in this document. Sound business, scientific, engineering, and safety judgement should be used in employing the information contained herein.

Users of Instructions should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgement should be used in emplying the information contained herein.

Work sites and equipment operations may differ. Users are solely responsible for assessing their specific equipment and premises in determining the appropriateness of applying the Instructions. At all times users should employ sound business, scientific, engineering, and judgement safety when using this Recommended Practice.

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

CONTENTS

Interim Guidance for Gulf of Mexico MODU Mooring Practice— 2006 Hurricane Season

1 Scope

This document provides guidance and processes and, when combined with an understanding of the environment at a particular location, the characteristics of the unit being utilized, and other factors, may be used to enhance operational integrity in the survival condition. This guidance was developed through a cooperative arrangement with the American Petroleum Institute's Subcommittee on Offshore Structures RP 2SK Task Group, the International Association of Drilling Contractors (IADC) Offshore Operations Division, and the Joint Industry Project entitled "US Gulf of Mexico Mooring Strength Reliabilty" (MODU JIP). The information presented herein is premised on the existence of a MODU evacuation plan, the intent of which is to assure timely and safe evacuation of all MODU personnel in anticipation of hurricane conditions.

This guidance is of an interim nature and is supplemental to the existing API RP 2SK, "Design and Analysis of Stationkeeping Systems for Floating Structures," 3rd Edition (2005). This guidance also addresses documentation expectations.

2 Basic Considerations

2.1 BACKGROUND

In 2004 and 2005, Hurricanes Ivan, Katrina, and Rita moved through the Gulf of Mexico with extreme wind and waves, causing a number of MODU mooring failures in their path. Mooring failures have occurred in previous hurricanes, including Hurricanes Andrew and Lili, but the number has been much lower.

Assessment of MODU mooring systems for worldwide operations has frequently been based on API Recommended Practices. The first MODU mooring recommended practice, released in 1987, specified a design environment lower than the 5-10 year return period in the present version of API RP 2SK, principally driven by the MODU mooring capacities available at that time. Building on the results of a Joint Industry Project focused on MODU mooring code calibration (Noble Denton, 1995), API RP 2SK incorporated more severe MODU metocean design criteria. These criteria, which are still in the current version of API RP2SK, are as follows:

- 5-year return period (away from other structure)
- 10-year return period (next to other structure)

There have been significant modifications in the underlying calibration parameters and Gulf of Mexico operations since the 1995 mooring code calibration study conducted 10 years ago which may influence the applicability to future activities. Differences include:

1. There are more floating and subsea installations and pipelines, which may result in higher risk of property damage or environmental impact, should a MODU break loose or drag its anchors under hurricane conditions.
2. The deepwater permanent installations have increased significantly, and therefore the cost for an incident can be much higher. These are high production rate installations that often share a pipeline to shore.
3. There are more deepwater MODU operations that typically use taut leg moorings with pile anchors, which may respond to hurricanes differently than the catenary moorings with drag anchors in shallow water operations.

2.2 MOORING ISSUES

This document supplements API RP 2SK for Gulf of Mexico MODU mooring design and operation practice during the hurricane season. Topics addressed herein that will be part of the overall mooring design and MODU operations include:

- Site-and well-specific data
- Design criteria for the mooring
- Indicative GOM hurricane extreme metocean conditions
- Mooring analysis
- Site-specific risk assessment and mitigation
- Mooring hardware issues such as anchor system and mooring system upgrade
- Mooring operation issues such as deployment, hurricane preparedness, and inspection

2.3   SITE-AND WELL-SPECIFIC DATA

For planning a MODU mooring operation, the following site-and well-specific data should be collected:

- Location Description
  - Block area
  - Water depth
  - Seabed conditions (soils) and hazards
  - Environmental description (e.g. chemosynthetics, archeological, etc.)

- Site-Specific Metocean Data and Source
- Well Description
  - Well type such as exploratory, development, workover
  - When it will be drilled (months)
  - Expected duration
  - Confidence in duration and potential overrun
  - Possible causes of delay

- Installation Hazards
- Close Critical Surface and Subsea Infrastructure
- Distant Critical Surface and Subsea Infrastructure

3   Mooring Analysis

3.1   MOORING ANALYSIS METHOD

Following API RP 2SK, both quasi-static and dynamic analyses may be utilized for MODU moorings. Either 1-minute wind speed or 1-hour wind speed with wind spectrum may be used for wind force calculation. It should be noted that the wind spectrum approach requires good estimates of low-frequency damping.

Wind, wave, and current forces and vessel motions should be evaluated using up-to-date MODU information. Many MODUs have gone through significant modifications involving additional hull structures and deck equipment that can change the environmental loads on the vessel. Wind, wave, and current force coefficients and models for hydrodynamic analysis should be adjusted to reflect the changes. The adjustment can be based on performance parameters derived from new model tests or rigorous analysis.

It is not possible to predict wind, wave, and current directions under hurricane conditions; therefore, sufficient environmental directions shall be investigated. As a minimum, bow, beam, quarter, down-line, and between-line environmental direction should be analyzed. Analysis for the damaged condition should investigate as many conditions as necessary to capture the critical case and as a minimum: damage of the most highly loaded line and adjacent lines.

3.2   MOORING STRENGTH ASSESSMENT

In addition to the conventional safety factor check, a mooring strength assessment should be performed. It is a useful tool for comparing different mooring systems for a given design criteria. Such an assessment can provide useful information for risk assessment and mitigation strategies.

The mooring strength limit is defined as the environmental return period at which the calculated maximum tension exceeds the strength of the mooring component. The mooring strength sensitivity assessment should be conducted for both the intact and the damaged conditions. Performing this analysis does not guarantee MODU mooring survival because of other potential failure modes, such as bending over the fairlead, wire fretting, elasto-plastic fatigue damage, etc. Anchor safety factors should be considered separately and appropriate factors chosen that adequately reflect the desired response.

Note: API RP 2I allows a mooring component to remain in use until its break strength is reduced to 90% of its catalog break strength. In addition, wire rope bending around the fairlead experiences further strength reduction; for a D/d ratio of 16, the strength is reduced to 90%.

4   Mooring Design Criteria

4.1   CURRENT DESIGN CRITERIA

API RP 2SK 3rd Edition (2005) provides the basis for mooring design in the Gulf of Mexico for both MODUs and permanent installations. Appendix I contains a listing of key MODU mooring design parameters extracted from API RP 2SK.

4.2   RECOMMENDED MODIFICATIONS FOR GULF OF MEXICO MODU MOORINGS

4.2.1   Design Environment Return Period

For operations during the hurricane season, the design environment return period should be established from the following principles:

- The return period should not be less than 10 years for the design of any mooring system based on site-specific metocean study
- A minimum 1-minute wind speed of 64 knots shall be used even if site-specific studies indicate a lower value
- In the absense of site-specific data, the environmental parameters presented in Section 11 shall be used
- Data used in preparing site-specific metocean parameters shall be inclusive of weather information for the period 1950 through 2005
- A site specific assessment as described in Section 5 shall be conducted for the specific drilling operation and loaction. Mitigation strategies should be considered during the design of the mooring system

4.2.2   Anchor Capacity

Anchor holding capacity (for all types of anchors) shall be considered in the design of the mooring system. Anchor selection should be based upon capacity, availablity, and protential to minmize damage to subsea infrastructure should an anchor failure occur in condition such as:

- A marine installation such as a pipeline, which lies in the dragging path between the anchor and the MODU
- A mooring line that crosses another mooring line
- Density or importance of seafloor or water column infrastructure merits a higher safety margin

Unless site-specific soil data is available, upper and lower bound soil conditions shall be considered.

5   Site-Specific Assessment

5.1   ASSESSMENT

The probablity and consequences of a MODU losing station when operating at any location within the US Gulf of Mexico should be assessed. The intent of the assessment process is to identify the characteristics of the area near the drilling operation, options related to mooring component selection and mooring system design, and mitigation opportunities prior to the finalization of the design, installation, and operation of the mooring system. The resulting mooring system should lead to an acceptable risk scenario through minimization of potential consequences due to the loss of function in a mooring component or mooring system or the reduction in the probablity that a mooring component or the mooring system will lose function for a given MODU and operation.

In performing the assessment, one souce of infrastructure information is the Gulf of Mexico infrastructure map maintained by the Minderals Management Service.

5.2   ASSESSMENT REQUIREMENT

Risk is defined as:

Risk = [Probability of an adverse effect occurring] x [The consequences associated with that event]

The risk can be reduced either by reducing the probability of experiencing an incident, or by reducing the consequences of that incident should it occur. A fundamental part of reducing the risk associated with MODU operations is to ensure that all parties have a clear understanding of their "Risk Exposure." These Guidelines contain two alternative approaches for assessing the mooring functionality and operation of any MODU location within the Gulf of Mexico. The two methods in order of increasing complexity are:

1. The checklist approach, which may be used for all drilling location assessments,
2. The full risk-based approach – an optional exercise that may be used to more accurately assess risk and risk mitigation options.

Note: The documented and structured approach including indentification of options available, impact of these options, and selection of lowest consequence available for the mooring system is valuable in the engineering of the mooring system.

5.2.1 Checklist Approach

The checklist approach is a simple evaluation methodology that allows the stakeholders to assess, on a relative basis, a level of risk the well operations represent. The intent of this approach is to be more conservative by comparison to a rigorous analysis. However, the checklist can be completed with the routinely available information and data that would be expected to be available to the Operator and Drilling Contractor.

