INDEX OF REVISIONS

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	REV. 0	REV. A	REV. B	REV. C	REV. D	REV. E
DATE	MAY/26/23	JUN/28/23	NOV/17/23			
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APPROVAL	BRR0	BRR0	BRR0			

SUMMARY

1. INTRODUCTION

This document provides an overview of the topside process for Marlim Leste e Sul – REVIT I Conceptual Design, for an FPSO (Floating Production Storage and Offloading Systems) Unit.

The figure below presents a simplified diagram for process plant. The main process systems will be described in more details in the following items.

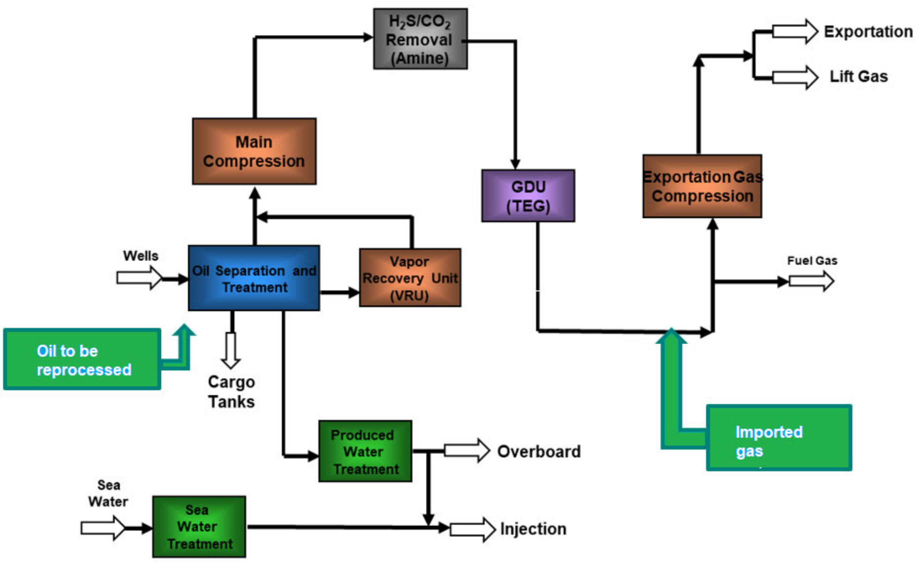


Figure 1 - Simplified Diagram of Process Plant for Marlim Leste e Sul – Revit I Conceptual Design

2. PROCESS MAIN DATA AND GUIDELINES

The main data and guidelines taken into account for process plant configuration, process simulations, dimensions estimative of equipment and auxiliary systems necessary in the unit are presented as follow. Standard flowrates (Sm³/d) are measured at 15.6°C and 101.3 kpa abs.

- OIL FLOWRATE: 22,300 Sm³/d (140,000 bpd);
- LIQUID FLOWRATE: 47,700 Sm³/d (300,000 bpd);
- LIQUID FLOWRATE (WITH RECYCLES): 52,190 Sm³/d (328,264 bpd);
- PRODUCED WATER FLOWRATE: 39,700 Sm³/d (250,000 bpd);
- THE MAXIMUM SALINITY OF PRODUCED WATER TO BE CONSIDERED IS 225,000 mg / L;
- PRODUCED GAS FLOWRATE: 3,000,000 Sm³/d;
- GAS FLOWRATE (WITH RECYCLES): 7,800,000 Sm³/d;
- GAS LIFT PRESSURE: 20,000 kPa abs;
- GAS LIFT TOTAL FLOWRATE: 5,000,000 Sm³/d;
- GAS LIFT FLOWRATE PER SLOT: 100,000 TO 300,000 Sm³/d;
- INJECTION WATER FLOWRATE: 47,700 Sm³/d (300,000 bpd) @ 20,000 kPa abs;

- INJECTION WATER FLOWRATE PER SATELLITE SLOT: UP TO 6,000 Sm^3/d;
- INJECTION WATER FLOWRATE PER MANIFOLD SLOT: UP TO 15,000 Sm^3/d;
- CO_2 CONTENT: 3,5% v/v
- H_2S CONTENT: 500 ppmv (MAXIMUM PER WELL) OR 200 ppmv (MAXIMUM ON WELLS MIXTURE).
- RESERVOIR FLUID COMPOSITION: THE NEXT TABLE PRESENTS THE AVAILABLE FLUID COMPOSITION.

Table 1 - Reservoir fluid composition (% molar)

Component	Oil 1	Oil 2	Oil 3	Oil 4	Oil 5
CO2	0.83	0.5	0.59	0.03	0.03
N2	0.55	0.09	0.08	0.31	0.08
C1	36.78	48.76	39.23	42.7	49.7
C2	7.16	3.41	7.64	5.25	1.24
C3	6.45	3.61	4.6	4.48	0.14
iC4	1.05	0.71	0.93	0.68	0.01
nC4	3.12	1.81	2.08	1.56	0.07
iC5	1.07	0.69	0.5	0.64	0.04
nC5	1.72	1.03	1.31	1.00	0.04
C6	2.32	1.22	1.91	1.32	0.06
C7	2.92	1.92	1.66	1.25	0.1
C8	3.35	2.24	4.12	2.31	0.25
C9	2.55	1.91	2.03	2.16	0.45
C10	2.18	1.75	2.64	1.97	0.71
C11	1.88	1.6	2.25	1.75	0.93
C12	1.58	1.44	2.11	1.72	1.26
C13	1.69	2.12	2.19	1.62	1.5
C14	1.38	1.52	1.88	1.55	1.6
C15	1.41	1.82	1.81	1.38	1.75
C16	1.07	1.3	1.39	1.16	1.6
C17	0.97	1.52	1.03	0.86	1.32
C18	1.00	1.26	1.07	0.86	1.48
C19	0.88	0.8	1.03	0.73	1.44
C20+	16.09	16.96	15.94	22.71	34.19

The percentages of aromatic components contained in the representative components can be obtained using Table 2.

Table 2 - Aromatic components

Component	Ci component that contains the aromatic component	Component Percentage in Component Ci				
		Oil 1	Oil 2	Oil 3	Oil 4	Oil 5
Benzene	C6	2%	3%	2%	2%	3%
Toluene	C7	5%	10%	11%	16%	16%
Ethylbenzene	C8	4%	0%	4%	0%	4%
M-Xylene and P-Xylene	C8	9%	0%	11%	4%	11%
O-Xylene	C8	5%	0%	7%	3%	7%

The next table presents the oil API, viscosity and WAT.

TABLE 3 - OIL PROPERTIES

Property	Oil 1	Oil 2	Oil 3	Oil 4	Oil 5
API [°]	27.20	23.60	27.78	25.53	13.40
Viscosity	21.68cP @ 30C 14.83cP @ 40C 10.66cP @ 50C 7.98cP @ 60C 6.17cP @ 70C 4.92cP @ 80C 4.01cP @ 90C 3.34cP @ 100C 3.12cP @ 104C	31.98cP @ 30C 22.78cP @ 40C 16.55cP @ 50C 12.23cP @ 60C 10.26cP @ 66C	5.47cP @20C 4.93cP @30C 4.54cP @40C 4.25cP @50C 4.00cP @60C 3.62cP @80C 3.29cP @102C	15.22cP @ 30C 11.79cP @ 40C 9.53cP @ 50C 7.93cP @ 60C	8203cP @ 30C 4736cP @ 35C 2851cP @ 40C 1782cP @ 45C 1152cP @ 50C 769cP @ 55C 660cP @ 57C
Wax Appearence Temperature - WAT (°C) - 1st event	40.93	19.08	46.88	43.11	11.88
Wax Appearence Temperature - WAT (°C) - 2nd event	16.9	N/A	20.63	22.22	N/A

The unit will be able to receive imported oil from two other units (P-51 and P-56) for storage and offloading. The limits for framing imported oil from P-51 and P-56 are distinct. In case of receipt of the product of this chain within the specifications, there should be no mixing with the oil of the MLS / MLL REVIT, and the relief of each chain should occur in a segregated way.

In addition to considering the segregated receipt of imported oil in the tanks, it is possible that there is a lack of control of the treatment in one or both units of origin (P-51 and P-56), resulting in the receipt of unframed oil. Thus, alignment must be provided for receipt of imported oil in the Off-spec Tank of oil for reprocessing. It is important to note that such alignment will imply in the double taxation of the volume of oil received from units P-51/P-56, considering that it will not be possible to perform the fiscal measurement of these volumes for discount, considering that the imported oil will be out of frame (BSW ≥ 1%) and may be mixed with the oil produced in the unit itself. In this way, it will be up to the operational team to decide whether to use this operation only in specific situations.

The next table presents the imported oil compositions.

Table 4 – Imported oil fluid composition (% molar)

Component	P-51	P-56
CO2	0	0
N2	0	0
C1	0	0
C2	0	0
C3	0.12	0.26
IC4	0.14	0.09
NC4	0.61	0.39
IC5	0.46	0.15
NC5	2.51	0.33
C6	1.30	0.54
C7	7.68	1.52
C8	7.76	1.72
C9	6.95	2.85
C10	6.85	2.95
C11	5.81	3.14
C12	5.38	3.36
C13	5.45	3.92
C14	4.71	3.67
C15	4.39	4.03
C16	3.49	3.22
C17	2.65	2.94
C18	2.77	3.16
C19	2.58	3.00
C20+	28.39	58.76
C20+ Density	0.9680	1.0050
C20+ Molec. Weight	580	543

3. GENERAL DESCRIPTION OF PRODUCTION PROCESS

3.1. Oil Separation and Treatment System (Area 1223)

The well fluids are collected in two production headers and routed to the oil/water/gas separation system, composed by two parallel production trains with 26,095 Sm^3/d liquid flowrate capacity each (with recycles), according to the process simplified described below:

This system comprises of three liquid-gas separation stages and three oil-water separation stages with the main goal to comply with the oil exported requirements:

- BSW (Basic and Sediment Water) < 0.5% v/v;
- Salinity < 285 mg/L - NaCl;
- TVP (True vapor pressure) ≤ 70 kPa abs @ rundown temperature to storage as stated in ANP/INMETRO Joint Resolution No. 1 of 06/10/2013;
- H_2S content < 1 mg/kg.

The limit value of RVP is an estimative based on simulation and will be informed in Descriptive Memorandum of the Basic Design. It shall be confirmed during operational phase to ensure compliance with the requirement of TVP ≤ 70 kPa abs @ rundown temperature.

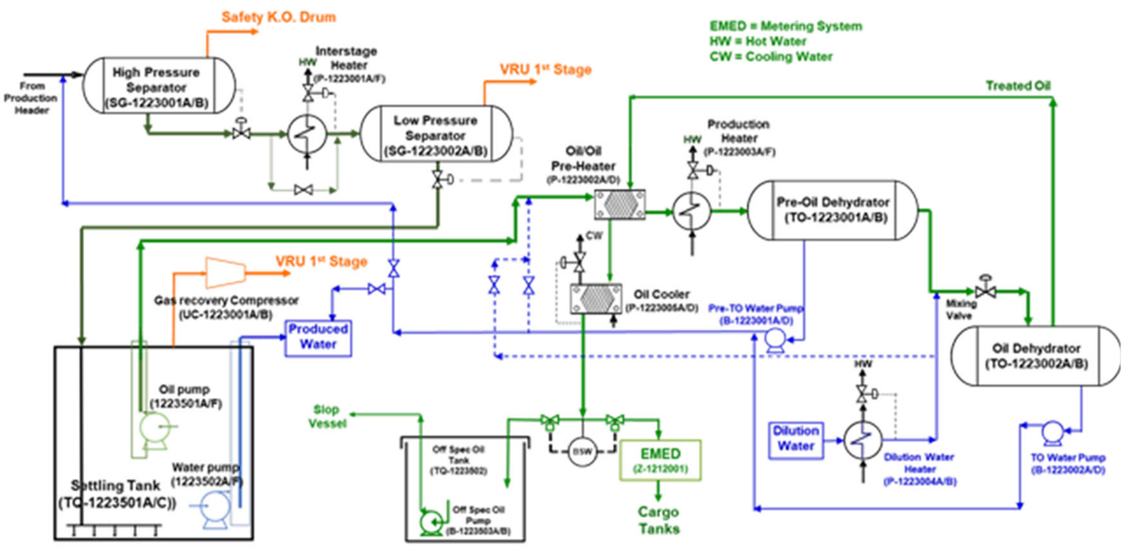


Figure 2 - Simplified Diagram for Oil Separation and Treatment System (Area 1223)

Downstream the production headers, there is the first separation stage comprised with 2 x 50% High Pressure Separator (SG-1223001A/B) where the oil/water is primary separated from associated gas at, approximately 1,000 kPa abs. The oil/water stream flow rate is controlled by the liquid level controller in SG-1223001A/B, which modulates the control valve in oil/water outlet piping, and then route the emulsion (oil + water) to Interstage Heater (P-1223001A/F). The gas is routed to Safety K.O Drum (V-1231001), in Main Compression.

This oil/water stream from the SG-1223001A/B is heated through the Interstage Heater (P-1223001A/F) up to 57-60°C, aiming to achieve the required TVP at stabilized oil stream that will be routed to storage tanks. The Interstage Heater (P-1223001A/F) is a shell and tube type and uses Hot Water at 120ºC.

