TECHNICAL SPECIFICATION	Nº I-ET-3010.00-1500-960-PPC-006	
CLIENT OR USER: DP&T / E&P		SHEET 1 from 46
JOB OR PROJECT:		CC

PETROBRAS

CENPES

STRUCTURAL ANALYSIS OF FLEXIBLE PIPES

INDEX OF REVISIONS

REV.	DESCRIPTION AND/OR AFFECTED SHEETS
0	ORIGINAL
A	General Revision
B	Inclusion of item 5.3
C	Chapter 3.
D	Installation conditions (table1), beam seas load cases (table 2), installation load cases (tables 5), output tables (tables 6 to 9 and 16 to 18) and reference to Metocean data on chapter 3
E	General Revision
F	Abnormal Operation conditions F.b (table1), 6th and 7th paragraphs of item 4.3.1, and tables 4.b, 16.b and 20
G	Table 20
H	General revision to comply with API Spec 17J – 4^{th} Edition

	ORIGINAL	REV. B	REV. C	REV. D	REV. E	REV. F	REV. G	REV. H
DATE	03/SEP/03	29/JUL/04	18/AUG/04	17/OCT/05	06/OCT/08	07/DEZ/12	08/FEB/13	27/12l/19
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1. PURPOSE

The purpose of this Technical Specification is to provide minimum requirements for structural analysis of static and dynamic conventional flexible pipes during installation and operating life phases. The Manufacturer is responsible to identify all hazards and define additional load cases to mitigate them based on risk assessment. Load conditions and design methodologies specified for design of dynamic flexible pipes are mainly applicable to risers in free hanging and deepwater lazy wave configurations and do not covers fatigue life and interference analyses. The utilization for other configurations can be accepted upon request to BR, but additional conditions might be necessary.

Particular cases, where geometric parameters, deformations or stresses are relevant in the pipe dimensioning shall be investigated and the whole set of analysis inputs and results shall be submitted to BR. The required scope of global and local load cases for strength calculations of flexible pipes shall include the following: (i) the scope based on the MANUFACTURER experience regarding loading combinations; (ii) the scope based on BR experience, as hereafter specified. In addition, MANUFACTURER shall provide results for requested special analyses.

2. ABBREVIATIONS AND DEFINITIONS

- BR PETROBRAS - Petróleo Brasileiro S.A.
- MANUFACTURER Company responsible for the supply of the flexible pipes
- shall Mandatory Requirement
- should Recommended Practice
- may On course of action
- Metocean Meteorological & Oceanographic
- SS Semi-submersible
- TDP Touch Down Point
- Hs Significant wave height
- Tp Peak period
- IWP Irregular Wave Procedure
- DWP Design Wave Procedure
- RAO Response Amplitude Operator
- CoM Center of Motion
- DoF Degree of Freedom
- MPM Most Probably Maximum

3. APPLIED DOCUMENTS

[1] API Spec 17J, Specification for Unbonded Flexible Pipe, 4th Edition, 2014

[2] I-ET-3000.00.1519-291-PAZ-001, Flexible Pipe Technical Specification

[3] API RP 17B, Recommended Practice for Flexible Pipe, 5th Edition, 2014

[4] I-ET-3000.00.1519-291-PAZ-008, Documentation

[5] API17L2 - API Recommended Practice 17L2, Recommended Practice for Flexible Pipe Ancillary Equipment.

[6] I-ET-3000.00.1519-291-PAZ-005, Design Requirements

4. STRENGTH CALCULATIONS

When MANUFACTURER is supplying a group of risers for the same floating unit, with similar functional and system requirements, MANUFACTURER shall supply these risers with the same flexible pipe structure.

The design of one specific riser or a group of risers with similar functional and section properties shall adopt one of the following procedures, depending on BR technical documentation:

(i) Riser connected to any possible platform connection point with any possible azimuth. According to the type of the platform and the mooring system the following shall be considered:

a. For ship shape unit with:

- Turret moored system - eight different connection points and riser azimuths shall be considered, being each one 45º apart from the other as shown in Figure 1;

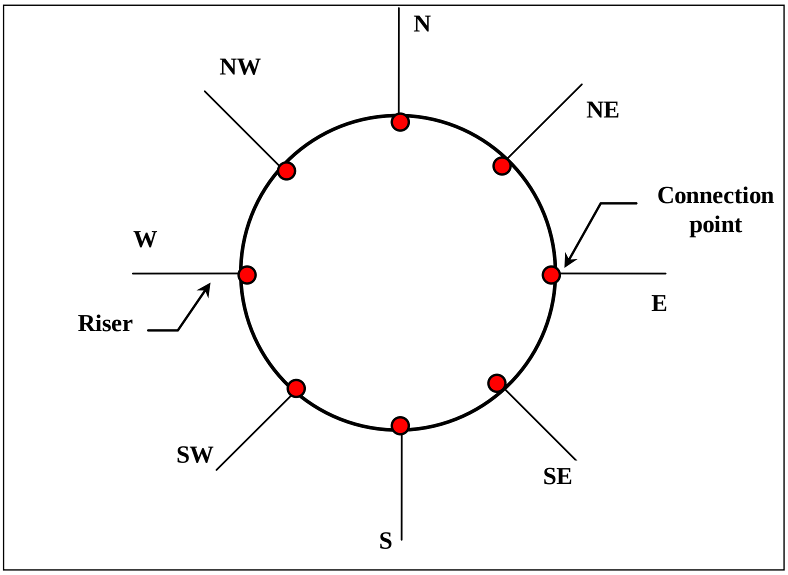
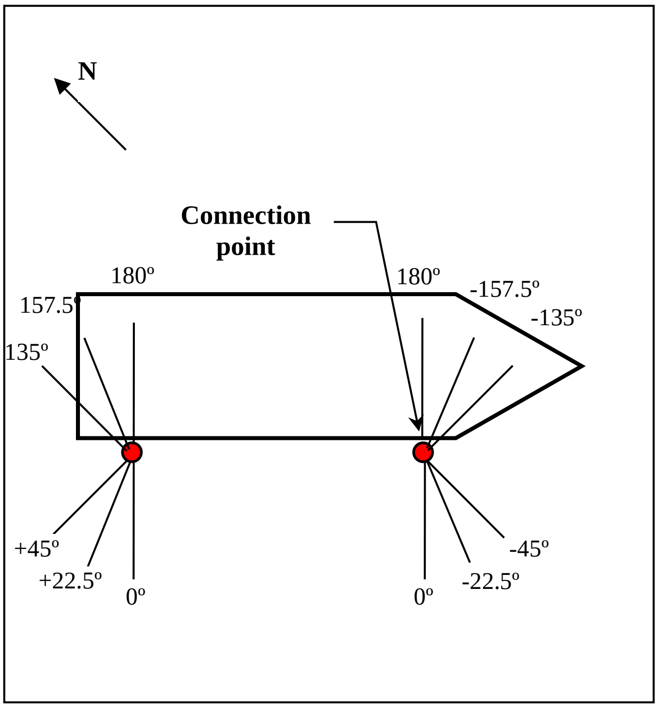


Figure 1 - Connection points and risers azimuth for turret moored system

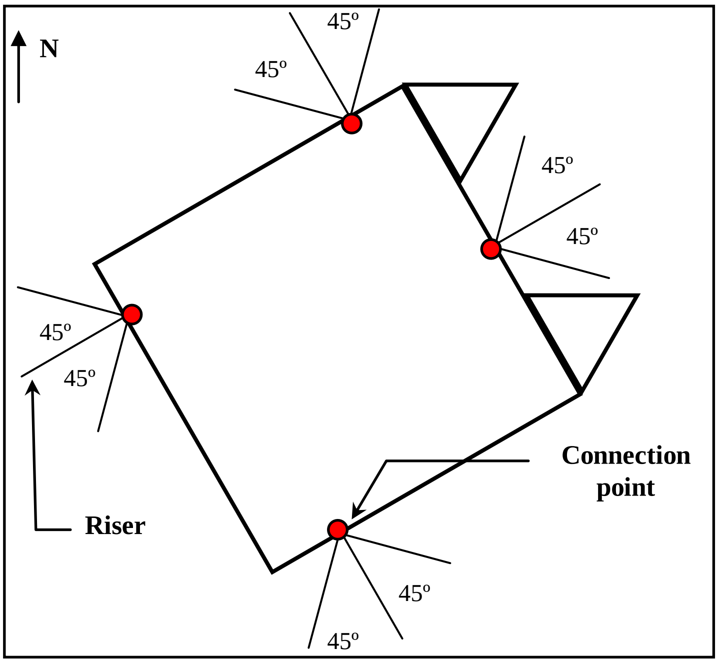
- Spread mooring system - two connection points and ten different riser azimuths shall be considered as shown in Figure 2a: one perpendicular to the platform side, and the others ±22.5º and ±45º apart from it, the same applies for keel hauling risers. The connection points shall be forward and backward from midship along the balcony, if applicable. The worst connection points shall be selected and properly justified.

b. For semi-submersible (SS) unit - three different riser azimuths shall be considered at each side of the platform as shown in Figure 2b: one perpendicular to the platform side, and the others ±45º apart from it. At each side, the worst connection point shall be selected and properly justified.

(ii) Riser connected to the actual connection point with its actual azimuth defined by the subsea lay-out and BR technical documentation.



(a) Ship shape unit



(b) Semi-submersible unit

Figure 2 – Connection points and risers azimuth for SS and ship shape unit with spread mooring

4.1. FLEXIBLE PIPE PROPERTIES

Section 8.4 of API 17J complemented by [5] present a list of flexible pipe properties that shall be informed in the Design Report. All properties used for the structural analysis shall be submitted to BR, even properties that depend on applied loads. For example, the permissible crushing, which is associated with the laying tension, and the bend stiffness, which is a function thermal and external loads. When properties depend on functional parameters (e.g. the bending stiffness), the envelope of the values of parameters shall be in accordance with the structural analysis conditions and with the qualification test conditions.

Regarding pipe properties dependent on applied loads, at least the following graphs should be provided for installation and operation conditions:

- Permissible crushing *versus* laying tension curve.
- Permissible bending radius (or curvature) *versus* axial compression (true wall) curve (see API 17J [1], Section 8.4, Item m). Alternatively, if dynamic axial compression is disregarded, the permissible bending radius can be presented as a function of the water depth. This graph should be provided for both wet and dry annulus conditions and for both empty and flooded bore.

The aforementioned permissible bending radius curve should be built from a set of at least ten points. As a minimum, this set of points should comprise the design water depth, the specified water depth, straight pipe, 1.5xMBR and 1.25MBR. Manufacturer should provide the associated UF for each point of the curve, even for the failure mechanisms (e.g. curved collapse, lateral buckling, etc.) with UF lesser then the allowable one.

4.2. DESIGN LOAD CASES

The pipe shall be analyzed under functional, environmental, and accidental loading combinations as per API Spec 17J [1]. The design load conditions that shall be analyzed are permanent operation (normal and extreme), abnormal operation and temporary non-operating (normal and extreme).

Global non-linear analysis cases shall be numerically simulated for the purpose of investigating and checking integrity, geometry, and stability of flexible pipes. Global analysis results provide the input for local stress analysis to determine if the pipe capacity and utilization factors are not exceeded under specified load conditions. Examples of main concerns are over tensioning of the pipe section at the top connection, and over bending or axial compression at the TDP and sea bottom regions.

Besides providing subsides to the local analyzes, specified in item 4.4, to obtain the utilization factors, global analysis should be compared to the properties of the pipe and any undesired results, such as excessive bending, should be clearly identified.

In order to adequately assess flexible pipe utilization factors, critical sections have to be evaluated in relation axial compression and curvature radius worst combinations. For the TDP region, improved accuracy of the global analysis results are required considering the severe influence of relevant parameters, such as temperature and interlayer contact pressures, on the pipe mechanical properties. As these parameters vary along the riser, it is necessary to divide the riser (or flowline during installation) into some segments in order to represent different section properties. For each segment all relevant parameters and equivalent section properties shall be informed. Nonlinear behaviors like for instance the stick-slip effects in the armors layers which cause hysteretic bend behavior and nonlinear polymeric stiffness, can be used and the data dully informed in the design premises.

The design premise shall specify a load case matrix, which shall include all potential load cases for the flexible pipe system, including the sub-set of load cases presented in Table 1.

