



Oleflex™ Process - Reactor and Fractionation Section: Propylene

With Huel's Selective Hydrogenation Process

General Operating Manual

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I. Introduction

A. Scope

UOP issues this General Operating Manual ("GOM") to provide background process information to the engineering group of the operating company or detail design engineering contractor ("Contractor") as an aid to the detailed design activities and development of operating procedures and practices. The GOM is not considered a part of the Project Specifications but they do provide information related to the specifications included in the Schedule A. This material is informational purposes only and is intended to augment the information provided in Project Specifications. This information is expected to be reasonably consistent with the Project Specifications; it may not represent exact consistency with the Project Specifications. Any major inconsistencies should be brought to the attention of UOP for clarification. In all situations, the information provided in the Project Specifications take precedence over information in the GOM. Accordingly, UOP assumes no responsibility for the misapplication of this information to a specific process, particularly the use of such information to prepare detailed operating instructions for a specific process.

B. Purpose

The Oleflex™ Process is a moving bed catalytic process designed to selectively dehydrogenate a paraffin feed to the corresponding mono-olefin. Feed to the Oleflex unit must be free of impurities that could harm the platinum containing catalyst or cause reactor fouling. The catalyst employed is highly selective for the desired reaction; successive and competing reactions such as skeletal isomerization, diolefin production, and cracking are minimized by proper catalyst formulation and choice of operating conditions.

The conversion of paraffin to olefin is equilibrium limited if selectivity to mono-olefins is maintained reasonably high. Therefore, recycle of unreacted paraffins from downstream units is moderately large. The reactions are promoted in a low pressure hydrogen environment at high temperatures. A side by side reactor system with continuous catalytic regeneration (CCR) is normally provided to maximize operational efficiency. The rate of catalyst regeneration and circulation depends strongly on operating conditions. Design catalyst cycle time is typically between 5 to 6 days.

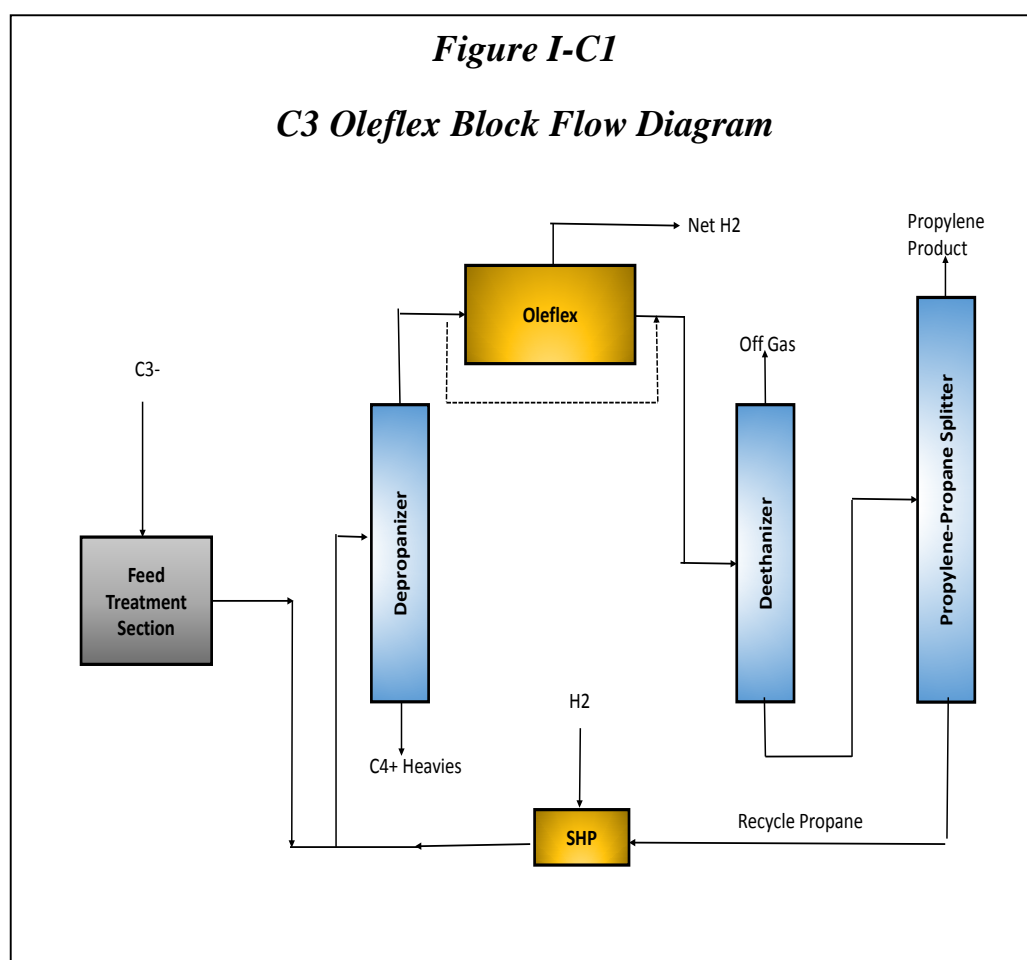
The Huel's Selective Hydrogenation Process (SHP) is a highly selective fixed bed process for the hydrogenation of dienes and acetylenes in a C3, C4, or C5 fraction to their respective mono-olefins. Due to its high selectivity, conversion of acetylenes and dienes is virtually 100%. In addition, there is minimal loss of olefins through

saturation. SHP is typically used to remove trace amounts of dienes and acetylenes from the reactor effluent stream of the Oleflex reactor section.

The first Oleflex unit was brought on stream in January 1990. As of November 2017, there are 31 Oleflex units which have been successfully started and operated. The units include both propane dehydrogenation to propylene (C3 units) and iso-butane dehydrogenation to isobutylene (iC4 units). There are 15 C3 units, 11 iC4 units and 5 C3/ iC4 mixed feed units. Over 180 CCR units are in operation all over the world.

C. Block Flow Diagram

This is the block flow diagram:



II. Process Principles

Information from this section will serve as the foundation upon which the rest of this manual is based. This section is written to assist the reader with understanding why this process performs the way it does.

A. Main Process Function

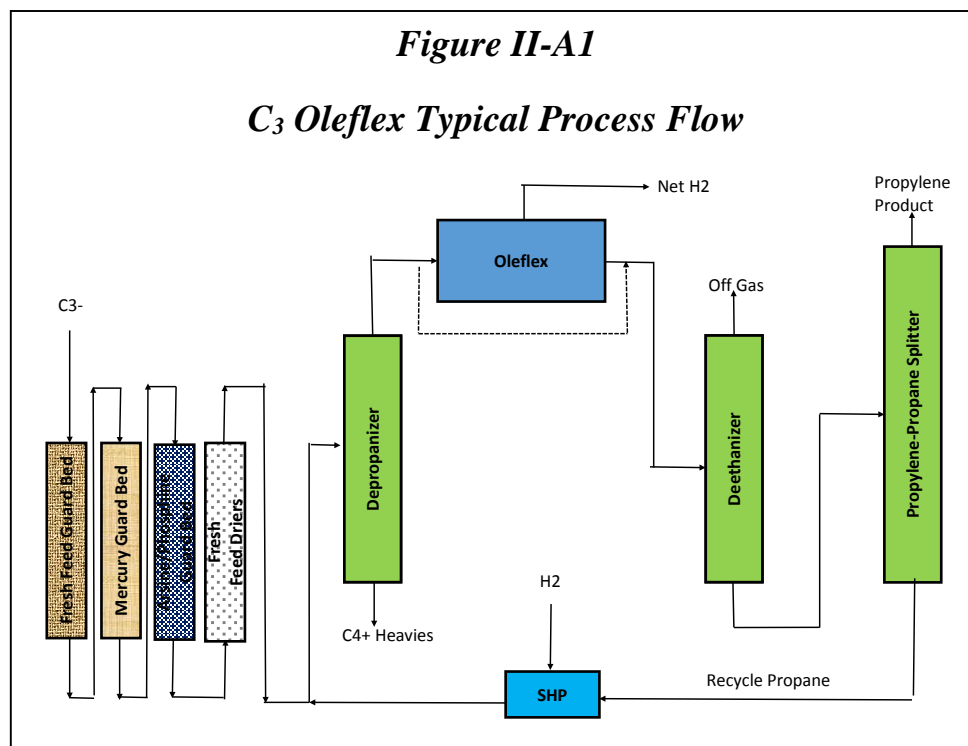
The Oleflex Process is designed to selectively dehydrogenate C₃, C₄, or C₅ paraffins to mono-olefins. Since the dehydrogenation reaction is equilibrium limited, the Oleflex reactor effluent consists of product mono-olefins and unconverted feed paraffins. Typically, feed to an Oleflex unit will be essentially single component propane, i-butane, n-butane, or i-pentane. However, the Oleflex Process can be designed to handle mixtures of these paraffins. This manual is written specifically for propane dehydrogenation.

The dehydrogenation reaction is favored by high temperatures (500 to 700°C or 930 to 1300°F) and low hydrogen partial pressure. Catalyst stability and thermal cracking reactions limit the reactor temperature levels, and safety considerations prevent reactor(s) operation below atmospheric pressure. As a result, the process must be designed for a relatively moderate conversion operation.

The product from the Oleflex Process is sent to downstream processing which can selectively separate or react out the olefins. The paraffins are recycled back to the Oleflex unit.

In all cases, the feedstock for the Oleflex Process must meet proper feed specifications. The feed must be free of potential poisons, such as excessive sulfur, oxygenates, nitrogen compounds, arsine/phosphine, mercury, acetylenes and diolefins etc. Feed treatment required depends on the impurities present in fresh feed stock. Typical C₃ Oleflex Process flow scheme is presented in Figure II-A1.

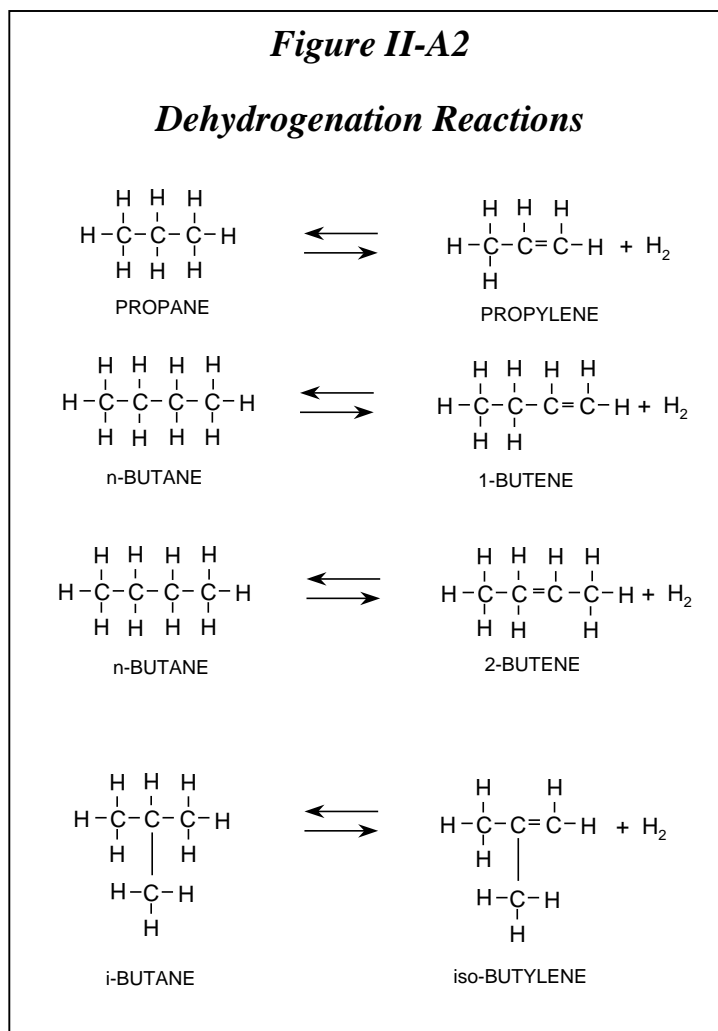
In the Oleflex reactor section, propane dehydrogenation is carried out. Hydrogen from the dehydrogenation product stream is separated and recovered as vapor product while hydrocarbons are recovered as liquid product. Liquid product is sent to fractionation section to remove the light ends, recover propylene product, and return unreacted propane back to the dehydrogenation section as recycle propane. Trace levels of acetylenes and diolefins produced in the Oleflex reactor section carried into the recycle propane stream are treated in Huel's Selective Hydrogenation Process (SHP) where these are converted to their respective mono olefins. Treated recycle propane is then returned to reactor section.



1. Dehydrogenation Section Reactions

1.1 Light Paraffin Dehydrogenation

Simplified reaction schemes for propane and butane dehydrogenation are shown in Figure II-A2. In Oleflex unit designed for propane dehydrogenation, predominant reactant species will be propane. Any associated butane species present will also be dehydrogenated. The dehydrogenation reaction is endothermic and the vapors exiting the adiabatic reactors will be at a lower temperature than that entering. Typically the material will be virtually an equilibrium mixture at the pressure and temperature exiting the last reactor.

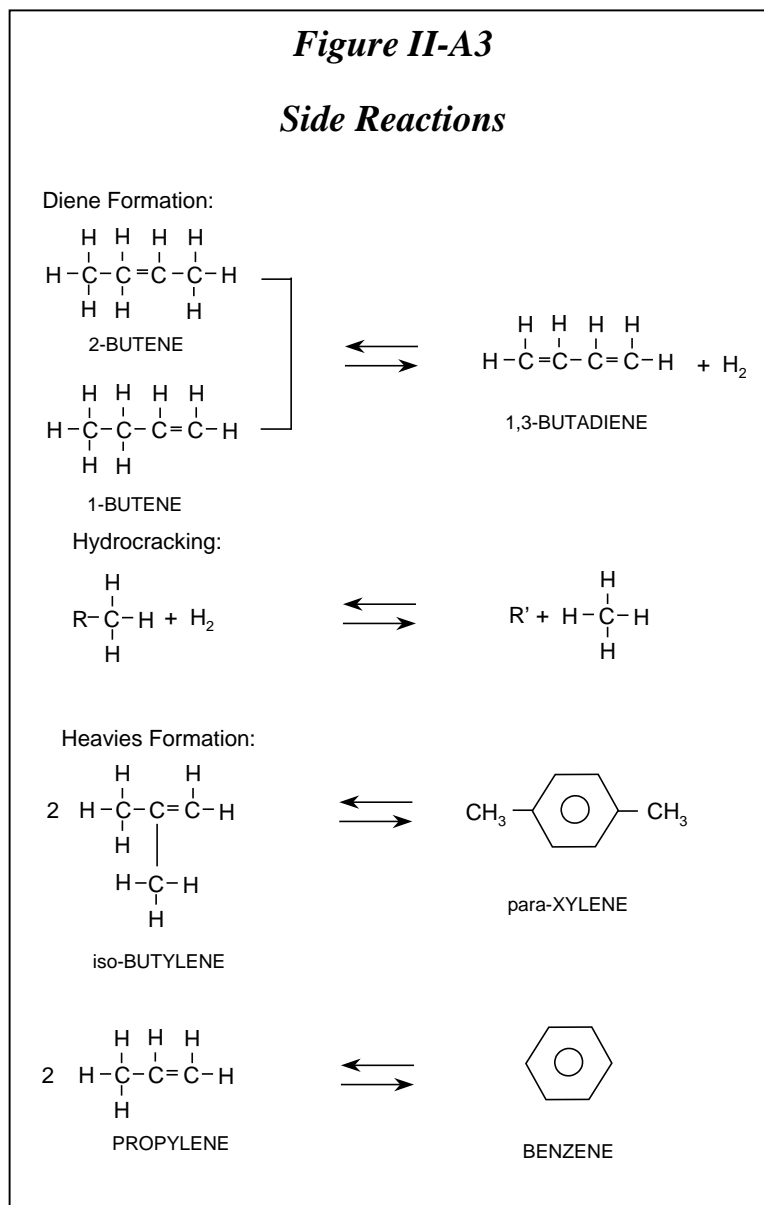


The selectivity of the reactants to mono-olefins having the same carbon range is approximately 75 to 90 weight percent when the unit is operated within the normal design range. The typical design conditions are an LHSV of 2.5 to 3.5 hr⁻¹, a last reactor outlet pressure of 1.068 to 1.383 kg/cm²a or 15.2 to 19.7 psia (~0.035 to 0.350 kg/cm²g or 0.5 to 5.0 psig based on atmospheric pressure of 1.033 kg/cm²a or 14.7 psia) , and a paraffin conversion of about 30 to 40 percent. The remainder of the converted paraffins form hydrogen, cracked light ends, diolefins and a small amount of heavies.

1.2 Catalytic Side Reactions

The main side reactions are cracking and diolefin formation as shown in Figure II-A3. The same processing conditions that favor the main dehydrogenation reaction also favor these side reactions. Although other reactions such as isomerization are certainly possible, the catalyst has been formulated to minimize these reactions.

Also depicted in Figure II-A3 is heavies' formation which occur to some degree over the catalyst and reactor effluent treating materials. Diolefins and aromatics can oligomerize into polynuclear aromatics, which can foul the reactor effluent equipment.



1.3 Thermally Driven Side Reactions

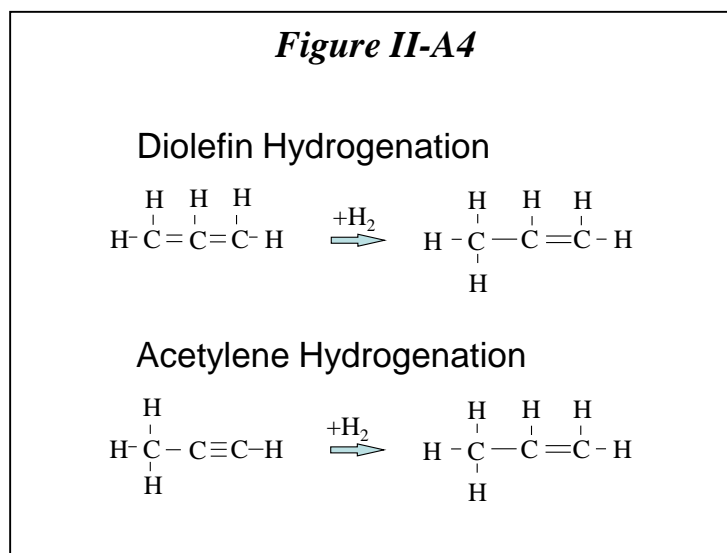
Some side reactions are inevitable at the elevated temperatures due to the nature of the processing environment. Thermal cracking produces coke which can impact equipment and reduce on stream efficiency. The Oleflex reactor circuit is designed to minimize hot residence time while actual processing conditions must be closely

monitored and controlled to minimize these adverse reactions. Cracking reactions are exothermic and consume hydrogen.

2. Selective Hydrogenation Section Reactions

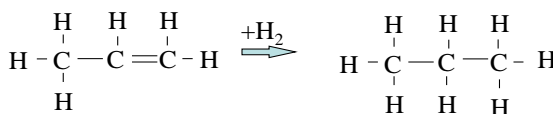
2.1 Diolefin and Acetylene Hydrogenation

Several hundred parts per million of methyl acetylene and propadiene (MAPD) are produced in the reactor section during normal operations. These materials are highly reactive and contribute to coke formation in the Charge Heater if recycled back to the feed, so the MAPD is hydrogenated back to a mono-olefin in the Selective Hydrogenation Process (SHP) unit. Simplified reaction schemes for propadiene (PD) and methyl acetylene (MA) are shown in Figure II-A4. The hydrogenation reaction is exothermic.



2.2 Olefin Hydrogenation

An excess of hydrogen is typically present, so although the catalyst preferentially saturates the di-olefins, some mono-olefins are hydrogenated to propane. Simplified reaction scheme for propylene hydrogenation is shown in Figure II-A5. The hydrogenation reaction to form the paraffin is also exothermic.

Figure II-A5**Olefin Hydrogenation****B. Catalyst and Adsorbents****1. Oleflex Catalyst**

The Oleflex catalyst is a 1/16-inch spherical dehydrogenation catalyst of stabilized **platinum on an alumina base**. The catalyst also contains chloride that has been specially treated to render it non-catalytic. Chloride is, however, important in the regeneration of the catalyst. The catalyst is regenerable in UOP's CCR™ technology and is manufactured to resist attrition as the catalyst is transported from reactor to reactor as well as to and from the regenerator.

1.1 Catalyst Poisons**1.1.1 Sulfur**

Excessive sulfur in the paraffin feed tends to lower the activity of the Oleflex catalyst system. This requires operating the reactors at higher inlet temperatures to maintain the desired paraffin conversion. Therefore, in some unit configurations where the paraffin fresh feed can have excessive levels of sulfur, additional treatment may be prescribed to remove sulfur from feed. However, some controlled injection of organic sulfur in the form of Dimethyl Disulfide (DMDS) is required at the level necessary to passivate metals and prevent excessive coke formation. That level is a function of the design and is set at approximately 75 to 85 wt.ppm sulfur based on liquid feed to the Oleflex Reactors in order to maintain a stable concentration of 50 – 60 mol ppm H₂S in reactor effluent. Sulfur content significantly higher than the guidelines stated can result in a temporary loss of activity and selectivity as well as increase the potential for iron sulfide scale formation leading to fouling of the reactor internals.

Excessive sulfur levels in the Oleflex unit can overload the reactor effluent driers to the point that H₂S will break through. This can result in corrosion in downstream units, will result in H₂S contamination of the deethanizer off gas. UOP specifies sulfur injection at 75-85 wt.ppm of sulfur injected as Dimethyl Disulfide (DMDS).

1.1.2 Nitrogen

Nitrogen compounds in the Oleflex feed react in the hydrogen atmosphere in the Oleflex reactor section to form ammonia. The ammonia will then react with the chloride ions present on the catalyst surface to form ammonium chloride salts, which will deposit throughout the cooler portions of the reactor and/or product circuit. The results of such deposits on the rotating equipment in the Oleflex reactor effluent section could be catastrophic. Deposits in the Reactor Effluent Compressor suction drum, interstage drum, or cold section separators foul the mesh blankets, while deposits in exchangers can affect exchanger performance. Salts can also plug trays in downstream fractionation towers. Finally, these salts will lay out in the fuel gas system, plugging the burner tips and possibly aiding in the corrosion of the piping. The total nitrogen allowable is 0.1 wt.ppm maximum in the propane liquid feed to the Oleflex unit.

1.1.3 Oxygenates

Heavy oxygenated compounds can react with the olefins within the reactor circuit to produce gums. The gums will tend to increase the coke deposition on the catalyst. Significantly higher coke levels will require higher reactor inlet temperatures at the same desired conversion. Lighter oxygenated compounds such as methanol will form water in the hydrogen atmosphere of the Oleflex reactor circuit. Excessive levels of water in the reactor section can affect catalyst and unit performance as described below. To maintain a reasonable operating temperature and to limit water formation in the reactor section, an upper limit exists for oxygenates in the Oleflex feed. The maximum allowable level of these compounds is 10 wt.ppm (as oxygen) in the propane liquid feed to the Oleflex unit.

1.1.4 Water

Water is removed to < 1 wt.ppm from the liquid feed by the fresh feed driers. If any significant moisture is in the liquid hydrocarbon feed to the cold separation system, freezing problems will result, with a corresponding decrease in the performance of the cold separation system. There is also a potential to mechanically damage the plate fins in the exchangers in the cold separation system due to freezing. Decrease in performance of the cold separation system can in turn result in lower purity recycle gas and cause reactor internals fouling and heavies' formation in the Oleflex unit. It is important to keep the liquid feed to the cold separation system dry.

The Oleflex reactor section receives a small level of water from incomplete drying of the regenerated catalyst entering the reactor circuit, and from the catalyst reduction step. Further, oxygen compounds can form water in the hydrogen atmosphere of the reactors as described above. The catalyst system is designed to handle a certain level of water, and in fact a small amount of water is beneficial to catalyst performance and catalyst life. However, water charged to or formed in the Oleflex reactor section will react with methane via a steam reforming type reaction to produce carbon

monoxide (CO). Excessive levels of CO in the reactor section will attenuate catalyst activity, resulting in a reduction in unit performance. The PSA unit can be overloaded with excessive quantities of CO, to the point that CO breakthrough occurs into the PSA product gas. In this case, the CO containing reduction gas sent to the reduction zone will permanently and severely deactivate the Oleflex catalyst.

Note that excessive quantities of water in the Oleflex reactor effluent can overload the Reactor Effluent Driers, resulting in breakthrough of H₂S and/or water. Any H₂O breakthrough will cause severe freezing problems in the cold separation system while any H₂S breakthrough will result in the problems listed above in section D.1.1, Catalyst Poisons - Sulfur.

In order to prevent freezing problems in the cold separation system and to properly control the amount of moisture in the reactor section, UOP specifies a maximum of 1.0 wt.ppm water in the propane liquid feed to the Oleflex unit.

1.1.5 Halides

Potential acidic poisons such as chloride and fluoride containing compounds must be limited to the lowest detectable levels in the Oleflex feed. These compounds decompose on the catalyst and deposit chloride or fluoride ions on the catalyst surface. Acid sites are then available to promote cracking reactions, light ends production, and isomerization. The result is a reduction in the selectivity to mono-olefins. To prevent fluoride contamination when recycle paraffins enter the Oleflex unit from an HF Alkylation unit, the recycle feed is alumina treated to remove any organic fluoride compounds or residual HF. UOP specifies a maximum of 1.0 wt.ppm halides in the propane liquid feed to the Oleflex unit.

1.1.6 Metals

Heavy metals such as mercury, lead, or arsenic in the Oleflex feed will permanently deposit on the catalyst surface. Eventually, catalyst activity and selectivity will be permanently reduced. Also, mercury has an adverse effect on the aluminum metallurgy of the Oleflex cold separation system. UOP specifies maximum levels of heavy metals in the Oleflex feed. The maximum allowable level of total heavy metals, excluding mercury, is 50 wt.ppb in the fresh propane liquid feed to the depropanizer. While the specification for mercury in the fresh propane liquid feed to the depropanizer is a maximum of 0.1 wt.ppb.

1.2 Catalyst Poison Summary

The following table summarizes the allowable levels of catalyst poisons in the depropanizer overhead liquid feed to the Oleflex unit:

Allowable Impurity Levels	
Sulfur	78 – 85 wt.ppm (injected as DMDS)
Total Nitrogen	<0.1 wt.ppm (as nitrogen)
Oxygenates	<10 wt.ppm (as oxygen)
Water	<1.0 wt.ppm
Halides	<1.0 wt.ppm
Heavy Metals (exc. Hg)	<50 wt.ppb*
Mercury	<0.1 wt.ppb

*Refers to fresh propane feed to the Oleflex unit at battery limit

2. SHP Catalyst

The catalyst typically used in the SHP unit is H-14171. This catalyst is a 1/16-inch spherical of an active metal on an alumina base. The active metal is palladium for H-14171, which is typical for Oleflex SHP service.

2.1 SHP Catalyst Poisons

2.1.1 Sulfur

Sulfur in the feed suppresses the activity of the SHP catalyst. Restoration of the activity, will normally require short term bypass of the SHP section and hot hydrogen strip procedure to restore performance in a timely manner. SHP located on the the recycle propane stream is unlikely to see feed sulfur in H₂S form in excess of permissible level. If the Reactor Effluent Driers (REDs) broke through in H₂S, almost all of the H₂S contaminating the Oleflex liquid product stream will get removed via de-ethanizer offgas upstream of SHP.

2.1.2 Nitrogen

Nitrogen compounds in the feed suppress the activity of the SHP catalyst. These compounds are unlikely in excess of permissible level in feed on the SHP located on the recycle propane stream. The effect may be reversible with hot hydrogen stripping.

2.1.3 Halides

Halides to SHP suppress the activity of the catalyst. These compounds are unlikely in excess of permissible level in feed on the SHP located on the recycle propane stream. Chlorides, either gas or organic liquid phase, can result in declining performance. Hot hydrogen stripping may restore performance, however the HCl liberated from this procedure should be considered.

2.1.4 Metals

Metals, such as arsenic or mercury, will permanently deactivate the SHP catalyst. Metals are unlikely in excess of permissible level in feed on the SHP located on the recycle propane stream in excess of permissible level.

2.1.5 Water

Dissolved water can be tolerated in the feed to the SHP as a reversible suppressor of activity. Any free water, however, will result in permanent damage to the SHP catalyst. Free water is unlikely to be present in feed on the SHP located on the recycle propane stream.

2.2 SHP Catalyst Poison Summary

Allowable Impurity Levels		
Total sulfur	<0.1 wt.ppm	Temporary
H₂S	<0.1 wt.ppm	Temporary
Organic nitrogen	<1 wt.ppm	Temporary
Total chloride	<1 wt.ppm	Temporary
CO	<1 wt.ppm	Temporary
O₂	<0.5 wt.ppm	Temporary
Water	No Free Water	Permanent
Metals	<0.01 wt.ppm	Permanent

C. Fractionation

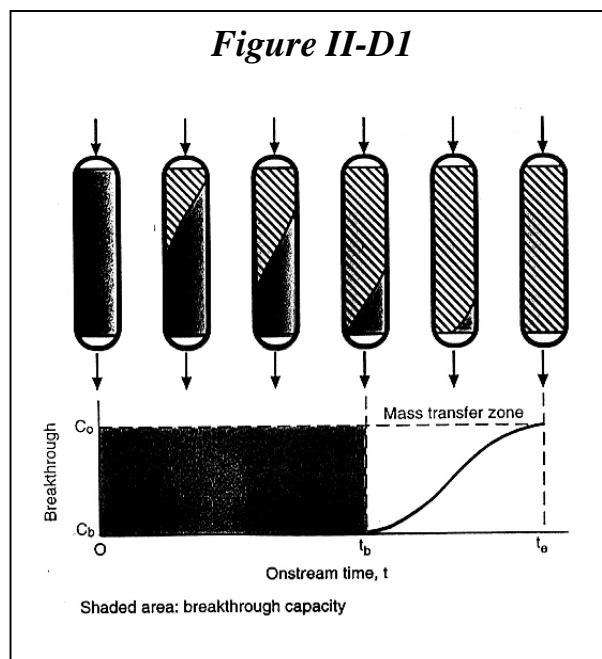
A number of equipment within the Oleflex Complex serve for the fractionation unit operation. Fractionation is a unit operation where the components in a given chemical mixture are separated by taking advantage of the boiling point difference between the components. There is enough openly accessible literature dedicated to the subject, so these fundamentals will not be covered in this section.

D. Adsorption

The PSA, fresh feed driers, reactor effluent driers, chloride treaters, feed guard beds, mercury guard bed (if provided), metal guard beds (if provided) and mercury treater (if provided) act essentially on the same principle of adsorption. The first three are reversible where regeneration restores capacity to the adsorption media. The latter four are not regenerable and the adsorbent must be replaced on a regular basis.

Adsorption is governed by mass transfer. As the fluid moves through the adsorbent bed, the contaminant is drawn into the adsorbent. Since it is not instantaneous, a mass transfer zone is established, as shown in Figure II-D1. At the start of this zone, the contaminant level is the same as in the feed. At the end of the mass transfer zone, it is essentially free of the adsorbed impurity. As the active sites are filled in the adsorbent pores, this mass transfer zone “moves” down the adsorber bed. Breakthrough begins when the fully spent fraction of the bed plus mass transfer zone is at the outlet. Note that breakthrough does not increase step-wise to the level of the inlet stream.

If the flow rate of material across the adsorbent is too high, the mass transfer zone can lengthen and the contaminant material could pass through the driers and/or the treater(s) and into the product.



1. Chloride Treater

The purpose of Chloride Treater is to remove minor amounts of chloride in the reactor effluent and prevent chlorides from getting adsorbed in the downstream reactor effluent driers. Some amount of HCl is generated in the Oleflex catalyst reduction step which eventually gets routed to the reactor effluent after the last reactor. Chloride can be adsorbed in the reactor effluent driers but cannot be removed by the drier regeneration and therefore it is necessary to remove it up stream of the reactor effluent driers. HCl being a halide will affect the performance of the SHP catalyst and Oleflex catalyst if not removed from the reactor effluent.

Chloride treater adsorbent is non-regenerable. Less than 1 mol ppm HCl is expected in the reactor effluent after passing through chloride treater.

2. Reactor Effluent Driers (REDs)

The purpose of the REDs is to remove water and H₂S from the reactor effluent. Some amount of water is generated in the Oleflex catalyst reduction step. H₂S is present in the reactor effluent due to sulfur injection in reactor section and any native sulfur that may have come in with the feed.

Water in reactor effluent can freeze in the downstream cold separation system and impact its performance. H₂S can contaminate the deethanizer off gas and product propylene. Further, H₂S is temporary poison for SHP catalyst in units where the SHP unit is located on the Oleflex liquid product stream; and can cause corrosion in the downstream units.

Only one RED will be in adsorption at any given time and other(s) in regeneration. At the drier outlet, <1 mol ppm moisture and <1 mol ppm H₂S is expected during normal operation.

3. Feed Guard Beds

The feed guard beds remove ammonia, basic nitrogen compounds and heavy metals in cationic form from the fresh propane feed. Strong cation exchange resin is used to remove these contaminants. If not removed, ammonia may get converted to ammonium chloride in the reactor section and come out with the reactor effluent. When the reactor effluent is cooled, ammonium chloride will precipitate as salt in the downstream fouling the equipment. Heavy metals impact the performance of the Oleflex catalyst.

There are two feed guard bed vessels each loaded with resin which operate in lead-lag mode. The resin can be replaced online.

4. Feed Driers

The purpose of feed driers is to remove the water from fresh feed propane by adsorption on the adsorbent bed to ensure that the combined liquid propane feed to Oleflex has <1 wt.ppm water. Water can freeze in the cold separation system affecting its performance. This adsorbent is regenerable.

If the feedstock contains elemental mercury additionally as a contaminant above acceptable limits, an additional bed of adsorbent may be provided within the feed driers to remove mercury to <1 wt.ppb limited by detection limit. This adsorbent is regenerable.

There are two fresh feed driers operating in lead-lag mode. Lead drier is periodically taken off service for regeneration and placed in lag mode after regeneration.

5. Metal Guard Beds

Arsine and phosphine are poisons for the Oleflex and SHP catalyst. If the feedstock contains arsine and phosphine above acceptable levels, metal guard beds will be provided to remove these contaminants to non-detectable level (<1 wt.ppb) upstream of the fresh feed driers. A single bed or two beds operating in lead-lag mode might be provided. The adsorbent loaded in metal guard beds is non-regenerable but it can be replaced on line.

6. Mercury Guard Bed

If the feedstock contains mercury in very minor concentration and/or its presence is irregular and infrequent, a mercury guard bed might be provided up stream of the metal guard beds (if provided) and fresh feed driers to remove mercury to non-detectable level (<1 wt.ppb). The adsorbent is non-regenerable but it can be replaced on line. The adsorbent may require loading under inert nitrogen atmosphere.

7. Mercury Treater

If the feed driers are provided with adsorbents to remove both water and mercury, the spent regenerant effluent vapors will contain mercury which will be removed in the mercury treater to non-detectable level (<1 wt. ppb). This is necessary to prevent the mercury contamination in services and locations where the spent regenerant is used.

III. Process Variables

This section introduces the major process variables (temperature, pressure, flow rate, etc.) and their effect on process performance. The relationship between the process operating conditions, process performance and the process variables is identified. Information is also given about feedstock quality.

Process variables for the Oleflex Process are discussed first, followed by the Huel's Selective Hydrogenation Process (SHP).

A. Oleflex Process Variables

The Oleflex Process is a chemical process that produces mono-olefins from paraffins. In the following definitions paraffin and the corresponding mono-olefin refer to the primary reactant and product species; for example- propane and propylene in a C3 or C3/iC4 Oleflex; isobutane and isobutylene in an iC4 or C3/iC4 Oleflex. The efficiency of this reaction is measured by two plant performance variables. The first, performance variable, conversion, is defined as:

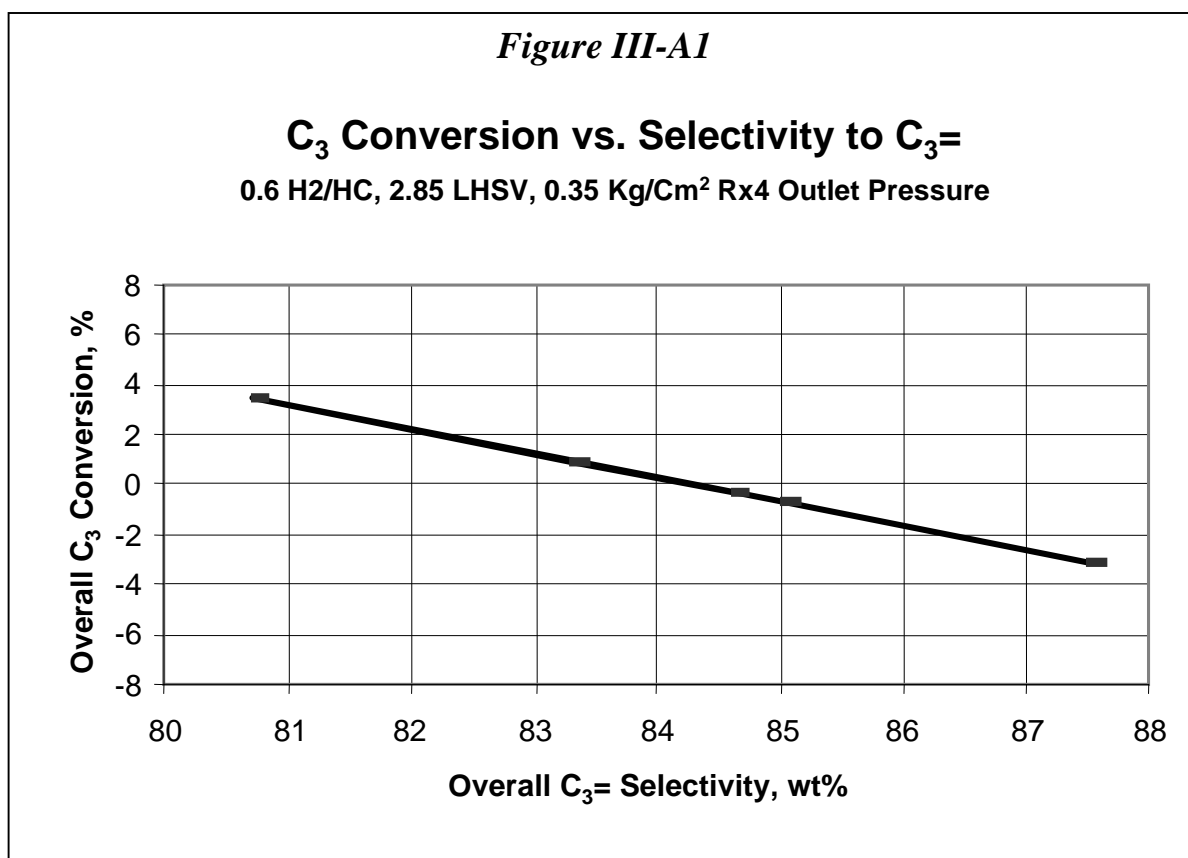
$$\frac{\text{mass of paraffin converted}}{\text{mass of paraffin charged}}$$

Conversion normally refers to the per-pass conversion, which is the amount of material that is converted in one pass through the reactor section. Conversion can also be defined across each individual reactor, or across the complex. The per-pass conversion typically varies from 20-36% depending on the process conditions. Since the main dehydrogenation reaction absorbs heat, the endotherms observed in the reactors are an excellent indicator of conversion.

The second performance variable, selectivity, is defined as:

$$\frac{\text{mass of mono-olefins produced}}{\text{mass of paraffin converted}}$$

Selectivity is linked to, and should have the same basis as the conversion. In this section, and normally, this will refer to selectivity on a per-pass basis. Figure III-A1 demonstrates the selectivity and the conversion at typical operating conditions.

Figure III-A1

These two main parameters are influenced to some degree by the various process variables, but are also effected by the condition of the catalyst, normally accounted by the catalyst life. The catalyst life can be defined in three different ways:

- a. The number of days on stream,
- b. The number of regeneration cycles the catalyst has been subjected to, and
- c. The cumulative feed the catalyst has processed, defined as:

$$\frac{\text{cumulative feed volume}}{\text{mass of total catalyst inventory}}$$

Since conversion and selectivity tend to offset each other, monitoring yield per pass over the catalyst lie is a good indicator of catalyst activity. Yield per pass is defined as:

$$\text{Conversion} * \text{Selectivity} = \frac{\text{mass of mono-olefin produced}}{\text{mass of paraffin charged}}$$

As the catalyst ages, the conversion and selectivity degrade and the yield per pass will decrease. Economics dictate when benefit in performance warrants a catalyst change, but normally this is three to four years. It is important for operations staff to

be aware that severe process conditions and certain operating problems can prematurely age the catalyst.

Several variables can be used to adjust conversion level and influence selectivity, although not all are directly manipulated. These variables include:

- a. Temperature
- b. Pressure
- c. LHSV
- d. H₂/HC Ratio
- e. Catalyst Coke Management
- f. Feed Composition
- g. Oxygenate Injection
- h. Sulfur
- i. Reactor Differential Pressure

The impact on the Oleflex process of each of the above variables is discussed in further detail in this section.

1. Temperature

Temperature is the primary variable that is used to adjust the conversion rate in the reactors. The temperature is adjusted as necessary to maintain the desired concentration of total olefins in the Oleflex liquid product. Reactor inlet temperatures are maintained in the range of 600-650°C (1110-1200°F). The actual operating temperature will depend on the throughput, desired conversion rate, condition of the catalyst, equipment design and general plant operation.

Since the dehydrogenation of paraffins to olefins is a reversible, endothermic reaction, equilibrium conversion of the paraffins to mono-olefins is favored by higher temperatures. The effect of temperature on conversion is shown in Figure III-A2. This plot is intended to be used as a guideline, as actual temperature requirements in any given unit may vary.

The advantages of increasing the conversion are less recycle paraffin per mass unit of product.

The disadvantages include:

- a. An increase in coke make on the catalyst, possibly requiring an increase in the catalyst circulation rate
- b. Reduced selectivity to mono-olefins
- c. Potential accelerated aging of the catalyst

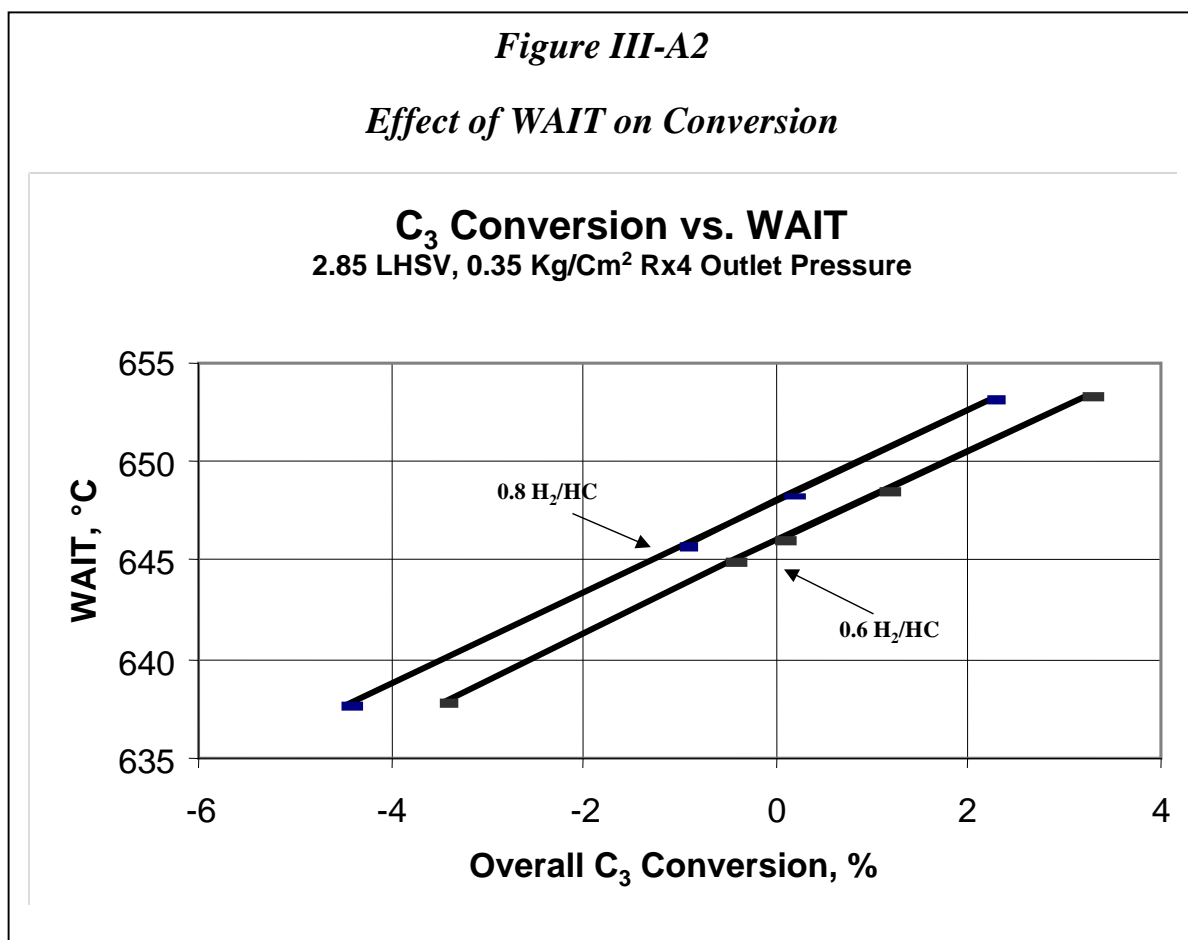
Selectivity to mono-olefins decreases as temperature increases due to increased thermal conversion within the non-catalyst areas of the Oleflex reactor section. These

areas include the fired heaters, the piping between the heaters and reactors, and the void spaces within the reactors. Thermal conversion of paraffins within these areas is much less selective to mono-olefins than the almost perfectly selective nature of UOP catalyst. Thus, although the catalytic conversion remains excellent at higher reaction temperatures, the overall Oleflex selectivity decreases due to the higher level of thermal conversion.

Note that an ascending or “humped” reactor inlet temperature profile is commonly used in Oleflex units. Specifically, the charge heater is operated at a lower outlet temperature than the downstream interheaters to take advantage of the fact that the presence of olefins inhibits thermal conversion. Thus, by operating the front end of the reactor section at relatively lower temperature and by using the downstream heaters to compensate for the lower conversion in the first reactor, less non-selective thermal cracking and better overall selectivity to mono-olefins is achieved.

Figure III-A2

Effect of WAIT on Conversion



2. Pressure

The last reactor outlet pressure is the pressure variable discussed in this section. This pressure is set by the suction pressure of the reactor effluent compressor and the

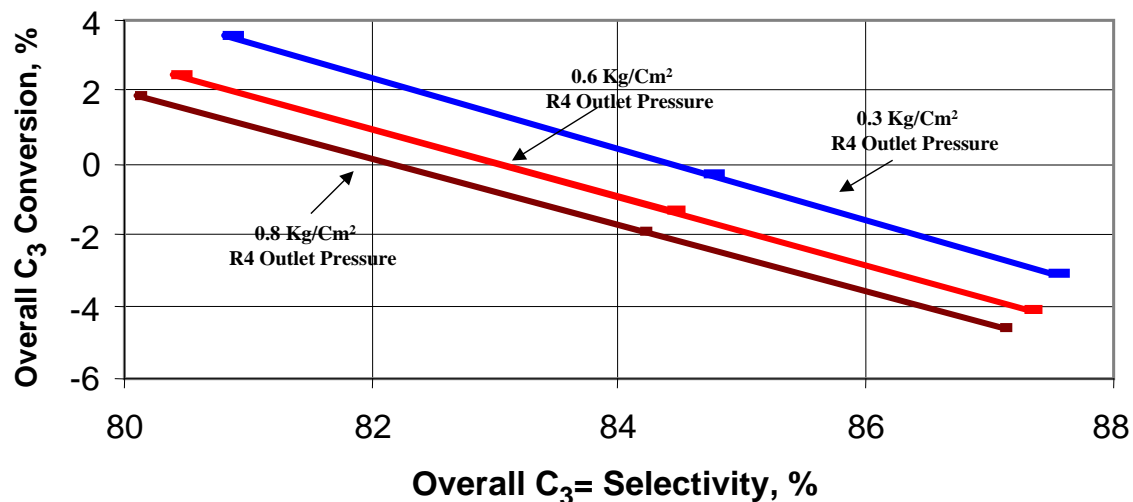
hydraulics through the section of the unit between the last reactor outlet and inlet to the reactor effluent compressor.

