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|---|--|--|-----------------------------------|
|  | <b>TECHNICAL SPECIFICATION</b>                               |  | Nº: I-ET-3010.XX-1200-941-P4X-001 |
|   | CLIENT:  |  | SHEET 1 of 170                    |
|   | JOB:   |  | --                                |
|   | AREA:  |  |                                   |
| SRGE  | TITLE: <b>GENERAL TECHNICAL DESCRIPTION FOR LEASED UNITS</b> |  |                                   |

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| EXECUTION |           |        |        |        |        |        |        |        |        |
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TITLE: **GENERAL TECHNICAL DESCRIPTION FOR  
LEASED UNITS**

**SUMMARY**

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**GENERAL TECHNICAL DESCRIPTION FOR  
LEASED UNITS****1 GENERAL****1.1 INTRODUCTION**

1.1.1 The intent of this specification and documents referenced hereinafter is to provide the CONTRACTOR with general information of intended service and requirements for the design, construction (or conversion), assembly, transport, installation and operation of one Floating Production Storage and Offloading System (FPSO), also called “the Unit” in this document.

1.1.2 All requirements herein provided must be considered as a minimum, according to the terms agreed upon in the Contract. All regulatory rules (Classification Society (CS), Brazilian Administration (including "Portaria 787 de 27 de novembro de 2018" from Brazilian Labor and Welfare Ministry (“Ministério do Trabalho e Previdência), Flag Administration, International Maritime Organization (IMO) and applicable rules and laws) shall be complied with. In addition, CONTRACTOR shall comply with PETROBRAS Technical Requirements outlined in this GENERAL TECHNICAL DESCRIPTION (GTD), which are considered mandatory unless it is not accepted by regulatory rules. In case of conflicting information among PETROBRAS’ technical requirements, PETROBRAS shall be notified to define the way forward.

1.1.2.1 Unless otherwise expressed herein or in clarifications letters during Tender, recommended practices, technical bulletins, technical standards and other technical documents issued by standardizing institutions shall be considered as references by their latest editions or revisions in force by the date of Tender commencement.

1.1.3 This GTD provides necessary information for the development of the Basic and Detailed Design. However, they do not exempt CONTRACTOR from contractual responsibilities during operation lifetime. CONTRACTOR shall be responsible for the provision of all services and other requirements necessary to deliver one complete functional Production Unit as described herein. Any calculation presented in this document is preliminary and shall be reviewed during the Detail Design Phase.

1.1.4 In all documents, the word “shall” and equivalent expressions like “to be”, “is to”, “is required to”, “has to”, “must” and “it is necessary” are used to state that a provision is mandatory.

1.1.5 Unless otherwise expressed, any reference to “CONTRACTOR responsibility” or “CONTRACTOR’s responsibilities” means that the CONTRACTOR will design, supply, install, operate and maintain according to the Contract provisions with no commercial interference or responsibility from PETROBRAS.

1.1.6 PETROBRAS “approval” or “comments” on the documents shall not exempt CONTRACTOR from responsibility to carry out the work in accordance with contractual and legal requirements.

1.1.7 The design of the Unit shall be based on field proven solutions and PETROBRAS, at their sole discretion, have the right to reject any detail of the Unit’s design.

1.1.8 CONTRACTOR shall provide stand-by equipment, ready to operate, for systems which require full capacity on continuous operation, in order to guarantee no process capacity reduction or degradation of the oil, gas and water specification. CONTRACTOR shall also comply with stand-by philosophy for equipment whenever specifically required in this GTD. This requirement includes the necessary redundancy for pressure safety valves (PSVs).

1.1.9 CONTRACTOR shall perform during Detail Design two workshops to address constructability and commissioning. The agenda and topics to be addressed on these workshops shall be mutually agreed between CONTRACTOR and PETROBRAS. The actions and outcomes from these workshops shall be shared with Petrobras.

## 1.2 GENERAL DESCRIPTION

### 1.2.1 REFERENCE DOCUMENTS

1.2.1.1 Throughout this document, the following Technical Specifications and drawings are referenced:

Table 1.2.1.1 – Reference Documents

| #  | Document Number | Rev. | Title   |
|----|-----------------|------|---|
| 1  |                 |      | METOCEAN DATA   |
| 2  |                 |      | RISER SYSTEM REQUIREMENTS   |
| 3  |                 |      | RISERS TOP INTERFACE LOADS ANALYSIS   |
| 4  |                 |      | FLOW METERING SYSTEM FOR LEASED UNITS   |
| 5  |                 |      | SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS   |
| 6  |                 |      | OFFSHORE LOADING SYSTEM REQUIREMENTS  |
| 7  |                 |      | SPREAD MOORING SYSTEM REQUIREMENTS  |
| 8  |                 |      | SUBSEA PRODUCTION CONTROL SYSTEM FOR FPSO   |
| 9  |                 |      | TELECOM MASTER SPECIFICATIONS FOR FPSO CHARTERED  |
| 10 |                 |      | METOCEAN DATA ACQUISITION SYSTEM REQUIREMENTS   |
| 11 |                 |      | UNIDADE HIDRÁULICA PARA EQUIPAMENTOS SUBMARINOS QUE PODERÃO ESTAR EQUIPADOS COM SISTEMA DE CONTROLE ELETRO-HIDRÁULICO MULTIPLEXADO OU SISTEMA DE CONTROLE HIDRÁULICO DIRETO, EM QUALQUER COMBINAÇÃO, E QUE REQUEREM ATÉ 5000 PSI DE PRESSÃO MÁXIMA DE ATUAÇÃO (HPU-FLEX 5000) |

|    |  |   |
|----|--|---|
| 12 |  | DADOS PARA PROJETO DA HPU DOS EQUIPAMENTOS SUBMARINOS   |
| 13 |  | SPECIFICATION OF HYDRAULIC ACTUATOR SYSTEM FOR BSDL-SI  |
| 14 |  | HYDRAULIC CIRCUIT FOR BSDL-SI   |
| 15 |  | ANNULUS PRESSURE MONITORING AND RELIEF SYSTEM   |
| 16 |  | OPERATIONAL PHILOSOPHY  |
| 17 |  | RISER SUPPORTS ARRANGEMENT CONCEPTUAL DESIGN - FPSO BALCONY   |
| 18 |  | POSITIONING AND NAVIGATION SYSTEMS  |
| 19 |  | MODA RISER MONITORING SYSTEM –FPU SCOPE (SPREAD MOORING)  |
| 20 |  | DIVERLESS BELL MOUTH SUPPLY SPECIFICATION   |
| 21 |  | DIVERLESS BELL MOUTH PART LIST DRAWINGS   |
| 22 |  | FLUIDS FOR SPECIAL OPERATIONS   |
| 23 |  | PIG FACILITIES  |
| 24 |  | OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS  |
| 25 |  | RELIABILITY AVAILABILITY AND MAINTENABILITY (RAM) ANALYSIS REQUIREMENTS FOR LEASED UNITS WITH COMBINED CYCLE GENERATION |

NOTE 1: Will be confirmed at Project kick-off meeting.

## 1.2.2 GENERAL DESCRIPTION

1.2.2.1 The Unit design life shall be at least 33 years. During the Contract period, the Unit shall be adequate for uninterrupted operation, without the need of dry-docking.

1.2.2.2 The Unit shall be capable to be moored offshore Brazil, at a location with water depth of 950 meters.

1.2.2.3 As a brief overview, the Unit will receive the production from subsea oil wells and shall have production plant facilities to process fluids, stabilize them and separate produced water and natural gas. Processed liquids will be metered, stored in the vessel cargo storage tanks and offloaded to shuttle tankers.

1.2.2.4 Produced gas, with CO<sub>2</sub> and H<sub>2</sub>S, shall be compressed, dehydrated, and used as a fuel gas and for lifting oil production. Remaining gas will be exported. Produced water will be reinjected into reservoir or disposed overboard. The Process Plant shall have the processing capacities as listed in Table 1.2.2.4.

Table 1.2.2.4- Process Plant Capacities

| Parameter   | Capacity                     |
|---|------------------------------|
| Total Maximum Liquids   | 31.800 Sm <sup>3</sup> /d    |
| Total Maximum Oil   | 15.900 Sm <sup>3</sup> /d    |
| Total Produced Water  | 23.850 Sm <sup>3</sup> /d    |
| Total De-Sulphated Sea Water Injection                            | 23.850 Sm <sup>3</sup> /d    |
| Total Gas Handling, including lift gas, treatment and compression | 6.000.000 Sm <sup>3</sup> /d |

1.2.2.5 The Unit shall have the minimum facilities specified in this document to be connected to a Subsea Multiphase Boosting Systems (SMBS); (see item 2.11 for detail). All additional facilities required for these scenarios and not specified in this GTD will be mutually agreed with CONTRACTOR.

1.2.2.6 CONTRACTOR shall consider the SUBSEA LAYOUT documents. The Unit shall consider 28 wells in the design (see section 15).

Table 1.2.2.6Wells

| Wells           | Quantity |
|-----------------|----------|
| Production      | 21       |
| Injection Water | 7        |

1.2.2.7 In summary, the Unit shall have the following main characteristics:

- Ship-shaped or barge-shaped Unit of Very Large Crude Carrier (VLCC) size or greater, with a minimum storage capacity, i.e. minimum volume of oil available, in the cargo tanks, to be offloaded, of 1,100,000 bbl of crude oil;
- Offloading system, including hawser and export hose;
- Spread Mooring System;
- Process plant, comprising deck structure, safety facilities, steel flare tower or flare boom, equipment for oil processing, associated gas treatment, compression and, sea water treatment and injection, produced water treatment and re-injection, etc.;
- Utilities necessary to keep the Unit's standalone operation capacity;
- Power generation system to meet all the needs of the Unit, based on dual fuel gas turbine-generators in cogeneration (i.e., gas turbine + waste heat recovery unit) or in combined cycle (gas turbine + waste heat recovery unit and steam generator + steam turbine generators);
- Gas compression plant comprising high-pressure centrifugal compressors driven by electric motor or gas turbine;
- Accommodation for normal operation crew, maintenance technicians required for contracted performance and for PETROBRAS representatives. The Unit design accommodation size shall be compatible with the People On Board (POB) required

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to accomplish the CONTRACTOR's operation, maintenance and asset integrity management plans;

- Facilities to connect risers for oil production, gas-lift, gas export, water injection and subsea processing and/or pumping system;
- Cargo handling systems, including cranes, monorails, rail cars, etc.;
- Helideck;
- Telecommunication facilities.

**1.3 CLASSIFICATION**

1.3.1 CONTRACTOR shall contract a single CS to follow and approve the whole FPSO project comprising the design, construction, installation on site, operation and decommissioning phases.

1.3.2 The CS shall also consider all construction loads and the environmental loads during transportation from construction/conversion shipyard to Brazil and, after decommissioning, from Brazil to a point outside its territory. The CS shall consider those conditions for the final approval of the Unit design.

1.3.3 The CS's Certificates shall clearly specify that the Unit shall comply with all requirements for continuous operation during its design life, as stated in item 1.2.2, at the site without the need to be dry-docked in a shipyard.

1.3.4 Acceptable CSs are DNV (Det Norske Veritas), BV (Bureau Veritas), ABS (American Bureau of Shipping) and LRS (Lloyd's Register of Shipping).

1.3.5 The Unit shall obtain Main Class and/or Class Notation encompassing the following items:

- Vessel structure, equipment and marine systems;
- Permanent mooring system;
- Production facilities and utilities;
- Fuel gas system;
- Oil storage;
- Offloading;
- Inert gas system;
- Automation and control systems;
- Centralized Control Room Operation;
- Lifting Appliances;
- Safety System/Equipment;
- Lifesaving System/Equipment.

1.3.6 Riser System Classification is not part of CONTRACTOR's scope of work. CONTRACTOR's scope shall cover down to the last flanged connection in all risers.

1.3.7 During construction and operational phase, CONTRACTOR shall provide, whenever requested by PETROBRAS, the Classification and Regulatory status reporting the pending items with corresponding due dates, and any other relevant information about the Unit.

## 1.4 UNITS AND IDENTIFICATION OF EQUIPMENT

1.4.1 The metric system complying with International Organization for Standardization (ISO) standard, as far as practicable shall be used for equipment, machinery and fittings identification and data.

1.4.2 The Standard conditions are defined as:

- $\text{Sm}^3$  @ 15.6 °C and 101.3 kPa(a);
- $\text{Nm}^3$  @ 20 °C and 101.325 kPa(a), as per *Agência Nacional do Petróleo, Gás Natural e Biocombustíveis* (ANP) metering regulation requirement.

1.4.3 All Unit identification, signs and documents shall be written according to the Brazilian Administration and Flag Authorities requirements. All stationary equipment, including those to which *Norma Regulamentadora* Nº 13 (NR-13) does not apply, must be identified on the field.

## 2 PROCESS

### 2.1 GENERAL

2.1.1 CONTRACTOR shall design Process plant according to the following norms: API RP 14C.

2.1.2 Process Plant and Utilities shall operate normally when subjected to the motions induced by the environmental conditions (see section 13).

2.1.3 CONTRACTOR shall bear in mind that, as the design is part of the Contract and falls under CONTRACTOR's responsibility, production shutdown or degraded oil, water or gas specification or any other equipment malfunction due to vessel motions shall not be acceptable. CONTRACTOR shall minimize vessel motions in all environmental conditions.

2.1.4 CONTRACTOR shall also design the topsides facilities according to riser characteristics included but not limited to item 15.2.

2.1.5 CONTRACTOR shall adopt an isolation philosophy for equipment/piping maintenance taking into consideration that the gas volume to be sent to flare shall be minimized.





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2.1.6 CONTRACTOR shall implement piping arrangement in order to allow operational/start-up procedures to minimize or avoid gas volume to be sent to flare.

**2.2 FLUID CHARACTERISTICS**

**2.2.1 PRODUCED OIL AND RESERVOIR**

2.2.1.1 The typical range of properties for the oil is indicated in the Table below and shall be taken into account for all design purposes. CONTRACTOR shall design the Unit to process oil with any blend within these properties. CONTRACTOR shall make simulations to assess the correct design parameters.

2.2.1.2 CONTRACTOR shall submit the process simulation files and report to PETROBRAS for comments considering the range of fluid components.

Table 2.2.1.2 Oil Properties and Contaminants

| <b>Oil Properties and contaminants</b> |  |   |   |   |
|--|--|---|---|---|
| Well                                   | A  | B   | C   | D   |
| Oil API grade                          | 24.3                                       | 28.6                                      | 20.8  | 24.98                                     |
| Viscosity (dry – dead oil) (1)         | 39.0 @ 30°C<br>27.0 @ 40°C<br>14.0 @ 60°C  | 42.4 @ 30°C<br>27.0 @ 40°C<br>13.0 @ 60°C | 303.6 @ 30°C<br>158.7 @ 40°C<br>55.8 @ 60°C | 38.6 @ 30°C<br>27.0 @ 40°C<br>13.8 @ 60°C |
| Wax Appearance Temperature (2,3)       | 40.08°C (1st event)<br>17.06°C (2nd event) | 34.22°C(1st event)<br>15.13°C (2nd event) | 44.41°C(1st event)<br>17.3°C (2nd event)    | 44.41°C(1st event)<br>17.3°C (2nd event)  |
| Foam                                   | Yes, severe                                |   |   |   |
| Sand/Solids (2,4)                      | Yes, 1 ppm (NOTE 5)                        |   |   |   |

NOTE 1: Pressure loss due to emulsified oil viscosity shall be considered.

NOTE 2: CONTRACTOR shall design production plant to ensure operational continuity considering wax crystals and wax deposition.

NOTE 3: Wax is expected to deposit only in the second event.

NOTE 4: The installation of facilities to remove solids (corrosion products, precipitated salts and sand) is required for HP Separator, LP Separator, Heaters, Coolers, Test Separator and electrostatic treaters. The system shall include sand wash connections as well as the flushing inside the vessel. It is CONTRACTOR's decision to use online or offline sand removal system taking into consideration the assurance of production continuity.

NOTE 5: To be confirmed during detail design phase.

## 2.2.2 PRODUCED WELLS COMPOSITION

2.2.2.1 CONTRACTOR shall design the Unit with the compositions given below. CONTRACTOR shall submit to PETROBRAS, during the execution phase, for comments the process simulation considering the range of reservoir fluid components.

2.2.2.2 These simulations shall clearly show the operating conditions of process plant equipment.

2.2.2.3 These simulations shall consider the premises in Table 2.2.2.3 (steady flow condition):

Table 2.2.2.3 Design Cases

| Cases                        | Number | Fluid <sup>(2)</sup>       | Temp. (°C) <sup>(1)</sup> | Oil Flowrate (Sm <sup>3</sup> /d) | Liquid Flowrate (Sm <sup>3</sup> /d) | Produced Gas Flowrate (Sm <sup>3</sup> /d) <sup>(3)</sup> | Gas Lift Flowrate(Sm <sup>3</sup> /d) <sup>(3)</sup> |
|------------------------------|--------|----------------------------|---------------------------|-----------------------------------|--------------------------------------|---|--|
| Max Oil                      | 1      | A 39%; B 31%; D 11%; C 19% | 54                        | 15.900                            | 24.050                               | 1.370.000   | 3.470.000  |
|                              | 2      |                            | 46                        | 15.900                            | 24.050                               | 1.370.000   | 3.470.000  |
| Max Gas/Max Liquid           | 3      | A 37%; B 38%; D 10%; C 15% | 57                        | 10.500                            | 31.800                               | 1.000.000   | 5.000.000  |
|                              | 4      |                            | 49                        | 10.500                            | 31.800                               | 1.000.000   | 5.000.000  |
| Max Produced Water           | 5      | A 49%; B 34%; D 10%; C 7%  | 57                        | 7.250                             | 31.100                               | 640.000   | 3.840.000  |
|                              | 6      |                            | 49                        | 7.250                             | 31.100                               | 640.000   | 3.840.000  |
| Intermediary                 | 7      | A 55%; B 36%; D 9%         | 55                        | 5.350                             | 19.680                               | 470.000   | 3.550.000  |
|                              | 8      |                            | 43                        | 5.350                             | 19.680                               | 470.000   | 3.550.000  |
| Minimum Flowrate             | 9      | A 56%; B 35%; D 9%         | 50                        | 3.590                             | 16.240                               | 310.000   | 3.190.000  |
|                              | 10     |                            | 41                        | 3.590                             | 16.240                               | 310.000   | 3.190.000  |
| B – Higher temperature       | 11     | 100% B                     | 89                        | 5.000                             | 5.500                                | 485.000   | 215.000  |
| B – Higher Liquid Flowrate   | 12     | 100% B                     | 79                        | 5.920                             | 10.400                               | 580.000   | 1.120.000  |
| A – Lower temperature        | 13     | 100% A                     | 30                        | 5.670                             | 6.530                                | 430.000   | 970.000  |
| A/D – Higher Liquid Flowrate | 14     | 87% A, 13% D               | 42                        | 2.950                             | 13.310                               | 240.000   | 1.960.000  |
| C – Higher Liquid Flowrate   | 15     | 100% C                     | 52                        | 5.020                             | 5.025                                | 500.000   | 300.000  |

NOTE 1: Operational temperature for the blend downstream of production choke valve. During the production the blend temperature can vary from 30°C to 85°C.

NOTE 2: The standard flow rate shall be applied to oil conditions as per item 2.3.1. It refers to dead oil conditions.

NOTE 3: Gas Flow rate at inlet of the Main Compressor, considering gas from HP Separator and VRU. Any recirculation of gas/condensate streams shall be added onto this Gas Flow Rate. Gas flow rate includes Gas Lift recirculation.

NOTE 4: In order to achieve the desired Gas Oil Ratio (GOR) for each design case, simulation may be adjusted by subjecting Well Fluids through a series of flashes and recombining the gas and oil rates to match the flowrates indicated in Table 2.2.2.3.

NOTE 5: The design water cut at the production header goes from 0% up to 95%.

NOTE 6: During project execution phase PETROBRAS will provide to CONTRACTOR the pressure, temperature and flow rate conditions (steady flow and well start-up) to size production choke valves.

NOTE 7: During project execution phase PETROBRAS will provide to CONTRACTOR the pressure, temperature and flow rate conditions to size lift gas, water injection and gas transfer choke valves.

NOTE 8: The shut-in pressure at top production riser is 25,000 kPa(a).

NOTE 9: The normal pressure range upstream of production choke valve is 1,500 to 10,000 kPa(a). Under some conditions, e.g. intermittent flow, pressure can achieve lower values.

NOTE 10: It shall be considered 350 ppmv of H<sub>2</sub>S in the produced gas.

2.2.2.4 Table 2.2.2.4 shall be considered for the fluid composition.

Table 2.2.2.4.a: Well Fluid Composition

| Component                        | A    | B     | C     | D     |
|----------------------------------|------|-------|-------|-------|
| CO <sub>2</sub>                  | 0,1  | 0,87  | 0,04  | 0,14  |
| N <sub>2</sub>                   | 1,1  | 0,42  | 0,14  | 0,49  |
| C1                               | 39,0 | 31,99 | 46,79 | 50,44 |
| C2                               | 6,5  | 7,81  | 2,84  | 6,04  |
| C3                               | 6,7  | 7,35  | 2,68  | 5,62  |
| iC4                              | 1,2  | 1,1   | 0,57  | 0,98  |
| nC4                              | 3,1  | 2,92  | 1,35  | 2,12  |
| iC5                              | 1,2  | 0,71  | 0,54  | 0,56  |
| nC5                              | 1,7  | 1,35  | 0,91  | 0,76  |
| C6                               | 2,0  | 1,71  | 1,16  | 0,52  |
| C7                               | 2,9  | 2,51  | 1,63  | 0,85  |
| C8                               | 2,9  | 3,59  | 2,12  | 1,33  |
| C9                               | 2,5  | 3,06  | 2,02  | 2,3   |
| C10                              | 2,3  | 2,54  | 1,82  | 2,68  |
| C11                              | 1,5  | 2,61  | 1,61  | 2,02  |
| C12                              | -    | 2,28  | 1,65  | -     |
| C13                              | -    | 2,2   | 1,7   | -     |
| C14                              | -    | 1,91  | 1,65  | -     |
| C15                              | -    | 1,83  | 1,62  | -     |
| C16                              | -    | 1,39  | 1,31  | -     |
| C17                              | -    | 0,97  | 1,16  | -     |
| C18                              | -    | 1,08  | 1,31  | -     |
| C19                              | -    | 0,94  | 1,12  | -     |
| C12+                             | 25,4 | -     | -     | 23,15 |
| C20+                             | -    | 16,88 | 22,25 | -     |
| Molecular weight<br>C12+ or C20+ | 560  | 459   | 474   | 567   |



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|---|-------|--------|--------|-------|
| Density C12+ or C20+ (g/cm <sup>3</sup> ) | 0,912 | 0,9437 | 0,9827 | 0,934 |
|---|-------|--------|--------|-------|

NOTE 1: Identify process currents (or fluid) with benzene at a concentration of 1% or more in volume, control actions shall be provided to eliminate/mitigate possible occupational exposures.

NOTE 2: Identify currents with H<sub>2</sub>S and define or estimate their concentration in ppm and control actions shall be provided.

Table 2.2.2.4.b: BTEX

| Oil (Nafta 15-150C) |       |
|---------------------|-------|
| Benzene (%m/m)      | 0,041 |
| Toluene (%m/m)      | 0,176 |
| C2-Benzene (%m/m)   | 0,072 |
| Xylenes (%m/m)      | 0,237 |

NOTE 1: This information is preliminary. Both use of this preliminary information and definitive data shall be confirmed by PETROBRAS.

**2.2.3 WELL TEST CHARACTERISTICS**

2.2.3.1 Table 2.2.3.1 shall be taken into account to define the test separator system (test heater, three-phase test separator, pumps and other related items).

Table 2.2.3.1a: FPSO Capacities

| CHARACTERISTICS                          | NOTE   | VALUE                             |
|--|--|-----------------------------------|
| Oil Flow rate                            | Maximum                                      | 5,500 Sm <sup>3</sup> /d (note 1) |
|  | Minimum, for accuracy of measurement purpose | 50 Sm <sup>3</sup> /d             |
| Gas Flow rate                            | Maximum                                      | 1,300,000 Sm <sup>3</sup> /d      |
|  | Minimum                                      | 100,000 Sm <sup>3</sup> /d        |
| Water cut                                | For accuracy of measurement purpose          | 0 to 95%                          |
| Arrival temperature upstream choke valve | -  | 10 °C to 89 °C<br>(Note 2)        |

NOTE 1: The standard flow rate shall be applied to oil conditions as per item 2.3.1. It refers to dead oil conditions for satellite wells and MSPs.

NOTE 2: CONTRACTOR shall consider the following scenarios for well test header:

Table 2.2.3.1b: Scenarios for Well Test Header

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| Fluid | Configuration | Arrival Temperature (°C) | Oil Flowrate Sm <sup>3</sup> /d | Liquid Flowrate Sm <sup>3</sup> /d | Gas Flowrate Sm <sup>3</sup> /d |
|-------|---------------|--------------------------|---------------------------------|------------------------------------|---------------------------------|
| A     | Satellite     | 40                       | 1.200                           | 1.800                              | 480.000                         |
| A     | Satellite     | 35                       | 400                             | 1.400                              | 250.000                         |
| A     | Satellite     | 10                       | 200                             | 210                                | 220.000                         |
| A     | Manifold      | 30                       | 1.000                           | 7.000                              | 560.000                         |
| A     | Manifold      | 25                       | 5.000                           | 7.000                              | 1.300.000                       |
| B     | Satellite     | 89                       | 5.000                           | 5.500                              | 700.000                         |
| B     | Satellite     | 25                       | 200                             | 450                                | 250.000                         |
| C     | Manifold      | 50                       | 300                             | 2.600                              | 220.000                         |
| C     | Manifold      | 65                       | 360                             | 7.000                              | 340.000                         |
| C     | Manifold      | 52                       | 5.020                           | 5.025                              | 800.000                         |
| C     | Manifold      | 45                       | 4.130                           | 4.135                              | 740.000                         |
| D     | Manifold      | 28                       | 640                             | 1.300                              | 400.000                         |
| D     | Manifold      | 45                       | 1.000                           | 3.600                              | 710.000                         |

NOTE 3: The well test system shall be able to operate with one or more wells within the capacities informed on table 2.2.3.1a.

- 2.2.3.2 CONTRACTOR shall consider that test separator will have a recycle of oil stream from a point upstream oil allocation metering to one point in the test header as close as possible to the choke valve. This recycle will be used to maintain the temperature upstream test heater above 15°C.
- 2.2.3.3 Well test separator shall be able to operate from low pressure up to the Hp Separator normal operating Pressure of 1,000 kPa(a). During low pressure operations, expected for well kick-off purpose, produced gas from test separator may be routed to flare and liquids routed to further lower pressure separation stages.
- 2.2.3.4 Test separator shall be sized for the maximum liquid and gas flow with the normal operating pressure of 1,000 kPa(a).
- 2.2.3.5 Test separator will also receive fluids such as wells completion fluids and special operations fluids. The list of expected completion and special operations fluids can be found in the FLUIDS FOR SPECIAL OPERATIONS (see item 1.2.1). Completion Fluids and special operations fluids shall be routed to oil offspec tank in order to

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prevent impacts in production. CONTRACTOR shall be responsible to treat completion fluids and special operations fluids for final destination.

2.2.3.6 Test separator pumps shall be installed in N+1 configuration to allow recirculation to oil treatment plant. Test separator pumps flow capacities shall be designed to handle well flow rates and to allow well service operations.

2.2.3.7 The test separator system shall be sized to guarantee a minimum operating temperature of 40°C for any of the scenarios presented on item 2.2.3.1 NOTE 2 above.

2.2.3.8 The well test heater and well test separator may receive wax crystals.

2.2.3.9 CONTRACTOR shall provide test heater bypass.

## 2.2.4 PRODUCED GAS

2.2.4.1 The complete description of the gas treatment and compression plant is found on item 2.7.3.

## 2.2.5 PRODUCED WATER

2.2.5.1 Salinity range: from 20,245 to 228,400 mg/L (as NaCl).

2.2.5.2 The complete description of the produced water plant is found on item 2.7.4.

## 2.3 PROCESS

### 2.3.1 CARGO TANKS/ EXPORTED OIL

2.3.1.1 The oil to be stored and exported shall meet the following specification:

- Basic Sediment & Water content (BS&W): lower than 0.5% vol.;
- Salinity: less than 285 mg/L (as NaCl);
- Reid Vapor Pressure (RVP): < 68.9 kPa (a) at 37.8°C (for storage purpose);
- Reid Vapor Pressure (RVP): 43 kPa (a) at 37.8°C. This value is intended for measurement purpose to comply with required TVP and can be reassessed in operation phase;
- H<sub>2</sub>S: < 1 mg/kg;
- Maximum Oil True Vapor Pressure (TVP) @measurement temperature: 70 kPa (a) (for measurement purpose - Resolução Conjunta ANP/Inmetro nº1 de 10/06/2013 or another updated documents which substitutes it
- Normal Storage temperature: 40°C;
- Resolução Conjunta ANP/Inmetro nº1 de 10/06/2013 (or another updated documents which substitutes it).

## 2.3.2 PRODUCED WATER DISPOSAL

2.3.2.1 The disposal of produced water shall comply with the Brazilian Administration regulations issued by Environmental Ministry, through its *Conselho Nacional do Meio Ambiente* (CONAMA) Resolutions 393/2007. The analytical method used to determine the content of Oil & Grease (TOG) in produced water to be discharged to overboard shall be the Standard Method (SM) SM-5520B, which determines the total hexane extractable material (HEM).

## 2.3.3 SERVICE, LIFT, IMPORTED AND EXPORTED GAS

2.3.3.1 The lift and exported gas to provide artificial lift shall meet the following specification:

- Normal operating temperature at the top of the riser: 40 °C;
- Maximum Operating temperature at the top of the riser: 55C
- Normal Operating Pressure at the top of gas lift riser: see item 15.2.2
- Normal Operating Pressure at the top of gas export riser: see item 15.2.2
- 
- Design Pressure: see item 15.2.2
- Gas Lift Flowrate Range: from 100,000 Sm<sup>3</sup>/d to 200,000 Sm<sup>3</sup>/d (each Satellite Wells); from 100,000 Sm<sup>3</sup>/d to 1,500,000 Sm<sup>3</sup>/d (each MSP) and 5,000,000 Sm<sup>3</sup>/d (total Gas Lift);
- Exported Gas Flowrate Range: up to 1,600,000 Sm<sup>3</sup>/d;
- Maximum condition 7 ppmv of H<sub>2</sub>S and normal condition 5 ppmv of H<sub>2</sub>S;
- Maximum 2% mol CO<sub>2</sub> (peaks); 1,5% mol CO<sub>2</sub>(eventually); <1% mol CO<sub>2</sub>(normal operation conditions);
- Maximum H<sub>2</sub>O content: 40 ppmv according to Gas Dehydration Unit (GDU) specification and process plant configuration;
- Design Temperature: see item 15.2.2

2.3.3.2 The imported gas shall meet the following specification:

- Operating Pressure: from 4,000 kPa(a) up to 12,500 kPa(a);
- Operating Temperature: 0 to 16°C;
- Maximum 7 ppmv of H<sub>2</sub>S;
- Maximum H<sub>2</sub>O content: 60 ppmv

Imported gas composition is shown in table 2.3.3.3.

Table 2.3.3.3: Imported Gas Composition

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| Gas Composition | MLS   | P-43  |
|-----------------|-------|-------|
| CO <sub>2</sub> | 0.65  | 0.76  |
| N <sub>2</sub>  | 0.70  | 0.99  |
| C1              | 81.29 | 75.62 |
| C2              | 7.05  | 10.38 |
| C3              | 5.75  | 8.57  |
| iC4             | 0.96  | 0.96  |
| nC4             | 2.04  | 1.83  |
| iC5             | 0.43  | 0.29  |
| nC5             | 0.52  | 0.33  |
| C6              | 0.28  | 0.13  |
| C7              | 0.19  | 0.07  |
| C8              | 0.09  | 0.04  |
| C9              | 0.04  | 0.02  |
| C10             | 0.01  | 0.01  |

NOTE 1: This information is preliminary. It will be confirmed during the detail design phase

NOTE 2: The compositions of exported gas resulting from the process simulations (Table 2.2.2.3 Design Cases) shall also be considered.

2.3.3.2.1 The imported gas will have two main purposes:

- provide a gas source to fuel gas during start-up and during final production period;
- provide a gas source to lift gas for start-up of the wells and restart-up operations.

If necessary, in order to allow the use as lift gas and fuel gas, the imported gas shall be treated in order to comply with the specification prescribed in 2.3.3.1.

2.3.3.2.2 CONTRACTOR shall consider, for design purpose, minimum import gas flow as the quantity necessary to supply the maximum lift gas flow rate for two wells (400,000 m<sup>3</sup>/d) start up plus fuel gas consumers.

2.3.3.2.3 PETROBRAS' procedures for well start-up will indicate the possibility of using imported gas, when applicable.

2.3.3.2.4 A Slug Catcher or a Safety K.O. drum shall be installed for import gas from pipeline, in order to separate any liquid carry-over. This condensate shall return to the oil separation system and under no circumstances it shall be sent to the slop or drain system.

2.3.3.2.5 For slug catcher design, CONTRACTOR shall consider the following design cases:

Gas composition: X

| Gas Pipeline Pressure [kPa(a)] | Gas Flowrate [kSm <sup>3</sup> /d] | Liquid Flowrate [Sm <sup>3</sup> /h] | Slug Conditions [Sm <sup>3</sup> ] /time [h] |
|--------------------------------|------------------------------------|--------------------------------------|--|
| 8,500                          | 150                                | 1,25                                 | 0,0  |
|                                | 600                                | 2,3                                  | 11/2,0                                       |



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|        |       |      |          |
|--------|-------|------|----------|
|        | 1.000 | 11,1 | 20/2,5   |
|        | 1.500 | 16,6 | 64/5,0   |
| 9,500  | 150   | 1,6  | 0,0      |
|        | 600   | 7,3  | 11,6/3,0 |
|        | 1.000 | 6,1  | 90/8,0   |
|        | 1.500 | 11   | 13/1,0   |
| 11,000 | 150   | 0    | 0,0      |
|        | 600   | 3,4  | 4,8/5,0  |
|        | 1.000 | 7,1  | 4,2/5,0  |
|        | 1.500 | 12,9 | 48/6,0   |
| 12,500 | 150   | 0    | 0,0      |
|        | 600   | 0,4  | 0,0      |
|        | 1.000 | 4,5  | 0,0      |
|        | 1.500 | 11,3 | 13/3,5   |

**Gas composition: Y**

| Gas Pipeline Pressure [kPa(a)] | Gas Flowrate [kSm <sup>3</sup> /d] | Líquid Flowrate [Sm <sup>3</sup> /h] | Slug Conditions [Sm <sup>3</sup> ] /time [h] |
|--------------------------------|------------------------------------|--------------------------------------|--|
| 8,500                          | 150                                | 2,3                                  | 0,0  |
|                                | 600                                | 2,9                                  | 80/5,4                                       |
|                                | 1.000                              | 3,8                                  | 52,5/4,7                                     |
|                                | 1.500                              | 5,1                                  | 55/3,6                                       |
| 9,500                          | 150                                | 2,5                                  | 0,0  |
|                                | 600                                | 9,4                                  | 0,0  |
|                                | 1.000                              | 13,6                                 | 0,0  |
|                                | 1.500                              | 18,3                                 | 28/1,7                                       |
| 11,000                         | 150                                | 3,0                                  | 0,0  |
|                                | 600                                | 8,5                                  | 0,0  |
|                                | 1.000                              | 10,7                                 | 0,0  |
|                                | 1.500                              | 9,0                                  | 0,0  |
| 12,500                         | 150                                | 0,0                                  | 0,0  |
|                                | 600                                | 0,0                                  | 0,0  |
|                                | 1.000                              | 0,0                                  | 0,0  |
|                                | 1.500                              | 0,0                                  | 0,0  |

NOTE 1: This information is preliminary. It will be confirmed during the detail design phase.

2.3.3.2.6 In case of import gas heating systems with electrical resistors, a jacket system provided with standby resistors shall be used, allowing the resistors to be changed. i.e. electrical heater shall be fully redundant (N+1, with one standby unit) in order to allow maintenance and replacement of heater in a way to not impact heating system availability and no production loss. Energy demand calculation shall consider the loss of thermal conductivity caused by this jacket.

## 2.4 WATER INJECTION

2.4.1 The Unit shall be able to operate continuously with only one water injection well up to 7 (seven) connected wells through 3 positions: I-1, MSPIA-1 (with 2 wells) and MSIA (with 4 wells).

2.4.1.1 Additionally unit may be required to operate one up to 10 (ten) new wells connected in spare positions to be installed in future: I-2 (with possible installation of an injection subsea manifold with maximum 6 wells), MSPIA-2 (with 2 wells) and MSIA (with 2 new additional wells connected directly at subsea manifold, totaling 6 wells in this subsea manifold).

2.4.2 The Unit shall be able to inject seawater, produced water and mixtures of them. The decision to switch from one mode to another mode (seawater or produced water injection or mixture) is a PETROBRAS prerogative. The mixture of sea water and produced water shall be done upstream water injection pumps.

2.4.3 Water injection facilities must be designed according to the operational cases listed in table 2.4.3

Table 2.4.3: Water Injection Operational Cases

| Cases                           |   | Flow rate          | Water injection pressure (1,2) |
|---------------------------------|---|--------------------|--------------------------------|
|                                 |   | Sm <sup>3</sup> /d | kPa(a)                         |
| Max Flowrate / Max Pressure     | 1 | 23,850 (3)         | 19,600                         |
| Max flowrate / high injectivity | 2 | 5,000 (3)          | 1,000                          |
| Max flowrate                    | 3 | 5,000 (3)          | 6,000                          |
| Ramp-up                         | 4 | 7,000              | 19,600                         |
| Mid Life                        | 5 | 14,000             | 19,600                         |
| Sattelite Well                  | 6 | 1,500              | 12,500                         |
| Max Flowrate Sattelite well     | 7 | 5,000              | 19,600                         |
| Max Flowrate Manifold           | 8 | 20,000             | 19,600                         |
| Min flowrate / one well         | 9 | 800                | 19,600                         |

NOTE 1: Pressure value upstream water injection choke valve. Pressures at the top of water injection risers may be significantly lower.

NOTE 2: During project execution phase PETROBRAS will provide to CONTRACTOR the pressure, temperature and flow rate conditions to size water injection choke valves.

NOTE 3: Extra flow rate design capacity does not need to be considered for Well Service Operations.

2.4.4 Seawater quality specification to injection shall meet the following specification:

- Operating Pressure: See item 15.2.2
- Operating Temperature: from 25°C up to 40°C;
- The system shall have a Sulphate Removal Unit (SRU);

- Seawater quality specification (maximum values):
  - Content of suspended solids: 1.5 mg/L, according to ISO 11923:1997 (E) – Annex B method;
  - Maximum particles/mL greater than 5 mm: 10 (ten) per milliliter;
  - Dissolved oxygen: 10 ppb (vol) O<sub>2</sub>;
  - Soluble sulfide content: 2 ppm (vol);
  - Bacteria (SRB planctonic – mesophile): 50 NMP/mL;
  - Total anaerobic bacteria (TAHB planctonic): 5,000 NMP/mL;
  - Maximum sulphate content: 100 mg/L (this value can be higher if requested by PETROBRAS during operational lifetime);
- pH of injected water: to be daily monitored.

2.4.5 Produced water quality specification to reinjection shall meet the following specification:

- Operating Pressure: see item 15.2.2;
- Operating Temperature: from 25°C up to 40°C;
- Produced Water quality specification (maximum values):
  - Dispersed Oil, as measured by SM5520F: 40 mg/L;
  - Content of suspended solids (TSS): 1,5 mg/L;
  - Particle size: 25 µm;
  - Dissolved oxygen: 10 ppb (vol) O<sub>2</sub>;
  - Soluble sulfide content: 2 mg/L;
  - Bacteria (SRB planctonic – mesophile): 50 NMP/mL;
  - Total anaerobic bacteria (TAHB planctonic): 5000 NMP/mL;
- pH of injected water: to be daily monitored.

2.4.6 Water injection riser characteristics:

- Normal Operating Pressure: see item 15.2.2;
- Design Pressure: see item 15.2.2;
- Maximum dissolved oxygen: 10 ppb (vol) O<sub>2</sub>;
- Design Temperature: see item 15.2.2.

2.4.7 The system shall consist of filtration, sulphate removal unit (including Clean-in-Place (CIP) system), deaerator system, chemical injection and injection pumps for a total flow rate of 23,850 m<sup>3</sup>/d of injected desulphated water. For the SRU configuration, at least three trains (3x50%) are required, however, 4x33%, 5x25%, 6x20% can also be considered. The services of SRU Feed Pumps, Booster Pumps and Main Injection Water Pumps shall be specified in a configuration with at least one spare pump (N+1).

The system shall be designed considering that, during operation, PETROBRAS may require lower injection flowrates that shall be achieved with the minimum number of injection pumps in operation.

2.4.7.1 Filtration system shall be, as a minimum, one of the following options:

- Self-cleaning filter and cartridge filter;
- Multi-media filter and cartridge filter;
- Self-cleaning filter and ultra-filtration (UF);

2.4.7.2 For ultra-filtration option, design of UF recovery shall consider inlet solid content defined by membrane supplier. UF unit shall comply with the following specifications as a minimum:

- The permeate flux (normal and maximum) to maintain the required water injection flowrate shall be kept constant even during backwashing, cleaning procedure and routine maintenance;
- Maximum permeate flux in operation during cleaning: 80 LMH@25°C;
- Membrane shall be sodium hypochlorite (NaOCl) resistant to a minimum of 500 ppm during cleaning procedure;
- Membrane absolute pore size: maximum of 0,22 µm;
- Ultrafiltration design specification shall be in accordance to SRU supplier's requirements.
- Full bypass of UF unit.

2.4.8 Full and partial bypass of SRU Unit shall be considered (bypass shall not cover the filtration system upstream membranes). The bypass may be used to sustain water injection flow, only whenever requested by PETROBRAS.

2.4.9 The Sulphate Removal Unit shall be located upstream Deaerator. Seawater deaeration with hydrocarbon gas stripping shall not be used.

2.4.10 Means shall be provided to allow water injection at the correct specification, even when operating at minimum flow rate (only one well connected with minimal flow) or at full capacity (all wells connected). Means shall be provided for individual well flow rate control, using information from operational flow meters. The water injection system shall have no stagnation points. If inevitable, water drainage points shall be provided.

2.4.11 The injection water system shall have an online O<sub>2</sub> analyzer installed on the water injection header and another one installed downstream of the deaerator system and oxygen scavenger injection point. The analyzer installed on the water injection header shall be connected to process interlock system. This interlock actuation will be defined later on by PETROBRAS. The analyzer shall have an installed stand-by instrument.

2.4.12 The produced water shall have options to be discharged overboard or reinjected in the reservoir, as shown on figure 2.4.12. It is Petrobras decision to discharge overboard or reinject the produced water.

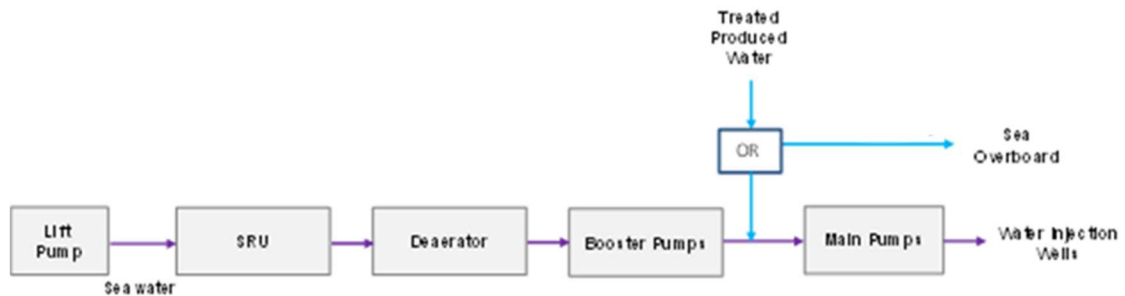


Figure 2.4.12- Simplified Diagram for Produced Water and/or Seawater Injection

2.4.13 The produced water treatment system description is detailed on item 2.7.4.

2.4.14 Means shall be provided to allow pressure equalization between pumps discharge and injection header during start-up procedures. Pressure transmitters shall be installed downstream and upstream of shutdown valves in order to enable control by differential pressure.

2.4.15 The water injection pumps (main, seawater booster, produced water booster and SRU feed pumps) shall comply with API 610. Pump drivers may be electric motors or gas turbines from the vendors listed in item 19.1.1.7.

2.4.16 The main water injection pump shall be monitored for bearing and motor temperature, axial displacement and vibration as specified in item 8.12.

2.4.17 The water injection pumps sealing system shall comply with API 682 and, for pumps with produced water as working fluid, its design and sealing plan shall be suitable for salty and hot produced water where applicable. Additionally, API 62 auxiliary sealing plan (quench) shall be provided.

2.4.18 For acceptable vendor list for water injection system, see item 19.

Note: CONTRACTOR shall evaluate the applicability of speed variation device for water injection pumps.

2.4.19 UV-c Sterilizer reactors shall be installed upstream of UF in order to inactivate microorganisms and minimize biofouling formation/deposition. The minimum requirements for this system shall be:

- Configuration: N+1 (one stand-by);
- Design UV dose  $\geq 40$  mJ/cm<sup>2</sup>.

## 2.5 DESIGN SUMMARY

### 2.5.1 WELL DESIGN SUMMARY

Table 2.5.1: Well Design Data

| Design data  |   |
|--|---|
| Maximum liquid production flow rate per satellite well | 7,000 Sm <sup>3</sup> /d <sup>(2)</sup> |
| Minimum liquid production flow rate per satellite well | 50 Sm <sup>3</sup> /d <sup>(1)(2)</sup> |
| Maximum liquid production flow rate per MSP            | 7,000 Sm <sup>3</sup> /d <sup>(2)</sup> |
| Minimum liquid production flow rate per MSP            | 50 Sm <sup>3</sup> /d <sup>(1)(2)</sup> |
| Maximum Oil production flow rate per satellite well    | 5,500 Sm <sup>3</sup> /d <sup>(2)</sup> |
| Minimum Oil production flow rate per satellite well    | 50 Sm <sup>3</sup> /d <sup>(1)(2)</sup> |
| Maximum Oil production flow rate per MSP               | 5,500 Sm <sup>3</sup> /d <sup>(2)</sup> |
| Minimum Oil production flow rate per MSP               | 50 Sm <sup>3</sup> /d <sup>(1)(2)</sup> |
| Water cut from one well                                | 0% to 95%                               |
| Maximum gas production flow rate per well              | 1,300,000 Sm <sup>3</sup> /d            |
| Minimum gas production flow rate per well              | 100,000 Sm <sup>3</sup> /d              |
| Maximum gas production flow rate per MSP               | 1,300,000 Sm <sup>3</sup> /d            |
| Minimum gas production flow rate per MSP               | 100,000 Sm <sup>3</sup> /d              |
| Arrival pressure range                                 | 1,500 to 10,000 kPa (a)                 |
| Shut in Pressure                                       | 25,000 kPa (a)                          |
| Arrival temperature <sup>(3)</sup>                     | 14°C to 89°C                            |

NOTE 1: For measurement accuracy purposes.

NOTE 2: The standard flow rate shall be applied to oil conditions as per item 2.3.1, that refers to dead oil conditions.

NOTE 3: Temperature in steady state condition. During transient conditions temperatures can be lower.