Table 1 – Design Load Cases

Load Condition				Design Load Case	Description
Operating Conditions	Permanent	Normal		A - Riser Operation Operating Internal Pressure	Pipe full of internal fluid, Maximum Operating Pressure[1] at the Production Unit, intact pipe outer sheath, intact mooring system and 100-year environmental conditions.
		Extreme		B - Riser Operation Design Internal Pressure & One mooring line broken	Pipe full of internal fluid, Maximum Design Pressure at the Production Unit, intact pipe outer sheath, one mooring line broken and 100-year environmental conditions.
				C - Riser Operation No Internal Pressure & One mooring line broken	Pipe full of internal fluid, Atmospheric Internal Pressure at the Production Unit, intact pipe outer sheath, one mooring line broken and 100-year environmental conditions.
				D – Riser Operation [2] No internal fluid & Breached pipe outer sheath	No internal fluid, breached pipe outer sheath, intact mooring system and 100-year environmental conditions.
				E – Riser Operation [2] No internal fluid & Intact pipe outer sheath	No internal fluid, intact pipe outer sheath, intact mooring system and 100-year environmental conditions.
				F - Riser Operation Design Internal Pressure & buoyancy/weight losses over service life	Pipe full of internal fluid, Maximum Design Pressure at the Production Unit, intact pipe outer sheath, buoyancy/weight losses as per defined in 8.2.4 of API17L2:2013 [5], intact mooring system and 100-year environmental conditions.
	Abnormal Operation			G – Riser Operation Floating Unit inclination due to a compartment flooding (as specified)	Pipe full of internal fluid, Maximum Design Pressure at the Production Unit, intact pipe outer sheath, intact mooring system, floating unit inclination due to a compartment flooding and 1-year environmental conditions.
				H - Riser Operation Incidental Pressure & One mooring line broken	Pipe full of internal fluid, Incidental Pressure[4] at the Production Unit, intact pipe outer sheath, one mooring line broken and 10-year environmental conditions.
Nonoperating Conditions	Temporary	Normal	Installation	I – Pipe Full of Seawater & Intact pipe outer sheath[5]	Pipe full of seawater, intact pipe outer sheath and installation environmental conditions.
				J – Pipe Empty & Intact pipe outer sheath	No internal fluid, intact pipe outer sheath and installation environmental conditions.
			Test	K – Offshore Leak Test Pipe Full of Sea Water	Pipe full of seawater, Maximum Offshore Test Pressure[3], intact pipe outer sheath and installation environmental conditions.
		Extreme		L – Installation Pipe Empty & Breached pipe outer sheath	No internal fluid, breached pipe outer sheath and installation environmental conditions.
				M – Installation Pipe Full of Sea Water & Intact pipe outer sheath	Unintended flood, intact pipe outer sheath and installation environmental conditions.

Notes:

1. The Maximum Operating Internal Pressure shall be assumed equal to the Maximum Design Pressure if not

informed by BR.

2. Unless otherwise specified, for water depth lower than 1000m Design Load Cases D and E can be disregarded.
3. Maximum Offshore Test Pressure shall be considered equal to 1.10*Maximum Design Pressure unless other value be specified.
4. The Incidental Pressure shall be assumed equal to 1.10*Maximum Design Pressure if not informed by BR. If the temperature associated to the Incidental Pressure is not informed by BR, it shall be assumed equal to the Design Maximum Temperature. When accessing utilization factors from table 8 of API Spec 17J [1] this pressure shall be considered as an accidental load, according to table 6 of API Spec 17J [1].
5. This load case may be waived, provided that BR informs that installation will be carried out with the pipe empty and that installation with the pipe flooded is an accidental condition. In this case, MANUFACTURER shall clearly indicate this assumption in the Design Premises.

4.3. GLOBAL NON-LINEAR ANALYSIS

4.3.1. Global Analysis Load Cases

The global analysis tables herein presented are related to one single riser. In case of several risers with the same properties and same internal fluid parameters, but different azimuths and connection points in the same floating unit, MANUFACTURER can present the results for the risers with most critical combinations of azimuth and connection point, considering their impact to the pipe integrity (e.g. level of stress/strain and possibility of interference), geometry, and stability. The selection shall be properly justified and confirmed with some spot check analysis. Output results of the global analyses shall be condensed in summary tables and graphs (see Item 4.3.3), and submitted to BR for approval.

Global analyses of the Design Load Case A presented in Table 1 shall include at least the load cases listed in Table 3. The motion and wave modeling procedures described in Item 4.3.2 shall be used for selection of the wave and draft of the floating unit (any other procedure have to be formally accepted by BR).

The purpose of load cases GA-17 to GA-20 is to consider a swell condition based on BR operational experience (see note 3 of Table 3).

Global analyses of the Design Load Case B to F presented in Table 1 shall include at least the load cases listed in Table 4. These load cases are selected considering the results of the dynamic analyses of the load cases in Table 3, according to specified in Table 4 (e.g. maximum top tension, maximum curvature, etc.).

Global analyses of the Design Load Case G presented in Table 1 shall include at least the load cases listed in Table 6. These load cases are selected considering the results of the dynamic analyses of the load cases in Table 3. The inclination shall be applied on the longitudinal axis for ship shape unit and on the diagonal for semisubmersible. The angle of inclination of 10º for ship shape unit and 15º for semisubmersible or other units shall be adopted if it is not specified on BR technical documentation. This load case shall be considered to check the integrity of the pipe and not to be used to size the bend stiffener or other ancillary equipment (no loss of containment is acceptable but no strain limitation in the bend stiffness is required).

Global analyses of the Design Load Case H presented in Table 1 shall include at least the load cases listed in Table 7. These load cases are selected considering the results of the dynamic analyses of the load cases in Table 3. If not specified by BR the following offsets shall be considered:

(i) Offset for damaged mooring system and 100-year environmental condition for the load cases in Table **7** obtained from load cases GA-1 to GA-16 in Table 3;

(ii) Offset for intact mooring system and 100-year environmental condition for the load cases in Table **7** obtained from load cases GA-17 to GA-20 in Table 3.

The purpose of the Design Load Cases I to M presented in Table 1 is to assure the installation feasibility of the flexible pipe and its ancillary equipment, besides to determine stresses and strains in the structural layers of the pipe and the respective utilization factors.

The manufacturer shall carry out installation feasibility analysis of product(s), including the evaluation of their stability during the laying phase. Verification of stability includes the addressing of all possible issues such as pipe large displacement in relation to the bundle (if it were the case) that can cause difficulties during its laying, pipe entanglement with other pipe or umbilical, and pipe pig tailing or kink formation.

Global analyses of the Design Load Cases I to K presented in Table 1 shall include at least load cases matrixes listed in Table 8 and Table 9. These load cases consider the line (riser or flowline) connected to the installation vessel. The effect of different lay azimuths shall be considered in the global analysis. If only one azimuth is considered, MANUFACTURER shall prove by some spot check calculations that this azimuth is the worst one.

Load case matrix presented in Table 9 shall be considered to cover the Load Case K for risers and flowlines during offshore test conditions at the installation vessel.

The load cases presented in Table 10 are applicable for risers only. These load cases are representative of the pull-in/out and offshore test conditions at the platform, and shall be included in the global analyses for the Design Load Cases K of Table 1 when applicable.

Load cases matrix presented in Table 11 are representative of pipe installation with the outer sheath damaged covering the Load Case L of Table 1.

The Load Case I presented in Table 1 may be waived, provided that BR informs that installation will be carried out with the pipe empty. In this case installation with the pipe flooded is an accidental condition covered by Load Case M in Table 1 and load cases matrix presented in Table 12 shall be considered.

In order to avoid compressive loads acting on the Installation Vessel for lazy wave configurations, the MANUFACTURER shall verify the necessity of a temporary dead weight collar and design this accessory in accordance with results of Load Cases I to M. The MANUFACTURER shall design the dead weight, the position of the collar and identify the proper steps for installation and removal of the dead weight. Flowline and riser sections shall also be dimensioned considering installation phases in accordance with Table 2 presented below, starting with the connection to the subsea equipment and ending with the pull-in on the floating unit (or the reverse way in case of first end pull-in, as both cases are required).

MANUFACTURER shall evaluate the influence in the bending radius of the settling of end fittings in the bottom or in the Touch Down Zone, in order to identify and inform the required laying top angle. If applicable, the installation of in-line equipment connected to the flexible pipes shall also be evaluated.

Table 2 – Phases for analysis of second end pull-in (considering lazy wave configuration)

Phase	Section to be analyzed (notes 1 and 2)	Sections connected to the PLSV (notes 1 and 2)
1	F	F
2	BotR	BotR + F
3	BotR	BotR
4	IR	BotR + DW
5	IR	IR + BotR + DW
6	IR	IR + BM + BotR + DW
7	TR	IR + BM + BotR + DW
8	TR	TR + IR + BM + BotR + DW

Note 1: Abbreviations: F: flowline / BotR : bottom riser / IR: intermediate riser / TR: top riser / DW: dead weight;

Note 2: This example is considering the weight collar assembled on IR / BotR connection.

During pipe installation and retrieval, the suggested laying top angle is 1° maximum. For the settlement of pipe connections on sea floor, the maximum allowed laying top angle is 4.5° if it is not specified on Petrobras technical documentation. For riser pull-in, a laying top angle greater than 1° (limited to 4.5°, regardless of the final top angle at the Production Unit) may be proposed by the MANUFACTURER, provided that the Installation Vessel and Production Unit support capacities are not exceed (including the winch and other specified equipment).

If applicable, any wave height restrictions considered by the MANUFACTURER shall be submitted to Petrobras for approval.

The following general notes shall be observed for all load cases:

1. The motion and wave modeling procedures described in Item 4.3.2 are applicable for all load cases including the installation load cases.
2. The wave data for the directions (e.g. N, NE, etc.) presented in BR Metocean technical documentation closest to load case wave direction shall be chosen. If the load case wave direction is exactly on between two wave data (e.g. 22.5º from N, or 11.25 from N if 16 directions are available), the one with the largest significant wave height shall be selected.
3. The current profile for the directions (e.g. N, NE, etc.) presented in BR Metocean technical documentation closest to load case current direction shall be chosen. The entire current profile shall be rotate, based on its surface direction, in order to match the load case current direction. If the load case current direction is exactly on between two current data (e.g. 22.5º from N, or 11.25 from N if 16 directions are available), the one with the largest surface current velocity shall be selected.
4. Current profile may be truncated if the water depth is shallower than the profile presented in BR Metocean technical documentation or may be expanded, repeating the last current direction and velocity if the water depth is deeper.
5. Maximum top tension means maximum effective tension at the top connection region. Maximum TDP tension means maximum effective tension at the TDP region. Minimum TDP tension means minimum effective tension at the TDP region or, if any riser section is under effective compression, it means maximum effective compression at that section.
6. Installation and positioning errors of 1.5% of water depth plus 7.5 m shall be considered if not specified.

Table 3 - Load Case Matrix for Permanent Normal Operating

<table>
<tr><th rowspan="3">Load Case</th><th rowspan="3">Position (Fig. 4)</th><th colspan="4">Functional Load</th><th colspan="4">Environmental load</th><th rowspan="3">OBS.</th></tr>
<tr><th rowspan="2">Floating Unit Draft</th><th colspan="2">Floating Unit Heading</th><th rowspan="2">Floating Unit offset</th><th colspan="2">Wave</th><th colspan="2">Current</th></tr>
<tr><th>FPSO Turret (Fig. 3)</th><th>others</th><th>RP</th><th>Direction</th><th>RP</th><th>Direction</th></tr>
<tr><td>GA-1</td><td>Near</td><td rowspan="20">Draft with the worst vertical acceleration and angular motion for each load case (1)</td><td rowspan="8">Head seas</td><td rowspan="20">Actual Heading</td><td rowspan="20">Extreme (2)</td><td>100</td><td rowspan="4">Collinear (Figure 4)</td><td>10</td><td rowspan="4">Collinear (Figure 4)</td><td></td></tr>
<tr><td>GA-2</td><td>Far</td><td>100</td><td>10</td><td></td></tr>
<tr><td>GA-3</td><td>Cross</td><td>100</td><td>10</td><td>Floating unit offset shall be applied ± 45º (cross near) and ± 135º (cross far) from the riser plane (Fig. 4 c)</td></tr>
<tr><td>GA-4</td><td>Transv.</td><td>100</td><td>10</td><td>Floating unit offset shall be applied ± 90º from the riser plane (Fig. 4 d)</td></tr>
<tr><td>GA-5</td><td>Near</td><td>10</td><td rowspan="4">Collinear (Figure 4)</td><td>100</td><td rowspan="4">Collinear (Figure 4)</td><td></td></tr>
<tr><td>GA-6</td><td>Far</td><td>10</td><td>100</td><td></td></tr>
<tr><td>GA-7</td><td>Cross</td><td>10</td><td>100</td><td>Floating unit offset shall be applied ± 45º (cross near) and ± 135º (cross far) from the riser plane (Fig. 4 c)</td></tr>
<tr><td>GA-8</td><td>Transv.</td><td>10</td><td>100</td><td>Floating unit offset shall be applied ± 90º from the riser plane (Fig. 4 d)</td></tr>
<tr><td>GA-9</td><td>Near</td><td rowspan="4">22.5° from bow</td><td>100</td><td rowspan="4">Crossed ± 22.5 of the riser (Figure 5)</td><td>10</td><td rowspan="4">Crossed ± 45 of the wave (Figure 5)</td><td></td></tr>
<tr><td>GA-10</td><td>Far</td><td>100</td><td>10</td><td></td></tr>
<tr><td>GA-11</td><td>Cross</td><td>100</td><td>10</td><td>Floating unit offset shall be applied ± 45º (cross near) and ± 135º (cross far) from the riser plane (Fig. 7)</td></tr>
<tr><td>GA-12</td><td>Transv.</td><td>100</td><td>10</td><td>Floating unit offset shall be applied ± 90º from the riser plane (Fig. 6)</td></tr>
<tr><td>GA-13</td><td>Near</td><td rowspan="4">22.5° from bow</td><td>10</td><td rowspan="4">Crossed ± 22.5 of the riser (Figure 5)</td><td>100</td><td rowspan="4">Crossed ± 45 of the wave (Figure 5)</td><td></td></tr>
<tr><td>GA-14</td><td>Far</td><td>10</td><td>100</td><td></td></tr>
<tr><td>GA-15</td><td>Cross</td><td>10</td><td>100</td><td>Floating unit offset shall be applied ± 45º (cross near) and ± 135º (cross far) from the riser plane (Fig. 7)</td></tr>
<tr><td>GA-16</td><td>Transv.</td><td>10</td><td>100</td><td>Floating unit offset shall be applied ± 90º from the riser plane (Fig. 6)</td></tr>
<tr><td>GA-17</td><td>Near</td><td rowspan="4">Beam seas (90°)</td><td rowspan="4">(3)</td><td rowspan="4">(4)</td><td>1</td><td rowspan="4">(5)</td><td></td></tr>
<tr><td>GA-18</td><td>Far</td><td>1</td><td></td></tr>
<tr><td>GA-19</td><td>Cross</td><td>1</td><td>Floating unit offset shall be applied ± 45º (cross near) and ± 135º (cross far) from the riser plane</td></tr>
<tr><td>GA-20</td><td>Transv.</td><td>1</td><td>Floating unit offset shall be applied ± 90º from the riser plane</td></tr>
</table>