An example checklist approach is included in Appendix II. The data portion within the checklist describes the attributes of the location and the drilling vessel mooring system. These include, for example, the local surface and subsea infrastructure, the general location, the type of mooring system to be used, and the months that the drilling operation is planned.

A checklist approach should be based on three dimensions:

1. Consequence factors based on location (infrastructure that could be damaged in the event of a mooring failure)
2. Design of mooring components and system
3. Likelihood of exceeding design conditons

5.2.2 Full Risk-Based Approach

The full risk-based approach is commonly used by a number of Operators. The process contains a series of steps to formally assess the risk at any given location. Due consideration should be given to the time required to complete this process. The steps can be summarized as:

- Definition of Location and Well Parameters
- Identification of Local and Distant Infrastructure
- Undertaking a Hazard Identification (HAZID) Study
- Likelihood of Mooring Failure
- Quantification of the Consequences of Failure (e.g., through Event Tree Analysis)
- Risk Mitigation
- Documentation

6   Mitigation and Consequences of Risk Reduction Measures

In all cases in which risk reduction measures are contemplated, their impact on other risks, often unrelated to the risk being mitigated, should be considered.

7   Mooring Considerations

7.1   MOORING SYSTEM UPGRADE

The ability to add additional mooring lines or replace existing chain and wire ropes with higher grade components of the same or larger size may be possible. Winches, windlasses, fairleads and their foundations should be checked to ensure that the additional strength of the upgraded components can be accommodated.

7.2   ANCHOR SYSTEM CONSIDERATIONS

The trade-off of using various anchor types should be evaluated for each individual operation to achieve best performance and minimize risk. Anchor handling vessel capability should be considered in selecting the best anchor option.

Note: Selection of anchor system plays an important role in hurricane survival and consequence of mooring failure. Currently drag anchors are commonly used for catenary moorings, while fixed anchors such as suction piles or VLAs (Vertically Loaded Anchors) are often used for taut or semi-taut moorings. In the event of mooring overload, drag anchors of the heavily loaded lines may slide causing favorable redistribution of the mooring load among the other mooring lines. This can help the mooring system survive storms that exceed the design environment. The use of fixed anchors may increase the likelihood of mooring failure under similar conditions because redistribution of mooring load cannot be

achieved. However, for locations where pipelines, subsea trees or manifolds exist, excessive anchor dragging can cause damage to these infrastructure elements.

In recent hurricanes, anchor drag distances for the windward lines were found to be less than 6,000 ft. In some cases anchor drag distances for the leeward lines have exceeded 100 miles. The large drag distances have been caused by failures of most of the windward lines with the MODU pulling and dragging the remaining few leeward anchors in the reverse direction.

VLAs typically have two options for fluke angle setting: normal and near-normal. In the normal setting, the anchor behaves as a fixed anchor, and overloading will either result in failure of the mooring line or cause the anchor to pull out. In the near normal setting, the anchor behaves as a drag anchor, and overloading will either reuslt in the failure of the mooring line or cause the anchor to drag and penetrate deeper. Selection of these options should be based on evaluation of the specific drilling operation.

Suction piles have been observed to fail at the pad-eye due to combination of tension and excessive out-of-plane bending. The out-of-plane bending occurs due to large vessel offset after the first line and subsequent line failures. Consideration should be given in the pad-eye design for the use of the breaking load of the mooring line applied at any angle.

8   Mooring Inspection

Mooring inspection for steel components shall be conducted according to the procedure and schedule specified in the current API RP 2I or per similar criteria as specified by the Drilling Contractor or rental equipment owner. The mooring inspection results shall be documented to show the inspection is current. Mooring inspection guidelines for fiber ropes are being developed and will be incorporated in a new edition of API RP 2I planned to be issued in late 2006. Special attention should be given to the following situations:

- Immediately after the passage of a hurricane, the reuse of mooring components (chain, wire, or polyester segments, or connecting hardware) from a mooring system damaged by the hurricane requires visual inspection of as much of the mooring system as is practical. This applies to all mooring components whether owned by the Drilling Contractor or Operator or supplied by a third party. All mooring components that do not pass inspection (criteria defined by API RP 2I or Drilling Contractor stated equivalence) shall be removed from service. After reconnection of inspected and/or modified damaged mooring lines, all of the mooring lines should be test loaded, and the test load should not be less than the original anchor test load.
- Reuse of fiber ropes from mooring systems damaged by hurricanes requires recertification.
- Fiber ropes with proven soil particle barriers that have come in contact with the seabed should be inspected prior to reuse. Ropes without proven soil particle barriers require recertification.
- Used mooring components for upgrading an existing mooring should be inspected before placing in service.
- If a MODU is used at one location for a period that is expected to exceed the recommended inspection interval, an inspection of the mooring system should be conducted before the MODU is moored on location.

9   Hurricane Preparedness

This section addresses specific mooring related issues that are part of a hurricane preparedness plan. The overall hurricane preparedness plan includes suitable provisions for other activities, such as personnel evacuation and suspension of drilling activities.

9.1   PREPAREDNESS OVERVIEW

The hurricane preparedness plan shall be a written plan and should consider the following mooring specific items:

- Ballasting operations
- Repositioning the vessel to a more favorable storm safe position within the already set anchor positions
- Mooring line payout and/or tension adjustments to optimize the mooring's storm survivability
- Engaging storm survival brakes and stoppers or securing and dogging winches
- Optimum mooring pattern and positions to maximize mooring performance
- Adequate anchor proof loading
- Provision of sufficient battery power, computer disc storage space, etc., to ensure that critical systems remain operational from the time the crew disembarks until the time the crew re-boards the MODU
- Confirmation that towing bridles and/or lines, navigation aids, and position tracking devices are installed and functional
- Operation and survival location moves

The hurricane preparedness plan should also include a schedule that reflects the time required to complete necessary mooring activities, operations to secure the well and the MODU, evacuate the crew to a safe location and allow for some contingency time.

9.2   LOOP AND EDDY CURRENTS

When a MODU is in a loop or eddy current, the Drilling Contractor and/or Operator must determine the mooring line adjustments required to maximize mooring line safety factors under combined loop/eddy and hurricane conditions. Adjustment of the mooring lines becomes a matter of abandoning the MODU in a condition that provides its best chance of riding out the storm with due consideration to the existing surface current velocity and direction.

Note: The Drilling Contractor and/or Operator should obtain the following information:

- Existing line payouts and tensions
- Latest measurements of the currents, particularly velocity and direction at the sea surface
- Any forecasts of the loop/eddy current velocity and direction

The Drilling Contractor and/or Operator should determine the optimum line payouts and/or pretensions that serve to maximize intact mooring line safety factors without exceeding equipment limits or endangering human life. The environmental conditions used for analysis should include the following weather combinations:

- Omnidirectional hurricane metocean criteria should be used
- Hurricane-driven surface currents should be vectorially added to the local eddy current
- The payouts and/or pretensions should be updated as surface current headings or velocities change

9.3   MODU RECOVERY

All units should be prepared to the extent feasible for towing. Each MODU should be equipped with a primary and secondary line. Transportation and marine vessels should receive priority allocation in any recovery operations immediately following passage of a hurricane for the purpose of MODU recovery.

9.4   CONTINGENCY PLANNING

Contingency plans shall address operations identified as critical to both hurricane survival and resumption of normal activities. The contingency plans shall address the need to have suitable personnel available to respond to the problem at hand. For example, if a mooring winch is inoperable and cannot be repaired, then it is necessary to have a mooring analyst determine suitable payouts and/or pretensions on the remaining lines that maximize survivability.

9.5   "MODU TRACKERS"

Satellite location transponders shall be installed and tested on board all moored MODUs operating in the Gulf of Mexico.   These transponder systems shall be function tested prior to Hurricane Season to ensure the system is functioning properly. Sufficient care shall be given to ensure these systems have adequate battery backup to enable the transponders to function after the MODU has been abandoned for a minimum period of seven days. Sufficient battery life should allow for reasonable assurance that the system will be operational through a given Hurricane Event and for a period of time after potential passage of the storm, to allow for speedy recovery operations in the event of mooring failure. The tracker system should be fully operational with seven day capacity within 48 hours of reboarding the MODU.

Redundancy in systems should be considered.

9.6   RESPONSE PLAN

MODU tracker data shall be made available to the USCG as one element of a comprehensive response plan. The information update frequency and content shall be defined in the response plan.

9.7   POST-STORM DATA

For all MODU's exposed to 60 knot winds (1-minute at 10 meters) or greater during a storm, the Drilling Contractor should fill out an information form capturing the MODU particulars and any storm related consequences. Appendix III contains a form that may be utilized for this purpose. API has granted license, without restriction, for reproduction of Appendix III for this purpose.

9.8   STACKED MODUS

These guidelines similarly apply to MODUs that are not working and "stacked." MODUs that are not actively working should be moored in accordance with the provisions of this document to minimize the likelihood of breaking free and inflicting damage.

Alternate methods of "stacking" MODUs, e.g. setting on bottom for MODUs that can accommodate bottom founding, may be acceptable provided appropriate engineering is performed to assure performance comparable to or better than that of moored MODUs.

If a stacked MODU looses station, the Drilling Contractor shall be responsible for all regulatory notification requirements.

10   Mooring Installation

10.1   MOORING INSTALLATION PLAN

The mooring system for a specific site should be deployed according to an installation plan that specifies a number of items related to the mooring design:

- MODU heading
- Mooring line headings, including installation tolerance
- Anchor locations, including installation tolerance
- Line segment lengths
- Pretensions
- Anchor test loads

The installation plan should also include information on:

- Minimum anchor handling vessel (AHV) specification (bollard pull, winch capacity and pull, other equipment requirements)
- Maximum sea states for safe operations
- Weather window requirements (i.e., duration of installation activities)
- Weather forecast requirements

Measures should be taken to avoid excessive deviation from the installation plan.