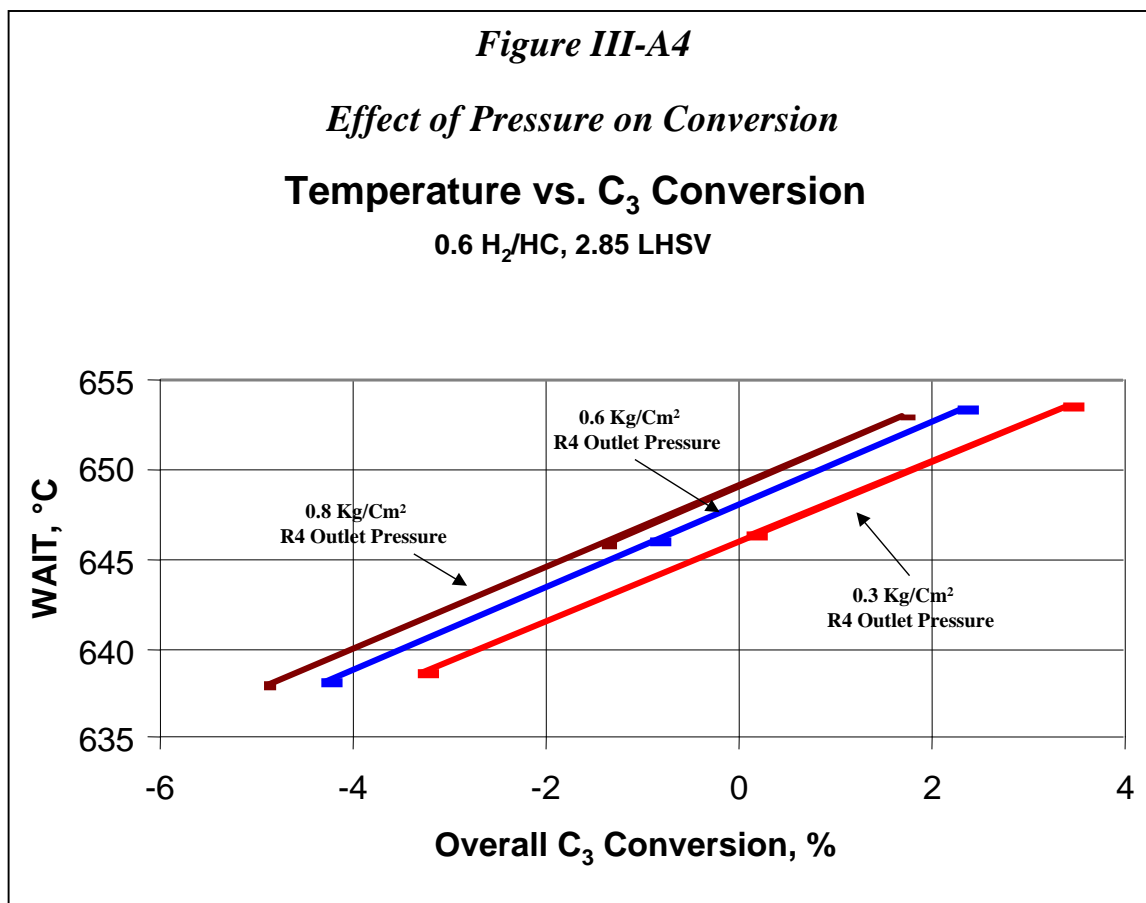
In C3 Oleflex unit designed with contact cooler for reactor effluent cooling, design pressure exiting the last reactor is typically 15.2 psia (104.825 KPa A or 1.068 kg/cm²a) which is only slightly above atmospheric pressure. Pressure downstream of the last reactor leading to the reactor effluent compressor will be slightly below atmospheric or under vacuum during normal operations. Sections of the unit expected to operate under vacuum have special features and provisions to mitigate air ingress and facilitate safe operation.

As the pressure is decreased, the olefin-paraffin equilibrium favors a higher selectivity to mono-olefins at higher conversion level. The last reactor pressure is maintained slightly above the atmospheric pressure to prevent air ingress into hydrogen and hydrocarbon environment of the unit.

Figures III-A3 and III-A4 indicate the expected performance responses when the pressure is adjusted. The conversion vs. selectivity as a function of pressure is shown in Figure III-A3. The required temperature vs. conversion as a function of pressure is shown in Figure III-A4.

Note that coke deposition is slightly decreased at increased pressure. Effects of coke level on unit performance will be discussed separately.

Figure III-A3**Effect of Pressure on Conversion and Selectivity****C₃ Conversion vs Selectivity to C₃=****0.6 H₂/HC, 2.85 LHSV**



3. Liquid Hourly Space Velocity (LHSV)

LHSV is a measure of the volume of feedstock charged to the reactor in an hour per volume of catalyst in the active areas of the reactors. As shown in Figure III-A5, the conversion decreases as LHSV is increased. To maintain a constant conversion, reactor inlet temperatures are typically varied based on changes in throughput.

The Oleflex reactors are typically designed to operate in a LHSV range of 2.5 to 3.5 hr⁻¹. At lower LHSV's, the conversion does not increase significantly. At LHSV's significantly above design, the conversion can reduce quite rapidly. Operating outside this range for LHSV is not recommended. Figure III-A5 indicates the relationship between the conversion and LHSV. Figure III-A6 details the changes in selectivity vs. conversion for varying LHSV.

In general, if the LHSV is significantly lowered, the reactor inlet temperature may have to be lowered to maintain the same conversion. Otherwise, the reduced LHSV will lead to increased conversion. However, the selectivity may decline due to increased non-selective thermal cracking.

The LHSV will also impact pressure as the hydraulic load on the reactor circuit is changed. Assuming other variables are held constant, higher LHSV will tend to increase the pressure at the outlet of the last reactor. In addition, higher LHSV could increase the potential for “void blowing”, an undesirable hydraulic effect detailed in the Troubleshooting Section.

Figure III-A5

Effect of LHSV on Conversion

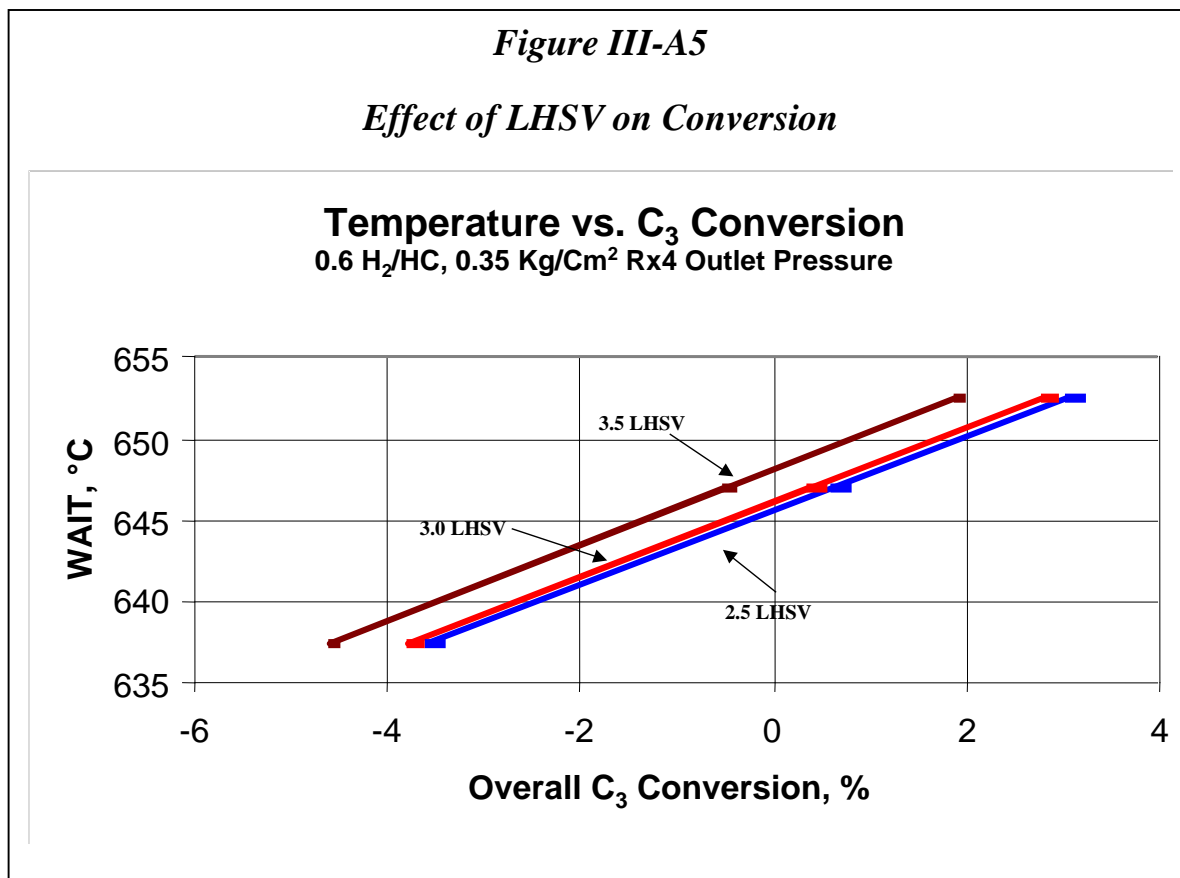
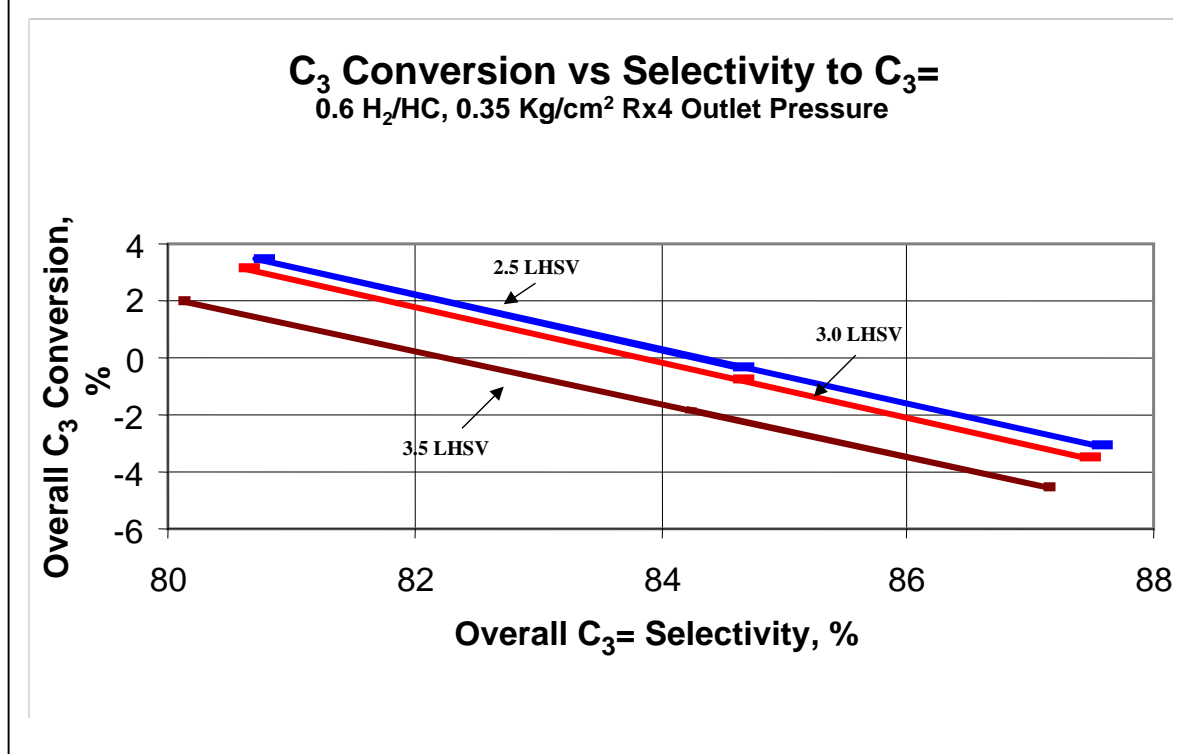
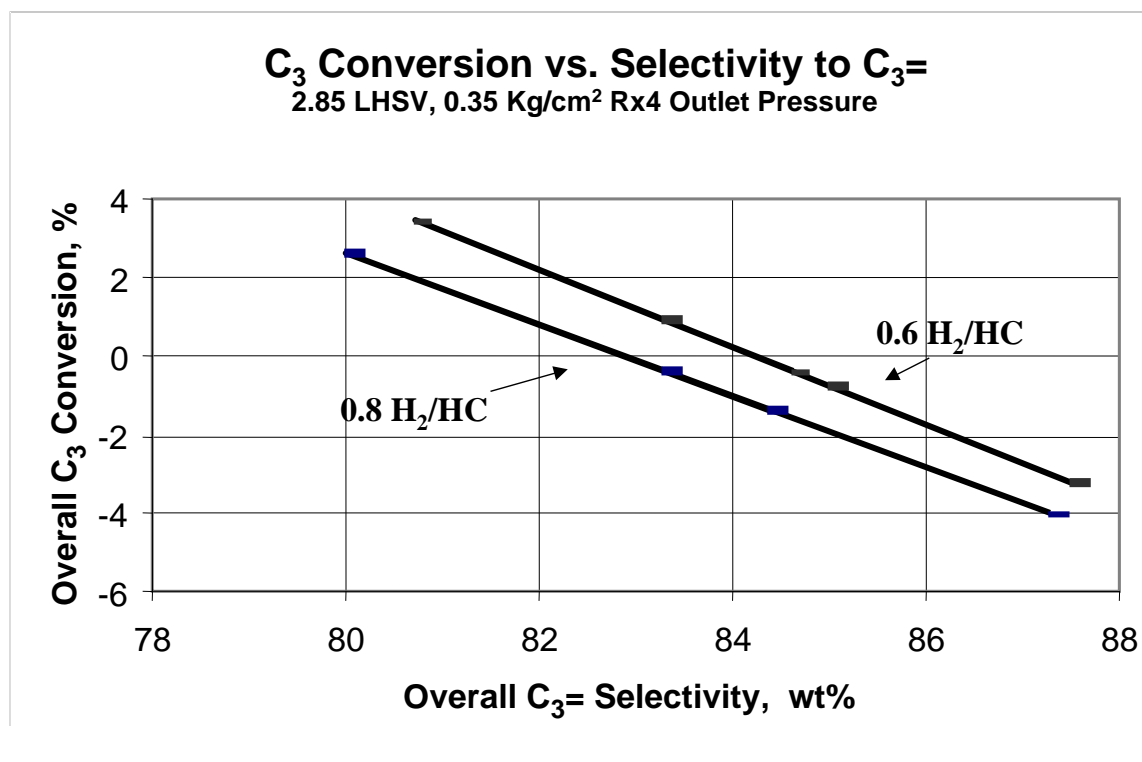


Figure III-A6**Effect of LHSV on Conversion and Selectivity****4. Hydrogen to Hydrocarbon Ratio**

The hydrogen to hydrocarbon mole ratio is defined as the ratio of the moles of hydrogen in the recycle gas to the moles of hydrocarbon in the combined feed. Decreased H₂/HC at a constant pressure lowers the hydrogen partial pressure. This in turn favors a higher selectivity to mono-olefins at constant conversion levels. Figure III-A7 can be used to estimate the change in selectivity and conversion with varying H₂/HC ratio. This relationship shows that a lower H₂/HC ratio directionally improves conversion and selectivity. However, the disadvantage of a low ratio is that the coke formation on catalyst increases, possibly shortening the catalyst life and requiring an increase in the catalyst circulation rate of the regenerator. Therefore, optimization of the H₂/HC may need to be done by balancing the loss in catalyst life (maximizing the CCR catalyst throughput) against the improvement in selectivity and compressor utilities. Design H₂/HC is 0.5.

In addition to increased coke formation on the catalyst, operating at too low a H₂/HC ratio will promote thermally derived coke formation in the Oleflex reactors and fired heaters. The coke formed may then result in plugging of the Oleflex reactor internals. The H₂/HC ratio should therefore not be reduced below the minimum value specified by the UOP Chief Technical Advisor or the UOP Technology Services group.

Figure III-A7**Effect of Hydrogen to Hydrocarbon Ratio on Conversion and Selectivity**

5. Catalyst Coke Management

The overall catalyst coke level, and thus the catalyst performance, can be adjusted by the catalyst regeneration rate. The greater the Continuous Catalyst Regeneration (CCR) rate, the greater the total amount of coke which can be removed from the reactor system. During operations, the reactor severity changes due to changes in the feedstock quality and quantity and/or changes in other process variables. The catalyst circulation rate can be adjusted to match the new coke formation rate. The result is a reactor system that can be maintained at optimal performance throughout the catalyst's useful life. Although maximizing catalyst circulation rate directionally may improve conversion and selectivity, each regeneration cycle can cause very minor, but cumulative damage to the catalyst.

Details on the CCR regenerator operation can be found in the UOP Oleflex Process CCR Section General Operating Manual.

6. Feed Composition

The Oleflex feed is normally a single carbon number paraffin, but two carbon numbers can be accommodated in the design. Limiting the carbon number range to two makes it possible to maintain the conversion of the lighter paraffin without excess side reaction of the heaviest paraffin.

In a C₃ Oleflex unit of particular importance is the amount of normal C₄ paraffins and C₄ olefins in the feed to the reactor section. These constituents are coke precursors at the operating temperatures required and contribute to fouling of the equipment, piping, and Oleflex reactor internals. Therefore, to avoid a premature shutdown of the unit and complete disassembly of the reactor screens for cleaning, the normal C₄'s and C₄ olefins should be limited to less than 100 wt.ppm in the combined propane liquid feed to the Oleflex unit.

7. Oxygenate Injection

For Oleflex (Propylene) process units, oxygenate injection is not currently recommended for DeH-14 or DeH-16 catalyst.

In the past, a small injection of water or methanol into the reactor section had proven to improve the performance of older generation Oleflex catalysts extending catalyst life. An injection rate of 25 to 100 wt. ppm equivalent –OH (based on liquid feed) was recommended.

Because of the potential for freezing problems in the cold separation system and because of the difficulty in controlling the small amount of water injected into the reactor section, all moisture in the fresh feed is first removed by the fresh feed driers. Then just upstream of one or more reactors, a controlled amount of water (or methanol) is injected.

Any oxygenates injected will form CO and CO₂ across the Oleflex reactors. Care should be taken not to overload the PSA unit since they are permanent catalyst poisons as explained in the Process Principles Section.

8. Sulfur

Sulfur attenuates the platinum sites of the catalyst. In fact, too much sulfur is considered a poison to the catalyst. However, the reactants (at the temperatures and pressure of the Oleflex Process) can be catalyzed to promote coke formation in the non-catalyst void volumes of the reactor circuit. The reactor metallurgy itself can catalyze these reactions. Sulfur attenuates the metal, and therefore reduces the formation of coke to a manageable level. UOP specifies 75 to 85 wt.ppm sulfur in the Oleflex liquid feed during normal operations. In this range, proper passivation of the reactor section metallurgy is ensured without impacting catalyst performance.

The following example illustrates how to calculate the desired DMDS flow for a given feed mass flow rate.

Example Calculation:

Find the target DMDS injection rate if the Oleflex liquid feed rate is 100,000 kg/hr (220,462 lb/hr) and the desired sulfur injection is 85 wt.ppm based on liquid feed.

DMDS Constants:

- Specific gravity: 1.063
- Wt.% Sulfur in DMDS: 68 wt. %
- Molecular Weight of DMDS: 94.2 g/mole

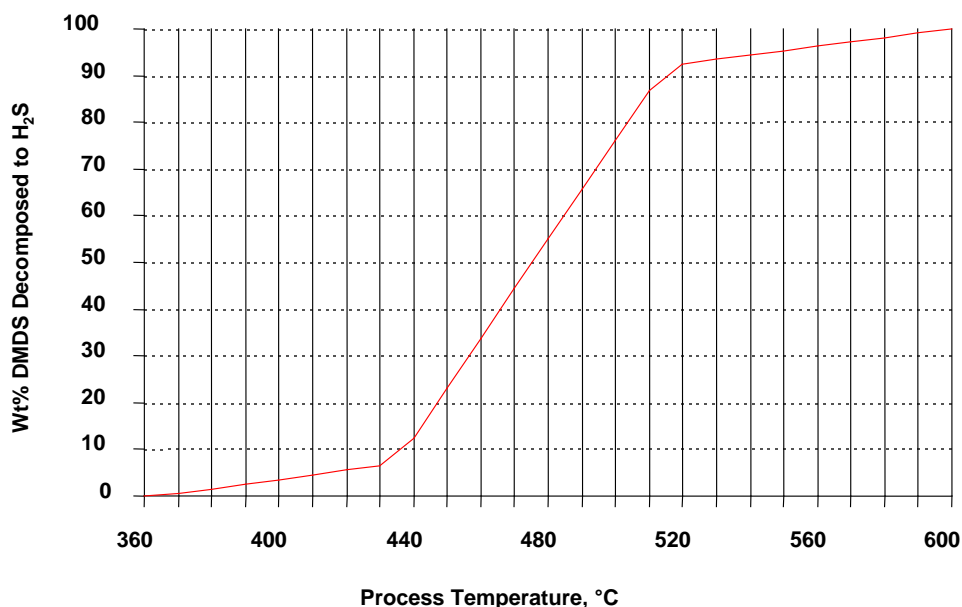
Solution:

$$\begin{aligned}\text{Target Sulfur injection} &= 100,000 \frac{\text{kg}}{\text{hr}} \left(220,462 \frac{\text{lb}}{\text{hr}} \right) * \frac{85 \text{ wt. ppm}}{1,000,000} \\ &= 8.5 \frac{\text{kg}}{\text{hr}} \text{ or } 18.7 \frac{\text{lbs}}{\text{hr}} \text{ of Sulfur}\end{aligned}$$

$$\begin{aligned}\text{Target DMDS injection} &= \frac{8.5 \text{ kg/hr (18.7 lbs/hr) of Sulfur}}{0.68 \text{ wt\% sulfur in DMDS}} \\ &= 12.5 \frac{\text{kg}}{\text{hr}} \text{ or } 27.6 \frac{\text{lbs}}{\text{hr}} \text{ of DMDS} \\ &= (12.5 \text{ Kg/hr}) / 1.063 \\ &= 11.76 \text{ Liters/hr or } 3.107 \text{ gallons/hr of DMDS}\end{aligned}$$

Note: Organic sulfur compounds native to the Oleflex feed are not considered to be effective agents of metal passivation within the Oleflex unit. DMDS (dimethyl disulfide) is the only sulfur agent which will ensure proper passivation of the entire Oleflex reactor circuit.

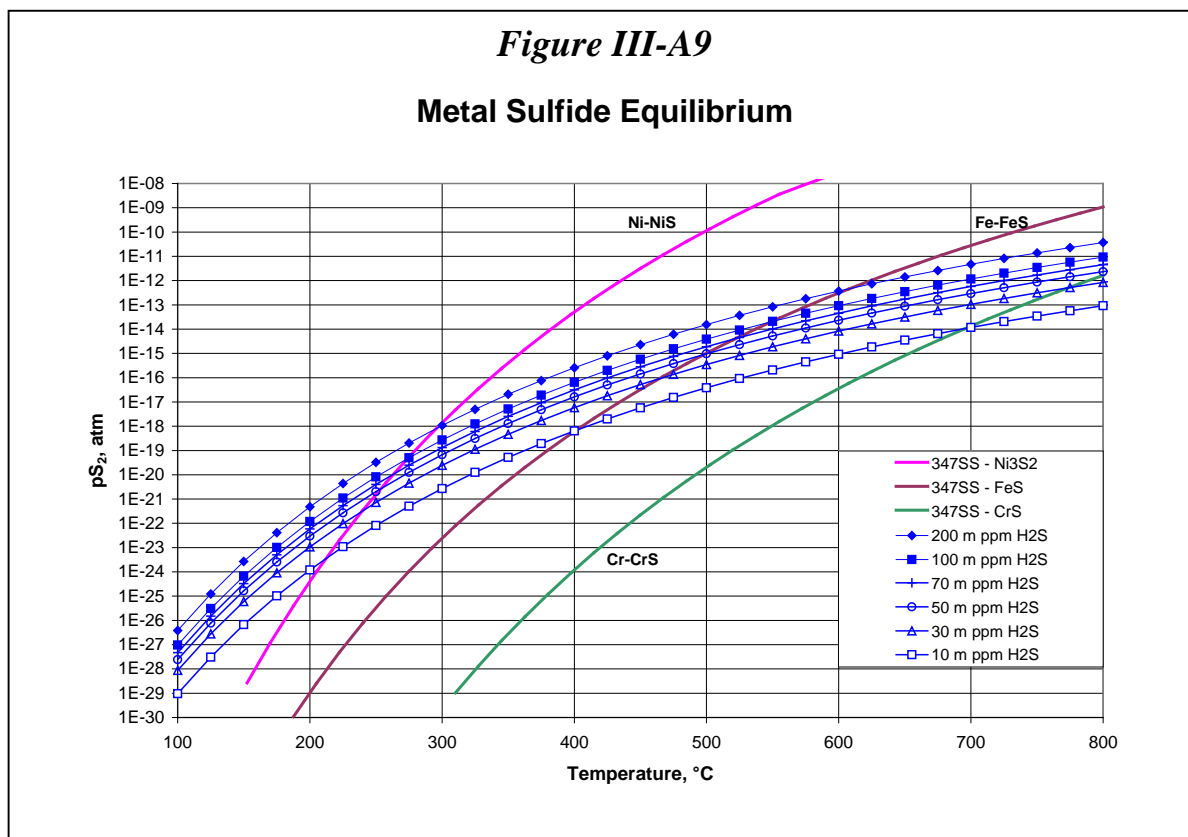
Only DMDS will thermally decompose to H₂S at temperatures equivalent to the HCFE feed side outlet temperature. Due to this characteristic, the outlet of the HCFE and the inlet area of the charge heater are properly passivated by the protective H₂S equilibrium. Other organic sulfides would not thermally decompose until significantly higher temperatures and severe coking of the charge heater would result. Thus, only the DMDS injected into the Oleflex feed should be used in calculating the sulfur level. Refer to Figure III-A8 for the thermal decomposition characteristics of DMDS.

Figure III-A8**Thermal Decomposition of DMDS**

To prevent the reactor metallurgy from catalyzing reactants to coke, a metal sulfide barrier is desired to "separate" the reactants from the metallurgy. Specifically, the desired and most stable barrier is a chrome-sulfide barrier. This barrier requires H₂S equilibrium at the metal's surface to effectively prevent any iron catalyzed coke formation. Unfortunately, other sulfide barriers, such as an iron-sulfide barrier, are not stable and will actually result in severe corrosion/erosion of the reactor section metallurgy. To obtain the desired chrome-sulfide barrier and minimize any of the unstable barriers, proper sulfur injection rates and sulfiding procedures have been developed by UOP. As Figure III-A9 shows, the desired chrome-sulfide layer is favored at a higher operating temperature for a given sulfur level, while other less stable sulfides (nickel and iron sulfides in particular) are favored at lower temperatures. Due to this, sulfur injection during startup does not begin until 400°C (750°F) reactor inlet temperatures are achieved. Even higher temperatures for initiating DMDS injection would be desired from a metal sulfide barrier point of view, but due to the onset of reaction and olefins at the 400°C (750°F) area, sulfur injection is required to prevent formation of coke and to attenuate the fresh catalyst activity such that cracking reactions are minimized.

Note: It is critical to maintain the DMDS based sulfur injection system. Failure to do so can lead to the formation of coke particles in the reactor circuit. These particles will foul the reactor screens,

generating pressure drop. Eventually (within days), a shutdown of the unit will be required to clean the entire reactor circuit.



9. Reactor Differential Pressure

Assuming all other operating conditions remaining constant, an increase in the differential pressure across the reactors is an indirect measure of process fouling or plugging of the reactor inner and/or outer screens. Both inner and outer screen differential pressures are measured and tracked during operation to assist in guiding severity versus run length. Excessive process fouling, particularly localized fouling can lead to premature void blowing and flow maldistribution within the reactors. Guideline for operation is to limit the incremental increase in differential pressure from clean/new screen condition over time on account of process fouling to ~ 0.5 psi (35 mbar, 3.5 kPa). It is possible to operate at values above this guideline, but with some risk of operational problems and mechanical damage. The maximum permissible differential pressure across an inner screen before either the plug distributor or expansion bellows may fail is a function of mechanical design of those components. The inner screen pressure drop shall never exceed permissible external pressure on the plug distributor during normal operations. Mechanical design limits for reactor internals should be obtained from UOP Chief Technical Advisor.

B. SHP Process Variables

Although the main process variables are discussed here, the SHP unit does not typically require frequent monitoring or adjustment.

1. Pressure

The SHP unit pressure is selected to ensure that the hydrocarbon remains in the liquid phase and that the hydrogen remains in solution across the SHP reactors. The pressure is fixed by design and is not normally varied by the operator. If the hydrogen were to come out of solution, an increase in operating pressure might be required.

2. Liquid Hourly Space Velocity

The Liquid Hourly Space Velocity (LHSV) across the SHP reactor(s) is defined as the volumetric ratio of feed rate charged per hour per unit volume of the SHP catalyst. The design LHSV is set based di-olefin concentration and a number of other factors. The operating LHSV is a result of the operation of the complex and is not normally directly varied by the operator.

As the LHSV decreases, the residence time in the catalyst bed increases. With the increased contact time, a conversion of di-olefins and olefins may be increased up to the point of complete consumption of hydrogen.

3. Temperature

The reaction temperature is selected to maximize di-olefin conversion at the lowest possible temperature. As long as there is sufficient hydrogen for reaction, increasing the temperature will increase the rate of di-olefin conversion as well as mono-olefin saturation. At a higher conversion, the reactor exotherm (ΔT) will increase to reflect the additional reactions. If the ΔT increases to the point that the outlet temperature is considered to be too high, it may be desirable to lower the reactor inlet temperature or reduce the hydrogen injection.

4. H₂/Di-olefin Ratio

The major reaction control variable is the hydrogen flow. The amount of saturation is limited by the number of moles of hydrogen available for saturation. The amount of di-olefins and then mono-olefins saturated is set by the excess hydrogen available for reaction. As the amount of hydrogen is increased, a corresponding heat of reaction will increase the reactor delta temperature. The increase in temperature is due to the exothermic heat of saturation generated when hydrogen saturates a double bond (about 30 kcal/mol hydrogen). Accordingly, it is important to have precise control of the hydrogen makeup flow, good mixing, and to avoid spikes that could lead to

excessive heats of saturation and overall poor performance. This precise control must be recognized as the most important task facing unit operating and instrumentation personnel and all possible steps must be taken to assure that this very low hydrogen flow is controlled as well as possible.

The selective and quantitative hydrogenation of di-olefins is achieved with a stoichiometric amount of hydrogen. However, normal operations will set the hydrogen injection level at slightly above the stoichiometric requirements, typically 1000 mol-ppm based on feed. This allows for small drifts in the feed di-olefin content.

5. Feed Composition

In the C3 Oleflex units with contact cooler, specially designed to operate at ~15.2 psia (104.825 KPa A or 1.068 Kg/cm²a) at the outlet of the last reactor, the SHP reactor is located on the recycle propane stream from the propylene-propane splitter bottoms.

In these Oleflex units, the section of the unit from last reactor outlet leading to the reactor effluent compressor suction will operate under vacuum during normal operations. Any potential air leak into the system can cause oxygen to be present in the Oleflex liquid product feeding the fractionation section. Oxygen will get removed via deethanizer off gas in the fractionation section allowing the recycle propane feed to the SHP reactor to be essentially free of oxygen.

In these units, the SHP feed is the combined stream of recycle propane (major) and diolefins rich side draw (minor) from the propylene-propane splitter column. If the feed to the SHP reactor is contaminated with oxygen, it will get converted to water on the SHP catalyst affecting its performance. Any water formed on SHP can get carried to Oleflex via depropanizer overheads creating frozen water-ice in the cold separation system impacting performance.

By locating the SHP reactor on the recycle propane stream, these problems are eliminated.

Under normal circumstances, feed to the SHP is free of the catalyst poisons listed in Section II. If the Reactor Effluent Driers experience H₂S breakthrough, H₂S contained in the Oleflex liquid product will get removed in the fractionation section via de-ethanizer off gas leaving the recycle propane stream feeding SHP essentially free of H₂S contaminant. It is still required to monitor deethanizer stripper bottoms for sulfur slip in the unit as this can contaminate the propylene product.

In some unit configurations, where the battery limit fresh feed can have unacceptable levels of diolefins and acetylenes as contaminants, the SHP reactor may be located on the combined stream of fresh propane, diolefins side draw and recycle propane or an independent fresh feed SHP may be provided as an additional feed treatment. In

such a case, any contaminants in the fresh feed will have to be limited to an acceptable level to ensure normal performance of the SHP catalyst.

IV. Process Flow and Control

The following section will describe the general process flow and control of the unit and its associated equipment.

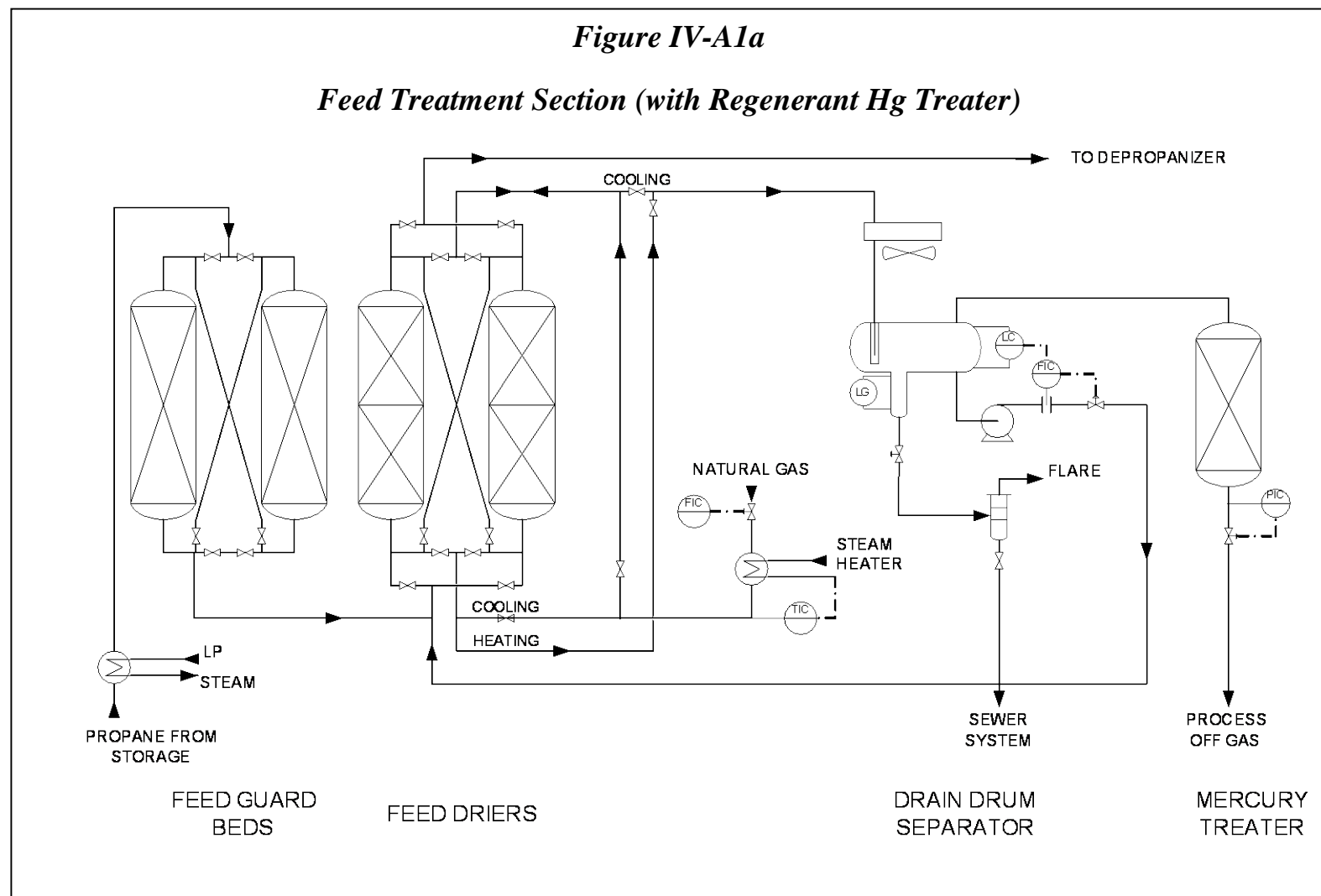
The Oleflex process unit is broken into multiple sections.

A. Feed Treatment Section (Figure IV-A1a/b/c)

The feed treatment section for the Oleflex unit is designed to remove basic nitrogen compounds, heavy metals, and water from the Oleflex feed.

If not removed, these materials would cause problems within the Oleflex Complex. Nitrogen compounds will form ammonium chloride salts at process conditions, and sublime out in the reactor effluent cooler, reactor effluent compressor, and the cold separation system. Mercury will attack the metallurgy in the cold separation system's aluminum plate fin exchangers. Mercury will tend to form amalgam with the aluminum alloy metallurgy of the cold separation system and come off solution when the affected section is exposed to ambient air leaving behind weakened metal leading to leaks during operation. Water will freeze out within the cold separation system potentially resulting in flow maldistribution, blockage of exchanger passes, and decreased recycle gas purity. Mechanical stress build-up due to solid ice formation can potentially damage the closely spaced exchanger plates. Contaminants like arsine and phosphine can poison Oleflex catalyst. The design and equipment of the feed treatment section depends on the quality of the feed being treated.

Flow rate through the feed treatment section is controlled by material balance control around the depropanizer. As the depropanizer receiver level drops, more fresh feed is brought into the unit. Feed guard bed, fresh feed driers and metal guard bed (if provided) operate at ambient temperatures, above the pressure of propane to keep the propane liquid phase.



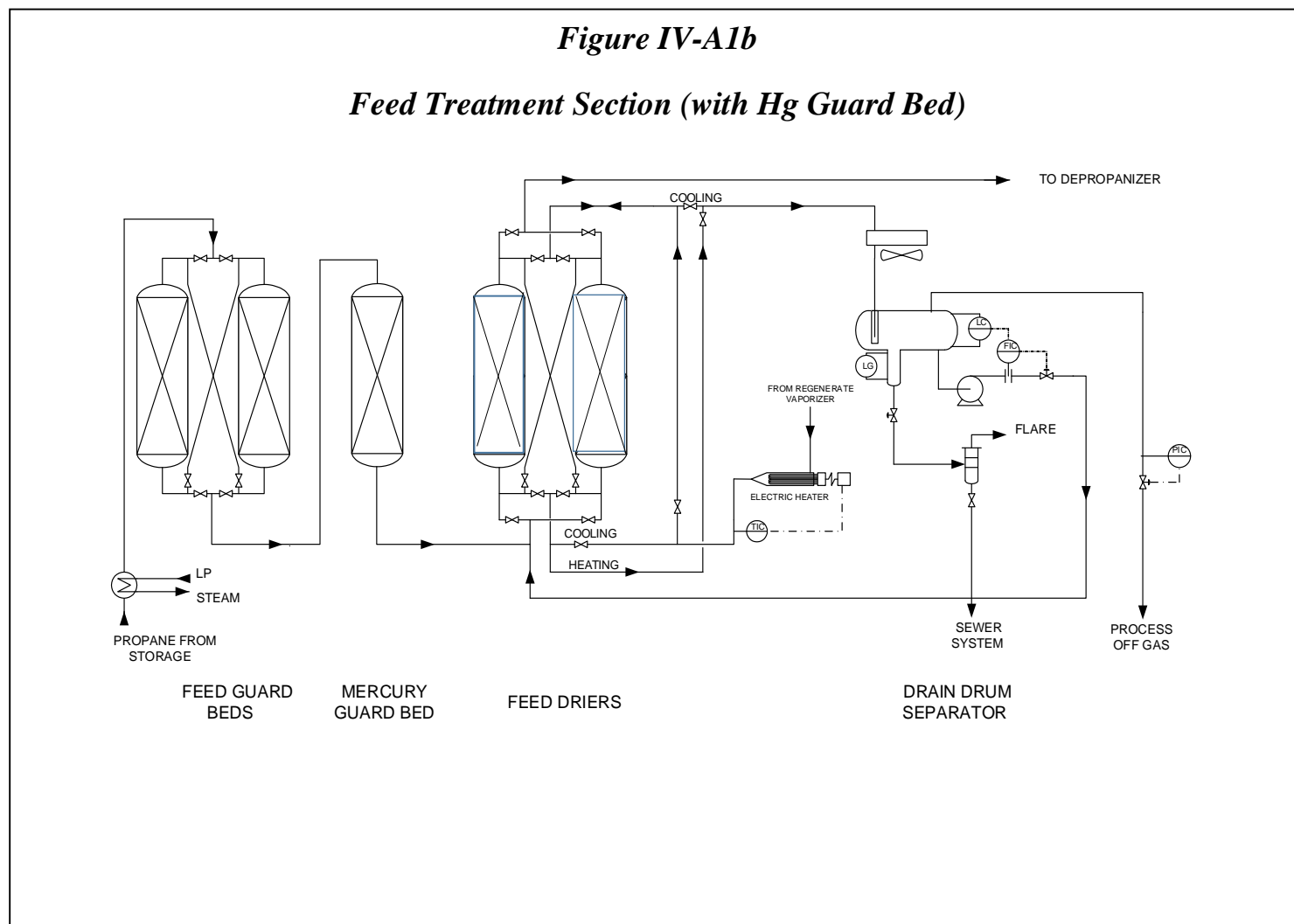
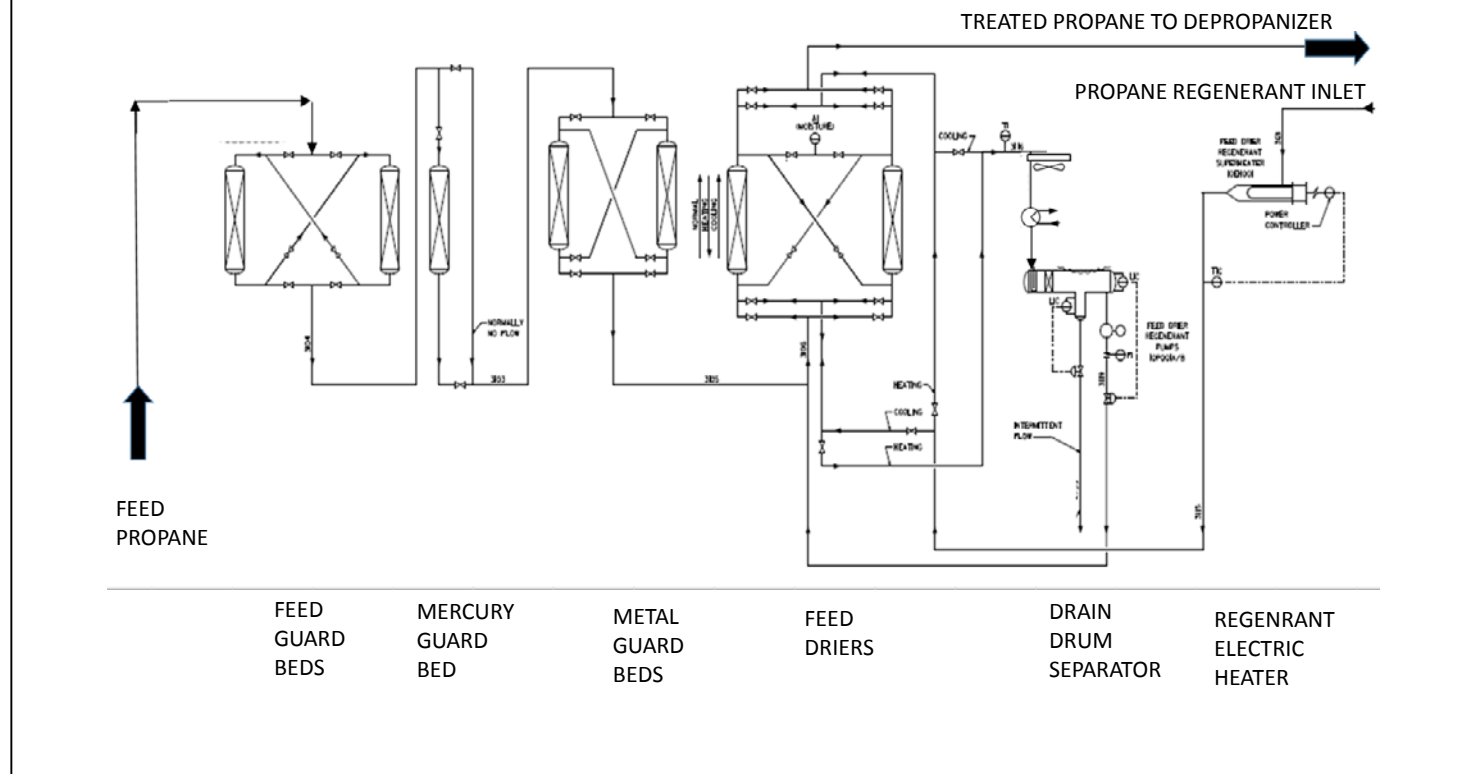


Figure IV-A1c**Feed Treatment Section (with Metal Guard Bed)**

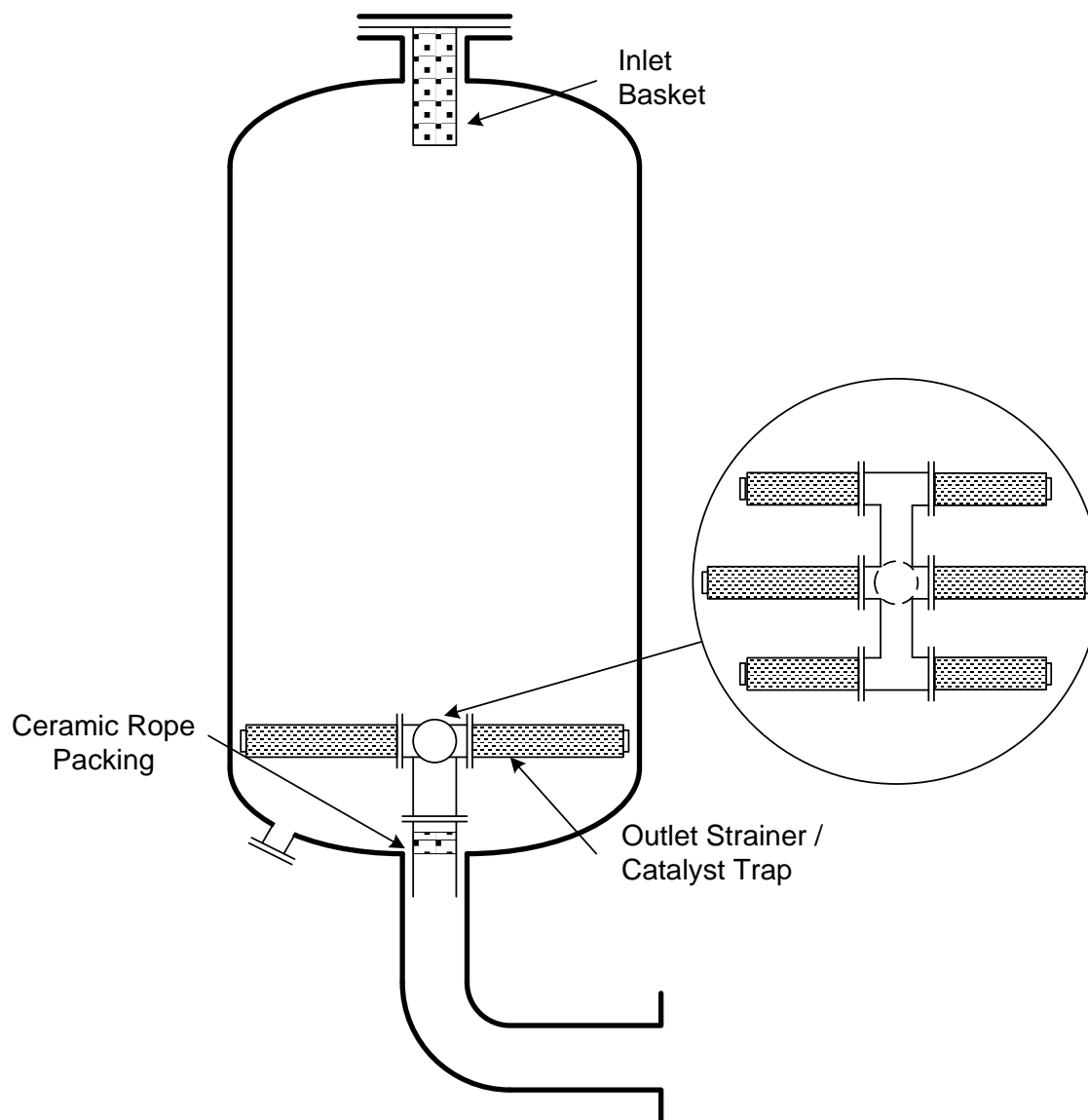
1. Feed Guard Beds

Feed guard beds remove basic nitrogen compounds, such as ammonia and amines, as well as organic metal compounds. The guard beds have no capacity for removing elemental metals such as arsenic, lead or mercury. Removal of elemental metals requires additional feed treatment steps.