Notes:

(1) For selection of the floating unit´s draft and waves for each load case follow the procedures presented in Item 4.3.2.

(2) Offset direction is defined by the riser azimuth and the load case position (NEAR, FAR, etc.) presented on the second column of the table. For load cases GA-17 to GA20 the offset for 1-year environmental condition and intact mooring system shall be considered. If not specified, offset for damage mooring system for load cases GA-17 to GA-20 shall be equal to the offset for 100-year environmental condition and intact mooring system.

(3) The purpose of these load cases is to represent a swell condition based on the BR operational experience. If not specified, wave height and period shall be determined as follow:

(i) Significant wave height (Hs) for a return period of 1-year. For floating units in operation at Campos Basin significant wave height shall be limited to 4.5 m;

(ii) Peak period (Tp) shall be equal to the natural period of roll motion of the floating unit.

(4) Wave direction is defined according to the mooring system as follow:

(i) For turret mooring system the wave direction shall be ± 90.0º relative to the offset direction defined in note [2]. There are two possible wave directions for each load case.

(ii) For spread mooring system (SS or ship shape unit) the wave direction shall be ± 90.0º relative to the heading direction of the unit. The wave direction shall be in accordance with the offset direction in order to the wave shall not be opposed to the offset. Therefore, there is one possible wave direction for each load case only.

(5) Current direction shall be the same of the offset direction. For turret moored systems the current and the floating unit shall be considered aligned with the current comes from bow to stern.

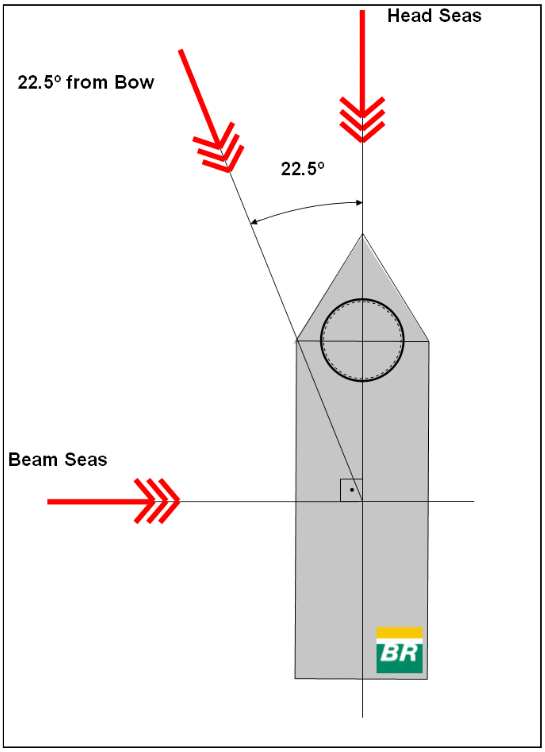


Figure 3 – Wave incidence for FPSO with turret mooring system

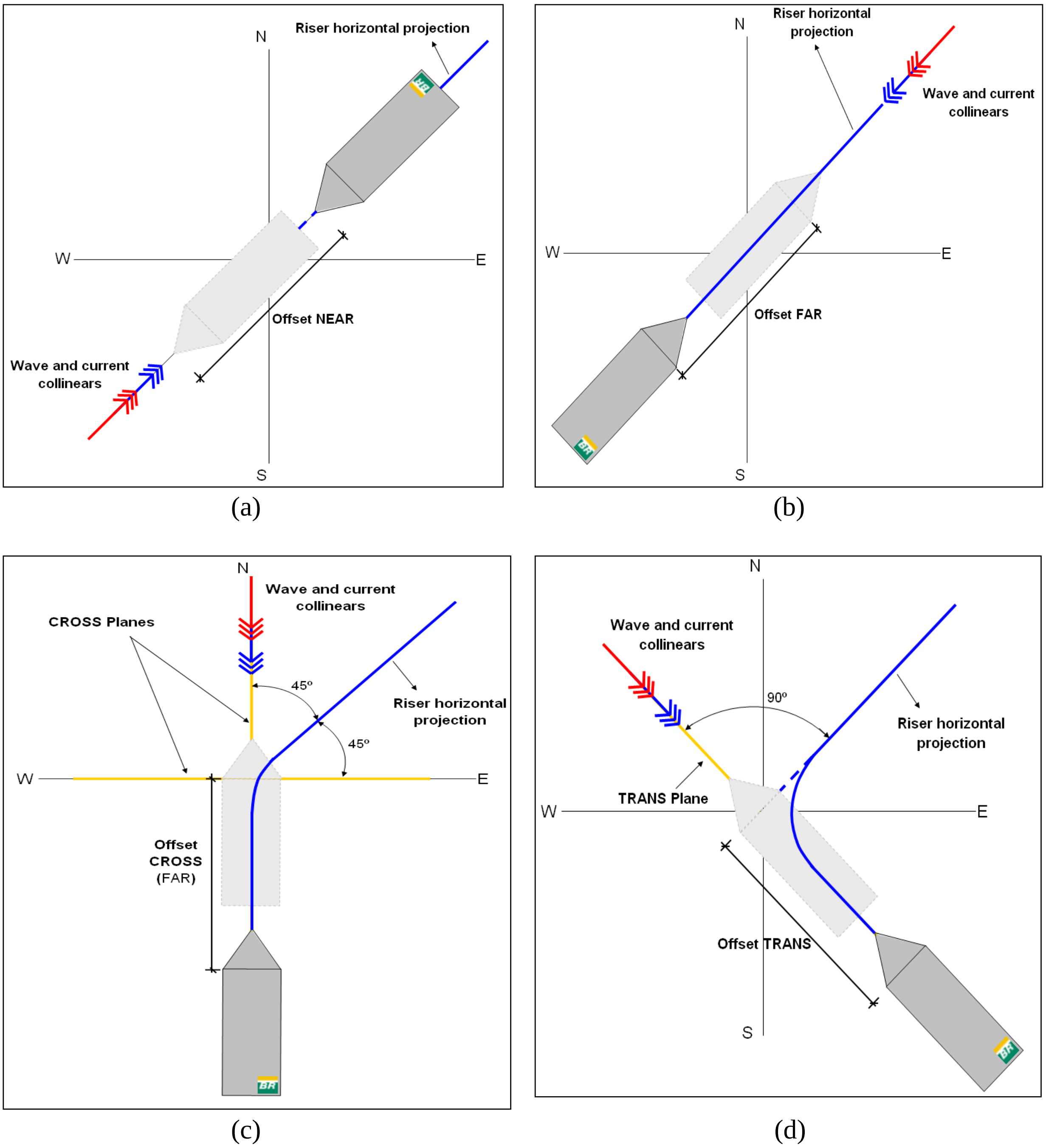
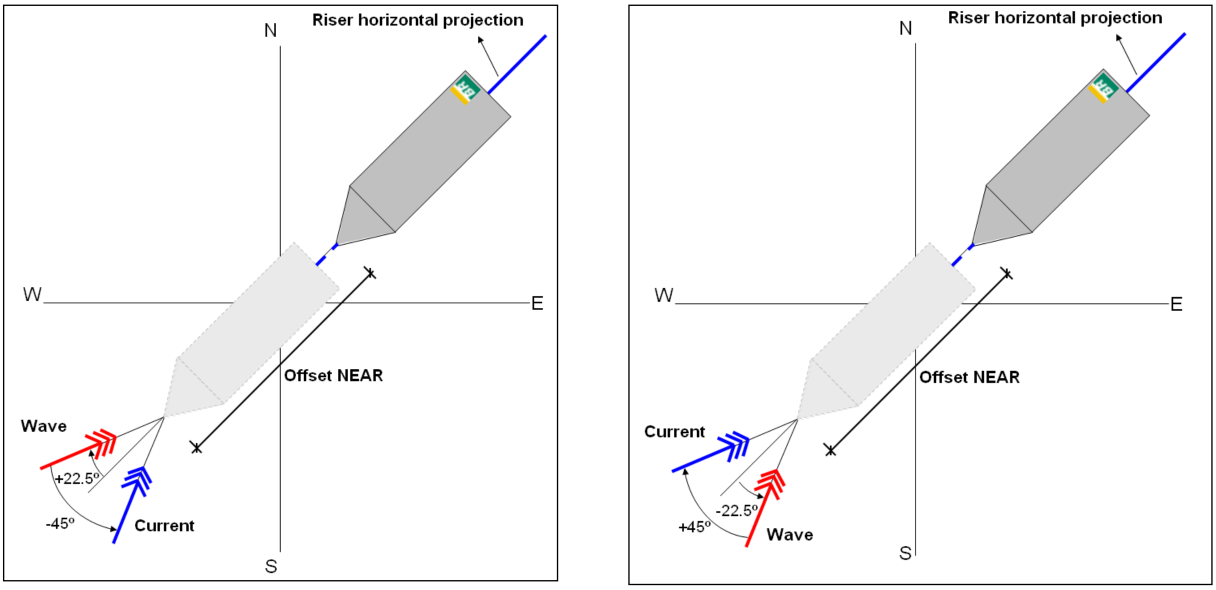
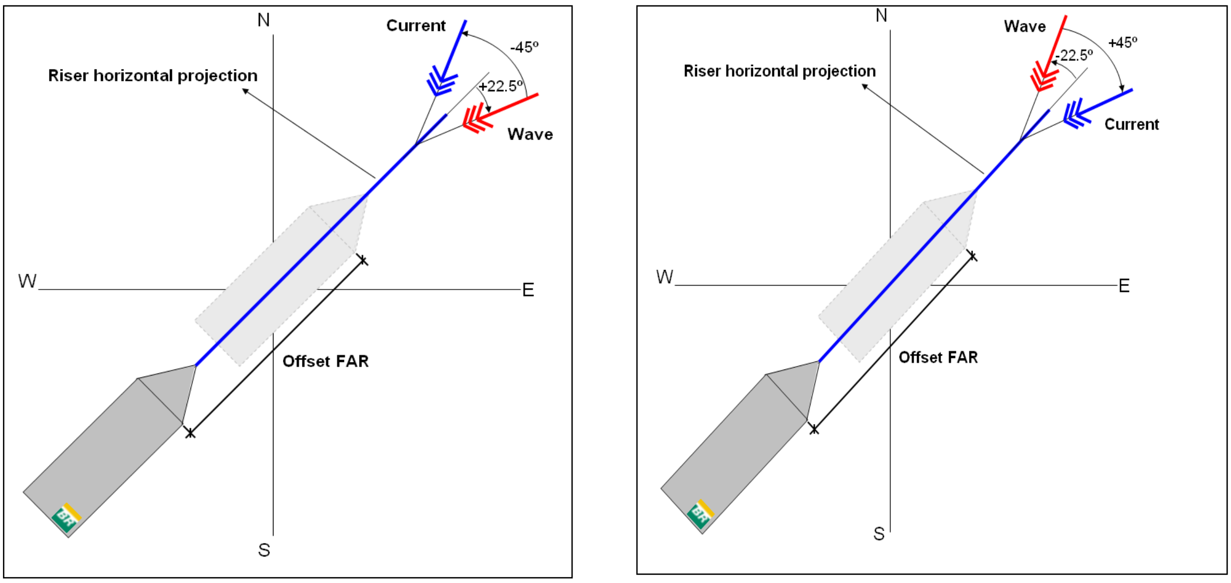