10.2   AS-INSTALLED MOORING SYSTEM INFORMATION

Once the installation is completed, information on the as-installed mooring system should be recorded and transmitted to the Drilling Contractor and Operator in a timely fashion. This information can be used by the Drilling Contractor and Operator for a number of purposes:

- Verify that the mooring system is installed within design tolerances,
- Verify that any deviations from the design tolerances will not have a negative impact on mooring system performance.

The Operator shall get the following information:

- Global Geometry
  - MODU heading and global position
  - Individual line headings
  - Initial and final anchor locations
- Mooring Composition
  - Lengths and locations of all mooring line sections
  - Number, locations, and types of connectors (i.e., shackles, connecting links, subsea connectors)
  - Anchor type, size, and fluke angle, as applicable
- Anchor Test Load
  - Test load at fairlead
  - Test load at anchor shackle
  - Estimated anchor drag distance
- Mooring Pretension
  - Pretension at fairlead, and estimation of accuracy
  - Line angle at fairlead, and estimation of accuracy.

10.3 POST INSTALLATION VERIFICATION

Based on the information specified in sections 10.1 and 10.2, the Operator should verify that the as-installed mooring meets the original safety factor requirements if it has been installed out of tolerance. If the as-installed mooring system does not meet the design saftey factor requirements, then appropriate action should be developed that provide acceptable mooring safety factors.

11 Indicative Gulf of Mexico Hurricane Extreme Environments

Site-specific criteria are the only manner that regional variations in storm climate as well as local topographic and bathymetric effects can be properly accounted. This criteria should be developed by a qualified metocean specialist. Site-specific criteria not only includes the tropical weather design conditions, but also addresses the various current types, profiles, and probabilities that may uniquely influence a given location. The weather data utilized in a site-specific study shall include at least the 56-year period beginning with 1950.

11.1 TABULAR METOCEAN PARAMETERS VS. RETURN PERIOD

The default metocean criteria used for MODU design, in the absence of site-specific data, shall be as follows:

- The peak enhancement factor, γ, for the JONSWAP spectrum should be 2.4 for hurricane seastates.\
- The NPD wind spectrum shall be used to describe the frequency content of wind energy

Return Period (yrs)	5		10		25		50		100	
Hourly wind speed @ 10 m (knots)	48.6		64.2		78.0		86.4		93.3	
One-minute wind speed @ 10 m (knots)	58.7		79.8		99.4		111.7		122.1	
Hs (ft)	23.0		31.8		41.3		45.9		48.9	
Tp (sec)	9.7 – 12.7		11.0 – 14.0		12.4 – 15.4		13.0 – 16.0		13.4 – 16.4	
Surge (ft)	0.48		0.91		1.33		1.56		1.76	
Current (knots)	Surface	1.50	Surface	2.14	Surface	2.77	Surface	3.13	Surface	3.40
	-11.2 ft	1.50	-16.1 ft	2.14	-20.7 ft	2.77	-24.6 ft	3.13	-25.6 ft	3.40
	-35.1 ft	1.32	-50.5 ft	1.91	64.6 ft	2.45	-76.1 ft	2.90	-79.7 ft	3.01
	-67.2 ft	0.86	-96.1	1.22	-121.4 ft	1.57	-146.0 ft	1.85	-150.9 ft	1.94
	-78.4 ft	0.43	-112.5 ft	0.60	-143.7 ft	0.78	-170.6 ft	0.93	-177.1 ft	0.97
	-103.0 ft	0.16	-147.9 ft	0.21	-188.9 ft	0.27	-224.0 ft	0.33	-233.2 ft	0.33
	-110.9 ft	0.0	-159.1 ft	0.0	-203.4 ft	0.0	-241.1 ft	0.0	-250.9 ft	0.0
The current direction can be taken to be between 0° and 30° clockwise of the wind The wave direction can be take to be between 0° and 20° clockwise of the wind										
Recommended Metocean Criteria for Gulf of Mexico Interim Guidance for MODU Mooring Operations during Hurricanes Peak Wind with associated wave, surge, and current case. U.S. units										
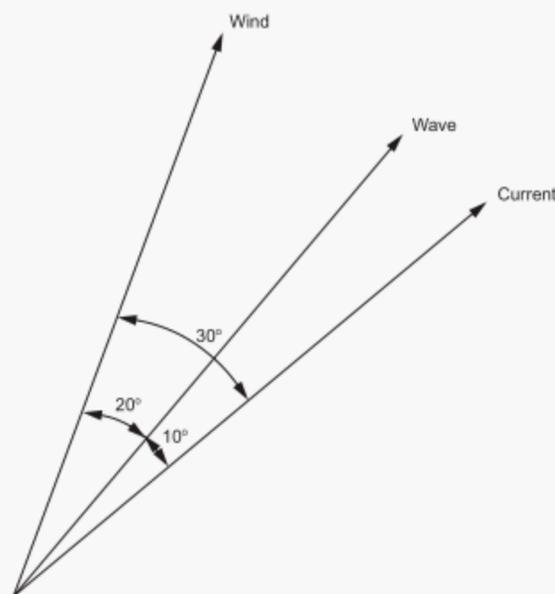
Directional Relationship for Peak Wind Case

Equations for metocean parameters:

$$V_R(\varepsilon, a, \beta) = V_{10}\left\{\varepsilon - \alpha\left[-\ln\left(1 - \frac{1}{R}\right)\right]^{\frac{1}{\beta}}\right\}, \text{ for } 10 \le R \le 200$$

where

V_R = R-year return period value of environmental parameter

R = return period (years)

V_{10} = 10-year return period value of enviromental parameter

ε = threshold parameter

α = scale parameter

β = shape parameter

	ε	α	β
1-hour Wind Speed at 10 m elevation	2.021	1.795	3.988
Significant Wave Height, Hs (m)	1.736	2.565	1.802
Surface Current Speed	2.068	2.311	2.917

The relationship between 1-hour and 1-minute wind speeds at 10 m, based on the NPD wind spectrum, is:

$$V_{1-\text{Min}} = V_{1\text{-Hr}}(1.1007 + 0.002226 V_{1\text{-Hr}}), \text{ where } V_{1\text{-Min}} \text{ and } V_{1\text{-Hr}} \text{ are in knots}$$

Note: A minimum site-specific hindcast study for the tropical weather and winter weather parameters requires the following:

Hurricane Extremes: These will be based on a hindcast database of winds, waves, and currents derived from numerical models that have been validated against severe historical storms. That validation will show the wave and wind models have a coefficient of variation (COV) no more than 15% when comparing model peak storm values to measurements. The acceptable COV for the current model validation can be as high as 30%. Any bias between the model and data will be removed with at least a simple linear fitting process.

The hindcasted period will include at least the 56 year period beginning 1950. The numerical models will be based upon discrete finite element or finite difference solutions of the governing partial differential equations, and not parametric models. Grid resolution will be a minimum of 15 km, and the overall domain will cover at least the northern half of the Gulf of Mexico.

An extremal analysis will be performed on the hindcast results using either a pooling method or a deductive model as described in Toro[1]. If pooling is chosen, then at least three sites in a general east-west direction will be pooled, with the pattern centered on the location of interest. These sites shall have a spacing of 75 to 150 km but will span a total distance of no more than 300 km. When pooling within 200 km of the coast, the pooled sites must be chosen to ensure that they have fetch and depth similar to the site of interest.

Winter Extremes: These will be based on either hindcast model results or analysis of nearby buoy data, i.e. the NDBC buoys. If hindcast models are used, they will cover at least 15 years encompassing the months of October-April, and have been validated in the same manner as described above for the hurricane models. If buoy wind and wave measurements are used, they will cover at least five years of measurements covering the months of October-April. Currents can be based on one year of data collected during October-April. Measurements should have been taken in a similar water depth and preferably within a few tens of kilometers of the site of interest. A trained metocean specialist will review the measurements and apply adjustments for fetch and water depth.

Operational Criteria: These will be based on the same methods used for the winter extremes described in the previous paragraph.

All three criteria categories need to be included in derivation of site-specific studies due to overlap of seasonal information in determination of design criteria for any given location and deployment period.

---

[1]Toro, et. al, 2005, Comparison of historical and deductive methods for the calculation of low probability sea states in the Gulf of Mexico, OMAE, 51634.

APPENDIX I—SUMMARY OF API RP 2SK, 3RD EDITION KEY DESIGN CRITERIA

Note: API RP 2SK aslo addresses moorings for permanent facilities.

A.1 Design Environment Return Period

A.1.1 PERMANENT MOORING: 100-YEAR (DEFAULT)

MODU mooring:

- 5-year (away from other structures)
- 10-year (close to other structures)

A.2 Tension Criteria

The following tension criteria are applicable for permanent and MODU moorings.