The Feed Guard Beds consist of two carbon steel vessels filled with resin. Profile wire screens on the inlet and outlet distributors are used to prevent debris from entering the vessel as well as contain the resin. Typically only one unloading nozzle is required for unloading the resin. Refer to Figure IV-A2 for a typical Feed Guard Bed vessel sketch.

Fresh feed in the liquid phase is passed down flow through the resin in these carbon steel vessels. The two identical vessels operate in series mode with appropriate bypass piping to allow for change-out of one bed while the other remains on-line. The resin is non-regenerable and is normally replaced when the basic nitrogen content of the lead guard bed effluent reaches one half the inlet value.

Depending on the fresh feed conditions, a low pressure steam heater may be installed upstream of the resin guard beds to prevent freezing in the Feed Guard Beds. This could occur during a start-up after reloading the bed when the resin is water-wet and the feed is coming from cold storage. Additionally, units with warm feed may have a cooler to protect the resin from high temperature damage. The maximum temperature the resin can typically handle is 65°C (150°F).

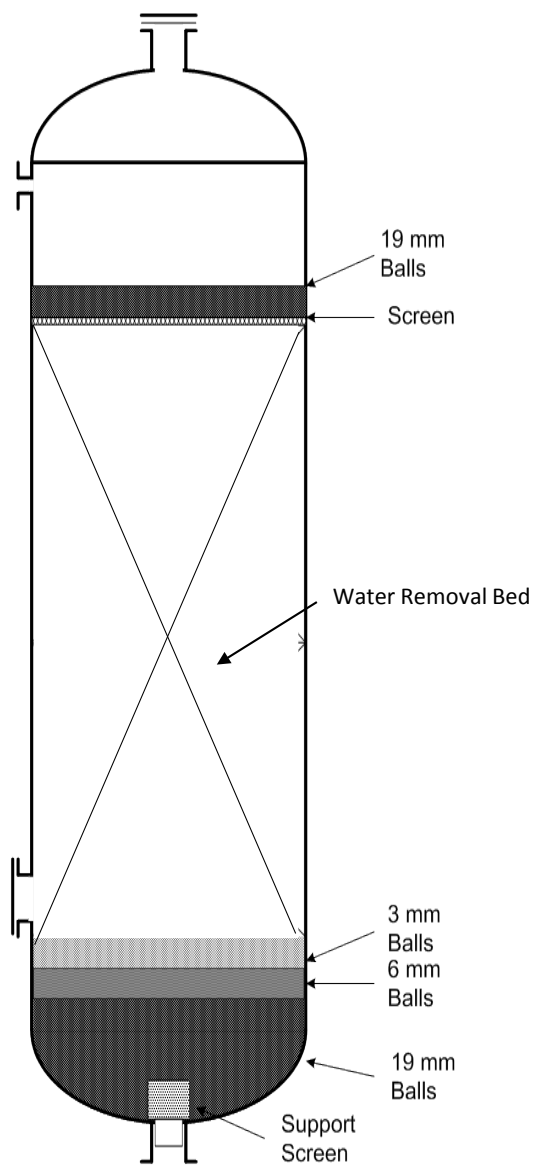
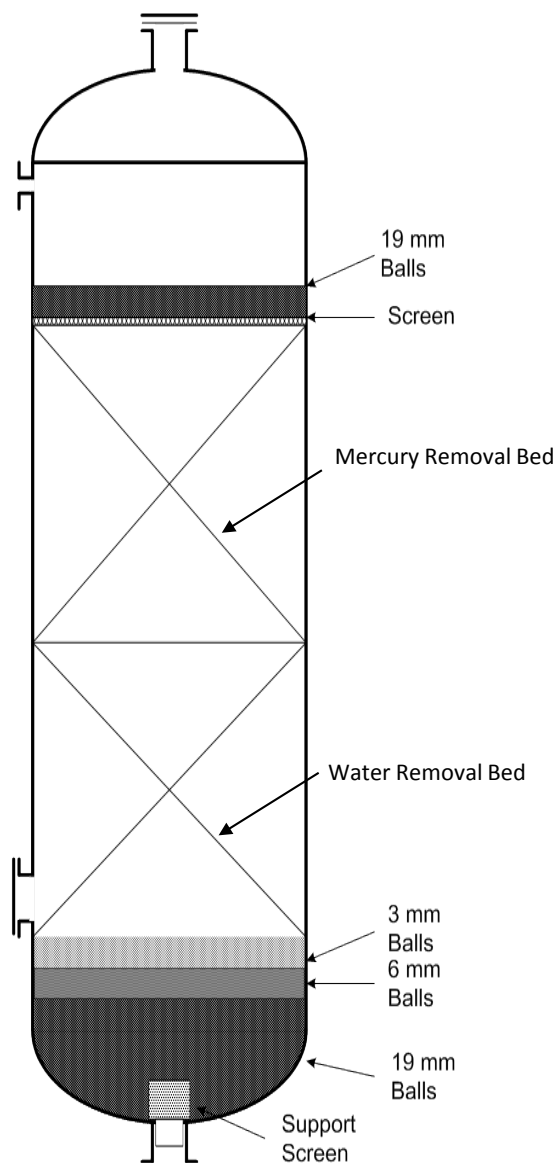
Figure IV-A2**Feed Guard Bed Details**

2. Feed Driers

The feed driers are two identical vessels operated in series and are typically loaded with a single adsorbent for water removal. Some units use two different adsorbents for water and mercury removal. The adsorbents selected will selectively adsorb water and, in some cases, elemental mercury from the fresh feed stream as it flows up flow through the beds. Refer to Figure IV-A3 for a typical Feed Drier vessel sketch.

The moisture content of the effluent from the lead drier is measured by an online analyzer. The driers are regenerated down flow when the moisture analyzer indicates breakthrough, or at least weekly as a minimum. Frequency of regeneration is the primary means of process control for these driers.

Typically the system is designed to be regenerated using dry propane. If mercury removal is required, an external non-condensing regenerant stream, such as deethanizer off-gas or fuel gas, is used to regenerate the driers in order to remove the mercury from the system without co-condensing it with the desorbed water. In addition to valve switching, pressure/depressure steps, etc., the regeneration includes heating in down flow at 230°C (450°F) to drive off the adsorbed compounds, followed by cooling. After regeneration, the drier is placed in the lag position. Details of the feed drier regeneration are provided in Section XII – Special Procedures.

Figure IV-A3**Feed Drier Details****Design with Single Bed****Design with Hg Removal Bed**

3. Feed Drier Regeneration Circuit

The equipment in the feed drier regeneration circuit consist of regenerant vaporizer and superheater, regenerant effluent condenser and cooler, drain drum separator and spent regenerant return pumps.

Regenerant vaporizer is provided where the regenerant is a slip stream of the dry hydrocarbon stream exiting the feed drier or an external regenerant liquid stream. Regenerant vaporizer is typically a bayonet type heat exchanger (Figure IV-A4) which has several pairs of concentric vertical tubes mounted within a shell. Hydrocarbon flows on shell side and steam flows on tube side. There exist separate chambers at the bottom of the exchanger to let in steam and remove condensate. Steam rises up the internal tube and flows down the annulus heating and vaporizing the regenerant liquid pool on the shell side. The vapors exit from the top. Regenerant vaporizer is not provided if the regenerant supplied is in the form of vapor or gas – for example deethanizer off gas or sales gas as regenerant.

In some units instead of a bayonet type vaporizer, a simple kettle type vaporizer might be provided.

A shell and tube type heat exchanger in carbon steel construction with steam on the tube side; or an electric heater with bundle heating elements with the process fluid on the shell side (Figure IV-A5); or a combination of both is used to superheat the regenerant to 230°C (450°F), typically the temperature required for the feed drier regeneration. Desired regenerant temperature is achieved by regulating the electrical power to the electric heater or condensate flow from the steam heater depending on the design.

After heating up the feed drier adsorbent bed in down flow, the regenerant effluent is routed to the condenser/cooler where it is condensed or partially condensed depending on the design. Any condensable water and hydrocarbon exit as liquid phase together with the non-condensable vapor phase to the downstream drain drum separator. The regenerant condenser/cooler may be an air cooled exchanger or water cooled exchanger or a combination of both depending on the design.

The drain drum separator (Figure IV-A6) is a horizontal carbon steel vessel with an inlet distributor, a coalescer pad and a water boot. Material of construction is carbon steel. The purpose of this vessel is to efficiently separate out the liquid phase water from liquid phase hydrocarbon while minimizing carryover of liquid hydrocarbon droplets into the vapor phase. Any water collected in the water boot is removed on level control. The hydrocarbons accumulated are pumped back to the feed drier inlet on level control.

When the regenerant used is non-condensable vapor stream such as deethanizer off gas or sales gas, there will be an additional spent regenerant vapor stream from the drain drum separator. If the spent regenerant vapor contains mercury, it is removed in the spent regenerant treater before sending the vapors to the fuel gas system.

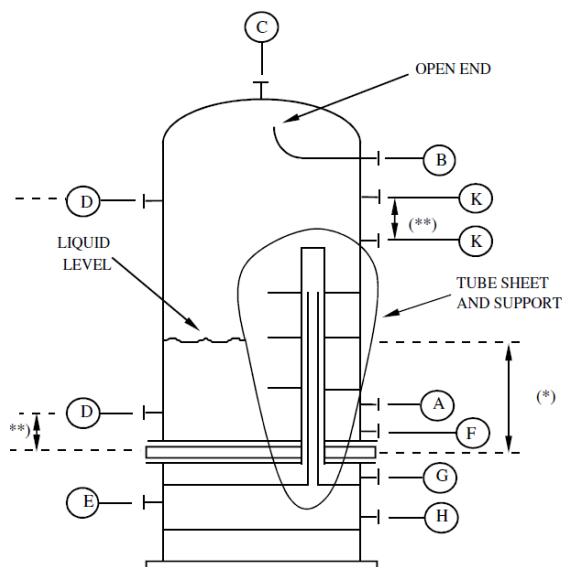
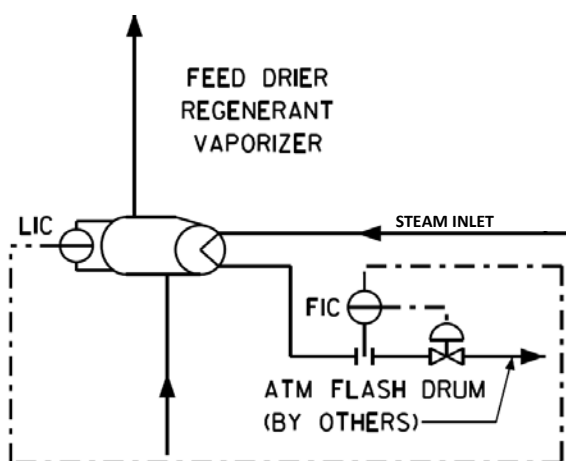
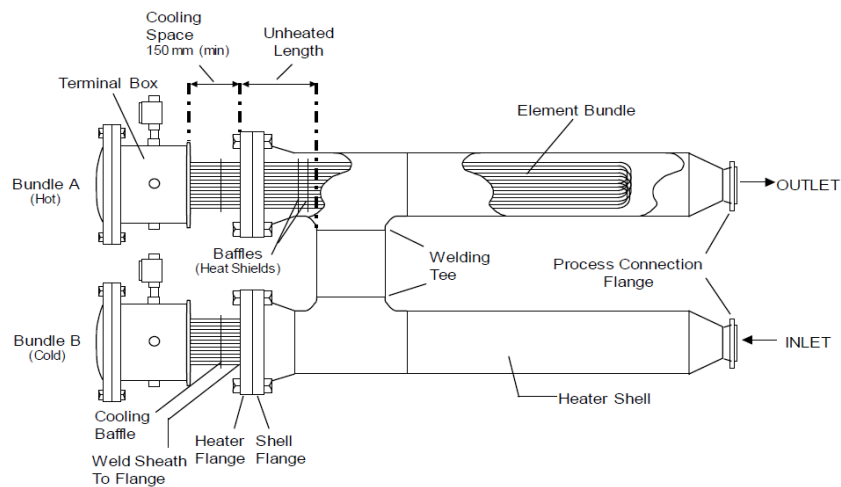
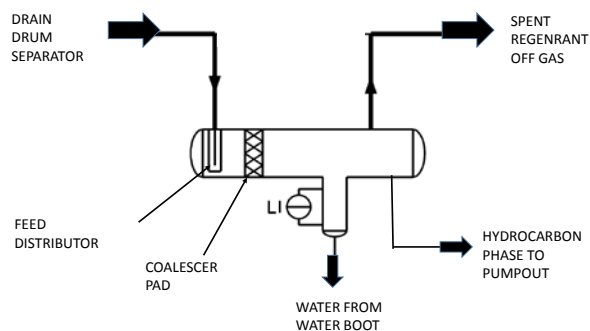
Figure IV-A4**Typical Bayonet Vaporizer Details****Vaporizer Typical Arrangement****Kettle Vaporizer Details**

Figure IV-A5**Typical Electric Superheater Details****Figure IV-A6****Drain Drum Separator Details**

4. Spent Regenerant Treater

If the fresh feed has elemental mercury, the feed drier will have a separate adsorbent to trap mercury in addition to the adsorbent to remove water. The mercury trapped in the feed drier is removed during the regeneration and is carried over with the spent regenerant vapors exiting the drain drum separator. Refer Figure IV-A1a for details.

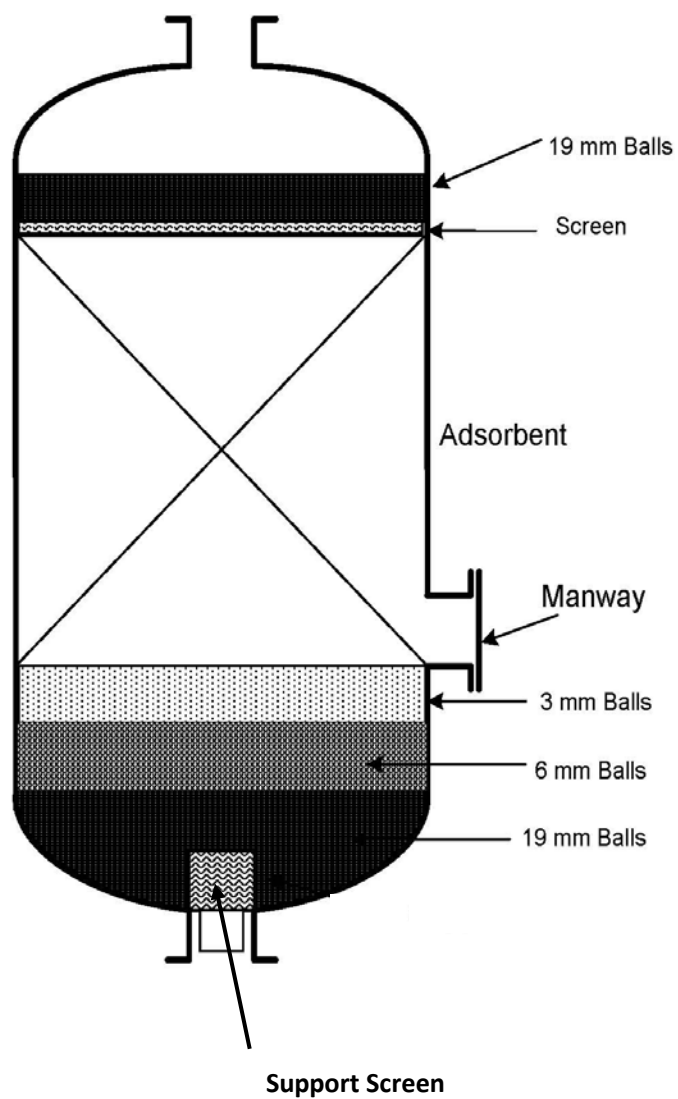
Spent Regenerant Treater removes mercury from the regenerant effluent vapors in down flow. The adsorbent is non-regenerable. In addition, the adsorbent will require loading under inert nitrogen atmosphere. The treater is a single vertical vessel fabricated in killed carbon steel.

5. Mercury Guard Bed

If mercury is present in the fresh liquid feed in very small quantities, a mercury guard bed may be specified up stream of the feed driers. The guard bed operates in liquid phase in down flow. Refer Figure IV-A1b and IV-A7 for details. The adsorbent is non-regenerable and will require loading under inert nitrogen atmosphere. The adsorbent can be replaced on line. Mercury guard bed is a single vertical vessel fabricated in killed carbon steel.

6. Metal Guard Beds

Metal Guard Beds remove arsine and phosphine from the fresh feed. When provided, they are located typically downstream of the feed driers. Refer Figure IV-A1c and IV-A7 for details. A single vessel or two vessels in series that operate in liquid phase down flow are provided depending on the contaminant level and anticipated frequency for change out. The metal guard beds are fabricated in carbon steel. The adsorbent is non-regenerable but can be replaced on line.

Figure IV-A7***Mercury Guard Bed or Metal Guard Bed Schematic***

7. Depropanizer (see Fractionation Section)

The treated fresh feed is combined with the unconverted propane from the Oleflex reactor section from the bottoms of the propylene-propane splitter and sent to the depropanizer column.

Flow rate through the feed treatment section is controlled by material balance control from the depropanizer receiver. As the depropanizer receiver level drops, more fresh feed is brought into the unit. Feed guard bed and fresh feed driers operate at ambient temperatures, above the pressure of propane to keep the propane liquid phase. Mercury treater and metal guard beds, if provided also operate in liquid phase. The depropanizer is covered in more detail in Section IV-F.

B. Reactor Section (Figure IV-B1)

Major equipment in the Oleflex reactor section are hot combined feed exchanger (HCFE), charge heater, reactor interheaters and Oleflex reactors. In addition, there are ancillary equipment – steam generation equipment for waste heat recovery, sulfur injection system for passivating austenitic metallurgy that support the operation of the reactor section. Sulfur is injected in the form of dimethyl disulphide (DMDS).

Propane and hydrogen are mixed in a specific proportion in the Cold Separation Section and constitute the combined vapor feed to the Oleflex reactor section. The combined feed flowing through the shell side of the HCFE gets heated by the hot reactor effluent vapors from the last reactor section flowing through the tube side of the HCFE. HCFE serves as heat recovery exchanger and helps reduce the heat duty on the charge heater. There may be one or more HCFEs depending on the unit capacity.

About 1/3rd of the required DMDS is injected into the combined feed stream at the inlet and 2/3rd at the outlet of the HCFEs to passivate the austenitic metallurgy in reactor section to limit the coke formation in the non-catalytic areas of the reactor section. Net gas from the Cold Separation Section is used to disperse and vaporize the liquid DMDS before injecting it into the combined feed stream. Vaporizing the DMDS prevents plugging of the injection nozzle with coke.

The combined feed is further heated to the required temperature in the charge heater and routed to reactor 1.

Since the reaction is endothermic, there will be net heat absorption with consequent temperature drop across the catalyst bed. Therefore, it is necessary to reheat the reactor effluent from the preceding reactor before feeding it to the next reactor in order to achieve the desired overall conversion. The interheaters 1-3 perform this function. The amount of fuel gas firing in the heater is used to regulate the reactor inlet temperature.

The hot reactor effluent exiting the last reactor rejects heat in the HCFE to the cold combined feed. The reactor section operating pressure is a function of the hydraulics and the location at which the pressure is regulated.

In C3 Oleflex units with contact cooler that are specifically designed to operate at relatively lower pressure at the last reactor outlet at 15.2 psia (104.825 KPa A or 1.068 Kg/cm²a), the pressure is controlled at the outlet of the last reactor by regulating the reactor effluent compressor speed. The low pressure limit controller will override the speed controller if the pressure at the last reactor outlet drops below atmospheric pressure to ensure that the pressure at the last reactor outlet always stays above the atmospheric pressure. In this design, all the process piping and equipment included in the section between the HCFEs and the reactor effluent compressor suction will be operating under slight vacuum during normal operation; and the reactor effluent compressor will operate at ~80 KPa A or 11.6 psia pressure at compressor suction governed by process hydraulics. All the major flanged joints in process equipment and piping that operate under vacuum in this unit configuration have lip seal welded gaskets as specified in the UOP Engineering Design Specifications to prevent air leaks into the system. It is critical to follow the seal welding requirements as specified in design.

The Reactor Section has four fired heaters including one charge heater and three Interheaters. The radiant coils for process stream heating are U-tube design and are typically constructed of 347 stainless steel. Type 347 stainless steel is an austenitic steel and susceptible to stress corrosion cracking as described later in this section under the Oleflex reactor design discussion.

One end of each of the U tube is attached to the inlet manifold and the other end to the outlet manifold. The outlet manifold contains a hollow conical shaped horizontal plug distributor concentric with the manifold resting freely on the bottom of the manifold. The conical tip of the plug distributor faces the outlet nozzle of the manifold. The other end of the manifold is at the end blind side of the manifold. The plug distributor reduces the hot residence time of the vapors in the non-catalytic area thereby reducing non-selective cracking. Refer to Figure IV-B2 for the typical depiction of the heater and details of the accompanying plug distributor.

The Charge Heater heats the incoming combined feed, and the three Interheaters heat the reactor effluent from each of the first three reactors. Each reactor inlet temperature is controlled in the range of 600-650°C (1112-1200°F) during normal operations, typically in a staggered profile. Reactor1 inlet temperature is typically set at the lowest amongst the four reactors to minimize thermal cracking. Propylene suppresses thermal cracking, which allows the downstream reactors to run at higher temperatures without a consequent loss in selectivity. Reactor4 inlet temperature is typically set slightly below the middle reactors since the greatest proportion of coke on catalyst is produced in the 4th reactor.

The heater outlet temperatures are measured directly by thermocouple in the inlet line to the downstream reactors and controlled by adjustment of the fuel gas pressure or flow provided to the respective heater. Special conditions are applied following certain upsets or shutdowns, including Low Fire Mode, to prevent damaging reactor internals due to rapid changes in temperature as described in Section XI - Emergency Procedures.

Fuel gas is used as the heating medium for the fired heaters. The heaters are wall fired typically using a low NO_x burner.

Depending on the design throughput, the heaters may have two separate cells. In this arrangement, symmetrical piping is specified to ensure nearly equal flow distribution between the two cells in each heater.

Waste heat is recovered in the heater convection section. Waste heat is used to generate steam that is typically used for captive consumption.

1. Reactors

The conversion of propane to propylene occurs stepwise in series through the four Oleflex reactors, each loaded with proprietary UOP dehydrogenation catalyst.

1.1 Oleflex Reactor Design

The purpose of the Oleflex reactor is to allow the feed to contact the catalyst at reaction conditions in a uniform and controlled manner. The Oleflex catalyst operates in a moving bed system. There are additional factors that govern the design beyond catalyst containment, such as minimizing catalyst attrition points and limitations on vapor velocity to avoid potential catalyst bed fluidization.

The Oleflex reactor is a modified radial flow design. The catalyst flows in the annulus between the inner and outer screens. The reactor feed flows across the catalyst bed from the inner screen to the outer screen. Figure IV-B3 details the various major components of the reactor. The following discussion identifies and comments on the particulars of each item.

The Reactor Screen Assembly is depicted in Figure IV-B4. Both the inner screen and outer screen are made of profile wire construction. The profile wires are triangular in shape, closely spaced, with the base facing radially outward and the apex welded to one end of the T shaped horizontal support rods. The other end of the horizontal support rods are welded to the center pipe that has several individual holes of prescribed size and pattern drilled into it. The horizontal support rods run through the circumference and entire length of the screen. The enclosed space between the two successive horizontal support rods, the profile wire and the center pipe constitute individual horizontal channels. Refer Figure IV-B5 and 6 for details. Vapors flowing through the holes into horizontal channels redistributes within the channel and enters

the catalyst bed through the narrow opening between individual profile wires termed slots.

The inner screen design for reactors 1, 2, 3 and 4 is specified as profile wire screens incorporating the More Open Upstream Screen Enhancement (MOUSE) with T shaped support rods discussed earlier. The T contraption on the MOUSE inner screen improves localized flow distribution within the horizontal channels discussed earlier, which reduces erosion/corrosion. Further, MOUSE inner screen has relatively more open area as compared to earlier versions of the profile wire inner screen, which reduces the potential for screen fouling. The details of the inner screen are shown in Figure IV-B5 and 6.

Typical specifications for the MOUSE inner screen are:

- a. No. 100 profile wire
- b. Average Slot Opening: 0.75 mm +/- 0.05 mm
- c. Maximum Slot Opening: 0.90 mm
- d. Minimum Slot Opening: 0.60 mm

The outer screen of the reactor is also profile wire screen. The wires are triangular in shape with the base facing radially inward and the apex welded to the perforated U shaped channels. The holes on the U channels provide for the reactor effluent vapors to exit the reactor. The size and number of the holes, and their distribution along the length of the screen is designed in a manner to provide uniform flow distribution throughout the length of the catalyst bed. The pressure drop through the outer screen is higher than the inner screen which further ensures uniform flow distribution through the bed. Refer to Figure IV-B7 for details of the outer screen.

Typical specifications for the outer screens for Reactor No.1, No.2, and No.3 are as follows:

- a. No. 130 profile wire
- b. Average Slot Opening: 0.50 mm +/- 0.05 mm
- c. Maximum Slot Opening: 0.65 mm
- d. Minimum Slot Opening: 0.35 mm

Due to the prevalence of carbonaceous fouling on reactor 4 outer screen, the More Open Outer Screen Enhancement (MOOSE) is specified. This design incorporates more open area on the screen, which reduces the impact of outer screen fouling on run length. Typical specifications for the MOOSE outer screen for reactor 4 are as follows:

- a. No. 110 profile wire
- b. Average Slot Opening: 0.65 mm +/- 0.05 mm
- c. Maximum Slot Opening: 0.80 mm
- d. Minimum Slot Opening: 0.50 mm

Refer to the UOP engineering specifications for specific unit dimensions of each screen and reactor internals.

The reactor charge enters the bottom of the reactor, flows through the turning and straightening vanes continuing to the expansion bellows assembly, and up into the inner screen. The plug distributor is tapered to facilitate uniform distribution of vapors into the catalyst bed as the vapors traverse up vertically and change the direction to progressively and radially enter the catalyst bed through the holes in the center pipe. Figure IV-B8 shows details of the plug distributor. Plug distributor reduces the residence time that the reactant vapors spend in the non-catalytic area of the reactor which helps reduce non-selective cracking of the feedstock.

The reactor purge gas line is shown in Figure IV-B9. The purpose of the purge gas is to prevent hydrocarbon vapors migrating to the non-catalytic void space above the cover deck and inside the hollow plug distributor. If allowed to migrate, it will generate soot coke in those areas. This purge gas, which is PSA grade hydrogen, flows through the purge gas line into the bottom of the plug distributor, continuously flushing it of possible hydrocarbon contamination. The purge gas then sweeps the void area above the cover deck and enters the catalyst bed through the catalyst free surface in the annular space between the screens at the very top where the catalyst enters the reactor through the catalyst transfer lines. The purge gas combines with the reactor effluent at the top and flows down the narrow space between the reactor shell and the outer screen combining progressively with the reactor effluent from the outer screen. The reactor effluent then exits via the reactor outlet nozzle.

The flow of high velocity vapor entering through the profile wire inner screen at the very top and flowing across the annular catalyst bed can potentially traverse upward to lift or fluidize the catalyst from the catalyst free surface in annulus where the catalyst enters through the catalyst transfer lines. If this were allowed to occur, the catalyst would be ground to fines and plug the reactor screens. The Oleflex reactor catalyst seal area at the top is designed to counteract the lifting forces of the charge vapors. First, the top portion of the inner and outer screens are blanked off. This allows a catalyst seal to exist at the top of the catalyst bed that does not see high vapor velocities. Second, a portion of the reactor inlet vapors is routed through the seal screen as seal gas to counteract the bed lifting forces by sending it downward through the catalyst seal. The seal gas flowing downward through the catalyst seal imposes downward forces that equal or exceed the lifting forces thereby preventing catalyst fluidization. Figure IV-B10 illustrates the seal area details.

The catalyst flow begins in the surge pot at the top of the reactor vessel. Surge pot has two zones one below the other to perform distinct functions. In the top surge zone, it receives the spent catalyst from the preceding reactor except in case of reactor 1 where it receives the regenerated catalyst from the catalyst regeneration section. The volume in this zone provides the necessary surge volume for inter reactor catalyst transfer. In the bottom zone, the catalyst is preheated with purge gas hydrogen prior to its entry into the reactor. In reactor 1 the bottom zone performs the

additional function of reducing the regenerated catalyst received from the catalyst regeneration section. Further, the volume of the catalyst in the bottom zone together with the purge gas ensure catalyst seal required to hold down the catalyst and prevent migration of vapors from the reactor below into surge pot which can result in coking.

The catalyst is transferred from the surge pot to the reactor screen annulus through the catalyst transfer pipes. Each of these transfer pipes runs through the cover deck and discharges the catalyst into the blank off area of the screen annulus through a catalyst distributor scoop attached to the end of the pipe. Figure IV-B11 shows the overall path the catalyst takes as it passes through the reactor.

Catalyst is removed from the reactor via an annular catalyst withdrawal system. Figure IV-B12 depicts the multiple withdrawal scoops attached to the base plate of the outer screen that make up an almost complete annular nozzle. These scoops remove the catalyst from the outer annulus area. This further improves the catalyst movement throughout the bed by allowing the vapor to 'assist' the catalyst from the inner screen out to the scoop. The "inner" catalyst transfer pipe attached at the bottom of each scoop passes through the concentric "outer" catalyst transfer pipe attached to the bottom head of the reactor. The other end of the "inner" transfer pipe is connected to an expansion bellow supported on the "outer" catalyst transfer pipe via a flanged assembly.

Refer to Figure IV-B13 for details of this connection. The expansion bellow assembly serves two purposes. First, it physically isolates the reactor effluent vapors and prevents them from flowing down via the annulus of the "inner" and "outer" catalyst transfer pipes into the catalyst collector which can fluidize the catalyst and cause soot coke. Second, the reactor screen assembly and the reactor shell exhibit different thermal growth rates when the process temperature is changed with the most severe impact during start up or shut down. As a consequence, the "inner" and "outer" catalyst transfer pipes tend to move at different rates. Expansion bellow will allow for differential thermal growth between the "inner and "outer" catalyst transfer pipes.

There exists an inlet expansion bellow located near the reactor inlet nozzle with stubs at either end. Bottom stub of the bellow is welded to the bottom head of the reactor and the top stub of the bellow is welded to the base plate of the outer screen. The bellow provides for the differential thermal expansion of the outer screen assembly in relation to the reactor shell as explained earlier. This bellow also isolates the reactor charge vapors from the reactor effluent. See Figure IV-B14 for details. A conical plate welded to the bottom head – other end being free- covers the bellow and protects it from erosion due to high velocity reactor charge vapors.

The above description and associated figures are meant to provide a general understanding of the reactor design. **UOP Engineering Specifications and its associated drawings are the absolute mechanical requirements.**

1.2 Austenitic Stainless Steel

Austenitic stainless steels are those of the "300 series," the compositions of which are nominally 18% chromium and 8% nickel. The most common types used in the petroleum industry are Types 304, 316, 321 and 347. Because of their inherent high temperature strength properties and superior corrosion resistance, they are particularly suitable for use in the Oleflex unit, in areas of moderate and high temperature, and where substantial resistance to hydrogen sulfide corrosion is required, such as in heater tubes, reactors, reactor effluent exchangers and piping.

Types 321 and 347 are stabilized grades of austenitic steel. These when specified, have been preferred because they are more resistant to the stress corrosion cracking caused by polythionic acid attack, which can occur during downtime periods when the metallurgy is exposed to air and moisture. Since these stabilized grades are not completely immune to corrosion cracking, special handling procedures are recommended for the protection of these materials as well as the unstabilized grades.

Inner and outer screens are fabricated in Type 347. LCP together with the containment screen are fabricated in Type 304. Heater tubes are fabricated in Type 347H. Reactor is fabricated in Type 304 with an additional specification 0.04 wt. % minimum carbon content for strength. Most of the piping in reactor section is in Type 304 with 0.04 wt. % minimum carbon. UOP Engineering specifications govern over any information provided in this manual.

Since corrosion cracking of austenitic stainless steel can lead to failure of the equipment involved, it is of the utmost importance that this equipment be properly protected to prevent corrosive environments from occurring. Therefore, all operating personnel, and especially the supervisory personnel, must be familiar with the locations of piping and equipment fabricated from austenitic stainless steel. They should also recognize the need for special handling of these sections of the unit during startup, shutdown, flushing, cleaning, maintenance and inspection, and should be thoroughly familiar with the procedures to be used for the proper protection of the equipment.

During any maintenance or shutdown work when the austenitic metallurgy of the reactor section can be exposed to ambient air, the metallurgy is protected by a special procedure called neutralization, the details of which are provided in Section XII, Special Procedures.

1.2.1 Chloride Attack

The presence of halides particularly chlorides, along with water and tensile stresses, can result in chloride stress corrosion cracking of austenitic stainless steels. This type of cracking is somewhat dependent on time, temperature and localized chloride concentration. Therefore, precautions should be taken to minimize the amount of

chloride in the process material that will come in contact with austenitic stainless steel equipment.

Under normal shutdown period conditions, chloride cracking is not likely to be a problem as long as chlorides are not allowed to accumulate and concentrate in hot equipment, and as long as precautions are taken to limit the chloride content to low levels in any flushing, purging or neutralizing agents used in the system.

1.2.2 Polythionic Acid (PTA) Attack

Sulfur injected in the form of DMDS decomposes to H₂S which will interact with the base metal to form stable equilibrium metal sulfide scale. Sulfur is injected in controlled amount to prevent coking. Once a unit has been placed on stream, all items made of austenitic stainless steel that are in contact with the H₂S in the reactor section flow path described earlier will have a metal sulfide scale.

As such all items made of austenitic stainless steel should be considered to contain a layer of metal sulfide scale. During normal operation, the metal sulfide scale serves as a barrier to prevent coking on the metal. However, when the unit is shut down for maintenance, if the piping and/or equipment with metal sulfide scale are exposed to ambient air and liquid water they pose a potential corrosion threat to the underlying steel. The action of liquid water and oxygen on this sulfide scale forms weak sulfurous type acids, commonly referred to as polythionic acids, which can attack austenitic stainless steels and cause inter-granular corrosion leaving behind a weakened base metal. The corrosion attack cannot be seen with the naked eyes. When the equipment is put back in service, the steel can crack under applied mechanical stresses at elevated temperature.

Protection against polythionic acid attack can be accomplished by preventing the corrosive environment from forming or by providing an agent that will neutralize any corrosive acids as they are formed.

Since these acids are formed by the action of water and oxygen with the sulfide scale, elimination of either liquid phase water and/or oxygen will prevent these acids from being formed. All the three need to be present to form polythionic acids and pose corrosion threat.

During normal operation, there will usually be an equilibrium amount of water vapor present in the reactor effluent but no oxygen is expected. The operating temperatures are high enough to prevent water from condensing out into liquid phase. Therefore polythionic acids cannot form during normal operation. If the shutdown is for short duration, the reactor section can remain under hydrogen/hydrocarbon atmosphere. When shutdown for longer duration is anticipated with no need to open the reactor section equipment, it is recommended to de-pressure and purge the reactor section with nitrogen until restart as safe practice.

Under normal operations, there should be essentially no oxygen present in the reactor system. The only other time any significant amount of oxygen might enter the system would be during a shutdown period when the system is de-pressured and the equipment is opened and exposed to ambient air- for example during catalyst unloading from the reactor and immediately thereafter. Under these conditions, a suitable purge of nitrogen should be established through the equipment involved to prevent any air from entering the system, and maintained until the system is again closed. If possible, the equipment should be blinded or blanked-off during this period and kept under a slight positive pressure of nitrogen.

During any maintenance work and/or unit turnaround, if the reactor internals for example – screens are dismantled and taken out, the austenitic metallurgy of the reactor section will be exposed to ambient air. In this event, the metallurgy should be protected by a special procedure called neutralization, the details of which are provided in Section XII, Special Procedures.

1.3 Dur-O-Lock Couplings

Dur-O-Lock couplings are used in preference to the welded and/or flanged joints to achieve a seamless, secure and smooth joint between the catalyst transfer pipe sections in order to minimize catalyst attrition in the catalyst transport system.

The catalyst transfer pipe from the surge pot to the reactor is in two pipe sections. The top vertical pipe section is integral with the surge pot above. The bottom pipe section has a bend. One end of the bottom pipe section is attached to the top pipe section and the other end to the catalyst distributor scoop using Dur-O-Lock couplings. The Dur-O-Lock coupling attached to the scoop lies just above the cover plates of the screen annulus though the scoop itself lies underneath the cover plates to facilitate easy assembly.

In addition, there exists a Dur-O-Lock coupling in the short horizontal run of the reactor plug purge line.

It is critical to assemble and install the Dur-O-Lock couplings in correct manner to prevent joint failures. Refer to the relevant vendor's procedures for proper installation.

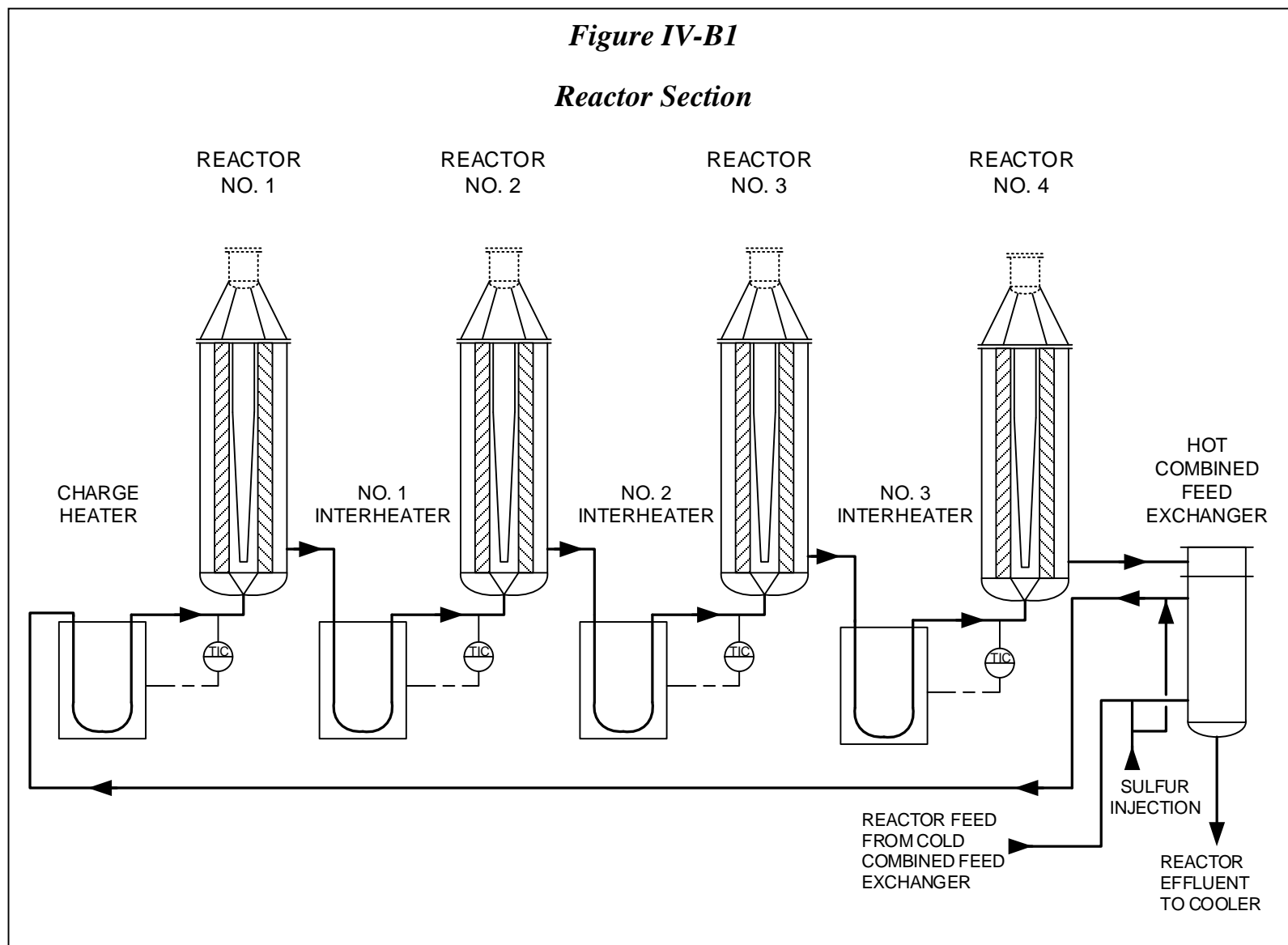


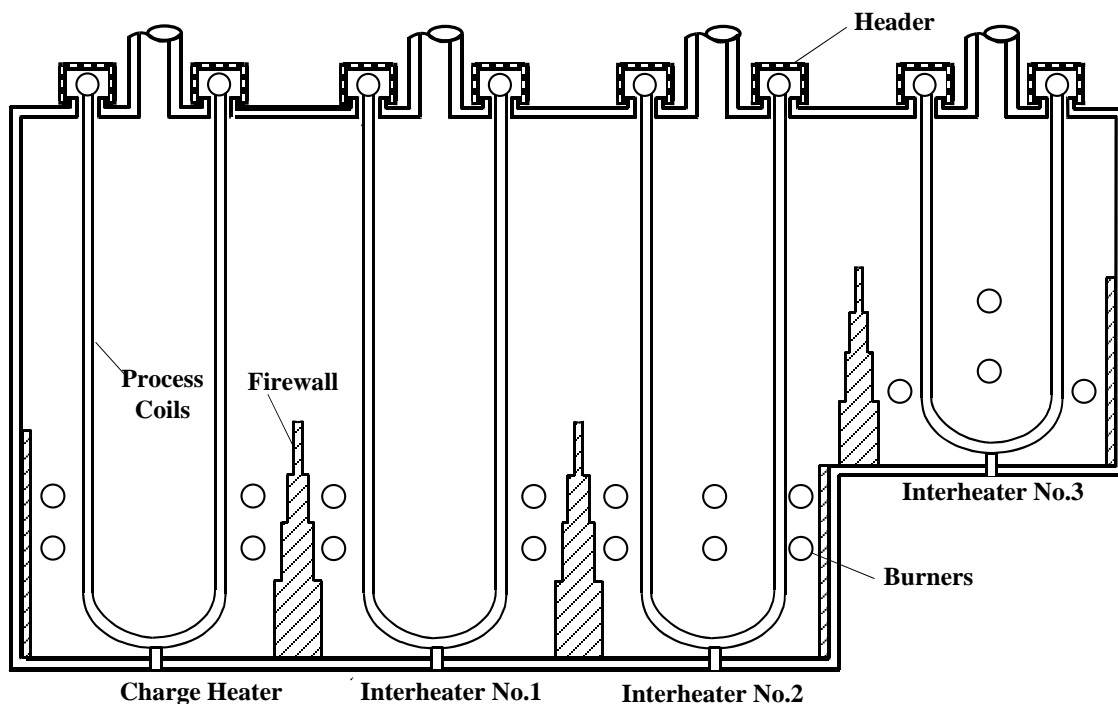
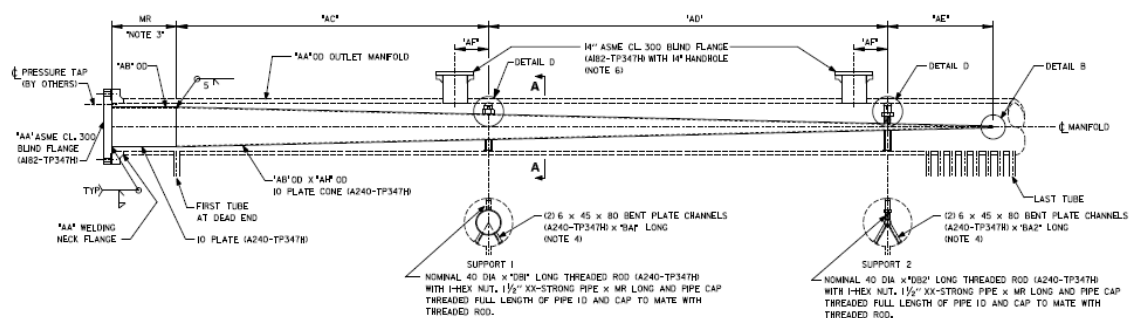
Figure IV-B2**Oleflex Process (Propylene) Heaters****U-tube Type****Details of Plug Distributor contained within the outlet manifold of Heater**

