

Introduction to natural gas plant LNG



Prepared by: DSc PhD Dževad Hadžihafizović (DEng)

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STANDARD OPERATION PRACTICES

The normal operation of the Inlet Separation and NGL Storage Unit consists primarily of monitoring the process conditions and correct operation of the various control loops.

- 1) Visual inspection of the equipment and piping is necessary as part of the normal operating duties.
- 2) Log sheets should be completed every four (4) hours recording levels, pressures, temperatures relevant flow rates and other instrumentation.
- 3) All controllers should be in the automatic mode, set at the correct operating values.
- 4) Items of equipment not in current service should be monitored for pressure build up and drained and vented as required to prevent blocked in thermal expansion.

PUMP CHECKS

- ✓ The general line-up of the pumps (on line and stand by), Suction and discharge valves must be wide opened for the pump on line.
- ✓ The spare pump should be set to auto ready to cut in if a failure occurs on the running pump (if applicable).
- ✓ The flow of lube oil through the sight glass if applicable
- ✓ The line up of the cooling water
- ✓ The line up of the filters
- ✓ The leaks on mechanical seals and bearings
- ✓ The temperature of the bearings
- ✓ The vibration of the shaft/bearings
- ✓ Report any abnormal noise or smell

ELECTRICAL MOTOR CHECKS

- ✓ The load current (amps consumption)
- ✓ The level in the oil reservoir
- ✓ The vibrations of the bearing
- ✓ Abnormal noise and/or smell
- ✓ The safety guard coupling is securely fitted
- ✓ The connection of electrical earth cables
- ✓ The air is coming out the fan
- ✓ The cooling fins are clean

OIL FILTERS CHECKS

INTRODUCTION TO LIQUEFACTION NATURAL GAS PLANT

General

What is LNG?

When natural gas is cooled to a temperature of approximately -256°F (-160°C) at atmospheric pressure it condenses to a liquid called liquefied natural gas (LNG). One volume of this liquid takes up about 1/600th the volume of natural gas at a stove burner tip. LNG weighs less than one-half of water, actually about 45% as much. It is odorless, colorless, non-corrosive, and non-toxic. When vaporized, it burns only in concentrations of 5% to 15% when mixed with air. Neither LNG nor its vapor can explode in an unconfined environment. By putting it into LNG state is making safe and efficient to transport the gas across long distances and bodies of water.

Composition

Natural gas is composed primarily of methane (typically, at least 90%), but may also contain ethane, propane and heavier hydrocarbons. Small quantities of nitrogen, oxygen, carbon dioxide, mercury, sulfur compounds, and water may also be found in “pipeline” natural gas. The LNG process removes the oxygen, carbon dioxide, mercury, sulfur compounds, and water. The process can also be designed to purify the LNG to almost 100% methane.

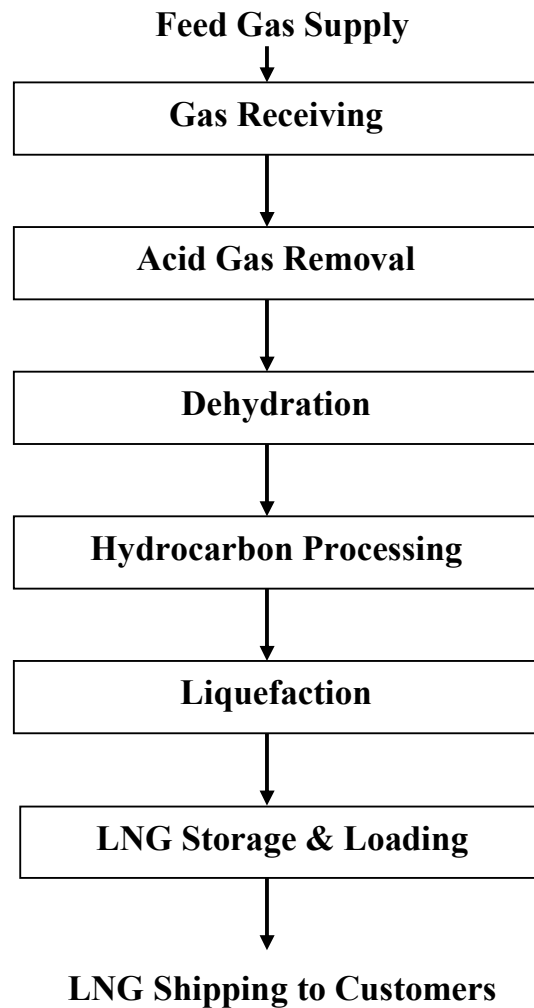
Have There Been Any Serious LNG Accidents?

First, one must remember that LNG is a form of energy and must be respected as such. Today LNG is transported and stored as safely as any other liquid fuel. Before the storage of cryogenic liquids was fully understood, however, there was a serious incident involving LNG in Cleveland, Ohio in 1944. This incident virtually stopped all development of the LNG industry for 20 years. The race to the Moon led to a much better understanding of cryogenics and cryogenic storage with the expanded use of liquid hydrogen (-423°F / -253°C) and liquid oxygen (-296°F / -182°C). LNG technology grew from NASA’s advancement.

In addition to Cleveland, there have been two other U.S. incidents sometimes attributed to LNG. A construction accident on Staten Island in 1973 has been cited by some parties as an “LNG accident” because the construction crew was working inside an (empty, warm) LNG tank. In another case, the failure of an electrical seal on an LNG pump in 1979 permitted gas (not LNG) to enter an enclosed building. A spark of undetermined origin caused the building to explode. As a result of this incident, the

electrical code has been revised for the design of electrical seals used with all flammable fluids under pressure.

Process Units of an LNG Plant



INTRODUCTION TO ELNG PLANT

The LNG Train1plant is a grassroots, completely self-sufficient facility designed to produce a nominal 3.6 million metric tons per annum (340 stream days) of LNG

Feedstock is supplied from an upstream gas plant, and is processed through a feed gas heater for hydrate prevention, filtered, and then a DGA (Diglycolamine) gas treating system to remove the carbon dioxide, hydrogen sulfide, and other sulfur components that may be present in the gas. Diglycolamine was selected as the treating solvent because of its efficiency and capacity to remove these objectionable components from the gas at a competitive cost compared to other similar treating agents. Treated gas from the treating system is air cooled and subsequently chilled to a temperature approximately 17 °C, which is just above the hydrate point, in order to remove as much water as possible prior to mol sieve dehydration. The condensed water is sent to the wet hydrocarbon liquid storage Drum prior to discharging to the battery limits through the CPI/Oil Water Separator.

The chilled gas is dried in a molecular sieve system to remove the remaining water. The dry gas is further processed through a Mercury Removal system to remove any mercury that may be present in the feed gas.

The dry mercury-free gas is subsequently fed to the refrigeration system where it is liquefied as the LNG product.

There are three refrigeration services, Propane, Ethylene, and Methane, which are optimally cascaded to provide maximum LNG production by efficiently utilizing the maximum available horsepower of the compressor/turbine sets

FACILITIES

The facility consists of the following units:

- Inlet Separation & NGL Storage
- Acid Gas Removal
- Dehydration and Mercury Removal
- Propane Refrigeration
- Ethylene Refrigeration
- Liquefaction and Methane Compression
- Heavies Removal/NGL Recovery
- Flares / Blowdown / Incinerator System
- Refrigerant Storage
- Diesel Storage
- Fuel Gas System
- LNG Storage and Loading

INLET SEPARATION AND NGL STORAGE

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Introduction

Purpose of unit

Main Equipment

Process description

Losses of utilities

PURPOSE

The purpose of the inlet separation and NGL storage unit is to meter the feed gas in term of quality and quantity .

The quality is measured by sampling the feed gas and knowing its composition and heating value, while the quantity is measured by calculating the flow rate at the inlet conditions in term of temperature and pressure.

Composition determination (Quality)

A chromatograph, is used to analyze the components of a gaseous mixture or of a liquid in vapor form. It operates on the principle that if a gaseous mixture is forced through a certain material that resists its flow, gases that have a lower density or boiling point will pass through more quickly than the ones that are more dense.

A basic chromatograph consists of a separation column, packed with an absorbent material and installed in an oven that is maintained at a constant temperature. The column is connected to a regulated supply of inert carrier gas, such as helium or argon, indicated in. The gas sample mixes with the carrier gas and flows through the column. Each component of the gas mixture is identifiable by the time that elapses between the injection of a sample into the column and the emergence of that component.

Quantitative measurement of each component depends on the difference in thermal conductivity between the mixture of carrier gas in the reference leg and that of the carrier gas and a component in the detector leg. The heat sensitive elements in the detector are often thermistors or semiconductors whose electrical resistance decreases rapidly with an increase in temperature. When a greater quantity of a specific gas passes through the detector, the wheatstone bridge, to which these heat sensitive elements are connected, will become more unbalanced. The resulting trace on a chart will appear like that shown in .Peak heights and peak areas above the base line are used to calculate the quantity of a particular gas component in the mixture.

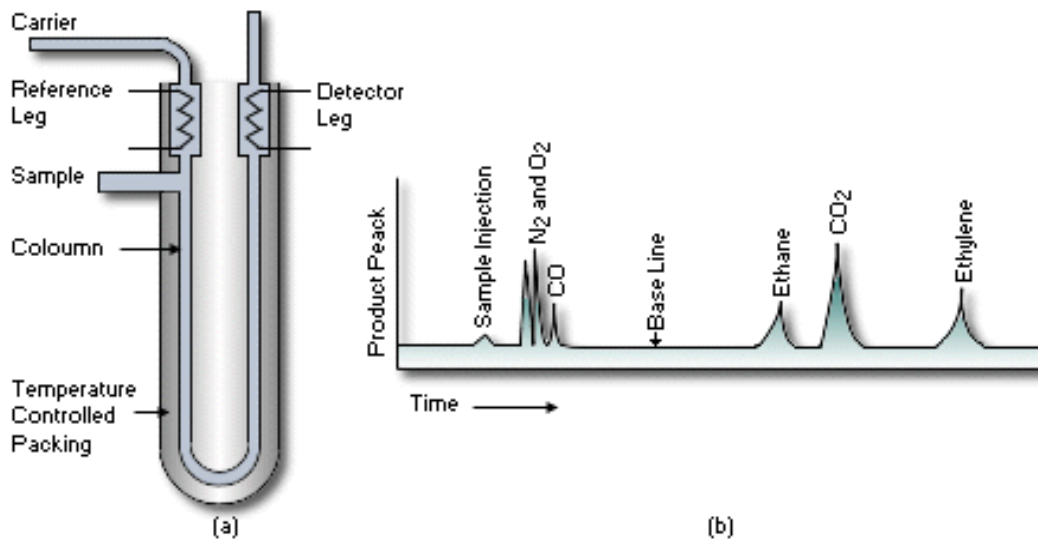


Figure 1. Gas chromatograph.

Quantity Measurement

Quantity is measured by one of the following methods :

1. Ultrasonic flow meter
2. Orifice plate
3. Venturi meter
4. Flow Nozzel

1. Ultrasonic flow meter

Doppler and transit-time flowmeters are two types of ultrasonic flow meters that have been extensively used in liquid applications around the world, certain companies are now applying the transit time method for gas flow measurement applications either flare gas or custody transfer.

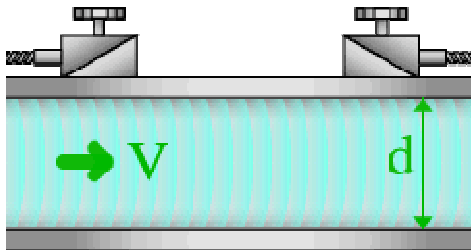


Figure 2 is clamp on ultrasonic flow meter transducers are installed on the same side of the pipe measuring a flow.

Measurement accuracy can be in the range 1 to 3 percent of measured value of 0.5 percent with process calibration depending on the application. The microprocessor-based electronics unit provides a local backlit display and has a keypad for setting up and diagnostics . The flowmeter can read flow units in common imperial or metric units , measures flow in both directions, can store up to 100,000 data points internally, give analog or serial .

The Electronics unit can log data for measuring sites. It can also provide a PC interface and an output of 4-20 mA DC for operating a digital controller, DCS, PLC, or recorder.

1. Orifice Plate

An orifice plate is the most common form of head meter that is used in flow measurement. It consists of a flat metal plate with an opening of a fixed area, Fig. 3. The concentric type shown in (a) is the most common, but the eccentric and segmental in (b) and (c), respectively, are also used in special applications. The outside of the plate is designed to fit inside the bolt circle on standard flanges.

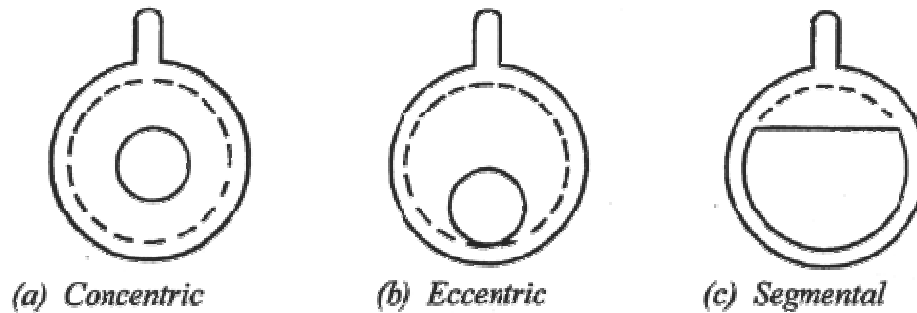


Figure 3. Orifice plates.

Fig. 4 illustrates the pressure drop or differential pressure across an orifice plate. Note that the flow pattern shows an effective decrease in cross section beyond the plate, with the maximum velocity and maximum change in static pressure occurring at the narrowest point of flow called the vena contracta. After this point in the flow stream only some of the pressure drop is recovered, as turbulence and friction have created considerable permanent pressure loss.

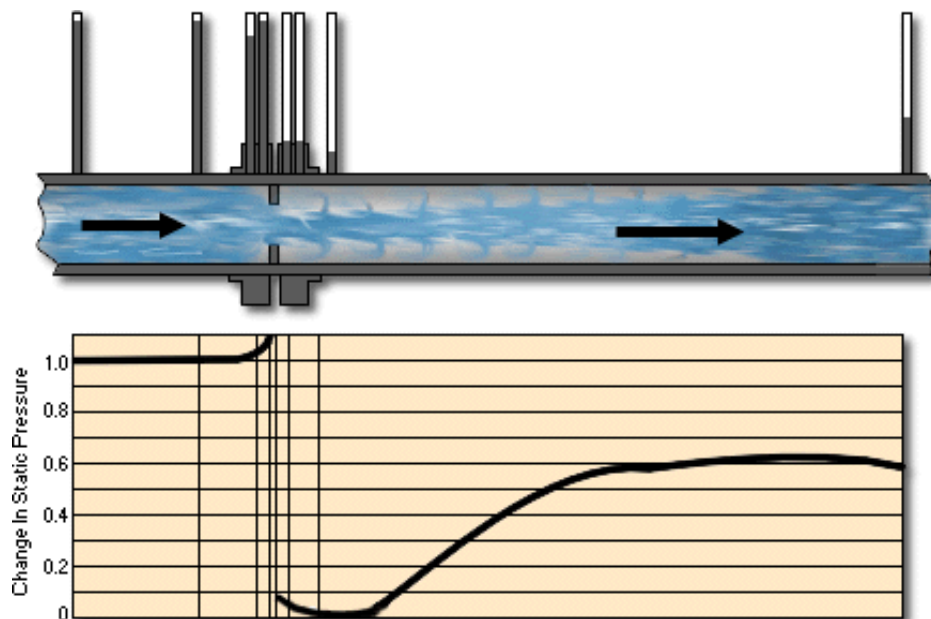
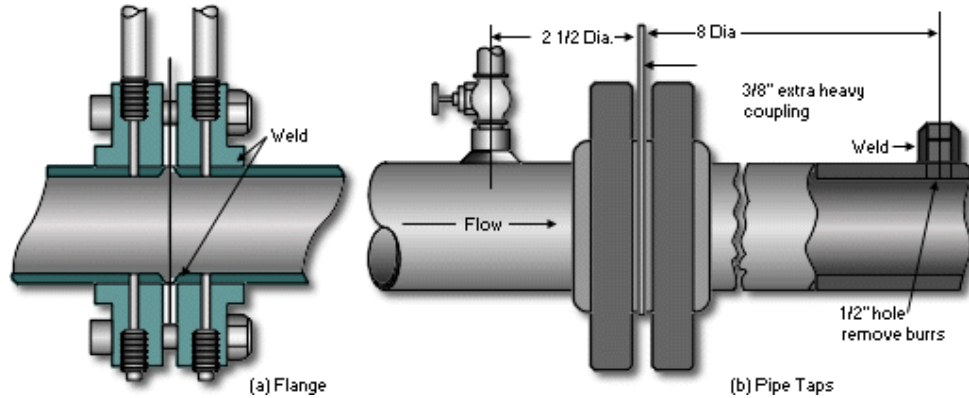


Figure 4. Pressure drop across an orifice plate.

The pressure differential across an orifice is measured by two pressure connections, one before the plate and another downstream from the plate. Fig. 5 (a) and (b) shows two types of connections. In (a) the pressure connections or taps are located directly on the flanges, while in (b) the taps are located on the pipe at a specific distance from the orifice plate.

Figure 5. Flange and pipe taps.

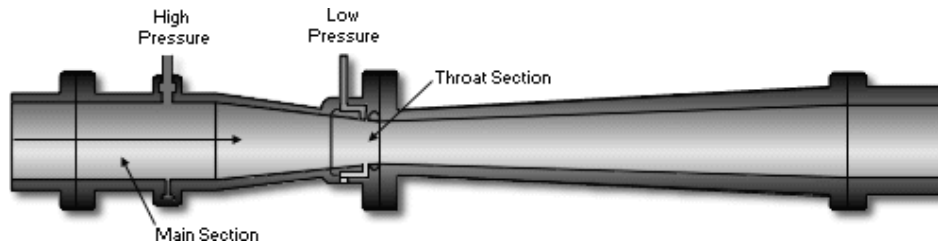


The orifice plate is easy to install and replace. It is low in cost, and different sizes may be easily substituted if the flow range is varied, but it is the least accurate and creates the highest permanent pressure loss.

2. Venturi Tube

This flow sensing element, installed between flanges, Fig. 6 converges to a minimum cross section, called the throat, and then diverges to the original pipe size. High- and low-pressure connections are installed at specified locations as indicated. The venturi tube produces less permanent pressure loss than an orifice plate. On the other hand, it has the disadvantages of higher cost and bulkiness.

Figure 6. Venturi tube.



3. Flow Nozzle

The flow nozzle in Fig. 7 is an adaptation of the venturi tube. It consists essentially of a venturi tube without the diverging section, but its pressure recovery is not as efficient. Flow nozzles are used principally for measurement of high velocity flows. The high-pressure connection is located one internal pipe diameter before the inlet face of the nozzle, while the low-pressure tap is usually one-half the pipe diameter downstream.

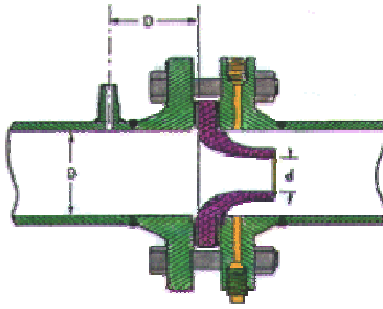


Figure 7. Flow nozzle.

MAIN EQUIPMENTS

TAG NAME	EQUIPMENT	FUNCTION
PK-1101	Feed gas metering package	Meter the feed gas in term of quality and quantity
E-1106	Feed gas heater	To maintain the feed gas temperature above its hydrate formation point.
V-1101	Wet hydrocarbon liquid separation vessel	Receive water hydrate inhibitor and hydrocarbon liquids from the acid gas removal unit .
V-1102	NGL liquid Storage .	To receive the NGL recovered from stabilization distillation column.
PK-1103	NGL metering package	To meter the NGL from the NGL liquid storage to upstream gas plant
P-1101 A/B	Oil water transfer pumps	To transfer oily water to unit 29

LOSS OF UTILITIES

1- Loss of Instrument Air

Loss of instrument air would result in all Control and Solenoid Valves failing to their safe positions. The unit will be shut down and discontinue to operate. BDV to flare will be open and isolation is required.

2- Loss of A.C. Power

The loss of A.C. power would result in the shutdown of all lube oil pumps of the Feed Gas Compressor and fan motors within the unit. The train ESD should be activated if the power cannot be re-established immediately.

PROCESS DESCRIPTION

3.1 Feed Gas

Feed gas is supplied to the plant through the Feed Gas Metering Package (1PK-1101). The feed gas is metered in gas metering system in term of quantity and quality as follows:

GAS COMPOSITION	UNITS	DESIGN FEED CASE	RICH FEED CASE
CO2	Mole %	0.225	0.192
N2	Mole %	0.110	0.068
C1	Mole %	97.358	92.381
C2	Mole %	2.122	4.717
C3	Mole %	0.098	1.309
i-C4	Mole %	0.041	0.430
n-C4	Mole %	0.028	0.419
i-C5	Mole %	0.005	0.173
n-C5	Mole %	0.003	0.105
C6	Mole %	0.003	0.109
C7	Mole %	0.002	0.060
C8	Mole %	0.001	0.025
C9+	Mole %	0.004	0.011
TOTAL	Mole %	100	100
BENZENE	ppm	25	250
H2S	ppm	50	50

The unit is furnished by Gas Heater (1E-1106). To maintain the feed gas temperature above its hydrate formation point. Under normal operation, little or no heat input will be required to reach the design inlet feed gas temperature of 31°C.

3.2 NGL Storage.

The wet Hydrocarbon Liquid separation vessel (V1101) is provided to receive water, hydrate inhibitor, and hydrocarbon liquids from the following units

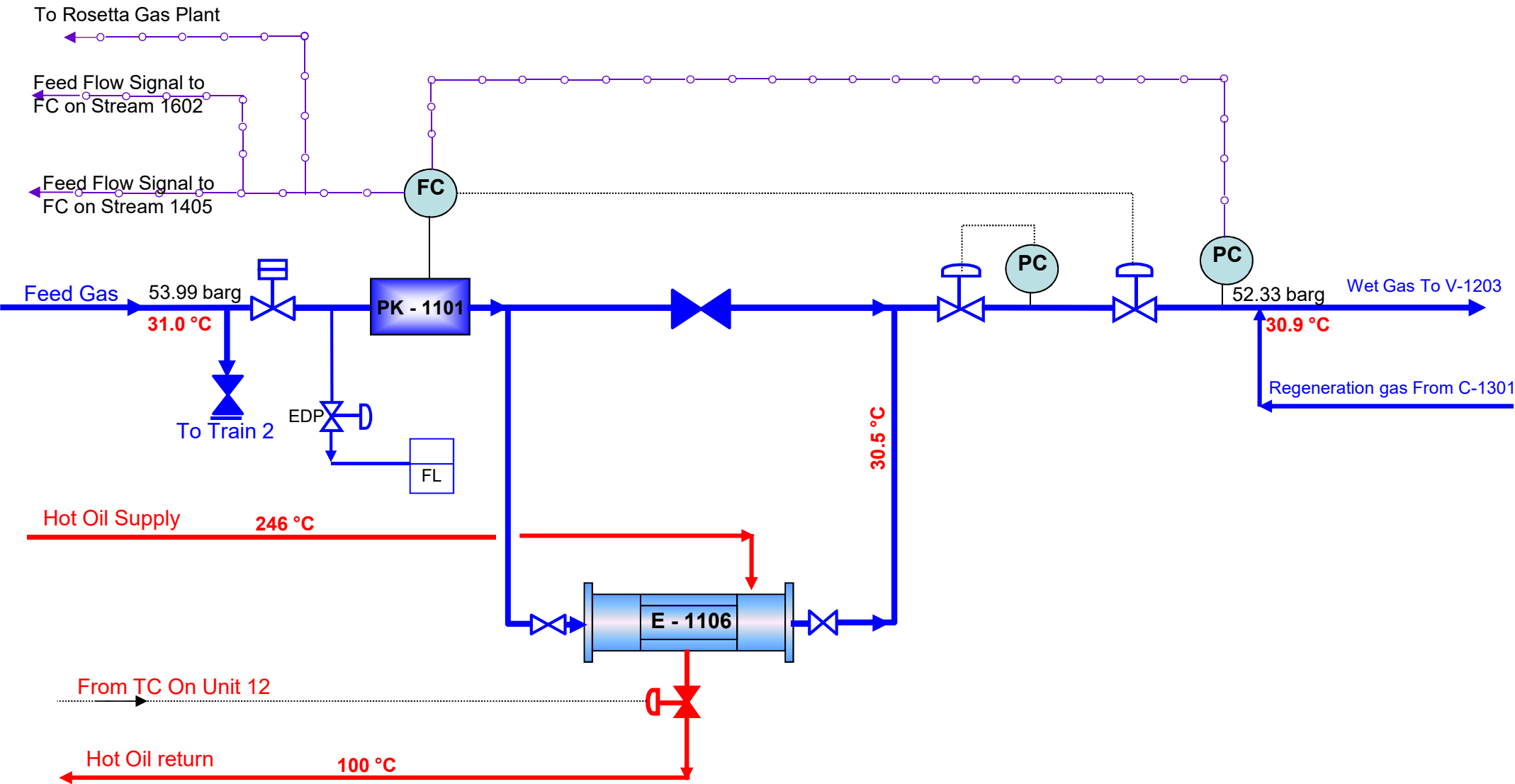
1. Acid Gas Removal Unit
2. Fuel Gas System
3. Dehydration
4. Mercury removal

Wet hydrocarbon collected in the vessel (V-1101) is pumped to oily water treatment unit (PK2905).

The storage vessel V1102 is provide in this unit to receive the NGL recovered from stabilization distillation column V1702. NGL from this vessel is pumped to upstream gas plant via a metering skid. PK- 1103.

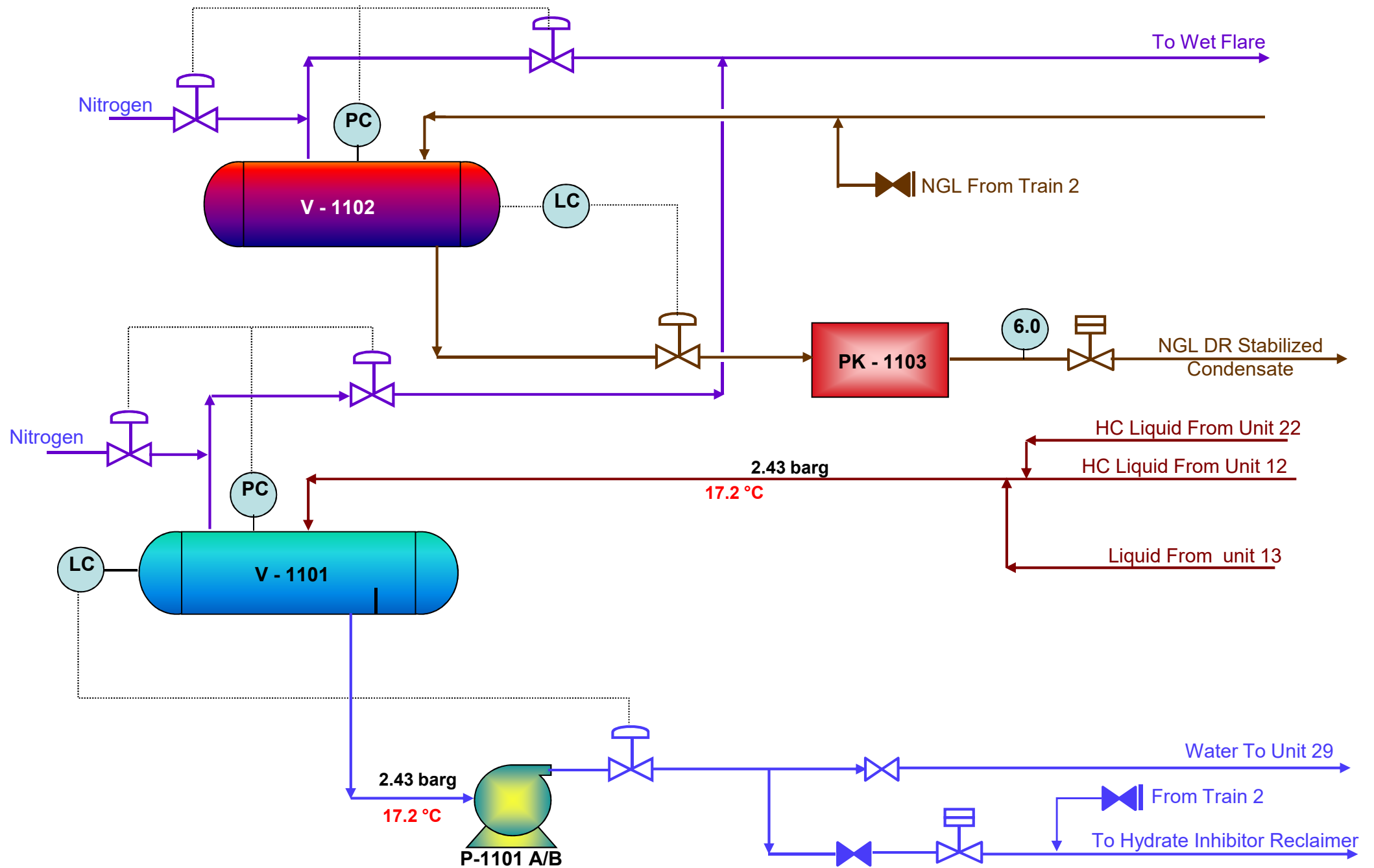
Inlet Separation and NGL storage

Feed Gas



Inlet Separation and NGL storage

NGL / Wet HC Storage



ACID GAS REMOVAL

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Introduction to Acid Gas Removal Process

Hydrogen sulfide and carbon dioxide are common contaminants of natural gas and are removed from the natural gas in order to produce a sales gas. Hydrogen sulfide and carbon dioxide are called “acid gases” because when dissolved in water they form weak acids.

Hydrogen sulfide must be removed- from natural gas because of its high toxicity and strong, offensive odor. Carbon dioxide would frozen up at cryogenic temperature causing blocking in the equipment, exchangers tubes. Another reason why these gases must be removed is because they are corrosive.

LNG must contain less than 5 ppm hydrogen sulfide and less than 100 ppm carbon dioxide, however different jurisdictions have different standards.

In the past it was permissible to flare small amounts of acid gas. However, with growing environmental concerns, such practices are being legislated out of existence.

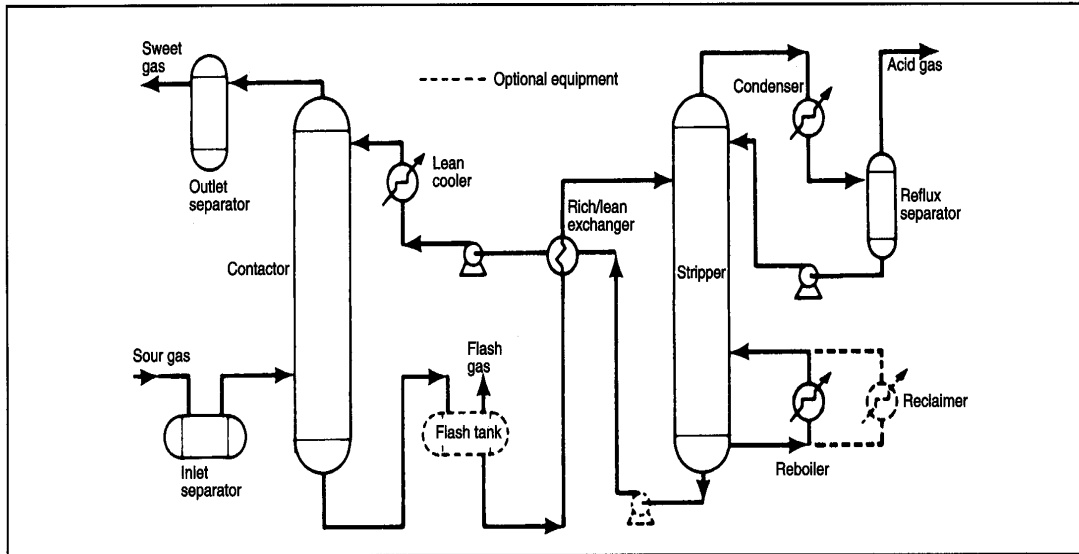
In addition, the disposal of carbon dioxide to the atmosphere is becoming an undesirable practice. Whether or not one believes that CO₂ is harmful to the environment has almost become a mute point.

Basic process for acid gas removal unit

Acid gas removal unit consists of the following process

1. Absorption
2. Flashing
3. Regeneration
4. Filtration

Typical Gas Sweetening by Chemical Reaction



Process Flow

The general process flow for an alkanolamine treating plant is shown in [figure](#). The basic flow varies little for different solutions though some designs incorporate multiple feeds and contactor sections.

Sour natural gas enters through an inlet separator for the removal of liquids and/or solids. From the separator, the gas stream enters the bottom of the contactor where it contacts the amine solution flowing down from the top of the column.

The acid gas components in the gas react with the amine to form a regenerable salt. As the gas continues to pass up the contactor, more acid gases chemically react with the amine.

The sweetened gas leaves the top of the contactor and passes through an outlet separator to catch any solution which may be carried over. If DGA is the sweetening agent, or the contactor is operating at unusually high temperature, a water wash may be used to attempt to recover some of the vaporized amine from the gas leaving the contactor. If a water wash is used it generally will consist of three or four trays at the top of the contactor, with makeup water to the unit being used as the wash liquid. The sweet gas leaving the contactor is saturated with water so dehydration is normally required priority. Rich amine solution leaving the contactor flows through a flash tank to remove absorbed hydrocarbons. From the flash tank, the rich solution passes through the rich/lean exchanger where heat is absorbed from the lean solution. The heated rich amine goes to the top portion of the stripper. As the solution flows down the column to the reboiler, it is stripped of H₂S and CO₂. The amine solution leaves the bottom of the stripper as lean solution. This lean solution is then passed through the rich/lean exchanger and a lean cooler to reduce the lean solution temperature to approximately 6°C warmer than the inlet gas temperature, to stay above the hydrocarbon dew point. At this point, the lean solution is returned to the contactor to repeat the cycle.

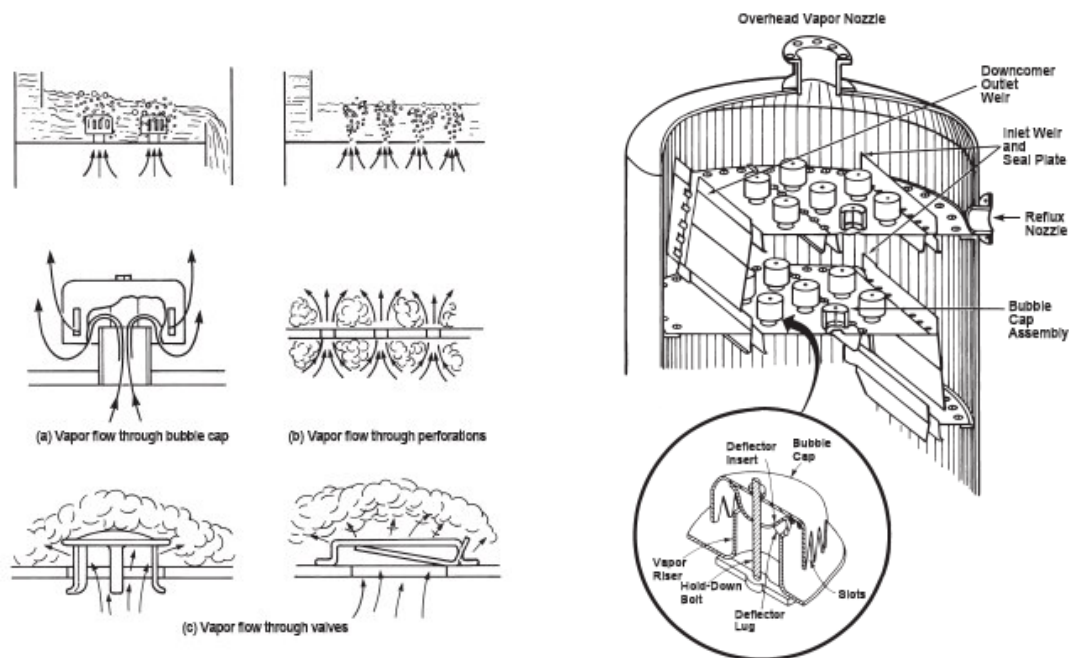
1. Absorption Process

Absorption: A separation process involving the transfer of a substance from a gaseous phase to a liquid phase through the phase boundary.