NOTE 4: The pressure drop between upstream of choke valve and the production separator shall be 500 kPa, maximum, considering the choke valve 100% opened.

NOTE 5: CONTRACTOR shall provide choke and downstream lines compatible with depressurizing temperature during well startup with gas segregation in the riser top. The minimum estimated temperature downstream the choke is -40°C.

NOTE 6: Multiphase flow meters shall be installed in each production subsea manifold topside line and inlet of Test Separator. Multiphase meters shall be based on physical measurement principles and shall not be based on simulations. The meters shall be inline and not based on partial separation. Oil flow rates, gas flow rates, and water flow rates shall be measured values. A salinity probe shall be included in the multiphase meter.

NOTE 7: Wells are susceptible to slugging. CONTRACTOR shall provide anti-slugging automatic control system, actuating on the choke valves for each production riser. CONTRACTOR shall submit anti-slugging control system design for PETROBRAS

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approval. Anti-slugging control system parameters shall be approved by PETROBRAS during operating phase. PETROBRAS will define the applicable wells at its sole discretion during operating phase

**2.6 TOPSIDE MANIFOLDS**

- 2.6.1 All oil production wells shall be connected to 1 (one) oil production header and 1 (one) oil test header. Both these headers shall be able to accommodate all producer wells.
- 2.6.2 Emergency Shutdown Valves (ESDV) shall be installed in all wells' lines. ESDVs shall be in a position:
- Such that it is above water;
  - Such that its exposure to topsides incidents is minimized;
  - Subject to the above, such that the distance from the ESD valve to the base of the riser is as short as reasonably practicable. Scenarios of risers releases shall be evaluated as part of Hazard Identification, Risk assessment and Consequence Analyses.
- 2.6.3 Problems on the test train shall not affect the main process train. The same philosophy applies to the production riser producing to the test header. Facilities to inject hot Diesel (maximum 60°C) upstream each production choke valve shall be provided to recirculate diesel towards the processing plant and/or towards the subsea lines. Facilities shall consider the possibility to inject diesel during shut-in conditions. The expected rate of hot Diesel injection is 34 m<sup>3</sup>/h. Pigging will not use hot Diesel.
- 2.6.4 The Flow Metering System (FMS) flow meter of each gas injection flexible line shall have its instantaneous flow rate signal sent to Process Shutdown System (PSD) through a hardwired connection. Logic implementation shall be discussed during detail design with PETROBRAS.
- 2.6.5 The Test Header and the Test Separator shall provide periodical production test for each well or each manifold with one or more wells connected.
- 2.6.6 Production and test headers shall be provided with chemical injection to enhance the separation and/or protect the facilities (anti-foaming, demulsifier, scale inhibitor, etc.).
- 2.6.7 Each production well shall have adjustable chokes at both lines (production and service/gas-lift). Opening accuracy/precision on the valve stroke shall be 0.2% and shall be remotely actuated from the Central Control Room. The production choke valve shall also be able to be manually operated. In addition, each gas lift line, gas injection and water injection wells shall have individual chokes that can be manually operated or remotely actuated from the Central Control Room.
- 2.6.8 CONTRACTOR shall provide temperature and pressure transmitters both upstream and downstream each choke valve connected to Process Shutdown System (PSD), as well as differential pressure indication on each production choke valve. Logic implementation associated to differential pressure interlock will be discussed during detail design.

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2.6.9 A service header to allow flexibility to access each bundle with no disturbance to the others shall also be provided. This service header shall be connected to Production, Gas Lift and Injection lines. This service header may be used to perform Diesel injection (pigging operations, Diesel circulation, bullhead operation, etc.), dead oil circulation, desulphated/deaerated water circulation, gas circulation as service gas (pigging operations). The service header shall also have facilities to inject ethanol or monoethylene glycol (MEG) bed during pigging, commissioning.

2.6.10 All Gas Lift Slots shall be capable to receive (back flow from well) small amounts (up to 10 m<sup>3</sup>) of liquid. This is not to be used often and is restricted to cases of depressurization to remove hydrate blockage in any part of the subsea system.

### 2.6.11 PIG FACILITIES

2.6.11.1 For PIG facilities, see item 1.2.1 (PIG FACILITIES).

### 2.6.12 WELL SERVICE SYSTEM

2.6.12.1 All subsea service operations (Diesel circulation, desulphated/deaerated water circulation, leak test, pigging, etc.) shall be done using facilities onboard. CONTRACTOR shall take into account the requirements of those operations, for example, volume control, pressure control, etc. Seawater could be used for well service operations until seawater injection treatment system is fully commissioned.

2.6.12.2 The Unit shall have facilities and space to allow the injection of nitrogen and service gas on top of production risers. The Nitrogen Generator Unit (NGU) will be supplied by PETROBRAS.

#### 2.6.12.3 Well service system requirements:

- The well service system shall be able to inject desulphated/deaerated water, an ethanol or MEG bed, diesel and oil from the cargo tanks in each of the production, service, water injection lines.
- The service pump shall operate with desulphated/deaerated water, diesel, crude oil or a mixture of Diesel and crude oil. In case of Ethanol or MEG bed injection, the well service pump will not run with ethanol/MEG; the pump to be used for this operation is the pump referenced in Table 2.8.12 (Product: Gas hydrate inhibitor: ethanol or MEG for oil production wells (subsea)).
- It shall be possible to inject a mixture of Diesel and oil in any proportion, it is under CONTRACTOR responsibility to provide proper facilities to measure and control the mixture. The fluids to be injected (Diesel, and crude oil or a mixture of Diesel/oil) shall be metered with dedicated operational metering.
- Protection filters shall be provided upstream of each pumps suction, the filter specification shall be according to manufacturer's pump recommendation.
- A dedicated atmospheric Diesel/oil service tank/vessel shall be installed at topsides for well service system operations (including Diesel and oil mixture) in



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order to avoid the return of reservoir fluid/gas to hull, protecting the Unit in case of gas return during well service operations. The minimum volume required for atmospheric Diesel /oil service tank/vessel shall be 30 m<sup>3</sup>. The atmospheric tank vent design shall comply with GTD item 2.7.5.10. The tank relief device shall be specified for emergency condition to avoid structural damage to the tank.

- The service pumps and tanks/vessels shall be sized for a total flow of 20 to 180 m<sup>3</sup>/h of Diesel at maximum discharge pressure up to 23,000 kPa(a) (The service pump shall be positive displacement type according to API 674 and shall have a flow fiscal meter, one flow meter for each fluid). Flow control shall be obtained by variation in pump speed with a variable speed drive, with or without supplemental recycle. If supplemental recycle is needed, CONTRACTOR shall take special care to avoid cross contamination between the different operating fluids and recycle shall return to the dedicated atmospheric tank/vessel installed at topsides, recirculation to hull is not allowed. In case of recirculation is necessary, besides variable control, the necessity of recycle cooling shall be evaluated. A minimum arrangement of 3x50% to the service pump is required. A spare connection from laydown area to downstream of well service pump shall be available to allow connection (chicksan) of a Diesel motor driven service pump (including connections for supply to rented pump tank).
- The service pumps range shall not comprise very low flow and very high pressure, related to piping leak test services. This application shall be attended by separated pump (leak test pump).
- It shall be provided means to perform the system flowrate test during commissioning.
- The well service system shall be prompt to be aligned, without the need to reassemble any piping element (e.g. removable spool, spectacle blind etc). CONTRACTOR shall consider Well Service pump operating continuously as an input for load balance calculation.
- Each well shall be capable to operate from 2,5 to 200 m<sup>3</sup>/h.
- The system shall be also able to perform pressurization after production stop, pressurization to equalize WCT valves pressure and pressurization to equalize DHSV. The system shall be composed by two different sets of pumps to perform high flow rate operations (e.g circulation and bull heading) and low flow rate operations (e.g pressurization). An additional pumps arrangement of 2 x 50% to the low flow rate operations (lines pressurization) shall be provided with a total flow rate of 4 m<sup>3</sup>/h of diesel at maximum operational discharge pressure of 32,000 kPa(a). Flow control is not required.

**2.6.12.4 Special operations requirements:**

- The Unit shall also be prepared to perform remote operations using pumps from Special Purpose Boats (squeeze, xylene, DTPA etc.) to operate alongside of the FPSO. Therefore, CONTRACTOR shall provide one permanent and dedicated line from the bunkering station to be tied into well service pump discharge header. This line shall be designed considering the pressure rating of the well service pump.



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CONTRACTOR shall have means and operation procedures to handle offspec production after those remote operations.

- The CONTRACTOR shall provide facilities to isolate and drain service line and also flush topsides piping (using inert fluid) after the remote operation.
- The Unit shall have a special permanent support with access and railing located at the side shell to fit the flexible lines coming from the special boat. Means for spill containment must be provided at the support. The place where the platform will install the special permanent support shall have structural capacity to support 18,000 kg. The flexible line shall be fitted using the FPSO crane. The flexible line weight will be 12,000 kg.

2.6.13 CONTRACTOR shall guarantee the performance of pigging operation regarding service fluid flowrate control.

2.6.14 PETROBRAS is responsible to supply those pigs during operational lifetime.

2.6.15 The gas-lift header shall allow individual injection to each gas-lift riser. CONTRACTOR shall take into account the requirements to control the flow rate at normal well production and during pigging operations.

2.6.16 An individual flow meter shall be installed for each gas-lift riser, including the production satellite wells and manifold system. For pigging purposes, the gas flow rate shall be controlled and totalized.

2.6.17 Facilities shall be provided to allow the depressurization of any riser, including production, gas lift, with no production disturbance. These facilities shall allow:

- a) Depressurization of all production risers within one hour (it shall consider the proposed subsea arrangement issued by PETROBRAS) in order to avoid hydrate blockage. Contractor shall consider as maximum subsea riser volume 200 m<sup>3</sup> and initial conditions 15.000 kPa(a) and 15 °C (to be confirmed in KoM);
- b) Depressurization of each gas lift riser within one hour and thirty minutes (it shall consider the proposed subsea arrangement issued by PETROBRAS). Contractor shall consider as maximum subsea riser volume 150 m<sup>3</sup> and initial conditions 20.000 kPa(a) and 4 °C (to be confirmed in KoM);
- c) Depressurization of gas exportation riser with no time constraint. Contractor shall consider as maximum subsea riser volume 1.300 m<sup>3</sup> and initial conditions 13.000 kPa(a) and 4 °C (to be confirmed in KoM);
- d) Control and monitoring the depressurization of production, gas lift and gas export risers at a rate up to 10 MPa/min, according to operational procedure to be defined by PETROBRAS.

NOTE 1: CONTRACTOR shall submit to PETROBRAS for comments simulation report of the subsea flowlines depressurization that shows that requirements (a) through (c) were fulfilled.

NOTE 2: The design may consider the depressurization through the pig receiver, where available.



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NOTE 3: Export gas pipeline depressurization through flare shall be minimized.

2.6.18 Drainage shall be in accordance with the same philosophies of the process plant.

2.6.19 CONTRACTOR shall take care during the design and construction phase to avoid any pigging problems such as protruding welds inside piping or other arrangement that cause risk to the pigging operation. Barred tees shall be provided when the diameter of a branch is equal to or larger than half main piping diameter, as required by NBR 16381.

2.6.20 All wells (oil or gas production and injection) shall be controlled and monitored through the Central Control Room Workstations, as described in section 7.

2.6.21 FPSO shall have manifolds with well piping flexibility as per Figure 2.6.21 in order to ensure that all well positions and manifolds are fitted before FPSO sails away from shipyard (including hard piping, instrumentation, valves, etc.).

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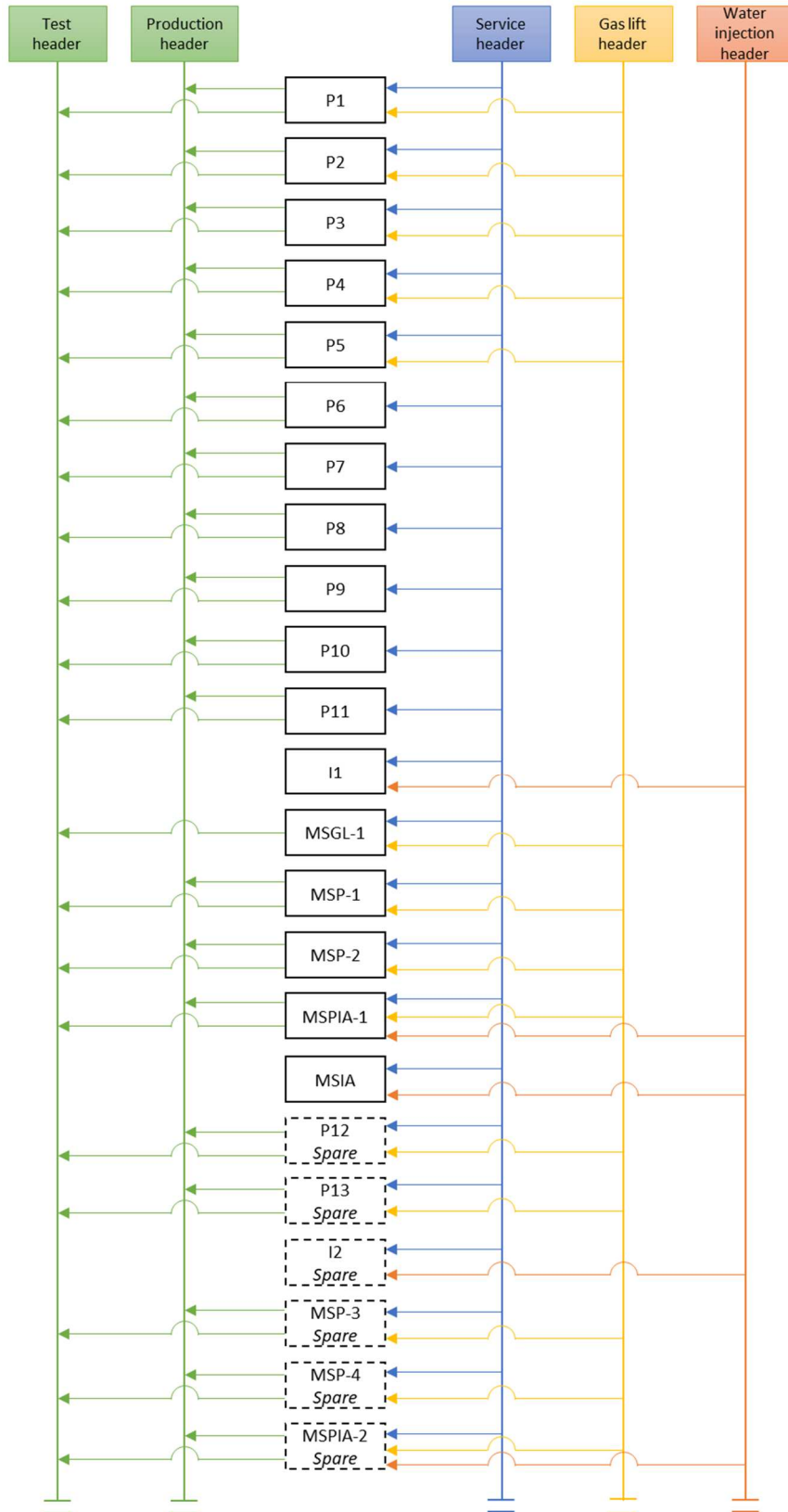


Figure 2.6.21 - Wells Piping Arrangement

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NOTE 1: This drawing represents table 15.1.3.1. The sequence, functions and diameters of each riser slot will be defined at the project kick-off meeting together with the subsea layout.

2.6.22 A preliminary description of all intended procedures for Subsea operations can be found in OPERATION PHILOSOPHY (see item 1.2.1). Design and operational philosophy are CONTRACTOR's scope and shall be sent to PETROBRAS for comments. CONTRACTOR to guarantee that these operations are included in Risk Assessment Studies.

## 2.7 PROCESS FACILITIES

### 2.7.1 SEPARATION AND TREATMENT

2.7.1.1 The oil processing will be carried preferably through one production train. It shall be constituted of a first stage two-phase separator (HP Separator), pre-heaters of produced liquid (using the heat recovered from the processed oil), oil heater, a second stage two-phase separator (LP Separator), oil cooler, a third stage three-phase separator (settling tank), pre-heaters of produced liquid (using the heat recovered from the processed oil), oil heater, electrostatic pre-treater, electrostatic treater, oil cooler as shown in Figure 2.7.1.21. A test separator for the wells production test shall also be installed.

2.7.1.2 The producing oil wells will flow to the test and production headers. From there oil is sent directly to a first stage two-phase separation, HP Separator, operating at 1,000 kPa(a).

2.7.1.3 Gas separated in the HP Separator is to be sent to Main Compressor.

2.7.1.4 Cyclone type or vane-type device shall be installed in the HP Separator, LP Separator and Test Separator for mist removal from the outlet gas.

2.7.1.5 The oily current is routed to the Oil Pre-heater interstage and the Interstage Production Heater in order to reach the temperature required to reach the vapor pressure of the stabilized oil (70 kPa-a) and avoid the gas outflow in the Settling Tank

2.7.1.6 The second separation stage is composed of a biphasic separator vessel (LP Separator). The gas is sent to the Vapor Recovery Unit (VRU) and the oily current is pumped and cooled by preheating the oil from the HP Separator and the interstage cooler up to 60°C and proceeds to the 3rd stage of separation, which is the Washing Tank (Settling Tank).

2.7.1.7 The settling tank is the third separation stage of the oil processing system. The first two stages are high and low pressure separators. Each tank contains three compartments; one large tank where separation takes place and two collection sections (caissons) for the crude oil and produced water. Contractor shall consider that vapor from settling tanks shall return to process plant for treatment, upstream

the VRU. This stage is able to reduce the BSW of the oily current to 20 %vol. The water produced separately in the Settling Tank is directed to the produced water treatment system.

- 2.7.1.8 The oil stream from the settling tank is sent to the heating system, pre-heaters and oil heater. The oil stream from the settling tank is heated to fit the treatment temperature, being this final temperature obtained through the use of heat from the treated oil and complemented by the hot water system. The heated oil at the treatment temperature (95 °C), is sent to an pre-oil electrostatic treater..
- 2.7.1.9 The heated oil at the treatment temperature, is sent to a electrostatic pre-treater, which has the function to specify the outlet oil phase for the final stage of treatment, constituted by an electrostatic treater, with addition of dilution (deaerated fresh or deaerated desulphated) water. CONTRACTOR shall foresee facilites to allow maintainance of dilution water mixing valve without loss of production.
- 2.7.1.10 The operational oil treatment temperature for design purpose shall be at least 95°C and CONTRACTOR may apply higher temperatures, if necessary, to meet GTD requirements. For oil treatment, the maximum heating medium temperature shall be at 120°C.
- 2.7.1.11 In the pre-treater outlet, the oil stream is sent to the electrostatic treater, where it shall be specified with the desired quality as per item 2.3.1. It is not expected the need of any additional crude processing to meet this H2S specification. The design shall include ability to inject H2S scavenger into the offloading pumps header or upstream offloading metering skid.
- 2.7.1.12 The produced water separated in Pre-oil and Oil Dehydrator shall be able to be routed directly to Produced Water System. The produced water shall also be able to be recycled upstream oil pre heater in order to help scale inhibition.
- 2.7.1.13 Regarding the field instrumentation required for oil-water interface level measurement: Standpipes shall not be used for oil-water interface level measurement neither in Gravitational Separators nor in Oil Dehydrators. In such cases, the oil-water interface level measurement shall be performed in the interior of the vessels, directly immersed in process fluid, using one of the following technologies: energy absorption, nuclear or electric conductivity profiler. For nuclear profiler, CONTRACTOR shall comply with "*Resolução CNEN 215/17*" and "*Anexo D – SMS – Segurança, Meio Ambiente e Saúde Ocupacional*".
- 2.7.1.14 The treated oil from the electrostatic treater is cooled in the oil/oil pre-heater and in the oil cooler to reach the maximum temperature of 40C. The stabilized oil will be metered and pumped to the cargo tanks of FPSO. If oil is not specified, it shall be aligned to an oil offspec tank. From this tank, oil shall be pumped do be reprocessed. The oil offspec tank shall have a minimum volume of 10.000 m3..
- 2.7.1.15 Oil processing plant heat exchangers, heaters and coolers shall be designed to guarantee high availability in the oil treatment and shall be provided with by-pass lines. CONTRACTOR shall provide spare heat exchanger for oil/oil pre-heater,

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production heater and oil cooler. Spare exchangers shall be installed and ready to operate.

- 2.7.1.16 CONTRATOR shall provide stand-by pumps for all process oil treatment system pumps. For test separator pumps configuration see item 2.2.3.6.
- 2.7.1.17 CONTRACTOR shall consider slug volume (Normal Liquid Level (NLL) to Level Alarm High (LAH) of the vessel) in the HP Separator and Test Separator design (36.0 m<sup>3</sup> in 10 minutes). The HP Separator and Test Separator design shall consider wax crystals dispersed in oil phase.
- 2.7.1.18 Test Separator heat exchanger shall be shell and tube type.
- 2.7.1.19 PETROBRAS highlights that in scaling and salt precipitation, including CaCO<sub>3</sub>, BaSO<sub>4</sub>, SrSO<sub>4</sub>, or NaCl, will have varying potential as oil, water and gas production progresses, and can occur even at very low water cuts. Facilities to bypass and to clean critical equipment and instrumentation on the oil processing plant shall be provided.
- 2.7.1.20 Optimizations on the Process described in items 2.7.1 and 2.7.3 or different solutions can be submitted to PETROBRAS approval. The same final specifications shall be met.
- 2.7.1.21 The Figure 2.7.1.21 present simplified proposed flow diagram of the Oil Processing scheme.

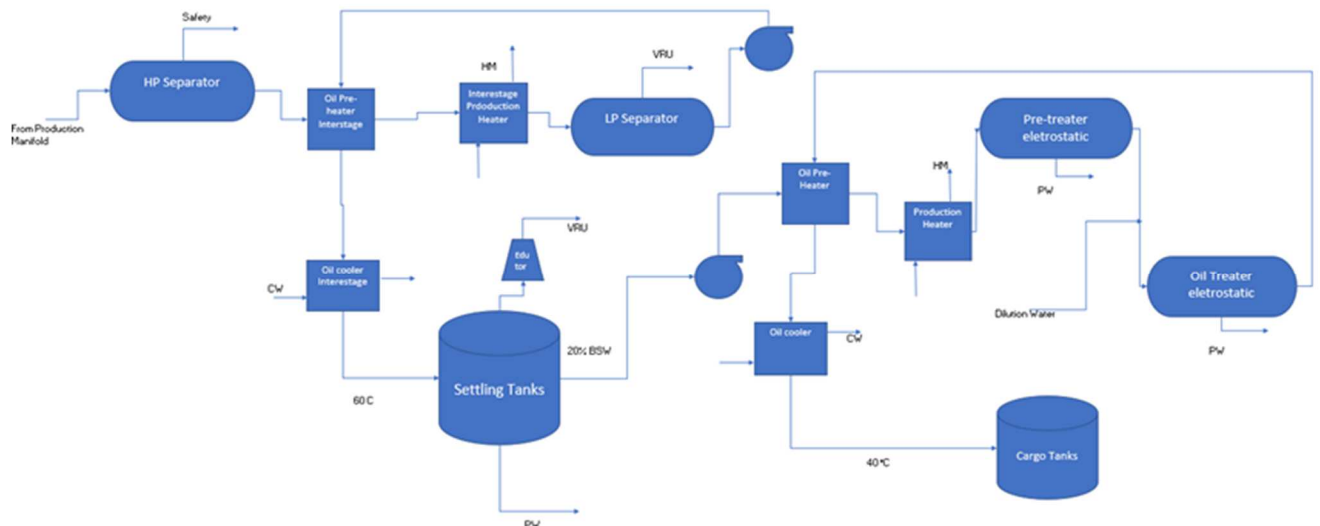


Figure 2.7.1.21 – Oil Processing Scheme

- 2.7.1.22 The Settling Tank shall be designed as following:
- 2.7.1.22.1 The process simulations shall consider maximum of 20% of water cut outlet of settling tank and minimum retention time of 08 hours based on liquid flow rate

- 2.7.1.22.2 To design settling tanks, the CONTRACTOR shall guarantee the minimum retention time of 08 hours based on total liquid capacity
- 2.7.1.22.3 The configuration of the settling tank is 2 x 100%. Each tank contains three compartments or caissons; one large tank where separation takes place and two collection sections (caissons) for the crude oil and produced water
- 2.7.1.22.4 The tank pressure control shall be done by an eductor, compressor or similar device. If the eductor (or similar device) fails, the pressure control shall be done by a HV vent valve (or similar device). The Settling Separator shall be protected against overpressure and underpressure by means of P/V breakers.
- 2.7.1.22.5 Liquids from the LP Separator shall be introduced below the oil/water interface level in order to maximize the fluids separation., (location to be defined by Contractor) and shall be distributed evenly via a sparged pipe type inlet device.
- 2.7.1.22.6 Additional internals could be included if necessary to guarantee separation requirements. It shall be considered the installation of minimum necessary internals to promote oil and water separation and mitigate movements of ship that could disturb both separation and withdrawal of separated fluids (oil and water) from tanks. The performance of the tank is influenced by many variables, some are as follows:
- Residence time of each phase (short-circuits and stagnation zones must be avoided);
  - Drag over the dispersed phases (high velocities of continuous phase must be avoided);
  - Temperature (defined);
  - Sloshing (outlets location must guarantee the suction of the correct phase);
  - Interfacial physical-chemical properties (defined). Additionally, the water outlet position must take into account for sedimented solids at the tank bottom.
- It is recommended one CFD (Computational Fluid Dynamics) study of good distributor design and optimization of its location (items (i) and (ii)) and optimization of outlets location checked against sloshing (iv)).
- The production water pump suction shall be at minimum 1(one) meter above of the bottom of tank
- 2.7.1.22.7 Liquid inlet in settling tank shall guarantee no disturbance in oil\_water interface and a good distribution for oil and water separation. The sparged pipe shall have a minimum length, to limit support requirements. To ensure even distribution, the pipe shall be designed with holes taking the bulk of the total pressure drop over the inlet device; the maximum allowable pressure drop shall be 0.2 bar.
- 2.7.1.22.8 Any settling tanks fluids operations (transfers, crude oil washing (COW), sea water washing (SWW) and stripping), shall not be performed through pump room.



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2.7.1.22.9 The submerged crude oil pump shall be located in the crude oil compartment/caissons, inside the settling tank. The oil compartments shall have the following connections for the various modes of operation:

- Crude Oil Overflow
- Crude Oil Underflow
- Vapour Outlet
- Stripping
- Submersible Pump (crude outlet)
- Standpipes connections for level measurement
- Breather valve return

2.7.1.22.10 The base of this compartment/caisson shall be defined by CONTRACTOR during design phase, based on the selected liquid levels (interface, oil/water)

2.7.1.22.11 The submerged produced water pump shall be located in the produced water compartment/caisson. The following connections shall be provided on produced water compartment for various modes of operation:

- Produced water underflow
- Vapour Outlet
- Stripping
- Submersible Pump (produced water outlet)
- Standpipes connections for level measurement
- Breather valve return

2.7.1.22.12 The underflow shall be located at the bottom of the produced water compartment/caisson and shall be located above the bottom of the compartment to avoid potential sand build up in the compartment

2.7.1.22.13 Compartment/caisson for oil and water installation shall be provided with facilities to allow pumps maintenance with no impact in operation. For pump maintenance no man entry is required in the crude oil/produced water compartments considering that the pump shall be pulled out of it. Contractor shall evaluate the necessity of cleaning the pump system prior of removal for maintenance/replacement. Single valve isolation between the underflow connection of the pump oil compartment/Caisson with the Settling Tank is acceptable. Compartment/caisson shall have means to allow inspection from the outside according to class requirements. Furthermore, the compartment shall not be attached to a bulkhead so it can be inspected from the outside.

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2.7.1.22.14 Minimum of 2 settlings tanks shall be considered. Those tanks shall not be adjacent or shall have a cofferdam between each other in order to not have a common bulkhead. Only one tank is inspected at the time, in order to not stop the production. At least double valve isolation is provided on the cross connections between the two tanks, for safety reason. Furthermore, it shall be possible to operate a pump in one compartment/tank while the other tank is under inspection.

2.7.1.22.15 All tanks and compartments are connected to one main vent header. Therefore, the tanks are communicating through the overflow and underflow connections . Due to gas flashing off from the liquids in the separator, pressure control is required to prevent overpressure. A back up protection shall be provided (e.g. HV vent). This vent shall also be used during start up when the tank shall be liquid filled and displaces the inert gas, start-up operation shall not be done by eductor. It is recommended to use the vent instead of the eductor to prevent inert gas in the VRU compressor.

2.7.1.22.16 The Settling Separator is a Cargo Tank converted into a process equipment. However, it still contains the required connections as for a cargo tank, which are:

- Stripping Connection
- Inert gas connections
- Crude Oil Washing (COW) machines.

2.7.1.22.17 As per the other Cargo Tanks the settling separator tank shall be provided with a Crude Oil Washing system. The fuel gas back-up (utility) shall be used if the level in the settling separator drops and the eductor (or similar device) is not able to control the pressure. For the compartments/caisson Contractor shall evaluate the wash/cleaning system to be provided. As per the other Cargo Tanks the settling separator tank shall be provided with inert gas connections; 1 supply line and 1 return line for each tank

2.7.1.22.18 Contractor shall evaluate at design phase the tank and caisson level control system to be used in order to not stop the production

2.7.1.22.19 The Settling Tank shall be designed as following:

- Settling Tank Vent to handle blow-by to Settling Tank.
- Settling tank pressure control shall consider eductor/compressor, FG for low press, BDV of independent Vent, PVSV of tank Vent and as back up IG connection for starting up / maintenance. Normally isolated
- The settling tank Vent shall be designed to handle gas blow-by from LP Separator.
- The settling tank Vent (including PV Breaker) shall be independent and dedicated vent to safety location.

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2.7.1.22.20 Contractor may propose different solutions, however, shall be subjected to PETROBRAS approval at his sole discretion.

## 2.7.2 OIL TRANSFER SYSTEM

2.7.2.1 For Oil Transfer System, see item 16.3.

## 2.7.3 GAS PROCESS PLANT

### 2.7.3.1 OBJECTIVES

2.7.3.1.1 The gas shall be gathered, treated and compressed, to comply with main applications:

- fuel gas;
- lift gas for the producing wells.
- Exported gas

2.7.3.1.2 A CO<sub>2</sub>/H<sub>2</sub>S removal unit using Amine is required for treatment of the gas to be consumed as fuel gas, gas lift and exported.

2.7.3.1.3 CONTRACTOR shall install online Chromatographic Analysis for hydrocarbon (up to C<sub>6</sub>+), CO<sub>2</sub> and N<sub>2</sub> to the following streams, as a minimum:

- HP and LP Separators gas outlet (also H<sub>2</sub>S content shall be determined);
- Settling Tank gas outlet (also H<sub>2</sub>S content shall be determined)
- Test Separator gas outlet for well test (also H<sub>2</sub>S content shall be determined);
- inlet Vapour Recovery Unit compressor;
- Inlet Main compressor system;
- CO<sub>2</sub>/H<sub>2</sub>S Removal Unit inlet and outlet (also H<sub>2</sub>S content shall be determined);
- Downstream Exportation Compressor (Exported gas and Gas Lift header);
- Fuel gas
- Gas to HP and LP flare tips (automatic vacuum sampler shall be provided);
- Sour gas Vent (also H<sub>2</sub>S content shall be determined);
- Imported gas.

### 2.7.3.2 DESIGN CASES

2.7.3.2.1 See item 2.2.2.

2.7.3.3 PROCESS CONFIGURATION – BASE CASE

2.7.3.3.1 The gas treatment plant shall consist of different units, in order to attain the contaminants removal, according to Figure 2.7.3.3.1.

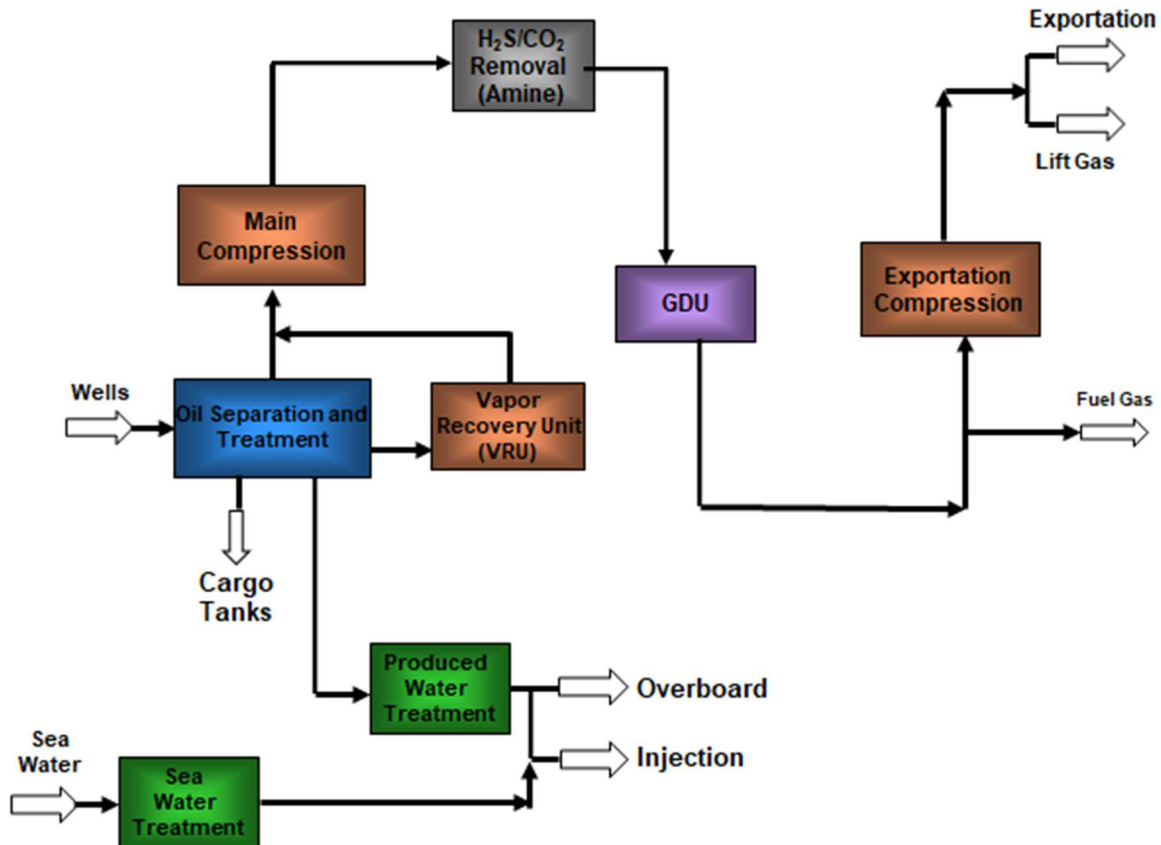


Figure 2.7.3.3.1 – Gas Treatment Plant

2.7.3.4 DEHYDRATION UNIT

2.7.3.4.1 The Gas Dehydration Unit shall be designed as following:

- Inlet gas specification = 2400 ppmv H<sub>2</sub>O;
- Inlet gas H<sub>2</sub>S content = 60 ppmv;
- Outlet gas specification = 40 ppmv H<sub>2</sub>O.

2.7.3.4.2 Two technology options are acceptable for the Dehydration Unit, according to the following:

2.7.3.4.2.1 MOLECULAR SIEVES UNIT

2.7.3.4.2.1.1 A standby vessel is required allowing bed replacement during normal operation.

- 2.7.3.4.2.1.2 The Molecular Sieve shall not adsorb H<sub>2</sub>S. The Molecular Sieve shall be resistant to the expected CO<sub>2</sub> concentrations.
- 2.7.3.4.2.1.3 All molecular sieves manufacturer recommendations shall be followed, including design parameters, monitoring instruments, subsystems and facilities for bed discharge and replacement. For Molecular Sieve design and specification purposes, maximum H<sub>2</sub>S content shall be considered and heat and mass balance for the unit shall include the maximum concentration on regeneration gas and recirculating H<sub>2</sub>S destiny after regeneration cycle.
- 2.7.3.4.2.1.4 A scrubber (1x100%) and a coalescer filter (2x100%) upstream the Molecular Sieve Unit shall be installed to avoid liquid carry over. A combined scrubber/filter configuration is acceptable. In this case a stand-by set (scrubber/filter) shall be considered (2x100%). The coalescer filter shall comply with the minimum following performance:
- Removal of 99% of solids with particle size higher than 1 µm;
  - Removal of 99% of liquid droplets with diameter higher than 0.3 µm;
  - The liquid allowed in the outlet gas shall be maximum of 5 ppm weight;
  - The maximum  $\Delta P$  allowed shall be 0.1 bar (clean) and 0.5 bar (dirty).
- 2.7.3.4.2.1.5 Layout and piping arrangement of the unit shall minimize risk of liquid condensation downstream coalescer filter, by avoiding liquid pocket points, using thermal insulation, minimizing piping length and height difference. A heater shall be installed upstream the molecular sieve unit, in order to guarantee superheating of at least 5°C and avoid condensation in the molecular sieve bed. The heater shall be downstream the coalescer filter. Inlet piping upstream the adsorbent beds, that have no flow during regeneration cycle, shall have electric tracer to avoid liquid condensation due to heat exchange with the external environment.
- 2.7.3.4.2.1.6 The scrubber design shall take in consideration:
- Three individual separation stages to ensure the required gas-liquid separation:
    - Inlet device to receive the incoming process stream and evenly distribute the flow to improve gravitational liquid separation in the vessel inlet zone;
    - Mesh or Vane device to separate large liquid droplets and drain them without re-entrainment;
    - Demisting cyclones to ensure high efficiency of droplet removal;
  - The maximum condensate liquid simulated increased by the condensate volume that corresponds to 5% of gas mass flow.
- 2.7.3.4.2.1.7 The molecular sieves regeneration gas shall be indirectly heated (electrical or hot water). Thermal oil fluid and directly heating by turbine exhaust gases will not be allowed. A stand-by heater shall be provided ready to operate.

2.7.3.4.2.1.8 For electrical requirements for heating systems, see item 2.7.3.4.3. Additionally, for electrical heating systems applied to Molecular Sieves Unit, the following requirements shall be complied with:

- Electrical heater bundle (resistance) shall be fully redundant and arranged in independent and separated gas heater vessels in order to allow maintenance and replacement of bundles in a way not to impact heating system availability. Disconnecting switch or circuit breakers shall be provided for quick change over of bundles.
- The method for sheath element to tubesheet joint of electrical heater bundle, shall be by means of a strength weld. Sheath's elements shall be directly connected to the tubesheet and to the power terminal box. The use of offset sleeves or standpipe is not acceptable. Sheath element shall be supplied in seamless incoloy 800H or inconel 625 grade 2.

2.7.3.4.2.1.9 A proper outlet gas filter (2x100%) shall be provided in the Molecular Sieves Unit to avoid fine particles carry-over to downstream units and to the regeneration gas system. CONTRACTOR to evaluate potential of hydrate formation on condensate/liquid return lines of the scrubber and coalescer filter and forecast a mitigation solution, such as a condensate heater, if required.

2.7.3.4.2.1.10 For the regeneration gas recycle, a specific blower may be used (2x100%). In this case, blowers shall comply with API Std 617 and API 692. If CONTRACTOR decides to send regeneration gas back to Main Compressor, this machine capacity shall be increased to accommodate this additional flow.

2.7.3.4.2.1.11 CONTRACTOR shall provide means of isolating and depressurizing each vessel, so that they can be operated separately, enabling bed exchange operation, without stopping the system. Bed pressurization and programmed shutdown depressurization rates shall be limited to a maximum of 3 bar/min or supplier requirement rate, whichever is lower. Vessels Emergency depressurization shall be downward flow.

2.7.3.4.2.1.12 CONTRACTOR shall install equalization valve to allow pressurization of each bed at the recommended rate, as well as individual pressure gauge, with reading in the supervisory, to monitor the pressurization and depressurization rates of each bed.

2.7.3.4.2.1.13 CONTRACTOR shall design unit considering procedure for change out of molecular sieve bed, including support structure for the new and spent molecular sieves, facilities to remove solids from the vessel, required purge gas (N<sub>2</sub>), among others. A material handling plan shall be provided evidencing that the arrangement of the process plant equipment complies with the requirements above. CONTRACTOR shall, during project execution phase, detail the procedure for solids bed replacement. A dump to flare valve shall be provided downstream the unit.

2.7.3.4.2.1.14 CONTRACTOR shall consider the following requirements regarding each molecular sieve vessel bed support, as minimum:

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- Ceramic spheres to support molecular sieve bed;
- Mesh screen above the ceramic spheres.

NOTE 1: CONTRACTOR shall design the vessels with insulation.

NOTE 2: CONTRACTOR shall consider that all gaskets materials be suitable for high temperature.

NOTE 3: Any different solution shall be presented to PETROBRAS during project execution phase.

2.7.3.4.2.1.15 CONTRACTOR shall install proper online instrumentation and analysis devices to determine H<sub>2</sub>O content in the outlet gas stream downstream of the gas outlet filter.

2.7.3.4.2.1.16 The analyzer shall be adjusted to execute gas water content validation by internal permeation tube (at least weekly checked) without the need of manual water make up in the tube.

2.7.3.4.2.1.17 CONTRACTOR to provide calibration of gas water content analyzer according to supplier recommendation or when it occurs some divergence during periodical check.

2.7.3.4.2.1.18 For acceptable vendor list for Moisture Analyzer, see item 19.1.1.3.

2.7.3.4.2.1.19 For Acceptable vendor list for Molecular Sieve Solid Bed (Zeolite), see item 19.1.1.2.

#### 2.7.3.4.2.2 TRIETHYLENE GLYCOL (TEG) UNIT

2.7.3.4.2.2.1 The gas dehydration unit by TEG absorption shall be designed to a maximum inlet gas operational temperature of 40°C. CONTRACTOR shall ensure this temperature as the maximum one and may consider design alternatives to achieve lower inlet gas temperatures. Only shell and tube heat exchangers are acceptable for TEG Unit inlet gas.

2.7.3.4.2.2.2 A scrubber (1 x 100%) and a coalescer filter (2 x 100%) upstream the TEG Unit shall be installed to avoid liquid carry over. A combined scrubber/filter configuration is acceptable. In this case a stand-by set (scrubber/filter) shall be considered (2 x 100%). The coalescer filter shall comply with the minimum following performance:

- Removal of 99% of solids with particle size higher than 1 µm;
- Removal of 99% of liquid droplets with diameter higher than 0.3 µm;
- The liquid allowed in the outlet gas shall be maximum of 5 ppm weight;
- The maximum  $\Delta P$  allowed shall be 0.1 bar (clean) and 0.5 bar (dirty).

2.7.3.4.2.2.3 Layout and piping arrangement of the unit shall minimize risk of liquid condensation downstream coalescer filter, by avoiding liquid pocket points, using thermal insulation, minimizing piping length and height difference.

CONTRACTOR shall provide an additional gas-liquid separation step, built into the bottom of the TEG absorber column. This does not exclude the external scrubber + coalescer filters upstream TEG Absorber.

2.7.3.4.2.2.4 The scrubber design shall consider:

- Minimum three different gas-liquid separation zones/devices:
  - Inlet device to receive the incoming process stream and evenly distribute the flow to improve gravitational liquid separation in the vessel inlet zone;
  - Mesh or Vane device to separate large liquid droplets and drain them without re-entrainment;
  - Demisting cyclones to ensure high efficiency of droplet removal.
- Range of operational flowrate shall be from 15% to 100% of nominal design gas flow;
- The maximum condensate liquid simulated increased by the condensate volume that corresponds to 5% of gas mass flow;
- Minimum removal of 99.5% of liquid droplets with diameter higher than 10 µm.

2.7.3.4.2.2.5 CONTRACTOR shall provide two level meters for the scrubber and two for each section of the coalescer filter. In each vessel, CONTRACTOR shall adopt two different technologies for the level meters and one of them will be used for controlling purpose. The measurements shall be displayed on the supervisory system of the Unit. In addition, a field level gauge shall be provided for each vessel.

2.7.3.4.2.2.6 CONTRACTOR to evaluate potential of hydrate formation on condensate/liquid return lines of the scrubber and coalescer filter and forecast a mitigation solution, if required.

2.7.3.4.2.2.7 TEG Unit shall meet the following specification:

- TEG Unit range of operational flowrate: from 15% to 100% of nominal design gas flow;
- Lean TEG specification: minimum 99.95% (mass %);
- Rich TEG specification: minimum 95% (mass %).

2.7.3.4.2.2.8 TEG absorber column shall be fitted with proper packing and liquid distributor in order to achieve a high efficiency. Means for minimizing TEG carry over shall also be provided in the form of column internals or a separate K.O. drum. Pressure Differential Transmitters shall be provided to monitor differential pressure across the packing.

2.7.3.4.2.2.9 Temperature of lean TEG entering the top of the absorber shall be controlled at 5°C higher than inlet gas temperature.

2.7.3.4.2.2.10 A by-pass around the absorber column shall be provided for lean TEG as to allow startup of the unit.



- 2.7.3.4.2.2.11 It shall consider 10°C of approach between the desired water dewpoint and equilibrium theoretical water dewpoint to design the number of equilibrium stages of absorber tower.
- 2.7.3.4.2.2.12 TEG Flash drum shall be designed considering 20 minutes of residence time for Rich TEG.
- 2.7.3.4.2.2.13 2x100% cartridge filters shall be provided for 100% of rich TEG flow. Activated carbon filter and a secondary cartridge filter, with a by-pass, shall be provided for 20% of rich TEG flow.
- 2.7.3.4.2.2.14 A flow meter shall be provided to deviated rich TEG flow.
- 2.7.3.4.2.2.15 TEG circulation pump shall meet the following specifications:
- Configuration: N+1 (one stand-by);
  - Reciprocating pump diaphragm type;
  - Pumps shall be designed according to API 674 or 675;
  - PSV shall return to surge vessel;
  - Pulsation damper in discharge pump is required;
  - Flow control with Variable Speed Driver (VSD);
  - Glycol flow rate: minimum 1m<sup>3</sup>/h/m<sup>2</sup> of dehydration column area section to ensure sufficient wetting of the structure packing.
- 2.7.3.4.2.2.16 A Coriolis flow meter shall be provided to measure the lean TEG flow. This equipment shall be installed as close as possible the absorber, downstream of any by-pass line to measure the TEG flow through the absorber.
- 2.7.3.4.2.2.17 The Reboiler shall operate as close as possible to atmospheric pressure. The backpressure shall not exceed 0.2 barg.
- 2.7.3.4.2.2.18 Flash vapor from Flash drum and Exhaust gas from still column shall be sent to VRU, using a boosting device if necessary. In case the streams are routed directly to Flare Gas Recovery System, the flowrate shall be added to flowrate defined on Item 2.7.5.9.5.
- 2.7.3.4.2.2.19 For TEG design and material specification purposes, maximum H<sub>2</sub>S content shall be considered and heat and mass balance for the unit shall include concentration on regeneration gas and recirculating H<sub>2</sub>S destiny.
- 2.7.3.4.2.2.20 Chemical injection skid(s) for pH control and antifoaming shall be provided.
- 2.7.3.4.2.2.21 For electrical requirements for heating systems, see item 2.7.3.4.3. Additionally, for electrical heating systems applied to TEG Unit, the following requirements shall be complied with:
- Electrical heater shall be fully redundant (N+1, with one standby unit) to allow maintenance and replacement of heater in a way to not impact heating



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system availability and to not lead to any production loss. Disconnecting switch or circuit breakers shall be provided for quick change over of bundles.