Figure 4 - Offsets convention for collinear conditions: (a) NEAR, (b) FAR, (c) CROSS and (d) TRANSVERSE



(a) NEAR



(b) FAR

Figure 5 - Crossed environmental conditions: (a) NEAR offset, (b) FAR offset

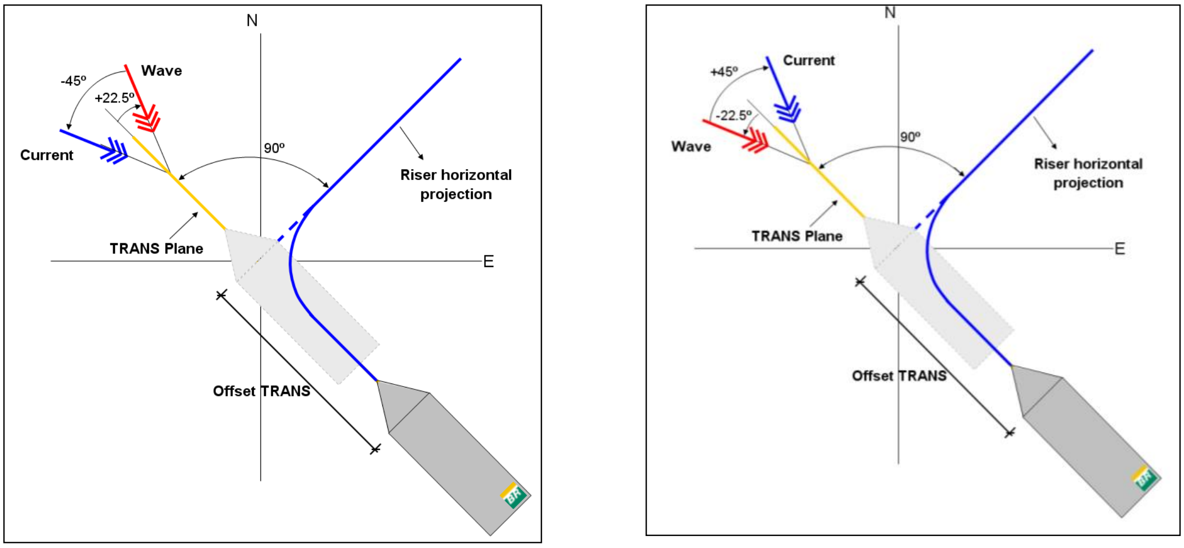


Figure 6 - Crossed environmental conditions: TRANSVERSE offset

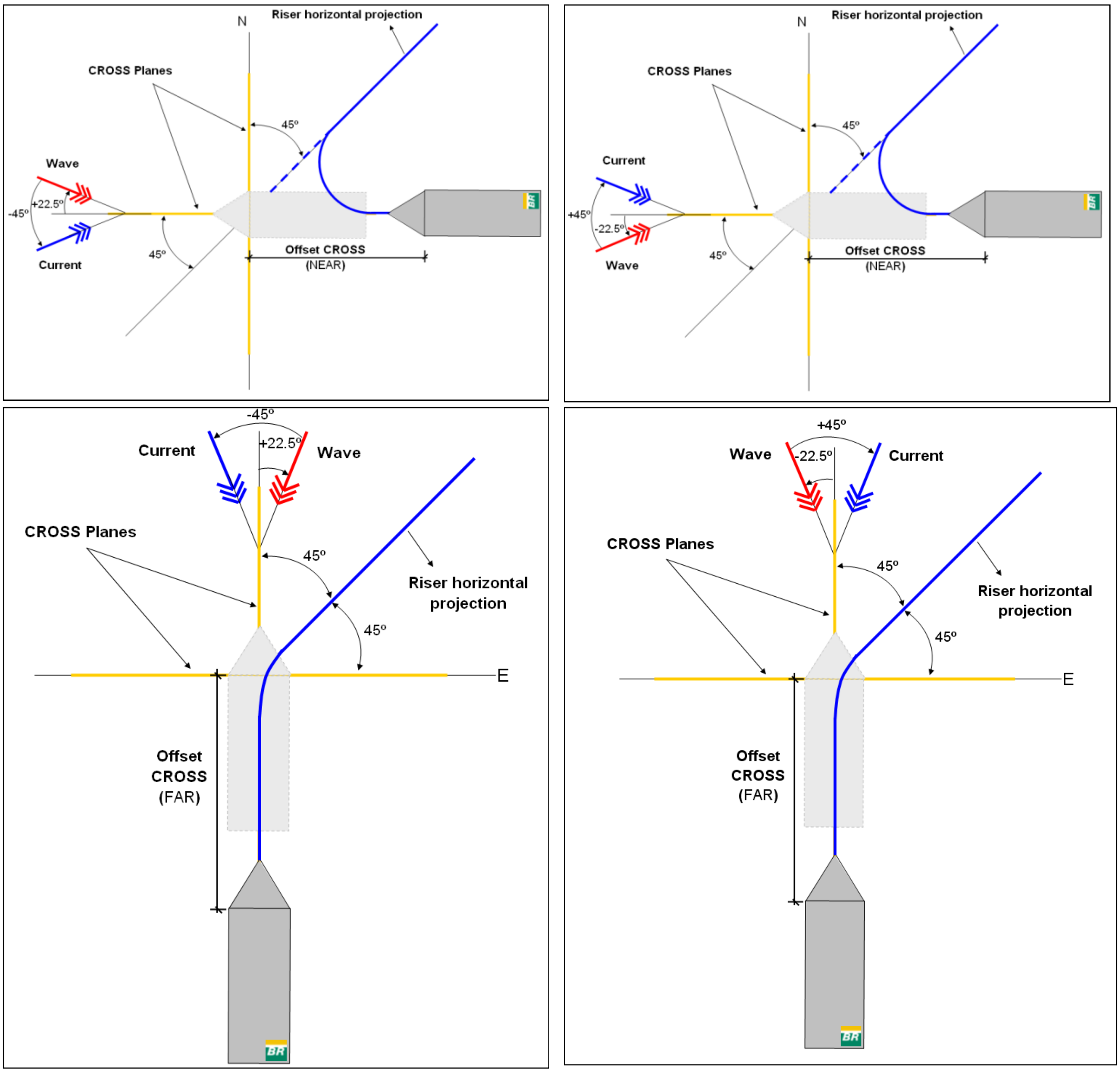


Figure 7 – Environmental crossed conditions: CROSS offset

Table 4 - Load Case Matrix for Permanent Extreme Operating Conditions

Load Case	Position	Functional Load			Environmental load				Accidental Loads	From Table 3 select the load cases which present:
		Floating Unit Draft	Floating Unit Heading	Floating Unit offset	Wave		Current			
					RP	Direction	RP	Direction		
GB-1	Near			Extreme					one mooring line failed	Maximum top tension and angle among near cases
GB-2	Far									Maximum top tension and angle among far cases
GB-3	Cross									Maximum top tension and angle among cross cases
GB-4	Transv.									Maximum top tension and angle among transv. cases
GB-5	Near									Maximum TDP, SAG or HOG curvature among near cases
GB-6	Far									Maximum TDP, SAG or HOG curvature among far cases
GB-7	Cross									Maximum TDP, SAG or HOG curvature among cross cases
GB-8	Transv.									Maximum TDP, SAG or HOG curvature among transv. cases
GD-1	Near			Extreme					Pipe empty & Breached pipe outer sheath	Minimum TDP, SAG or HOG tension among near cases
GD-2	Far									Minimum TDP, SAG or HOG tension among far cases
GD-3	Cross									Minimum TDP, SAG or HOG tension among cross cases
GD-4	Transv.									Minimum TDP, SAG or HOG tension among transv. cases
GD-5	Near									Maximum TDP, SAG or HOG curvature among near cases
GD-6	Far									Maximum TDP, SAG or HOG curvature among far cases
GD-7	Cross									Maximum TDP, SAG or HOG curvature among cross cases
GD-8	Transv.									Maximum TDP, SAG or HOG curvature among transv. cases
GE-1	Near			Extreme					Pipe empty	Minimum TDP, SAG or HOG tension among near cases
GE-2	Far									Minimum TDP, SAG or HOG tension among far cases
GE-3	Cross									Minimum TDP, SAG or HOG tension among cross cases
GE-4	Transv.									Minimum TDP, SAG or HOG tension among transv. cases
GE-5	Near									Maximum TDP, SAG or HOG curvature among near cases
GE-6	Far									Maximum TDP, SAG or HOG curvature among far cases
GE-7	Cross									Maximum TDP, SAG or HOG curvature among cross cases
GE-8	Transv.									Maximum TDP, SAG or HOG curvature among transv. cases

Table 5 - Load Case Matrix for Permanent Extreme Operating Conditions – Buoyance losses

Load Case	Position	Functional Load			Environmental load				Accidental Loads	From Table 3 select the load cases which present:
		Floating Unit Draft	Floating Unit Heading	Floating Unit offset	Wave		Current			
					RP	Direction	RP	Direction		
GF-1	Near			Extreme					buoyancy/weight losses over service life	Maximum top tension and angle among near cases
GF-2	Far									Maximum top tension and angle among far cases
GF-3	Cross									Maximum top tension and angle among cross cases
GF-4	Transv.									Maximum top tension and angle among transv. cases
GF-5	Near									Maximum TDP, SAG or HOG curvature among near cases
GF-6	Far									Maximum TDP, SAG or HOG curvature among far cases
GF-7	Cross									Maximum TDP, SAG or HOG curvature among cross cases
GF-8	Transv.									Maximum TDP, SAG or HOG curvature among transv. cases

Table 6 - Load Case Matrix for Abnormal Operating Conditions (Floating Unit inclination due to a compartment flooding)

Load Case	Position	Functional Load			Environmental load				Accidental Loads	From Table 3 select the load cases which present:
		Floating Unit Draft	Floating Unit Heading	Floating Unit offset	Wave		Current			
					RP	Direction	RP	Direction		
GG-1	Near	Survival (or the worst in each load case)		Annual	1		1		compartment flooding	Maximum top tension and angle among near cases
GG-2	Far				1		1			Maximum top tension and angle among far cases
GG-3	Cross				1		1			Maximum top tension and angle among cross cases
GG-4	Transv.				1		1			Maximum top tension and angle among transv. cases

Table 7 - Load Case Matrix for Abnormal Operating Conditions (Incidental Pressure and one mooring line broken)

Load Case	Position	Functional Load			Environmental load				Accidental Loads	From Table 3 select the load cases which present:
		Floating Unit Draft	Floating Unit Heading	Floating Unit offset	Wave		Current			
					RP	Direction	RP	Direction		
GH-1	Near	Draft with the worst vertical acceleration and angular motion		Extreme [1]	10		10		Incidental Pressure and one mooring line failed	Maximum top tension and angle among near cases
GH-2	Far				10		10			Maximum top tension and angle among far cases
GH-3	Cross				10		10			Maximum top tension and angle among cross cases
GH-4	Transv.				10		10			Maximum top tension and angle among transv. cases

Notes 1 If not specified by BR the following offsets shall be considered:

(i) Offset for damaged mooring system and 100-year environmental condition for the load cases in Table 7 obtained from load cases GA-1 to GA-16 in Table 3;

(ii) Offset for intact mooring system and 100-year environmental condition for the load cases in Table 7 obtained from load cases GA-17 to GA-20 in Table 3.

The beam sea wave scenario for the nonoperational load conditions can be disregard for flowlines.

For any riser configuration, the beam sea scenario have to be considered for the final stage, during pull-in (or the stage with double catenary in case of first end pull-in) when the installation vessel is close to the platform unit.