Acid Gas Absorber (Contactor)

The natural gas feed at ambient temperature enters the bottom of the absorber and flows up through the column which is equipped with valve trays.

CO₂ is removed by countercurrent contact of the feed gas with DGA solution recycled from the amine stripper. The lean amine solution enters the absorber through an internal liquid distributor above the trays. As it flows down through the column the CO₂ is absorbed into the amine solution. The treated gas is passed through the water wash section at the top of the tower to prevent loss of amine solution as the gas exists the conductor.



The sweetened gas is passed through a separator to remove any amine solution (or liquid water) that may be traveling with the gas flow .

The gas is now saturated with water and must proceed through dehydration facilities.

Diglycolamine (DGA)

DGA is a primary amine capable of removing not only H₂S and CO₂, but also COS and mercaptans from gas and liquid streams. Because of this, DGA has been used in natural gas applications. DGA has been used to treat natural gas to 0.25 grains/100 scf at pressures as low as 125 psig. DGA has a greater affinity for the absorption of aromatics, olefins, and heavy hydrocarbons other systems.

Chemistry of acid gas absorbing

1. CO₂ reaction

- Carbonate formation (0.0 to 0.5 m/m)
 - $\text{CO}_2 + 2[\text{Amine}] \rightleftharpoons [\text{Amine}]^+ + [\text{Amine}]\text{Coo}^-$
- Acid base reaction (0.5 to 1.0 m/m)
 - $\text{CO}_2 + \text{H}_2\text{O} \rightleftharpoons \text{H}_2\text{CO}_3$
 - $\text{H}_2\text{CO}_3 \rightleftharpoons \text{H}^+ + \text{HCO}_3^-$
 - $\text{H}^+ + [\text{Amine}] \rightleftharpoons [\text{Amine}]^+$

2. H₂S reaction

- Dissociation
 - $\text{H}_2\text{S} + \text{H}_2\text{O} \rightleftharpoons \text{H}^+ + \text{HS}^- + \text{H}_2\text{O}$
- Acid base reaction
 - $\text{HS}^- + [\text{Amine}] \rightleftharpoons [\text{Amine}]^+ + \text{S}^{2-}$
- H₂S reaction
 - $\text{H}_2\text{S} + [\text{Amine}] \rightleftharpoons [\text{Amine}]^+ + \text{HS}^-$

2- Flashing

Rich solution leaving the contactor may pass through a flash tank. Gases entrained in the rich solution will be separated. In addition, the amount of absorbed gas will be decreased because of the lower operating pressure of the flash tank. Using a flash tank will:

- Reduce erosion in rich/lean exchangers.
- Minimize the hydrocarbon content in the acid gas.
- Reduce the vapor load on the stripper.
- Possibly allow the off-gas from the flash tank to be used as fuel (may require sweetening).

When heavy hydrocarbons are present in the natural gas, the flash tank can also be used to skim off the heavy hydrocarbons that were absorbed by the solution. Residence times for flash tanks in amine service vary from 5-30 minutes depending on separation requirements. Inlet gas streams containing only methane and ethane require shorter residence times. Rich gas streams require longer time for the dissociation of gas from solution and/or the separation of liquid phases.

3. Regeneration / Stripping process

Where the acid gas in rich amine solution is stripped out to obtain the lean amine solution. The rich amine enters the stripper, where hot acid gas and steam heat the rich amine, removing the H₂S and CO₂ that is bound into the product.

Process variables of regeneration

1. High temperature
2. Low pressure
3. High stripping steam rate
4. Low amine concentration
5. Intimate contacting

Reboiler

- The amine at the bottom of the stripper tower is heated to 105°C – 140°C (depending on the type of amine being used).
- This causes the acid gas/amine reaction to reverse and the acid gas vapourizes with steam from the amine solution.
- The acid gas/steam vapour re-enters the stripper and contacts new rich amine on its way out the top. Amine carried with the acid gas/steam vapour tends to reunite with the rich liquid amine thereby removing it from the vapour flow.

Condenser

- After leaving the top of the stripper tower, the acid gas/steam vapour is cooled to remove heat and condense out the water from the flow.
- The water is separated in a reflux drum and returned to the stripper tower as a liquid.
- If the plant has a gas sulphur inlet rate of less than 1 tonne/day (this is a very small amount), the acid gas may be incinerated. Burning the H₂S creates SO₂ which is a monitored pollutant.

Reclaimer

A reclaimer may be used in DGA service. Reclaimer operation is a semi-continuous batch operation.

The reclaimer is filled with hot amine solution and, if necessary, soda ash is added. As the temperature in the reclaimer increases, the liquid will begin to distill. Overhead vapors can be condensed and pumped back into the amine system, but generally the reclaimer is operated at slightly above stripper column pressure and the vapors are returned to the stripper. The initial vapor composition is essentially water. Continued distillation will cause the solution to become more and more concentrated with amine. This raises the boiling point of the solution and amine will begin to distill overhead. Fresh feed is continually added until the boiling point of the material in the reclaimer reboiler reaches 138° to 149°C. At this point, distillation is continued for a short time adding only water to help recover residual amine in the reclaimer reboiler. The reclaimer is then cleaned, recharged, and the cycle is repeated.

Reclaimer "sludge" removed during cleaning must be handled with care. Disposal of the "sludge" must be in accordance with the governing regulations.

Lean Amine

- A lean amine stream from the bottom of the reboiler (or bottom of the tower) is pumped back to the contactor.

- The lean amine is often passed through a charcoal filtration system to remove entrained solids
- If anti-foam additives are added to the system, the charcoal filters will remove them, so they should be taken off-line during addition.
- The lean amine must be cooled to approximately 6°C warmer than the inlet gas temperature before it enters the contactor.

Amine treating plant operating problems

- Corrosion
- Foaming

1. Corrosion

Cause of corrosion

1. Amine concentration too high
2. Acid gas loading too high
3. High CO₂/H₂S ratio in gas
4. Oxygen in feed
5. Particulate in solution
6. High stripping over head pressure

Corrosion prevention measures

1. Monitor amine solution condition
2. Maintain low pressure on stripping column and reboiler
3. Maintain pressure on heat exchanger to minimize flashing
4. Maintain reboiler liquid level above the heating tubes
5. filter out suspended solids

2. Foaming

A sudden increase in differential pressure across a contactor often indicates severe foaming. When foaming occurs, there is poor contact between the gas and the chemical solution. The result is reduced treating capacity and sweetening efficiency, possibly to the point that outlet specification cannot be met.

Some reasons for foaming are:

1. Suspended solids
2. Organic acids
3. Corrosion inhibitors
4. Condensed hydrocarbons .
5. Soap-based valve greases .
6. Makeup water impurities .
7. Degradation products
8. Lube Oil

Solution to foaming problems

Improve inlet gas separation

1. Good solution purification
- Reclaimer, Mechanical and Activated carbon filters
2. Raised lean solvent temperature to contactor
3. Skimming of liquid hydrocarbons from columns
4. Reduce gas flow rate
5. Inject antifoam

Type : Silica based solution

Quantity : Based on vendor recommendation

Injection point:

1. Suction of amine charge pump
2. Reflux stream

PURPOSE OF UNIT 12

The purpose of the Acid Gas Removal Unit is to remove acid gas, mainly Carbon Dioxide CO₂ and Hydrogen Sulfide H₂S, from the natural gas feed from the Common Plant Feed Conditioning Unit to prevent these components from freezing out at low/cryogenic temperature and causing blockages and to meet LNG specification.

The DGA (diglycol amine) is used for this purpose.

MAIN EQUIPMENT UNIT 12.

Tag Number	Name	Function
V-1203	Feed gas separator	Separate liquid HC from sour gas
F-1202	Feed gas filter coalesce	Prevents gas carried contaminates of 1 microns and larger from getting into circulating amine solution.
V-1201	CO ₂ Absorber	Absorb the acid gas using DGA CO ₂ less than 100 ppmv H ₂ S less than 4 ppmv.
E-1206	Absorber over head gas cooler	Cool the sweetened gas in the absorber overhead and lowering the saturated water content
V-1204	Treated gas knock out drum	Remove condensed water.
V1205	Solvent flash drum	Receive rich amine (liquid) and allows most dissolved hydrocarbons to flash out of the solution
F-1203	Rich solvent filter	Remove any particles of size 10 micron and above from rich amine solution.
P-1204A/B	Wash water pumps	Supply the fresh demineralized water to remove any entrained

		amine solution from the gas leaving the absorber.
P-1203A/B	Regeneration reflux pump	Pump the condensate water from Solvent regenerator reflux drum to the regenerator column.
E-1203 A/B	Lean/rich solvent heat exchanger.	To heat the rich amine with hot stripped lean amine before being fed to the top of the stripping section of the solvent regenerator
E-1202	Regenerator overhead condenser.	Allow the water vapor from regenerator overhead to condense
V-1206	Solvent regeneration reflux drum	Receive the condensed water and acid gas . Send acid gas vapor for incinerator.
E-1204	Regenerator reboiler	To maintain the temperature at the bottom of the solvent regenerator.
E-1201	Lean solvent cooler	To cool the lean amine before filter to achieve a determined temperature for absorbing function.
F1205	Carbon treater	Receive about 12% of cool solvent and remove all dissolved organic contaminants.
F-1204	Lean solvent filter.	To filter the lean amine from particles larger than 10 micron.
F-1204	Lean solvent after filter	To filter the amine after the carbon filter.
T-1202	Amine Surge tank	Receiving the treated effluent
P-1202 A/B	Lean solvent charge pump.	To pump the treated amine

		solution to the absorber.
T-1201	Amine storage tank.	To fulfill amine need for the unit.
P-1205	Amine storage pump	Provide make up to the unit
E-1205	Solvent reclaimer.	To remove amine degradation product.
V-1209	Amine sump drum	Collect all drains from units
P-1201 A/B	Lean solvent booster pumps	To transfer the lean amine solution from the regenerator to be cooled and filtered to amine storage tank
F-1206	Amine sump filter.	To filter the recovered amine from drains

PROCESS DESCRIPTION

1 - Acid gas removal

As the name indicates the acid gas removal unit is meant to remove acid gas from the feed gas namely carbon dioxide and hydrogen sulfide.

Carbon dioxide present in amounts as high as 0.225 to 0.5 mol % can cause freezing and blocking problems in the downstream LNG liquefaction equipment, while hydrogen sulfide present in amounts as high as 50 ppmv makes the LNG produced out of specification.

Diglycol amine was selected to be the solvent for the removal of these gases for its high capacity to absorb carbon dioxide to less than 100 ppmv, it will also remove some of the mercaptans if present in the feed gas stream.

A 50% by weight solution of Diglycol Amine is used at flow rate of 116 m³/hr in order for the treated gas to meet the specifications.

Feed gas at 52.3 bar and 30.9°C is fed to the feed gas separator (V-1203) to knock out any liquid hydrocarbons and is then passed through the feed gas filter coalescer (F-1202) which will remove any contaminants larger than 1 micron which can cause foaming when in contact with DGA.

Liquid hydrocarbons from both (V-1203) and (F-1202) are routed back on level control to (V-1101).

The feed gas then enters the absorber column (V-1201) from the bottom and flows upwards to meet the down flowing DGA solution in a counter current absorption process.

The absorber column consists of two sections, the lower section where all the absorption takes place, consists of 20 amine deflecting trays with 7.62 cm (3 inch) weir height to maximize contact time between gas and solvent; and top section where the gas is washed with water to prevent loss of amine solution as the gas exits the column. The wash water section consists of 4 bubble cap trays.

The wash water to the top of the column is supplied by demineralized water system and by the solvent regenerator reflux pump (P-1203A/B) through the wash water pump (P-1204A/B)

Feed gas from the absorber OVHD's is cooled against air in the absorber overhead gas cooler (E-1206) to 30.7°C in order to condense the water content of the gas, this water is removed in the treated gas K.O.D (V-1204).

The gas is then chilled to 17.2°C in the high stage propane – feed chiller (E-1406) prior to drying in the molecular sieve driers.

During the winter season if the weather is extremely cold the outlet temperature of (E1206) should be kept above 18 °C to avoid hydrate formation.

Diglycol amine rich in carbon dioxide and hydrogen sulfide (Rich Amine) is fed from the bottom of the absorber (V-1201) to the solvent flash drum (V-1205) on level control. The solvent flash drum is operated at low pressure (5.88 bar) to allow most of the dissolved hydrocarbons to flash out of the solution, these flashed hydrocarbons are routed to the incinerator on back pressure control.

The rich amine filtered in the rich solvent filter (F-1203) which is rated at 10 microns before being regenerated.

2 - Amine Regeneration

The rich amine from the absorber (V-1201) after being filtered in (F-1203) is heat exchanged with hot stripped lean amine in the two parallel running lean/rich solvent heat exchanger (E-1203A/B) before being fed to the top section of the solvent regenerator (V-1202) on level control.

The solvent regenerator is operated at low pressure and high temperature to ensure the removal of acid gases from the amine solution. This regeneration process takes place over a set of 20 trays in the column three of which are in the upper rectifying section and 17 in the lower stripping section.

The amine solution is collected in the bottom of the regenerator and is pumped by the lean solvent booster pumps (P-1201A/B). The discharge of the pump is divided into two stream. The first stream is fed on flow control to a forced circulation regenerator reboiler (E-1204) to be heat exchanged against hot oil from the reboiler a two phase stream is returned to the regenerator where the vapor phase flows up the column stripping the acid gas from the amine solution.

The OVHD vapor from the regenerator (V-1202) primarily consisting of acid gases and water vapor are partially condensed in the regenerator over head condenser (E-1202) at 40 °C to separate the water from the acid gases. The condensed water is collected in the solvent regenerator reflux drum (V-1206) and is then fed as reflux to regenerator using the regenerator reflux pump (P-1203 A/B).

The acid gases from the reflux drum (V-1206) are fed to the incinerator (H-1901) on back pressure control for final disposal. This back pressure can controller and a N2 blanket controller both in split range maintain the regenerator operating pressure at 0.90 bar.

If for any reason the incinerator is out of service the acid gases will be directed to the wet flare system for final disposal.

The other stream from the (P-1201 A/B) discharge at 126.7 °C is cooled against rich solvent in the lean/rich solvent heat exchangers (E-1203A/B) and is further cooled to 34.6 °C against air in the lean solvent cooler (E-1201). This temperature is to be maintained at least 6°C higher than the feed gas inlet temperature, in order to avoid any hydrocarbon condensation in the absorber which leads to foaming problems.

A slip stream of cooled lean solvent from (E-1201) is passed through the lean solvent filter (F-1201), the carbon treater (F-1205) and the lean solvent after filter (F-1204) respectively to recover dissolved organic contaminants and solids larger than 10 microns from the amine solution and is then re-combined with the main stream before being fed to the amine surge tank (T-1202).

The amine surge tank (T-1202) is provided to ensure stable operation of the unit and to provide sufficient surge capacity for the amine inventory during maintenance.

The lean solvent from (T-1202) is pumped back to the top of the absorber (V-1201) using the lean solvent charge pumps (P-1202 A/B) completing the recirculation loop.

Amine storage tank (T-1201) is provided to store the amine solution to fulfill the needs for both train 1 and 2, through amine charge pump (P-1205).

3 - Amine Reclaiming

The reactions between DGA and CO₂, COS or CS₂ may form undesirable degradation products.

These reactions are reversible at temperatures between 176°C and 182°C so that a reclaimed amine solution can be recovered in the system.

This is done using a kettle type exchanger called the solvent reclaimer (E-1205) which is operated on batch basis. This exchanger is sized to handle 0.5 to 1.0% of the circulating solution volume, and is supplied with heat from hot oil passing through its tubes.

Amine solution from (P-1201 A/B) is fed on level control to the shell side of the reclaimer and is vaporized against hot oil in the shell side, the OVHD vapors are returned to the bottom tray of the solvent regenerator (V-1202). A supplemental water feed from the reflux pump (P-1203 A/B) is used to minimize the thermal decomposition of the DGA, by maintaining the temperature in the reclaimer at 176.7°C.

The heat stable salts formed in the system can be freed or recovered in the reclaiming process by addition of a low chloride content alkali to the reclaimer.

4 - Amine recovery

An amine sump drum (V-1209) is provided to facilitate the drainage of the units equipment during their maintenance and to collect all drained solvent from the unit.

This sump drum is equipped with one amine sump pump (P-1206) and an amine sump filter (F-1206) to recover the drained amine.

If required an antifoam package (PK-1201) is provided to supply a continuous injection to either the suction of lean solvent charge pump (P-1202 A/B) or the suction of the regenerator reflux pump (P-1203 A/B).

LOSS OF UTILITIES SUPPLIES

1- Loss of Instrument Air

Loss of instrument air would result in all Control and Solenoid Valves failing to their safe positions. The unit will be shut down and discontinue to operate.

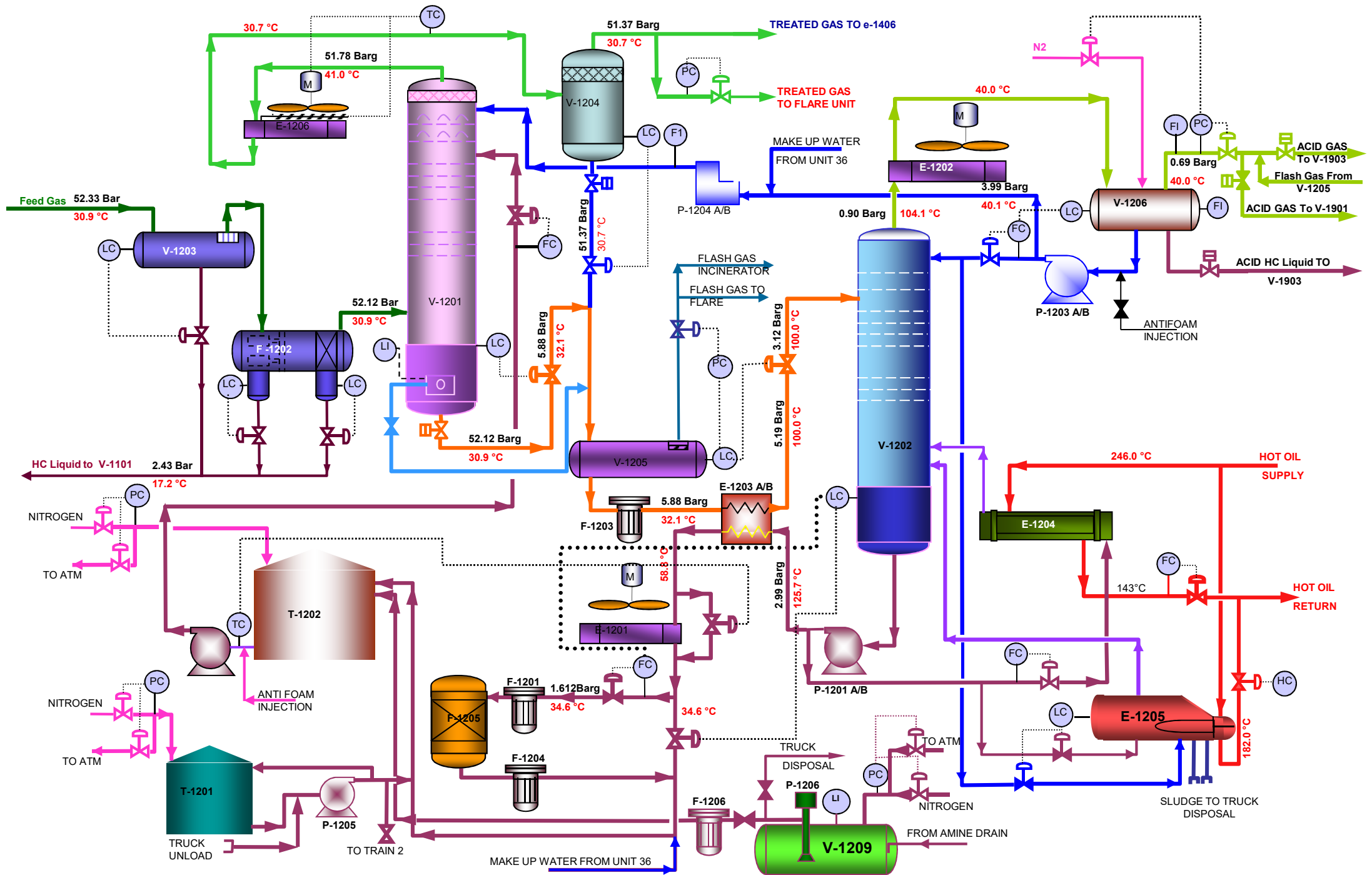
2- Loss of A.C. Power

The loss of A.C. power would result in the shutdown of all pumps and fan motors within the unit, thus circulation of amine would stop. The train ESD should be activated if the power cannot be re-established immediately. Prevention of high levels of CO₂ reaching downstream units is extremely important.

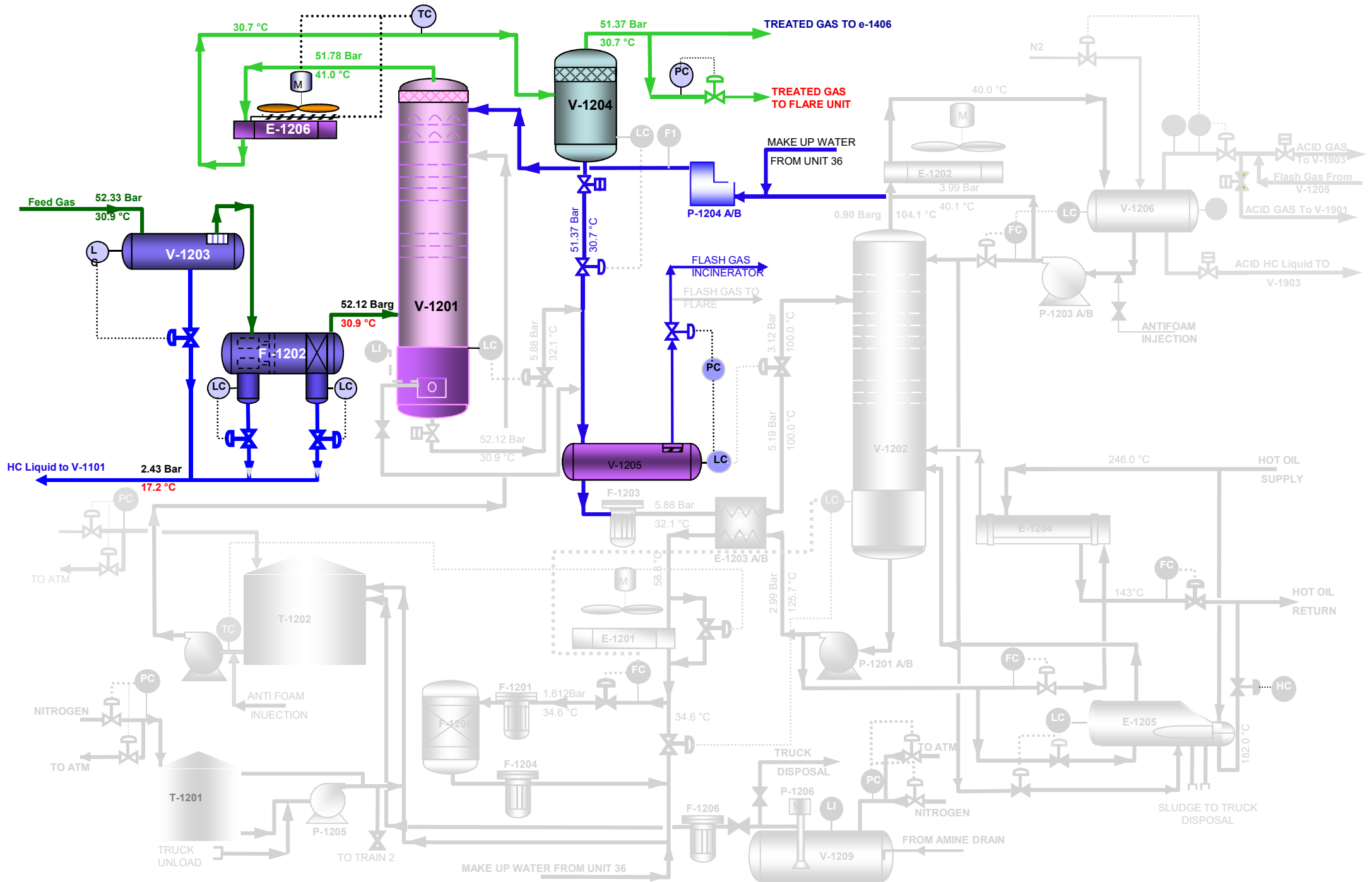
3. Loss of HTF:

Heat transfer fluid (HTF) is used as the heat source for regeneration of amine. If HTF supply is lost, the feed gas flow should be immediately reduced to a minimum. Loss for an extended period will result in low regeneration temperatures and a high residual CO₂ concentration in the lean amine. The CO₂ of the treated gas must be continuously monitored while HTF flow is being re-established.

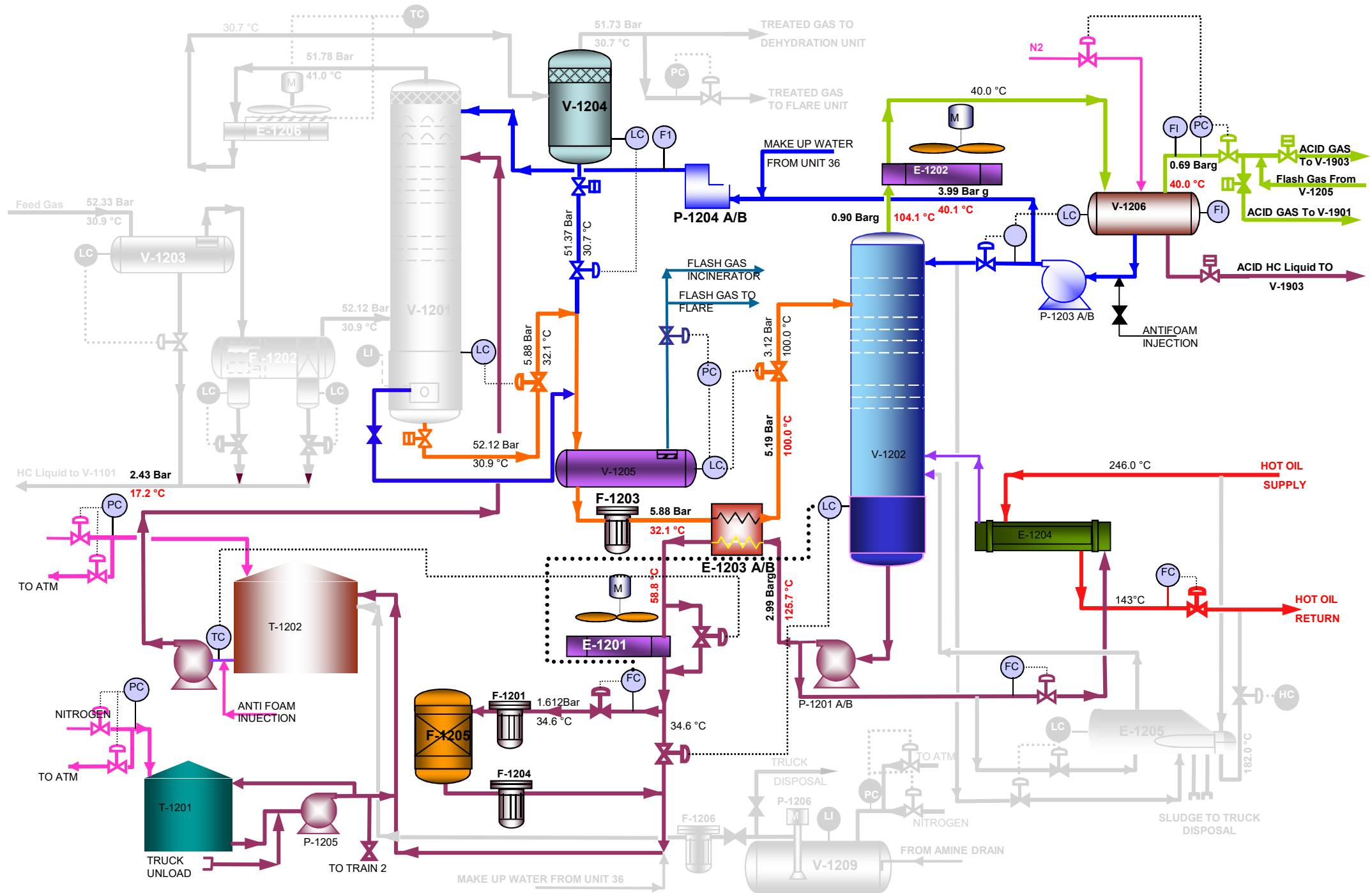
Acid Gas Removal



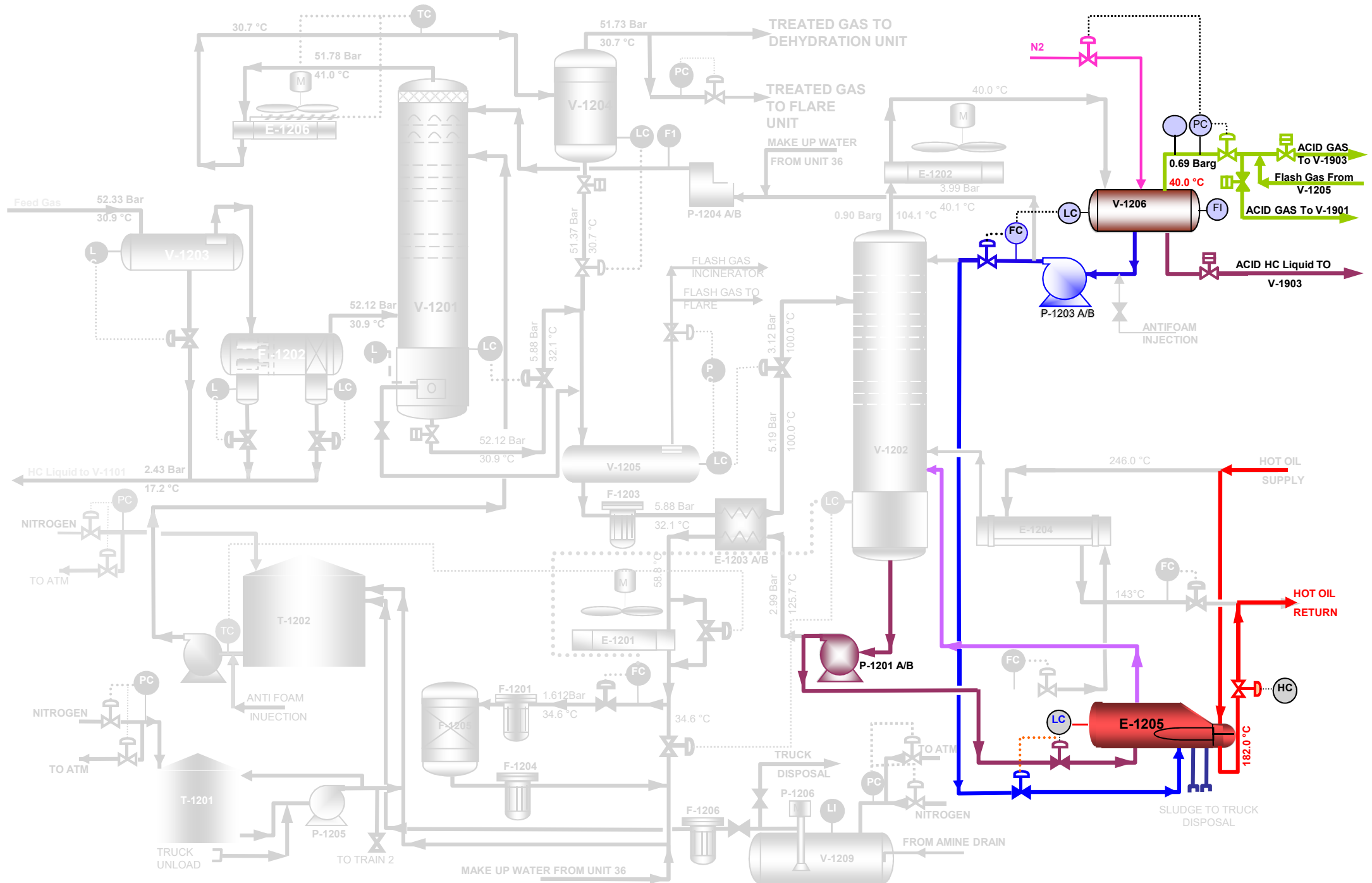
Acid gas removal



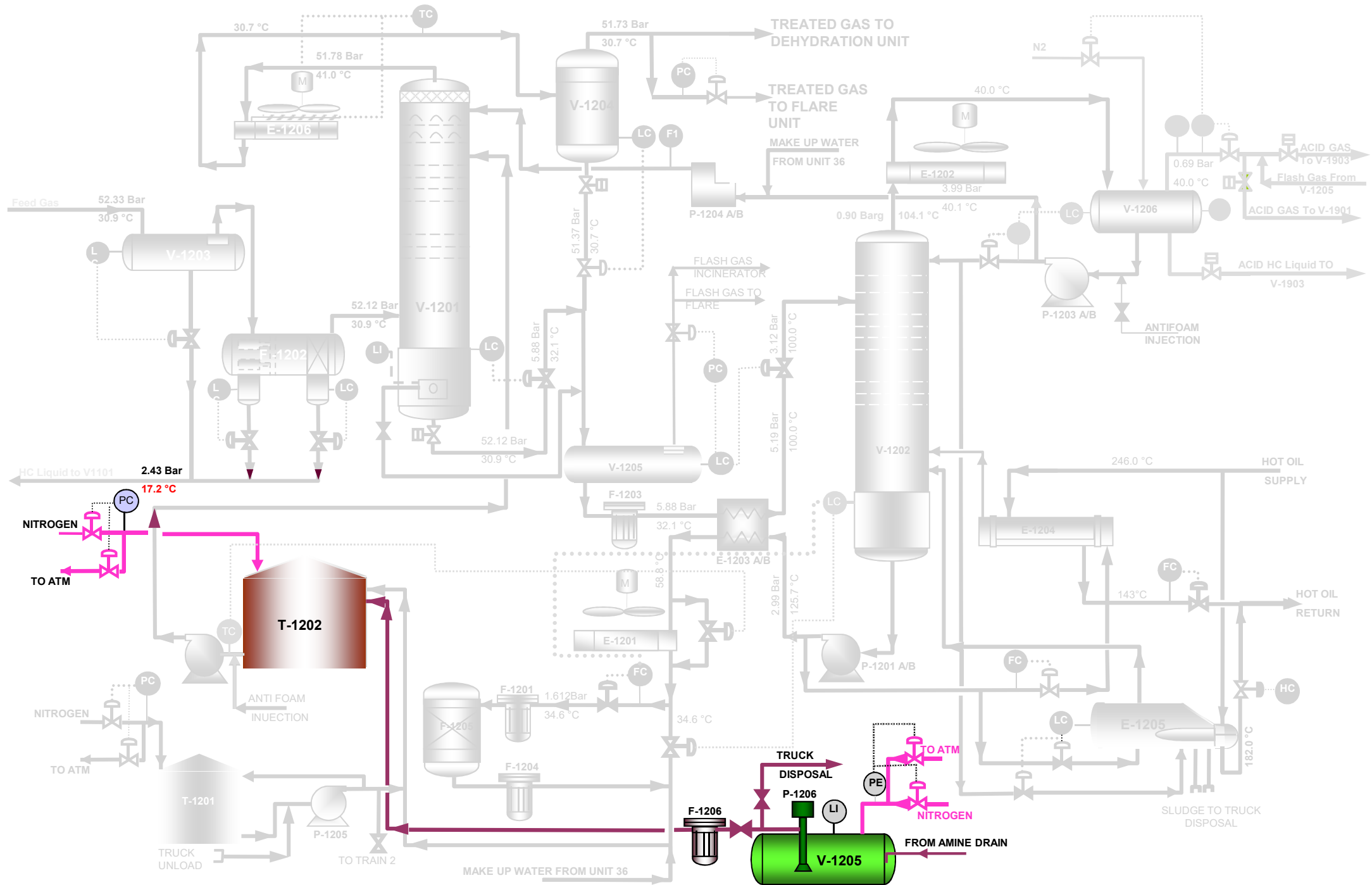
Amine regeneration



Amine reclaiming



Amine recovery



Dehydration and Mercury Removal

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INTRODUCTION TO DEHYDRATION PROCESS

Natural Gas usually contains significant quantities of water vapor. Changes in temperature and pressure condense this vapor altering the physical state from gas to liquid to solid. This water must be removed in order to protect the system from corrosion and hydrate formation.