- The maximum heat flux to be considered for electrical heating design shall be 1.25 W/cm<sup>2</sup> and the maximum skin temperature shall not exceed 230°C.
- The Reboiler shall control the glycol temperature in 204°C.

- 2.7.3.4.2.22 CONTRACTOR shall provide a secondary stripping gas injection system in the bottom of the reboiler. Automated gas stripping flow control shall be provided using Cone flowmeter.
- 2.7.3.4.2.23 CONTRACTOR shall provide Stahl Column with a main stripping gas injection system, containing a minimum of 3 equilibrium stages, at a lower level than the reboiler. Automated gas stripping flow control shall be provided using Cone flowmeter.
- 2.7.3.4.2.24 Surge Vessel shall be designed to store the entire TEG inventory during maintenance shutdowns.
- 2.7.3.4.2.25 Sampling points shall be provided in accordance with item 2.9.
- 2.7.3.4.2.26 CONTRACTOR shall install proper online instrumentation and analysis devices to determine H<sub>2</sub>O content in the gas dehydration outlet stream. Analyzer shall be installed downstream of absorber.
- 2.7.3.4.2.27 The analyzer shall be adjusted to execute gas water content validation by internal permeation tube (at least weekly checked) without the need of manual water make up in the tube.
- 2.7.3.4.2.28 CONTRACTOR to provide calibration of gas water content analyzer according to supplier recommendation or when it occurs some divergence during periodical check.
- 2.7.3.4.2.29 At any time, analyzer measurement will be compared to most recent version of GPSA Equilibrium Chart "Equilibrium H<sub>2</sub>O Dew point vs. Temperature at Various TEG Concentrations". These results will be used to mediate divergences about measured values. CONTRACTOR shall consider McKetta Method (GPSA chart: "Water Content of Hydrocarbon Gas") to convert equilibrium dew point to lb/MMscf.
- 2.7.3.4.2.30 At any time, PETROBRAS can ask gas water content analyses by manual chilled mirror according to ASTM D-1142 to mediate divergences about measured values. CONTRACTOR shall consider "GPSA + Wichert (acid gases correction)" to convert equilibrium dew point to lb/MMscf.
- 2.7.3.4.2.31 The off-spec treated gas shall be deviated to flare, through a pressure control valve, installed downstream TEG Contactor.
- 2.7.3.4.2.32 For acceptable vendor list for Moisture Analyzer, see item 19.1.1.3.

#### 2.7.3.4.2.2.33 Minimum Requirements for TEG Units Suppliers:

- Proven experience on offshore TEG units design with 6 MM Sm<sup>3</sup>/d gas capacity;
- Proven experience on onshore or offshore TEG units design to dehydrate the gas with minimum 30% mol CO<sub>2</sub> content. These units shall be in operation.

#### 2.7.3.4.3 ELECTRICAL REQUIREMENTS FOR HEATING SYSTEMS:

2.7.3.4.3.1 If electrical heating is used, the electrical heater panel shall be powered by 2x100% transformers from different panels to assure high reliability:

- Redundant feeding transformers, each one capable of supplying 100% load.
- Transformers shall be suitable for low power factor and high harmonic content.

2.7.3.4.3.2 Silicon Controlled Rectifiers (SCRs) shall have (n+1) configuration, with one standby unit.

2.7.3.4.3.3 At least one spare resistance bundle shall be available for prompt replacement of faulty resistance bundle. In warehouse where stored, the resistive bundle set will have low insulation if not well preserved. It shall be kept heated and housed in moisture-free environments.

2.7.3.4.3.4 It shall be considered a 10% additional margin in the maximum estimated heating demand;

2.7.3.4.3.5 All resistance systems shall be of encapsulated type to assure better isolation from environmental moisture and longer life expectancy.

2.7.3.4.3.6 For electrical heating panels, the following requirements apply:

2.7.3.4.3.6.1 The Power Panel shall contain thyristors suitable for the requested power, the thyristors control system and all necessary components for the temperature control.

2.7.3.4.3.6.2 In order to modulate the semiconductors conduction time, Thyristors control system shall receive an external set point signal.

2.7.3.4.3.6.3 The Thyristors triggering shall be controlled in such way to synchronize this triggering to the instant the sine wave has a zero value, avoiding undesirable transients in the electrical system.

2.7.3.4.3.6.4 Harmonic content shall be kept within IEEE Std. 519 and on IEC 61892-1 limits. For Power Panel, the control system shall automatically bypass/skip and do the compensation for an out of service stage.

2.7.3.4.3.6.5 In order to make easy the installation and maintenance, the control system shall be constructed in a modular way.



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- 2.7.3.4.3.6.6 A prompt replacement of the damaged module shall assure the non-interruption of the equipment operation.
- 2.7.3.4.3.6.7 Power Panel shall be fitted with a double cooling system with automatic changeover and alarm, so that in case of failure of a set, the remaining units shall be enough to permit the panel operation without restrictions.
- 2.7.3.4.3.6.8 All external control (ON/OFF) and set point signals (that may be 4~20 mA) shall be received from Control Panel, besides any other interface defined by Packager and from Automation and Control (A&C), according to interface requirements.
- 2.7.3.4.3.6.9 The Power Panel shall be controlled by its respective control package unit.
- 2.7.3.4.3.6.10 Communication shall be according to unit Packager Standard.
- 2.7.3.4.3.6.11 The Power Panel shall have local visual alarms for internal malfunction and shutdown. Resume alarm signals shall be sent to Control Panel according to Packager standard. All signals from the Package to A&C shall be sent by Control Panel.
- 2.7.3.4.3.6.12 The communication standard (network or hardwired) between Power Panel and Control Panel shall be defined by Packager.
- 2.7.3.4.3.6.13 Emergency shutdown signals from A&C shall be sent to Control Panel that shall be responsible to turn off the Power Panel.
- 2.7.3.4.3.6.14 For each Regeneration gas heater shall be provided a self-standing Heater control panel. The location of these panels shall be in the electrical room in safe area. These panels shall be responsible for control and safeguarding of the heaters.
- 2.7.3.4.3.6.15 In order to control the temperature of the heater the control panels will receive a 0-100% reference signal from the unit control panel. The safeguarding system of the Heater control panel will protect the heater from overheating and secures the vessel temperature in order to comply with the temperature class.
- 2.7.3.4.3.6.16 The power terminal boxes shall be fitted with sunshades, with anti-condensation heaters (fed from external 220Vac 2phases ungrounded) controlled by thermostats and with thermal cutouts to guarantee that the limit of the temperature class T3 will not be exceeded. The construction of power terminal box shall comply with IEC 60079. The power terminal box shall have type protection Ex e in accordance with IEC 60079-7.
- 2.7.3.4.3.6.17 The power terminal boxes shall be fitted with gas detection system.

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2.7.3.7 .VAPOR RECOVERY UNIT (VRU)

2.7.3.7.1 The Vapor Recovery Units (VRU) shall be dry screw compressor type according to API 619.

2.7.3.7.2 Vapor Recovery Unit shall be supplied as complete package by the compressor Original Equipment Manufacturer (OEM). Package means main equipment train (dry screw(s) compressor(s) Gear Unit Variable Speed Drive (HVSD or VSD) and driver) and all auxiliaries equipment and components required for proper functioning of the gas compression service (accessories, control panels, machinery protection system, oil system, sealing system as minimum).

2.7.3.7.3 The shaft seals shall be of self-acting tandem dry gas seals (DGS) type with intermediate seal gas labyrinth as per API 692. For the VRUs the primary seal gas shall be fuel gas, or nitrogen in case of plant start up or commissioning.

2.7.3.7.4 The primary seal gas shall be sufficiently clean to avoid particulate and its temperature far from the dew point to avoid liquid condensation. Each compressor package shall include a seal gas treatment system for each compressor casing consisting, as a minimum, of a booster compressor to provide the required positive feed pressure to the seals on any operating/stop condition, one dedicated scrubber (upstream to the duplex coalescent filters), one separator/coalescer duplex filter and either one electric heater with spare heater element installed or, alternatively, a duplex electric heater. Seal gas system shall be supplied by the DGS manufacturer. The requirement for a seal gas booster can be disregarded for the VRU compressor package if an alternate seal gas supply is provided in accordance with the following:

2.7.3.7.4.1 Alternate seal gas supply shall be immediately available and used as a backup in standby mode whenever main seal gas source is not available. CONTRACTOR may also submit an alternative primary gas supply for fuel gas during normal operation, when necessary, taken from downstream of dehydration unit.

2.7.3.7.4.2 The nitrogen supply capacity shall be defined for VRU seal system considering all compressor cases including commissioning, startups, normal stops, emergency shutdowns and lube oil running conditions, if any, CONTRACTOR is required to demonstrate;

2.7.3.7.4.3 Alternate seal gas supply shall be also conditioned by seal gas treatment system.

2.7.3.7.4.4 Undersized Seal Treatment Gas system, including DGS, or unproven designs or prototypes (including parts) with no previous service on offshore installations are not acceptable: A minimum of 25.000 hours continuous operation under similar operating conditions shall be demonstrated for, at least, 4 machines of the same model and same size to meet data sheet operating conditions required;

- 2.7.3.7.4.5 Alternate seal gas supply shall maintain the minimum sealing gas conditions required by DGS Manufacturer and API Std. 692, 20°C higher than the dew point line (see Figure B.1 – Annex B), during all normal and alternate operating conditions, including compressor and/or process plant commissioning, startups, normal stops, emergency shutdowns and other transient conditions (CONTRACTOR is required to demonstrate);
- 2.7.3.7.4.6 Main/alternate seal gas systems changeover shall be automatic, performed or commanded by compressor PLC. Actual running system status signals shall be sent from compressor PLC to plant control system.
- 2.7.3.7.5 O-rings and any other polymer-based sealing element in contact with process gas shall be strongly resistant to explosive decompression taking into account a large number of compressor starts/stops.
- 2.7.3.7.6 Nitrogen as the secondary seal gas shall be injected in the intermediate labyrinth seal. The separation seal gas shall be also nitrogen.
- 2.7.3.7.7 A stand-by unit installed is required (2x100%). CONTRACTOR shall consider “unit” as compressor machine, scrubber, coolers, etc.
- 2.7.3.7.8 VRU capacity shall be defined by CONTRACTOR, in accordance with all design cases simulations and it shall consider all recycles.
- 2.7.3.7.9 Capacity of VRU 1st and 2nd Stages shall be defined based on process simulation output plus a design margin of 20%. Nevertheless, the capacity of the 1st Stage shall not be lower than 410,000 Sm<sup>3</sup>/d and the capacity of the 2nd stage shall not be lower than 380,000 Sm<sup>3</sup>/d.
- 2.7.3.7.10 The compressor shall be designed for continuous operation at any flow rate between zero and 100% of the design capacity.
- 2.7.3.7.11 The driver shall be electric motor. The capacity control may be performed by recycling and/or HVSD (Hydraulic Variable Speed Drive) or VSD (Variable Frequency Drivers).
- 2.7.3.7.12 For acceptable vendor list for Rotary Compressor for Vapor Recovery Unit API 619, see item 19.1.1.5.
- 2.7.3.8 CENTRIFUGAL GAS COMPRESSORS**
- 2.7.3.8.1 All centrifugal gas compressors shall be designed according to API 617.
- 2.7.3.8.2 Centrifugal Gas Compressor shall be supplied as complete package by the compressor OEM. Package means main equipment train (centrifugal(s) compressor(s) Gear Unit/Variable Speed Driver (HVSD or VSD) and driver) and all auxiliaries equipment and components required for proper functioning of the gas compression service (accessories, anti-surge valve, control panels, machinery protection system, oil system, seal system as minimum).



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- 2.7.3.8.3 The shaft seals shall be of self-acting tandem dry gas seals (DGS) type with intermediate seal gas labyrinth as per API 692.
- 2.7.3.8.4 For the Centrifugal Gas compressors, the primary seal gas shall be treated and conditioned from compressor discharge process gas or fuel gas.
- 2.7.3.8.5 The primary seal gas shall be sufficiently clean to avoid particulate and its temperature far from the dew point to avoid liquid condensation. Each compressor package shall include a seal gas treatment system for each compressor barrel consisting, as a minimum, of a booster compressor to provide the required positive feed pressure to the seals on any operating/stop condition, one separator/coalescer duplex filter and either one electric heater with spare heater element installed or, alternatively, a duplex electric heater. For Main Compressors, one dedicated scrubber shall also be included in the seal gas treatment system, upstream to the duplex coalescent filters. Seal gas system shall be supplied by the DGS manufacturer and according to API 692.
- 2.7.3.8.6 O-rings and any other polymer-based sealing element in contact with process gas shall be strongly resistant to explosive decompression taking into account a large number of compressor starts/stops.
- 2.7.3.8.7 Nitrogen as the secondary seal gas shall be injected in the intermediate labyrinth seal. The separation seal gas shall be also nitrogen.
- 2.7.3.8.8 The condensate from inlet, inter-stage and final compressor stage collected on the scrubber vessels shall be routed to the oil plant or to upstream gas scrubbers. They shall not be sent to slop or drain system.
- 2.7.3.8.9 The compressors shall be designed for continuous operation from full recycle to full capacity (0 to 100%), considering all the design cases.
- 2.7.3.8.10 Recycle system for anti-surge control shall be "hot recycle", meaning that there is no cooler or scrubber vessel installed in between the compressor discharge and the related recycle valve. CONTRACTOR shall consider one antisurge recycle line for each stage. Overall recycle line shall not be accepted. Additionally, CONTRACTOR should also provide cooled recycle, nevertheless a hot recycle in a secondary recycle line shall be provided.
- 2.7.3.8.11 An electronic decoupling algorithm (decoupling control) shall be used to avoid interaction between anti surge control and performance/load sharing control for each compressor package service. A similar control strategy shall be designed in order to avoid trip from different service compressor.
- 2.7.3.8.12 Capacity control, load sharing and anti-surge system shall be implemented on dedicated hardware. This hardware shall be designed exclusively for the aforementioned functions and shall not be used for any other purposes (such as protection). All control data shall be available to PETROBRAS (read access).

- 2.7.3.8.13 Each compressor package shall include a dedicated lube oil system (in accordance with the applicable requirements of API 614 for special purpose applications).
- 2.7.3.8.14 Each compressor package shall include a dedicated and control process panel (in accordance with the applicable requirements of API 670). Machinery Protection System (MPS) shall be also in accordance with API 670.
- 2.7.3.8.15 Extraction/injection gas stream from/into a compressor casing (except for sealing or balance line) or between two compressor casings of one train are not acceptable.
- 2.7.3.8.16 CONTRACTOR shall design the compressor package considering pressurized shutdowns. The design of all equipment in the compressor service, including the auxiliaries (e.g. seal gas system) and static equipment (e.g. vessels), shall be suitable to compressor Settle Out Pressure (SOP).
- 2.7.3.8.17 CONTRACTOR shall consider the molecular weight range corresponding to all design cases.
- 2.7.3.8.18 CONTRACTOR shall perform a stability test at compressor manufacturer shop for any compressor which fails to meet the minimum log decrement of 0.2 during the analysis. These tests shall be witnessed by PETROBRAS. During these tests, shop driver may be used.
- 2.7.3.8.19 Each compression stage shall have a compressor suction scrubber. The suction scrubber of the 1st compression stage shall be different from the Safety K.O. Drum (described in item 2.7.3.8.20.2).
- 2.7.3.8.20 CONTRACTOR shall perform a full-pressure, full-load, full-speed test at compressor manufacturer shop for Gas Lift/Export compressors. This test shall be witnessed by PETROBRAS. The test procedures and the approval criteria shall demonstrate the Unit's performance and reliability. During execution phase, CONTRACTOR shall provide Lateral Analysis and Stability Analysis Reports as per API 617.
- 2.7.3.8.21 MAIN COMPRESSOR
- 2.7.3.8.21.1 The first step compressors shall be designed according to the following:
- inlet pressure = 710 kPa(a) (estimated, depends on previous pressure drop);
  - discharge pressure range = 5610 kPa(a) (estimated, determined by dehydration unit operating pressure), shall consider the molecular weight range corresponding to all design cases;
  - A stand-by unit is required as follows: 2x100% or 3x50% or 4x33%.
- 2.7.3.8.21.2 A Safety K.O. drum shall be installed upstream Main Compressor, in order to separate the condensate formed due to inlet gas cooling, as well as to avoid



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any liquid carried-over. This condensate shall be routed back to oil plant. Under no circumstances it shall be sent to the slop or drain system.

2.7.3.8.21.3 The Safety K.O. drum design shall take in consideration:

- Minimum three different gas-liquid separation zones/devices:
  - Inlet device to receive the incoming process stream and evenly distribute the flow to improve gravitational liquid separation in the vessel inlet zone;
  - Mesh or Vane device to separate large liquid droplets and drain them the liquid without re-entrainment;
  - Demisting cyclones to ensure high efficiency of droplet removal.
- The maximum condensate liquid simulated increased by the condensate volume that corresponds to 5% of gas mass flow.

#### 2.7.3.8.22 GAS LIFT/EXPORT COMPRESSORS

2.7.3.8.22.1 The second step compressors shall be designed according to the following:

- capacity and gas compositions = according to process simulations for all design cases and Operation Modes;
- inlet pressure = 4790 kPa(a) (estimated, to be confirmed);
- discharge pressure = up to 18800 kPa(a);
- Normal operating temperature downstream discharge cooler (due to riser limitation): 40°C;
- H<sub>2</sub>S content at least 5 ppmv, CO<sub>2</sub> content at least 1% according to CO<sub>2</sub>/H<sub>2</sub>S Removal Unit performance for all design cases and Operation Modes;
- A stand-by unit is required as follows 2x100% or 3x50% or 4x33%.

2.7.3.8.22.2 For Gas Lift/Export Compressors, the condensate from inlet, inter-stage and final coolers vessels shall be routed to oil plant or to previous gas scrubbers. It shall not be sent to slop or drain system.

2.7.3.8.22.3 Gas Lift extraction point shall be Gas Lift/Export Compressors.

#### 2.7.3.8.23 CENTRIFUGAL COMPRESSOR DRIVERS

2.7.3.8.23.1 Electric motors or gas turbines are acceptable as compressors drivers.

2.7.3.8.23.2 For speed variation with electric motor driver the solutions with hydraulic variable speed drive (HVSD) or variable frequency drive (VFD) are accepted. Dry Low Emission Turbines (DLE) are not accepted for aero-derivative gas turbine type.

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2.7.3.8.23.3 If Gas Turbine is selected as driver such turbine shall be dual fuel (gas and Diesel).

2.7.3.8.23.4 Gas turbine ISO Power shall be at least 33 % higher than compressor greatest power required (including gear and coupling losses) indicated in the supplier data sheet, considering fuel gas operation;

2.7.3.8.23.5 In case of Electric Motor driver, the available power shall be at least 12% higher than compressor greatest power required (including gear and coupling losses) indicated in the supplier data sheet.

2.7.3.8.24 For acceptable vendor list for Gas Compressor API 617 and Gas Turbines, see item 19.

### 2.7.3.9 OTHER REQUIREMENTS

2.7.3.9.1 Utilities (including power generation system) shall be designed considering at least the capacity of 6,000,000 Sm<sup>3</sup>/d representing the produced gas including lift gas, for the compression system, without considering internal recycles. All internal recycles from process plant shall be added to this flowrate to define the total compression capacity. The utilities shall be designed to allow one standby train start-up of any compression unit with no capacity reduction.

### 2.7.3.10 CO<sub>2</sub>/H<sub>2</sub>S REMOVAL UNIT

2.7.3.10.1 In order to reduce the CO<sub>2</sub> and H<sub>2</sub>S content on the associated gas, the UEP shall be equipped with a CO<sub>2</sub>/H<sub>2</sub>S Removal Unit based on amine absorption.

#### 2.7.3.10.2 DESIGN CASES

2.7.3.10.2.1 The CO<sub>2</sub>/H<sub>2</sub>S removal Unit shall consider the following design cases, in steady state condition:

- Max flow (6 MM Sm<sup>3</sup>/d, Inlet gas CO<sub>2</sub> content = 2% mol. Inlet gas H<sub>2</sub>S content = 350 ppmv. Any recirculation of gas streams shall be added to the gas flow rate.
- Min flow (700000 Sm<sup>3</sup>/d, Inlet gas CO<sub>2</sub> content = 1,5% mol to 2% mol. Inlet gas H<sub>2</sub>S content = 40 ppmv to 350 ppmv)

NOTE: CO<sub>2</sub>/H<sub>2</sub>S Removal Unit shall be able to operate with H<sub>2</sub>S content from 0 to 350 ppmv and CO<sub>2</sub> content from 0 to 2%.

2.7.3.10.2.2 During commissioning phase and startup of wells lower gas flowrate may occur.

#### 2.7.3.10.3 MINIMUM DESIGN PARAMETERS

2.7.3.10.3.1 The CO<sub>2</sub>/H<sub>2</sub>S Removal Unit shall be designed in accordance with API RP 945 – Avoiding Environmental Cracking in Amine Units.

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2.7.3.10.3.2 It shall be fed with gas from the common discharge header of the Main Compression Units..

2.7.3.10.3.3 A scrubber (1 x 100%) and a coalescer filter (2 x 100%) upstream the CO<sub>2</sub>/H<sub>2</sub>S Removal Unit shall be installed to avoid liquid carry over. A combined scrubber/filter configuration is acceptable. In this case a stand-by set (scrubber/filter) shall be considered (2 x 100%). The coalescer filter shall comply with the minimum following performance:

- Removal of 99% of solids with particle size higher than 1 µm;
- Removal of 99% of liquid droplets with diameter higher than 0.3 µm;
- The liquid allowed in the outlet gas shall be maximum of 5 ppm weight;
- The maximum ΔP allowed shall be 0.1 bar (clean) and 0.5 bar (dirty).

2.7.3.10.3.4 The scrubber vessel shall have at least three devices (three individual separation stages) to ensure the required gas-liquid separation:

- Inlet device to receive the incoming process stream and evenly distribute the flow to improve gravitational liquid separation in the vessel inlet zone;
- Mesh or Vane device to separate large liquid droplets, drain it without re-entrainment;
- Demisting cyclones to ensure high efficiency of droplet removal.

2.7.3.10.3.5 Layout and piping arrangement of the unit shall minimize risk of liquid condensation downstream coalescer filter, by avoiding liquid pocket points, using thermal insulation, minimizing piping length and height difference.

2.7.3.10.3.6 The coalescer filters shall have differential pressure transmitter (PDT).

2.7.3.10.3.7 The scrubber vessel and the coalescer filter shall have independent level control loops ( LIT, LIC and LV).

2.7.3.10.3.8 The level meters shall have at least three side connections to avoid measurement errors in case of two liquid phases.

2.7.3.10.3.9 The amine contactor(s) and amine stripper shall use packing. The liquid distributor shall be tubular type or similar. PDTs shall be installed around the packings.

2.7.3.10.3.10 The amine contactor (s) shall have a bucket to eventually separate condensed hydrocarbons.

2.7.3.10.3.11 It shall be provided an amine contactor(s) by-pass in order to allow the lean amine circulation during start-up.

2.7.3.10.3.12 It shall be provided a CO<sub>2</sub>/H<sub>2</sub>S Removal Unit total by-pass.

2.7.3.10.3.13 Temperature of lean amine entering the top of the amine contactor shall be controlled at 5°C higher than inlet gas temperature.

- 2.7.3.10.3.14 All heaters shall use hot water (as heating medium) or electrical resistors. In case of electrical resistors at reboiler heating system compliance to item 2.7.3.4.2.3 ELECTRICAL REQUIREMENTS FOR HEATING SYSTEMS is mandatory.
- 2.7.3.10.3.15 In case of venting the sour gas from the amine regeneration a dedicated vent shall be provided for this stream. The height and the location shall be based on dispersion calculation supported by CFD analysis. In case of vent trap installed, the drainage shall be sent to reflux drum. If no vent trap installed the line shall not have low points.
- 2.7.3.10.3.16 In case of flaring the sour gas, the minimum requirements shall be complied:
- Appropriate dispersion of SO<sub>x</sub> and H<sub>2</sub>S shall be guaranteed in case of ignited and non ignited;
  - It shall be considered a dedicated pipeline for the sour gas stream;
  - The flare design shall consider all expected sour gas conditions (composition, pressure, etc).
- 2.7.3.10.3.17 The amine flash drum shall be a three-phase horizontal separator, to separate amine hydrocarbon and gas, with dedicated level control loops (LIT, LIC, LV) for each liquid phase.
- 2.7.3.10.3.18 Amine tank or vessels with connections to atmospheric vent shall be equipped with nitrogen or other inert gas blanketing system.
- 2.7.3.10.3.19 Flow meter (transmitter) in the lean amine inlet of the contactor(s) shall be provided.
- 2.7.3.10.3.20 2 x 100% Cartridge filters shall be provided for 100% of amine flow. Activated carbon filter and a secondary cartridge filter, with a by-pass, shall be provided for 20% of amine flow.
- 2.7.3.10.3.21 The unit shall have online H<sub>2</sub>S/CO<sub>2</sub> content analyzer downstream of the amine contactor and upstream of Amine unit. The analyzers shall be calibrated with certificate issue in accordance with the manufacturer's specifications at least annually.
- 2.7.3.10.3.22 All facilities (tanks, pump, instrumentation, etc) for chemicals injection shall be provided;
- 2.7.3.10.3.23 The regeneration system shall be design in order to avoid oxygen entrance during a shutdown/cooling-condensation of the steam inside de tower.
- 2.7.3.10.3.24 The CO<sub>2</sub>/H<sub>2</sub>S Removal Unit shall also be designed taking into account the minimum temperature that occurs during the depressurizing condition of unit to the flare system.

2.7.3.10.3.25 For plate heat exchangers, consider hydrocarbon presence in order to specify the equipment. Furthermore, a spare equipment or spare plates and gaskets on board are required.

2.7.3.10.3.26 The offspec treated gas shall be deviated to flare, through a pressure control valve installed on downstream the unit. The gas is considered offspec when H<sub>2</sub>S is higher than 5ppmv or CO<sub>2</sub> higher than 0.25%mol or amine flow is lower than amine plant designer specification.

2.7.3.10.3.27 Continuous gas released in the Amine Flash Drum is to be returned to the process as vapor recovered in order to avoid hydrocarbon flaring.

2.7.3.10.3.28 The make-up water shall have the following quality parameters, as a minimum, or more restrictive parameters according to the amine plant designer specification.

- Total Hardness (Ca & Mg) < 50 ppmw max
- Chlorides < 2 ppmw max
- Sodium < 3 ppmw max
- Potassium < 3 ppmw max
- Iron < 10 ppmw max

#### 2.7.3.10.4 SPARE PHILOSOPHY

2.7.3.10.4.1 CO<sub>2</sub>/H<sub>2</sub>S Removal Unit equipments shall comply with the following minimum requirements as spare philosophy:

- Pumps: N+1 (one stand-by);
- Filters: N+1 (one stand-by); except Amine Carbon Filter and its associated cartridge downstream filter which shall be 1 x 100%;
- Lean/Rich Amine Exchanger (2 x 100%);
- Amine Stripper Reboiler (2 x 50%).

#### 2.7.4 PRODUCED WATER TREATMENT

2.7.4.1 The following figure presents the simplified scheme proposed for the Produced Water System considering both alternatives, reinjection back to reservoir as well as disposal to overboard.

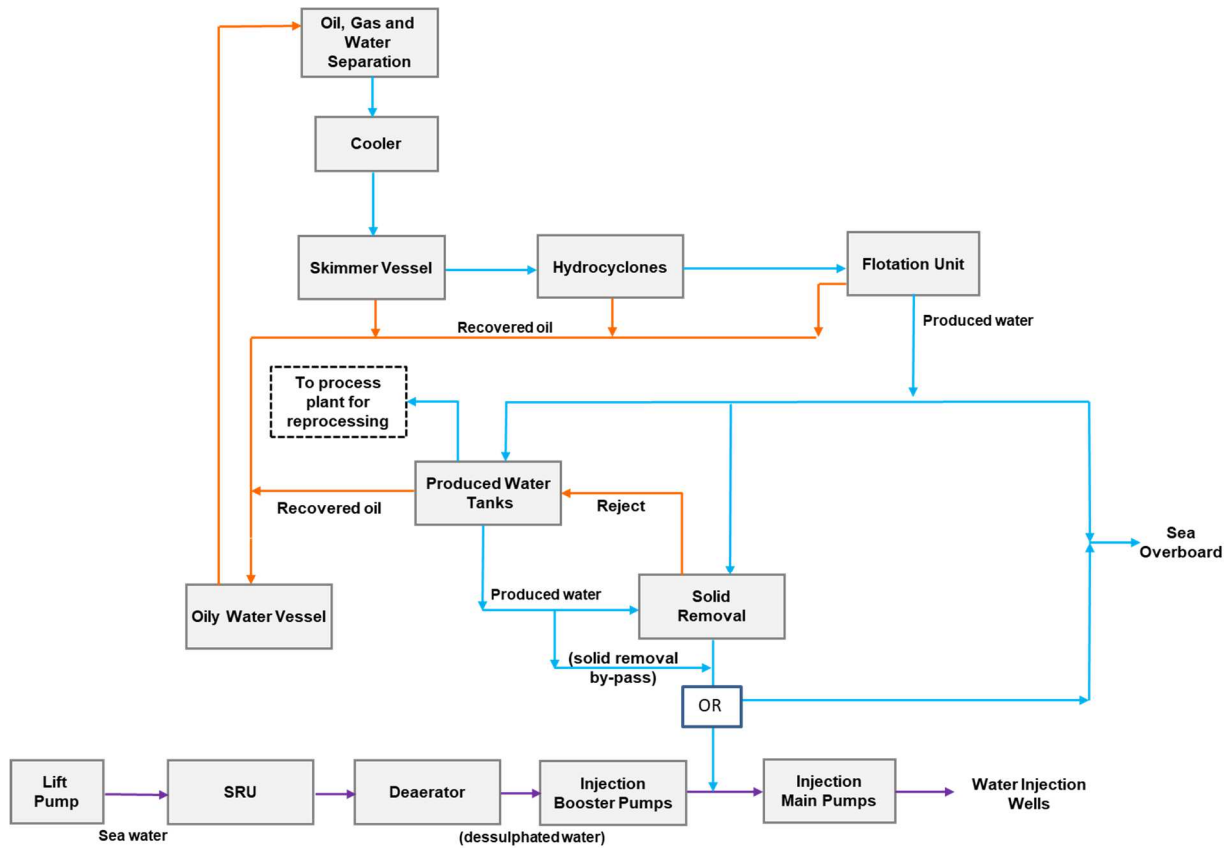
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Figure 2.7.4.1 - Simplified Diagram for Produced Water Treatment, Reinjection and Seawater Injection

2.7.4.2 Alternative configuration shall be submitted for PETROBRAS approval.

2.7.4.3 Produced water plant shall be designed to treat as per Table 1.2.2.4 and to meet specification described on item 2.3.2.

2.7.4.4 Configurations of the following equipment shall be assessed for disposal treatment: skimmer vessel, hydrocyclones, and flotation unit.

2.7.4.5 Configuration of the following equipment shall be assessed complementing treatment for water reinjection: produced water tank and solid removal system.

2.7.4.6 Recovered oil from produced water treatment shall be sent to the oil process plant.

2.7.4.7 The produced water from Process Plant is accumulated in the Skimmer and further routed to Hydrocyclones and Flotation Unit. Treated Produced Water may be routed to one of the following destinations:

- Overboard;
- Produced Water Tank for additional polishing or to be routed back to process plant for reprocessing. The offspec produced water reprocessing shall be routed to the Settling Tank or PW Treatment (dispersed oil) and also to the inlet of the Degasser or oily water vessel (dissolved oil);
- Solid Removal step, bypassing the Produced Water Tank.

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2.7.4.8 For produced water reinjection, the water from Flotation Unit shall be routed to Produced Water Tank from where it shall be pumped to Solid Removal Unit and then to reinjection in the reservoir (with or without mixing with seawater).

2.7.4.9 A by-pass of Solid Removal Unit shall be provided.

2.7.4.10 The filtration step – Solid Removal Unit – shall be one of the following: self-cleaning filters or ceramic membranes or multi-media filters. Additionally, CONTRACTOR shall use hydrocyclones upstream the filtration step in order to guarantee produced water quality specification to reinjection.

2.7.4.10.1 The hydrocyclones for solid removal shall be designed considering the following data:

- Maximum DP: 5 bar
- Split: 2 (min) and 5 (max)
- Maximum solids content at inlet: 100 mg/L
- Solid density: 1,5 kg/cm<sup>3</sup>
- Average particle size (d<sub>50</sub>): 30 µm
- Maximum particle size at water outlet (d<sub>98</sub>) 25 µm;

2.7.4.11 The system shall consider that desulphated water (sea water) will supply the necessary water injection flowrate of production life of the Unit. However, if produced water is available for injection, it will be another possible source for injection and in this case, total injection flowrate may be produced water complemented with desulphated water.

2.7.4.12 Connection with overboard (ex.: from pressure valves or flow control valves for pump capacity control) is not allowed after the mixture of streams, during the reinjection operation.

2.7.4.13 Based on the expected range of temperature for produced water, produced water cooler location and target temperature shall be defined taking into account at least the following requirements:

- Adequate temperature for the operation of hydrocyclones and floatation unit;
- Maximum allowed temperature for the Produced Water Tank;
- Normal, maximum and minimum temperatures for the injection risers;

2.7.4.14 Produced Water Tank

2.7.4.14.1 The tank is an accumulator before solid removal in the case of produced water is reinjected into reservoir.



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- 2.7.4.14.2 CONTRACTOR shall provide facilities and develop a procedure to remove solids accumulated in the produced water tank.
- 2.7.4.14.3 The following configuration shall be considered for Produced Water Tank: at least two separated Produced Water tanks. The volume of each tank shall be at least 10,000 m<sup>3</sup>. One of these Produced Water tanks shall be capable to receive cargo.
- 2.7.4.14.4 The fluid inlets and outlets should be designed to minimize turbulence and recirculation, hampering the separation process by decantation.
- 2.7.4.14.5 Shock Biocide shall be foreseen to be injected in the inlet line of tank in order to allow a proper mixing and effectiveness of chemical product as well as to minimize turbulence in the tank.
- 2.7.4.14.6 Produced water tanks shall be provided with proper device (ex.: collector, pumps) installed at a convenient vertical level in order to remove skimmed oil from tank.
- 2.7.4.15 Pumps
- 2.7.4.15.1 Produced Water tanks shall be fitted with bottom pumps (hydraulic or electrical driven submerged on main deck) for water removal and to route to solid removal. The pumps shall be provided with variable flow and automatic control, taking into account the expected produced water forecast and shall be dimensioned to keep oil water surface within an acceptable level range, during the whole field production life.
- 2.7.4.15.2 The configuration for water pumps shall consider at least 2x50% (2x12,000 m<sup>3</sup>/d), per tank.
- 2.7.4.15.3 For skimmed oil pumps, the configuration shall be defined by CONTRACTOR.
- 2.7.4.15.4 If produced water booster pumps are specified, they shall comply with API 610 Their sealing system shall comply with API 682 and its design and sealing plan shall be suitable for salty and hot produced water where applicable. Additionally, API 62 auxiliary sealing plan (quench) shall be provided.
- 2.7.4.16 Solid Removal
- 2.7.4.16.1 The necessary injection flowrate and produced water required specification (see item 2.4) shall be kept during the cleaning step of device.
- 2.7.4.16.2 The reject stream of this system shall be sent back to Produced Water Tank and may also be sent back the Oily Vessel. The reject return line to Produced Water Tank shall be provided anyway. The inlet pipe in the tank shall be arranged in order to not cause re-entrainment of solid in the water stream to be filtered. CONTRACTOR shall be responsible for managing residual disposal. Different configuration for the solid removal reject routing shall be submitted to PETROBRAS approval.



2.7.4.16.3 The minimum requirements for filtration are summarized below.

- The configuration shall consider at least 3x50% (3x12,000 m<sup>3</sup>/d) trains.
- Filters shall have differential pressure transmitter.
- Filtration shall collect particles above 25 µm.
- Self-cleaning filters shall have a maximum filtration flux of 1,200 m<sup>3</sup>/m<sup>2</sup>.h.
- Multimedia filters shall have a maximum filtration flux of 15 m<sup>3</sup>/m<sup>2</sup>.h.
- Ceramic membranes filters shall have a maximum filtration flux of 4.5 m<sup>3</sup>/m<sup>2</sup>.h.
- The filter vessel and backwashing facilities shall be designed in order to allow interchangeability considering the range of 25 µm and 80 µm filtering element set. Filtration elements fall under CONTRATOR's scope of supply.

2.7.4.17 For produced water reinjection, the produced water quality specification defined on item 2.4 shall be met.

2.7.4.18 For produced water disposal line, 2x100% online TOG analyzer (Content of oil and grease in water) shall be provided and the minimum requirements are summarized below:

- UV-fluorescence technology;
- Automatic cleaning system of acoustic (ultrasonic) type and manual sampling devices shall be provided.
- Guarantee the minimum analyzer flow as per supplier specification
- The analyzer shall be installed close to the sampling points, with preference at upwards flow points, aiming to avoid possible interference from phase stratification commonly observed in horizontal flows
- Logics shall also be implemented so that the overboard is interrupted if produced water is out of discharge limits.

2.7.4.19 Slop tanks shall not be used for treating produced water.

2.7.4.20 The produced water shall not be mixed with any other water or effluent.

2.7.4.21 Only one discharge point for produced water shall be considered in order to facilitate the routine of oil content monitoring (sample daily routine).

2.7.4.22 The end of the disposal line shall be above sea level, on all draft of the vessel, in order to allow visual inspection of the quality of the water.

2.7.4.23 The dissolved oil in the produced water shall be monitored and controlled by acid/coagulant injection and PH monitoring. The acid/coagulant injection rate and the PH range will be defined by Petrobras, during operation phase. Connections

and facilities for the future installation of a pH analyzer must be provided for in the following points: Settling Tank, PW Outlet and PW Offspec tank outlet.

## 2.7.5 FLARE AND VENT SYSTEM

- 2.7.5.1 The Unit shall be equipped with at least 2 (two) independent disposal systems, one receiving gas from higher operating pressure sources (HP) and the other receiving gas from lower operating pressure sources (LP), to collect and safely discharge residual gases released from safety valves, pressure control valves, blow down valves, pipelines, etc. Flare headers and equipment shall be designed to withstand temperature as low as -100°C unless specific study results in different temperature value. These systems shall be designed to operate simultaneously. Design of the disposal systems shall comply with API STD 521, CS Requirements and Guidelines, and NR-13 requirements for periodical testing of PSVs.
- 2.7.5.2 Refer also to API 521, clause 4.4, for possible causes of overpressure to be considered in the design, such as choke valve failure and check valve failure.
- 2.7.5.3 The system shall be designed for emergency disposal, as well as for a continuous disposal from low flowrates to at least 1,300,000 Sm<sup>3</sup>/d. Process disposal streams like regeneration and flash gas from TEG Unit, outlet gas from produced water flash drum, flotation unit, flash gas from low pressure vessels with continuous operation,, liquid from compressor scrubbers shall be sent back to the treatment plant. CONTRACTOR to evaluate the possibility of routing the gas to production plant in order to minimize gas flaring and its consequences.
- 2.7.5.4 CONTRACTOR shall submit to PETROBRAS a complete Depressurization System Study assumptions, methodology and results for comments during the engineering design phase. Assumptions and methodology shall be submitted prior to the development of the study. The Depressurization System Study shall contain an evaluation of the flare depressurization rate obtained in each scenario and the implemented safeguards to prevent the occurrence of those in which flare system capacity is exceeded.
- 2.7.5.5 The disposal system K.O. drums shall be designed to accommodate gas and liquids relief flows and have effective level measurement and control. The disposal system K.O. drums shall also be designed according to API RP 14C to avoid gas blow-by scenario. Disposal system headers shall be designed to accommodate multiphase flow depending on the characteristics of the relief.
- 2.7.5.6 Relief lines and headers shall be provided with adequate slope and drain points to guarantee liquid drainage considering all operational trim conditions.
- 2.7.5.7 CONTRACTOR shall submit to PETROBRAS the Gas Dispersion Study for Cargo Vent Post Location assumptions, methodology and results for comments during the engineering design phase. Assumptions and methodology shall be submitted previously of development of the study.



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2.7.5.8 The venting system shall be provided with devices to prevent against passage of flame into the cargo tanks.

#### 2.7.5.9 FLARES

2.7.5.9.1 The methodology established in API 521 shall be followed to determine radiation levels limits during emergency and continuous flaring. CONTRACTOR shall also conduct dispersion analysis during flare snuffing scenarios and noise level studies for the determination of the flare stack height.

2.7.5.9.2 The required radiation levels shall not be exceeded in any weather condition and in any continuous or emergency gas flow. Special attention shall be given on radiation levels on offloading equipment, flare startup system location (propane/liquefied petroleum gas), electrical, and gas and flame detectors.

2.7.5.9.3 CONTRACTOR shall guarantee that:

- Flare system has suitable supports in order to avoid transferring vibration to the flare piping system;
- Flare design be a non-pollutant type, with low NOx emissions. Combustion efficiency shall be high enough (CE>99% and 98% conversion to CO<sub>2</sub>) to guarantee low HC emissions to atmosphere ;
- Operational flaring scenarios be evaluated to guarantee flame stability and quality, especially for the lowest expected flowrates. Concern is excessive radiation and damage to flare structure in staged flare designs;
- Flare designs consider fire scenarios according to fire propagation study results which can lead to high depressurization flow rates;
- Flare lines, including the vertical lines in the flare stack, are designed avoiding pockets and considering possible rainwater accumulation;
- Pressure relief/depressurization systems and flare system design and calculation consider scenarios involving electric and automation systems' shutdown, such as UPS or PLC shutdown, which could lead to Unit blackout followed by simultaneous opening of all blowdown valves (BDVs) and fail-open pressure control valves (PVs) ;
- Safeguards are provided to prevent that flare system capacity is exceeded in any of the presented depressurization scenario.

2.7.5.9.4 The flare system shall be designed with a gas recovery. Outlet gas from either low pressure or high pressure flare knockout drums shall be routed to Flare Gas Recovery System (FGRS). The FGRS shall consist of a complete system with a pressure recovering equipment to make possible to return gas to process. FGRS compressors shall be either liquid-ring compressors (as per API Std. 681) or screw compressors (as per API Std. 619). Configuration shall be N+1..

2.7.5.9.5 CONTRACTOR shall consider minimum the capacity of 75,000 Sm<sup>3</sup>/d for FGRS design. The pressure recovering equipment shall start to recover the flare gas as

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the flare header pressure reaches a control set point. Whenever discharges exceed FGRS capacity, the system shall stop and gas shall be directed to the flare stack. In order to keep system reliability, QOVs (Quick Opening Valves) shall be installed on HP and LP headers. Each QOV shall have at least 2 (two) Buckling Pin Valve (BPV) protection with a bypass line. Each header pressure shall be monitored by 3 (three) pressure transmitters, located upstream QOV, and shall be configured with a voting logic of 2 (two) of 3 (three) in order to open/close QOV.

- 2.7.5.9.6 For the design of the Safety Instrumented Functions (SIFs) responsible for the QOVs actuation, installed in the flare gas relief lines (low and high pressure), SIL (Safety Integrity Level) 3 shall be considered as the level of integrity required.
- 2.7.5.9.7 Flares shall be designed with a backup of the ignition system. Flare and pilot shall be designed to guarantee flammability and flame stability considering the range of CO<sub>2</sub> concentration expected.
- 2.7.5.9.8 Flare pilots shall comply with NR-37. Furthermore, the flare pilots project shall consider the flexibility to operate with the flare flame pilot "on" and "off".
- 2.7.5.9.9 Purge gas shall be injected in the gas piping system to the flare at the farthest point(s) upstream flare so that all the piping shall be full of purge gas.
- 2.7.5.9.10 For staged systems, provide a point for nitrogen purge downstream each valve of the stages normally closed, in order to maintain a continuous flow of purge gas up to the top of the flare.
- 2.7.5.9.11 The minimum purge gas flow shall be according to API STD 521 requirements or supplier information, whichever is higher.
- 2.7.5.9.12 In the Flare Gas Recovery System (FGRS), the high pressure and low pressure headers shall be purged with nitrogen locally generated from the atmosphere. The nitrogen generators shall have a 2x100% configuration and its electrical energy source shall be from emergency generator (Essential Switchgear). The nitrogen generators shall be dedicated and exclusive for flare purge, it shall not be shared with other plant consumers.
- 2.7.5.9.13 The Nitrogen Generator Units shall be connected in the supervisory system to allow an automatic start-up. In case of failure of both generators, a dedicated fuel gas source shall be used to purge the flare system. Purge gas shall be injected in HP and LP headers downstream respective QOV (Quick Opening Valve) valves. O<sub>2</sub> analysers and flow meters shall be installed.
- 2.7.5.9.14 At least two sources of purge gas shall be provided, with provision for measuring flow, low flow alarm and automatic changing between sources. The maximum oxygen content of purge gas shall be 5%.

### 2.7.5.10 ATMOSPHERIC VENTS

2.7.5.10.1 The design of Atmospheric Vents shall follow the API STD 2000.

2.7.5.10.2 CONTRACTOR shall consider proper access to flame arrestor for all atmospheric vents. Flame arrestors shall be installed in safe location complying with API 14C.

## 2.8 CHEMICAL INJECTION

2.8.1 The Unit shall be equipped with a chemical injection system, which shall be used to improve and enhance the operating conditions of equipment and subsea lines. The oil, gas, water treatment and water injection systems shall be designed to inject the following main products:

- H<sub>2</sub>S scavenger for subsea;
- H<sub>2</sub>S scavenger for offloading;
- Gas hydrate inhibitor for topside and subsea;
- Scale inhibitor for topside;
- Scale inhibitor for subsea;
- Wax inhibitor for subsea;
- Corrosion inhibitor for subsea;
- Water-in-oil demulsifier for topside;
- Water-in-oil demulsifier for subsea;
- Oil defoamer for topside;
- Polyelectrolyte;
- Biocide for Slop Tank, Off-spec Tanks and Cargo Tanks;
- All the manufacturer recommended chemicals for the Sulphate Removal Unit and Ultrafiltration Unit. As a minimum CONTRACTOR shall consider:
  - Membrane biocide and/or shock biocide;
  - Chlorine scavenger and/or oxygen scavenger;
  - Scale inhibitor;
  - Acid cleaning;
  - Alkaline cleaning;
  - Water Injection Shock biocide;
  - Biofouling disperser.

2.8.2 Where not specifically mentioned, storage tanks for chemicals shall have enough capacity for 10 days of normal consumption, calculated by using 80% of the maximum injection rate indicated in Table 2.8.12.