	Analysis Method	Tension Limit (Percent of MBS)	Equivalent Factor of Safety
Intact	Quasi-static	50	2.0
Intact	Dynamic	60	1.67
Damaged	Quasi-static	70	1.43
Damaged	Dynamic	80	1.25

A.3 Drag Anchor Safety Factors

	Quasi Static Analysis	Dynamic Analysis
Permanent Mooring		
Intact condition		1.5
Damaged condition		1.0
Mobile Mooring		
Intact condition	1.0	0.8
Damaged condition	not required	not required

A.4 Safety Factors for Pile, Plate, and Gravity Anchors (Dynamic Analysis)

Condition	Suction/Driven Pile and Gravity Anchor				Plate Anchor	
	Permanent		Mobile		Permanent	Mobile
	Lateral	Axil	Lateral	Axil		
Intact	1.6	2.0	1.2	1.5	2.0	1.5
Damaged	1.2	1.5	1.0	1.2	1.5	1.2

APPENDIX II—RISK ASSESSMENT WORKSHEET

This appendix is composed of three sections:

- The assessment questionnaire
- Listing of values for the various parameters
- Discussion on the formulation of the tool

Notes regarding usage of Checklist Assessment Tool:

1. A user can base decisions as to preferred mitigation options in design by use of the tool, or a similar tool, and the qualitative assessments.

2. If a user desires to compute numerical scores, a value of unity may be used for a Base value and values less than unity developed for terms such as Slightly Better, Better, Much Better, Significantly Better. User selected values allow for rapid sensitivity assessments.

3. Some questions have a multiplier range provided. The values provided are indicative of values that may be used in a numerical analysis to account for relative importance, likelihood, and/or consequence. The user is encouraged to select a value commensurate with these items and consistent throughout the evaluation.

4. Following the 24 topic questions, a tabular listing of groupings can be found. This table, along with the subsequent tables and notes, provides one means for a user to compute numerical scores, identify sensititives by various groups of consequences, etc. via numerical models if desired.

5. There is a discussion section at the end of the questions and tables providing additional information related to background and/or basis.

1.   What block area is the location within?

Certain areas of the Gulf of Mexico are more densely populated with both surface and subsea infrastructure. Area can be used to help identify infrastructure elements as well as area of the highest expected storm activity based on hindcast studies. Use of infrastructure maps, such as the MMS map referenced in the main document (see 5.1), provide guidance in selection of infrastructure importance for given areas of siting and nearby waters.

Response		Response	
Destin Dome		Eugene Island	
Desoto Canyon		Ewing Bank	
Lloyd Ridge		Green Canyon	
Henderson		Walker Ridge	
Florida Plain		Amery Terrace	
Lund South		Keathley Canyon	
Lund		Garden Banks	
Atwater Valley		South Marsh Island	
Mississippi Canyon		Vermilion	
South Pass		East Cameron	
Viosca Knoll		West Cameron	
Main Pass		East Breaks	
West Delta		Alaminos Canyon	
Grand Isle		Port Isabel	
South Timbalier		Corpus Cristi	
Ship Shoal			

Areas of high density infrastructure may include Eugene Island, Ewing Bank, SouthMarsh Island, Vermilion, East Cameron, West Cameron, Mississippi Canyon, West Delta, Grand Isle, South Timablier, Ship Shoal.

Areas of low density may include Destin Dome, Desoto Canyon, Port Isabel, Corpus Christi.

2.   What is the water depth category for the location?

Most MODU units have an optimum water depth range. Generally, shallow water of less than 1,000 feet, will tend to result in less robust mooring systems, with a higher probability of failure. Note that the cost and impact of damage to subsea infrastructure

in deepwater is often greater than in the shallower waters. The checklist accounts for an increase in the probability of failure in shallow water, but an increase in the subsea damage consequence of failure in deepwater.

Response	Surface value	Subsea value

Response	Surface value	Subsea value
<1000 ft	Base	Slightly Better
1000 ft – 4000 ft	Slightly Better	Base
>4000 ft	Slightly Better	Base

3. Does the location have complex seafloor bathymetry? (Complex defined as greater than 15% variation over Mooring Pattern)

Complex seafloor bathymetry increases the uncertainty in the mooring analysis and can adversely affect the reliability of the installed mooring system.

Response	Value

Response	Value
Yes	Base
No	Slightly Better

4. During what months is the operation planned? (Check all that apply)

The months of operation probably have a great influence on a risk assessment. Not only are there more storms at the height of the hurricane season, but they also tend to be more severe. When performing an evaluation, one month should be added to the end of the drilling program for contingency. Drilling programs should incorporate contingencies to account for either delays in start, or overruns during operations. It is recommended that contingency plans be pre-established to account for possible delays. If there is a change in actual drilling program that has not been fully accounted for in the risk assessment, then the evaluation should be re-run for the actual case.

Altering the drilling season is one of the most effective ways to reduce the risk of drilling a particular location. Serious consideration should be given, wherever practicable, to drilling the highest risk wells at the least intense parts of the hurricane season.

The values below are representative of a normalized distribution based on historical activity in the Gulf of Mexico (see details in the discussion section of this appendix). There will be some variation to the values listed below based on site-specific studies and/or usage of different databases.

Response	Value

Response	Check months including contingency		Probability of storm occurring	Probability of storm not occurring
			A	B
January			0.001	0.999
February			0.001	0.999
March			0.001	0.999
April			0.01	0.99
May			0.05	0.95
June			0.109L	0.891
July			0.145	0.855

Response	Check months including contingency		Probability of storm occurring	Probability of storm not occurring
			A	B
August			0.273	0.727
September			0.291	0.709
October			0.2	0.8
November			0.1	0.9
December			0.01	0.99

Procedure

1. Check boxes next to months in which operation will occur
2. Check next month as a contingency (e.g. if operations are expected for the months May and June, check May, June, and July)

5. Are there mooring lines over pipelines? (If "Yes" proceed to question 5A, if "No" skip to question 6)

This question, and those that follow, ask specific questions about the local subsea infrastructure. Pipelines represent a relatively high consequence.

Response	Value
Yes	Base
No	

Response	Value

If computing numerical values, a multiplier of 20-40 may be considered for this question.

Note: Some of the yes/no responses are binary. Base could be taken as unity with the other term essentially Null.

5A. Are the pipelines greater than 10 inch?

A 10-inch pipeline has been chosen as the "break point" between small and large, consistent with MMS reporting following recent hurricanes. Large lines have significantly higher consequence factors as they may be transporting hydrocarbons from a number of wells and facilities. Loss of a large line could cause significant loss of production. No account is taken for multiple pipelines, so if there is more than one, the size of the largest should be used.

Response	Value

Response	Value
Yes	Base
No	Significantly Better

5B. Which direction from the rig location are these pipelines? (Check all that apply)

Should a storm adversely affect the mooring system, the direction to subsea infrastructure affects the probability that it will be damaged. The highest winds within a hurricane are normally in the northeast quadrant, blowing towards the northwest. If a MODU is exposed to a number of different quadrants of a passing storm, then the NE quadrant is most likely to cause an adverse effect. Also, it is likely that a MODU will first be affected by the northern side of a hurricane before the southern side. Hence the most likely direction of MODU drift can be estimated.

Directional bearings are intended to be TRUE and not relative to rig heading. These values are relative values normalized to Northwest based on historical paths. Values different from those below may be developed should different data sources or interpretive methods be used.

Response	Values for your response	Value
North		0.8
Northeast		0.7
East		0.6
Southeast		0.7
South		0.6
Southwest		0.6
West		0.9
Northwest		1.0

6.   Are there pipelines within one mooring radius of any anchor? (If "Yes" proceed to question 6A, if "No" skip to question 7)

See comments to 5.

Response	Value
Yes	Base
No	

Response	Subsea Value

If computing numerical values, a multiplier of 20-30 may be considered for this question.

6A. Are the pipelines greater than 10 inch?

See comments to 5A.

Response	Value

Response	Value
Yes	Base
No	

6B. Which direction from the rig location are these pipelines? (Check all that apply)

See comments to 5B.

Response	Values to your response	Relative Value
North		0.8
Northeast		0.7
East		0.6
Southeast		0.7
South		0.6
Southwest		0.6
West		0.9
Northwest		1.0

7.   Are there any pipelines between one mooring radius from any anchor and 10 miles? (If "Yes" proceed to question 7A, if "No" skip to question 8)

See comments to 5.

Response	Value
Yes	Base
No	

Response	Subsea Value

If computing numerical values, a multiplier of 10-20 may be considered for this question.

7A. Are any of the pipelines greater than 10 inch?

See comments to 5A.

Response	Subsea Value

Response	Value
Yes	Base
No	

7B. Which direction from the rig location are these pipelines?

See comments to 5B.

Response	Values for your response	Relative Value
North		0.8
Northeast		0.7
East		0.6
Southeast		0.7
South		0.6
Southwest		0.6
West		0.9
Northwest		1.0

8.   Are there mooring lines over umbilicals? (If "Yes" proceed to question 8A, if "No" skip to question 9)

Umbilicals are easily damaged, but have a relatively low consequence rating within this approach. While they are important, they generally affect only one well or a small number of wells, and may not have a major impact on the overall production levels within the Gulf of Mexico. However, they can be extremely difficult to replace, and may have long lead times on replacement. Companies may want to increase the significance of umbilicals for their own internal purposes, but from a Gulf of Mexico production perspective, they are less important than pipelines.

Response	Value
Yes	Base
No	

Response	Subsea Value

If computing numerical values, a multiplier of 1-10 may be considered for this question.

8A. Which direction from the rig location are these umbilicals?

See comments to 5B.

Response	Values for your response	Relative Values
North		0.8
Northeast		0.7
East		0.6
Southeast		0.7
South		0.6
Southwest		0.6
West		0.9
Northwest		1.0

9.   Is there a template manifold or pipeline end manifold (PLEM) within one mooring radius? (If "Yes" proceed to question 9A, if "No" skip to question 10)

Templates and PLEMS have a higher consequence value than umbilicals, but are often considered of lower consequence than pipelines.

Response	Value
Yes	Base
No	

If computing numerical values, a multiplier of 1-10 may be considered for this question.