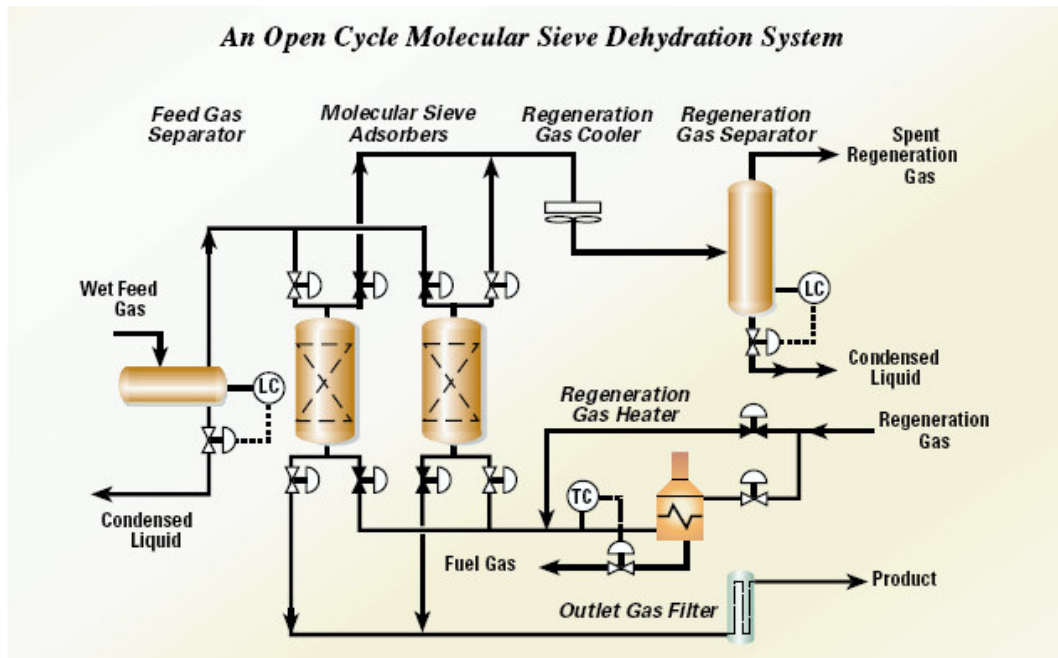
The wet inlet gas temperature and supply pressures are the most important factors in the accurate design of a gas dehydration system. Without this basic information the sizing of an adequate dehydrator is impossible.

There are many other important pieces of design information required to accurately size a dehydration system. These include pressures, flow rates and volumes.

There are basically three methods employed to reduce this water content. These are:

1. Joule-Thomson Expansion
2. Solid Desiccant Dehydration
3. Liquid Desiccant Dehydration

Solid desiccant dehydration, also known as solid bed, employs the principal of adsorption to remove water vapor. Adsorbents used include silica gel (most commonly used), molecular sieve, activated alumina and activated carbon. The wet gas enters into an inlet separator to insure removal of contaminants and free water. The gas stream is then directed into an adsorption tower where the water is adsorbed by the desiccant. When the adsorption tower approaches maximum loading, the gas stream is automatically switched to another tower allowing the first tower to be regenerated.



Heating a portion of the mainstream gas flow and passing it through the desiccant bed regenerates the loaded adsorbent bed. The regeneration gas is typically heated in an indirect heater. This undersaturated regeneration gas is passed through the bed removing water and liquid hydrocarbons.

The regeneration gas exits the top of the tower and is cooled most commonly with an air-cooled heat exchanger. Condensed water and hydrocarbons are separated and the gas is recycled back into the wet gas inlet for processing.

A. Regeneration (activation)

Regeneration in typical cyclic systems constitutes removal of the adsorbate from the molecularsieve bed by heating and purging with a carrier gas. Sufficient heat must be applied to raise the temperature of the adsorbate, the adsorbent and the vessel to vaporize the liquid and offset the heat of wetting the molecular-sieve surface.

After regeneration, a cooling period is necessary to reduce the molecularsieve temperature to within 15° of the temperature of the stream to be processed. This is most conveniently done by using the same gas stream as for heating, but with no heat input. For optimum regeneration, gas flow should be countercurrent to adsorption during the heatup cycle, and concurrent (relative to the process stream) during cooling. Alternatively, small quantities of molecular sieves may be dried in the absence of a purge gas by oven heating followed by slow cooling in a closed system, such as a desiccator.

Adsorption

- Adsorption is the process of using solid desiccant to dry natural gas.
- Adsorber systems use at least two towers – one onstream and the other in regeneration.
- When an adsorber has accepted all the water that it can on its cycle, it is taken offstream and hot gas is passed through it to remove the water.

Types of Solid Desiccants

1- Silica Gel

1. Essentially pure silicon dioxide SiO_2
2. Purchased in bead or powder form
3. Outlet dewpoints of -60°C can be achieved

2- Alumina

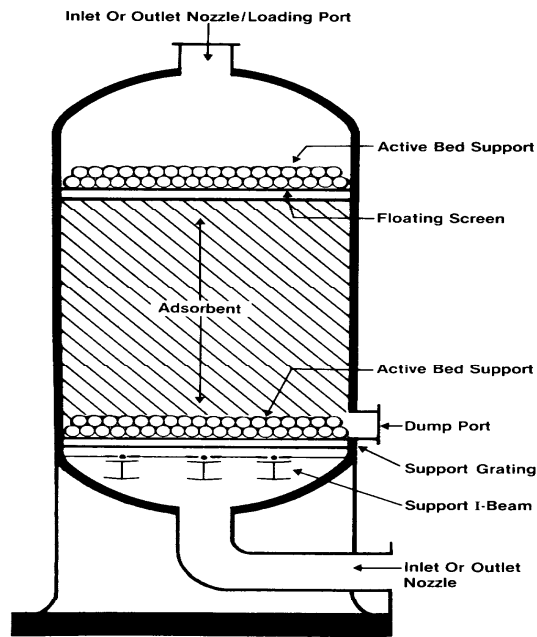
1. Hydrated form of alumina oxide (AlO_3)
2. Purchased in extrudate or pellet form
3. Outlet dewpoints of -70°C can be achieved
4. Less heat is required to regenerate alumina than for molecular sieve.

3- Molecular sieves

Molecular sieves are adsorbents composed of aluminosilicate crystalline polymers (zeolites). They efficiently remove low concentrations of polar or polarizable contaminants such as H₂O, methanol, H₂S, CO₂, COS, mercaptans, sulfides, ammonia, aromatics and mercury down to trace concentrations. The molecular sieve products in various forms: beads, granules and extrudates.

Desiccant Bed Life

- Desiccant is expected to last 3-5 years, depending on the conditions of operation.
- New desiccant is more efficient at accepting water than older desiccant.
- This means it picks up more water and the reaction is faster with new desiccant.
- When designing systems, desiccant capacity should be calculated using 3-5 year old product.
- For example, new mole sieve could accept 20 kg of water for every 100 kg of desiccant. Design estimates should use a lower figure of 13 kg of water for every 100 kg of desiccant.
- Gas that is not saturated (already dried in an absorber for instance) will prolong the life of the desiccant bed. In plant applications where very low dewpoints are required, it is common to dry the gas in a glycol tower before passing it through the adsorber.



Adsorption tower (Alcoa, 1986).

Adsorption Systems

- Adsorption systems can consist of two or three tower systems.
- A three-tower system would be used if additional regeneration and cooling time is required.
- In a two tower system a typical operational cycle is : ..

Adsorber Cycle – 8 hrs

Regeneration Cycle – 8 hrs

- Heat with gas – 4 ½ hrs
- Cool to operation Temp – 3 hrs
- Switching & Standby – ½ hr

- The entire cycle is controlled by automatic valves.

Potential Concerns

- Desiccants can be poisoned by H₂S which will reduce the affinity for H₂O.
- Gas streams with significant amounts of C₅+ can cause problems in the regeneration stage as some of the aromatic hydrocarbons decompose leaving carbon and tar on the desiccant.

Advantages

- Changes in the inlet temperatures and pressures can better be accommodated with a solid desiccant system than with a glycol unit.
- The capital cost of a solid desiccant system can be 3 times that of a comparable glycol unit, and the operational costs are also usually higher.
- Glycol units can not compete with the dewpoint and flexibility of a solid desiccant system. BUT, solid desiccant systems are expensive \$\$\$.

Adsorber Components

1- Inlet Separator

- Absolutely necessary to protect the desiccant from impurities such as water, liquids, compressor oils, solids, etc.
- If liquids are entering the desiccant towers, desiccant can be broken or powdered, causing plugging and pressure drop problems.

2- Adsorber Towers:

- Typically, the gas moves down through the bed during adsorption to permit higher gas velocities without lifting the bed.
- The regen gas moves upward through the bed.

3- Regeneration Gas Heater:

- Providing hot gas for the regeneration of the desiccant.
- Hot gas vapourizes the water and hydrocarbons trapped and removes them to a separator.

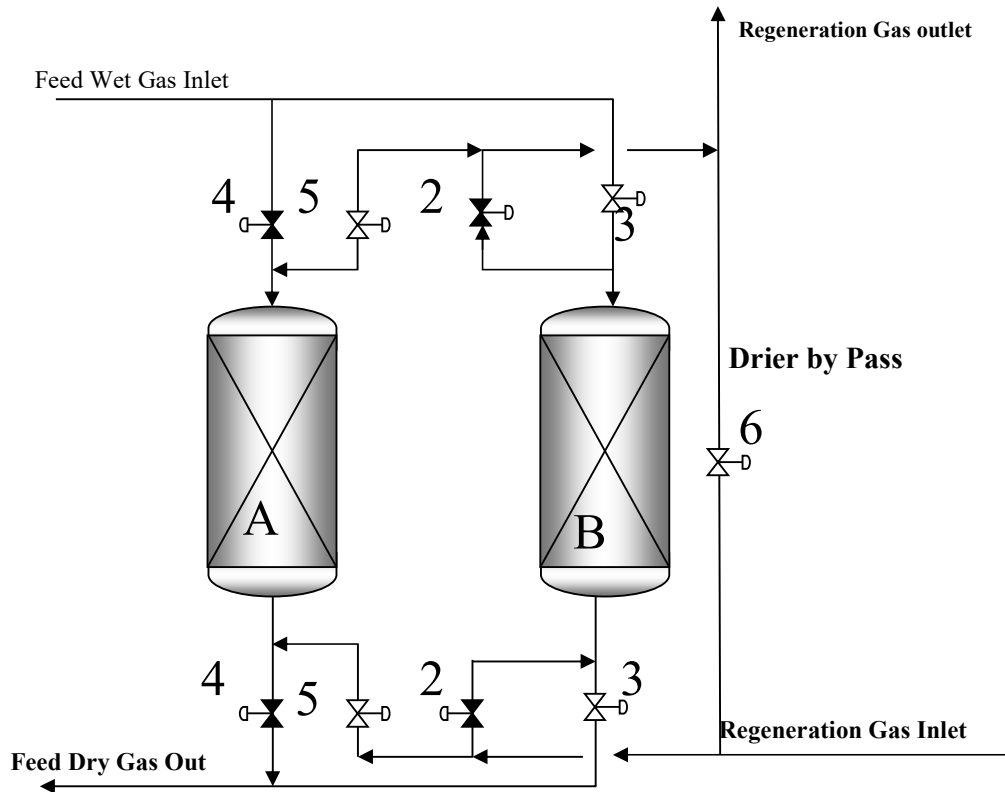
4- Regen Condenser (or cooler):

- Lowering the temperature of the regen gas leaving the regeneration tower. Water in the vapour phase will start to drop out as liquid.

5- Regen Separator:

- Separates the condensed liquids (water and liquid hydrocarbons) from the regen gas stream.
- The gas outlet from the separator is now wet and is returned to the main gas flow.

Gas Drier Sequence



Assumption

Drier bed **A** is on Adsorption

Drier bed **B** is on cooling

The basic drier bypass Sequence change over bed **A** to **B**

1. Open Drier Bypass **No.6**
2. Close cooling valves bed **B** (2 Valves **No.2**)
3. Open Adsorption Valve bed **B** (2 valves **No.3**)
4. Close adsorption valve bed **A** (2 valves **No.4**)
5. Open regeneration valves bed **A** (2 valves **No.5**)
6. Close drier bypass Valve **No.6**
7. Sequence start regeneration bed **A**

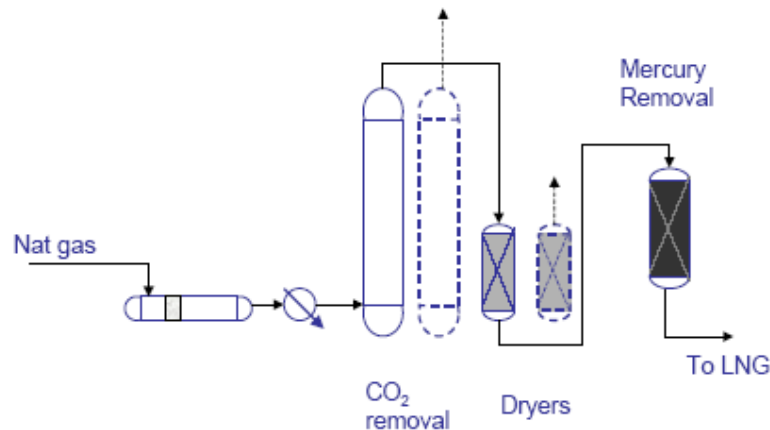
Mercury Removal

Elemental and compounded mercury is present in many natural gas regions of the world. Complete removal is needed to avoid catastrophic failures in cryogenic equipment or chemical process catalyst poisoning.

The primary reason for removing mercury from natural gas is to protect downstream aluminum heat exchangers, such as those used in cryogenic hydrocarbon recovery natural gas plants and in natural gas liquefaction plants. Mercury has caused numerous aluminum exchanger failures. It amalgamates with aluminum, resulting in a mechanical failure and gas leakage. Since the level of mercury that can be tolerated is not established, most operators want to remove it "all." That is, remove it to a level where it can not be detected with the available analytical capability. Currently, this

means reducing the mercury to less than $0.01 \text{ } \mu\text{g}/\text{Nm}^3$, which corresponds to about 1 ppt by volume.

The designs of LNG plants used beds of sulphur impregnated carbon to remove mercury from the raw gas. these beds are generally located at the final stage of purification after the molecular sieve dryers.



PURPOSE OF THE UNIT

The purpose of the Dehydration Unit is to remove water from the treating gas leaving the Acid Gas Removal Unit. Drying is required to prevent ice and hydrate formation in the Liquefaction Unit, which would cause blockage of lines and equipment

The Dehydration Unit (Unit 13) dries natural gas in the adsorber column before it enters the Mercury Removal Unit and Liquefaction Unit

Gas exiting Unit 12 is saturated with water that has to be removed before further processing can take place.

The presence of water in the feed gas can result in hydrate or ice formation, leading to equipment / line blockage or damage in the downstream units.

Unit 13 consists of:

- A drier feed separator;
- Three natural gas driers (adsorbers) (two duty, one regeneration / standby);
- A regeneration gas heater;
- A regeneration gas cooler;
- A regeneration gas knock-out drum;
- A regeneration gas compressor.

In the Dehydration Unit, the water content of the feed gas is reduced to less than 1 ppmv by adsorption using a bed of molecular sieve.

After the molecular sieve has been adsorbing water for a specified time the water is removed from the molecular sieve by passing a stream of hot dry regeneration gas up through the bed.

The bed is then returned to normal operating temperature by passing a stream of cool dry regeneration gas up through it.

MAIN EQUIPMENT

Refer to «*Figure 1* »

Tag Number	Equipment	Function
V-1301	Dryer inlet separator	Separate any condensed hydrocarbon and water greater than 10 micron.
F-1304	Filter coalescer	Remove any liquid or solid greater than 1 micron
V-1302 A/B/C	Molecular sieve dehydrators	Remove the moisture content from the gas
F-1303	Molecular sieve after filter	Filter any contaminant from the molecular sieve outlet gas
V-1304 A/B	Mercury removal bed	Remove mercury from the feed gas
F-1302 A/B	Mercury removal after filter	Remove any liquid or solid greater than 1 micron
F-1301	Regeneration gas cooler	Cool the hot, wet regeneration gas to 32 °C
C-1301	Regeneration gas compressor	Compress the regeneration gas to treating
V-1305	Regeneration gas K.O.Drum	Separate liquids from the regeneration gas.
H-1301 A/B	Regeneration gas heater	Heat and dry regeneration gas to 287.8 °C

PROCESS DESCRIPTION

Filtration

The sweet gas from the acid gas removal unit is chilled against high stage propane in (E-1406) to a temperature not lower than 17.2 °C before it enters the dryer inlet separator (V-1301) to separate any condensed water or hydrocarbons, The dry inlet separator is designed to remove any liquids greater than 10 microns in size in order to reduce the size of the driers.

Additional filtration takes place in the filter coalescer (F-1304) downstream (V-1301), this filter removes any liquids or solids greater than 1 micron in size .

The filter can be bypassed to allow for changing out of the filter elements without any interruption to the plant operation .

Liquid collected in both vessels (V-1301) and (F-1304) is sent on level control back to (V-1101).

Adsorption

The dehydration unit consists of three molecular sieve dehydrators (V-1302 A/B/C) two of which are in service while the third is either on regeneration or on standby.

The water vapour flowing with the gas stream is adsorbed on the molecular sieve during the whole adsorption cycle.

The gas flows downwards to avoid channelling in the bed.

Regeneration:

Each bed has the following schedule.

Adsorption	16.00 hrs
------------	-----------

Regeneration	
--------------	--

Heating	4.5 hrs
---------	---------

Cooling	3.0 hrs
---------	---------

Standby	0.5 hr
---------	--------

Heating

The first step in the thermal regeneration process is the heating step which lasts 4.5 hrs. A slip stream of the dried gas is heated in the two regeneration gas heaters (H-1301-A/B) up to a temperature of 287.8 °C. The gas is then routed to the bottom of the regenerated bed to remove the adsorbed water as it flows up the bed. Some heavy hydrocarbons and CO₂ are removed with the water to restore the adsorption capacity of the bed.

The hot wet regeneration gas from the top of the drier bed is cooled against air using the fin fan cooler (E-1301 regeneration gas cooler) to a temperature of 32°C to condense the removed water.

Water is then separated from the regeneration gas in the regeneration gas K. O. Drum (V-1305) and is sent on level control to the wet hydrocarbons liquid storage drum (V-1101).

After water separation the regeneration gas is recompressed in the regeneration gas compressor (C-1301) in order to be re circulated back on flow control to the front-end to join the feed gas. If the regeneration gas compressor (C-1301) is out of service the regeneration gas is sent automatically to the wet flare or the operator can manually transfer the gas to the high pressure fuel gas system in case the compressor is out of service for a long time.

Cooling

The second step of the regeneration step is the cooling step which lasts for 3 hours in order to bring the bed back to its normal operating temperature.

This is done by passing a slip stream of the dried gas without heating through the bed for over a period of 3 hrs.

Mercury removal

Mercury if found in the gas stream, attacks the aluminum heat exchanger in the cold end and causes corrosion by forming amalgam with the aluminum, This is why the downstream equipment must be protected against mercury.

Two beds running in parallel are provided to remove mercury. The mercury removal beds (V-1304 A/B) contain activated carbon impregnated with sulphur, which is not regenerable, but depending on plant through put and based on $<0.01 \mu\text{g}/\text{Nm}^3$ mercury in their outlet are expected to last approximately three years before they need to be replaced.

The gas after being dried in the dehydrators (V-1302A/B/C) is filtered in molecular sieve after (F-1303) before it is routed to the mercury removal beds (V-1304 A/B) and is then dust filtered in the mercury removal after filters (F-1302 A/B) in order to be fed to the cryogenic section for liquefaction.

During the process shutdown the dry gas is used as make up to the high pressure fuel gas system to maintain the fuel gas supply.

LOSS OF UTILITIES SUPPLIES

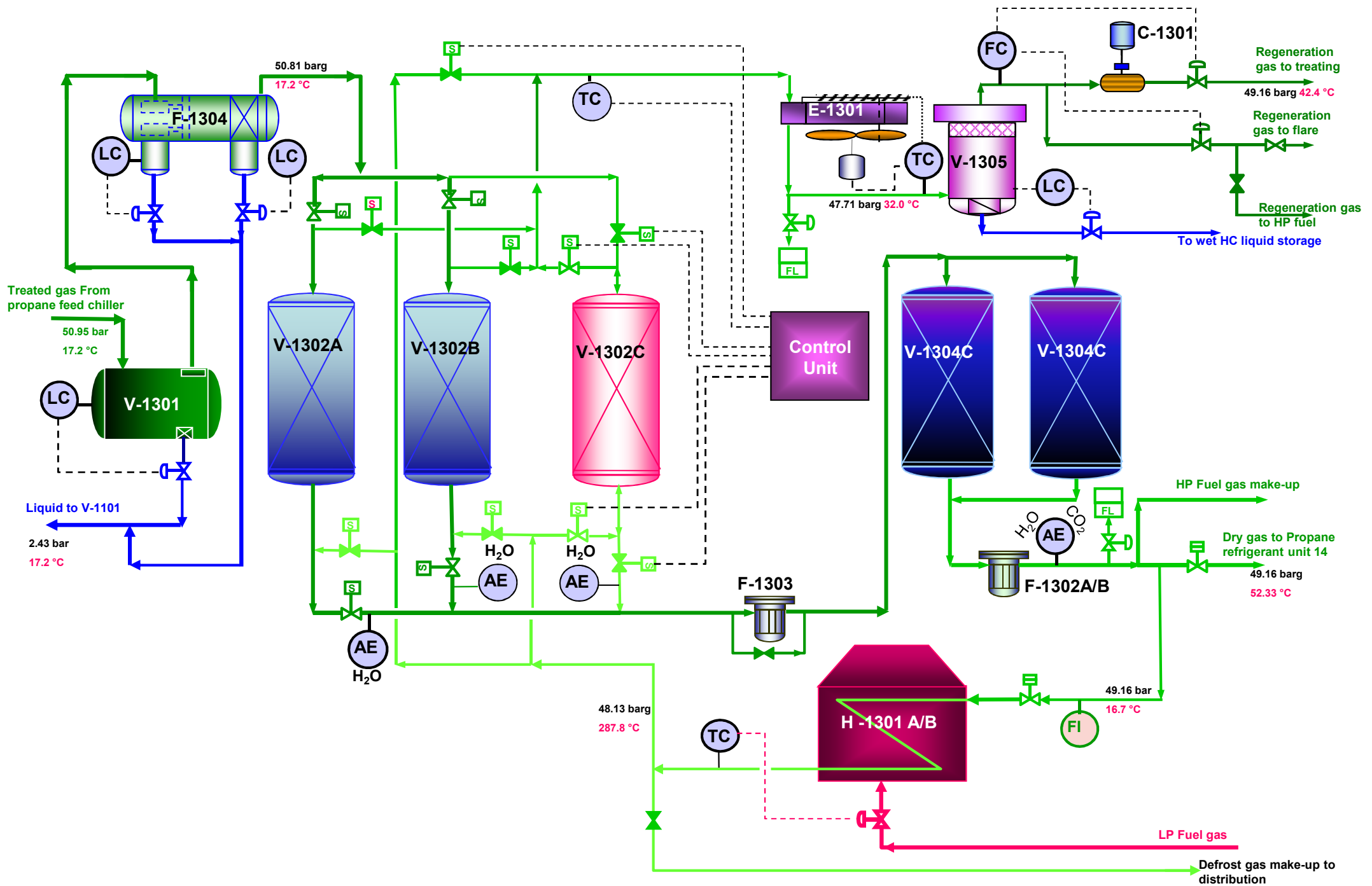
Loss of A.C. power

In the event of A.C. power failure, the Regeneration Gas Coolers (13-MC03 will stop and the high temperature of the Wet Regeneration Gas from heating bed will cease the Regeneration Gas flow supply to the treatment unit and will direct it to flare. The unit must be shutdown manually if the power failure is prolonged.

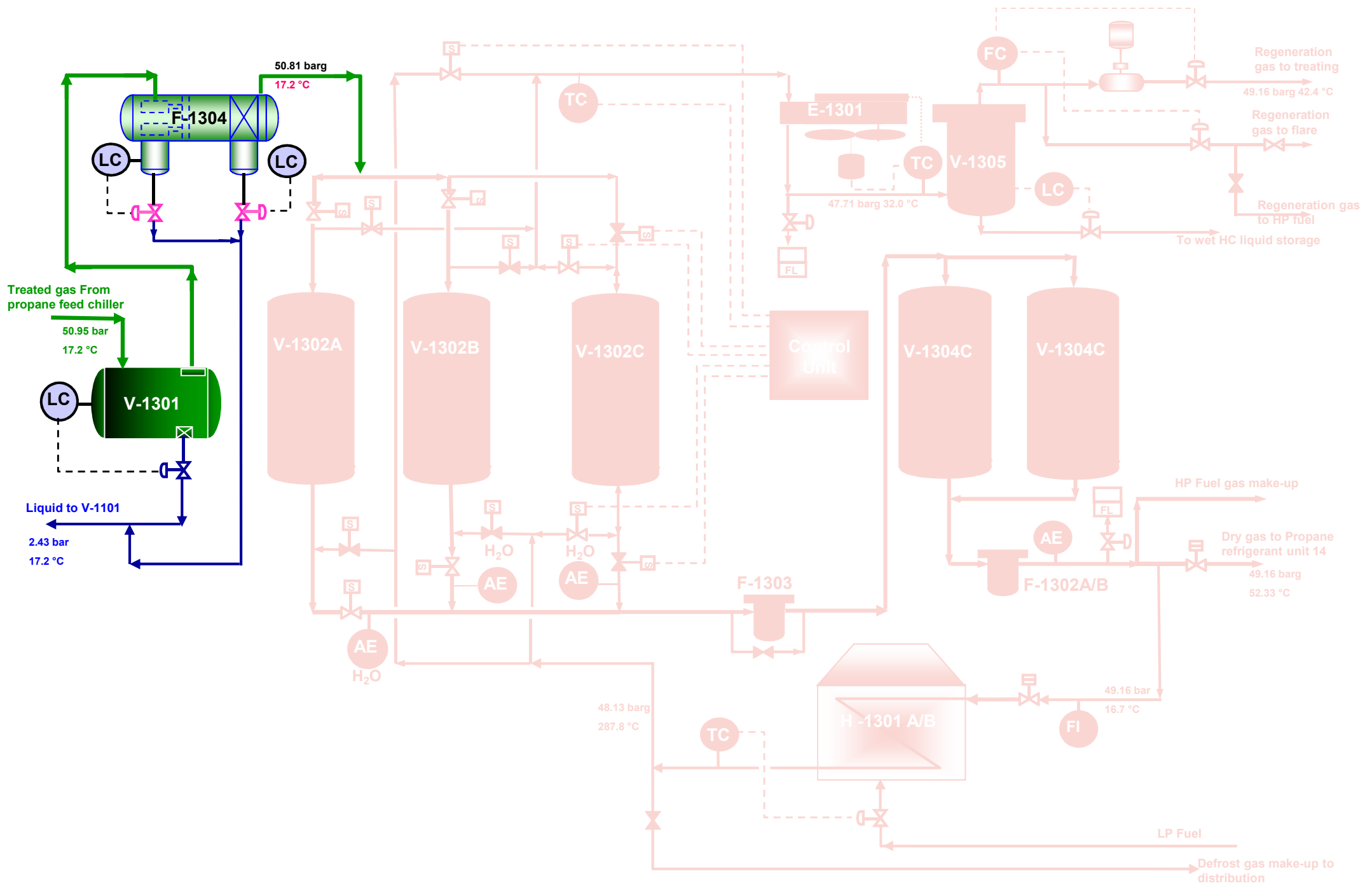
Loss of Instrument Air

In the event of total Instrument Air failure all drier valves will hold at their last position and the control valves will go fail-safe position. The unit must be shutdown manually if total Instrument Air failure is prolonged. Once the Instrument air is supplied again, the Regeneration and Adsorption cycle will be reinstated from last valve position.