Figure IV-B3
Oleflex Reactor Details

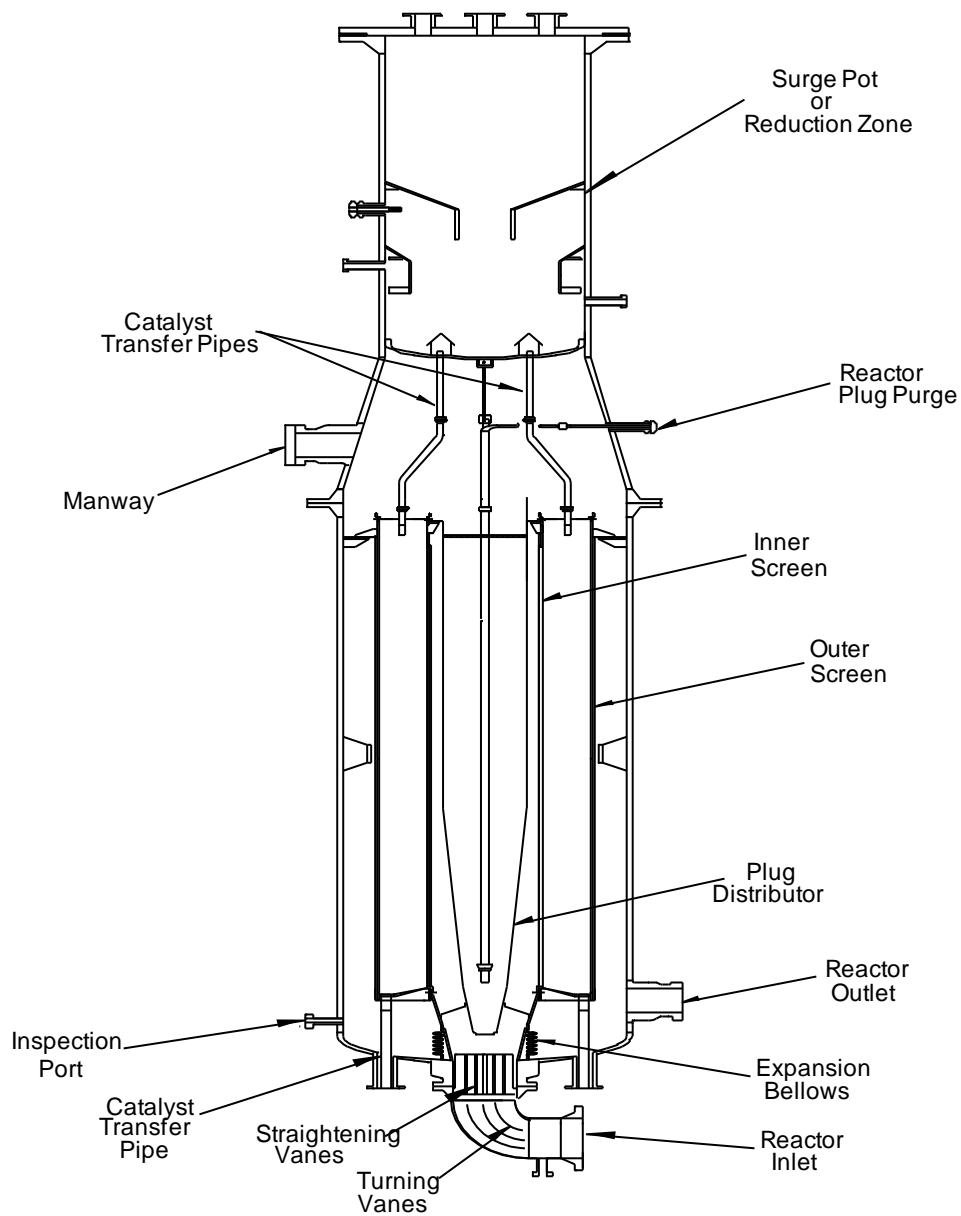


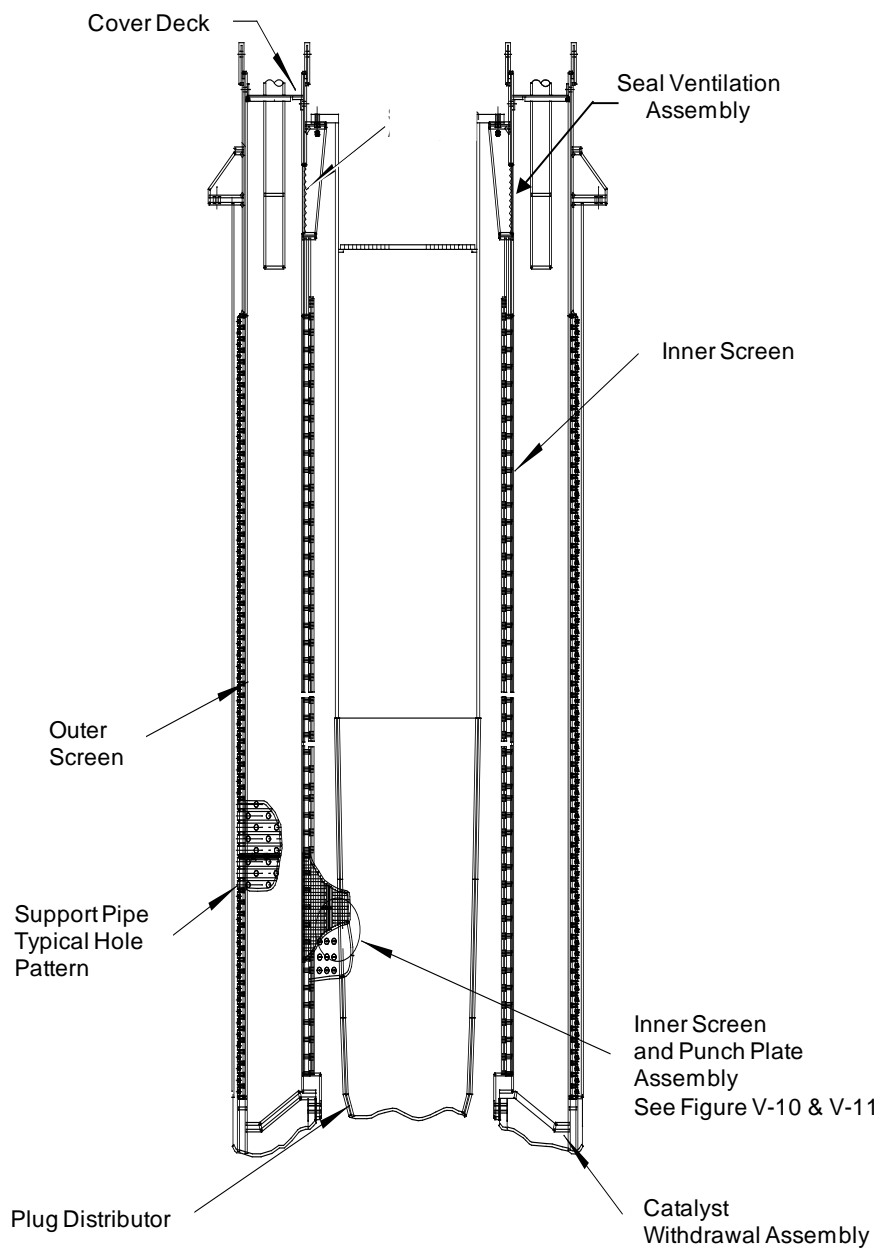
Figure IV-B4**Oleflex Reactor Screen Assembly**

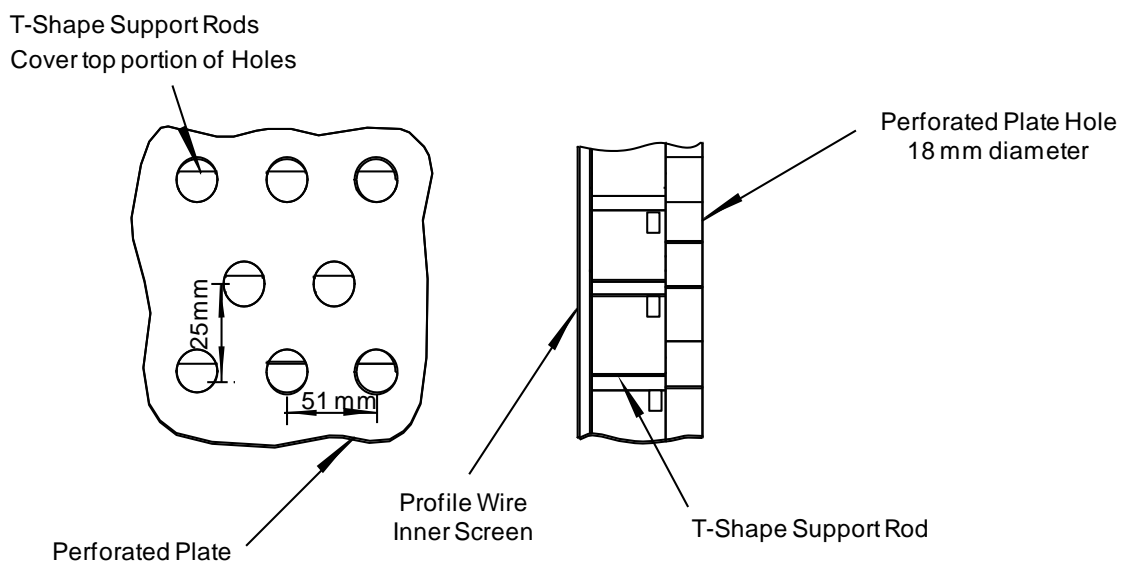
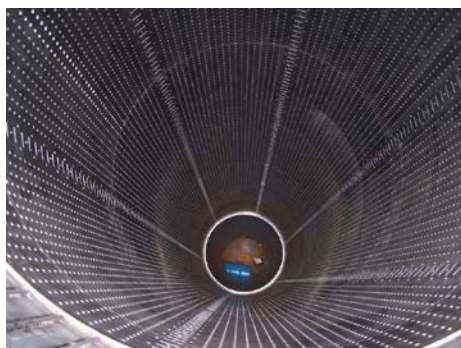
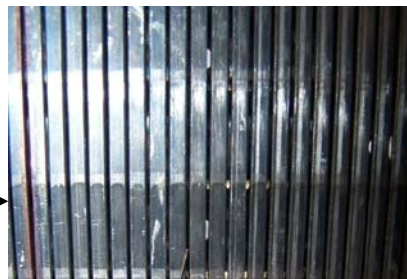
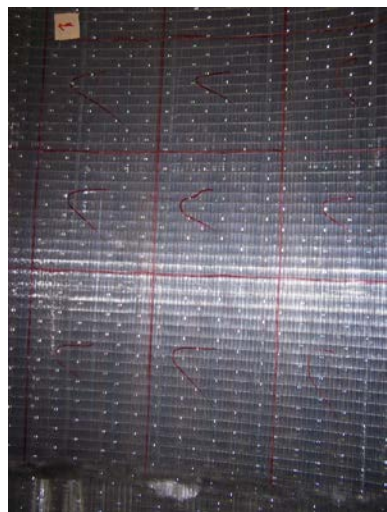
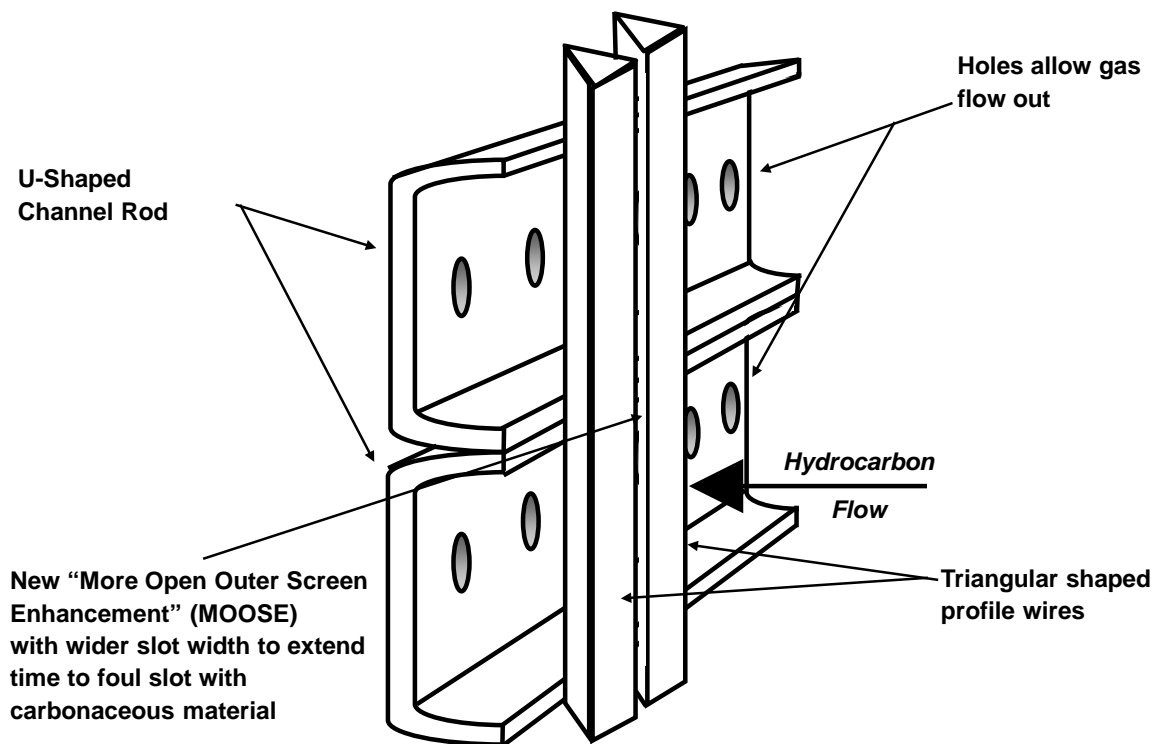
Figure IV-B5**Oleflex Reactor Inner Screen Details****MOUSE Inner Screen**

Figure IV-B6***Oleflex Reactor Inner Screen Details******MOUSE Inner Screen***

← ID view of the Inner Screen
Punch Plate is visible



→ OD view of the Inner Screen
Profile wire is visible
Support rods behind profile wire can be Seen

Figure IV-B7**Oleflex Reactor Outer Screen Details**

← ID view of the Outer Screen
Profile wire is visible
Perforated channel rod can be seen

OD view of the Outer Screen
Perforated channel rods are visible



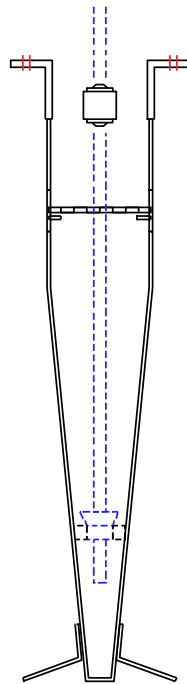
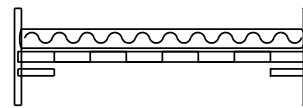
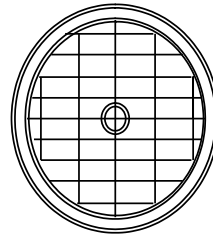
Figure IV-B8***Oleflex Reactor Plug Distributor Assembly*****PLUG****GRATING AND SCREEN
DETAIL**

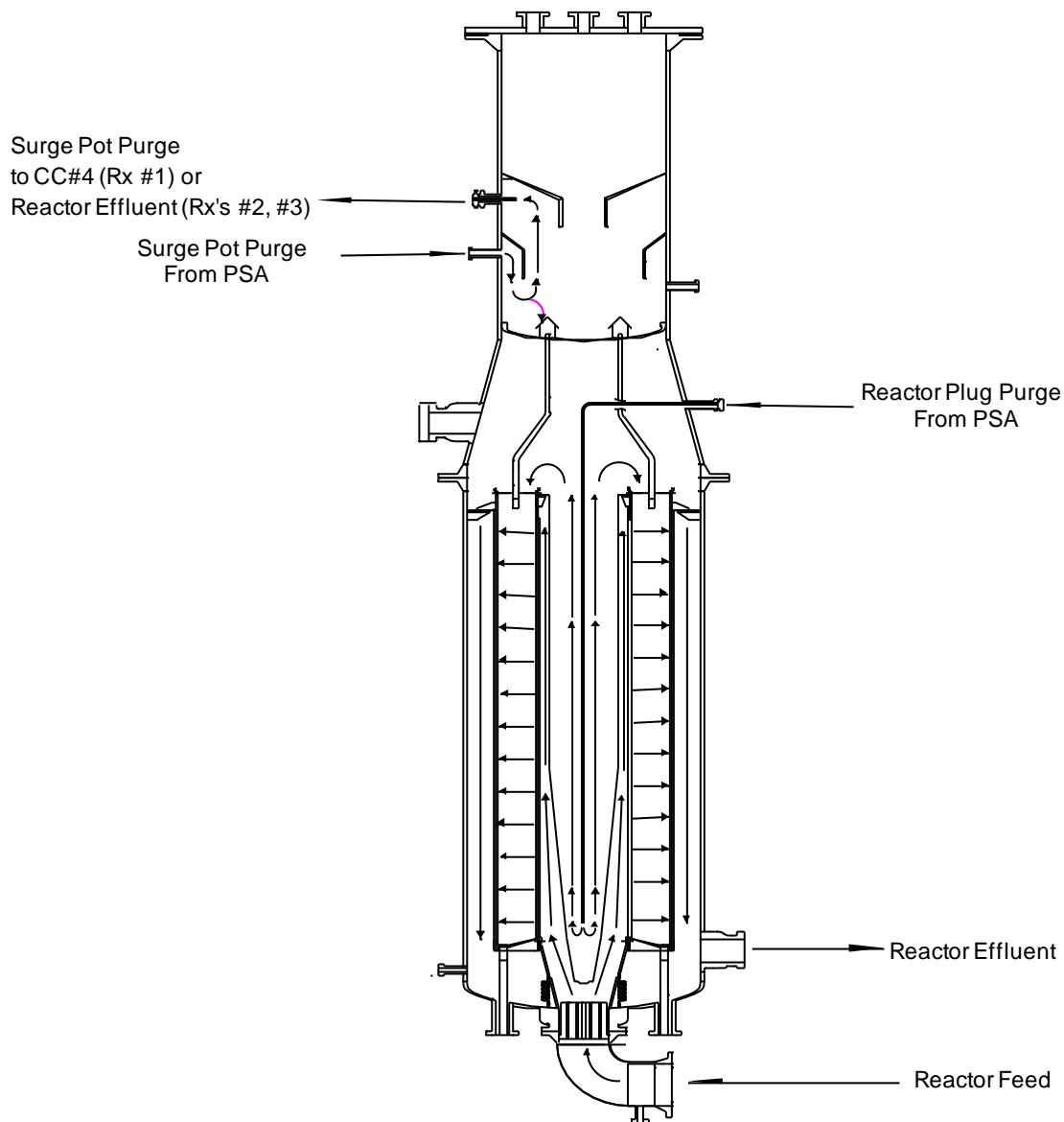
Figure IV-B9***Oleflex Reactor Purge Gas Line Hydrocarbon Flow***

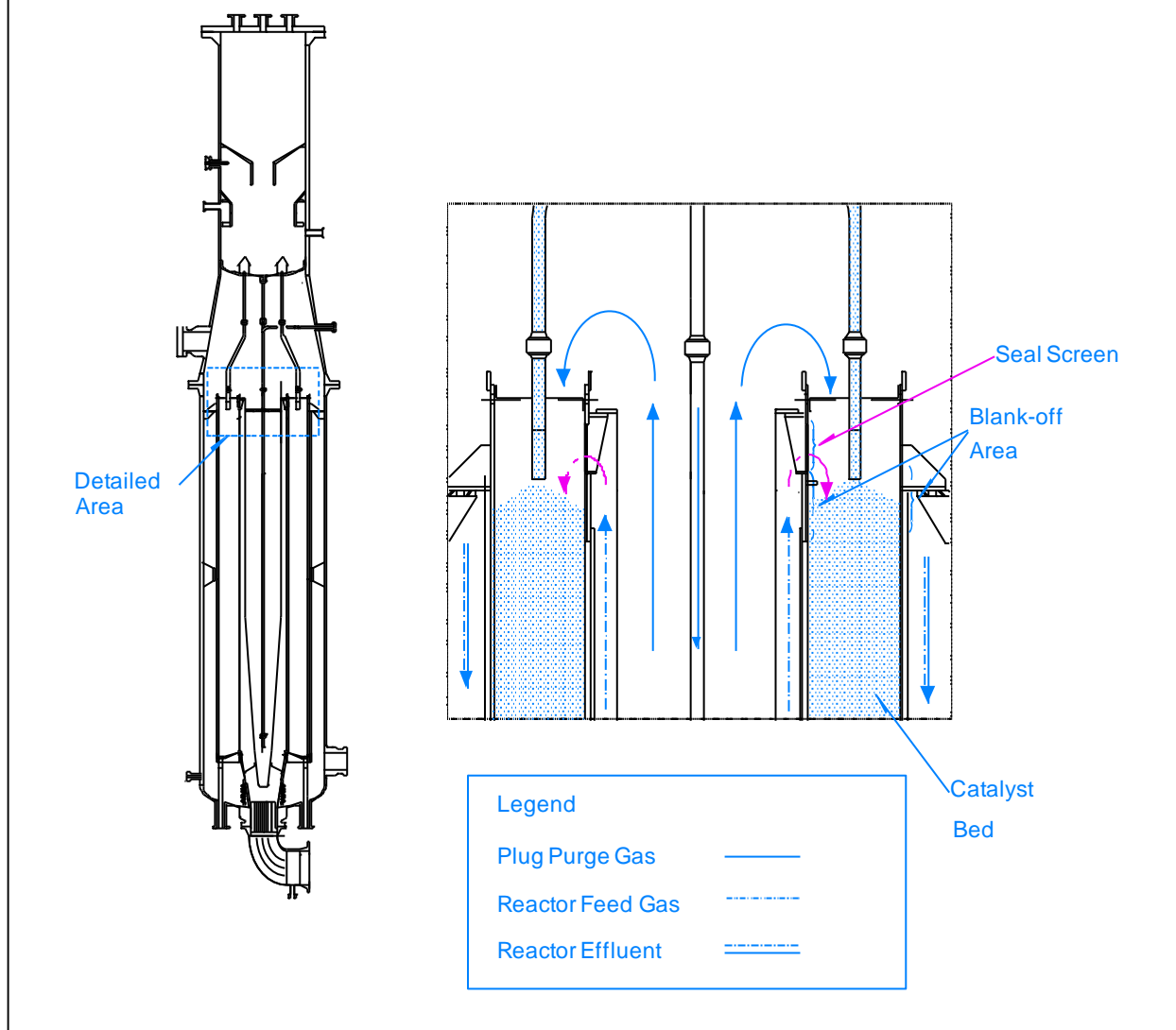
Figure IV-B10**Oleflex Reactor Seal Ventilation Area**

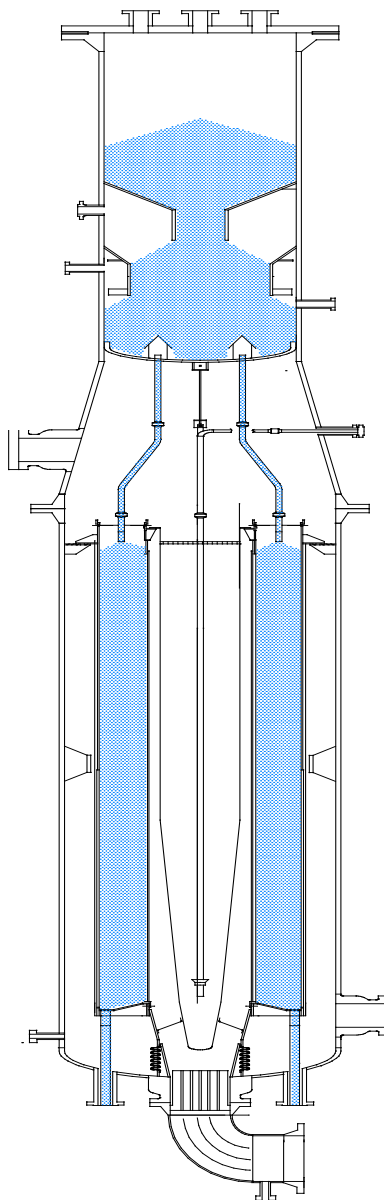
Figure IV-B11***Catalyst Flow Path through Oleflex Reactors***

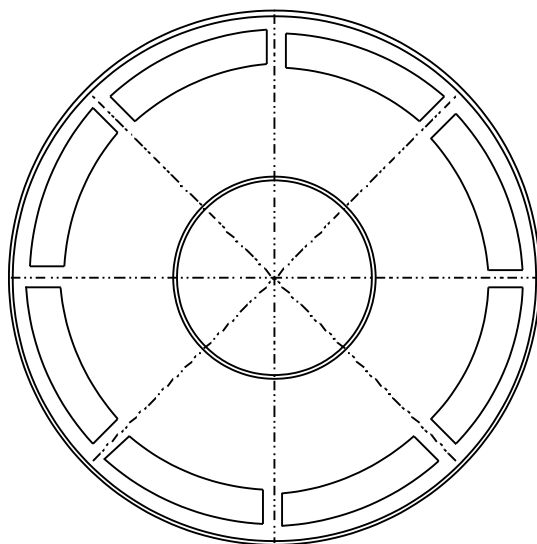
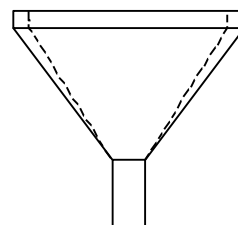
Figure IV-B12***Catalyst Withdrawal Assembly*****SUPPORT PLATE FOR SCOOPS****CATALYST WITHDRAWAL SCOOP**

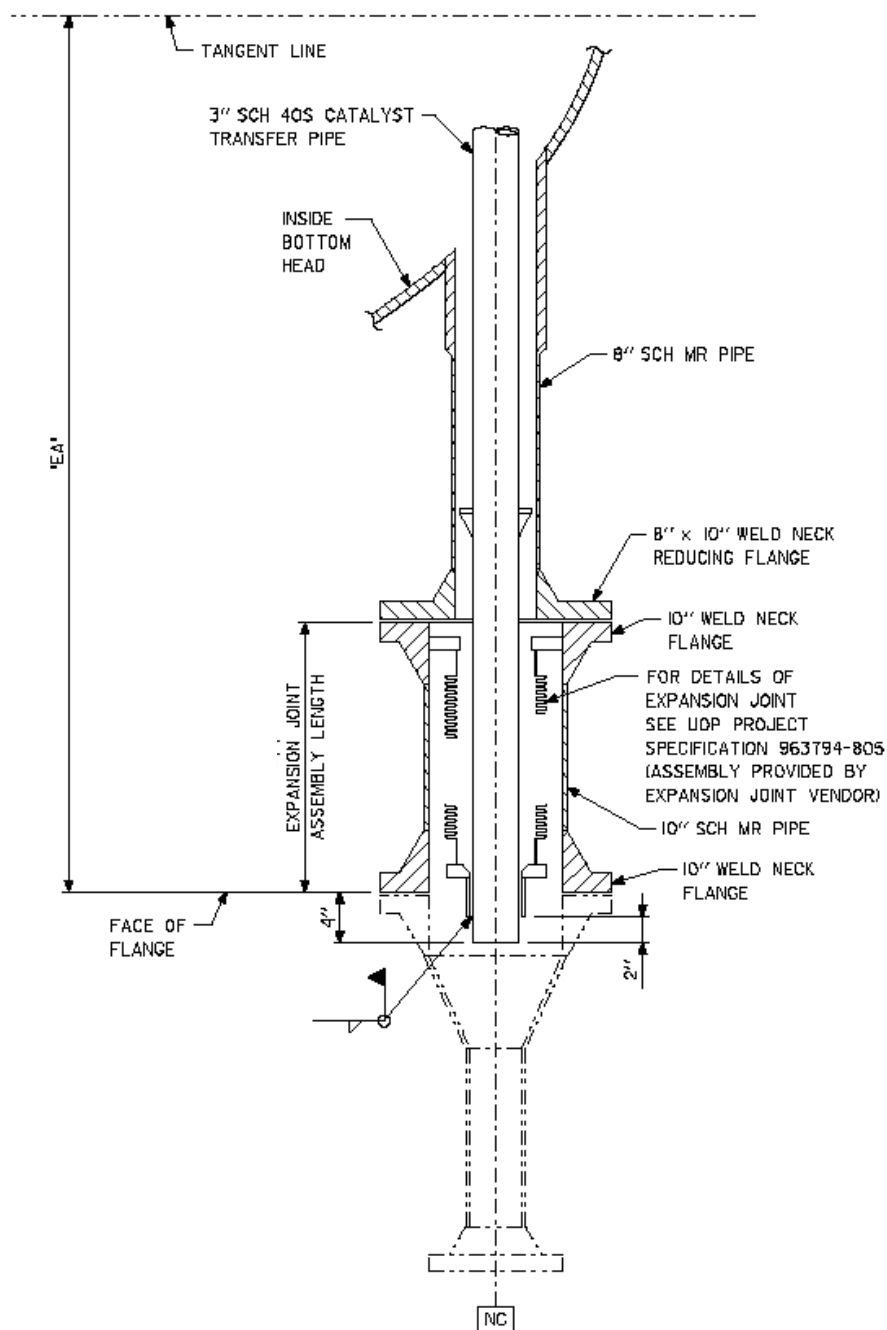
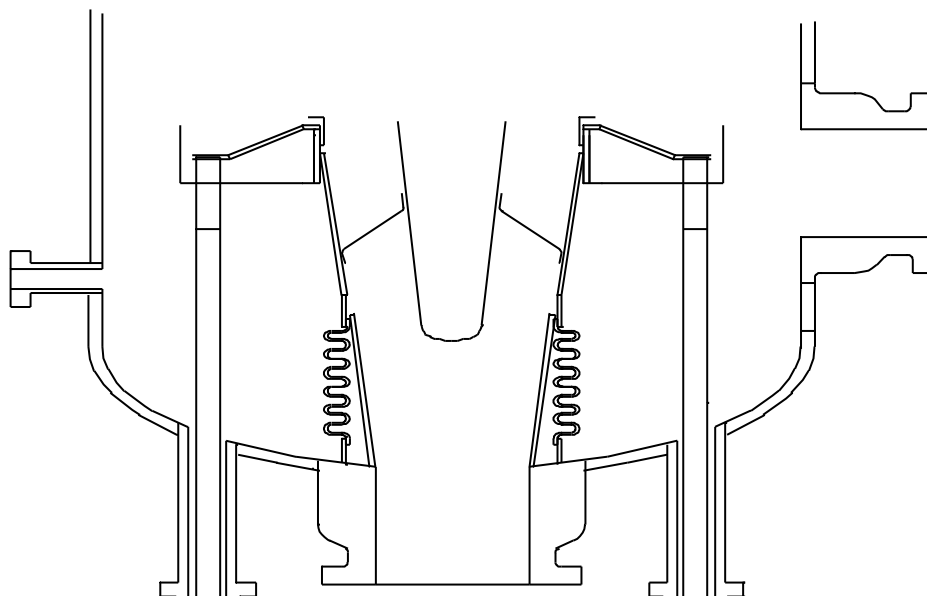
Figure IV-B13***Expansion Bellow on the Catalyst Transfer Line between the Reactor and the Catalyst Collector***

Figure IV-B14
Expansion Bellows



2. Hot Combined Feed Exchanger (HCFE)

The HCFE recovers the heat from the reactor effluent coming from the last reactor and impart it to the cold combined feed from the cold separation section. This reduces the heat duty on the charge heater and cooling duty of the reactor products.

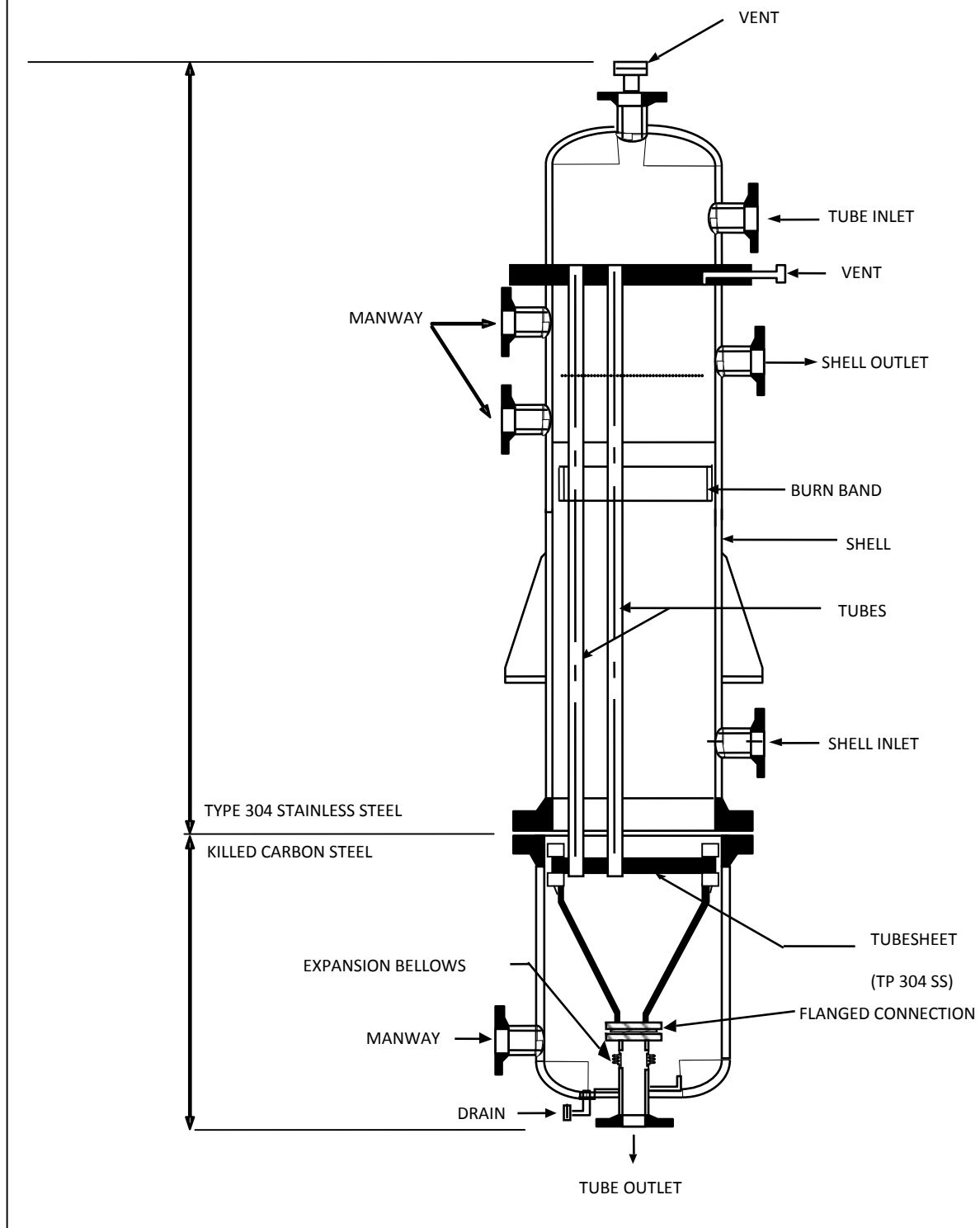
HCFE is a single pass shell and tube and shell heat exchanger. The top head, shell and tubes, the top and bottom tube sheets are constructed of Type 304 or 304H stainless steel with carbon content minimum 0.04 wt.%. The top head and tube sheet is “fixed” whereas the bottom tube sheet connected to a conical head cover is floating type design to provide for thermal expansion. The “floating” conical bottom head cover is connected to the outlet nozzle via an expansion bellow to facilitate thermal expansion of the tubes and tube sheet assembly. The bottom tube sheet and “floating” conical bottom head are encased in a shell cover (external head) that is attached to the shell. The shell cover and floating head are constructed of killed carbon steel material since the operating temperatures are lower in this section. Refer to Figure IV-B15 for details of construction.

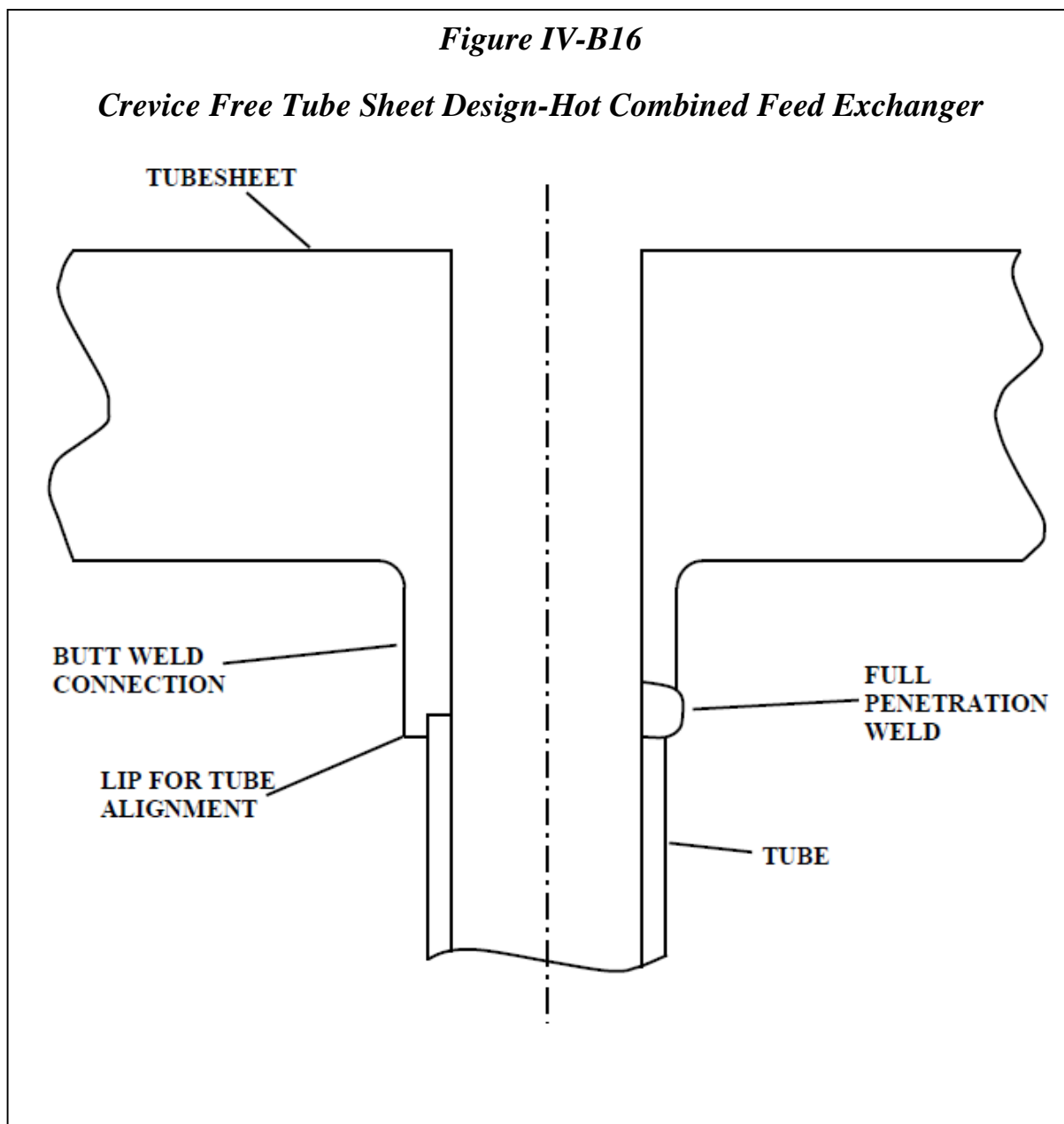
The top tube sheet is fabricated in special “crevice free” design where there is no gap between the tube and the tube sheet. The tubes are aligned with the butt which has a lip for seamless joint and welded at the rear side of the top tube sheet through full penetration weld. The “crevice free” design prevents coke induced mechanical problems at the hot end of the exchanger. Refer to Figure IV-B16 for details of crevice free construction.

Depending on unit specific designs, an Oleflex Unit can have one or more HCFEs. The designs that require multiple exchangers will have identical HCFEs installed in parallel. The reactor effluent distribution piping from the last reactor to the HCFEs and the downstream reactor effluent coolers; and the cooled reactor effluent collection piping from the coolers are required to be symmetrical to ensure equal flow distribution. If the flow distribution between the HCFEs is not even, the approach temperatures will not be identical even if the exchanger is clean.

About $1/3^{\text{rd}}$ of the required DMDS is injected at the inlet and $2/3^{\text{rd}}$ at the outlet of the HCFEs to achieve optimal metal passivation within the HCFE. There exists a temperature profile within the HCFE as the cold combined feed gets progressively heated as it traverses up the exchanger. At lower temperatures iron sulfide scale, which is fractious and unstable, is favored. Potential for iron sulfide scale is reduced by limiting the amount of DMDS injected at the inlet to $1/3^{\text{rd}}$ of the required amount. Injection at the inlet cannot be entirely eliminated due to the presence of contaminants in the combined feed which can cause coking on the shell side of the exchanger. The shell side of the HCFEs tend to foul with time on stream. The tube side of these exchangers do not tend to foul significantly. The HCFEs in parallel may or may not foul at the same rate and their approach temperatures may diverge over time.

Figure IV-B15
Typical Combined Feed Exchanger





3. DMDS Injection System (Figure IV-B17)

Sulfur is injected into the reactor feed to prevent excessive coke formation in the Oleflex reactor section. Without sulfur injection, metal catalyzed reactions will generate excessive coke in the reactor circuit which can plug the reactor inner screens resulting eventually in extended unit shutdown to clean the screens. For this reason, redundancy is built into the DMDS injection system by provision of three independent injection pumps, lines, flow indicators, and injection points.

For Oleflex, the only acceptable organic sulfur compound is dimethyl disulfide (DMDS). This compound has thermal decomposition properties and vapor pressure characteristics best aligned to Oleflex process requirements as explained in Section III process Variables.

DMDS is pumped from the drum at the desired injection rate, dispersed and vaporized with net gas and injected through the injection quills into combined feed. 1/3rd is injected at the inlet and 2/3rd is injected at the outlet of HCFEs. The net gas used for dispersion and vaporization of the liquid DMDS is injected into the liquid DMDS injection line and is adjusted by flow control. Net gas is injected into the line at a certain minimum distance from the injection quill on the combined feed line to ensure that the liquid DMDS has been fully vaporized before reaching the quill.

The DMDS injection rate is controlled by adjusting the pump stroke on the DMDS Injection Pumps. Liquid DMDS Three pumps shall be operating with each at one third the desired injection rate. The sight glass on the DMDS Injection Drum shall be calibrated and used to determine the volumetric flow for each operating injection pump. Flow meters on the DMDS injection lines will trigger a low flow alarm in case of pump failure, but are not intended to be used to precisely control the DMDS injection rate.

3.1 Sulfur Injection Drum

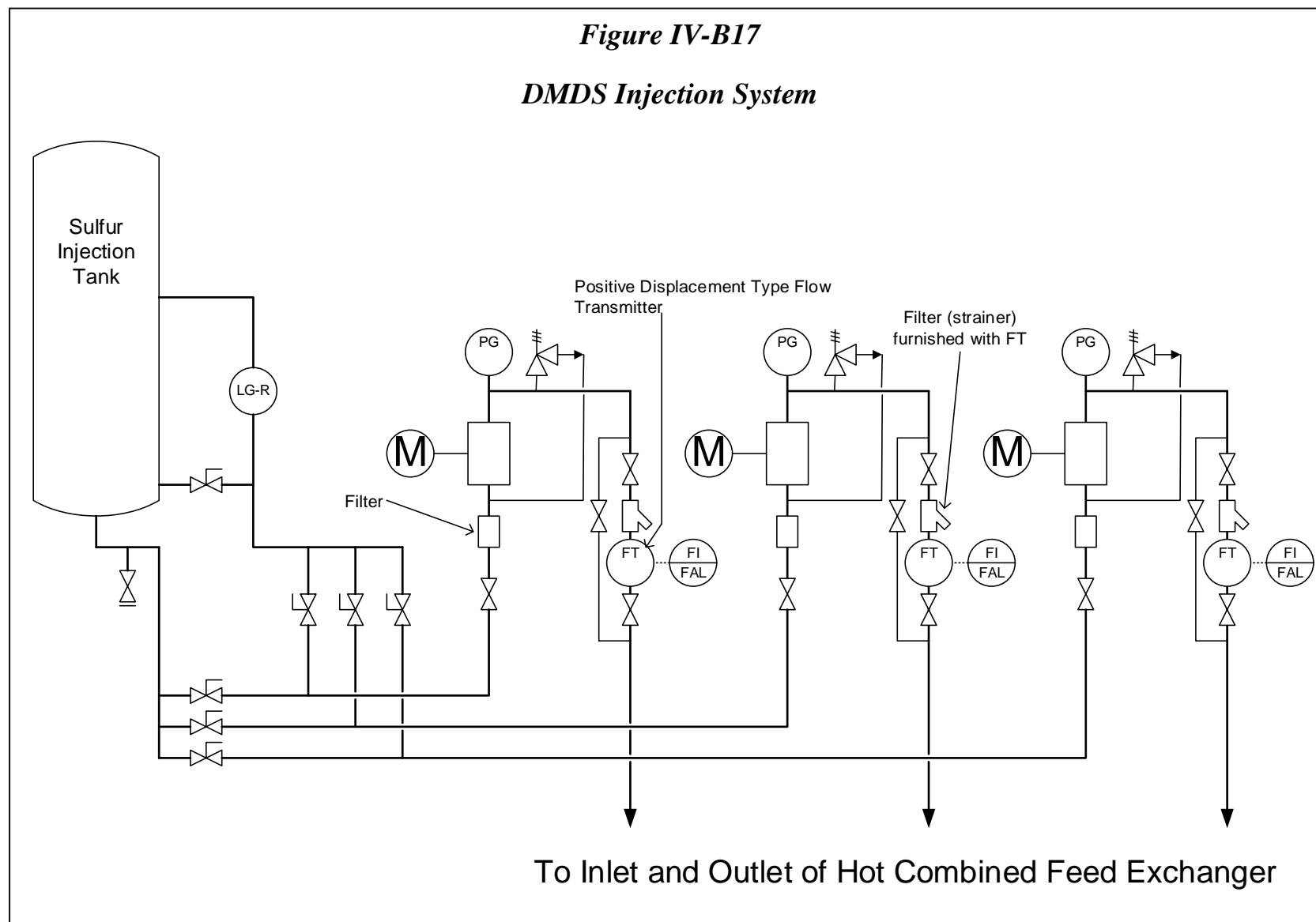
The sulfur injection drum, Figure IV-B17a, is constructed of carbon steel and floats on relief system pressure at ambient temperature. Nitrogen is used to blanket the drum contents.

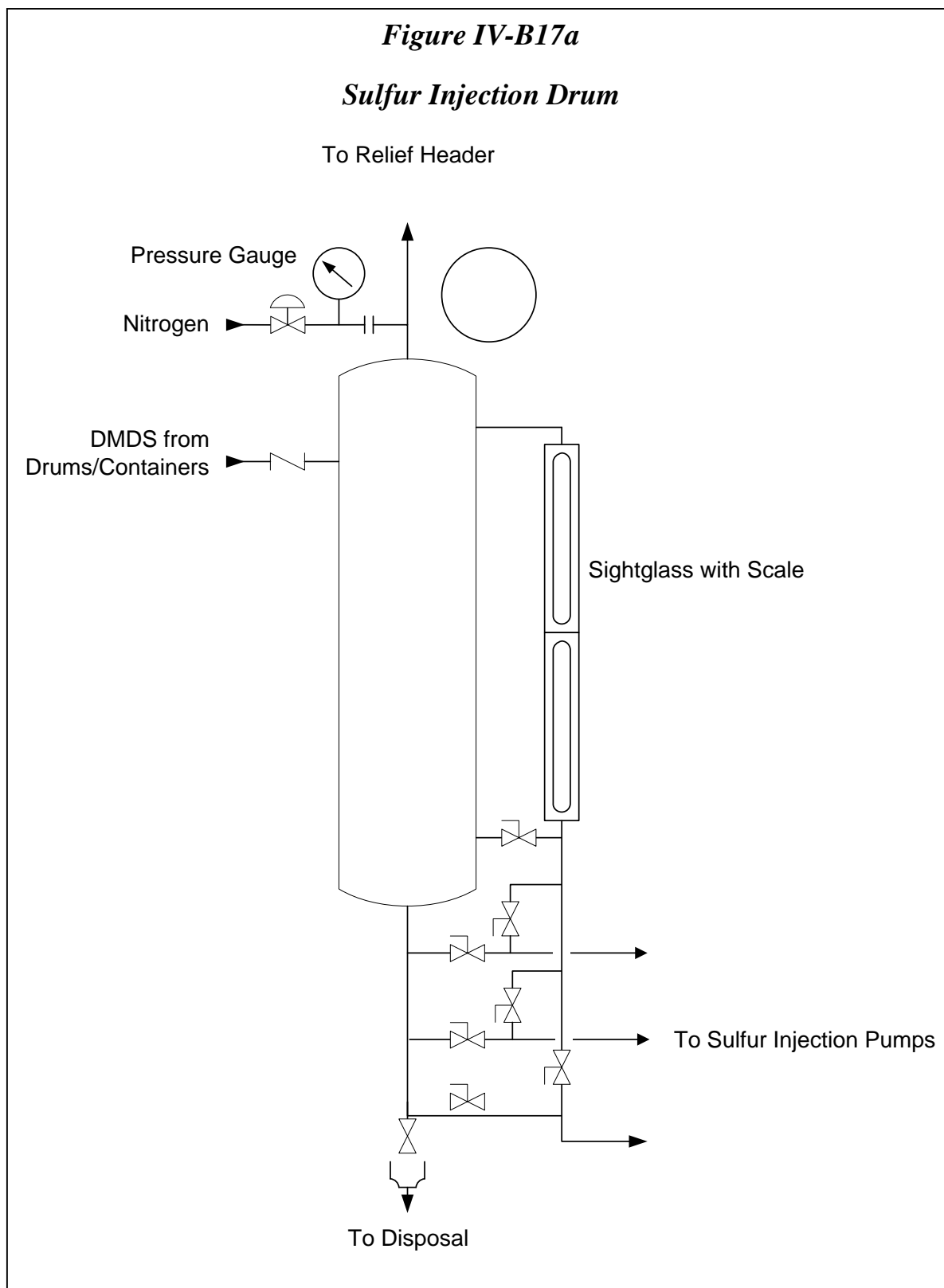
The piping arrangement allows the flow from each pump to be calibrated from the sight glass on the DMDS Injection Drum. During commissioning, the sight glass on the injection drum is calibrated to determine the volume per millimeter gradient on the sight glass. During start-up and routinely during normal operations, the flow from each pump is confirmed with the use of the calibrated sight glass.