After being heated, the liquid is routed to the second separation stage comprised with 2 x 50% Low Pressure Separator (SG-1223002A/B) where the oil/water is again separated from associated gas at, approximately 240 kPa abs. The oil/water stream flow rate is controlled by the liquid level controller in SG-1223002A/B, which modulates the control valve in oil/water outlet piping, and then route the emulsion (oil + water) to 3 x 50% Settling Tanks (TQ-1223501A/C).

The Settling Tanks, the third separation stage, are located in the Hull. There occurs the last associated gas separation of the oil/water at atmospheric pressure. The maximum BSW considered in the outlet of Settling Tanks is 20% v/v. Both the gas streams separated at Low Pressure Separator (SG-1223002A/B) and Settling Tanks (TQ-1223501A/C) are routed to VRU first Stage Compression. In Settling Tanks, the residence time allows the first oil-water separation. The Produced Water stream is pumped from the deepest section of the tanks by the 6 x 50% Water Settling Tank Transfer Pump (B-1223502A/F), a Submerged Pump type, and then it is routed to the Produced Water Flash Drum (V-5331001A/B), after being cooled in Produced Water Cooler (P-5331001A/D). The remaining oil/water stream is pumped from the intermediate section of the tanks by the 6 x 50% Oil Settling Tank Transfer Pump (B-1223501A/C), a Submerged Pump type too, and routed to be heated in Oil/Oil Pre-heater (P-1223002A/D) and Production Heater (P-1223003A/F).

The Oil/Oil Pre-heater (P-1223002A/D) is a plate type and uses the treated oil from Oil Dehydrator (TO-1223002A/B) at about 99ºC to heat up the oil/water stream from TQ-1223501A/C. The Production Heater (P-1223003A/F) is shell and tube type and uses the Hot Water at 120ºC to heat the oil/water stream from Oil/Oil Pre-Heater up to 99ºC.

After being heated, the liquid is routed to the fourth separation stage comprised with 2 x 50% Pre-Oil dehydrator (TO-1223001A/B). Oil and water are then separated by electrostatic field applied in the dehydrator. This separation stage is carried out at 661 kPa abs and shall achieve 0.5% BSW at outlet stream. The oil stream from Pre-Oil Dehydrator is directed to Oil Dehydrator (TO-1223002A/B).

The oil/water interface level in TO-1223001A/B is controlled by modulating the control valve in the Pre-Oil Dehydrator Recirculation Water Pump (B-1223001A/D) discharge. The produced water separated in Pre-Dehydrator is recycled to SG-1223001A/B to achieve optimization energy recovery or can be routed directly to the Produced Water Treatment System (Area 5331).

The fourth stage of separation is designed to comply with the following oil stabilization requirements:

- RVP (Reid vapor pressure) ≤ 40 kPa abs @ 37.8ºC;
- TVP (True Vapor Pressure) ≤ 70 kPa abs @ rundown temperature to storage;
- Salinity < 285 mg/L;
- BSW < 0.5% v/v.

The Oil Dehydrator (TO-1223002A/B) is kept at, approximately, 521 kPa abs. Hot fresh water (at the same temperature as the outlet oil in Production Heaters) is required to increase the inlet BSW to a minimum of 5% v/v and maximum of 10% v/v and reduce salinity of produced water in order to achieve the required specification.

The level controller regulates the interface level in TO-1223002A/B, controlling the water outlet flow rate by modulating the control valve in the Oil Dehydrators Recirculation Water Pump (B-1223002A/D) discharge. The water stream can be recycled to SG-1223001A/B or be routed directly to the Produced Water Treatment System (Area 5331).

The dead oil stream from TO-1223002A/B is routed initially to the Oil/Oil Pre-Heater (P-1223002A/D) and next to Oil Cooler plate type (P-1223005A/D), to be cooled down to 40°C. Then, the oil is routed through the Fiscal Crude Oil Metering Skid (Z-1212001) and finally to the Cargo Tanks. If oil is not specified, there is a manual alignment to Off-Spec Oil Tank (TQ-1223502) upstream Z-1212001. From there, oil can be pumped by Off-Spec Oil Pump (B-1223503A/B) to Slop Vessel (V-5336501) and further to oil plant to be reprocessed.

3.2. Produced Water Treatment (Area 5331)

The produced water separated at topsides during the steps of oil separation and treatment, may contain various dispersed and dissolved organic components. According to IBAMA Regulation, the daily maximum limit for Oil and Grease (TOG) is 42 mg/L and the monthly average limit is 29 mg/L. The analytical method used to determine the content of Oil & Grease (TOG) in produced water to be discharged to overboard is the Standard Method (SM) SM-5520B, which determines the total hexane extractable material (HEM).

Produced Water Treatment System is composed of Hydrocyclone batteries and Gas Flotation Units with recirculation system, and it has the total capacity of treating 39,700 m^3/d of produced water divided in two trains, each one with capacity of 19,850 m^3/d.

The simplified scheme of the produced water system is presented as follow:

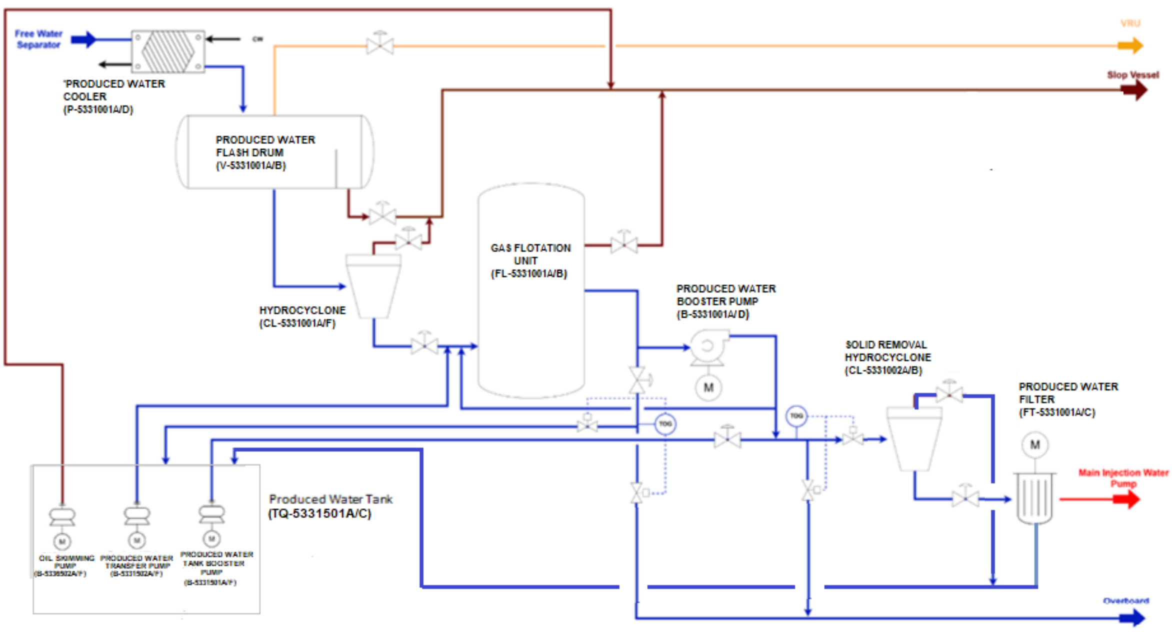


Figure 3 – Simplified Diagram for Produced Water System (Area 5331)

Produced water separated in Settling Tank or from Pre-Oil Dehydrator or Oil Dehydrator is routed to Produced Water Cooler (P-5331001A/D) to reduce the fluid temperature to 55ºC. The cooled stream is then routed to Produced Water Flash Drum (V-5331001A/B) with the aim to eliminate any residual gas before next stage of water treatment, carried out in the Hydrocyclones (CI-5331001A/F). The residual gas from V-5331001A/B will be recovered to VRU or routed to Flare System in case VRU is not available.

After oil removal in Hydrocyclones, an additional step for produced water polishing is carried out in Gas Flotation Unit (FL-5331001A/B), in order to meet oil and grease content (TOG) required for overboard discarding.

Taking into account that the configuration comprised of Hydrocyclones has only the capacity to reduce dispersed oil from produced water, the project still considers the injection of acetic acid in order to reduce dissolved oil content.

Produced water can be also reinjected back into reservoir. Therefore, the concept of Produced Water Treatment System had considered additional steps beyond Hydrocyclones and Flotator in order to achieve the required solid content. After Gas Flotation Unit, the stream is routed to Produced Water Tank (TQ-5331501A/C) to reduce solid particles and TOG and then to Solid Removal Hydrocyclones (CL-5331002A/B) and to Produced Water Filter (FT-5331001A/C) for final polishing. Filter manufacturer shall design filtering element to retain particles greater than 25 µm. Afterwards, stream is routed to suction of Injection Water Main Pump (B-1251002A/C). The configuration also has the flexibility to pump produced water directly to filters in case the Production Water Tanks are not available.

During downtime of Seawater Injection System, equipment from Produced Water System shall be able to comply with IBAMA and CONAMA 393 requirement, especially regarding to maximum TOG according to standard (29 mg/L average in a month), and downstream FL-5331001A/B the stream shall be diverted to overboard.

3.3. Gas System

3.3.1. General Description

The natural gas separated in the previous process description is received, treated and compressed and can be routed to three (3) different purposes:

- Gas Lift;
- Gas Exportation;
- Fuel Gas.

The natural gas shall be treated according to the following ways:

- Vapor Recovery Unit;
- Main Gas Compression Unit;

- H_2S And CO_2 Removal with Amine Solution;
- Gas Dehydration Unit with Teg Solution;
- Exportation Gas Compression Unit.

3.3.2. Vapor Recovery Unit (VRU) (Area 1225)

The Vapor Recovery Unit (VRU) has the aim of compressing the low pressure gases released in Low Pressure Separator and Settling Tanks to be mixed with main gas stream from High Pressure Separator. Besides gas streams from Oil Separation Area, VRU will also compress streams from Produced Water Flash Drum (V-5331001A/B), Flare/Slop Vessel Gas Recovery System (UC-5412001), TEG Regeneration Package (Z-1227001), Rich Amine Flash Drum (V-Z-1235001-01) and Settling Tanks Recovery Gas Compressor (UC-1223001A/B). Additionally, as the possibility of HC Blanketing (see Chapter 5) in the project, an additional stream from Structural Tanks Gas Recovery Compression Unit (UC-Z-1350001) will also be recovered in VRU.

A simplified diagram of VRU is presented on figure below.

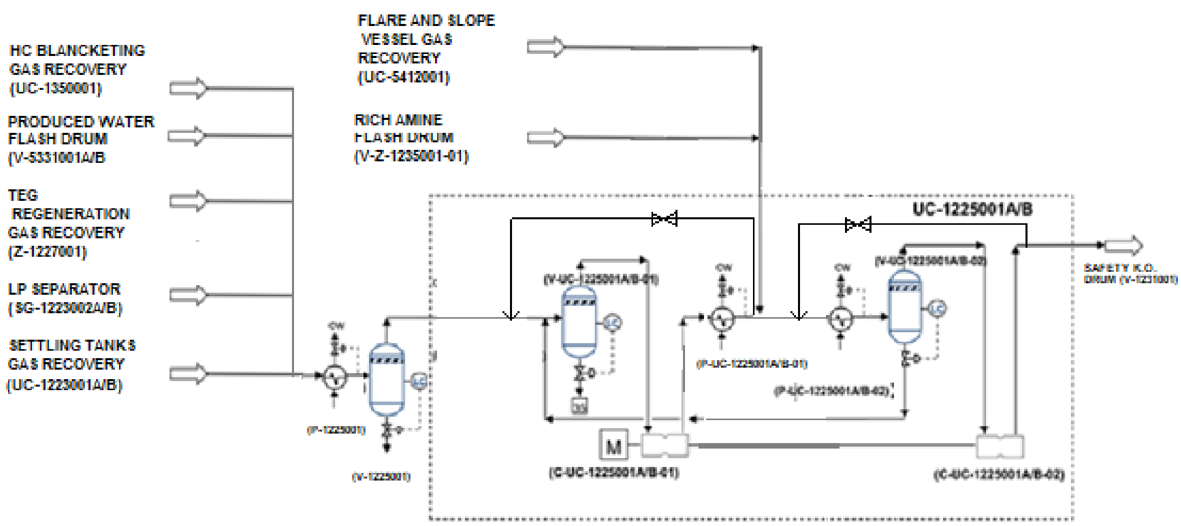


Figure 4 – Simplified Diagram for Vapor Recovery Unit (VRU) (Area 1225)

The VRU is comprised with 2 x 100% train and 2 stages (UC-1225001A/B), and the discharge pressure at the second stage compressor is 920 kPa abs. First stage capacity: 270,000 Sm^3/d. Second stage capacity: 410,000 Sm^3/d.