Response	Subsea Value

9A. Can failed mooring components drop on these components?

The questions concern the possibility of any mooring component falling onto the subsea component, and hence damaging it. Due consideration needs to be given to possible mooring failure scenarios when answering this question. The fact that a subsea component is located between two mooring legs is not, by itself, sufficient argument that a mooring component could not fall onto the wellhead, given the possible movements of the MODU.

Response	Value

Response	Value
Yes	Base
No	Much Better

10. Are there any live wellheads within one mooring radius? (If "Yes" proceed to question 10A, if "No" skip to question 11)

See comments to 9.

Response	Value
Yes	Base
No	

Response	Subsea Value

If computing numerical values, a multiplier of 5-20 may be considered for this question.

10A. Can failed mooring components drop on these components?

See comments to 9A.

Response	Value

Response	Subsea Value
Yes	Base
No	

11. Do any of the mooring lines cross moorings of other temporary facilities (e.g. Other MODU)?

There is clearly a threat that if either of the mooring systems fail, then there could be an adverse effect on the moorings of the other unit. This would a high-consequence event. There is, however, a relatively high probability that even in the worst case, the MODU and other facility will not be irreparably damaged.

Response	Surface Value

If computing numerical values, a multiplier of 15-25 may be considered for this question.

Response	Value
Yes	Base
No	

12. Do any of the mooring lines cross moorings of other permanent facilities?

Similar to question 11 comments, although the consequences are even greater.

Response	Surface Value

If computing numerical values, a multiplier of 30-50 may be considered for this question.

Response	Value
Yes	Base
No	

13. Is there a surface facility within one mooring radius? (If "Yes" proceed to question 13A, if "No" skip to question 14)

This is a potentially higher consequence situation than even 11 or 12. The concern is that a mooring will fail, and the MODU will swing on the remaining moorings into the floating facility. The resulting impact would likely cause considerable damage, especially given the severe weather prevalent at the time, and could even result in loss of one or both units.

Response	Value
Yes	Base
No	

Response	Surface Value

If computing numerical values, a multiplier of 50-70 may be considered for this question.

13A. What type of facility is it?

All floating facilities have the same consequence factor. Bottom founded structures have been included as lower consequence because they may be more likely to survive in a repairable condition, generally have lower capital investment, and riser damage would likely be more easily repaired.

Response	Values for your response	Relative Value
Fixed Jacket		0.5
Mini TLP		1
TLP		1
SPAR		1
Semi Submersible		1

14. Is there a surface facility between one mooring radius from any anchor and 10 miles? (If "Yes" proceed to question 14A, if "No" skip to question 15)

Distance to surface facility is considered between 1 mooring radius from the position of any anchor and 10 miles from the position of any anchor. The use of a 10-mile radius is slightly arbitrary, but infrastructure outside that range was considered to be covered by Question 1, the block area of operation.

Response	Value
Yes	Base
No	

Response	Surface Value

If computing numerical values, a multiplier of 20-30 may be considered for this question

14A. What type of facility is it?

Surface facilities that have a mooring system are taken as being larger targets, hence have a higher probability of being hit. Consequently, spread moored facilities are given a higher factor than TLPs and jackets/compliant towers. Relative value for spread moored systems may also be a function of expected anchor behavior, i.e. drag anchors vs. VLA vs. suction piles..

Response	Values for your response	Relative Value
Fixed Jacket		1
Mini TLP		1
TLP		1
SPAR		2-10
Semi Submersible		2-10

15. What type of mooring system is planned?

An inherent assumption of this checklist approach is that any system chosen is designed to the same level of utilization. Different levels of analysis may have been undertaken, and credit is given for that, but regardless of the level of analysis, if two systems are "compared," it is assumed that they will have the same safety factor in the same return period event. Hence differences are due to those that are inherent within the design, be they features or disadvantages.

The type of mooring system has an impact on the probability of failure, and the consequences of failure. However, a system that may be good in one way may be bad in another. For example, a conventional catenary moored unit is likely to have a robust mooring system. There considerable experience with these, hence they are better understood, and they are generally more robust and less sensitive to small errors in either installation or analysis. However, a catenary mooring system will have a considerable quantity of chain at the seabed, and in the event of the MODU drifting, could do significant subsea infrastructure damage. Con-

versely, a semi-taut steel wire system may have a higher probability of failing, but the damage to subsea equipment may be significantly less.

Note: Two values are generated through an answer to this question: one for surface damage probability and one for subsurface.

Semi-taut systems allow for grounded length. Taut systems are designed to allow for zero-grounded length.

Response	Surface value	Subsea value

Response	Surface value	Subsea value
Catenary	Better	Base Value
Semi-taut Steel	Base Value	Better
Semi-taut Poly	Better	Better
Taut Poly	Better	Better
Hybrid Taut	Slightly Better	Better
Hybrid Cat. Semi-taut	Slightly Better	Base Value

16. Number of mooring lines.

The number of mooring lines has an effect on the mooring system reliability. Generally, more lines leads to a higher reliability, although certain grouped moorings may not accurately fit the pattern. The checklist is not very sensitive to the number of lines (i.e. the response to this question) because it is assumed in these calculations that any of the systems will have been designed for the same extreme event (see comments to question 15). Relative values cannot be pre-assigned without knowledge of a given line geometry.

Response	Value (Same for Surface and Subsea value)

Response	Value
8	
9	
10	
12	
16	

17. Is there a planned survival location?

A planned survival location, with optimized line tensions, will generally increase the reliability of the mooring system.

Response	Value (Same for Surface and Subsea value)

Response	Value
Yes	Slightly Better
No	Base Value

18. Is the mooring system biased for subsea architecture?

This question is intended to address the reduced performance possible when mooring spreads are asymmetrical to avoid bottom hazards. A mooring system optimized for survivability is less likely to have mooring problems than a biased or skewed system.

Response	Value (Same for Surface and Subsea value)

Response	Value
Yes	Base Value
No	Slightly Better

19. Complexity of mooring installation requirements (the more complex the system, the more time it takes to hook up).

This factor is intended to capture the exposure associated with long installation times with the unit partially moored during the rig move. The complexity refers to the time taken while the unit is on location connecting up. The time to install a pre-installed system should not be considered.

Response	Value (Same for Surface and Subsea value)

Response	Value
Low	Base to Slight Better
Medium	Base to Slightly Better
High	Base Value

20. What type of anchors will be used?

Two numbers are required for anchors: one for potential surface infrastructure damage and the other for subsea damage. For potential surface damage, most of the anchors are the same. Only the conventional and High Holding Capacity Drag Anchors (HHCDA) with capacity less than the mooring line strength have slightly higher probability values. In most cases, the type of anchor has limited impact on the probability, or consequences, of a MODU causing surface infrastructure damage.

For subsea infrastructure damage, however, the situation is very different. The best anchors are those that will not pull out of the seabed, and will not drag components across the seafloor in the event of any mooring failure.   Drag anchors have a higher risk number than other anchor types (excluding drag embedment VLAs). The reason is that there is relatively high probability the leeward anchors will pull out in the event of windward mooring line failure. Hence, even if the anchor has a higher holding capacity than the strength of the mooring line, if the windward lines fail, the leeward anchors likely will be dragged as the MODU drifts over them and pulls them in the "wrong" direction.

Note: It is important that if piles/VLAs/SEPLA are used to mitigate the probability of damaging subsurface equipment, then their holding capacity should be greater than the maximum breaking strength of the mooring line in any possible loading direction, and all reasonably possible soils conditions, even considering all possible mooring line failure combinations. In addition, the installation procedure should be developed to ensure that this holding capacity can be achieved. This is particularly important for VLAs. It is of note that during Hurricane Rita one unit fitted with VLAs suffered a mooring failure and dragged the anchors for over 100 miles. Unless this type of failure can be absolutely guarded against through design and installation, VLAs should be rated at the same level as "high holding capacity anchors (less capacity than mooring minimum break load (MBL))."

Response	Surface value	Subsea value

Response	Surface	Subsea
Suction pile (designed for significant out-of-plane loading)	Better	Best Option
Suction pile (NOT designed for significant out-of-plane loading)	Better	Significantly Better
High holding capacity drag anchor (greater capacity than mooring mbl)	Better	Much Better
High holding capacity drag anchor (less capacity than mooring mbl)	Base Value	Better
Conventional drag anchor (no anchor uplift allowance)	Base Value	Base Value
Drag installed VLA	Better	Significantly Better
SEPLA	Better	Significantly Better

21. What type of mooring analysis was conducted? (If "Quasi-Static" or "Dynamic" proceed to question 22A, if "None" skip to question 23.

There is no distinction, at this stage, between a quasi-static and a dynamic mooring analysis since API RP 2SK accounts for difference in the required safety factors. There is, however, a heavy penalty for "no mooring analysis."

Response	Value (Same for Surface and Subsea value)

Response	Value
None	Base
Quasi-Static	Much Better
Dynamic	Much Better

21A. Which of the following factors apply to the analysis conducted?

3 DOF is the least good type of analysis as in many cases the heave component at the fairlead can have a significant effect on the mooring line loads.

Response	Values for your response	Relative Value
3 DOF		Base
6 DOF		Better

22. Which of the following component are used at the seafloor in the mooring configuration?

The component at the seafloor affects the potential damage to subsea equipment in the event of a mooring failure. Chain on the seafloor can do considerably more damage to subsea equipment than wire, and wire, in turn, more than polyester.

Response	Subsea value

Response	Value
Chain on the seafloor	Base case
Wire on the seafloor	Better
Polyester on the seafloor	Significantly Better

22A. Which of the following components are used at the fairlead in the mooring configuration?