3.2 Sulfur Injection Pumps

Each pump is connected to independent power system within the refinery power network and is designed to inject greater than 100% of the total required sulfur. The injection pump motor speed or stroke length or number of strokes is manually adjusted to achieve the desired injection rate.

Figure IV-B17
DMDS Injection System





4. Steam Generation System (Figure IV-B18)

The steam generation system utilizes waste heat from the convection sections of the charge and interheaters to generate high pressure steam for refinery use. Depending on design, all four heaters may share a common convection section or multiple convection sections may be provided. The convection design include typically 3 rows of bare, or shock, tubes as well as a number of rows of extended surface tubes, either studded or finned, of low chrome steels and carbon steel, depending on tube location and design.

Convection section tubes of the charge and inter-heaters can be functionally grouped into three types; economizer pass which is the top section, steam generation pass which is the middle section and steam super heating pass which is the bottom section.

Water circulation pumps circulate the hot water from the steam disengaging drum on flow control, through the steam generation pass, before returning it to the steam disengaging drum. In this pass, a portion of the circulating water will get vaporized. Liquid water and steam will get separated in the steam disengaging drum. Water vapors from the disengaging drum are then sent through the steam super heater pass where the steam is superheated. Balancing valves help control and distribute the steam between different convection sections to achieve approximately the same degree of superheat. The superheated steam from different convection sections is then combined and routed to the desuperheater where it is desuperheated to the required temperature by the boiler feed water. The steam is then sent to the high pressure steam header of the refinery.

As steam is generated and taken out of the system, water level in the disengaging drum will drop and fresh boiler feed water will have to be added continuously to make-up the level. The amount of make-up should equal the amount of steam generated plus any losses due to blow down. This make-up boiler feed water stream is passed through the economizer section to pre-heat the water. After getting pre-heated, it then combines with the circulating water and vapor mixture coming out from the steam generation pass. The combined stream is then routed to the steam disengaging drum where the water and vapor are separated. Water is recirculated back to the steam generation pass and steam is sent to the super heater pass as explained earlier.

Make-up boiler feed water will have dissolved solids which accumulate and concentrate over time in the circulating water. If the concentration of dissolved solids is not controlled, they will tend to scale the convection section tubes affecting the heat transfer efficiency. If carried over to steam, they impact the steam quality and may not be able to meet the stringent quality requirements for the steam used in the steam turbine drives. Continuous blowdown, wherein a small amount of water is continuously withdrawn from the steam disengaging drum, helps control the concentration of the dissolved solids in the circulating water stream.

Suspended solids tend to accumulate in the circulating water stream if not periodically removed from the system. These are generally corrosion products dislodged from the convection section tubes in addition to the suspended solids that may have entered the

system with the make-up boiler feed water. The suspended solids tend to settle as “sludge” at the bottom of the disengaging drum due to low velocity of water traversing across the drum.

There may be separate drums provided for continuous and intermittent blowdown or a single drum may be provided to for both functions.

4.1 Steam Disengaging Drum (Figure IV-B18a)

The primary function of the steam disengaging drum is to separate the steam and water contained in the feed to the drum efficiently. The drum also provides for adequate surge volume to account for the difference in steam generation and make-up water and adequate settling time for the suspended solids.

During operation, steam vapor and boiler water enter the steam disengaging drum through a distributor. The distributor is simply an extra strong short radius elbow of appropriate size. The distributor directs flow onto a horizontal baffle that is provided for even distribution and vapor-liquid disengagement. A vertical baffle provided prevents turbulence within the vessel.

The high pressure steam exiting the steam disengaging drum first passes through a steam separator. The purpose of the separator is to remove any water droplets entrained in the steam to assure a dry steam product. The separator is designed and supplied by the vendor, and can vary depending on the application. However, typically, it consists of a series of parallel baffles positioned vertically along the inner circumference of the separator. Steam entering the separator is forced into a spinning motion, thereby displacing any entrained liquid droplets by centrifugal action. The water is then returned to the steam drum through eject pipes, while the dry steam exits the separator.

A vortex breaker is provided on the circulating water outlet port to prevent gases from escaping with the liquid stream. Two pressure relief valves are provided on the steam disengaging drum as called for by ASME boiler code to prevent operation pressures in excess of the vessel design. The steam disengaging drum is made entirely of carbon steel.

4.2 Water Circulation Pumps

There are two centrifugal-type water circulation pumps provided. One pump is motor-driven while the other is steam-driven. During normal operations, one pump will be in operation and the other will be in the standby mode with both the suction and the discharge block valves open. Both pumps are designed for standby service and selection of the normal operating pump will depend on refinery needs.

The standby pump is automatically started by a low flow switch if the circulating water flow rate drops to a critically low level, most often associated with failure of the primary pump (see sub-Section 5.4 – Steam Generation Process Control).

4.3 Blowdown System

The steam generation system is equipped with a blowdown system which is used to control and remove the dissolved and suspended solids from the circulating water. Separate drums for continuous and intermittent blowdown may be provided or a single drum may serve both functions.

The continuous blowdown drum, shown in Figure IV-B18b, draws liquid water from the side of the disengaging drum at a location slightly below the steam-water interphase. A portion of the water drawn from the steam disengaging drum that operates at high pressure, flashes into steam downstream of the blowdown valve since the blowdown drum operates at low pressure. Flashed steam is recovered and sent to low pressure steam header. The liquid water containing concentrated dissolved solids is drawn out on level control. The internals of the continuous blowdown drum consist of a tee-shaped inlet distributor and a baffle around the top LC-LG port. The continuous blowdown drum is made entirely of carbon steel.

The intermittent blowdown drum typically has a tangential entry nozzles and wear plates to prevent erosion. Unlike continuous blowdown, intermittent blowdown is manual operation and blowdown rates can be relatively high during the short duration of blowdown. That is the reason for the provision of a wear plate. Tangential entry nozzle facilitates vapor-liquid separation by impingement and centrifugal action. In addition to the liquid from the continuous blowdown drum, liquid can also be drawn from the bottom of the disengaging drum to remove any sludge or solids buildup. Vent is to atmosphere in order to maximize cooling by the flash since the liquid is normally high in solids and sent to treatment facilities. The intermittent blowdown drum is made entirely of carbon steel.

Since the erosive nature of these streams is rather high, special valves are used to let down the liquid from the high pressure to the low pressure and atmospheric services. Continuous blowdown valves are coated with special hardened materials and allow for continuous use, where intermittent blowdown valves are not fabricated with special materials as they are intended only for on/off service.

4.4 Steam Generation System Process Control

The rate of boiler feed water to the steam generation system is controlled by signals from the steam production flow indicator and steam disengaging drum level. During normal operations, the amount of boiler feed-water directed to the system will be equal to the amount of steam generated. Any offset in this equilibrium will be reflected in the level in the steam disengaging drum and an appropriate signal will be sent to the make-up boiler feed water flow control valve to increase or decrease the rate accordingly.

The circulating water rate to each convection section is controlled by a flow control valve. The rate is preset and will remain constant unless the set point is changed. Generally, the circulating water rate is fixed according to operational requirements and is not changed during normal operations.

A flow element is provided on each circulating water stream which, in turn, is used to generate pressure drop for the three flow transmitters. If two of the three flow transmitters were to detect that the circulating water flow rate dropped below a predetermined value, the low-low flow switch would generate a signal to automatically start the standby pump and thereby sustain adequate flow through the circulating water circuit. If the low flow condition were to continue to exist, a signal would then be sent to shut down the heaters in order to protect the tubes in the convection section from mechanical damage.

The temperature of the high pressure steam to the refinery steam header is maintained by sending superheated steam through a desuperheater. A temperature controller regulates the flow of condensate that mixes with the superheated steam. The temperature of the high pressure steam at the outlet of the desuperheater is set to conform to the refinery steam system and this temperature will generally not be changed.

The blowdown valve is used to throttle the blowdown rate to the desired level. Generally, the continuous blowdown rate will be adjusted to avoid exceeding a specified maximum concentration of total solids, dissolved solids, suspended solids, silica and/or alkalinity. Some of the blown down water will flash to steam in the continuous blowdown drum and exits the drum to the refinery low pressure steam header. The remaining boiler water exits the drum, on level control, to the intermittent blowdown drum.

There are two intermittent blowdown draw-off points (located on opposite sides of the circulating water outlet port) with corresponding blowdown valves in addition to the stream from the continuous blowdown drum. The three streams are combined before entering the intermittent blowdown drum. Any boiler water that flashes to steam in the intermittent blowdown drum exits the drum to atmosphere. The remaining boiler water concentrated in dissolved and suspended solids exits the drum, on level control, to the drain. The intermittent blowdown schedule will depend on the solids content of the boiler feed water and will have to be established through laboratory analysis.

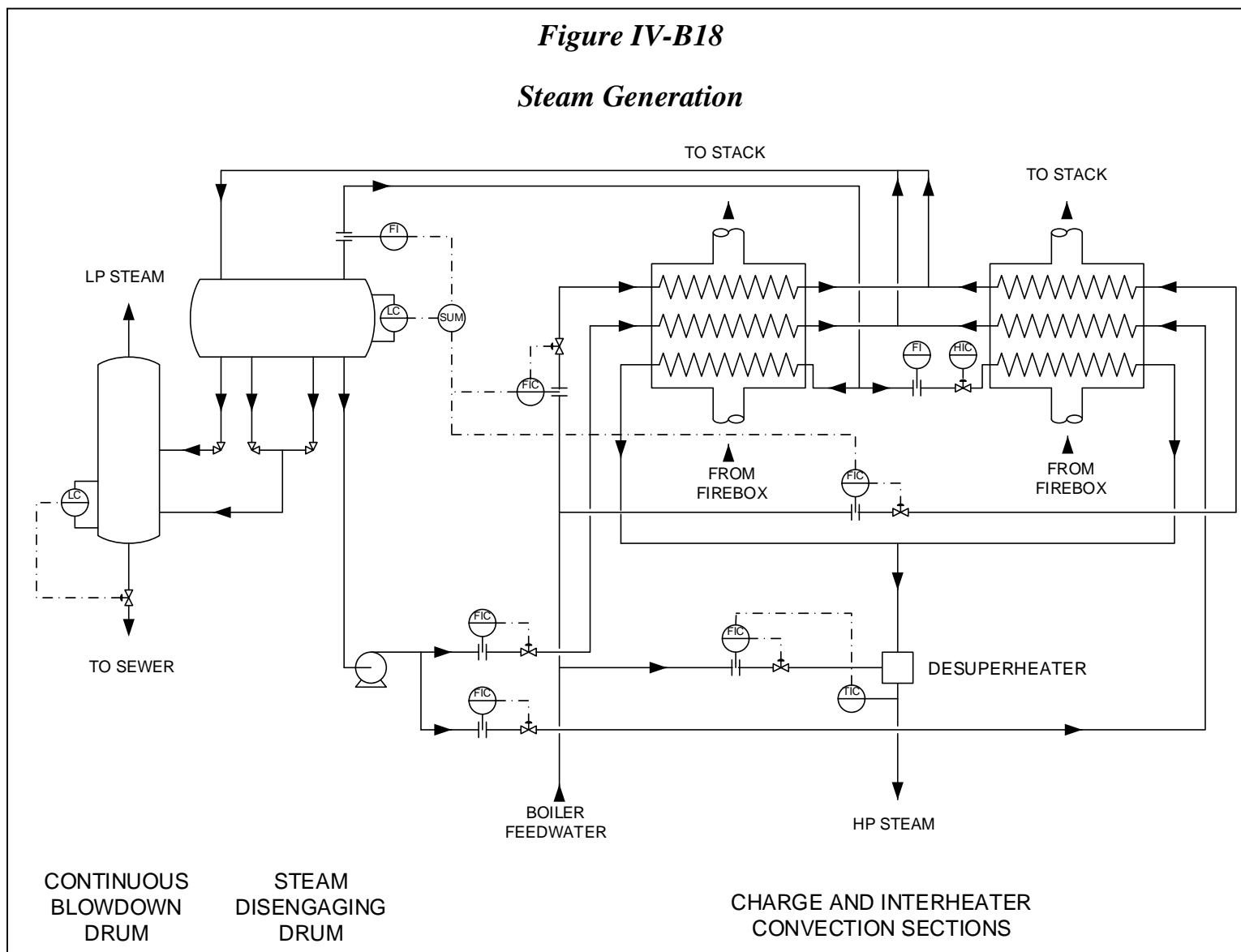


Figure IV-B18a
Steam Disengaging Drum

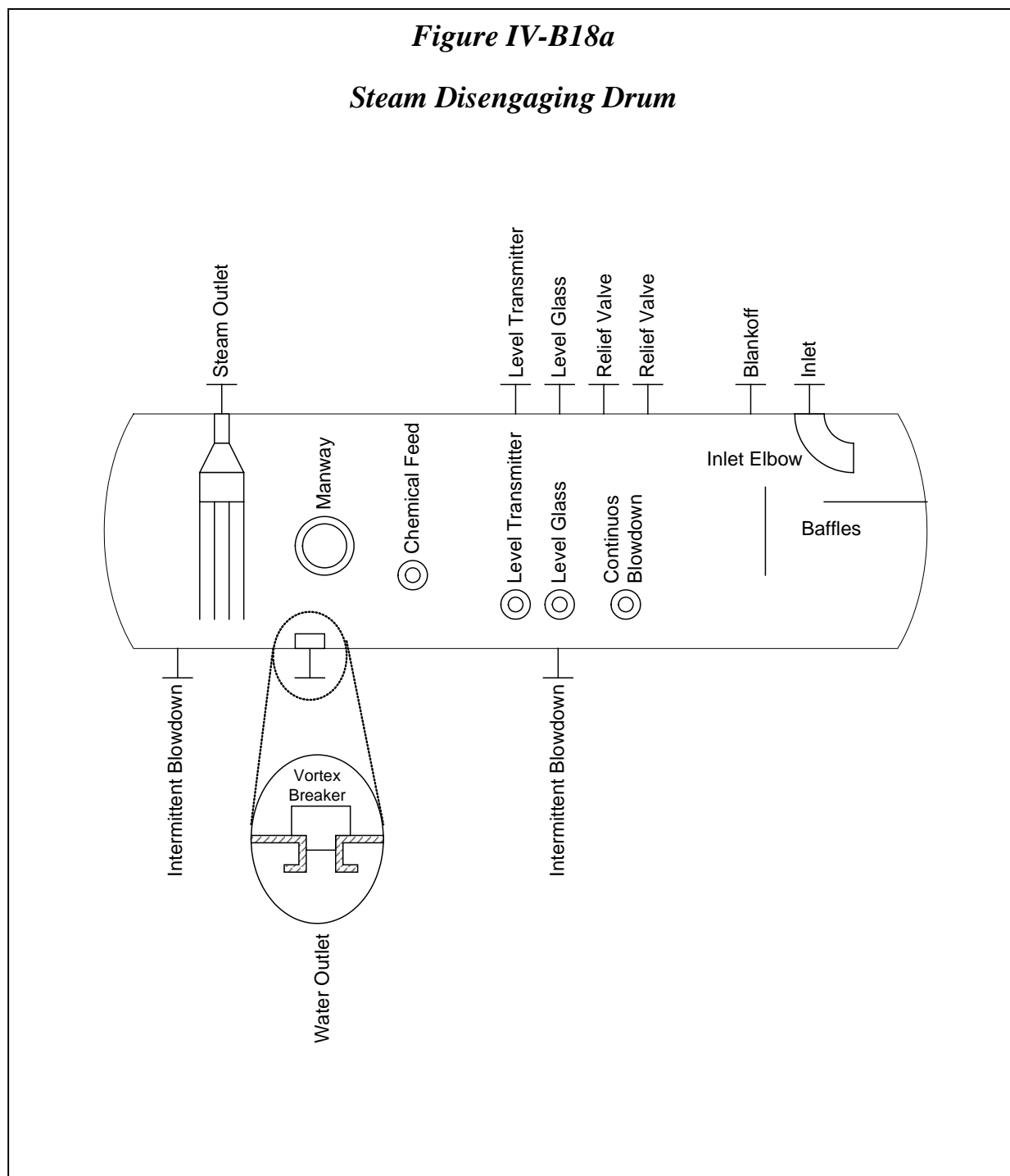
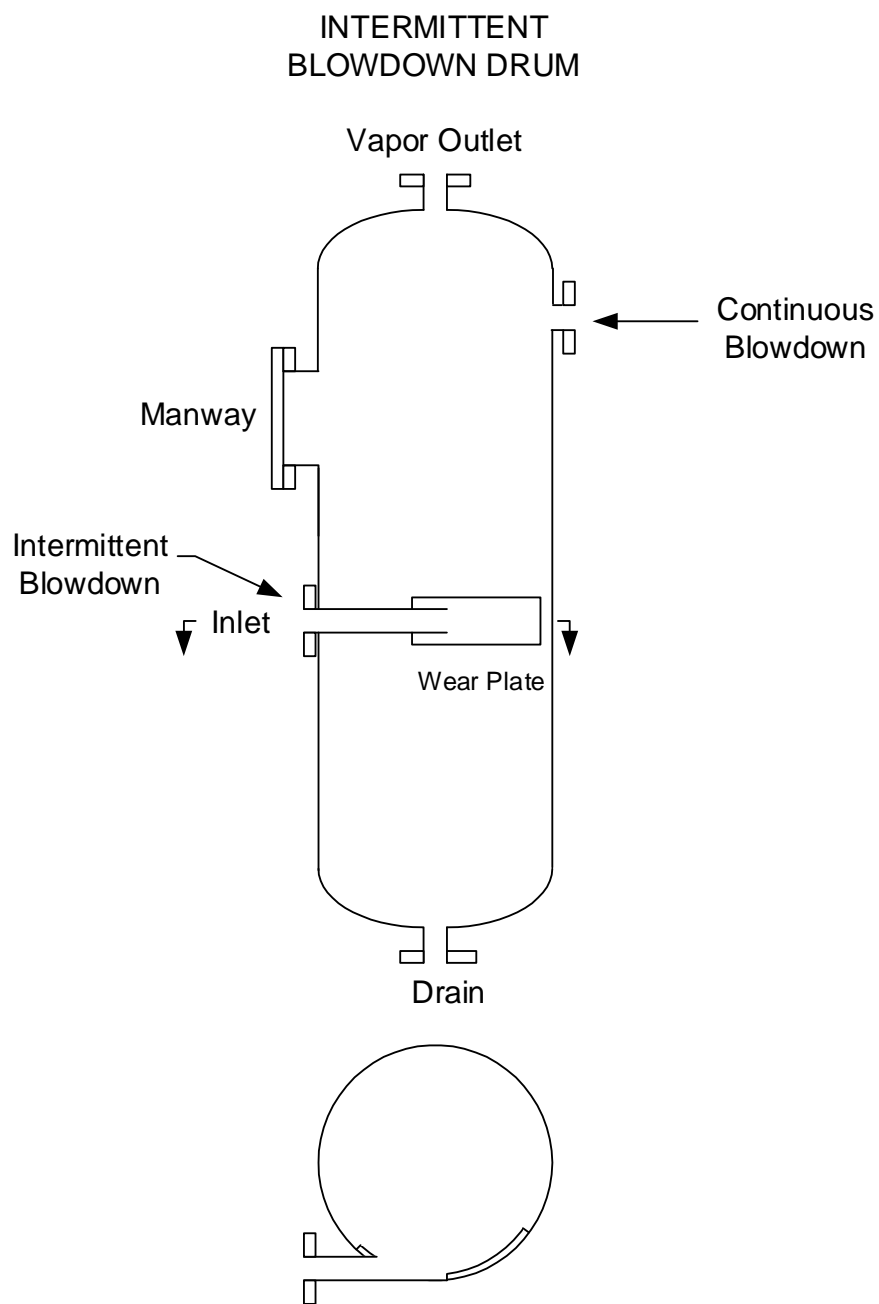


Figure IV-B18b

C. Reactor Effluent Cooling, Compression and Treating Section

This section discusses the Process Flow and Control and equipment contained within the circuit from the downstream of the HCFE leading to the cold separation system. For easy comprehension, this is divided into two circuits – first, reactor effluent cooling and compression circuit; and the second, reactor effluent treating circuit.

1. Reactor Effluent Cooling and Compressor Circuit

After the HCFEs, the reactor effluent is cooled further and flows to the suction of the Reactor Effluent Compressor (REC).

In the C3 Oleflex units with reactor effluent contact cooler, cooling is achieved by direct contact cooling with the circulating solvent. In these units, the contact cooler also acts as the suction drum for the REC stages. The cooled reactor effluent is then compressed in the REC sufficiently for efficient product recovery and to obtain the desired purity of the recycle hydrogen gas in the downstream cold separation system.

The reactor effluent is compressed by the REC in typically two stages – the axial first stage and the radial second stage. After the 1st stage compression, the gas is cooled in the interstage contact cooler before routing the gas to the 2nd stage. After the 2nd stage compression, the gas is cooled in the discharge cooler and trim cooler, if provided, after which it flows to the discharge knockout drum where any condensed liquids are separated out. The compressed reactor effluent vapors are then treated in the downstream treaters before sending them to the Cold Separation System for product recovery. This will be discussed later in the section.

Note that in some C3 Oleflex units, both the stages of the REC may be radial. In yet some other very large C3 Oleflex units, a three stage REC may be employed requiring an additional interstage cooler and associated knockout drum.

Interstage cooling increases the compressor efficiency and reduces the required power for compression.

Reactor effluent contact cooler and interstage contact cooler provide the necessary surge volume for the respective stage of the compressor. The discharge drum primarily acts as a knockout drum.

C3 Oleflex Units with Reactor Effluent Contact Cooler (Figures IV-C1a/b/c)

In the C3 Oleflex unit that has been specifically designed to operate at lower pressure (15.2 psia or 104.825 KPa A or 1.068 Kg/cm²a) at the outlet of the last reactor, it is necessary to limit the pressure drop further in the reactor effluent circuit leading to the REC. This is achieved by using reactor effluent contact cooler in place of an air cooled or water cooled exchanger. Contact cooler system can be designed either as a once through

system as shown in Figure IV-C1a or provided additionally with a spent solvent recovery system as shown in Figures IV-C1b/c.

The reactor effluent from HCFE flows to the downstream reactor effluent contact cooler where it is cooled in direct contact countercurrent cooling with the circulating solvent. Cooled reactor effluent vapors saturated with solvent exit the contact cooler and directly reach the REC.

In this process configuration, the pressure is controlled at the outlet of the last reactor by regulating the compressor speed. If the pressure drops below atmospheric during process transients, the low pressure limit controller overrides the speed controller to maintain the above atmospheric at the last reactor outlet preventing air leakage into the reactors.

Reactor Effluent Contact Cooler (Figures IV-C1a/b)

After the HCFEs, the hot reactor effluent vapors enter at the bottom of the reactor effluent contact cooler. The vapors are cooled by countercurrent contact with the circulating solvent to approximately 40°C (100°F) before entering the REC. This reduces the pressure drop when compared with either water cooled or air cooled exchangers upstream of the REC and allows for the reactors to be operated at slightly lower pressure, which results in higher propane conversion and propylene selectivity.

The circulating solvent is then pumped through a heat recovery exchanger if provided, followed by air or water cooled exchangers to remove the heat transferred from the reactor effluent before being recycled back to the contact cooler. The trace amount of PNA type heavies produced in the reactor section is removed by countercurrent absorption into the circulating solvent. Absorption of the heavies is favored by the use of a solvent that is rich in aromatics. A low vapor pressure solvent is favored to minimize the amount of saturation solvent that is carried forward with the reactor effluent through the compressor and the downstream equipment. Solvent used is typically an aromatic light cycle oil or light gas oil from a refinery. Refer to UOP Engineering Design Specifications for the solvent specified for the unit.

The contact cooler contains a section of disk and donut trays below a bed of structured packing. Cooled solvent is circulated to the top of the contact cooler on flow control. The solvent flows through a distributor, down through the packing where it continues to flow down through the disk and donut trays. The intimate countercurrent contact between the solvent and the reactor effluent removes the heavies from the reactor effluent by absorption into the circulating solvent. The vapors leaving the packed bed section, saturated with solvent, pass through the demister where any entrained liquids are removed and then flow to the REC where the vapors are compressed.

Part of the solvent contained in the reactor effluent vapors condenses out in the interstage and discharge coolers due to vapor compression followed by cooling and gets washed down to the respective downstream knockout drums, achieving in the process continuous cleaning of the exchangers. Washed down solvent from the knockout drums is recycled back to the contact cooler on level control by utilizing the system pressure.

Hot solvent leaving the bottom of the contact cooler is cooled in the heat recovery exchanger, if provided, followed by solvent circulation cooler. A slip stream of the spent solvent is continuously removed on flow control to regulate the concentration of heavies in the circulating solvent stream. Fresh “make-up” solvent is added to the contact cooler on bottom level control.

Spent solvent is removed to storage when the reactor effluent contact cooler is a once through system as shown in Figure IV-C1a. Concentration of the absorbed “heavies” in the spent solvent is relatively small at ~1 wt. %. In this system, the solvent fraction of the spent solvent slip stream and the solvent carried over with the reactor effluent downstream of the discharge cooler is not recovered. Therefore, solvent consumption will be relatively higher than the system with solvent recovery facility.

Solvent Recovery System (Figures IV-C1c)

Reactor effluent contact cooler system with the solvent recovery facility is shown in Figure IV-C1b and Figure IV-C1c. There will always be equilibrium solvent vapors carryover with the reactor effluent which is removed in the fractionation section at depropanizer bottoms stripper together with the light aromatics like benzene native to Oleflex. A portion of the depropanizer stripper bottoms stream is drawn out on flow-ratio control, combined with the spent solvent slip stream from the contact cooler, and sent as feed to the solvent recovery column. Remainder of the stream is rejected as “benzene drag” to provide an essential and necessary exit for the lighter aromatics like benzene preventing them from building up in the system.

The solvent recovery column operates at slightly above atmospheric pressure and the pressure is regulated by a self-actuated pressure regulator at the top of the column. There are three packed beds loaded with random packing in the column. The top bed acts as a condenser by direct contact cooling and condensing of the vapors. The middle and bottom packed beds perform rectification and stripping as in a normal fractionator.

Feed enters the column above the bottom packed bed. An external thermosiphon reboiler vaporizes the spent solvent. Condensate flow control regulates the heat input to the column. Vapors strip off the solvent leaving behind the heavies in the bottom bed. Any heavies carried over are washed down with the reflux liquids in the middle bed. The hot solvent vapors rise through the vapor riser and condense over the packings in the top bed by direct countercurrent contact with the solvent liquids. Latent heat of condensation is transferred to the liquids as sensible heat resulting in the increase in temperature of liquids. The hot liquids from the liquid collector tray are pumped out and a portion is returned as reflux on tray level control while the remainder is cooled to reject the heat of condensation. A portion of the cooled solvent is returned on flow control to the top bed and the remainder, which is the net recovered solvent, is drawn out on temperature control and recycled back to the contact cooler.

The amount and quality of net solvent recovery is set by the temperature controller that senses the temperature at the middle of the bottom packed bed. The amount of solvent recovery is limited by the temperature of the heating medium in the reboiler.

Net spent solvent, rich in PNA compounds that were produced in trace quantity in the Oleflex reactor section, is drawn out on level control from the bottom of the column which is then combined with the “benzene drag” and sent to storage via a cooler.

2. Reactor Effluent Treating Circuit (Figure IV-C2a)

The compressed reactor effluent from the REC discharge knockout drum then flows through the chloride treater in down flow where the chloride in the reactor effluent is removed over the non-regenerable adsorbent bed. The reactor effluent then passes through the reactor effluent drier (RED) where the water and H₂S contaminants are removed over the regenerable adsorbent bed. Moisture and H₂S detector probes and analyzers mounted on the drier outlet line help continuously monitor and detect any breakthrough of H₂S and water.

In the C3 Oleflex units designed with the reactor effluent contact cooler that operate at slightly lower pressure (15.2 psia or 104.825 KPa A or 1.068 Kg/cm²a) at the last reactor outlet, the section between the HCFE and REC operates at slightly below atmospheric pressure. For these units, an oxygen detector probe and analyzer assembly is provided at the outlet of the RED in addition to the H₂S and moisture analyzers to identify and fix any air leaks into the system.

The treated reactor effluent then flows through the reactor effluent filters, which has coalescing type filter elements, to remove any particulate and liquids. Clean, treated and compressed reactor effluent is then sent to the cold separation system for product recovery which will be discussed in that section.

Reactor Effluent Drier (RED) Regeneration Circuit (Figures IV-C2 b/c)

The reactor effluent drier system is provided to operate either in two driers configuration (Figure IV-C2b) or three driers configuration (Figure IV-C2c) depending on the amount of regenerant available. However, the regeneration system and equipment and basic principles of regeneration remain the same for both the configurations.

The reactor effluent driers are sequentially regenerated online with a suitable regenerant. The regenerant is typically hydrogen rich net gas stream from the Cold Separation Section. In addition to net gas, tail gas from the hydrogen purification system and/or deethanizer off gas may be used as supplementary regenerants.

At any given time, only one RED will be in adsorption cycle while the other RED(s) will be in various steps of regeneration. The purpose of the regeneration is to remove the water and H₂S adsorbed during the adsorption cycle and prepare the drier for the next cycle of adsorption. Some amount of heavies and solvent compounds which may have been

adsorbed will also be removed during the regeneration. RED regeneration involves several steps which are explained in detail in Section XII– Special Procedures. Regenerant is heated in the regenerant heater to ~230 Deg C (450 Deg F) on temperature control and contacts the adsorbent in up flow. A shell & tube steam heater or an electric heater or a combination of both may serve as heater. If steam heater is used, temperature is controlled by regulating the condensate flow. In case of an electric heater, temperature is controlled by regulating the power to the electric heater bundle elements. The regenerant effluent from the drier is cooled in the regenerant cooler and flows to the regenerant knockout drum. Any liquids collected in the regenerant knockout drum are removed on level control. Regenerant effluent from the regenerant knockout drum is then routed to the downstream treatment system. The regeneration system pressure will be floating on the back pressure of the downstream system depending on where the treated regenerant effluent is routed. Treated effluent may be routed to the net gas compression system or the refinery fuel gas system.

After the heating step, the drier is cooled and readied to be placed on line. The RED that has been regenerated is placed online while the other RED is taken off line for regeneration.

Regenerant Gas Scrubber System (Figure IV-C2 a)

The regenerant effluent stream which carries H₂S that has been removed from the RED during regeneration will need to be treated to remove the H₂S before it can be used elsewhere in the unit. When specified by UOP, it will be typically a caustic scrubber system. The UOP system is described below.

The regenerant effluent is routed to the regenerant gas scrubber which consists of two packed beds. The top bed operates with circulating wash water and the bottom bed operates with circulating caustic. A liquid collector tray with vapor riser and draw off well is provided between the two beds to collect and withdraw the wash water from the top packed bed while permitting the vapors from the bottom packed bed to pass through. An inventory of caustic is maintained at the bottom of the scrubber which is continuously circulated by the caustic circulation pumps. A portion is sent through the distributor to the bottom packed bed on manual flow control. The other portion is sent on manual flow control to the swaged section to keep the wall wetted by spraying caustic through the spray nozzles provided on the ring distributor. Wetting the wall protects against corrosion due to H₂S in the wet environment. Water is circulated through top bed on manual flow control by the wash water circulation pumps. Since the inlet regenerant vapors are dry while the outlet is water saturated, there will be a continuous loss of water from the system requiring make-up. Loss of water shows as drop in level on the liquid collector tray over time. Make-up water is clean condensate which is injected by the water injection pumps to maintain tray level. Water injection rate is adjusted manually. A water break tank blanketed with nitrogen on push-pull control is provided to receive clean condensate on level control.

The regenerant effluent vapors enter the scrubber at the bottom through a gas distributor constructed from Monel where the gas is bubbled through the caustic. The scrubber is initially inventoried with 10 wt. % caustic. H_2S reacts with caustic to form initially disodium sulfide (Na_2S) and water. Once all the caustic has stoichiometrically reacted out to form Na_2S , it is considered 50% spent. H_2S further reacts with Na_2S to form sodium hydrogen sulfide (NaHS). NaHS cannot react further with H_2S . Majority of the H_2S is expected to be removed while bubbling through the caustic at the bottom of the scrubber. H_2S that may have slipped through is removed in the bottom packed section with circulating caustic. Any caustic entrained with the vapors and carried through the vapor riser to the top packed section is removed contacting with water. Regenerant effluent vapors essentially free of H_2S exit from the scrubber and are sent to the downstream system.

The circulating caustic is analyzed after every RED regeneration. When the caustic is 60% spent, it is dumped from the scrubber. It passes through a degassing drum where any dissolved gaseous hydrogen and hydrocarbon is removed by splashing over the trays. The released gases are sent to the relief header. Spent caustic is then sent to the unit's effluent treatment system.

3. Reactor Effluent Compressor

Typically the REC has an axial first stage and a centrifugal second stage. In some units, both stages may be centrifugal. In yet some other large units there may be three stages of compression. The axial stage has multiple rows of rotor and stator blades. The centrifugal stage will have several impellers. The casing is fabricated from carbon steel but the rotors are fabricated in stainless steel or a suitable alloy. The driver can be a steam turbine, gas turbine or an electric motor.

Dry Gas Seals that are provided at drive and non-drive end of each stage. Pressurized Dual Seals are specified in UOP Engineering Design Specifications. Clean and dry process gas from a reliable source is used as seal gas. Nitrogen is not to be used as primary seal gas as it can leak into the process contaminating the reactor effluent. Nitrogen can be used as buffer gas or separation gas. Seal gas filters remove any particulate from the supply seal gas. The Dry Gas Seal system is engineered and specified by the vendor.

Each stage of the REC will have an antisurge control system provided by the vendor to protect the compressor from mechanical damage in the event of a surge. The inputs to such a system include but are not limited to temperature, pressure and flow to each stage of the compressor.

4. REC Suction, Interstage and Discharge Drum

In the C3 Oleflex units with reactor effluent contact cooler and interstage contact cooler, a separate REC suction drum and interstage drum is not required since the upstream contact cooler itself provides adequate surge volume for each stage.

The REC discharge drum is fabricated from killed carbon steel. Vapors enter the vessel through the inlet nozzle and impinge on the impingement plate of the inlet distributor, distribute laterally and move up through the vessel. The impingement and distribution action helps knock out any liquid droplets. The vapors then pass through the demister pad, 150 mm thick in Alloy 400 construction, located at the top where any entrained liquid droplets are removed before the vapors exit the vessel. A vortex breaker is provided on the liquid outlet nozzle at the bottom. Adequate nozzles are provided for level instruments.

5. Reactor Effluent Discharge Coolers

REC discharge cooler can be air cooled exchangers with a single pass or two passes on the process (tube) side or water cooled shell & tube type exchangers with single pass on process (tube) side. With water cooled exchangers, process gas is specified on tube side for ease of cleaning. The trim cooler, when provided, is usually a shell & tube exchanger with single pass on tube side for ease of cleaning. Both air cooled and water cooled exchangers are fabricated in killed carbon steel construction.

In the air cooled exchangers cooling is effected typically using forced draft fans. The channel heads at the hot end and cold end of the exchanger and the tubes are fabricated in carbon steel construction. Each air cooled exchanger consists of multiple tube bundles arranged in parallel. Finned tubes with closely spaced circular fins are generally used to enhance the heat transfer surface. Fins are typically constructed in light material with good thermal conductivity such as aluminum for efficient cooling and to limit the overall weight of the equipment.

6. Reactor Effluent Contact Cooler (Figure IV-C3)

This vessel is fabricated out of killed carbon steel. The vessel has one bed of random packings supported on a bed support plate. The packings are held down by the bed limiter. A feed inlet liquid distributor tray is provided to redistribute the cooled recirculating solvent returning to the column. A 150 mm thick mist eliminator blanket in Alloy 400 construction is provided at the top to trap and drain back any entrained liquids. Trays # 1, 3 and 5 counted from bottom are donut type whereas trays # 2 and 4 are disc type. The vessel has adequate manway provision to insert the column internals and perform maintenance jobs during shutdown. A vortex breaker is provided on the circulating solvent outlet nozzle at the bottom. Vapor inlet nozzle has impingement plate inlet distributor to distribute the vapors laterally before they move up the column. Adequate nozzles are provided for level instruments.

7. Solvent Recovery Column (Figure IV-C4)

This vessel is fabricated from killed carbon steel. It has three packed bed sections with random packing. Each bed has bed support plate, bed limiter and feed distributor. The liquid collector tray located below the top bed has a vapor riser and liquid draw off well. A vortex breaker is provided on the liquid outlet nozzle at the bottom.

8. Chloride Treater (Figure IV-C5)

Chloride Treater is fabricated from killed carbon steel. It has an inlet distributor at the top to distribute the feed vapors and an outlet support screen at the bottom that retains the ceramic balls and adsorbent material but permits vapors to pass through. Adequate freeboard space is provided at the top between the distributor and the bed to allow for redistribution of vapors across the bed. A floating screen in stainless steel construction is provided underneath the top 19mm ceramic ball layer to prevent sinking of inert ceramic balls into the adsorbent material. Top 19 mm ceramic balls help to hold down the adsorbent material. Adsorbent is normally loaded from the top and consists of a single bed. Layers of 3 mm, 6 mm and 19 mm ceramic balls at the bottom help prevent migration of the adsorbent material out through the bottom support screen. A manway is provided near the bottom of the shell to enable loading the bottom inert ceramic balls and unloading of adsorbents. A bypass line has been provided to enable change out of the adsorbent online.

9. Reactor Effluent Driers (Figure IV-C6)

Reactor Effluent Driers can be of either the two or three bed design, and are fabricated from killed carbon steel. The vessel has an inlet feed distributor to distribute the incoming vapor feed. Adequate freeboard space is provided at the top between the distributor and the bed below to allow for redistribution of vapors across the bed. A floating screen in stainless steel construction is provided underneath the top 19mm ceramic ball layer to prevent sinking of inert ceramic balls into the adsorbent material. Top 19 mm ceramic balls help to hold down the adsorbent material. There are two beds of adsorbents one for each type. Layers of 3 mm, 6 mm and 19 mm ceramic balls at the bottom help prevent migration of the adsorbent material out through the bottom support screen. Unlike the chloride treater, the bed support is a profile wire screen. The profile wire screen is fabricated in stainless steel in a number of screen panels secured by bolting. The assembly is adequately supported on beams. This design eliminates the need to fill the bottom head with inert ceramic balls to retain the adsorbent material. Further, by limiting the total mass in the vessel it reduces the bed heating and cooling time and saves associated utilities. The vessel operates in vapor phase down flow during adsorption.

10. Regenerant Gas Scrubber (Figure IV-C7)

This vessel is constructed from killed carbon steel. Due to caustic environment the vessel is post weld heat treated. The bottom distributor is in Monel construction due to the corrosive environment. Carbon raschig rings are used in both the packed sections. Each packed section is provided with bed support, bed limiter and liquid distributor. The liquid collector tray has a vapor riser and draw off well. The manways are provided as necessary for inserting the internals.

11. Reactor Effluent Filters

The purpose of these filters is to remove any solid particulate that might have been carried with the compressed reactor effluent from the upstream reactor effluent driers and to coalesce and remove any entrained liquids in the reactor effluent.

When the driers are loaded with fresh adsorbent, the adsorbent may have some dust from manufacturing. The dust particulate in reactor effluent is therefore expected only when the freshly loaded drier is taken in service. During normal operations dust or particulate is not expected in the reactor effluent in any significant amount. Entrained solvent liquids similarly are not expected during normal operation as these are expected to be trapped in the upstream reactor effluent driers that are regularly regenerated. The reactor effluent filters trap any minor amounts of particulate or liquid droplets that are carried forward.

Typically two filters each with multiple coalescing cartridge type elements housed in a casing are provided. The reactor effluent enters the filters elements from outside, through the cartridges and escapes through the hollow inside cylindrical space. Construction is in killed carbon steel. A differential pressure instrument provided across the filter helps monitor the pressure drop across the filter. If the operating pressure drop increases over time, it indicates fouling of the filter elements. When the pressure drop across the filter exceeds the value recommended by the vendor, the filter elements need to be replaced which can be done online by taking the filter off service.