Low pressure gas from Low Pressure Separator (SG-1223002A/B), Produced Water Flash Drum (V-5331001A/B), TEG Regeneration Gas Recovery (Z-1227001), Settling Tanks Gas Recovery (UC-1223001A/B) and HC Blanketing Gas Recovery (UC-1350001) are routed to VRU Cooler (P-1225001) shell and tube type to be cooled down to 40°C and then to K.O. Drum (V-1225001) to separate any liquid from gas stream. Afterwards, the gas separated at V-1225001 enters at VRU 1st Suction Scrubber (V-UC-1225001A/B-01) that promotes the separation of vapor condensate in order to guarantee a higher efficiency in the VRU - 1st Stage Compressor (C-UC-1225001A/B-01).

The compressed stream is cooled down to 40°C at VRU 1st Stage Discharge Cooler (P-UC-1225001A/B-01) shell and tube type.

In addition to this stream, associated gas from Flare and Slop Vessel Gas Recovery System (UC-5412001) and from Rich Amine Flash Drum (V-Z-1235001-01) are routed to VRU 2nd Stage Suction Cooler (P-UC-1225001A/B-02), shell and tube type. The function of this equipment is to cool down this stream in case of receiving any second stage hot recirculation. After that, this stream is routed to VRU 2nd Stage Suction Scrubber (V-UC-1225001A/B-02) that promotes the separation of vapor condensate in order to guarantee a higher efficiency in the VRU – 2nd Stage Compressor (C-UC-1225001A/B-02).

After compressed in the C-UC-1225001A/B-02, the gas from VRU is mixed with gas from High Pressure Separator and finally routed to Main Gas Compressor Unit (Area 1231).

3.3.3. Main Gas Compression Unit (Area 1231)

The Main Gas Compression Unit (UC-1231001A/C) has the aim of increasing the pressure of total gas flowrate to route to H_2S and CO_2 removal step. The main stream is the outlet of High Pressure Separator (SG-1223001A/B) that will be comingled with other sources as Vapor Recovery Unit (UC-1225001A/B), Test Separator (SG-1223003) and recycles from gas plant.

A simplified diagram of UC-1231001A/C is showed in next figure and comprises of 2 (two) stages of centrifugal compressor plus gas coolers and scrubbers.

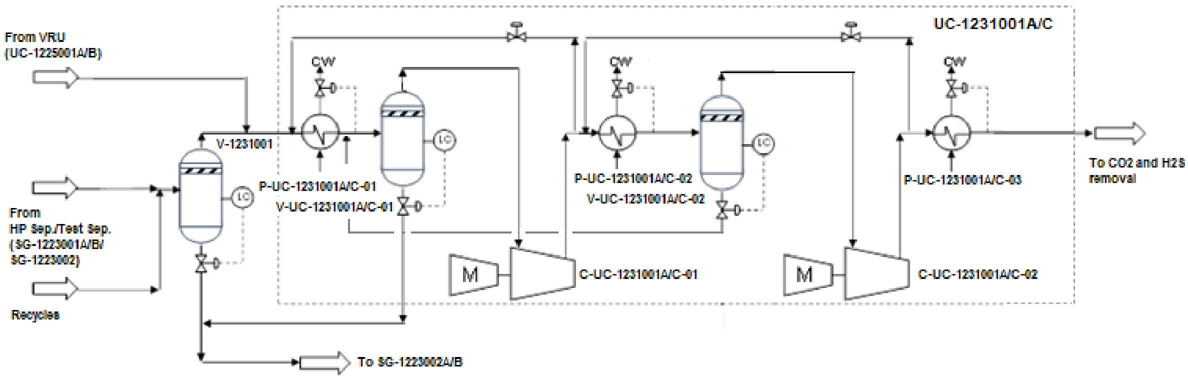


Figure 5 – Simplified Diagram for Main Gas Compression Unit (Area 1231(001))

The Main Gas Compression Unit is comprised with 3 x 50% trains (UC-1231001A/C), and the compressor discharge pressure at the second stage is 5,610 kPa abs. Each compressor capacity: 3,600,000 Sm^3/d.

Separated gas from High Pressure Separator is mixed with gas from Test Separator and routed to Safety Gas K.O. Drum (V-1231001). Additionally, streams from other process plant units (condensate from compressor scrubbers, condensate from Fuel Gas System, recycles, etc.)

are also routed to V-1231001. Liquid collected in V-1231001, mixed with liquid from Main Compression 1st Stage Suction Scrubber (V-UC-1231001A/C-01) is routed to SG-1223002A/B.

Gas from V-1231001 is mixed with gas from VRU and is cooled down to 40°C in Main Compression 1st Stage Suction Cooler (P-UC-1231001A/C-01), shell and tube type, and routed to Main Compression 1st Stage Suction Scrubber (V-UC-1231001A/C-01) and further to the suction of Main 1st Stage Compressor (C-UC-1231001A/C-01).

Discharge from Main 1st Stage Compressor is cooled down to 40°C in Main Compression 1st Stage Discharge Cooler (P-UC-1231001A/C-02), shell and tube type, and routed to Main Compression 1st Stage Discharge Scrubber (V-UC-1231001A/C-02). Any formed condensate is separated in this vessel and routed to V-UC-1231001A/C-01. Gas in the outlet of V-UC-1231001A/C-02 is routed to be compressed in Main 2nd Stage Compressor (C-UC-1231001A/C-02) and further cooled down to 40°C in Main Compression 2nd Stage Discharge Cooler (P-UC-1231001A/C-03) to be routed to CO_2 and H_2S removal (Area 1235).

3.3.4. Acid Gases Removal Unit (Area 1235)

H_2S removal is a necessary step in the gas treatment plant in order to meet the requirement for gas pipeline specification. Required H_2S content for gas exportation is 5 ppmv.

CO_2 removal is also a necessary step in the gas treatment plant in order to meet the requirement for gas pipeline specification and for fuel gas consumption. Required CO_2 content for gas exportation is 1% mol.

This decontamination is carried out by Amine solution.

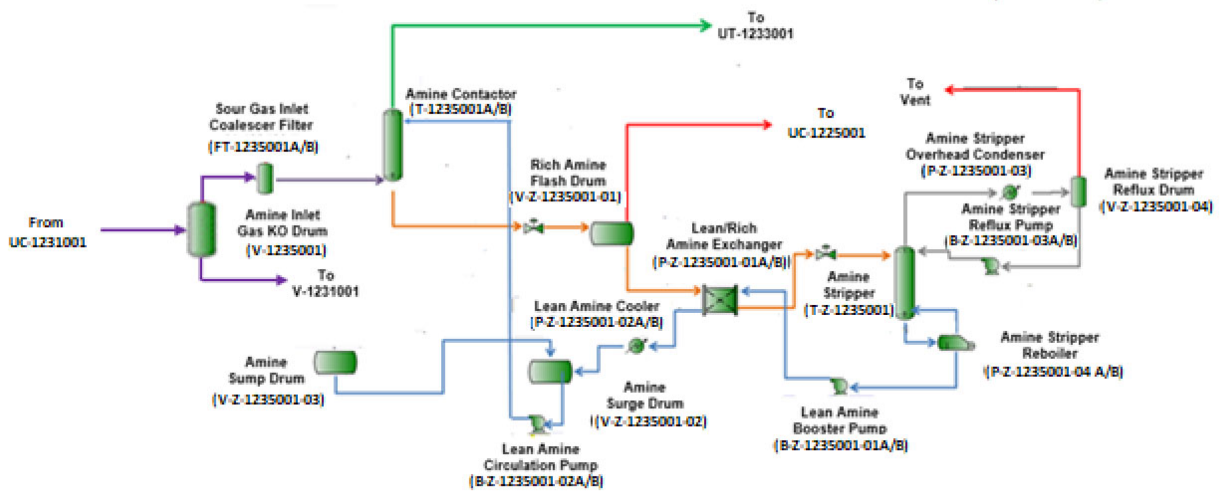


FIGURE 6 - Simplified Diagram for Acid Gases Removal Unit

Gas effluent from Main Compression Unit containing up to 200 ppmv of H_2S and 3,5% molar of CO_2 is routed to Amine Contactor (T-1235001A/B) where these contaminants will be reduced to required specification mentioned previously. Amine Inlet Gas KO Drum (V-1235001) and Sour Gas Coalescer Filter (FT-1235001A/B) upstream absorber are foreseen in order to avoid any liquid carry over to towers.

Sweet gas in the top of absorbers is saturated in water as a result of contact with aqueous amine solution and is routed to Dehydration Unit (UT-1233001) before Exportation Gas Compression Unit.

Rich amine from the bottom of Amine Absorbers is sent to regeneration unit, comprised basically of Flash Drum (which separates condensable and incondensable hydrocarbons eventually removed by the solvent), Heat Exchangers, Filters and Stripping Tower where original amine solution concentration is achieved.

Incondensable gas from Rich Amine Flash Drum (V-Z-1235001-01) is routed to VRU. Gases from the top of Amine Stripper (T-Z-1235001) are routed to vent.

3.3.5. Gas Dehydration Unit (Area 1233)

The wet gas downstream Acid Gases Removal Unit (UT-1235001) shall be dehydrated in order to avoid water condensation and hydrate formation in the exportation gas stream. This dehydration is carried out by TEG (TriEthileneGlycol).

Water content in dry gas shall be less than 40 ppmv.

A simplified diagram for TEG unit is showed in figure below.

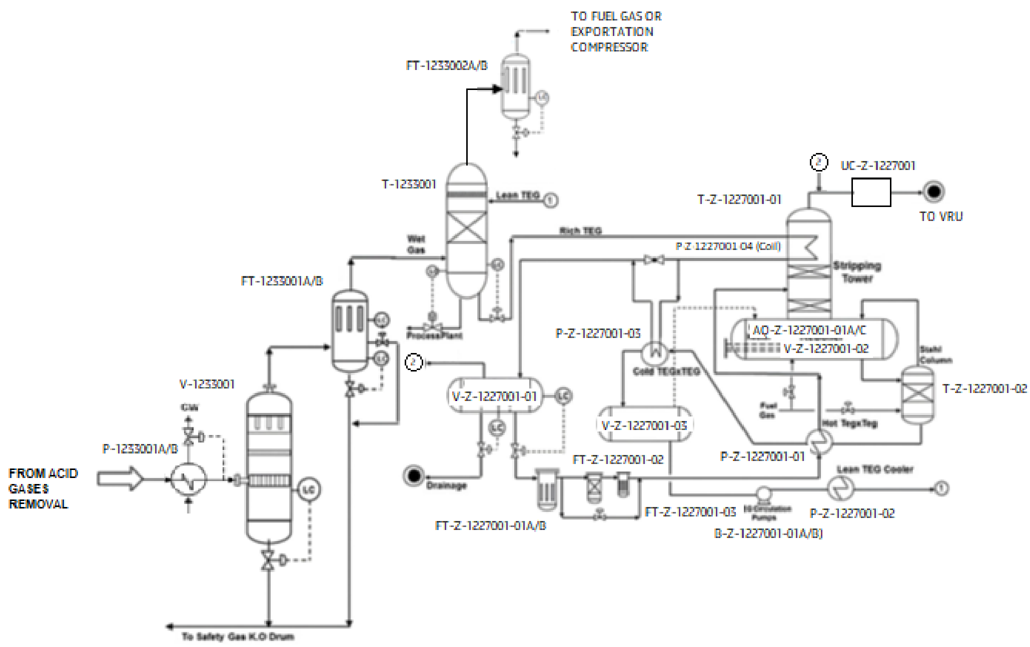


FIGURE 7 - Simplified Diagram for TEG Unit

Wet gas in the inlet of system shall be firstly cooled down before dehydration process in TEG Contactor. For the purpose of this work, around 40°C was used for estimative of unit, lower temperature is recommended if an appropriate cooling medium is available. After being cooled in TEG Inlet Gas Cooler (P-1233001A/B), a shell and tube type, any formed liquid is removed in the TEG Inlet Gas K.O. Drum (V-1233001). Small liquid droplets carried over in scrubber are removed in TEG Inlet Gas Coalescer Filter (FT-1233001A/B) immediately upstream of the TEG Contactor (T-1233001).

Gas in the outlet of FT-1233001A/B is routed to T-1233001, where wet gas is dehydrated through contact with Lean TEG (concentrated glycol). Water dew point in the top of the tower is specified according to requirement mentioned above.

Before leaving the contactor, dehydrated gas crosses a demister. After leaving the contactor, the gas is routed to TEG Outlet Coalescer Filter (FT-1233002A/B) to prevent glycol loss and can be routed to be exported or consumed as fuel gas.

Regenerated glycol (Lean TEG) is cooled to a suitable temperature before entering the TEG Contactor, considering the range of 0 to 8°C above temperature of inlet wet gas, with normal value of 8°C, to avoid gas heavier fraction condensation which leads to TEG contamination and foam formation.

Rich TEG (Lean TEG + removed water) in the bottom of contactor is routed through level control to a coil (P-Z-1227001-04) in the top of TEG Regeneration Unit Stripper (T-Z-1227001-01) where it will be pre-heated besides generating reflux in the top of tower. Pre-heated rich glycol is further heated in Cold Lean/Rich TEG Heat Exchanger (P-Z-1227001-03) and is routed to TEG Flash Drum V-Z-1227001-01.