Table 8 – Load Case Matrix for Nonoperation Conditions, Temporary Normal Installation

Load Case	Position	Functional Load				Environmental load					OBS.
		Internal Fluid	Floating Unit Draft	Floating Unit Heading	Floating Unit offset	Wave			Current		
						H (m)	T (s)	Dir.	RP	Dir.	
GI-1	Neutral	Full of water	Installation Vessel	Head seas	-	8.55	Note 1	Collinear	1	Collinear	
GI-2				Quartering seas		7.60	Note 1		1		
GI-3				Beam seas		6.08	Note 1		1		
GJ-1	Neutral	Empty	Installation Vessel	Head seas	-	8.55	Note 1	Collinear	1	Collinear	
GJ-2				Quartering seas		7.60	Note 1		1		
GJ-3				Beam seas		6.08	Note 1		1		

Note 1. For each load case a screening analysis shall be performed to choose the worst period between 6 to 15 s.

Table 9 – Load Case Matrix for Nonoperation Conditions, Temporary Normal Offshore Leak Test

Load Case	Position	Functional Load				Environmental load					OBS.
		Internal Fluid	Floating Unit Draft	Floating Unit Heading	Floating Unit offset	Wave H (m)	Wave T (s)	Wave Dir.	Current RP	Current Dir.	
GK-1	Neutral	Full of water	Installation Vessel	Head seas	-	3.8	Note 1	Collinear	1	Collinear	
GK-2				Quartering seas		3.8	Note 1		1		
GK-3				Beam seas		3.8	Note 1		1		

Note 1. For each load case a screening analysis shall be performed to choose the worst period between 6 to 15 s.

Table 10 – Load Case Matrix for Nonoperation Conditions, Temporary Normal Pull-in/out and Offshore Leak Test (risers only)

Load Case	Position (Fig. 4)	Functional Load				Environmental load					OBS.
		Floating Unit Draft Note 1	Floating Unit Heading: FPSO Turret (Fig. 3)	Floating Unit Heading: others	Floating Unit offset Note 3	Wave H (m)	Wave T (s)	Wave Direction	Current RP	Current Direction	
GK-4	Near	Draft with the worst vertical acceleration for each load case	Head seas	Actual Heading	Annual	3,8	Note 6	Collinear	1	Collinear	
GK-5	Far					3,8	Note 6		1		
GK-6	Cross					3,8	Note 6		1		
GK-7	Transv.					3,8	Note 6		1		
GK-8	Near		22.5° from bow			3,8	Note 6	Crossed ± 22.5 of the riser (Figure 5)	1	Crossed ± 45 of the wave (Figure 5)	
GK-9	Far					3,8	Note 6		1		
GK-10	Cross					3,8	Note 6		1		
GK-11	Transv.					3,8	Note 6		1		
GK-12	Near		Beam seas (90°)	Note 2		3,8	Note 6	Note 4	1	Note 5	Applicable only for turret mooring system
GK-13	Far					3,8	Note 6		1		
GK-14	Cross					3,8	Note 6		1		
GK-15	Transv.					3,8	Note 6		1		

Notes:

1 For selection of the floating unit´s draft and waves for each load case follow the procedures presented in Item 4.3.2.

2 These load cases are applicable for turret mooring system only, because the load cases GJ-4 to GJ-7 and GJ-8 to GJ-11 for collinear and crossed conditions have the same wave height and period. Therefore, according to the directions of offset, wave and current defined in this table, collinear and crossed cases are already considering a wave incidence direction close to 90º for spread mooring systems.

3 Offset direction is defined by the riser azimuth and the load case position (NEAR, FAR, etc.) presented on the second column of the table.

4 Wave direction shall be ± 90.0º relative to the offset direction defined in note [2]. There are two possible wave directions for each load case. For near and far cases the two possibiliteis are the same and just one may be checked. For cross and transverse cases although the wave be the same, the connection point may be different.

5 Current direction shall be the same of the offset direction and the floating unit shall be considered aligned with the current comes from bow to stern.

6. For each load case a screening analysis shall be performed to choose the worst period between 6 to 15 s

Table 11 – Load Case Matrix for Nonoperation Conditions, Temporary Extreme – Breached pipe outer sheath

Load Case	Position	Functional Load				Environmental load					OBS.
		Internal Fluid	Floating Unit Draft	Floating Unit Heading	Floating Unit offset	Wave			Current		
						H (m)	T (s)	Dir.	RP	Dir.	
GL-1	Neutral	Empty	Installation Vessel	Head seas	-	8.55	Note 1	Collinear	1	Collinear	Breached pipe outer sheath
GL-2				Quartering seas		7.60	Note 1		1		
GL-3				Beam seas		6.08	Note 1		1		

Note:1. For each load case a screening analysis shall be performed to choose the worst period between 6 to 15 s.

Table 12 – Load Case Matrix for Nonoperation Conditions, Temporary Extreme – Accidental Flooding

Load Case	Position	Functional Load				Environmental load					OBS.
		Internal Fluid	Floating Unit Draft	Floating Unit Heading	Floating Unit offset	Wave			Current		
						H (m)	T (s)	Dir.	RP	Dir.	
GM-1	Neutral	Full of water	Installation Vessel	Head seas	-	8.55	Note 1	Collinear	1	Collinear	
GM-2				Quartering seas		7.60	Note 1		1		
GM-3				Beam seas		6.08	Note 1		1		

Note 1. For each load case a screening analysis shall be performed to choose the worst period between 6 to 15 s.

If the design criteria are not met for the wave height (Hmax) and period (6 to 15s) specified for any wave direction (Heading seas, Quartering seas and Beam seas) then for that wave direction the manufacture shall determine the maximum wave height for each period that the design criteria are met and submit for Petrobras approval.

4.3.2. Motion and Wave Modeling Procedures

It is recommended (not mandatory) that the global analyses for the load cases specified should be carried out adopting an irregular wave procedure (IWP) as described in ANNEX A – Motion and Wave Modeling Procedures. The irregular wave procedure shall be presented in the Design Premise Report and submitted for approval by BR.

Alternatively, global analyses may be carried out considering a regular wave procedure (Design Wave Procedure - DWP), but in this case it is recommended to re-run considering an irregular wave procedure (IWP) at least the load cases (GA) from Table 3 that present the highest top tension and the highest angle between the line and the bend stiffener’s neutral axis.

It is recommended (not mandatory) that the procedure adopted for regular wave analysis (DWP) should be the maximum response procedure described in Annex A for operating and non-operating conditions (installation). A procedure different from the procedure in Annex A may be adopted, but it shall be presented previously for BR approval in a technical query or in the Design Premise Report, depending the schedule of approval foreseen.

At least one of the following combinations of axial tension and angle between the riser and bending stiffener neutral axis shall be considered in the bending stiffener design:

- Maximum axial tension with associated angle and maximum angle with associated axial tension for load case that is analyzed by an irregular wave procedure (IWP) or by both wave procedures (DWP and IWP);
- Maximum bend moment represented by the maximum pseudo curvature ($kp = T(1 - \cos(\alpha))$ or $kp = 2T(sen^2 \frac{\alpha}{2})$) and associated angle ($\alpha$) and tension ($T$);
- Maximum axial tension associated with maximum angle for load case that is analyzed by a regular wave procedure (DWP) only.

The selection of wave spectrum properties per direction and unit draft depends on the environmental data available on BR metocean technical specification. If tables or curves of extreme significant wave height (Hs) as function of the peak period (Tp) for each wave direction and for a given return period (e.g. 100-years) is available (Hs x Tp contour curves) the following procedure shall be adopted for the load cases analyzed:

1. First, for each draft that RAO table is available (at least full and ballasted), the movements of the floating unit shall be transferred from the center of motion (CoM) to the riser's connection point obtaining the RAOs of movements and vertical acceleration at the connection point;
2. For each wave direction, the wave spectrum defined by each pair of values Hs x Tp found in the contour table shall be crossed with the RAOs at the connection point for each draft and, assuming a Rayleigh distribution, the Most Probably Maximum (MPM) amplitude for roll, pitch and vertical acceleration shall be determined for a storm of 3 hr.;
3. The pair (Hs, Tp) and draft that present the highest vertical acceleration and highest angular motion shall be selected to be considered in the dynamic analysis. Angular motion is defined as follow: $\theta = \sqrt{RMAX2 + PMAX2}$ (1)

   Where RMAX and PMAX are the MPM amplitudes for roll and pitch, respectively. It should be noted that the same load case may be analyzed for different drafts and different waves;
4. For each wave spectra and draft selected, a regular wave procedure (DWP) or an irregular wave procedure (IWP) shall be adopted in the dynamic analyses following the recommendations presented previously.

Otherwise, if the contour table is not available and the significant wave height (Hs) and peak period (Tp) are specified as for the load cases GA-17 to GA-20 and for installation load cases the following procedure shall be adopted:

1. First, for each draft that RAO table is available (at least full and ballasted), the movements of the floating unit shall be transferred from the center of motion (CoM) to the riser's connection point obtaining the RAOs of movements and vertical acceleration at the connection point;

2. Considering the values of Hs and Tp for a given return period specified for each wave direction, the wave spectrum shall be crossed with the RAO´s at the connection point for each draft and, assuming a Rayleigh distribution, the MPM amplitude for roll, pitch and vertical acceleration shall be determined for a storm of 3 hr.;
3. The draft(s) that presents the highest vertical acceleration and highest angular motion are selected to be considered in dynamic analyses. Angular motion is defined according to equation (1).
4. For each wave spectra and draft selected, a regular wave procedure (DWP) or an irregular wave procedure (IWP) shall be adopted in the dynamic analyses following the recommendations presented previously.

For installation vessels the connection points are defined by the position of the wheel or by the vertical lay system (VLS).

4.3.3. Global Analysis Output

MANUFACTURER shall present, for the global analyses, tables containing at least the information requested on Table 13. It is important to note that the tables shall be present for all design load cases specified in Table 1.

Table 13 – Initial condition for Dynamic Analysis

Id	Load Case	Offset		Wave			Current		
		Value (m)	Direction (deg.)	Direction (deg.)	Compass Direction (N, NE, …)	Return Period (year)	Direction (deg.)	Compass Direction (N, NE, …)	Return Period (year)
1	GA-1	-	-	-	-	-	-	-	-
2	GA-2	-	-	-	-	-	-	-	-
3	GA-3								
N									

Id	Load Case	Regular Wave		Draft	Hs (m)	Tp (s)	gamma
		H (m)	T (s)				
1	GA-1						
2	GA-2						
3	GA-3						
N							

Table output: MANUFACTURER shall present a table output containing at least the information requested in Table 14 to Table 17.

Table 14 – Results for the Riser Top

Id	Load Case	Top Angle (deg.)		Top Tension (kN)		Shear Force (1) (kN) Max	Moment (1) (kN.m) Max	Curvat. 1/m
		Min	Max	Min	Max			
1	GA-1							
2	GA-2							
3	GA-3							
N								

Note 1 – Bend stiffener level

Table 15 – Results for the riser SAG and HOG

Id	Load Case	F_{SAG} (kN)		MBR_{SAG} (m)	F_{HOG} (kN)		MBR_{HOG} (m)
		Min	Max		Min	Max	
1	GA-1						
2	GA-2						
3	GA-3						
N							

Table 16 – **Results for the TDP Region and Sea Bottom**

Id	Load Case	TDP Region & Sea Bottom				
		F_{axial} Max (kN)	F_{axial} Min & Associated RC		RC Min & Associated F_{axial}	
			max	min	Max	Min
1	GA-1					
2	GA-2					
3	GA-3					
N	N					

Notes:

1. F_{axial} - axial tension acting on the riser;
2. RC - radius of curvature.

Table 17 – Tension at all riser connection

Id	Load Case	Intermediate connection 1 (kN)		Intermediate connection N (kN)		Riser Flow Connection (kN)	
		T min	T max	T min	T max	T min	T max
1	GA-1						
2	GA-2						
3	GA-3						
N							

4.4. LOCAL STRESS ANALYSIS

4.4.1. Introduction

The pipe layers shall be designed according to the criteria specified in [6]. When selecting local stress analysis load cases, it was assumed that all information requested in [1] are accomplished in the design report.

The specified local analysis load cases shall be performed to determine stresses and strains in the structural layers of the pipe and the respective utilization factors. The analyses results shall be condensed in summary tables and submitted to BR for analysis and approval. The following data shall be submitted to BR:

(i) Specification of materials and properties of steel layers (e.g. ultimate tensile strength and yield strength, wire cross section dimensions, lay angle, number of wires);

(ii) Specification of materials and properties of holding bandages (e.g. thickness, wideness, ultimate tensile strength, axial elongation at ultimate tensile strength);

(iii) Section loads for each local analysis load case (e.g. internal pressure, external pressure, effective tension or effective compression, true wall tension or true wall compression, curvature radius).

The following results shall be submitted to BR for each local stress analysis load case:

(i) Applied stress and structural capacity for each layer;

(ii) Radial and longitudinal deformations;

(iii) Predicted gap between layers and allowable gap when applicable;

(iv) Contact pressure between layers;

(v) Utilization factor related to the combined stress state assessed.

