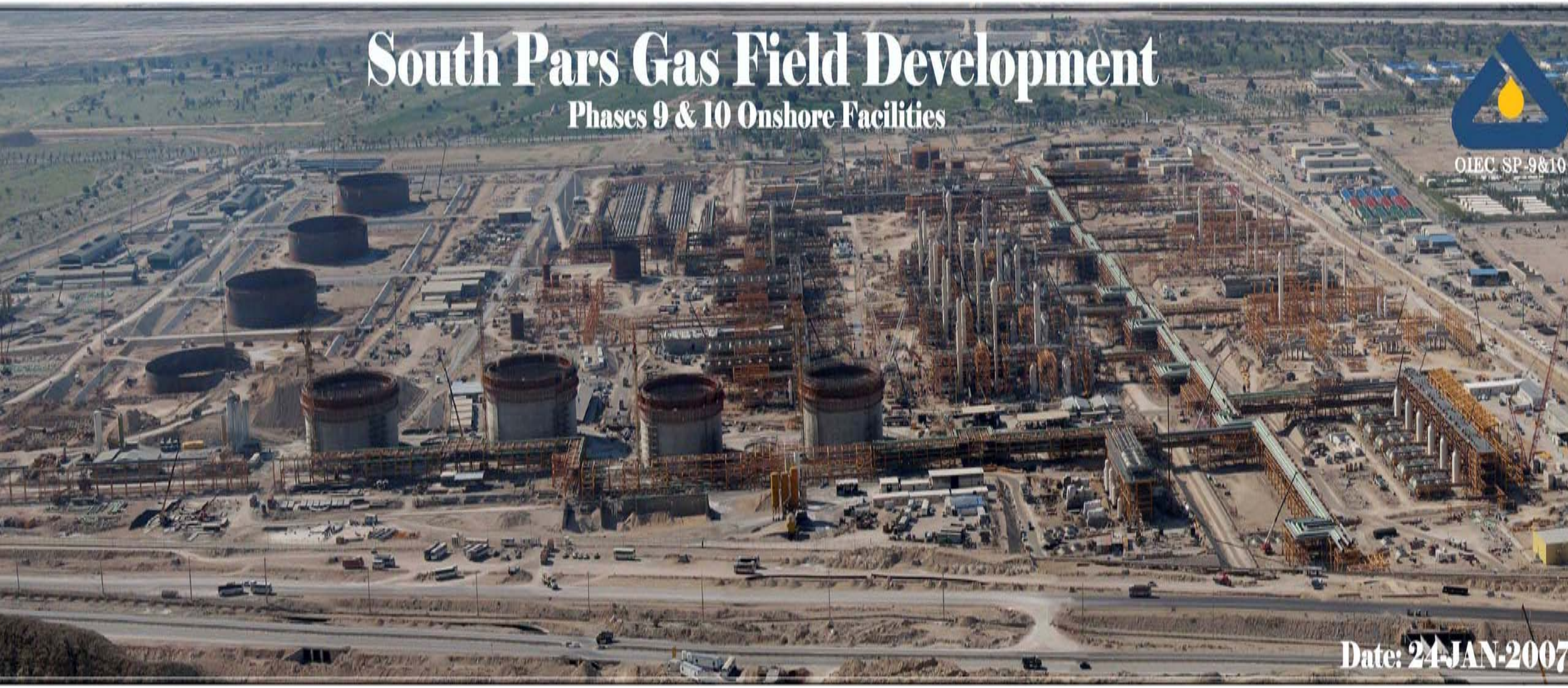

South Pars Gas Field Development
Phases 9 & 10 Onshore Facilities
OIEC SP-9&10
Date: 24-JAN-2007

Booklet

South-Pars Project

- Off shore : two wellhead platforms
- Two 32 inches sea-lines
- On shore Plant : two phases
- Two gas trains per phase.
- Design base : **2000 MMSCFD of feed**.

Corresponding to approximately :

Sales gas	$50*10^6$ $stdm^3/d$	Condensate	77000 std bbl/d
Ethane	2600 t/d	Propane	2000 t/d
Butane	1200 t/d	Sulfur	400 t/d

Off-Shore

• “Wet” Scheme (no offshore treatment, multiphasic transportation with continuous glycol injection)

•Two blocks including each :

- Wellhead Platform 15 slots and test separator
- flare tripod connected to WHPF be bridge
- 10 deviated wells
- 32 inches gas sea-line 84/92 km long
- 4” piggy-back glycol sea-line

On-Shore

- **Process Units**
- **Utility Units**
- **Offsite Units**
- **Miscellaneous Units**

- One slug catcher for each phase liquid separation
- Gas treatment (2 trains per phase)
- Acid gas removal (H_2S) with MDEA
- Acid gas removal (CO_2) with DEA
- Hydration Inhibitor with MEG
- Dew-point unit
- Mercaptan removal (Sulfrex)
- Dry gas compression to pipe pressure
- Condensate stabilisation and storage
- NGL fractionation
- Sulfur recovery and solidification
- Utilities

Process units :

- 100 (2 train) Reception facilities
- 101 (4 train) Gas treating unit amine MDEA solvent **ELF process**
- 102 (6 train) MEG Regeneration & injection
- 103 (2 train) Condensate Stabilization
- 104 (4 train) Dehydration & Mercury Guard
- 105 (4 train) Ethane Recovery
- 106 (6 train) Export Gas Compression & Metering
- 107 (2 train) NGL Fractionation
- 108 (4 train) Sulfur Recovery **LURGI process**
- 109 (1 train) Sour Water Stripping
- 110 (1 train) Back-up Stabilization
- 111 (4 train) Propane Refrigeration

Process units :

- 113 (2 train) Caustic Regeneration   Sulfres Process
- 114 (2 train) Propane treatment & drying
- 115 (2 train) Butane treatment & drying
- 116 (2 train) Ethane treatment & drying

Utilities units :

- 120 Electricity : 2*33kw External supplier & 2*6 kw EDG
- 121 Steam : 6 Steam Boilers A/B/C/D/E/F 6*160 t/hr
- 122 Fuel gas
- 123 Instrument & Service air
- 124 Nitrogen
- 125 Sea water intake & Booster
- 126 Sea water desalination packages A/B/C
- 127 Polishing water mix bed A/B
- 128 Potable water units
- 129 Waste Effluent Disposal
- 130 Fire water system
- 131 Diesel
- 132 Cooling Water

Offsite units

- 140 Flares and blow down
- 141 Drains
- 142 Burn pit
- 143 Condensate storage and export
- 144 Sulfur storage and solidification
- 145 Propane refrigeration storage
- 146 Chemicals storage
- 147 Propane storage
- 178 Butane storage

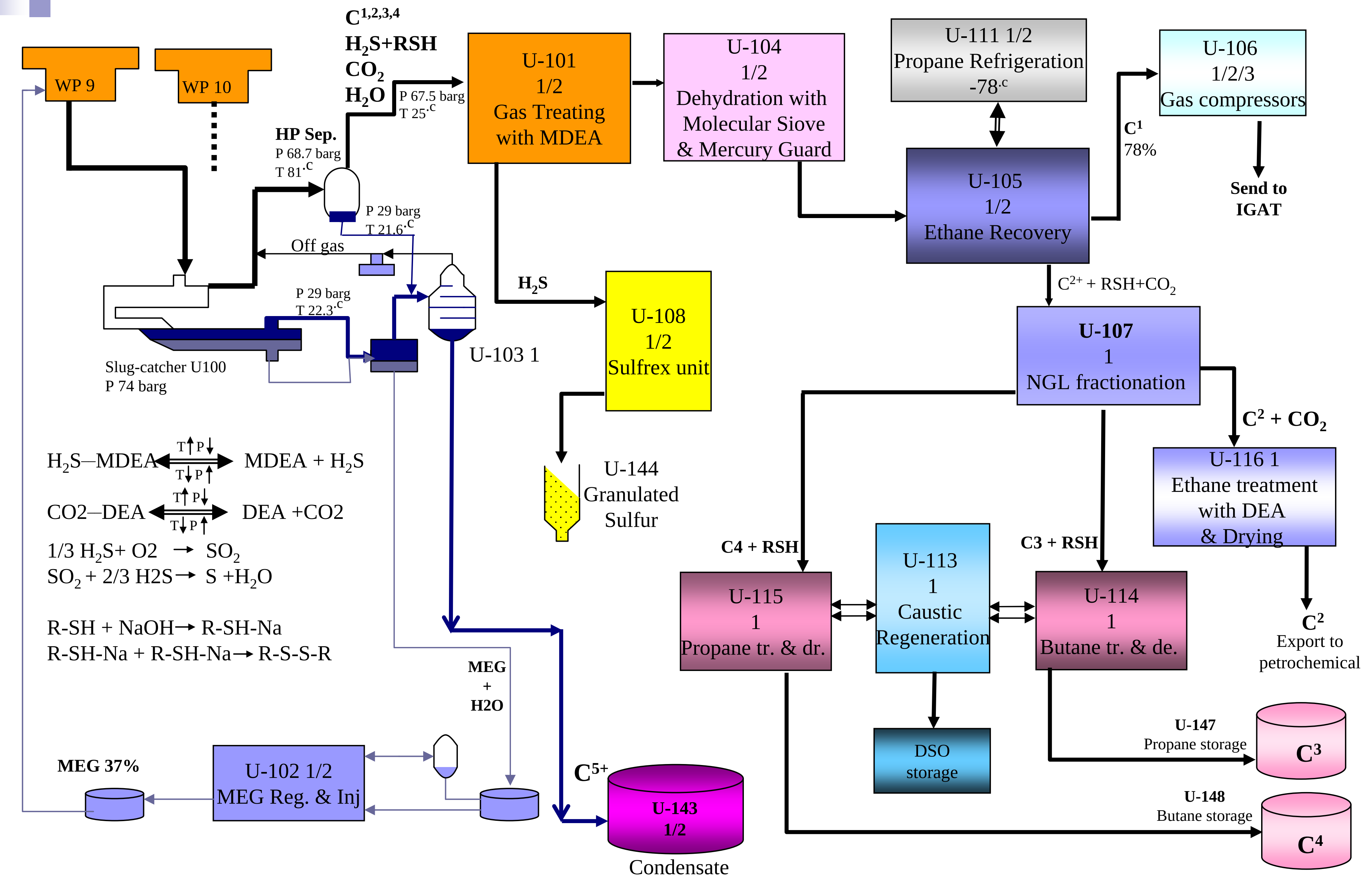
Miscellaneous Unit

- 160 interconnection
- 161 control room
- 162 laboratory
- 163 fire fighting building
- 164 work shop
- 165 Non-process building
- 167 RTU’s , PCS , MTU
- 168 Radios
- 169 Telecommunication
- 174 fire & gas
- 175 ESD
- 179 Technical Room (substations and ITR)
- 999 General facilities
- 000 Interface / Interconnecting outside buttery limits

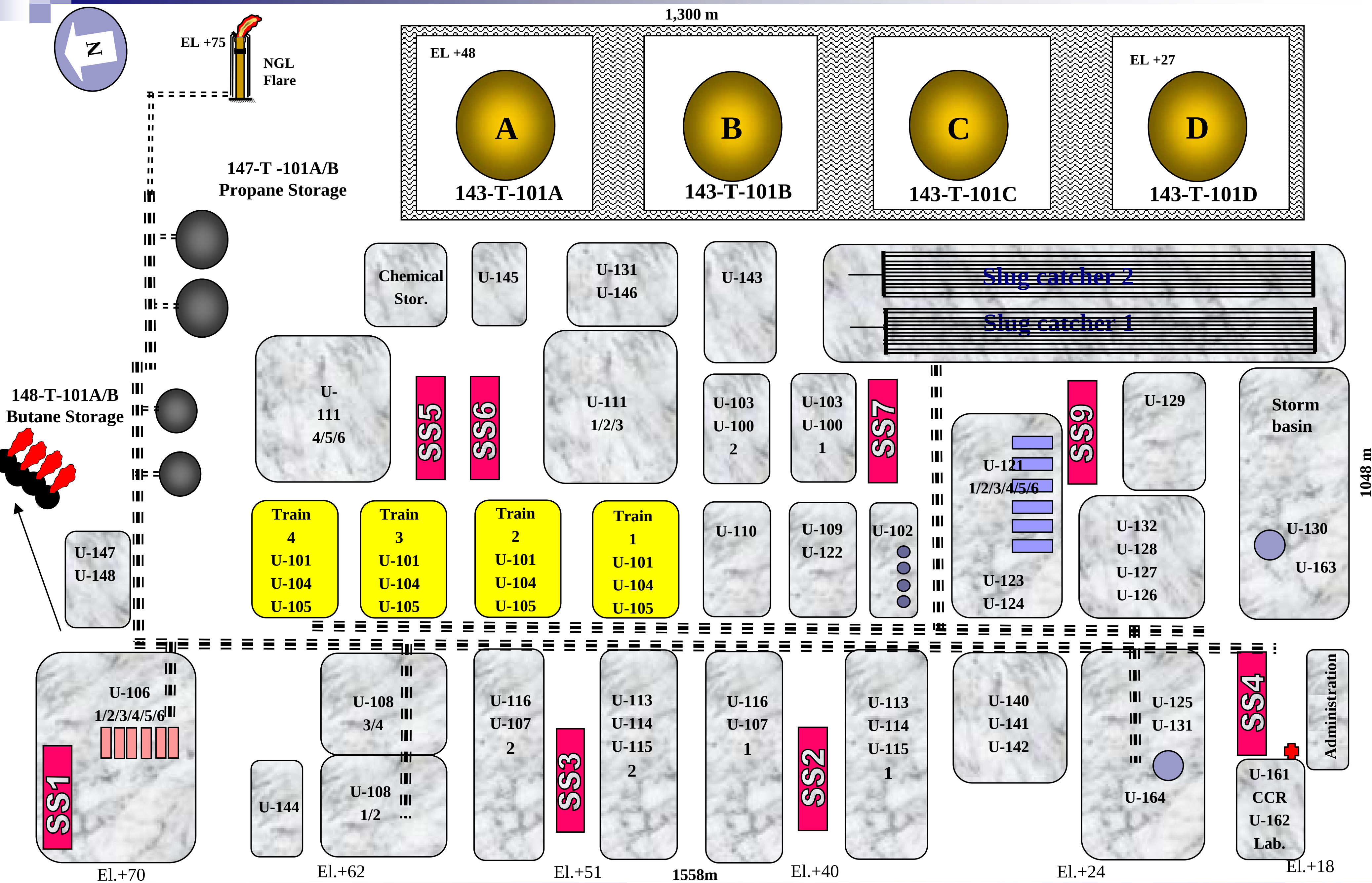
General project description

The phase 9&10 onshore compels is located on Iranian coast of Assaluyeh village (approximately 280 km south east of Bandar Bushhher). They include all processing units, utilities, off-sites and infrastructure necessary to produce sales gas, gaseous Ethane cut of petrochemical feedstock quality, commercial grade propane and butane for export and stabilized condensate. The complex is fed by the reservoir fluid delivered to the onshore plant via two multiphase sea lines:

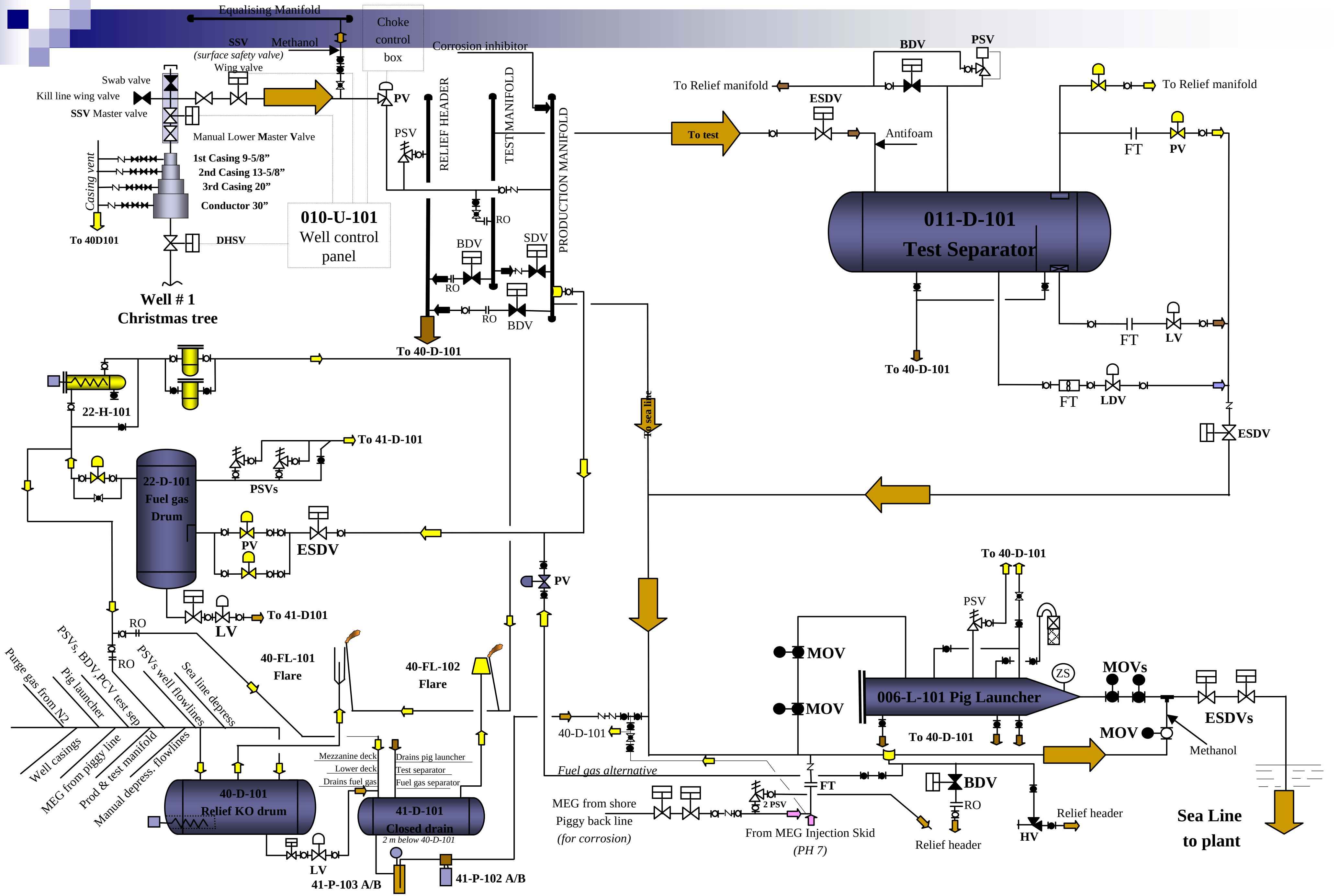
- Receiving facilities for HP separation of raw gas and condensate/ water mixture.
- Condensate stabilization for storage and export and light ends recycled in HP gas system. One condensate flashing unit, normally not operated, is provided as a back-up of the stabilization facilities.
- gas treating facilities producing sales gas and NGL's ,consisting of:
  1. H2S removal from gas
  2. dehydration unit, using molecular sieves technology.
  3. mercury guard
  4. ethane extraction unit, producing sales gas and NGL's
- NGL fractionation facilities to produce gaseous ethane, and sour liquid Propane & Butane
- Gaseous ethane cut treatment for co_2 removal with DEA and drying for further export
- Propane & Butane treatment for mercaptans removal and drying for further storage and export
- Export gas compression to export pipeline pressure
- MEG regeneration and injection for hydration inhibitor
- Sulfur recovery producing liquid sulfur for further solidification and export
- Utilities, offsites required for operation.



WP 9
WP 10
C1,2,3,4
H2S+RSH
CO2
H2O
P 67.5 barg
T 25°C
HP Sep.
P 68.7 barg
T 81°C
P 29 barg
T 21.6°C
Off gas
P 29 barg
T 22.3°C
Slug-catcher U100
P 74 barg
U-103 1
U-101
1/2
Gas Treating
with MDEA
U-104
1/2
Dehydration with
Molecular Sieve
& Mercury Guard
U-111 1/2
Propane Refrigeration
-78°C
U-106
1/2/3
Gas compressors
C1
78%
Send to
IGAT
U-105
1/2
Ethane Recovery
H2S
U-108
1/2
Sulfrex unit
C2+ + RSH+CO2
U-107
1
NGL fractionation
C2 + CO2
U-116 1
Ethane treatment
with DEA
& Drying
U-144
Granulated
Sulfur
H2S—MDEA ⇄ MDEA + H2S
T↑ P↓
T↓ P↑
CO2—DEA ⇄ DEA +CO2
T↑ P↓
T↓ P↑
1/3 H2S+ O2 → SO2
SO2 + 2/3 H2S → S +H2O
R-SH + NaOH → R-SH-Na
R-SH-Na + R-SH-Na → R-S-S-R
C4 + RSH
C3 + RSH
U-115
1
Propane tr. & dr.
U-113
1
Caustic
Regeneration
U-114
1
Butane tr. & de.
C2
Export to
petrochemical
MEG
+
H2O
DSO
storage
U-147
Propane storage
C3
U-148
Butane storage
C4
MEG 37%
U-102 1/2
MEG Reg. & Inj
C5+
U-143
1/2
Condensate


N
EL +75
NGL Flare
1,300 m
EL +48
A
143-T-101A
B
143-T-101B
C
143-T-101C
EL +27
D
143-T-101D
147-T -101A/B
Propane Storage
148-T-101A/B
Butane Storage
Chemical Stor.
U-145
U-131
U-146
U-143
Slug catcher 2
Slug catcher 1
U-111 4/5/6
SS5
SS6
U-111 1/2/3
U-103
U-100
2
U-103
U-100
1
SS7
U-121 1/2/3/4/5/6
U-123
U-124
SS9
U-129
Storm basin
U-130
U-163
1048 m
U-147
U-148
Train 4 U-101 U-104 U-105
Train 3 U-101 U-104 U-105
Train 2 U-101 U-104 U-105
Train 1 U-101 U-104 U-105
U-110
U-109
U-122
U-102
U-132
U-128
U-127
U-126
U-106 1/2/3/4/5/6
SS1
U-108 3/4
U-108 1/2
U-144
U-116
U-107
2
SS3
U-113
U-114
U-115
2
U-116
U-107
1
SS2
U-113
U-114
U-115
1
U-140
U-141
U-142
U-125
U-131
U-164
SS4
Administration
U-161
CCR
U-162
Lab.
El.+70
El.+62
El.+51
1558m
El.+40
El.+24
El.+18

LAYOUT PLAN



platform wellhead platform

Unit 100: Reception Facility

Design Slug catcher feed

Composition	(% mole)
H_2O	1.5579
N_2	3.3062
CO_2	1.7411
H_2S	0.6572
C1	80.9659
C2	5.1747
C3	1.9173
iC4	0.4109
nC4	0.6946
iC5	0.2838
nC5	0.2838
C6cut	0.4109
C^{7-20}	2.1031
COS	0.0003
CH4S	0.0029
ETSH	0.0245
PR1THIOL	0.0138
HX1THIOL	0.0082
MEG	0.4391

Feed stock Condition

Operating :

Pressure : 74 barg

Max : 109 barg

Temperature : 10 ~ 25 $^{\cdot C}$

Design :

Pressure : 139 bara

Temperature : -29 ~ 40 $^{\cdot C}$

Stream flow-rates per sea-line:

Summer case :

• Gas (saturated 25C and 74 barg) :	901 t/h
• Dry condensate :	194 t/h

Winter case :

• Gas (saturated 25C and 74 barg) :	880 t/h
• Dry condensate :	214 t/h

MEG flow-rate : 25 t/h

The slug catcher is designed for a gas flowrate of 991 t/h.

Each Slug Catcher Includes

- ✓ Gas / Liquid separation section
- ✓ Intermediate Section
- ✓ Storage section
- ✓ Liquid-liquid section

Equipments:

HP Separators

2 HP Separators per unit

Gas / Liquid separation section

This section is sized for 100 % of the normal gas flow rate summer case (50 % per separator).

Liquid section

This section is sized for packing / depacking winter case.

Gas Heater

This equipment is sized for packing / depacking winter case

Slug-catcher sections

✓ **Gas-liquid separation section**

The gas / liquid separation is achieved in the first zone of fingers, which has a 1/20 slope. In order to achieve the highest separation efficiency an adequate length is provided upstream the gas outlet header (**13 m**).

✓ **Intermediate section**

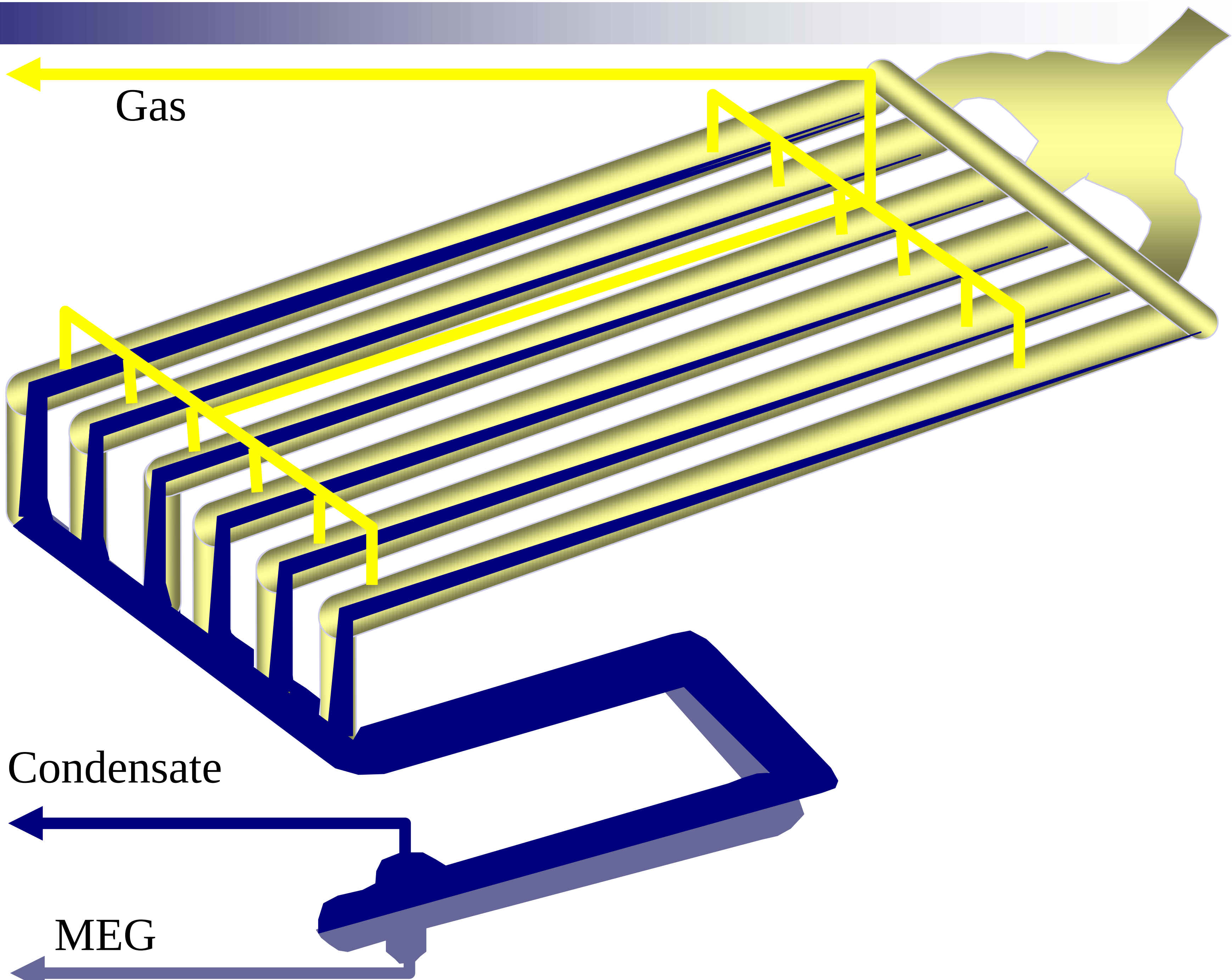
When the storage section is completely filled with liquid, the liquid level in the separation section may reach the gas outlet of the separation section, but it shall never come directly beneath it. This requires an additional length of straight finger downstream the gas outlet of the separation section (**23 m**).

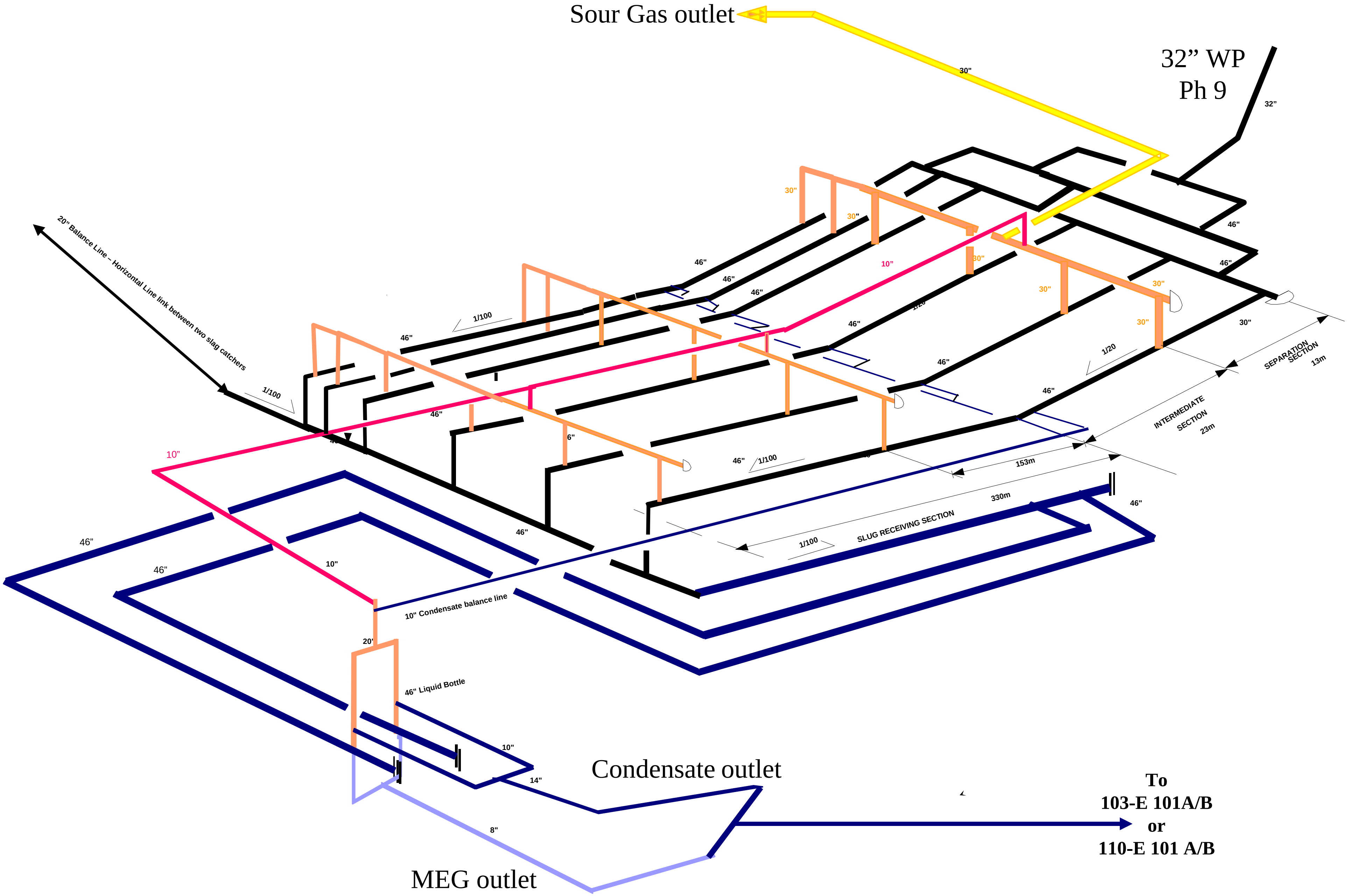
✓ **Storage Section**

A 4000 m^3 design storage capacity (total, two slug catchers) shall be achieved through a sufficient fingers length with a 1:100 slope. gas disengagement from the storage section is achieved by headers connected to the main gas outlet header of the separation section.(**330 m**).