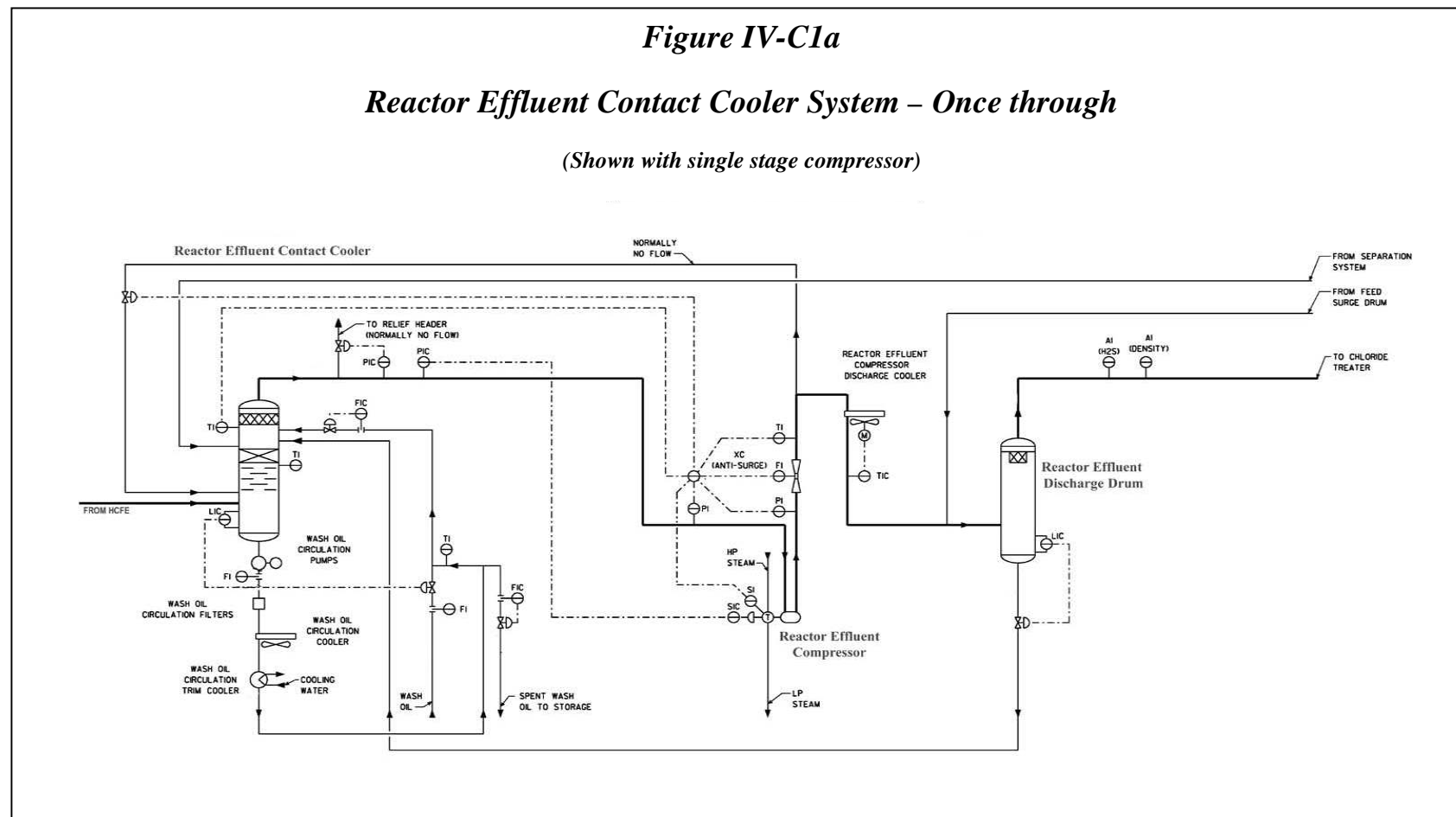
Figure IV-C1a**Reactor Effluent Contact Cooler System – Once through***(Shown with single stage compressor)*

Figure IV-C1b

Reactor Effluent & Interstage Contact Cooler System – with Spent Solvent Recovery

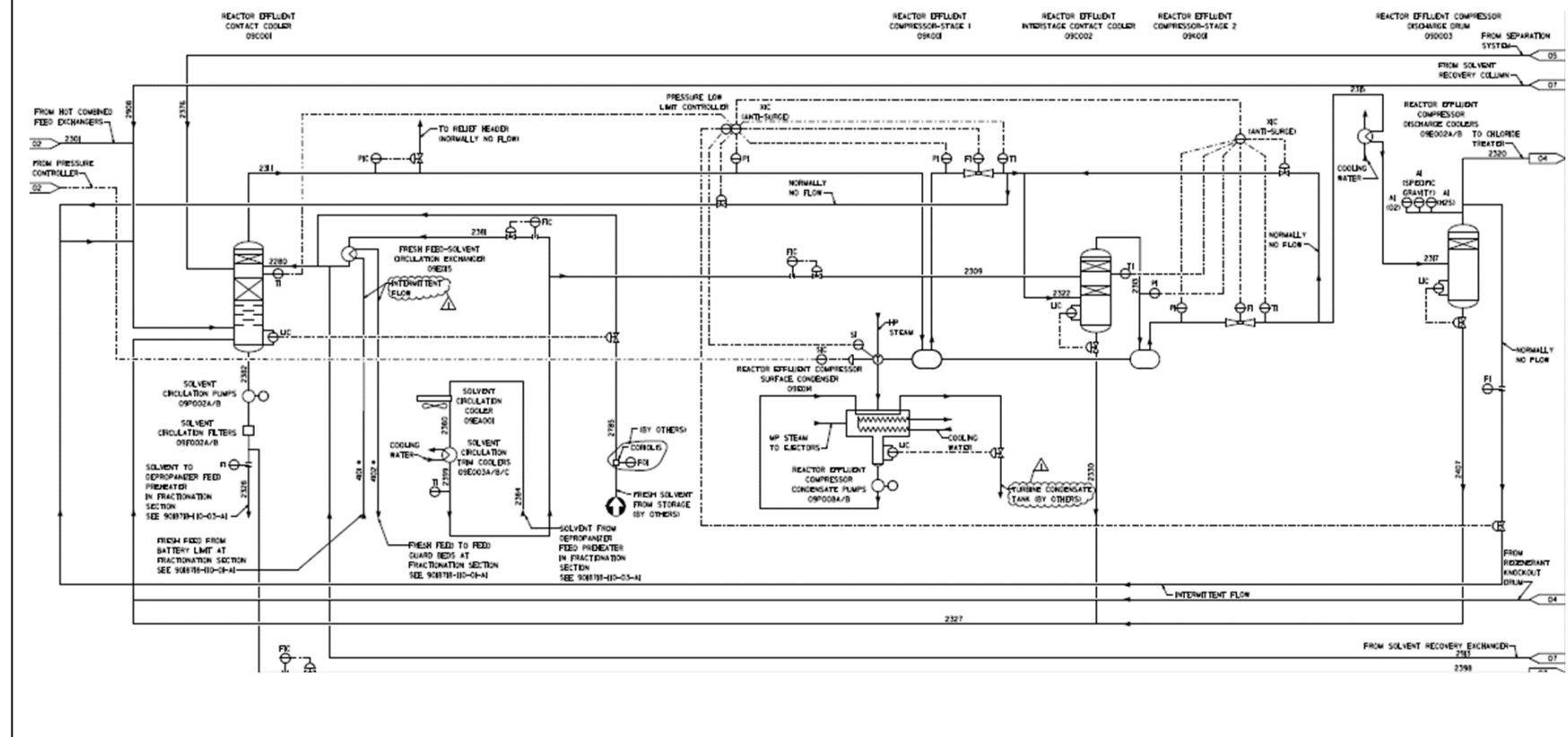


Figure IV-C1c

Spent Solvent Recovery System

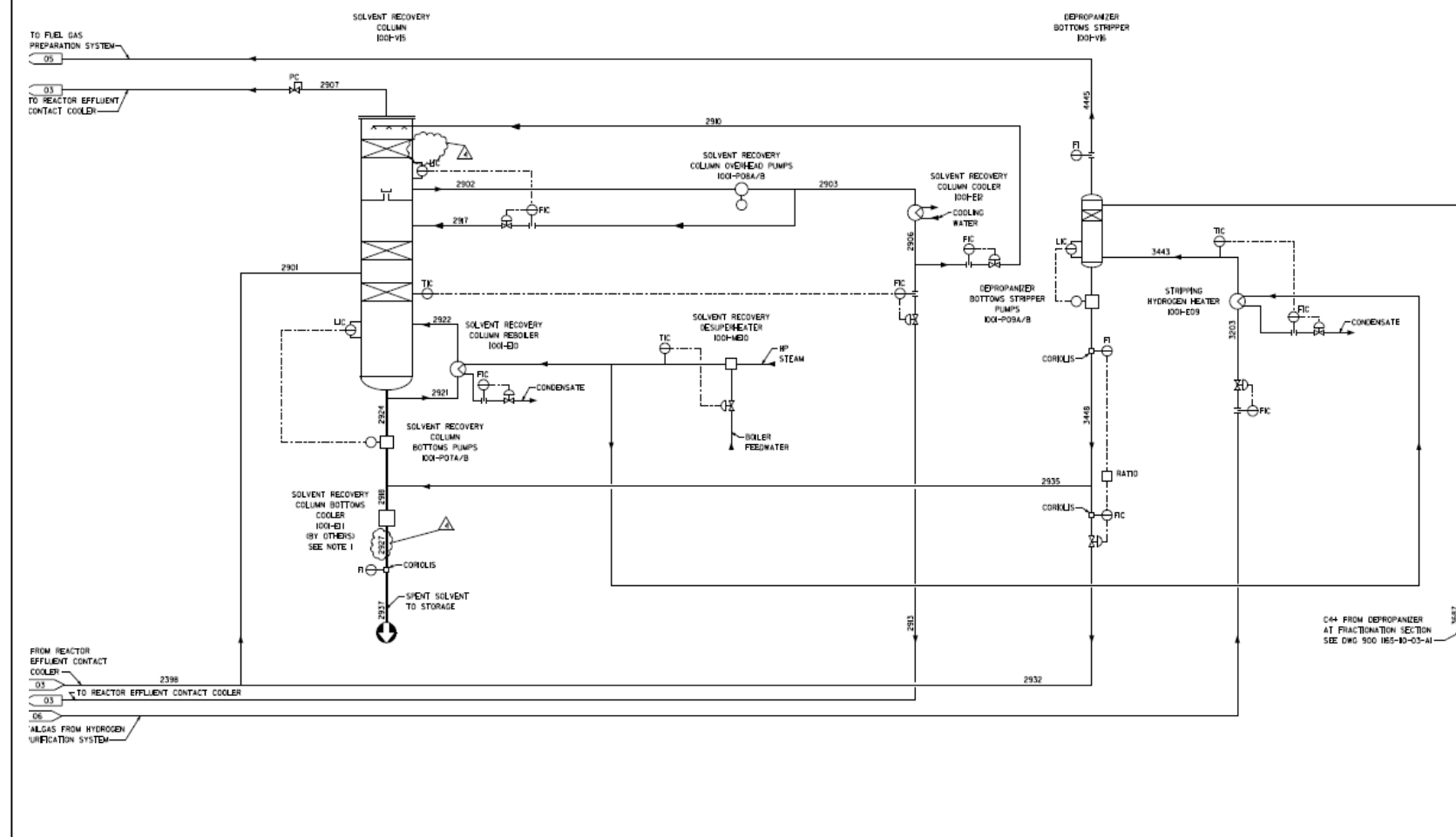
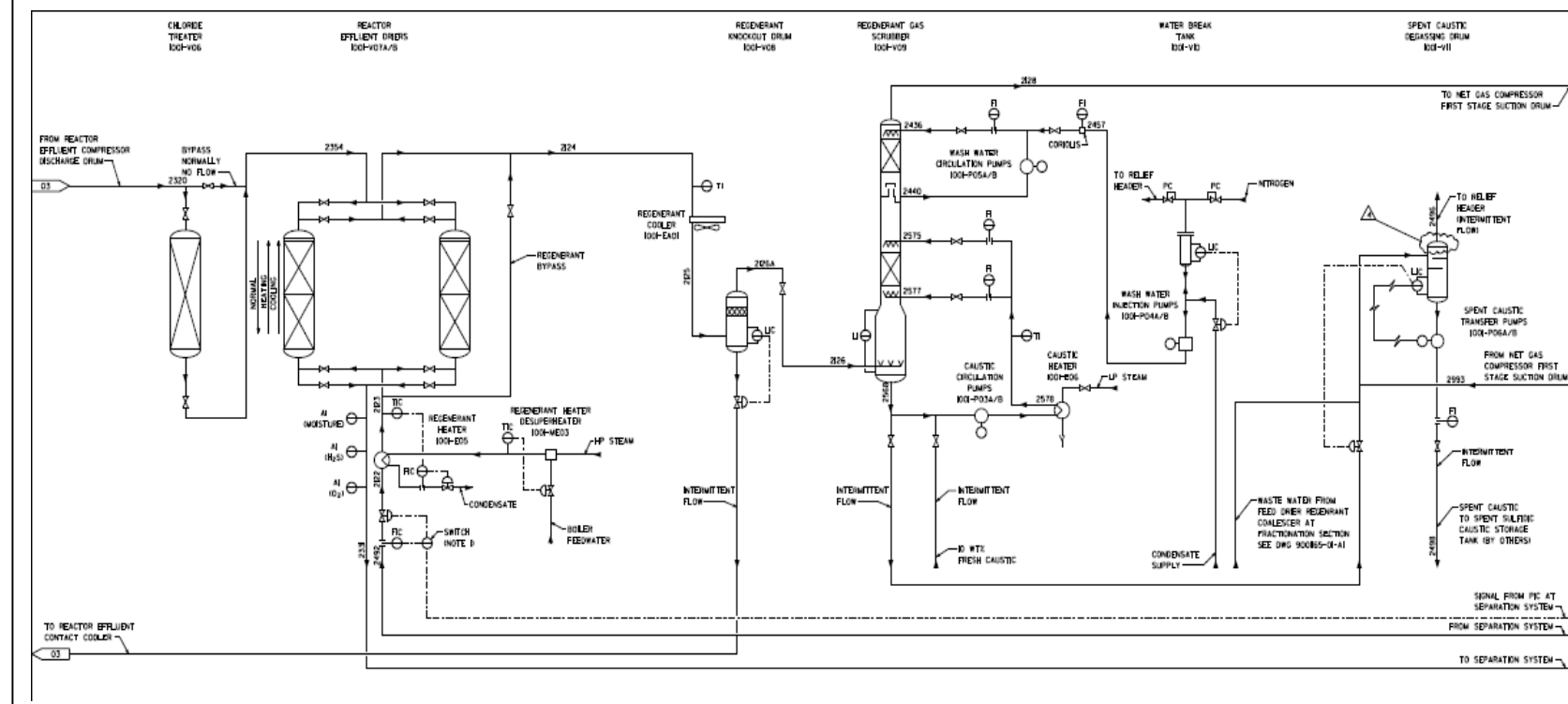
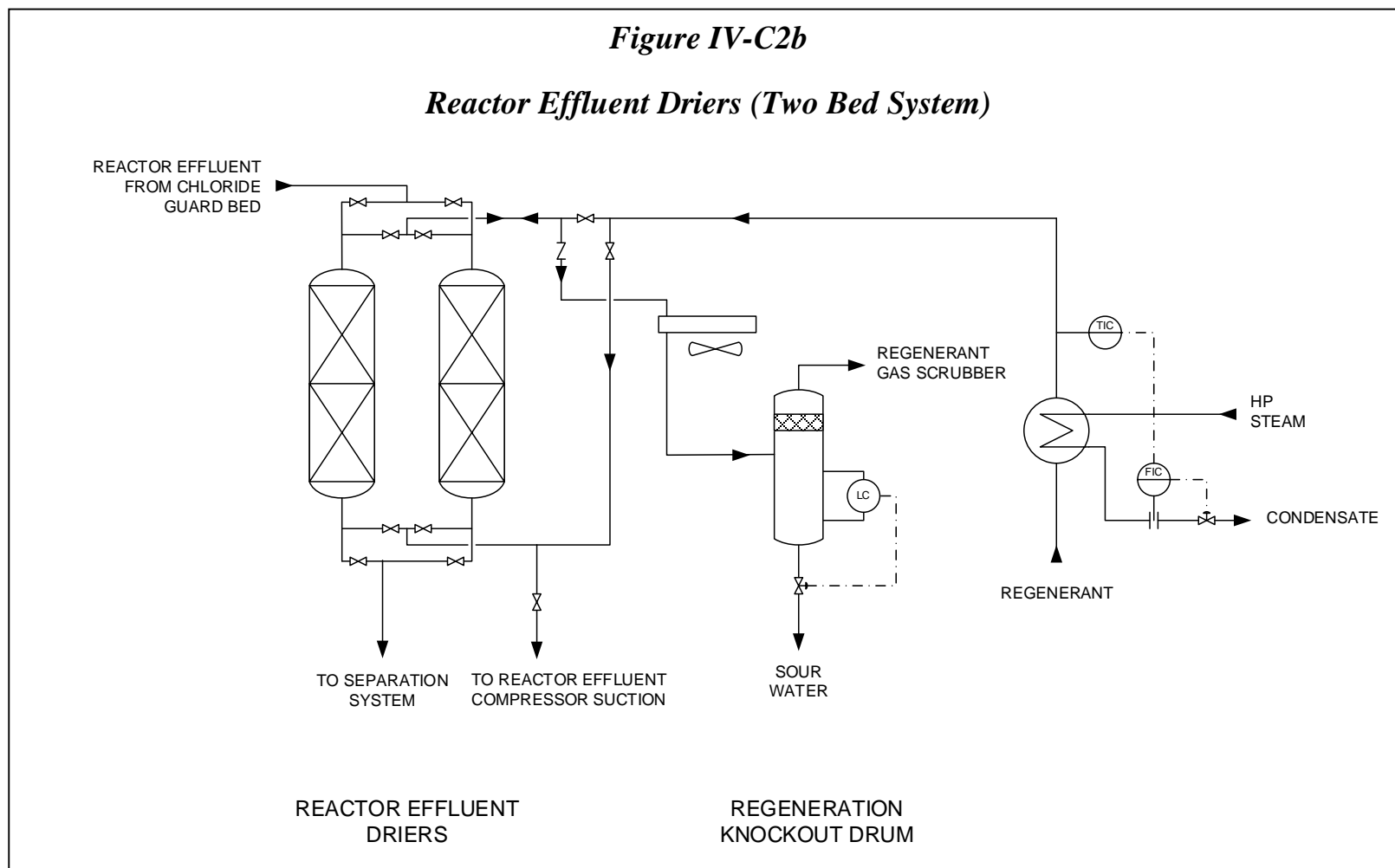


Figure IV-C2a

Regenerant Gas Scrubber System with Two Bed Reactor Effluent Drier System



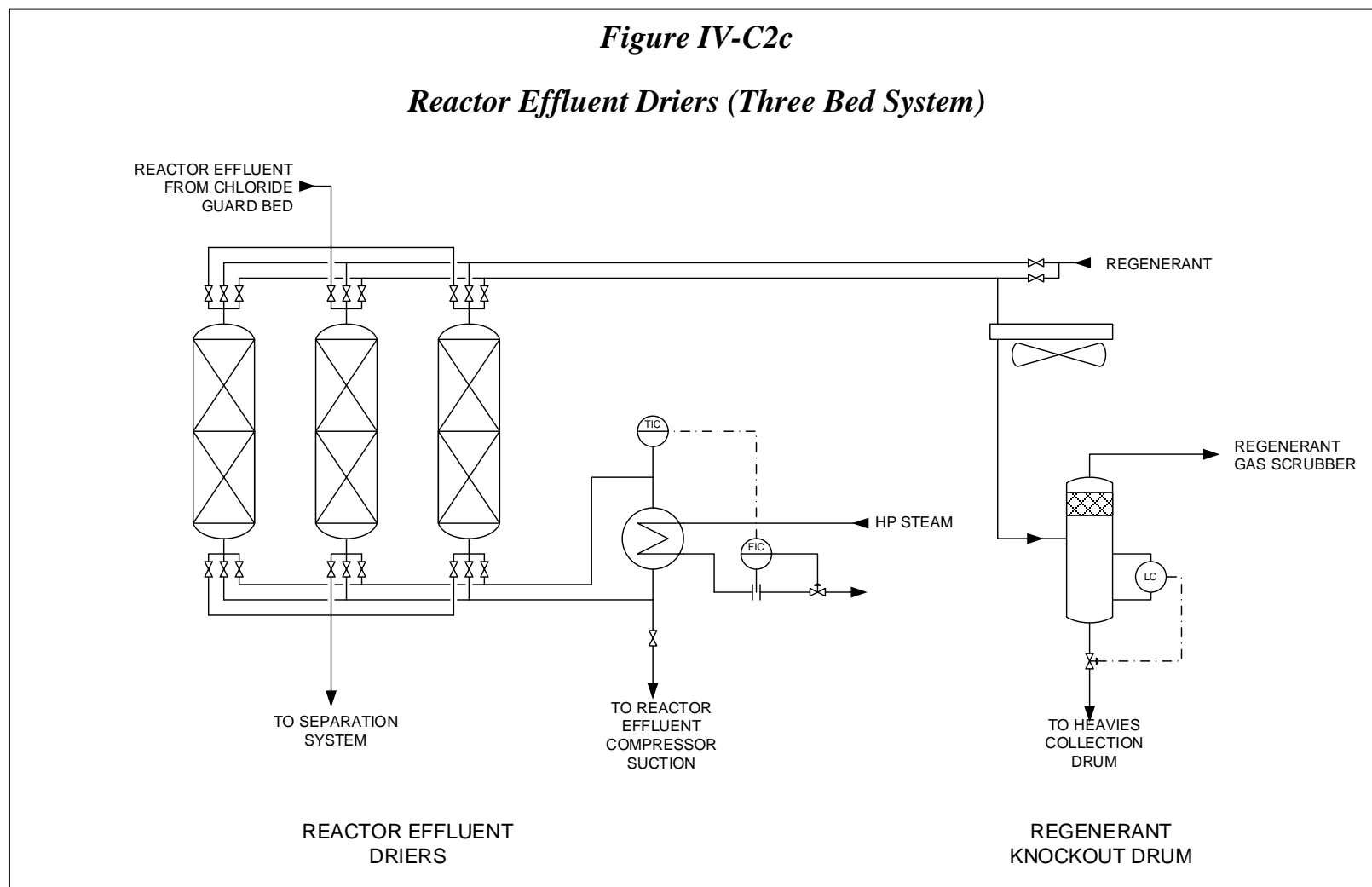


Figure IV-C3
Reactor Effluent Contact Cooler

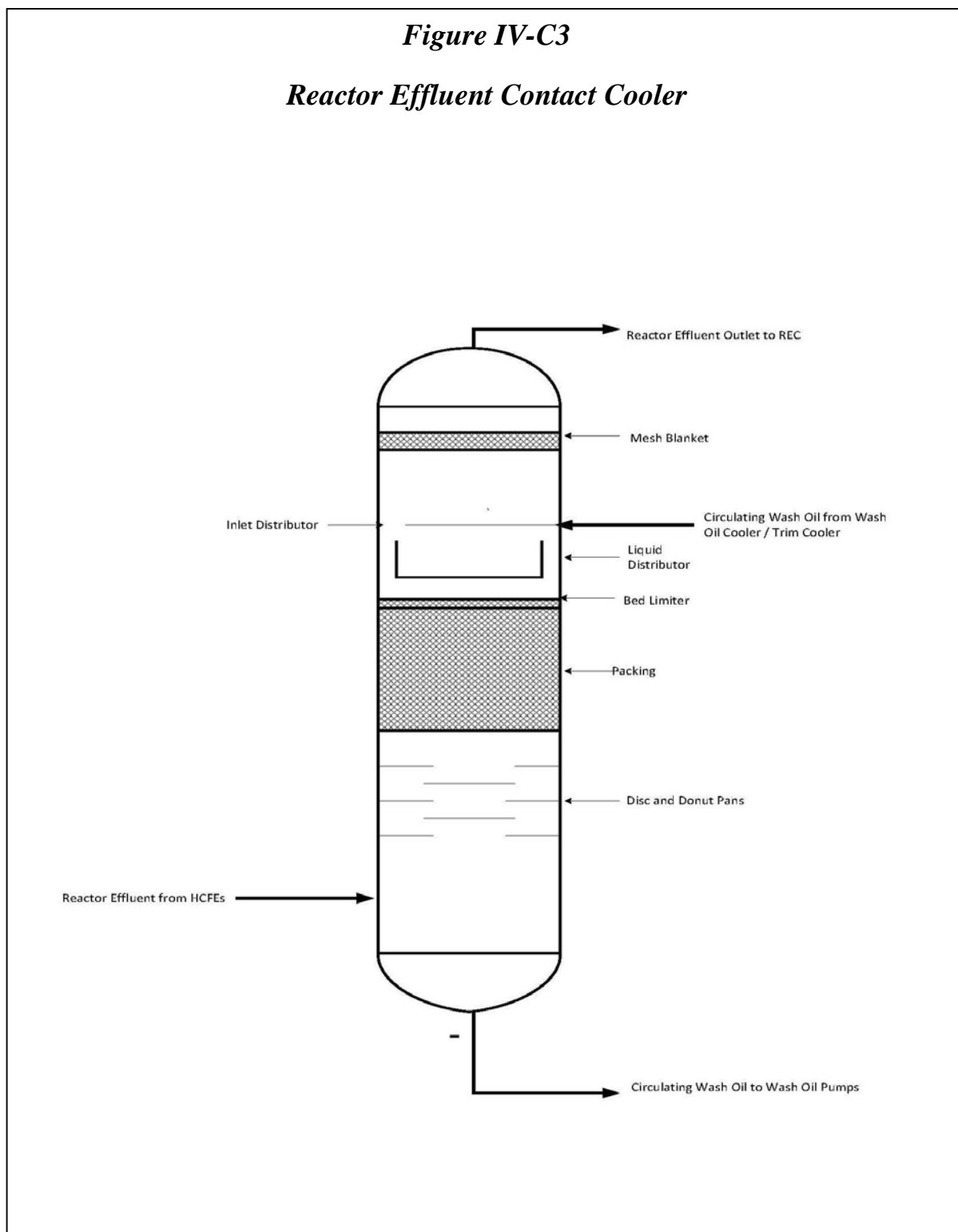


Figure IV-C4
Solvent Recovery Column

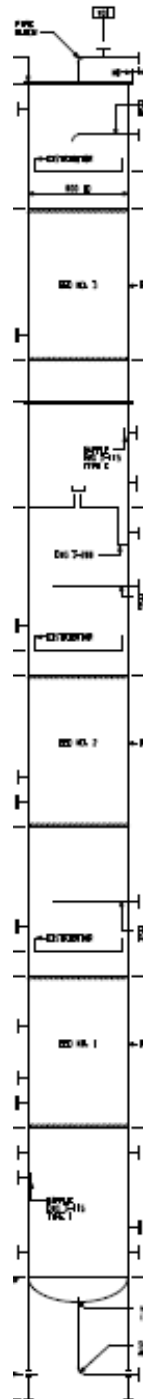


Figure IV-C5
Chloride Treater

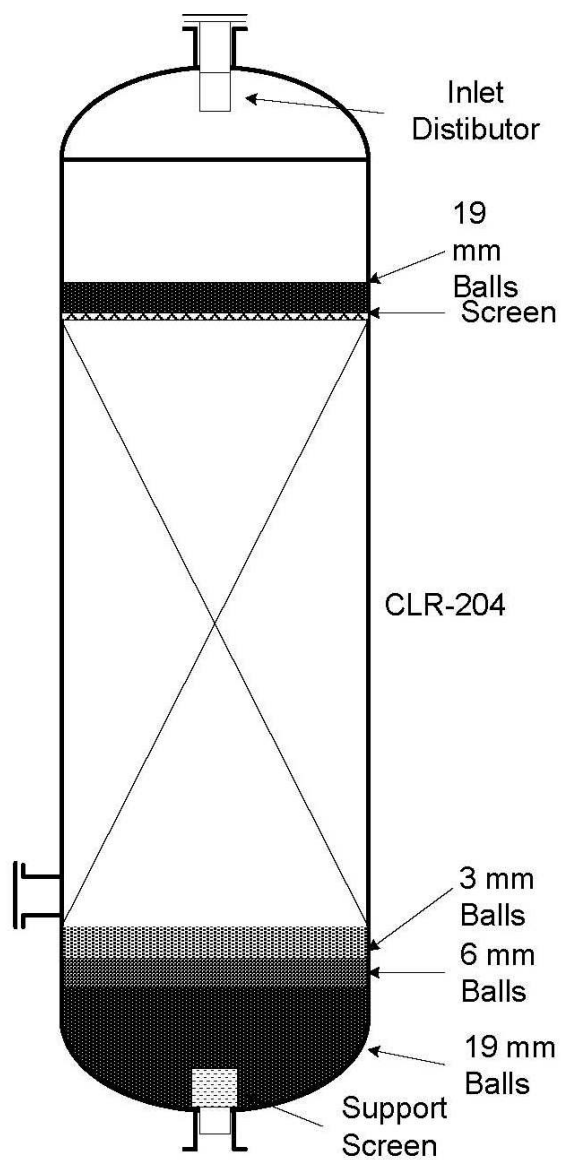


Figure IV-C6
Reactor Effluent Drier

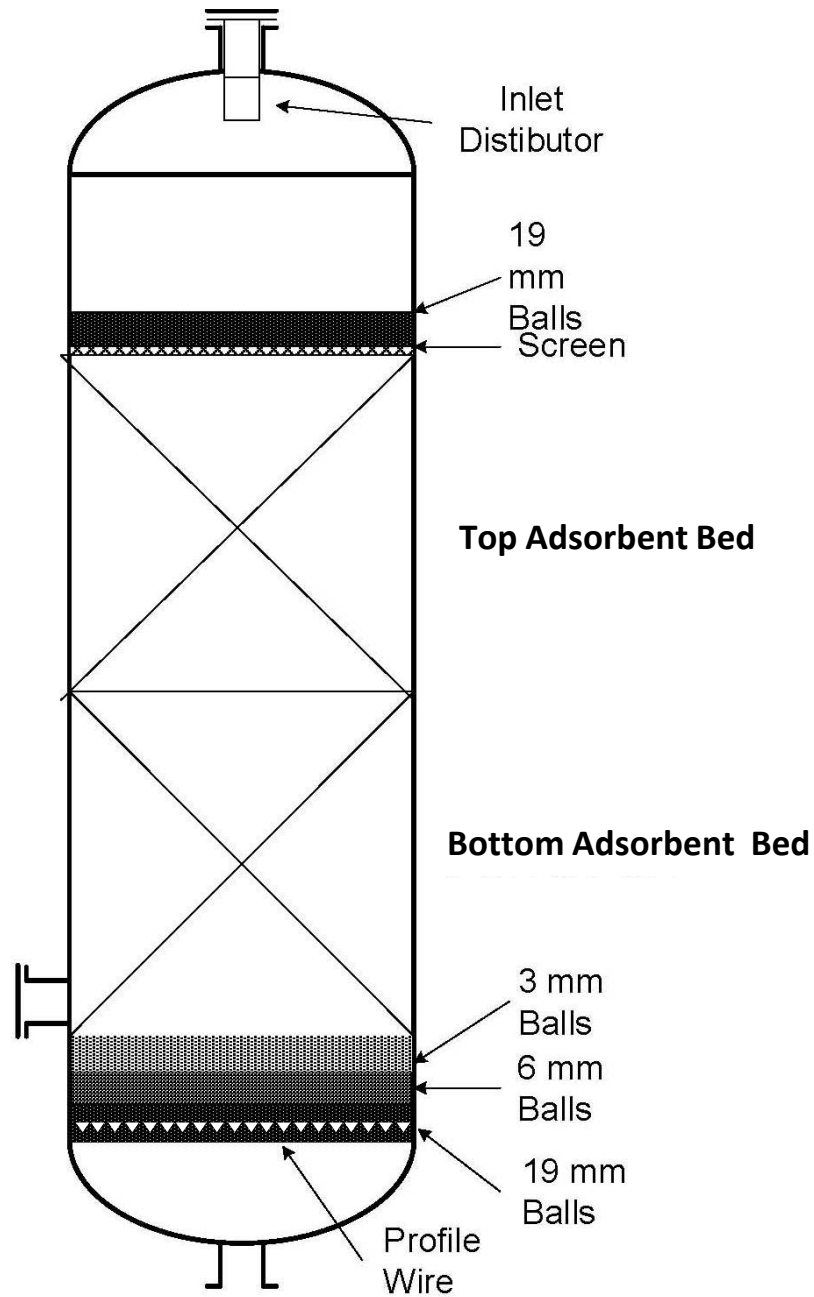
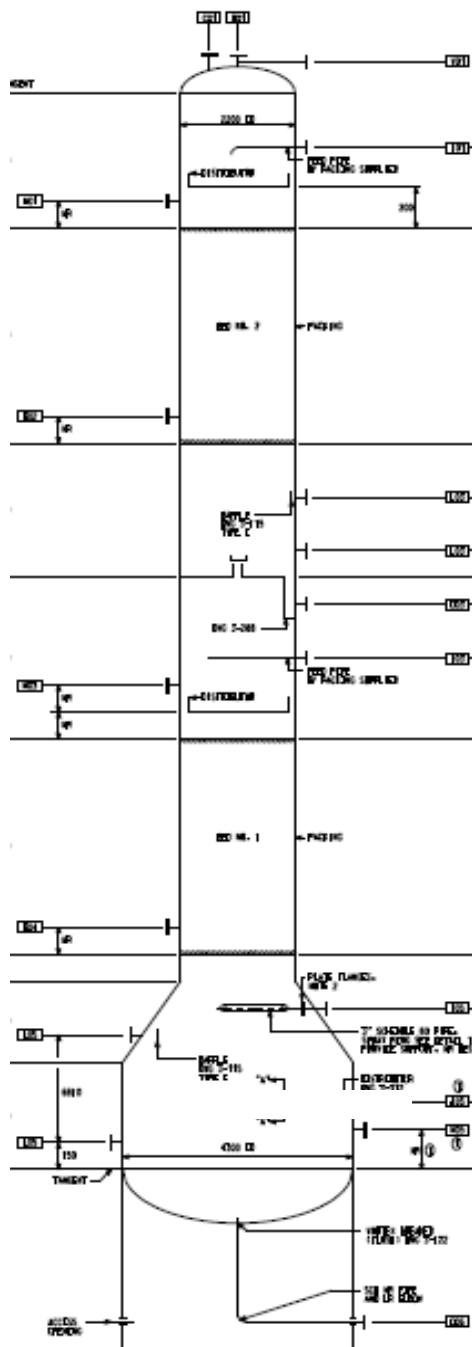


Figure IV-C7
Regenerant Gas Scrubber



D. Separation System

After moisture and H₂S have been removed, the reactor effluent stream proceeds to the cold separation system which will hereafter be referred as “separation system”. The purpose of the separation system is to separate the hydrogen primarily from unreacted propane and product propylene contained in the reactor effluent vapors to obtain a hydrogen rich gas product of required purity and the designed liquid product.

The separation is done at cryogenic temperatures to minimize the pressure required to condense the reactor effluent and reduce the utilities associated with the reactor effluent compression. Cryogenic temperatures are achieved by two means [a] simultaneous vaporization and expansion of liquid propane with H₂ rich gas and [b] by isentropic expansion of the vapors in expanders where mechanical work extracted from the vapors results in chilling of the process vapors.

Heat exchange within the system is achieved by a number of plate heat exchangers which are chosen due to their compact size and relatively low pressure drop when compared with shell and tube type exchangers. Refer Figure IV-D1 for details. Each exchanger has a “warm end” where the “warm” streams enter and “cold” streams exit; and a “cold end” where the “warm” streams exit and “cold” streams enter. Typically the streams enter the exchanger plate passes through slot openings in the half moon jacket headers at either of the “warm” and “cold” ends. The ability to handle more than one “warm” and/or “cold” stream in a single plate heat exchanger eliminates the need for multiple shell and tube exchangers.

All the exchangers within the system are brazed aluminum plate heat exchangers. The closely spaced plates have proprietary corrugated pattern to improve transfer rate service. The vessels and piping are also fabricated in aluminum metallurgy. Aluminum is chosen due to its light weight, excellent heat conductivity and ability to withstand the cryogenic temperatures. The exchangers, associated piping and vessels are all housed within a carbon steel shell casing. The void space between the shell casing and internal piping and equipment is filled with a suitable cold insulation material to prevent heat absorption into the system from the surroundings. Cold insulation material is typically perlite, a light weight material, derived from a naturally occurring silica-alumina mineral suited to the application.

This section is typically customized by a specialty vendor for each unit, and the actual layout may differ slightly from that depicted in this manual. The reader should refer the manual provided by the vendor for their specific unit for specific details on equipment and control.

1. Separation System Process Flow (Figure IV-D2)

The reactor effluent stream is cooled and partially condensed in the cold combined feed exchanger (CCFE) passes by rejecting heat to the propane and recycle

hydrogen combined feed stream and net gas stream. The two phase vapor-liquid mixture proceeds to the primary separator (High Pressure Separator) where majority of the hydrogen and some of the associated light hydrocarbon compounds like methane, ethylene and ethane are separated from the liquid products.

The vapors exiting the primary separator are sent to the intermediate heat exchanger where it rejects heat to the hydrogen rich gas stream from the high pressure (HP) expander knockout drum and recycle hydrogen stream from the low pressure (LP) expander. This knocks down additional hydrocarbon components into liquid phase from the hydrogen rich gas purifying it further. Knocked down liquids are separated from the vapor in the secondary separator.

The vapors from the secondary separator reach the HP expander, where the vapors are isentropically expanded to lower pressure. Extracted work from the vapors in the HP expander may be expended as mechanical work in another mechanical drive or used to generate electricity via generator. As a result of work extracted from the process vapors, the temperature of the vapors drops across the expander.

The pressure is controlled at the inlet of the HP expander by regulating the flow through the expander with inlet guide vanes located just upstream of the expander rotor. A bypass around the expander provided with a control valve can be operated in either on pressure control mode or temperature control mode. When on pressure control mode, it regulates the pressure up stream of the expander via an independent pressure controller. When on temperature control mode, it regulates the temperature at the outlet of the HP expander indirectly by regulating the net gas temperature from the intermediate heat exchanger. A switch is provided to select between the modes. Temperature control mode is selected when the temperature at the outlet of the expander tends to fall below the design temperature.

The effluent of the HP expander is two phase flow and therefore sent to the expander knockout drum (Intermediate Pressure Separator) where the condensed out liquids are knocked down and separated from vapor achieving further purification of the hydrogen rich gas stream.

The “cold” vapor from the expander knockout drum, which is ≥ 92.5 mol% hydrogen, is passed through the intermediate heat exchanger where it warms up slightly, and splits into two streams at the outlet. One portion, is routed through the fresh feed exchangers and cold combined feed exchanger where it is further warmed up by the “warm” streams, and exit the separation system as net gas. Part of the net gas is recycled as “CCR Gas” and the remainder is typically used as “regenerant” for the reactor effluent driers and as feed to the PSA unit for hydrogen purification.

The other portion of the hydrogen rich gas from the intermediate heat exchanger constitutes the recycle hydrogen gas and is routed to the LP Expander which works on similar principles as HP expander. In the LP expander, the vapor is further expanded decreasing the process gas temperature.

The LP expander operates on recycle gas flow control. The flow through the expander is regulated by the split range control between the inlet guide vanes and expander bypass control valve. Bypass valve will start to open to regulate the flow when the inlet guide vanes are fully open.

This “cold” stream from the LP expander then passes through the intermediate heat exchanger where it is slightly warmed and flows to the combined feed passes of the cold combined feed exchanger where it combines with the “cold” liquid propane feed stream in each pass. “Cold” liquid propane is distributed in each pass via a proprietary distribution device. Hydrogen vapor tends to get saturated with propane chilling the stream even as the combined stream gets warmed and expanded in up flow by exchanging heat primarily with the warm reactor effluent stream in the adjoining pass flowing in down flow. The combined propane and recycle hydrogen feed stream is then sent to the HCFEs in the Oleflex Reactor Section.

The “cold” liquid products which collected in the primary separator, secondary separator and the expander knockout drum exit on level control via the level control valve provided at the liquid outlet stream from each vessel, are combined and sent through the fresh feed cold exchanger to cool the “warm” liquid feed stream, then collected in the liquid product tank. Operating the liquid product tank to operate with relatively cold liquid product allows to reduce the design pressure on the liquid product tank. Depending on the design temperature, the liquid product tank may be in killed carbon steel or aluminum construction. The liquid product tank operates at slightly higher pressure than the REC suction drum or the reactor effluent contact cooler as applicable. Any flashed “cold” vapor from the tank is routed via the fresh feed warm end exchanger to REC suction. The “cold” liquid product is pumped on level control through the fresh feed warm end exchanger, where it is warmed by the “warm” fresh liquid propane feed, and sent to the fractionation section.

The liquid feed is pumped from the depropanizer overhead receiver on flow control. The “warm” liquid feed is cooled in the fresh feed warm end exchanger and the fresh feed cold end exchanger by the “cold” liquid product stream net gas and flash gas streams. The “cold” liquid feed is then combined with the recycle gas in the cold combined feed exchanger as explained earlier and is sent to the Oleflex reactor section.

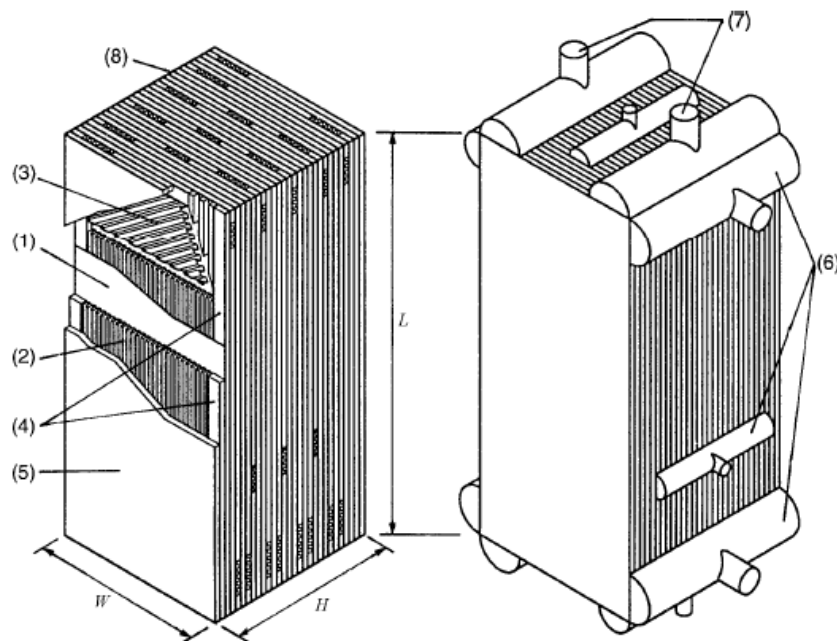
2. Equipment Integrity

Aluminum is the typical material of construction for these cold exchanger cores due to the low temperatures required. The brazed plate joints are mechanically designed for certain specific differential temperature, to withstand thermal stresses induced due to differential thermal expansion between the two streams exiting or entering the adjoining passes in the exchanger. Vendor should be consulted for the allowable differential temperature limits. During normal operation, the differential temperatures are expected to be well within design. It is critical to follow procedures as prescribed

by the vendor during process transients like start-up or shut-down and perform them in a controlled manner so as to minimize thermal shock to the equipment. The maximum allowable rate of chilling in (Deg C/F)/Hour and maximum allowable rate of feed increase (M³ Liquid Feed / Hour)/Hour as specified by the vendor should not be exceeded.

Aluminum metallurgy is impacted by mercury attack even in low concentrations. Mercury will form solid phase amalgam with the base metal which tends to come off the metal when exposed to ambient air leaving behind a porous and weakened metal. It is therefore important to ensure that mercury is not present in the liquid propane feed to the cold box. In addition, if it is necessary to hydrocarbon free the equipment, it should be purged with and preserved under dry nitrogen (less than 1 vol ppm H₂O corresponding to atmospheric dew point less than minus 76 Deg C or 105 Deg F). Ambient air ingress should be prevented.

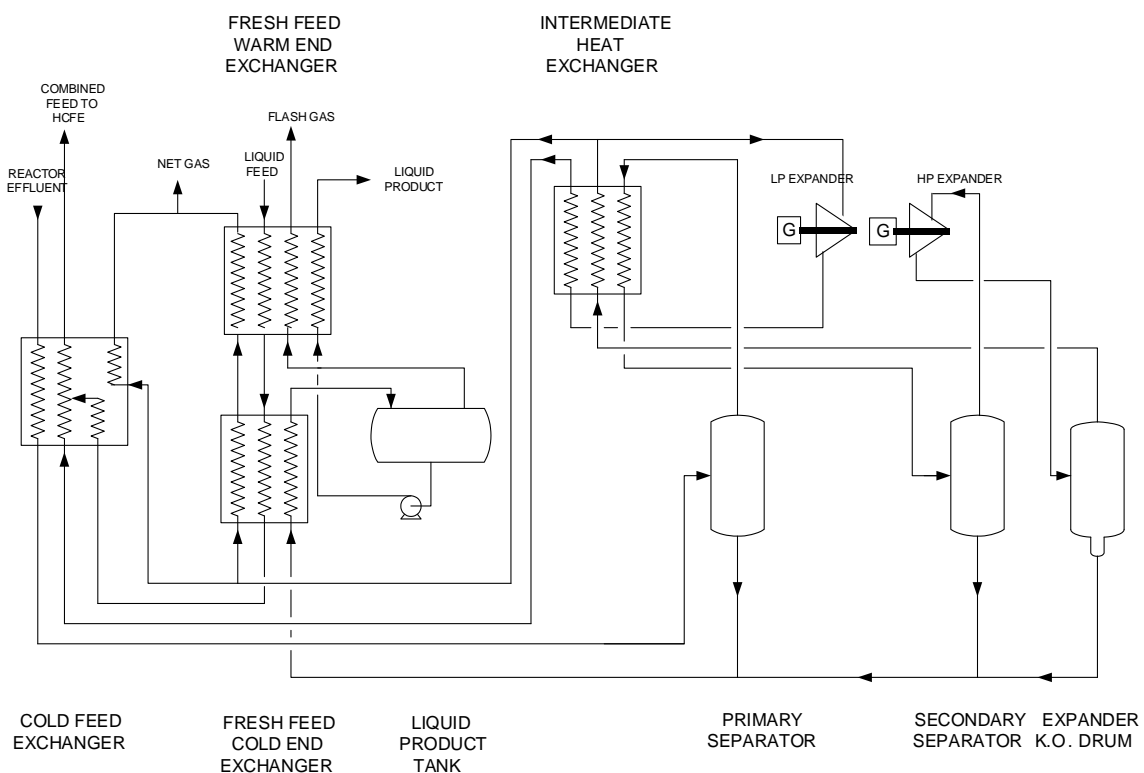
Another concern at the cryogenic temperatures generated within the cold box is the potential for even low levels of water and other species like CO₂ and “heavies” to “freeze out” in the various passes of the cold box impacting thermal performance. Whether a given contaminant will freeze out depends on the phase, composition, temperature and pressure at a given location. Solid ice can additionally cause mechanical stresses leading to joint failure and/or leaks. Feed driers and reactor effluent driers should be able to prevent water ingress.

Figure IV-D1**Brazed Aluminum Plate-Fin Heat Exchanger**

- | | | |
|-----------------------|-----------------|--------------|
| 1. Parting sheet | 5. Cap sheet | L ; Length |
| 2. Heat transfer fins | 6. Headers | W ; Width |
| 3. Distributor fins | 7. Nozzles | H ; Height |
| 4. Side bars | 8. Block (core) | |

Figure 1-2: Components of a Brazed Aluminium Plate-Fin Heat Exchanger

Figure IV-D2
Separation System



E. SHP Section (Figure IV-E1)

For C3 Oleflex units with reactor effluent contact cooler where SHP is located on the recycle propane stream, skip to section F Fractionation for more detailed description of process flow and control.

A small amount of dienes in form of methyl acetylene and propadiene (MAPD) and acetylene are produced in the reactor section of Oleflex. These will condense out in the cold separation section and will be present in Oleflex liquid product typically in the range of 80-150 wt.ppm. In the fractionation section, MAPD tend to concentrate around the middle section of Propane – Propylene Splitter exiting via recycle propane stream. If not removed from the recycle propane stream, these impurities will fractionate out from depropanizer overheads contaminating the Oleflex propane feed stream. MAPD tend to produce coke in the fired heaters and on catalyst. Purpose of the SHP is to eliminate these impurities by selectively hydrogenating them to their respective mono olefins, which in this case is propylene. SHP catalyst is engineered to minimize saturation of mono olefins to paraffins, which in this case is propylene saturating to propane.

A small slip stream from the PP splitter rich in MAPD is drawn out from PP splitter and combined with recycle propane stream to constitute SHP feed. Typically, SHP product will have <1 wt.ppm MAPD.

The feed to the SHP reactor is heated to the desired temperature in SHP feed heater on temperature control, and injected with a small amount of high purity hydrogen on flow control. Refer Figure IV-E1 for a generic flow scheme of SHP.

Hydrogen is injected through the mixing nozzle typically a sintered metal diffuser element that generates fine bubbles of hydrogen aiding dissolution. Refer to Figure IV-E2 right side sketch for details of the injection nozzle. A static mixer downstream of the mixing nozzle prevents stratification of the hydrogen bubbles at top of the pipe by swirling action of fluids ensuring intimate contact and complete dissolution of hydrogen into the feed before reaching the catalyst bed. MAPD is selectively hydrogenated on the catalyst by reacting with dissolved hydrogen. The reaction is exothermic. The bed temperature thermocouples located at top, middle and bottom of the catalyst bed help monitor the temperature profile within the reactor.

A set of two independent SHP hydrogen compressors is provided when necessary to inject hydrogen at the required pressure. The reactor operates under liquid phase and it is therefore necessary to maintain adequate pressure in the reactor to prevent hydrocarbons from vaporizing as also dissolved hydrogen coming out of solution to form a vapor bubble. If there vapor bubbles form in the reactor, its performance will be affected.

1. SHP Feed Heater

It can be a finned double pipe exchanger or a shell and tube exchanger in carbon steel construction with heating medium on tube side and hydrocarbon on the shell side.

2. SHP Reactor

Refer to the left side sketch in the Figure IV-E2. The SHP reactor is constructed out of killed carbon steel. It has a top spider leg type feed inlet distributor with multiple horizontal interconnected distribution pipe segments with perforated holes, which distributes the feed uniformly across the cross-section of the vessel. At the bottom, a catalyst withdrawal nozzle is provided that allows the catalyst to be removed, without disturbing the alumina support. The 19 mm and 6 mm inert ceramic balls help hold down the catalyst bed. The bottom 3 mm, 6 mm and 19 mm ceramic ball layers together prevent catalyst migration to the outlet basket. Three layers of alumina balls rest in the bottom head and support the catalyst bed.

Additional process piping includes a bypass line around the reactor and provision of hydrogen line for use during catalyst Hot Hydrogen Stripping operations. Additional information is available in Section XII – Special Procedures.