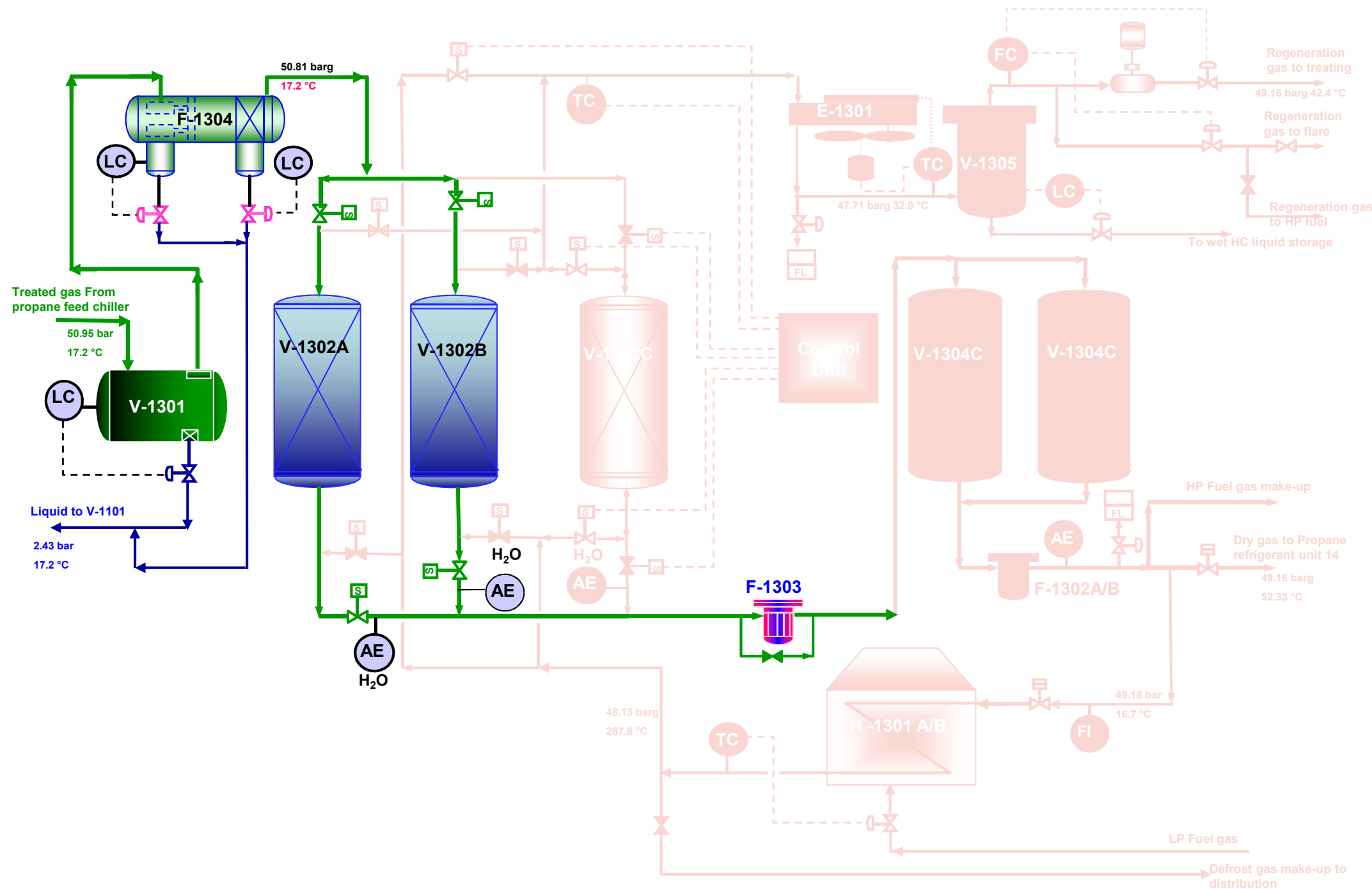
Dehydration and Mercury Removal



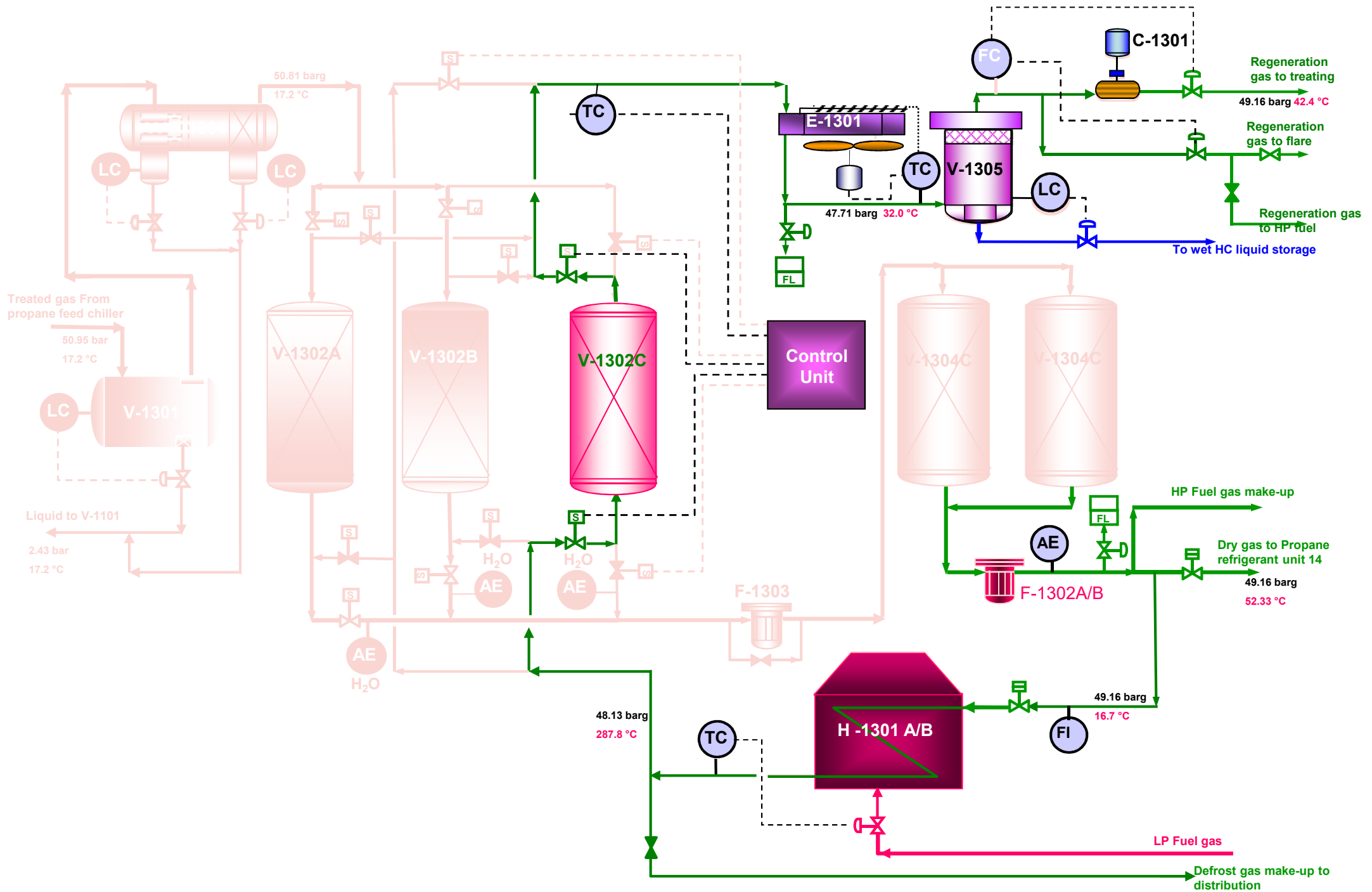
Filtration



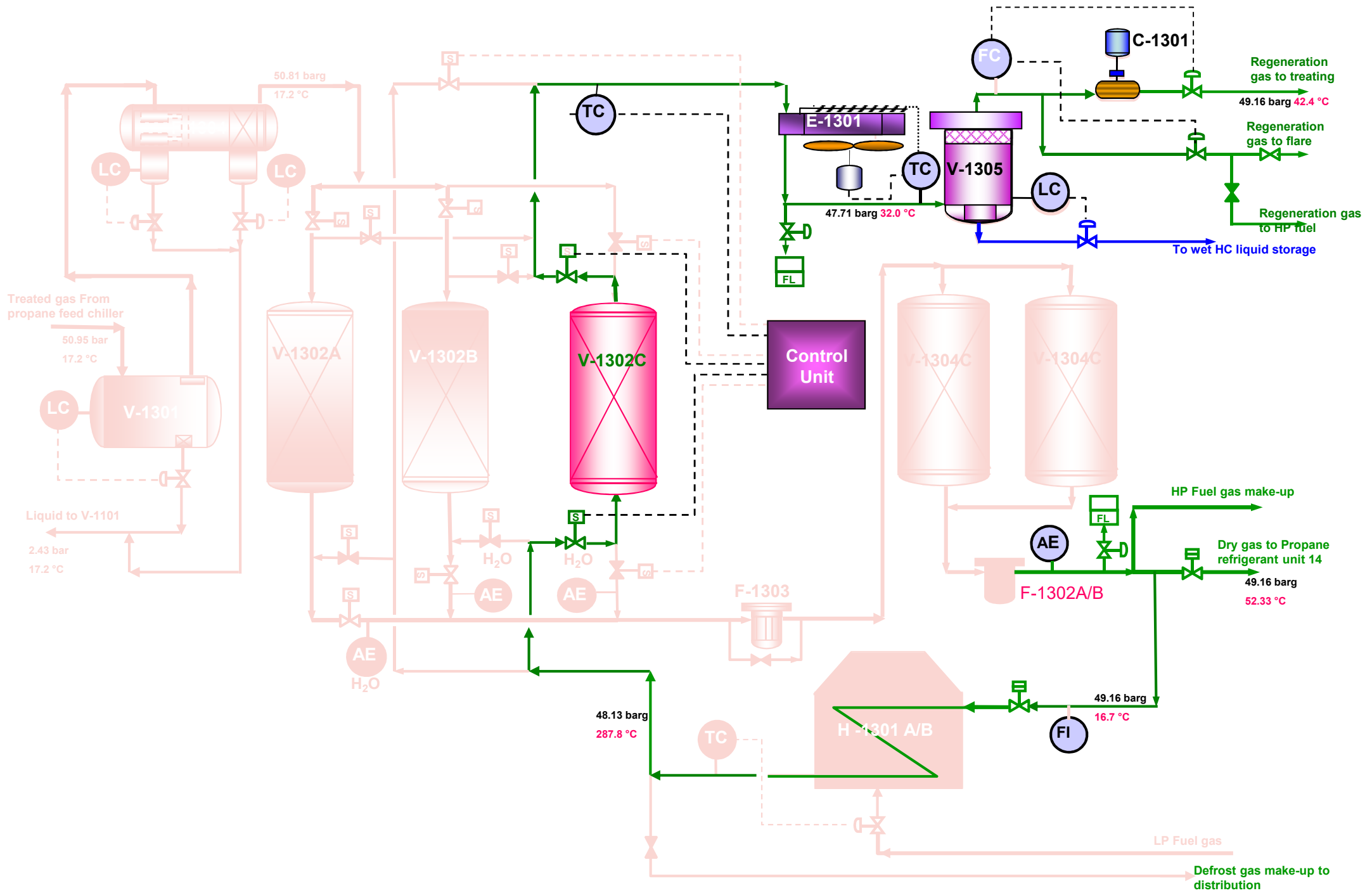
Adsorption cycle



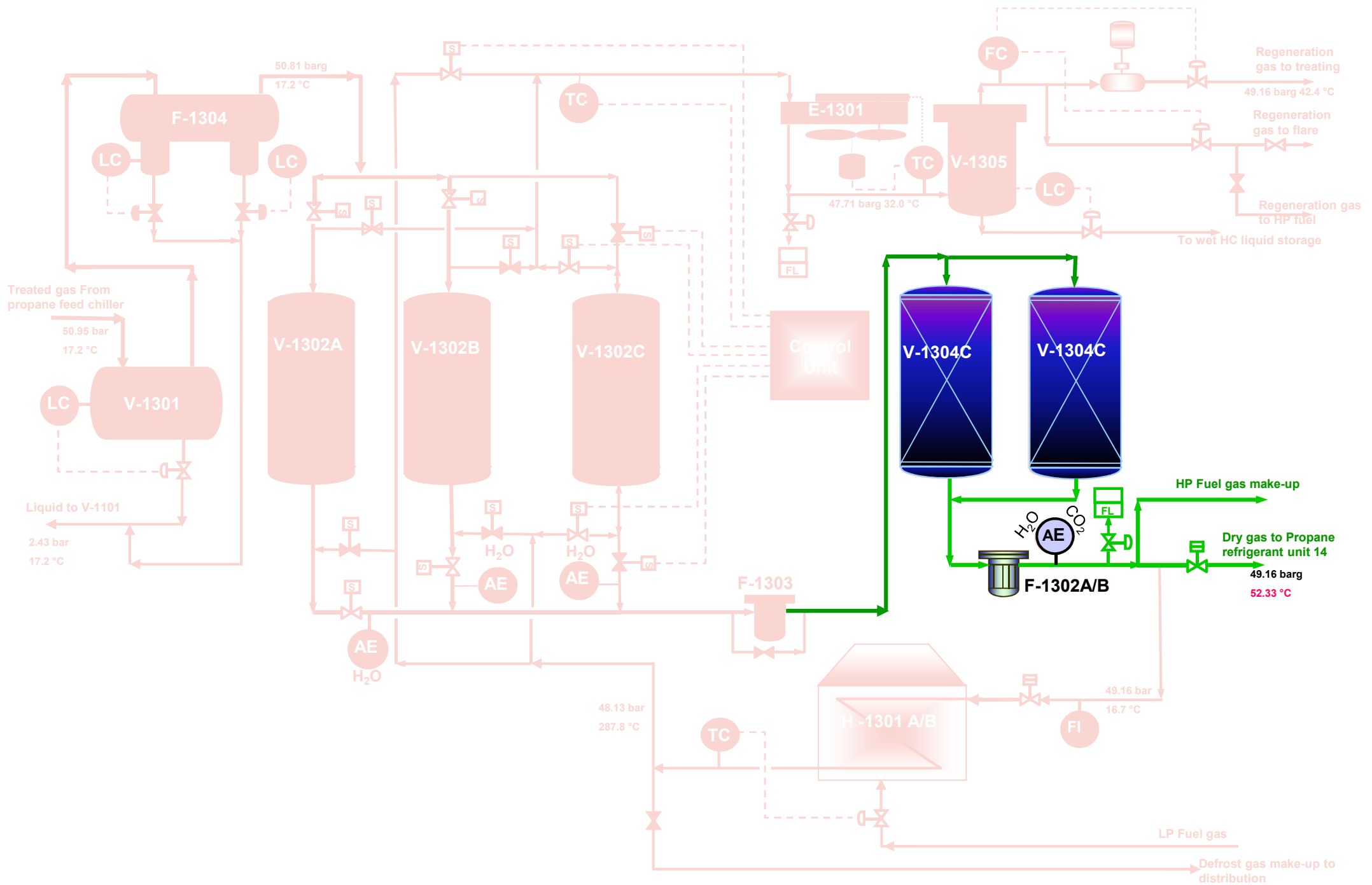
Heating cycle



Cooling cycle



Mercury Removal



PROPANE REFRIGERATION SYSTEM

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Introduction to refrigeration system

Purpose of the unit

Main Equipment

Process description

Loss of utilities

INTRODUCTION FOR REFRIGERATION SYSTEMS

This section introduces and briefly describes the following types of refrigeration Cycle that are covered in :

1. Compression
2. Condensation
3. Expansion
4. Evaporation

The information contained in the following sections is used to narrow the choice of refrigeration systems.

The final selection of the most appropriate system will be made by comparing the capital and operating costs of the systems and determining schedule availability.

Vapor Compression-Expansion Refrigeration Systems Operation

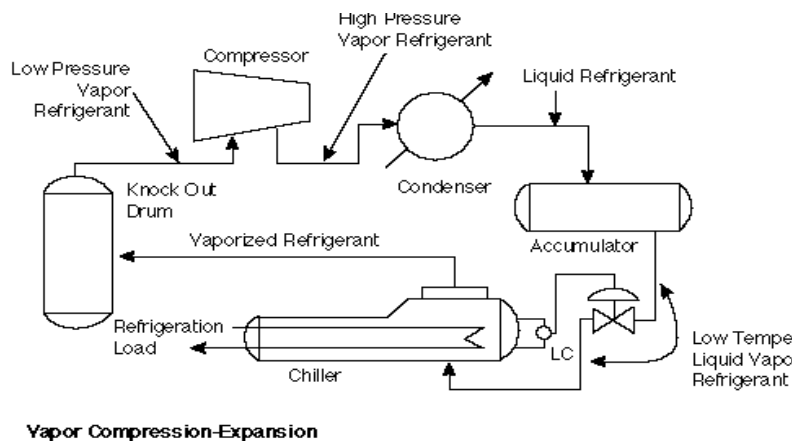
Figure (1) shows a simplified schematic of a vapor compression-expansion system. The compressor compresses the vaporized refrigerant and then the condenser condenses the vapor to a liquid. The liquid from the accumulator then expands across an expansion valve which causes it to flash and its temperature to drop substantially. The liquid portion of this flash is the refrigerant which then goes to a heat exchanger (the chiller).

In the chiller, the liquid refrigerant absorbs heat from the process stream, which lowers the process stream's temperature. The heat vaporizes the liquid refrigerant. The system then returns this vapor and the vapor from the flash to the compressor to repeat the cycle.

Size and Achievable Temperatures

Vapor compression-expansion systems can be built in very large sizes. These systems can also reach very low temperatures. A cascaded system consists of two or more vapor compression-expansion systems that are connected in a series with each system having a different refrigerant.

These systems can achieve temperatures low enough to liquefy natural gas.



Vapor compression-expansion systems typically use Hydrocarbons, Freon, ammonia, and sulfur dioxide for refrigerants.

Major Equipment List

- Compressor
- Condenser
- Receiver
- Suction drum
- Driver – gas turbine
- Refrigerant storage

SELECTING the most appropriate refrigerants

Once a designer has selected a refrigeration system, he must choose a refrigerant. The following points must be considered when selecting the most appropriate refrigerants.

- The minimum temperature the refrigerant must achieve (refrigerant level).
- The suitability of the refrigerant.
- Environmental regulations and concerns.

The minimum temperature that the refrigerant must achieve (refrigerant level) narrows the list of possible appropriate refrigerants and sets the system pressure.

The suitability of the refrigerant derives from the availability, cost, flammability, and toxicity of the refrigerant.

Freon, for example, is becoming difficult to obtain because of environmental regulations and concerns which restrict its manufacture and use. Hydrocarbons should be used in refinery applications because the material is readily available, can be vented into the refinery system during turnaround, and have a low cost.

Flammability is not a large factor in the normal refinery environment.

Water is a good choice as long as freezing is not a constraint. Ammonia absorption could be considered if waste heat is available for solution regeneration.

Refrigerants often affect the materials they contact in refrigeration systems. Therefore, the consideration of a refrigerant's thermal stability and its compatibility with other materials is important. Elastomers and the electrical insulation of refrigeration systems must also be chosen carefully.

It is important to choose a refrigerant that will not operate under vacuum at the lowest pressure point in the system. Operation at sub-atmospheric conditions with a flammable refrigerant could cause an explosive mixture to form if there is any leakage. In the case of non-flammable material (Freon), the in-leakage of air will cause problems when the refrigerant is condensed.

Commonly Used Refrigerants

Typically, a refrigerant is referred to by the refrigerant number ("R" Number) assigned to it by ASHRAE.

Latent Heat

According to an empirical rule of chemistry (Trouton's Rule), the latent heat of vaporization of a material at its boiling point (on a molar basis) divided by the boiling temperature (in absolute units) is a constant for most materials.

PROCEDURES AND RESOURCES FOR

Selecting the most appropriate refrigerants

To select the most appropriate refrigerant, analyze the refrigeration system (already selected) and the following operating considerations and refrigerant properties.

- Availability of low-level (waste) heat
- Availability of steam
- Availability (both generally and for the specific application)
- Capital cost
- Compatibility with system building materials
- Environmental regulations (both existing and anticipated)
- Flammability
- Minimum achievable temperature
- Operating cost
- Thermal stability
- Toxicity
-

Determine the relevance of each consideration and property for the application. For each relevant property refer to the following appropriate Figures for more information. Based on the information in the relevant Figure and the information covered in the Information Sheet, select the most appropriate refrigerant.

Minimum Refrigerant Temperature

	°C
Ammonia Absorption/Water	+2
Lithium Bromide/Water	+2
Ammonia	-32
Freon 12	-29
Freon 22	-40
Ethane	-88
Propane	-41
Butane	0
Ethylene	-103
Propylene	-46

PROPANE

Propane refrigerant System supplies heating and cooling medium for energy transfer requirements in the process purification steps down to a level of temperature

Refrigerant used is propane

C3 Refrigeration Basics :

Two types of heat:

Latent Heat

heat that involves the changing of states of material, no change in temperature

Sensible Heat

heat that changes temperature but does not change states of material

Changing a refrigerant vapor to a liquid state supplies heat energy to the process

Changing refrigerant liquid to a vapor state absorbs heat energy from the process

Refrigerant is in a closed loop system

Refrigerant exist as:

- Vapor.
- Liquid.

PURPOSE OF THE UNIT

Propane refrigerant is a closed multi stage refrigerant system that provides three level of refrigerant to the process plant.

It used to provide chilling to the feed gas stream by vaporizing liquid propane at three different pressure stages. It also provides chilling, desuperheating and condensation to the ethylene refrigerant system.

Propane refrigerant also provides desuperheating to methane compressor discharge.

MAIN EQUIPMENT

Tag Number	Equipment	Function
C-1411/21	Propane Compressors	Provide three pressure stages with three levels temperature.
V-1411/21	Low stage propane suction drum	Prevent any fluctuations in vapor flow to the suction of compressor and prevent any entrapped liquid carry over to the compressor
V-1413/23	High stage propane suction drum	Prevent any fluctuations in vapor flow to the suction of compressor and prevent any entrapped liquid carry over to the compressor
V-1412/22	Intermediate stage propane suction drum	Prevent any fluctuations in vapor flow to the suction of compressor and prevent any entrapped liquid carry over to the compressor
V-1404	Propane refrigerant accumulator	Receive a condensed propane from propane refrigerant condenser.
E-1401	Propane refrigerant condenser	Condense the discharge propane from the high stage propane compressor discharge.
E-1407	Propane purge condenser section	Remove the light ends as LP fuel gas
E-1402	High stage propane / methane / ethylene chiller	Provides chilling and desuperheating to methane gas and ethylene refrigerant
E-1406	High stage propane feed chiller	Drops temperature of feed gas by vaporizing liquid propane in order to remove any entrapped water in feed gas stream
E-1403	Intermediate stage propane – ethylene/ feed / methane chiller	Provide chilling and desuperheat to feed gas, ethylene and methane by vaporizing Intermediate stage propane

		liquid
E-1404 A/B	Low stage propane –ethylene condenser /feed chiller	Provides chilling to the feed gas stream and condenses ethylene refrigerant by vaporizing Low stage propane
P-1403	Propane de-inventory pump	De-inventory most of the propane liquid from all evaporator shell to the storage drum

PROCESS DESCRIPTION

4.1 General

There are two types of heat

Latent heat: Heat that involves the changing of states of material.

Sensible heat :Heat that does not change state of material

C3 Refrigerant basis

Refrigerant is in a closed loop system

Refrigerant exist as vapor / liquid

Purity more than 98 %

Changing refrigerant vapor to a liquid state supplies heat energy to the process .

Changing refrigerant liquid to a vapor state absorbs heat energy from the process.

Control

Control is based on balanced levels, pressure, temperature and flow to individual pieces of equipments.

PROCESS DESCRIPTION

4.2 Introduction to the system

Propane refrigeration chills the feed prior to liquefaction, condenses ethylene compressor discharge, and de-superheats methane compressor discharge.

4.3 The System

4.3.1 Two parallel units

The unit consists of two fifty percent compressors running parallel to each other. The compressor are horizontally split single case units provided with two side stream inlets. Each of the compressor is driven by an individual prime mover (General Electric Frame 5D gas turbine). The unit also consists of six suction drums, three for each compressor (a drum for each of the pressure stages). An anti surge control system is used to protect the machines against surge. The discharge of both compressor is joined together.

Anyone of the two machines can be turned off or put on total recycle without upsetting the system, provided that plant throughput is adjusted to the corresponding situation. Load is balanced between the two compressors using a load balancing control program.

4.3.2 Refrigerant level

There are 3 level of propane refrigeration according to the pressure:-

High stage propane 5.47 bar, 10.3 °C

Intermediate stage propane 2.72 bar, -7.8 °C

Low stage propane 0.39 bar, -34.5 °C

The discharge propane from compressors is desuperheated and condensed using ambient air in the propane refrigerant condenser (E-1401) and then accumulated as liquid in the propane refrigerant accumulator (V-1404) which is large enough to hold the entire propane inventory.

The propane refrigerant accumulator is provided with a propane purge absorber (V-1405) and propane purge condenser section (E-1407) to remove any lights entrained in the system and vent them to low pressure fuel gas system.

4.3.3 High stage propane refrigerant

Propane liquid at 5.47 bar from the accumulator (V-1404) is fed to the shell side of high stage Propane-Methane/Ethylene chiller (E-1402) and high stage Propane feed chiller (E-1406) on level control. This liquid propane is vaporized by heat exchange with the corresponding streams in each heat exchanger in order to cool them.

This propane vapor flows to high stage propane suction drum (V1413/23) which removes any entrapped liquid in the vapor before it flow to the suction of the compressor.

(E-1406) is provided with a pressure controller on the propane vapor outlet to maintain the boiling point of propane by maintaining its pressure to prevent any hydrate formation in the wet inlet gas.

4.3.4 Intermediate stage propane refrigerant

Propane liquid at 2.72 bar is feed to intermediate stage Propane-Ethylene/Feed/Methan chiller (E-1403) and is reduced in pressure by the level control valve.

Propane vapor produced by heat exchange against the process streams is routed to the compressors through the intermediate stage propane suction drum (V-1412/22) which in turn stabilizes the flow and removes any entrapped liquid propane from the vapor stream.

The temperature of methane gas passing through (E-1403) is adjusted using a bypass across the exchanger.

4.3.5 Low stage propane refrigerant

Liquid propane from (E-1403) is sub cooled in the ethylene/propane economizer (E-1505) and then supplied to the shell side of low stage propane-ethylene condenser/feed chiller (E-1404-A/B) and level controls at 0.39 bar to provide low refrigerant to the process streams.

Propane vapor from the shell side of (E-1404A/B) is the routed to the compressor suction through the low stage propane drum (V-1411/21).

4.3.6 Level control for suction drums

The suction drums are supplied with vane internal and sufficient liquid slug holding volumes to prevent liquid carry-over to the compressors.

High stage propane suction drums and intermediate stage propane suction drums are equipped with level controllers to send any entrapped liquid to the low stage propane-ethylene condenser/feed chiller (E-1404A/B) shell side.

Low stage propane suction drum are equipped with gravity drains to send any accumulated liquid directly into the shell side of low stage propane-ethylene condenser (E-1404A/B).

If high-high liquid level was detected in any suction drum the corresponding compressor will be tripped to protect it and the corresponding valves will be closed.

4.3.7 De-inventory

A propane De-inventory pump (P-1403) is provided to transfer the liquid propane from the system to storage as follows.

- During the times where the compressors are running it can transfer liquid from the intermediate stage core-in-shell evaporator to storage.
- When the compressors are shut down it can transfer liquid propane from all evaporator shells to propane storage drum (V-2002).
- Transfer liquid from low stage suction drum to propane accumulator (V-1404) or to storage drum (V-2002) during upset.

LOOSE OF UTILITIES

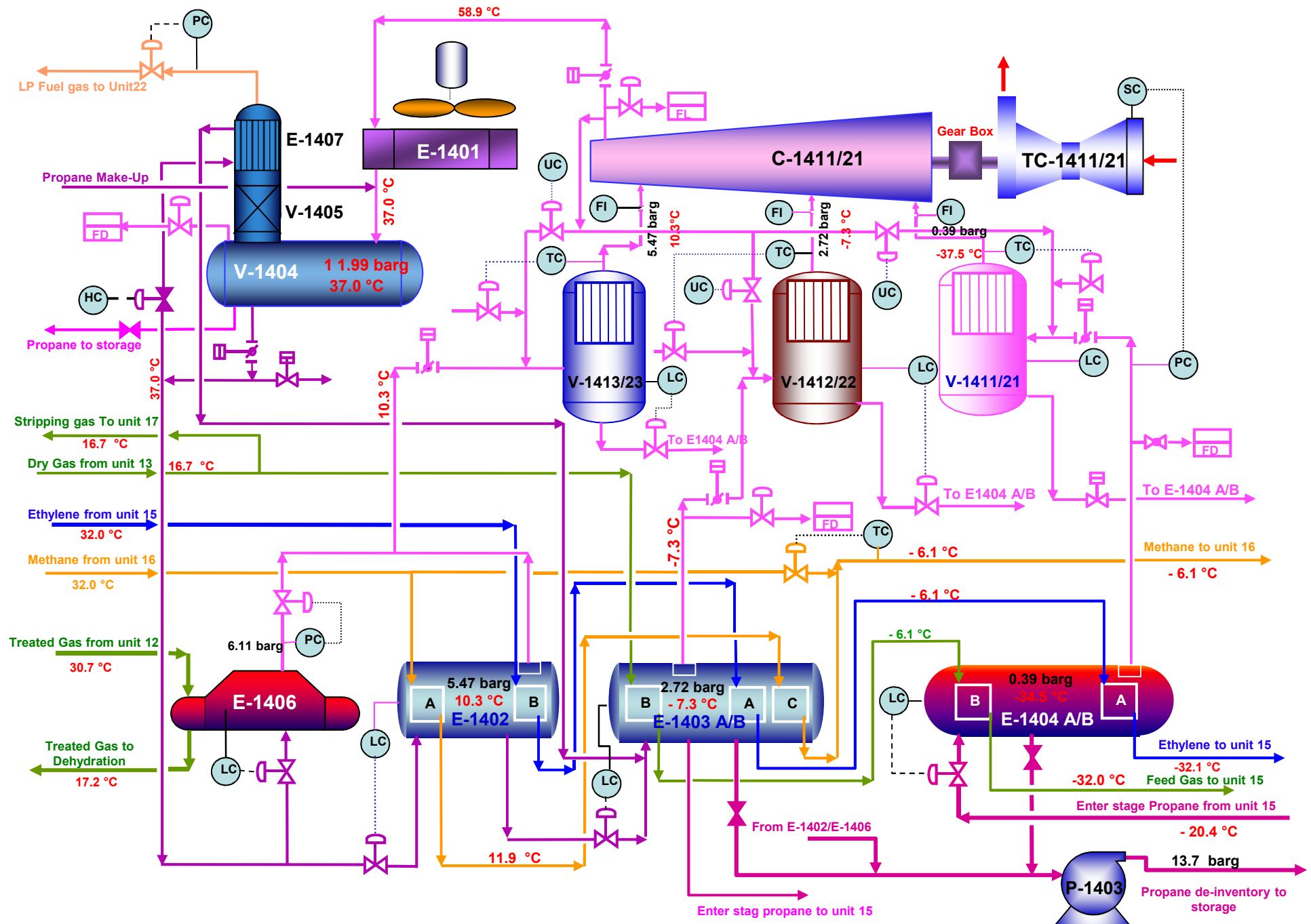
1. Loss of Instrument Air

Loss of instrument air would result in all Control and Solenoid Valves failing to their safe positions. The unit will be shut down and discontinue to operate.

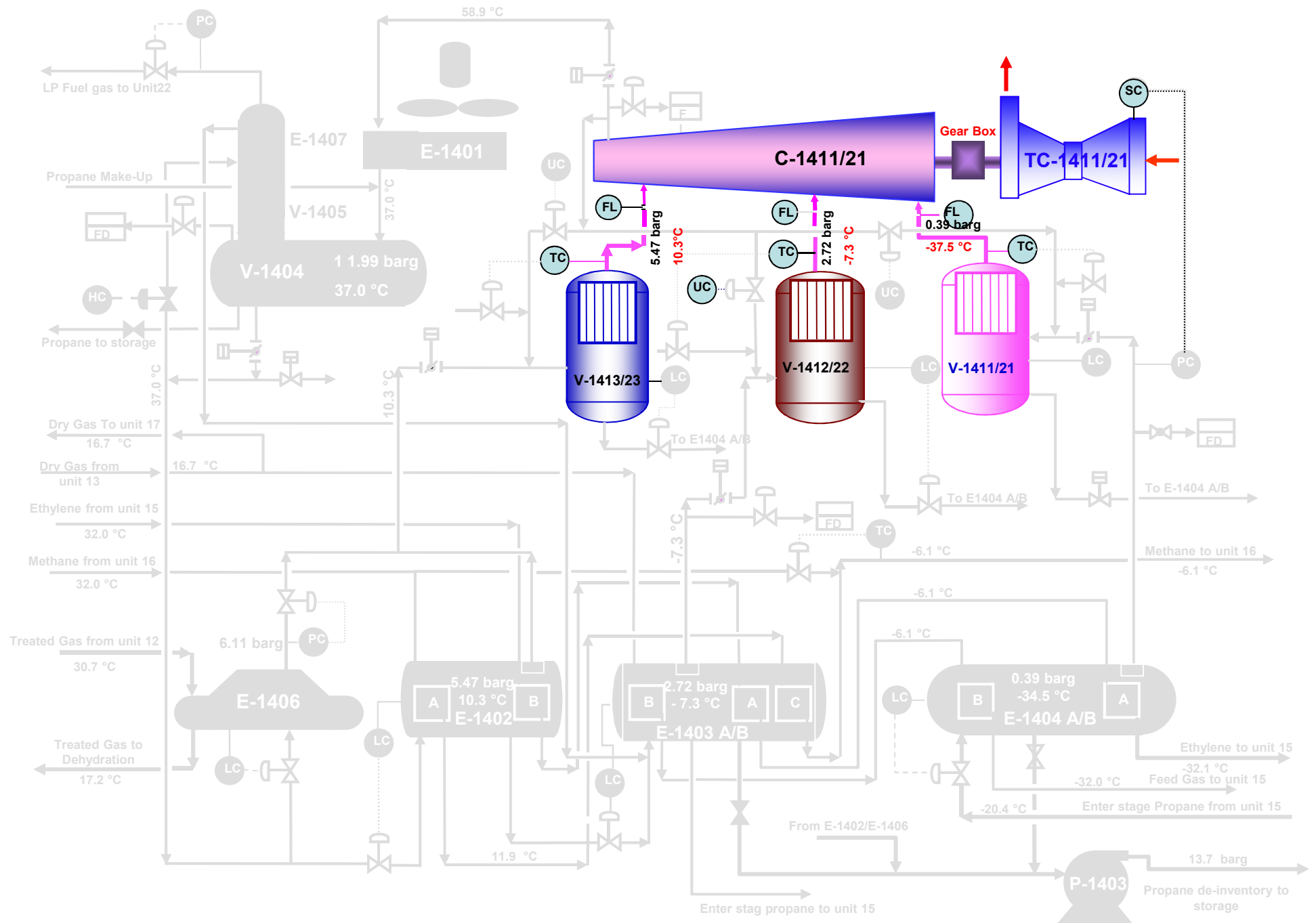
2. Loss of A.C. Power

The loss of A.C. power would result in the shutdown of the lube, hydraulic oil pumps and cooling fan motors to the propane compressor. The train will be shutdown automatically in a safe manner if there is loss of power.