✓ liquid-liquid separation

Liquid from storage fingers are collected in slug receiving section and routed via a sloped 44” liquid header to two horizontal 46” liquid bottles. the liquid bottle is located parallel to the fingers to reduce overall dimension. The out let lines from the 46” liquid bottles extract the glycolayted water and condensate separately under level control.(**303 m**)


Gas
Condensate
MEG



Reception Facilities

Exceptional Operations

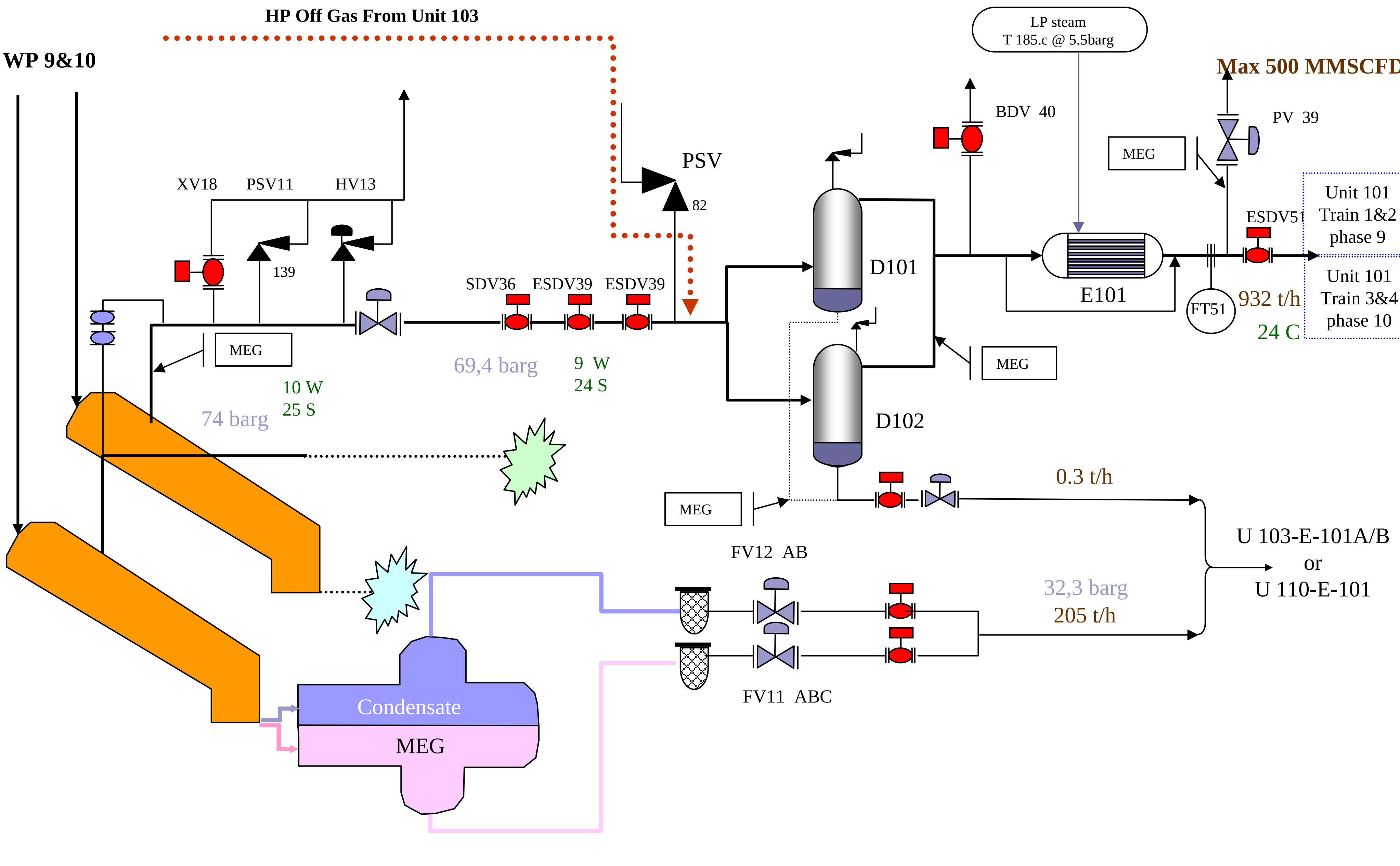
Packing / Depacking

In some transient phases when the offshore production is higher than the onshore available capacity, for example when a gas train is shut-down, the pressure of the sea line and the slug catcher increases. **It is possible to pack the sea line until the maximum pressure of 109 bar g is reached in the slug catcher.**

During these phases of packing / depacking, due to pressure variation, the gas / liquid equilibrium is modified in the slug catcher and the hydrocarbon liquid flowrate is increased versus normal operation.

The pressures in HP separators and stabilization units are maintained at their normal values during packing / depacking phase, and the expansion is done by the Pressure Control Reduction Station for gas, and by the level control valves for liquids in the slug catcher.

During packing / depacking phases, for winter and summer cases, lean MEG is injected upstream of the Pressure Control Reduction station for hydrates inhibition and the gas heater 100-E-101 is put on line.


HP Off Gas From Unit 103
WP 9&10
LP steam
T 185.c @ 5.5barg
Max 500 MMSCFD
BDV 40
PV 39
MEG
PSV
82
XV18
PSV11
HV13
139
SDV36
ESDV39
ESDV39
D101
E101
ESDV51
Unit 101
Train 1&2
phase 9
Unit 101
Train 3&4
phase 10
FT51
932 t/h
24 C
MEG
69,4 barg
9 W
24 S
10 W
25 S
74 barg
D102
0.3 t/h
MEG
FV12 AB
U 103-E-101A/B
or
U 110-E-101
32,3 barg
205 t/h
FV11 ABC
Condensate
MEG

Unit 101: Gag Treatment

Purpose of the unit

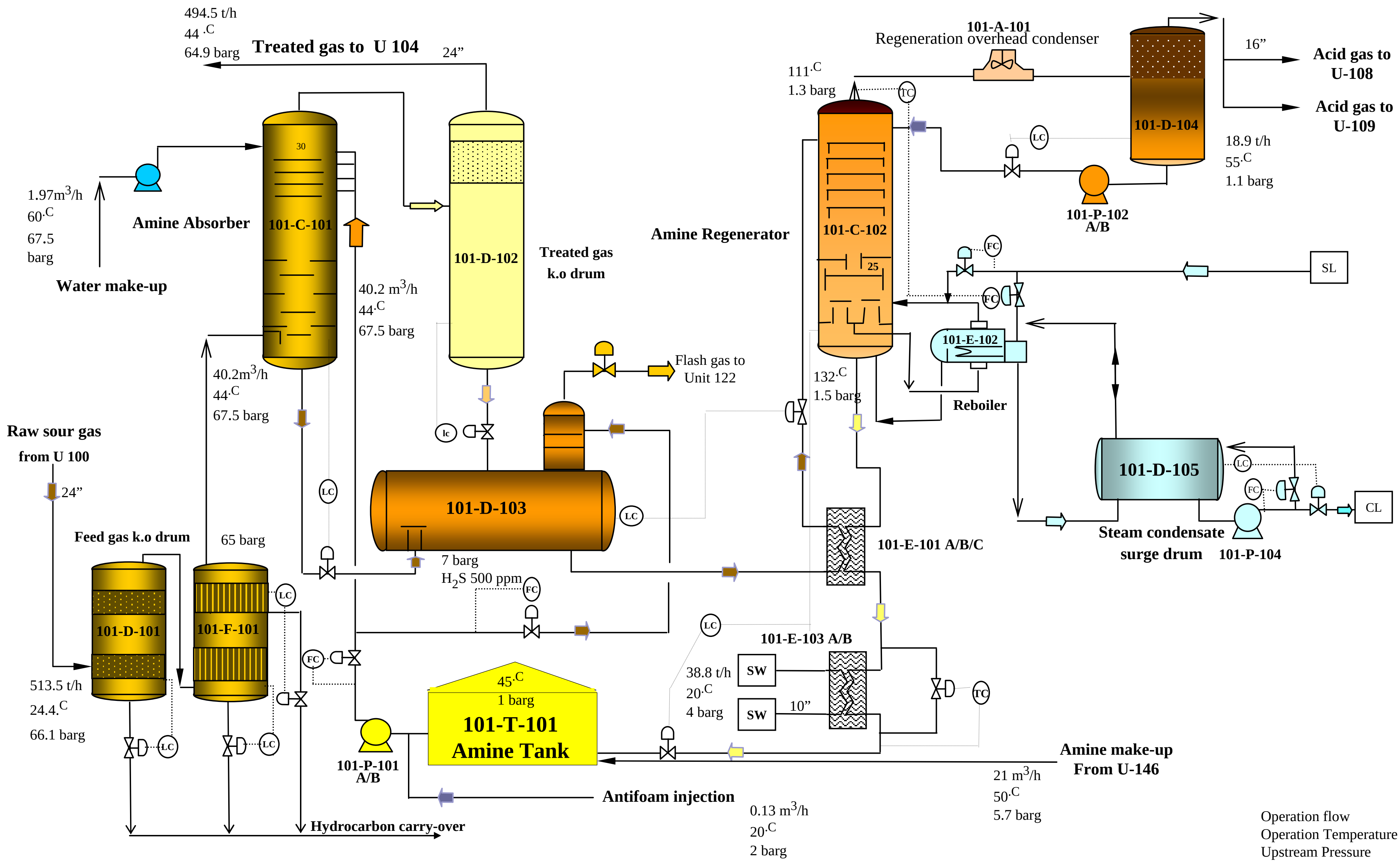
the feed gas contains H2S,CO2 and organic sulfur compounds (mainly mercaptans). The GTU's shall remove the H2S down to the required specification .mercaptans removal in the GTU's is desirable, as it will simplify the downstream gas processing. Bulk CO2 removal is not required for pipeline specification. The total GTU's nominal capacity is 2000 MMSCFD of reservoir fluid. This capacity is to treated in 4parllel identical trains, each processing 25% of sour gas. Each train shall be designed to treated 535 MMSCFD raw sour gas.

Use of the selective solvent MDEA (Methyl Diethanol Amine)

product specification

- **H_2S** content : 3 ppm vol max
- **CO_2** content : 1 % mole max
- **COS** content : maximum COS removal

Turndown Ratios of each one of the four Gas Treating Unit shall be designed in order to 40% of its nominal capacity(195 MMSCFD) whatever the operating case.



Gas Treating

Unit 102: MEG Regeneration

MEG Regeneration and Injection unit which shall perform

Feed of unit:

- ✓ Diluted MEG solution from unit 103 or 110 (P: 12 barg & T: 59$^{\cdot c}$)

products of unit:

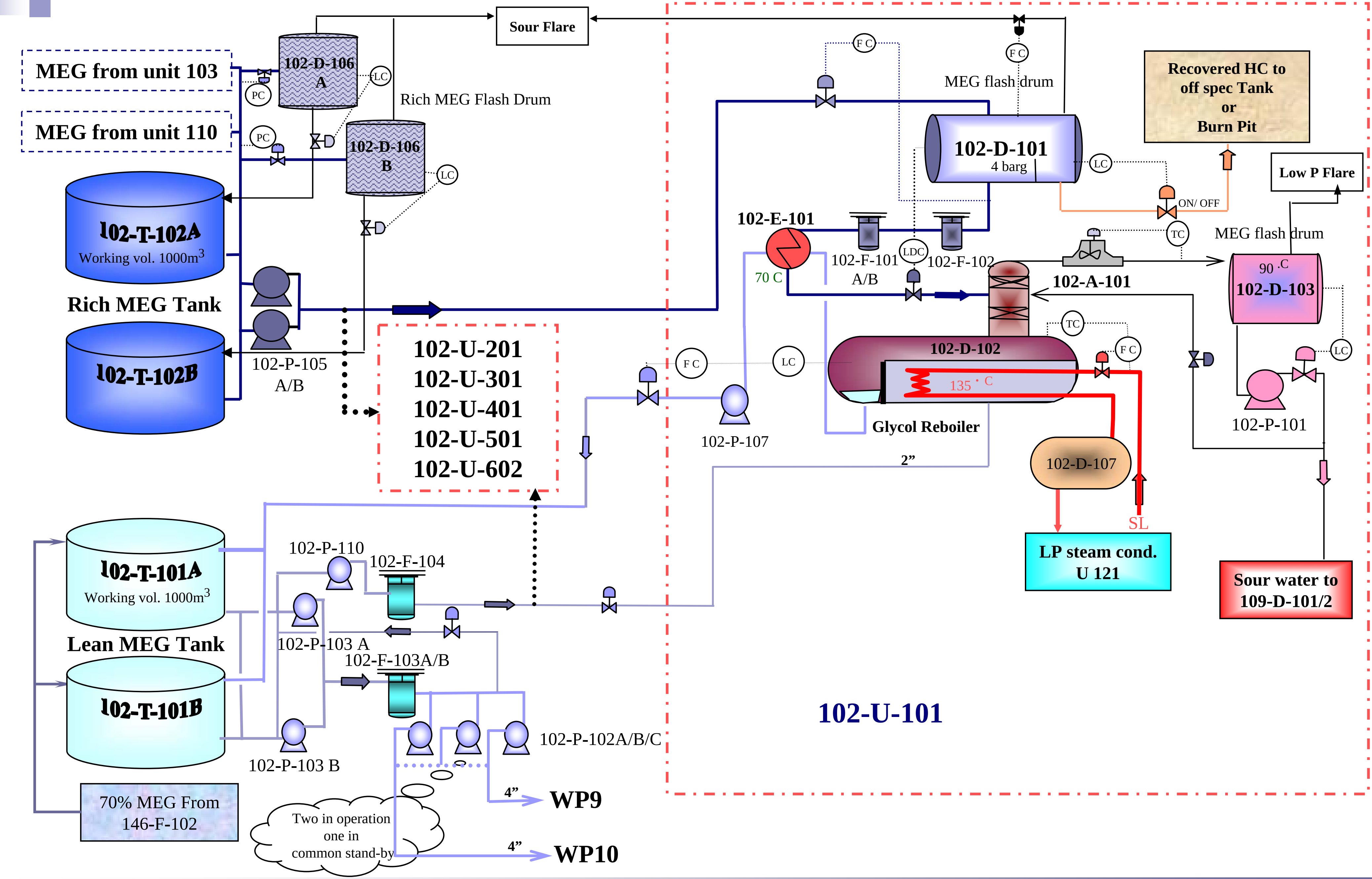
- ✓ Solution of MEC at 70% weight, exported to offshore facilities (P: 213.8 barg & T: 70$^{\cdot c}$)
- ✓ Excess water sent to the sour water stripper (max MEG content 150ppm %wt) (P: 3.3 barg & T: 90$^{\cdot c}$)

Turndown ratios :

- ✓ The MEG regeneration and injection units are designed for 15 to 100% of the overall design capacity.

Unit 102 is common to both phases 9-10, which is composed of four MEG regeneration package operating in parallel plus two in stand-by.

In normal operation the rich glycol is sent directly to the regeneration package. in case of a package shutdown, the corresponding flow rate is routed under pressure control to the rich glycol tanks 102-T-102 A/B until the stand-by unit is put on line.



MEG Regeneration & Injection

Unit 103: Condensate Stabilization

Condensate stabilisation

Liquid separated in slug catcher are sent respectively to the two condensate stabilisation units. The function of this unit is to remove the lightest components from the raw feed and to produce a liquid product, which after mixing with the C5+ from unit 107,will give a stabilised condensate having a Reid Vapor Pressure (RVP) of 10 psia in summer and 12 psia in winter.

Products of unite 103 are :

- Stabilised condensate sent to stabilised condensate storage tank
- Off-gas to HP separators.

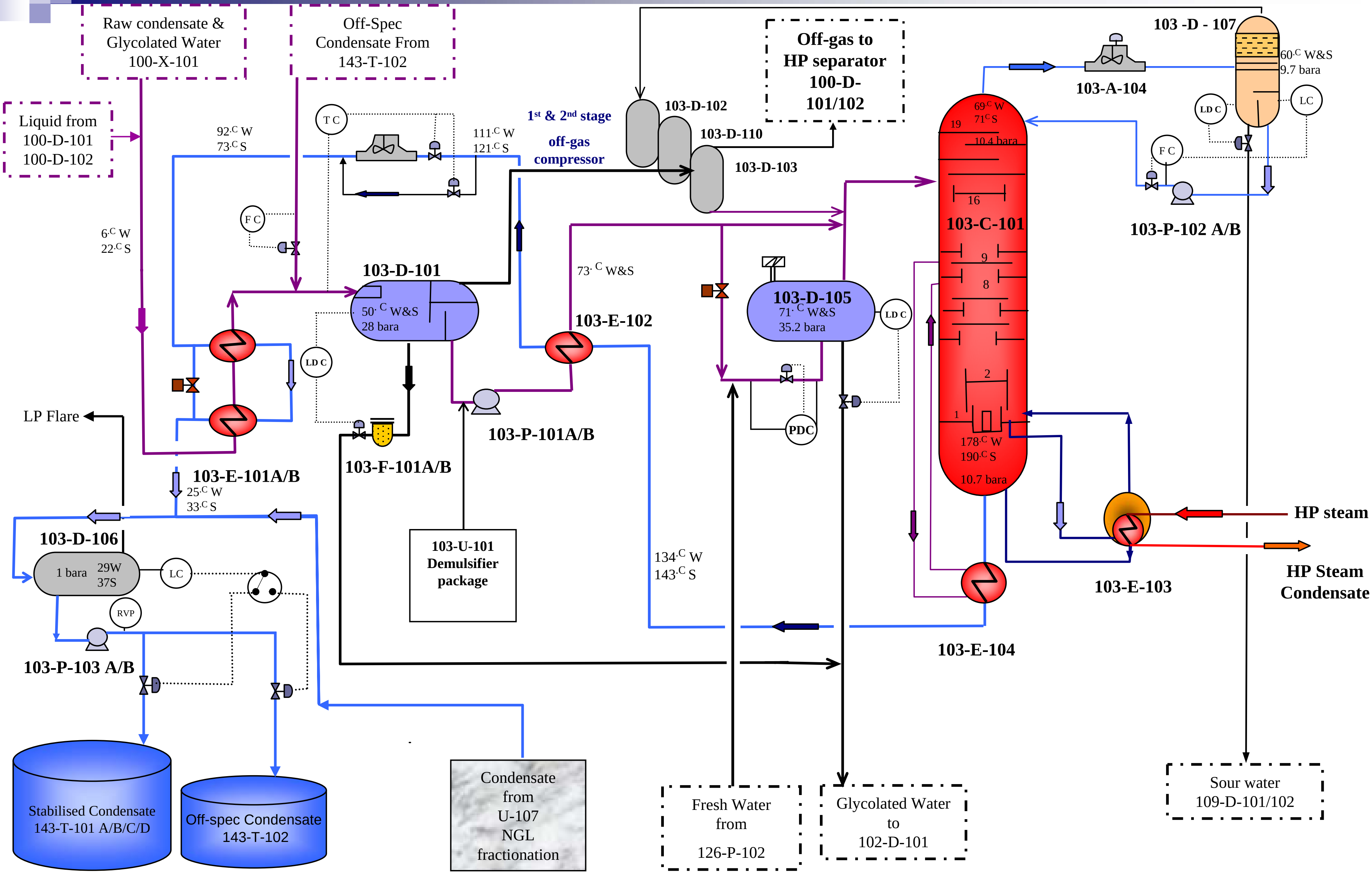
All pumps except the HC sump pump 103-P-104 and condensate recycle pump 103-P-108 used in intermittent operation, are provided with spare.

Condensate stabiliser column is fed with high pressure steam under flow control reset by bottom trays temperature the stabiliser column bottom temperature is about 190.C for summer case and 178.C for winter case.

In normal operation, the stabilised condensate from both phases are combined and sent to the stabilised condensate storage tanks 143-T-101 A/B/C/D .during exceptional operating phases, when the stabilised condensates do not meet the required specification, they are routed to the off-space condensate tank 143-T-102, after flashing in 103-D-106.

Product specifications

- Reid Vapor Pressure = 10 psia in Summer @ 37.8^{oc}
- Reid Vapor Pressure = 12 psia in winter @ 37.8^{oc}
- Free water content = Trace (< 500 ppm vol.)
- Salt content = 10 mg/L



Condensate Stabilisation

Unit 104: Dehydration & Hg Guard

Dehydration & Mercury Guard

The molecular sieve dehydration facilities and mercury guard shall be implemented in four parallel and identical trains.

(2 trains for each phase)

The function of the unit is to lower the water content of the in coming water saturated sweet gas to an acceptable level for cryogenic liquefaction. High concentration of water would freeze and plug in the cryogenic section of Ethane recovery unit.

The dehydration unit comprises:

- 3 dryers (molecular sieve beds) operation in parallel,(2in operation & 1in stand-by)
- 2 dryers after filters
- Dryer regeneration facilities. (including furnace, air cooler, separator and compressor)

The dryers shall be design for a period of at least three years of continues operation

The dryer operated on an 18 hours cycle time. it is divided into the following step:

- Adsorption 12 hours
- Regeneration time 5.5 hours
- Stand by 0.5 hors

When a dryer is water saturated , it is taken off adsorption mode and is regenerated to remove the residual water .

The regeneration time is divided into the following steps:

- Heating 4 hours including 0.5h ramp–up
- Cooling 1.5 hours including 0.5h ramp-down
- Stand-by 0.5hours

A slipstream of clean dry gas exiting the filters is used as regeneration gas. The flow rate is set to 70% mole of the total feed gas flow to the dryer. The gas is heated to 300$^{\cdot c}$ in the furnace and passes through the molecular sieve beds in an upward direction. The design assumes a temperature drop of 20$^{\cdot c}$ in the transfer line. a regeneration gas temperature of 280$^{\cdot c}$ entering the dryer.

Dehydration & Mercury Guard

Heating will be performed in tow steps:

- Heating up to120$^{.c}$ in order to heat all bed prior to desorbed water and allow hydrocarbon / impurities release.
- Final heating up to 280$^{.c}$ in order to desorbed water. expected plateau temperature around 171$^{.c}$)to achieve required sieve regeneration

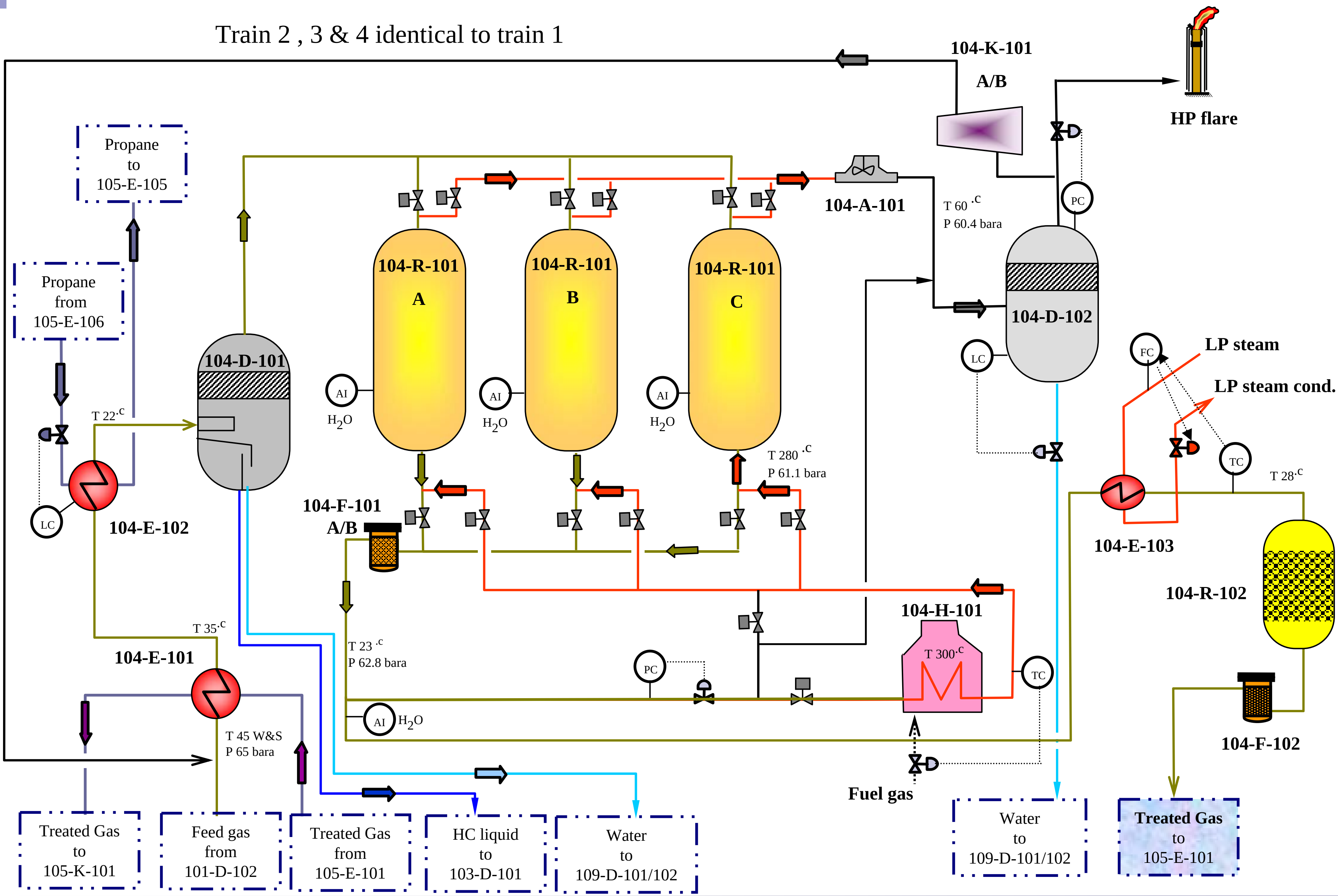
Mercury Guard Unit

The MGU is required to protect the Ethane recovery unit downstream facilities and particular the Aluminum based cryogenic cold box. A design value of 900 nm/Nm^3 is specified. The maximum concentration of mercury in the treated gas at the outlet of MGU shall be 10 nm/Nm^3. the operating temperature is 28$^{.c}$,5$^{.c}$ above the hydrocarbon dew point. The hot stream used to perform this exchange is LP steam.

Mercury guard shall be via sulfur impregnated Carbon catalyst or impregnated Alumina or equivalent process. The catalyst will not be regenerated on site , but will be remove and disposed off. The maximum available presser drop across the mercury guard absorber shall be 0.7 bar.

A treated gas outlet filter will be installed downstream the absorber vessel. There are one 100% cartridge filter designed to remove fines 10 µm and larger. the pressure drop through the fouled filter shall not exceed 0.5 bar.

Train 2 , 3 & 4 identical to train 1



Dehydration and Mercury Guard

Unit 105: Ethane Recovery

Ethane Recovery

After H2S removal , dehydration and mercury removal, the dry sweet gas is routed to the Ethane recovery unit 105where the gas is first precooled down to -35$^{\cdot c}$ in the cold box 105-E-101. at -35$^{\cdot c}$ a major portion of the butane and heavier components are condensed. The liquid phase also contains significant amounts of methane and ethane which must be removed. then the two phases flow is separated in feed flash KO Drum 105-D-101. liquid is sent under level control, through a flashing valve, as a feed stream to 105-C-101,at 30 bara and -48.5$^{\cdot c}$ (there are 8 actual trays "two passes per tray" in top section, 23 actual trays for bottom section "two passes per tray" plus three bottom draw trays). Gas exiting 105-D-101 is split into two stream; one side is sent to cold box which it is cooled from -35$^{\cdot c}$ down to -84.5$^{\cdot c}$ is sent to the top of 105-C-101 as a column reflux to improve C2+ recovery efficiency and light products separation. Another one ,the main stream feeds the feed gas expander 105-X-101 , in which it is letdown to 30.4 bara and -66.5$^{\cdot c}$ before feeding 105-C-101, which is a stripper-absorber column that produces Sales gas as an overhead and wide –range liquid as bottom. between the bottom tray and feed tray, light components are stripped out of the liquid phase and heavy components are absorbed from the gas phase. Between the feed tray and the top tray , heavier compounds are removed from the gas phase being absorbed by the liquid reflux coming from the demethaniser x exchanger 105-E-102. to minimize the amount of light component in the liquid a stripping action is provided by means of low pressure steam used in as a heating medium in the demethaniser reboiler 105-E-103. Gas leaving the top of the demethaniser at-87.2$^{\cdot c}$ is heated to 16.9$^{\cdot c}$ in cold box and to 33.6$^{\cdot c}$ the gas/gas exchanger 104-E-101.this gas then sent by gas compressor 105-k-101 which increase the pressure up to 33.5 bara to Unit 106.