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- 2.8.3 All the chemical products tanks shall have a level transmitter and inclined bottom with a drain, containments for leaks, manhole for inspection, easy access to instruments and valves, high and low level alarms and sampling point. Sampling point can be at the pump.
- 2.8.4 Chemical tanks and their lines should be made of stainless steel, except if not compatible with the fluid. Tanks shall be installed in naturally ventilated areas and equipped with individual vents. The flammable products tanks must have flame arresters.
- 2.8.5 Vents for flammable products shall be in accordance to API STD 2000 or NFPA 30. For vent sizing, reduction factors foreseen in API STD 2000 and NFPA 30 shall not be considered. CONTRACTOR can evaluate the use of pressurized vessel for flammable and combustible products.
- 2.8.6 At least scale inhibitor (subsea), demulsifier (topside), defoamer and polyelectrolyte tanks/vessels shall be divided in two partitions with isolating valves from the common pump suction header and also isolating valves on filling line. Instrumentation, drains and vents shall consider the partition. These facilities are to be used during testing of new products or different batches of the same products.
- 2.8.7 For umbilical (subsea) injection, filters (2x100%, 10 micrometers stainless steel filter element) on pump discharge shall be added. The discharge filters shall have remote differential pressure alarm for replacement. CONTRACTOR shall follow practices and recommendations of API TR 17TR5 (Avoidance of Blockages in Subsea Production Control and Chemical Injection System) during design and operation. A specific drainage routine / procedure shall be established in agreement with PETROBRAS during operation phase.
- 2.8.8 All chemical injection pumps shall have a filter upstream. CONTRACTOR shall install stand-by pumps at all chemical units to guarantee continuous performance, except for ethanol / MEG pumps. Also, chemical dosing pumps shall have an adjustable flow range of 10:1 unless if defined differently on Table 2.8.12.
- 2.8.9 Each injection point shall have individual pump or multi head pump or dedicated head in a multi head pump, including online pressure meter (transmitter).
- 2.8.10 Each injection point shall have an online flow meter (transmitter) and a calibration gauge glass in order to measure the injection rate. CONTRACTOR shall comply with flow meter maintenance plan recommended by the supplier. Flow meters for topside scale inhibitor, oil defoamer, demulsifier, polyelectrolyte, acids and subsea chemicals shall be Coriolis type, transmitting online flow and density.
- 2.8.11 Each injection point shall be in the center of pipe ("quill device"). All topsides injection points in gas streams shall be installed with spray nozzle to accelerate chemical mixing. The chemical injection points should be installed far from any fiscal, allocation or custody transfer measurement system (including its respective sampling point), preferably downstream the flow meter, so as to avoid inaccuracies on the flow meters.

2.8.12 Concentration ranges for each chemical to be complied with when designing the chemical injection system are (during operational life, different dosages within pump or system capacities may be applied):

Table 2.8.12 – Chemical Injection Rates &amp; Requirements

| PRODUCT  | INJECTION RATE   |
|--|--|
| H <sub>2</sub> S scavenger for subsea            | <p>The injection system provided shall operate in the range of 5 to 80 L/h per well.</p> <p>There shall be a storage of 1 (one) tank of 15 m<sup>3</sup>.</p> <p>Each scavenger line will pass through X-tree and tubing hanger (TH) down to the well bottom to allow H<sub>2</sub>S scavenger to react with H<sub>2</sub>S in the tubing;</p>   |
| H <sub>2</sub> S scavenger for topsides          | <p>Injection point: upstream each offloading pump.</p> <p>The injection system provided shall operate in the range of 200 ppm of product based on total offloading pump flowrate.</p> <p>There shall be a total storage of 40m<sup>3</sup>.</p> <p>This product should be used just contingently and in agreement with PETROBRAS.</p>  |
| Gas hydrate inhibitor: ethanol or MEG (1)        | <p>Topside: 1 to 100/h (multi head pump) (10)</p> <p>Subsea: 5,000 L/h. Two pumps are required.</p> <p>There shall be a storage of 2 (two) tanks of 35 m<sup>3</sup> each. At any time, each of the tanks may be used for ethanol or MEG.</p>  |
| Scale inhibitor for topside (2)                  | <p>Topside: from 2 to 200 ppm per injection point based on produced water.</p> <p>Minimum tank capacity: 50.0 m<sup>3</sup>.</p>   |
| Scale inhibitor for subsea (pre-salt wells) (2)  | <p>Each scale inhibitor line will pass through X-tree and TH down to the well bottom to guarantee the scale inhibition as close as possible of perforations;</p> <p>The injection system provided shall operate in the range of 1 to 20 L/h per well. More than one head pump may be required to reach the maximum injection rate.</p> <p>There shall be a total storage of 25 m<sup>3</sup></p>   |
| Scale inhibitor for subsea (post-salt wells) (2) | <p>Each scale inhibitor line will pass through X-tree and TH down to the well bottom to guarantee the scale inhibition as close as possible of perforations;</p> <p>The injection system provided shall operate in the range of 1 to 40 L/h per well. More than one head pump may be required to reach the maximum injection rate.</p> <p>There shall be a total storage of 25 m<sup>3</sup></p> <p>One of the H<sub>2</sub>S scavenger tanks and the Wax Inhibitor tank shall be able to be used for Scale inhibitor.</p> |
| Wax inhibitor for subsea                         | <p>The injection system provided shall operate in the range of 3 to 40 L/h per well."</p> <p>There shall be a total storage of 10 m<sup>3</sup></p>  |



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| PRODUCT  | INJECTION RATE  |
|--|---|
|  | The Wax Inhibitor tank shall be able to be used for hydrate inhibitor. Water-in-oil demulsifier for subsea may use the same tank. These products will not be used simultaneously. |
| Corrosion inhibitor  | Injection point: gas exportation pipeline<br>The injection system provided shall operate in the range of 1 to 1,7 L/h.<br>There shall be a total storage of 5 m3                  |
| Water-in-oil demulsifier for topsides (3)  | The injection system shall provide 10 a 100 ppm per injection point based on produced liquid.<br>Minimum tank capacity: 40m <sup>3</sup>  |
| Water-in-oil demulsifier for subsea  | The injection system provided shall operate in the range of 10 to 90 L/h per well<br>There shall be a total storage of 25 m3  |
| Oil defoamer (3,4)   | The injection system shall provide 20 a 200 ppm per injection point based on total produced liquid.<br>Minimum tank capacity: 70.0 m <sup>3</sup>                                 |
| Biocide for Slop Tank, Produced Water Tank, Cargo Tanks, Settling Tanks and Off-spec Tanks (5)     | . The injection system provided shall operate in the range of 10 to 200 ppm based on the volume of water in the tanks.<br>There shall be a total storage of 35 m <sup>3</sup>     |
| (SRU) Acid cleaning  | Batch use (6)<br>Tank capacity: To be defined by CONTRACTOR.  |
| (SRU) Alkaline cleaning  | Batch use (6)<br>Tank capacity: To be defined by CONTRACTOR.  |
| Water injection shock Biocide: DBNPA (7)   | From 100 to 500 ppm twice a week during one hour, upstream SRU<br>Tank capacity: To be defined by CONTRACTOR.   |
| Water injection shock biocide: THPS (tetrakis hydroxymethyl phosphonium sulfate) or Glutaraldehyde | from 100 to 1000 ppm twice a week during one hour, upstream deaerator<br>Tank capacity: To be defined by CONTRACTOR.  |
| Scale inhibitor for SRU  | from 1 to 20 ppm upstream SRU<br>Minimum tank capacity: 6 m <sup>3</sup>  |
| Chlorine scavenger   | from 1 to 30 ppm upstream SRU<br>Tank capacity: To be defined by CONTRACTOR.  |
| Oxygen scavenger   | from 5 to 25 ppm (operational deaerator)<br>from 100 to 200 ppm (non-operational deaerator)<br>Tank capacity: To be defined by CONTRACTOR.  |
| Biofouling disperser   | from 5 to 20 ppm downstream deaerator<br>Tank capacity: To be defined by CONTRACTOR.  |





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| PRODUCT   | INJECTION RATE  |
|---|---|
| Polyelectrolyte (inverted emulsion inhibitor) (8) | From 10 to 100 ppm<br>Tank capacity: 10 m3  |
| Oxygen Scavenger (for produced water)             | Injection point: upstream Solid Removal Unit<br>From 1 to 25 ppm<br>No additional storage required; CONTRACTOR may use the same system mentioned for injection water.   |
| Coagulant (10, 11)                                | Injection point: upstream and downstream hydrocyclone<br>From 10 to 60 ppm<br>There shall be a total storage of 15m3  |
| Acetic acid (75%)/Glycolic acid (10,11)           | Injection points: upstream production header, test header and reprocessing production water stream (if applicable).<br>The injection system provided shall operate up to 1000 ppm based on produced water<br>There shall be a total storage of 80m3 |

**NOTE 1:** To inhibit hydrate formation, ethanol / MEG shall be injected into the Wells Wet Christmas Trees. The injection is not planned to be continuous, however, it should be possible to inject it in up to two points at the same time. CONTRACTOR shall provide the required flow rate and pressure at the top connection of each control umbilical at the FPSO. The Subsea pump shall be used in the commissioning of all risers. The Subsea pumping system shall have a configuration of at least 2x50% pumps, with a total flowrate of 5,000 L/h.

Injection points are required at the top of all risers, and on the chemical routing plates shown in Figure 2.8.16.

The tanks may store ethanol or MEG.

The pumps may be used to inject ethanol or MEG, not simultaneously. No dedicated headers are required.

Ethanol or MEG may be used for umbilical cleaning before a chemical product exchange. CONTRACTOR shall provide a permanent or removable connection of ethanol/MEG line to the other chemical products umbilical tubes as presented in Figure 2.8.15.

**NOTE 2:** The Unit shall be prepared to inject the scale inhibitor continuously at the well down hole (in all production wells at the same time) and at the topside facilities (production header, test header, downstream Settling tank oil pump, upstream of treaters and/or heat exchangers, upstream of hydrocyclones, upstream mixing with desulphated water (reinjection scenario) and others) whenever required by PETROBRAS. Separate systems shall be provided, as different products are injected topsides and subsea. PETROBRAS informs that there is a high potential of scaling at topside and subsea. In the case of dosage ranges exceeding 10: 1, the CONTRACTOR must provide sets of heads / pumps of complementary ranges.

**NOTE 3:** The Unit shall be prepared to inject this product continuously topsides.

NOTE 4: Points of injection: production and test headers (nearest possible), upstream of the liquid level control valve of the HP Separator, upstream of the liquid level control valve of the LP Separator and upstream flash vessels.

NOTE 5: If CONTRACTOR decides to use a combo product for Biocide/Biostatic, only one tank is necessary. The value of 5mg / L of H<sub>2</sub>S should be used in the aqueous phase of the slops tanks as a reference for the control of the biocide dosage. The methodology to be used for the measurement of sulfides is that referenced in NOTE 3 of item 2.10.1. As per Contract requirement, CONTRACTOR must have an operating procedure and facilities that incorporates the injection of biocide and/or other means that may be necessary, so as to keep the Unit's tanks free from sulfate reducing bacteria.

NOTE 6: During project execution phase, SRU cleaning procedure shall be submitted to PETROBRAS for comments.

NOTE 7: DBNPA is a corrosive product so its injection system shall not be metallic However, titanium/hastelloy C is acceptable for use with DBNPA.

NOTE 8: Polyelectrolyte must be injected upstream of the flotation cell and the injection points must be downstream of the hydrocyclones. This product should be diluted 10 to 30 times in fresh water. The CONTRACTOR must use in-line dilution systems or pumps that allow automatic product dilution in water, without the need for a dilution tank.

NOTE 9: Injecting the product at the topside during commissioning of the gas plant may be required due to the bypass of the molecular sieves or because of the import of gas through the export pipeline (when applicable). The minimum injection points required are: export pipeline (when applicable), one point upstream and another point downstream of the fuel gas scrubber vessel.

NOTE 10: The necessary amount of acetic acid/glycolic acid and coagulant will be provided by PETROBRAS at no cost.

NOTE 11: Facilities defined for acetic acid and coagulant may be the same. These products will not be used simultaneously. Coagulant and acetic acid injection, if necessary, to be defined by PETROBRAS.

2.8.13 Chemicals are received from supply vessels in portable tanks (tote tanks) within 5m<sup>3</sup> capacity and must be stored in specific chemical storage areas within the range of at least one of the Unit's cranes. These chemical storage areas shall preferably allow the gravity transfer of chemicals to the storage tanks in the chemical injection unit.

2.8.14 Sufficient area shall be provided for receiving and storing a quantity of tote tanks as per Table 2.8.14. Products of non-continuous use shall not be considered in this calculation. No stacking of tote tanks is allowed.

Table 2.8.14 – Tote Tanks Quantity for Storage Area Definition

| PRODUCT                               | TOTE TANKS<br>QUANTITY<br>(reference 5m <sup>3</sup> ) |
|---------------------------------------|--|
| H <sub>2</sub> S scavenger for subsea | 2  |

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|   |   |
|---|---|
| H <sub>2</sub> S scavenger for topsides   | 3 |
| Gas hydrate inhibitor: ethanol or MEG (1)   | 7 |
| Scale inhibitor for topside   | 5 |
| Scale inhibitor for subsea  | 6 |
| Wax inhibitor   | 1 |
| Corrosion inhibitor   | 1 |
| Water-in-oil demulsifier for topsides   | 3 |
| Water-in-oil demulsifier for subsea   | 3 |
| Oil defoamer  | 6 |
| Biocide for Slop Tank, Settling Tank, Produced Water Tanks, Cargo Tanks and Off-spec Tanks            | 1 |
| Biostatic for Slop Tank, Produced Water Tanks, Cargo Tanks and Off-spec Tanks                         | 1 |
| (SRU) Acid cleaning   | 1 |
| (SRU) Alkaline cleaning   | 2 |
| Water injection shock Biocide: DBNPA  | 1 |
| Water injection shock<br>biocide: THPS (tetrakis hydroxymethyl phosphonium sulfate) or Glutaraldehyde | 1 |
| Scale inhibitor for SRU   | 1 |
| Chlorine scavenger or Oxygen scavenger  | 1 |
| Biofouling disperser  | 1 |
| Polyelectrolyte   | 2 |
| Acetic Acid   | 5 |

2.8.15 Configuration for Chemical Routing Panels is presented in the following Figure.

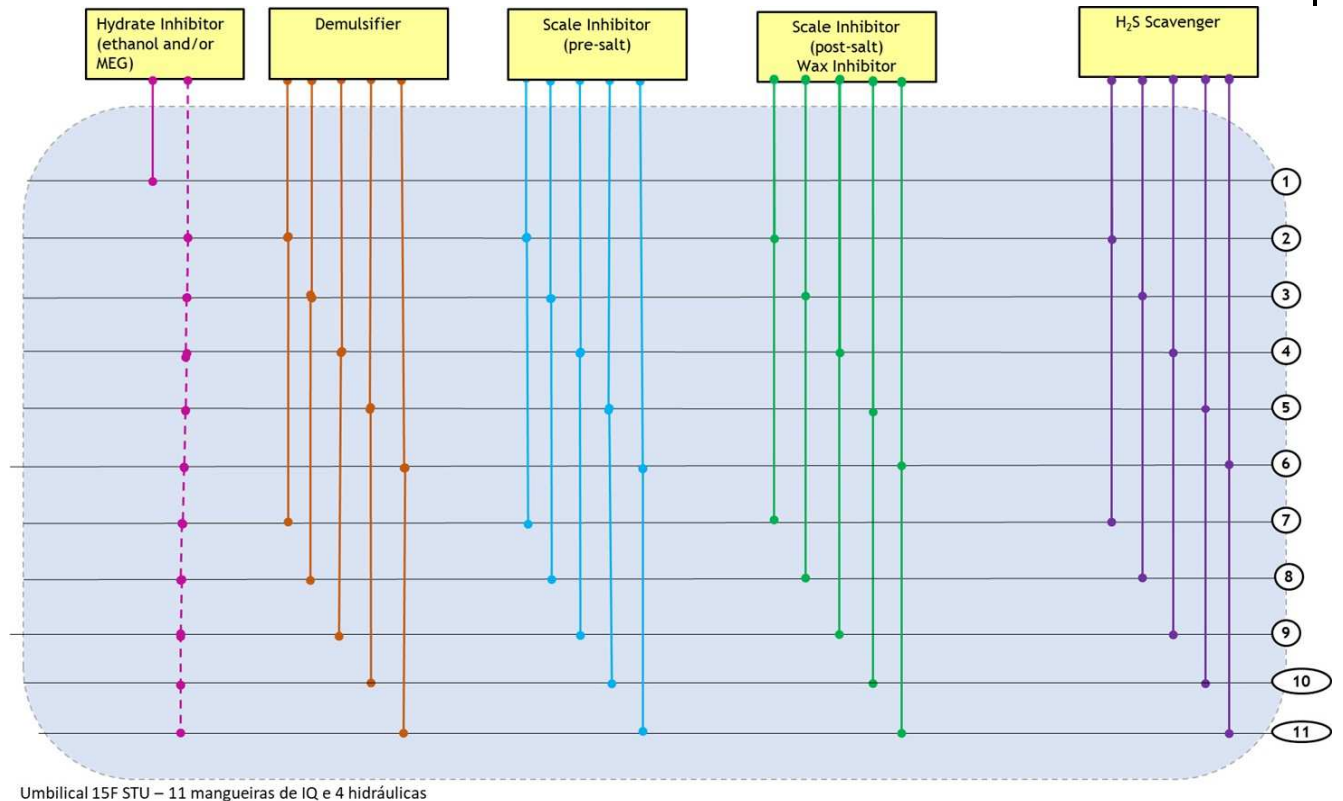


Figure 2.8.15: Chemical Routing for all Wells

NOTE 1: Design shall consider the risk of reverse flow from chemical injection hoses from subsea.

2.8.16 CONTRACTOR shall also provide a connection point for eventual injection of chemical tracers in the reservoir. This connection point must be available in the injection line of the water in a point where the flow is specific for each injection well. The point must be such that it is possible to connect a portable (pneumatic) injection skid without depressurizing the injection line and header (double blocking/purging and/or other mechanism).

2.8.17 PETROBRAS will provide the following chemicals up to the limit mentioned in the table below, measured monthly. These quantities are referred to the maximum flowrate (refer to item 1.2.2.4) or storage capacity mentioned in the table 2.8.12. For flow rates smaller than the maximum, a proportional amount will be considered.

Table 2.8.17 – Chemicals Provided

| PRODUCT                                       | Quantities (Maximum limits / month) |
|---|-------------------------------------|
| Scale inhibitor for subsea                    | See remark 2 below                  |
| Scale inhibitor for topside                   | 143 m <sup>3</sup> (1)              |
| Water-in-oil Demulsifier                      | 95 m <sup>3</sup> (2)               |
| Oil defoamer                                  | 190 m <sup>3</sup> (2)              |
| Polyelectrolyte (inverted emulsion inhibitor) | 72 m <sup>3</sup> (1)               |

| PRODUCT   | Quantities (Maximum limits / month)                       |
|---|---|
| Biocides to water injection   | THPS or Glutaraldehyde – 9 m <sup>3</sup>                 |
| Hydrate inhibitor   | See remark below  |
| Chemicals to be used in the Sulphate Removal Unit and Ultrafiltration Unit (if necessary) | Oxygen scavenger and chlorine scavenger -22m <sup>3</sup> |
| Wax inhibitor   | See remark 2 below  |
| H <sub>2</sub> S scavenger for subsea   | See remark 2 below  |
| Biofouling disperser  | 14m <sup>3</sup>  |
| Acetic Acid   | 179 m <sup>3</sup>  |

NOTE 1: Based on Produced Water.

NOTE 2: Based on Produced Liquids.

Remarks:

1. The necessary amount of hydrate inhibitor necessary for cleaning the flowlines will be provided by PETROBRAS at no cost.
2. Subsea chemicals will be provided by PETROBRAS at no cost. CONTRACTOR must use the volume or dosage requested by PETROBRAS.
3. The quantities above may be revised during the operation, if CONTRACTOR presents technical evidence that supports such need and is accepted by PETROBRAS.
4. As chemical injection facilities may contain low flashpoint, flammable and/or toxic substances, these risks shall be used in development of the appropriate protection requirements.
5. Due to potential hazards, the location of chemical injections packages shall not obstruct escape and evacuation routes by any very toxic substances that might result from an incident.

2.8.18 PETROBRAS will provide reference chemical product data sheets for each function during design phase. However, the supplier of the chemicals will be defined based on PETROBRAS internal procedures and regulations and might change suppliers during operation phase.

2.8.19 For tote tanks dimensions, CONTRACTOR shall consider:

Table 2.8.19 – Tote Tank Dimensions

| m <sup>3</sup> | Valve    | Connection | PB                         | Dimension                  | Tare (kg) |
|----------------|----------|------------|----------------------------|----------------------------|-----------|
| 1,0            | ball Ø2" | Screw BSP  | restricted gate            | H=1,5m X L=1,3m X W=1,5m   | 265       |
| 1,5            | ball Ø2" | Screw BSP  | restricted gate            | H=1,9m X L=1,3m X W=1,5m   | 440       |
| 3,0            | ball Ø3" | Screw BSP  | restricted gate            | H=2,3m X L=2,3m X W=2,3m   | 1.500     |
| 5,0            | ball Ø3" | Screw BSP  | restricted gate            | H= 2,3m X L= 3,0m X W=2,3m | 1.700     |
| 5,2            | ball Ø3" | Screw BSP  | tripartite restricted gate | H=2,3m X L=3,1m X W=2,3m   | 1.700     |

W: Width, H: Height, L: Length

2.8.20 Required pressure at top of riser and flowrates per well for the subsea chemical injection is presented in Table 2.8.21. During execution phase, PETROBRAS will confirm these values.

Table 2.8.20 – Subsea Chemicals Requirements

| Product                                       | Injection Point            | Pressure at top of riser/umbilical (bara) | Min Flow Rate (m <sup>3</sup> /d) | Max Flow Rate (m <sup>3</sup> /d) |
|---|----------------------------|---|-----------------------------------|-----------------------------------|
| Ethanol                                       | Subsea Tree <sup>(1)</sup> | 350                                       | 6.8                               | 68.0                              |
| MEG   | Subsea Tree <sup>(1)</sup> | 350                                       | 3.2                               | 32.0                              |
| Wax Inhibitor/<br>Water-in-oil<br>Demulsifier | Subsea Tree                | 370                                       | 0.4                               | 4.0                               |
| Scale Inhibitor                               | Well                       | 260                                       | 0.16                              | 1.6                               |
| H <sub>2</sub> S Scavenger                    | Well                       | 370                                       | 0.3                               | 3.4                               |
| Asphaltene Inhibitor                          | Well                       | 370                                       | 0.65                              | 6.5                               |

NOTE 1: For Production and Injection positions.

## 2.9 SAMPLE COLLECTORS

2.9.1 Provisions to collect samples shall be designed in such a way as to guarantee correct sample accuracy. Each collecting point shall be in accordance with regulations and shall allow safe operation with no environmental impact. Therefore, CONTRACTOR shall install an adequate drain and/or vent system, for each of the collecting points listed below:

Table 2.9.1 – Sample Points

| POINTS                             | SAMPLE COLLECTION  |
|------------------------------------|--|
| Produced oil /Condensate (1,2,3,8) | <ul style="list-style-type: none"> <li>• Test and production header (upstream from the chemical injection points);</li> <li>• Upstream and downstream of process vessels;</li> <li>• Try-cocks on electrostatic treater and Separators;</li> <li>• Transference pump discharge (from the process plant to the cargo tanks);</li> <li>• All production lines;</li> <li>• Offloading line;</li> <li>• Slop and Cargo Tanks.</li> </ul> |
| Gas (3,4,5)                        | <ul style="list-style-type: none"> <li>• Upstream and downstream of process vessels;</li> <li>• Fuel Gas;</li> <li>• High Pressure Flare gas;</li> </ul>   |



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|                         |  |
|-------------------------|--|
|                         | <ul style="list-style-type: none"> <li>• Low pressure Flare gas;</li> <li>• Service header;</li> <li>• Gas lift header;</li> <li>• Gas reinjection header;</li> <li>• Slop and Cargo Tanks;</li> <li>• CO<sub>2</sub>/H<sub>2</sub>S Removal unit: inlet gas, treated gas and CO<sub>2</sub> rich stream (each elements cluster, as a minimum)</li> </ul>  |
| Produced water (6)      | <ul style="list-style-type: none"> <li>• Upstream and downstream of process vessels (HP Separator; LP Separator; Test Separator; Settling Tanks; Electrostatic Treaters; Hydrocyclones; Flotation Units; Offspec PW Tanks)</li> <li>• Produced water tank (inlet and outlet)</li> <li>• Solid removal unit (inlet and outlet). The outlet point shall be upstream the produced water and desulphated water mixture.</li> <li>• Any points to allow control/troubleshooting of produced water treatment</li> <li>• Water discharge piping to overboard (located near and downstream the oil and water online analyzer) (9)</li> </ul> |
| Injection water         | <ul style="list-style-type: none"> <li>• Upstream and downstream of deaerator;</li> <li>• Seawater intake, upstream of water lift pumps;</li> <li>• Sulfate removal membrane unit: inlet, treated water and Sulfate stream (in each vessel);</li> <li>• Injection header and risers.</li> </ul>  |
| Dilution water          | <ul style="list-style-type: none"> <li>• Upstream dilution water heater.</li> </ul>  |
| Cooling Water           | <ul style="list-style-type: none"> <li>• Downstream circulation pumps.</li> <li>• Downstream heat exchangers</li> </ul>  |
| Hydraulic control fluid | <ul style="list-style-type: none"> <li>• High pressure header for Down hole Safety Valves (DHSVs);</li> <li>• Low pressure header for Wet Christmas Trees (WCTs).</li> </ul>   |
| Slop water              | <ul style="list-style-type: none"> <li>• Slop tank water disposal line to overboard</li> <li>• Upstream and downstream of slop water treatment systems.</li> </ul>   |
| Ballast water           | <ul style="list-style-type: none"> <li>• Ballast water disposal line to overboard</li> </ul>   |
| Subsea Chemicals        | <ul style="list-style-type: none"> <li>• Upstream of the Subsea chemical injection pumps</li> </ul>  |
| Sewage system (10)      | <ul style="list-style-type: none"> <li>• Upstream (after mixture of grey and black waters) and downstream sanitary effluent treatment unit to allow</li> </ul>   |



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|                      |   |
|----------------------|---|
|                      | quantification of COD (chemical oxygen demand) and BOD (biological oxygen demand) reduction efficiency.   |
| TEG Unit             | <ul style="list-style-type: none"> <li>Lean TEG stream in the inlet of absorber</li> <li>Rich TEG stream upstream of absorber level control valve</li> <li>Rich TEG stream downstream of activated carbon filter</li> <li>Wet gas stream upstream of absorber, downstream of coalescer filter</li> <li>Dry gas stream downstream of absorber</li> </ul>   |
| CO2/H2S Removal Unit | <ul style="list-style-type: none"> <li>Sour gas - at gas inlet of amine contactor (s)</li> <li>Sweet gas - at gas outlet of amine contactor</li> <li>Lean amine - at inlet of amine contactor(s)</li> <li>Rich amine - downstream of amine contactor(s) level control valve</li> <li>Rich amine - downstream of activated carbon filter</li> <li>Reflux water to the stripper tower</li> <li>Make-up water</li> <li>Sour gas - at gas outlet of regeneration tower</li> <li>Sour gas - at gas outlet of Amine Flash Drum</li> </ul> |
| Settling Tank        | <ul style="list-style-type: none"> <li>Upstream and downstream of Settling Tanks</li> </ul>   |

NOTE 1: CONTRACTOR shall provide means to collect samples and to determine BTEX content in produced oil (according to EPA 8260D e EPA 3585), condensate (ASTM D 3606) and produced water (according to EPA 8015D).

NOTE 2: CONTRACTOR must provide facilities to collect samples of oil in vessels of 0,25L up to 1,000 L (container). Sampling condition must be at atmospheric pressure (test and production separators and crude oil fiscal meter to cargo tanks shall also foresee pressurized samples). All the gas released in this process must be sent to a safe place.

NOTE 3: For gas and oil sampler points related to the flow meters of the FMS, Resolução Conjunta ANP/Inmetro nº1 of 2013 shall be complied with. For a list of all metering points and additional requirements see FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1).

NOTE 4: CONTRACTOR shall also provide manual sample collection in every online analyzer (gas chromatographer, moisture analyzer, oil in water content, etc.) and meter.

NOTE 5: CONTRACTOR shall provide means to collect and to determine BTEX content in produced gas according to GPA 2286.

NOTE 6: Sample points shall be representative and located at turbulent flow line.

The sample points shall be, at least, according to the following requirements:

- It shall be intrusive, positioned in the center line of piping and with a curvature of 90° against the flow (see Figure 2.9.1);



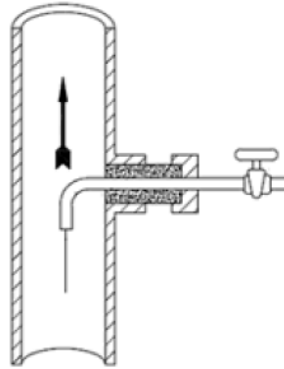
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Figure 2.9.1 – Intrusive Sample Point

- It shall be located in a vertical section of piping with ascendant flow;
- The piping shall be of stainless steel with a minimum diameter of ½”;
- In case where intrusive sampling is not practicable (e.g.: small diameter piping), a lateral nozzle shall be used;
- The length of sampling piping shall be as minimum as possible, preferably lower than 4 (four) meters;

NOTE 7: The sample systems shall have material specification compatible with sampled fluids.

NOTE 8: CONTRACTOR shall provide a hermetic system to collect and determine benzene content (%v/v) in all condensate streams, as presented in *Norma Regulamentadora* Nº 15 – NR-15 (Portaria SSST n.º 14, December 20, 1995) Annex 13 A.

- NOTE 9: Additionally to the NOTE 6 requirements, this sample point shall comply with the following requirements:
- It shall be located downstream the last equipment before produced water discharge;
- It shall be kept constantly opened in the maximum opening of sampling valve.

NOTE 10: Sampling points shall be in compliance with *NOTA TÉCNICA CGPEG/DILIC/IBAMA Nº 01/11*

## 2.10 LABORATORY

2.10.1 CONTRACTOR shall provide onboard a Laboratory equipped to perform, as a minimum, the following analysis onboard:

Table 2.10.1.a – Laboratory Analyses - Offshore

| SYSTEMS                     | ANALYSIS          | REFERENCED DOCUMENT                                  |
|-----------------------------|-------------------|--|
| Produced Oil and Condensate | BS&W and watercut | ASTM D4007 or API MPMS 10.4 ; ASTM D4928; ASTM D4377 |
|                             | Salinity          | ASTM D3230 or ASTM D6470                             |
|                             | Sand content      | ASTM D4381   |


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| SYSTEMS  | ANALYSIS                      | REFERENCED DOCUMENT  |
|--|-------------------------------|--|
|  | Density/API gravity           | ASTM D5002   |
|  | H2S content                   | UOP 163  |
|  | pH; two-phase oil (1)         | SMEWW 4500 pH Value; ASTM E70; ASTM D1293  |
|  | RVP                           | ASTM D6377   |
| Cargo and Slop tanks   | BS&W and watercut             | ASTM D4007 or API MPMS 10.4; ASTM D4928; ASTM D4377  |
|  | H2S content in oil            | UOP 163  |
|  | H2S content in water          | UOP 209  |
|  | H2S content in vapor phases   | ASTM D4810   |
| Produced and discharged water  | Oil content (2)               | API RP 45; ASTM D8193  |
|  | Chloride content              | ASTM D512; ASTM D4458  |
|  | Calcium and Magnesium content | ASTM D511  |
|  | pH                            | SMEWW 4500 pH Value; ASTM E70; ASTM D1293  |
|  | O2 content (3)                | ASTM D5543   |
| Injection water (from sea water treatment or produced water treatment) | O2 content (3)                | ASTM D5543   |
|  | SDI (Silt Density Index)      | ASTM D4189.  |
|  | Number of particles           | SMEWW 2560 C. Light-Blockage Method  |
|  | Sulfate Content               | ASTM D516, EPA 375.4, SMEWW 4500-SO42- (turbidimetric method) or ASTM D4327 (ion chromatography) |
|  | Chlorine content (4)          | 4500-Cl G. DPD Colorimetric Method   |
|  | H2S content in water          | UOP 209 (potenciometric method) or SMEWW 4500-S2- G (ion-selective electrode method)             |
|  | pH                            | SMEWW 4500 pH Value; ASTM E70; ASTM D1293  |
|  | Sulfite                       | SMEWW 4500-SO32- B (iodometric method)   |
|  | Oil content in water          | API RP 45  |
| Produced gas   | H2S content                   | GPA STD 2265; ASTM D2385; ISO 6326-3; ASTM D4810   |



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| SYSTEMS                             | ANALYSIS   | REFERENCED DOCUMENT   |
|-------------------------------------|--|---|
|                                     | Composition of natural gas by Gas Chromatography (5) | ASTM D1945; ABNT NBR 14903; ISO 6974;   |
| Treated gas                         | H2O content (6)                                      | ASTM 1142 and ASTM D 5454   |
|                                     | H2S content  | GPA STD 2265; ASTM D2385; ISO 6326-3; ASTM D4810  |
|                                     | Composition of natural gas by Gas Chromatography     | ASTM D1945; ABNT NBR 14903; ISO 6974;   |
|                                     | Gas Compliance Certificate                           | Note (7)  |
| Heavy Hydrocarbon Rich Stream       | Composition by Gas Chromatography                    | ASTM D1945; ABNT NBR 14903  |
|                                     | Density  | ASTM D1657;ASTM D2598; ISO 3993 or ISO 8973   |
|                                     | H2O content  | ASTM 1142; ASTM D 5454  |
| Hydraulic control fluid             | Cleanliness  | ISO 11500; ISO 4406; SAE AS4059   |
| Sea Water Lift System               | Chlorine content (4)                                 | 4500-Cl G. DPD Colorimetric Method  |
| Cooling and Heating Medium Systems; | pH   | SMEWW 4500 pH Value; ASTM E70; ASTM D1293   |
|                                     | Chloride   | ASTM D512; ASTM D4458   |
|                                     | Corrosion inhibitor content                          | Hach Method 8153 Nitrite, or another test method depending on the type of corrosion inhibitor used. |
|                                     | Iron content   | Hach Method 8008 Iron; Application Note Merck MColorTest™ Iron Test; SMEWW 3500-Fe-B                |
| Make-up water                       | pH   | SMEWW 4500 pH Value; ASTM E70; ASTM D1293   |
|                                     | Chloride   | ASTM D512; ASTM D4458   |
|                                     | Chlorine content (4)                                 | 4500-Cl G. DPD Colorimetric Method  |
|                                     | Iron content   | Hach Method 8008 Iron; Application Note Merck MColorTest™ Iron Test; SMEWW 3500-Fe-B                |
|                                     | Sulfate Content                                      | ASTM D516; EPA 375.4  |
|                                     | O2 content (3)                                       | ASTM D5543  |



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| SYSTEMS           | ANALYSIS   | REFERENCED DOCUMENT  |
|-------------------|--|--|
| Potable Water (8) | pH   | SMEWW 4500 pH Value; ASTM E70; ASTM D1293  |
|                   | Chloride   | ASTM D512; ASTM D4458  |
|                   | Chlorine content (4)   | 4500-Cl G. DPD Colorimetric Method   |
|                   | Iron content   | Hach Method 8008 Iron; Application Note Merck MColorTest™ Iron Test; SMEWW 3500-Fe-B |
|                   | Color  | SMEWW 2120-B (Visual Comparison Method)  |
|                   | Turbidity  | SMEWW 2130-B (Nephelometric Method)  |
|                   | O2 content   | ASTM D5543   |
| Subsea Chemicals  | Cleanliness  | ISO 11500; ISO 4406; SAE AS4059  |
| Lean and Rich TEG | TEG Content  | ASTM E1064; ASTM D4928; ASTM E203  |
|                   | Salinity   | ASTM D3230   |
| Lean and Rich TEG | Glycol Concentration   | ASTM E1064; ASTM D4928; ASTM E203  |
| Sewage system (8) | pH   | SMEWW 4500 pH Value; ASTM E70; ASTM D1293  |
|                   | Chlorine content (4)   | 4500-Cl G. DPD Colorimetric Method   |
| Amine             | Gas chromatography (including CO2)<br>H2S content by iodometry (GPA STD 2265);<br>Lean and rich amine concentration<br>Amine acid gas loading<br>Nitrite ion in the reflux water to the stripper tower<br>Oxygen content, pH, free chlorine, total hardness, total iron and alkalinity in the make up water. |  |

Table 2.10.1.b – Laboratory Analyses - Onshore

| SYSTEMS                     | ANALYSIS                                 | REFERENCED DOCUMENT   |
|-----------------------------|--|---|
| Produced Oil and Condensate | PVT - shrinkage factor and gas oil ratio | Petrobras Test Method (Pressurized density and flash release) |



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| SYSTEMS  | ANALYSIS   | REFERENCED DOCUMENT   |
|--|--|---|
| Produced and discharged water  | Composition (9)  | USEPA Method 300; ASTM D4327; SMEWW 4110 B; ASTM D691; ASTM D1976.                                |
|  | Oil content (8)  | SMEWW 5520 B and SMEWW 5520 F   |
| Injection water (from sea water treatment or produced water treatment) | Bacteria SBR planctonic, mesophilic and thermophilic   | Standard Test Method to be defined by Petrobras   |
|  | BANHT - Total Anaerobic Heterotrophic Bacteria   | Standard Test Method to be defined by Petrobras   |
|  | Total suspended solids (TSS)   | SMEWW 2540 D or ISO 11923   |
| Potable Water  | Water potability requeriments  | Note (8)  |
| Sewage system (8)  | BOD  | SMEWW 5210 B. 5-Day BOD Test; SMEWW 5210 D. Respirometric Method                                  |
|  | COD  | SMEWW 5220 C. Closed Reflux, Titrimetric Method; SMEWW 5220 D. Closed Reflux, Colorimetric Method |
|  | Oil content  | SMEWW 5520 B; SMEWW 5520 D; SMEWW 5520 D;   |
|  | Total coliform bacteria; E.coli  | 9223 Enzyme Substrate Coliform Test   |
|  | Organochlorine compounds (chlorobenzenes, dichloroethene, trichloroethene, chloroform, carbon tetrachloride) | EPA 8260  |
| Polychlorinated Biphenyls (PCBs)                                       | EPA 8082; EPA7270  |   |

NOTE 1: Endpoint titration with potentiometric pH measurement (SET pH) and Dynamic equivalence point titrations with potentiometric voltage measurement (DET U). CONTRACTOR may request a pH analysis of the water separated in the laboratory



TITLE:

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from a mixture of oil, deionized water, demulsifier and toluene, at a frequency and with an experimental procedure to be defined later

NOTE 2: OIL CONTENT AT ALL POINTS OF DISCHARGE TO OVERBOARD, UPSTREAM AND DOWNSTREAM OF PROCESS VESSELS. API RP45 MUST BE APPLIED TO DETERMINE THE OIL IN WATER CONTENT IN SLOP TANK SAMPLES. CONTRACTOR SHALL BE ABLE TO PERFORM STANDARD METHODS 5520 B ONSHORE TO COMPLY WITH CONAMA REGULATIONS.

NOTE 3: Measurement range shall be from 0 to 1000 ppb.

NOTE 4: Laboratory analyses should be able to measure at least the specification of 0,1 to 2 ppm of chlorine content.

NOTE 5: CONTRACTOR shall supply chromatographic analysis of any gas sampling point, under PETROBRAS occasional demands.

NOTE 6: CONTRACTOR have to be able to perform analysis with chandler chanscope digital dew point meter, including accessories for dew points down to -100°f (-75°c). contractor shall provide portable aluminum oxide moisture sensor according to astm d 5454. the portable aluminum analyzer SHALL BE ABLE TO MEASURE H2O CONTENT IN THE TREATED GAS STREAM WITHIN THE MOISTURE SPECIFICATION RANGE.

NOTE 7: The CONTRACTOR shall carry out the tests required by the current ANP Technical Regulation and issue a Quality Certificate proving compliance with the specification of natural gas to be marketed throughout national territory.

NOTE 8: CONTRACTOR shall carry out the tests in accordance with current legislation.

NOTE 9: Composition shall include: Salinity, Organic acids, Bicarbonates, Calcium, Magnesium, Bromide, Barium, Strontium, Iron, Manganese, Potassium, Lithium, Boron, Sulfate.

NOTE 10: CONTRACTOR shall carry out the tests required by Combined Cycle equipment suppliers to assure proper and safe operation of every equipment of the steam power generation system.

2.10.2 All Laboratory equipment and analysis methodology shall provide reliable results and shall be submitted to PETROBRAS for comments/information during the engineering design phase. PETROBRAS at their own discretion will collect samples for further comparison with the measured results obtained in the Unit.

2.10.3 All glassware and equipment should be calibrated with certified standards of RBC/Inmetro.

2.10.4 Laboratory shall be located in a non-hazardous area, next to the Utilities Module and as close to the Accommodation Module as possible.

2.10.5 All organic or toxic reagents shall be stored in cabinets with proper exhaustion.

2.10.6 Laboratory drain system shall prevent the possibility of back-flow of flammable vapors.

2.10.7 Air conditioning should be exclusive for laboratory facilities.



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2.10.8 Separates sinks shall be installed. One sink dedicated to inorganics (e.g. water) and other sink dedicated to organics (e.g. kerosene).

2.10.9 An eye-washer and shower shall be provided inside the laboratory.

2.10.10 Each equipment should have its own socket.

2.10.11 CONTRACTOR shall calibrate all laboratory equipment according to the manufacturer's guidelines on a regular basis, calibration certificates must be kept onboard.

2.10.12 CONTRACTOR shall provide a local test certificate for fume hood with face speed measurement and smoke test according to ANSI/ASHRAE 110 standard.

**2.11 SUBSEA MULTIPHASE BOOSTING SYSTEMS****2.11.1 SYSTEM DEFINITION**

2.11.1.1 3 (three) Subsea Multiphase Boosting Systems (SMBS) are planned to be installed and to produce to the FPSO. The installation of an Integrated SMBS Topside Module (TM#01) shall occur at the shipyard during FPSO module lifting campaign. All infrastructure, all electrical and non-electrical facilities to receive, install, integrate, commission and operate TM#01 shall be provided by CONTRACTOR at the shipyard.

2.11.1.2 Additionally, 2 (two) Subsea Multiphase Boosting Systems (SMBS) are planned to be installed in the future, after FPSO is in operation in its final location, and to produce to the FPSO. The installation of this second Integrated SMBS Topside Module (TM#02) shall occur offshore. All infrastructure and all electrical and non-electrical facilities to receive, install, integrate, commission and operate TM#02 shall be provided by CONTRACTOR at the shipyard. TM#02 power demand do not need to be considered in the load balance of the unit.

2.11.1.3 Figures 2.11.1.1 and 2.11.1.2 presents the main interfaces between FPSO and the TM#01 and the TM#02, respectively. In RED are highlighted the main scope and

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interfaces that shall be provided by FPSO to host these Integrated SMBS Topside Modules and to produce the SMBS.

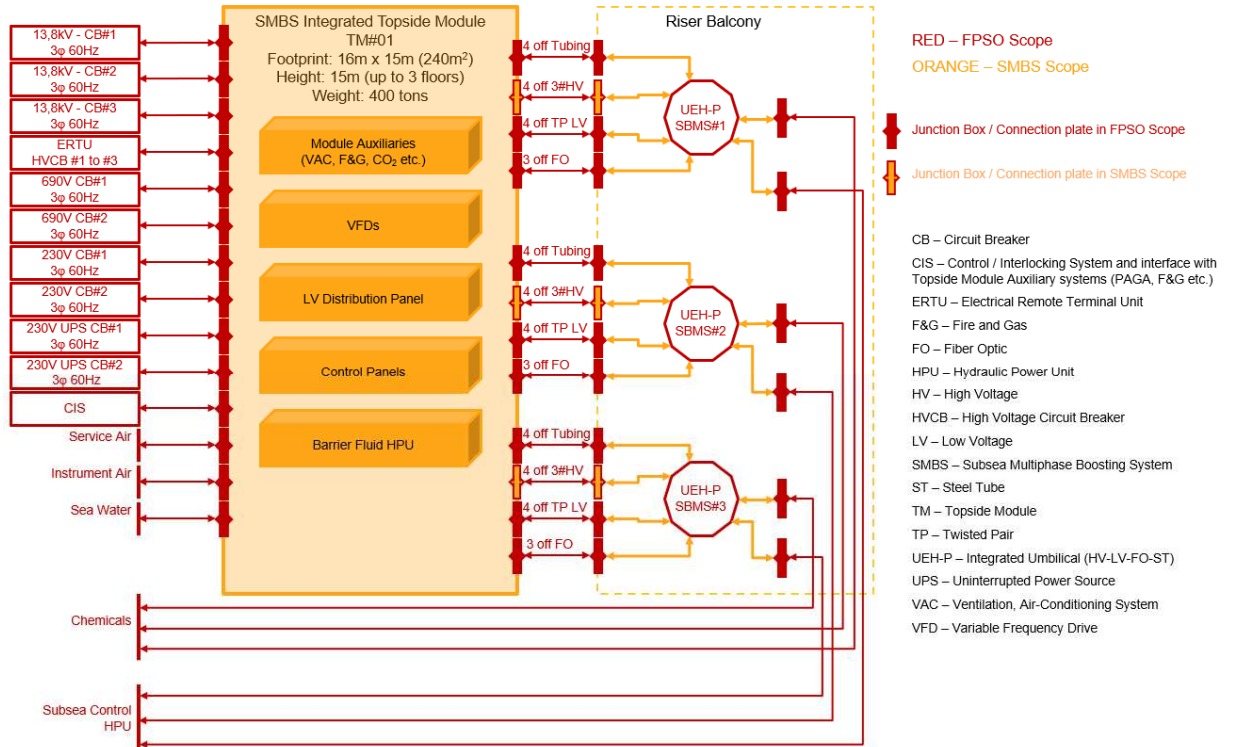


Figure **Erro! Fonte de referência não encontrada.** – SMBS Integrated Topside Module TM#01 interconnection schematics

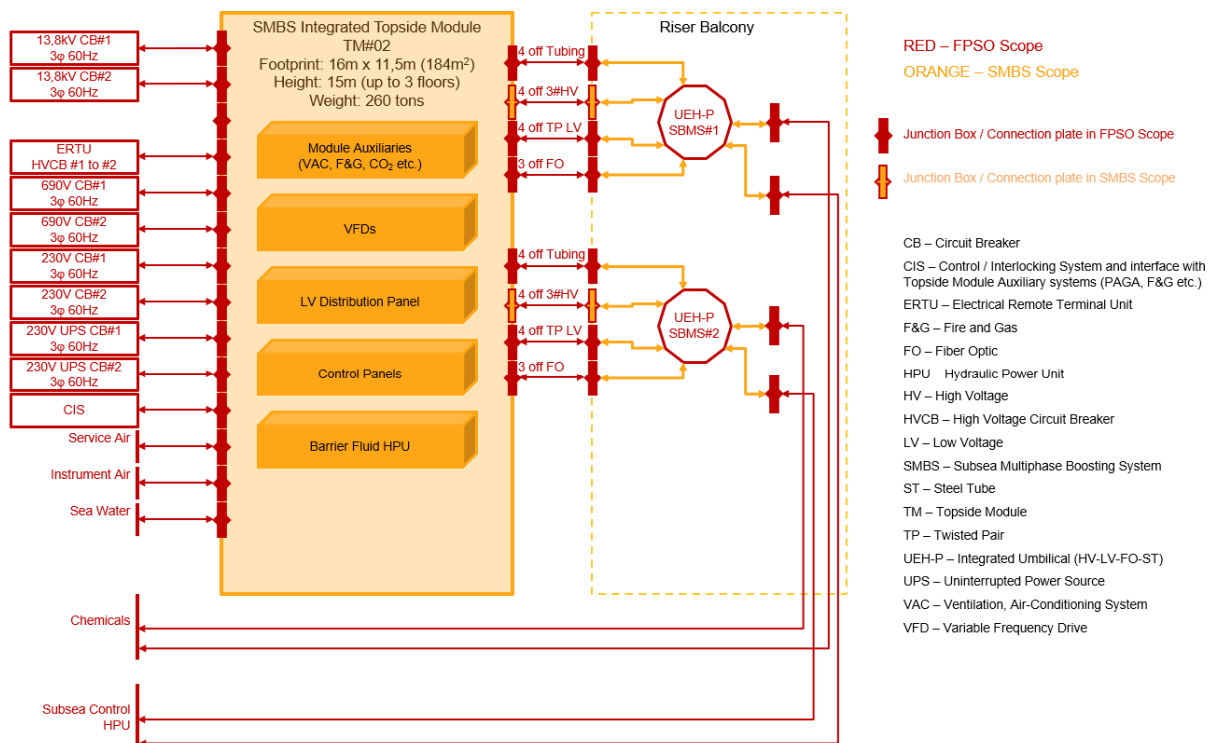




Figure **Erro! Fonte de referência não encontrada.** – SMBS Integrated Topside Module TM#02 interconnection schematics

### 2.11.2 SMBS REQUIREMENTS AND INTERFACE CONNECTIONS WITH FPSO

2 (two) complete independent SMBS Integrated Topside Modules will be installed in the FPSO as schematically presented in Figure 2.11.1.1 and Figure 2.11.1.2.