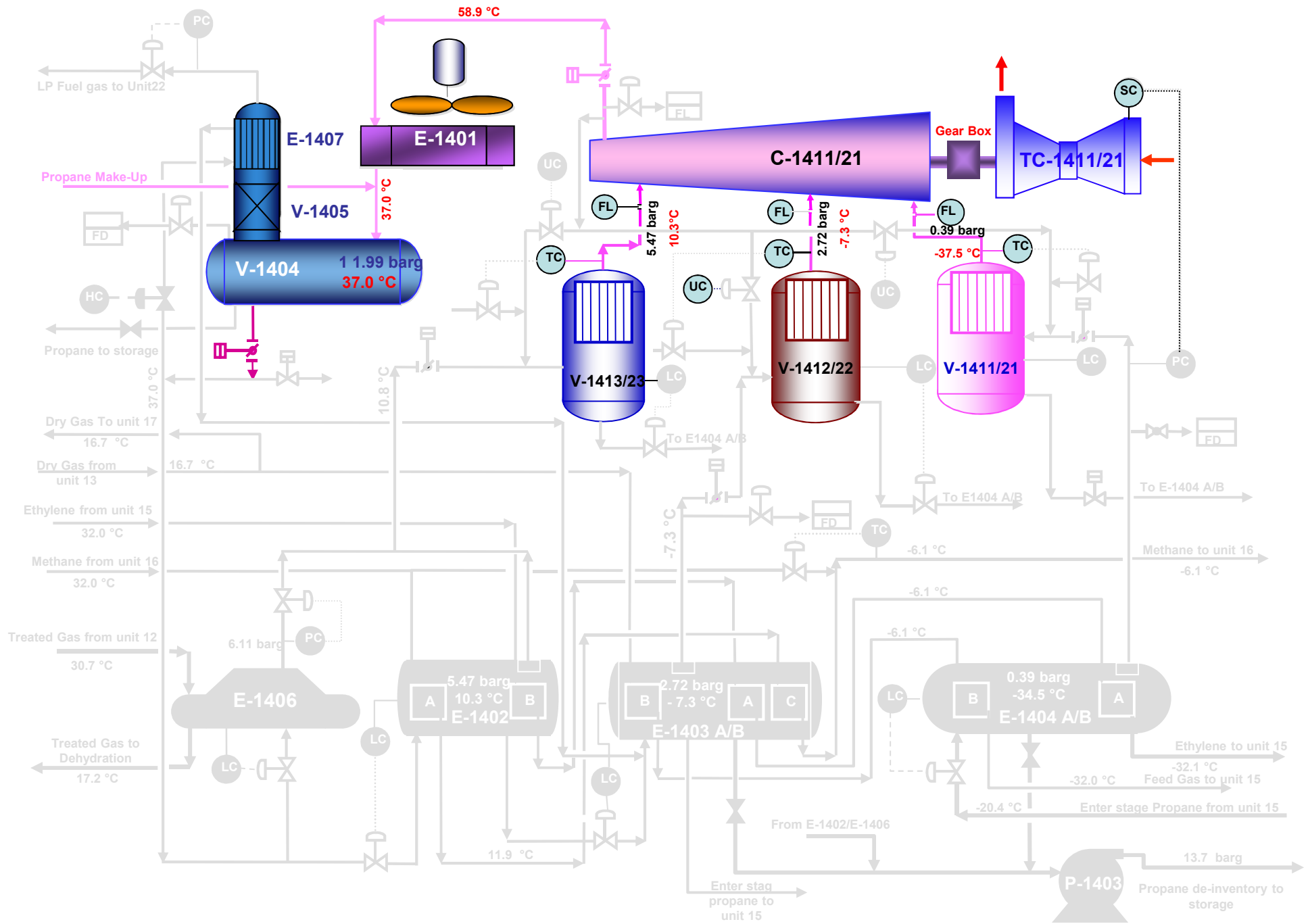
Propane Refrigeration System



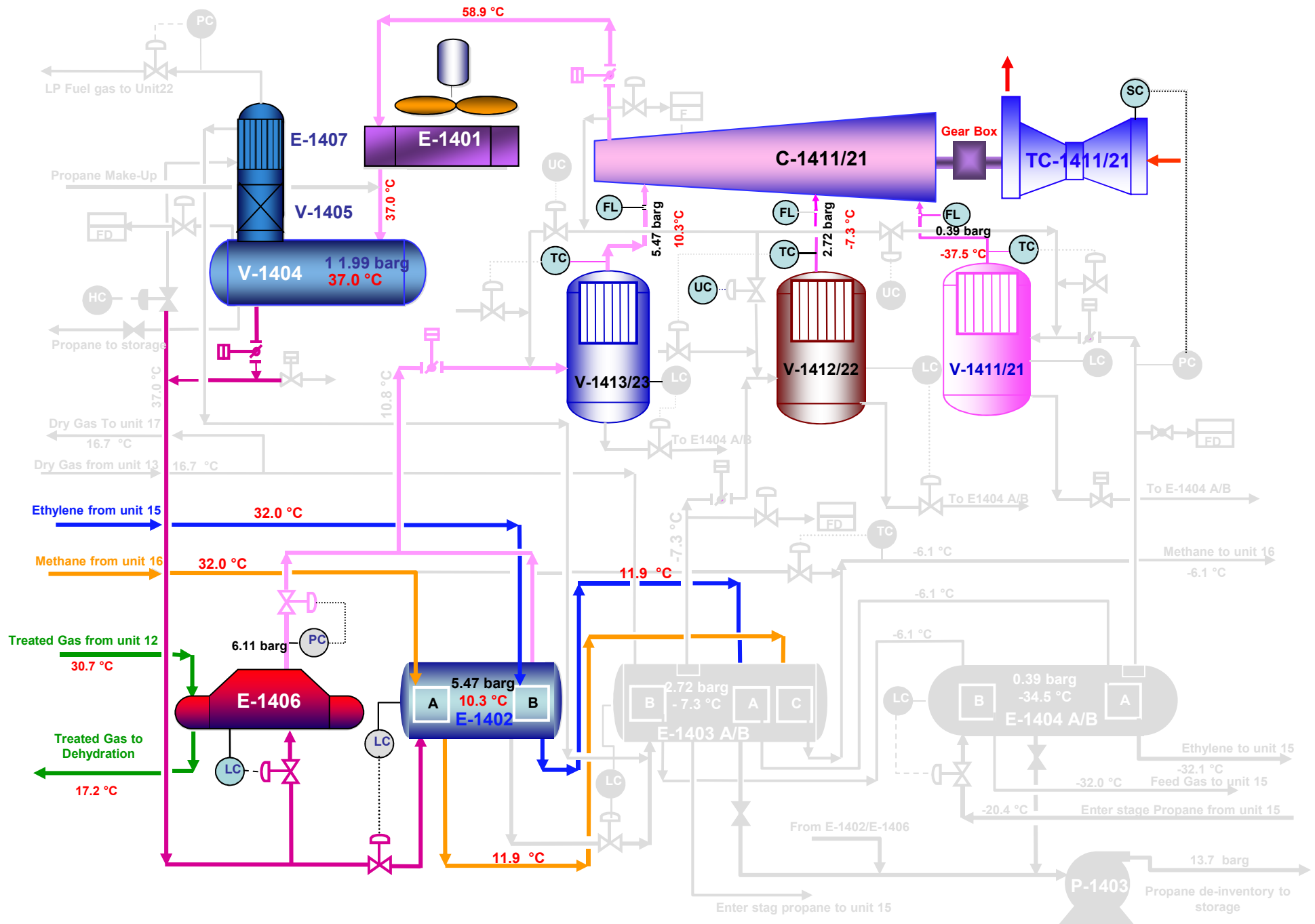
Two parallel units



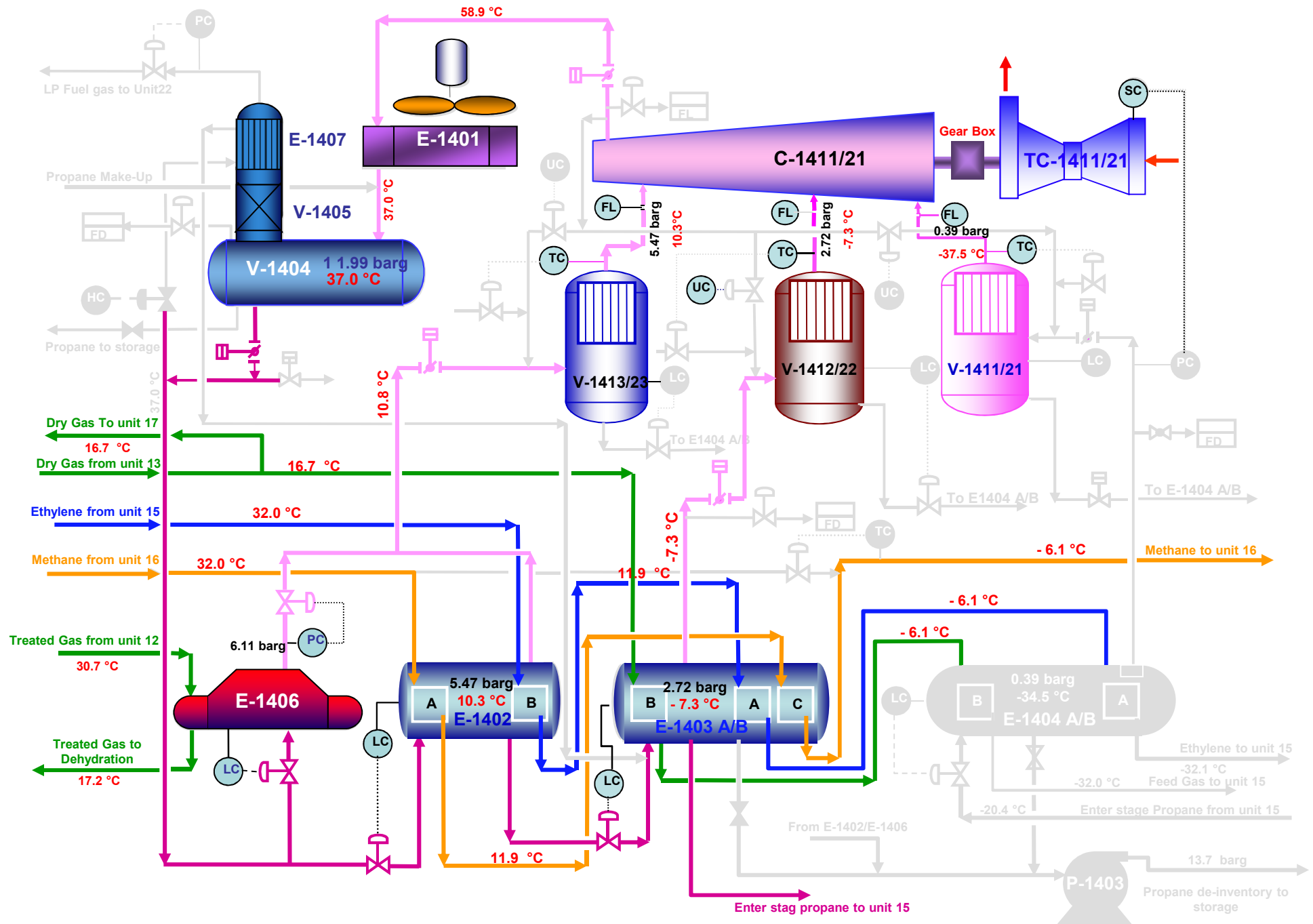
Refrigerant level



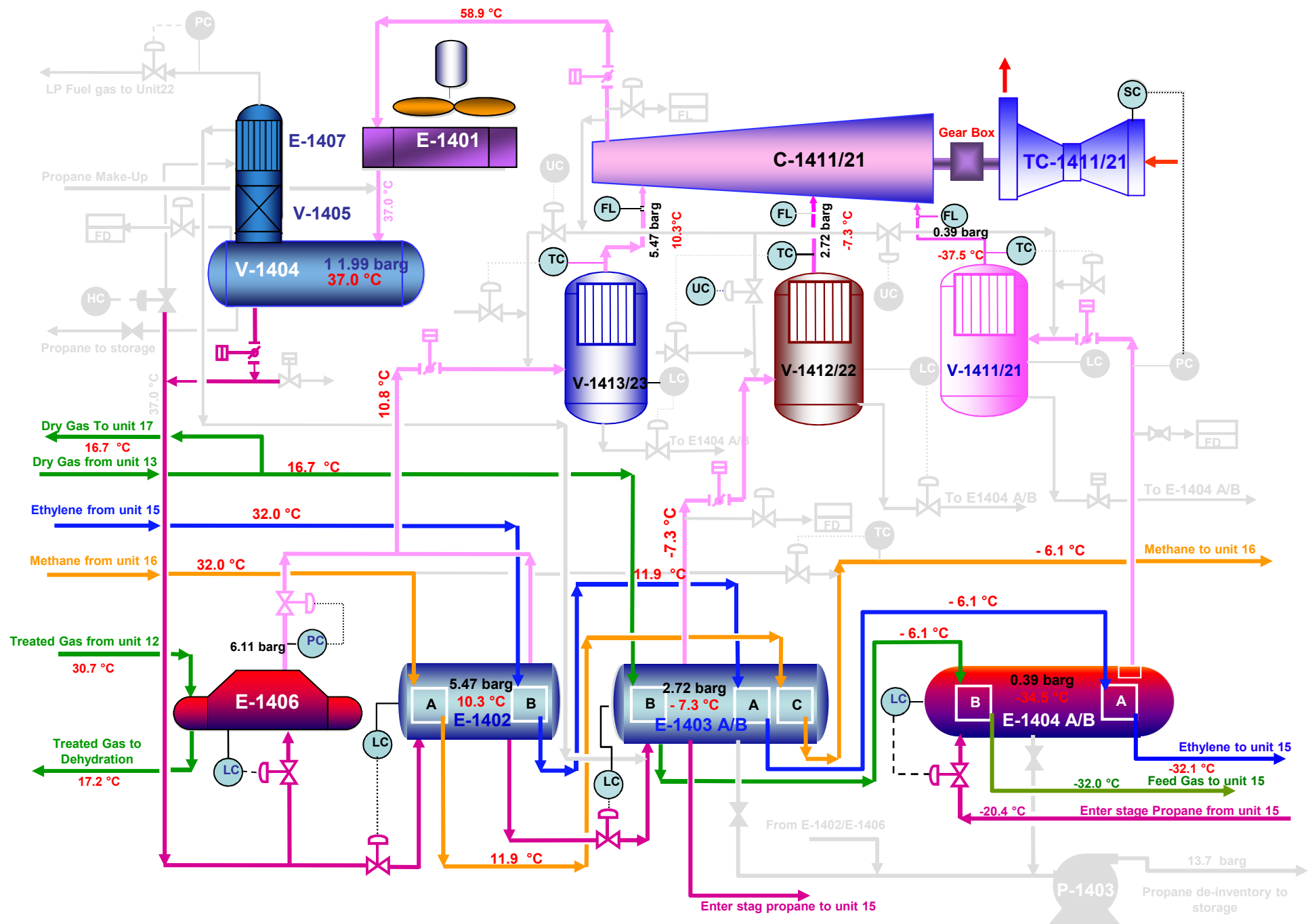
High Stage Propane Refrigerant



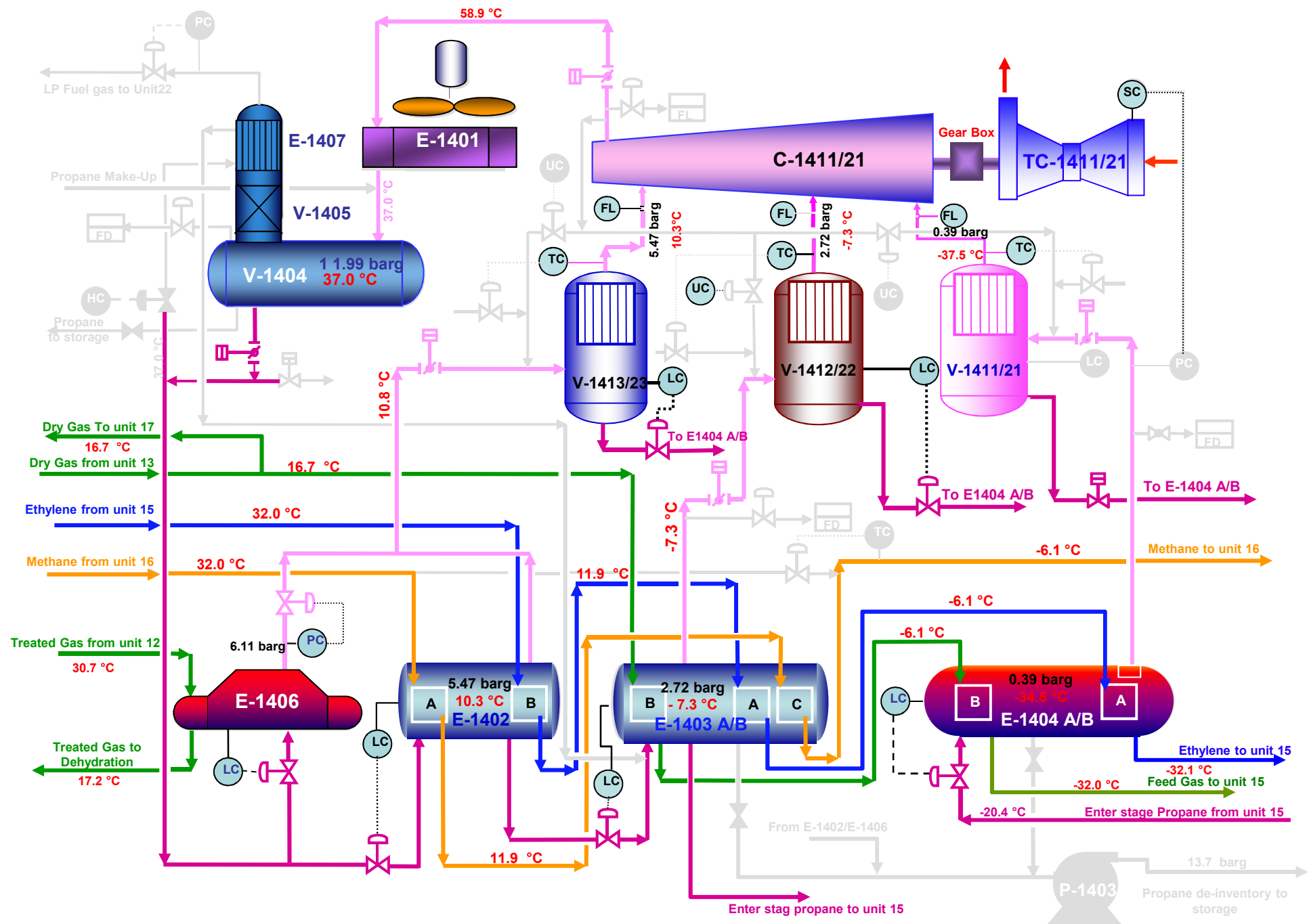
Intermediate Stage Propane Refrigerant



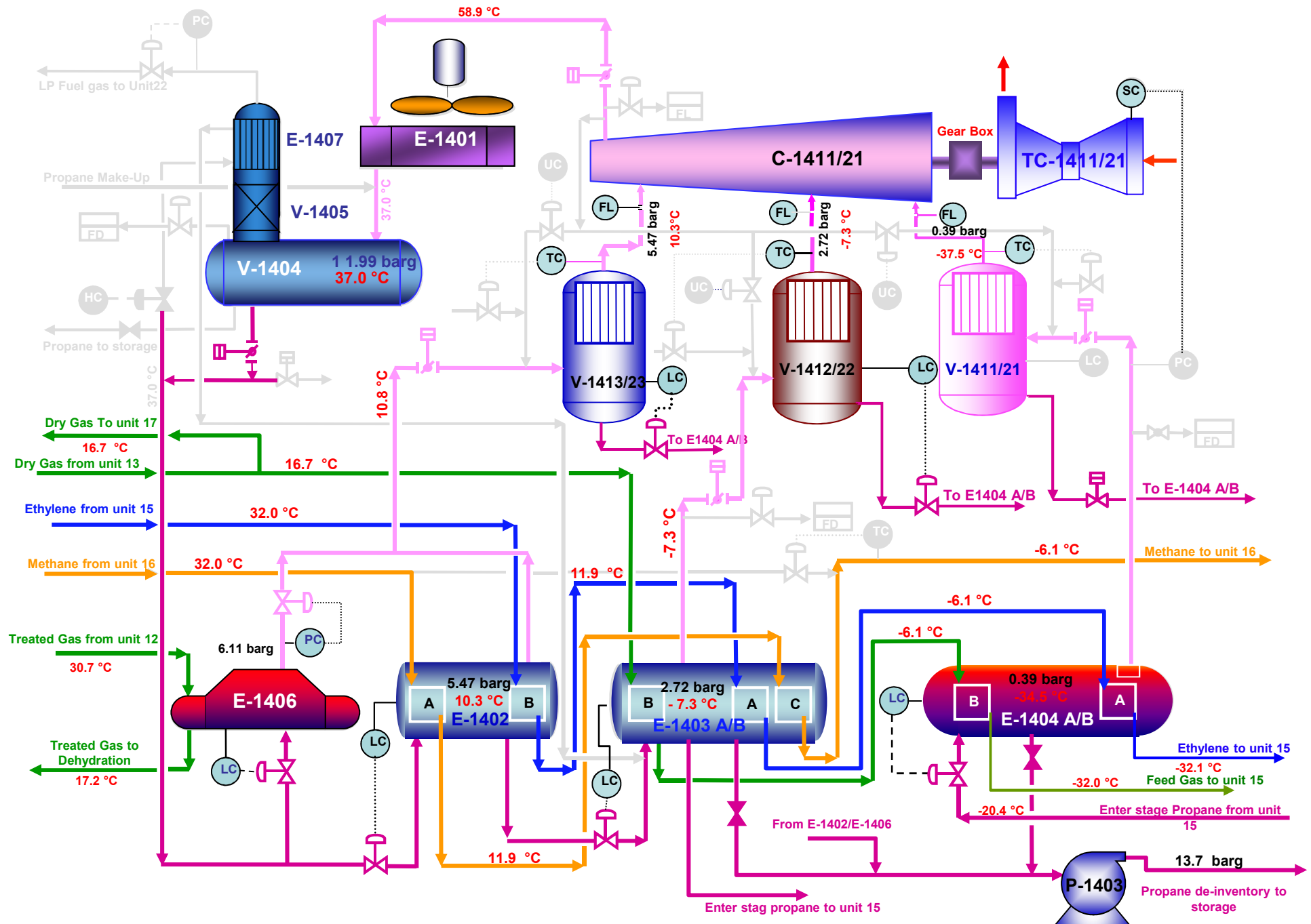
Low Stage Propane Refrigerant



Level control for suction drum



De Inventory



Ethylene Refrigeration

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Process description

Loss of utilities

PURPOSE OF THE UNIT

The purpose of the ethylene refrigerant circuit is to supply refrigeration cooling to the natural gas feed circuit and propane refrigerant circuit at two pressure levels in a closed loop .

MAIN EQUIPMENT

Tag Number	Equipment	Function
C-1512/21	Ethylene compressors	Provide two different pressure level
E-1512/22	Ethylene compressor discharge coolers	Cool and desuperheat high stage ethane compressor discharge
E-1511/21	Ethylene compressor intercooler	Provide cooling to ethylene gas between 1 st and 2 nd stage to save energy
V-1502	Ethylene surge drum	Receive the condensed ethylene and hold the entire transferable ethylene inventory .
V-1503	Ethylene purger absorption section	For removal of light ends
E-1506	Ethylene purger condenser section	For removal of light ends.
E-1503	High stage ethylene feed/ methane chiller	Provide chilling to feed gas and methane stream
E-1507	Feed gas chiller	Provide chilling to feed gas stream
E-1504 A/B	Low stage ethylene feed condenser	Condenses feed gas to produce LNG
E-1505	Ethylene / Propane economizer	Provides subcooling to propane refrigerant

PROCESS DESCRIPTION

1- Two parallel units

The ethylene refrigeration system consists of two compressors running in parallel to each other, each one is two stage compressor in single casing. Each compressor is provided with an intercooler and a discharge cooler which use air as their coolant.

Two GE frame 5D gas turbine are used to drive both compressor (each compressor is driven by a gas turbine)

The discharge of both compressors is joined together after cooling and is then desuperheated and condensed.

Any one of the machines can be started, turned off or put on total recycle without stopping the production.

2- Refrigerant levels

Liquid ethylene provides cooling condensing and partial subcooling to feed gas stream and subsequently to methane compressor discharge.

This is done at two refrigerant Stages :-

- a. High stage (H.S) at 6.5 bar , -61.4 °C
- b. Low stage (L.S) at 1.36 bar , -88.8 °C

Compressed ethylene gas at 10.4 bar is desuperheated against air in the ethylene compressor discharge cooler (E-1512/22) and is further cooled after joining against high stage and intermediate stage propane in (E-1402) and (E-1403), and is then totally condensed against low stage propane in (E1404A/B).

The condensed ethylene liquid is accumulated in the ethylene surge drum (V-1504) which is provided with a refrigerated and refluxed column to remove any light ends.

The ethylene surge drum (V-1502) is designed to be large enough to hold the entire ethylene inventory inside the largest ethylene core-in-shell exchanger.

3. High stage ethylene

Saturated liquid inside the ethylene surge drum (V-1502) is subcooled in the ethylene/propane economizer (E-1505) and is then fed to remove the shell side of the high stage ethylene feed/methane chiller (E-1503) on level control, it provides chilling to the feed and methane gas streams, by vaporizing the ethylene liquid at 6.5 bar.

The vapor from (E-1503) is then routed through the ethylene/propane economizer (E1505) to be superheated before it enters the high stage suction nozzle of the compressors

4. Low stage ethylene

Ethylene liquid from (E-1503) is routed to (E1505) to be further sub cooled and is then fed on level control to the shell sides of low stage ethylene feed condense (E-1504A/B) and the feed gas chiller (E-1507) to be vaporized at 1.36 bar in order to chill and condense the feed stream.

The ethylene vapor from both exchangers is routed to (E-1505) to be superheated and then to low stage suction nozzle of the compressor.

5. Feed gas condensing

Feed gas passes through (E-1503) and (E-1507) respectively where it is partially condensed at a controlled temperature by adjusting a flow to by pass both exchangers, this is done in order to condense aromatics and heavy hydrocarbons so that they can be removed before freezing in the downstream equipment, this is done in the heavies removal column (V-1701).

The overheads of the heavies removal column (V-1701) are joined with methane recycle from (E-1605) and are routed to (E-1504A/B) where they are totally condensed and partially sub-cooled.

There is a methane side draw from (E-1605) which is fed to (E-1503) to be cooled and then condensed in (E-1504A/B) in order to form reflux to (V-1701).

The ethylene vapors of the high stage and low stage leaving the economizer (E-1505) to the compressor must be at temperature higher than -45°C in order to protect the compressor suction piping material and compressor casing material.

If the temperature drops below -45°C It will cause the suction valves to close.

LOSS OF UTILITIES

1. Loss of Instrument Air

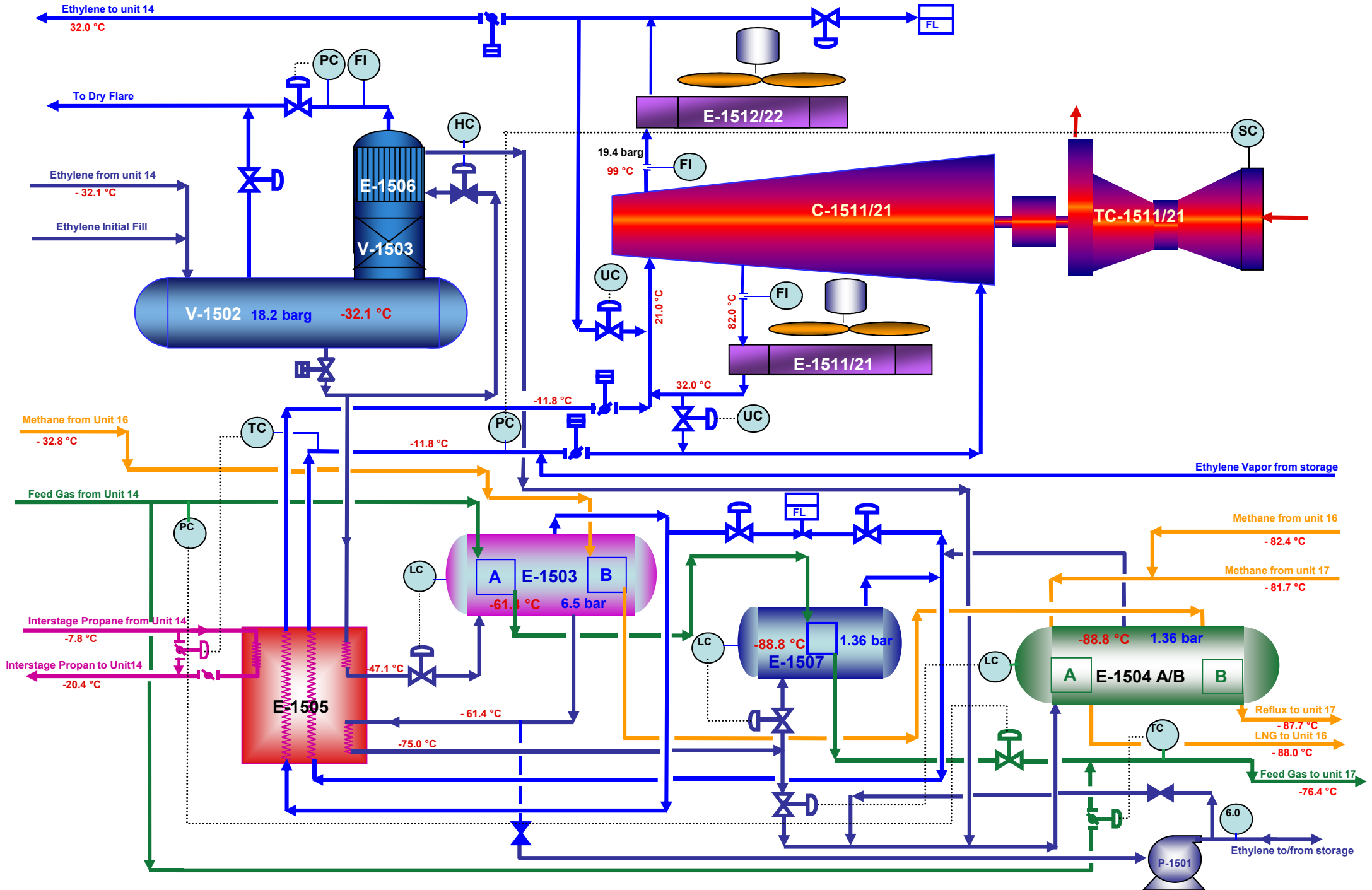
Loss of instrument air would result in all Control and Solenoid Valves failing to their safe positions. The unit will be shut down and discontinue to operate.

2. Loss of A.C. Power

The loss of A.C. power would result in the shutdown of the lube, hydraulic oil pumps and cooling fan motors to the ethylene compressor. The train will be shutdown automatically in a safe manner if there is loss of power.

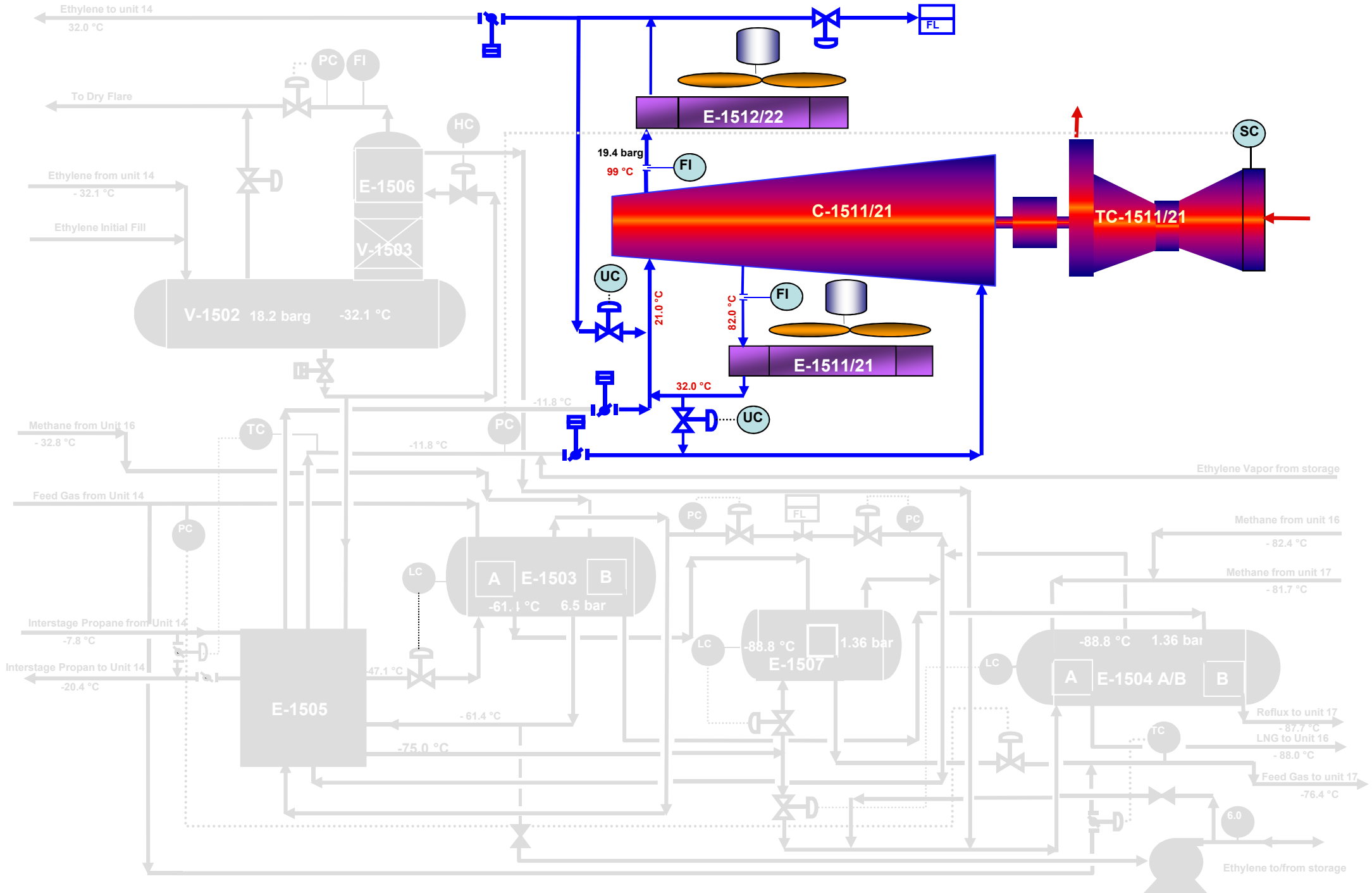
Ethylene Refrigeration System

Overview



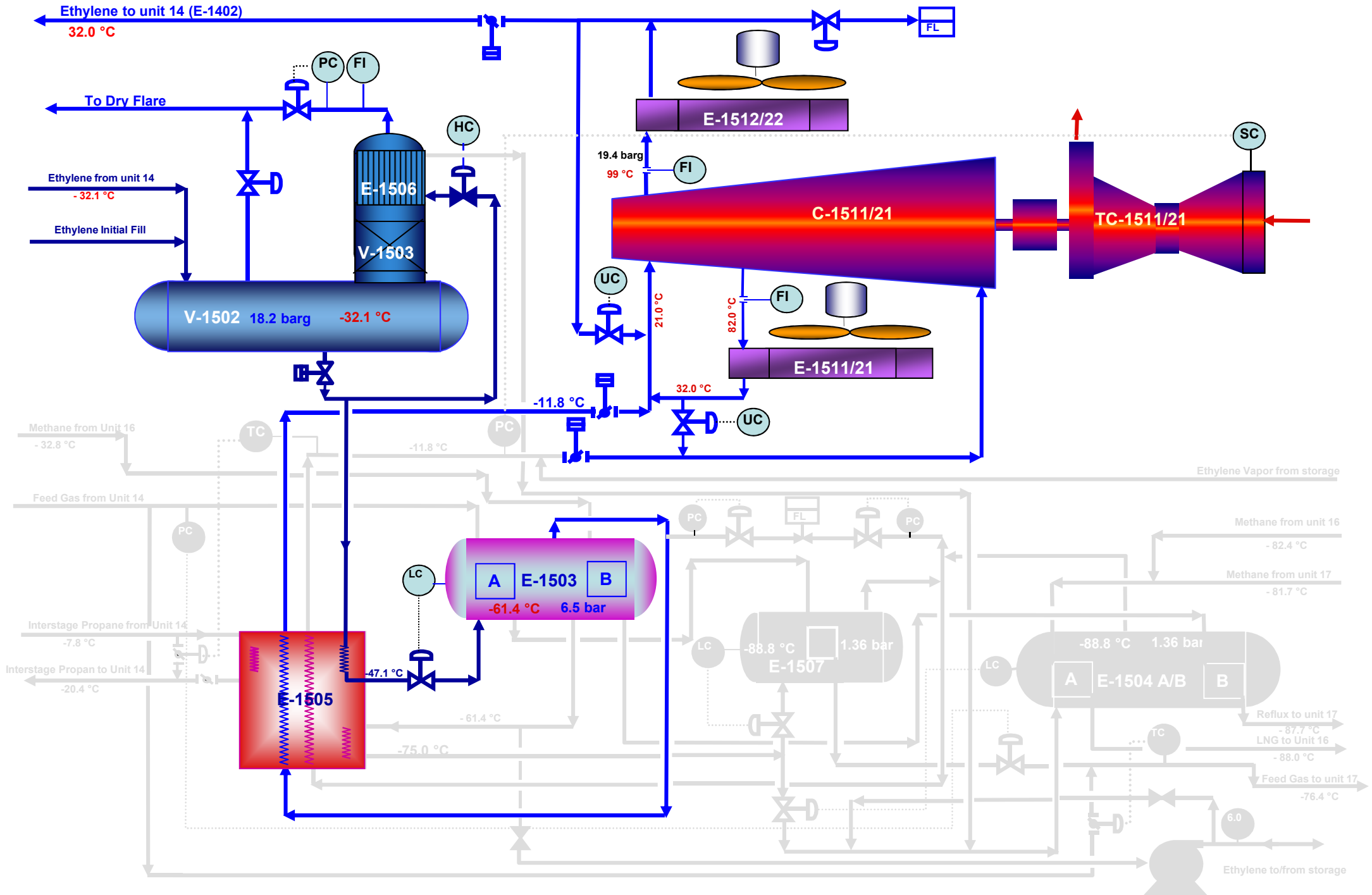
Ethylene Refrigeration System

Two parallel units



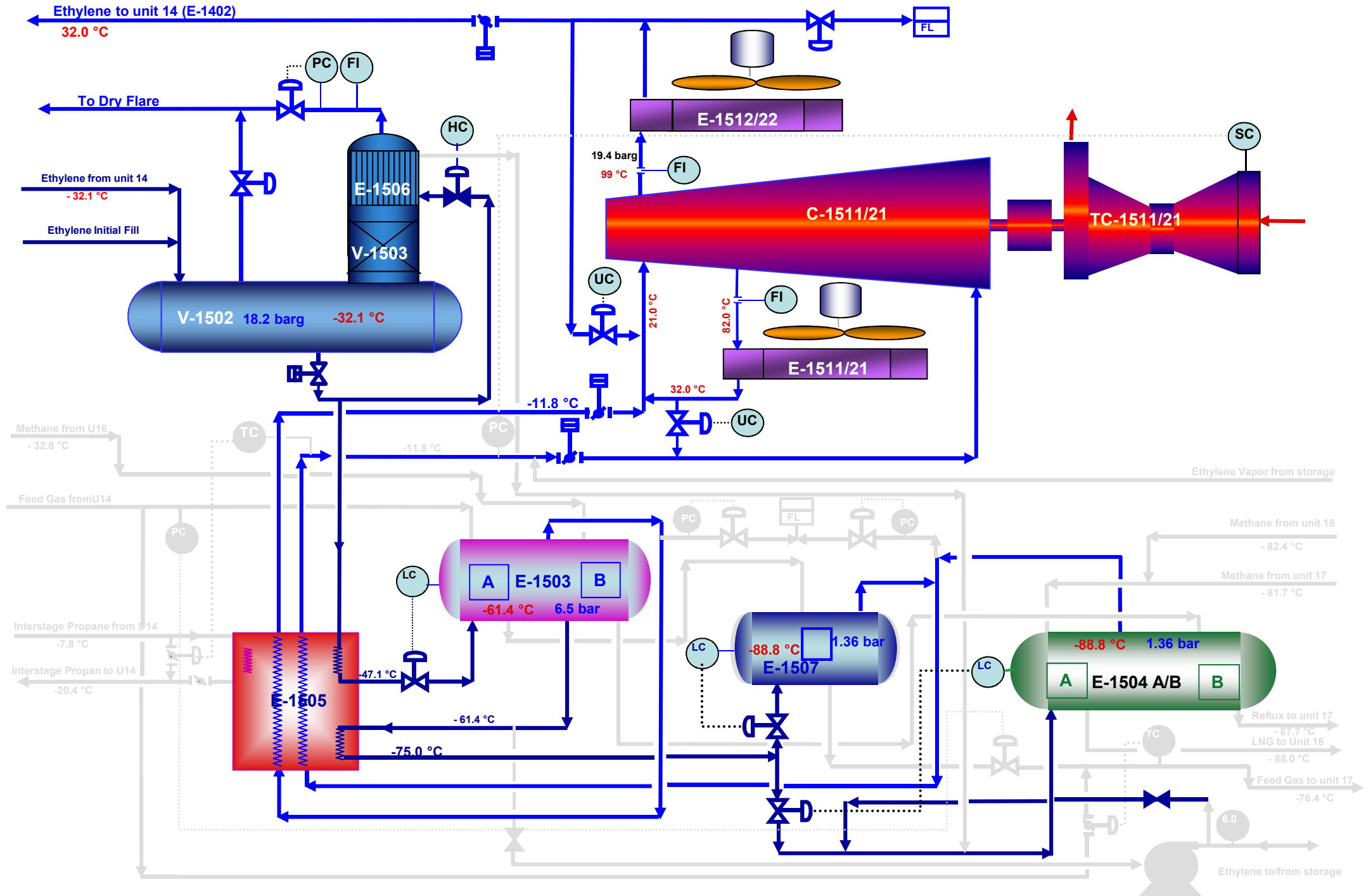
Ethylene Refrigeration System

High stage ethylene



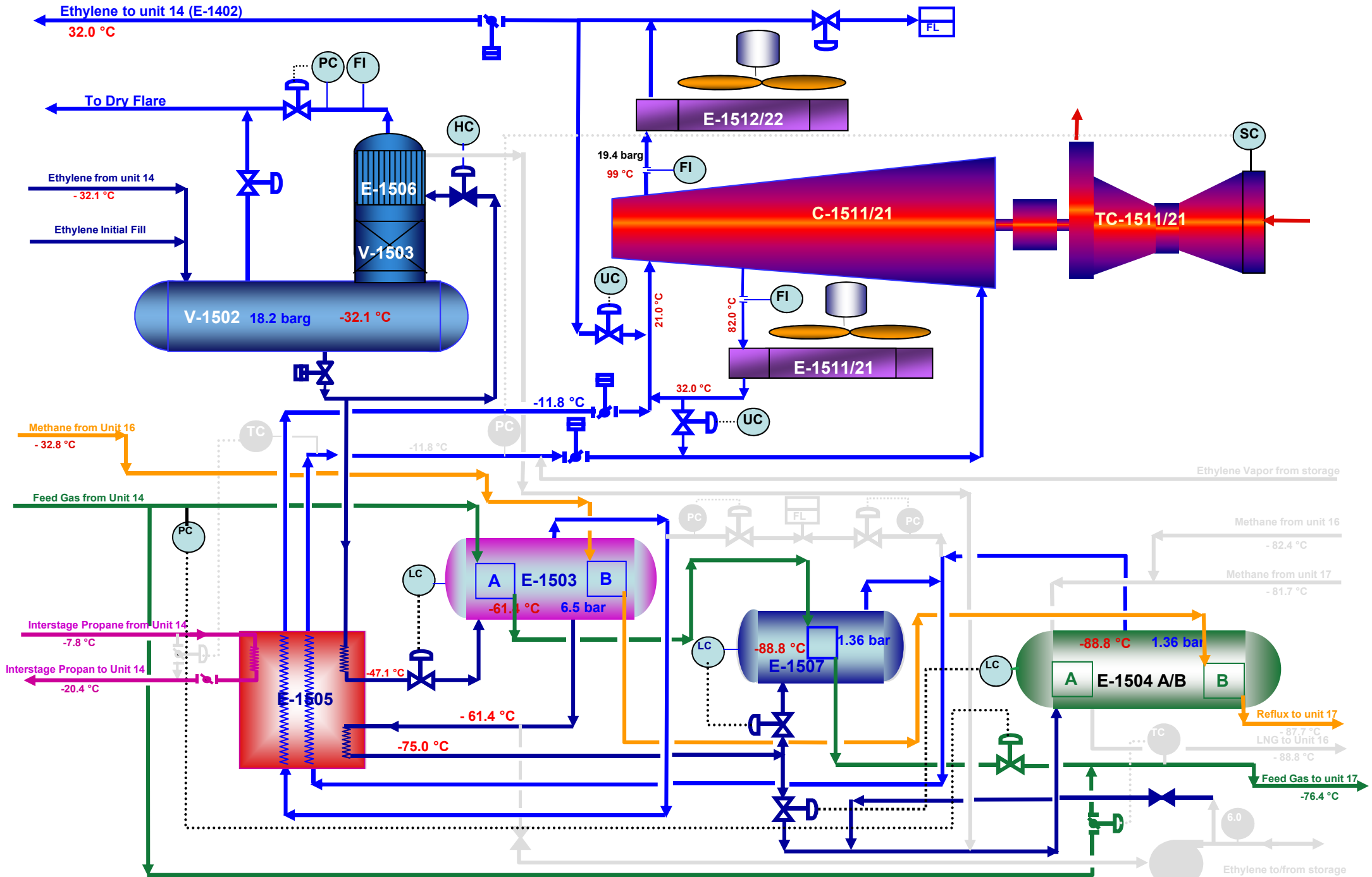
Ethylene Refrigeration System

Low stage ethylene



Ethylene Refrigeration System

Feed gas condensing



LIQUEFACTION AND METHANE COMPRESSION

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PURPOSE OF THE UNIT

The purpose of the liquefaction and methane compression unit is to further subcool and flash the LNG tree different pressure levels in order to store at almost atmospheric pressure, also the flash gas will be recompressed in order to be liquefied again.