Demethaniser bottom liquid is sent to the Deethaniser 105-C-102. this column , which operates at 30.5bara (there are 12 actual trays "two passes per tray" in top section, 27 actual trays for bottom section "two passes per tray" plus one bottom draw tray). On top, is to remove ethane as an overhead vapor stream and yield a product containing all the propane and heavier. The overhead of the Deethaniser is chilled to 8.8$^{\cdot c}$ by the 2.4$^{\cdot c}$ propane refrigerant in the 105-E-105 Deethaniser condenser then mixed phase is routed to the Deethaniser reflux drum 105-D-102. after separation in the Deethaniser reflux drum, the liquid is pumped under flow control by the Deethaniser reflux pumps 105-P-102 A/B to the top try of 105-C-102. the Ethan stream exiting the Deethaniser reflux Drum is heated up to 43.2$^{\cdot c}$ by means of liquid propane at 60$^{\cdot c}$. a possibility to mix this stream with the sales gas in case of off-spec product or upsets in the downstream units. The Deethaniser bottom temperature is of approximately 108.5$^{\cdot c}$. the liquid hydrocarbons recovered at Deethaniser bottom (C3+ cut) are sent under level control resetting a flow control valve to NGL fractionation Unit for further processing.

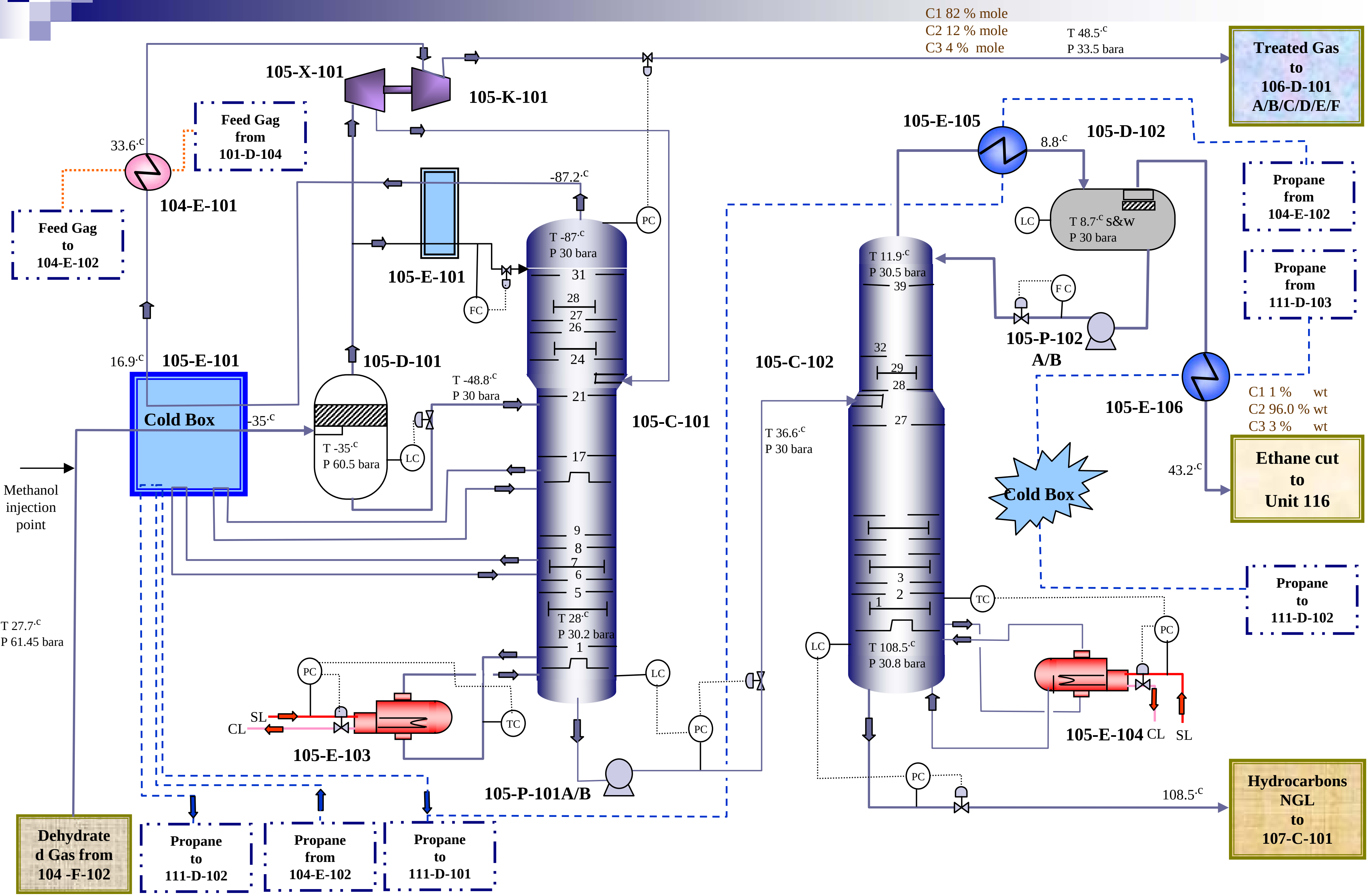
Feedstock & Product specifications

Feedstock characteristics and capacity

		Design Case summer	Design Case winter
Dry gas design flow rate			
Kmole/h		23875 per train	23814 per train
H2O	%mole	0.0000	0.00000
N2	"	3.5259	3.5350
CO2	"	0.9992	1.0001
Methane	"	86.3446	86.5664
Ethane	"	5.5184	5.5325
Propane	"	2.0352	2.0200
i-C4	"	0.3755	0.3503
n-C4	"	0.5764	0.5249
i-C5	"	0.1764	0.1467
n-C5	"	0.1574	0.1269
C6 cut	"	0.2653	0.177
C10+	ppm mole	34.0	21.0
H2S	"	3.0	3.0
COS	"	4.2	4.2
M-Mercaptan	"	24	21.8
E-Mercaptan	"	144.0	119
Dray gas feed Molecular weight		**18.90**	**18.76**

The specifications of the sales gas from the unit 105 shall comply with the following specifications:

C1	min.	82	% mol
C2	max.	12	% mol
C3	max.	4	% mol
C4	max.	1	% mol
C5+	max.	0.4	% mol
N2	max.	5.5	% mol
CO2	max.	2.0	% mol
H2S	max.	4.8	mg/Nm3
COS	max.	8	ppm mol
Mercaptans (as S) :	max.	15	mg/Nm3
Total Sulphur (as S) :	max.	141	mg/Nm3
Sulphur daily avg :	max.	100	mg/Nm3
Water **dew point** at 44 barg:	max.	-10·C	
HC **dew point** at 55 barg :	max.	-10 ·C	°C +/- 5°C
Gross Heating Value :	min.	9000	kcal/Nm3



Ethane Recovery

Unit 106: Export gas compression

Export Gas

The export gas unit 106 is common to the four gas treatment trains, one export gas unit is provided for the two phases, which including 4 centrifugal compressor in parallel plus 2 spare. Each compression section includes one suction drum, one compressor and associated gas turbine and one after cooler.

The lean gas from unit 105 is combined in two step ; first train 1 & 2 are combined in a subheader and train 3 & 4 are combined also in a second subheader. These two subheaders feed a common header that serves export compressors. To be delivered at the required export pressure 90 bara, the lean gas, which is at about 33.5 bara at the Ethane recovery unit outlet, needs to be recompressed in the export gas unit. The export gas is delivered at 91 bara at tie-in point for export via the IGAT.

Gas from the common header is first routed to the export gas compressor suction drum 106-D-101 where any entrained liquid are separated. The gas is recompressed by 106-K-101 to 93.5 bara, then air-cooled in the export gas compressor after cooler down to 58$^{.c}$ before being exported.

The export gas compressor is a single stage compressor , driven by a gas turbine. Each compression section including one suction drum, one compressor and associated gas turbine and one after-cooler.

During periods when unit 116 is not available the Ethane product from unit 105 is mixed with the export gas from Demethaniser column in unit 105 and sent to unit 106 via compressor 105-xk-101 or under pressure if 105-xk-101 is not operational. During periods when unit 114 or 115 Propane or Butane product goes off spec provision is available to route the Propane or Butane stream to unit 106 via pump 114-P-013 or 115-P-013 and mixed with the export gas from unit 105.

Fuel gas take offs are provided downstream of the Ethane recovery units 105 and before unite 106 for both phases. Unit 106 equipment design dose not take into account the fuel gas withdrawal from these take off lines.

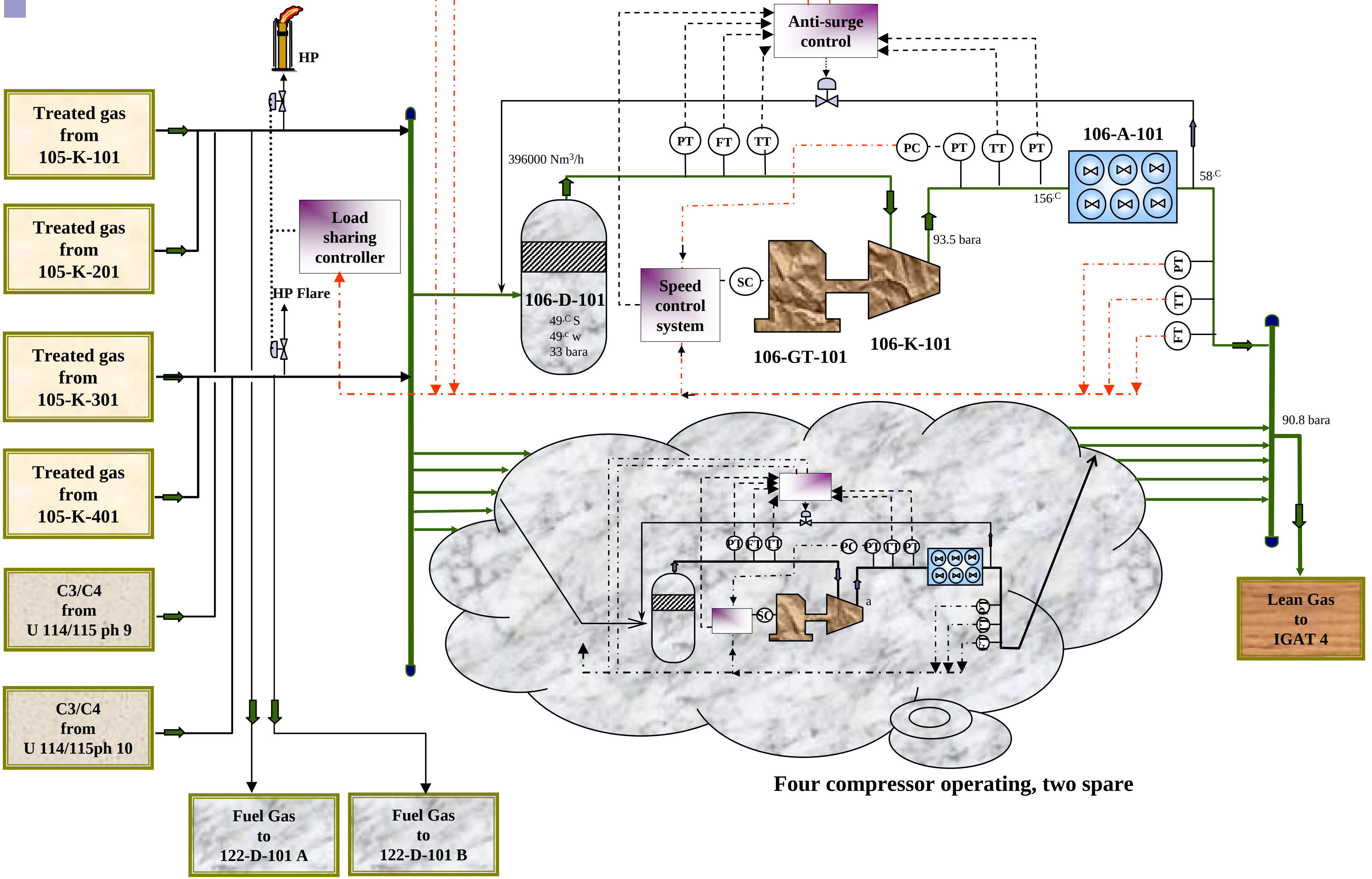
The condition of the main streams from and to the unit 106 are :

		Pressure (barg)		Temperature (°C)	
		Operating	Design	Operating	Design
Feed	gas from unit 105	32.0	47	49.4 S 48.5 W	85
	Mixed C3/C4 from unit 114/115	32.0	47.0	40 S 40 W	85
Products	sales gas to export	90	115	58	85

product specification

Product from unit 106 is sales gas to export

C1	min.	82	% mol
C2	max.	12	% mol
C3	max.	4	% mol
C4	max.	1	% mol
C5+	max.	0.4	% mol
N2	max.	5.5	% mol
CO2	max.	2.0	% mol
H2S	max.	4.8	mg/Nm3
COS	max.	8	ppm mol
Mercaptans (as S) :	max.	15	mg/Nm3
Total Sulphur (as S) :	max.	141	mg/Nm3
Sulphur daily avg :	max.	100	mg/Nm3
Water **dew point** at30 barg:	max.	-90 °C	
HC **dew point** at 55 barg :	max.	-10 °C +/- 5°C	
Gross Heating Value :	min.	9000	kcal/Nm3



Export Gas Compression

Unit 107: NGL Fractionation

The unit 107 is designed to draw off both a Propane cut and Butane cut from liquid heavy phase prouduct in the Ethane recovery unit 105 and make avilable at   The NGL fractionation will be implemented in one unit per phase.

Depropanizer

Demethanizer bottom liquids from train 1&2 unite Unit 105 are mixed in unite 107 and are sent to the Depropanizer 107-C-101 under level control resetting flow control, the function of this column, which operates at 22.3 bara (there are 11 actual trays ”two passes per tray” in the top section, 21actual trays for bottom section “four passes per tray” plus one bottom draw tray), is to produce a propane stream as an overhead liquid stream. The bottom product containing all the butanes and heavier feeds the Debutanizer. The overhead gas of the Depropanizer is air-cooled and totally condensed at 60^{oc} in the Depropanizer condenser 107-A-101. the liquid Propane product is routed to the Depropaniser reflux drum 107-D101. part of the liquid is returned to the top tray of the Depropanizer as reflux. The other part is sent by Propane feed pump 107-P-107 A/B to the propane treatment unit where COS and Mercaptans will be removed.

Debutanizer

The Depropanizer bottom liquid is sent to the Debutanizer 107-C-102 under level control resetting flow control and mixed with the sour washing C4 cut from 114. the Debutanizer operates at 8.2 bara (there are 11 actual trays ”one pass tray” in the top section, 17 actual trays for the bottom section “two passes per tray” plus one bottom draw tray), and is equipped with both condenser and reboiler. The overhead gas of the column is air-cooled and totally condensed at 60^{oC} in the Debutaniser condenser 107-A-102. the liquid butane product is then routed to the Debutanizer reflux drum 107-D-102. part of liquid is pimped from the Debutanizer reflux drum to the top tray of the Debutanizer as reflux. The other part is pumped from the Debutanizer reflux drum and cooled down by sea water to 40^{oC}, then butane is sent, under 107-D-102 level control resetting flow control, to the Butane treatment unit where the Mercaptans will be remove. The Debutanizer reboiler 107-E-102 uses LP saturated steam as heating medium. The Debutanizer bottom temperature is of approximately 130^{oC}. The Debutanizer bottom liquid first to be air-cooled down at 60^{oC}, then the liquid is sent under 107-C-102 level control resetting flow control, to the stabilization unit to be mixed with stabilized condensates.

Feedstock characteristics and capacity

		Design Case summer	Design Case winter
design flow rate Kmole/h		3340 total for 2 Ph	3095 total for 2 Ph
Ethane	% mole	0.55	0.58
Propane	“	54.50	58.13
i-C4	“	10.67	10.71
n-C4	“	16.43	16.10
i-C5	“	5.04	4.51
n-C5	“	4.50	3.91
C6 cut	“	3.90	2.98
C7 cut	“	2.22	1.53
C8 cut	“	1.15	0.74
C9 cut	“	0.32	0.20
C10+	“	0.098	0.063
H2S	ppm mole	trace	trace
COS	% mole	0.009	0.010
M-Mercaptan	“	0.07	0.07
E-Mercaptan	“	0.41	0.37
Pr1Thiol	“	0.12	0.09
Bu1Thiol	”	0.02	0.01
Hx1Thiol	“	0.005	0.003
Molecular weight		**54.39**	**52.91**

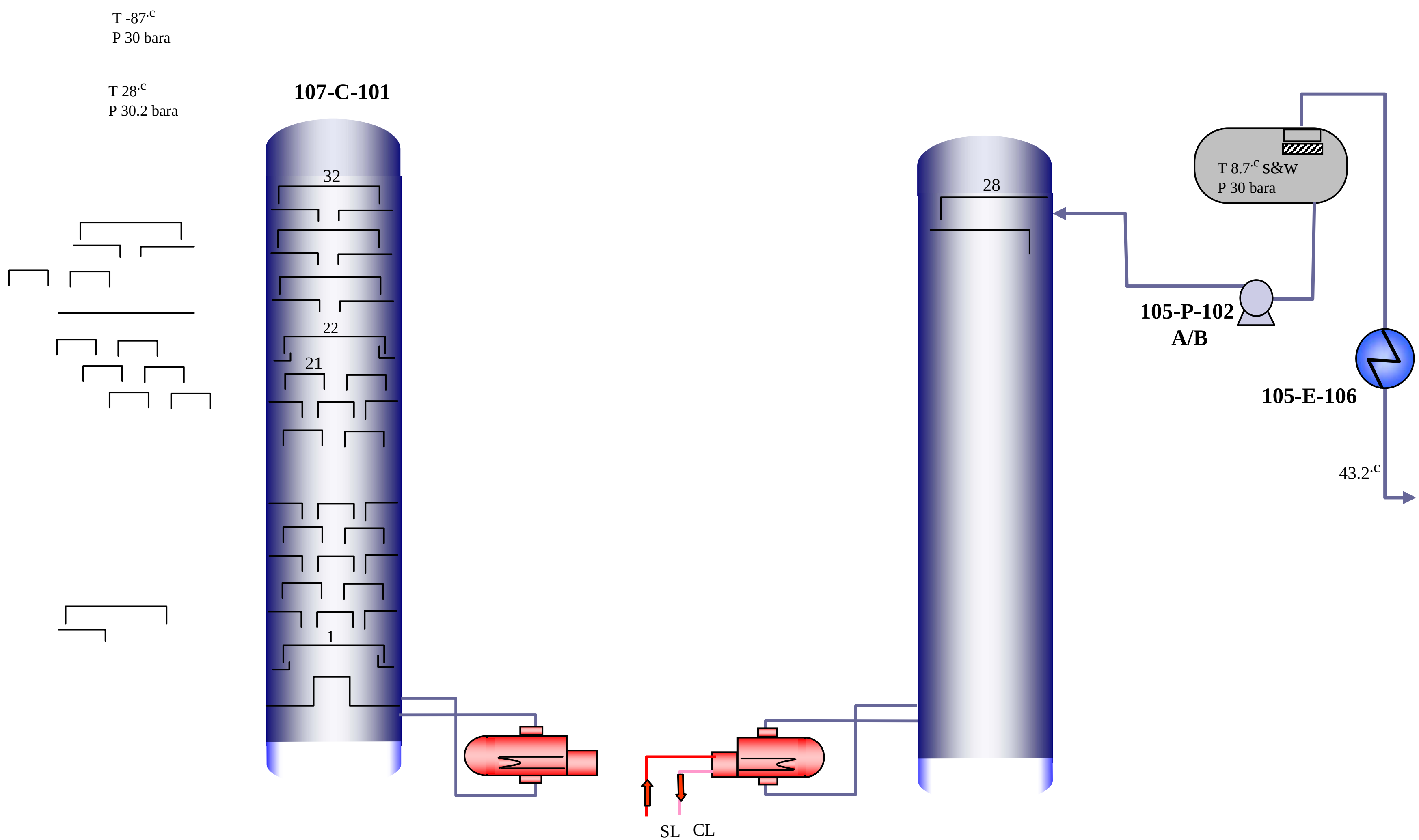
Product specification

Liquid propane:

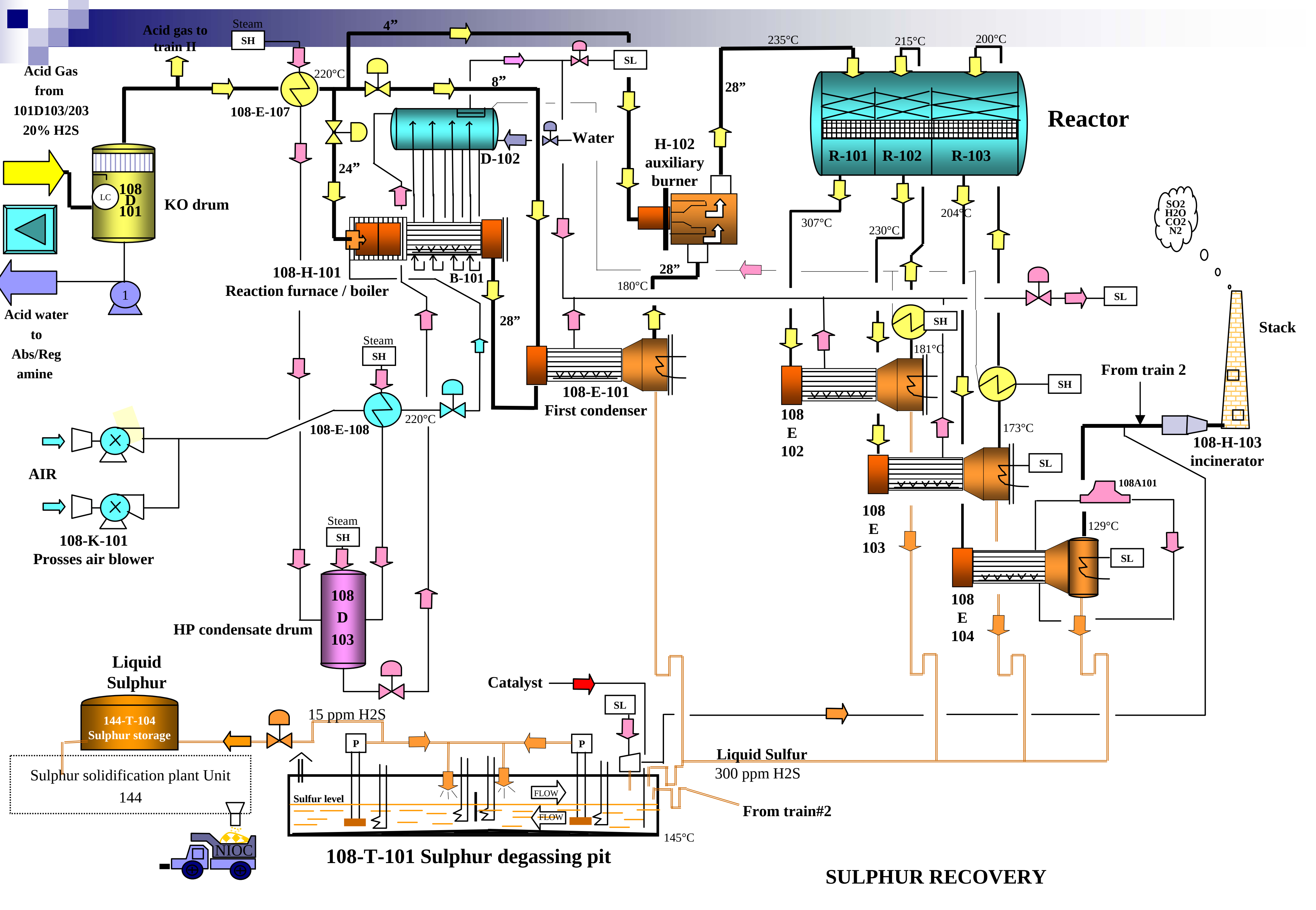
Propane content	% Vol	96.0	min
Ethane content	% Vol	2.0	max
Vap. pressure@ 100 ºF	psig	200	max
Volatile residual: Butane and heavier	%Vol	2.5	max

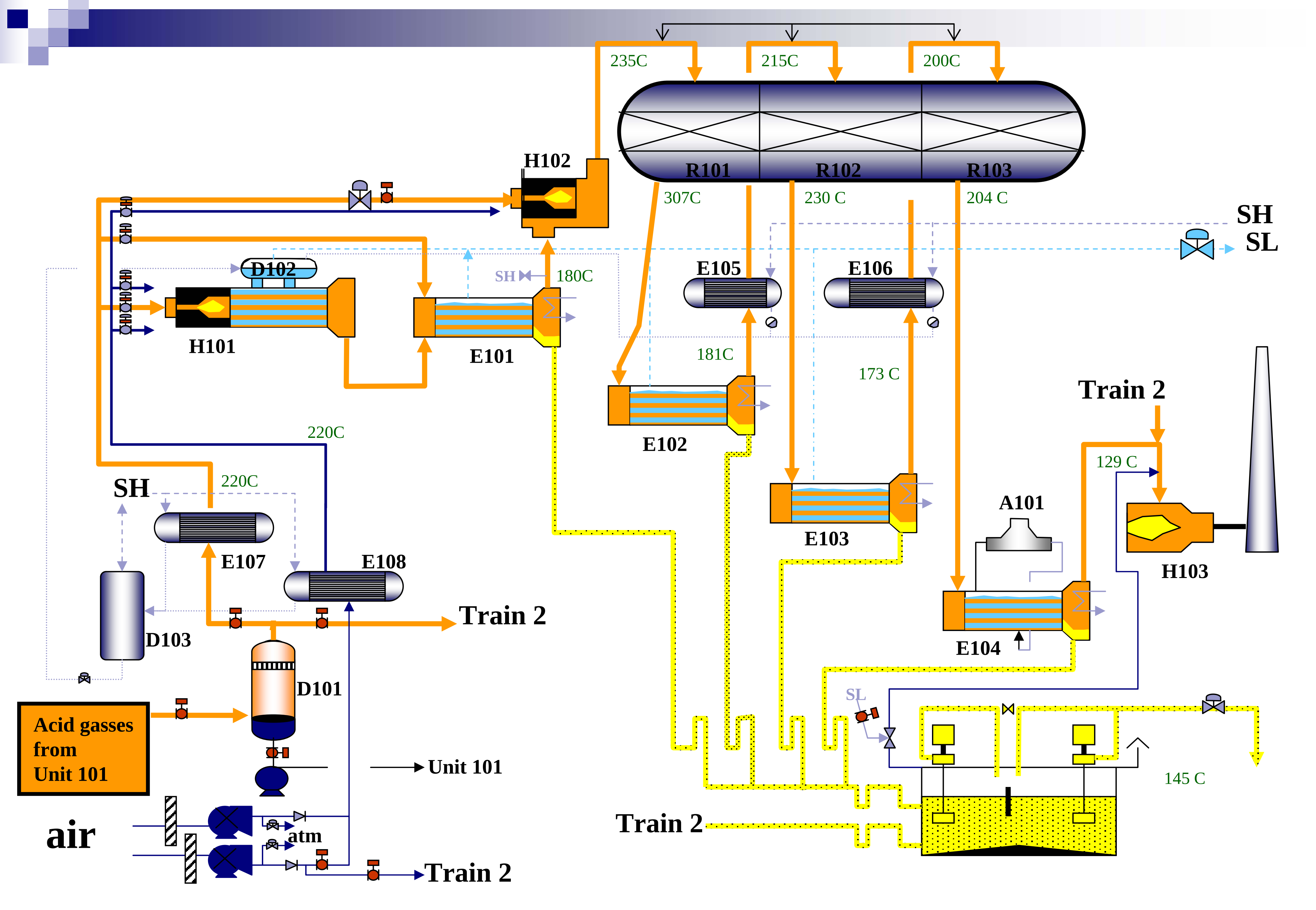
Liquid Butane:

Butane content	% Vol	95.0	min
Vap. pressure@ 100 oF	psig	70	max
Volatile residual: pentane and heavier	%Vol	2.0	max


T -87°C
P 30 bara
T 28°C
P 30.2 bara
107-C-101
32
22
21
1
28
T 8.7°C S&W
P 30 bara
105-P-102
A/B
105-E-106
43.2°C
SL
CL

Unit 108: Sulfur Recovery


Acid gas to train II
Steam
SH
4”
SL
235°C
215°C
200°C
Acid Gas from 101D103/203 20% H2S
220°C
108-E-107
8”
Reactor
28”
D-102
Water
H-102 auxiliary burner
R-101
R-102
R-103
24”
LC
108 D 101
KO drum
SO2 H2O CO2 N2
307°C
230°C
204°C
108-H-101 Reaction furnace / boiler
B-101
28”
180°C
SL
1
Acid water to Abs/Reg amine
28”
SH
Stack
Steam
SH
181°C
From train 2
108-E-101 First condenser
SH
220°C
108-E-108
108 E 102
173°C
108-H-103 incinerator
AIR
SL
108A101
Steam
SH
108 E 103
129°C
108-K-101 Prosses air blower
SL
108 D 103
HP condensate drum
108 E 104
Liquid Sulphur
Catalyst
SL
144-T-104 Sulphur storage
15 ppm H2S
P
P
Liquid Sulfur
300 ppm H2S
Sulphur solidification plant Unit 144
Sulfur level
FLOW
FLOW
From train#2
NIOC
145°C
108-T-101 Sulphur degassing pit
SULPHUR RECOVERY


235C
215C
200C
R101
R102
R103
H102
307C
230 C
204 C
SH
SL
D102
SH
180C
E105
E106
H101
E101
181C
173 C
E102
Train 2
220C
129 C
SH
220C
A101
E103
E107
E108
H103
Train 2
D103
E104
D101
SL
Acid gasses from Unit 101
Unit 101
145 C
Train 2
air
atm
Train 2

Design case winter : max H_2S in the feed : 31.6 % H_2S in the plant feed
Sensitivity case : min H_2S in the feed : 26.8 % H_2S in the feed
Turndown case : 40% design feed with 26.8 %H_2S