CONTRACTOR shall provide all supplies, facilities, and infrastructure to receive, install, integrate, commission and operated TM#01 and TM#02, as follow:

- High Voltage (HV)
- Low Voltage (LV)
- Low Voltage UPS
- HVAC cooling water
- HVAC drain
- Barrier Fluid (BF) drain (might be oil or water/MEG)
- Control Fluid
- Air supply for BF system
- Fire and Gas hardwired
- PA/GA & Telephone
- HVCB hardwired
- ESD hardwired
- PSD hardwired
- CIS and CCR interface
- Chemicals
- Service air
- Fresh air intake
- Air outlet
- High Voltage junction boxes
- Low Voltage junction boxes
- Fiber Optic (FO) junction boxes
- TUTU plates

- All HV, LV, hardwired, FO, tubing etc. infrastructure from FPSO facilities up to the SMBS Integrated Topside Modules area and between SMBS Integrated Topside Modules area and the SMBS umbilical slot positions at the Riser Balcony.

### 2.11.3 AREA AND MATERIAL HANDLING

CONTRACTOR shall provide:

Overall free area prepared to receive the TM#01 and the TM#02 of 19m x 31m (589m<sup>2</sup>) as presented in Figure 12.11.3.1. TM#01 is a topside module of dimensions 16m x 15m x 15m and of 400 ton of weight and TM#02 is a topside module of dimensions 16m x 11,5m x 15m and of 260 ton of weight. A minimum distance of 1,5m shall be considered around each side of TM#01 and TM#02, as presented in a preliminary view in Figure 2.11.3.1

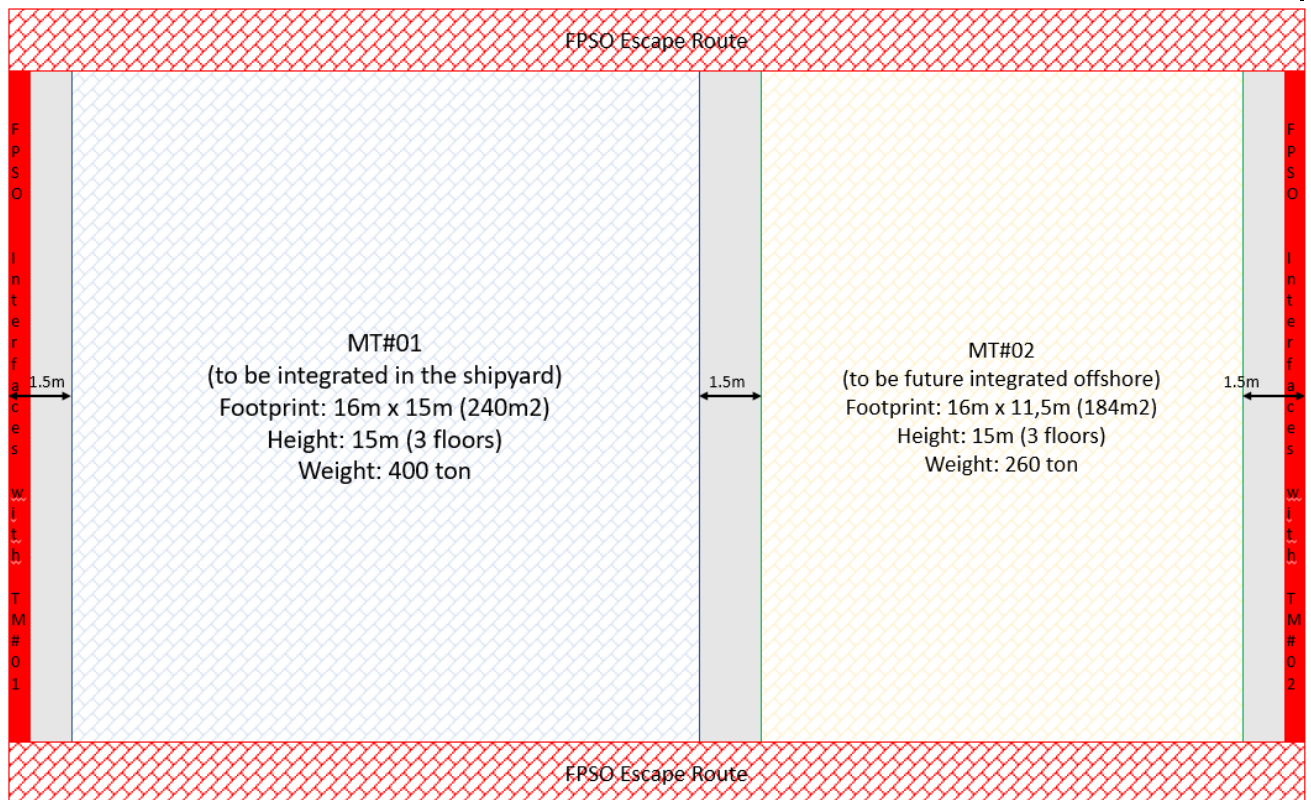


Figure 0 – Area prepared to receive TM#01 and TM#02

Each SMBS Integrated Topside Module may be stacked in more than 1 level with total height of 15m.

The overall free area shall be located within a Non-hazardous Zone covered by fixed crane provided by CONTRACTOR.

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The area shall be covered by FPSO offshore crane capable to make an offshore lifting operation of maximum 25 ton.

Proper means (cranes, mono-rails, skidding, crawlers, slings, rigging, etc.) for the installation/de-installation of equipment shall be available. The heaviest piece of equipment to be individually handled is 20 ton.

Dedicated team and infrastructure providing support to all SMBS lifting, installation, integration, and commissioning services in the FPSO, including but not limited to cable laying, scaffolding assembly, cable interconnection and termination, material handling, equipment installation and fastening, etc.

#### 2.11.4 NON ELECTRICAL UTILITIES

CONTRACTOR shall provide the following infrastructure from FPSO facilities to TM#01:

- Service air and Instrument air supply: 500 Sm<sup>3</sup>/h @ 100psi;
- Sea water supply: 450 m<sup>3</sup>/h @ 32°C @ 2 to 10bar;
- Instrument air supply, Nitrogen, Pneumatic Fluids;
- Control fluid.
- A suitable storage area protected from rain and weather able to move and store enough subsea pump barrier fluid barrels between refills considering possible contingencies (reference 16 barrels)

CONTRACTOR shall provide the following infrastructure from FPSO facilities to TM#02:

- Service air and Instrument air supply: 250 Sm<sup>3</sup>/h @ 100psi;
- Sea water supply: 370 m<sup>3</sup>/h @ 32°C @ 2 to 10bar;
- Instrument air supply, Nitrogen, Pneumatic Fluids;
- Control fluid.
- A suitable storage area protected from rain and weather able to move and store enough subsea pump barrier fluid barrels between refills considering possible contingencies (reference 12 barrels)

Location of supplies for each SMBS Integrated Topside Module shall be mutually agreed during early stage of the detailed design.

The utilities supply data informed in this item 2.11.4 shall be confirmed during detailed design.

#### 2.11.5 ELECTRICAL AND INSTRUMENTATION FACILITIES

CONTRACTOR shall provide the power supply to TM#01 as detailed below. TM#01 loads shall be considered in the unit load list:

- 13MW@0.95 power factor, three-phase, 60Hz, 13,8kV;
- 450kW@0,80 power factor, three-phase, 60Hz, 690V;
- 100kW@0,80 power factor, three-phase, 60Hz, 230V
- 30kVA UPS supply, three-phase, 60Hz, 230V.

CONTRACTOR shall provide the power supply to TM#02 as detailed below. TM#02 loads do not need to be considered in the unit load list:

- 11MW@0.95 power factor, three-phase, 60Hz, 13,8kV;
- 370kW@0,80 power factor, three-phase, 60Hz, 690V;
- 70kW@0,80 power factor, three-phase, 60Hz, 230V;
- 20kVA UPS supply, three-phase, 60Hz, 230V.

CONTRACTOR shall provide the following infrastructure (circuit breakers, cables, cables trays, supports, junction boxes etc.) from FPSO LER to TM#01:

- 01 (one) 13,8kV Circuit Breaker to protect each SMBS feeder cables and SMBS VFD input transformer: 5,2MW @ 0.95PF – 3 phases – 60Hz – 13,8kV;
- 02 (two) 13,8kV Circuit Breaker to protect each SMBS feeder cables and SMBS VFD input transformer: 3,9MW @ 0.95PF – 3 phases – 60Hz – 13,8kV;
- 01 (one) HV Junction Boxes, installed near TM#01 area, rated for 5,2MW @ 0.95PF – 3 phases – 60Hz – operational voltage 13,8kV from the 13,8kV Circuit Breaker;



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- 02 (two) HV Junction Boxes, installed near TM#01 area, rated for 3,9MW @ 0.95PF – 3 phases – 60Hz – operational voltage 13,8kV from the 13,8kV Circuit Breaker;
- 01 (one) Electrical Remote Termination Unit (ERTU) installed near TM#01 area;
- Redundant cabling from 13,8kV Circuit Breaker to the ERTU for hardwired protection signal from each SMBS VFD and the respective 13,8kV Circuit Breaker;
- Redundant auxiliary power for HVAC: 02 (two) LV Junction Boxes with 690V – 450kW each;
- Redundant auxiliary power for control: 02 (two) LV Junction Boxes with 230V – 100kW each;
- Redundant UPS: 02 (two) Junction Box with 230V – 30kVA each.

CONTRACTOR shall provide the following infrastructure (circuit breakers, cables trays, supports, junction boxes etc.) from FPSO LER to TM#02:

- 02 (two) 13,8kV Circuit Breaker to protect each SMBS feeder cables and SMBS VFD input transformer: 5,5MW @ 0.95PF – 3 phases – 60Hz – 13,8kV;
- 02 (two) HV Junction Boxes, installed near TM#02 area, rated for 5,5MW @ 0.95PF – 3 phases – 60Hz – operational voltage 13,8kV from the 13,8kV Circuit Breaker;
- 01 (one) Electrical Remote Termination Unit (ERTU) installed near TM#02 area;
- Redundant cabling from 13,8kV Circuit Breaker to the ERTU for hardwired protection signal from each SMBS VFD and the respective 13,8kV Circuit Breaker;
- Redundant auxiliary power for HVAC: 02 (two) LV Junction Boxes with 690V – 370kW each;
- Redundant auxiliary power for control: 02 (two) LV Junction Boxes with 230V – 70kW each;
- Redundant UPS: 02 (two) Junction Box with 230V – 20kVA each.

CONTRACTOR shall provide the following independent infrastructure (cable trays, cables, supports, junction boxes etc.) from TM#01 to each of the 3 (three) SMBS umbilical (UEH-P) slot at Riser Balcony:



- Space for installation of 1 (one) HV Junction Box (minimum 1500mm width, 2500mm height and 500mm depth) close to TM#01 and 1 (one) HV Junction Box (minimum 1500mm width, 2500mm height and 500mm depth) at the SMBS umbilical (UEH-P) slot position at the Riser Balcony, per SMBS. HV Junction Box space at Riser Balcony position shall be on top of umbilical hang-off flange.
- Separate and exclusive cable tray connecting the HV Junction Boxes with 4 three-phase armored cables of 3#150mm<sup>2</sup>@18/30(36) kV.
- LV Junction Box close to TM#01 (2 off) + LV electrical cabling (2 off) on separate cable tray + LV Junction Box (2 off) at the SMBS umbilical (UEH-P) positions at the Riser Balcony, per SMBS. Electrical Cable specification: 4 cables x 2 conductors x 16mm<sup>2</sup>, 1.8/3kV, Type: Twisted pair. Screened. Armored. Junction Box insulation voltage 3kV.
- FO Junction Box close to TM#01 (2 off) + Fiber Optic cable tray (2 off) + FO Junction Box (2 off) at SMBS umbilical (UEH-P) positions at the Riser Balcony, per SMBS. Fiber Optic Cable specification: Single Mode Fiber Optic Cable (ITU-G.652), 3 cables, each containing 24 individual fibers rating 9/125 μm, wavelength 1550nm.
- TUTU plate close to TM#01 + 4 (four) tubing for the SMBS Barrier Fluid HPU (might be oil or water/MEG) + TUTU plate at each SMBS umbilical slot at the Riser Balcony. Tubing specification: ½", 10kpsi, superduplex.
- 4 (four) tubing from Subsea Equipment Control HPU to each SMBS umbilical slot at the Riser Balcony + TUTU plate, per SMBS. Tubing specification: ½", 10kpsi, superduplex.

CONTRACTOR shall provide the following independent infrastructure (cable trays, cables, supports, junction boxes etc.) from TM#02 to each of the 2 (two) SMBS umbilical (UEH-P) slot at Riser Balcony:

- Space for installation of 1 (one) HV Junction Box (minimum 1500mm width, 2500mm height and 500mm depth) close to TM#02 and 1 (one) HV Junction Box (minimum 1500mm width, 2500mm height and 500mm depth) at the SMBS umbilical (UEH-P) slot position at the Riser Balcony, per SMBS. HV Junction Box space at Riser Balcony position shall be on top of umbilical hang-off flange.



- Separate and exclusive cable tray connecting the HV Junction Boxes with 6 three-phase armored cables of 3#150mm<sup>2</sup>@18/30(36) kV.
- LV Junction Box close to TM#02 (2 off) + LV electrical cabling (2 off) on separate cable tray + LV Junction Box (2 off) at the SMBS umbilical (UEH-P) positions at the Riser Balcony, per SMBS. Electrical Cable specification: 4 cables x 2 conductors x 16mm<sup>2</sup>, 1.8/3kV, Type: Twisted pair. Screened. Armored. Junction Box insulation voltage 3kV.
- FO Junction Box close to TM#02 (2 off) + Fiber Optic cabling (2 off) + FO Junction Box (2 off) at SMBS umbilical (UEH-P) positions at the Riser Balcony, per SMBS. Fiber Optic Cable specification: Single Mode Fiber Optic Cable (ITU-G.652), 3 cables, each containing 24 individual fibers rating 9/125 μm, wavelength 1550nm.
- TUTU plate close to TM#02 + 4 (four) tubing for the SMBS Barrier Fluid HPU (might be oil or water/MEG) + TUTU plate at each SMBS umbilical slot at the Riser Balcony. Tubing specification: ½", 10kpsi, superduplex.
- 4 (four) tubing from Subsea Equipment Control HPU to at each SMBS umbilical slot at the Riser Balcony + TUTU plate, per SMBS. Tubing specification: ½", 10kpsi, superduplex.

HV, LV and FO junction boxes as well as TUTU plate distance from the umbilical shall be agreed with PETROBRAS during early stage of the detailed design.

CONTRACTOR shall consider scope listed in item 8.13 for integration between SMBS containers to FPSO CIS at Central Control Room.

CONTRACTOR shall provide proper means for hard-wired signals and serial links to FPSO facility control system to each SMBS Integrated Topside Module.

### 2.11.6 SAFETY REQUIREMENTS

CONTRACTOR shall provide all safety equipment needed for each SMBS Integrated Topside Module in accordance with applicable rules and standards, including but not limited to: fire detection, gas detection at air intakes, manual alarm call point (MAC), fire

extinguishers, telecommunication means (PA speakers, telephone), safety signaling.

Fire/gas detectors and MAC shall be hardwired to the F&G System.

Consequence analysis to be performed by CONTRACTOR, such as fire propagation study, explosion study and gas dispersion for air intakes, shall take into consideration the SMBS Integrated Topside Modules location to assess impacts of accidental loads on this module, according to requirements of SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

#### 2.11.7 CHEMICALS AND HYDRAULICS FLUIDS REQUIREMENTS

CONTRACTOR shall consider the 5 (five) SMBS demand of control fluid in the subsea system HPU.

CONTRACTOR shall provide all chemicals and respective infrastructure at each SMBS umbilical slot at the Riser Balcony + TUTU plate, per SMBS.

#### 2.12 ENERGY EFFICIENCY & ATMOSPHERIC EMISSIONS

2.12.1 CONTRACTOR shall comply with "Zero Routine Flaring by 2030" initiative of the World Bank (<https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030>). This requirement applies for flaring and hydrocarbon venting from process plant. It does not apply for venting of cargo tanks neither flare pilots. Emergency conditions and safety reasons shall not be considered "routine".

##### 2.12.2 FUGITIVE EMISSIONS

2.12.2.1 Valve specifications shall comply with the following ISO 15848 requirements:

- tightness class = BH;
- endurance = CC1 (control) or CO1 (on-off);
- temperature = according to temperature range;
- test pressure = according to valve pressure rate;
- number of stem seal adjustments = maximum of 1 (one),

where the handled fluid has at least one of the characteristics below:

- methane and/or NMHC (Non-Methane HydroCarbon) content higher or equal to 20% mass;
- BTEX content higher or equal to 1 % weight;
- benzene content higher or equal to 1 % vol.



2.12.2.2 Pump seal specifications shall comply with API 682 requirements where the handled fluid has at least one of the characteristics below:

- methane and/or NMHC (Non-Methane hydrocarbon) content higher or equal to 20% mass;
- BTEX content higher or equal to 1 % weight;
- benzene content higher or equal to 1 % vol.

2.12.3 During the execution phase CONTRATOR shall provide 18 months after LOI, only for information, Energy Efficiency report(s) having the following analysis during FPSO design phase, after issue of HAZOP report::

- Analysis of the use of mechanical energy from streams (e.g. turboexpander, hydraulic turbines)
- Optimization of heat exchange processes;
- Analysis of application of VSD;
- Internal process plant gas recirculation;
- Optimization of electrical consumption for liquid and gas transfer equipment.

### **3 UTILITIES**

#### **3.1 GENERAL**

3.1.1 This item describes the minimum requirements and specifications that shall be applied to utility systems and equipment of the Unit.

#### **3.2 SEAWATER LIFT SYSTEM**

3.2.1 A Sea Water Lift System shall be installed to supply seawater to the deaerated water injection system, to the production plant cooling water system and to meet other Unit's needs. For seawater characteristics, CONTRACTOR shall consider sea water composition in item 3.2.9 and METOCEAN DATA (see item 1.2.1). For seawater temperature, CONTRACTOR shall consider p95 temperature at each water depth.

3.2.2 The seawater lift system shall be designed in order to supply, besides all other consumption requirements, fresh/sea water to fill the subsea system (riser and flow lines) before pressurization and leak test.

3.2.3 Ionized chlorine shall be injected at the inlet of the seawater lift system, to avoid fouling or marine growth.

3.2.4 There shall be modules of independent electrochlorination cells, including a stand-by module, allowing isolation for maintenance without dosage interruption for consumers.

- 3.2.5 CONTRACTOR is responsible to supply the ionized chlorine to be used onboard. To control the injection, according to demand, the residual chlorine content shall be monitored through the redox potential, which shall be between 0.5 and 1 mg/L. The design shall define the monitoring point to assure the entire system protection.
- 3.2.6 For installation/maintenance purposes, the Unit shall be designed to install and repair the intake water pipe in the final location offshore.
- 3.2.7 Sea Water Lift pumps may be dry mounted or submerged types. For acceptable vendor list for Submerged Electric Sea Water Lift Pumps, see item 19.1.1.8.
- 3.2.8 During project execution phase, CONTRACTOR shall evaluate the seawater intake depth in order to reduce seawater intake temperature and achieve lower organic residual content. For each seawater intake, CONTRACTOR shall provide an extension hose with length at least 40m below hull base line.
- 3.2.9 Seawater Composition:

Table 3.2.9A: Seawater Composition

| <b>SEAWATER ANALYSIS</b>     |                       |
|------------------------------|-----------------------|
| pH                           | 8.45                  |
| Conductivity                 | 5,800 µmho/m          |
| K <sup>+</sup>               | 500 mg/L              |
| Na <sup>+</sup>              | 12,000 mg/L           |
| Ca <sup>++</sup>             | 500 mg/L              |
| Mg <sup>++</sup>             | 1,700 mg/L            |
| Ba <sup>++</sup>             | <1 mg/L               |
| Sr <sup>++</sup>             | 9 mg/L                |
| Fe total                     | <1 mg/L               |
| CO <sub>3</sub> <sup>-</sup> | 31 mg/L               |
| HCO <sup>-</sup>             | 101 mg/L              |
| NO <sub>3</sub> <sup>-</sup> | <1 mg/L               |
| Cl <sup>-</sup>              | 21,347 mg/L           |
| SO <sub>4</sub> <sup>-</sup> | 2,800 mg/L            |
| Salinity                     | 35,177 mg/L (as NaCl) |
| Total suspended solids       | 2.0 mg/L              |
| Oxygen content               | 7 mg/L                |
| Turbidity                    | 0.20 FTU              |
| Silt density index           | 5.1                   |
| m-SRB                        | 25 MPN/mL             |
| Aerobic bacterias            | 7,500 MPN/mL          |
| Facultative bacterias        | 44 CFU/mL             |

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MPN – Most Probable Number

CFU – Colony Formation Unit

Table 3.2.9B: Seawater Particle Size Distribution

| <b>PARTICLE SIZE DISTRIBUTION</b> |                                |
|-----------------------------------|--------------------------------|
| SIZE RANGE (µm)                   | NUMBER OF PARTICLES (part./mL) |
| 3 to 5                            | 424.1                          |
| 5 to 7                            | 151.1                          |
| 7 to 10                           | 103.4                          |
| 10 to 15                          | 52.8                           |
| 15 to 30                          | 30.5                           |
| 30 to 50                          | 5.8                            |
| 50 to 100                         | 1.2                            |
| 100 to 250                        | 0.0                            |
| <b>TOTAL</b>                      | <b>769.2</b>                   |

NOTE 1: This information does not take into consideration the vessel and UNIT overboard lines interferences, e.g., temperature, particles and others.

NOTE 2: First filter downstream sea water lift pumps shall be specified for 1,000 µm.

### 3.3 COOLING WATER SYSTEM

3.3.1 Directly hydrocarbon (including lube oils, hydraulic oil fluids and produced water) cooling with seawater is not acceptable. Acceptable alternatives are fresh water closed cooling system or air coolers.

3.3.2 A closed freshwater cooling system shall be provided to supply cooling medium to the Unit systems as follows:

- Independent cooling medium for marine and utilities systems located within machinery spaces and accommodation;
- Independent cooling medium for topsides hazardous area consumer (gas-cooling water or oil-cooling water heat exchangers). This system cannot be used for cooling any topsides non-hazardous area (E-house, Turbo-Generators, Water Injection, etc.).
- For topsides non-hazardous consumers the following is acceptable to be adopted if allowed by CS: (i) air cooling, (ii) utilization of cooling medium for marine and utilities system or (iii) direct sea water open circuit provided will not cool any hydrocarbon fluid.

3.3.3 For heat exchangers design, see item 10.3.

3.3.4 CONTRACTOR shall fulfill all Brazilian Administration regulations issued by Environment Ministry (“Ministério do Meio Ambiente”), through its CONAMA Resolução Nº357/2005 and CONAMA Resolução Nº430/2011.



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- 3.3.5 CONTRACTOR shall provide a temperature transmitter with high temperature alarm to monitor sea cooling water overboard discharge temperature.
- 3.3.6 Cooling water expansion tank/vessel gaseous exhaust shall be vented to safe location or directed to flare.
- 3.4 HEATING MEDIUM SYSTEM
- 3.4.1 A Heating Medium System shall be provided to recover the heat from the turbines exhaust gas and from other systems.
- 3.4.2 For cogeneration, each turbogenerator shall have its own individual Waste Heat Recovery Unit (WHRU). For heat exchangers design, see item 10.3.
- 3.4.2.1 WHRUs can also be installed in turbocompressors, if required. Whenever WHRUs are provided to recover the turbine exhaust heat of a compressor service, all equipment in that service must have its own dedicated WHRU.
- 3.4.3 For combined cycle power generation, each gas turbogenerator shall have its own individual steam generator and Waste Heat Recovery Unit (WHRU). WHRU coil shall be segregated from the steam loop, serving as a backup source of heat to the process in case of steam system outages. WHRUs shall be capable of providing the full amount of heat required by the FPSO at peak thermal demand conditions. The Heat Recovery Steam Generator (HRSG) or Once Through Steam Generator (OTSG) shall use the exhausted gases from gas turbines.
- 3.4.3.1 The routing of steam through FPSO shall be minimized for safety reasons. Steam shall be generated at HSTG/OTSG and it shall be treated, conditioned and used only to steam turbogenerators and to transfer heat to hot water heating medium.
- 3.4.3.2 The steam generator shall be capable of running dry indefinitely, and the gas turbogenerators shall run even with its steam generator out of service.
- 3.4.3.3 Hot water heating medium shall be available even if steam turbine is not available; steam turbine by-pass shall be available.
- 3.4.3.4 CONTRACTOR and Steam Generator/WHRU Vendor shall pay special attention to the presence of sulfur in fuel gas/diesel, which might cause acid corrosion in case of condensation. The minimum margin from metal surface temperature to dew point shall be 10°C.
- 3.4.3.5 The steam line shall be designed considering a minimum amount of flanged connections, basically considering it on equipment nozzles. The steam lines routing shall be far away from escape routes and areas with permanent presence of people, in cases it is not feasible, flanged connections shall not be used and line personal protections shall be provided. In other areas with presence of people for maintenance

or operations close to steam lines means of personal protection against contact with lines and vapor jets, such as thermal insulation and flange covers, shall be provided.

3.4.3.6 CONTRACTOR is responsible to provide the laboratory equipment to perform the necessary analysis associated to the water quality used on combined cycle system.

3.4.3.7 CONTRACTOR is responsible to provide the chemical products required for combined cycle system operation.

3.4.4 Hot water expansion tank/vessel gaseous exhaust shall be vented to safe location or directed to flare.

### 3.5 DRAIN SYSTEMS

3.5.1 CONTRACTOR shall design drain system to collect and convey Unit drained liquids to an appropriate treating and/or disposal system in such a way as to protect personnel, equipment and to avoid environmental pollution. Drainage system shall comply with *NOTA TÉCNICA CGPEG/DILIC/IBAMA Nº 01/11* and MARPOL requirements. The effluents shall be segregated, treated (TOG lower than 15 ppm) and monitored through dedicated TOG analyzer(s), previously to being discharged overboard.

3.5.2 Drains systems from hazardous areas shall be collected and routed completely separated from the non-hazardous areas drains.

3.5.3 Drain systems shall be segregated into specific systems, each designed for a particular type of stream, with no interconnection between the systems. Further to this, when appropriate, features such as seal loops and air gaps shall be used to segregate areas served for the same drain system.

3.5.4 Process vessels, piping or other sources containing hazardous liquids which need to be drained for interventions/maintenance/inspection reasons and may not be drained directly to atmosphere without undue risk to personnel, environment or assets from release of toxic vapours, shall be connected to a permanent and contained drain system (closed drain). By toxic vapors CONTRACTOR shall consider streams containing poisonous substances at critical concentrations, such as, but not limited to H<sub>2</sub>S and benzene. For critical concentrations refer to Brazilian Regulations (NR-15) and API RP 55. Pig launchers and receivers shall be drained to a closed drain system, even though the fluids are not considered hazardous.

3.5.5 Instrument drains shall be accounted for in hazardous area classification. The handling of instrument drains shall be on a case by case analysis (special attention for poisonous substances at critical concentrations), however in all cases, the instrument drain piping or tubing shall be arranged so that the draining liquid is visible to the operator when the instrument is being drained.

3.5.6 The drainage system shall follow ISO 13702 and additionally be designed to handle credible spills, rainwater and coincident with deluge and/or fire-fighting activities.

- 3.5.7 Means for oil containment and drainage shall be considered at the main deck and in each section of upper riser balcony (perimeter) including connections and SDVs in the production lines and gas injection lines in order to prevent oil, chemical products or oily water spill on the sea. Riser's SDVs shall have independent and segregated containment and drainage of adjacent areas (such as main deck, for instance).
- 3.5.8 Drain piping shall be designed according to Norsok P-002, clause 7.2.
- 3.5.9 The location of the drain pits and drain boxes shall take into consideration the vessel motion (roll and pitch) and the ship trim to avoid liquid accumulation. Open drain piping diameters shall have at least 3" to avoid clogging.

## **4 MATERIALS AND CORROSION MONITORING**

### **4.1 GENERAL SELECTION RULE**

- 4.1.1 CONTRACTOR must perform the material selection as oriented in ISO 21457, with the additional requirements and limitations herein stated.
- 4.1.2 Material selection must be compatible with the Unit design lifetime, as stated in item 1.2.2.1.

### **4.2 MATERIAL SELECTION REPORT**

- 4.2.1 CONTRACTOR must issue a Material Selection Report for the UNIT as described in ISO 21457. This report must explicitly include all the piping and valves (as per the piping specifications) and the equipment of the UNIT (all TAGs).
- 4.2.2 The Material Selection Report must also include due considerations regarding corrosion allowances, predictions for regular replacements, corrosion protection systems applied (e.g. cathodic protection, scavengers, inhibitors), as well as the efficiencies of the protection systems applied.
- 4.2.3 The Material Selection Report must include General Corrosion Studies, which must explicit the corrosion models and the corrosion allowances calculated for the equipment and piping systems. CONTRACTOR shall submit the reasoning and calculations considered during the design to specify the materials, for all piping, valves, fittings and equipment, according to each type of fluid, considering the corrosion allowance as well as the protection considered.
- 4.2.4 The Material Selection Report must include Corrosion Sensibility Studies, that must evaluate the effect of operational transients and temporary conditions (e.g. temporary by-passes or shut down of processing units), the effect of possible deviations from normal operating conditions (higher temperature, lower pH or higher water cut, for example) and the effect of failure of the corrosion protection systems. Temporary conditions must include upset conditions such as units malfunction (e.g. dehydration and gas sweetening units malfunction).

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4.2.5 All the data necessary to perform the material selection, including the General Corrosion Studies, The Corrosion Sensibility Studies, and the Low Temperature Effect Studies, must be included in the Material Selection Report.

4.2.6 CONTRACTOR must issue a Coating Report with a detailed description of all paint schemes used in the unit.

**4.3 SPECIAL CONSIDERATIONS ABOUT MATERIAL SELECTION****4.3.1 LOW TEMPERATURE SERVICE**

4.3.1.1 CONTRACTOR shall perform the material selection with due considerations regarding to the low temperature effects caused by depressurization events. and the compatibility of gas with non-metallic materials and high strength ferritic materials. For materials selection purposes, CONTRACTOR must determine the lower design temperature (LDT) or alternatively the minimum allowable temperature (MAT) for all unfired pressure vessels, heat exchangers, piping, piping components and valves (including control valves) or rotating equipment containing compressed gas (hydrocarbon or CO<sub>2</sub>) or liquefied gas.

4.3.1.2 CONTRACTOR must also take measures to prevent the equipment from being at temperature below the LDT or alternatively ensure the equipment metal temperature is not below the appropriate MAT, at any given operating pressure. CONTRACTOR must consider scenarios in which equipment temperature can drop such as blowdowns, as well as scenarios of subsequent repressurization of equipment.

4.3.1.3 LDT or MAT must be specified as the lowest of the following values:

- The minimum operating temperature;
- The minimum startup/shutdown, test or upset temperature while at normal operating pressure;
- The minimum temperature during depressurization or repressurization.

4.3.1.4 CONTRACTOR must also take in account the low temperature effects of sudden fluid depressurization and leakage in connections (e.g. flanges, threaded connections), since low temperature may affect the selection of the parts (e.g. low temperature bolting materials shall be selected).

**4.3.2 FLUID COMPOSITION AND CONTAMINANTS**

4.3.2.1 Materials selection must be carried out based on the fluid compositions, as described in Chapter 2 of this General Technical Description, including all of the

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contaminants therein cited (e.g. CO<sub>2</sub> content, H<sub>2</sub>S content, H<sub>2</sub>O content, BS&W) and the worst scenarios.

4.3.2.2 Materials selection shall also meet the inlet fluids characteristics and normal operating conditions below:

- Produced gas CO<sub>2</sub> content: up to 2% mol;
- Produced gas H<sub>2</sub>S content: up to 350 ppmv;
- Produced gas H<sub>2</sub>O content: up to saturated;
- BS&W: up to 95%;
- Chloride (Cl-1): up to 138,200 ppm;
- Minimum pH: 6.4.

4.3.2.3 Materials Selection shall consider the Glycolic Acid/ Acetic acid injection in the production header, test header and any produced water reprocessing line to second stage degasser or production header. The Minimum pH of produced water downstream of the acetic acid injection: 4,5.

#### 4.3.3 H<sub>2</sub>S SERVICE

4.3.3.1 Where H<sub>2</sub>S is expected as a contaminant in the fluids, all materials shall meet the requirements of ISO 15156 for the lowest anticipated pH and the highest H<sub>2</sub>S partial pressure (carbon steel shall be compatible with Sulfide Stress Cracking (SSC) region 3 of ISO 15156-2 as a minimum, with due consideration regarding the lowest pH).

4.3.3.2 All welding procedures will have to be qualified taking into account requirements of piping/equipment construction codes plus the applicable requirements of ISO 15156.

4.3.3.3 Maximum hardness as prescribed by ISO 15156 for both base material and welds must be ensured to all vessels, equipment, piping, fittings and accessories. Dehydration of gas, organic coatings, use of corrosion inhibitors or even H<sub>2</sub>S scavengers will not, in any case, be accepted as measures to relax the requirement to use H<sub>2</sub>S resistant materials, if the operational conditions are categorized as sour in accordance with ISO 15156 (all parts). Operational conditions must include upset conditions such as, but not limited to, dehydration and H<sub>2</sub>S removal systems malfunction.

#### 4.4 MINIMUM MATERIAL GRADE SELECTION

4.4.1 CONTRACTOR must also comply with the following minimum materials specifications, for the indicated portions of the topsides process facilities. Deviations from the materials specifications mentioned must be submitted for PETROBRAS approval, and shall always be fully justified based on technical reasons.



- 4.4.1.1 Piping that will connect the rigid risers (usually starting at the lower riser balcony) to the top side piping (at the upper riser balcony), will cross the splash zone of the unit, and therefore shall be designed with due consideration regarding the hydrogen charging caused by the cathodic protection potential (from both the hull and the riser protection systems) and the extreme corrosivity of this area. As such, the material of construction for these piping (a.k.a. "hard pipes") shall be carbon steel (with external corrosion allowance of 6 mm minimum) with internal overlay of Inconel 625 (with 3 mm thickness minimum). The hard pipe system shall be externally coated with polychloroprene as per ISO 18797-1. Field repair of the polychloroprene coating shall also be performed as per the same standard.
- 4.4.1.2 From the top of the hard pipe up to HP separator, away from the splash zone, where cathodic protection potential does not affect the material, either of the options below may be followed:
- a) Carbon steel with Inconel 625 or 825 cladding (min. cladding thickness 3 mm);
  - b) Duplex (22Cr) or Super duplex stainless steel (25Cr).
  - c) Stainless Steel 6Mo (UNS 31254)
- 4.4.1.3 Heat exchangers:
- Shell:
    - Carbon steel with 625 or 825 cladding (3 mm) or weld overlay.
    - Carbon steel with 3 mm corrosion allowance, if the cooling/heating fluid is not corrosive;
    - SS 316L, Super duplex 25Cr or duplex 22Cr, when corrosion studies have shown it must be suitable for service and there is no risk of crevice corrosion, stress corrosion cracking and/or corrosion under deposits.
  - Tube: Carbon steel, if the cooling/heating fluid is not corrosive, SS 316L, Super duplex 25Cr, Duplex 22Cr, or Inconel 625.
  - Plate Heat Exchanger: Titanium or SS 316L
  - Printed Circuit Heat Exchanger (Core): Duplex Stainless Steel 22Cr, Super Duplex Stainless Steel 25Cr, SS 6Mo or SS 316L
- 4.4.1.4 Choke and downstream lines must be compatible with depressurizing temperature during well startup with gas segregation in the riser top. Minimum temperature to be considered downstream the choke is at least -40°C. Depressurizing temperatures may also occur at production lines.
- 4.4.1.5 Separation and degassing vessels must follow (a) or (b) or (c) below:
- a) Carbon steel with Inconel 625 or 825 cladding (min. cladding thickness 3 mm);
  - b) Carbon steel with SS 904L weld overlay;

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c) Duplex (22Cr) or Super duplex stainless steel (25Cr), when corrosion studies have shown it must be suitable for service and there is no risk of crevice corrosion, stress corrosion cracking and/or corrosion under deposits.

4.4.1.6 Saturated Gas lines must follow (a), (b) or (c) below, taking into consideration operating parameters such as temperature and chlorine content:

- a) Carbon steel with Inconel 625 or 825 (3 mm) clad;
- b) Duplex 22Cr or Super duplex 25Cr;
- c) SS 316L with external coating if temperature greater than 60°C.

4.4.1.7 K.O. Drum & Scrubbers:

- K.O. Drum & Scrubbers (upstream and including Gas Dehydration Unit): Carbon steel with SS 316L, Inconel 625 or 825 cladding (3 mm) or SS 904L weld overlay;
- K.O. Drum & Scrubbers (downstream Gas Dehydration Unit): Carbon Steel according to item 4.3.3, with 3mm corrosion allowance. If necessary, corrosion resistant alloy shall be specified.
- All equipment, piping and accessories of TEG Unit submitted to contact with wet gas plus CO<sub>2</sub> and H<sub>2</sub>S or TEG and presence of Water, CO<sub>2</sub> and H<sub>2</sub>S must consider Corrosion Resistant Alloy as a basic material;
- At least the following equipment are included with such characteristics: Gas Scrubber, Coalescer Filter, Absorber Column, Flash Vessel, TEG Filters, Reboiler, Surge Vessel, Stahl Column.

4.4.1.8 Seawater lines upstream deaerator and Seawater lines upstream deaerator and Produced Water upstream Solid Removal Unit:

- Carbon steel with internal coating or Fiber Reinforced Plastic (FRP);
- The use of alternative materials must take into consideration operating parameters such as temperature and chloride content;

NOTE: SRU Package lines must not be internally coated. In this case, as an alternative to FRP, lines may be of superduplex material;

NOTE: In case of use of Carbon Steel with internal coating, the use of polyethylene (PE) coating is prohibited. CONTRACTOR shall use preferably Fusion Bonded Epoxy (FBE) as internal coating.

4.4.1.9 Water injection lines downstream deaerator and Produced water lines downstream Solid Removal Unit:

- Superduplex or Carbon steel with Inconel 625 clad (3mm) considering the operational limits of pressure, temperature and water composition for each material. Oxygen contamination must be taken into account for materials selection. Oxygen scavenger must not be taken into consideration for material selection due to uncertainties of produced water compatibility.
- From Deaerator to SW Booster Pumps, FRP material may be used, considering the pressure rating.

- 4.4.1.10 For the Main Compressors, construction materials must be selected considering the following contents on the process gas:
- CO<sub>2</sub>: up to 2% mol (or higher, as per process simulations);
  - H<sub>2</sub>S: up to 350 ppmv (or higher, as per process simulations);
  - H<sub>2</sub>O: up to saturated.
- 4.4.1.11 For the VRU compressors, construction materials must be selected considering the following contents on the process gas:
- CO<sub>2</sub>: up to 2% mol (or higher, as per process simulations);
  - H<sub>2</sub>S: up to 350 ppmv (or higher, as per process simulations);
  - H<sub>2</sub>O: up to saturated at all conditions.
- 4.4.1.12 For the Gas Lift/Export Compressors, construction materials must be selected considering the following contents on the process gas:
- CO<sub>2</sub>: at least 2% mol (or higher, as per process simulations);
  - H<sub>2</sub>S: at least 5 ppmv (or higher, as per process simulations);
  - H<sub>2</sub>O: up to 40ppmv.
- 4.4.1.13 For Dehydration / Hydrocarbon dew point adjustment unit (TEG), construction material shall be selected considering the following contents on the process:
- CO<sub>2</sub>: at least 2% mol (or higher, as per process simulations);
  - H<sub>2</sub>S: at least 350 ppmv (or higher, as per process simulations);
- H<sub>2</sub>O: up to saturated.
- 4.4.1.14 CONTRACTOR shall use materials in compliance with IOGP-JIP33 S-716 for pneumatic and hydraulic instruments and transmission lines, including its connections (junction boxes). Tubing must be electrically isolated from carbon steel supports and materials to avoid galvanic corrosion.
- 4.4.1.15 CONTRACTOR must consider the marine atmosphere (CX for atmospheric zone and IM-2/Im1 for splash and immersion zone according to ISO 12944-Part 2) for the design of external coating of piping and equipment. Carbon steel piping provided with thermal insulation must also be painted in order to avoid corrosion in case of liquid accumulation.
- 4.4.1.16 CONTRACTOR must consider flowrate regime (stagnant, intermittent or continuously flowing) when evaluating corrosivity and selecting piping and equipment material.
- 4.4.1.17 CONTRACTOR shall consider maximum temperature of 89°C for arrival systems, including production and test headers and respective relief alignments to flare. From production and test headers to downstream systems, it shall be considered the design cases.

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NOTE 1: Operational conditions shall include upset conditions such as, but not limited to sweetening and dehydration unit malfunction.

NOTE 2: PETROBRAS may accept deviation from materials specifications whenever asked based on technical reasons provided by CONTRACTOR, during the design phase.

NOTE 3: For gas compressors, free water carryover shall also be considered due to the scrubbers' efficiency and water condensation along the piping, both suitable to occur on normal running, on cold startup and on pressurized stop condition.

NOTE 4: CONTRACTOR shall take measures to guarantee compressor performance and availability if wet gas is used for commissioning, start-ups or fuel gas.

NOTE 5: Gaskets materials shall be compatible with fluid and operational temperatures to avoid risk of leakage. Hydraulic paper shall not be used for hot water piping systems

#### **4.5 CORROSION MONITORING**

4.5.1 Due to the presence of contaminants in the oil, CONTRACTOR provide means to monitor the corrosion on piping and equipment.

4.5.2 As a minimum, corrosion monitoring equipment shall be provided in the points along the produced oil, gas and water flow, as follows:

4.5.2.1 Gas injection:

- Coupon and electrical resistance at a common point on reinjection compressor discharge, in order to monitor subsea and well material;
- Non-intrusive monitoring at a common point on reinjection compressor discharge, in order to monitor carbon steel piping on topsides;
- Placement of corrosion monitoring must guarantee exposure to flow conditions irrespective of the slots/risers being used for injection.

4.5.2.2 Water injection lines:

- Linear polarization resistance (LPR) sensor, electric resistance sensor (ER) and galvanic sensor provided on the common water injection header installed downstream of water injection pumps;
- Oxygen analyzer downstream water injection pumps;
- Placement of corrosion monitoring must guarantee exposure to flow conditions irrespective of the slots/risers being used for injection.

#### 4.5.2.3 Produced water lines:

- Linear polarization resistance (LPR) sensor, electric resistance sensor (ER) and galvanic sensor provided on the produced water piping downstream produced water treatment and upstream mixing point with treated seawater;
- The analyzer shall be installed upstream the solid removal unit and shall be connected to process interlock system. This interlock actuation will be defined later on by PETROBRAS. The analyzer shall have an installed stand-by instrument.

#### 4.5.2.4 Not applicable.

#### 4.5.2.5 Production chokes:

- Probe for erosion evaluation installed upstream of the production choke and coupon of mass loss installed downstream of the production.

#### 4.5.3 Lines and equipment built in CRA (Corrosion Resistant Alloys) or internally coated on CRA can be considered as exempted from monitoring the corrosion, unless otherwise cited in item 4.5.2 above.

#### 4.5.4 The coupons, ER/LPR probes shall be tangential type if they will be installed in the "PIG" path.

#### 4.5.5 All ER and LPR probes shall be provided with automated transmission of corrosion data to the Unit supervisory system. The maximum scan time allowed for those transmitters shall be 6 hours.

#### 4.5.6 The places for installing the monitors shall be according the criteria below:

- At least two points of access, one for coupon and one for probes, spaced at least 500 mm;
- Downstream of corrosion inhibitors injection.

#### 4.5.7 All coupons and probes access fitting bodies shall be high pressure type, regardless of the operating pressure, welded to the pipe.

#### 4.5.8 PETROBRAS highlights the following:

- Coupons positioning in horizontal section should be at 6 o'clock position and optionally at 12 o'clock position;
- Enough clearance and access shall be provided to enable the coupons exchange, with no impact to Unit operation.

#### 4.5.9 CONTRACTOR shall provide an Acoustic Sand Detector (solid) per each well and they shall be installed according to supplier requirements.

## 5 ARRANGEMENT

### 5.1 GENERAL

5.1.1 In the developing of the facility layout, the following Health, Safety and Environment (HSE) points shall be considered, as a minimum:

- Outputs of risk assessments shall be incorporated into the layout development and optimization;
- Maximize natural ventilation;
- Minimize escalation of ignited flammable or toxic release;
- Minimize probability of ignition;
- Continuous permanent ignition sources shall always be installed in non-classified areas;
- Layout shall provide the maximum practical separation between: Classified Areas vs. Non Classified Areas, Systems with hydrocarbon-containing inventory vs. potential sources of ignition;
- The risk of loss of containment should be minimized by minimizing the possibility of mechanical damage. Protecting hydrocarbon equipment from dropped objects should be a main consideration;
- Provision of suitable means for escape (whether or not these are regularly manned), temporary refuge and evacuation. Stairs shall be used as the mainly way to escape from areas. The use of ladders shall be minimized. Note: In accordance with item 11.2.1 of ASTM F1166 (Standard practice for human engineering design for marine systems, equipment and facilities) angle of Inclination for Stairs shall be determined by the vertical change in height. Angles between 30° and 50° are acceptable but a stair angle of 38° is preferred.;
- Proper implementation of working environment (Human Factors) guidelines, tools and techniques into the design;
- Human Factors Engineering shall be considered in the design, according to NR-17 (Ergonomics). Specific report shall be issued, according to the NR-17 (Ergonomics) and its application manual. All reports shall be issued according the Ergonomic Analysis of Work method;
- All equipment associated with emergency power (Emergency generator, emergency switchboard, storage batteries and inverters, etc.) shall be situated in non-hazardous areas, with adequate protection against fire and explosion.
- An area for temporary waste storage shall be provided, in compliance with Nota Técnica IBAMA 01/2011 and Resolução Conama nº 275/01.

5.1.2 CONTRACTOR shall carry out Layout Reviews considering HSE aspects.

5.1.3 The objective of these Layout Reviews is to identify any issues associated with the overall planned layout of the topsides, utilities, marine systems and accommodations.