Figure IV-E1

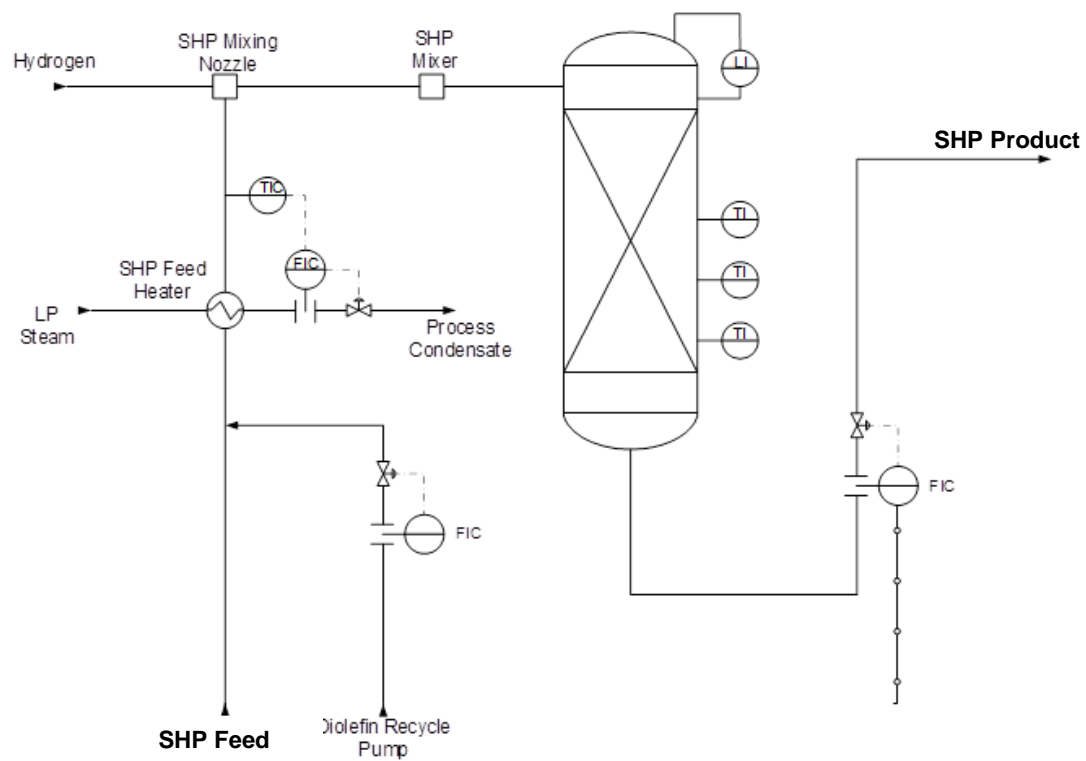
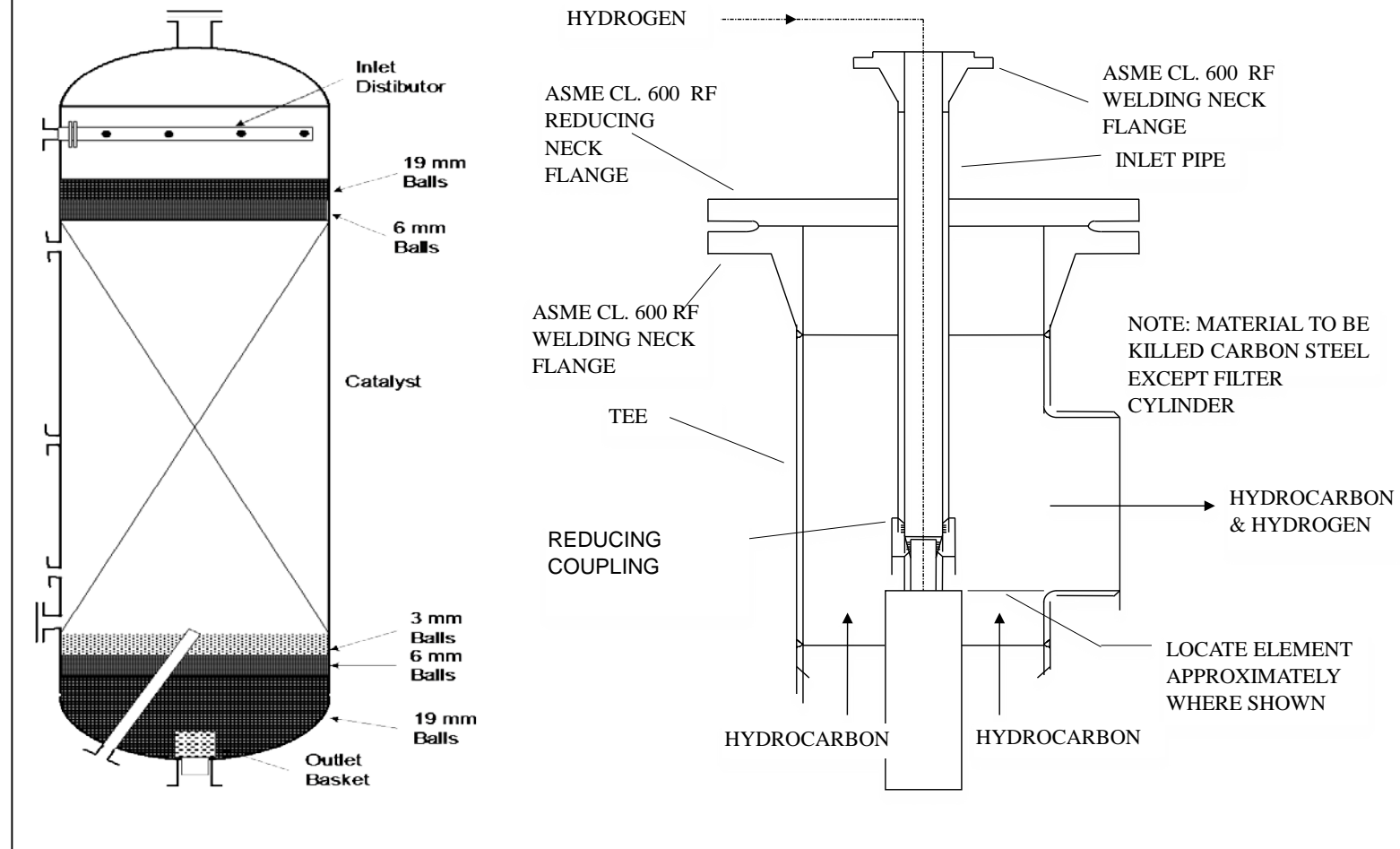


Figure IV-E2**SHP Reactor and Hydrogen Injection Nozzle**

F. Fractionation Section

Oleflex fractionation section is designed to perform two main functions – [a] to purify the fresh and recycle propane streams to obtain a combined propane stream of required purity to feed Oleflex reactor section [b] to remove light ends and heavies from the Oleflex liquid product to recover product propylene while recycling unreacted propane back to Oleflex

Fresh and recycle propane feed are purified together in the depropanizer system to remove C4+ heavies and deliver a net overhead propane product meeting Oleflex feed specifications.

Liquid product contains propylene, unconverted propane, light ends and C4+ heavies. Hydrogen, methane, ethane and ethylene constitute majority of light ends. Butanes, butenes, light aromatics like benzene, xylenes, and solvent species from the intermittent solvent injection or contact cooler constitute majority of C4+ heavies. The liquid product also contains minor amounts of methyl acetylene and propadiene (MAPD) which constitute main acetylenes and dienes.

In the C3 Oleflex units with the reactor effluent contact cooler designed to operate at lower pressure at the last reactor outlet, liquid product is directly sent for fractionation since the SHP unit is located on the recycle propane stream.

Liquid product is sent to the de-ethanizer stripper and rectifier system to remove the light ends as net overheads. The de-ethanizer stripper bottoms is sent as feed to the propylene-propane splitter (PP splitter) to recover the propylene product as net overheads. The bottoms from the PP splitter column constitutes recycle propane which contains C4+ heavies. This stream is treated in SHP if applicable, combined with the treated fresh propane stream and sent to the depropanizer system. C4+ heavies are fractionated out from the depropanizer bottoms and sent to the depropanizer bottoms stripper. Net overheads is sent to the cold separation system as combined propane feed to Oleflex.

Associated equipment and controls are discussed in detail in the following sections.

1. Depropanizer System (Figure IV-F1a/b/c)

Fresh propane from the fresh feed treatment section is combined with the recycle propane and sent as feed to the depropanizer system. The main purpose of the depropanizer system is to purify the combined propane feed stream by fractionating out C4+ heavies as bottoms product and deliver a net overhead propane stream meeting the specifications of Oleflex feed propane. It is essential to prevent contamination of Oleflex feed with C4+ heavies which can cause fouling and coking

problems in the reactor section. At the same time, propane slip from the depropanizer bottoms C4+ rich stream need to be minimized to limit propane consumption.

The depropanizer system flow schemes are shown in Figures IV-F1a/b/c. The control strategies employed can vary slightly in different schemes.

The overhead vapors are condensed in air or water cooled condenser and sent to the receiver. Column pressure control schemes somewhat vary depending on whether the condenser is water cooled shell and tube exchanger located at grade as in Figure IV-F1a/b or air cooled fin fan exchanger as in Figure IV-F1c.

With water cooled condenser designs, Figure IV-F1a/b, the exchanger operates with a partially submerged tube bundle where the amount of submergence and condensing surface vary during the operation. The receiver normally operates at a pressure slightly less than the column pressure. This difference in pressure helps to hold the liquid leg and drive the flow through the condenser to the receiver. Some of the overhead vapor is allowed to bypass the condenser via a pressure control valve to regulate the column pressure. If the column pressure increases, control valve tends to close, decreasing the bypass flow which in turn decreases the vapor pressure in the receiver. The increased pressure difference between condenser and receiver pushes away the liquids into the receiver exposing additional surface for condensation. Increased condensation restores the pressure to normal value. Opposite sequence of effects happen if the column pressure decreases.

With air cooled condenser designs, Figure IV-F1c, surface area control as in water cooled condenser design is not practical because of limited number of tube rows where a small change in submergence can cause a large change in condensing surface resulting in unstable operation. For air cooled systems, system pressure is controlled by directly regulating the flow to the condenser via a control valve acted upon by a pressure controller. The condensing pressure and temperature will therefore be slightly lower than the column overhead vapors. It is necessary then to maintain and stabilize the liquid leg between the condenser and the receiver. This is achieved by a differential pressure controller that allows a portion of the hot column vapors to bypass the condenser to maintain a stable pressure difference between the receiver and upstream of the condenser. If the column pressure decreases, the pressure control valve tends to close in response permitting less vapors to condense to restore the column pressure; the differential pressure control valve tends to close in response to restore the differential pressure. Opposite sequence of effects happen if the column pressure increases.

The receiver level controller resets the combined propane feed flow controller which regulates the control valve on the fresh propane feed. The net overhead draw is set independently by the flow controller on the liquid feed to the Oleflex. Column reflux is controlled by independent flow control. These control schemes are same for the configurations shown in Figures IV-F1a/b/c.

There can be different control strategies adopted for the bottoms level, bottoms withdrawal and heat input into the column depending on the unit.

For the scheme shown in Figure IV-F1a, depropanizer bottoms level controller regulates the level by resetting the bottoms flow controller. As C4+ heavies accumulate, the level increases which in turn increases the bottoms draw. The disadvantage is that the bottoms withdrawal is entirely based on level without looking at composition which can cause excess propane slip or send C4+ heavies up the column during process transients. The bottoms composition will have to be adjusted by the reboil on the column. Heat input to the column is regulated by the condensate flow controller which can be set independently to obtain the desired reflux but will have to be manually adjusted by the operator in response to the changes in forward feed to the Oleflex unit.

For the scheme shown in Figure IV-F1b, column bottoms level controller regulates the level by resetting the condensate flow controller on the steam reboiler eliminating the need for operator intervention when changes are made to the forward feed to Oleflex. When Oleflex feed is increased, more fresh feed is brought into the column which tends to increase the bottoms level and decrease the bottoms temperature. The bottoms level controller will increase the heat input by resetting the condensate flow controller to restore the level. The temperature controller decreases the bottoms draw by resetting the bottoms draw flow controller to restore the bottoms temperature and composition. Opposite sequence of effects happen when the Oleflex feed is decreased. The control scheme also responds to the changes in the feed composition. If the feed richer in C4+ components is brought in, the bottoms temperature tends to increase. The temperature controller increases the bottoms draw by resetting the bottoms draw flow controller to regulate the bottoms composition. Opposite sequence of effects happen when the feed is leaner in C4+ components is brought in.

Configurations as shown in Figure IV-F1b and Figure IV-F1c incorporate the heat recovery reboiler into design. In these schemes, the heat from the heat pump compressor second stage is recovered by providing a percentage of total heat duty on the depropanizer column with balance duty provided by the steam reboiler.

In the control scheme shown in Figure IV-F1b, the amount of reboil provided by the heat recovery reboiler can be adjusted by setting a portion of the total flow to bypass the reboiler. The bypass flow combines with the effluent from heat recovery reboiler and proceeds to the trim cooler from where it is returned to the PP splitter system on flow control. Balance reboil is provided by the steam reboiler on condensate flow control reset by the bottoms level controller.

In the control scheme shown in Figure IV-F1c, the heat input controller calculates the required heat input to the steam reboiler reset by the column bottoms level and total flow through the heat recovery reboiler. The effluent from heat recovery reboiler is

cooled in the downstream trim cooler and returned to the PP splitter system on flow control.

In all the configurations as shown in Figures IV-F1a/b/c, the C₄+ material withdrawn from the depropanizer column bottoms is sent to the depropanizer bottoms stripper.

The depropanizer column, condenser, receiver and reboilers are all fabricated from killed carbon steel. The sieve trays are specified to be constructed from carbon steel.

1.1 Depropanizer System with Two Columns (Skip to section 1.2 for units with single depropanizer system)

This type of design is specified where the unit capacity exceeds a certain threshold making the design with two depropanizer columns operating in parallel economical. Refer Figure IV-F1c for the flow scheme. In depropanizer 1, a crude bottoms draw amounting to approximately 10% of the total feed with more propane slip than that allowed in a single depropanizer column configuration; is taken and sent to the depropanizer 2 which is much smaller in size. A ratio controller together with a lead/lag function on the upstream resets the depropanizer 2 feed flow controller as a percentage of the total feed to the system. Lead/lag function acts as feed forward control to provide faster response to changes in feed to depropanizer 1. Depropanizer 2, which now handles a much smaller feed that is richer in C₄+ components, is designed to efficiently fractionate out the heavier C₄+ components.

The overhead vapors from both the depropanizer columns combine into a single stream and flow to the condenser. Condensed liquids flow to the receiver. The condenser can be a water cooled shell and tube heat exchanger or an air cooled exchanger. Column pressure, net overhead draw, reflux, receiver level are controlled exactly in the same manner as described in the previous section.

The C₄+ material from depropanizer 2 bottoms is drawn on level control which resets the bottoms flow controller. C₄+ material is sent either to the depropanizer bottoms stripper to recover LPG.

Heat input to depropanizer 2 is set independently by the steam condensate flow controller. Depropanizer 1 has two thermosiphon reboilers. During normal operation, approximately 60% of the heat duty is provided by the heat recovery reboiler, which recovers heat from the second stage discharge from the heat pump compressor. The remainder 40% of the heat duty is provided by the steam reboiler.

1.2 Depropanizer Bottoms Stripper

Depropanizer bottoms stripper fabricated in killed carbon steel, containing a single packed bed of random packings, removes the light LPG fraction containing mainly butanes and propane from the depropanizer bottoms stream. The feed enters at the top of the packed bed via a feed distributor. Liquid distributor distributes in the found

onto the packings. Tail gas, rich in hydrogen sourced from the PSA hydrogen purification system, is heated in a steam heater and sent to stripper bottoms. Hot tail gas strips off the LPG from the liquids cascading down the packings. Overhead vapors are sent to the fuel gas pool. The accumulated heavies are withdrawn from the bottom on level control that resets the pump strokes/stroke length on the proportioning pumps. The heavies drawn are routed to heavies' storage or spent solvent recovery as applicable.

For C3 Oleflex units with reactor effluent contact cooler and solvent recovery system, refer to Section IV-C for details on process flow from depropanizer bottoms stripper.

2. Deethanizer System (Figure IV-F2a/b)

The de-ethanizer system consists of de-ethanizer stripper and rectifier. The purpose of the stripper column is to strip and remove the light ends from the liquid product to yield a bottoms product that contains predominantly propylene and propane with some C4+ heavies. Stripper bottoms is sent as feed to PP splitter. The stripper overhead vapors which contain propane and propylene together with stripped light ends, are condensed in a water or air cooled partial condenser. Propane and propylene predominantly condense out into liquid phase leaving light ends uncondensed in vapor phase.

The liquids and vapors from the condenser enter into rectifier column where the vapor and liquid are separated. Liquid phase is returned back to the stripper column as reflux. Uncondensed light ends from the bottom of the rectifier, though rich in light ends, will still have some propane and propylene which need to be recovered. These are recovered by employing a refrigerated cooling medium in the de-ethanizer rectifier condenser which permits designing the system to a lower pressure. De-ethanizer rectifier condenser works as a partial condenser. Liquids and vapors from the condenser are separated in the de-ethanizer rectifier receiver vessel. Liquids from the receiver with recovered propane and propylene are returned back to the rectifier column as reflux. Cold light ends rich off gas from the receiver, lean in propane and propylene, is warmed-up exchanging heat with the stripper reflux before being removed from the system.

2.1 Deethanizer Stripper

Although almost all of the hydrogen and most of methane gets removed in the cold separation system, the liquid product will have some dissolved hydrogen and in addition light ends like methane, ethane and ethylene which need to be removed. The de-ethanizer stripper is designed to remove these light ends. The column, reboiler, condenser are all constructed in killed carbon steel. Column trays are constructed from carbon steel.

The de-ethanizer stripper receives Oleflex liquid product via a flow controller that is reset by the liquid product drum level controller in the cold separation system.

De-ethanizer stripper is provided either with a stabbed-in reboiler or an external thermosiphon reboiler. Steam is used as the heating medium. Heat input to the stripper column can be set independently. Reboil is controlled by regulating the condensate flow via a flow controller.

Vapors from de-ethanizer overhead get partially condensed in the condenser and the vapor and liquids are sent to the rectifier column where they separate out. Liquids are pumped back to the stripper by the de-ethanizer stripper reflux pumps. Rectifier column bottoms level controller resets the stripper reflux flow controller to control the rectifier column bottoms level and stripper reflux.

A portion of the de-ethanizer overhead vapors is sent to the bottom of the rectifier column as “hot vapor bypass” on flow control to help maintain the required reflux in the rectifier column. Depending on the operating severity in the reactor section, the amount of light ends generated can vary. At low severities when the light ends in the liquid product will be low, it will be necessary to increase the hot vapor bypass flow to achieve stable reflux in the rectifier column.

Overhead vapors from the rectifier column are condensed employing refrigerated cooling medium which is normally propylene. The refrigerant will be on the shell side immersing the tube bundle. Process vapors flow in the tubes, get partially condensed and sub-cooled. The heat is rejected to the refrigerant on the shell side which then evaporates and flows to the refrigeration compressor. More refrigerant is brought into the condenser on level control to restore the level and keep the tube bundle immersed in refrigerant. Certain amount of sub-cooling helps in minimizing propane and propylene loss through the off gas system. This is achieved with the temperature controller which controls the process temperature at condenser outlet. When the temperature set point is decreased, it will lead to increase in compression and refrigeration load. Refrigeration system is supplied by the vendor. Reader is directed to consult vendor manual for the details on the refrigeration system controls and equipment.

The mixed vapor-liquid phase material from the refrigeration condenser is routed to the rectifier receiver where the vapor is separated from the liquid. The liquids from the rectifier receiver are pumped back to the rectifier as reflux. The receiver vessel level controller resets the reflux flow controller at rectifier reflux pump discharge to control the receiver level and reflux.

The receiver vapors which constitute “de-ethanizer off gas” are removed from the system on receiver pressure control. Since de-ethanizer stripper and rectifier columns float on back pressure from the receiver, they do not need separate pressure control.

2.2 Deethanizer Rectifier and Rectifier Receiver

Rectifier column has a swaged bottom section below the feed point that acts as stripper receiver. Construction of the column is in killed carbon steel. The trays are

fabricated in carbon steel. Rectifier receiver vessel is constructed from killed carbon steel. Since the rectifier system and associated refrigeration system operate at relatively low temperatures, cold insulation material is used for piping and equipment.

3. Propylene-Propane (PP Splitter) System (Figures IV-F3)

The purpose of the PP splitter column is to fractionate propylene from propane to deliver the product propylene meeting required purity specification. Propane and propylene are close boiling compounds with a narrow normal boiling point difference of ~5.3 Deg C (~9.6 Deg F) and close volatilities requiring large number of equilibrium stages and high reflux to feed ratio of approximately 7-9 to separate by distillation.

Lowering the fractionation pressure improves relative volatility requiring less reflux for a given degree of separation or increases purity for same reflux. Lowering the increases volumetric vapor traffic through the column. A balance is therefore required for optimal design.

Feed to PP splitter enters from the de-ethanizer stripper bottoms on flow control reset by the de-ethanizer stripper bottoms level controller. De-ethanizer stripper operates at higher pressure than PP splitter, eliminating the need for separate feed pumps. Feed tray is located roughly one-quarter of the way up the column.

The overhead propylene vapors from the PP splitter flow to the heat pump compressor (HPC) via the HPC suction drum, where they are adiabatically compressed to a pressure sufficient enough to drive the flow through the downstream reboiler-condenser circuit and a co-incident temperature sufficient enough to effect reboil. HPC speed controller provides to regulate discharge flow and pressure.

Typically a two stage HPC is specified. This is because with single stage HPC, the discharge pressure needs to be high enough to condense in water/ air cooled exchanger imposing a lower limit on the column operating pressure requiring additional trays for a given degree of separation. Two stage compression, as in Figures IV-F3, permits to lower column operating pressure reducing the number of trays.

Majority of vapors from 1st stage are condensed at lower pressure and temperature to provide reboil; remainder vapors are compressed in 2nd stage enabling condensing/cooling in water/air cooled exchangers reducing overall utility cost.

In several units' heat contained in 2nd stage discharge vapors is recovered in a heat recovery reboiler providing part of depropanizer reboil heat duty.

Further, Figure IV-F3 scheme is two stage HPC with independent suction drum for each stage which is advantageous as follows. Propylene liquids from the trim cooler returning to the 2nd stage suction drum operating at higher pressure produce relatively less amount of flashed vapors as compared to returning to the 1st stage suction drum

that operates at lower pressure. This results in savings on overall compression work and associated utilities.

Majority of the propylene vapors from HPC discharge (or 1st stage discharge in case of 2 stage HPC) are sent to the tube side of the reboiler-condensers where they condense out rejecting heat to reboil propane liquid on the shell side. There can be more than one horizontal thermosiphon reboiler-condensers depending on the unit capacity. Flow controllers with the respective control valves at the outlet of each reboiler-condenser are set to deliver equal flow for balanced reboil. Flows are adjusted to achieve the desired reboil. In addition, HPC speed is used to control the reboil and keep the flow control valves in normal control range. Propylene liquids from reboiler-condensers are directly refluxed back to the column constituting ~90-92% of the total reflux during normal operation. Reboiler-condensers provide all the reboil heat duty and a major percentage but not all of the total condensing heat duty. It is therefore required to remove balance heat from the system.

The remainder of the propylene vapors from HPC discharge are sent to the trim condenser/cooler and the liquids are returned to the HPC suction drum. In case of 2 stage HPC, the remainder of the 1st stage discharge vapors are compressed in the 2nd stage and sent to the heat recovery reboiler and trim cooler. The total flow through the trim condenser/cooler as in single stage HPC or heat recovery reboiler/trim cooler circuit as in two stage HPC is proportional to the propylene entering the PP splitter system with the feed. Propylene entering and exiting the system should match failing which it will accumulate as vapor and increase system pressure. This is the reason PP splitter pressure is controlled by a pressure controller located on the HPC suction or 1st stage suction drum that resets the flow controller on the trim cooler outlet. If pressure increases, the flow through the trim condenser/cooler or heat recovery reboiler/trim cooler circuit is increased allowing more propylene to be condensed and removed as liquid restoring the pressure.

Propylene from the trim cooler is returned to the HPC 2nd stage suction drum. A portion of the liquids from product pump suction, is sent as reflux to the column on "sum flow controller" to regulate sum of the reflux and net product. HPC suction drum level controller resets the "sum flow controller" to regulate drum level. Pump is not required with 2nd stage suction drum as it operates at a higher pressure than PP splitter.

Net product is drawn on flow control that is reset by the product quality controller. Product quality control is based on propane content in the product. Propane analyzer controller located either on the HPC 2nd stage discharge serves as product quality controller. If the propane content in product increases, product quality controller resets the net product draw and causes it to decrease. This increases the level in the HPC suction drum which causes the drum level controller to increase the reflux. Increased reflux eventually restores the product quality. Opposite sequence of effects happen if propane in product decreases.

PP splitter bottoms level is controlled by a level controller that resets the bottoms flow controller. Propane from PP splitter bottom is pumped out by the propane recycle pumps to the depropanizer system.

A slip of di-olefins, rich in MAPD, is drawn by gravity assist to join recycle propane stream at propane recycle pump suction before being pumped out to the SHP. Pump provides for intimate mixing of the combined feed stream to the SHP.

3.1 Splitter System Process Equipment

The PP Splitter is fabricated from killed carbon steel vessel. The column is provided with proprietary Multi-Downcomer (MD) trays (see Figure IV-F5), though Enhanced-Capacity Multi-Downcomer (ECMD) trays may also be specified. These trays are supplied by UOP. A significant advantage to the MD/ECMD trays is that their design allows the tray spacing to be significantly less than conventional trays reducing the column height significantly.

The HPC is a single or two-stage centrifugal compressor. Each stage of the compressor is protected by a suction drum which provides the necessary surge volume for vapors. Compressor is driven by either an electric motor or a steam turbine drive.

The HPC suction drum (see Figure IV-F6) is constructed from killed carbon steel. It has an inlet feed distributor to knockout the entrained liquids in feed vapor. A 150 mm thick mesh blanket is provided at the top to remove any entrained liquids from the outgoing vapor. A vortex breaker is provided on the liquid outlet.

PP splitter reboiler-condensers are horizontal thermosiphon type shell and tube exchangers in killed carbon steel construction. There may be one or more tube bundles provided limited by the shell diameter and tube length. HYFLUX tubes supplied by UOP are typically specified that provide enhanced transfer rate that helps limit overall equipment size and/or number of tube bundles required with normal tubes.

4. SHP Unit on recycle propane stream (Figure IV-F4)

In the C3 Oleflex units with reactor effluent contact cooler that are designed to operate at relatively lower pressure (15.2 psia or 104.825 KPa A or 1.068 Kg/cm²a) at the last reactor outlet, section between the HCFE and reactor effluent compressor (REC) suction operate under slight vacuum during normal operations. The process flanges from the last reactor outlet to REC suction are therefore specified to be seal welded to prevent air ingress into the system.

In addition, oxygen analyzer provided at the reactor effluent drier outlet, net gas and PSA H₂ serve to warn the operator of any air ingress into the system. If PSA H₂ is contaminated with oxygen, it shall not be used for the SHP service.

Supply switchover to a stand-by trolley supplied PSA grade hydrogen with attendant regulator shall be ensured in under 10 minutes. It is contractor responsibility to design this system and make adequate piping/instrument provisions.

Oxygen will react with hydrogen on the SHP catalyst to generate water affecting its activity and performance. Further such water generated can get carried over to cold separation system via depropanizer and cause solid-water ice in the feed chiller section potentially leading to Oleflex shutdown requiring deriming of the cold separation system.

Therefore, SHP reactor is located on the recycle propane stream rather than on the liquid product stream. In the unlikely event of air ingress into the system, any oxygen contained in the liquid product stream will leave the system with the de-ethanizer off gas.

MAPD contained in the liquid product will be leaving with the PP splitter system with the recycle propane stream from the column bottoms. Since recycle propane stream constitutes only about 2/3rd of the liquid product stream, concentration of MAPD in the SHP feed will be relatively rich when compared to conventional C3 Oleflex units. Diolefins slip stream from PP splitter is combined with the recycle propane stream to constitute SHP feed. SHP feed is pre-heated to the desired temperature in the SHP feed exchanger exchanging heat with the de-ethanizer stripper bottoms stream. A temperature controller that operates in split range regulates the feed temperature. This will be explained later.

In designs where high pressure PSA H₂ is not available, a reciprocating type SHP hydrogen compressor is provided to inject hydrogen into the feed stream in a certain ratio of recycle propane to maintain the desired H₂/Di-Olefins ratio. Ratio block resets the hydrogen injection flow controller that acts on the compressor spill back control valve to regulate the injection rate. If the required hydrogen injection decreases, the spill back valve tends to open and vice versa. The compressor is required to always operate at a discharge pressure that is above the pressure of the feed stream to enable hydrogen injection. For this purpose, the outputs from the compressor discharge pressure and hydrogen flow controllers are routed through the high signal selector preventing the discharge pressure dropping below the feed pressure. During normal operation, the output from the flow controller will regulate the spill back valve. Pressure controller provided at the compressor suction regulates the flow through the compressor. If the injection flow increases, suction pressure will drop causing the suction control valve to open to permit more flow through the compressor and vice versa.

The feed with dissolved hydrogen then flows through the reactor where the MAPD are selectively converted to propylene to deliver a product effluent virtually extinct in MAPD. The process flow through this circuit and associated equipment/instruments are exactly similar to that described in Section IV E.

SHP reactor system must operate at a sufficient pressure to enable proper dissolution of hydrogen and to maintain the liquid phase in reactor. SHP feed pressure controller and PP splitter bottoms flow controller outputs are routed through a low signal selector to regulate the feed pressure and flow. The control valve is located at SHP outlet. During normal operation, the flow controller output is expected to regulate the control valve.

SHP effluent essentially free of MAPD then combines with the fresh propane stream from the feed treatment section, to constitute the combined feed stream to the depropanizer. Combined feed stream is pre-heated in the SHP feed effluent exchanger by the de-ethanizer stripper bottoms stream. It is further preheated in the depropanizer feed preheater by the circulating hot solvent and the sent to the depropanizer column.

SHP Feed Temperature Control

Hot de-ethanizer stripper bottoms stream flows through the SHP effluent exchanger and the SHP feed exchanger in series where it rejects the heat. SHP feed temperature control is accomplished by a three-way split range control that acts on the SHP effluent exchanger exit flow control valve and the two exchanger bypass flow control valves. The two variables that are regulated are the temperature and flow of the hot stream through the SHP feed exchanger.

High SHP feed temperature signal first opens the control valve at SHP effluent exchanger exit to decrease the temperature of the hot stream to SHP feed exchanger. Second, it closes the SHP effluent exchanger bypass control valve further decreasing the hot stream temperature. Third, it decreases the hot stream flow through the SHP feed exchanger by opening its bypass control valve.

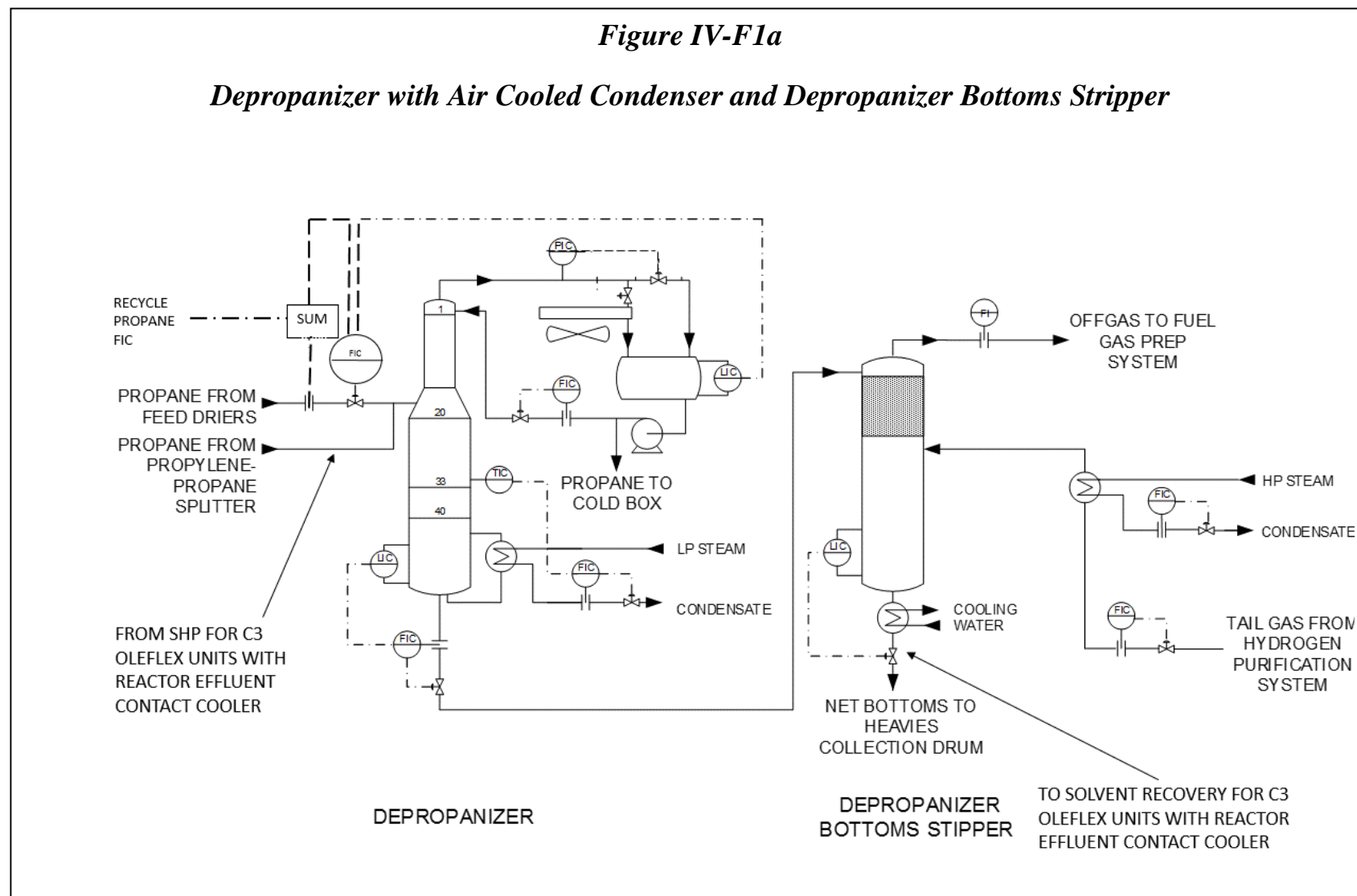
Figure IV-F1a***Depropanizer with Air Cooled Condenser and Depropanizer Bottoms Stripper***

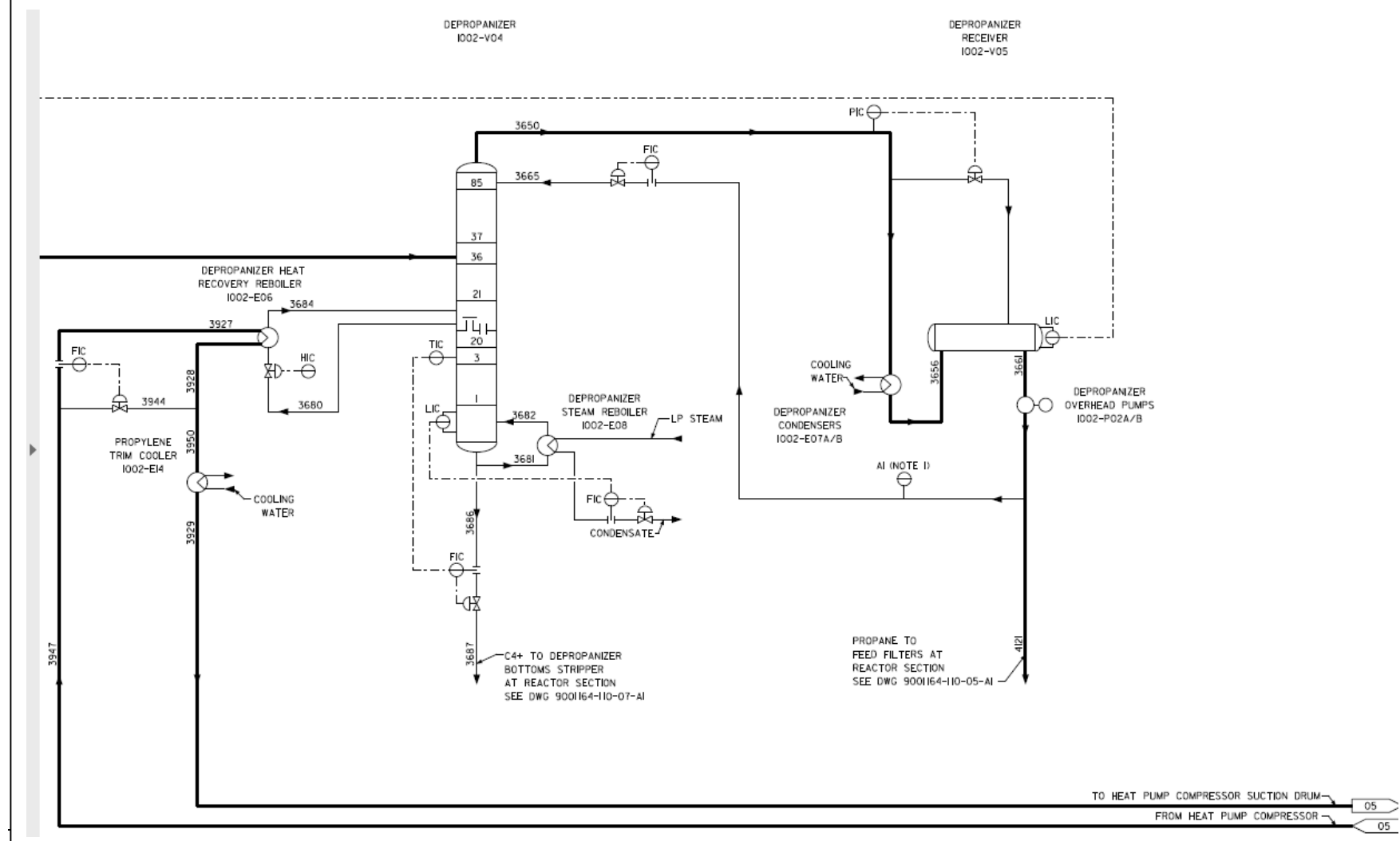
Figure IV-F1b**Single Depropanizer with Heat Recovery Reboiler & Water Cooled Condenser**

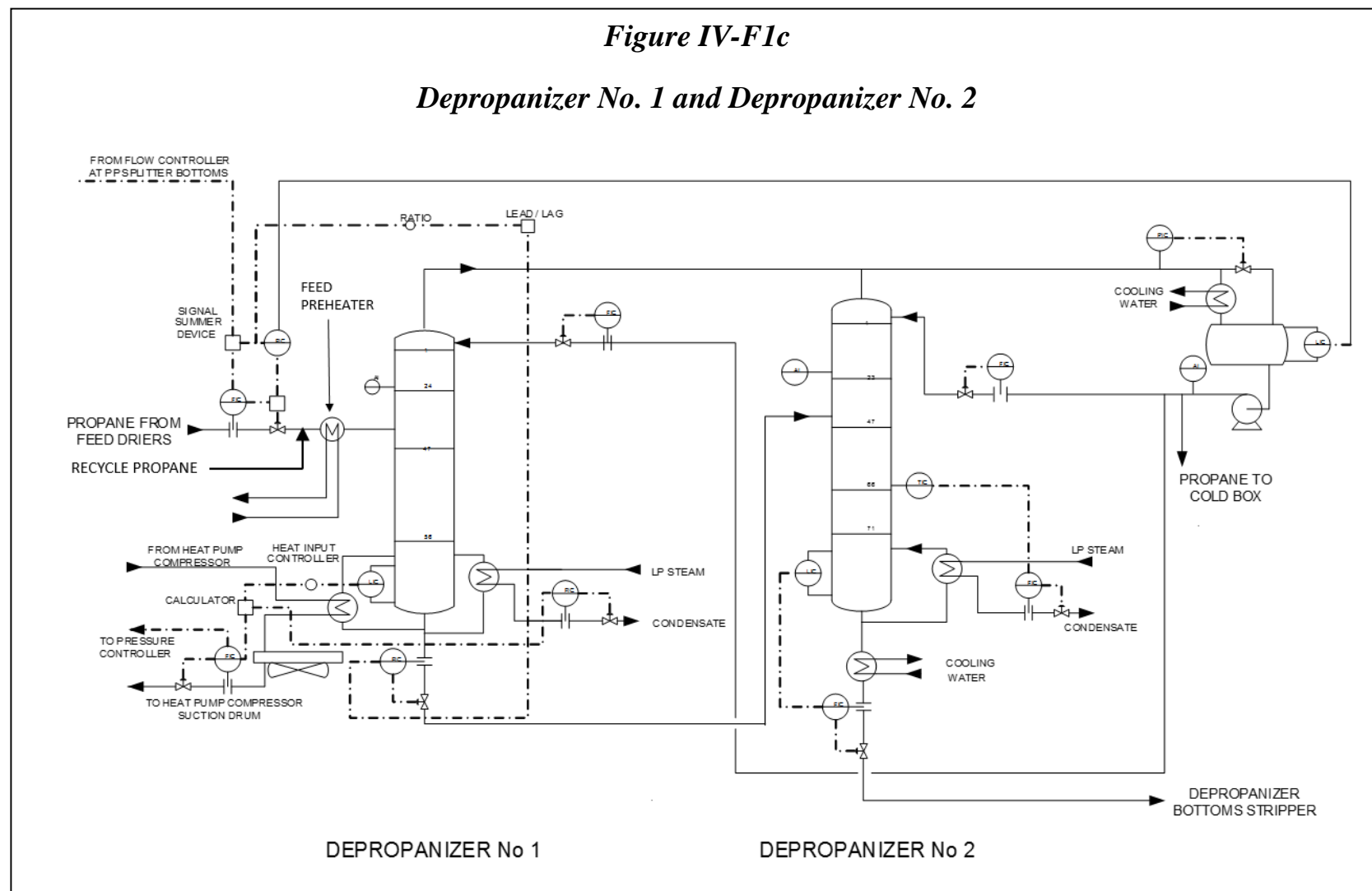
Figure IV-F1c**Depropanizer No. 1 and Depropanizer No. 2**

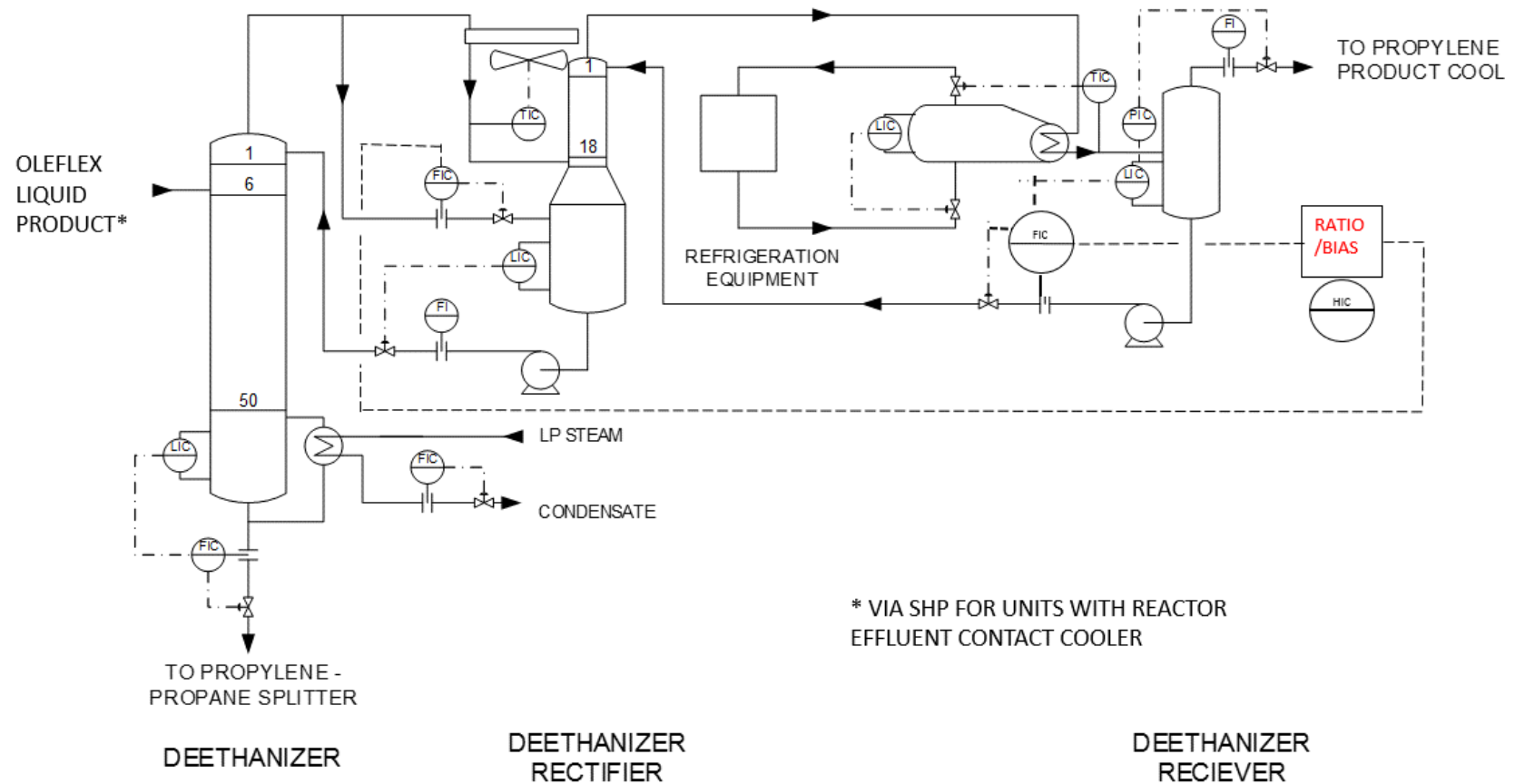
Figure IV-F2a**Deethanizer and Refrigeration Equipment with Air Cooled Stripper Condenser**

Figure IV-F2b

Deethanizer and Refrigeration Equipment with Water Cooled Stripper Condenser

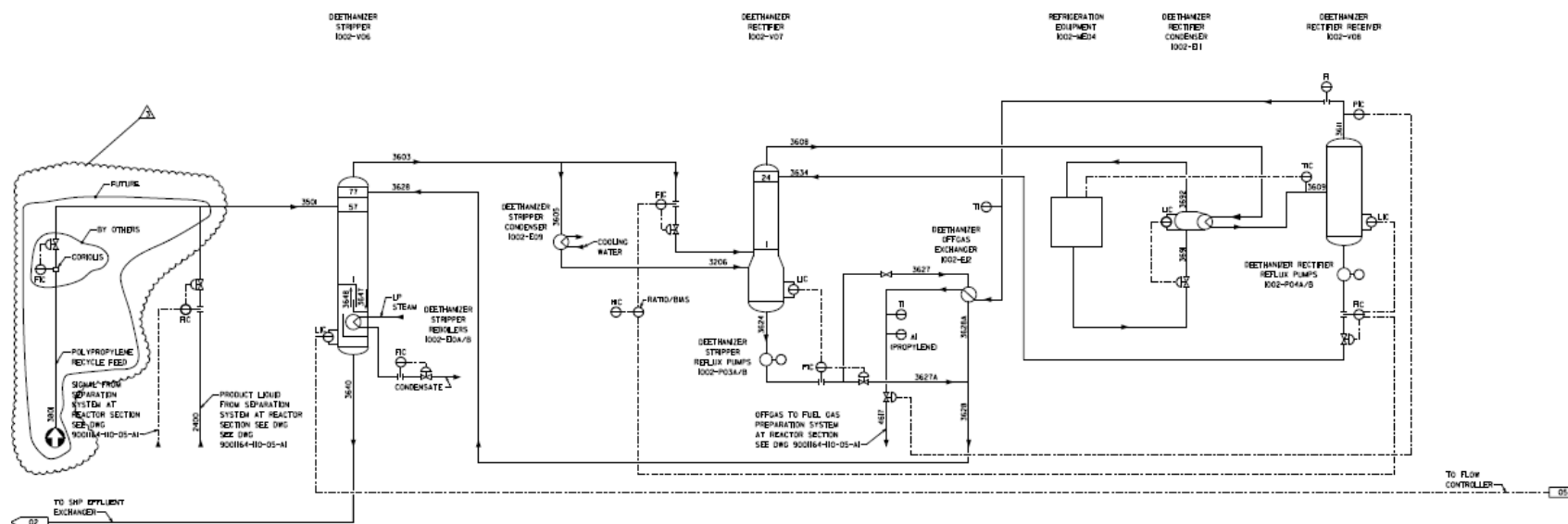


Figure IV-F3

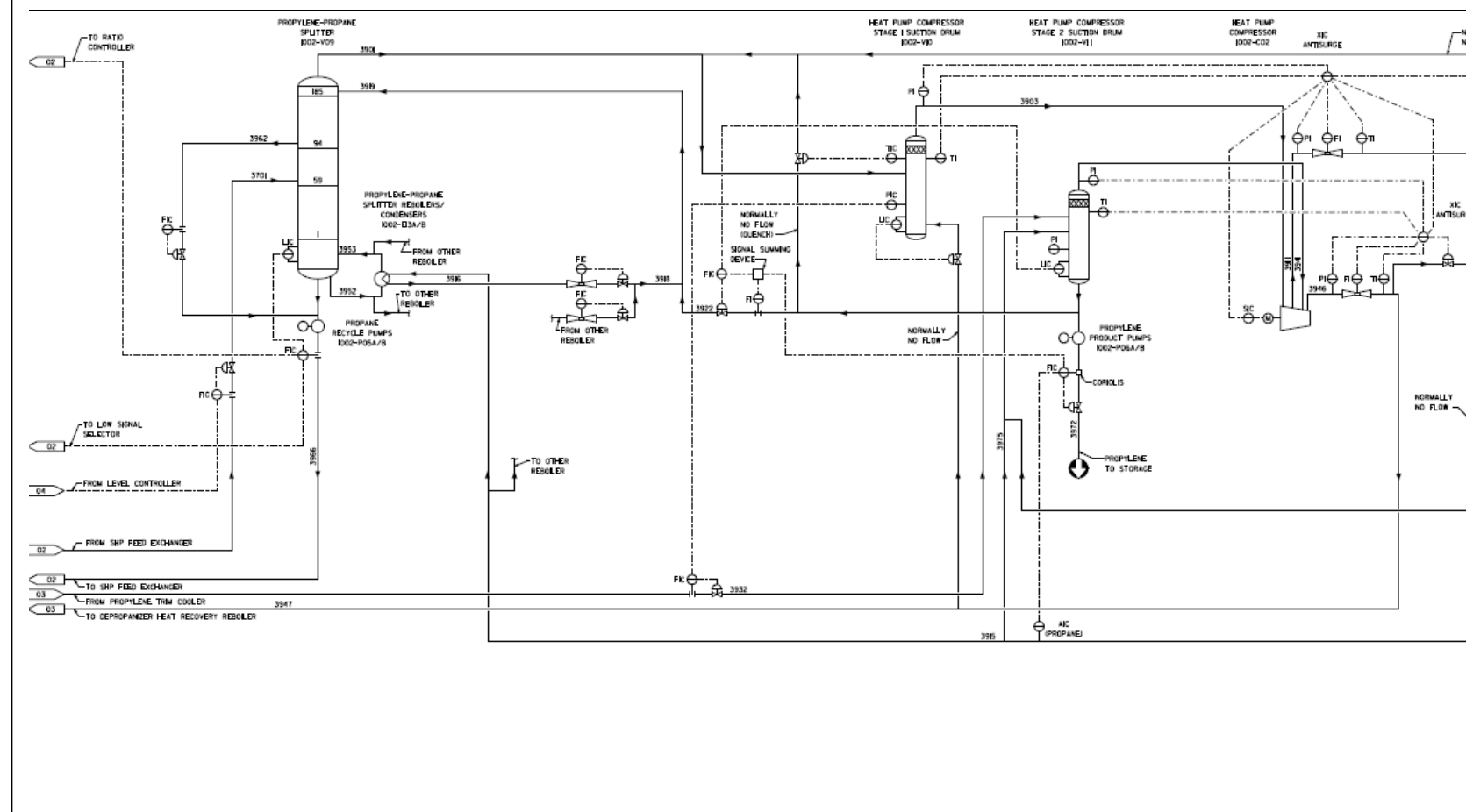
Propylene-Propane Splitter Two Stage Heat Pump with Independent Suction Drums