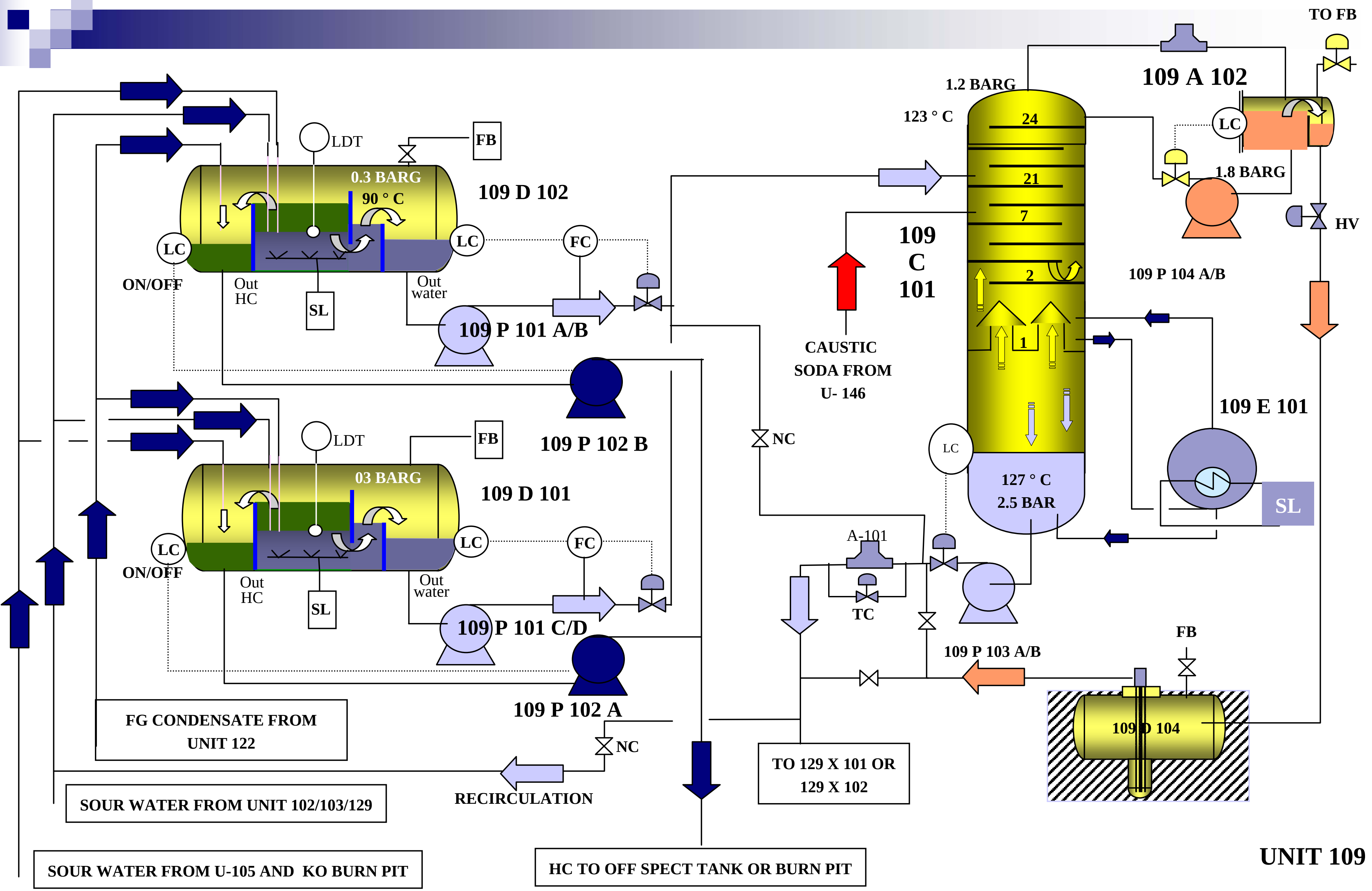
Design case winter : 98 t/d S
Sensitivity case : 84.6 t/d S
Turndown case : 33.7 t/d S

Design case (100%)	Sensitivity case	Turndown case	
Component	**kmol/h**	**kmol/h**	**kmol/h**
H_2S	134.520	115.872	46.330
CO_2	254.530	279.693	150.046
CH_4	3.519	3.516	3.658
C_2H_6	0.270	0.267	0.267
C_3H_8	0.082	0.082	0.085
NC_4	0.022	0.022	0.023
IC_4	0.014	0.014	0.015
IC_5	0.004	0.005	0.005
NC_5	0.004	0.004	0.004
NC_6	0.050	0.048	0.038
BENZENE	0.098	0.0998	0.073
TOLUENE	0.024	0.024	0.018
CH_3SH	0.012	0.012	0.009
Ethyl-SH	0.057	0.056	0.041
Ipropyl-SH	0.012	0.011	0.007
N_2	0.086	0.089	0.107
H_2O	31.599	32.122	16.126
TOTAL	**424.901**	**431.934**	**216.852**

Product specifications :

Purity on dry basis	: min 99.8 % wt
Colour	: bright yellow (in solid form)
Organic matter	: 500 ppm wt max
Ashes	: 200 ppm wt max
H2S content	: 10 ppm wt max

Unit 109: Sour Water Stripping



UNIT 109

SOUR WATER STRIPPER

Unit 110: Back-Up stabilization

Unit 111: Propane Refrigeration

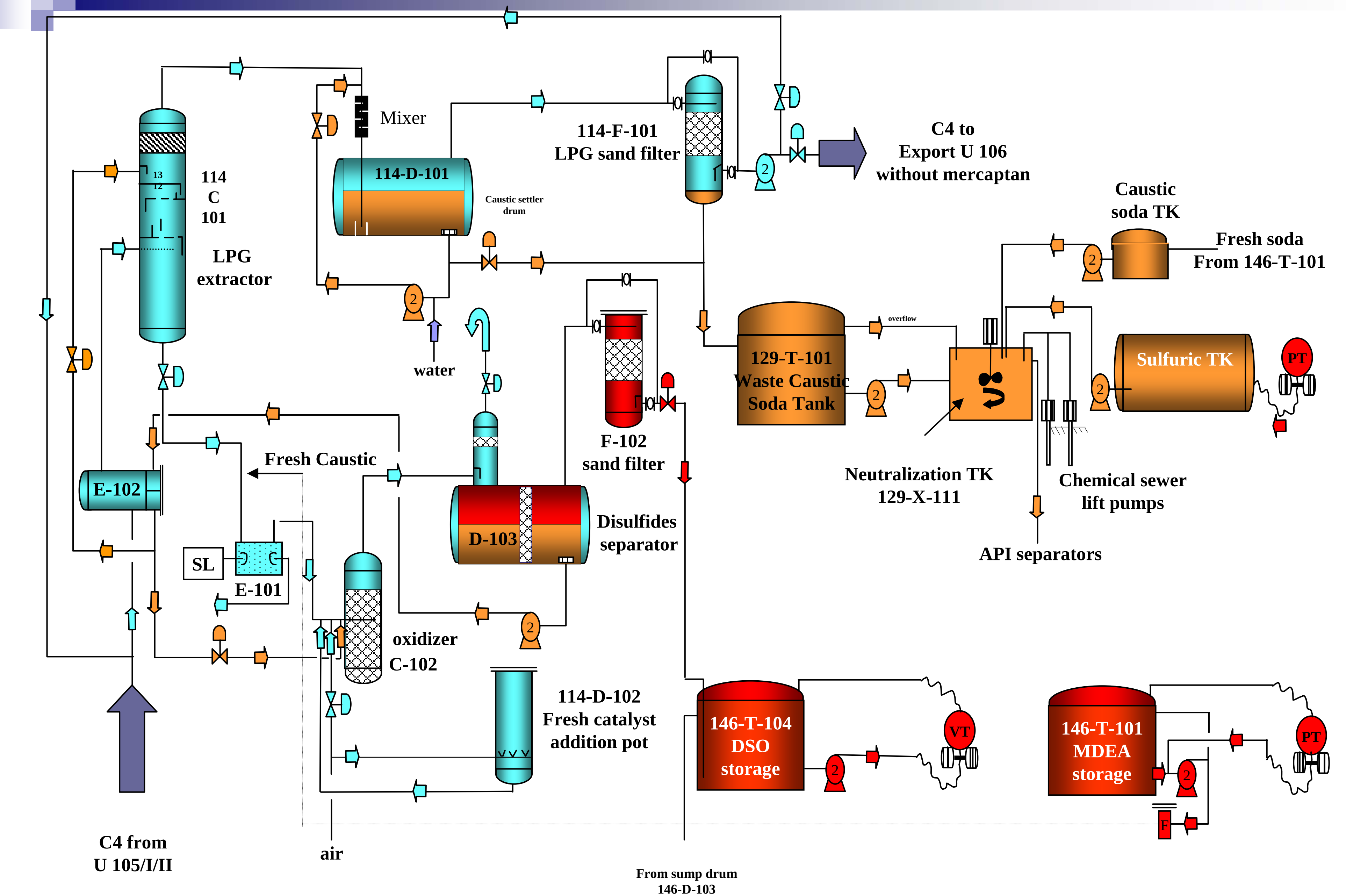
Unit 113: Sulfrex Caustic Regeneration

Unit 114: Propane Treatment &

Drying

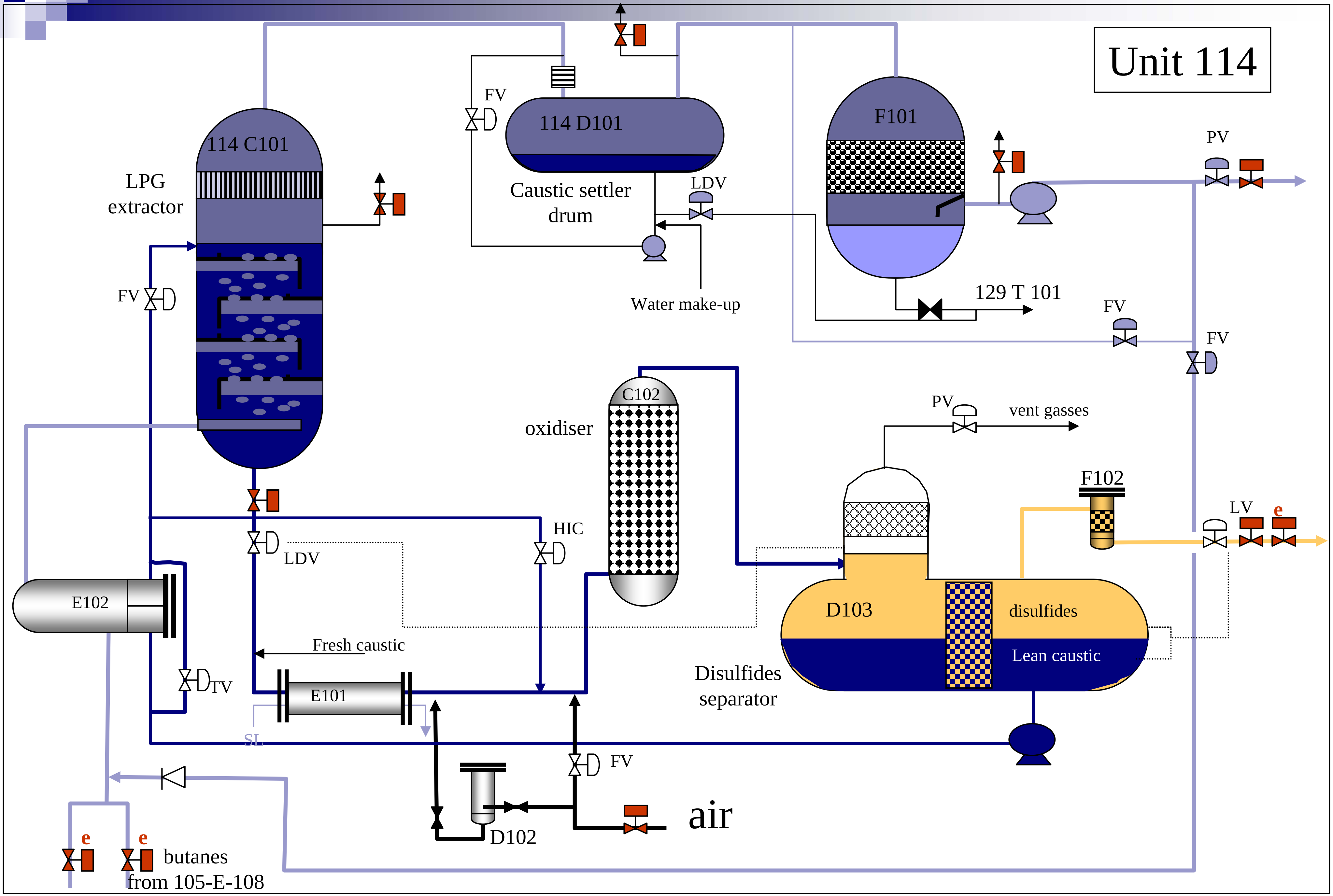
Unit 115: Butane Treatment & Drying

Unit 116: Ethane Treatment & Drying



Unit 114

LPG TREATMENT SULFREX


Unit 114
114 C101
LPG
extractor
FV
114 D101
FV
Caustic settler
drum
LDV
Water make-up
F101
PV
129 T 101
FV
FV
C102
oxidiser
PV
vent gasses
F102
LV
e
HIC
LDV
E102
D103
disulfides
Lean caustic
Fresh caustic
TV
E101
Disulfides
separator
SL
FV
air
D102
e
e
butanes
from 105-E-108

Unit 114	DESIGN CASE	
B.L. Conditions (operating)		
• Pressure barg	10.0	
• Temperature (°C **)**	20 to 40	
RAW LPG DESIGN FLOWRATE		
• tons/h	55.0	
• kmole/h	950	
Composition	**% mole**	**% weight**
H2S	Traces	Traces
C3	2.92 max.	2.23 max.
iC4	**35.52**	**35.68**
nC4	**59.27**	**59.52**
iC5	0.76	0.95
nC5	0.24	0.30
C6+	Traces	Traces
COS	Traces	Traces
Methyl Mercaptan	0.199	0.165
Ethyl Mercaptan	1.085	1.165)
C3+ mercaptans	Traces	Traces
Total	100.00	100.00
LPG Feed Molecular weight	57.9	

Feed stock specifications :

Design mercaptans content in the feedstock :

Methyl mercaptan : 1100 ppm weight (as sulphur)

Ethyl mercaptan : 6000 ppm Weight (as sulphur)

COS < 1 ppm

H_2S < 1 ppm

Treated LPG specifications :

B.L. conditions 64.0 barg

- Mercaptans content : 15 ppm weight(as Sulphur maximum
- Other sulphur content 200 ppm weight as Sulphur
- Total water content 1000 ppm weight maximum (solubility water plus free water)
- Caustic in LPG products 2 ppm weight as NaOH maximum

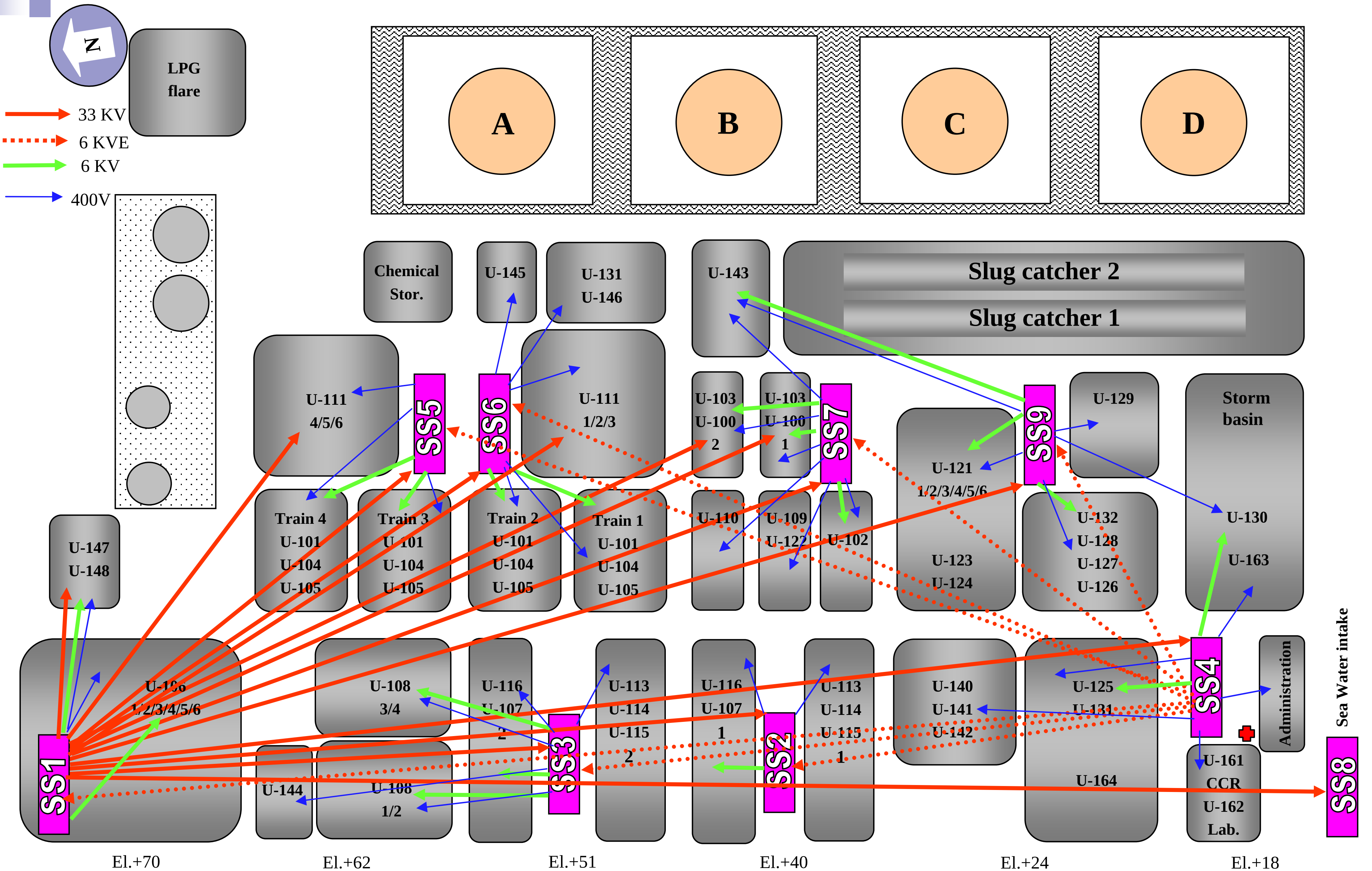
Unit 120: Electrical distribution

Electrical system overview :

Normal electrical supply to site will be delivered from 2* 33KW intake feeders from the external generation plant. Each intake feeder will be rated to supply 100% of site electrical demand. the 33 KV supply cables will enter the north west cornel of site and will terminate in the 33KV switchboard 1S11, in substation No1.

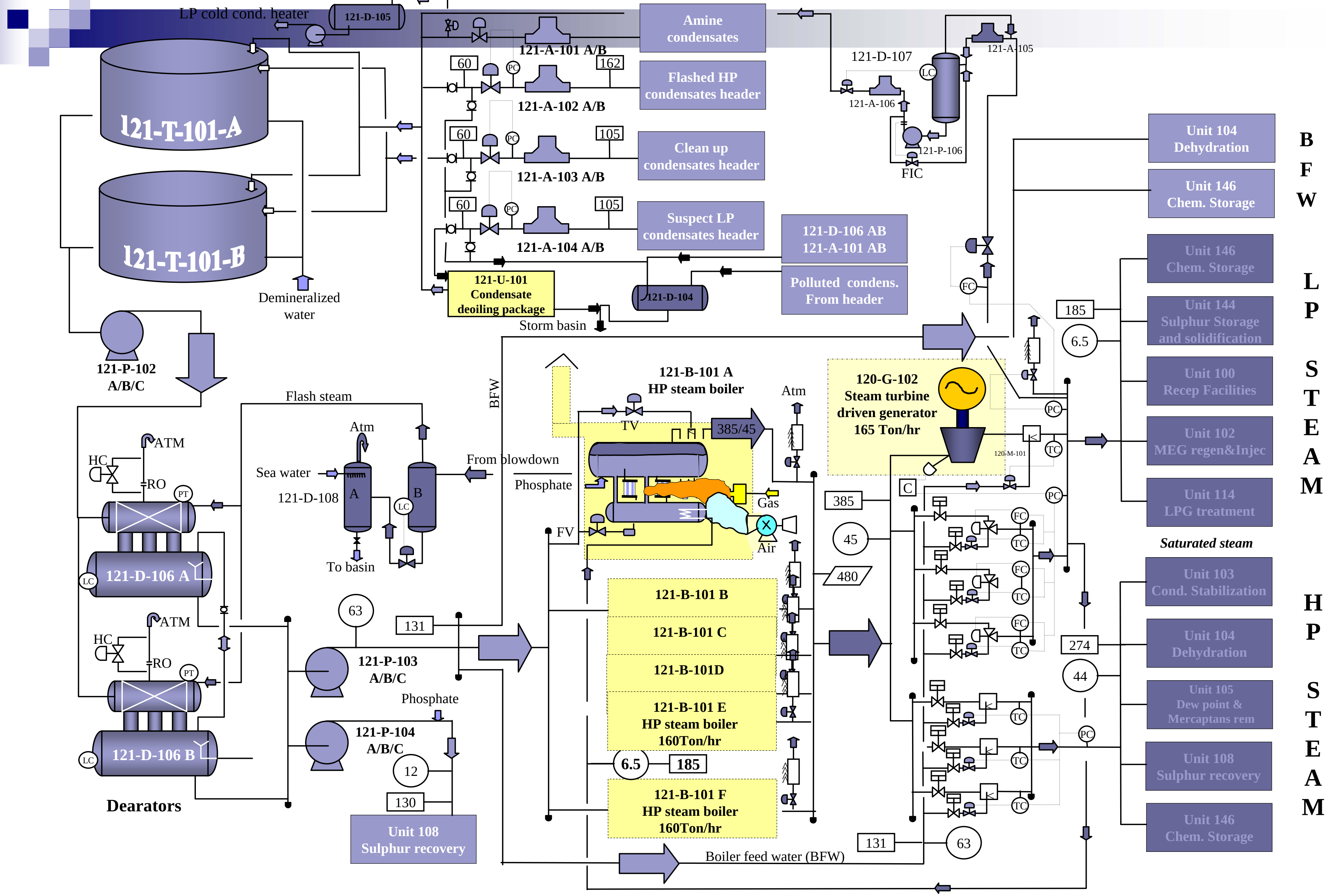
Distribution of power from switchboard 1S11 will be by means of underground cable to each of 8 distribution substation. Substation No. 1 will contain both the intake 33KV switchboard and distribution equipment for adjacent units. Substation No.8 will be located at the sea water intake which is approximately 6KV from the south plot boundary. The 33KV feed to each substation will comprise 2* feeder cables, each rated for the full load current of the downstream transformer.

Emergency electrical supply to the site will be derived from to diesel generator sets, which will be located north of substation No.4 these will generate power at 6 KV and will de connected to the main emergency switchboard 4ES31.