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5.1.4 Layout review activities shall take place at different stages during the project development cycle including all changes during the course of the project. These reviews shall be conducted with a multidisciplinary team to ensure that the requirements of all disciplines have been incorporated in the layout design.

**5.2 SUPERSTRUCTURE (ACCOMMODATIONS)**

5.2.1 Accommodation refurbishment shall follow the “all new” philosophy as described in section 16 (MARINE SYSTEMS AND HULL UTILITY SYSTEMS). It means all systems (piping, electrical, HVAC , drainage, water, cabling, furniture, etc.) and related outfitting shall be brand new. The only exemption is steel that can be kept however fully painted.

5.2.2 Concepts for living quarters and storage areas shall comply with the CS Rules, Brazilian Regulations (NRs, especially NR 37) and safety requirements of SOLAS.

5.2.3 In addition, CONTRACTOR shall provide accommodations for PETROBRAS / partners representatives onboard as defined on Operation Contract. One of these cabins shall be 1 (one) single bed cabin, equivalent to the Offshore Installation Manager’s or the Chief Unit Superintendent’s, and the others cabins shall be for 2 persons each with bunk bed. An office and a meeting/video-conference room (as per TELECOM MASTER SPECIFICATIONS FOR FPSO CHARTERED – see item 1.2.1) shall also be provided for PETROBRAS representatives onboard. Both PETROBRAS office and PETROBRAS main Fiscal cabin shall be fitted with windows at front wall of the accommodation Block.

5.2.4 The smoking area shall be an open safe area, 360 degrees open (no shelter is acceptable) to the environment with natural ventilation.

5.2.5 Galley, mess room and storage area shall comply with *Agência Nacional de Vigilância Sanitária (ANVISA)*, especially *Resolução da Diretoria Colegiada (RDC) 216/2004 and RDC 72/2009* and their updates, with emphasis on the separation between vegetables, meat (poultry, fish and red meat), pasta and storage areas, and waste disposal.

5.2.6 The infirmary installations shall comply with NORMAM 01 CHAPTER 9, SECTION V; ANVISA, especially RDC 50/2002 and RDC 222/2018 and their updates.

5.2.7 Food waste disposal facilities shall meet the following requirements:

- Compliance with MARPOL Convention;
- Compliance IBAMA Technical Note 08/2012;
- 2 x 100% configuration for food waste disposers;
- The waste disposers shall be installed in the waste treatment area, preferably located as close as possible to the place of dumping of waste at sea and served by pipes with minimal length and curves;

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- Capacity to crush any debris and leftovers from biodegradable food, including animal bones, lumps and fruit peels in general;

**5.3 PROCESS PLANT**

- 5.3.1 CONTRACTOR shall submit a maintenance and load handling plan evidencing that the arrangement of the process plant equipment, skids and accessories allows maintenance at site without affecting the production/processing capacity of the Unit according to the technical specification hereinafter considered.
- 5.3.2 Enough space for operational maintenance of production plant equipment shall be provided, taking into account the personnel circulation, safety and CS requirements. Human Factors Engineering shall be considered as part of this assessment.
- 5.3.3 CONTRACTOR shall define the height of the main process plant deck level as well as its layout. CONTRACTOR shall take into account the effects of green water, with the vessel in a maximum draft condition.
- 5.3.4 For the design of layout, drainage system and firefighting means of the areas reserved for storage of chemicals and gas cylinders, CONTRACTOR shall follow applicable requirements for safety, health and environment, as well as take in consideration chemical compatibility. The storage areas for chemical products used for maintenance (lube oil, grease etc) shall be sheltered and bounded with dedicated coamings, in compliance with Nota Técnica IBAMA 08/2012.
- 5.3.5 Each module shall be provided with proper means of containment with a coaming to prevent liquids falling on sea, main deck or the deck below.
- 5.3.6 Additionally, areas around equipment containing liquid hydrocarbons, chemicals, flammable liquids, combustible liquids or contaminated liquids shall be provided with a secondary coaming / bounding or drip pan to prevent these liquids spreading over the module.

**5.4 UTILITY ROOM (ENGINE ROOM)**

- 5.4.1 CONTRACTOR shall submit a maintenance procedure plan evidencing that the Unit arrangement for utility systems, skids and accessories allows maintenance at site with a minimum disturbance of the Unit's performance.

**5.5 DIVING AREAS**

- 5.5.1 Any facility related to diving operation shall fall under CONTRACTOR's responsibility.
- 5.5.2 CONTRACTOR shall provide diving stations to be used during CS underwater surveys, pull-in/pull-out operations, etc.



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- 5.5.3 The number and location of diving stations shall be defined in accordance with NR-15 and NORMAM 15. Section 4 (Diver Launch and Recovery System (LARS)) Item 4 (Secondary Recovery) of IMCA D023 is mandatory.
- 5.5.4 In order to assist pull-in operations, at least two fixed stations or one movable station throughout the riser balcony shall be provided. In case of fixed stations, at least two shall be equipped in order to avoid time concerns related to diving operations. The pull-in diving stations shall be positioned considering 33 m as the maximum allowable outreach (measured from the diving bell) and diving operations at night. During operational phase, these stations may be used by PETROBRAS for riser inspections.
- 5.5.4.1 The areas must be large enough to accommodate all diving equipment with minimum distance between parts of 600mm. These areas shall be projected with 12m x 6m at a minimum, outside of the ship's deck. The total diving system weight is 30t. In locations where diving areas are provided, the handrail must be removable, because the system will extend through it.
- 5.5.5 The stations shall not interfere with the Unit facilities and operations (cargo transfers, etc.). All diving stations shall be fully equipped in accordance with the requirements listed below:
- Proper means (cranes, mono-rails, skidding, crawlers, slings, rigging, etc.) for the installation/de-installation of diving equipment on the stations shall be available. The heaviest piece of equipment to be handled is 5 t.
  - Each station shall be provided with the utilities listed below:
    - Compressed air - 2 outlets for each Launch and Recovery System (LARS) (according to IMCA D023, the stations shall be provided with 2 independent LARS systems):
      - Required pressure: 7 kg/cm<sup>2</sup>;
      - Required Outflow: 20 Nm<sup>3</sup>/min (Approximately 2,85 m<sup>3</sup>/min, at constant pressure of 7 kgf/cm<sup>2</sup>), allowing  $\pm 10\%$  of tolerance.
    - Electric power supply - electrical outlets shall be fed from different power sources and backed-up by the emergency generator:
      - two (2) electrical outlets 440V/60Hz/max 100 A;
      - two (2) electrical outlets 220V/60Hz/30 A.  
NOTE: All 440V diving power sockets shall be fed by emergency generation systems, or by panels connected to them (220V sockets).
    - Fresh water supply – one outlet for cleaning diving equipment and clothes:
      - Required pressure: 1 kg/cm<sup>2</sup>;
      - Required outflow: 20 l/min.
    - Communication:
      - One telephone connection for internal and external calls.

- 5.5.6 Access to the diving stations shall not be dependent on vertical ladders, which may require specific training for work at height and hinder evacuation of injured personnel.
- 5.5.7 Gas discharges (e.g. inert gas vent posts) and overboard points (e.g. slop tanks, produced water) shall not interfere with diving operations from the FPSO or Shallow Diving Support Vessel (SDSVs).
- 5.5.8 Sea chests and other hull openings below maximum draft line shall be provided handrails nearby to help divers work during CS inspections.
- 5.5.9 The underneath of the LRB (Lower Riser Balcony) shall be provided with four padeyes for each I-tube (minimum safe working load 12 t) and a handrail system in a closed pattern.
- 5.5.10 CONTRACTOR shall provide the necessary facilities to enable remote monitoring of the pull-in operations and risers inspections by electric ROVs (Remoted Operated Vehicle). The specification and requirements of the ROV will be informed by PETROBRAS during execution phase.
- 5.5.11 The diving stations location and handling plan shall be submitted to PETROBRAS for comments. See also reference document SPREAD MOORING AND RISER SYSTEM REQUIREMENTS (see item 1.2.1) for additional provisions.

## 5.6 HELIDECK

- 5.6.1 Helideck shall be suitable for landings of the helicopter types: frequent operation (S-92, S-76, AW-139, AW-189, AW-101, H175, BELL430) and eventual search & rescue operations (UH-60M, EC 225 and EC725).
- 5.6.2 The helideck shall be designed and located according to Brazilian Navy Regulations (NORMAM) including NORMAM 27 and CAP 437. In addition, the following international/national standards shall also be complied with:
- ICA 63-10 Estações Prestadoras de Serviços de Telecomunicações e de Tráfego Aéreo – EPTA. DECEA;
  - ICA 63-25 Preservação e Reprodução de Dados de Revisualizações e Comunicações ATS – EPTA. DECEA;
  - “Standard Measuring Equipment for Helideck Monitoring System (HMS) and Weather Data”, HCA, Bristow Group, Bond Offshore, CHC;
  - MCA 105-2/2013 Manual de Estações Meteorológicas de Superfície - DECEA.
- 5.6.3 Meteorological and ship motion data shall be transmitted to HMS (Helideck Monitoring System) in real time, through analogic or digital applicable interface.
- 5.6.4 CONTRACTOR shall ensure remote access to HMS, at any time, through internet. Such access shall be available in real time to PETROBRAS and Helicopter Operator Company through the same screen/system used by radio-operator of FPU. The Internet access shall be compatible with readily available browsers.

- 5.6.5 HMS and all related systems/sensors shall be considered emergency loads and shall operate even in case of loss of power in the main generators.
- 5.6.6 In addition, CONTRACTOR shall present evidence that there is no interference between Unit's normal operation and helicopter operations.
- 5.6.7 To establish the safe location of the helideck, the environmental effects shall be considered, such as wind direction and velocity, as well as aerodynamic aspects (turbulence over the helideck), and the temperature rise due to exhaust gases. Hot plumes over the helideck, generally, are related to main turbo-generator exhaust outlet, however, the other equipment (for instance: emergency generators or auxiliaries and fire-fighting pumps, etc.) should also be considered in the identification of potential sources of hot gases.
- 5.6.8 CONTRACTOR shall present evidence that helideck final location minimizes downtime by using computational fluid dynamics (CFD) studies, considering all the aspects mentioned above. CONTRACTOR shall submit to PETROBRAS CFD studies for the evaluation of hot air flow and exhaust according to CAP 437, section 3.10. PETROBRAS recommends using Method 3 described in Norsok C-004, section 5.4: "A method using Computational Fluid Dynamics (CFD) codes to determine the acceptable level of risk for helicopter offshore operations in relation to the emission of hot gas of Turbine Exhaust Outlets - "Method 3".
- 5.6.9 CONTRACTOR shall paint in the helideck a codification (to be informed during execution phase) as per NORMAM 27.

## **6 HEATING, VENTILATION AND AIR CONDITIONING SYSTEMS (HVAC)**

### **6.1 GENERAL**

6.1.1 The air conditioning and ventilation systems shall be calculated to suit the site environmental conditions (see METOCEAN DATA). For determining the climatic design conditions (dry-bulb temperature and coincident-wet bulb temperatures – 0,4% summer cumulative frequency of occurrence), CONTRACTOR to use ASHRAE methodology (Fundamentals Handbook - Climatic Design Information – 2013 edition).

- Dry Bulb Temperature (TBS): 32°C
- Relative Humidity: 61%
- Daily Temperature Range: 3,6°C

6.1.2 The HVAC safety requirements shall comply with SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

### **6.2 HVAC SYSTEMS**



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- 6.2.1 Cooling fluids with hydrochlorofluorocarbons (HCFC) and Chlorofluorocarbons (CFC) are not acceptable. Only cooling fluids with hydrofluorocarbon (HFC) and hydrofluoro-olefin (HFO) (not flammable) are acceptable.
- 6.2.2 In case of application of insulation with foam injected under pressure polyurethane, it shall be provided with CFC-free.
- 6.2.3 The air intakes shall be placed in a safe area and, whenever possible, where the prevailing winds are favorable.
- 6.2.4 All air intakes shall have devices to avoid gas entrance to the inner side of protected areas.
- 6.2.5 All Fire Dampers and Tightness/Shut-Off Dampers shall have a manual opening means.
- 6.2.6 There shall be a dedicated HVAC system for batteries room. The selection and operational condition of the HVAC equipment for these rooms shall be 2x100%, always with a standby unit. The minimum airflow rate (changes per hour) shall comply with SOLA/MODU and Classification Society. The minimum airflow shall be also calculated for the H2 dilution as defined in IEC 61892-7..
- 6.2.7 All Battery Rooms with sealed batteries and/or valve regulated lead–acid (VRLA) batteries installed shall have an independent dedicated exhaust fans and air conditioning system (maximum room internal temperature 25°C). The selection and operational condition of the HVAC equipment for these rooms shall be 2x100%, always with a standby unit. The minimum airflow rate (changes per hour) shall comply with, SOLAS/MODU and Classification Society. The minimum airflow shall be also calculated for the H2 dilution as defined in IEC 61892-7..

**6.3 REFRIGERATION SYSTEM (PROVISIONS)**

- 6.3.1 Cooling fluids with HCFC and CFC are not acceptable. Only cooling fluids with HFC and HFO (not flammable) are acceptable.
- 6.3.2 In case of application of insulation with foam injected under pressure polyurethane, it shall be provided with CFC-free.

**6.4 CONTROL AND OPERATION**

- 6.4.1 Pneumatic and electrical fire dampers actuators are acceptable. In case the pneumatic actuator is chosen an independent air supply system, with their own air reservoirs, shall be provided for fire dampers and pressurization of instrumentation panels located in hazardous areas. This shall be provided in order to avoid any further consequence caused by a fault in the air supply.
- 6.4.2 All the fire dampers shall be CS type approval.

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6.4.3 Application and installation of fire damper shall be based on the recommendations of SOLAS and Classification Society requirements.

6.4.4 The HVAC system shall be capable of sustaining an adjustable of air temperatures in indoor manned personnel accommodation spaces. This temperature shall be maintained by a temperature controller according with NR-37.

**6.5 VENTILATION OF THE TURRET AREA (NOT APPLICABLE)**

6.5.1 Not applicable.

**6.6 STANDARDS AND BRAZILIAN REGULATION**

6.6.1 CONTRACTOR shall comply with applicable Brazilian Regulations. ISO 15138 shall be used as reference for HVAC System design.

6.6.2 The minimum outside airflow per person is 27 m<sup>3</sup>/h, in order to comply with Brazilian Legislation for Conditioned Rooms ("*Portarias do Ministério da Saúde MS 3523/1998*" and "*MS 9/2003*"). Ducts shall be designed and assembled taking into consideration the requirements for inspection and maintenance established by Health Ministry.

**6.7 ELECTRICAL SWITCHBOARD ROOMS (E-HOUSE)**

6.7.1 E-House (Electrical Switchboard Room) shall be pressurized and air-conditioned (maximum room internal temperature 24°C), 2x100% or 3x50% equipment configuration machines with a stand-by unit.

6.7.2 Variable Speed Drive, if used, shall be installed in air-conditioned rooms (maximum room internal temperature 24°C).

6.7.3 The battery rooms shall comply with the item 6.2. UPS and battery chargers shall be installed in air-conditioned rooms.

6.7.4 Chilled Water Pipes and/or Cooling Water shall not be installed inside panels rooms, electrical equipment, transformers rooms, control rooms, radio room and telecom. Exception to condensed water piping from Air Cooled HVAC machines coil, if there is any. In this case, equipment and piping shall be installed at floor level, closed to a wall, contained by physical barrier and with a drain directly to outside.

6.7.5 The E-HOUSE air conditioning design shall also consider cabinets supplied by PETROBRAS.

**7 SAFETY****7.1 GENERAL**

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7.1.1 The Unit's safety philosophy shall comply with SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

7.1.2 For acceptable vendor list for Diesel-Hydraulic Fire Water Pumping Unit, see item 19.1.1.9.

**7.2 RISK MANAGEMENT**

7.2.1 A Risk Management Program shall be implemented, to continuously monitor and control the risks identified in risk assessment studies during the operational lifetime, as defined in SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

7.2.2 PETROBRAS at their sole discretion shall take part in any Risk Assessment or workshop, for example: Layout Reviews, HAZOPs, HAZIDs, ALARP, SIL and BOW-TIE.

7.2.3 An independent Consultant Company shall be hired to perform the risk assessment studies established in the scope of the project. This Consultant Company shall have a proven previous experience in this type of studies.

7.2.4 CONTRACTOR shall demonstrate the measures taken to reduce the risk of H<sub>2</sub>S release to an ALARP level. The following shall be complied with, as a minimum:

- Identification of areas with potential H<sub>2</sub>S releases through Risk Assessment and Safety Studies. Loss of containment on topside, as well as in main deck region, especially regarding the settling tanks operations, shall be considered.
- The unit shall be provided with portable breathing apparatus.
- A gas dispersion / vent dispersion study shall be developed to evaluate, among others, the mapping of H<sub>2</sub>S clouds to support safety precautions for H<sub>2</sub>S exposition strategy; allocation of H<sub>2</sub>S detectors; safely allocate cargo / process vents, including, but not limited to settling tank/header vent and PV Breaker vent.
- Operating Procedures, Training, Emergency Response Plan, Permit-to-work, Preventive Maintenance / Inspection Plan, among others shall consider H<sub>2</sub>S exposition.

**7.3 PEOPLE ON BOARD (POB) MANAGEMENT SYSTEM**

7.3.1 CONTRACTOR shall design and install an Electronic POB Management System incorporated to Unit's Safety Procedures. This System aims to:

- Provide in real time the number and identification of persons on site (POB system);
- Provide an electronic solution to perform the mustering process in case of General Alarm (E-mustering system);

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- Register the personnel location and control the access (E-Tracking system).
- The Electronic POB Management System shall be based on RFID technology. Different solutions can be accepted by PETROBRAS, provided the following:
  - Same final specifications;
  - Any different solution must be presented to PETROBRAS.

7.3.2 The system shall be able to accommodate extraordinary events (major maintenance, construction work, etc.) leading to the presence of additional personnel and also some routine events such as daily visitors.

### 7.3.3 E-MUSTERING (POB-M)

7.3.3.1 The system shall provide accurate on-line real-time information to site relevant personnel in order to control/manage the mustering and evacuation process and allow emergency follow-up:

- Allow people to check at mustering area;
- Allow follow-up of mustered people on the site itself and on connected installation (if relevant);
- Allow identification and location of people member of the Emergency Response Team;
- Allow management of escape means;
- Allow the possibility of managing people having evacuated and then returning to the Unit;
- Identify missing personnel during mustering process.

7.3.3.2 Each person allocated to an emergency role must be clearly identified in the system.

7.3.3.3 The system shall be able to generate a report which will indicate, as a minimum, personnel's name and surname, assigned TAG number, his/her last registered location, his/her job position and eventually his emergency role, his/her assigned lifeboat, his/her assigned muster point.

7.3.3.4 The System shall also be able to provide typical statistics and indicators (timing of movements of people, duration of mustering, anomalies, etc.).

### 7.3.4 E-TRACKING (POB-T)

7.3.4.1 The system shall record when personnel is entering/exiting selected locations to be defined by CONTRACTOR, for example, restricted access areas, accommodations, e-house, pump room, machinery room. Readers shall be placed at entry/exit points to allow personnel to register in/out. Real-time information shall be available on the

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central system concerning identification and tracking of all personnel on each location. A general view shall represent the status of the site.

7.3.4.2 All events (entry allowed or refused, bad TAG reading) shall be logged.

### 7.3.5 TECHNICAL REQUIREMENTS

7.3.5.1 All system equipment shall be adequate for the hazardous zone it will be installed/used. POB-M/T field equipment shall be certified for zone 1 so that they can remain energized in case of gas detection.

7.3.5.2 The full system shall be suitably designed for permanent operation in marine environment.

7.3.5.3 Considered as a safety system, the POB-M/T system shall be fully redundant.

7.3.5.4 The POB-M/T system shall be designed in such a way that the failure of any server, communication or network equipment, power supply unit, interconnection cables shall not result in a loss of service in any situation. The POB-M/T hard disk backup shall be performed using RAID technology.

7.3.5.5 The POB-M/T system shall be stand-alone (dedicated system), with minimum interaction with CSS.

7.3.5.6 The POB-M/T central system shall be duplicated on site in two systems (system "A" and "B") located in different technical rooms. Those systems shall be interconnected through duplicated link and synchronized at all time. Sign-in operations shall be updated on both systems in real time.

7.3.5.7 POB-M/T central systems shall be fed from redundant UPS power supplies with minimum autonomy of 12 hours.

7.3.5.8 At the Muster Points, Emergency Response Room, PETROBRAS' representative office and Control Room, a secured Wireless Access point and HMI (Human Machine Interface) shall be provided. The HMI of the application shall be user friendly and provide in a very clear way all useful information for the mustering process. All wireless access point shall be duplicated; one connected to System "A" and the other one to System "B". Wireless network for POB-M/T shall be independent from other operational wireless networks.

7.3.5.9 It shall be ensured that all POB-M/T field equipment are always connected and synchronized with the system in operation. All field equipment shall be powered and data connected to both systems "A" and "B" through segregated cable route, for real-time update.

7.3.5.10 Readers shall be equipped with LED and sounders to show correct sign-in regarding POB-M/T and refused sign-in (location overmanned, tag incorrect, etc.), as well as lost link with POB-M/T system. Readers and their supports shall be visible and clearly identified.



- 7.3.5.11 In case of central systems failure, readers shall be equipped with buffer in such a way to ensure local sign-in storage. Reader memory capacity shall allow local sign-in operations (capacity to be defined during execution phase). Sign-in data shall be updated on servers as soon as systems recover.
- 7.3.5.12 The TAG shall be generated on site. TAG shall be based on a bracelet waterproof or equivalent. It shall be ensured that the tag shall be easily worn by personnel at all time, without creating any safety risk.
- 7.3.5.13 The system shall take future requirements into consideration: 20% input/output spare shall be supplied for future expansion (i.e. increase in number of readers). In addition, 20% of unused shelf space shall be available in the cabinets.
- 7.3.5.14 The system access shall be controlled according to the level of authorization to access/modify the system.
- 7.3.5.15 The System shall allow remote access using IP protocol and shall be directly connected to the FPSO firewall.

### 7.3.6 INTERFACES

- 7.3.6.1 The POB-M system shall be connected to the General Alarm system to allow beginning of muster process as soon as an alarm occurs.
- 7.3.6.2 POB-M/T systems shall be minimally interfaced with the CSS system:
- POB-M/T shall report system failure alarm to CSS (alarm shall be available in control room);
  - CSS shall send shutdown signals to POB-M/T.

## 8 AUTOMATION AND CONTROL

### 8.1 GENERAL

- 8.1.1 The Instrumentation/Automation and Control design is to be mainly based on an integrated operation and supervision system of the Unit as a whole, through graphics interfaces.
- 8.1.2 The Unit shall be supplied with an overall Automation and Control (A&C) Architecture composed by field instruments and control/automation systems. The main characteristic of the Architecture is the integration promoted among these systems by means of redundant digital communications along all layers, including optical and electrical networks, switches, hubs, modems etc.
- 8.1.3 The AC and DC power supply for all components of the A&C Architecture shall be redundant, fed from duplicated and redundant UPS. Common failure mode shall not be present.

8.1.4 The systems of the A&C Architecture encompass the following:

- Control & Safety System (CSS);
- Central Control Room (CCR);
- Cargo Tank Monitoring System (CTMS);
- Optimization and advanced control server;
- Machinery Monitoring System (MMS).
- Flow Metering System (FMS);
- Closed Circuit Television System (CCTV);
- Offshore Loading System;
- Environmental Monitoring System (ENV);
- Positioning System for Mooring Operation and Offset Diagram (POS)
- Subsea Production Control System (SPCS);
- Riser Monitoring System:
  - MODA Riser Monitoring System (MODA);
- Annulus Pressure and Relief System.
- SMBS Control and Monitoring System.
- Addressable Fire Detection System (AFDS)

8.1.5 Redundancy shall be applied to the A&C systems and field instrumentation for maintaining the safe and reliable operation of the Unit and for achieving the required overall reliability, maintainability and availability.

8.1.6 The A&C systems shall be designed in order to assure that a single failure at any component of the system would not cause a loss of a safety function or system.

8.1.7 Network between any CSS Controller and its respective RIO (Remote Input/Output) Panels shall be routed by redundant physical independent routes.

8.1.8 Signals from process redundant systems and voting instruments shall be distributed in the I/O cards in a way that avoids the loss of more than one system in case of an I/O card failure.

8.1.9 Regarding adequacy to hazardous area classification for electrical/electronic equipment and instrumentation, refer to section 6.4 of SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

8.1.10 All instruments, panels and equipment (if applicable) proper to be used in hazardous areas, shall have conformity certificates complying with: IEC-60079 and all its parts; *PORTARIA INMETRO N° 115, de 21/março/2022*, and its annexes and shall be approved by Classification Society.

## 8.2 CENTRAL CONTROL ROOM (CCR)

8.2.1 The Unit shall have a CCR with an integrated working area from which the Topsides process and utilities plant, subsea production/injection systems and Hull/Marine systems shall be continuously monitored, operated and controlled, enabling the proper operation of the Unit as a whole.

8.2.2 The supervision and monitoring shall be done by navigating through HMI (human machine interface) screens showing the Topsides and Hull/Marine diagrams and other fixed structures. The main components of this hardware (such as equipment, valves, detectors, process analyzers and instruments) shall be animated by displaying changes to their status, such as the opening of a valve, start-up of a pump, indication of a process variable etc.

8.2.3 The term HMI refers to the displays, computers and software that serve as an interface with CSS, specialized in processing/displaying the field data in a suitable format, leaving the tasks of data gathering to the other systems, such as CSS, CTMS, and SPCS.

8.2.4 The HMI shall have at least five primary functions:

- Provide visualization of process parameters and methods with which to control the process;
- Provide alarms summary and history, as well as indications to the operator that the process is outside limits or behaving abnormally or that the CSS has detected faults or failures;
- Provide a method to allow the operator to understand the process behavior, such as process tendency and time response (trending functionality).
- Provide reports of the Unit, such as overrides;
- Provide means to collect and register historical data.

8.2.5 The CONTRACTOR shall mirror all CCR (and ECR, if applicable) HMIs in 2 independent machines at the PETROBRAS Office (according to item 5.2), including Alarms Management System (alarms' and events' logs and statistics screens), in order to allow PETROBRAS to monitor the UNIT.

8.2.6 If the Unit is provided with a permanently manned engine control room (ECR), the engine room equipment can be controlled from the ECR and only the critical alarms and status signals repeated back to the CCR.

8.2.7 A "black box" device shall be foreseen into the CCR, in which all Topsides, subsea and Hull/Marine systems monitored data, events, audit trails and alarms of the last 60 (sixty) days shall be recorded in an easily removable data storage unit which shall be carried off the Unit in case of abandonment.

8.2.8 CONTRACTOR shall design and operate an Alarm Management System according to the standard IEC 62682, in order to ensure that:



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- UNIT shall have an alarm management system that provides the operator with an adequate set of warnings against excursions beyond its safe operating limits both during normal operation and during abnormal situations (startups, shutdowns and upsets);
- Actions necessary to bring the process back to its normal state shall be defined for every safe operating limit and details shall be available to the operator. The operator shall be capable to execute such actions.

8.2.9 The alarm management system shall have functions to allow operators to minimize and when necessary suppress standing alarms, nuisance alarms, repeating alarms and alarm floods.

#### 8.2.10 PLANT INFORMATION SYSTEM (PI System™)

8.2.10.1 During the operation phase, all main Topsides, Subsea, Turbomachinery, Main Pumps and Hull/Marine data shall be available online at PETROBRAS' PI System™-Server, with the following conditions:

- The interface between supervisory system and Plant Information System (PI System™) shall be based on OPC-UA (Open Platform Communications) (provided that the supervisory system is based on Windows®).
- The interface between the supervisory system and OPC-UA shall be hosted in a dedicated server in the supervisory system layer or in the supervisory system workstation, if it is Native OPC-UA Client-Server. (By CONTRACTOR)
- OPC-UA-PI System™ drivers with store and forward mechanism shall be hosted in a computer on the Automation network and shall communicate through DMZ (demilitarized zone) firewalls installed in Telecommunications Room. (By CONTRACTOR)
- Both supervisory system-OPC-UA and OPC-UA-PI System™ interfaces shall be installed in redundancy, including hardware and licenses. (By CONTRACTOR)
- PI System™-Server software shall also run in DMZ (PI System™-Server will be located in onshore DMZ). (By PETROBRAS)
- The data to be stored in PI System™ will be defined by PETROBRAS during the Detail Engineering Design Phase.
- If CONTRACTOR needs to use a different protocol for the communication between supervisory system and PI System™, PETROBRAS shall be consulted for acceptance, the licenses and configuration, if the protocol is accepted, shall be provided by CONTRACTOR.
- Information and network security mechanisms between owner supervision and operation system and PI System™ shall be installed and configured by CONTRACTOR.

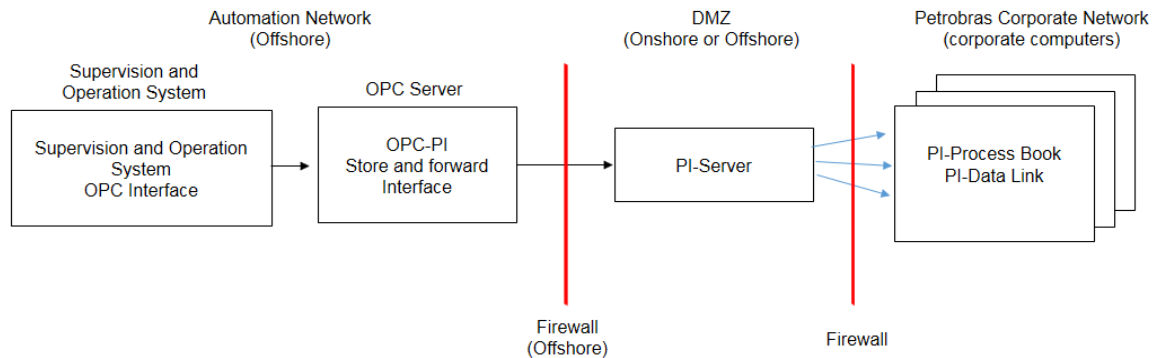


Figure 8.2.10.1 – Plant Information Architecture

8.2.10.2 For details of Telecommunications infrastructure, see TELECOM MASTER SPECIFICATIONS FOR FPSO CHARTERED (see item 1.2.1).

### 8.2.11 CONTROL NETWORK ARCHITECTURE

8.2.11.1 Network communications among the CSS Controllers shall preferentially be by a deterministic network protocol. Signals to indicate safety interlock actions between Controllers shall be fail safe.

8.2.11.2 All network levels, supervision network, control network and field network shall have diagnostics and Management System in order to indicate fault of communication at any level.

8.2.11.3 The Network Management System shall, at minimum:

- Be capable to show the installed topology;
- Have network sniffer function;
- Switch remote configuration function (such as SNMP (Simple Network Management Protocol)).

8.2.11.4 Communication protocols that use DCOM technology shall not be used. OPC-UA shall be used instead of OPC-DA and Windows licenses shall have at least patch KB5004442 and possibility of registering in Event Viewer logs.

### 8.2.12 CYBERSECURITY

8.2.12.1 In order to protect data to be transferred from the Unit Automation network to CONTRACTOR network, PETROBRAS corporate network and to the Onshore PETROBRAS Facilities, it shall be foreseen firewalls, passwords, virtual LANs (VLANs), flash drives disabling and routers.

8.2.12.2 Writing in CSS processors and in the supervisory software from outside the Automation network shall not be allowed, unless explicitly authorized for Operation

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necessity. All writing and reading accesses in the Automation network shall be logged.

8.2.12.3 It shall be foreseen different firewalls for connection between the Automation network and PETROBRAS corporate network/Onshore PETROBRAS Facilities and between Automation network and CONTRACTOR network.

**8.3 CONTROL & SAFETY SYSTEM (CSS)**

8.3.1 The Unit shall be equipped with fully automated control system, named Control & Safety System (CSS), to provide both control and safeguarding functions according to SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

8.3.2 A number of dedicated CSS controllers (redundant CPUs/processor modules in a fully hot stand-by scheme), shall be foreseen for the following functions:

- a) Process Control System (PCS), for Unit systems remote controlling and monitoring. Regulatory control (PID), monitoring, remote actuation, control transmitters data acquisition and process alarms shall be carried out by this system;
- b) Process Shutdown System (PSD), for carrying out overall Unit safety and safeguarding preventive automatic and manual actions. The purpose of this system is to prevent escalation of abnormal conditions into a major hazardous event and to limit the extent and duration of any such events that do occur;
- c) Fire & Gas/ESD System (FGS/ESD), for carrying out overall Unit safety mitigation automatic actions mainly due to fire, flammable and toxic gas releases/leaks and explosion events. This system shall monitor continuously for the presence of a fire or gas leakage to alert personnel and allow control actions to be initiated manually or automatically to minimize the likelihood of fire or gas escalation and probability of personnel exposure.

8.3.3 PCS shall be an independent system from PSD and FGS/ESD. It is recommended that PCS, PSD and FGS/ESD be from the same vendor.

8.3.4 A single time reference shall be used for the CSS and Electrical System. The interface between CSS and the Electrical System shall be such that, in the event of a failure of the communication, the electrical loads go to a safe state.

8.3.5 Automation system commissioning shall follow IEC 62381 and its references.

8.3.6 Some equipment may be supplied as package units with their own Control and Automation System. These shall also be integrated to the Unit's Automation & Control Architecture, and shall comply with Classification Society rules, especially regarding to the segregation between control and safeguarding functions. Fire and Gas signals of these package units shall also be integrated to the Unit Fire and Gas system.

**8.4 CARGO TANK MONITORING SYSTEM (CTMS)**



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8.4.1 The Cargo Tank Monitoring System shall provide reliable, fast and highly accurate information on tank level and related variables (draft, pressure, etc.).

8.4.2 The CTMS shall comply with Class Society requirements.

**8.5 SUBSEA PRODUCTION CONTROL SYSTEM (SPCS)**

8.5.1 For Subsea Production Control System, refer to SUBSEA PRODUCTION CONTROL SYSTEM FOR FPSO (see item 1.2.1).

**8.6 OFFSHORE LOADING SYSTEM**

8.6.1 For Offshore Loading System, see OFFSHORE LOADING SYSTEM REQUIREMENTS and OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS (see item 1.2.1).

**8.7 METERING**

8.7.1 For Flow Metering System, refer to FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1).

8.7.2 In addition to the conventional measurement system, the test separator shall have a multiphase flow meter installed upstream of the test train, suitable for the operating ranges of the wells, to allow the appropriation of each satellite well.

8.7.3 The allocation measurement of the production wells in subsea manifolds will be made through individual subsea multiphase flow meters.

8.7.4 The verification of the subsea multiphase flow meters shall be done by dedicated multiphase flow meters, installed on topsides, at each production riser of the subsea manifolds, using an appropriate algorithm of data conciliation.

8.7.5 Additionally, the verification of the topsides multiphase flow meters shall be done using the test separator, with periodicity to be defined by the Flow Metering System design.

**8.8 CCTV**

8.8.1 For CCTV, see TELECOM MASTER SPECIFICATIONS FOR FPSO CHARTERED (see item 1.2.1).

**8.9 ENV – METOCEAN DATA GATHERING AND TRANSMISSION SYSTEM**



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8.9.1 For ENV, see METOCEAN DATA ACQUISITION SYSTEM REQUIREMENTS (see item 1.2.1).

**8.10 POS - POSITIONING SYSTEM FOR MOORING OPERATION AND OFFSET DIAGRAM**

8.10.1 For POS, see POSITIONING AND NAVIGATION SYSTEMS (item 1.2.1).

**8.11 RISER MONITORING SYSTEM**

8.11.1 MODA RISER MONITORING SYSTEM (MODA)

8.11.1.1 For MODA, see MODA RISER MONITORING SYSTEM – FPU SCOPE (SPREAD MOORING) – see item 1.2.1.

8.11.2 ANNULUS PRESSURE MONITORING AND RELIEF SYSTEM

8.11.2.1 The permeated gas in the flexible riser annulus of every flexible riser connected to the Floating Production Unit shall be vented to a safe area.

8.11.2.2 CONTRACTOR shall design, provide and operate the Annulus Pressure Monitoring and Relief System, as detailed on the technical specification "Annulus Pressure Monitoring and Relief System" (I-ET-3010.00-5529-812-PAZ-001) in order to:

- Guarantee a safe release on board for the permeated gas in the flexible riser annulus;
- Monitor, detect and control any abnormal pressure build up that may - for example - damage the flexible risers.

8.11.2.3 This specification allows some variations of the Annulus Pressure Monitoring and Relief System. For this project the Continuous Vented type shall be used by the CONTRACTOR and the Continuous Vented type shall be applied to all flexible risers, except for umbilicals and water injection risers.

8.11.2.4 CONTRACTOR shall perform detailed engineering of this system (including piping, valves, pressure sensors, supervisory integration, etc.).

8.11.2.5 This system shall be applied to all flexible risers (production risers, injection risers (gas or water) and service risers (gas lift) of all wells).

**8.12 MACHINERY MONITORING SYSTEM (MMS)**

8.12.1 CONTRACTOR shall provide a Machinery Monitoring System for critical rotating equipment (at least for all gas compressors, electrical generators, gas and steam turbines, SRU Feed pumps, main water injection pumps, booster water injection



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pumps and sea water lift pumps) and its drivers and gearboxes/HVSD. MMS shall be integrated with the Machinery Protection System (MPS).

8.12.2 In addition to the signal available through MPS Communication, CONTRACTOR shall make available the process variable signals through the Fast Ethernet Network to perform the functions above in the Machinery Monitoring System, with acquisition interval of at least one second.

8.12.3 For a basic description, the primary function of the MMS is to perform analysis of the mechanical parameters: all machinery protection system signals, with possibility to make analysis like FFT (Fast Fourier Transform), full spectrum, Bode plot, cascade and waterfall diagrams, shaft average center line, orbit, X-Y plot and experience-based vibration analysis, and auxiliary system signals (lube, seal, etc.).

8.12.4 The Machinery Monitoring System shall have the following functions:

- Data acquisition of vibration signals from machinery sensors and bearing temperatures as a minimum;
- Data logging and event/variable recording and storing (compressed data feature to allow the access of significant values with high resolution within measurements spanning five years);
- Listing of all incoming alarms chronologically in a directory and a user-defined actions;
- Historical trending (all variables);
- Real-time measurements in order to allow diagnostics of fault detection and analysis;
- Display of equipment schematic layout;
- Measurements covering the widest possible range of machine faults.
- Real-time display of process variables such as temperatures, pressures, vibration, flows, speed, electrical measurements, valve position, tank levels, etc.; and others applicable variables for each equipment class. The CONTRACTOR shall provide access to MMS at the PETROBRAS Onshore Office through offshore DMZ (see TELECOM MASTER SPECIFICATIONS FOR FPSO CHARTERED – item 1.2.1), in order to allow PETROBRAS to monitor the Machines. MMS and MPS shall have a dedicated Ethernet network for vibration signals, different from the network used to mirror MMS to PETROBRAS Office.

### 8.13 SMBS Control and Monitoring System

8.13.1 CONTRACTOR is responsible for all the Instrumentation, Automation and tubing/piping interfaces on topsides related to SMBS, including, but not limited to, Automation panels, their connection with the Automation and Control System of the unit and development of new screens in the Supervisory System, in order to comply with the objective of integrated and centralized operation in CCR.

8.13.2 PSD and FGS/ESD hardwired signals shall be exchanged bidirectional between the SMBS Control Panels to the CIS. Besides, the SMBS Control Panels shall make the main process variables of each SMBS available to the supervisory system via computer network using Modbus TCP or OPC-UA protocols, to be defined by PETROBRAS. An external connection to the Internet through the platform firewall shall be provided to each SMBS Control Panel

8.13.3 Additionally, the CCR HMI shall display in dedicated screens and in real-time all the variables of each SMBS. A dedicated Operation Workstation will be supplied as part of each SMBS and shall be placed in the CCR and all its interconnections with the CIS/MCS shall be supplied, installed, and configured by CONTRACTOR.

8.13.4 CONTRACTOR shall provide the correct interconnection of all SMBS Topide Modules systems with FPSO systems (automation, electrical, pneumatic, hydraulic, etc.)

8.13.5 CONTRACTOR shall provide, configuring, testing, and commissioning of SMBS system integration with the CIS in order for the SMBS system to be fully functional in the FPSO.

8.13.6 CONTRACTOR shall provide the connections between umbilical terminal units and the umbilical.

## 8.14 OPTIMIZATION AND ADVANCED CONTROL

8.14.1 Optimization and advanced control are intended to increase production efficiency, process plant stability and safety of control loops of critical equipment. CONTRACTOR shall be responsible for providing infrastructure for optimization and advanced control:

- 1 (one) machine (server) in the platform automation network to host advanced control applications. Through this microcomputer, it shall be possible to access (read/write) all control loops running in CSS (main topsides, subsea and Hull/Marine data) via OPC-UA protocol.
- PETROBRAS will provide the ADVANCED CONTROL software solution and CONTRACTOR will configure the OPC-UA connection with the Supervisory System to access the control loops in CSS. This server shall be provided with Windows Server Operational System (latest version) and be suitable to continuously working on a 24 x 7 duty. Drivers to convert from others protocols to OPC-UA are CONTRACTOR's scope. Minimum Hardware requirements: Processor for Server systems released on 2021 or after, 8 cores, 16 threads, at least 3,2GHz base clock (or better), 32Gb RAM and at least 500Gb free on storage, all storage shall be Solid State Drives (SSD).
- CONTRACTOR shall provide means, via supervision HMIs, allow the operator to enable (on/off) the advanced control, as well as to define its limits and setpoints.
- CONTRACTOR shall set up watchdog logic in automation (A&C) systems to take the correct actions and inform the operator when a communication fail has

occurred between the computer, where advanced control is running, and the automation system of the platform.

- All the necessary instrumentation and intervention in automation (A&C) system for the implementation of optimization and advanced control is CONTRACTOR responsibility.
- The advanced control loops are:
  - Anti-slug, for each production inlet - this advanced control loop shall use choke valves with remote actuation and a pressure control valve for each production header. (Suggestion: due to previous experiences, PETROBRAS suggests the use of choke valves with electrical actuator and internal multistaging and configured as equal percentage);
  - Gas-lift optimization;
  - Level control by bands in separators.
  - Assisted startup;
  - Wellbot.
- . The advanced control algorithms that run in advanced control server are defined by PETROBRAS and run under MPA software.
- CONTRACTOR shall supply, install and configure the advanced control tools (hardware and software) and integrate them to the Unit Automation and Control System.

## 8.15 PRESSURE AND TEMPERATURE MONITORING POINTS

8.15.1 CONTRACTOR is responsible for the definition of the instrumentation required for legal compliance and stable, continuous and safe operation.

8.15.2 Pressure and temperature transmitters indicated on table 8.16.3 and 8.16.4 shall not be duplicated if this instrumentation is required for pressure and temperature correction for flow measurement as stated in FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1) or mentioned on items of GTD. Instrumentation requirements prescribed on FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1) are mandatory.

8.15.3 CONTRACTOR shall provide at least the monitoring points indicated in Table 8.16.3 with indication in the supervisory system for energy efficiency and atmospheric emissions assessment. These monitoring points shall be available at Plant Information system, for onshore monitoring.

Table 8.16.3 – Pressure and temperature monitoring points for energy efficiency and atmospheric emissions assessment

| Item | Monitoring points  | Temperature | Pressure |
|------|--|-------------|----------|
| 1    | Inlet and outlet hot and cold streams of the heat exchangers from the following systems: |             |          |
| 1.1  | Oil separation and treatment   | x           | x        |
| 1.2  | Condensate   | x           | x        |

**GENERAL TECHNICAL DESCRIPTION FOR  
LEASED UNITS**

|     |   |   |   |
|-----|---|---|---|
| 1.3 | Gas   | x | x |
| 1.4 | Produced water  | x | x |
| 1.5 | Cooling medium  | x | x |
| 1.6 | Heating medium  | x | x |
| 1.7 | Amine   | x | x |
| 1.8 | Glycol (if applicable)  | x | x |
| 2   | Injection water header  | x | x |
| 3   | Production header   | x | x |
| 4   | First separator oil outlet  | x | x |
| 5   | First separator gas outlet  | x | x |
| 6   | First separator water outlet  | x | x |
| 7   | Recycle streams routed to first separator                                   | x | x |
| 8   | Oil transference pump discharge (from the process plant to the cargo tanks) | x | x |
| 9   | Gas Export Line   | x | x |
| 10  | Fuel gas total  | x | x |
| 11  | Produced water disposal   | x |   |
| 12  | Seawater disposal from cooling system                                       | x |   |
| 13  | Inlet and outlet of flue gas and heating medium streams from each WHRU      | x |   |
| 14  | Turbine intake air and flue gas chimney exit                                | x |   |
| 15  | Inlet and outlet of Main Seawater Injection Pump                            | x | x |
| 16  | Diesel engine - fuel  | x | x |
| 17  | Diesel engines - flue gas   | x |   |
| 18  | Diesel engines - inlet and outlet cooling water                             | x |   |
| 19  | Sulphate removal reject   | x |   |
| 20  | Ultrafiltration reject  | x |   |
| 21  | Reverse Osmosis reject  | x |   |

8.15.4 CONTRACTOR shall provide the instrumentation listed on table 8.16.4.

Table 8.16.4 – Pressure and temperature monitoring points for operational purposes

| Item | Monitoring points   | Type                     |
|------|---|--------------------------|
| 1    | Downstream and upstream of shutdown valves at water injection pumps discharge | Pressure                 |
| 2    | Bearing and motor of main water injection pump                                | Temperature              |
| 3    | Upstream and downstream of each choke valve                                   | Pressure and Temperature |
| 4    | Topsides water injection lines  | Pressure                 |
| 5    | Each molecular sieve bed (if applicable)                                      | Pressure                 |

**GENERAL TECHNICAL DESCRIPTION FOR  
LEASED UNITS**

|    |  |                          |
|----|--|--------------------------|
| 6  | TEG absorber column packing (if applicable)  | Pressure                 |
| 7  | Each Regeneration gas heater   | Temperature              |
| 8  | Solid removal filters of produced water treatment  | Pressure                 |
| 9  | HP and LP headers upstream QOV   | Pressure                 |
| 10 | Pump discharge filters of umbilical (subsea) chemical injection  | Pressure                 |
| 11 | Each chemical injection point  | Pressure                 |
| 12 | Sea cooling water overboard discharge  | Temperature              |
| 13 | Cargo tanks  | Pressure                 |
| 14 | Critical rotating equipment (at least all gas compressors, turbogenerators, crude oil pumps, crude oil settling tank pumps, produced water settling tank pumps, main water injection pumps, booster water injection pumps and sea water lift pumps) and its drivers and gearboxes/HVSD | Pressure and Temperature |
| 15 | Printed Circuit Heat Exchanger (PCHE) core   | Pressure                 |
| 16 | Gas inlet strainer of PCHE   | Pressure                 |
| 17 | Cooling medium inlet strainer of PCHE  | Pressure                 |
| 18 | Top of injection/service risers  | Temperature              |
| 19 | Downstream of each service choke valve   | Pressure                 |
| 20 | fuel gas individual consumers (e.g. gas-turbines, flare, boilers, etc)   | Pressure and Temperature |
| 21 | Hull HC distribution header (HC Blanketing System)   | Pressure                 |
| 22 | Vent post header (HC Blanketing System)  | Temperature              |
| 23 | Amine Contactor  | Temperature              |
| 24 | Amine Reboiler   | Temperature              |

## 8.16 FLOW MONITORING POINTS

8.16.1 CONTRACTOR is responsible for the definition of the instrumentation required for legal compliance and stable, continuous and safe operation.