MAIN EQUIPMENTS

Tag Number	Equipment	Function
C-1611-12-13-21-22-23	Methane compressors	Provide three pressure and cooling levels for methane gas
E-1605	Methane Economizer	Exchange vapor from flash drums with main LNG stream
E-1606	Intermediate stage methane economizer	Exchange liquid from high stage flash drum with vapor from inter stage flash drum and vapor from low stage flash drum for further subcooling.
E1613/23	High stage methane discharge coolers	Exchange the compressor discharge with air to cool it.
E-1612/22	Intermediate stage methane discharge coolers	Exchange the compressor discharge with air to cool it.
E-1611/21	Low stage methane discharge coolers	Exchange the compressor discharge with air to cool it.
V-1603	Inter stage flash drum	Flash liquid at 3.87 bar
TC-1611/21	Methane compressor gas turbine	Drive the compressors
V-1604	Low stage flash drum	Flashing liquid at 0.72 bar
V-1602	High stage flash drum	Flash liquid at 14.1 bar
P-1601 A/B	LNG transfer pumps	Pumps the LNG from V-1604 to the LNG storage tanks

PROCESS DESCRIPTION

Liquefaction and methane compression

The feed gas after being condensed in unit 15 is subcooled by passing through the methane economizer (E-1605) by exchange with flashed methane gas and is then flashed to three pressure levels, and the liquid coming from the last pressure stage being LNG product is pumped to the storage tanks (T-2401A/B) using LNG transfer pump(P-1606A/B).

The flashed gas from the three pressure levels is recompressed by the methane compressors (C-1611/21, 1612/22, 1613/23) and recycled to the process units upstream of the feed gas condensing operations.

The flash gas however before compression passes through the methane econonize, where they cool the methane compressor discharge and subcool the LNG before being flashed as they are warmed up to about -8.4°C.

Two parallel compressors

There are two sets of methane compressors running in parallel. Each of them is driven by a GE frame 5D gas turbine. Each set is composed of three stage, each in a separate casing and are equipped with two intercoolers and one aftercooler that use air as the coolant. Each stage has its own independent anti surge control system.

Discharge of compressors is joined together after being cooled in the after coolers and is desuperheated, condensed and flashed.

Any one of the sets can be started, shutdown or being on total recycle without shutting the system, provided that the plant throughput is adjusted to the situation.

Subcooling and flashing

LNG from unit 15 is joined with the reflux from (E-1504A/B) and is first subcooled in the methane economizer (E-1605) and is then flashed into the high stage flash drum (V-1602) at 14.10 bar.

The flashed liquids is further subcooled against inter stage and low stage flashed gases in the inter stage methane economizer (E-1606) and is then flashed to the inter stage flash drum (V-1603) on level control at a pressure of 3.97 bar.

Liquid from inter stage flash drum is routed to low stage flash drum (V-1604) which is operated at 0.72 bar on level control to be flashed for the last time.

The inter stage economizer (E-1606) is equipped with pressure difference indicator the LNG core to detect any solid formation cause by carbon dioxide or aromatics.

Flashed gas

The flashed gas from the low stage flash drum is joined with boil off gas from boil gas compressor (C-2401) downstream of (E-1606) and is fed to (C-1611-21).

The flashed gas from the inter stage flash drum (V-1603) after being superheated in both (E-1606) and (E-1605) is joined with (C-611/21) discharge and fed to (C-1612/22).

While for the flashed gas from high stage flash drum (V-1602) it is superheated in (E-1605) and then joined with (C-1612/22) discharge to be compressed in (C-1613/23).

The methane compressors are protected against cold temperature by high-high level alarms on each LNG flash drum and low-low temperature alarm (-29°C) each suction line that will initiate a process structure to close the suction valves of compressors and send the flashed gases an pressure control to the fuel gas system.

LOSS OF UTILITIES

1. Loss of Instrument Air

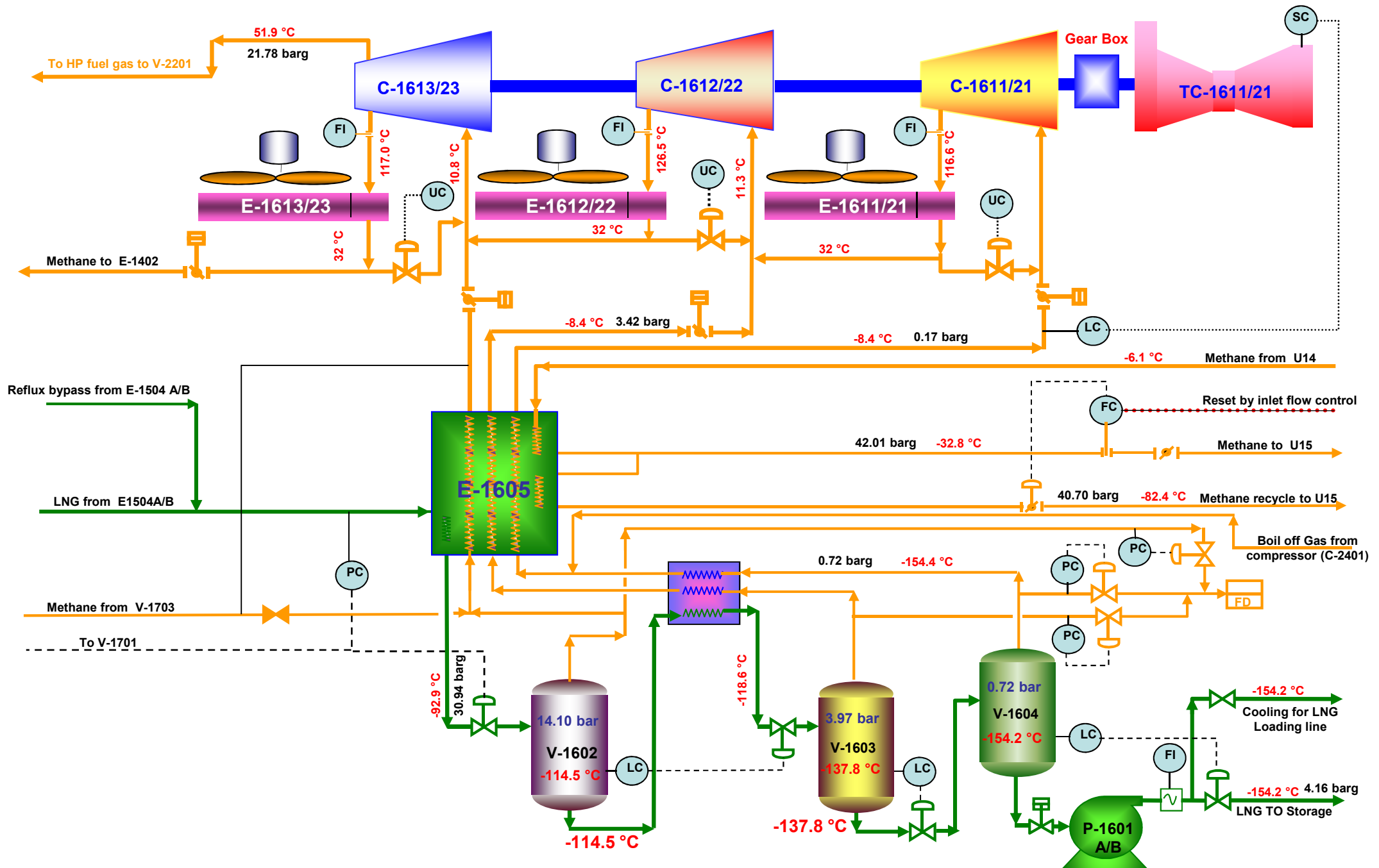
Loss of instrument air would result in all Control and Solenoid Valves failing to their safe positions. The unit will be shut down and discontinue to operate.

2. Loss of A.C. Power

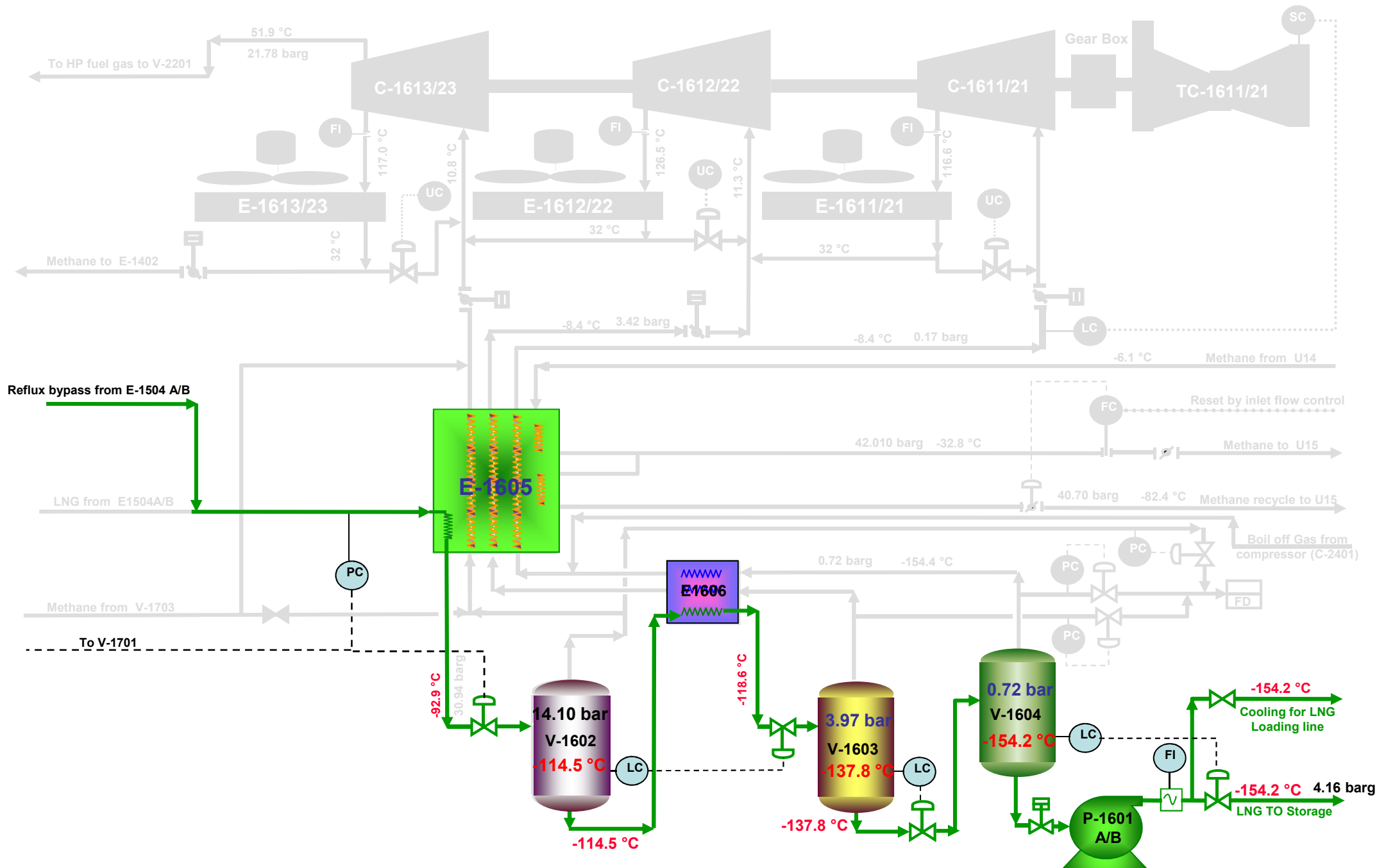
The loss of A.C. power would result in the shutdown of the lube, hydraulic oil pumps and cooling fan motors to the methane compressor. The train will be shutdown automatically in a safe manner if there is loss of power.

Liquefaction and methane compressor Figure

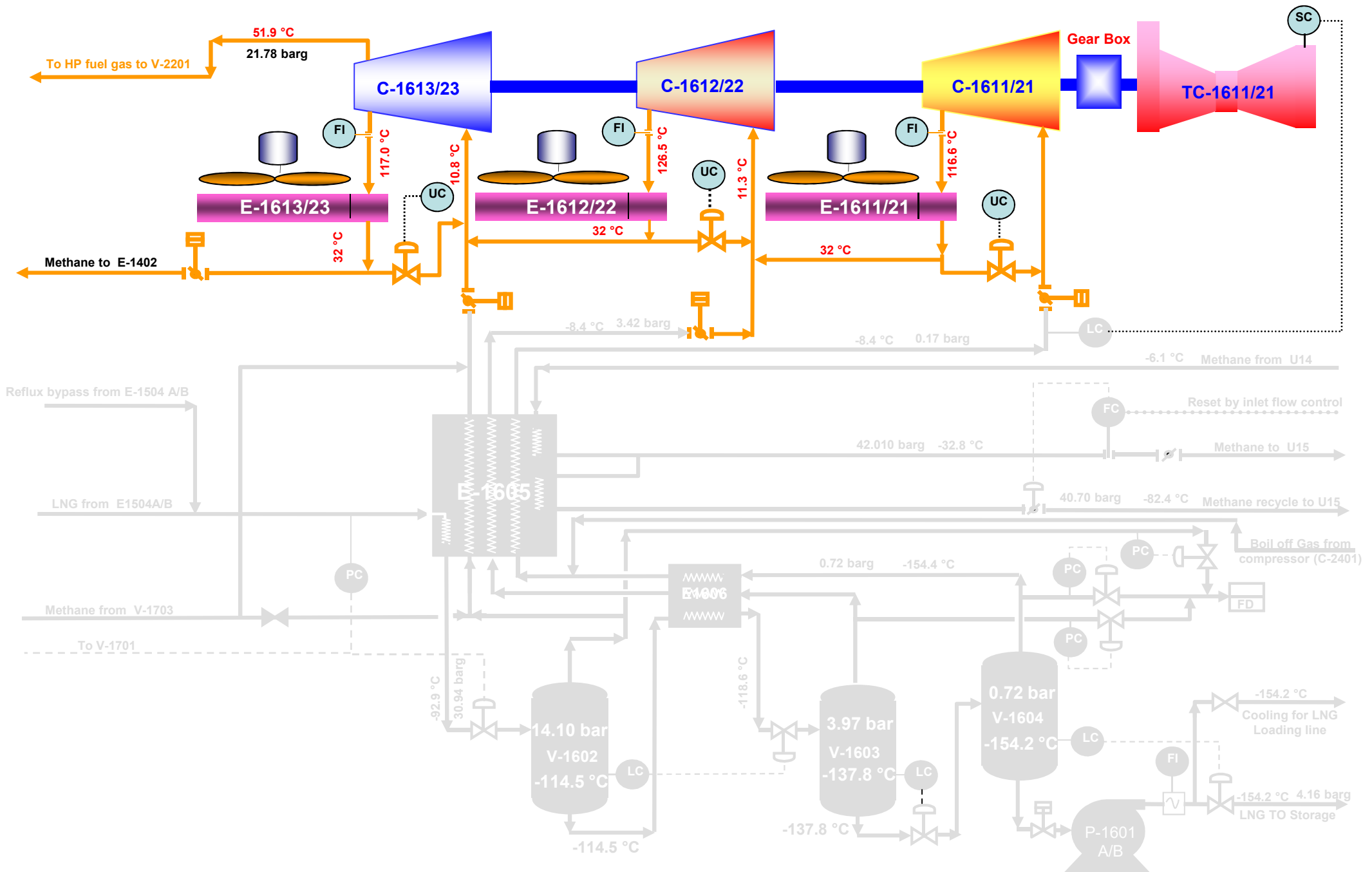
Overview



Liquefaction and Methane Compression

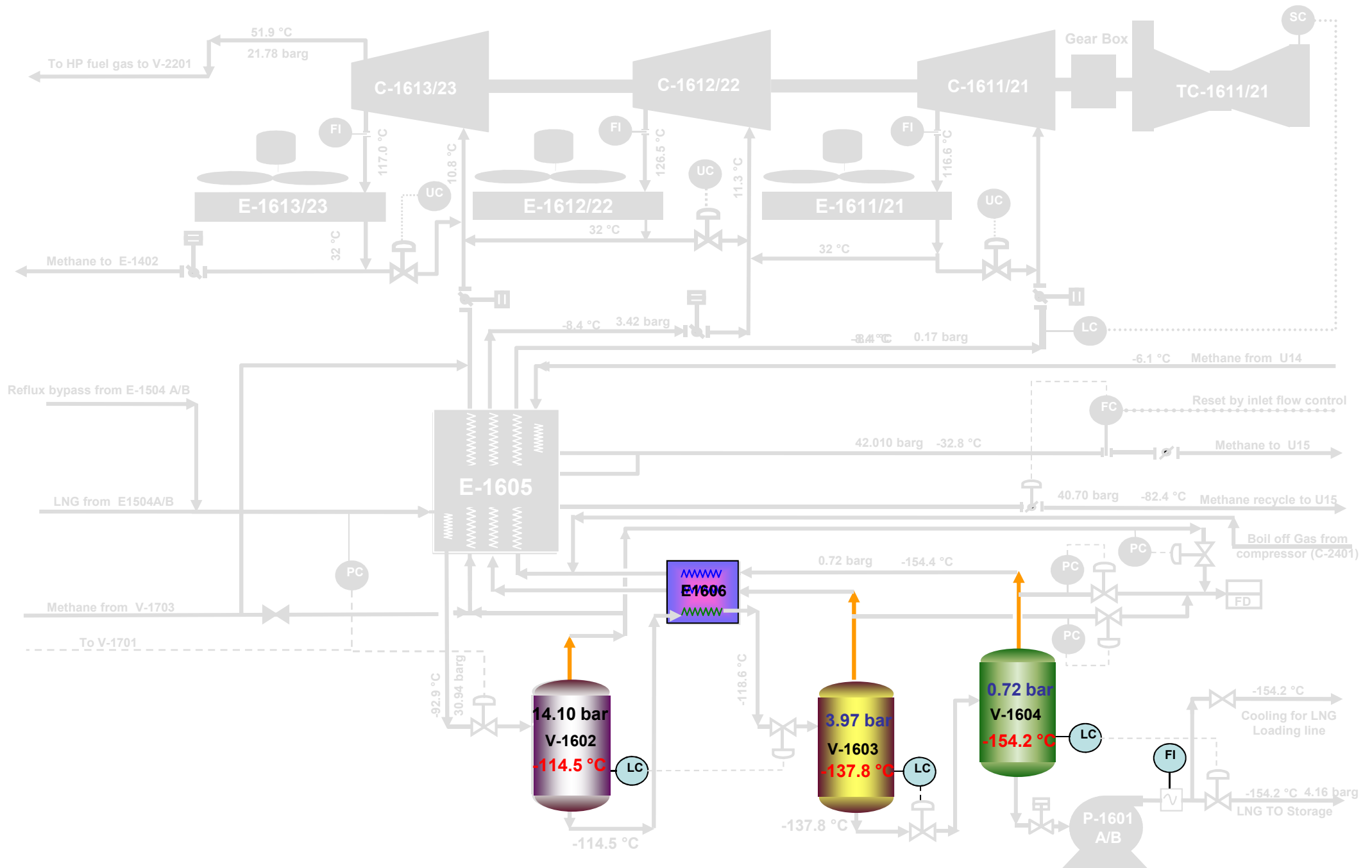


Liquefaction and methane compressor
Two parallel units - Parallel Compressor



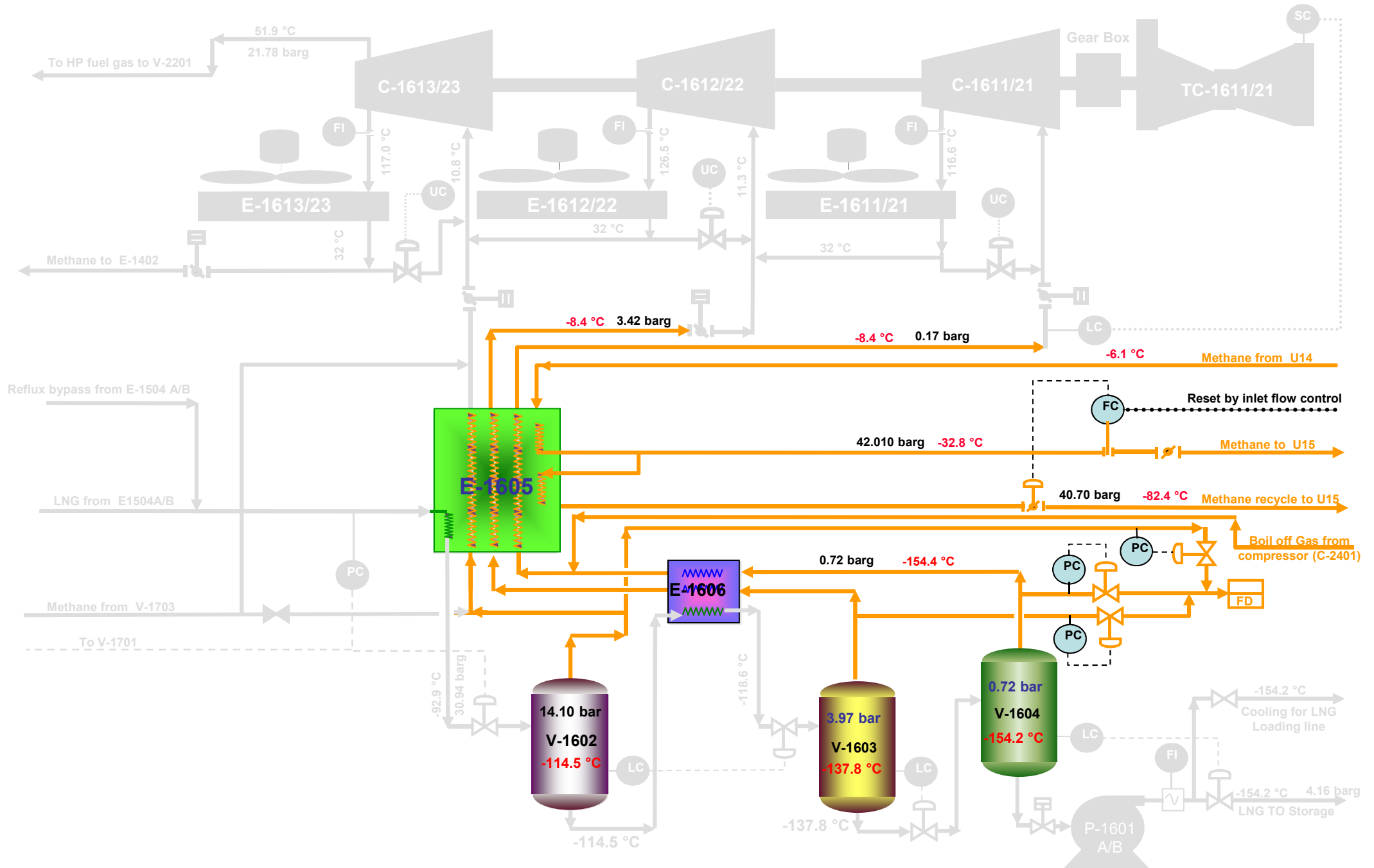
Liquefaction and methane compressor

Subcooling and flash



Liquefaction and methane compressor

Flash gas



HEAVIES REMOVAL / NGL RECOVERY

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INTRODUCTION TO HEAVIES REMOVAL

1. OVERVIEW

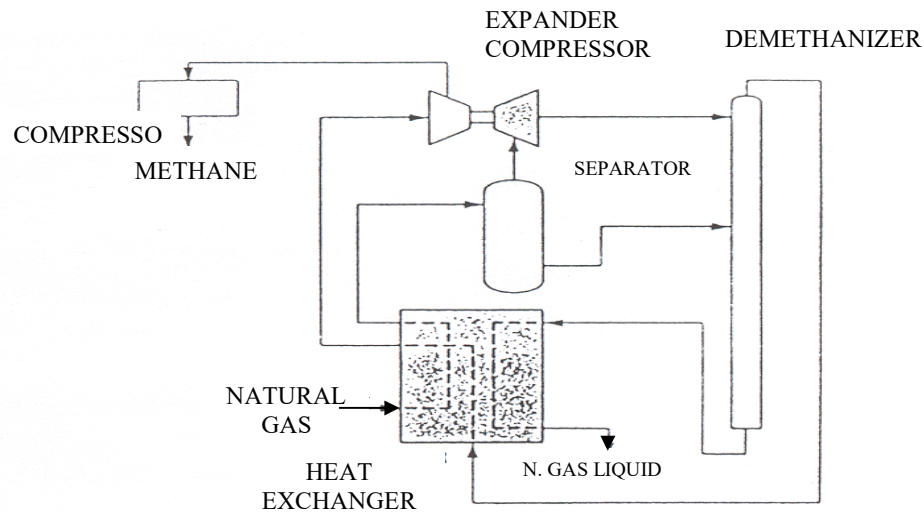
Natural gas liquids (or "NGL's"), are hydrocarbons in a Liquid state. There are many reasons for removing NGLS from the gas stream, including:

1. The hydrocarbon components may be more valuable in their liquid state, either mixed or separated into their different individual elements.
2. Pipeline gas quality specifications may restrict the amount of NGLS allowed.
3. Heavier NGL's can separate from the gas stream in pipelines as temperatures drop, thus restricting flow in the pipeline.
4. The NGL's may be used for re-injection on enhanced oil recovery projects. That is, they will be injected into a formation to help "sweep" crude Oil through the reservoir by mixing with the oil and pushing the crude toward the well bore.

There are several different processes that can be used to separate NGL's from the natural gas stream. The three most common are: Cryogenics, refrigeration and lean oil absorption.

2. CRYOGENICS

In the cryogenic process, a natural gas stream is cooled to extremely low temperatures to liquefy the ethane and heavier hydrocarbons. When a gas stream is chilled to below -50°F (-45°C), heavier gas components are easily liquefied. The ethane and heavier hydrocarbons are then separated from the methane.

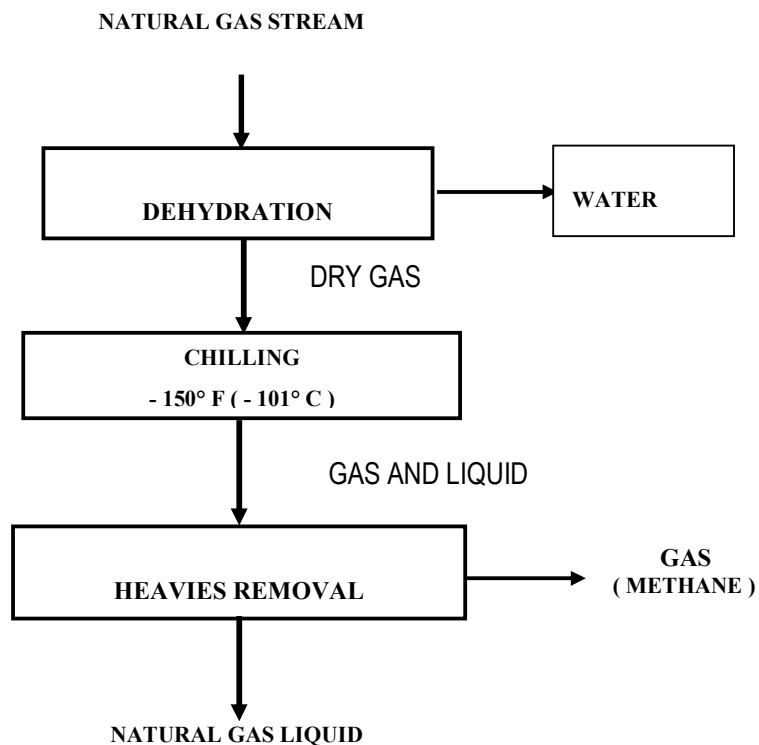


CRYOGENICS

Cryogenic processing of a natural gas stream involves three basic steps: dehydration, chilling and fractionation.

Because of the very cold temperatures in cryogenic processing, the gas stream must be almost totally dehydrated to prevent the formation of Hydrates .

Dehydration is usually accomplished with either a liquid or solid desiccant. The method depends on the water content of the inlet gas at your facility. Some cryogenic processes will use only dry-desiccant dehydration. But if the water content of the inlet gas is-high, first there would be liquid desiccant dehydration, followed by dry-desiccant dehydration.



CRYOGENIC PROCESSING

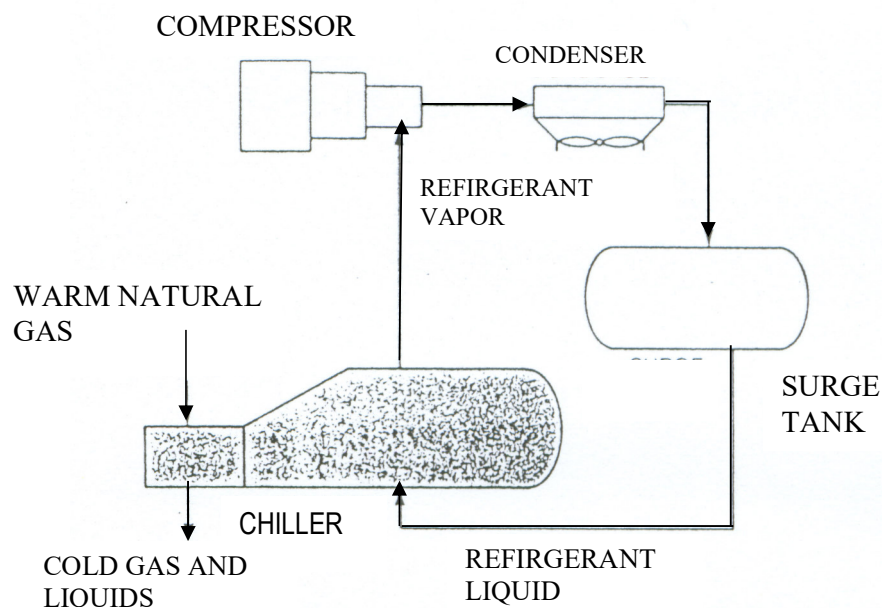
Chilling of the gas is the cornerstone of the cryogenic process. The gas stream can be chilled by heat exchange with cold gas, and by pressure reduction or pressure reduction with energy removal. The pressure reduction method ("J.T " or Joule-Thompson), provides cold temperatures in the range of -50 ° F (-45°C) to -100° F (-73 °C). To obtain the lowest temperatures, -100°F (-73°C) to -200° F (-129°C), pressure reduction with energy removal is accomplished using an expander - compressor.

METHOD	TEMPERATURE RANGE	TYPICAL PERCENT RECOVERY	
Refrigeration	(- 18 ° to - 29 °C)	Ethane	25
		Propane	55
		Butanes	93
		Heavier	97
Pressure Reduction (J.T Process)	(- 46 ° to - 57 °C)	Ethane	70
		Propane	80
		Butanes	97
		Heavier	99
Expander Process	(- 87 ° to - 101 °C)	Ethane	80
		Propane	96
		Butanes	99
		Heavier	100

Cryogenics has relatively moderate energy requirements, and is considered the most efficient method for removing NGLS from the gas stream. .

3. REFRIGERATION

Refrigeration is a separation process that has been in use for many years. The principle is to chill the natural gas stream by passing the gas through a chiller. Temperatures in this process range from 0°F (-18° C) to -20° F (-29° C). Chilling causes the heavier hydrocarbons to liquefy, and then these NGLS can be separated from the gas.



REFRIGERANT

The energy requirements of refrigeration are primarily for compressing the refrigerant and driving the condenser. While the volume of heavier hydrocarbons recovered is less than with lean oil absorption, the amount of equipment and energy used for recovery with refrigeration is much less, making it a more economical method than lean oil absorption.

Purpose of the unit

The purpose of this unit is to remove the heavy components from the feed gas stream, which may cause freezing and blocking in the liquefaction section. Also to recover these heavies as NGL used for export.

Main Equipments

Tag Number	Equipment	Function
V-1701	Heavies removal column	Separate methane from the top (98.0 mol%), methane (48 mol %) and ethane (29 mol %) from the bottom
E-1704	Inlet exchanger	Cool the stripping gas stream before entering the heavies removal
V-1702	NGL recovery column	Separate C5 ⁺ (85.62 mol %) from the bottom and recovers C1,C2,C3 and C4 from OVHD
E-1701	NGL recovery condenser	Condense the over head vapor of NGL recovery column
V-1703	NGL recovery column reflux drum	Provide reflux for NGL recovery column
E-1702	NGL recovery column reboiler	Heat the NGL recovery column bottom using hot oil system
E-1703	NGL recovery bottom cooler	Cool the NGL recovery column bottom product before sending to V-1102 (NGL liquid storage drum) prior to export.

PROCESS DESCRIPTION

Heavies removal column

The heavies removal column (V-1701) is a packed column designed to separate ethane and heavier components from the feed gas stream.