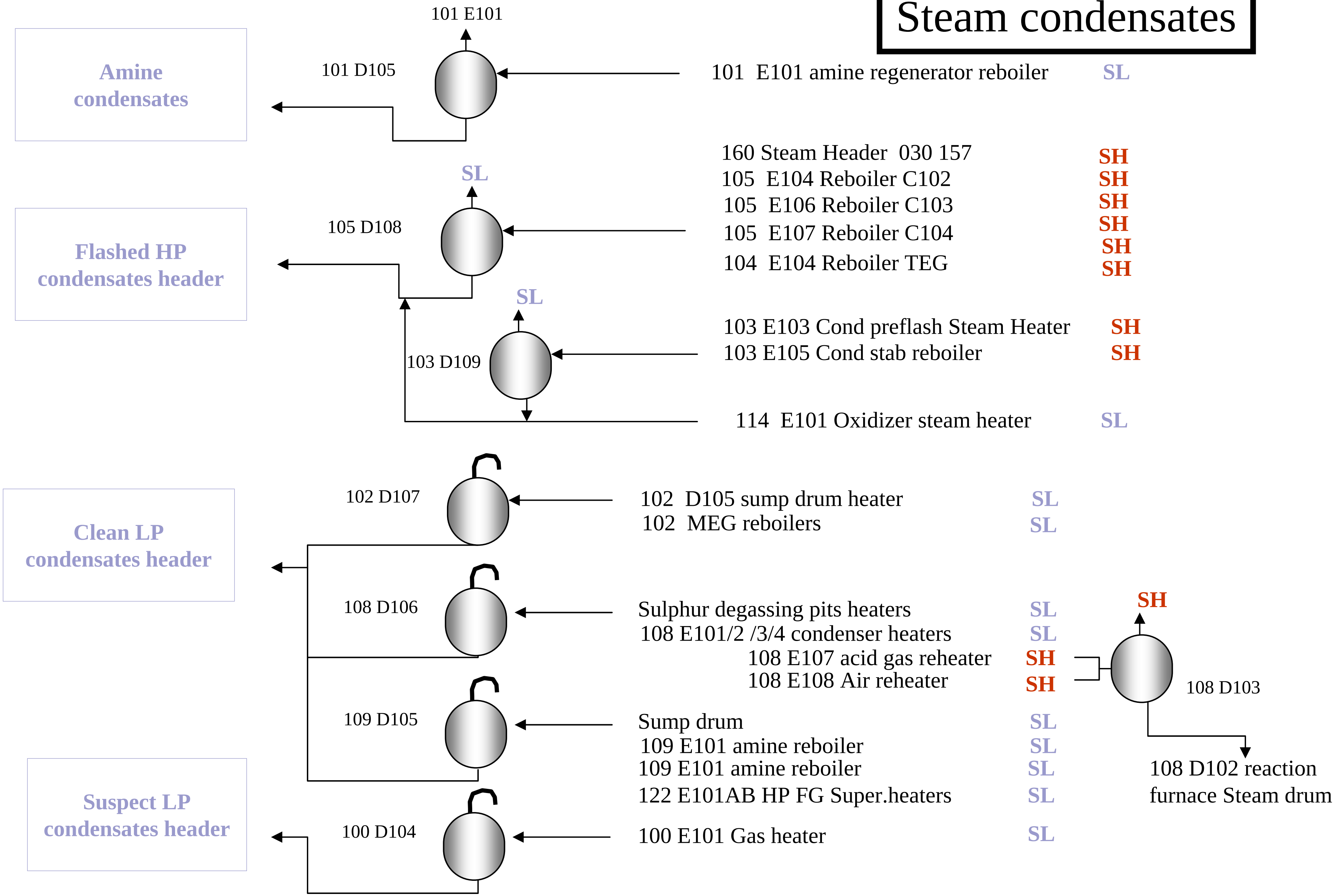
Electrical Distribution

Unit 121:Steam Generation

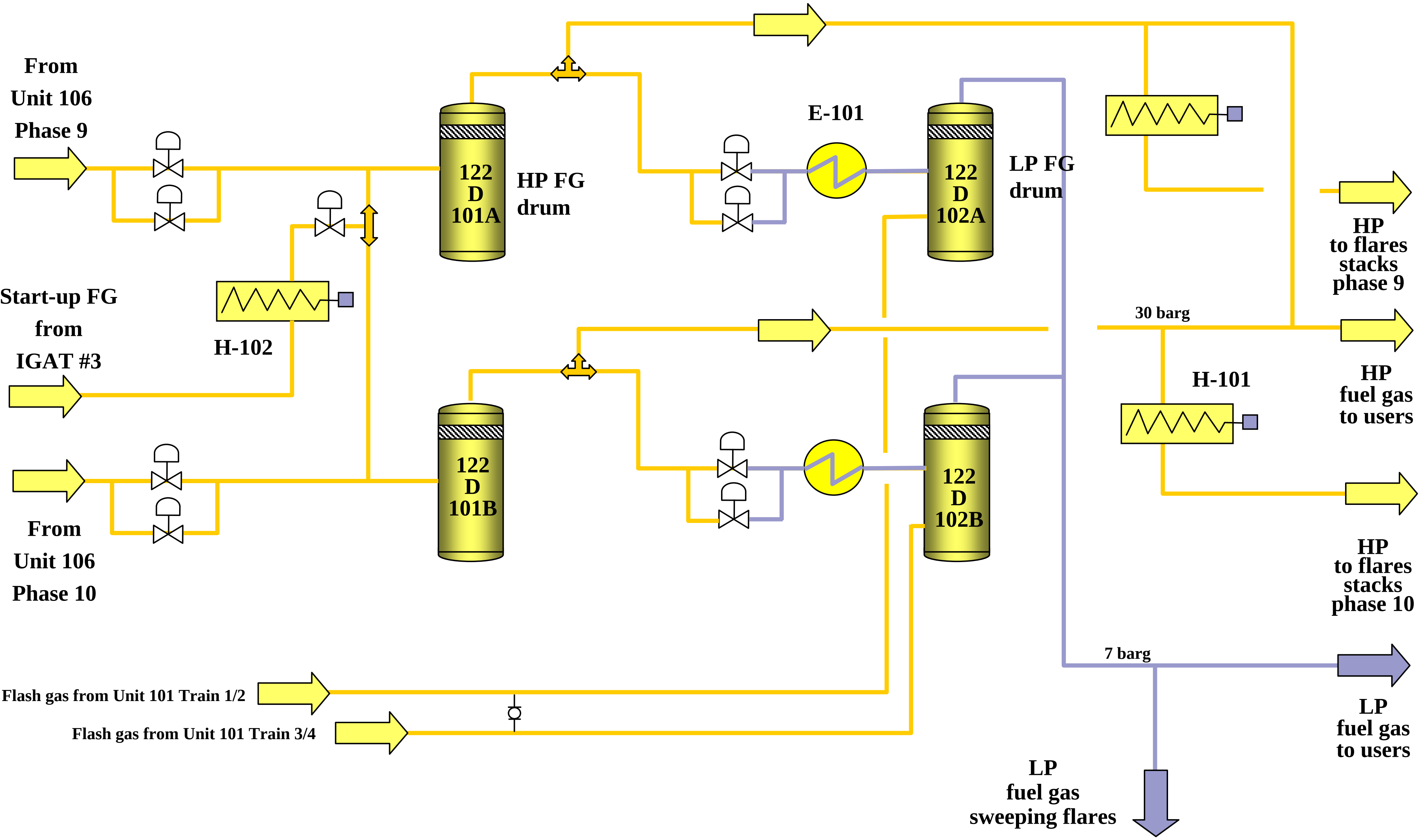


Steam generation

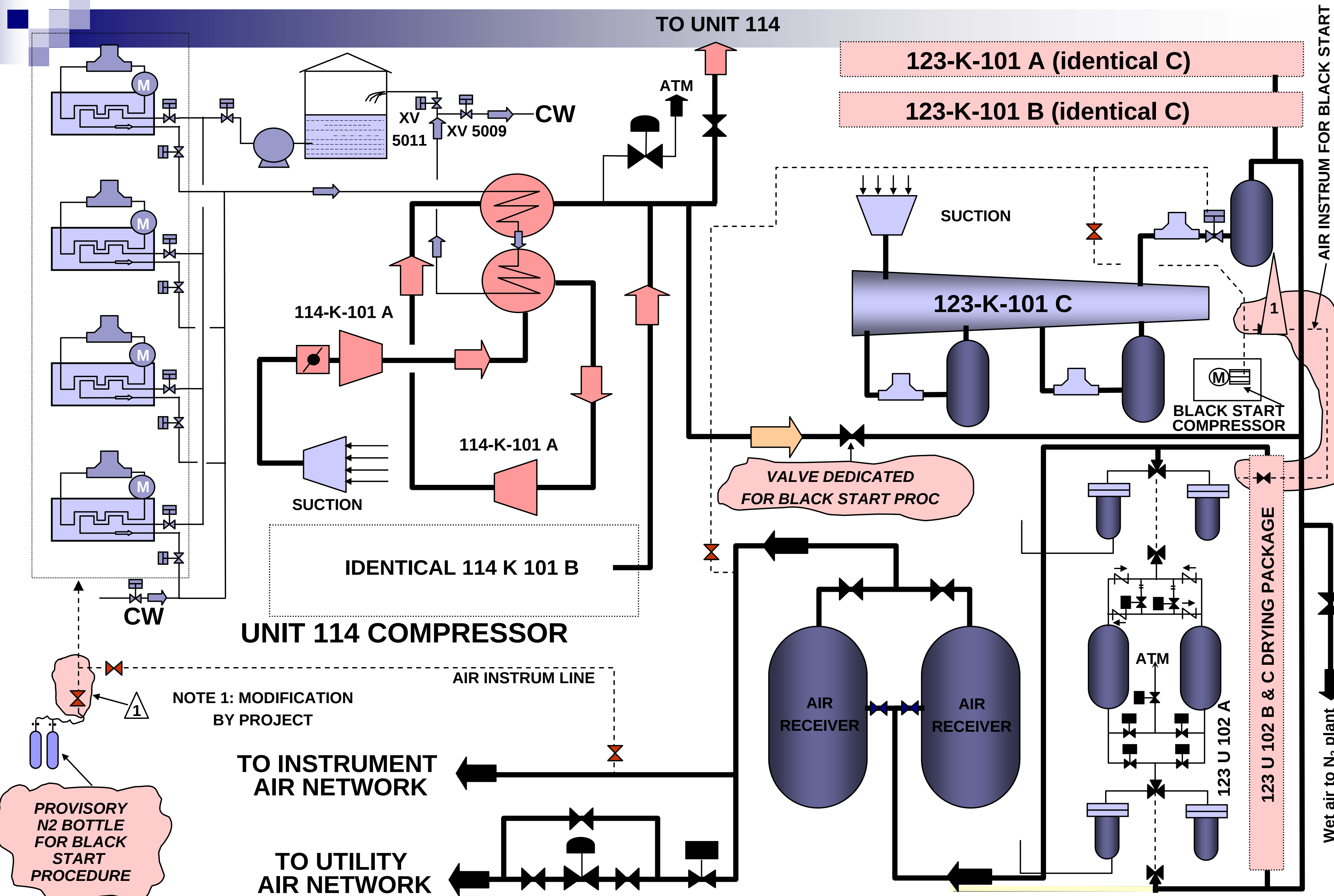
Steam condensates



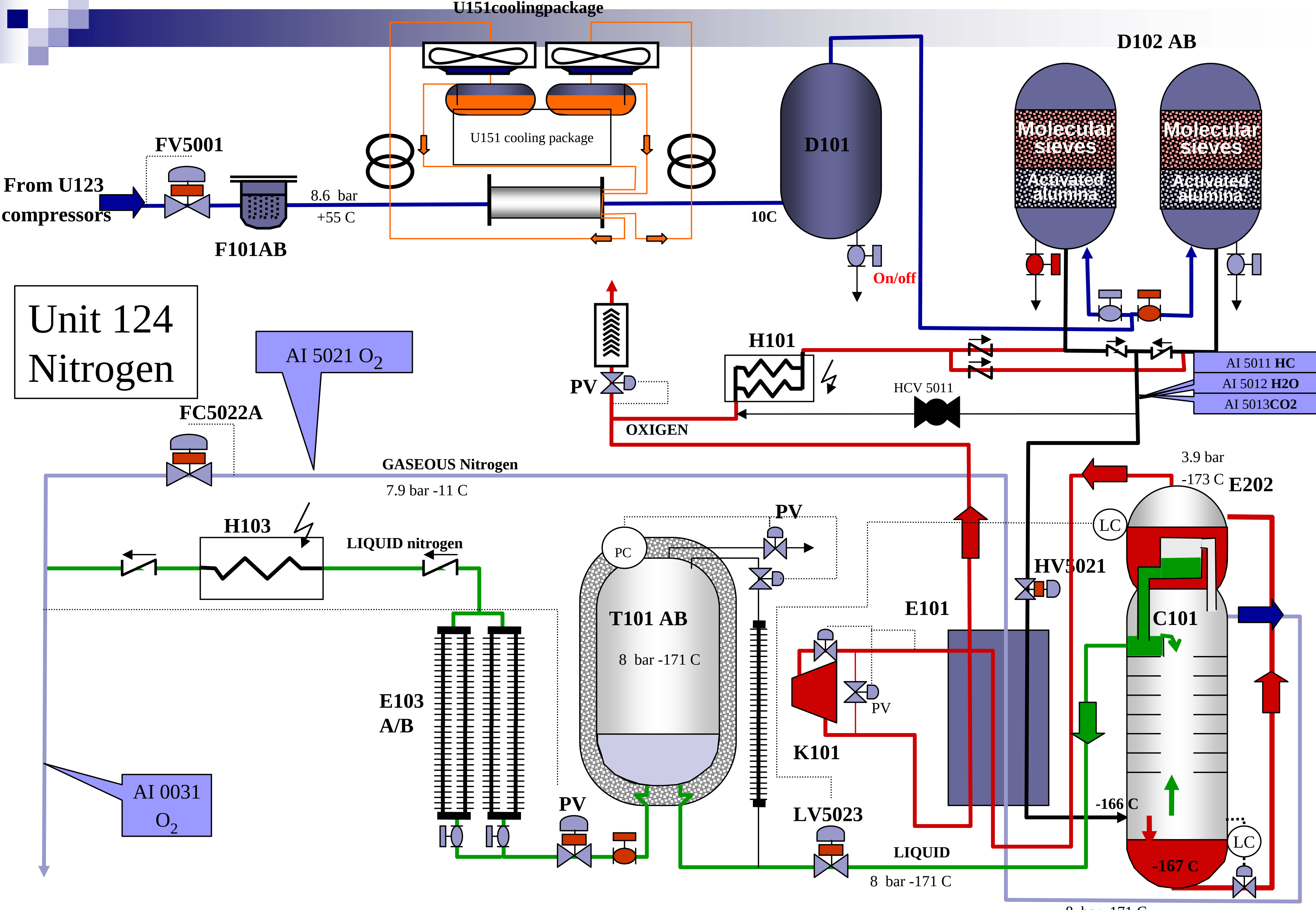
Unit 122:Fuel Gas


From
Unit 106
Phase 9
122
D
101A
HP FG
drum
E-101
122
D
102A
LP FG
drum
HP
to flares
stacks
phase 9
Start-up FG
from
IGAT #3
H-102
30 barg
H-101
HP
fuel gas
to users
122
D
101B
122
D
102B
From
Unit 106
Phase 10
HP
to flares
stacks
phase 10
7 barg
Flash gas from Unit 101 Train 1/2
Flash gas from Unit 101 Train 3/4
LP
fuel gas
to users
LP
fuel gas
sweeping flares

Unit 125: Instrument & Service Air


TO UNIT 114
123-K-101 A (identical C)
123-K-101 B (identical C)
AIR INSTRUM FOR BLACK START
ATM
CW
XV 5011
XV 5009
M
SUCTION
123-K-101 C
1
114-K-101 A
114-K-101 A
SUCTION
BLACK START COMPRESSOR
VALVE DEDICATED FOR BLACK START PROC
IDENTICAL 114 K 101 B
CW
UNIT 114 COMPRESSOR
AIR INSTRUM LINE
NOTE 1: MODIFICATION BY PROJECT
123 U 102 B & C DRYING PACKAGE
123 U 102 A
ATM
AIR RECEIVER
AIR RECEIVER
TO INSTRUMENT AIR NETWORK
TO UTILITY AIR NETWORK
PROVISORY N2 BOTTLE FOR BLACK START PROCEDURE

Unit 124: Nitrogen


U151coolingpackage
D102 AB
U151 cooling package
D101
Molecular sieves
Activated alumina
Molecular sieves
Activated alumina
FV5001
From U123 compressors
8.6 bar
+55 C
10C
F101AB
On/off
Unit 124 Nitrogen
AI 5021 O_2
PV
H101
AI 5011 HC
AI 5012 H2O
AI 5013CO2
HCV 5011
FC5022A
OXIGEN
GASEOUS Nitrogen
7.9 bar -11 C
3.9 bar
-173 C
E202
H103
LIQUID nitrogen
PV
PC
LC
HV5021
T101 AB
8 bar -171 C
E101
C101
E103 A/B
PV
K101
AI 0031 O_2
PV
LV5023
-166 C
LIQUID
8 bar -171 C
-167 C
LC

Unit 125:Sea water intake

Unit 125:Sea water intake and Booster

- **The sea water system is designed to provide sea water:**

- **Desalination package feed** **857m^3/h Normal (1552 m^3/h Design)**
- **Cooling water for process and utility** **3978m^3/h Normal (4352m^3/h Design)**
- **Fire water in emergency case** **500m^3/h Normal**

Total **4835m^3/h Normal (5904m^3/h Design)**

Sea water requirement for pump design;

Pumped flow rate (P)		Normal m^3/h	(P barg)	Design	(P barg)
125-P-101 A/B/C/D	(4*33%)	4849	12.36	6000	15
125-P-102 A/B/C	(3*50%)	3910	10.2	4229	13.1

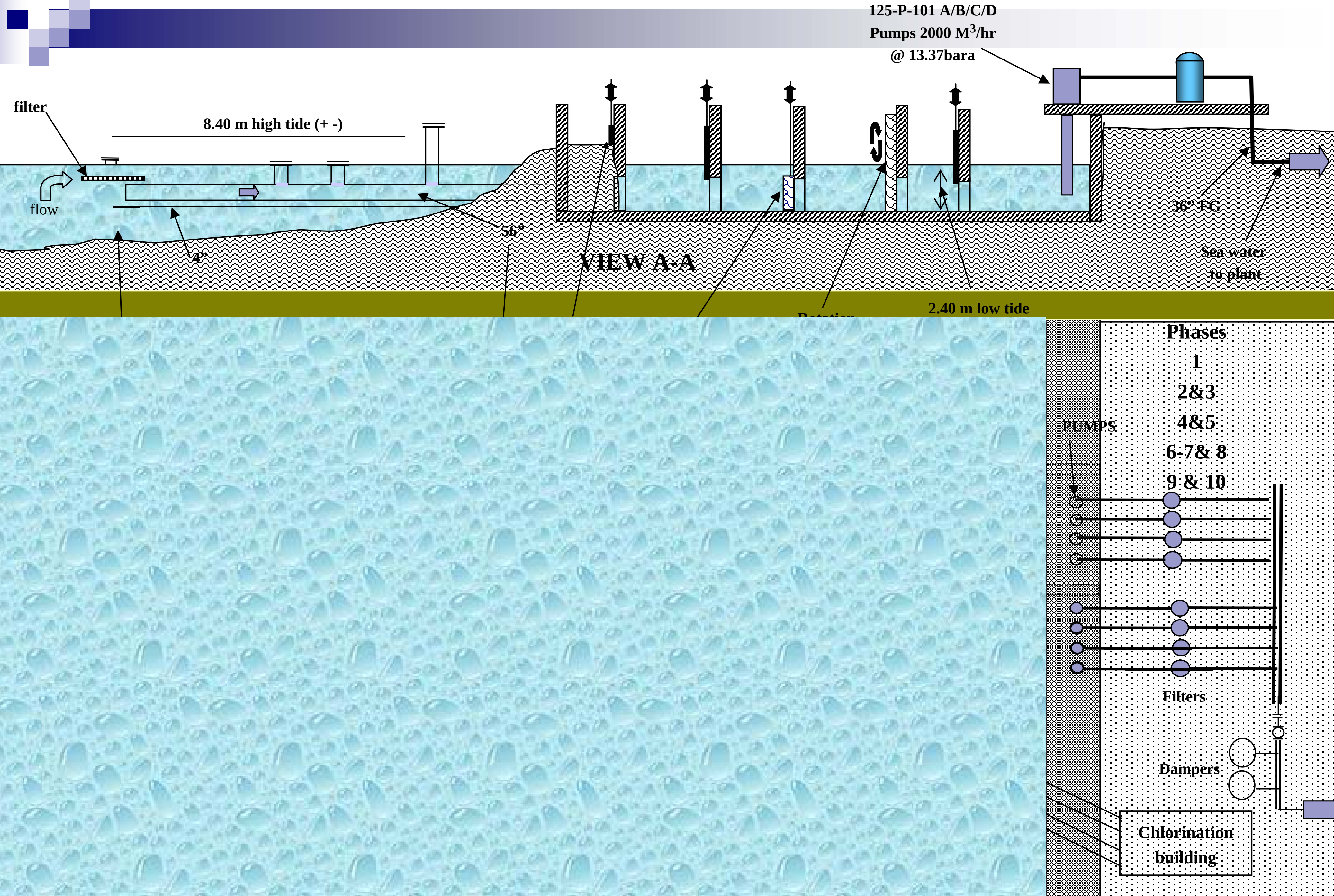
- **The sea water shall be chlorinated an screened, sea water will be filtered@500 µm through coarse filters.**

- **1 sea water storage tank 125-T-101 have 30minutes hold-up based on normal case**

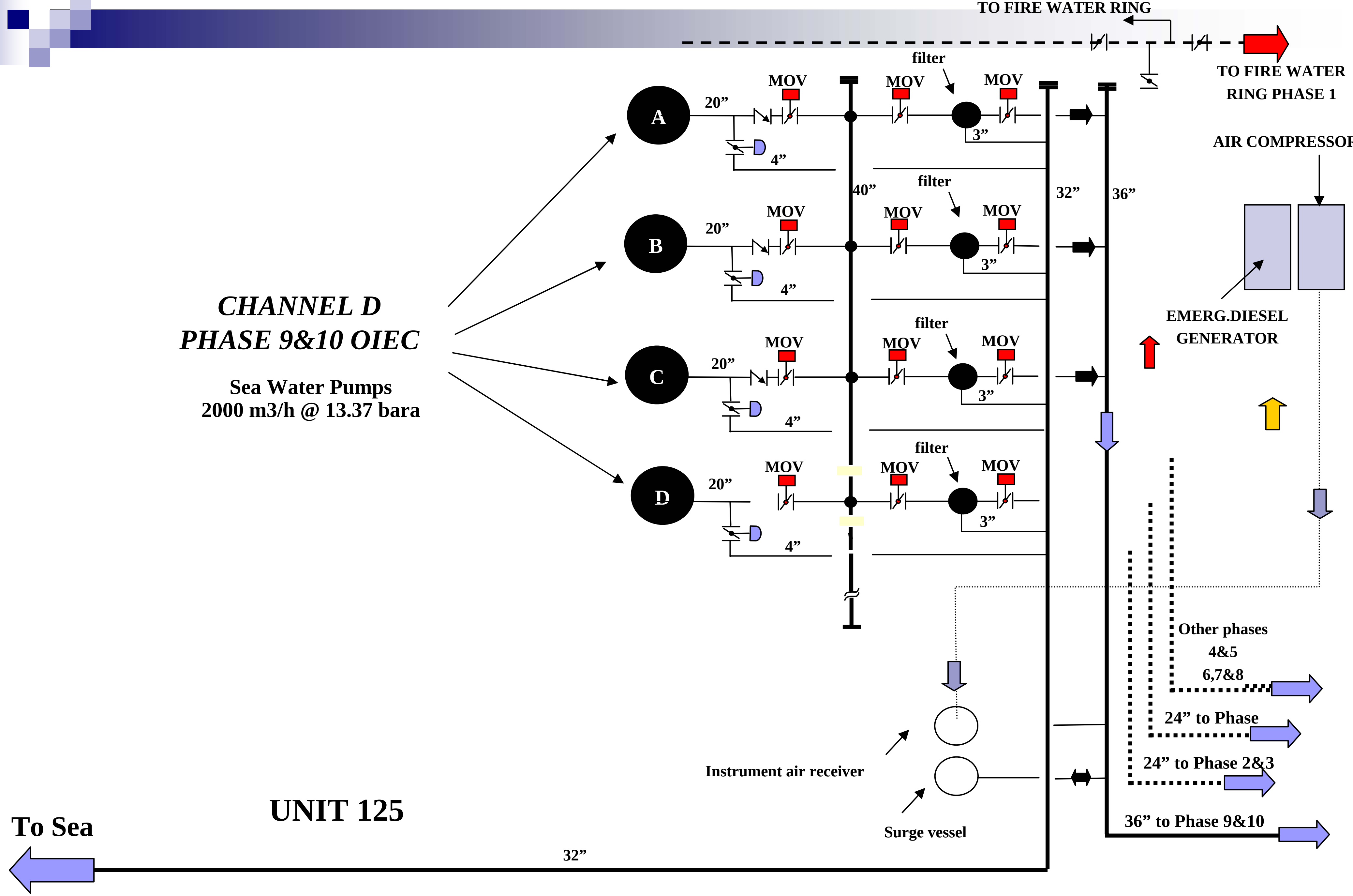
- **The booster pumps have been provided to provide the necessary pressure at battery limits of Units 101,107,113,114,115,116and 144. the booster station has an elevation 24m, pumping to unit101 at an elevation of 62m. The required battery limit pressure is 4.5barg.**

- **Chlorination : taken from out side battery limit, will be injected at each seawater pump**

- **Warm seawater return and brine from desalination unit, after quenching, will flow by gravity to clean water out fall basin 125-x-102 before being discharged to sea.**

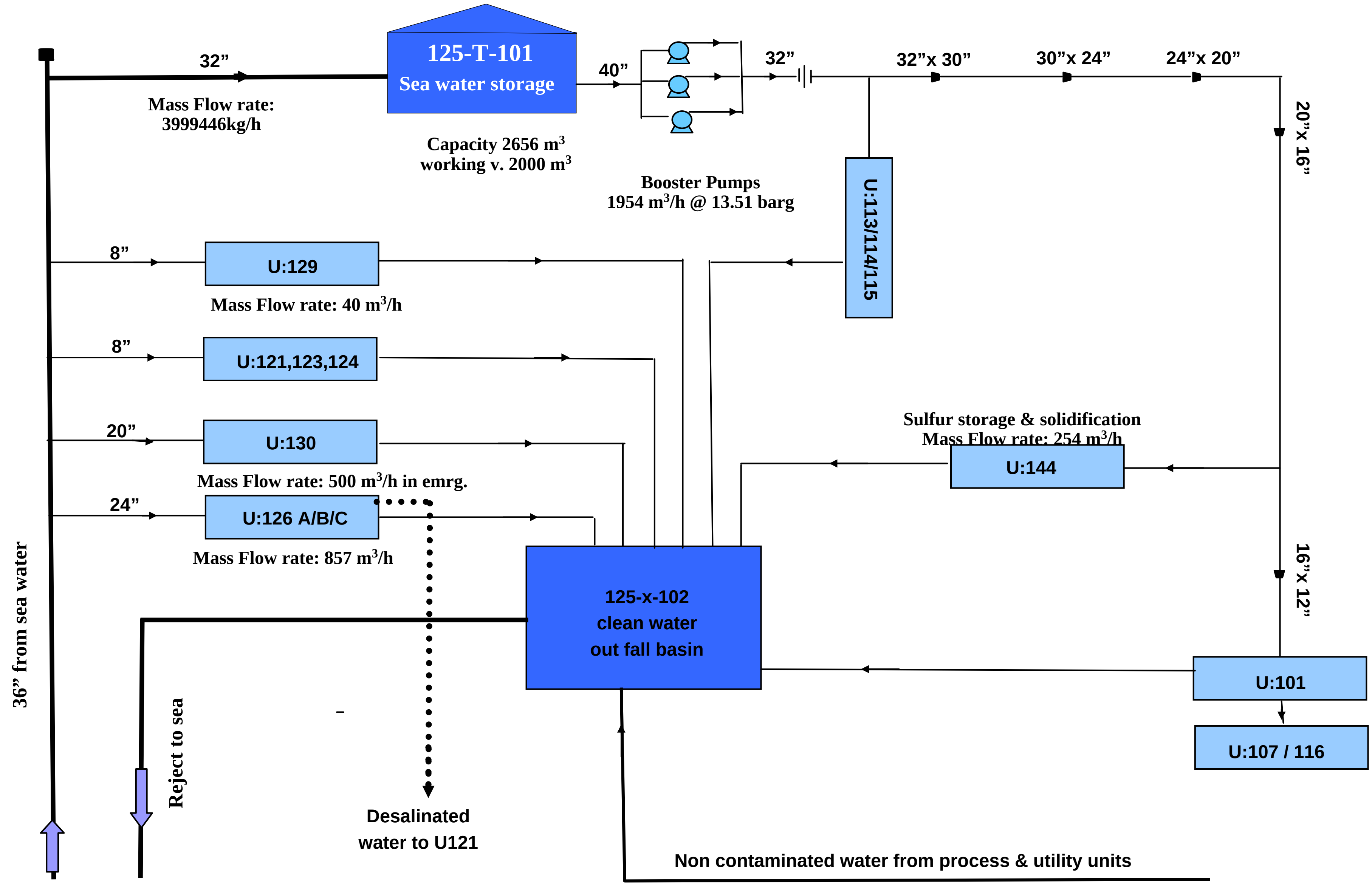


Sea Water Intake & Booster

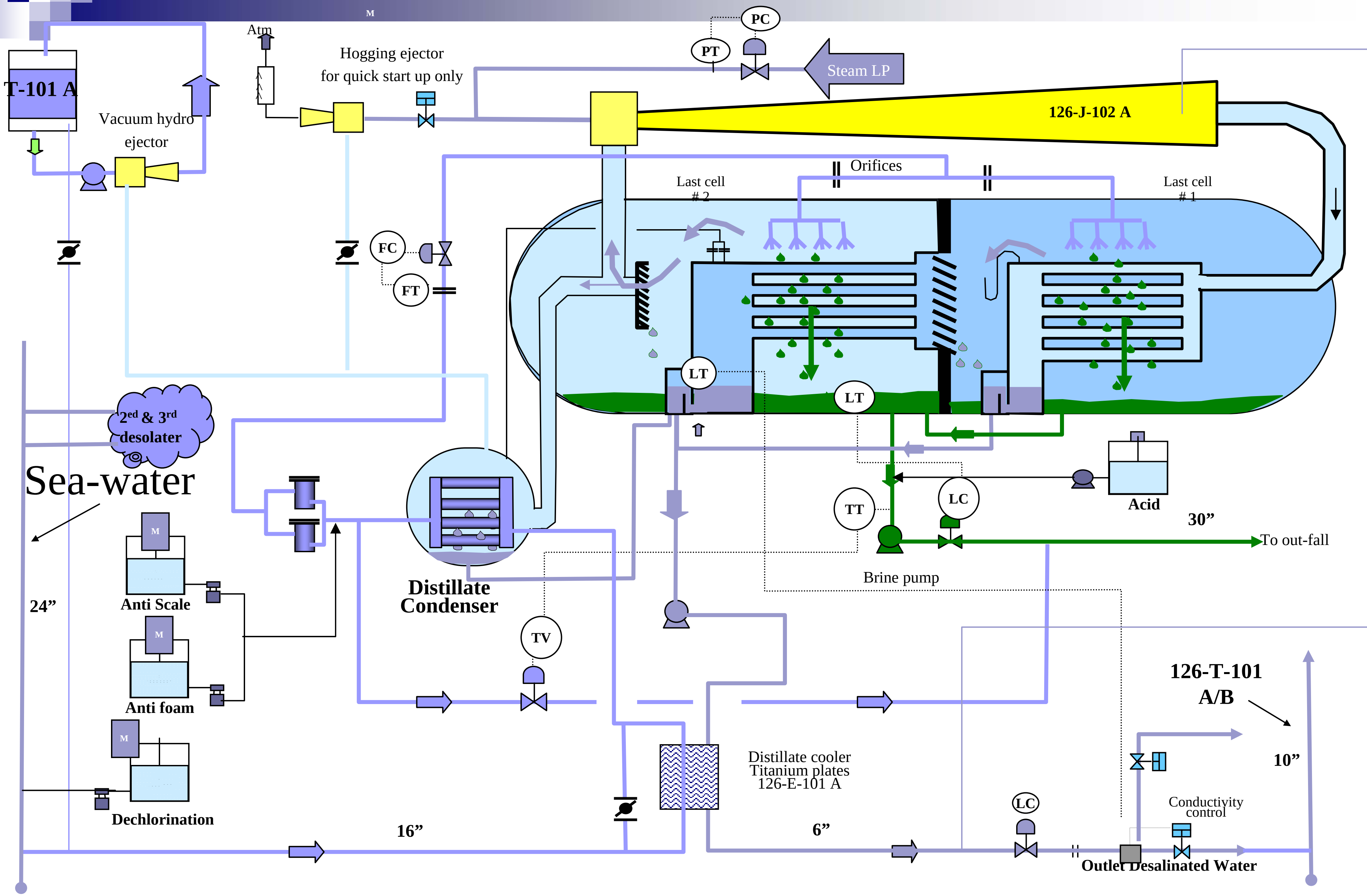


TO FIRE WATER RING
TO FIRE WATER RING PHASE 1
AIR COMPRESSOR
filter
MOV
A
B
C
D
20”
4”
3”
40”
32”
36”
CHANNEL D
PHASE 9&10 OIEC
Sea Water Pumps
2000 m3/h @ 13.37 bara
EMERG.DIESEL GENERATOR
Other phases
4&5
6,7&8
24” to Phase
24” to Phase 2&3
36” to Phase 9&10
Instrument air receiver
Surge vessel
UNIT 125
To Sea
32”