8.16.2 Flow monitoring transmitters indicated on table 8.17.3 and 8.17.4 shall not be duplicated if this instrumentation is required on FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1) or mentioned on items of GTD. Instrumentation requirements prescribed on FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1) are mandatory

8.16.3 CONTRACTOR shall provide at least the monitoring points indicated in Table 8.17.3 with indication in the supervisory system for energy efficiency and atmospheric emissions assessment. These monitoring points shall be available at Plant Information system, for onshore monitoring.

Table 8.17.3 – Flow monitoring points for energy efficiency and atmospheric emissions assessment

| Item | Monitoring points |
|------|-------------------|
|------|-------------------|

**GENERAL TECHNICAL DESCRIPTION FOR  
LEASED UNITS**

|    |  |
|----|--|
| 1  | Main Gas Compressor suction                            |
| 2  | Export Gas Compressor suction                          |
| 3  | VRU suction  |
| 4  | Produced water flotation gas                           |
| 5  | Gas from TEG Flash Drum (if applicable)                |
| 6  | Stripping Gas for TEG Regeneration (if applicable)     |
| 7  | Gas from Amine Flash Drum                              |
| 8  | Sour gas from amine regeneration                       |
| 9  | All recycle streams routed to 1st production separator |
| 10 | Produced water from 1st production separator           |
| 11 | Ultrafiltration reject                                 |
| 12 | Sulphate removal reject                                |
| 13 | Reverse Osmosis reject                                 |
| 14 | Main Injection Water Pump suction                      |
| 15 | Cooling water for each turbogenerator                  |
| 16 | Cooling water for each motogenerator                   |
| 17 | Sea cooling water to overboard                         |
| 18 | Sea water to fresh water maker                         |
| 19 | Generated fresh water                                  |
| 20 | Inert gas  |
| 21 | Diesel for each turbogenerator                         |
| 22 | Diesel for each motogenerator                          |

8.16.4 CONTRACTOR shall provide the instrumentation listed on table 8.17.4.

Table 8.17.4 – Flow monitoring points for operational purposes

| Item | Monitoring points  |
|------|--|
| 1    | Service pump   |
| 2    | Each gas-lift riser, including the production satellite wells  |
| 3    | Deviated rich TEG flow (if applicable)   |
| 4    | Lean TEG flow (if applicable)  |
| 5    | Stripping gas flow of TEG Regeneration Reboiler (if applicable)  |
| 6    | Stripping gas flow of Stahl Column (if applicable)   |
| 7    | Each source of purge gas   |
| 8    | Each chemical injection point  |
| 9    | Critical rotating equipment (at least all gas compressors, turbogenerators, main water injection pumps, booster water injection pumps and sea water lift pumps) and its drivers and gearboxes/HVSD |
| 10   | fuel gas individual consumers (e.g. gas-turbines, flare, boilers, etc)   |

## **9 ELECTRICAL SYSTEM**

### **9.1 GENERAL**

9.1.1 The electrical system design and installation shall comply with IEC 61892 series. Additionally, the requirements defined below shall be mandatory.

### **9.2 GENERATION POWER MANAGEMENT SYSTEM**

9.2.1 Apart from the usual generation Unit controls (frequency, voltage control and turbine controllers), an independent generation control shall be supplied in order to maintain full simultaneous control of all generators of the FPSO. This controller shall be hereinafter called PMS (Power Management System).

9.2.2 A Power Management System (PMS) shall be provided, including functions of main generation voltage control, main generation frequency control, load shedding, load sharing and permission of starting for high demand loads and maximum turbogenerator demand.

NOTE: turbogenerator demand limit control under 100 MW is applicable only if turbines are also used for non-electrical generation. (Eg: turbo compressors, turbo pumps...).

9.2.3 To prevent total or partial loss of power, the load shedding shall command fast selective tripping of pre-determined HV consumers, in the event of main generation overload (sudden or gradual) and main generation under frequency, to prevent total or partial loss of power.

#### **9.2.4 PMS GENERAL REQUIREMENTS**

9.2.4.1 The system shall be type approved by Class Societies.

9.2.4.2 The PMS shall at least comprise generator paralleling control, load sharing, peak shaving, automatic load shedding, load import/export control and protection.

9.2.4.3 The load shedding function shall allow temporary overload of main generation due to starting of large motors and transformers.

9.2.4.4 The load sharing function shall be capable to share active power demand evenly (in proportion of their capacities) among the main generators running, or to set adjustable fixed active power to keep one generator with variable active power, according to the demand variation.

### **9.3 GENERATORS**

#### **9.3.1 MAIN GENERATORS GENERAL REQUIREMENTS**



TITLE: **GENERAL TECHNICAL DESCRIPTION FOR LEASED UNITS**

- 9.3.1.1 The power generation system shall be designed considering operational cases defined on section 2.
- 9.3.1.2 Each power generation package consists of a synchronous alternator driven by dual fuel gas turbine, designed to operate on fuel gas (normal) or on Diesel fuel (no fuel gas available). Dry Low Emission Turbines (DLE) are not accepted for aero-derivative gas turbine type.
- 9.3.1.3 For main power generation based on gas turbines, the auxiliary and the emergency generator shall be capable independently to start-up the main generator, assuming dead-ship condition.
- 9.3.1.4 Main turbogenerator packager shall be the gas turbine OEM (original equipment manufacturer).
- 9.3.1.5 CONTRACTOR may propose Combined Cycle system for main power generation. Combined cycle configuration shall be based on gas turbines and steam turbines. For details about combined cycle system, see item 9.10.

**9.3.2 MAIN GENERATOR TURBINE REQUIREMENTS**

9.3.2.1 CONTRACTOR is requested to present the following on the technical proposal submission in order to evidence power generation compliance to GTD:

$$X(KW) = [\text{Turbine ISO output power at 15 degrees Celsius temperature}](KW) * [N-1] \text{ generators} / [Z] + \text{Steam turbine driven generator power (kW)} * [M];$$

$$Y(KW) = [\text{maximum electrical demand from electrical load balance calculation report}] (KW) * [Z];$$

X(KW) shall be greater or equal than Y (KW);

[N] = total number of main turbogenerators sets installed;

[M] = total number of main steam turbine generator sets running, if any;

[Z] = derate factor (see table 9.3.2.1)

Table 9.3.2.1: "Z" Factor by Model

| [Z]= 1.25  | [Z] = 1.33   |
|--|--|
| BHGE Baker Hughes GE: LM2500+G4;<br>SIEMENS: SGT-A35 (34 MW ISO) | BHGE Baker Hughes GE: LM2000, LM2500, LM2500+, LM6000 PC/PG SAC;<br>SIEMENS: SGT-A05, SGT-A65 SAC (WLE DRY), SGT-100, SGT-600; |





TITLE:

**GENERAL TECHNICAL DESCRIPTION FOR  
LEASED UNITS**

SOLAR: SATURN, CENTAUR  
50, TAURUS 60, MARS100,  
TITAN 130, TITAN 250.

NOTE 1: PETROBRAS considers that CONTRACTOR will built-in design contingencies into the maximum expected electrical demand. PETROBRAS consider those contingencies (margins) as a CONTRACTOR internal issue. However, all contingencies (margins) applied to all gas compressors shall be clearly stated including all losses and degradations applied to calculate the maximum power on the compressor's driver shaft.

NOTE 2: The generators packages on duty shall be designed at least to supply the maximum electrical load at 30 degrees Celsius (maximum ambient temperatures to be considered for design purpose).

NOTE 3: [Z] factor value is the minimum required for main generators design.

NOTE 4: In case of power generation with combined cycle, CONTRACTOR shall inform during tender period the additional pressure drop on the gas turbine exhaust gas (anything above 250 mm H<sub>2</sub>O for exhaust pressure loss) according to the proposed combined cycle configuration. Such additional pressure loss, if any, shall be included in Z factor and shall be clearly stated along with its effects on the turbine output.

9.3.2.2 The main generators shall be capable to immediately restart at any time after a shutdown event. Restriction of the turbine restart due to mechanical locking of the gas generator (GG) is not acceptable. Forced lockout time is not acceptable.

9.3.2.3 For acceptable vendor list for Gas Turbines for Main Generators, see item 19.

### 9.3.3 MAIN GENERATOR ELECTRICAL REQUIREMENTS

9.3.3.1 The configuration of the main generator packages shall consider one generator in stand-by condition, for all operational modes defined on section 2, with [N-1] generators running.

NOTE: "N" is the total number of main generators installed in the FPSO.

9.3.3.2 For direct on-line starting the largest motor, it shall be considered maximum 2 main generators running, to keep transient voltage drop within tolerable limit of +/- 20% (voltage excursions - sum of transient and steady state deviation - on switchboards and distribution panels which electrical system and consumers in general shall withstand).

NOTE: The use of alternative starting solutions is allowed, i.e.: Soft-starters, Soft-Starter-VSDs, and VSD or other.

9.3.3.3 CONTRACTOR shall consider stand-by compressor start-up without turn off the running compressor during load transfer.

### 9.3.4 ESSENTIAL/AUXILIARY GENERATOR

- 9.3.4.1 For auxiliary generator package, CONTRACTOR shall use new equipment.
- 9.3.4.2 Auxiliary generators can be used to complement main power generation during offloading operations; in this case, one standby auxiliary generator is required.
- 9.3.4.3 Auxiliary generator shall have a dedicated starting system independent from the emergency generator.

### 9.3.5 EMERGENCY GENERATOR

- 9.3.5.1 For emergency generator package, CONTRACTOR shall use new equipment.
- 9.3.5.2 Emergency generator shall be dimensioned to feed simultaneously all loads indicated in the SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1), IMO MODU CODE and required by C.S., for at least 18 hours.
- 9.3.5.3 Emergency and auxiliary generators shall have a quick-closing fuel valve shall be a normally-open, “energize to close” coil. A manual acting closing device shall be provided to close the fuel valve, outside the emergency and auxiliary generator rooms, in case of fire inside.
- 9.3.5.4 The starting sources for Emergency Generator shall not be shared with any other generator.

## 9.4 DISTRIBUTION SYSTEM

### 9.4.1 POWER DISTRIBUTION

- 9.4.1.1 The HV, LV and UPS distribution system shall be designed with required redundancy, so that a single failure in any equipment, circuit or bus section does not impair the whole system and neither reduce the production/processing capacity of the Unit.
- 9.4.1.2 For main generation systems, the main bus shall be subdivided in at least two parts which shall be normally connected by a tie circuit breaker.
- 9.4.1.3 The earthing and detection methods shall comply with Chapter 6 of IEC 61892-2 (System Earthing) requirements and the CS rules, as applicable.

### 9.4.2 HIGH/MEDIUM VOLTAGE SYSTEM

- 9.4.2.1 For Medium Voltage generation and distribution systems, the high resistance earthing shall be adopted with instantaneous selective tripping in the event of earth fault.

### 9.4.3 LOW VOLTAGE SYSTEM

9.4.3.1 The Low Voltage power distribution system shall be of secondary-selective type, with main bus subdivided in at least two parts which shall be normally connected by a tie circuit breaker; each bus part shall normally be fed from secondary of duplicated and fully redundant HV/LV transformers with tie circuit breaker open.

9.4.3.2 Low voltage distribution system shall be divided into different groups and switchboards:

- Normal Process Plant loads;
- Normal Utilities/Ship Service loads;
- Essential/Emergency loads.

### 9.4.4 DEDICATED VDC SYSTEM

9.4.4.1 In case CONTRACTOR opts for VDC systems (e.g. 24 VDC) for control and starting of Emergency Generator and Fire water pumps, the following requirements shall be met:

- VDC system shall be dedicated;
- VDC system shall be powered by essential busbars;
- VDC system shall have its own battery bank;
- VDC system shall be installed as close as possible to their loads.

## 9.5 ELECTRICAL EQUIPMENT

### 9.5.1 GENERAL REQUIREMENTS

9.5.1.1 Electric panels shall have the front and rear floor covered by insulating rubber matting complying with ASTM D-178-01 requirements for Type II – ABC (ozone, fire and oil resistant) and minimum Class 0 (tested for 5kV) for panels with rated voltage up to 690V and minimum Class 2 (tested for 20kV) for panels with rated voltage above 690V..

### 9.5.2 POWER TRANSFORMERS

9.5.2.1 Each power transformer shall be dimensioned to feed 100% of the maximum switchboard load demand, with no forced ventilation, on a contingency condition with the duplicated redundant unit out of service.

9.5.2.2 For dry-type power transformers, the Fire Behavior Class shall be F1, according to defined IEC 60076.

### 9.5.3 VARIABLE SPEED DRIVERS

**GENERAL TECHNICAL DESCRIPTION FOR  
LEASED UNITS**

- 9.5.3.1 VSD-FC shall be designed, manufactured, and tested according to IEC 61800.
- 9.5.3.2 Manufacturer is responsible for detailed electrical design and engineering within the VSD and shall perform all functions required to interface with the design of electrical system, as well as guarantee the control and monitoring from Control Panel.
- Note: When driving compressor systems, Compressor OEM (Original Equipment Manufacturer) shall assume unit responsibility and shall assure that all vendors comply with the requirements stated herein this document including VSD. Therefore, Compressor Vendor is responsible for the design, development, engineering, coordination, procurement, fabrication, assembly, test and shall guarantee overall performance (fully functional and operable) of complete compressor package.
- 9.5.3.3 For VSD-FCs feeding motors installed in hazardous areas Zone 1 or Zone 2 or installed in safe external area but kept in operation during shutdown conditions, shall be certified as a unit association (motor-VSD-protective device) as required by IEC 60079-14.
- Note: Alternatives foreseen in IEC 60079-14 for this certification (as a unit association) are acceptable.
- 9.5.3.4 MEDIUM VOLTAGE VSIDS
- 9.5.3.4.1 Medium Voltage VSD-FC shall be supplied with internal electric arc monitor device able to send a signal for instantaneous opening of the feeding panel circuit breaker to shut down the converter.
- 9.5.3.4.2 Safety requirements for VSD-FC shall comply with IEC 62477-1 and IEC 62477-2.
- 9.5.3.4.3 If VSD-FC has arc withstand capability, it shall comply with IEC 62271-200.
- 9.5.3.4.4 Medium Voltage VSD-FC harmonics shall comply with maximum values defined in IEEE Std. 519.
- 9.5.3.4.5 The minimum efficiency for the VSD-FC system including, i.e., VSD-FC, power transformers, cooling auxiliary devices, control and protection devices and accessories shall be: 96.0% efficiency at 100% rated load.
- 9.5.3.4.6 The minimum power factor at the VSD-FC set input with rated voltage and frequency shall be: 0.95 lag, with tolerance -0%, at 100% rated load.
- 9.5.3.4.7 A dv/dt filter or sine wave filter shall be provided whenever required by the motor insulation limits, considering the effects of the connection cables.
- 9.5.3.4.8 VSD-FC shall comply with emission and immunity EMC (Electromagnetic Compatibility) and RFI (Radio Frequency Interference) requirements according to IEC 61800.
- 9.5.3.4.9 VSD-FC shall have the protection functions defined in IEC 61800.

9.5.3.4.10 For Medium Voltage VSD driving compressor systems the following requirements apply:

9.5.3.4.10.1 The proposed equipment shall be field proven and have satisfactory operation in floating offshore units.

9.5.3.4.10.2 Transformer requirements for VSD:

- Transformer rating shall follow IEC 61378 or IEEE C57.18.10
- Insulation: class F with temperature rise plus ambient temperature under the limits of class B (all windings) or class H with temperature rise plus ambient temperature under the limits of class F (all windings).
- Two RTD, platinum resistance temperature detectors type (PT100Ω @ 0°C) per winding or thermostats (see 4.3); These RTDs shall be in contact with the hottest temperature parts of the windings.
- VSC-FC Input Transformer Temperature Rise Tests shall be repeated during String Tests.

9.5.3.4.10.3 Transformers and Drives Cooling systems and controls tests shall be included as defined in IEC 61800.

9.5.3.4.10.4 Tests shall follow IEC 61800. All routine test, special tests and string tests (full load) shall be witnessed by PETROBRAS. These tests procedures and approval criteria shall demonstrate the unit's performance and reliability. During the execution phase, CONTRACTOR shall provide all test reports.

## **9.6 UNINTERRUPTIBLE POWER SUPPLY (UPS) SYSTEM - AC AND DC**

### **9.6.1 GENERAL**

9.6.1.1 UPS source of power may be provided by AC or DC UPS.

9.6.1.2 UPS shall be arranged and dimensioned to feed simultaneously all loads indicated in the SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1), IMO MODU CODE, and required by C.S., and corresponding autonomy time.

9.6.1.3 UPS log report shall be recordable, retrievable and available for PETROBRAS as requested, providing comprehensive information on the equipment status and diagnostic information.

### **9.6.2 UPS FOR AUTOMATION/INSTRUMENTATION SYSTEM**

9.6.2.1 UPS source of power may be provided by AC or DC UPS.



TITLE:

**GENERAL TECHNICAL DESCRIPTION FOR  
LEASED UNITS**

- 9.6.2.2 The UPS system for Automation shall be comprised by two redundant and electrically separated units, "A" and "B", each of them sized for supplying all loads (2 x 100%), operating isolated.
- 9.6.2.3 Each UPS, if AC, shall be provided with dedicated by-pass transformer, with automatic transfer through static switches.
- 9.6.2.4 Each distribution switchgear shall have option to be fed either from UPS A or UPS B. Therefore, all switchgears shall have circuit breakers facilities to transfer the UPS supply from UPS A to UPS B (or the other way round, from UPS B to UPS A).
- 9.6.2.5 The distribution switchgears shall have full capacity interconnecting circuit breakers for transfer all connected loads to and from redundant UPS, keeping the loads operating (without temporary black-out).
- 9.6.2.6 UPS output voltage shall be isolated from earth. Ground fault detection with local and remote alarm at CCR shall be provided; means for troubleshooting and locating ground fault as portable clamp meter shall be provided without interrupting services.

**9.7 LIGHTING**

- 9.7.1 Design of external lighting and illumination system shall avoid the disturbance on seawater, meaning that CONTRACTOR shall avoid directing the lighting to the sea. Outdoors lighting fixtures shall be preferentially directed to internal areas of the Unit, in order to not affect/impact marine life. CONTRACTOR shall consider that only specific lighting systems required by Brazilian and international regulations, Class and Flag requirements and Unit safe operation shall be directed to overboard in direction to seawater area.
- 9.7.2 The emergency lighting UPS system shall be redundant (2x100%).
- 9.7.3 Floodlights shall be additionally fitted with protection device against falling, according to IEC 61892-6. This is a recommended practice to be used for lighting fixtures installed in locations which are difficult to be reached by maintenance workers.
- 9.7.4 All floodlights and lighting fixtures for internal or external areas (except searchlights and offloading hoses lights) shall be of LED type. Lighting fixtures installed on external areas shall be increased safety type (Ex-e).

**9.8 LIGHTNING PROTECTION**

- 9.8.1 A Lightning Protection Study shall be carried out according to NFPA 780 - Standard for the Installation of Lightning Protection Systems, mainly chapters 4 and 7. Elevation views of protected zones shall be shown, considering the rolling spheres graphical method with sphere radius of 30 meters. Special regard shall be given to

**GENERAL TECHNICAL DESCRIPTION FOR  
LEASED UNITS**

high structures ( flare stack, telecom tower and flare booms) as well as to packages and structures containing flammable vapors, gases and liquids.

**9.9 ELECTRICAL STUDIES**

9.9.1 CONTRACTOR shall present to PETROBRAS, the following electrical studies:

- Main and Emergency Generation electrical load balance;
- Load Flow calculation report;
- Short-circuit calculation report;
- Voltage drop due to motor starting calculation report;
- Transient stability calculation report;
- Harmonic analysis calculation report;
- Protection coordination and selectivity calculation report;
- Arc fault incident energy calculation report;
- UPS and battery bank sizing report;
- Grounding Fault Analysis;
- Lightning Protection Study.

**9.10 COMBINED CYCLE MINIMUM REQUIREMENTS**

9.10.1 CONTRACTOR shall provide stand-by equipment, ready to operate, to guarantee no process capacity reduction nor degradation of the oil, gas and water specification occur.

9.10.2 For combined cycle configuration, the stand-by generator unit shall be gas turbine driven.

9.10.3 Steam turbine generator rated power shall not be greater than gas turbine generator rated power.

9.10.4 Steam turbine generator (STG) shall be driven by a condensing-type, special-purpose steam turbine with controlled extraction, in accordance with API STD 612. Lube and control oil system shall be according to API STD 614 for special purpose applications.

9.10.5 Centrifugal pumps shall be provided in accordance with API 610.

9.10.5.1 Boiler feedwater pumps shall be barrel-type (BB-5), electric motor driven, fitted with variable speed drives (VSD).

9.10.6 If main power generation is based on a combined cycle, a Reliability, Availability and Maintainability (RAM) analysis as described in AVAILABILITY AND



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MAINTAINABILITY (RAM) ANALYSIS REQUIREMENTS FOR LEASED UNITS WITH COMBINED CYCLE GENERATION (see item 1.2.1) shall be provided. The effects of Combined Cycle subsystems in the oil production shall be considered.

9.10.7 The combined cycle power plant shall be capable of providing the required heat demand to the process and the required power demand to the electrical grid (in accordance with operational cases defined on chapter 2) without disturbing the turbomachinery redundancy philosophy of the entire system, as per item 9.3.2.

9.10.8 Condenser(s) shall comply with HEI-2629 - STANDARDS FOR STEAM SURFACE CONDENSERS (Heat Exchanger Institute). Condenser tubes shall be made of full titanium material (other parts in contact with sea water shall also be in titanium).

9.10.9 Full condensate recovery (start-up venting, blowdown, drain etc.) is required.

9.10.10 The Combined Cycle Power Plant shall be provided with a dedicated online analytical instrumentation system for automatic water quality monitoring and chemicals dosing control. Sample points and additional analytical equipment for any required or recommended offline lab analysis shall also be provided.

#### 9.10.11 VENDOR LIST

9.10.11.1 For Vendor List for combined cycle main equipment, refer to item 19.

9.10.11.2 Vendor list for other equipment (condenser, balance of plant (BOP) system, heat exchanger etc.) shall be provided in the technical proposal during tender period. It shall include equipment operating in similar conditions in three floating units for at least three years.

## 10 EQUIPMENT

### 10.1 NOISE AND VIBRATION

10.1.1 CONTRACTOR shall conduct Noise and Vibration Study including process areas, marine areas and accommodations to evaluate working environment and implement mitigating measures whenever required. Specifically for compression and generation areas and whenever possible, Noise and Vibration study shall be based on existing similar equipment and projects.

#### 10.1.2 NOISE

10.1.2.1 Noise limits shall be in accordance with the Brazilian Regulations (NRs), CS rules and guidelines requirements for FPSO and / or MODU where applicable.

10.1.2.2 Equipment operating at high noise levels shall be acoustically treated using hoods, silencers, filters or other noise control system to meet the requirements.





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10.1.2.3 After completion of services, if noise levels exceed the specified limits, CONTRACTOR may be required to carry out additional improvements in order to insulate individual noise sources. Such remedial measures can be, for example, the installation of AVMs (Anti-Vibration Mounts), foundations for smaller equipment and additional insulation for limited areas.

**10.1.3 VIBRATION**

10.1.3.1 CONTRACTOR shall carry out structural and main equipment vibration measurements during commissioning and sea trials in order to verify acceptable levels of vibration, according to NRs, CS rules and guidelines requirements for FPSO and / or MODU where applicable.

10.1.3.2 CONTRACTOR shall rectify the stiffening of equipment and/or the equipment itself, if vibrations are clearly in excess of the recommendations of the above mentioned standards.

**10.2 HOISTING AND HANDLING SYSTEMS**

10.2.1 CONTRACTOR shall submit to PETROBRAS for comments a detailed procedure for equipment maintenance that includes their removal/disassembly from any part of the Unit to allow the installation of a new one. The procedure shall include facilities to allow offshore maintenance of the Unit, without affecting the production/processing capacity of the Unit.

10.2.2 Special attention shall be given to the area necessary for hoisting, handling and maintenance of the main generators, gas compressors, seawater lift pumps and diving equipment that are composed by large pieces with large weights.

**10.2.3 CRANES**

10.2.3.1 Cranes shall comply with API-2C - Offshore Pedestal Mounted Cranes or BS EN 13852-1 Cranes – Offshore Cranes Part 1: General Purpose Offshore Cranes for load and personnel lifting.

10.2.3.2 Cranes shall be classified by CS and shall comply with Brazilian Government Regulations Rules (NRs).

10.2.3.3 Crane capacities shall be compatible with equipment parts to be removed/disassembled (e.g. main generator rotor, heat exchanger tube bundles, diving equipment, etc.) and to transfer material/equipment to/from supply vessels to the Unit. Crane outreaches are measured outboard from the Unit's side shell.

10.2.3.4 In this option, as the risers shall come up on the Unit's Portside, this side shall not be used for any supply boat operations. All cranes shall be located on the Starboard side.

10.2.3.5 At least two cranes are required, Aft (AFT) Starboard and Forward (FWD) Starboard, built to operate under the following conditions:

- Loading/unloading from/to a supply vessel with an outreach able to transship at a distance of 28 m from FPSO's side at capacities defined on item 10.2.3.6;
- The whip hoisting system shall be able to lift 15,000 kg (minimum) with any boom angle;
- Transportation of personnel to/from the supply vessels.

10.2.3.6 The minimum loading/unloading capacity of one crane shall be 25,000 kg and the minimum for the other shall be 15,000 kg.

10.2.3.7 All above mentioned capacities are net lift capacities. Vessel motions and dynamic loads shall also be considered to properly design each crane.

10.2.3.8 CONTRACTOR shall provide means of transporting supplies/goods/spares from a lay-down area to the galley store, machineries spaces, warehouses, etc. (i.e., aft spaces/compartments).

### 10.3 HEAT EXCHANGERS

10.3.1 CONTRACTOR shall comply with all requirements and recommendations for the design of heat exchangers and pressure protection systems according to the internal failures scenarios as per API 521 item 4.4.14, especially where large pressure difference is observed (e.g. 7000 kPa or more), where dynamic analysis are recommended in addition to the steady state approach, and where the low pressure side is liquid-full and the high-pressure side contains a gas or a fluid that flashes across the rupture.

#### 10.3.2 GASKET PLATE HEAT EXCHANGER

10.3.2.1 Gasket Plate Heat Exchangers, if considered by CONTRACTOR, shall be in accordance with API STD 667 – PLATE AND FRAME HEAT EXCHANGERS, and be capable to withstand pressure surges (dynamic pressure variations) due to process and control fluctuations. For cyclic services, fatigue design shall be in accordance with ASME BPVC Section VIII, Division 2.

#### 10.3.3 PRINTED CIRCUIT HEAT EXCHANGER (PCHE)

10.3.3.1 PCHE will only be accepted for gas coolers in gas compression systems. Vapor Recovery Unit (URV) and Main Compression System are not included in the PCHE use option due to the characteristics of the processed gas. If CONTRACTOR decides to use PCHE (Printed Circuit Heat Exchanger), one additional PCHE per compression stage stored onshore (capital spare) and ready for installation shall be provided and the commissioning, operation and maintenance procedure shall be defined by PCHE vendor. An integral T-type (or similar) strainer shall be supplied on the gas inlet and a separate Duplex in line cleanable strainer shall be

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supplied for the cooling medium side, and the strainer aperture for both cases shall be advised by manufacturer. All the cooling medium control valves shall guarantee the minimum flow rate to the PCHE (typically around 20%), rudder stop valves are recommended. In addition, the pressure drop across the PCHE (core) and also the pressure drop across the strainers shall be individually and remotely monitored for both streams.

10.3.3.2 A side stream filtration (polishing) system shall be included and all measures necessary to guarantee the high quality and cleanliness of the cooling water, as recommended by PCHE manufacturer. The cooling medium operating pressure shall be higher than its vapor pressure at the maximum exchanger process inlet temperature, to prevent boiling in low flow or turndown conditions, and higher than the sea water pressure, to prevent sea water ingress to the closed loop in case of any leaks in the sea water cooler.

#### 10.3.4 SHELL AND TUBE HEAT EXCHANGER

10.3.4.1 Process system shell and tubes heat exchanger shall be in accordance with API 660 and ASME BPVC Section VIII, Division 1 standards.

### 10.4 PIPING

10.4.1 Piping and valves design, materials fabrication, assembly, erection, inspection and testing shall comply with ASME B31.3 and CS rules. Piping system layout, design, structural and fatigue analyses are required. Special attention shall be taken, but not limited to, well production lines, vents/drains of hydrocarbon system and other lines subjected to vibration (e.g. compression/pump systems), including small line diameters and instrument connections. Regarding such subject the compliance to NORSOK L-002 is required.

10.4.2 The use of long-bolt (wafer) type valves for services which contain flammable or combustible fluids shall not be acceptable. Lug and flanged types are acceptable.

## 11 TELECOMMUNICATIONS

### 11.1 GENERAL

11.1.1 The Unit's telecommunications shall comply with the TELECOM MASTER SPECIFICATIONS FOR FPSO CHARTERED document (see item 1.2.1).

## 12 STRUCTURAL DESIGN

### 12.1 GENERAL

12.1.1 Besides the CS load requirements for the operation of the Unit at the site, CONTRACTOR shall also design the Unit to withstand all construction loads and the

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environmental loads during transportation from construction/conversion shipyard to Brazil. For decommissioning purpose (including risers pull-out), the design shall ensure that in the end of the leased contract, the Unit shall have enough strength to be transported or towed to outside Brazilian waters.

12.1.2 Current revision of the CS rules shall be used to check and design the structures (hull and topsides), reinforcements and complementary structures. CONTRACTOR shall use net scantlings that are obtained deducting corrosion margins (as presented in item 12.2.7) from final scantlings or “as-built” scantlings in case of new building. “Final scantlings” means the plate thickness measured at the beginning of the conversion or after plate replacement.

**12.2 CONVERSION SURVEY (IF APPLICABLE)**

12.2.1 The hull assessment shall be submitted to a third party for reviewing and validation. This third party shall be a CS, other than the one that is classing the Unit. For acceptable CSs see item 1.3.4.

12.2.2 The hull shall be fully inspected according to CS requirements. Regardless of those CS requirements, as the Unit shall maintain continuous offshore operation during its whole operational lifetime with no dry-docking. All damaged areas, cracks of any nature, and all defective structural pieces, including welds and all warped areas, shall be replaced or restored to fit conversion specifications.

12.2.3 The Unit shall be surveyed prior to the installation of any new structure. The survey report shall inform all items that do not match the original design. Special attention shall be paid to the following items:

- Structure dimensions- girders, beams, stiffeners and plates;
- Out of tolerance imperfections of structural elements;
- Changes in the material specifications;
- Corrosion of structural elements.

12.2.4 Ships that have been involved in explosion, grounding damage, lay-up (3 years or more) and/or relevant collision incident during their operational life shall not be utilized for conversion.

12.2.5 Both ultrasonic gauging report and the reassessment study shall be submitted to CS for approval and to PETROBRAS for information. Also, the pitting map for the inner surface of cargo, slop, ballast, produced water and oil offspec tanks bottom plates shall be submitted for Petrobras information. In case any cargo tank has been converted to Diesel Storage Tank, this requirement is also applicable.

12.2.6 Further inspections (to be made by a third party) may be required by Petrobras during the engineering design phase, as part of the Survey Report

**12.2.7 PLATE REPLACEMENT CRITERIA**

- 12.2.7.1 The design philosophy shall consider that no hot work will be done, due to plating/structural replacement, during the Unit's operational lifetime.
- 12.2.7.2 Specification of hull steel renewal at conversion is based on the requirement that no part of the hull will fall under substantial corrosion during the contract period.
- 12.2.7.3 Hull steel renewal shall consider both local corrosion (pitting and grooving) and overall corrosion.
- 12.2.7.4 For overall corrosion of plating and stiffeners, renewal thickness at conversion is defined such that the substantial corrosion margin will not be reached within the FPSO life, taking into account anticipated corrosion losses during the FPSO life. The substantial corrosion margin is defined as 75% of the allowable corrosion margin as specified in the inspection criteria of the rules.
- 12.2.7.5 When re-assessment is performed, the FPSO required gross thickness (TR) is defined as the required thickness for use as FPSO without reduction for corrosion, based on the environmental site specific design parameters, even in the case that the re-assessed thickness is lower than the original "as-built" thickness.
- 12.2.7.6 As a minimum criterion, the following procedure shall be adopted to determine the steel renewal thickness at conversion:

$T_{\text{measured}} \leq T_R * (1 - 0.75 * R_L) + M \rightarrow$  Element shall be renewed.

$T_{\text{measured}}$  – Structural element thickness – based on the Thickness Reading Report.

$M$  – 24,75 years corrosion margin.

$T_R$  – rule required gross thickness – to be defined by the Reassessment Study.

$R_L$  – rule allowed corrosion percentage according to Classification Society rules.

- 12.2.7.7 The following table shows the corrosion margin values (M) to be used for 24,75 years of operation (Contract period) for different uncoated structural elements ("F" factor is 1,238 (M / 20 years)):

Table 12.2.6.7: Corrosion Margin Values

| LOCATION              | ITEM                                 | CORROSION MARGIN (mm) |                             |
|-----------------------|--------------------------------------|-----------------------|-----------------------------|
|                       |                                      | Cargo Tank            | Ballast Tank <sup>(1)</sup> |
| LONGITUDINAL ELEMENTS | Deck plating                         | 1.3 x F               | 2.0 x F                     |
|                       | Deck longitudinals                   | 1.3 x F               | 2.0 x F                     |
|                       | Side shell plating                   | 1.0 x F               | 1.5 x F                     |
|                       | Side shell longitudinals             | 1.0 x F               | 2.0 x F                     |
|                       | Longitudinal bulkheads plating       | 1.0 x F               | 1.5 x F                     |
|                       | Longitudinal bulkheads longitudinals | 1.0 x F               | 2.0 x F                     |
|                       | Bottom shell plating                 | 1.4 x F               | 1.5 x F                     |
|                       | Bottom shell longitudinals           | 1.0 x F               | 2.0 x F                     |
|                       | Deck transverse web plating          | 1.5 x F               | 2.0 x F                     |

|                          |                                   |         |         |
|--------------------------|-----------------------------------|---------|---------|
| TRANSVERSE<br>WEB FRAMES | Bottom transverse web plating     | 1.0 x F | 2.0 x F |
|                          | Side shell transverse web plating | 1.0 x F | 2.0 x F |
|                          | Long. bhd. transverse web plating | 1.0 x F | 2.0 x F |
| TRANSVERSE<br>BULKHEADS  | Plating                           | 1.0 x F | 1.5 x F |
|                          | Vertical stiffener (web)          | 1.0 x F | 1.5 x F |
|                          | Horizontal stringer web plating   | 1.6 x F | 2.0 x F |
|                          | Vertical girder plating           | 1.0 x F | 1.5 x F |
| SWASH<br>BULKHEADS       | Web plating                       | 1.0 x F | 1.5 x F |
|                          | Horizontal stringer web plating   | 1.6 x F | 1.6 x F |
|                          | Vertical girder plating           | 1.0 x F | 1.5 x F |

NOTE 1: Slop tanks, off-spec tanks and settling tanks (if applicable) shall consider same corrosion margins as ballast tanks.

12.2.7.8 By means of coating, the start of corrosion will be postponed. Therefore, a corrosion postponement can be considered, if CONTRACTOR ensures application of painting scheme with guarantee not lesser than 10 years. As so, the corrosion margins given in the table above can be de-rated, due to the referred corrosion postponement effect, for structural elements that are fully painted with NOVOLAC coating. Alternative solutions to NOVOLAC may be accepted by Petrobras. The reduction on the required corrosion margins in case of coated steel structural elements can be 5 years/24,75 years (20,2% reduction) on the corrosion margins given in the table above.

12.2.7.9 For pitting inspection/acceptance bottom plating shall be fully inspected after being properly blasted. The following plating renewal criteria shall be considered:

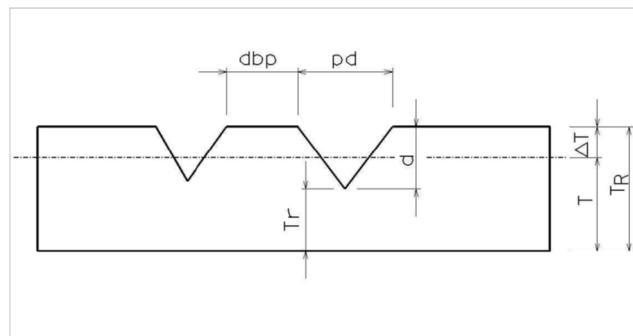


Figure 12.2.6.9: Plating Renewal Criteria

- 1 - If in the inspected region  $d < 0,15 \cdot TR$ : Plate to be treated and painted;
- 2 - If in the inspected region  $0,15 \cdot TR < d < TR / 3$ : See note below;
- 3 - If in the inspected region  $d > TR / 3$ : Plate to be renewed.

NOTE: Additional criteria shall be considered for those regions related to item 2 above:

- If  $pd > 200 \text{ mm} \Rightarrow$  plate renewing
- If  $pd \leq 200 \text{ mm}$  and either:
  - $dbp < 75 \text{ mm} \Rightarrow$  plate renewing
  - $dbp \geq 75 \text{ mm}$  and  $cpfd \leq 80 \text{ mm}$  P plate renewing

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- $dbp \geq 75$  mm and  $cpfd > 80$  mm and  $tr < 6$  mm or to TR/3 P plate renewing  
 where: pd - pitting diameter  
           dbp - distance between pittings  
           cpfd - continuous pitting weld filling distance  
           tr - residual plate thickness below pitting  
           to - original plate thickness

REMARK: Cpfd is the minimum continuous weld bead necessary to fill up a pit.

### 12.3 MATERIALS

12.3.1 To prevent the lamellar tearing effect, steel with Z quality (strength through the thickness) shall be used in places where plate stress occurs through thickness, such as fairlead connections, riser balcony connections, crane pedestal connection, etc. Special details may be adopted to avoid stress in the transversal direction of steel plate.

12.3.2 Double plates under the cargo pumps suction lines, drop lines, sounding pipes and ullage pipes inside the cargo tanks, ballast tanks, diesel tanks, oil and water offspec tanks, fresh water tanks, etc shall be welded in order to prevent erosion corrosion on structure. Alternative design solutions shall be submitted for PETROBRAS approval.

### 12.4 HULL

12.4.1 The following alternatives shall be adopted for new build hull:

- a) Double side, with, at least, three longitudinal bulkheads;
- b) Double hull, without any hydrocarbon piping system routed inside the double bottom and/or void spaces.

12.4.2 In case of converted hull, the double hull alternative, without any hydrocarbon piping system routed inside the double bottom and/or void spaces, shall be adopted.

12.4.3 CONTRACTOR shall comply with MARPOL Regulation 19 requirements.

12.4.4 In lieu of a risk analysis and/or a drifting analysis that defines the scenarios for vessel collision structural analyses, side shell structure at supply vessel approaching area shall withstand an impact energy (collision accidental load) imposed by a 9,000-MT displacement supply vessel, plus added mass, with speed of 2 m/s, for the worst cases of sideways, bow and stern impact scenarios, without causing the rupture of FPSOs cargo tank longitudinal bulkhead and without compromising the global structure. Supply vessel approaching area shall comprise the following region of the side shell: + 30 meters and -30 meters of each crane position, and 3.5 meters above maximum draft and -1.5 meters below minimum draft.

12.4.5 Side shell structure shall be designed at the same area to withstand an impact energy imposed by the same 9,000-MT displacement supply vessel, plus added mass, at 0.5

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m/s for the worst cases of sideways, bow and stern impact scenarios, associated with normal operational conditions, without any rupture to the side shell structure.

12.4.6 Criteria and methodology shall follow Norsok N-003 and N-004.

12.4.7 The referred area shall preferably have elastomeric fenders fixed to side shell by steel beams, in order to prevent contact between supply boat and the Unit's side shell plate. The fenders and their foundations shall be designed (dimensioned and spaced) to absorb the collision energy for normal operation conditions of supply vessel. In case of using floating fenders, at least 3 (three) shall be considered in each supply vessel approaching area.

12.4.8 Other external equipment/structures/piping (e.g. caissons for seawater uptake) connected to side shell at the supply vessel approaching area shall be protected by specific steel structure.

12.4.9 CONTRACTOR shall provide welded doubler plates in line with the suction and discharge of each tank. Insert plates with increased thickness is also acceptable alternative. If CONTRACTOR decides to provide suction bilge boxes on the tank bottom then plates shall also be designed with increased thickness.

12.4.10 TURRET AND CARGO TANK INTERFACE (NOT APPLICABLE)

12.4.10.1 Not applicable.

12.4.11 RISER BALCONY AND CARGO TANK INTERFACE (SPREAD MOORING OPTION)

12.4.11.1 CONTRACTOR shall perform a finite element analysis at the balcony/hull interface region to assess the structural strength and fatigue life. This analysis shall be submitted to CS for approval.

12.4.12 BALCONIES AND AFT STRUCTURE

12.4.12.1 Fairlead support structures, riser balconies, aft hull structures and other attached structures subject to wave slamming loads shall be analyzed considering the probability of occurrence and the corresponding load. Significance of effects on onboard comfort and on hull stresses are also to be addressed.

12.4.12.2 Sufficiently inclined flat plates at the bottom of each of these structures shall be employed in order to minimize wave slamming, and, in consequence, whipping hull girder effects.

12.4.12.3 Slamming loads can be calculated using CFD software in association with model test results and/or potential hydrodynamic simulations. Alternatively, the simplified approach as described in DNV-RP-C205 – "Environmental Conditions and Environmental Loads" may be used.





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- 12.4.12.4 Fatigue calculations shall also include the slamming loads with the corresponding probability of occurrence.
- 12.4.13 CATHODIC PROTECTION AND PAINTING
- 12.4.13.1 The cathodic protection (CP) system, painting specification and corrosion protection shall be part of the philosophy to allow the Unit to operate continuously during its operational lifetime without any production interruption. Therefore, design shall clearly identify those requirements.
- 12.4.13.2 Galvanic anode CP system shall be used for internal of tanks. Fresh water tanks shall have a different solution in order to avoid water contamination.
- 12.4.13.3 For external hull, impressed current cathodic protection systems is the preferred solution. The potential range to be adopted as a cathodic protection criterion for carbon steel structures shall be from -900 mV to -1000 mV, measured to the silver/silver chloride (Ag/AgCl sea water) reference electrode. Submerged defective parts replacement shall be feasible via diving operation. Additionally, galvanic anode CP may be accepted for external hull and limited areas with complex geometry. In this case, CONTRACTOR shall design the system to comply with design life requirement.
- 12.4.13.4 Special attention shall be given to chain pipes and other similar underwater structures to allow maintenance, inspection and replacement with no dry-docking/shutdown and to avoid problems caused by corrosion and marine growth.
- 12.4.13.5 Bottom cargo tank plating and structures shall be fully painted up to 2.0 meters of vertical structures or maximum water level, whichever is greater. Top cargo tank plating and structures shall be fully painted at least 2.0 meters from top. Painting specification shall consider the design life as stated in item 1.2.2.
- 12.4.13.6 Zinc anodes shall be adopted in ballast tanks if the “anode installation height X anode gross weight” is greater than 28 kgf x m and the maximum operation temperature is less or equal to 50°C.
- 12.4.13.7 Cargo and slop tanks bottom shall be provided with anodes. These galvanic anodes shall be placed at the bottom of the tank.
- 12.4.13.8 Produced Water Tanks, Slop Tanks, Off-spec tanks (if applicable) and Settling Tank (if applicable) shall be entirely painted with NOVOLAC coating considering design life as stated in item 1.1 herein. Alternative solutions to NOVOLAC may be accepted by Petrobras. Anodes shall also be provided to protect the entire tank.
- 12.4.13.9 CONTRACTOR shall provide an anti-fouling painting scheme for the external hull, encompassing bottom plate and side shell plate up to transit draft (maximum foreseen draft during transit phase from yards and final location). The anti-fouling painting scheme shall follow chapter 3 of NORMAM 20 requirements and IMO



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Resolution MEPC.207(62) - Guidelines for the Control and Management of Ships' Biofouling to Minimize the Transfer of Invasive Aquatic Species requirements.

**12.4.14 CARGO AND BALLAST TANKS STRUCTURAL INSPECTION**

12.4.14.1 All tanks access arrangements shall comply with IMO Recommendations A 272 (VIII) and A 330 (IX).

12.4.14.2 CONTRACTOR shall submit to PETROBRAS and CS an inspection plan of the cargo, ballast tanks or any other structural compartments evidencing that the Unit enables safe inspection inside all tanks. This plan shall be based on the Fatigue Analysis.

12.4.14.3 Means shall be provided to allow a safe "free-for-fire" certificate with minimum disturbance of the Unit's operation. In addition, cargo piping shall be installed with devices to reduce the risk of any accidents during inspection and "hot" services (e.g.: devices to avoid valves or expansion joints leakage).

**12.4.15 HULL EXTERNAL INSPECTION**

12.4.15.1 CONTRACTOR shall provide facilities for the installation of the temporary diving support equipment and for the diving operation itself, considering that the entire hull shall be visually inspected, as required by CS.

12.4.15.2 CONTRACTOR shall ensure the UNIT is designed to enable 100% in-service hull survey without any need of diving activities. In-service underwater Hull Class surveys and inspections shall be fully performed by ROV. In addition, the following requirements shall be complied with:

- Hull appendices structures (e.g seachest, lower riser balcony, fairleads, bilge-keel, etc.) shall be non-inspectable during unit design life.
- Contractor shall provide docking points in the hull to enable under water ROV activities ( e.g sea chest, bilge-keel, etc).
- The diving stations shall provide the facilities required for operations with electric mini-ROVs for UWILD (Underwater Inspection in Lieu of Dry-Docking), mooring and SURF (Subsea Umbilicals, Risers, and Flowlines) inspections to the extent possible.
- All hull frames shall be identified through double plates and paintings in contrasting color on the following locations:
  - vessel keel and both port and starboard sides in order to facilitate orientation of the ROVs;
  - side shell on both port and starboard sides close to main deck, above operational maximum draft.

12.4.15.2.1 During execution phase, CONTRACTOR shall demonstrate the requirements are being complied with.

## 12.5 TOPSIDE STRUCTURES

12.5.1 Green Water occurrence and the effects on the main deck and topside structures of FPSO shall be considered on the design, according to motion analysis results.

12.5.2 The structures and their foundations shall be designed according to CS requirements in order to withstand the worst of the following:

- Motions and accelerations associated with DOC and DEC design condition (item 13.6.3);
- All CS requirements, including accidental and towing condition.

NOTE: All safety systems and life-saving systems, including emergency equipment and vessel abandonment equipment, shall continue to operate while under the worst of the conditions listed above in this item.

12.5.3 When wave slamming loads on hull as those identified in item 12.4.12 are significant and may affect the dynamic response of a topside structure, then, its natural frequencies shall be kept away from hull girder natural frequencies a minimum of 20% difference for full range of operational drafts (light loading up to full loading conditions) and in transient condition, in order to avoid large dynamic amplification. CONTRACTOR shall perform integrated analyses for most susceptible structures, that is, slender structures and other potentially affected structures, e.g. hull/flare tower model, including dynamic effects, to evaluate the flare tower integrity under dynamic hull deflections, for both strength and fatigue, similarly for the other structures.

12.5.4 When, otherwise, those impact loads are not significant for these structures, then the difference between their natural frequencies and those of hull girder shall still be a minimum of 10%.