V-Z-1227001-01 has the aim of separate hydrocarbons eventually dissolved by glycol during dehydration step in TEG Contactor. Light gas, if any, is sent to Teg Vent Recovery Unit (UC-Z-1227001) and condensable hydrocarbons are separated from Rich TEG and routed to drainage.

Rich TEG, free of hydrocarbons in the outlet of V-Z-1227001-01, is routed to filters with the aim of removing solids and dissolved organic compound in glycol. The Primary TEG Cartridge Filter (FT-Z-1227001-01A/B) receives the total flowrate of rich TEG in order to remove solids from glycol. Part of TEG in the outlet of primary cartridge filters (10% to 20% of inlet flowrate) is routed to a TEG Charcoal Filter (FT-Z-1227001-02) where dissolved organics in TEG are removed. Secondary TEG Cartridge Filter (FT-Z-1227001-03) in sequence with carbon filter will avoid any carbon carry over from FT-Z-1227001-02.

Glycol stream from this filter is comingled with remaining Rich TEG from FT-Z-1227001-01A/B and total stream is routed to regeneration in T-Z-1227001-01, after being heated by Hot Lean/Rich TEG Heat Exchanger (P-Z-1227001-01).

Rich TEG will be regenerated to original concentration through heating by TEG Regeneration Unit Reboiler (AQ-Z-1227001-01A/C), an electrical heater in TEG Reboiler Drum (V-Z-1227001-02). In this equipment, maximum temperature is limited to 204°C, because of degradation temperature of tryethylene glycol and as a consequence maximum concentration is limited as well.

In order to increase the glycol concentration without additional temperature increase, a second step is carried out in a TEG Sparger Column (T-Z-1227001-02), where the required concentration is achieved by water desorption from glycol with a fuel gas stream. In the outlet of column, glycol has its highest concentration (Lean TEG) and before routing to TEG Surge Drum (V-Z-1227001-03), it preheats Rich TEG upstream T-Z-1227001-01.

From the V-Z-1227001-03, Lean TEG is routed back to T-1233001 by TEG Circulation Pump (B-Z-1227001-01A/B) after cooling in Lean TEG Cooler (P-Z-1227001-02). The V-Z-1227001-

03 works as a TEG accumulator for circulation pumps, for glycol make-up into the system and as a drainage vessel for the unit during maintenance operation.

A rich water stream from the top of T-Z-1227001-01 is routed to Teg Vent Recovery Unit (UC-Z-1227001) with the V-Z-1227001-01 gas stream (already mentioned) and sent to VRU.

3.3.6. Exportation Gas Compression Unit (Area 1231002)

The Exportation Gas Compression Unit is comprised of 3 (three) trains, each one with 1 (one) stage of compression. The maximum compressor discharge pressure is 20,070 kPa abs. Each compressor capacity: 3,450,000 Sm^3/d.

The exported gas shall comply with the main requirements:

- CO_2 content: 1% mol (maximum)
- H_2S content: 5 ppmv (maximum)
- H_2O content: 40 ppmv (maximum)

Treated gas from Dehydration Unit is received in the Exportation Gas Compression Suction Scrubber (V-UC-1231002A/C) and it will be compressed in Exportation Gas Compressor (C-UC-1231002A/C). In discharge, after cooling in Exportation Gas Compression Discharge Cooler (P-UC-1231002A/C), gas is routed to exportation through pipeline or to gas lift.

Exportation Gas Capacity depends on fuel gas consumed. As previously informed, the gas treatment is limited to 7,000,000 Sm^3/d and the treated gas part is exported discounting the fuel gas.

Figure below represents a simplified diagram for Exportation Gas Compression Unit.

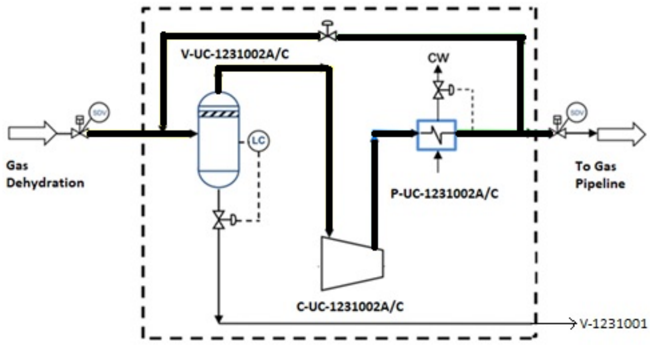


FIGURE 8 – Simplified Diagram for Exportation Gas Compression Unit (Area 1231002)

4. TOPSIDE UTILITIES

4.1. Sea Water Lift System (Area 5111)

Sea water is lifted by submerged Sea Water Lift Pumps (B-5111001A/E) by means of caissons from deep water and is used mainly for water injection and cooling needs for classified and non-classified areas. The next tables present the sea water composition and particle distribution.

TABLE 5 - SEA WATER PARTICLE SIZE DISTRIBUTION

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
TOTAL	769.2

TABLE 6 - SEA WATER COMPOSITION

SEA WATER ANALYSIS		
pH	8,45	
Conductivity	5,800	µmho/m
K^+	500	mg/L
Na^+	12,000	mg/L
Ca^{++}	500	mg/L
Mg^{++}	1,700	mg/L
Ba^{++}	<1	mg/L
Sr^{++}	9	mg/L
Fe total	<1	mg/L
CO_3^{--}	31	mg/L
HCO^-	101	mg/L
NO_3^{--}	<1	mg/L
Cl^-	21,347	mg/L
SO_4^{--}	2,800	mg/L
Salinity	35,177	mg/L
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

MPN - Most Probable Number
CFU - Colony Formation Unit

Hypochlorite solution is produced in Sea Water Electrochlorination Unit (UE-5121501) and is routed to each seawater lift pump suction to minimize the growth of bacteria and other marine growths.

A simplified diagram for Sea Water Lift System is shown in figure below.

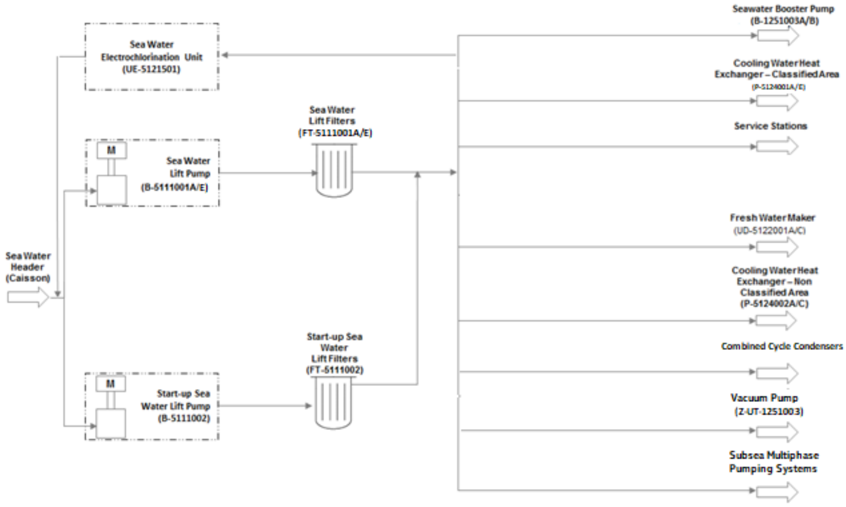


FIGURE 9 – Simplified Diagram for Sea Water Lift System (Area 5111)

4.2. Water Injection System (Area 1251)

Seawater for reservoir injection has the main characteristics:

- Flowrate: 47,760 m^3/d @ 20,000 kPa abs;
- Sea Water Quality specification (maximum values):
  - Content of suspended solids: 1.5 mg/L;
  - Maximum particles/mL greater than 5 µm: 10 (ten) per milliliter;
  - Dissolved oxygen: 10 ppb (vol);
  - Soluble sulfide content: 2 ppm (vol);
  - Bacteria (SBR planctonic – mesophile): 50 NMP/mL;
  - Total anaerobic bacteria (BANHT planctonic): 5,000 NMP/mL;
  - Maximum sulphate content: 100 mg/L.
- Produced Water Quality specification (maximum values):
  - Maximum particles size: 25 µm;
  - Dissolved oxygen: 10 ppb (vol);
  - Maximum Dispersed OG (SM-5520-F method): 10 mg/L;
  - Bacteria (SBR planctonic – mesophile): 50 NMP/mL;
  - Total anaerobic bacteria (BANHT planctonic): 5,000 NMP/mL;

A simplified diagram for Injection Water System is represented in next figure.

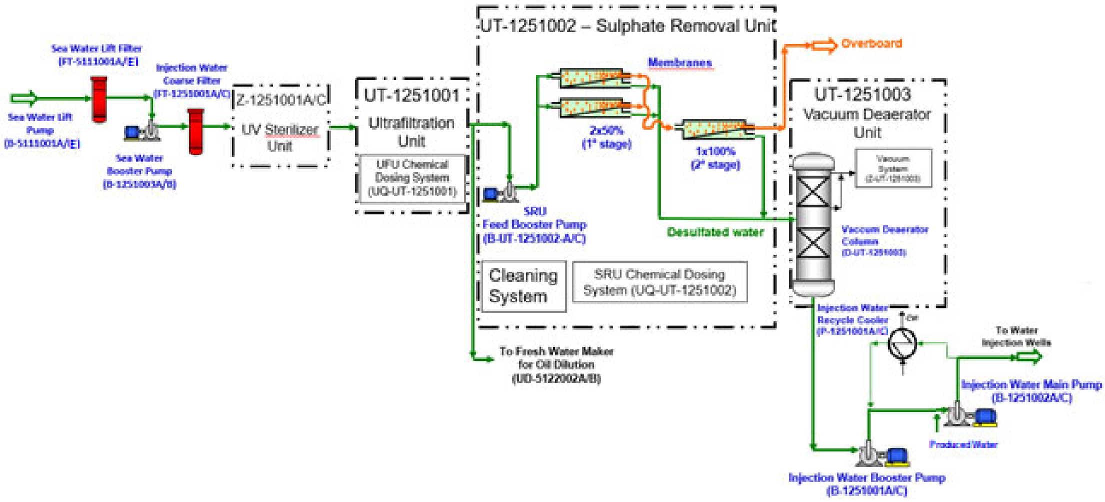


FIGURE 10 – Simplified Diagram for Injection Water System (Area 1251)

Seawater will be firstly pumped by Seawater Booster Pump (B-1251003A/B) to be filtered in the Injection Water Coarse Filter (FT-1251001A/C). After, the water is routed to UV Sterilizer Unit (Z-1251001A/C), then is routed to Ultrafiltration Unit (UT-1251001) and further pumped to nanofiltration membranes for sulphate content specification. UV Sterilizer Unit is to protect membranes against microbiological growth.

Downstream the Sulphate Removal Unit (UT-1251002), sea water is routed to the Vacuum Deaerator Unit (UT-1251003), that is designed to reduce the sea water dissolved oxygen content from 7 ppm to 50 ppb (maximum). The required specification of 10 ppb O_2, (to prevent corrosion and promotion of bacterial growth), will be achieved through the injection of oxygen scavenger.

Treated sea water from Vacuum Deaerator Column (D-UT-1251003) is pumped by Booster Injection Water Pumps (B-1251001A/C) through to Main Injection Water Pumps (B-1251002A/C) and then, to be injected in water injection wells at a maximum pressure of 20,000 kPa abs. This pump is centrifugal type. Receives in the suction header seawater (from B-1251001A/C) and/or produced water (from FT-5331001A/C) and can operate with a ratio between 0 and 100 % either IW (Injection Water, Sea Water pre-treated for injection) or PW (Produced water).

Two injection headers, A and B are provided. Pump B-1251002A will be dedicated to suction/injection header A. Pump B-1251002B will be dedicated to suction/injection header B. The pump B-1251002C will be the reserve pump and can be aligned to the suction / injection header A or B. Each injection header has the capacity to meet 50% of the maximum injection flow. Each injection pump will be associated with a Injection Water Recycle Cooler, P-1251001A/C.

4.3. Cooling Water System (Area 5124)

The cooling water systems consist in two closed fresh water systems, indirectly cooled by sea water: one system dedicated to classified area (hazardous area) and the other for non-classified area (non-hazardous area).

Simplified diagram for classified area cooling medium is presented in figure below.

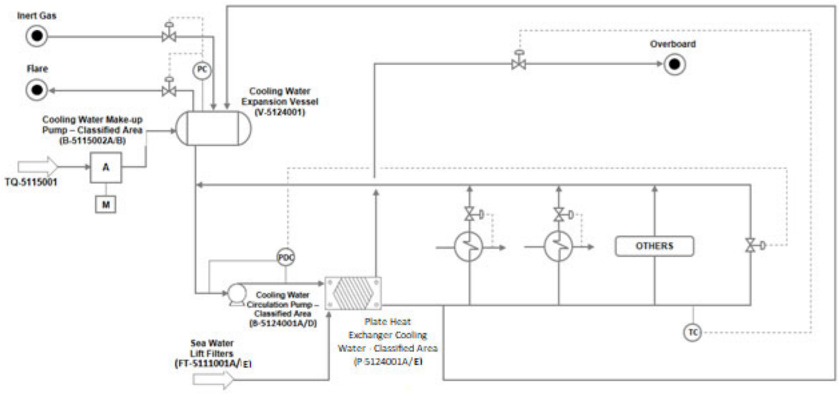


FIGURE 11 – Simplified Diagram for Cooling Water System (Classified Area)

The system is basically comprised of a Cooling Water Expansion Vessel (V-5124001) and Cooling Water Circulation Pump (B-5124001A/D).