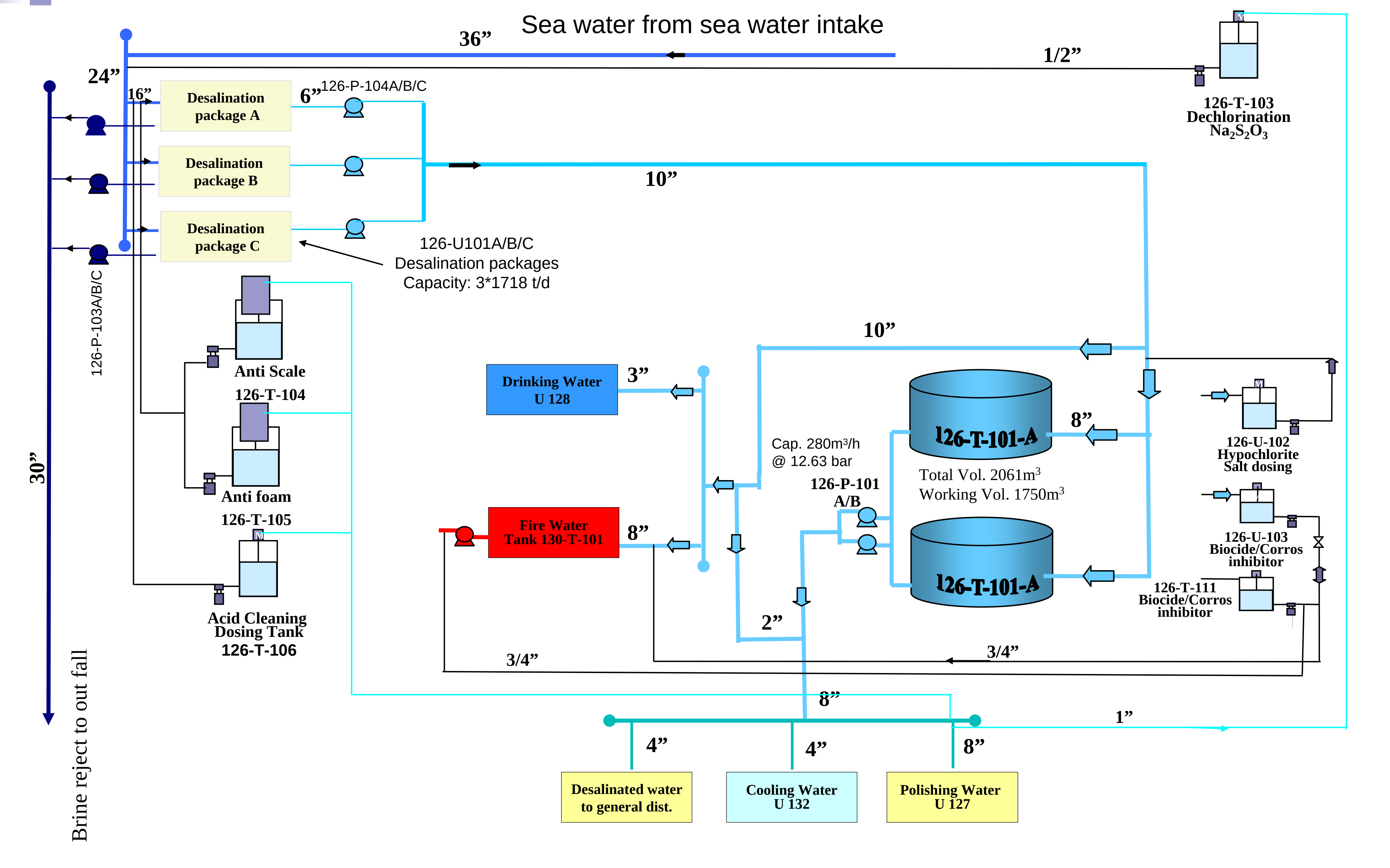
Sea Water Booster System



Unit 126: Desalination unit

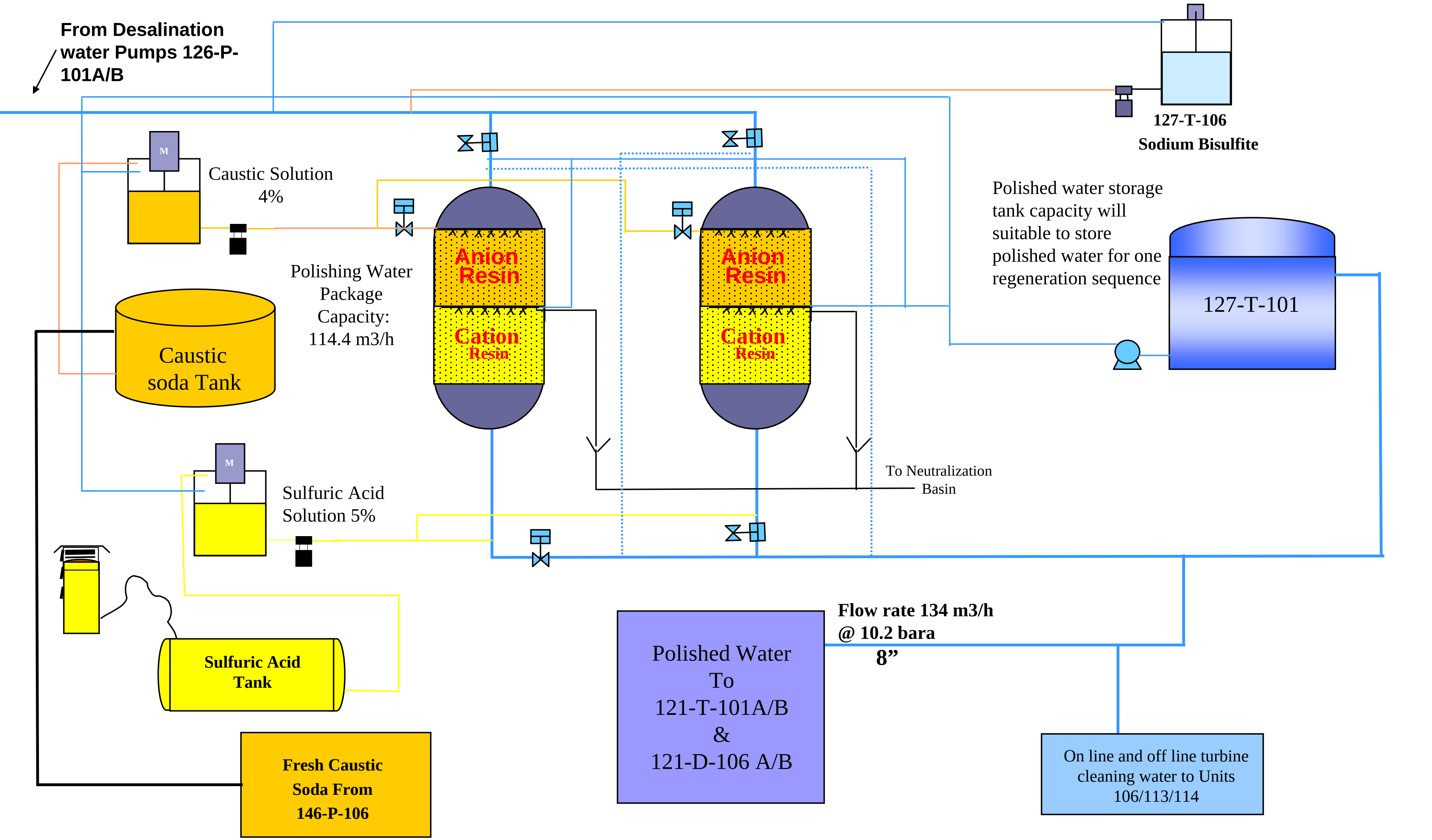


Sea Water Desalination



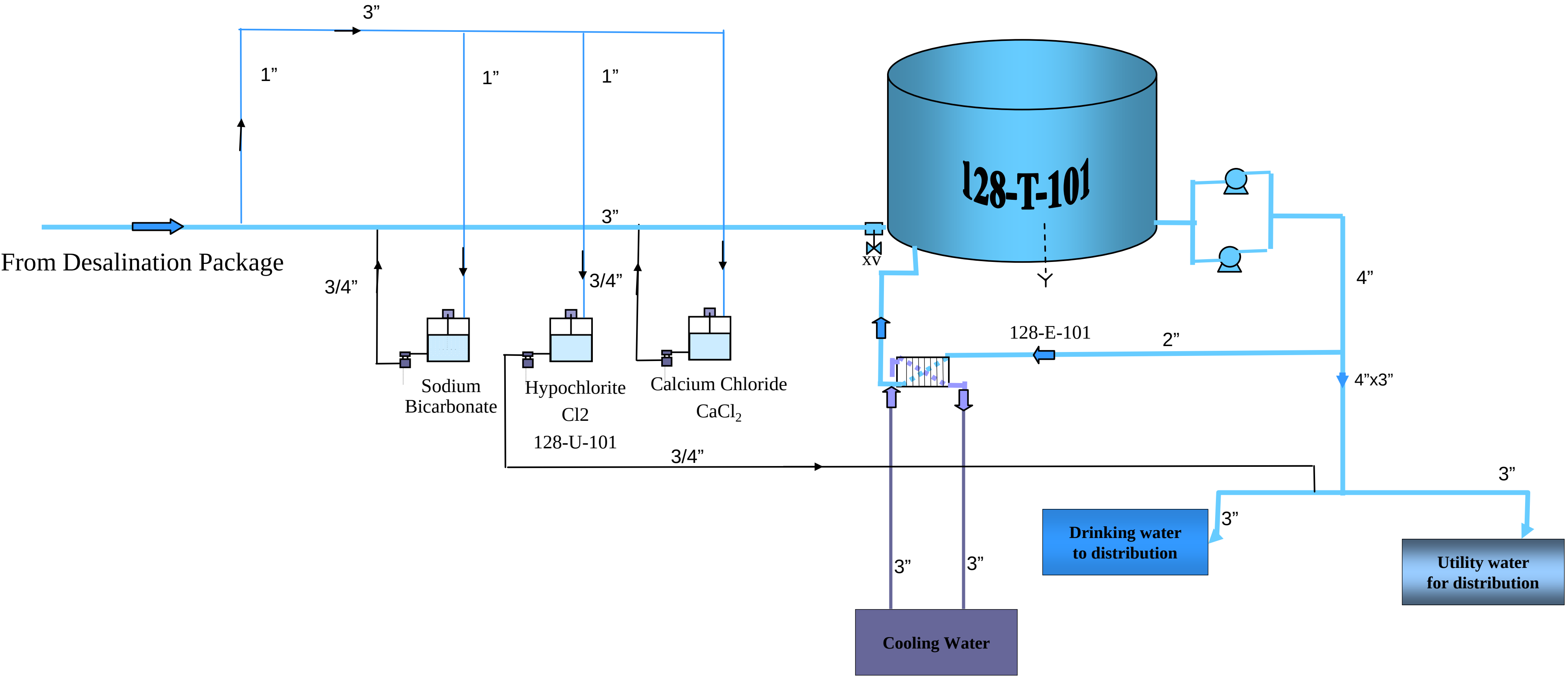
Sea water from sea water intake
36”
24”
1/2”
126-T-103
Dechlorination
$Na_2S_2O_3$
16”
Desalination package A
Desalination package B
Desalination package C
6”
126-P-104A/B/C
10”
126-U101A/B/C
Desalination packages
Capacity: 3*1718 t/d
126-P-103A/B/C
30”
Brine reject to out fall
Anti Scale
126-T-104
Anti foam
126-T-105
Acid Cleaning
Dosing Tank
126-T-106
10”
Drinking Water
U 128
3”
Fire Water
Tank 130-T-101
8”
Cap. 280m³/h
@ 12.63 bar
126-P-101
A/B
126-T-101-A
Total Vol. 2061m^3
Working Vol. 1750m^3
126-T-101-A
8”
126-U-102
Hypochlorite
Salt dosing
126-U-103
Biocide/Corros
inhibitor
126-T-111
Biocide/Corros
inhibitor
2”
3/4”
3/4”
8”
1”
4”
4”
8”
Desalinated water
to general dist.
Cooling Water
U 132
Polishing Water
U 127

Unit 127: Polishing Water



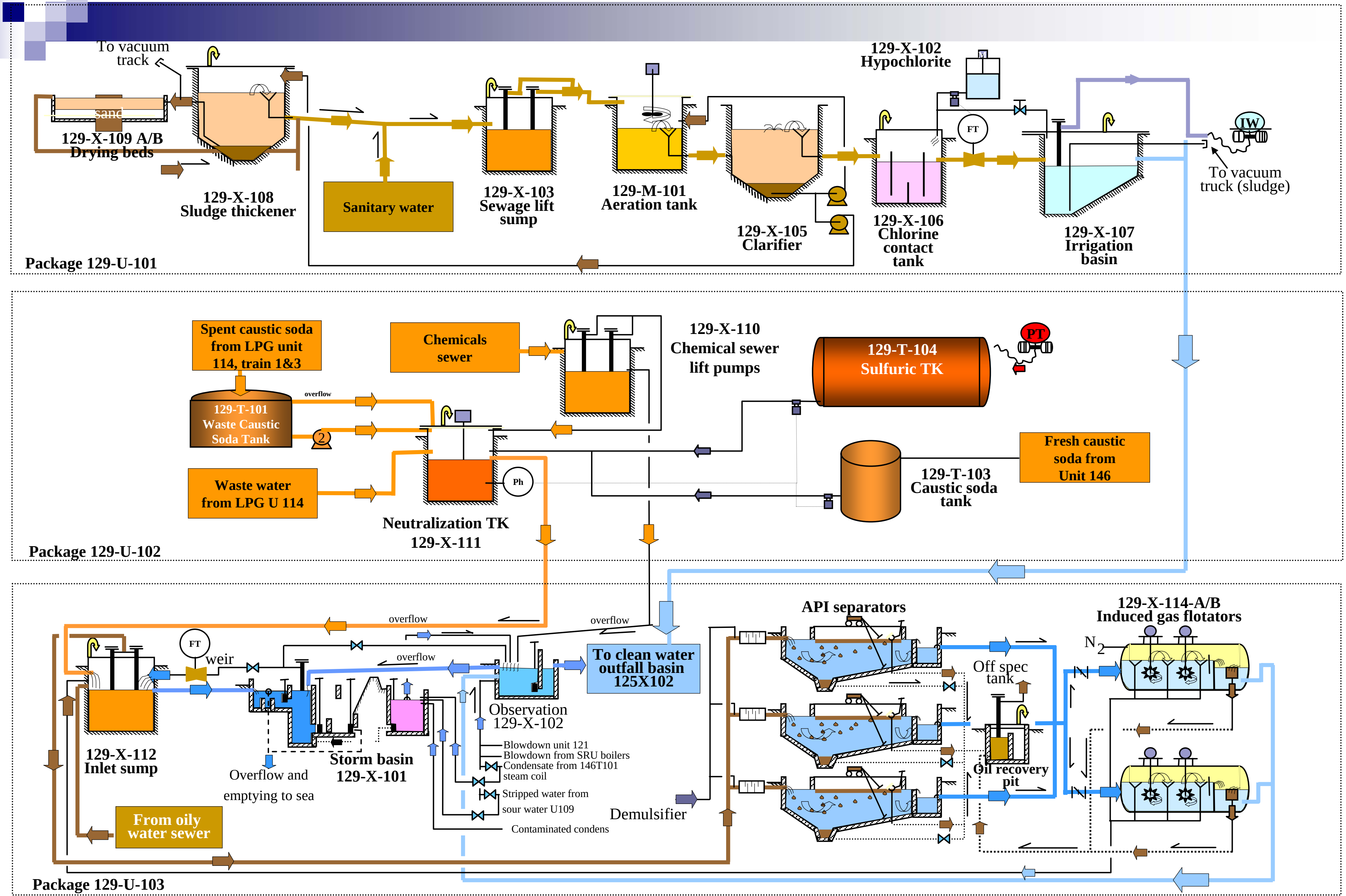
Polishing Water

Unit 128: Potable Water

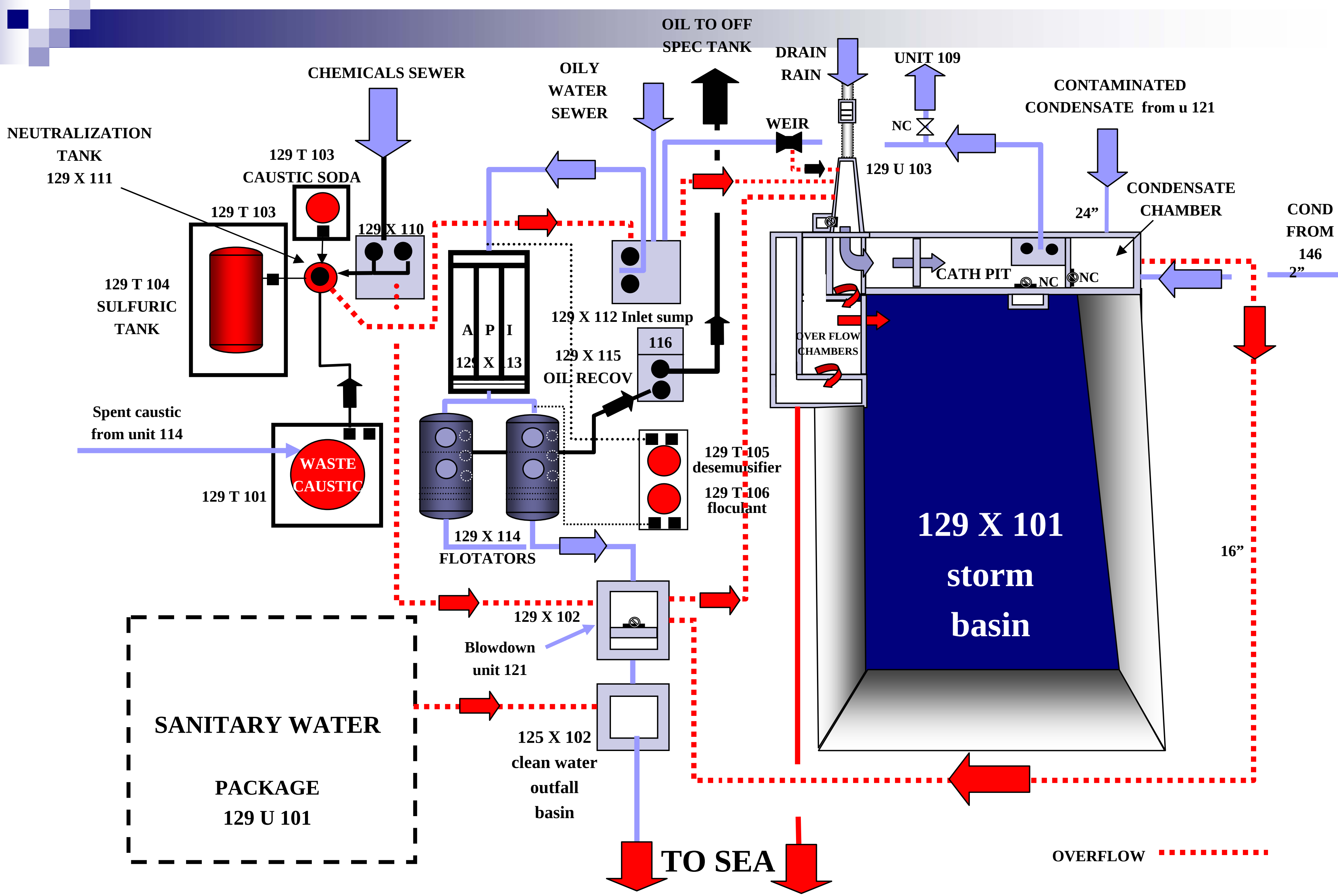


Potable Water

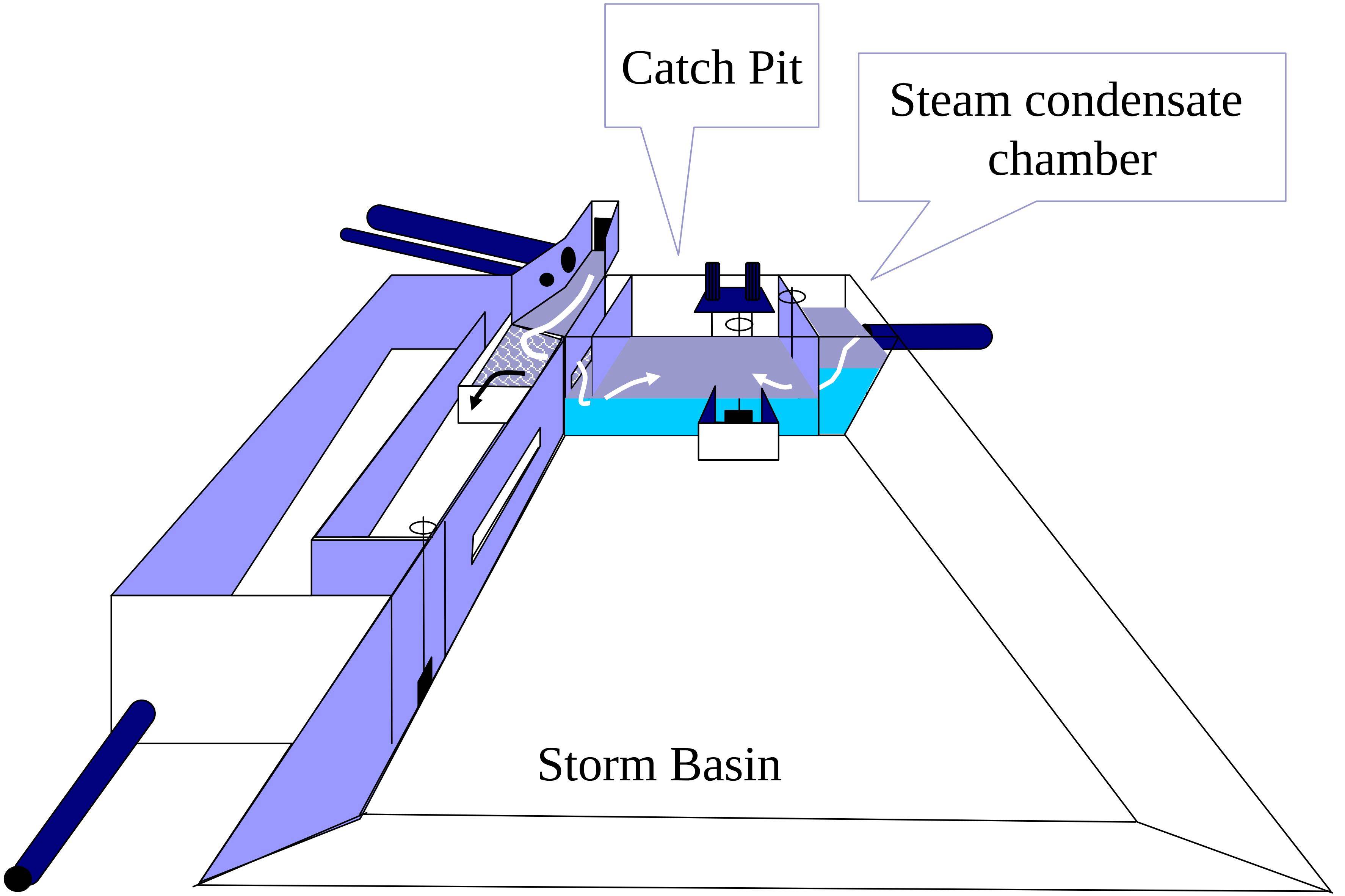
Unit 129: Waste Effluents Disposal & Sanitary treatment



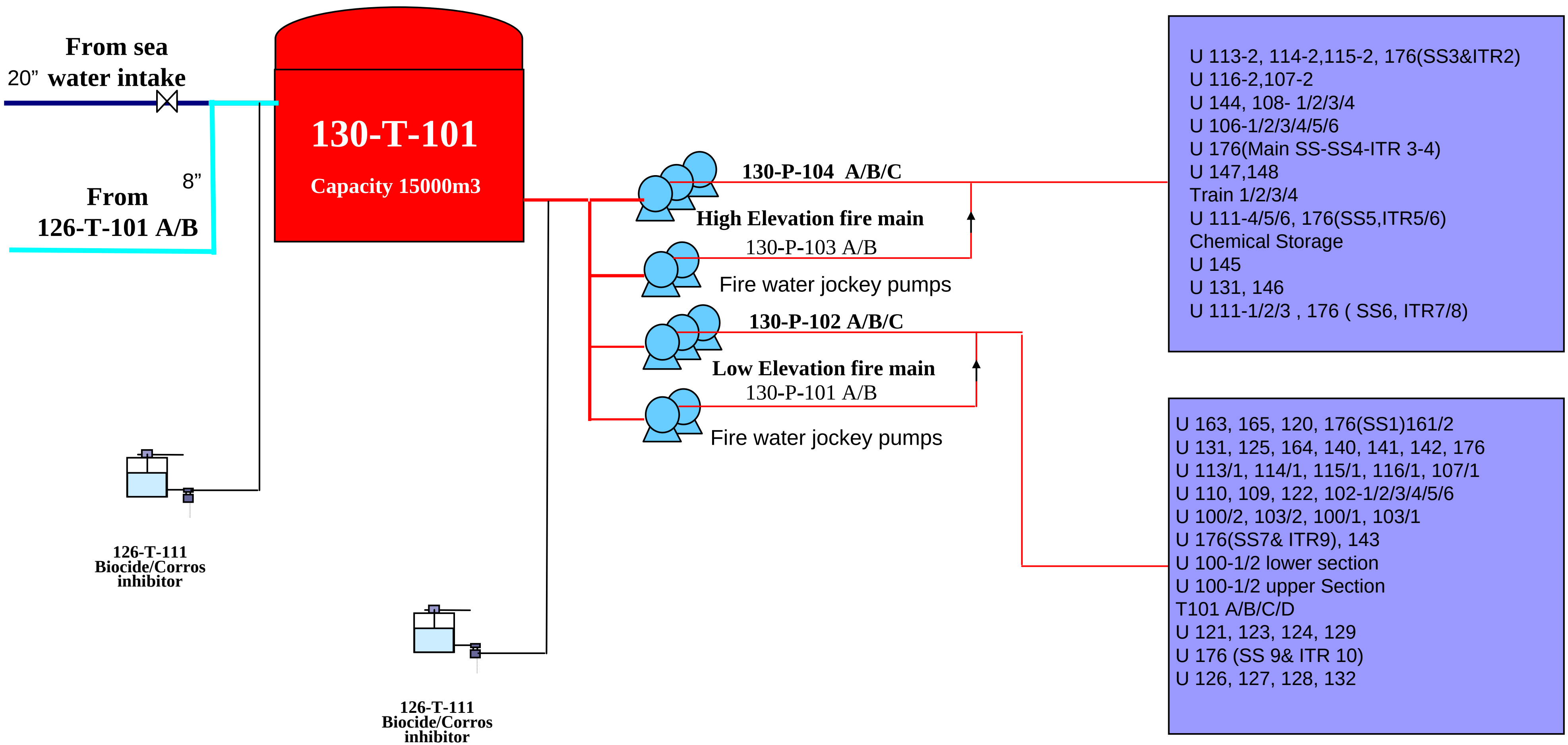
waste effluents disposal



waste effluents disposal

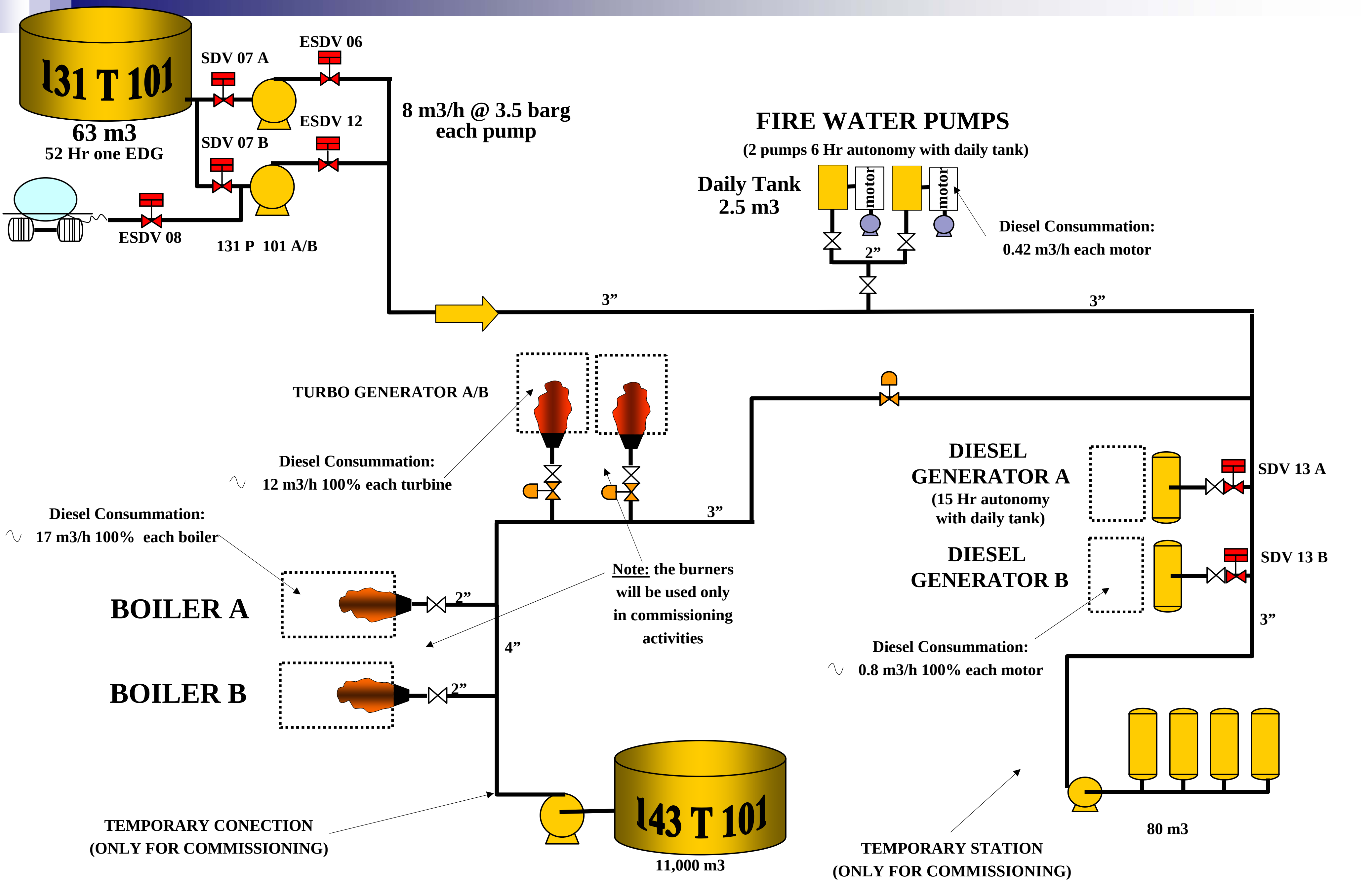

Catch Pit
Steam condensate chamber
Storm Basin

Unit 130 : Fire Water

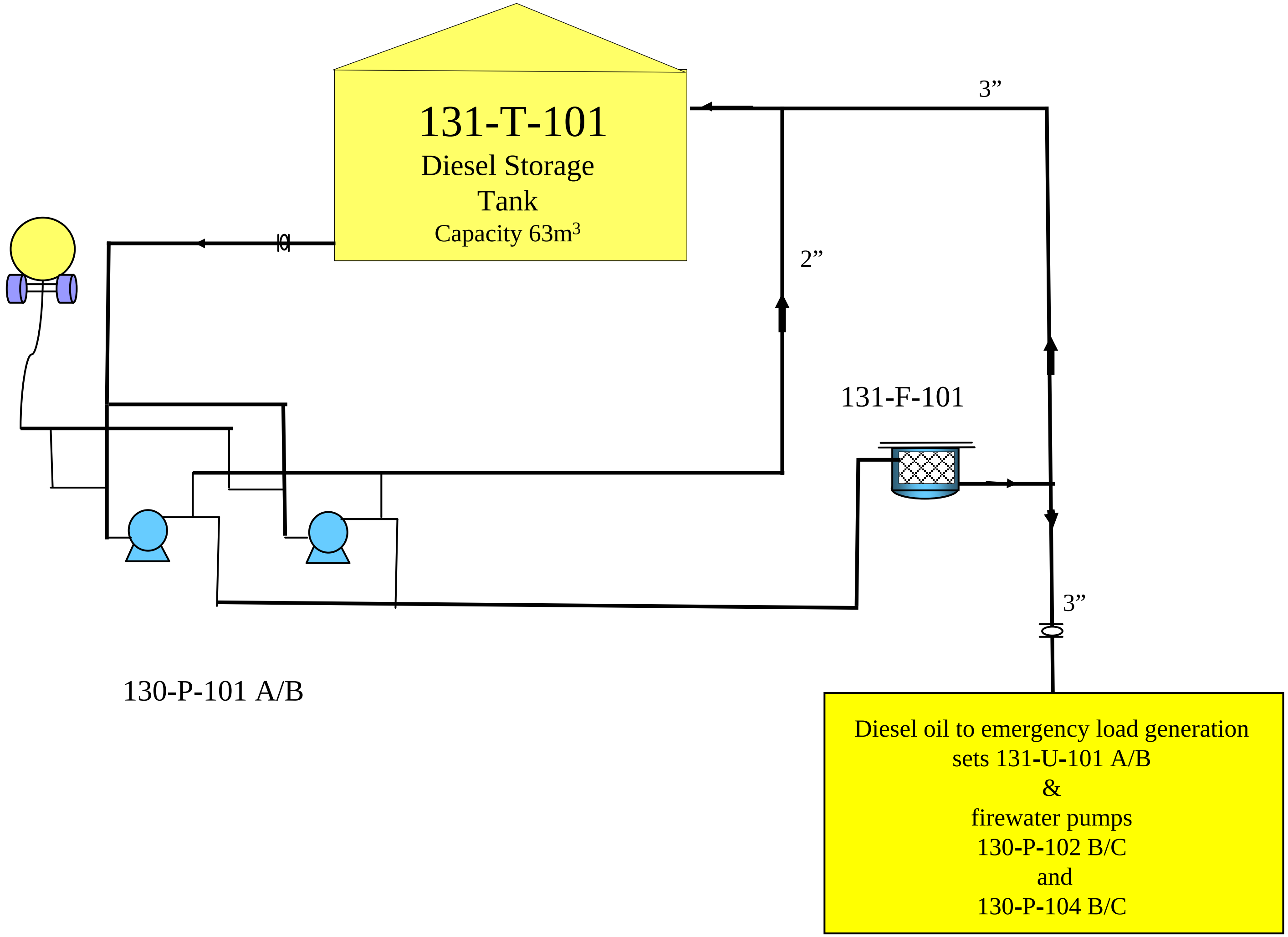

From sea
20” water intake
8”
From
126-T-101 A/B
130-T-101
Capacity 15000m3
130-P-104 A/B/C
High Elevation fire main
130-P-103 A/B
Fire water jockey pumps
130-P-102 A/B/C
Low Elevation fire main
130-P-101 A/B
Fire water jockey pumps
126-T-111
Biocide/Corros
inhibitor
126-T-111
Biocide/Corros
inhibitor
U 113-2, 114-2,115-2, 176(SS3&ITR2)
U 116-2,107-2
U 144, 108- 1/2/3/4
U 106-1/2/3/4/5/6
U 176(Main SS-SS4-ITR 3-4)
U 147,148
Train 1/2/3/4
U 111-4/5/6, 176(SS5,ITR5/6)
Chemical Storage
U 145
U 131, 146
U 111-1/2/3 , 176 (SS6, ITR7/8)
U 163, 165, 120, 176(SS1)161/2
U 131, 125, 164, 140, 141, 142, 176
U 113/1, 114/1, 115/1, 116/1, 107/1
U 110, 109, 122, 102-1/2/3/4/5/6
U 100/2, 103/2, 100/1, 103/1
U 176(SS7& ITR9), 143
U 100-1/2 lower section
U 100-1/2 upper Section
T101 A/B/C/D
U 121, 123, 124, 129
U 176 (SS 9& ITR 10)
U 126, 127, 128, 132