Local Stress Analysis of Design Load Cases A to M from the load case matrix presented in Table 1 shall include at least the Local Analysis Load Cases listed in Table 18 to Table 30. The following general notes shall be observed for all load cases:

1. The terms Top section and TDP section used in Table 18 to Table 30 refer to a typical free hanging riser configuration with just one section. For multiple section risers and/or for other riser configurations, MANUFACTURER shall determine the appropriate cross-sections to be verified for the load cases of each table. This selection should take into account positions where axial tension, axial compression and curvature are maxima for each riser section (i.e. top riser, intermediate riser, etc.).
2. All local analysis load cases shall consider the internal fluid, internal pressure and external pressure defined in Table 1 for the focused design load case.
3. Torque can be applied or induced by internal and external pressure, tension and bending, mainly when pipes with two different section designs are connected.
4. Maximum global analysis results selection shall be made comparing effective tension but when assessing applied stresses and deformations the true wall tension (or true wall compression) shall be adopted. The true wall tension is a function of the effective tension, the internal and external pressures at the local analysis section and of the internal and external cross-sectional areas of the pipe, using the assumption of pipe closed ends.

5. If any riser section is under effective compression, minimum effective tension means the maximum effective compression.
6. When the focused potential failure mechanism is the hydrostatic collapse of carcass and/or pressure armor, the utilization factor should be calculated either as the rate between applied stress and buckling stress or as the rate between the applied external pressure and the hydrostatic collapse external pressure, which is obtained when the associated loads are kept constant and the external pressure is increased until the collapse external pressure is achieved. Applied stresses shall ever be reported and utilization factors shall comply with requirements of [1]. In addition, the Carcass Design Tolerance used for hydrostatic collapse calculations shall be reported.

Table 18 – Design Load Case A - Riser Operation (maximum operating pressure)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LA-1	RISER Top Region For each structure	Maximum from GA-1 to 20	---	---	Tensile Failure	Breakage of tensile armors due to excessive tension
LA-2	RISER Top Region For each structure	Maximum from GA-1 to 20	---	---	Collapse	Collapse of carcass and/or pressure armor due to excessive tension (squeezing)

4.4.2. Permanent Operation (Extreme) Local Analysis Load Cases

Table 19 – Design Load Case B - Riser Operation (maximum design pressure and one mooring line broken)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LB-1	RISER Top Region For each structure	Maximum from GB-1 to 8	---	---	Tensile Failure	Breakage of tensile armors due to excessive tension
LB-2	RISER Top Region For each structure	Maximum from GB-1 to 8	---	---	Mechanical Collapse	Collapse of carcass and/or pressure armor due to excessive tension (squeezing)

Table 20 – Design Load Case C - Riser Operation (atmospheric internal pressure and one mooring line broken)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LC-1	RISER Top Region For each structure	Maximum from GB-1 to 8	---	---	Tensile failure	Collapse of carcass and/or pressure armor due to excessive tension (squeezing)
LC-2	RISER TDP, SAG or HOG Region	Maximum from GB-1 to 8	---	---	Mechanical Collapse and/or Hydrostatic Collapse	Collapse of carcass and/or pressure armor because of excess external pressure and excessive tension (squeezing)
LC-3	RISER TDP, SAG or HOG Region	---	Minimum from GB-1 to 8	---	Hydrostatic Collapse	Collapse of carcass and/or pressure armor because of excess external pressure and bending
LC-4	RISER TDP, SAG or HOG Region	Minimum from GB-1 to 8	Minimum in the section where the minimum effective tension occurs	Maximum in the section where the minimum effective tension occurs (Note 1)	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature
LC-5	RISER TDP, SAG or HOG Region	Minimum in the section where the minimum curvature radius occurs	Minimum from GB-1 to 8	Maximum in the section where the minimum effective tension occurs (Note 1)	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature

Note 1 - Torque is to be considered only if it increases the compressive stress of the critical tensile armor layer

Table 21 – Design Load Case D - Riser Operation (no internal fluid and breached pipe outer sheath)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LD1	RISER Top Region For each structure	Maximum from GB-1 to 8	---	---	Mechanical Collapse	Collapse of carcass and/or pressure armor due to excessive tension (squeezing)
LD-1	RISER TDP, SAG or HOG Region	---	Minimum from GD-1 to 8	---	Hydrostatic Collapse	Collapse of carcass and/or pressure armor because of excess external pressure and bending
LD-2	RISER TDP, SAG or HOG Region	Minimum from GD-1 to 8	---	Maximum in the section where the minimum effective tension occurs (Note 1)	Compressive Failure	Wire disorganization caused by radial gap between each tensile armor and its adjacent layers due to excessive axial compression
LD-3	RISER TDP, SAG or HOG Region	Minimum from GD-1 to 8	---	Maximum in the section where the minimum effective tension occurs (Note 1)	Compressive Failure	Birdcaging of the tensile armor wires caused by excessive stress or strain of the antibuckling tapes due to excessive axial compression
LD-4	RISER TDP, SAG or HOG Region	Minimum from GD-1 to 8	Minimum in the section where the minimum effective tension occurs	---	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature
LD-5	RISER TDP, SAG or HOG Region	Minimum in the section where the minimum curvature radius occurs	Minimum from GD-1 to 8	---	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature

Note 1 - Torque is to be considered only if it increases the compressive stress of critical tensile armor layer

Table 22 – Design Load Case E - Riser Operation (no internal fluid and intact pipe outer sheath)

Local Analysis Load Case	Line Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LE-1	RISER TDP, SAG or HOG Region	Minimum from GE-1 to 8	Minimum in the section where the minimum effective tension occurs	Maximum in the section where the minimum effective tension occurs (Note 1)	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature
LE-2	RISER TDP, SAG or HOG Region	Minimum in the section where the minimum curvature radius occurs	Minimum from GE-1 to 8	Maximum in the section where the minimum effective tension occurs (Note 1)	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature

Note 1 - Torque is to be considered only if it increases the compressive stress of critical tensile armor layer

Table 23– Design Load Case F - Riser Operation (design internal pressure and buoyancy/weight losses over service life)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LF-1	RISER Top Region	Maximum from GF-1 to 8	---	---	Tensile Failure	Breakage of tensile armors due to excessive tension
LF-2	RISER Top Region	Maximum from GF-1 to 8	---	---	Mechanical Collapse	Collapse of carcass and/or pressure armor due to excessive tension (squeezing)
LF-3	RISER TDP, SAG or HOG Region	Minimum from GE-1 to 8	Minimum in the section where the minimum effective tension occurs	Maximum in the section where the minimum effective tension occurs (Note 1)	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature
LF-4	RISER TDP, SAG or HOG Region	Minimum in the section where the minimum curvature radius occurs	Minimum from GE-1 to 8	Maximum in the section where the minimum effective tension occurs (Note 1)	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature

4.4.3. Abnormal Operation Local Analysis Load Cases

Table 24 – Design Load Case G - Riser Operation (floating unit inclination due to a compartment flooding, as specified)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LG-1	RISER Top Region	Maximum in the section where the minimum curvature radius occurs	Minimum from GG - 1 to 4	---	Tensile Failure	Rupture of tensile armors because of excess tension combined with curvature
LG-2	RISER Top Region	Maximum from GG - 1 to 4	Minimum in the section where the maximum effective tension occurs	---	Tensile Failure	Rupture of tensile armors because of excess tension combined with curvature

Table 25 – Design Load Case H - Riser Operation (incidental pressure and one mooring line broken)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LH-1	RISER Top Region	Maximum from GH - 1 to 4	---	---	Tensile Failure	Rupture of tensile armors because of excess tension
LH-2	RISER Top Region	---	---	---	Burst	Rupture of pressure armors because of excess internal pressure
LH-3	RISER TDP, SAG or HOG Region and FLOW	---	---	---	Burst	Rupture of tensile armors because of excess internal pressure
LH-4	RISER TDP, SAG or HOG Region and FLOW	---	---	---	Burst	Rupture of pressure armors because of excess internal pressure
LH-5	RISER TDP, SAG or HOG Region	---	Minimum from GH - 1 to 4	---	Creep	Creep of the internal pressure sheath due to internal pressure and temperature ([1], item 5.3.2.1.2)
LH-6	FLOW	---	---	---	Creep	Creep of the internal pressure sheath due to internal pressure and temperature ([1], item 5.3.2.1.2)

4.4.4. Temporary Normal Installation Local Analysis Load Cases

Table 26 – Design Load Case I - Installation (pipe full of sea water & intact outer sheath)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Other Loads	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LI-1	RISER and FLOW Top Region	Maximum from GI-1 to 3	---	---	Tensile Failure	Breakage of tensile armors due to excessive tension
LI-2	RISER and FLOW Top Region	Maximum from GI-1 to 3	---	Maximum Crushing Load	Collapse	Collapse of carcass and/or pressure armor due to installation loads or ovalisation caused by installation loads ([1], Items 5.3.2.4 and 5.3.2.5)

Table 27 – Design Load Case J - Installation (pipe empty and intact pipe outer sheath)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LJ-1	RISER and FLOW Top Region	Maximum from GJ-1 to 3	---	---	Tensile Failure	Breakage of tensile armors due to excessive tension
LJ-2	RISER and FLOW Top Region	Maximum from GJ-1 to 3	---	Maximum Crushing Load	Collapse	Collapse of carcass and/or pressure armor due to installation loads or ovalisation caused by installation loads ([1], Items 5.3.2.4 and 5.3.2.5)
LJ-3	RISER TDP Region	Maximum from GJ-1 to 3	---	---	Collapse	Collapse of carcass and/or pressure armor due to excessive external pressure
LJ-4	RISER and FLOW TDP Region	Minimum from GJ-1 to 3	Minimum in the section where the minimum effective tension occurs	Maximum in the section where the minimum effective tension occurs (Note 1)	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature
LJ-5	RISER and FLOW TDP Region	Minimum in the section where the minimum curvature radius occurs	Minimum from GJ-1 to 3	---	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature

Note 1 - Torque is to be considered only if it increases the compressive stress of critical tensile armor layer

4.4.5. Temporary Normal Non Operation Test Local Analysis Load Cases

Table 28 – Design Load Case K – Offshore Test (maximum offshore test pressure)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LK-1	FLOW Top Region	Maximum from GK-1 to 3	---	---	Tensile Failure	Breakage of tensile armors due to excessive tension
LK-2	RISER Top Region	Maximum from GK-1 to 15	---	---	Tensile Failure	Breakage of tensile armors due to excessive tension
LK-3	RISER TDP Region and FLOW	---	---	---	Burst	Breakage of tensile armors due to excessive internal pressure
LK-4	RISER TDP Region and FLOW	---	---	---	Burst	Breakage of pressure armors due to excessive internal pressure
LK-5	FLOW TDP Region	---	Minimum from GK - 1 to 3	---	Creep	Creep of the internal pressure sheath due to internal pressure and temperature ([1], item 5.3.2.1.2)
LK-6	RISER TDP Region	---	Minimum from GK - 1 to 15	---	Creep	Creep of the internal pressure sheath due to internal pressure and temperature ([1], item 5.3.2.1.2)
LK-7	RISER and FLOW TDP Region	---	---	---	Burst	Breakage of tensile armors due to excessive internal pressure
LK-8	RISER and FLOW TDP Region	---	---	---	Burst	Breakage of pressure armors due to excessive internal pressure

4.4.6. Temporary Extreme Installation Local Analysis Load Cases

Table 29 – Design Load Case L - Installation (pipe empty and breached pipe outer sheath)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LL-1	RISER TDP Region	Maximum from GL-1 to 3	---	---	Collapse	Collapse of carcass and/or pressure armor due to excessive external pressure
LL-2	RISER and FLOW TDP Region	Minimum from GL-1 to 3	---	Maximum in the section where the minimum effective tension occurs (Note 1	Compressive Failure	Wire disorganization caused by radial gap between each tensile armor and its adjacent layer due to excessive axial compression
LL-3	RISER and FLOW TDP Region	Minimum from GL-1 to 3	---	Maximum in the section where the minimum effective tension occurs (Note 1)	Compressive Failure	Birdcaging of the tensile armor wires caused by excessive stress or strain of the antibuckling tapes due to excessive axial compression
LL-4	RISER and FLOW TDP Region	Minimum from GL-1 to 3	Minimum in the section where the minimum effective tension occurs	---	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature
LL-5	RISER and FLOW TDP Region	Minimum in the section where the minimum curvature radius occurs	Minimum from GL-1 to 3	---	Compressive Failure	Buckling of the tensile armor wires due to excessive axial compression combined with dynamic curvature

Note 1 - Torque is to be considered only if it increases the compressive stress of critical tensile armor layer

Table 30 – Design Load Case M - Installation (pipe full of sea water, unintended flood & intact outer sheath)

Local Analysis Load Case	Pipe Type/ Position	Effective Tension	Curvature Radius	Torque	Pipe Global Failure Mode to Design Against	Potential Failure Mechanism
LM-1	RISER and FLOW Top Region	Maximum from GI-1 to 3	---	---	Tensile Failure	Breakage of tensile armors due to excessive tension
LM-2	RISER and FLOW Top Region	Maximum from GI-1 to 3	---	Maximum Crushing Load	Collapse	Collapse of carcass and/or pressure armor due to installation loads or ovalisation caused by installation loads ([1], Items 5.3.2.4 and 5.3.2.5)

Note 1 - Torque is to be considered only if it increases the compressive stress of critical tensile armor layer

4.4.7. Utilization Factor Curves

For the following load cases, stress utilization factor curves (throughout line with the discretization used in the global analysis) shall be provided in spreadsheet format:

- Static condition at the neutral position - Pipe full of internal fluid, Atmospheric Internal Pressure at the Production Unit, breached pipe outer sheath, no offset and no current.