The cooling water system for classified area supplies cooling water for the Oil cooler, Produced Water Cooler, gas compressors and their coolers, gas treatment units, gas recovery units and nitrogen generator. The cooling medium is pumped by Cooling Water Circulation Pumps – Classified Area (B-5124001A/D), through the Plate Heat Exchangers Cooling Water – Classified Area (P-5124001A/E), where is cooled down from 55 to 30°C, to the consumers and then, back to pump suction. The Cooling Water Expansion Vessel (V-5124001) is connected to the cooling loop to pressurize and to guarantee that it is always filled with water.

Simplified diagram for non-classified area cooling medium is presented in figure below.

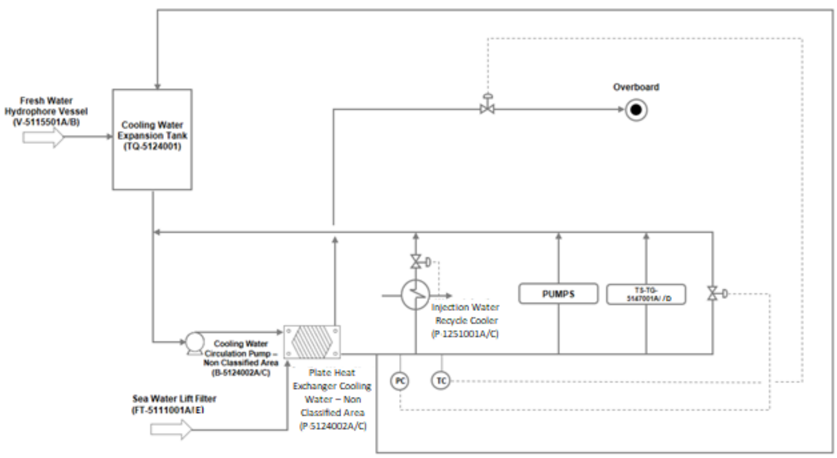


FIGURE 12 – Simplified Diagram for Cooling Water System (Non Classified Area)

The cooling water system for non-classified area supplies cooling water for the turbogenerators (TS-TG-5147001A/D), injection water pumps and hot water circulation pumps. The cooling medium is pumped by Cooling Water Circulation Pump – Non Classified Area (B-5124002A/C), through the Plate Heat Exchangers Cooling Water – Non Classified Area (P-5124002A/C); where is cooled down from 45 to 30ºC, to the consumers and, then, back to pump suction. The Cooling Water Expansion Tank (TQ-5124001) is connected to the cooling loop to guarantee that it is always filled with water. Other consumers of non classified area (ex.: compressed air system, VAC) will be attended with a cooling system located at Hull.

4.4. Hot Water System (Area 5125)

The most important heating medium consumers are the oil treatment system (for oil treatment). Hot Medium System will be used to provide required heating demand.

Simplified diagram for Hot Water System is presented in figure below.

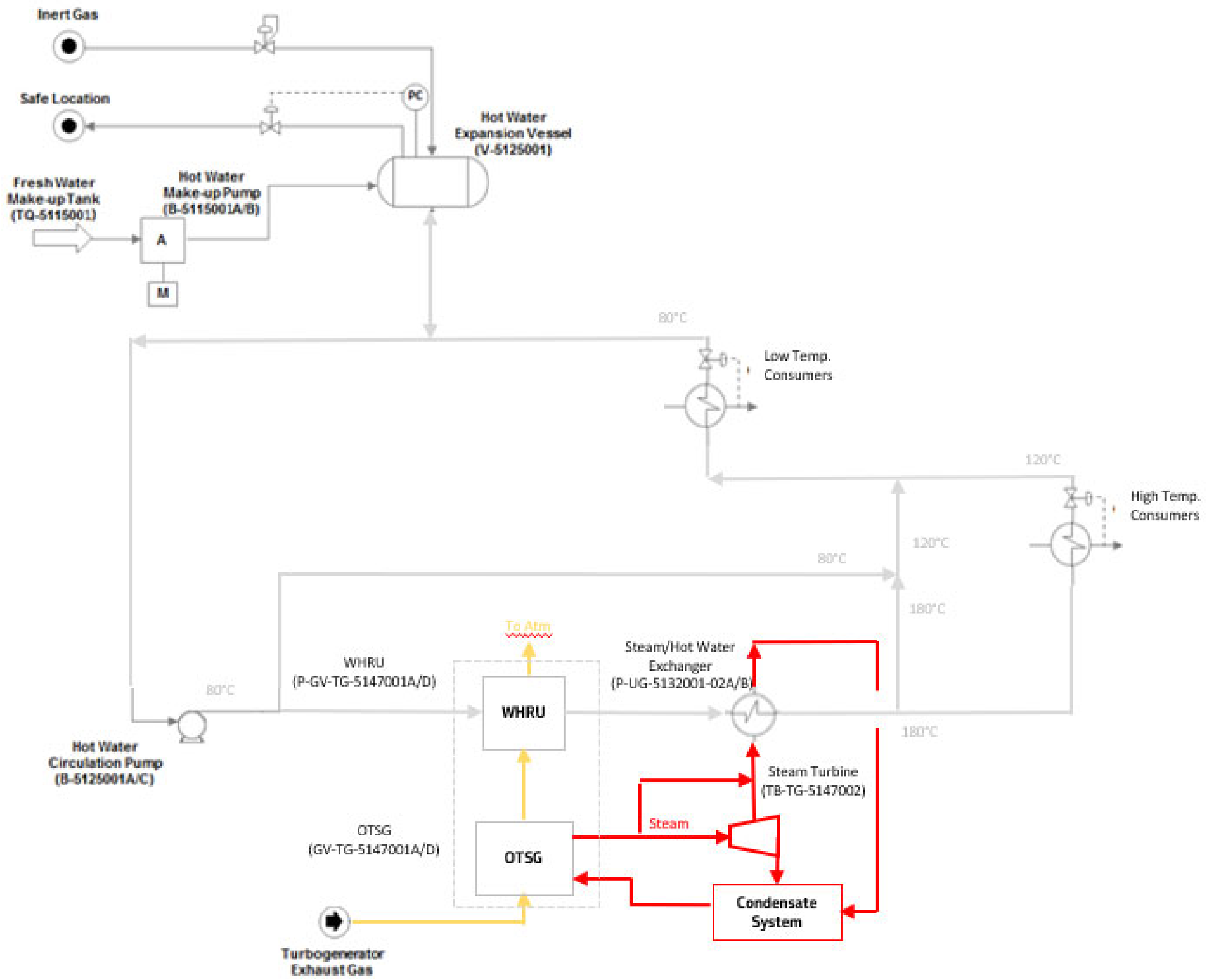


FIGURE 13 – Simplified Diagram for Hot Water System (Area 5125)

Combined Circuit:

Hot water at 80°C is pumped by Hot Water Circulation Pump (B-5125001A/C), through the Turbogenerator Waste Heat Recovery Unit (WHRU)(P-GV-TG-5147001A/D), located in the cold zone of the Once Through Steam Generators (OTSG)(GV-TG-5147001A/D), where it is heated up to an intermediate temperature (approximately 130°C). In the sequence, the pre heated water is routed to Steam/Hot Water Exchanger (P-UG-5132001-02A/B), where the temperature of 180°C is reached, exchanging heat with superheated steam coming from the combined cycle/cogeneration plant (U-5132). Part of the hot water at 180°C is routed to the high temperature consumers (AQ-5271501, P-5125001, P-5135001, P-5135002, P-5135003, V-5412001, V-5412002, P-Z-1235001-04A/B and P-5147001).

Hot Water leaves the High Temperature Consumers at 120°C and then it is routed to Low Temperature Consumers (P-1223001A/F, P-1223003A/F, P-1223004A/B and P-1223006). These Low Temperature Consumers need a Hot Water flow higher than High Temperature Consumers, so, it is necessary to add more Hot Water at 120°C upstream Low Temperature Consumers. This is obtained through mixing part of the 180°C Hot Water that wasn't routed to the High Temperature Consumers with 80°C Hot Water from Hot Water Circulation Pump (B-5125001A/C) discharge.

Hot Water leaves Low Temperature Consumers at 80°C and is returned to B-5125001A/C suction, closing the circuit. The Hot Water Expansion Vessel (V-5125001) is pressurized with Nitrogen and connected to Hot Water System in order to guarantee a minimum pressure higher than the boiling point to avoid vaporization in piping and equipment. Make up water is fed to the V-5125001 by Hot Water Make-up Pump (B-5115001A/B).

Superheated steam used in (P-UG-5132001-02A/B) comes from the extraction of Steam Turbine (TB-TG-5147002). This equipment receives superheated steam produced by the Once Through Steam Generator (OTSG) (GV-TG-5147001A/D), generating electric power and supplying steam to attend thermal energy demand. The OTSG produce steam recovering energy from the exhaust gases of the Gas TurboGenerator (TS-TG-5147001A/D). After suppling energy for steam generation, this exhaust gas follows its path towards the WHRU, optimizing energy recovery.

Open Circuit:

In this operation mode, there is no steam generation in OTSG and consequently, no electrical energy generation in TB-TG-5132002 neither Hot Water heating in P-UG-5132001-02A/B. Hot Water heating is made only in WHRU.

For Combined Cycle details, see I-MD-3010.2Q-5132-940-PEI-001 - DESCRIPTIVE MEMORANDUM - COMBINED CYCLE/COGENERATION SYSTEM.

4.5. Fresh Water System (Area 5122)

Fresh water will be generated through a set of 3x50% Vacuum Distillers (Fresh Water Maker – UD-5122001A/C) and 2x100% Reverse Osmosis Units (Fresh Water Maker for Oil Dilution – UD-5122002A/B).

Distilled water, in a total flowrate of 120 m^3/d, will be generated in order to be provided for the following main consumers:

- Accommodation
- Make-up for cooling and heating systems
- Turbines and reverse osmosis membranes cleaning
- Workshops, laboratories, high pressure cleaning with fresh water
- Diving area
- Diesel oil purifiers
- Chloride dilution
- Utilities station
- Oil centrifuges cleaning

Remaining fresh water to attend the total consumption of the unit will be generated by Reverse Osmosis Units (2x100%), configured with two passes of membranes. First pass (total capacity of 1920 m^3/d of fresh water) will generate 830 m^3/d of a fresh water with salinity/chloride content of 250 mg/L to be used for oil dilution, in order to achieve the required salinity for oil exportation. The remaining water flow will feed the second pass.

The second pass of reverse osmosis unit (capacity of 1090 m^3/d of fresh water) with a salinity/chloride content of 50 mg/L will be used for the following main consumers:

- Chemical dilution
- Sulfate Removal Unit (SRU) and Ultrafiltration (UF) CIPs
- Compressors of Gas Recovery Units
- Make-up of OTSG (Once Through Steam Generator)

4.6. Fuel Gas System (Area 5135)

The Fuel Gas System operation depends on the three operation modes (normal operation, contingency or fuel gas importation) according to the descriptions below.

Normal Operation: The treated gas from Acid Gases Removal Unit (Area 1235) and Dehydration Unit (Area 1233) is routed to Fuel Gas System.

Contingency operation/start-up: Acid Gases Removal Unit (Area 1235) is by passed and gas is routed from Gas Dehydration Unit to Fuel Gas System.

Fuel gas importation: gas is imported from gas pipeline and routed to fuel gas system.

Simplified diagram for Fuel Gas System is presented in figure below.