Feed gas from (F-1302 A/B) is divided into two streams, the majority of the gas is cooled to temperature of -76.4°C and a pressure of 40.9 bar. when processed in the refrigeration units 14 and 15. this gas stream from (E-1507) is then fed to the middle part of the heavies removal column (V-1701) where liquid flashed out of the gas.

The other stream from (F-1302 A/B) is cooled by exchanging against the (V-1701) bottoms stream in the inlet exchanger (E-1704) to a temperature of -20.8 °C before being fed to the bottom part of HRC (V-1701), as the gas flows up the column it partially strips ethane and lighter components from the down flowing liquid.

The amount of gas fed from the bottom of the column is adjusted as a ratio to the inletfeed rate.

Reflux to the top of the column a totally condensed methane stream from (E-1504A/B) strips the up flowing vapours from ethane and heavier components

The amount of reflux used is adjusted by measuring the OVHDS temperature and the remainder of reflux is sent back to mix with the LNG upstream of (E-1605)

The overhead vapours from HRC (V-1701) now free of heavies are combined with recycle methane gas from (E-1605) and are fed to the first core in (E-1504A/B) for total condensation.

The bottoms liquid from (V-1701) mainly heavies is fed on flow control reset by level control to the inlet exchanger (E-1704) to exchange heat with the dry gas stream from (F-1302 A/B) which is equipped with a bypass across (E-1704) to reduce the risk of thermal shock by maintaining a specific temperature difference inside (E-1704).

The bottom of (V-1701) is further cross-exchanged against the over head vapours of the NGL recovery column (V-1702) in NGL recovery condenser (E-1701) to reach a temperature 29.1 °C.

NGL Recover column

The NGL recovery column (V-1702) is a trayed column designed to separate pentane and heavier components as bottom product from the HRC (V-1701) bottoms stream and is designed to separate propane and heavier components as bottoms products during rich feed gas case.

The HRC (V-1701) bottoms stream now at 29.1 °C and mostly in vapor phase is fed to the top of the fifteenth tray of the NGL recovery column (V-1702).

The column is equipped with a NGL recovery column reboiler (E-1702) heated by hot oil, vapor's from the reboiler are fed to the bottom of the column to strip butane and lighter component from the down flowing liquids during lean gas case , and to strip ethane and lighter component during reach gas case.

The overheads from the column are partially condensed against the HRC bottoms stream in the NGL recovery Column condenser (E-1701) and liquids collected in the NGL recovery column reflux drum (V-1703) to be sent on level control as reflux to (V-1702) using the NGL recovery column reflux pump (P-1701 A/B)

The net overhead at 13.4 °C is sent to the high stage methane compressor (C-1613/23) suction.

The bottoms product at 188.2 °C is cooled against air in the NGL recovery column bottom cooler (E-1703) to a temperature 43.3 °C in order to be sent to the NGL liquid storage drum (V-1102) prior to export.

C3 Plus recovery (rich gas case)

During rich feed gas case where the feed gas is rich in C₂, C₃ or C₄ the bottoms stream from HRC (V-1701) is heated first in NGL recovery condenser (E-1701) then in the inlet exchanger (E-1704). This change in passage shall be done during a shut down situation otherwise a significant thermal shock can happen to the brazed aluminum heat exchanger (E-1701).

Also the net over head's stream from (V-1705) should be routed to upstream of the methane economizer (E-1605) rather than to the compressor suction directly.

LOSS OF UTILITIES

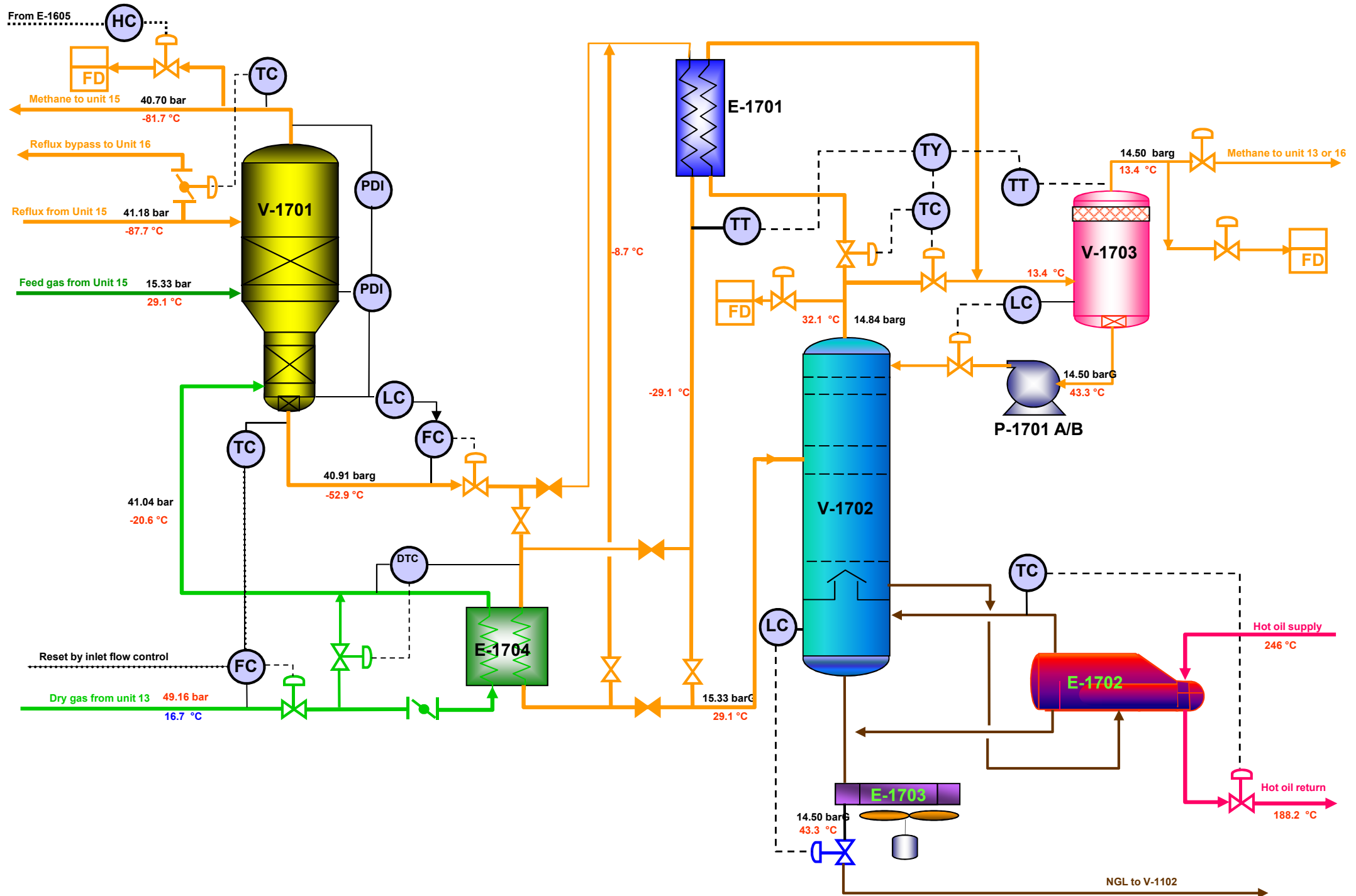
1. Loss of Instrument Air

Loss of instrument air would result in all Control and Solenoid Valves failing to their safe positions. The unit will be shut down and discontinue to operate.

2. Loss of A.C. Power

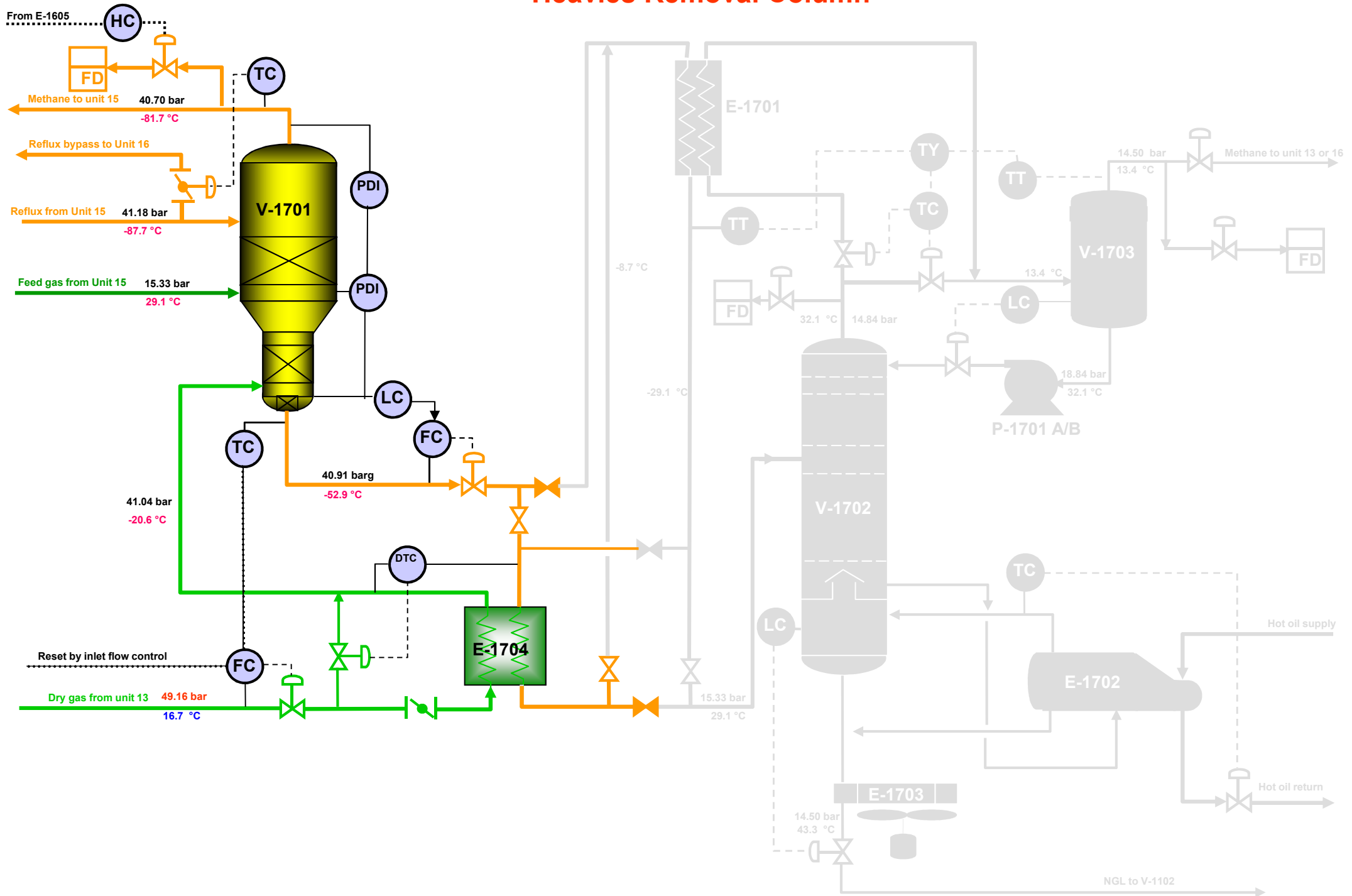
The loss of A.C. power would result in the shutdown of the lube, hydraulic oil pumps and cooling fan motors. The train will be shutdown automatically in a safe manner if there is loss of power.

Heavies Removal /NGL Recovery Overview

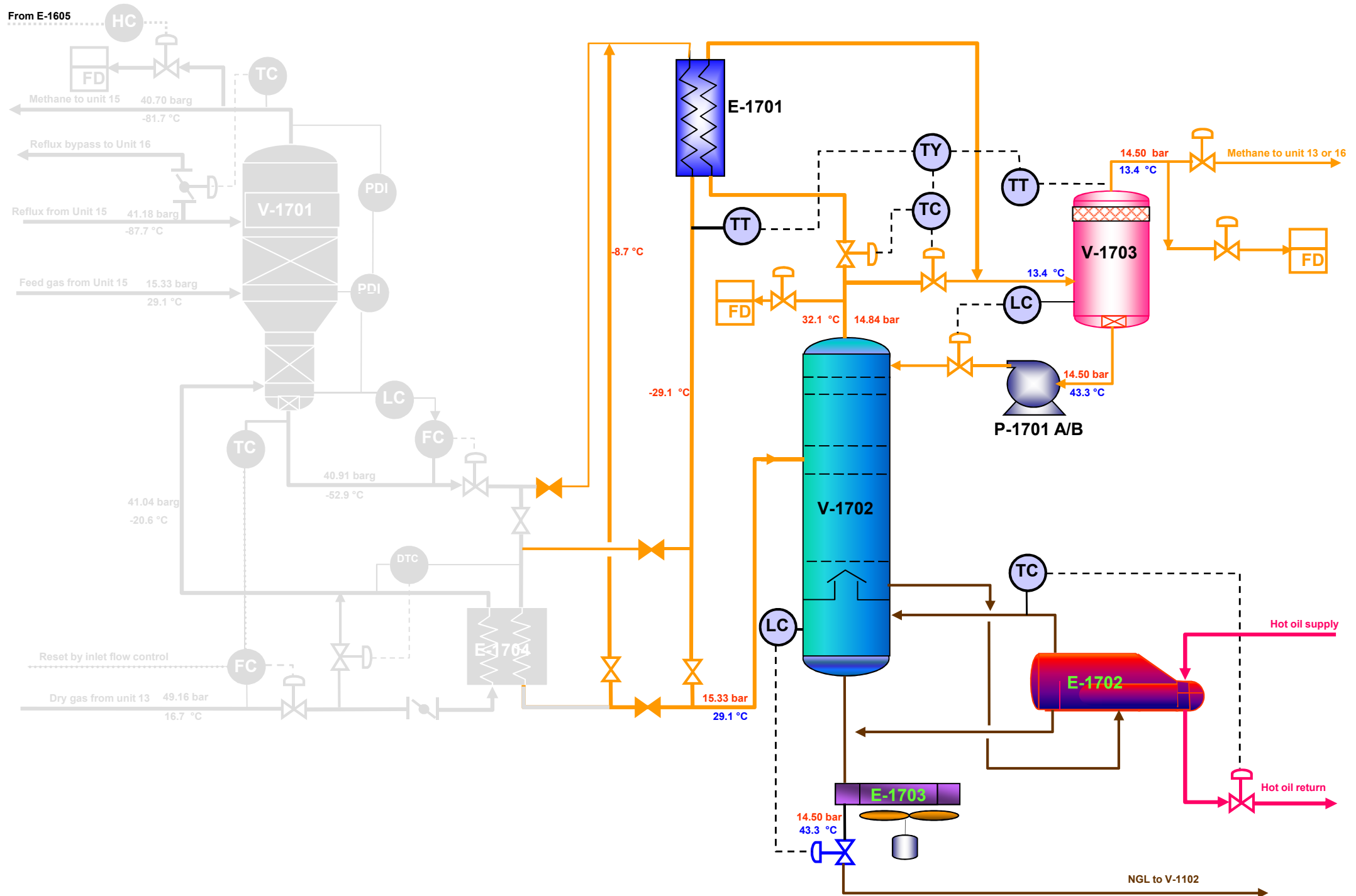


Heavies Removal /NGL Recovery

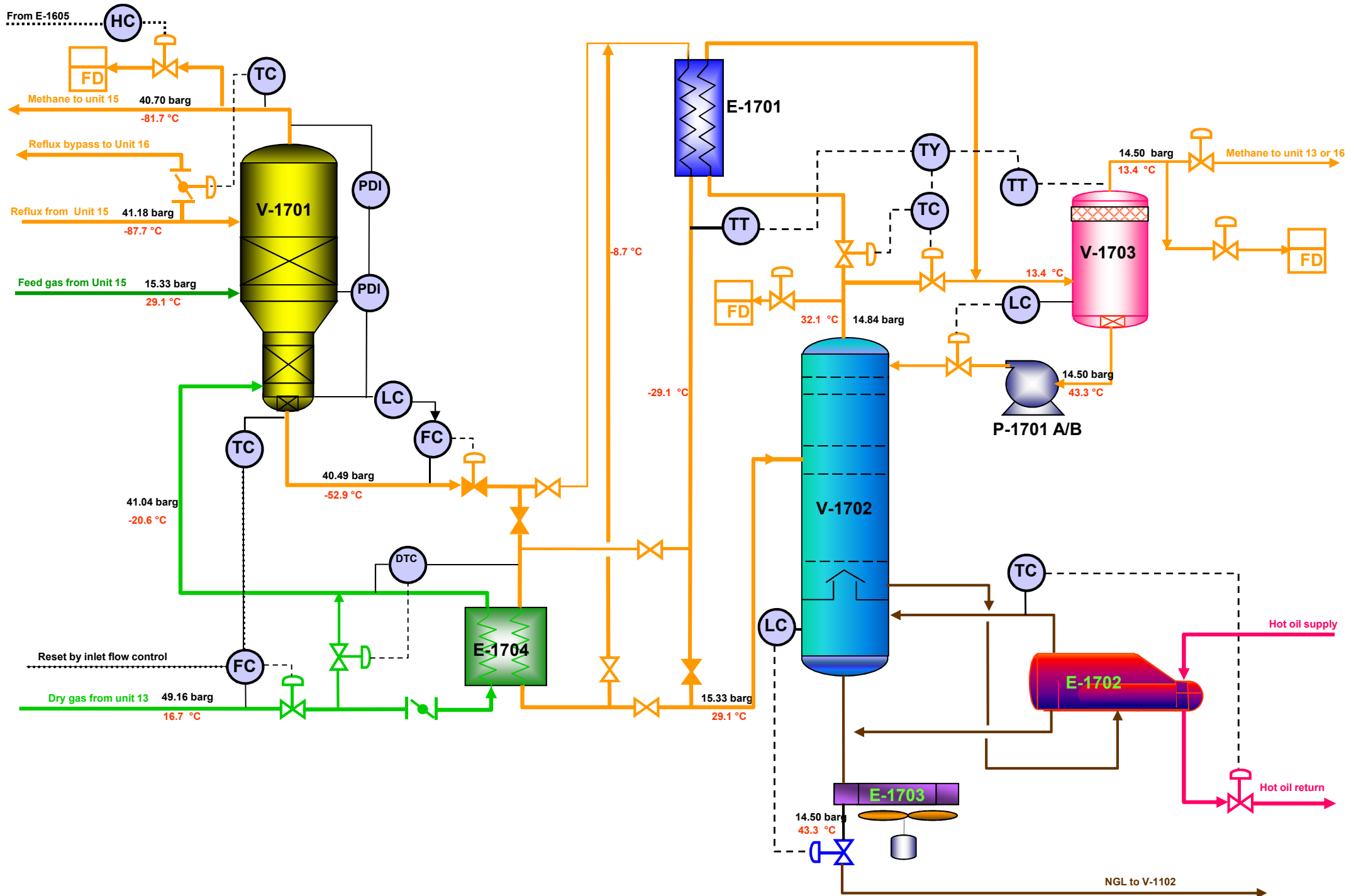
Heavies Removal Column



NGL Recovery Column



C+3 Plus Recovery Case



FLARE SYSTEMS

Index

Purpose of the unit

Main equipment

Process description

Loss of utility

PURPOSE OF THE UNIT

The flare provides a mean of safe disposal of the vapor streams from the facilities by burning them under controlled conditions to ensure that adjacent equipment or personnel are not exposed to hazard.

In addition pollution control and public relation requirements must be met.

For reliable and safe disposal of hydrocarbon vapor and liquid stream that result from upset and emergencies.

In addition the unit shall be capable of handling hydrocarbon streams that result from operating conditions such as start-up, shutdown, venting, draining, gas purging, heating and cooling of equipment piping.

To segregate flare headers for wet, heavy hydrocarbons and light, dry cold hydrocarbons so that hydrate formation and freezing do not block any system.

MAIN EQUIPMENT

Tag Number	Equipment	Function
K-1901	Wet gas flare	Handle warm hydrocarbon stream that may be saturated with water vapor and /or free liquid hydrocarbon and water
V-1901	Wet gas flare drum	Collect condensed liquid from wet flared gases
K-1902	Dry gas flare	Handle cryogenic hydrocarbons vapor and liquid
V-1902	Dry gas flare Knock out drum	Collect condensed liquid from the dry flared gases
K-1903	Marine flare	Handle the flashed LNG vapor during LNG loading to the ship's storage
P-1209 A/B	Wet gas flare Knock out drum pumps	Pump the condensed water to waste water system
E-1901	Wet gas flare vaporizer	Vaporize the condensed hydrocarbon from V-1902
H-1901	Acid gas incinerator	Burn waste gas from amine systems

PROCESS DESCRIPTION

The flare systems includes three separate flare as follows:

1- Wet gas flare (K-1901)

The wet gas flare designed to handle warm hydrocarbon streams that may be saturated with water vapor and/or contain free liquid hydrocarbons and water from the following equipment:-

- NGL liquid storage drum (V-1102)
- Regeneration gas knock out drum (V-1305)
- Wet hydrocarbon storage drum (V-1101)
- Treated gas knock out drum (V-1204)
- Solvent regenerator reflux drum (V-1206)
- Solvent flash drum (V-1205)
- Drain pot.

2- Dry gas Flare (K-1902)

The dry gas flare is designed to handle cryogenic hydrocarbons vapor and liquids from the following equipment:-

- Ethylene burg condenser section (E-1506)
- Propane storage drum (V-2002)
- Ethylene storage drum (V-2001A/B)

Wet flare and dry flare stacks are stand side by side in the same area, at the same height. Both systems include Knock out drums to separate any liquids from the gas before it is routed to the flare stake. The liquid separated from wet gas flare are pumped to waste water tank (T-2912) via the wet gas flare Knock out drum pumps (P-1901A/B) for disposal.

Any liquid separated from the flared gas in the dry gas flare are gradually vaporized through the wet gas flare vaporizers (E-1901A/B) to the flare stack via ambient heating.

Each flare system is provided by electronic spark ignition system.

The construction of the wet flare is carbon steel.

The construction of the dry gas is stainless steel.

3- Marine Flare (K-1903)

The marine flare is located near the LNG ship loading area , this flare is provided to handle the flashed LNG vapors during loading of LNG product to the ship's storage tanks or during any of the BOG compressors trip condition.

4- Acid gas incinerator (H-1901)

Refer to «*Figure 4*»

Acid gas incinerator (H-1901) is provided to burn waste gas from amine systems. The acid gas after being flashed in the K . O. Drum (V-1901) to separate any liquids is routed to the incinerator (H-1901). The liquid from knock out drum (V-1901) are pumped to the waste water tank (T-29012) via the acid gas incinerator knock out drum pump(P-1901)

LOSS OF UTILITIES

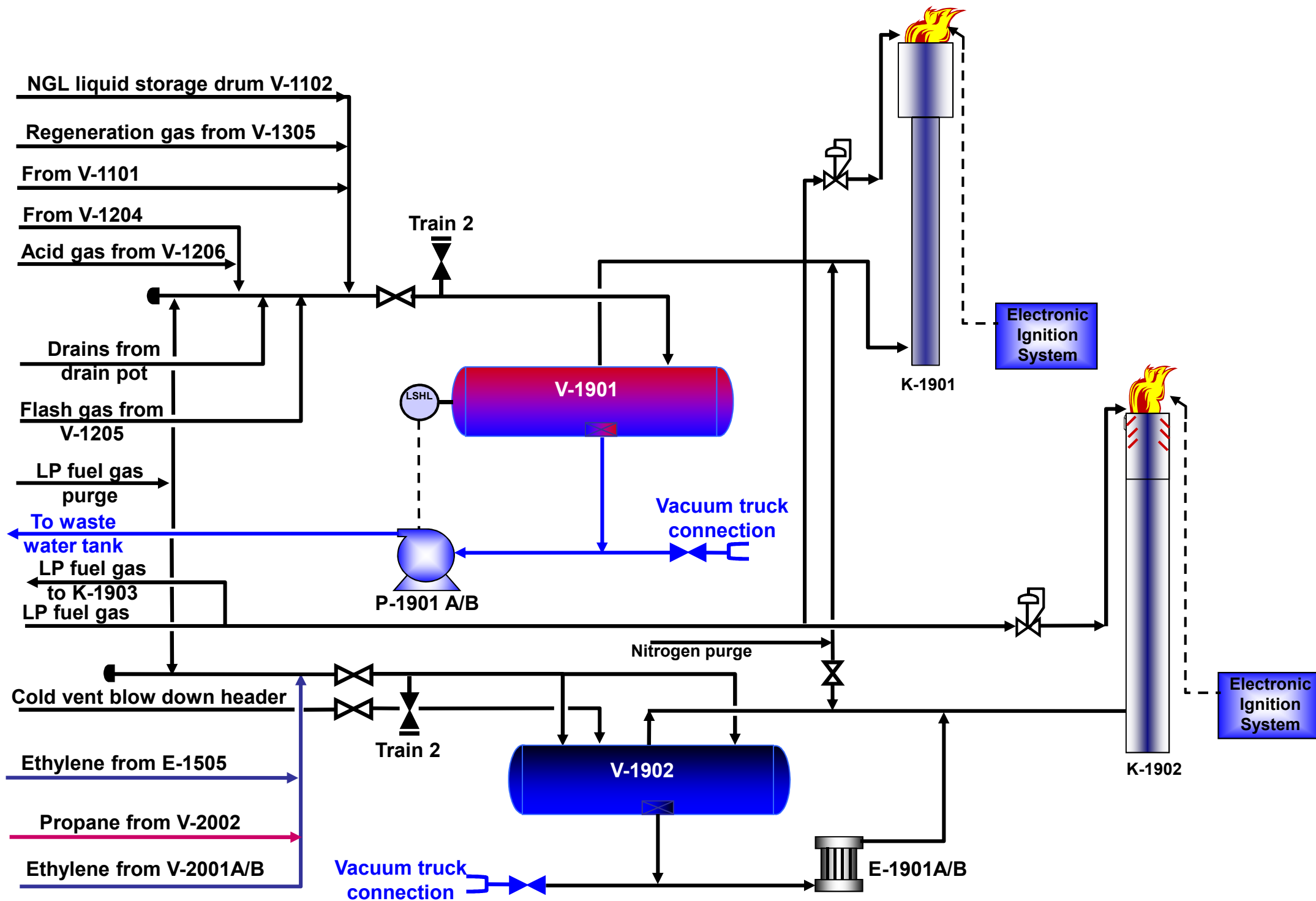
1- Loss of instrument air

The unit will fail safe and the process units will shutdown on an ESD and / or BD and ESD valves will fail safe.

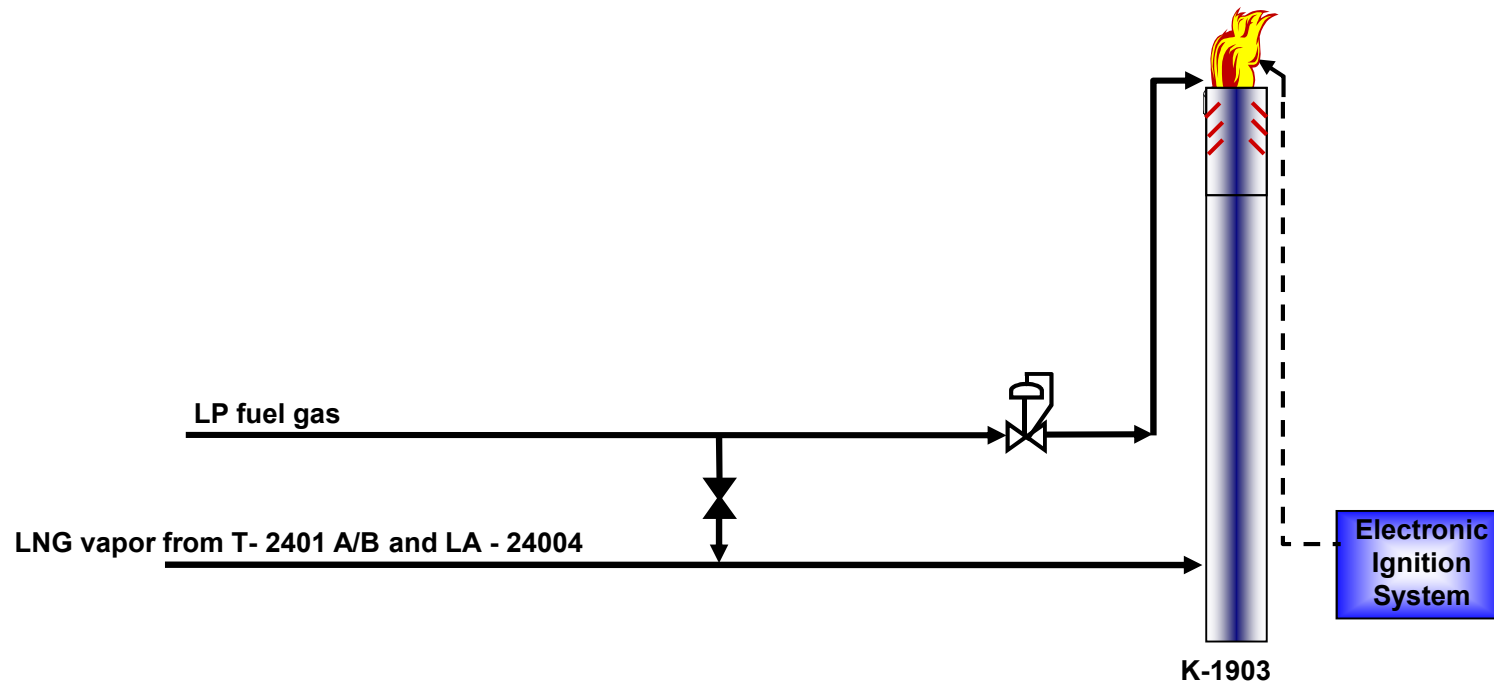
2- Loss of electric power

In event of loss of electrical power the emergency diesel generators supply power to the essential services.

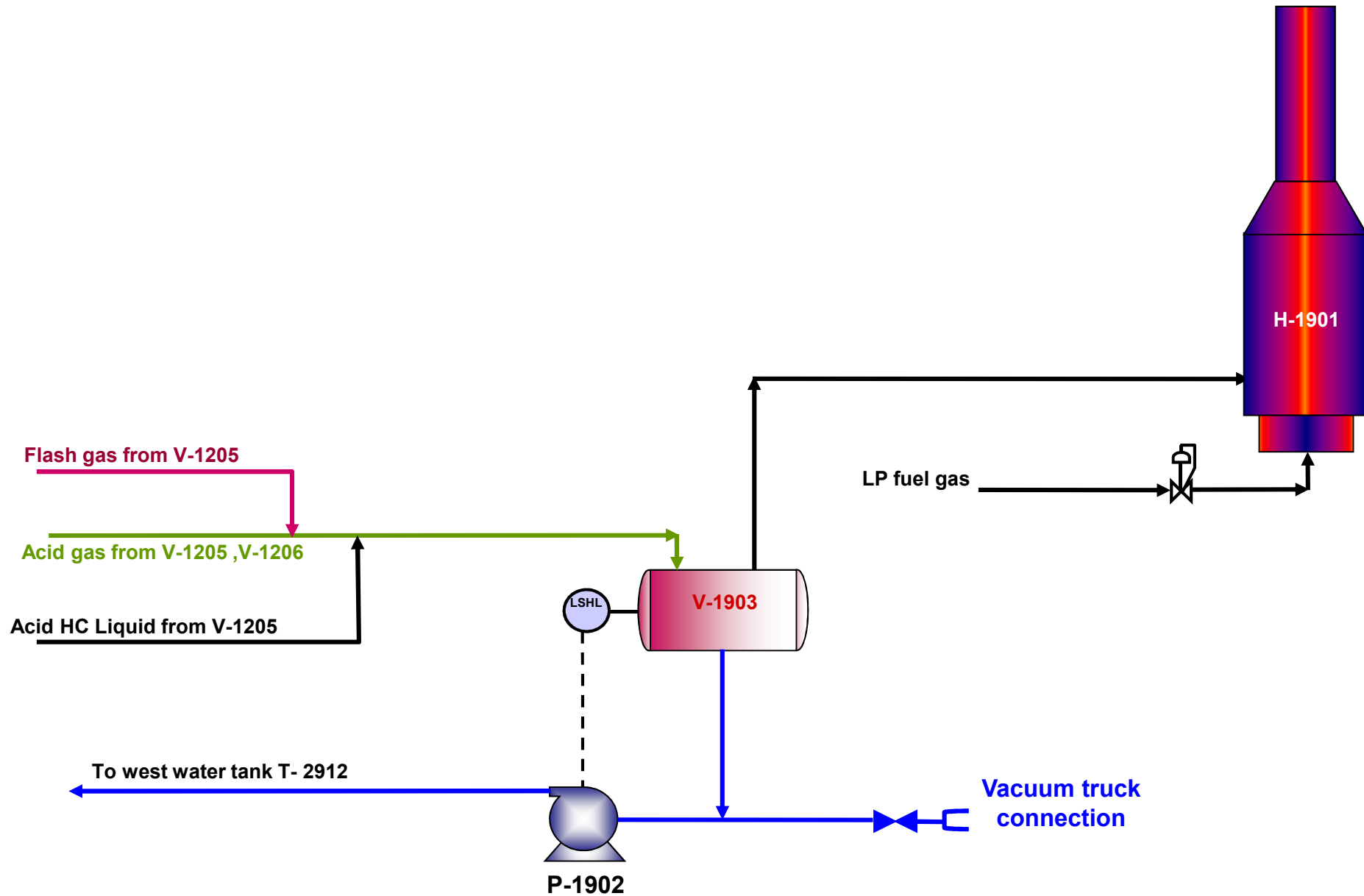
Flare / Blow own system



Marine flare



Acid gas incinerator



REFRIGERATION STORAGE

Index

Purpose of the unit

Main equipment

Process description

Loss of utilities

PURPOSE OF THE UNIT

Refrigerant storage will be used for both the ethylene and propane systems, allowing for periodic make-up to each refrigerant circuit, as well as refrigerant storage during maintenance. These systems (Ethylene and Propane Storage) are common for both Train 1 and Train 2.

Main equipment

Tag Number	Equipment	Function
V-2001 A/B	Ethylene storage drum	Receive ethylene from isotanks and refrigerant system divinator and provides supply / makeup ethylene for the system
V-2002	Propane storage drum	Receive propane from isotanks and refrigerant system divinator and provides supply / makeup propane for the system.
P-2002	Propane makeup pump	Pump propane from propane storage drum to propane refrigerant accumulator.
E-2001	Pressure building coil	Allow for some ethylene liquid to be vaporized and increase drums pressure.

PROCESS DESCRIPTION

Ethylene refrigerant storage

There are two Ethylene Storage Drums (V-2001 A/B). each storage is horizontal drum with the following specification :

- Capacity 238.5 m³,
- Pressurized
- Double wall
- Vacuum jacketed
- Loaded from top entry.

Ethylene transported from transportable cryogenic containers into to the tank via ethylene make-up pump (P-2001). Ethylene can also be transported directly into the ethylene process refrigeration system via the same pump.

Start-up ethylene, from either the cryogenic containers or from the ethylene storage drums, will feed the Ethylene Surge Drum (V-1502). This ethylene will also feed the make-up line to the L.S. Ethylene Feed Condenser, 1E-1504 A/B, via 1P-2001 Ethylene make-up pump

Vapors from ethylene storage drums will also be vented into the L.S. ethylene vapor stream via a pressure control valve. Excess vapors will be vented, via pressure control valve to the dry flare.

Propane refrigerant storage

Propane will be stored in the Propane Storage Drum (V-2002). This pressurized tank has a net capacity of about 425 m³ at ambient temperatures. It has been sized to charge a propane refrigerant system for start-up and to provide propane for make-up.

The Propane Make-up Pump (P-2002) pumps propane from (V-2002) to the Propane Refrigerant Accumulator (V-1404). Propane will be off-loaded from tanker truck directly to (V-2002). An equalization line between the truck and (V-2002) will be provided. Excess vapor will be vented, via pressure control valve to the dry flare.