The component at the fairlead affects the probability that there is a mooring failure. Chain is more robust, and less likely to suffer abrasive damage during the storm, and hence is preferable.

Response	Value (Same for Surface and Subsea value)

Response	Value
Chain in the fairlead	Better
Wire in the fairlead	Base

23. Is subsea buoyancy utilized to mitigate component failure consequences?

Buoyancy can be used to help reduce the probability of damaging subsea equipment.

Response	Subsea value

Response	Value
Yes	Slightly Better
No	Base

24. Are synthetic mooring components utilized to mitigate component failure consequences?

Synthetic mooring components can be used to help reduce the probability of damaging subsea equipment.

Response	Subsea value

Response	Value
Yes	Slightly Better
No	Base

Factors	Raw values	Min possible value	Min. value	Surface Weight	Surface value	Min. value	Near Subsea Weight	Near subsea value	Min value	Far Subsea Weight	Far subsea value
Columns	C1	C2	C3	C4	C5	C6	C7	C8	C9	C10	C11
Overall mooring improvement factor	= Product of response values of questions 17,18,19										
Analysis factor	Product of response values of questions 21										
Reliability factor	Product of response values of questions 16, 22A, 25 and 3										
Near subsea protection factor (excluding anchors)	Product of response values of questions 22, 23 24										
Mooring type factor	Surface value of question 15	-	-			-		-		-	-
	Subsea value of question 15										
Anchor factor	Surface value of question 20	-	-			-		-		-	-
	Subsea value of question 20										
					SUM			SUM			SUM

Equations:

Surface value: C5 = (1-((1-C1) * (1-C3)) / (1-C2)) * C4 (For mooring and anchor factors use surface value of C1)

Near Subsea value: C8 = (1-((1-C1) * (1-C6)) / (1-C2)) * C7 (For mooring and anchor factors use subsea value of C1)

Far Subsea value: C11 = (1-((1-C1) * (1-C9)) / (1-C2)) * C10 (For mooring and anchor factors use subsea value of C1)

Factors	Raw values	Min possible value	Surface			Near Subsea			Far Subsea		
Columns	C1	C2	Min. value C3	Weight C4	Surface value C5	Min. value C6	Weight C7	Near subsea value C8	Min value C9	Weight C10	Far subsea value C11
Overall mooring improvement factor											
Analysis factor											
Reliability factor											
Near subsea protection factor (excluding anchors)											
Mooring type factor											
Anchor factor											

Equations:

Surface value: $C5 = (1-((1-C1) * (1-C3)) / (1-C2)) * C4$ (For mooring and anchor factors use surface value of C1)

Near Subsea value: $C8 = (1-((1-C1) * (1-C6)) / (1-C2)) * C7$ (For mooring and anchor factors use subsea value of C1)

Far Subsea value: $C11 = (1-((1-C1) * (1-C9)) / (1-C2)) * C10$ (For mooring and anchor factors use subsea value of C1)

26

Consequence factor

| Consequence factor	Equation	Value
Block area consequence factor	Value of question 1	
Near surface consequence factor	Value from question (11 + 12 + 13)	
Far surface consequence factor	Value of question 14	
Near subsea consequence factor	Value from question (5 + 6 + 8 + 9 + 10)	
Far subsea consequence factor	Value of question 7	

Risk	Raw risk value	Significance/ Confidence	Season factor	Water depth	Risk
Block area	= Block area consequence factor * (sum C5 + sum C8)/2		Surface value of question 4	Surface value of question 2	= raw risk value * significance/confidence * season factor * water depth
Near surface	= near surface consequence factor * sum C5		Surface value of question 4	Surface value of question 2	= raw risk value * significance/confidence * season factor * water depth
Far surface	= far surface consequence factor * sum C5		Surface value of question 4	Surface value of question 2	= raw risk value * significance/confidence * season factor * water depth
Near subsea	= near subsea consequence factor * sum C8		Subsea value of question 4	Subsea value of question 2	= raw risk value * significance/confidence * season factor * water depth
Far subsea	= far subsea consequence factor * sum C11		Subsea value of question 4	Subsea value of question 2	= raw risk value * significance/confidence * season factor * water depth
Total risk factor					= Sum
Location adjusted risk					= Total risk factor, if value of question =

Risk	Raw risk value	Significane/ Confidence	Season factor	Water depth	Risk
Block area					
Near surface					
Far surface					
Near subsea					
Far subsea			Location adjusted risk	Total risk factor	

Details of Checklist Approach

Overview

The checklist approach is a simple risk assessment methodology that allows the stakeholders to assess, on a consistent basis, the level of risk the well operations represent. This appendix gives a more detailed description of the process, and includes a series of worksheets that can be completed to derive the combined location and mooring risk assessment. The primary purpose of the approach is to develop a high-level overview of the risks, but without completing the full calculations: the last part is left open for the analyst to then complete by deciding on a suitable design return period, and other mitigation measures that may be suitable. The basic simplified flow of the checklist is given in the figure below.
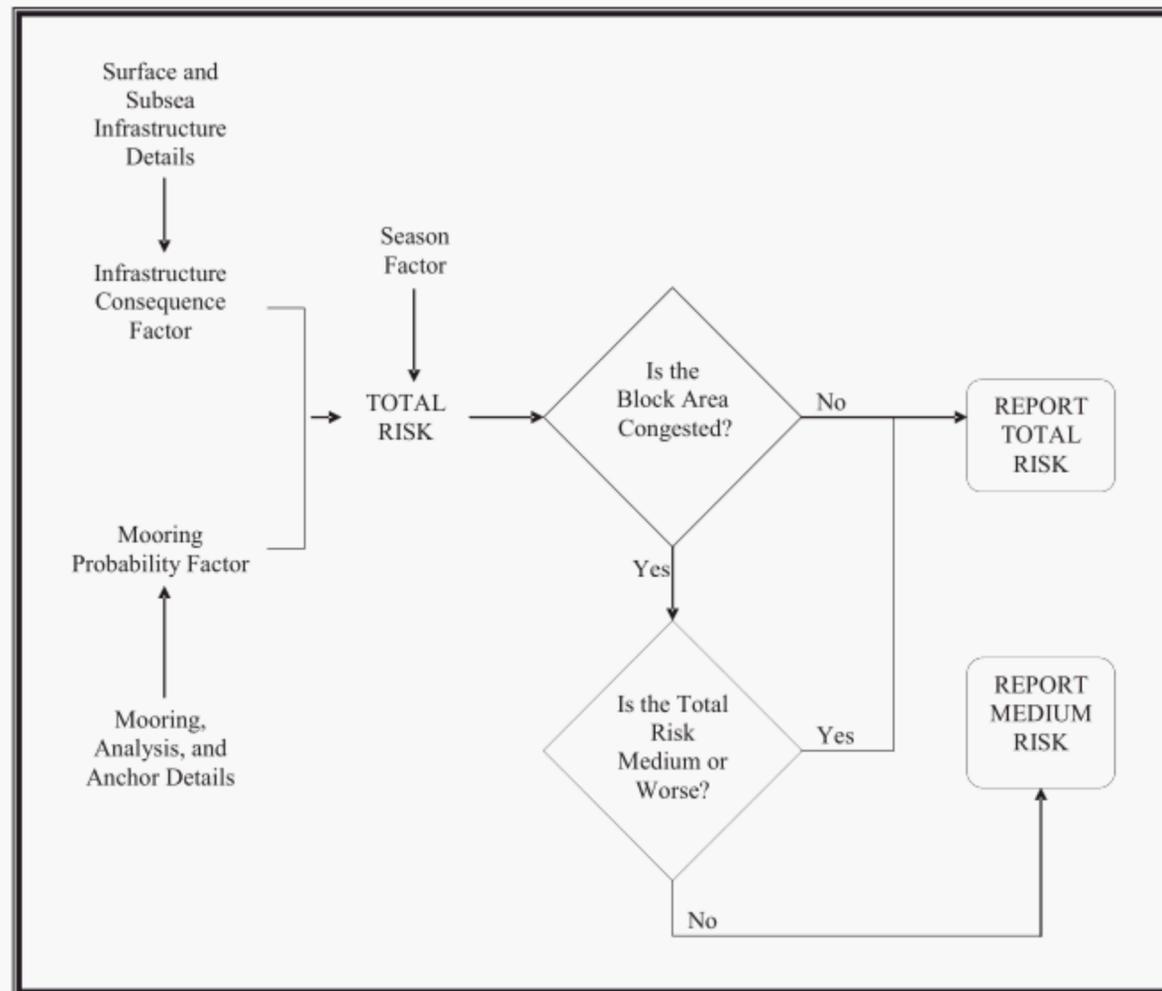
The risks associated with drilling a specific location can be considered to be a combination of the probability that a unit will suffer a mooring failure and the consequences should such a failure occur. Probably the most important factor affecting the suitability of a location is the season in which it is to be drilled. Choice of the months on location has a large impact on the resulting risk assessment, and can be a powerful method of altering the derived risk value. This is discussed in greater detail below, but it is important to note that schedules do slip, and delays can occur when defining the months of operation. Realistic values should be chosen in order to reduce the probability of later modifications.

Questions & Factors

A factor representing the consequences of a mooring failure is derived from a series of detailed questions about the infrastructure around the proposed location. This factor includes different numbers for both local and far surface and subsea infrastructure. The intent has been to consider the consequences from the standpoint of someone interested in protection of hydrocarbon production from the overall Gulf of Mexico. The impact of damage on individual companies is given a much lower significance than damage that may affect major production. Hence the consequences of damaging a component that will affect the production from only one well is given a lower value than the consequence of damaging a transmission pipeline that would affect production from a number of wells. This is true even if the pipeline could be more easily and inexpensively repaired than, for example, a specific umbilical.