Table 31 – Static condition stress utilization factors

Structure number	Section name (top, intermediate, bottom, flowline)	Arc length from riser top (m)	Position from riser top (m) – Note 2		Residual stress (MPa) Nota 1		Internal pressure (MPa)	Minimum effective tension (kN)	Maximum effective tension (kN)	Utilization Factor (pressure armor)	Utilization Factor (Tensile armors)
			Vertical	Horizontal	Tensile armours	Pressure armour					

Notes:

1. Residual stresses calculation shall consider the manufacturing process, FAT and OLT
2. Coordinates in the plane of the line

- 100-year environmental conditions - Maximum effective top tension among GA1 to GA16 cases, Pipe full of internal fluid, Maximum design pressure, breached pipe outer sheath, intact mooring system and 100-year environmental conditions. (following the requirements of Table 32)
- 1-year environmental conditions - Maximum effective top tension among GA17 to GA20 cases, Pipe full of internal fluid, Maximum design pressure, breached pipe outer sheath, intact mooring system and 1-year environmental conditions. (following the requirements of Table 32)

Table 32 – Dynamic condition stress utilization factors

Depth (m)	Arc length from riser top (m)	Internal pressure (MPa)	Minimum effective tension (kN)	Maximum effective tension (kN)	Utilization Factor (pressure armor)	Utilization Factor (Tensile armor)

5. SPECIAL ANALYSES

5.1. ON-BOTTOM STABILITY ANALYSIS

MANUFACTURER shall provide results of on-bottom stability analysis for all flowlines being supplied. In addition, MANUFACTURER shall provide and justify the criteria used. API 17B [3] shall be used as a reference for such analysis.

5.2. DESIGN VERIFICATION FOR THE USE CONDITIONS

The manufacturer shall demonstrate the compliance with the specification, considering the use and the bore conditions from [6].

The calculated utilizations shall be based on the worst annulus conditions and account for the effects of cathodic protection, considering the position of the focused section of the pipe.

The utilization values determined by the manufacturer shall comply with the specified utilizations limits [1].

The manufacturer shall demonstrate that even taking into account the wire cross section reduction due to corrosion for the tensile and pressure armours, utilization factors comply with utilization factors, for the most critical load conditions at the end of the service life. The following results shall be submitted to Petrobras for each local stress analysis load case:

(i) Local Analysis Load Case identification;
(ii) Wire cross section dimensions considering the reduction due to corrosion;
(iii) Applied stress and structural capacity for each layer; and
(iv) Utilization factor related to the combined stress state assessed.

5.2.1. Tension RAO (Response Amplitude Operator)

In this technical specification, the Tension Response Amplitude Operator's (RAO) is adopted to describe the relation between top risers' tension amplitude and the vertical motion amplitude (Figure 8). Normally, RAO is obtained considering only related to the period, but in order to take into account non-linearities of the top tension riser response, it is necessary to evaluate the tension RAO for different vertical motion amplitudes. The RAO shall be obtained with the pipe full of internal fluid, no internal pressure and top vertical motion, with no wave applied.

The purpose of this RAO is to allow quick verifications and sensitivity studies of the riser top end fitting and also intermediary end fittings (if they exist). These analyses shall observe the following guidelines:

1. The analyses are characterized as directly imposed top vertical motions which amplitudes and periods are specified in the Table 33. Horizontal motions, rotations, wave and current effects are not to be taken into account.
2. The riser model needs to be built considering the vertical projection and top angle of the designed riser, in its mean position, and mean (or operating) draft.
3. The riser top connection boundary condition shall be pinned;

4. The tension RAOs shall be provided for all end fittings of the riser configuration.
5. If more than one internal fluid is specified, one tension RAO shall be provided for each one of them.
6. For free hanging catenary risers in water depths greater than 500m, and for lazy wave risers as well as other complacent configurations, the analysis shall be performed with no offsets.
7. Only for free hanging catenary risers in water depths lower than 500m, the tension RAOs need to be presented for three offset conditions*:

   a) No offset;
   b) Maximum 1-year for all directions, applied as far condition relative to the riser;
   c) Maximum 1-year for all directions, applied as near condition relative to the riser.

Note:* In this way, the number of tension RAOs to be provided is 3 times the “number of end fittings” times the “number of internal fluids specific weights”, where “3” is the number of offsets.

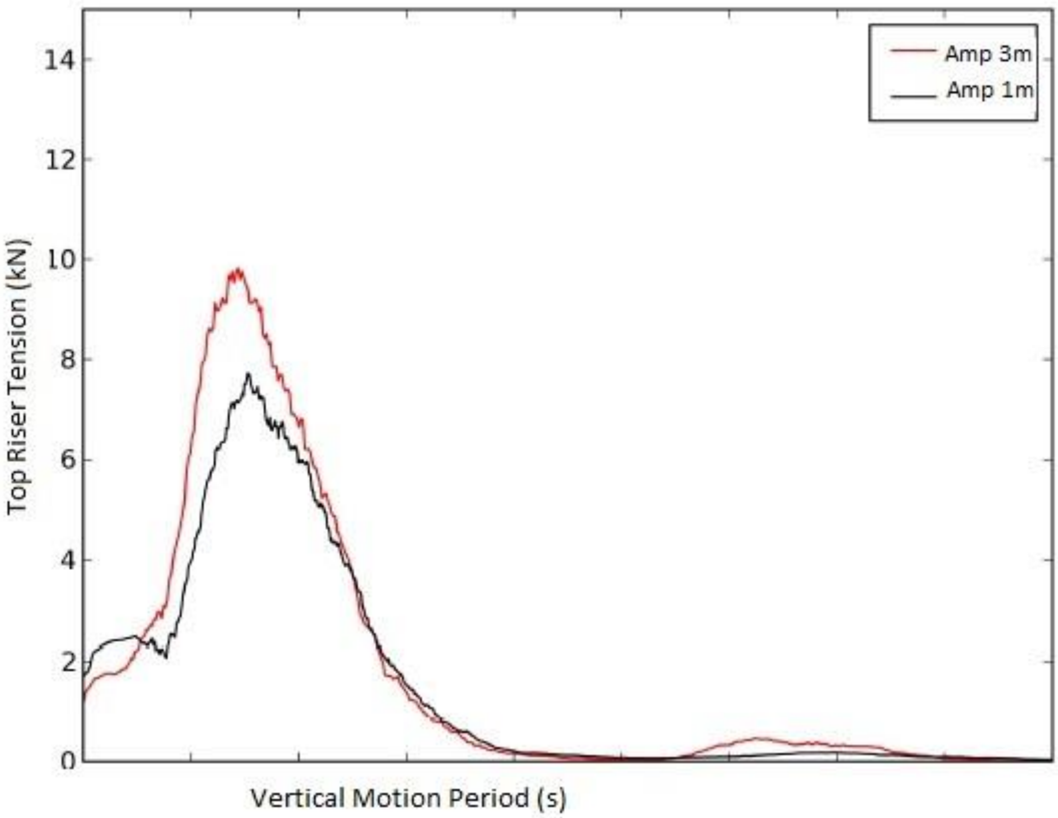


Figure 8 – Top Tension RAO as function of the Vertical Motion Amplitude

If non-linearities are detected during the generation of tension RAO’s, the MANUFACTURER shall also provide results for the intermediary amplitudes in Table 33 (2m, 4m, 6m, 8m, 9m), in order to properly define the dynamic behavior or the riser.

Table 33 – Tension RAO loading cases.

Vertical motions periods (s)	Vertical motions amplitudes (m)									
	1	2	3	4	5	6	7	8	9	10
4	X									
5	X									
6	X									
7	X									
8	X									
9	X		X							
10	X		X		X					
11	X		X		X					
12	X		X		X		X			
13	X		X		X		X			
14	X		X		X		X			
15	X		X		X		X			X
16	X		X		X		X			X
17	X		X		X		X			X
18	X		X		X		X			X
19	X		X		X		X			X
20	X		X		X		X			X
21	X		X		X		X			X
22	X		X		X		X			X
23	X		X		X					
24	X		X		X					
25	X		X							
26	X		X							

Table 34 - Tension RAOs – output files format

End Fitting name: top				
Condition: mean fluid, no offset				
Mean tension: XXX (kN)				
Period (s) of imposed vertical motions	Amplitudes (m) of imposed vertical motions			
	1	2	...	15
3	XXX	XXX	...	XXX
4	XXX	XXX	...	XXX
5	XXX	XXX	...	XXX
⋮	XXX	XXX	...	XXX
24	XXX	XXX	...	XXX
25	XXX	XXX	...	XXX
26	XXX	XXX	...	XXX
End fitting: first intermediate connection				
Condition: heavy fluid, far offset (example)				
Mean tension: XXX (kN)				
Period (s) of imposed vertical motions	Amplitudes (m) of imposed vertical motions			
	1	2	...	15
3	XXX	XXX	...	XXX
4	XXX	XXX	...	XXX
5	XXX	XXX	...	XXX
⋮	XXX	XXX	...	XXX
24	XXX	XXX	...	XXX
25	XXX	XXX	...	XXX
26	XXX	XXX	...	XXX

Tension Amplitudes (kN)

Tension Amplitudes (kN)

Note: tension amplitudes in kN.

5.3. TEMPORARY MOORING CONDITION VERIFICATION

Temporary mooring conditions might happen during the production system installation phase, when the platform can be held in position for a short period of time by a mooring pattern different from the permanent mooring system designed to moor the platform for the whole service life. This condition can subject the risers system to greater offsets, than those expected for the extreme design, but with reduced environmental or functional loads. The temporary conditions to be considered are:

- Pull-in with temporary mooring system;
- First oil with temporary mooring system.

The design premises and specified load cases for these temporary conditions shall not be used for configuration or structural design neither for flexible pipes or ancillary equipment dimensioning, they shall be used for verification only. These temporary mooring load conditions shall be evaluated for all production and gas lift risers.

Manufacturer shall inform if all design criteria were satisfied in these temporary mooring conditions providing in the Design Report all utilization factors.

5.3.1. Pull-in with Temporary Mooring System

The pull-in with temporary mooring system is considered as Normal Temporary Non-operational Condition [1] considering the following:

- Risers full of sea water with no internal pressure;
- One year return period wave and one year return period of current;
- Production platform in the minimum draft and at the actual design heading (for turret mooring systems, head, quartering and beam seas shall be verified);
- Wave, current and offset directions shall be the same chosen to define the Design Load Case B of Table **4**
- Offsets as defined below.

Manufacturer shall consider the maximum offset of 14% of the water depth plus 0.5% of water depth as installation error. If any design criteria was not fulfilled the analysis shall be redone changing the offset to 12% of the water depth plus 0.5% of water depth as installation error.

For lazy wave configurations verification for pull-in with temporary mooring system shall be verified for the start of life (SOL) condition of the buoyance modules and for the end of life (EOL) condition due to the possibility of pre-abandonment of the riser. At least the results required on Table **35** shall be clearly provided in the Design Report for each riser analyzed.

Table 35 – Results for pull-in with temporary mooring system

Riser	PO 1		GL 1	
Configuration	Lazy wave		Free Hanging	
Azimuth related to the North (degrees)				
Buoyance modulus condition	SOL	EOL	-	-
Offset (% water depth)	14.5	14.5	14.5	12.5
Max. Tension at the top (kN)				
Max. tension at the intermediary connection #1 (kN)				
Max. tension at the intermediary connection #2 (kN)				
Max. tension at the intermediary connection #3 (kN)				
Max. tension at the riser flow connection (kN)				
Minimum bend radius (m)				
Max. compression load (kN)				
Max. suspended length (m)				
Minimum bend radius at the bend stiffener region (m)				
Max. strain at the bend stiffener region (%)				
Max. depth of buoyance modulus (m)				
Max. shear load at bend stiffener base (kN)				
Max. moment at bend stiffener base (KN*m)				
All design criteria fulfilled or which one was not	Y	Y	N	Y

5.3.2. First oil condition with temporary mooring system

Load cases presented on Table 36 shall be considered for first oil condition with temporary mooring system.