Fife water

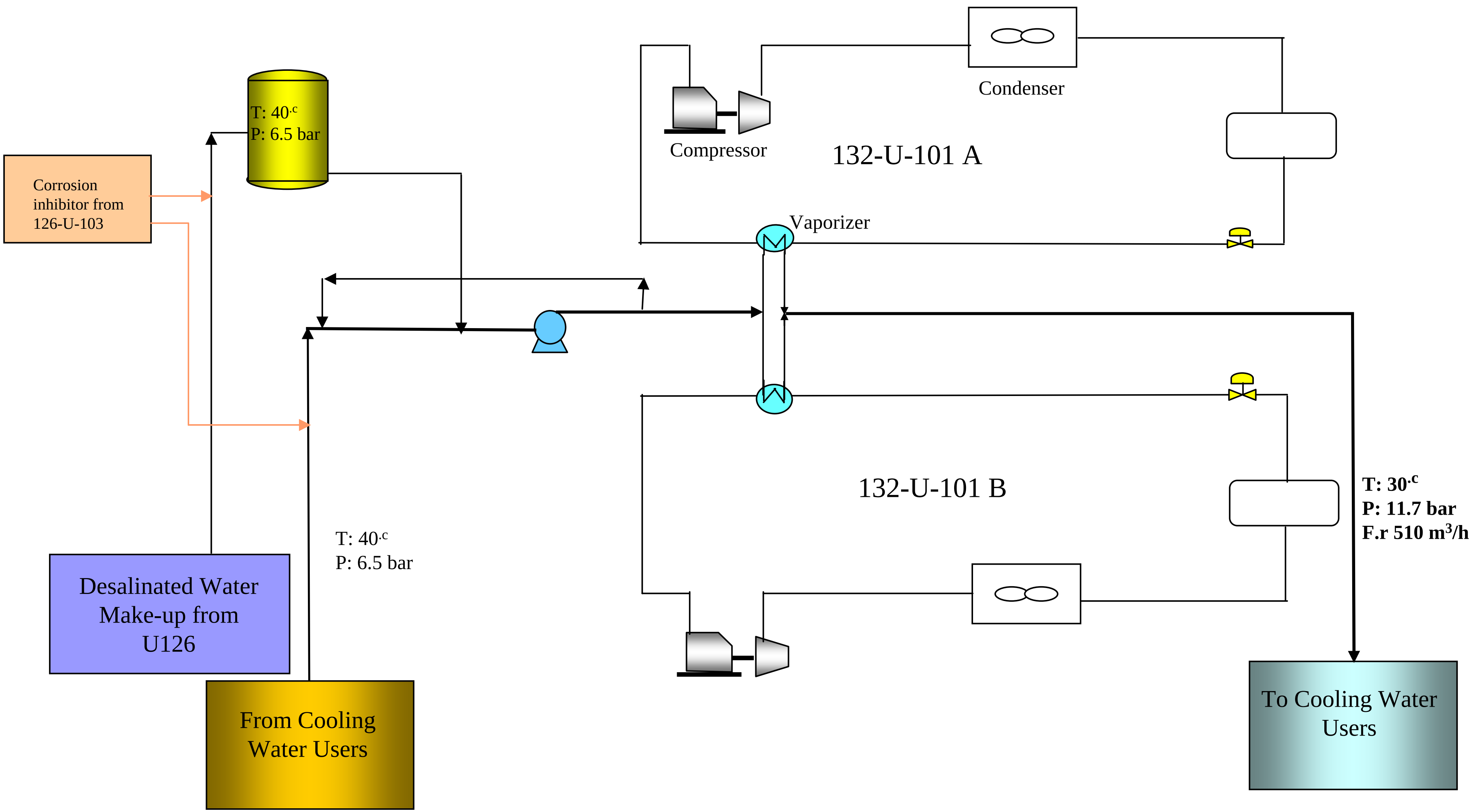
Unit 131 : Diesel Oil

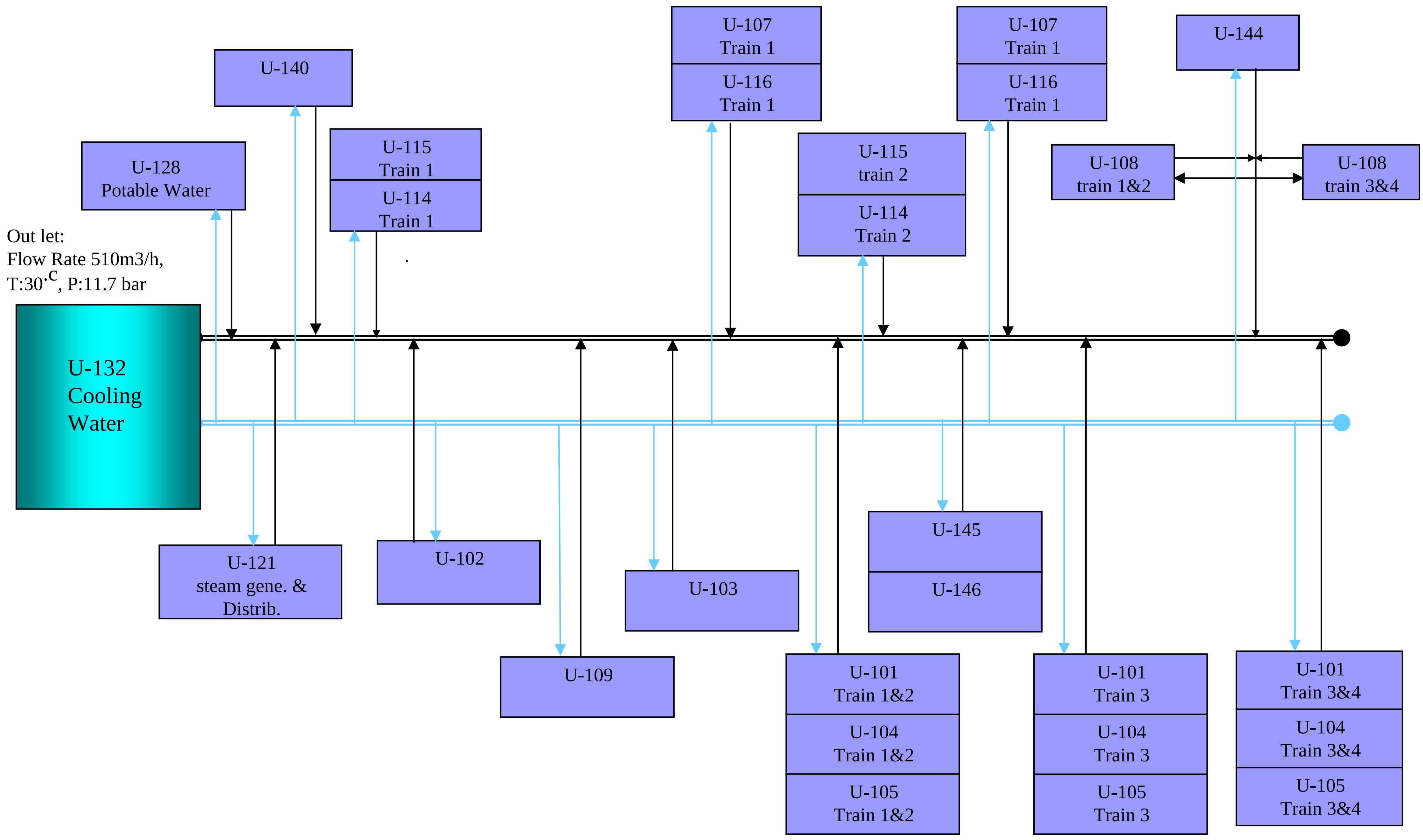

131 T 101
63 m3
52 Hr one EDG
SDV 07 A
ESDV 06
ESDV 12
SDV 07 B
ESDV 08
131 P 101 A/B
8 m3/h @ 3.5 barg
each pump
FIRE WATER PUMPS
(2 pumps 6 Hr autonomy with daily tank)
Daily Tank
2.5 m3
motor
motor
Diesel Consummation:
0.42 m3/h each motor
2”
3”
3”
TURBO GENERATOR A/B
Diesel Consummation:
12 m3/h 100% each turbine
Diesel Consummation:
17 m3/h 100% each boiler
3”
DIESEL
GENERATOR A
(15 Hr autonomy
with daily tank)
SDV 13 A
DIESEL
GENERATOR B
SDV 13 B
3”
BOILER A
2”
Note: the burners
will be used only
in commissioning
activities
4”
Diesel Consummation:
0.8 m3/h 100% each motor
BOILER B
2”
143 T 101
11,000 m3
80 m3
TEMPORARY CONECTION
(ONLY FOR COMMISSIONING)
TEMPORARY STATION
(ONLY FOR COMMISSIONING)

Diesel Oil


131-T-101
Diesel Storage
Tank
Capacity 63m3
3”
2”
131-F-101
3”
130-P-101 A/B
Diesel oil to emergency load generation
sets 131-U-101 A/B
&
firewater pumps
130-P-102 B/C
and
130-P-104 B/C

Unit 132 : Cooling Water

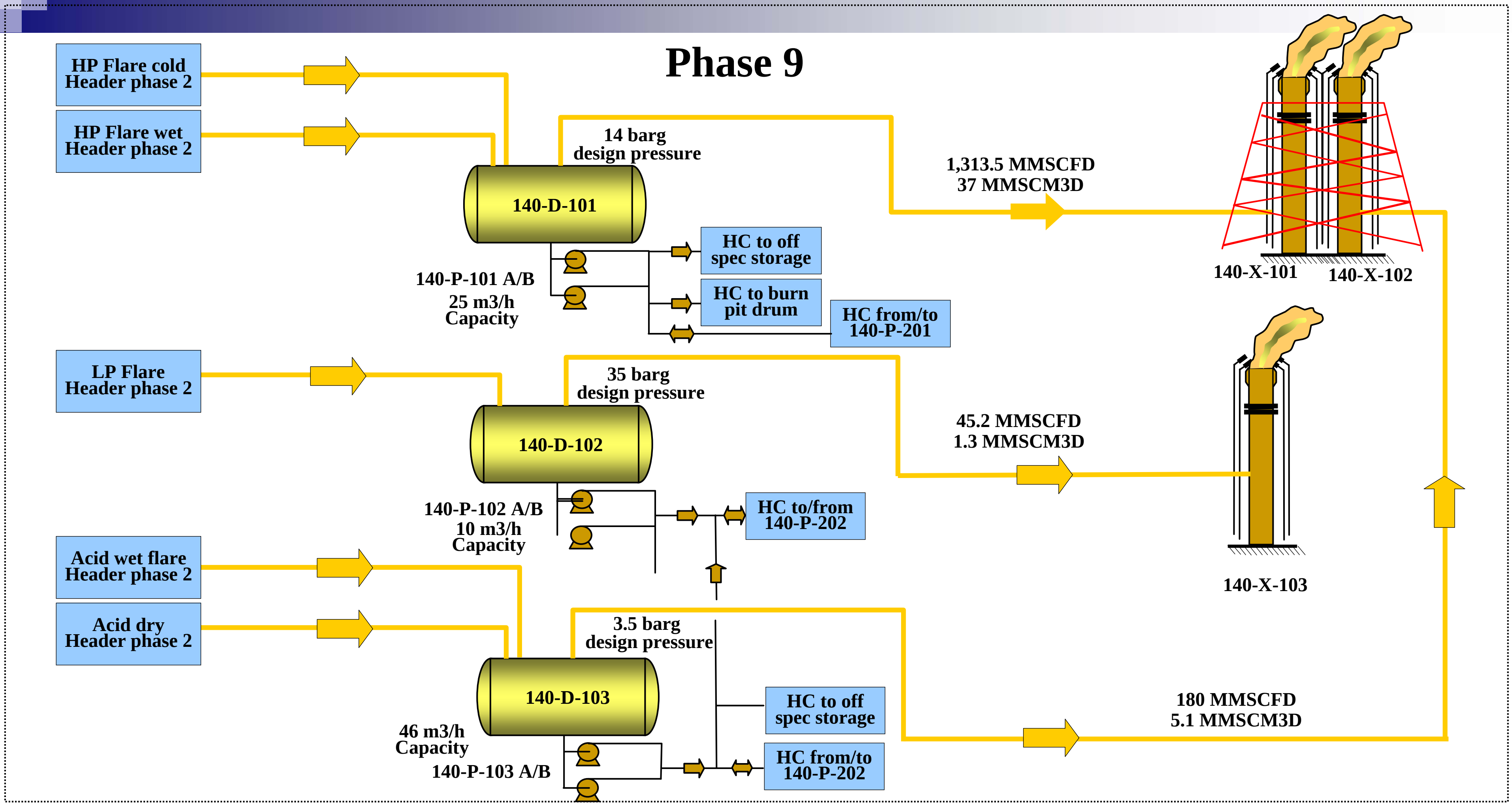

Condenser
Compressor
132-U-101 A
T: 40°C
P: 6.5 bar
Corrosion inhibitor from 126-U-103
Vaporizer
132-U-101 B
T: 30°C
P: 11.7 bar
F.r 510 m^3/h
T: 40°C
P: 6.5 bar
Desalinated Water Make-up from U126
From Cooling Water Users
To Cooling Water Users



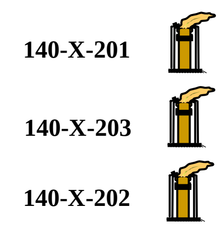
Cooling Water

Unit 140 : Flares

Phase 9



Phase 10 identical Phase 9

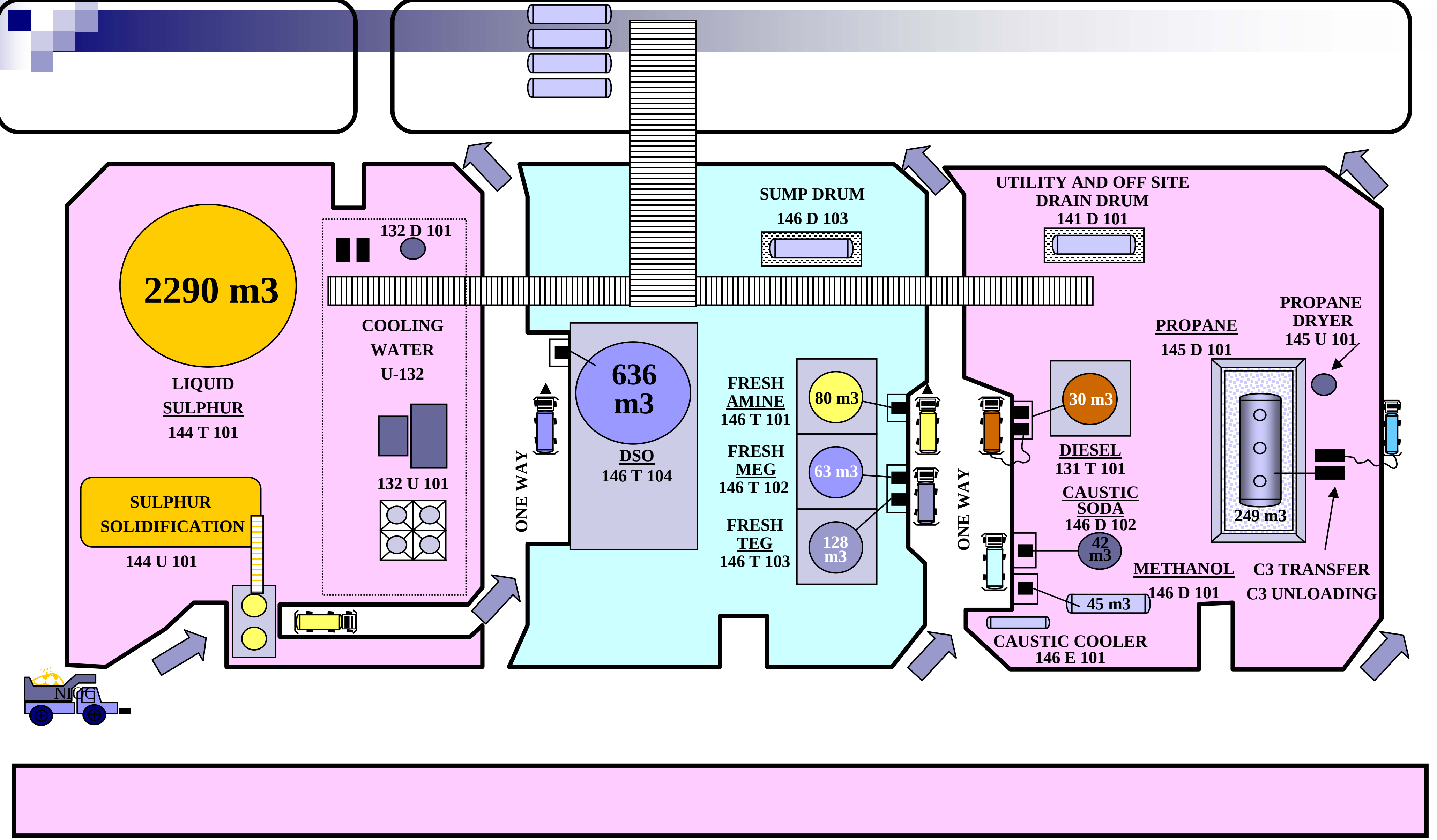


Unit	flare	Flare_network	vessels	ID	pressure
100	HP	FA	the whole unit	all	
101	HP	FA	feed KO drum	D101	
	HP	FA	feed filter	F101	
	HP	FA	absorber	C101	
	HP	FA	product coalescer	D104	
	ACID	FS	amine flash drum PV/PSV	D102	8 barg
	ACID	FS	regenerator	C102	1.3 barg
	ACID	FS	regenerator reflux drum	D103	1 barg
	ACID	FS	filtration package		
	ACID	FS	drain		
	ACID	FS	skiming pot		
102	ACID	FS	flash KO drum		
	ACID	FS	trains surge drums		
	LP	FB	drain	D105 P2P3	
	LP	FB	trains regeneratos	D102	
	LP	FB	trains reflux drums	D103	
103	HP	FC	pre-flash drum	D101	27 barg
	HP	FC	glycol filters	F101 AB	27 barg
	HP	FC	Feed heat exchanger	E102	27 barg
	HP	FC	suction drum 2nd stage K101	D103	27 barg
	ACID	FS	stabilisation column	C101	
	ACID	FS	reflux drum	D107	
	ACID	FS	1st stage suction drum	D102	
	ACID	FS	C101 skiming pot		
	ACID	FS	drain	D108	
	LP	FB	condensate degassing drum	D106	
104	HP	FA	feed filter	F101	
	HP	FA	absorber	C101	
	HP	FA	product coalescer	F102	
	ACID	FS	absorber skiming pot		
	ACID	FS	glycol flash drum	D101	
	ACID	FS	TEG sump drum	D103	
	LP	FB	still column	C102	
105	HP	FA	drier inlet KO drum	D101	
	HP	FC	recycle compressor	K101 AB	65 barg
	HP	FC	recycle compressor suction drum	D102	24 barg
	HP	FC	cold oil contactor	C101	62 barg
	HP	FC	depropaniser	C102	24 barg
	HP	FC	depropaniser reflux rum	D103	24 barg
	ACID	FS	sump drum	DH106	
	ACID	FT	depropaniser condenser (C3)	E105	
	ACID	FT	debutaniser	C103	
	ACID	FT	debutaniser reflux drum	D104	
	ACID	FT	butane cooler	E108	
	ACID	FT	dehexaniser	C104	
	ACID	FT	reflux drum	D105	
106	HP	FA	inlet gas		
	HP	FA	export gas suction drum	D101	
	HP	FA	compressors	K101	
	HP	FA	FG supply to TAG	H501 AB / F501 AB	
107	HP	FC	discharge K101	K101	23 barg
	HP	FC	surge drum	D105	23 barg
	ACID	FT	compressor suction drums		
108	LP	FB	acid gas K.O drum	D101	
	LP	FB	acid gas preheater	E107	
109	LP	FB	the whole unit		
114	ACID	FS	extractor	C101	
	ACID	FS	caustic settler	D101	
	ACID	FS	sand filter	F101	
	ACID	FS	spent caustic sump drum	D104	

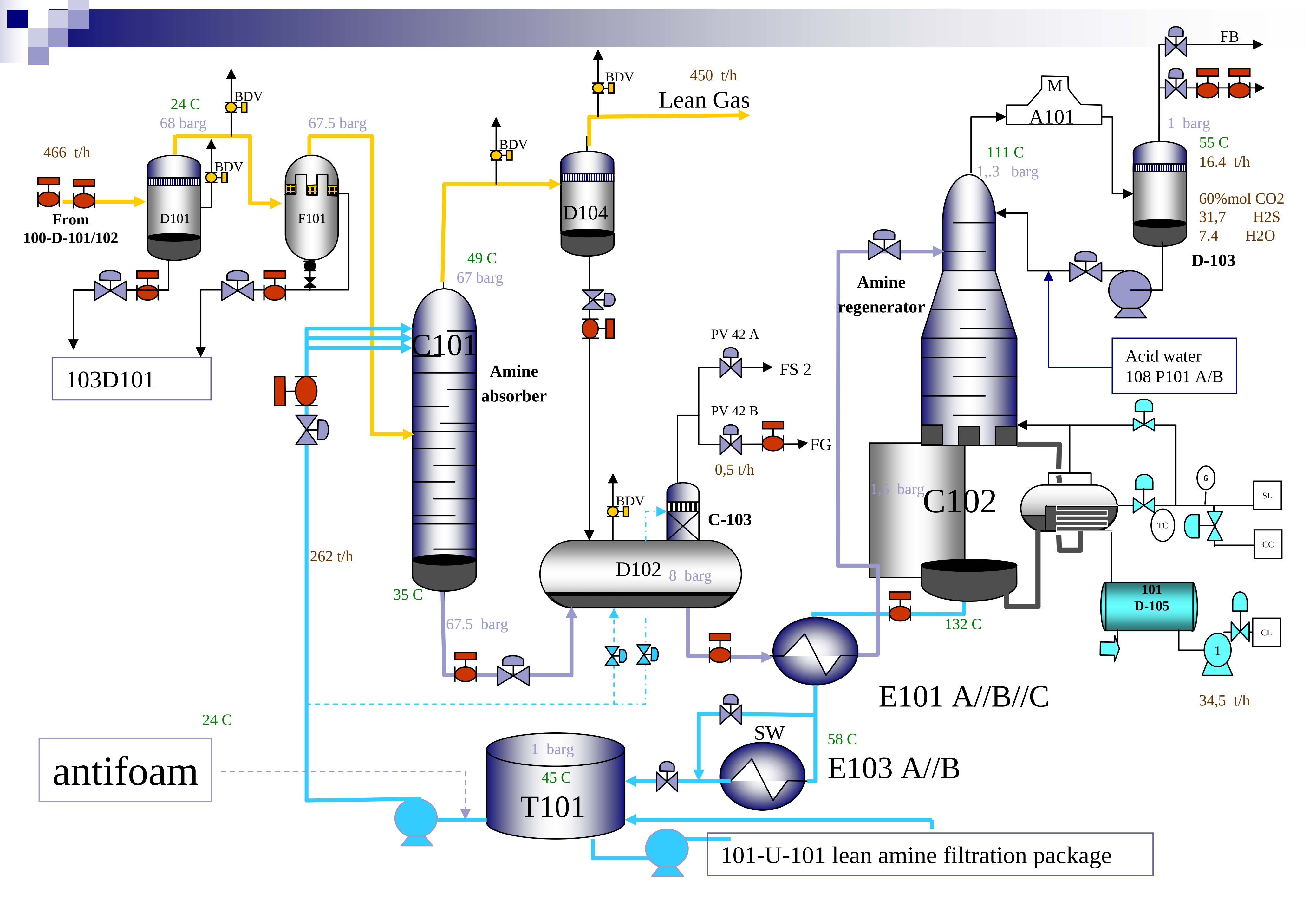
flare	Flare_network	Unit	vessels	ID	pressure
HP	FA	100	all	all	
HP	FA	101	feed KO drum	D101	
HP	FA		feed filter	F101	
HP	FA		absorber	C101	
HP	FA		product coalescer	D104	
HP	FC	103	pre-flash drum	D101	27 barg
HP	FC		glycol filters	F101 AB	27 barg
HP	FC		Feed heat exchanger	E102	27 barg
HP	FC		suction drum 2nd stage K101	D103	27 barg
HP	FA	104	feed filter	F101	
HP	FA		absorber	C101	
HP	FA		product coalescer	F102	
HP	FA	105	drier inlet KO drum	D101	
HP	FC		recycle compressor	K101 AB	65 barg
HP	FC		recycle compressor suction drum	D102	24 barg
HP	FC		cold oil contactor	C101	62 barg
HP	FC		depropaniser	C102	24 barg
HP	FC		depropaniser reflux rum	D103	24 barg
HP	FA	106	inlet gas		
HP	FA		export gas suction drum	D101	
HP	FA		compressors	K101	
HP	FA		FG supply to TAG	H501 AB / F501 AB	
HP	FC	107	discharge K101	K101	23 barg
HP	FC		surge drum	D105	23 barg
HP	FC	122	flare gas sweeping heater	H101AB	
HP	FC		start-up gas heater	H102	
HP	FC		HP FG KO drum	D101 AB	
ACID	FS	101	amine flash drum PV/PSV	D102	8 barg
ACID	FS		regenerator	C102	1.3 barg
ACID	FS		regenerator reflux drum	D103	1 barg
ACID	FS		filtration package		
ACID	FS		drain		
ACID	FS		skiming pot		
ACID	FS	102	flash KO drum		
ACID	FS		trains surge drums		
ACID	FS	103	stabilisation column	C101	
ACID	FS		reflux drum	D107	
ACID	FS		1st stage suction drum	D102	
ACID	FS		C101 skiming pot		
ACID	FS		drain	D108	
ACID	FS	104	absorber skiming pot		
ACID	FS		glycol flash drum	D101	
ACID	FS		TEG sump drum	D103	
ACID	FS	105	sump drum	DH106	
ACID	FT		depropaniser condenser (C3)	E105	
ACID	FT		debutaniser	C103	
ACID	FT		debutaniser reflux drum	D104	
ACID	FT		butane cooler	E108	
ACID	FT		dehexaniser	C104	
ACID	FT		reflux drum	D105	
ACID	FT	107	compressor suction drums		
ACID	FS	114	extractor	C101	
ACID	FS		caustic settler	D101	
ACID	FS		sand filter	F101	
ACID	FS		spent caustic sump drum	D104	
ACID	FS		flare K.O drum	DH 107	
ACID	FS	122	LP FG K.O drum	D102 AB	
ACID	FS	141	utilities sump drum	D101	
ACID	FS	142	burn pit surge drum	D101	
ACID	FT	145	storage propane	D101	