The next series of questions concerns details of the mooring system to be deployed. These include type of mooring and anchors, level of analysis undertaken, infrastructure protections included, etc. The answers to these questions feed into a factor that repre-

sents a partial view of the mooring failure probability. However, there is no account taken for the metocean conditions for which the mooring system has been designed. The reason for this omission is that the design criteria can be considered one of the most significant mitigations of risk: high risk necessitates a high-return period, low risk can use a lower return period.

Information Required

Only a limited amount of information is required to complete the checklist, but it is imperative it be correct. Most of the local infrastructure information should be easily available, and can be garnered from various plots of the proposed location. More distant information may need to be obtained from the owners of the adjacent leases. One of the reasons that the checklist only asks about infrastructure within 10 miles is to limit the difficulty in gathering the necessary information. Infrastructure that is farther away than 10 miles is accounted for by considering the block area in which the well is located: the block area factor used has been chosen based on the proximity to, and significance of, the infrastructure in the general area of the well. It is anticipated that the operator would need to obtain the infrastructure details.

The mooring system details are mainly those that would be needed to undertake a mooring analysis, and could normally be supplied by the drilling contractor.

Use of the Results

Having completed the checklist analysis, the results will indicate the unmitigated risk assessment for the specific location. As stated previously, the derived value does not represent a true risk since the design metocean conditions have not been incorporated into the assessment. As the consequences or numeric scores increase, different mooring system alternatives may be selected to mitigate consequences. Alternatively, if there are limits on the mooring system capability, then it may be possible to use other mitigating factors such as altering the drilling months, or changing out critical components (e.g. replace drag embedment anchors for VLAs, use a preset polyester insert mooring, etc.)

Iterative Analysis

It is anticipated that the checklist approach will often be used iteratively and to help highlight the critical factors for a given location. For example, the process may follow these steps:

1. A specific mooring system is proposed, and the checklist is run.
2. The results are found to be inconsistent with the probable design capability of the chosen mooring system.
3. The main drivers of either the probability or consequence are identified, and alternative options considered.
4. Changes are made to the mooring to help mitigate the risks.
5. The checklist is re-run.

The process can then be repeated until an acceptable solution is found. Alternatively, it may be that the results indicate that the checklist approach is not a sufficiently refined tool, and a more rigorous risk analysis needs to be undertaken. In this case, the full risk based approach would be used. Another possibility is that certain aspects of the checklist could be refined by more detailed risk assessment, and specific drivers mitigated. This would allow the use of complex risk analysis tools only in those areas of greatest concern.

Discussion of Checklist Factors

There follow some discussion of the factors used within the checklist and how the calculations were performed. In many cases, there is discussion on the checklist worksheets which is repeated here. Even if the checklist method is computerized, it will be helpful to keep the worksheets available to help give guidance on how to complete the answers, and what the questions mean.

Block Area

Certain areas of the Gulf of Mexico are more densely populated with both surface and subsea infrastructure. Despite the answers to the questions below about pipelines and permanent facilities close to the proposed location, there is a certain "overhead" consequence of drilling in these locations.

Water Depth

Most units have a preferred water depth range. Generally, shallow water, of less than 1,000 feet, will tend to result in less robust mooring systems, with a higher probability of failure.

Conversely, the cost and impact of damage to subsea infrastructure in deepwater is greater than in shallow. The checklist accounts for an increase in the probability of failure in shallow water, but an increase in the subsea damage consequence of failure in deepwater.

Complexity of Bathymetry

Complex seafloor bathymetry increases the uncertainty in the mooring analysis and can adversely affect the reliability of the installed mooring system.

Season

The months of operation probably have the greatest effect on checklist analysis outcome. Not only are there more storms at the height of the hurricane season, but they also tend to be more severe. During the calculations, one month is added to the end of the drilling program for contingency. Drilling programs should incorporate contingencies to account for either delays in start, or overruns during operations. It is recommended that contingency plans are pre-established to account for possible start delays. If there is a change in actual drilling program that has not been fully accounted for in the risk assessment, then this checklist must be re-run for the actual case. It is also worth noting that if the timing of a drilling location cannot be well planned, then all variations of timing should be considered. This will reduce the probability that unexpected changes will be required that could make the location unsuitable during those particular months.

Altering the drilling season is one of the most effective ways to reduce the risk of drilling a particular location. Serious consideration should be given, wherever practicable, to drilling the highest risk wells at the least intense parts of the hurricane season.

Note: If all months are checked, a value of 1.0 will be returned for use in the calculations. This approach is not suitable, as it stands, for assessment of a MODU to be used on a single location for more than one year.

The drilling season factor is based on the number of tropical revolving storms to enter the US Gulf of Mexico between 1992 and 2005. The question will return a value of between zero and 1 to the main calculation sheet, depending on the months chosen. The database contains a total of 55 events, so the value for each month was taken as the number of events within that month, divided by 55. It would be possible to use a longer dataset, but the increase in accuracy would not significantly affect the results of the overall assessment. (It could, however, be argued that the most active months should have a higher weighting since the storms during August and September are also generally more intense. This has not been accounted for.)

Having derived the individual month values, the value for the chosen months needs to be developed. This is performed assuming that the probability for each month is totally independent, so the probability is related to:

P(Storm) = 1 – (Product of P(Storm NOT occurring) over the months considered)

The calculation, however, is not trying to determine a true probability, but a relative value, so it was decided to set the value to unity if the whole year is chosen. This requires the calculated value to be divided by a factor of 0.738.

Pipelines and Other Subsea Infrastructure

There are a series of questions that ask specific questions about the local subsea infrastructure.

Pipelines represent a relatively high consequence. A 10-inch pipeline has been decided as the "break point" between small and large. Large lines have significantly higher consequence factors as they may be transporting hydrocarbons from a number of wells and facilities. Loss of a large line could cause significant loss of production. No account is taken for multiple pipelines, so if there is more than one, the size of the largest should be used.

Should a storm adversely affect the mooring system, the direction to subsea infrastructure affects the probability that it will be damaged. The highest winds within a hurricane are normally in the northeast quadrant, blowing towards the northwest. If a MODU is exposed to a number of different quadrants of a passing storm, then the NE quadrant is most likely to cause failure. Also, it is likely that a MODU will first be affected by the northern side of a hurricane before the southern side. Hence the most likely direction of MODU drift can be estimated.

Umbilicals are easily damaged, but have a relatively low consequence rating within this approach. While they are important, they generally affect only one well, so do not have a major impact on the overall production levels within the GoM. Conversely, they can be extremely difficult to replace, and may have long lead times on replacement. Companies may want to increase the significance of umbilicals for their own internal purposes, but from an overall production perspective, they are less important than pipelines.

There is a possibility of any mooring component falling onto the subsea component, and hence damaging it. Due consideration needs to be given to possible mooring failure scenarios when answering the relevant questions. The fact that a subsea component is located between two mooring legs is not, by itself, sufficient argument that a mooring component could not fall onto the wellhead, given the possible movements of the MODU.

Adjacent Surface Infrastructure

There is a series of questions that ask about surface infrastructure that is both adjacent to the location and located within a 10 mile radius of any anchor. As with the subsurface infrastructure, more distant surface infrastructure is covered in the "Block Area" question.

If the MODU has a mooring system that crosses the moorings of another temporary facility (e.g. another MODU), there is clearly a threat that if either of the mooring systems fail, then there could be an adverse effect on the moorings of the other unit. This is a consequence event. There is, however, a relatively high probability that even in the worst case, the MODU and other facility will not be irreparably damaged. A similar question is asked about crossed moorings with a permanent facility, but in that case the consequences of a failure are considered higher.

The next question concerns surface facilities within one mooring radius of any anchor. The intent is to ascertain if it is possible to suffer a mooring failure on the MODU and swing on an anchor into the permanent facility. This is a potentially higher consequence situation than even the crossed mooring cases. The concern is that a mooring will fail, and the MODU will swing on the remaining moorings into the facility. The resulting impact would likely cause considerable damage, especially given the severe weather prevalent at the time, and could even result in loss of one or both units.

The consequence of damage will, to an extent, depend on the type of facility. All floating facilities have the same consequence factor. This accounts for the greater survival chances of the larger floating facilities (e.g. SPAR or TLPs) and the lower survival probability of the smaller units (e.g. mini-TLPs), but the higher capital investment is in the larger facilities: It is a trade-off between survival and cost. Bottom founded structures, except for hubs, have been included as lower consequence because they are more likely to survive in a repairable condition, generally have lower capital investment, and riser damage would likely be more easily repaired. Hub jackets have been included at a higher level to account for the effect on overall GoM production were they to be damaged.

Surface facility between one mooring radius from the position of any anchor and 10 miles from the position of any anchor need to be identified. The use of a 10-mile radius is slightly arbitrary, but infrastructure outside that range was considered to be covered by Question 1, the block area of operation. Surface facilities that have a mooring system are taken as being larger targets, hence have a higher probability of being hit. Consequently, spread moored facilities are given a higher factor than TLPs and jackets/compliant towers.

Mooring System Description

The next series of questions concerns the description of the mooring system. An inherent assumption of this checklist approach is that any system chosen is designed to the same level of utilization. Different levels of analysis may have been undertaken, and credit is given for that, but regardless of the level of analysis, if two systems are "compared," it is assumed that they will have the same safety factor in the same return period event. Hence, differences are due to those that are inherent within the design, be they features or disadvantages.