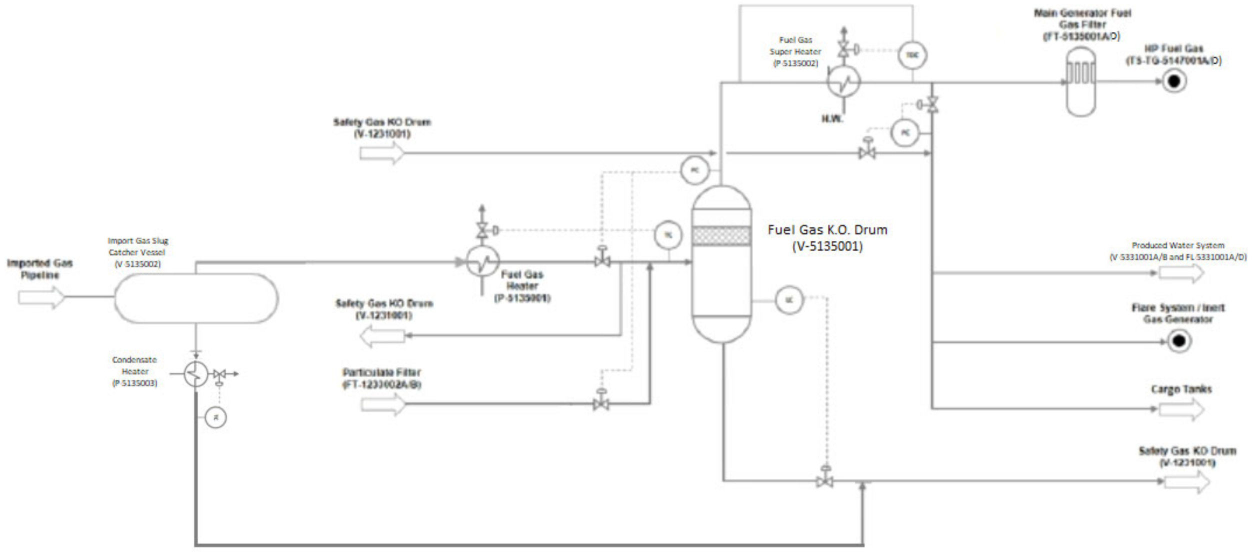


FIGURE 14 – Simplified Diagram for Fuel Gas System (Area 5135)

Part of treated gas from Dehydration Unit is sent to Fuel Gas K.O. Drum (V-5135001) and the other part is sent to Gas Exportation Compression Unit (UC-1231002A/C). In case of importation, gas at -3.2 to 2°C from pipeline is sent to Import Slug Catcher Vessel (V-5135002) and heated in Fuel Gas Heater (P-5135001) to reach 40°C after pressure break in the valve located downstream Fuel Gas Heater, before being routed to V-5135001.

Part of this gas to Fuel Gas System is used as L.P. Fuel Gas and routed to HULL, Produced Water Treatment Unit, Flare (purge and pilots) and others as shown in figure above. The other part is routed to Main Generator Fuel Gas Filter (FT-5135001A/D) and is used as H.P. Fuel Gas, being routed to TurboGenerators (TG-5147001A/D).

The Fuel Gas is superheated in the Fuel Gas Super Heater (P-5135002) in order to avoid condensation in lines to TurboGenerators.

Liquid from V-5135002 is heated in Condensate Heater (P-5135003) and added to liquid stream from V-5135001, returning to Safety Gas K.O. Drum (V-1231001).

4.7. Flare System (Area 5412)

The flare system is designed to provide safe and efficient means of collection and disposal of hydrocarbons fluids, via combustion at the flare tip, associated with:

- Systems/equipment pressure relief cases (PSVs, BDVs and PVs);
- Partial or total platform depressurization cases;
- Disposal of hydrocarbons from process systems during maintenance procedure.

HP Flare capacity: 11,000,000 Sm^3/d. LP Flare capacity: 574,320 Sm^3/d. Simplified diagram for Flare System is presented in figure below.

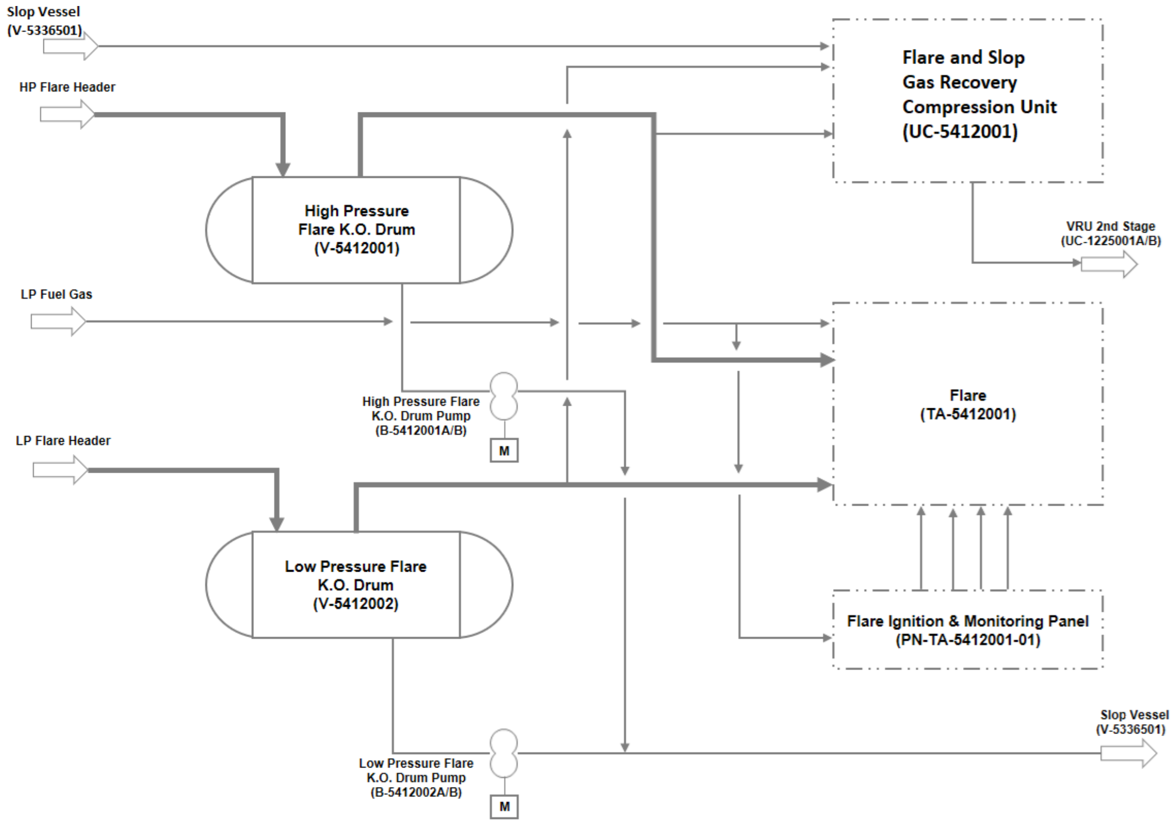


FIGURE 15 – Simplified Diagram for Flare System

The process equipment/system releases shall be collected by HP and LP Flare Headers spread abroad all the topsides conducting Flare System. Fluids shall arrive at High Pressure Flare K.O. Drum (V-5412001) from HP Flare Header and shall arrive at Low Pressure Flare K.O. Drum (V-5412002) from LP Flare Header.

Recovered liquid collected at drums boots shall be pumped by High Pressure Flare K.O. Drum Pump (B-5412001A/B) and Low Pressure Flare K.O. Drum Pump (B-5412002A/B) to Slop Vessel (V-5336501), located on Main Deck.

In order to minimize gas burning at Flare System, either Low Pressure or High Pressure Flare K.O. Drum demisted outgoing gas shall be routed to Flare and Slop Vessel Gas Recovery Compression Unit (UC-5412001) to be returned to process. The UC-5412001 consists of a system that elevates the pressure of the Unit discharged gas and sends it back to the process plant, specifically to VRU 2nd stage (upstream P-UC-1225001A/B-02).

4.8. Drain Systems (Area 5336)

The purpose of this system is to conduct to the Slop Vessel and Aft Slop Vessel (V-5336501 and V-5336502) - closed drain, and to Slop Tanks (TQ-5336506P/S) - open drain, the oily water mixtures.

The closed drain streams are routed to Slop Vessels (V-5336501 and V-5336502) and after is sent back to the High Pressure Separator (SG-1223001A/B) through Slop Vessel Pump (B-5336501A/D).

The opened drain streams from non-classified area and classified areas are filtered (FT-5336001A/B and FT-5336002A/B) and routed to Slop Tanks located at Hull. The laboratory drain is directed to Open Drain Tank – Non Classified Area (TQ-5336001), and after is mixed with open drain non-classified area downstream filtration.

Simplified diagram for Drain System is presented in next figure.

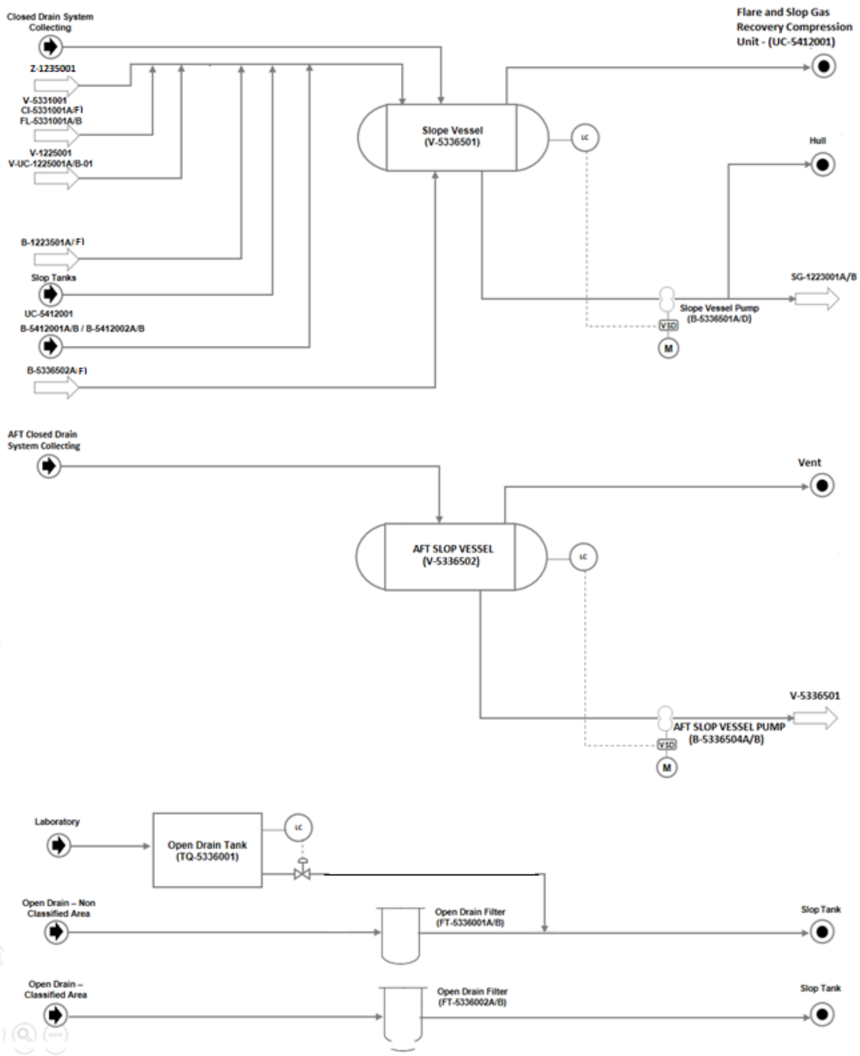


FIGURE 16 – Simplified Diagram for Drain System (Area 5336)

4.9. Nitrogen Generation System (Area 5241)

Nitrogen Generation System is comprised by three units, Nitrogen Generation Unit (Z-5241001A/B), Nitrogen Generation Unit for Flare (Z-5241002A/B) and Nitrogen Generation Unit for OTSG (Z-5241003A/B).

Simplified diagram for Nitrogen Generation System is presented in figure below.

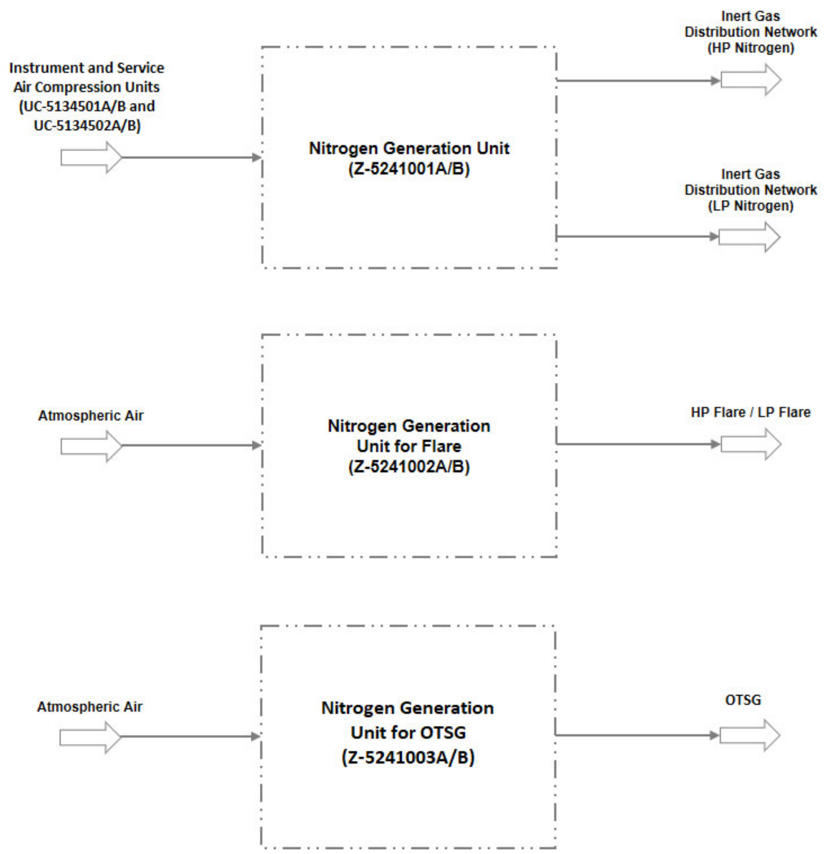


FIGURE 17 – Simplified Diagram for Nitrogen Generation System

Nitrogen gas is generated from atmospheric air. For Nitrogen Generation Unit (Z-5241001A/B) the air is sent by Instrument and Service Air Compression Units (UC-5134501A/B and UC-5134502A/B). This unit is designed for attending the following demands: gas blanketing in V-5133001, V-5124001 and V-5125001 plus equipment purging plus compressors sealing. For Nitrogen Generation Unit for Flare (Z-5241002A/B) and Nitrogen Generation Unit for OTSG (Z-5241003A/B), the air is originated from atmosphere directly.