Train 1 Loop

Unit 146 : Chemical Storage

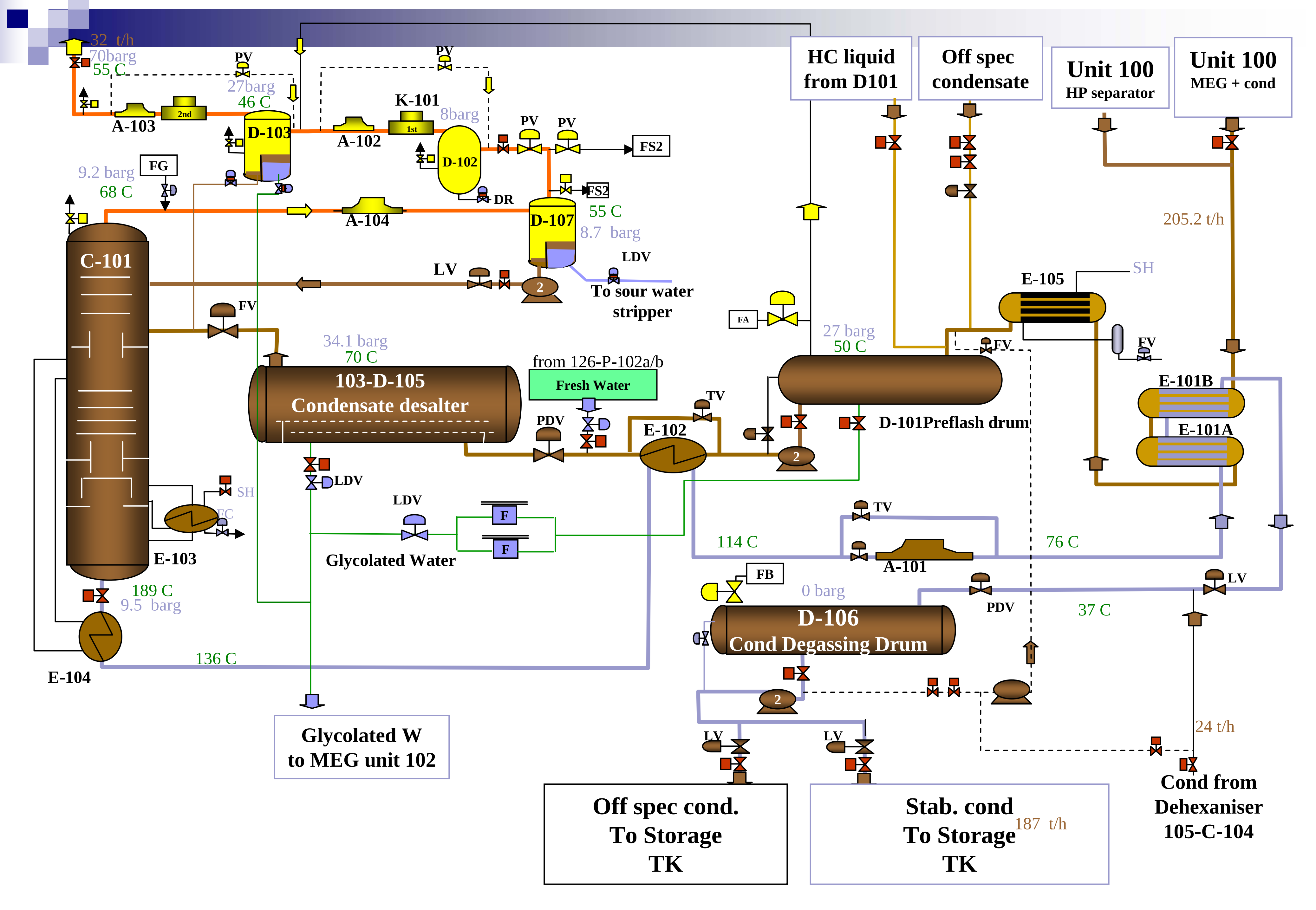


LOADING/UNLOADING CHEMICAL ZONE

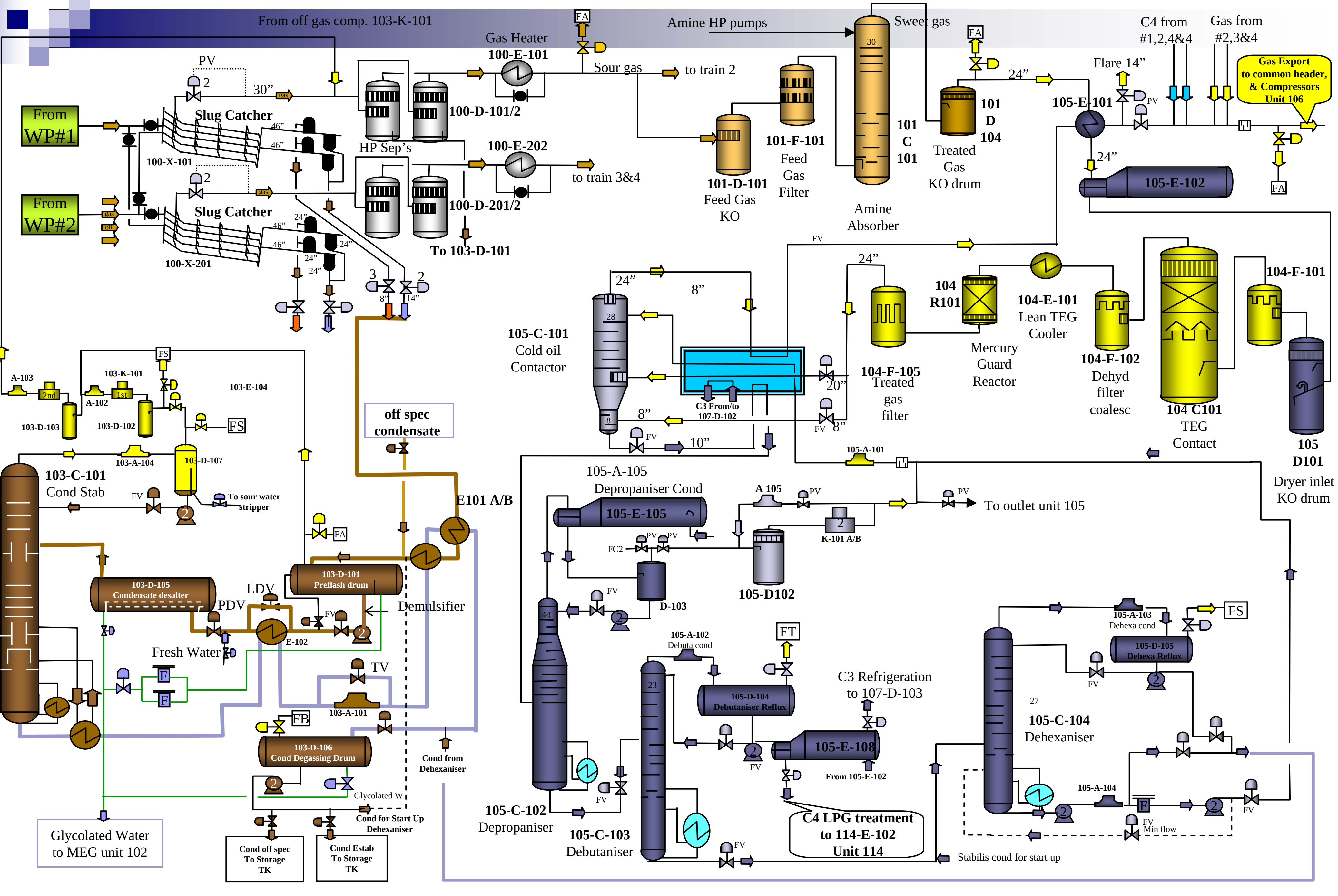


466 t/h
From
100-D-101/102
24 C
68 barg
BDV
D101
67.5 barg
F101
103D101
BDV
D104
450 t/h
Lean Gas
49 C
67 barg
C101
Amine
absorber
262 t/h
35 C
67.5 barg
PV 42 A
FS 2
PV 42 B
FG
0,5 t/h
C-103
D102
8 barg
M
A101
111 C
1,.3 barg
FB
1 barg
55 C
16.4 t/h
60%mol CO2
31,7 H2S
7.4 H2O
D-103
Amine
regenerator
Acid water
108 P101 A/B
1,5 barg
C102
SL
TC
CC
101
D-105
CL
34,5 t/h
132 C
E101 A//B//C
SW
58 C
E103 A//B
24 C
antifoam
1 barg
45 C
T101
101-U-101 lean amine filtration package

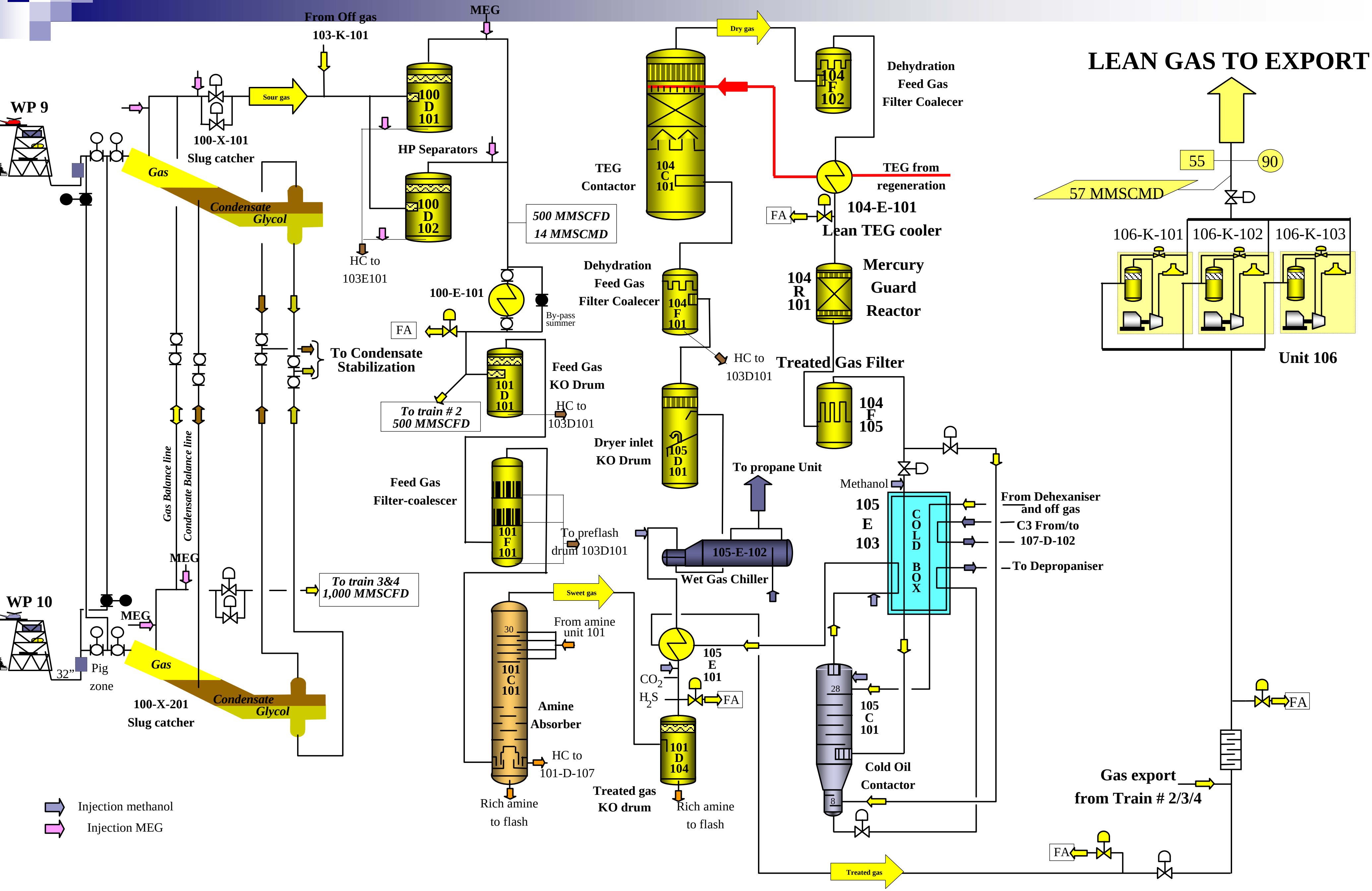
		DESIGN CASE SUMMER	DESIGN CASE WINTER	SENSITIVITY CASE SUMMER	SENSITIVITY CASE WINTER
Flowrate (Total Plant)	**MMSCFD**	1 945	1 940	1 941	1 935
	Kmole/h	97 052	96 786	96 846	96 571
Composition					
H20	% mole	0.060	0.037	0.059	0.036
N2	"	3.474	3.484	3.605	3.616
CO2	"	1.830	1.835	2.014	2.020
H2S	"	0.555	0.556	0.479	0.480
Methane	"	85.076	85.308	84.844	85.086
Ethane	"	5.438	5.452	5.393	5.408
Propane	"	1.991	1.973	1.996	1.979
ic4	"	0.369	0.349	0.373	0.353
nC4	"	0.573	0.528	0.578	0.531
iC 5	"	0.178	0.150	0.192	0.160
n c5	"	0.159	0.130	0.168	0.135
C6 cut	"	0.139	0.099	0.140	0.099
C7 cut	"	0.079	0.050	0.082	0.051
C8 cut	"	0.042	0.024	0.039	0.022
C9 cut	"	0.013	0.007	0.012	0.006
C10+	ppm mole	52.8	28.4	52.6	25.2
COS					
M- Mercaptan	ppm mole	3.1	3.1	3.1	3.0
E- Mercaptan	ppm mole	21.4	20.2	20.9	19.5
PR1 Thiol	ppm mole	138.0	119.0	135.0	116.0
BU1Thiol	ppm mole	37.5	27.1	33.2	23.5
HX1Thiol	ppm mole	6.2	4.1	5.4	3.5
	ppm mole	1.8	1.0	1.7	0.9
Total mole %					
		100.00	100.00	100.00	100.00
Molecular weight		19.20	19.07	19.27	19.12
Pressure	Bar abs	69.2 (*)	69.2 (*)	69.2 (*)	69.2 (*)
Temperature	°C	24	24	24	24



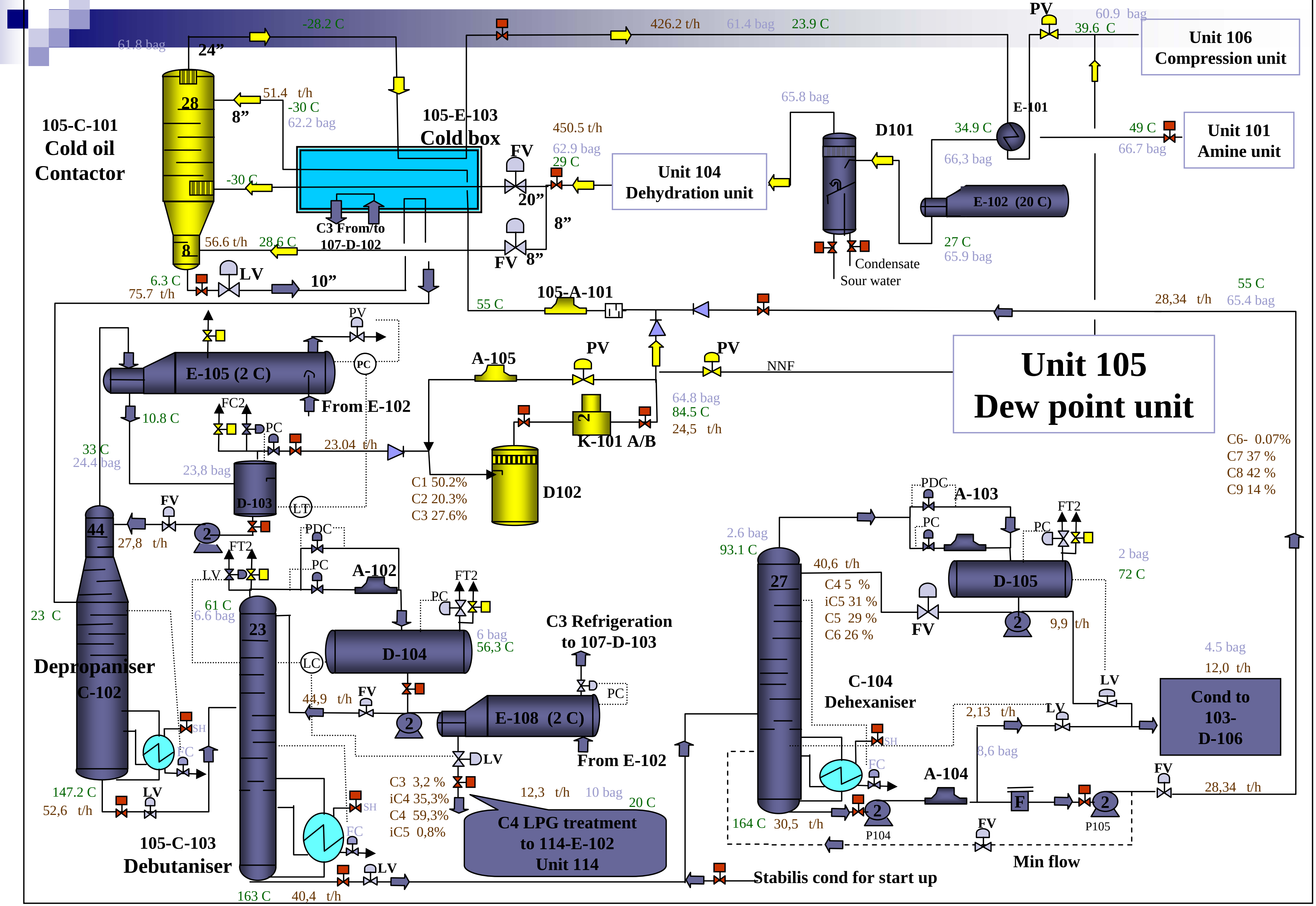
32 t/h
70barg
55 C
PV
27barg
46 C
A-103
2nd
D-103
A-102
K-101
1st
8barg
PV
D-102
PV
PV
FS2
FS2
DR
9.2 barg
68 C
FG
A-104
D-107
55 C
8.7 barg
LDV
To sour water stripper
LV
C-101
FV
34.1 barg
70 C
103-D-105
Condensate desalter
from 126-P-102a/b
Fresh Water
PDV
TV
E-102
HC liquid from D101
Off spec condensate
Unit 100
HP separator
Unit 100
MEG + cond
205.2 t/h
E-105
SH
FA
27 barg
50 C
FV
FV
E-101B
E-101A
D-101Preflash drum
LDV
SH
FC
LDV
E-103
F
F
Glycolated Water
TV
114 C
A-101
76 C
189 C
9.5 barg
E-104
136 C
FB
0 barg
PDV
LV
37 C
D-106
Cond Degassing Drum
Glycolated W to MEG unit 102
LV
LV
24 t/h
Off spec cond. To Storage TK
Stab. cond To Storage TK
187 t/h
Cond from Dehexaniser 105-C-104


From off gas comp. 103-K-101
Gas Heater
100-E-101
FA
Amine HP pumps
Sweet gas
C4 from #1,2,4&4
Gas from #2,3&4
PV
30"
Sour gas
to train 2
FA
24"
Flare 14"
Gas Export to common header, & Compressors Unit 106
From WP#1
Slug Catcher
100-D-101/2
HP Sep's
100-X-101
100-E-202
to train 3&4
101-D-101 Feed Gas KO
101-F-101 Feed Gas Filter
101 C 101
Amine Absorber
101 D 104
Treated Gas KO drum
105-E-101
24"
105-E-102
FA
From WP#2
Slug Catcher
100-D-201/2
100-X-201
To 103-D-101
FV
24"
104 R101
104-E-101 Lean TEG Cooler
104-F-101
105-C-101 Cold oil Contactor
24"
8"
20"
8"
C3 From/to 107-D-102
104-F-105 Treated gas filter
Mercury Guard Reactor
104-F-102 Dehyd filter coalesc
104 C101 TEG Contact
105 D101 Dryer inlet KO drum
A-103
103-K-101
103-E-104
FS
103-D-103
A-102
103-D-102
FS
off spec condensate
103-A-104
103-D-107
103-C-101 Cond Stab
FV
To sour water stripper
E101 A/B
10"
105-A-101
105-A-105 Depropaniser Cond
A 105
PV
105-E-105
To outlet unit 105
FC2
K-101 A/B
FA
103-D-101 Preflash drum
103-D-105 Condensate desalter
LDV
PDV
Demulsifier
E-102
FV
D-103
105-D102
Fresh Water
TV
103-A-101
105-A-102 Debuta cond
FT
105-D-104 Debutaniser Reflux
C3 Refrigeration to 107-D-103
105-A-103 Dehexa cond
FS
105-D-105 Dehexa Reflux
105-C-104 Dehexaniser
FB
103-D-106 Cond Degassing Drum
Cond from Dehexaniser
105-E-108
From 105-E-102
105-C-102 Depropaniser
105-C-103 Debutaniser
C4 LPG treatment to 114-E-102 Unit 114
105-A-104
FV Min flow
Glycolated W
Cond for Start Up Dehexaniser
Glycolated Water to MEG unit 102
Cond off spec To Storage TK
Cond Estab To Storage TK
Stabilis cond for start up

GENERAL PDF

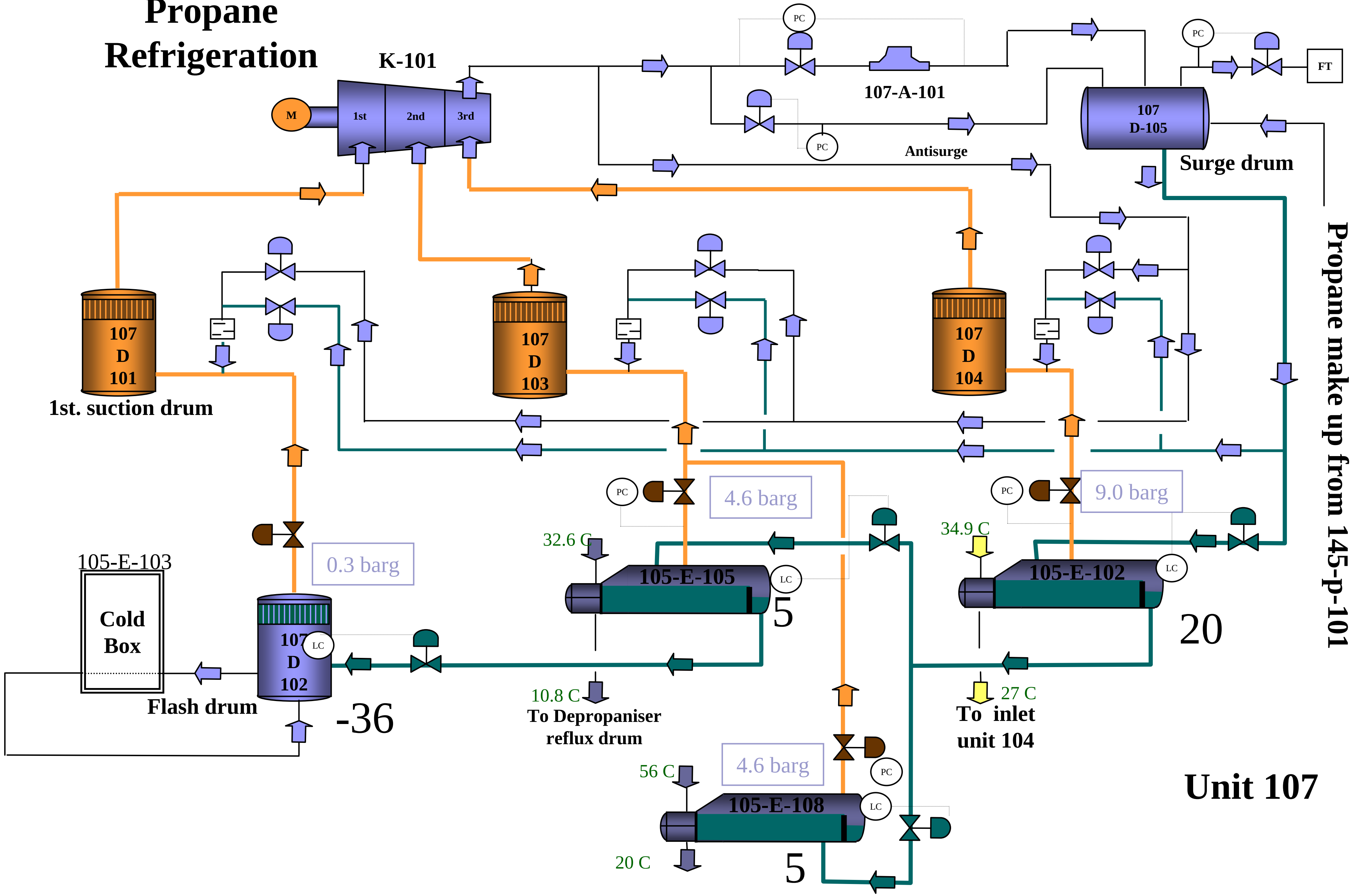


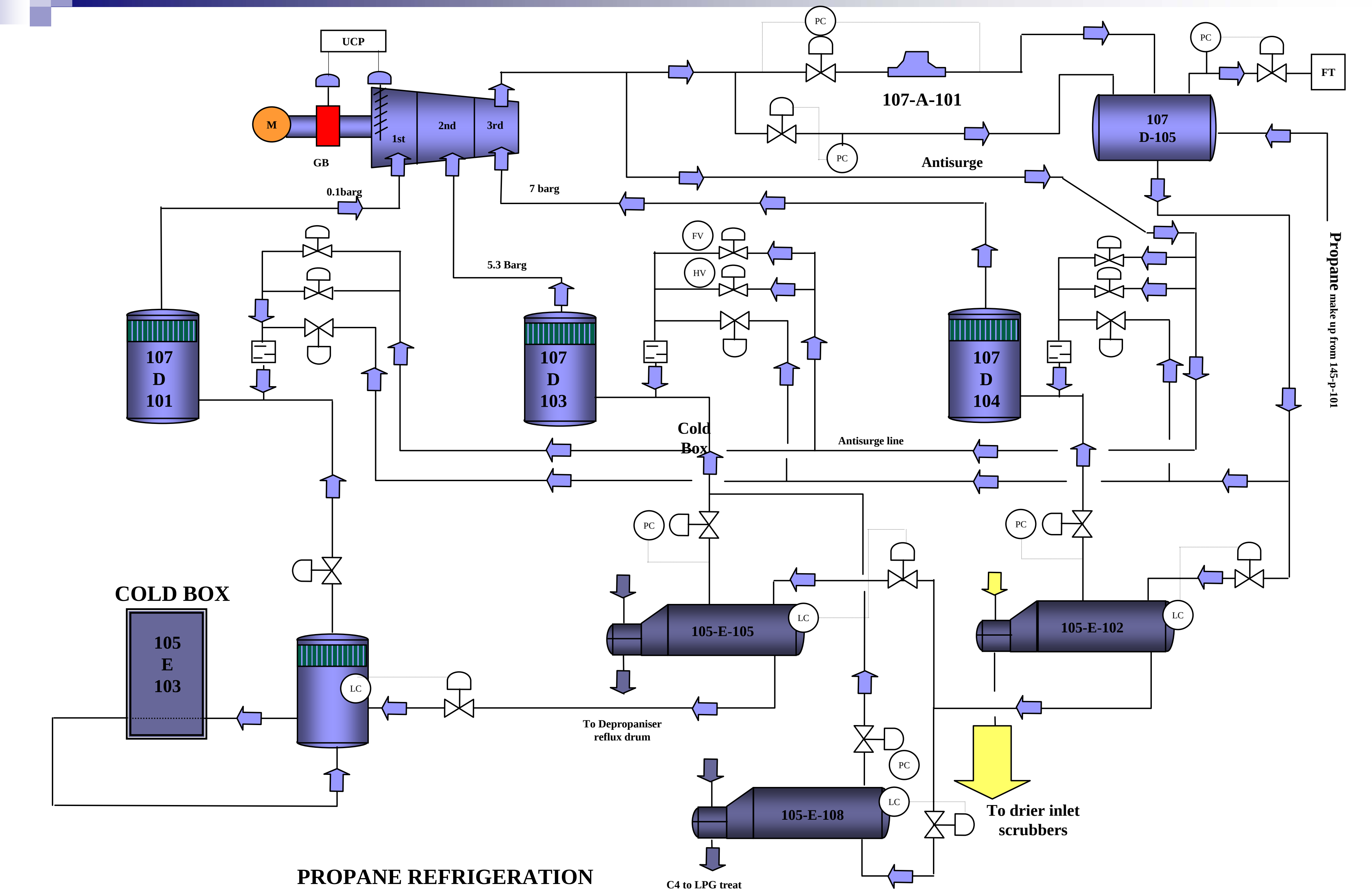
Gas Treating Train 1



-28.2 C
61.8 bag
24”
426.2 t/h
61.4 bag
23.9 C
PV
60.9 bag
39.6 C
Unit 106
Compression unit
105-C-101
Cold oil
Contactor
28
51.4 t/h
-30 C
62.2 bag
8”
105-E-103
Cold box
450.5 t/h
62.9 bag
29 C
FV
65.8 bag
D101
34.9 C
E-101
49 C
66.7 bag
Unit 101
Amine unit
66,3 bag
-30 C
20”
Unit 104
Dehydration unit
E-102 (20 C)
C3 From/to
107-D-102
8”
56.6 t/h
28.6 C
8
FV
8”
27 C
65.9 bag
Condensate
Sour water
6.3 C
75.7 t/h
LV
10”
105-A-101
55 C
55 C
28,34 t/h
65.4 bag
PV
E-105 (2 C)
PC
From E-102
A-105
PV
PV
NNF
Unit 105
Dew point unit
10.8 C
FC2
PC
64.8 bag
84.5 C
24,5 t/h
K-101 A/B
33 C
24.4 bag
23,8 bag
23.04 t/h
D-103
LT
C1 50.2%
C2 20.3%
C3 27.6%
D102
C6- 0.07%
C7 37 %
C8 42 %
C9 14 %
FV
44
27,8 t/h
2
FT2
PDC
PC
LV
A-102
FT2
PC
PDC
A-103
PC
FT2
PC
2.6 bag
93.1 C
40,6 t/h
27
C4 5 %
iC5 31 %
C5 29 %
C6 26 %
D-105
2 bag
72 C
FV
9,9 t/h
23 C
61 C
6.6 bag
23
D-104
6 bag
56,3 C
C3 Refrigeration
to 107-D-103
LC
Depropaniser
C-102
44,9 t/h
FV
2
E-108 (2 C)
PC
From E-102
LV
C-104
Dehexaniser
4.5 bag
12,0 t/h
LV
Cond to
103-
D-106
2,13 t/h
LV
SH
FC
SH
FC
8,6 bag
A-104
147.2 C
52,6 t/h
LV
C3 3,2 %
iC4 35,3%
C4 59,3%
iC5 0,8%
12,3 t/h
10 bag
20 C
C4 LPG treatment
to 114-E-102
Unit 114
SH
FC
F
2
P104
2
P105
FV
28,34 t/h
FV
164 C
30,5 t/h
105-C-103
Debutaniser
LV
Min flow
Stabilis cond for start up
163 C
40,4 t/h

Propane Refrigeration





PROPANE REFRIGERATION