The type of mooring system has an impact on the probability of failure and the consequences of failure. However, a system that may be good in one way may be bad in another. For example, a conventional catenary moored unit is likely to have a robust mooring system. Not only is there considerable experience with these, hence they are better understood, but they are generally more robust and less sensitive to small errors in either installation or analysis. However, a catenary mooring system will have a considerable quantity of chain at the seabed, and in the event of failure, could do significant subsea infrastructure damage. Conversely, an semi-taut steel wire system may have a higher probability of failing, but the damage to subsea equipment may be significantly less.

Note: Two values are generated through an answer to this question: one for surface damage probability and one for subsurface.

Semi-taut systems allow for grounded length. Taut systems are designed for zero-grounded length.

Number of Mooring Lines

The number of mooring lines has an effect on the mooring system reliability. Generally, "more lines" leads to a higher reliability, although certain "grouped moorings" may not accurately fit the pattern. The checklist is not very sensitive to the number of lines (i.e. the response to this question) because it is assumed in these calculations that any of the systems will have been designed for the same extreme event. It should not be inferred that increasing the number of mooring lines will not help improve a system's reliability, but in most cases, extra lines are added to increase the capability over that of the system with less lines. Hence the design return period is higher for the system with more lines. This increased design capability is NOT included in this simplified approach.

Survival Location and Mooring System Bias

There are two questions about a planned survival location and if the mooring system has to be biased because of subsea architecture. The intent is that through use of a survival location, line tensions can be optimized, and storm survival probability is increased. Conversely, if the mooring system has to be biased to avoid subsea interactions, then it may not be possible to optimize it for survival.

Complexity of Mooring System Installation

Complexity of mooring installation can affect the probability of being affected by a sudden hurricane. This factor is intended to capture the exposure associated with long installation times with the unit partially moored during the rig move. The complexity refers to the time taken while the unit is on location connecting up. The time to install a pre-installed system should not be considered.

Type of Anchors

One of the factors that has a great influence on the mooring risk is the type of anchor chosen. Two numbers are required for anchors: one for potential surface infrastructure damage, and the other for subsea damage. For potential surface damage, most of the anchors are the same. Only the conventional and High Holding Capacity Drag Anchors (HHCDA) with capacity less than the mooring line strength have slightly higher probability values. In most cases, the type of anchor has limited impact on the probability or consequences of a MODU causing surface infrastructure damage.

For subsea infrastructure damage, however, the situation is very different. The best anchors are those that will not pull out of the seabed, and will not drag components across the seafloor in the event of any mooring failure. Drag anchors have a higher risk number than other anchor types (excluding drag embedment VLAs). The reason is that there is relatively high probability the leeward anchors will pull out in the event of windward mooring line failure. Hence, even if the anchor has a higher holding capacity than the strength of the mooring line, if the windward lines fail, the leeward anchors likely will be dragged as the MODU drifts over them and pulls them in the "wrong" direction.

Note: It is important that if piles/VLAs/SEPLA are used to mitigate the probability of damaging subsurface equipment, then their holding capacity should be greater than the maximum breaking strength of the mooring line in any possible loading direction, and all reasonably possible soils conditions, even considering all possible mooring line failure combinations. In addition, the installation procedure should be developed to ensure that this holding capacity can be achieved. This is particularly important for VLAs. It is of note that during Hurricane Rita one unit fitted with VLAs suffered a mooring failure and dragged the anchors for over 100 miles. Unless this type of failure can be absolutely guarded against through design and installation, VLAs should be rated at the same level as "high holding capacity anchors (less capacity than mooring minimum break load (MBL))".

Mooring Analyses Undertaken

The type of mooring analysis can have an effect on the reliability of a mooring system although initially it is assumed that a quasi-static and dynamic mooring analysis are each equally effective since API RP 2SK has suitable safety factors for each. The differences arise when the type of dynamic analysis is considered: 3 degree of freedom (DOF) is the least good type of dynamic analysis, as in many cases the heave component at the fairlead can have a significant effect on the mooring line loads, 6 DOF is better.

Mooring Component at Fairlead and at Seafloor

The mooring component at the seafloor affects the potential damage to subsea equipment in the event of a mooring failure. Chain on the seafloor can do considerably more damage to subsea equipment than wire, and wire, in turn, more than polyester.

The component at the fairlead affects the probability that there is a mooring failure. Chain is more robust and less likely to suffer abrasive damage during the storm, and hence is preferable.

APPENDIX III—STORM REPORTING SHEET SEMI-SUBMERSIBLE RIG STATUS REPORT

Complete a sheet for each unit that experienced winds of 50 knots or greater, regardless of whether it suffered any damage (the fact that no damage was suffered gives valuable information). If in doubt about the proximity of a location to a storm, complete a form anyway. Please complete a separate sheet for each Hurricane. Every effort has been taken to make the form cover all situations. However, there will be cases where it does not exactly ask the right questions. Please be flexible. The intent is to be able to analyze the rig as exposed to the storm, using real values rather than nominal values wherever possible.

Please use consistent units throughout (either Feet and Kips or Tonnes and Metres – line diameters in inch or mm)

Storm Reporting Data Sheet

Drilling contactor:	Date form completed:	
Contact name:	Telephone:	E-Mail:
Rig name:		
Sheet being completed for which surricane/ storm?		
General Rig Characteristics:		
Designer:	Designer class description:	
Rig modified since delivery?	Yes	No
Brief description of modifications:		
Location Description:		
Operator of well:		
Latitude / Longitude	Block Name and No.	Rig Orientation
Water depth (feet)		
Soils data available?	Yes	No
If soils data is available, please supply brief description and strength profile.		
What was Draft of Evacuation (feet)?		
Mooring System Details:		
Was mooring rig's own system or preset?　　Own　　Preset　　Both own and preset		
If preset, whose equipment was used?		
Number of mooring lines (details requested in table below):		
Type of anchors　　Drag　　VLA　　Pile　　Other		
Anchor description (e.g. weight, size, manufacturer, etc.):		
For Drag Embedment Anchors:		
Manufacturer	Type	Weight
Installation vessel name:	Bollard Pull (ton)	BHP
(Note: Bollard Pull should be that ACTUALLY USED, which is not necessarily the maximum quoted)		
Were any anchor legs run short?	Yes	No
If any were run short, why?		

Storm Reporting Data Sheet (Continued)

Method of payout measurement during installation:		
Method of measuring pretension and operating tension:		
Was rig position modified for evacuation?	Yes	No
How modified? (distance and direction)		
Were line tensions modified prior to evacuation?	Yes	No
Was line slackening complicated by high currents, high winds, etc. that made it difficult to accurately establish the line tensions on evacuation?		
	Yes	No
Are anchor scopes known or estimated?	known	estimated
What is mooring line 1 (e.g. Starboard; Bow):		
What is numbering sequence?	clockwise from above	anti-clockwise from above

Please Complete for EVACUATION Condition												
Mooring Line Number												
	1	2	3	4	5	6	7	8	9	10	11	12
Line length to anchor												
Direction of anchor from rig												
Pretension test load of each leg												
Anchor drag distance during installation												
Normal operating tension												
Payout length at evacuation (for both positioning and slackening)												
Evacuation tension (actual)												
Type of anchor (if different for each line)												

Note: The table above has been developed to ease information flow. If mooring system cannot easily be described through use of this table, please attach a separate and full description. Anchor heading should be given from Rig Bow

	Type (e.g. wire, chain)	Construction	Diameter (inch)	Length (feet)	Break Strength (kips)	Manufacturer and Age
At Fairlead						
Intermediate line						
Intermediate line 2						
At anchor						

If the makeup of some mooring lines was different (e.g. had an insert piece in certain directions/lines), please indicate the line details in the table above and specify "Only in lines xxx & xxx" in the left hand column.

Were buoys or clump weights used in the mooring system, and if so please describe?		
Damage:		
Did the unit suffer any damage during the hurricane?	Yes	No
Can repairs be effected on site?	Yes	No
Major: Description of hull/structural damage requiring third party of shipyard repair?		
Significant: Description of hull/structural damage that must be completed prior to restarting drilling ops:		
Minor: Description of Hull/structural damage that can be repaired during normal operations. Please include whether there was green water damage under deck.		
Expected cost (excluding loss of income) and duration of repairs:		
Expected number of lost operating days, excluding those shut down for actual storm, and loss of income:		

What suprised you when you got back on the rig? (either damage or indications of things)		
Did the unit suffer any mooring related failures?	Yes	No
Did any anchors drag, and if so, how far?	Yes	No
	How far?	

Mooring Line Number												
	1	2	3	4	5	6	7	8	9	10	11	12
Fail at fairlead												
Failed at intermediate												
Failed at anchor												
Dragged anchor												
Other failure (e.g. anchor broke, brake failure, etc.)												
Component recovered for inspection?												
Inspection results and availablity?												

How far did unit drift?	Miles	
Where was the unit after the storm when found?		
Was the unit grounded?	Yes	No
Were tugs dispatched to recover the unit?	Yes	No
Did the tugs prevent additional drift?	Yes	No
Any comments on effectiveness of tugs?		
Is course of unit drift known (e.g. through transponder)?	Yes	No
Did the transponder operate properly during the storm, and if not, why (e.g. batteries failed, etc.)?		
Can we get the plot of location against time (to help with hindcasting and drift prediction)?		
What was the length of any "dangling" mooring component below the keel?		

1220 L Street, NW
Washington, DC 20005-4070
USA

202.682.8000

Product No. G95F01