4.10. Diesel Oil System for Well Service (Area 5133)

The Diesel Oil System for Well Service is designed for attending the following events: resources for shutdown production; lines cleaning and wax removal; resource for well reopened; well conditioning; and hydrate prevention in lines flows.

Simplified diagram for Diesel Oil System for Well Service is presented in figure below.

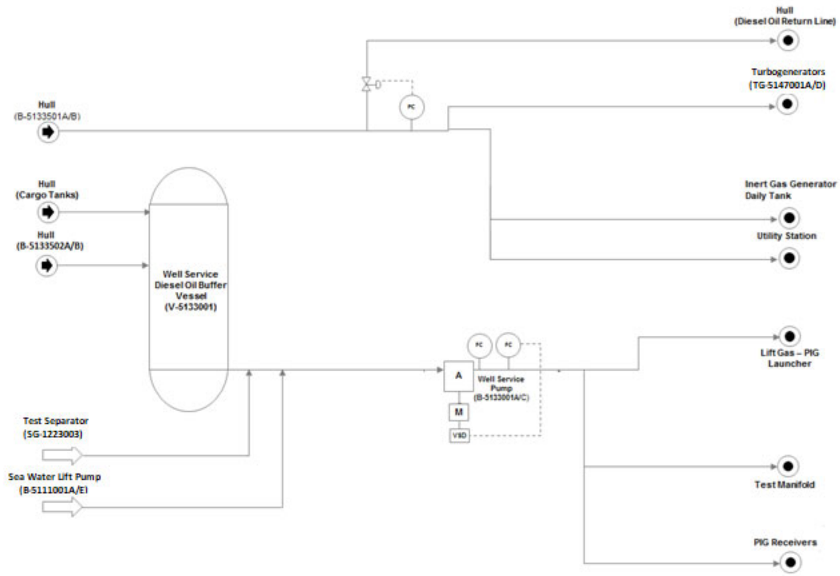


FIGURE 18 – Simplified Diagram for Diesel Oil System for Well Service

The Diesel Oil System for Well Service is capable to delivery cold or hot diesel oil for process.

The cold diesel oil stored on Well Service Diesel Oil Buffer Vessel (V-5133001) is routed to Well Service Pump (B-5133001A/C) and then is sent to distribution header and after to pig launchers. Then, the diesel oil outlet from wells is routed to pig receiver and is directed do Test Separator (SG-1223003).

The hot diesel oil is obtained by warming up the diesel oil in the Test Heater (P-1223006), and then routed to Test Separator (SG-1223003). After the diesel oil is directed to Well Service Pump (B-5133001A/C) and follows the same cold diesel oil path.

4.11. Chemical Injection Systems (Areas 1261/1262/1263)

The Chemical Injection Systems consist of storage tanks, pumps and auxiliaries and is divided in three units:

- Oil and Gas Chemical Injection Unit (UQ-1261001);
- Produced Water Chemical Injection Unit (UQ-1262001);
- Injection Water Chemical Injection Unit (UQ-1263001).

4.11.1. Oil And Gas Chemical Injection Unit (UQ-1261001)

Oil and Gas Chemical Injection Unit (UQ-1261001) is represented by the simplified diagram below:

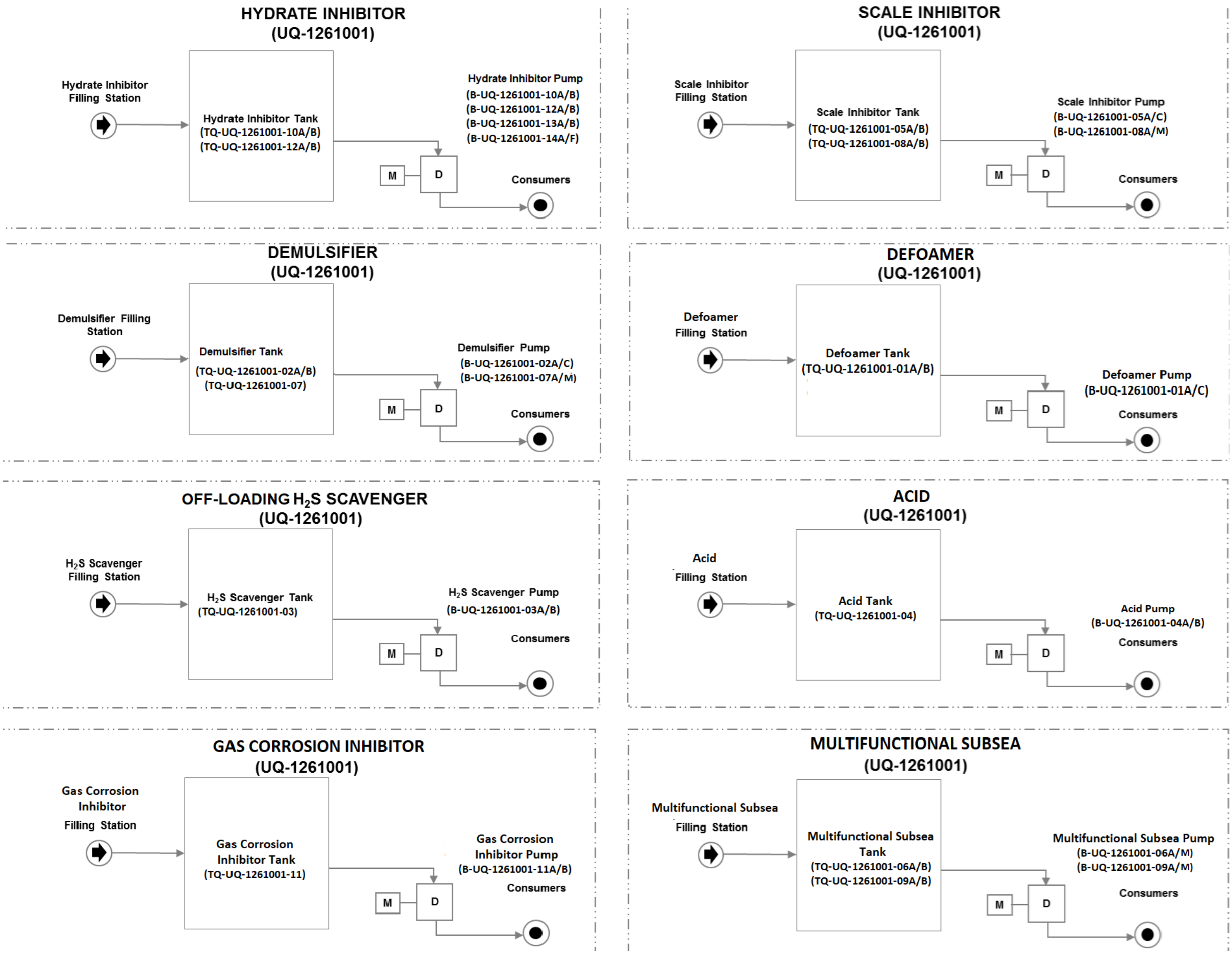


FIGURE 19 - Simplified Diagram for Oil & Gas Chemical Injection 01 (Area 1261)

The system includes the following chemicals:

- TOPSIDES
  - DEFOAMER

    Defoamer will be injected into the production headers, test header, upstream the oil level control valve of the H.P. and L.P. Separators and upstream the oil level control valve of the Test Separator. The injection will be continuous.

  - DEMULSIFIER

    To break water-in-oil emulsions in the topsides facilities, demulsifier will be injected into the production headers, test header, upstream Pre Oil Dehydrator and upstream Oil Dehydrator. The injection will be continuous into the production header.

- SCALE INHIBITOR

To prevent scaling in the topsides facilities, scale inhibitor will be injected into the production headers, test header, downstream Oil Settling Tank Transfer Pump and upstream the Oil Dehydrator.

- HYDRATE INHIBITOR

Ethanol/MEG injection is required in the Gas Lift injection lines (before each Pig Launcher), Gas Lift Header, export header, V-UC-1231002A/C condensate line, C-UC-1231002A/C cold recycle line, upstream Fuel Gas Vessel (before pressure control valve), Fuel Gas Vessel condensate outlet line, imported/exported fuel gas line, V-5135002 gas outlet line and V-5135002 condensate outlet line.

- H_2S SCAVENGER

Hydrogen sulfide scavenger injection is required to remove hydrogen sulfide (H_2S) from produced oil. The chemical product will be injected upstream P-1223005A/D, oil offloading header, oil off-spec tank and produced water tank.

- ACID

Acid will be injected into the production headers and test header. It has the purpose of reducing the dissolved oil parcel in produced water in scenario of discharge to overboard.

- GAS CORROSION INHIBITOR

Corrosion inhibitor will be injected into export pipeline, fuel gas vessel condensate outlet line and upstream the fuel gas high pressure control valve. The injection is not planned to be continuous.

- SUBSEA
  - SCALE INHIBITOR

To prevent scaling, scale inhibitor will be injected into downhole. The injection is planned to be continuous, either up to all trees at the same time or in the chemical injection points of the Topsides.

- HYDRATE INHIBITOR

Under combinations of high pressure and low temperature, well fluids will be in the hydrate formation region. To inhibit hydrate formation, ethanol will be injected into the producing wells wet Christmas trees (WCTs). The injection is not planned to be continuous, however in the (WCTs), it will be possible to inject it in up to two points at the same time.
Ethanol may also be injected to help the removal of any hydrates that are inadvertently formed, and to equalize pressure across tree valves prior to opening. The Subsea hydrate inhibitor is distributed continuously into each production well via their respective well umbilical.

- DEMULSIFIER

To break water-in-oil emulsions, demulsifier will be injected into the subsea Christmas Trees through umbilical or downhole.

- MULTIFUNCTIONAL I

Can be used to inject Antifoam, H_2S Scavenger, Scale Inhibitor, Asphaltene Inhibitor or Wax Inhibitor in the wells.

- MULTIFUNCTIONAL II

Can be used to inject Antifoam, H_2S Scavenger or Scale Inhibitor in the wells.

4.11.2. Produced Water Chemical Injection Unit (UQ-1262001)

Produced Water Chemical Injection Unit (UQ-1262001) is represented by the simplified diagram below:

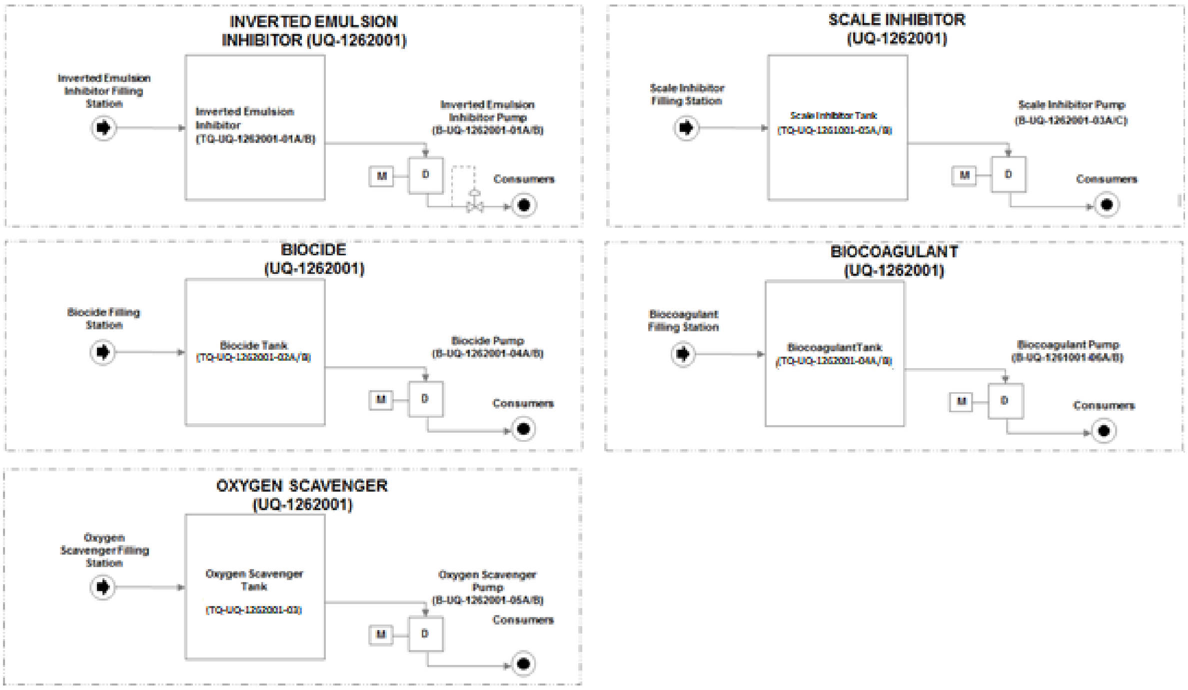


FIGURE 20 - Simplified Diagram for Produced Water Chemical Injection (Area 1262)

The system includes the following chemicals:

- INVERTED EMULSION BREAKER

To break oil-in-water (reverse) emulsions in the produced water treatment system, polyelectrolyte will be injected upstream the flotation units. The injection will be continuous.