## 12.6 FATIGUE ASSESSMENT REQUIREMENTS

12.6.1 CONTRACTOR shall obtain Class Certificate for a fatigue design life equal to the design life defined in item 1.2.2.1.

12.6.2 Fatigue life and hull substantial corrosion criteria used during the design shall comply with the CS requirements and Structure and Naval Design requirements, in order to allow continuous offshore operation during its contract period, with no dry-docking in a shipyard. In addition, the Unit shall be fitted with facilities that enable any maintenance required during the operational lifetime as well as the surveys required by the CS, Port Administration, or Flag Statutory requirements without affecting the production/processing capacity of the Unit.

12.6.3 The fatigue analysis shall be submitted to a third party for reviewing and validation. This third party shall be a CS, other than the one that is classifying the Unit. For acceptable CSs see item 1.3.4

12.6.4 Fatigue Damage calculation for the support structures, foundations, etc., shall be carried out in accordance with the CS rules.

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12.6.5 CONTRACTOR shall use the waves, wind and current for fatigue analysis given in the annex METOCEAN DATA (see item 1.2.1). In this document, it is important to note that the specific direction reference for wind, wave and current can be different among them.

12.6.6 For converted hull, the fatigue assessment shall also consider the early fatigue effects in the hull during the early operation of the vessel before the hull conversion.

## 13 NAVAL DESIGN

### 13.1 GENERAL

13.1.1 The Unit shall have the following main naval characteristics:

13.1.2 Ship-shaped or barge-shaped unit, with a minimum storage capacity, i.e. minimum volume of oil available, in the cargo tanks, to be offloaded, of 1,100,000 bbl of crude oil. The amount of oil considered as permanent ballast and a residual tank volume of least 2% for each tank shall be added to this value. Stability criteria and structural constraints shall also be considered.

In addition, the 1,100,000 bbl of oil for offloading shall be available when:

- a) the two largest tanks are isolated for inspection and repair;
- b) the slop tanks, oil offspec tanks and the produced water tanks shall be excluded from the volume of 1.100.000 barrels of oil.

To calculate the "volume of oil available to be offloaded", CONTRACTOR shall proceed as follows:

1) One condition approved by the Classification Society of maximum loading of oil shall be included in the "Trim and Stability booklet"; This condition shall include the exclusions defined above.

2) One condition of minimum loading safe operational condition approved by the Classification Society shall be included in the "Trim and Stability booklet";

3) The "volume of oil available to be offloaded" is to be calculated as follows:

(Volume of oil available to be offloaded) = (Oil capacity in the maximum loading condition) – (Oil Capacity in the minimum loading safe operational condition) – Volume of Slop Tanks ( if applicable ) – Volume of the Produced Water Tanks ( if applicable ) – Volume of the two largest cargo tanks ( 98% full ) – Volume of oil offspec tank

4) The volume of oil available to be offloaded shall be equal or greater than 1,100,000 bbl

### 13.2 WEIGHT CONTROL PROCEDURES



TITLE:

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13.2.1 It is CONTRACTOR's responsibility to evaluate the Unit's weight and Center of Gravity Coordinates during design, installation and operational phases, according to the design and CS requirements.

**13.3 STABILITY ANALYSIS**

13.3.1 The Unit shall comply with the latest CS rules, MARPOL Annex I, MODU Code and International Load Line Convention, regarding intact and damage stability.

13.3.2 The distribution of static weights and vertical reactions imposed by the Spread Mooring and Riser System on the FPU shall be calculated for the purpose of evaluating the Unit trim and stability conditions.

13.3.3 PETROBRAS shall receive the FPSO model (latest version) used for stability analysis in \*.IGS format including hull, tanks and compartments (different file extensions may be agreed with PETROBRAS).

**13.4 MAXIMUM OFFLOADING OPERATIONAL CONDITION**

13.4.1 For maximum offloading operational condition, see OFFSHORE LOADING SYSTEM REQUIREMENTS and OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS (see item 1.2.1).

**13.5 BEAM SEA CONDITION (Applicable only for TURRET)**

13.5.1 Not applicable.

**13.6 MOTION ANALYSIS****13.6.1 GENERAL**

13.6.1.1 The most stringent criteria between the GTD and CS requirements shall be considered.

13.6.1.2 Motion analysis results, regarding displacements, velocities and accelerations, shall be used for the analysis of the following items:

- Process plant structural design;
- Fairlead and riser support structure/hull interface design (Spread-Mooring);
- Flare boom / tower structural design;
- Vent tower structural design;
- Helideck structural design;
- Crane foundation structural design;

- Equipment operational limit assessment;
- Offloading operational limit assessment;
- Pull-in / pull-out operational limit assessment.

### 13.6.2 RAO – RESPONSE AMPLITUDE OPERATOR

13.6.2.1 CONTRACTOR shall issue to PETROBRAS the RAO (Response Amplitude Operator) curves and tables with their corresponding phase angles, for Unit's 6 (six) degrees of freedom.

13.6.2.2 For each degree of freedom and selected draughts, respective RAO curves shall be informed together with natural periods and linearized viscous damping, when applicable, as for Roll motion for instance. The viscous damping coefficients shall be submitted to PETROBRAS for comments. Model tests shall be used to validate the CONTRACTOR proposal. In addition, the Model Test Report shall be provided for PETROBRAS for information.

13.6.2.3 Roll RAO curves shall be computed considering viscous damping varying according to the significant wave heights as follows:

- $H_s < 2.5\text{m}$  (irregular waves contour curves);
- $2.5 < H_s < 4$  (irregular waves contour curves);
- $H_s > 4$  (irregular waves contour curves).

13.6.2.4 The RAO curves shall be computed also considering the following:

- At least five loading conditions: minimum loaded, 40% loaded, 60% loaded, 80% loaded and fully loaded. The roll viscous damping shall be derived for each draught.
- The mooring lines and risers shall be considered only as weight items to compose the loading condition and no dynamic effect shall be included in the RAO analysis.
- Regular wave frequencies ranging from 0,16 to 3,0 rad/sec.
- The number of calculated frequency components shall be at least 60.
- Around natural frequency peaks (in the Roll and Heave RAO amplitude curves, the regular wave frequency discretization in the curves shall correspond to 0,1s steps within a range of  $\pm 1,0$  s around natural period value.
- Regular wave incidences ranging from 0 to 360 degrees with 7,5 degrees increments, being 0 degree value the "aft", 90 degrees value the "starboard", 180 degrees the "bow".
- RAO curves shall be referred to the C.O.G. (Center of Gravity of the Unit) for each draught. Thus, the C.O.G shall be informed with the RAO curves, apart from respective radius of gyrations about longitudinal, transversal and vertical axes, all of them calculated at C.O.G.
- The waves considered for the roll damping estimation shall be the beam sea condition (irregular waves) that causes the higher motions (higher  $H_s$  or wave peak

period:  $T_p$  equal to the natural period of the roll motion for each specific draft). All roll damping estimation shall be done with no current.

- 13.6.2.5 The RAO curves will be used on the analysis of forces and the stresses acting on the risers, mooring lines and secondary structures. The reference system and direction conventions shall be included in the Motion Analysis report. The expression that needs to be employed to generate displacements, velocities and accelerations time series shall be also published by CONTRACTOR.
- 13.6.2.6 All numerical output data (RAO, curves and tables, added mass coefficients, potential damping coefficients, wave exciting forces and full quadratic transfer functions) shall be released in Microsoft Excel file and \*.txt format by CONTRACTOR (different file extensions may be agreed with PETROBRAS). The RAO shall be released to PETROBRAS 9 months after LOI (Letter of Intent).
- 13.6.2.7 For fatigue analyses, the time percentages of each operational draft shall be informed in Motion Analysis Report.

### 13.6.3 MOTIONS AND ACCELERATIONS DESIGN CONDITIONS

- 13.6.3.1 For displacements and accelerations responses, short term statistics shall be evaluated for the DEC (design extreme conditions – 100 year return period waves) and DOC (design operational condition – 1 year return period waves) according to wave contour plots distribution available in METOCEAN DATA (see item 1.2.1). The most probable maximum responses shall be appraised on the COG of the FPSO and at additional evaluation points that are required for structural sizing as well. The distribution of the points to be evaluated in this analysis shall be in accordance with CS requirements.
- 13.6.3.2 Unit's displacements and accelerations responses shall be demonstrated by the CONTRACTOR through calculations, including input information such as METOCEAN DATA (see item 1.2.1) and the Unit's 1st and 2nd order motions (RAOs and QTFs), considering the Unit at free-floating condition (without any mooring lines or risers contribution in terms of stiffness and damping).
- 13.6.3.3 For Motion Analysis, extreme sea states ( $H_s \times T_p$  contour plots distributions for each incidence direction and return periods) that are specific for Unit's final offshore location shall be taken from METOCEAN DATA (see item 1.2.1).
- 13.6.3.4 CONTRACTOR shall design and install a bilge keel in the hull as following:
- CONTRACTOR shall present calculations in order to back-up the bilge keel width and length definition. This shall be submitted to PETROBRAS for comments.
  - Regardless the calculations in item (i), the minimum width of the bilge-keel shall be 1,5m.
  - Under DOC conditions, the Unit's single-amplitude roll motion shall not exceed 8 degrees, while under DEC conditions the Unit's single-amplitude roll motion shall not exceed 15 degrees. The roll motion single-amplitude values shall be demonstrated during the model tests to be carried out by CONTRACTOR.

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iv. Single-amplitude vertical motion at any riser support location shall not exceed 9,5 m (displacement) and 2,0 m/s<sup>2</sup> (acceleration) while under DEC conditions.

13.6.3.5 The Unit shall be designed to operate normally up to DEC condition. To “operate normally” means a state in which all systems and processes on the Unit can be started or kept running without tripping alarms or safety shut-down or endangering equipment and personnel involved. This includes the oil collecting system, utility systems, vessel systems, oil transfer to/from cargo tanks. In addition, process facilities shall be designed to ensure the efficiency of separation and treatment and transfer of oil, gas and water.

13.6.3.6 In addition, the Unit shall be verified for environmental conditions along specified route between construction site and offshore final location in Brazil, during sail-away phase, and, on specified route between the Brazilian offshore location and elsewhere outside Brazilian waters, after Unit decommissioning, at the end of the Contract.

13.6.3.7 If the CONTRACTOR decides to use a wave spreading formulation, it shall be used spreading parameters prescribed in METOCEAN DATA document (see item 1.2.1). The decision to use or not use a wave spreading formulation is CONTRACTOR’s responsibility.

#### 13.6.4 MODEL TESTS

13.6.4.1 Seakeeping model tests are required during the engineering design phase.

13.6.4.2 In order to calibrate numerical models and predict Unit’s motions and non-linear effects such as roll viscous damping mainly provided by bilge keel (RAOs), green water, and wave slamming occurrences with their mitigation options and induced loads, second-order effects (QTFs) CONTRACTOR shall submit the model test matrix to PETROBRAS for comments, carrying out model test program based on agreed matrix.

13.6.4.3 For Roll natural periods beyond 17 seconds, considering all operational draught range, second-order effects for rolling motions must be addressed in model test scope.

13.6.4.4 Wave basin Unit’s model scale shall be between 1:70 and 1:100, in order to obtain adequate model dimensions associated with sufficiently accurate results.

### 14 MOORING

#### 14.1 GENERAL

14.1.1 The Unit’s Maximum Design Condition shall comply with the SPREAD MOORING AND RISER SYSTEM REQUIREMENTS document (see item 1.2.1).



## 14.2 MOORING SYSTEM DESIGN PREMISES

14.2.1 The Unit's Mooring System shall be designed to withstand extreme environmental combinations of waves, wind and currents at any draught ranging from slightly loaded to fully loaded conditions, in accordance with requirements from CS and ISO 19901-7, and shall consider all design condition defined in SPREAD MOORING AND RISER SYSTEM REQUIREMENTS document (see 1.2.1). Under these conditions, the Unit's Mooring System shall demonstrate its adequate station keeping performance according to limits and constraints stated in that document.

14.2.2 In terms of environmental combinations (simultaneous wind, waves and current loads), CONTRACTOR shall comply with CS standards associated with specific field METOCEAN DATA (see item 1.2.1).

## 14.3 WIND AND CURRENT DRAG COEFFICIENTS

14.3.1 For Mooring System Design purposes wind and current drag coefficients shall comply with CS requirements. If necessary and agreed with CS, wind and current drag coefficients can be obtained from Wind Tunnel Tests, with model scale 1:200. In this case, Wind Tunnel Test Report shall be provided for PETROBRAS for information.

14.3.2 The coefficients shall be given from 0 to 360 degrees incidence directions, stepped by 15 degrees, for three distinct draughts (slightly loaded, intermediate loaded and fully loaded), for both Wind and Current Drag coefficients achievement. The coefficients shall be reported in Mooring Analysis Report.

14.3.3 OCIMF (Oil Companies International Marine Forum) standards shall be followed either in reference system or non-dimensional coefficients representation.

## 14.4 POLYESTER ROPE STIFFNESS MODEL

14.4.1 In Mooring Analysis Report, a detailed description on polyester ropes' stiffness model shall be provided, together with related references.

## 14.5 MOORING FIXED POINTS

14.5.1 PETROBRAS will be responsible for design, installation of the mooring fixed points (torpedo piles). CONTRACTOR shall assume that the anchor points will support the maximum loads mentioned in document SPREAD MOORING AND RISER SYSTEM REQUIREMENTS (see item 1.2.1).

## 14.6 SOIL DATA

14.6.1 Mooring system design shall comply with bathymetry chart (stratigraphy and soil profile) of the Unit's installation site.

14.6.2 During the detailed design phase, PETROBRAS will inform the "fine bathymetry map" for the intended location of the Unit's mooring fixed point.

## 15 FLEXIBLE AND RIGID RISERS

### 15.1 GENERAL

15.1.1 The riser balcony of the Unit shall be designed on the Portside, with guide tubes or receptacles and a support for the upper balcony installed on the Hull upper side. PETROBRAS highlights this is a preliminary plan. It can be changed up to Kick-off Meeting.

15.1.2 CONTRACTOR shall consider all risers – production, service/gas lift, gas transfer and water injection – will be flexible during the lifetime of the FPSO.

15.1.3 The flexible risers can come from portside and/or starboard side of Unit in an interleaved pattern.

15.1.3.1 The riser balcony of the Unit shall be designed in order to connect the flexible risers listed in Table 15.1.3.1.

Table 15.1.3.1 - Risers Details

| FPSO                                   | Risers (NOTE 1) | Function                     | Total | Comments  |
|--|-----------------|------------------------------|-------|---|
| Satellite production wells (P1 to P11) | 6"              | Oil Production               | 11    | P9 will be 8" ID  |
|  | 4"              | Gas Lift                     | 5     | 6 satellite production wells will be connected to MSGL                  |
|  | UEH             | Control / Power supply       | 5     | 6 satellite production wells will be connected to MSGL                  |
| Satellite water injection well (I1)    | 6"              | Water injection              | 1     |   |
|  | UEH             | Control / Power supply       | 1     |   |
| MSGL-1                                 | 6"              | Gas lift                     | 1     |   |
|  | 6"              | Gas lift test                | 1     |   |
|  | UEH             | Control / Power supply       | 2     |   |
| MSP-1                                  | 8"              | Production                   | 1     | This slot shall have a dedicated topside multiphase flowmeter.          |
|  | 6"              | Gas lift                     | 1     |   |
|  | 4"              | Gas lift test                | 1     |   |
|  | UEH             | Control / Power supply       | 1     |   |
| MSP-2                                  | 8"              | Production                   | 2     | Both of these slots shall have dedicated topside multiphase flowmeters. |
|  | 6"              | Gas lift                     | 1     |   |
| MSP-2 MSPIA-1                          | 4"              | Gas lift test                | 1     |   |
|  | UEH             | Control / Power supply       | 1     |   |
|  | 8"              | Production                   | 1     | This slot shall have a dedicated topside multiphase flowmeter           |
| MSPIA-1 MSIA-1                         | 6"              | Gas lift                     | 1     |   |
|  | 4"              | Gas lift test                | 1     |   |
|  | 8"              | Water injection              | 1     |   |
|  | UEH             | Control / Power supply       | 1     |   |
|  | UEHP            | MPP control and power supply | 1     | For medium voltage power supply to subsea multiphase pumping systems    |
|  | 8"              | Water injection              | 1     |   |

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|   |       |                              |    |  |
|---|-------|------------------------------|----|--|
| MSIA-1<br>Gas export                            | UEH   | Control / Power supply       | 1  |  |
|   | 9,13" | Gas export                   | 1  |  |
| Gas export<br>Fiber optic                       | UEH   | Control / Power supply       | 1  |  |
|   | CO    | Communication                | 1  | For Unit communications.   |
| MSP-3 (spare)                                   | 8"    | Production                   | 1  | This slot shall have a dedicated topside multiphase flowmeter  |
|   | 6"    | Gas lift                     | 1  |  |
| MSP-3 (spare)<br>MSP-4 (spare)                  | UEH   | Control / Power supply       | 1  |  |
|   | 8"    | Production                   | 1  | This slot shall have a dedicated topside multiphase flowmeter  |
| MSP-4 (spare)<br>MSPIA-2 (spare)                | 6"    | Gas lift                     | 1  |  |
|   | UEH   | Control / Power supply       | 1  |  |
| MSP-4 (spare)<br>MSPIA-2 (spare)                | 8"    | Production                   | 1  | This slot shall have a dedicated topside multiphase flowmeter  |
|   | 6"    | Gas lift                     | 1  |  |
| MSPIA-2 (spare)<br>Water injection (spare) (I2) | 4"    | Gas lift test                | 1  |  |
|   | 8"    | Water injection              | 1  |  |
| MSPIA-2 (spare)<br>Water injection (spare) (I2) | UEH   | Control / Power supply       | 1  |  |
|   | UEHP  | MPP control and power supply | 2  | For medium voltage power supply to subsea multiphase pumping systems. These slots may also be used to import electric power to Unit from external sources. |
| MSPIA-2 (spare)<br>Water injection (spare) (I2) | 8"    | Water injection              | 1  |  |
|   | UEH   | Control / Power supply       | 1  |  |
| Satellite wells (spare) (P12 to P14)            | 8"    | Production                   | 1  | Slot P14 shall have a dedicated topside multiphase flowmeter and can also be connected to MSP-1  |
|   | 6"    | Production                   | 2  |  |
|   | 6"    | Gas lift                     | 1  |  |
|   | 4"    | Gas lift                     | 2  |  |
|   | UEH   | Control / Power supply       | 2  |  |
| TOTAL   |       |                              | 72 |  |

NOTE 1: The sequence, functions and diameters of each riser slot will be defined at the project kick-off meeting together with the subsea layout.

NOTE 2: All 8" Production or Injection slots shall have flexibility to receive 8"ID or 6"ID risers. 6" Gas Lift or Gas Lift Test shall have flexibility to receive 6" ID or 4" ID risers.

NOTE 3: All risers will be flexible. Umbilicals may be either TPU or STU.

NOTE 4: The slots associated with MSP, MSIA and MSPIA shall have flexibility to receive satellite wells or equipment with multiple wells.

## 15.2 RISERS CHARACTERISTICS

15.2.1 CONTRACTOR shall provide supports for flexible risers that may be connected to the Unit in accordance with RISER SYSTEM REQUIREMENTS (see 1.2.1).

15.2.2 CONTRACTOR shall consider the following to protect the risers regarding pressure and temperature:

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Table 15.2.2A - Pressure for Risers Protection

| Subsea Line        | Design Pressure (kPa(a)) | Leak Test Pressure (kPa(a)) <sup>(1,2)</sup> | Max. Process Operating Pressure (kPa(a)) |
|--------------------|--------------------------|--|--|
| Production         | 34,500                   | 38,000                                       | 34,500                                   |
| Gas Lift / Service | 34,500                   | 38,000                                       | 25,000                                   |
| Water injection    | 34,500                   | 38,000                                       | 31,000                                   |
| Gas export         | 27,500                   | 30,250                                       | 25,000                                   |

Table 15.2.2B - Temperature for Risers Protection

| Subsea Line        | Maximum Design Temperature (°C) | Minimum Design Temperature (°C) | Operating Temperature (°C)   |
|--------------------|---------------------------------|---------------------------------|--|
| Production (6" ID) | 130                             | -20                             | 4 to 100 (production)<br>Ambient temperature to 40 (well service operations with diesel) |
| Production (8" ID) | 90                              | -20                             | 4 to 45 (production)<br>Ambient temperature to 40 (well service operations with diesel)  |
| Gas Lift/Service   | 90                              | -20                             | -20 to 60  |
| Water Injection    | 65                              | 4                               | 15 to 65   |
| Gas Export         | 90                              | -20                             | -20 to 60  |

NOTE 1: During the leak test an overpressure of 4% above the leak test pressure for all risers may be requested by PETROBRAS.

NOTE 2: A separate low capacity (fresh water, 2.5 m<sup>3</sup>/h with 100% re-circulation), high pressure pump shall also be provided to achieve the required pressure up to 47,400 kPa(g) to leak test all risers: production, water injection, gas lift and gas export risers after hook-up. Leak-test pump outlet shall have connection to the risers to allow opening of DHSV valve. Piping and accessories design shall consider the presence of sea water. A portable and/or movable skid pump is acceptable. The pump shall be permanently onboard.

NOTE 3: The required leak test pressures are related to riser test. Topsides piping and accessories may not be designed considering the riser leak test pressure. The conceptual design shall be submitted to PETROBRAS for comments/information.

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NOTE 4: Facilities to allow the leak test of the risers using rented service pumps shall be provided.

NOTE 5: During execution phase PETROBRAS will confirm to CONTRACTOR the pressure and temperature requirement for riser protection. Temperature at top of injection/service risers shall be monitored.

NOTE 6: The selection of relief devices to protect the risers against overpressure during service pump operation shall take into consideration: (i) operating conditions defined on item 2.6; (ii) each riser required design pressure as per Table 15.2.2A; (iii) maximum overpressure (full open condition) of 10% of relief device set pressure.

NOTE 7: The selection of relief devices on the discharge of Main/Injection Compressors and Water Injection Pumps shall also take into consideration each riser required design pressure as per Table 15.2.2A.

NOTE 8: Facilities to monitor the pressure and depressurize risers during leak test operation shall be provided.

NOTE 9: A PSLI shall be installed downstream of each service choke valve and interlocked with the service pump when operating in this mode. Additionally, PSLI shall be interlocked with the respective gas lift riser boarding SDV valve when operating in gas lift mode. The set points will be informed during the project execution phase and updated during operational phase.

NOTE 10: The leak test pressure is equal to the maximum incidental pressure.

**15.3 RISERS INSTALLATION AND DE-INSTALLATION PROCEDURES**

15.3.1 The Unit's Risers Installation and De-installation Procedures shall comply with the SPREAD MOORING AND RISER SYSTEM REQUIREMENTS document (see item 1.2.1).

**15.4 RISER HANGOFF AND PULL-IN SYSTEMS**

15.4.1 CONTRACTOR shall refer to the Annex documents (see 1.2.1):

- SPREAD MOORING AND RISER SYSTEM REQUIREMENTS;
- SPREAD MOORING SYSTEM REQUIREMENTS
- RISERS TOP INTERFACE LOADS ANALYSIS;
- DIVERLESS BELL MOUTH SUPPLY SPECIFICATION
- DIVERLESS BELL MOUTH PART LIST DRAWINGS
- HYDRAULIC CIRCUIT FOR BSDL-SI;
- SPECIFICATION OF HYDRAULIC ACTUATOR SYSTEM FOR BSDL-SI

**GENERAL TECHNICAL DESCRIPTION FOR  
LEASED UNITS****16 MARINE SYSTEMS AND HULL UTILITY SYSTEMS****16.1 GENERAL**

16.1.1 In case of conversion, CONTRACTOR shall adopt the so called “all new” philosophy for marine and utility systems. This means that all existent marine and utility system shall be fully removed (including, but not limited to, rudder, shaft, main engine and auxiliary propulsion systems, marine boiler, former cargo pumps, etc.) or replaced by brand new item (such as but not limited to equipment, piping, cable, panels, valves, HVAC). This also includes the items inside accommodation. Exception can be made for former tanker anchor windlass.

16.1.2 CONTRACTOR shall provide an emergency anchoring system in accordance to CS's and Brazilian Naval Authorities requirements. This system shall be similar to the anchoring system required for a ship of similar size under the CS's normal “Steel Vessel Rules” and is intended for use in shallow coastal waters and harbors.

**16.2 CARGO OIL SYSTEM, CRUDE OIL WASHING SYSTEM, BALLAST SYSTEM, INERT GAS SYSTEM AND HYDROCARBON GAS BLANKETING SYSTEM**

16.2.1 The Cargo Oil System, Crude Oil Washing System, Ballast System and Inert Gas and Cargo Tanks Venting System shall follow the requirements of SOLAS and CS rules, guidelines and requirements.

16.2.2 In addition to Inert Gas System for tank blanketing, Hydrocarbon (HC) Gas Blanketing System shall be installed to reduce emissions to the atmosphere.

16.2.2.1 HC Gas Blanketing System shall operate in cargo tanks, slop and structural process tanks (e.g produced water tanks, oil off-spec tanks, etc). Structural process tanks are the tanks installed in the hull cargo area, dedicated to the process plant.

16.2.2.2 For Hydrocarbon Gas Blanketing system minimum requirements, refer to section 10.2 of SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

16.2.3 Crude Oil Washing System shall have a dedicated heater using Unit heat medium.

16.2.4 The FPSO shall not have any pump room. In case of conversion, the former pump room shall be converted in void space and shall not have any equipment, piping and other accessories.

NOTE: The fluid transfer system dedicated to cargo, ballast, slop, produced water, off-spec and settling tanks (if applicable) shall be based on submerged type pumps.

16.2.5 Independent Inert gas, purge gas and vent gas headers shall be provided for cargo tanks.

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16.2.6 Inert gas generator system shall be fed by a dual fuel system, burning preferably fuel gas and alternatively marine Diesel oil. Oxygen content shall be measured with indication in the supervisory system.

16.2.7 The Ballast System shall comply with all Brazilian Administration requirements.

16.2.8 .Scrape water (displacement water eventually settling out of stabilized crude oil in cargo storage tanks) shall be sent to the oil offspec tank instead of the slop tank.

16.2.9 HC Gas Blanketing System gas recovery compressors shall be either liquid-ring compressors (as per API Std. 681) or screw compressors (as per API Std. 619). Configuration shall be N+1.

**16.3 OIL TRANSFER SYSTEM**

16.3.1 The oil from the storage tanks will be exported to a shuttle tanker, according to the document OFFSHORE LOADING SYSTEM REQUIREMENTS and OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS (see 1.2.1).

16.3.2 Oil Transfer System with individual submerged pumps (deep-well) in each tank shall comply with the following requirements:

- A longitudinal header shall be installed on the main deck and branches provided with manual valves and blind flanges for the connection of the portable cargo pump to every and each tank. For further details, cargo portable pumps supplier standards shall be used. CONTRACTOR shall include cargo portable pump and accessories in the mechanical handling study.
- Submerged hydraulic or electrical driven pumps on main deck for each cargo and each slop tank.

16.3.3 CONTRACTOR shall limit exported oil temperature through export hoses, from a minimum of 35°C to a maximum of 55°C, to comply with shuttle tankers requirements.

16.3.4 CONTRACTOR shall provide arrangements and facilities to allow proper flushing of the offloading system (including the offloading hose), which will be performed immediately after every cargo transfer (offloading) as follows:

- The Unit shall allow pumping water through the offloading hose from the Unit to the shuttle tanker.
- After the oil offloading being performed, the shuttle tanker will pump the water back to the Unit at a flowrate of at most 3000 m<sup>3</sup>/h. Therefore, the Unit shall not have any constraint, such as non-return valves at the hose reel that may jeopardize the seawater pump-back operation from shuttle tanker to FPSO.
- Additionally, Unit shall be capable to perform final flushing of the offloading hose on a "closed circuit mode". The close circuit mode means the offloading hose will be reeled and stored onboard the Unit.

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16.3.5 The offloading system, including the hose reel, shall be designed considering the operation with Suezmax shuttle tankers, as described in document OFFSHORE LOADING SYSTEM REQUIREMENTS and OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS (see item 1.2.1).

16.3.6 CONTRACTOR shall provide means to store the NSV (North Sea Valve) in an area with secondary containment in order to avoid possibility of oil spills overboard.

**16.4 HULL UTILITIES**

16.4.1 In addition to the Unit Utilities detailed on section 3 of this GTD, Hull utilities mainly dedicated to the Hull Marine Systems are herein detailed: Fresh Water and Potable Water System, Filling Stations, Diesel Oil System and Sewage.

**16.4.2 FRESH AND POTABLE WATER SYSTEM**

16.4.2.1 Water maker units shall be installed to generate sufficient fresh and potable water for the Unit's consumption.

16.4.2.2 The fresh and potable water aboard shall comply with Ordinance Anexo XX da Portaria De Consolidação Nº 5, de setembro de 2017 (Consolidação das normas sobre as ações e os serviços de saúde do Sistema Único de Saúde) and ANVISA RDC 72/2009. Chlorination Unit is required. Special attention shall be given to the quality parameters as well as cleanness requirements, tanks and distribution lines disinfection, analysis routine and the separate storage of water for human consumption of distinct sources. Material selection for Piping (upstream and within accommodation) shall avoid corrosion particles and contaminants in potable water.

16.4.2.3 CONTRACTOR shall provide sampling points in accordance with Portaria GM/MS Nº 888, 4/maio/2021.

16.4.2.4 Power consumption of fresh water maker unit shall be registered on unit supervisory system.

**16.4.3 FILLING STATIONS**

16.4.3.1 Despite the Unit being prepared to generate fresh and potable water, a minimum of 2 (two) filling connections (one for water and another for Diesel) shall be installed at each bunkering station. The bunkering stations to be located at Starboard side of the Unit near each aft and forward cranes respectively. The bunkering stations shall be located as close as possible to the supply boat mooring area and allow quick operation. Piping shall be at least 4" diameter. A drip-pan shall be installed to collect any leakage from all bunkering station connections with manually operated drainage valve located at the pan bottom.



16.4.3.2 The bunkering stations shall be provided with separate hoses, connections and valves for Diesel and fresh water, so that both stations are full time available to allow quick and immediate operation, in compliance with the following:

16.4.3.2.1 Connections:

- Type EVER-TITE® quick connect-disconnect couplers for Diesel and freshwater hoses;
- Filling station end: swaged-on male NPT carbon steel nipple + female thread/male adapter + female coupler/female straight pipe thread (connected to the filling station piping);
- Supply-boat end: swaged-on male NPT carbon steel nipple + female straight pipe thread/female coupler.

16.4.3.2.2 Diesel oil hose:

- The hose sections of Diesel hoses shall be connected by non-leakage couplings. WECO wing union type SHU and similar are not allowed. One connection between the Diesel hoses sections shall be of Safety Break-Away Coupling type to prevent pull-away accidents and avoiding sea contamination.
- Nominal diameter (ND) 4”;
- 120 m length with three (3) sections of 40 m each;
- 150 psi working pressure. Test pressure 1.5 x working pressure;
- Hose cover: black color, weather, ozone and oil resistant high quality chloroprene rubber or EPDM;
- Reinforcement layers: synthetic textile yarns, antistatic wire.
- Inner tube or liner: smooth fuel/oil resistant high quality nitrile rubber, shall withstand an internal fluid with up to 50% aromatic content (maritime diesel);
- Temperature range: -30 to 80 °C;
- All hoses shall be self-floating (floaters are not allowed);
- All hoses shall be equipped with abrasion resistant material.
- All hoses shall be equipped with lifting clamps at hose ends.
- FPSO side shall be provided with 4” flange ASME B16.5, RF, class 150#, AISI 316, with 135° angled termination (gooseneck);
- The diesel hoses supply vessel end shall be provided with a dry disconnect female coupling type manufactured according to NATO STANAG 3756 (AISI 316). In addition, it shall be provided, as a loose item, one adaptor to connect the dry coupling to a female CamLock coupling of the supply vessel.
- One of the intermediate connections for diesel oil hoses shall be provided with a weak link device (also known as safety breakaway coupling, marine break-away valve), consisting of an auto closing device, to protect against diesel oil spillage in case of

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excessive hose tension. Weak link device breaking load (axial load) shall be 80% of the hose breaking load.

- Hose sections shall have female connection at one end and male connection on the opposite end, both threaded. The termination of the connection to the hose shall be permanent. Crimped, swaged or built-in (vulcanized) terminations may be used. Reusable, clamp-like terminations (clamp, spanfix, ISO 14420-3) are not allowed. Detailed male and female connections shall be supplied as per below requirements:
  - i. Male NPT (ASME B1.20.1) connection, 30° Flare, NPS 4, permanent termination, AISI 316.
  - ii. Female NPSM (ASME B1.20.1) connection, Swivel, Flare 30°, NPS 4, permanent termination, AISI 316.
- Diesel hoses shall not use hammer lug union, wing union or similar connections in order to avoid pollution due to leakages.

#### 16.4.3.2.3 Fresh water hose:

- Nominal diameter (ND) 4”;
- 120 m length with three (3) sections of 40 m each.
- 150 psi working pressure. Test pressure 1.5 x working pressure.
- Hose cover: yellow, orange or blue color, weather, ozone and oil resistant high quality chloroprene rubber or EPDM – other materials may be accepted by Petrobras, upon consultation;
- Reinforcement layers: synthetic textile yarns or metal threads impregnated into the rubber/elastomer;
- Inner tube or liner: manufactured in water resistant elastomeric material up to 80°C, with smooth finishing and nominal internal diameter of 100 millimeters. The elastomer shall not be vulcanized with sulfur and shall be white or translucent (without color or black pigmentation, that is, without the use of carbon black); it shall be considered non-toxic, according to at least one of the following resolutions or regulations:
  - NSF/ANSI/CAN 61
  - RESOLUÇÃO ANVISA 105/99
  - FDA CFR 21
  - CE 1935/04

Note: tests related to other resolutions and regulations can be evaluated and accepted by Petrobras, upon consultation. The inner tube or liner shall be tested for its toxicity and release of chemical compounds to the transported water, since it will be used for human consumption. Examples of applicable materials for the inner layer are:

- PVC/SBR Blend
- SILICONE
- EPDM (white)

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- Natural Rubber (NR) (white)
- NBR vulcanized with adequate peroxides, without sulfur (white)
- Temperature range: 0°C to 80 °C;
- All hoses shall be self-floating (floaters are not allowed);
- All hoses shall be equipped with abrasion resistant material;
- All hoses shall be equipped with lifting clamps at hose ends;
- FPSO side shall be provided with a 4" flange ASME B16.5, RF, class 150#, AISI 316, with 135° angled termination (gooseneck);
- Supply vessel end shall be provided with CamLock type connector, standard EN 14420-7, in AISI 316;
- Hose sections shall have female connection at one end and male connection on the opposite end, both threaded. The termination of the connection to the hose shall be permanent. Crimped, swaged or built-in (vulcanized) terminations may be used. Reusable, clamp-like terminations (clamp, spanfix, ISO 14420-3) are not allowed. Detailed male and female connections shall be supplied as per below requirements:
- Male NPT (ASME B1.20.1) connection, 30° Flare, NPS 4, permanent termination, AISI 316.
  - Female NPSM (ASME B1.20.1) connection, Swivel, Flare 30°, NPS 4, permanent termination, AISI 316.
- One of the intermediate connections for fresh water hoses shall be provided with a non-closure marine break-away coupling (this device acts as a safe parting point within the transfer system, protecting equipment and personnel);
- CONTRACTOR shall comply with Ordinance MS Nº 2914/2011 and present evidence of harmlessness of the materials used in freshwater bunkering hose.

#### 16.4.4 DIESEL SYSTEM

16.4.4.1 The Diesel system shall be designed in order to supply, besides all other consumption requirements, feed the well service pump operations (e.g. to push pigs, and subsea system clean flowlines (see item 2.6).

16.4.4.2 For details of bunkering station connections see item 16.4.3.

16.4.4.3 Diesel oil shall be filtered and on-line metered before being sent to the storage tank.

16.4.4.4 A minimum configuration of 2x100% is required for Diesel pumps dedicated for well service which shall be designed in order to guarantee the required flowrate of the well service pump (as per item 2.6). The Diesel pumps shall have filter upstream and recycle for flow control to avoid frequent start/stop.



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16.4.4.5 The Diesel oil storage tank volume shall have enough capacity to provide Diesel oil to be used as fuel for 7 (seven) days continuously plus 3,000 m<sup>3</sup> for subsea lines flushing.

16.4.4.6 PETROBRAS will provide Diesel oil in accordance with ANP requisition. DMA (Diesel Marítimo TIPO A) shall be considered for turbogenerator projects.

**16.4.5 SEWAGE SYSTEM**

16.4.5.1 Unit shall have a sewage treatment unit in compliance with MARPOL, and IBAMA requirements specially but not limited to the “Resoluções CONAMA” and the “NOTA TÉCNICA CGPEG/DILIC/IBAMA Nº 01/11”. Sampling point shall be provided according to item 2.9.

16.4.5.2 Both grey and black waters shall be previously treated and metered before discharged to sea.

16.4.5.3 The FPSO is not allowed to discard sewage (black and grey waters) overboard without treatment even during the sewage treatment unit maintenance period. CONTRACTOR shall submit to Petrobras a plan that allows the FPSO continuous operation without any impact.

16.4.5.4 The sewage treatment unit shall be capable to treat at least 250 liters/person/day.

**16.4.6 TANKS REQUIREMENTS**

16.4.6.1 Online Gas Sampling System shall be provided in ballast tanks and void spaces adjacent to cargo/slop tanks, according to the requirements of FSS Code (International Code for Fire Safety Systems).

16.4.6.2 Permanent means to connect a contingency hose for inert gas shall also be provided for each ballast tank and void spaces adjacent to cargo tanks.

16.4.6.3 It shall be possible to recirculate the slop tank fluids passing through a heat exchanger, with sample points in the return line. It is acceptable to use Crude Oil Washing System heater (item 16.2.2).

**16.4.7 SLOP DISCHARGE TREATMENT**

16.4.7.1 To complement gravitational separation in the slop tanks, the Unit shall have a separate water treatment system using centrifuge (2x100%), in order to treat the oily water prior to discharge. This water treatment system shall have a by-pass and the minimum and maximum flow to each centrifuge shall be 50 m<sup>3</sup>/h and 100 m<sup>3</sup>/h, respectively. Alternative configuration shall be submitted for PETROBRAS approval provided that dynamic equipment be 2x100%.

16.4.7.2 Water discharge from slop tanks shall be measured and monitored for TOG, as followed:.

- 2x100% online TOG analyzer;
- TOG analyzer with an IMO MEPC 107(49) certification, to attend MARPOL 73/78;
- Automatic cleaning system of acoustic (ultrasonic) type and manual sampling devices shall be provided;
- Logics shall also be implemented so that the overboard discharge is interrupted if the slop water downstream treatment system is out of specification. The water out of specification shall be returned to slop tank;
- The discharge point shall have a redundant flow meter (2x100%).

## 17 ENVIRONMENT IMPACT STUDIES AND LICENSING

### 17.1 GENERAL

17.1.1 PETROBRAS will engage third party for Environmental Studies, in which case CONTRACTOR shall take part in the assessment, provide all necessary information and comply with recommendations.

17.1.2 CONTRATOR shall provide a report with information requested by PETROBRAS during FPSO licensing process.

17.1.3 This report shall include the following items:

- a) Table with the FPSO characteristics including FPSO name, mooring type, length, molded breadth, depth, molded depth, light weight, maximum draft, flare height, total FPSO storage capacity, fuel gas and Diesel consumption list, crane capacities, power generation (main, auxiliary, emergency) rating, sewage treatment system capacity and technology, living quarters capacity, helideck specification, life saving equipment;
- b) Hull description;
- c) Tank capacity plan including each tank material specification and specific requirements e.g. painting;
- d) Inert gas system description;
- e) Ballast system description;
- f) Description of the Fluid processing plant (oil, gas, produced water and injected water);
- g) Simplified process block diagram containing produced oil, produced water, produced gas and sea water treatment; gas export; seawater and produced water injection;
- h) Diagram (for each process: oil treatment, gas treatment, produced water treatment and sea water treatment for injection) containing main equipment as separators, scrubbers, heat exchangers, compressors and pumps;
- i) Table with pressure, temperature, flow rate and contaminant content (water cut for liquid systems, CO<sub>2</sub>, H<sub>2</sub>S and water for gas systems) for inlet and outlets of each main process equipment as separators, heat exchangers, compressors and pumps



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- j) Cooling sea water overboard characteristics such as discharge maximum flow rate, temperature, internal diameter, direction and position in relationship to sea water surface. The draft variation due to FPSO load shall be informed;
- k) Cooling water closed loop system description, including pumping configuration and flow rate;
- l) Industrial water supply system description including type of treatment, suction depth, flow rate and consumers list;
- m) Potable water system description including type of treatment and flow rate;
- n) Simplified diagram of industrial and potable water treatment;
- o) Power generation description including capacities of main, auxiliary, uninterruptible and emergency systems, as well as fuel consumption for each generator considering all fuel sources;
- p) Cranes description including length and capacity;
- q) Flare and vent systems description including flow rate capacities, and stack height;
- r) Topsides and Subsea Chemical injection system description including a table expected chemical, dosage rate, injection points, and storage capacity.

**17.2 EFFLUENTS**

17.2.1 CONTRACTOR shall provide details about effluent treatment and discharge on sea are required to support plume dispersion included in environmental studies:

- a) Sulphate removal/ Ultrafiltration/ Reverse Osmosis reject flow rate, composition, discharge temperature, density (measured or calculated), pipe internal diameter, direction and position in relationship to sea water surface. The draft variation due to FPSO load shall be informed;
- b) Sulphate removal/ Ultrafiltration/ Reverse Osmosis membranes cleaning procedure description including expected frequency and the duration of each step, waste water overboard description containing composition, pH, discharge volume, temperature and duration, density, salinity, chemical concentration, flow rate, pipe internal diameter, direction and position in relationship to sea water surface. The draft variation due to FPSO load shall be informed;
- c) Produced water system description, oil content, sample connections, measurement points, interlock between measurement and discharge, reprocessing philosophy description, discharge flow rate, temperature, density (measured or calculated), pipe internal diameter, direction and position in relationship to sea water surface. The draft variation due to FPSO load shall be informed;
- d) Drainage system description, estimate of volume generated monthly, composition, oil content, measurement points, interlock between measurement and discharge, reprocessing philosophy description, discharge flow rate, pipe internal diameter, direction and position in relationship to sea water surface. The draft variation due to FPSO load shall be informed;
- e) Simplified scheme containing all drainage systems (topsides and marine).

- f) Sewage treatment system description, including Oil and Grease and Biochemical Oxygen Demand (BOD) removal capacity, considering the expected POB in all the FPSO's lifecycle.

### 17.3 ATMOSPHERIC EMISSIONS

17.3.1 CONTRACTOR shall provide:

- a) Annual quantification (volume) per type of fuel used for the design cases (Table 2.2.2.3);
- b) Characteristics and composition (up to C10+ in case of gas) of fuel, volume and type of fuel used by emitting sources. In case of fuel gas with different CO<sub>2</sub> contents, normal and the highest concentration must be used. For dual fuel generators the quantification must be done for each fuel;
- c) Quantification of fugitive emission sources from equipment and piping handling fluid with methane content equal or higher than 20% in weight and/or handling non stabilized liquid hydrocarbon. The sources to be considered shall be, but not limited to, valve stem, valve flanges, pumps seals, drains, vents etc;

17.3.2 A description of Unit Commissioning Procedure, including the volume of gas flaring , fuel (diesel and gas) consumption and estimated time for commissioning of each system.

### 17.4 WASTE MANAGEMENT

17.4.1 CONTRACTOR shall provide solid residues characterization, residue class, disposal destination, annual mass generation including change out process materials (molecular sieve, CO<sub>2</sub> membranes cartridges, sulphate removal membranes cartridges, etc.), sewage sludge, oil tank sludge, slop tank sludge, flotation cell unit sludge, ordinary garbage, nursery garbage, dangerous residues, food debris, oily residues, chemicals, etc.

## 18 PETROBRAS LOGOTYPE

### 18.1 GENERAL

18.1.1 CONTRACTOR shall paint PETROBRAS logo type in the following Unit places:

- Funnel (both sides);
- Port side and Starboard in visible area;
- Front wall of the accommodation block.

## 19 VENDOR LIST

### 19.1 GENERAL

19.1.1 Vendor list defined for the equipment below shall be followed. The selection of proper equipment among supplier's portfolio is under CONTRACTOR responsibility.

#### 19.1.1.1 Water Injection Pumps

- Sulzer;
- Flowserve;
- Nuovo Pignone;
- FRAMO.

#### 19.1.1.2 Molecular Sieve Solid Bed (Zeolite)

- CECA;
- UOP (Honeywell);
- ZEOCHEM L.L.C;
- Axens;
- Grace GmbH.

#### 19.1.1.3 Moisture Analyzer

- Ametek
- Spectrasensors

#### 19.1.1.4 NOT APPLICABLE

#### 19.1.1.5 Rotary compressor for Vapor Recovery Unit API 619:

- Kobelco;
- MAN;
- HOWDEN,

#### 19.1.1.6 Centrifugal Compressors:

- BHGE;
- Hitachi;



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- MAN;
- Mitsubishi;
- Siemens/ Dresser-Rand;
- Elliot.

**19.1.1.7 Aero-derivative or light industrial gas turbine API 616 for offshore environment (Compressor Driver):**

- SOLAR : SATURN, CENTAUR, TAURUS 60, MARS100, TITAN 130, TITAN 250;
- BHGE Baker Hughes GE: LM2000, LM2500, LM2500+, LM2500+G4, LM6000 PC/PG;
- SIEMENS: SGT-A35 (up to 34 MWISO), SGT-100, SGT-600, SGT-750 (no propane, only diesel start up system).

**19.1.1.8 Submerged Sea water Lift Pumps (Electric)**

- KSB
- FRAMO

**19.1.1.9 Diesel-Hydraulic Fire Water Pumping Unit**

- Sulzer;
- CSH (FISCHCON);
- Frank Mohn.

**19.1.1.10 Aero-derivative or light industrial gas turbine API 616 for offshore environment (Main Generatrs):**

- BHGE Baker Hughes GE: LM 2000, LM2500, LM2500+, LM2500+G4, LM6000 PC/PG SAC;
- SIEMENS: SGT-A35 (34MW ISO), SGT-100, SGT-600, SGT-750 (No propane, only diesel startup system);
- SOLAR: SATURN, CENTAUR , TAURUS 60, MARS100, TITAN 130, TITAN 250.

**19.1.1.11 Flare flow meter:**

- Fluenta;
- BHGE;

**19.1.1.12 Variable Speed Drives (VSD) (Medium Voltage : 5MW):**

- ABB;



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- DANFOSS;
- GE;
- ROCKWELL;
- SCHNEIDER;
- SIEMENS;
- TMEIC;
- WEG.

## 19.1.1.13 Combined Cycle – Main Vendors:

- BH;
- Siemens.

## 19.1.1.14 Boiler Feed Water Pump:

- BH;
- Flowserve;
- Sulzer.

## 19.1.1.15 OTSG:

- BIH;
- Siemens;
- IST/PROPAK.

## 19.1.1.16 Steam Turbine:

- BH;
- Siemens;
- Peter Brotherhood.

19.1.2 Vendor List does not exempt CONTRACTOR from its responsibilities for events caused by the selection of equipment among suppliers' portfolio or equipment malfunction or defect.