Table 36 – Load cases for first oil condition with temporary mooring system area

Load Condition				Design Load Case	Description
Operating Conditions	Permanent	Normal		A-T - Riser Operation Operating Internal Pressure	Pipe full of internal fluid, Maximum Operating Pressure[1] at the Production Unit, intact pipe outer sheath, intact mooring system and 10-year environmental conditions.
Operating Conditions	Permanent	Extreme		B-T - Riser Operation Design Internal Pressure & One mooring line broken	Pipe full of internal fluid, Maximum Design Pressure at the Production Unit, intact pipe outer sheath, one mooring line broken and 10-year environmental conditions.
Operating Conditions	Permanent	Extreme		C-T - Riser Operation No Internal Pressure & One mooring line broken	Pipe full of internal fluid, Atmospheric Internal Pressure at the Production Unit, intact pipe outer sheath, one mooring line broken and 10-year environmental conditions.
Operating Conditions	Permanent	Extreme		D-T - Riser Operation [2] No internal fluid & Breached pipe outer sheath	No internal fluid, breached pipe outer sheath, intact mooring system and 10-year environmental conditions.
Operating Conditions	Permanent	Extreme		E-T - Riser Operation [2] No internal fluid & Intact pipe outer sheath	No internal fluid, intact pipe outer sheath, intact mooring system and 10-year environmental conditions.
Operating Conditions	Permanent	Extreme		F-T - Riser Operation Design Internal Pressure & buoyancy/weight losses over service life	Pipe full of internal fluid, Maximum Design Pressure at the Production Unit, intact pipe outer sheath, buoyancy/weight losses as per defined in 8.2.4 of API17L2:2013 [5], intact mooring system and 10-year environmental conditions.
Operating Conditions	Abnormal Operation			H-T - Riser Operation Incidental Pressure & One mooring line broken	Pipe full of internal fluid, Incidental Pressure[4] at the Production Unit, intact pipe outer sheath, one mooring line broken and 1-year environmental conditions.
Nonoperating Conditions	Temporary	Normal	Test	K-T - Offshore Leak Test Pipe Full of Sea Water	Pipe full of seawater, Maximum Offshore Test Pressure[3], intact pipe outer sheath, intact mooring system and installation environmental conditions.

Notes:

1. The Maximum Operating Internal Pressure shall be assumed equal to the Maximum Design Pressure if not informed by BR.
2. Unless otherwise specified, for water depth lower than 1000m Design Load Cases D and E can be disregarded.
3. Maximum Offshore Test Pressure shall be considered equal to 1.10*Maximum Design Pressure unless other value be specified.
4. The Incidental Pressure shall be assumed equal to 1.10*Maximum Design Pressure if not informed by BR. If the temperature associated to the Incidental Pressure is not informed by BR, it shall be assumed equal to the Design Maximum Temperature. When accessing utilization factors from table 8 of API Spec 17J [1] this pressure shall be considered as an accidental load, according to table 6 of API Spec 17J [1].

The environmental conditions presented on Table 37 shall be used for load cases of Table 36.

Table 37 – Environmental conditions for first oil condition with temporary mooring system

Environmental condition	Wave	Current
1-year	1-year	1-year
10-years	10-years	1-year
	1-year	10-years

Case I offsets presented on Table 38 shall be used for load cases of Table 36 for riser verification for first oil condition with temporary mooring system. The MANUFACTURER shall clearly present in the Design Report if all design criteria were fulfilled or not for this offset case.

Table 38 – Offsets for first oil condition with temporary mooring system

Case	Environmental condition	Mooring	Offset (% WD)	Offset errors (% WD)
I	1-year	Intact	8.0	0.5
	10-years	Intact	12.0	0.5
	10-years	One mooring line broken	14.0	0.5
II	1-year	Intact	6.0	0.5
	10-years	Intact	10.0	0.5
	10-years	One mooring line broken	12.0	0.5

Risers (or ancillary equipment) which design criteria were not fulfilled considering case I offsets (Table 38) shall be reevaluated by MANUFACTURER considering case II offsets (Table 38). The MANUFACTURER shall also clearly present in the Design Report if all design criteria were fulfilled or not for case II offsets.

Gas lift (or service) risers shall be verified not only for the gas, as internal fluid, but also for diesel (850 kg/m^3) with 20 bar as internal pressure (pressure necessary for recirculation).

All platform drafts found in the motion analysis report shall be considered for first oil conditions with temporary mooring system and the platform design heading shall be considered.

The load cases presented in Table 36 for the first oil condition with temporary mooring system are a sub-group extracted from Table 1 changing offsets and environmental conditions return period and considering the start of life fluid condition only.

To reduce the number of analyses required, the risers' verification for the first oil condition with temporary mooring system for the case GA-T from Table 36 shall be performed only for the critical cases identified for load cases GA from Table 1, and used for load cases GB with offsets and environmental conditions for the first oil condition and start of life fluid condition.

For load cases GB-T, GC-T, GD-T, GE-T, GF-T, GH-T and GK-T of Table 36 the risers' verification for the first oil condition with temporary mooring system shall be performed for the same cases of load cases GB, GC, GD, GE, GF, GH and GK used for the operational cases from Table 1 with offsets and environmental conditions for the first oil condition and start of life fluid condition.

It can be point out that for the selected analysis cases the motion analysis for the riser connection point shall be redone for the actual environmental conditions (Significant wave height and Peak period) for return periods shown on the Table 37 and for all platform drafts.

For lazy wave configurations verification for pull-in with temporary mooring system shall be verified for the start of life (SOL) condition of the buoyance modules and for the end of life (EOL) condition due to the possibility of pre-abandonment of the riser. At least the results required on Table **39** shall be clearly provided in the Design Report for each riser analyzed.

Table 39 – Results for first oil with temporary mooring system

Riser	PO 1		GL 1	
Configuration	Lazy wave		Free Hanging	
Azimuth related to the North (degrees)				
Buoyance modulus condition	SOL	EOL	-	-
Offset (% water depth)	Case I	Case I	Case I	Case II
Max. Tension at the top (kN)				
Max. tension at the intermediary connection #1 (kN)				
Max. tension at the intermediary connection #2 (kN)				
Max. tension at the intermediary connection #3 (kN)				
Max. tension at the riser flow connection (kN)				
Minimum bend radius (m)				
Max. compression load (kN)				
Max. suspended length (m)				
Minimum bend radius at the bend stiffener region (m)				
Max. strain at the bend stiffener region (%)				
Max. depth of buoyance modulus (m)				
Max. shear load at bend stiffener base (kN)				
Max. moment at bend stiffener base (KN*m)				
All design criteria fulfilled or which one was not				

ANNEX A – Motion and Wave Modeling Procedures

Hereinafter motion and wave modelling procedures are suggested to perform global dynamic analysis.

Maximum Response Procedure

The purpose of the maximum response procedure it is to carry out the global dynamic analysis considering a regular wave that reproduces the same maximum movements (6 DoF) and the same maximum vertical acceleration at the riser connection for a storm of 3 hours. The following procedure determines the height (H) and period (T) of a regular wave and the response amplitude operator for the riser connection:

1. For a given wave direction relative to the floating unit, the RAOs for the movements in 6 DoF and the RAO for the vertical acceleration at the riser connection shall be determined for each draft of the floating unit;

2. For a wave spectrum (S) defined by Hs, Tp and gamma, the response spectrum (Su) for the movements and vertical acceleration shall be determined, crossing the wave spectrum and the RAOs previously calculated in the following way:

   $$Su(w) = [RAO(w)]^2 * S(w)$$

3. The significant amplitude (using) of the movements (6 DoF) and vertical acceleration shall be calculated from the response spectrum as follow:

   $$usig = 2 * \sqrt{m0}$$

   Where m0 is the response spectrum (Su) area;

4. The maximum amplitude (umax) for the movements (6 DoF) and for the vertical acceleration shall be determined for a storm duration of 3 hours (10800 s) as follow:

   $$umax = \sqrt{2 * \ln(N)} * \frac{usig}{2}$$

   Where $N = \frac{10800}{Tz}$ and $Tz = \sqrt{\frac{m0}{m2}}$

5. The draft of the floating unit that has the highest maximum amplitude for the vertical acceleration and highest angular movement shall be selected. The following definition shall be considered for angular movement:

   $$\theta = \sqrt{R_{MAX}^2 + P_{MAX}^2}$$

   Where R_{MAX} and P_{MAX} are the maximum amplitudes for roll and pitch, respectively. If the floating unit´s draft with the highest maximum vertical acceleration is different for the draft with the highest angular movement, the load case shall be analyzed for the two drafts.

6. For the selected draft(s) the period (T) of the regular wave is determined from the maximum amplitude for the vertical motion and vertical acceleration by the following expression:

$$T = 2\pi \sqrt{\frac{umax_{vert}}{amax_{vert}}}$$

7. The response amplitude operators for the 6 DoF at the riser connection point are determined by the following expression from the amplitude of the maximum motions calculated in item 4 and the maximum wave height (Hmax) assuming a Rayleigh distribution for the wave spectrum (S) considered in item 2:

$$RAO_{ampl} = \frac{2 * umax}{Hmax}$$

8. The phases for the response amplitude operators at the riser connection point are obtained from the RAOs determined in item 1 considering the wave period (T) calculated in item 6.

9. Dynamic analysis shall be performed considering the response amplitude operator at the riser connection point (RAO_{RISER}) and a regular wave with maximum wave height (Hmax) and period (T) determined in item 6.

Equivalent Harmonic Motion Procedure (EHMP)

The Equivalent Harmonic Motion Procedure is a simplified procedure to consider the maximum displacement and acceleration only. It should be used with care and may be not recommended for shallow waters. The following steps shall be considered:

a) transfer the RAOs from the vessel center of movements to the riser top connection coordinates;
b) obtain the response spectrum for the movements of the connection by crossing the wave spectrum and RAOs for the riser connection;
c) determine the Rayleigh most probable maxima of motion displacements, for the connection movements;
d) determine the zero up-crossing period for the vertical movement response;
e) assume, for the riser connection regular movements, the maxima amplitude values as per paragraph c) above and period according to paragraph d) above;
f) assume, for the regular movements of the riser connection, the same phase values of the transferred RAOs in paragraph a), taken for the corresponding period of paragraph d).

Note: The above approach does not consider the direct wave action on the riser.

Design Wave Procedure (DWP)

The following steps shall be considered:

a) transfer the RAOs from the vessel center of movements to the riser top connection coordinates;
b) obtain the response spectrum for the movements of the top connection by crossing the wave spectrum and RAOs for the riser top connection;

c) determine the Rayleigh most probable maxima of motion displacements and accelerations, for the connection movements;

d) determine the wave height (H_{design}) as the Rayleigh most probable maxima from Hs (significant wave height) as used to describe wave spectrum in paragraph b);
e) evaluate periods ($T_{design1}$ and $T_{design2}$), which associated with H_{design}, furnish, respectively, the maximum harmonic displacement and maximum harmonic acceleration, both calculated as per paragraph c); among the possible T design values, chose the closest value to the wave peak period (Tp); this procedure shall be carried out, at least, 2 times, depending on top connection motion: (1) the most critical between surge/sway and heave, (2) the most critical between roll and pitch.

Irregular Wave Procedure (IWP)

This procedure is to be considered at least as a validation check of the results of the above-mentioned procedures. If used as validation check, only the most critical loading cases shall be analysed according to this method. For each pipe, a minimum number of 4 full irregular analyses shall be chosen by following criteria:

a) worst loading case for compression value;
b) worst loading case for top tension;
c) worst loading case for bending radius;
d) worst loading case for bending stiffener design.

Notes:

1) When considering the specification of the number of harmonic components to describe wave spectra, a minimum number of 100 shall be considered.

2) The results coming from random analyses shall be statically processed in a way to give consistent and reliable maximum values. When simulating the chosen loading cases, 3 options are considered valid:

i) to perform, at least 5, 30-minute simulations varying random seed for the initial harmonic components phases. The significant wave height shall occur at least once in each simulation;
ii) from simulated long time history (minimum 60 hours) of critical pipe top movement, select a minimum of 10, 5-minute windows to be analysed;
iii) to perform a 3-hour simulation.

If the manufacturer is supplying a set of risers of the same structure which are to be connected to the same floating unit, the purchaser might accept, if duly justified by the manufacturer, irregular wave analysis carried out for the riser(s) subjected to the most critical load conditions. For this purpose, the manufacturer shall submit analysis that includes the riser(s) worst conditions indicated in paragraphs a) to d) above.