- PRODUCED WATER SCALE INHIBITOR

To prevent scaling in the produced water treatment system, scale inhibitor will be injected in the water outlet lines of the Test Separator, Settling Tanks, Pre-Oil Dehydrators and Oil Dehydrators and in the Reinjection Water Collector (downstream Reinjection Water Filter). The injection will be continuous.
Scale Inhibitor for UQ-1262001 is supplied by UQ-1261001 (TQ-UQ-1261001-05A/B).

- PRODUCED WATER BIOCIDE

To kill bacteria in the produced water treatment system, facilities are provided for periodic shock dosing of biocide THPS (tetrakishy(droxymethyl) phosphonium sulfate). The chemical will be injected in the liquid inlet of Slop Tanks, Oil Off-spec Tank, Settling Tanks and Produced Water Tanks. There will be also a continuous injection of biocide in Oil Off-spec Tank.

- PRODUCED WATER OXYGEN SCAVENGER

Oxygen scavenger injection is required to reduce the oxygen content to 10 ppb. Oxygen scavenger will be injected in the water outlet lines of the Slop Tank, Oil Off-spec Tank and Produced Water Tanks. The injection will be continuous in Oil Off-spec Tank and Produced Water Tank and non-continuous in Slop Tank.

- PRODUCED WATER BIOCOAGULANT

Biocoagulant will be injected in the water inlet and outlet lines of the Hydrocyclones. The injection will be continuous and non-simultaneous.

4.11.3. Injection Water Chemical Injection Unit (UQ-1263001)

The simplified diagram below represents injection Water Chemical Injection Unit (UQ-1263001):

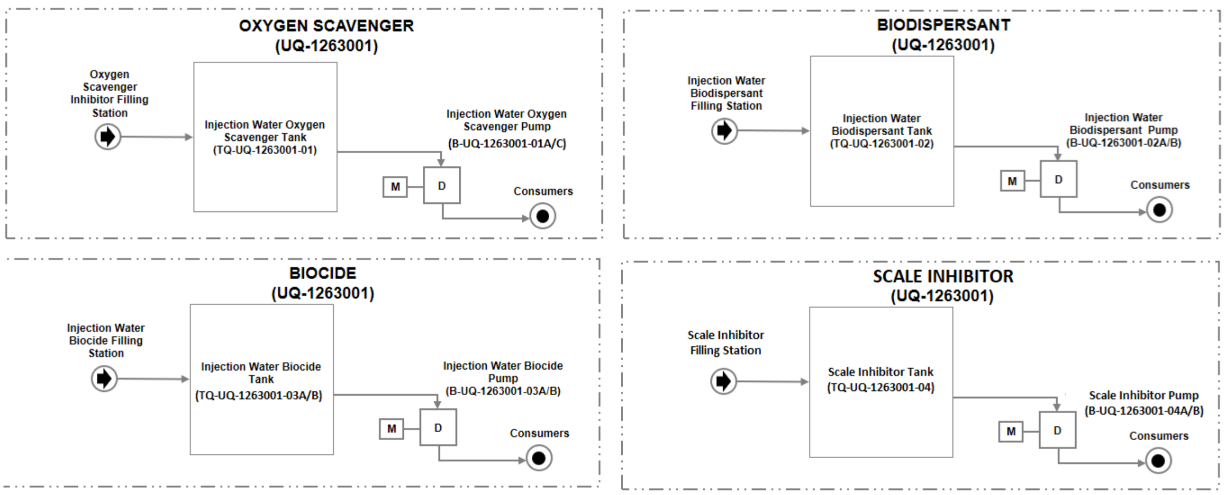


FIGURE 21 - Simplified Diagram for Injection Water Chemical Injection (Area 1263)

The system includes the following chemicals:

- BIOCIDE

To kill bacteria in the injection water system, facilities are provided for periodic shock dosing of biocide THPS (tetrakis(hydroxymethyl) phosphonium sulfate). The chemical will be injected downstream or upstream of the Deaeration Column, but not simultaneously.

- OXYGEN SCAVENGER

Oxygen scavenger injection is required to reduce the oxygen content in the Deaerator Column from typically 50 ppb (mechanical deaerator alone, i.e. no chemicals) to 10 ppb. The chemical will be continuously injected into the accumulator or Booster Pumps Suction Header, Produced Water Pump Suction Header (reinjection), in the water outlet lines of the Dilution Water Storage Tank and Fresh Water Make-up Tank for UC-5412001/ UC-Z-1350001/ UC-Z-1227001. There will be also a shock dosing injection into the accumulator, downstream the Deaerator Column by-pass line.

- BIODISPERSANT

Biodispersant will be injected downstream the Deaerator column by-pass line. The injection will be continuous.

- SCALE INHIBITOR

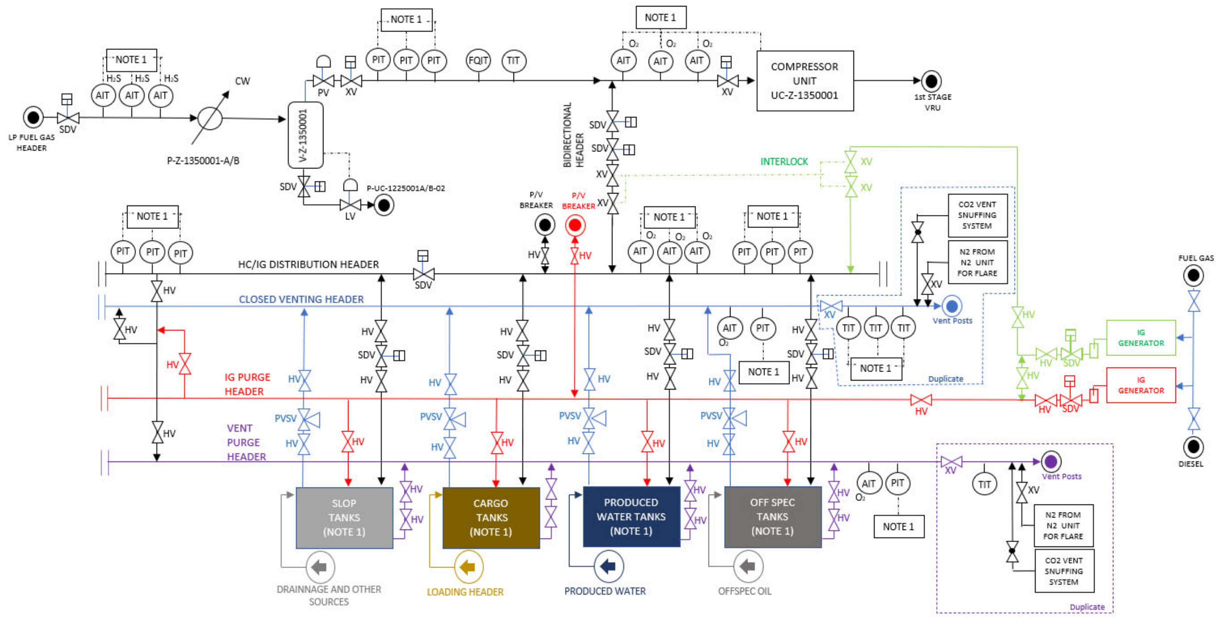
To prevent scaling, scale inhibitor will be injected downstream the pretreatment of Ultrafiltration (UT-1251001).

4.12. Hydrocarbon Blanket Gas System

In order to adhere to Zero Routine Flaring by 2030" initiative, introduced by the World Bank, project shall consider minimize hydrocarbon release from cargo tanks by means of using process gas (low pressure fuel gas) to maintain a non-explosive atmosphere inside the cargo tanks. With the use of hydrocarbon blanketing systems, oxygen is eliminated from tanks via the use of process gas, forming an atmosphere inside the tank saturated with hydrocarbon to a level above the Upper Explosive Limit (UEL), at which combustion cannot be supported. Moreover, evaporation in the cargo tank is minimal since process gas is likely to be in equilibrium with crude stream than to inert gas, and the displaced gas from the tanks shall be recovered to process plant by new recovery gas system, which enable reduction in volatile organic compound (VOC) emissions to the atmosphere.

Hydrocarbon blanket consists in a new system to provide low pressure fuel gas (LP FG) to maintain stable the pressure inside cargo tanks, specially, during offloading operations where liquid level reduction might lead to underpressure scenario. Furthermore, during oil production loading to tanks light hydrocarbon components can evaporate to tank atmosphere and shall be recovered to process plant by means of cargo tank recovery unit (UC-Z-1350001). In addition to the mentioned above, inert gas system is still provided as backup for hydrocarbon blanket and for purging and gas-freeing operations. Both inert gas and hydrocarbon are provided to the tanks through Hydrocarbon Header / Inert Gas Distribution Header (HC/IG header), therefore, to prevent contamination of inert gas system with hydrocarbon and process plant with inert gases it is foreseen interlocked key operated valves on each source to ensure proper alignment and isolation between the two blanket sources. As it is shown in the schematic drawing in Figure 26, the crude oil tanks, offspec oil, produced water and slop tanks are interconnected to LP FG through Hydrocarbon Inert Gas Distribution Header (HC/IG header) which is fed by the two sources hydrocarbon and inert gas.

Primary source for blanket system shall be provided from LP FG header, its pressure and temperature shall be adjusted to 40°C and around 70 mbar before routing to the tanks in order to avoid evaporation and overpressure inside them. During offloading, when liquids are pumped out from tanks, pressure inside tanks may decrease, PIT located on HC/IG header shall open control valve downstream V-Z-1350001 to supply gas to tanks through a bidirectional piping to maintain pressure stable. On the other hand, during crude oil, offspec oil, produced water loading, pressure increases, and excess of gas shall be recovered by UC-Z-1350001, comprised of 2 x 100% compressors, through the bidirectional piping to prevent pressure build up on tanks.



Note 1: Control and Interlock architecture will be documented in Basic Design Phase.

FIGURE 22 – Simplified Sketch of Hydrocarbon Recovery Gas System

Some concerns arise when considering hydrocarbon from LP FG for tank blanketing, especially regarding to process safety system/devices to prevent or mitigate undesirable events.

Hydrocarbon blanket system could lead to overpressure scenario into the HC/IG header in case of pressure control valve fully open failure, to prevent it, design provides high-high pressure sensor (PSHH) in a 2oo3 architecture downstream V-Z-1350001 to shut off gas inflow by closing shutdown valves (SDVs) on the bidirectional header. Furthermore, additional layers of protection are foreseen in case of SDVs failure closing on demand to prevent overpressure, closed venting header relieving excess gas through vent posts to atmosphere and P/V breaker located on HC/IG header as highest layer of protection relieving excess gas to atmosphere as well. For both devices, it shall be carried out gas dispersion analysis to guarantee gas disposal to safe location.

Underpressure might occur due to recovery compressor overspeed or even control valve closed failure not providing gas during offloading. In these situations, pressure reduction can lead to structural tank collapse or a leak. To prevent it, it is provided low-low pressure sensor (PSLL) in a 2oo3 architecture to close SDVs on bidirectional header, shutdown hydraulic submerged pumps to cease fluid withdraw from tanks and to minimize the risk of collapse or leak. Another layers of protection foreseen for vacuum prevention on traditional gas inert blanket system as vacuum/high pressure valves and P/V breaker are installed.

Hydrocarbon blanket system shall maintain tanks with positive pressure to prevent oxygen intrusion and hence maintain vapor atmosphere outside the flammable range, above UEL, in a non-flammable condition at which combustion cannot be supported. In case of oxygen ingress, it is provided an high-high oxygen sensor (ASHH) to isolate all inflows and outflows to the tanks including to close SDVs on the bidirectional header, to close liquid inlet and to shut off cargo pumps to prevent reducing tank pressure and hence air ingress. Other related aspect to oxygen is likelihood air ingress through vent post and its accumulation on closed venting header, since normally no flow condition during hydrocarbon blanketing operation. To prevent air ingress through vent post stack it is provided continuous purge rate with nitrogen from Nitrogen Generation Unit for Flare (Z-5241002A/B).

In case of vent post ignition, it is provided flame arrestor on each vent post stack to prevent flame migration back to the tanks and CO_2 snuffing system for fire suppression actuated by high-high temperature sensor (TSHH) in 2oo3 architecture. Furthermore, due to enriched hydrocarbon environment when operating the blanket system with fuel gas, TSHH sensor shall cut off gas inflow to tanks, by closing SDVs on bidirectional header, to prevent escalating to a larger fire.

Another concern is related to oxygen carry over to process plant after tank inspection and maintenance. It is provided oxygen analyzer upstream UC-Z-1350001 for oxygen content monitoring oxygen which shall be recovered to process plant. Basic design shall take into consideration oxygen content for material selection after tank inspection and maintenance.