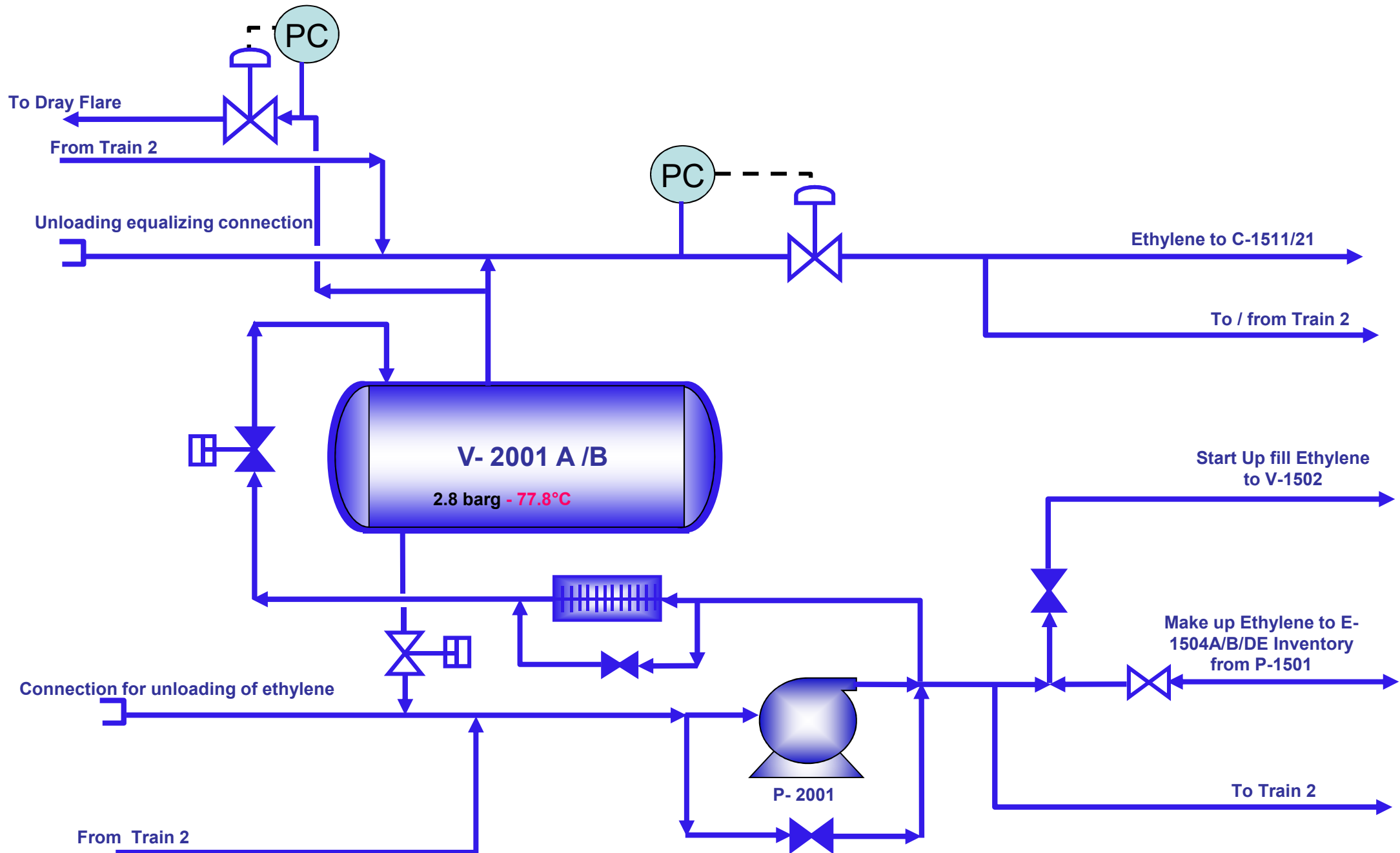
LOSS OF UTILITIES

1. Loss of Instrument Air

Loss of instrument air would result in all Control and Solenoid Valves failing to their safe positions. The unit will be shut down and discontinue to operate.

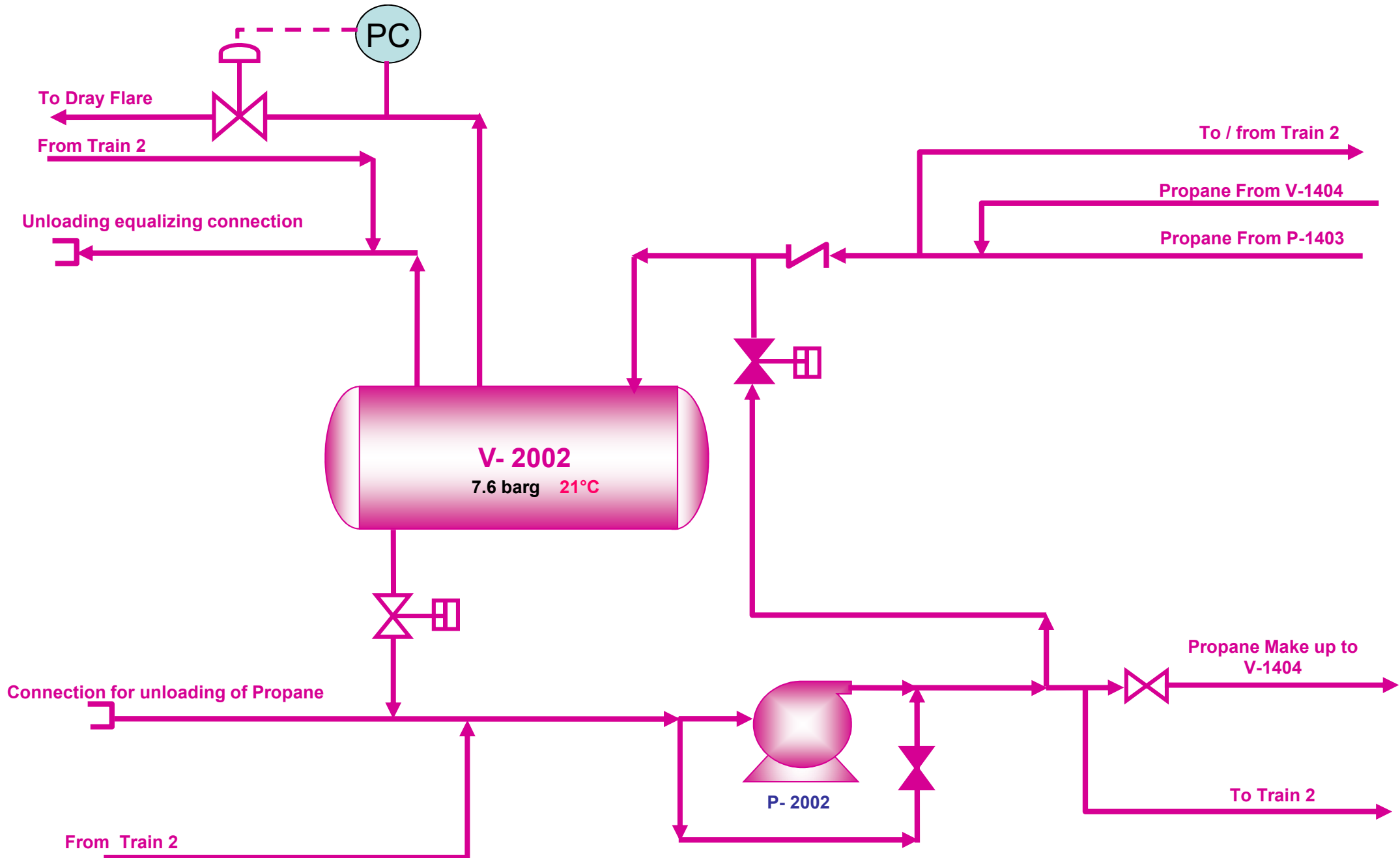
Refrigerant Storage

Ethylene Storage



Refrigerant Storage

Propane Storage



DIESEL STORAGE

Index

Purpose of the unit

Main Equipment

Unit description

Loss of utilities

Purpose of the unit

Diesel fuel used for the following:-

- Emergency diesel Generator
- Firewater pump
- Start Up of the air compressor

Main equipment

Tag Number	Equipment	Function
T-2101	Storage for diesel fuel, capacity about 19 m ³	
P-2101	Diesel oil Transfer pump	Filling the storage tank Transfer diesel oil to the day tank.

Unit description

Diesel Supply by road tanker. The fuel is unloaded from the road tankers into the storage tank (T-2101) by using transfer pump (P-2101) this pump also be used to transfer the fuel to the following equipment :

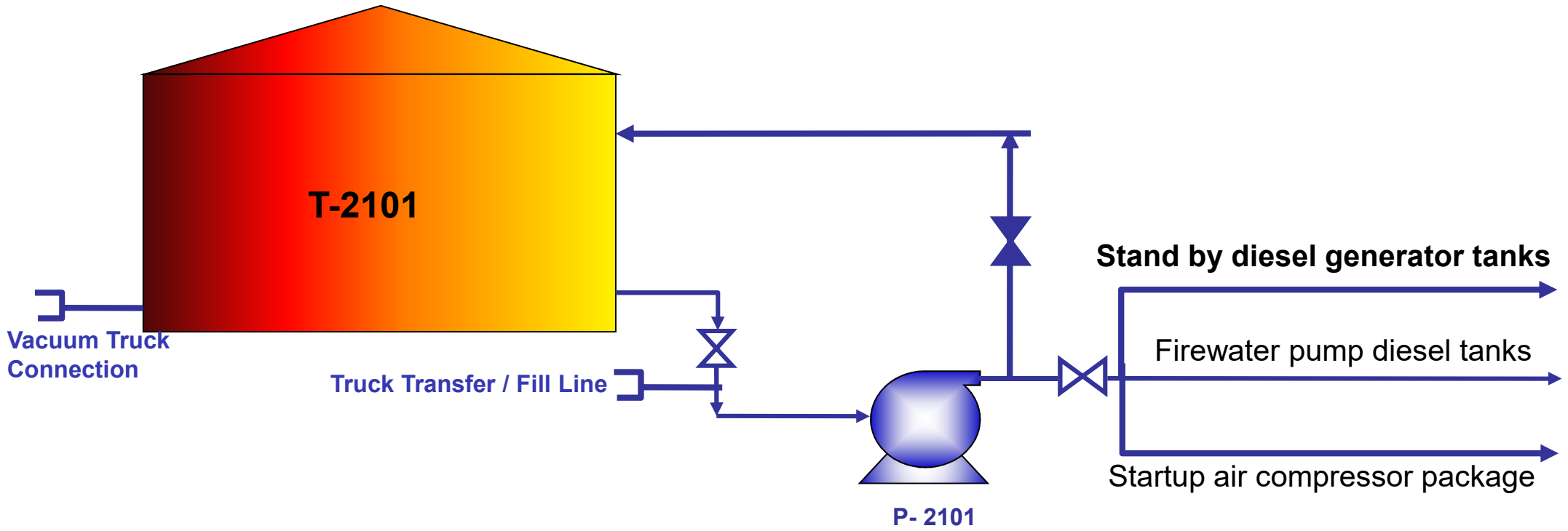
- Stand by diesel generator tanks (DG-3105,T01 and DG-3106.T01)
- Firewater pump diesel tanks (P-3303A/B , T-01A/B)
- Startup air compressor package tank (PK-3503, T-01)

Loss of utilities

1- Loss of electric power

In event of loss of electrical power the emergency diesel generators supply power to the essential services.

Diesel Storage



FUEL GAS SYSTEM

Index

Purpose of the unit

Main Equipment

Unit description

Loss of utilities

PURPOSE OF THE UNIT

The purpose of the fuel gas system unit 22 is to provide fuel for the plant complex under all operating condition. for the following equipment:

- Generator turbine driven
- Refrigerant compressor turbine driven
- Fired heaters
- Flares
- Tank and vessel blanketing

MAIN EQUIPMENT

Tag Number	Equipment	Function
V-2201	High pressure fuel gas knock out drum	Remove condensed HC from high pressure fuel gas
E-2201	Make up-fuel gas heater	Maintain the temperature above the dew point of hydrocarbon of the gas
V-2202	Fuel gas knock out drum	Remove condensed HC from low pressure fuel gas
E2202	Start up fuel gas electric heater	Meet the temperature requirement and prevent formation of hydrates during startup
V-2211	Compressor turbine fuel gas filter	Remove condensate from the fuel gas
F-2203	Turbine generator fuel gas filter	Remove contaminants from fuel gas upstream of the turbine generators

Process description

The fuel gas system collect hydrocarbon vapor from the following points

- Methane compressor (C-1613-23)
- Propane purge condenser (1407)
- Mercury removal after filter (F-1302 A/B)
- Regeneration knock out drum (V-1305)
- Sales gas coming from Rosetta (Start up source)

The fuel gas system is separated into two pressure level, high and low pressure.

High pressure fuel gas normally supplied by high stage methane compressor (C-1313-23).

Low pressure fuel gas is normally supplied from high pressure fuel gas system by using pressure reducing valve.

1.4 High pressure fuel gas system.

High pressure fuel gas system at 21 bar is used for the following equipment:-

- Generator turbine driven (TG-3101/3102/3103)

- Six refrigerant compressor turbine driven
 - (TC-1411/21)
 - (TC-1611/21)
 - (TC-1511/21)

2.4 Low pressure fuel gas

Low pressure fuel gas system at 3.5 bar is used for the following equipment.

- Fire heaters
 - (H-1301A/B)
 - (H-3401A/B)
 - (H-1901)
- Flares pilots and headers
 - (K-1901)
 - (K-1902)
 - (K-1903)
- Tank and vessel blanketing
 - (T2401A/B)
 - (V-34010)
 - (V-1101)

LOOSE OF UTILITIES

1. Loss of Instrument Air

Loss of instrument air would result in all Control and Solenoid Valves failing to their safe positions. The unit will be shut down and discontinue to operate.

LNG STORAGE AND LOADING

Index

Introduction

Purpose of the unit

Main equipment

Process description

Loss of utilities

INTRODUCTION

This will serve as an introduction and general description of LNG storage and loading, and will give an overview of the plant followed by brief description of the safety system.

The LNG storage and loading unit is designed to provide adequate storage and loading facilities to allow for continuous production of LNG at the design production rate and to enable intermittent exports by ship.

The unit is designed to operate in two modes: holding mode and loading mode.

In holding mode LNG is rundown from train into both of the LNG storage tanks.

During loading mode there is simultaneous LNG rundown from train and LNG loading from both storage tanks to the LNG ship.

All boil off gas generated from the LNG lines and storage tanks, plus the excess vapor return from the ship is compressed, cooled and returned to the methane refrigerant gas compression unit.

PURPOSE

The function of the Liquefied Natural Gas (LNG) Storage and Loading System (Unit 24) is to:

- Store LNG produced by the liquefaction trains;
- Load LNG ships for transportation; and
- Recover the boil-off vapors for delivery to the fuel gas system.

Unit consists of:

- LNG rundown system
- LNG storage tanks
- LNG loading and circulation systems
- Boil-off gas (BOG) handling systems
- Vacuum protection system

MAIN EQUIPMENT

Tag Number	Equipment	Function
T-2401A/B	LNG storage tanks	To store LNG produced in process train
C-2401	LNG boil off gas compressor	Compress the boil off gas and ships vapor return into the methane compressor system
P-2401 A/B/C/D/E/G/ G/H	LNG loading pump	To transfer LNG from the tanks to the ship and also are used for circulation to prevent stratification and rollover.
LA-2404	LNG loading arm-vapor return	To receive the ship vapor return
LA-2401 A/B	LNG loading arm	To transfer LNG to ship

PROCESS DESCRIPTION

3.1 General

LNG produced from the liquefaction train is pumped into the two LNG storage tanks where it is stored at slightly above atmospheric pressure. All two tanks are filled continuously during the two different modes of operation:

- Holding mode
- Loading mode.

Unit feeds

The primary feed to Unit 24 is LNG from the liquefaction train. A secondary feed to Unit 24 is warm gas from the fuel system (V-2202) for vacuum protection of the tanks.

Unit products

The products exported from Unit 24 are:

- LNG – for export; and
- Boil-off vapors – for the methane compressor.

3.2 Process flow

3.2.1 LNG rundown system

LNG produced by the LNG Plant Liquefaction Train is pumped into two LNG Storage Tanks (T2401A/B).

Vaporization in the rundown lines from ambient heat leak into the piping and heat of pumping is suppressed by the backpressure control system located in each rundown line .

The sections of rundown headers that are not being used for LNG rundown are kept at cryogenic temperatures by maintaining a small bleed flow into the appropriate tank.

A cross-over line between the tank circulation line and the rundown line, at each tank manifold, is provided to circulate the rundown system during an extended shutdown period of LNG train. Any one of the LNG Circulation Pumps (P-2401A/B/C/D/E/F/G/H) can be used to circulate the rundown system.

3.2.2 LNG storage tanks

Two LNG Storage Tanks (T2401A/B) are installed, each with a capacity of 140,000 m3. The wall, base, and roof of the tank are insulated to reduce heat in leak and thus LNG losses.

The space between the outer wall and the 9% nickel steel inner tank is filled with insulation. Refer to [«Figure 3 - LNG Tank drawing»](#).

Each LNG tank contains four submerged loading pumps and any one of them can be used for circulation pump as follows:

P-2401A/E	Loading/Circulation
P-2401B/F	Loading/Circulation
P-2401C/G	Loading/Circulation
P-2401D/H	Loading/Circulation

The tank has top connections only. No pipeline or instrument connections penetrate the sides or bottom of the tank. The internal piping permits only top-filling. This is done via a roof supported splash plate device to obtain good vapor disengagement thus desuperheating the incoming LNG product.

Each tank is provided with a tank platform, located on top of the tank and a valve manifold located at a safe distance from the tanks. The valve manifolds for adjacent tank has remotely operated valves (motor operated valves and control valves) and manual isolation valves located at the valve manifold. The purposes of these valves are:

- To control loading, holding and filling operations by lining up tanks to the respective systems.
- To isolate and / or depressure tanks in case of a tank fire.

The operation of each tank and its pumps is controlled by the automatic control system provided at the tank platform together with the control system located at the valve manifold.

The normal operating pressure of the tanks is controlled by the boil-off vapor handling system.

The tanks are protected against overpressure by:

- A pressure control valve to flare.
- Tank relief valves to the atmosphere.

The tanks are protected against vacuum by:

- Hot gas from the process units
- Atmospheric vacuum breakers.

3.2.3 LNG Loading and circulation system

3.2.3.1 Loading mode

In the loading mode, all LNG loading pumps from two storage tanks are normally used to load a ship at the maximum rate of 10,080 m³/h. The LNG is pumped from (T2401A/B) by (P2401A/B/C/D/E/F/G/H) through one loading line to the LNG Loading Arms (LA2401) and hence the ship. All LNG pumps in the tanks are started remotely from the Central Control Room (CCR). Each pump has a minimum flow control system which has the following functions:

- To protect pump against low flow.
- To release LNG vapor from the pump column and discharge lines during startup
- To reduce surge pressures during ESD activation by quick opening.

The LNG which flows under flow control to the loading arm and hence to the shipping

3.2.3.2 Holding mode

In the holding mode, a split stream of the LNG rundown from (P-1601A/B) is used to maintain the temperature of the loading line and then back to storage tank.

3.2.4 Boil-off vapor recovery

Refer to «**Figure5 - Unit 24 Boil-off Gas Handling System Control**».

The boil-off vapor recovery system consists of:

- A boil-off gas collection header;
- Boil-off Compressor (C2401)

3.2.5 Vacuum protection

Refer to «**Figure6 - Unit 24 Vacuum protection**».

LNG vacuum protection system protects the LNG Storage Tanks (T-2401A/B) against vacuum conditions produced by the following:

- Maximum liquid pump-out rate without vapor return;
- Maximum boil-off compressor suction from the tanks; and
- Rapid barometric pressure rises.

The system consists of a piping network to supply hot gas for vacuum protection to the LNG tanks. This gas is normally supplied from Low pressure fuel gas system.

LOSS OF UTILITIES

1. Loss of electrical power

The following items on unit 24 are directly affected by loss of electrical power.

Tag Number	Equipment	Function
(P-2401A/B/C/D/E/F/G/H)	LNG loading pumps	Loss of LNG loading pumps will result in shutdown of loading operation
(C-2401)	Boil off gas compressor	Loss of power to the boil off gas compressor will trip the compressor and will divert boil off gas to marine flare.

2. Loss of Instrument Air

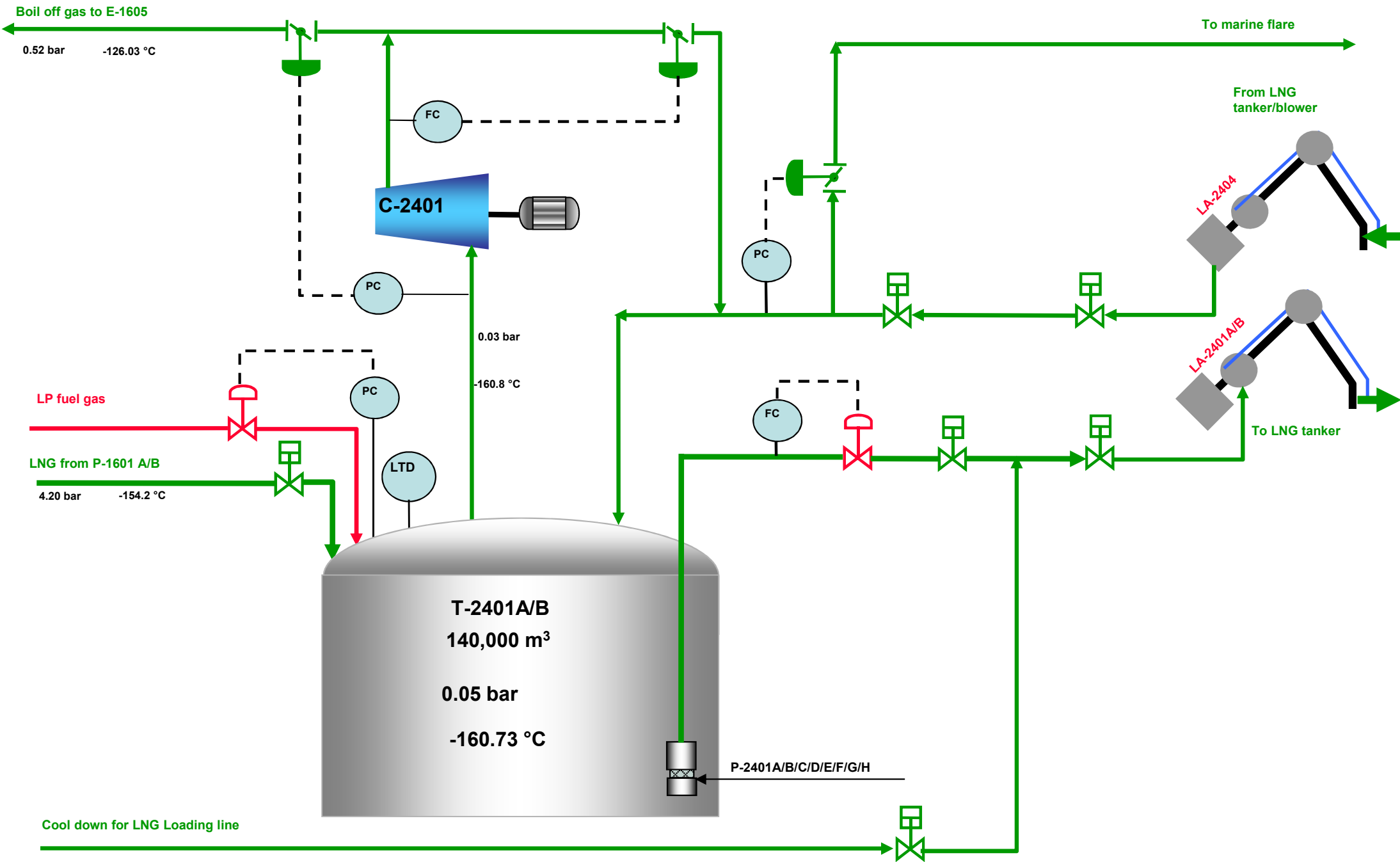
The plant will continue to operate satisfactory until air header and accumulator pressure fall. The operator must make a judgment as to the best course of action should the instrument air failure persist for a prolonged period.

Loss of instrument air will cause control valves to fail to their safe position, unless protected by air accumulators. This will rapidly cause interruption of both the main gas processing flow and the major liquid flows on the unit. This will lead to the closedown of rundown and loading operations.

3. Loss of feed gas

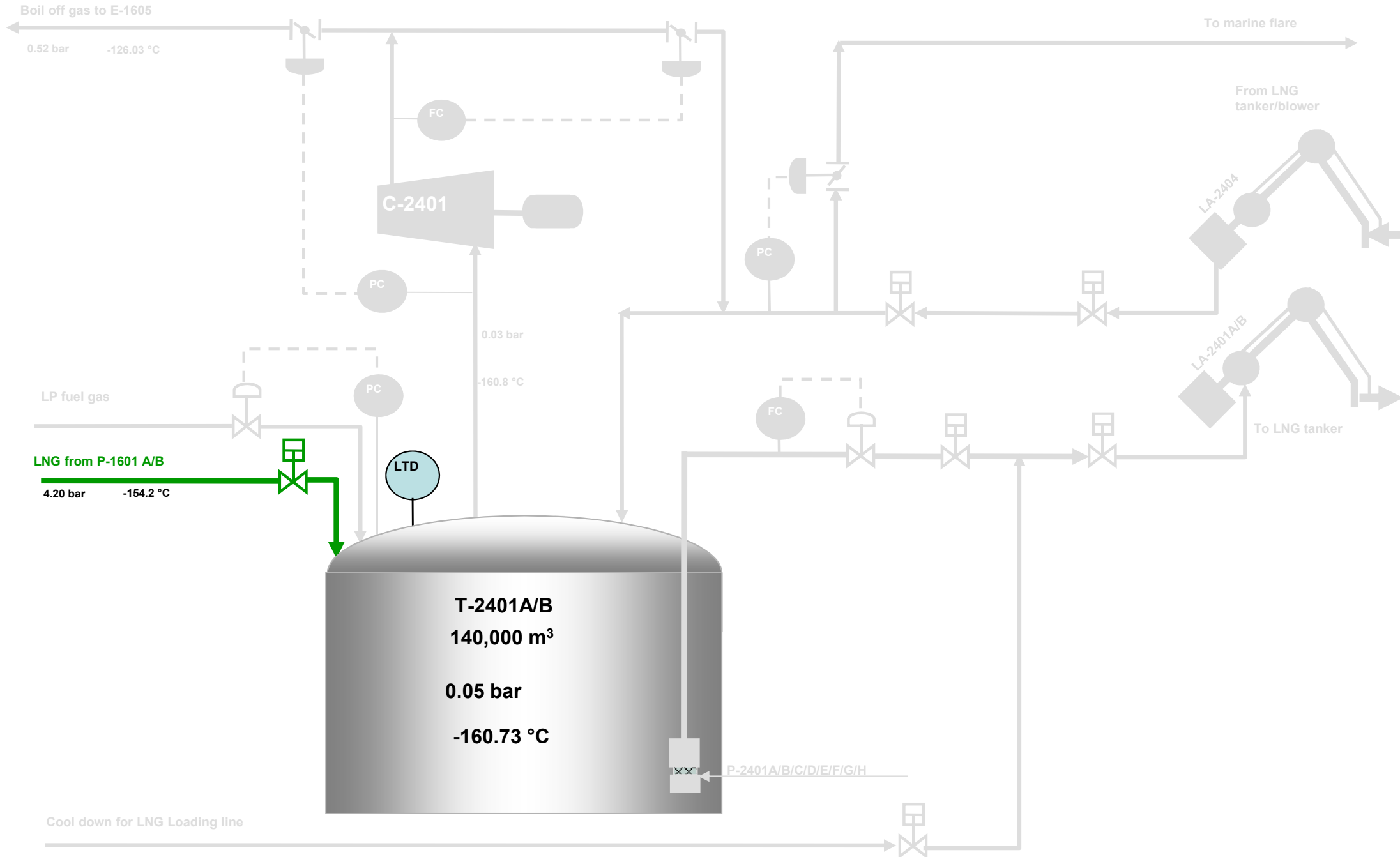
The direct consequence of loss of feed gas is that LNG rundown to storage will cease.

LNG STORAGE AND LOADING



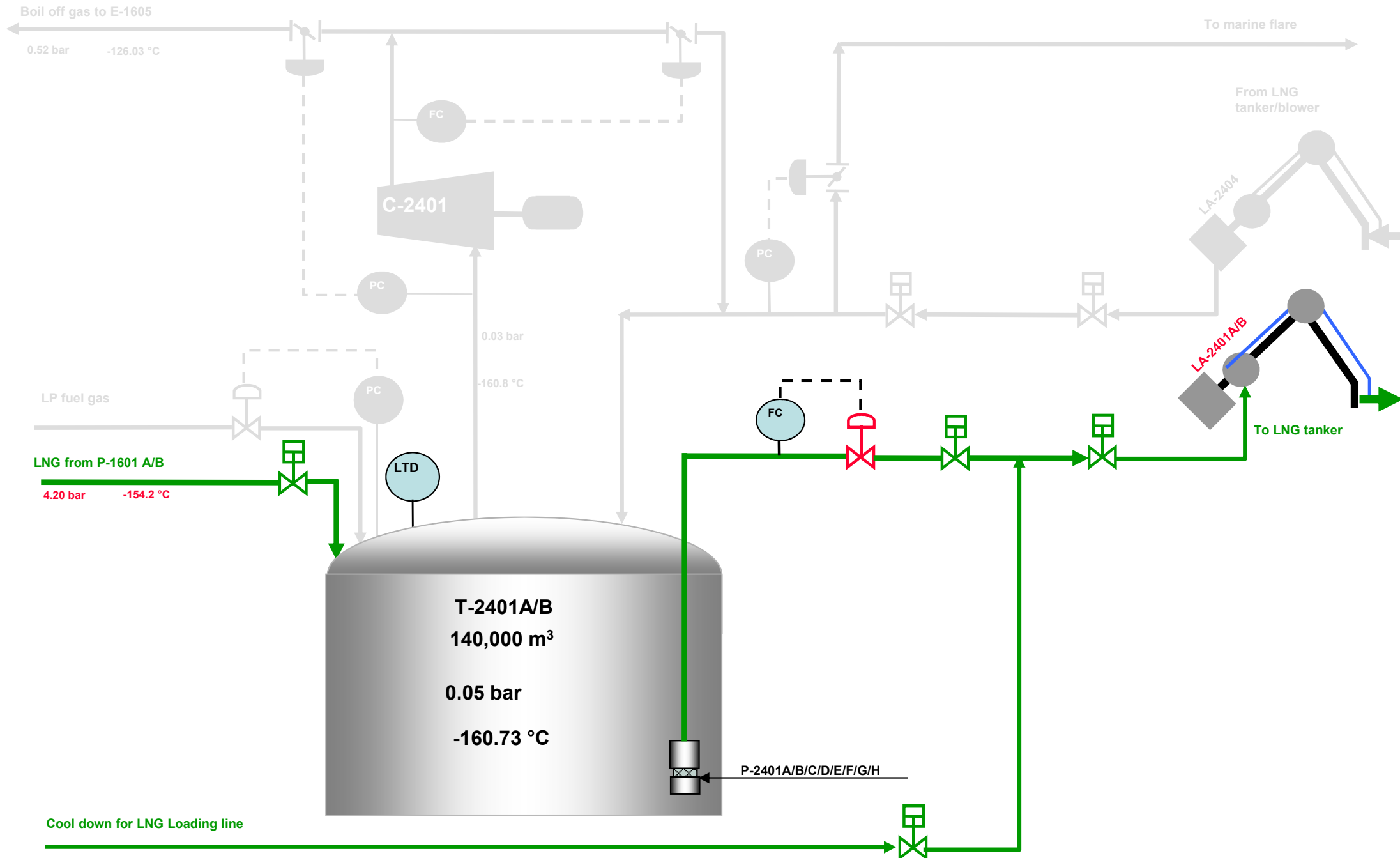
LNG STORAGE AND LOADING

LNG Rundown system



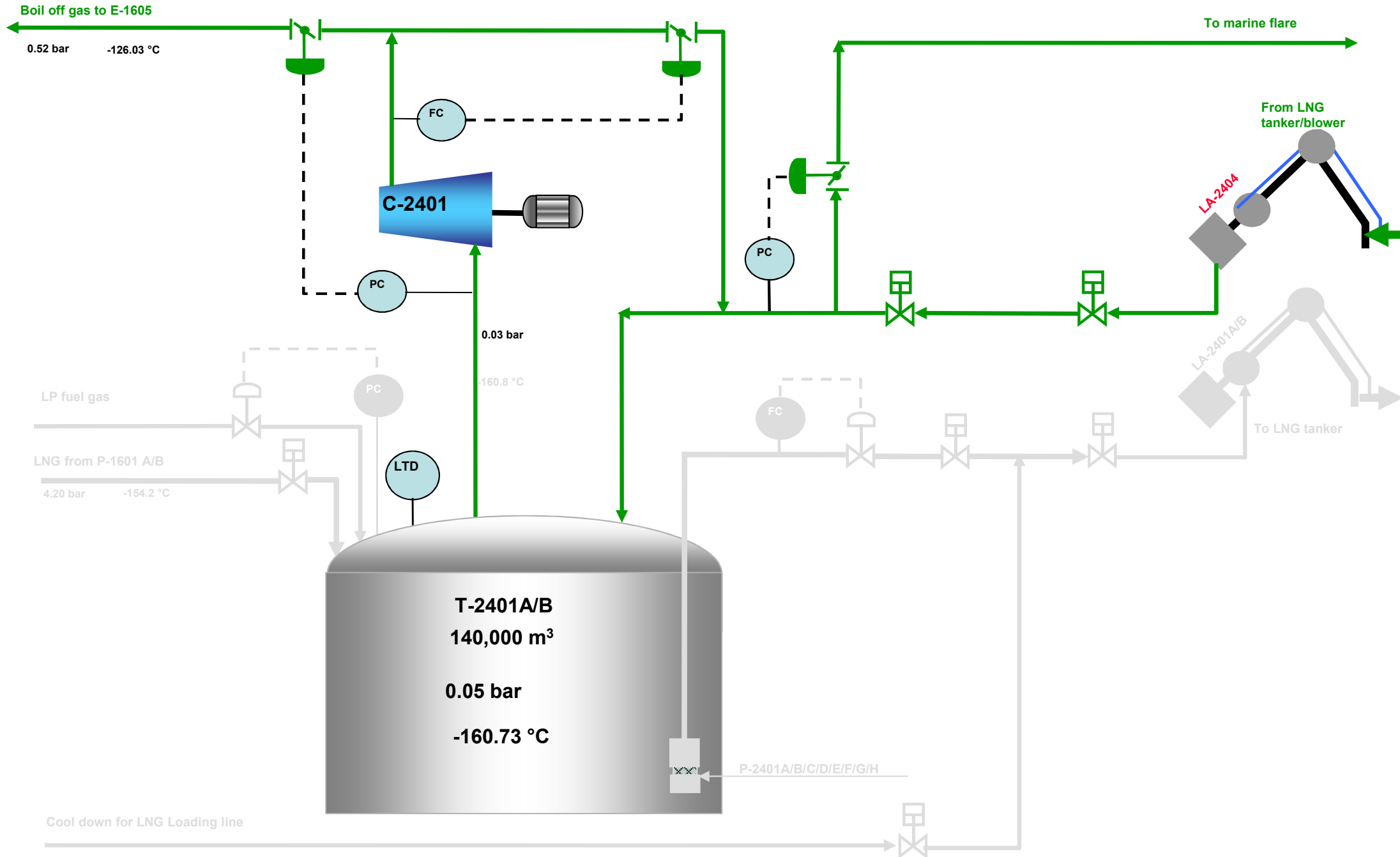
LNG STORAGE AND LOADING

LNG Loading



LNG STORAGE AND LOADING

Boil off and gas handling



LNG STORAGE AND LOADING

Vacuum protection