Figure IV-F4

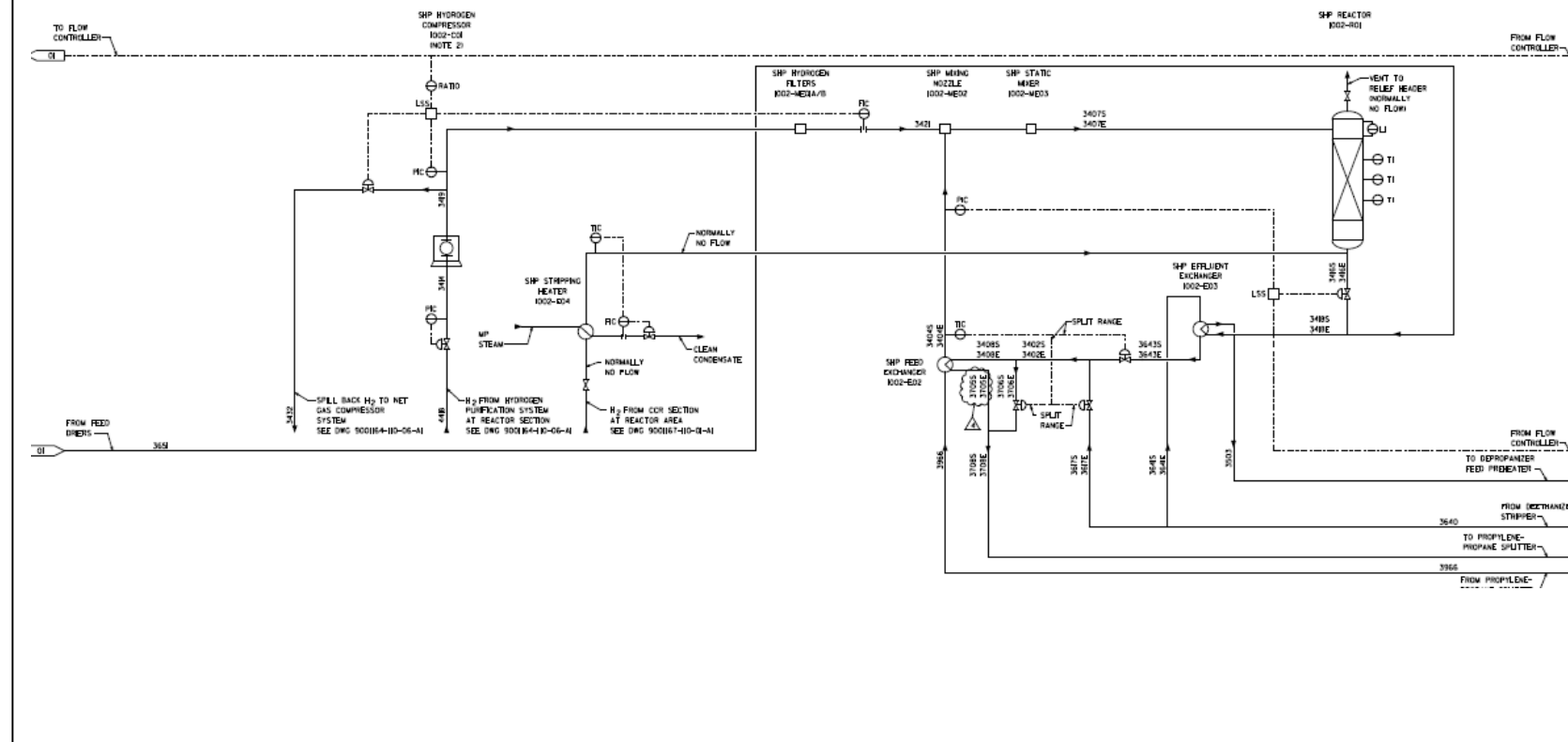
SHP Reactor in C3 Oleflex Units with Reactor Effluent Contact Cooler

Figure IV-F5
Multi-Downcomer (MD) Trays

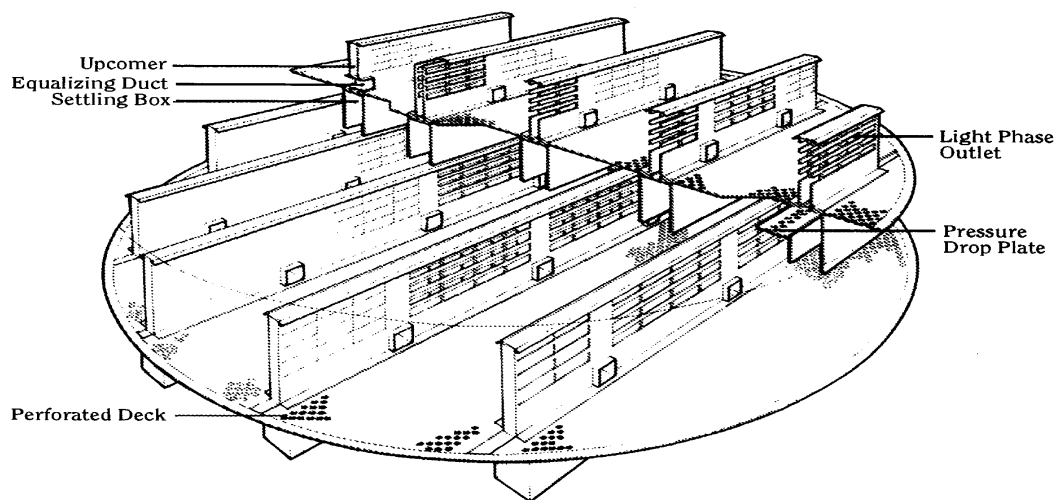
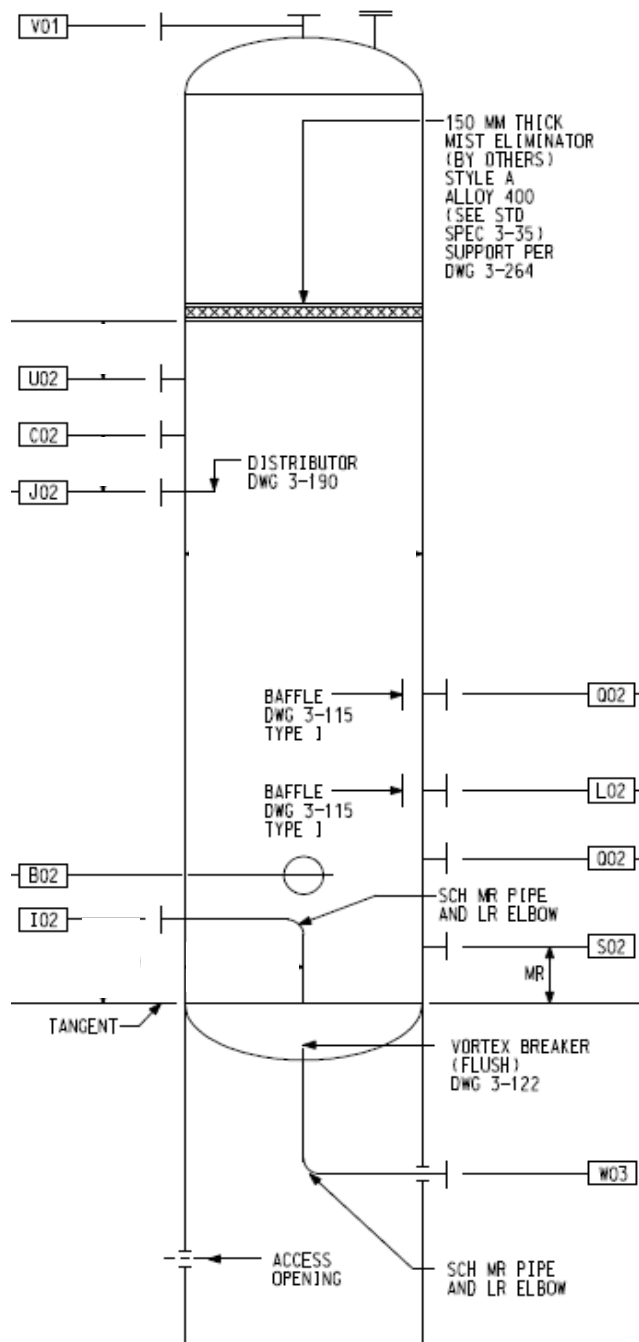


Figure IV-F6
Heat Pump Compressor Suction Drum



V. Pre-commissioning

The pre-commissioning activities and attendant procedures ensure by thorough cleaning, inspection and testing that the equipment and associated piping is clean, safe, operable and constructed as specified. The material in this section gives general guidelines for preparation before startup. Should a certain section not apply to a particular process unit, that section should be ignored.

As the construction of the unit nears mechanical completion, a number of activities and associated work must begin in order to prepare it for startup. These pre-commissioning activities have three main purposes: (1) to ensure, by thorough inspection and testing, that the unit is safe, operable, and constructed as specified; (2) to prepare equipment and associated piping for operation by thorough cleaning/flushing, running in, etc.; and (3) to acquaint the operators with the unit. The importance of these activities cannot be overemphasized. No matter how well a unit is designed, if the equipment is not constructed as specified, not properly brought on stream, or it's functioning not understood by the operators, it will not perform as expected.

All of the following activities are required to properly pre-commission the unit. However, the exact order of presentation need not be strictly obeyed. Depending on the progress of construction, certain procedures may be required earlier or later than suggested here. A thorough knowledge of the entire pre-commissioning operation will allow the plant personnel to schedule activities in the most time-saving and labor-efficient way. These are the necessary pre-commissioning activities:

- a. Oleflex Reactors Cleaning and Inspection
- b. Oleflex Fired Heaters Cleaning and Inspection
- c. Vessel Cleaning and Inspection
- d. Cleaning and Inspection of Other Major Equipment
- e. Piping and Instrument Check
- f. Hydrostatic Testing
- g. Line Flushing
- h. Run-In of Pumps and Drivers
- i. Run-In of Compressors
- j. Servicing and Calibration of Instruments
- k. Commissioning of Plant Utilities
- l. Availability Check of Chemicals and Other Materials
- m. Plant Pressure Test
- n. Air-Freeing
- o. Commissioning of Additional Plant Services
- p. Heater Refractory Dry-Out
- q. Reactor Loading

A. Oleflex Reactors Inspection

The inspection of the Oleflex reactors is important due to the high operating temperature and hydrogen partial pressure. The reactor vessel nameplate, vendor drawings and specification sheets should be checked against the UOP project specifications. Any deviations should be documented and resolved before placing the reactor into operation. Particular attention should be given to the vessel temperature rating, pressure rating, vacuum rating, shell thickness, metallurgy, vessel elevation, support and construction of internals.

B. Oleflex Fired Heaters Inspection

Heater headers and tubes should be inspected for cleanliness and construction in accordance with UOP project specifications. Tube spacing, tube supports, tube insulation where specified, tube-manifold joints should conform to the requirements. Associated piping and equipment in fuel gas system should be inspected. Metallurgy, burners, refractory, insulation, baffles, stack dampers, instrument connections, steam connections, explosion doors, access doors, observation ports, stack arrangement, expansion provisions should be checked.

C. Vessel Inspection

Inspection of all vessels, separators, columns, receivers, storage tanks, etc., should be made at an early stage of construction. The actual installation should be compared to the vessel drawings in the Project Specifications. Particular attention should be given to the following details:

- a. Vessel temperature, pressure and vacuum rating
- b. Vessel wall thickness and metallurgy
- c. Vessel elevation and support.
- d. Vessel cladding: thickness and metallurgy
- e. Trays: number, type, spacing, levelness, liquid seal, weir height, valve number and type, sieve hole diameter and pitch, metallurgy, weep holes, supports
- f. Partition walls: location, height, seal
- g. Distributors: type, levelness, orientation, size, number and size of openings
- h. Nozzles: location, size and levelness
- i. Vortex breakers, baffles, wear plates
- j. Demisters and coalescing screens: thickness, materials, support and tightness
- k. Thermowells: location, length, pressure rating and metallurgy
- l. Level instruments: type, length, location of nozzles and metallurgy
- m. Insulation

- n. Fireproofing
- o. Inspection plates in place
- p. Cleanliness

CAUTION: Before entering a vessel, the refinery's safety precautions should be observed. These usually include the following: sampling the vessel for toxic vapors and oxygen concentration, wearing a safety harness, and having an attendant outside the vessel. AN UNATTENDED VESSEL SHOULD NEVER BE ENTERED.

D. Inspection of Other Major Equipment

When inspecting the following equipment, special attention should be given to the associated items:

Heat Exchangers: refractory lining, metallurgies, tubes, grounding wires, expansion provisions; manufacturer's ratings for temperature, pressure and pressure drop; nozzles, flanges.

- a. Shell and Tube: elevation, insulation, tube sheets, baffles, channel covers, differential pressure rating.
- b. Fin-Fan: header boxes, louvers, tube fins, fans, motor, bearings, motor grounding wire, fan pitch control, vibration switch, belt.

Pumps: metallurgy, suction and discharge block valves, suction strainer, discharge pressure gauge, check valves, lubrication and cooling systems, piping expansion provisions, drains, steam tracing and insulation of pump and associated lines; vendors ratings for head, capacity, temperature and pressure.

- a. Centrifugal: NPSH and speed rating, balancing line, warm-up lines, seal flush, bearings.
- b. Positive Displacement: discharge relief valve, pulsation dampeners, packing, speed and stroke rating.

Compressors: metallurgy, lube oil system, suction and discharge block valves, suction strainer, instruments, insulation, number of stages, piping supports; vendor ratings for capacity, pressure, temperature, specific gravity and compression ratio.

- a. Centrifugal: seal oil system, vibration monitor.
- b. Reciprocating: cooling water system, packing vents, suction valve unloaders, steam tracing, pulsation dampeners, distance pieces.

E. Piping and Instrument Check

The unit should be checked to ensure that it conforms to the UOP piping and instrument diagram. In addition to verification of the correct process flow, the inspection should include the following:

- a. Line sizes and metallurgy
- b. Flanges and gaskets
- c. Bolting
- d. Drains and vents
- e. Relief valve settings
- f. Piping supports and expansion provisions
- g. Equipment accessibility
- h. Utility lines
- i. Tie-ins with other units/storage
- j. General safety requirements

F. Strength (Hydro-Test) and Leak Testing

Hydrostatic tests are made on new or repaired equipment and piping to confirm strength of materials and welds. On new equipment, if the strength test (hydro test) has been done at fabrication shop, witnessed and certified normally it is not required to hydro test in field unless the connections to the vessel are not flanged but welded. Large equipment – for example fractionator- if constructed at site, will need to be hydro-tested at site. Most of the process piping welded at site will also require hydro-test at site. Following the completion of construction the unit must be strength tested to make certain that no leaks exist in any joints or welds. Any equipment, whether piping, vessels, or exchangers, which has been modified, repaired, or had connections made to it by welding during a downtime or construction period preceding a startup should be strength tested before any hydrocarbon is admitted to the unit. This strength testing is normally done by hydrostatic pressure. This test is made by completely filling the equipment with water and increasing the pressure. Normally, a portable positive displacement pump is used to raise the pressure. This test should not be confused with other less severe tests generally carried out before a startup to check the tightness of connections.

NOTE: Chloride deposits from plant water that contains high chloride levels can cause stress corrosion cracking in austenitic steels. In areas of the plant that contain austenitic steel, serious consideration should be given to using treated water for hydrostatic testing. Initially, however, the plant water should be analyzed for chloride content. Additional analyses, as hydrostatic testing continues, should be performed to ensure the continued suitability of the plant water. If analyses ever indicate high chloride

levels in the plant water, treated water should be used exclusively in the austenitic steel equipment.

The contractor typically carries out these tests with the assistance of operation personnel. When hydrostatic pressure testing is performed in the field, operating personnel assigned to witness and record the test should determine that blinds have been properly placed to isolate the equipment to be tested from all other equipment which has a lower design pressure. The recommended procedure is to divide the unit into groups of similar test pressures and isolate them by installing suitable blinds. If for any reason it should become necessary for the operators to carry out the test, these suggestions are extended:

An Air Pressure Test using plant air can be placed on the sections of the unit prior to the hydrostatic test so that any open lines or flanges may be discovered and taken care of before water is admitted. However, a water hydrostatic test is considered necessary for final testing and to determine the location of all leaks.

The hydro test should be performed as prescribed by the relevant standard/code test procedure for the piping and equipment. Vendor mechanical design data sheets must be referred for the specified hydro test pressure.

All items under test must be liquid full, with all air vented from high point legs and other pockets. Relief valves or rupture discs must be removed, blinded, or gagged so that they will not open during the testing. Internals, such as level ball floats or other instruments that are not designed for the test pressure, must be removed. Remove all orifice plates in lines to be tested.

It is not practical to test all of the piping/equipment together. Thus the unit will be divided into sections as governed by the test pressures to which each item will be subjected. Suitable blinds must be made up for insertion in nozzles and between flanges to isolate the various sections of equipment as required by different pressure ratings.

Items which are capable of withstanding the test, such as piping connected to a vessel under test, may be subjected to the test together with the equipment. Ensure that all valves within the test system are open. The refinery piping code ANSI B31.3 must always be followed when testing process piping.

Items which are not capable of withstanding the test, such as vessels connected to piping under test, must be isolated by blinding.

Test Gauges must be placed at the low point of a large line vessel so that the liquid head will be taken into account.

Fine Mesh Screens should be placed in the suction lines of all pumps before any liquid or gas is allowed to pass through them from newly constructed or dirty lines. If

this is not done, scale, weld metal, slag, stones, etc., may damage the pumps. The screens also act to trap such dirt in a place where it can be conveniently removed. Suction screens are normally placed in a flange or T-type strainer (for larger lines) between the suction valve and the pump. The screens should be made of fine screen retained by a heavy gauge; punched-hole; cone-type strainer. These should be placed in the lines before the unit is pressure tested so that the test liquid can be pumped through the lines. The flow through the screen should preferably be downward or horizontal. Precautions should be taken to place screen in a location where the dirt particles will not drop into an inaccessible place in the line when the flow through the pump stops. If this should happen, it may not be possible to remove the dirt upon removal of the screen. See the section on Line Flushing.

Special attention should be given to hydro test on the critical shell-and-tube type heat exchangers where there is a possibility that an exchange medium such as hot oil or cooling water, can enter the process side of the exchanger during normal operation.

NOTE: Check exchanger vendor name plate test pressure regulations in cases where differential design is used on the tube bundles.

NOTE: Make sure all the water from hydro test is drained out from the system from the low points. This is critical to minimize amount of free water left over in the system

All relief valves (PSV's) are required to be bench tested and set before final installation. This testing and setting may be done while hydrostatic testing is in progress. Do not return relief valves to service until after the line flushing procedure has been completed.

CAUTION: A water filled system requires venting when being emptied in order to avoid pulling a vacuum and possibly collapsing equipment.

G. Line Flushing

This activity must be permitted only after certification of completion of construction of all the piping/equipment system components within the system by the contractor – material identification, as-built check against issued drawings, line check, insulation, hydro test, radiography etc. The purpose of this activity is to thoroughly clean the system to remove weld slag, grit, sand, rust, and other debris.

This may be done soon after hydrostatic testing, before the test water is drained to reduce utility water consumption. In general, liquid lines are flushed with water and thoroughly drained. Vapor lines may be either water flushed or air blown, but water

should be blown from vapor lines if water flushed. Gas lines to compressors must be free of water. Steam lines are flushed with steam through heating/cooling cycles to remove all the surface rust.

Following are the suggested guidelines for line flushing:

Where practical, clean water should be supplied to the vessels, and contiguous lines should be flushed away from the vessel. Never flush into equipment.

No matter what the flushing medium – steam, air, or water – maximum volume and velocity should be used for thorough cleaning.

Orifice plates must not be in place while flushing.

Control valves should be removed. It is strongly recommended that line flushing should not be conducted through the control valves. If construction trash or debris becomes trapped in the valve and/or valve seat, the valve may be damaged. This is especially true of on/off valves that require a tight shut off. Refer to vendor recommendations for specialized valves. Additionally, refer to UOP Project Specifications 616 sheets for further notes on control valves.

Instrument lines should be flushed with the transmitter removed.

Flexitallic gaskets and other final gaskets cannot be reused so they should not be put in until final installation. Temporary gaskets can be used for initial installation.

At pumps:

- Disconnect suction and discharge piping and flush lines.
- Install temporary screens in pump suction strainers.
- Reconnect lines for circulating water.

See further discussion under "Run-in of Pumps and Drivers".

Regulate the flushing medium at its source. As examples, water from a tower should be regulated at the tower; and steam, at the valve in the supply to the line being blown.

Flush through all vents and drains. Where possible, flush downward or horizontally. Flush or blow:

- The main header, from source to end, then
- Each lateral header, from the main to end, and
- Each branch line, from the lateral header to end.

Always flush through a piece of equipment's bypass to an open end before flushing through the equipment.

Disconnect lines at exchangers and flush to the openings.

For steam systems, flush well through dirt leg drains and steam trap bypasses before placing the traps in service.

Relief valves should be blinded if they have been returned to service following hydrostatic testing. (Set pressure can be checked at this time in the shop.)

Water flushed lines which do not drain freely should be blown clean with air.

Vapor/gas-handling piping may be either water flushed or blown clear with air. Water should be blown from the vapor/gas lines on completion of flushing. Vapor/gas piping to compressors must be free of water.

Upon completion of line flushing of any system, carefully check that all temporary breaks are reconnected, control valves are replaced, and pump alignments are normal. Also, see that all free water has been drained out thoroughly if water was used for flushing.

Oleflex specific guidelines for line flushing:

Following are the guidelines for line flushing/blowing in the Oleflex unit. It is the responsibility of the contractor to develop appropriate site specific procedures and techniques to ensure that the equipment and the lines are cleaned to remove all the construction debris, grit, sand and foreign material in addition to removal of free water to deliver a clean and dry system in preparation for commissioning.

Flushing Medium:

Water is not a convenient flushing medium for the process piping and equipment in the Oleflex reactor section and the reactor effluent circuit all the way up to the Cold Separation System given large line sizes and system volumes. If filled with water and drained or flushed with water in the first pass to remove soluble debris or if the water retention is from hydro test, they shall be air blown in second pass to remove all free water with clean and dry instrument air.

A minimum of 1 meter/second velocity is required to ensure good cleaning if water is used as flushing medium for line sizes 4" NB or smaller. It is preferred to use demineralized water for flushing to ensure no sediment is left behind. When this is not possible, potable water must be used. Raw water shall be avoided as flushing medium. Flushing shall continue until the water coming out of the discharge point is free of suspended particulate and is as clear as the water at the injection point. This must be confirmed by collecting the discharge water sample in clean glass bottle and

comparing with injection water. Upon completion of flushing with water, the lines must be air blown with clean and dry instrument air until all free water has been removed.

“Packing Blow” or “Plastic Sheet Blow” with dry oil free instrument air may be employed in large lines, typically for lines larger than 4” NB, where continuous instrument air blow is not practical. This provides for excellent cleaning due to high velocity of air in the line upon sheet rupture. Limit maximum “sheet rupture” pressure to 1.5-2.0 Kg/cm² g (21-28 psig) or equipment/piping design pressure whichever is lower. Equipment/piping design pressure shall not be exceeded. As large amount of stored energy is released at the point of rupture, a wooden board that is properly supported shall be placed opposite the blow point to absorb and dissipate the energy on impact. Attach a white thick sheet of cardboard paper to the impact board. Check the appearance of the paper after “sheet rupture”. If the line is not clean, the white sheet will become indented with dirt, weld slag and debris. Continue the “packing blow” until the white sheet remains clean post impact.

For small lines, typically less than 6” NB, where continuous instrument air blow is employed in second pass (if first pass cleaning was performed with water); the efficacy of cleaning must still be confirmed. Prepare an 8”x8” square flange contraption made out of aluminum or 1 mm stainless steel sheet with handle. Attach a thick clean white cotton cloth tightly stretched across between flange faces. Hold at the blow point for at least 1 minute and check after blowing the line for at least about ½ hour. Any weld slag, metallic or other debris and dirt will stick to the cloth. If dirty, replace with new piece of cloth. Continue blowing and check after another ½ hour of air blow. Continue until the cloth remains clean.

Other means like mechanical pigging/power brush may be used if necessary for very large lines. The necessary special procedures in these cases shall be developed by the contractor.

Chloride Treater, Reactor Effluent Drier and Fresh Feed Drier Systems:

Chloride treater, reactor effluent drier vessels including the regeneration circuit piping/equipment and fresh feed drier vessels including the regeneration circuit piping/equipment shall be thoroughly cleaned and dried at this point. All the sequence valves within the reactor effluent system and fresh feed drier system must be removed and replaced with pipe spools.

Ensure the sequence valves do not get damaged during pre-commissioning line flushing activity and start to leak during normal operation!

Immediately upon completion of hydrostatic test, all the water must be drained from all the piping/equipment within the chloride treater, reactor effluent driers system and fresh feed drier system including the associated regeneration systems.

This shall be immediately followed by flushing with “packing blow” or plastic sheet blow with dry instrument air to ensure complete removal of all free water and debris like weld slag within the piping and equipment. On large piping, insert Boroscope through vantage points to make sure that all weld slag, debris and free water has been removed completely. Only after this the sequence valves in the reactor effluent drier system must be reinstalled to normalize the system.

This is essential to prevent the adsorbents in the chloride treater, reactor effluent drier and fresh feed drier getting damaged in contact with free water. Further, In addition, the precautions above aid in efficient “Initial Dry Out” or “Bulk Dry Out” operations covered later in this section.

For C3 Oleflex units with reactor effluent contact cooler and/or REC interstage contact cooler, it may be necessary to load adsorbents and take chloride treater and RED in line during bulk dry-out to trap and minimize solvent carryover during bulk dry-out phase to prevent coking in reactors. This requires that the process lines leading to these vessels and upstream lines/vessels are thoroughly cleaned to ensure they are free of weld slag and are essentially dry.

Oleflex Fired Heaters:

Fired heater U tubes should be cleaned by vacuuming out each tube separately. Cap the tube at both ends after vacuuming. The headers must be cleaned by stainless steel power brush or manually and vacuumed out. Upon completion the caps inserted on tubes must be removed. Boroscope examination must be done for cleanliness particularly weld slag. Air blowing is not practical since debris blown from one tube can fall into another.

Cold Separation System:

The equipment and piping within the cold separation system shall be flushed only as prescribed by the vendor. For this system flushing, air freeing and dry out are often combined in single step where applicable. Only nitrogen with less than 1 vol ppm H₂O as flushing/air freeing/drying medium is recommended which requires liquid nitrogen with portable nitrogen gas generator made available at site.

Upon completion of line/equipment flushing and removal of all free water by blowing with clean air, the system must be immediately taken-up for pressure holding test and air freeing with nitrogen in sequence to prevent flash corrosion. The “System” is kept under nitrogen blanket at ~10-20 KPaG for preservation. All the inlet and outlet points contained within the “System” boundary must be positively isolated by inserting blinds for process safety

H. Run-In of Pumps and Drivers

Proper installation and operation of pumps and drivers is essential for trouble-free performance. The pumps and drivers should receive careful handling during initial run-in. The initial run-in of pumps is generally done by circulating water through the new equipment. Temporary strainers are installed in the suction line of the pumps, conveniently located for removal and cleaning. The screens also should be positioned so that dirt particles will not gravitate to inaccessible places when flow is stopped. During run-in of pumps, the strainers may cause some restriction of flow. As debris collects in the strainers, flow to the pumps will fall off. When this happens to a centrifugal pump, it is necessary to throttle the pump discharge by partially closing the discharge valve. This prevents the pump from cavitating, which can cause damage to the pump. However, also avoid restricting the pump discharge to the extent that it causes internal slippage and excessive heat generation.

In starting a turbine-driven centrifugal pump, the rotation should be brought up to speed as rapidly as possible. Normal operating speeds are usually attained rapidly and automatically with motor-driven pumps, assuming proper motor starting.

The development of discharge pressure is essential to flush and lubricate the wearing rings. After initially starting the pump, close the discharge valve for a short time. Subsequently, it is always advisable, where practical, to close the pump discharge valve immediately prior to shutting down a centrifugal pump. However, discharge valves on operating positive displacement pumps should never be closed. These pumps can often overpressure themselves and downstream lines and equipment. The following items are suggested for checking prior to run-in:

- 1) The manufacturer's operating instructions and any specific precautions
- 2) Completion of overall installation.
- 3) Alignment of pump and driver for cold operation.
- 4) No undue strain by the piping on the pump or driver is allowable.
- 5) Cooling fluid piping and seal or gland oil piping:

Conventionally packed pumps in hot service are generally furnished with gland oil. Verify that this installation is correct and complete.

For pumps with mechanical seals, verify that all of the components of the flushing system (such as strainers, separators, restriction orifices and coolers) have been correctly installed and are clean. Loss of flush or dirty flush may cause the failure of seals. Process flushing to mechanical seals and to stuffing box jackets for some hot pumps has been specified for this unit. In addition, cooled product flushing material

is specified for stuffing box jackets with return to pump suction or to mechanical seals. Make sure:

- 1) Packing or seals are installed.
- 2) Bearings and shafts have been cleaned prior to final lubrication.
- 3) Pump and driver are lubricated according to lubrication instructions.
- 4) Rotation of electric motor drives uncoupled from the pump: Run-in uncoupled for a minimum of four hours, verifying good motor operation.
- 5) During run-in, many pumps are delivering a higher density liquid (water) than the normal process fluid.
 - a. Pumps' drivers are sized for the normal pumping fluid, therefore there is potential for the electric motor overload while running with water.
 - b. To avoid overloading the motor of a centrifugal pump, the flow must be limited by throttling the pump discharge valve.
 - c. When doing so, if possible, check the amperage usage against design.
- 6) The following procedure is suggested for pump run-in:
 - a. Rotate pump and driver by hand, verifying that they roll freely.
 - b. Check that run-in water circulation is lined up.
 - c. Open suction valves fully, venting air from piping and pumps, completely filling with liquid.
 - d. Establish flow of cooling fluid, where required.
 - e. Check that lubrication is satisfactory.
 - f. Make sure electric power is available from the switch gear to the starter of the electric motor driver.
 - g. Barely open the discharge valve on the centrifugal pump.
 - h. Start the pump; if the pressure does not build immediately, stop and resolve problem.
 - i. When the discharge pressure has increased satisfactorily after starting, gradually open the discharge valve to obtain the desired flow rate.
 - j. In the event of unusual noise, vibration, overheating, or other abnormal conditions, shut the pump down immediately. Correct the cause before resuming use of the pump. Continue to check for abnormal conditions as these may occur after prolonged operation.
 - k. Check shaft sealing; mechanical seals should show no leakage. Conventionally packed stuffing boxes must always be permitted

to leak slightly to provide some lubrication and to prevent overheating. Stuffing box gland nuts are generally only finger tight. A leaking mechanical seal will show some leakage on startup. However, after the pump is started and stopped a few times, the leakage may stop.

- l. Operate the pump, directing flows through all suction and discharge piping circuits.
- m. Inspect and clean screens as required.
- n. Recheck and realign if required, after any disturbance of piping, such as required for suction screen inspection if pipe flanges have to be parted for screen removal.
- o. When shutting down, close the discharge valve first, thereby maintaining discharge pressure while the pump rolls to a stop. This will also help protect against the pump rolling backwards should the discharge check valve leak, and gives the wearing rings a quick flush.
- p. After all lines available to a pump have had suitable flushing, the temporary screen may be removed, but only after it has been free of debris on two successive examinations. The permanent strainers may then be installed where required.

I. Run-In of Compressors

The run-in procedures for centrifugal and reciprocating compressors are somewhat different. Therefore, following some general compressor run-in guidelines, the two run-in procedures are presented separately.

Maintaining the recycle compressor is essential to continuous, safe and efficient unit operation. Therefore, it is very important that all operating personnel be familiar with startup and operation of the compressors. The run-in of these compressors is a good opportunity for the operating personnel to learn the compressors and the proper startup and operating procedures. The compressors should be started and operated according to the manufacturer's instructions.

In general, manufacturer's representatives will pre-check the compressors, drivers and the lube oil systems prior to initial machine run-in. Some of their responsibilities are:

- 1) Checking drive motor for proper rotational direction by pushing, once, the compressor starter switch.
- 2) Checking compressor-driver alignment, both hot and cold.
- 3) Checking for proper base grouting and equipment support.
- 4) Removing slushing oils from bearings and seals.
- 5) Checking all seal and bearing clearances.
- 6) Evaluating suction and discharge piping for proper vibrational support.

- 7) Acidizing and flushing lube oil systems.
- 8) Run-in of main and auxiliary lube oil pumps.
- 9) Establishing normal oil levels in all lube oil systems.

Once the pre-check is completed, the compressor should be ready for operation. Since these machines are important and expensive pieces of process equipment, their proper operation cannot be overemphasized. Manufacturer's recommendations should be consulted for a more thorough discussion of any item mentioned here.

1. Centrifugal Compressor Run-in

The following general run-in guidelines should be used for a centrifugal compressor in conjunction with the manufacturer's instructions.

- 1) Because of the high speed involved with this machine's operation, it may be desirable to leave a coarse suction screen in the machine for the duration of the first run to guard against the possibility of miscellaneous construction debris entering the compressor.
- 2) Check the rotating element of the compressor for free rotation by turning slowly by hand. If the rotor rubs, rotation should be stopped immediately and the difficulty located and repaired.
- 3) Line up and start the lube oil circulation system, including filters and coolers, to make certain that the bearings of the compressor and driver are well lubricated. The manufacturer's instructions will give the proper values for the lube oil pressure, as well as other necessary settings. Generally, the minimum inlet lube oil pressure to each bearing should be about 0.7 kg/cm² (10 psig).
- 4) Remove any suction or discharge line blinds.
- 5) Unblock the compressor suction and discharge.
- 6) Put the stand-by lube oil pump on auto-start.
- 7) Drain the compressor casing, before starting the compressor.
- 8) If the compressor driver is a condensing steam turbine, commission the surface condenser system and warm up the turbine. Warm-up should be extended evenly over a thirty minute period. During warm-up, the high pressure steam should be checked to ensure that all condensate is out of the system.
- 9) Start the compressor rotating using the inlet steam block valve for control (startup is best done on manual control) and bring the machine's speed to 500 rpm. If the compressor is motor driven, start the motor. Note any excessive vibration or noise. If either occurs, shut down immediately and locate the problem.

NOTE: With a flexible shaft, multistage turbine driver, the startup acceleration places considerable torque strain on

the coupling and, with startup heating effects, can warp the shaft. To minimize this possibility, the machine should be brought up to operating speed in several steps which may be automatic.

Allow the compressor to run at the specified rpm until the lube oil temperatures rise to near normal operating temperature, usually about 120°F (50°C). Start cooling water flows to the oil cooler to maintain lube oil temperature at the desired level. Do not allow lube oil temperatures to exceed 175°F (80°C).

If the machine is turbine driven, increase the compressor speed stepwise to above the critical speeds, being sure to increase the speed smoothly and rapidly through the critical speeds. Put the compressor on governor control and establish the desired gas flow rate.

While operating, inspect the compressor carefully and record your observation. This information may prove very useful should the compressor subsequently fail. Make any necessary adjustments, as required, in the manufacturer's instructions for continuous operation.

2. Reciprocating Compressor Run-In

The following general procedure can be used, along with the manufacturer's instructions, to run-in a reciprocating recycle gas or booster gas compressor:

- 1) By hand, bar or jack turn over the machine to make certain it is free to move.
- 2) Commission the compressor cooling water and lube oil systems. Check temperature, flow, and integrity of systems.
- 3) Air free the circuit with nitrogen and leave the system at nitrogen header pressure.
- 4) Purge the compressor with nitrogen from the purge line on the compressor suction. Vent to flare or atmosphere.
- 5) Roll the machine over to ensure complete purging.
- 6) Open the compressor suction block valves to pressure up the machine to reactor system pressure (also, nitrogen header pressure). Open the compressor discharge block valves.
- 7) Drain the suction line of any liquid. Liquid is extremely harmful to reciprocating compressors, if allowed into the cylinders.
- 8) Start steam to the steam tracing on the suction line of the compressor. This steam tracing prevents vapor condensation between the compressor suction drum and the compressor. It serves no purpose with only nitrogen in the system, but should be commissioned to ensure that it functions.

- 9) Make sure that there are no restrictions to gas flow in the reactor recycle circuit.

Start the machine as follows:

- a. Open all of the suction unloading valves. Close the bypass-vent line, if open.
- b. Check the compressor's lubricating oil level in the crank case or reservoir.
- c. Check the cooling water temperature and flow through the cylinder jacket.
- d. Start the compressor and check the oil pressure.
- e. Let the compressor idle for a few minutes while closely watching the suction temperature.
- f. Put the machine on line by closing the suction unloading valves. Follow the manufacturer's loading sequence, if one has been provided.
- g. Start cooling water to the lube oil cooler, when the lube oil temperature reaches a normal operating temperature (50°C).
- h. While operating, inspect the compressor carefully and record your observations. This information may prove very useful in the event the compressor fails.

Follow the manufacturer's suggestions regarding maintenance of the compressor.

J. Servicing and Calibration of Instruments

Preparation of the plant instrumentation for startup and operation should include the following inspections and tests:

- a. Visual inspection of instruments to verify compliance with specifications.
- b. Visual inspection of instrument installation to verify compliance with installation specifications in the instrument instruction manual.
- c. Pressure testing of instrument piping
- d. Testing and calibration of instruments
- e. Testing of instrument air signal lines
- f. Testing of thermocouple wiring
- g. Loop checking
- h. Testing of safety relief valves, if not done during hydrostatic testing
- i. Final preparation.

In inspecting instruments for compliance with specification, attention should be given to instrument range, pressure rating, connections, and materials of construction, size, electrical characteristics and special features. Special attention should be paid to notes in the specification. Orifice plates should be inspected as soon as possible so they will be ready for installation when line flushing is complete; inspection should include size, materials of construction, location of weep hole, if any, counter bore,

overall condition, measurement of orifice bore, and verification of information stamped on tab.

Inspection of installations should include attention to location of transmitters with respect to the connection point; to piping for proper drainage, and for proper valves and gaskets; to transmitters and control valves to ensure that they are not installed backwards; and to special treatments such as winterizing for proper coverage and insulation. Orifice installations should be checked as soon as possible to ensure that straight run requirements are met, so that required piping changes can be completed before startup.

Instrument piping should be inspected visually for completeness and condition of welds and connections, and tested by pressuring with instrument air and brushing joints with soap solution. During hydrostatic testing of the plant, control valves should be isolated from the test system and adjacent drain valves should be opened to relieve any pressure. Control valve assemblies may be included in the hydrostatic test, provided that it is understood by all personnel that any leaks at control valve stem packing will be corrected by a qualified instrument technician. It is generally safer to exclude the control valve assemblies from the hydrostatic test.

Testing and calibration of instruments should include calibration of transmitters (in place, if possible), control board equipment and local controllers. Control valves and positioners should be adjusted. Special attention should be given to instrumentation used in critical services (such as temperature control) and accounting service (such as charge and product meters). Temperature transmitters should be checked for proper thermocouple burnout protection. Meter factor tags and valve position indication on controller output indicators should be installed at this time, and control actions should be set.

Instrument air signal lines should be checked for leakage, kinked tubing, and for connections to the proper port of shutdown solenoid valves and controllers. Thermocouple wiring should be inspected for proper polarity at the thermocouple head. Point by point verification of the switch identification at the temperature indicator in the control room can be accomplished by selecting a point to be checked and opening the circuit at the thermocouple head. With proper identification, the corresponding temperature indicator will drive upscale or otherwise indicate an open circuit. The same applies for TRC instruments on the control board. Loop checking involved checking inputs and outputs to ensure that piping and wiring has been properly installed. A signal should be simulated at the transmitter, and the control should be watched for response. The controller output should be adjusted manually, and the control valve watched for response. Proper response of control valves to air failure should be verified. Special attention should be given to the complicated trip systems in the Reactor Section of the unit.

All safety relief valves should be bench tested and set, if this was not done previously during the hydrostatic testing.

Final preparation includes checking instrument piping to verify that valves are in the proper position, making preliminary control mode adjustments, filling seal pots and seal legs, and making sure that instrument air and electrical power are supplied to all instruments. It may also be necessary to have the steam tracing operable at this time.

Commissioning of instruments will be carried out as the plant comes on stream. In commissioning of instruments, most attention will be directed toward liquid flow measurements. Differential pressure instrument piping must be drained to eliminate accumulated dirt and water, and the instrument zero must be adjusted to obtain a correct zero reading on the indicator scale on the control board. Controllers must be tuned, interface level transmitters must be zero checked. Scale, weld slag, and trash must be removed from sticking control valves, and other malfunctions must be corrected. Inspection and commissioning of analyzers should include attention to sample line lengths, analyzer enclosures, auxiliary equipment (such as carrier gas for chromatographs) and other items as indicated in the instruction manual for the particular analyzer.

In general, analyzers should be inspected, calibrated, and commissioned in accordance with procedures and instructions in the instruction manual for the analyzer. The specifications for the chromatographs include the services of a competent service engineer to review installation and supervise calibration and initial startup. Chromatographs should be inspected to see that all external piping and wiring is complete, and that no parts have been lost or damaged in shipment. No other action should be taken until the arrival of the service engineer.

K. Commissioning of Plant Services

For ease of operation, the plant's utility systems should be placed into service as soon as possible. Lines should be flushed and leak tested. Steam lines should be warmed up slowly to prevent damage from water hammer. All steam traps and control valves are to be placed into service and tested. The following list of systems should be commissioned:

- a. Plant water and treated water systems. These systems should already have been commissioned prior to the line flushing procedure.
- b. All electrical and light systems, including emergency power backups.
- c. All plant and instrument air systems.
- d. Nitrogen system.
- e. Fuel oil and fuel gas systems should be flushed and leak tested, but not commissioned within the units battery limits until it is needed, as for heater dry-outs.
- f. Steam and condensate systems, excluding steam tracing for the moment.
- g. Tempered water and refrigerated water systems should be flushed and leak tested, but not commissioned until startup is imminent.
- h. All drains and effluent systems.

A leak test of all drain and sump systems should be conducted to ensure that the systems are tight. Also, it should be verified that all drains lead to the proper sumps, pits or other collection facilities. This leak test can be effected by blinding or blocking all drain lines at the collection vessel and filling the drains to the brim of the drain funnels. A level loss indicates the existence, but not the exact location, of the leak(s). To verify correct drainage piping, the blinds and blocks should be removed. By water hosing each drain point individually and watching the collection vessel for the appearance of water, the correct drainage line-ups can be confirmed.

All storage tanks must be thoroughly flushed, leak tested, dried, and perhaps air-freed if the tank is in hydrocarbon service. Those tanks that have been air-freed should be left under slight positive nitrogen pressure. All lines to and from tankage must be flushed, blown dry with nitrogen, and pressure tested.

L. Availability Check of Required Materials

A check of chemicals, catalyst, ceramic balls, sand and other materials should be made to assure no delays due to shortages. The UOP Schedule "A" will list the quantities of these materials required in standards 106, 304 and other locations.

M. Plant Pressure Holding Test – Applies to both Reactor Section and Fractionation Section

The purpose of the plant pressure test, also termed leak test, is to check the piping and equipment for tightness of flanges, connections and fittings.

Note: These tests shall be performed only after completion of strength test (hydro-test) and line/equipment flushing/cleaning activities have been completed on all the components in the test system. These tests should not be confused with the strength tests or hydrostatic tests.

Pressure tests are made near, or at, the design rated pressure of the piping and equipment. Compressed dry (atm. dew point less than -40 Deg C or -40 Deg F) and oil free instrument air or plant nitrogen can be used on new equipment/piping to perform the pressure test. Portable oil free compressor fitted with drier may be used to supply dry air or the plant instrument air may be used. Plant air is not recommended if it is not dry as this can lead to flash corrosion in piping/equipment. Using dry air is less expensive than nitrogen, but either is acceptable in most cases. Advantage of using nitrogen is that it prevents flash corrosion on equipment/piping.

Note: When nitrogen is used, adequate safety precautions need to be exercised for positive isolation of the system under pressure

holding test to eliminate the risks of asphyxiation by cross leakages into areas where personnel could be working.

When pressure testing, particularly in cold weather, care should be taken that the testing is not carried out at a temperature so low that the metal has become brittle. As metal temperature decreases, brittleness increases. The vessel manufacturer should be consulted on the minimum temperature allowable before the vessel can be brought up to operating pressure. This is especially critical for the reactor, charge heater, combined feed exchangers and steam generation equipment.

If the utility air or utility nitrogen pressure is as yet unavailable, a source of higher pressure air or nitrogen is required. Generally, a small, portable oil free instrument air compressor is convenient as it can be transported around the plant to the various sections being pressure tested.

It is not possible to test all of the piping and equipment at once. Therefore, the unit should be tested in sections according to location and necessary test pressure, as in hydro test Isolation blinds should be used to segregate the sections. During testing, all safety relief valves and rupture discs must be removed or blinded, because the normal relieving pressure may be exceeded.

Steps in Pressure Testing a Section of the Process Plant:

Install all necessary blinds. Open all valves within the pressure test system.

Connect source of high pressure air or nitrogen to a drain or some other convenient point within the system.

Install calibrated pressure gauges of appropriate range at vantage points.

Pressure up the system.

- a. The applied pressure shall not exceed the design pressure of any component of piping/equipment included within the system. Typically, reactor system can be pressured up to maximum 300 KPaG (43.5 psig)
- b. Where the design of the equipment and piping within the system under test exceed the supply air/nitrogen pressure, pressure up the system close to the supply air/nitrogen pressure

Hold the pressure for 2 hours. If the loss in gauge pressure is less than 5% of the initial pressure within 2 hours of pressure holding, the system is considered to have passed the pressure holding test.

Apply masking tapes around the flanges, pierce a hole on the tape and apply soap solution on the hole. Directly apply soap solution to the screwed connections. If there is leak, one will be able to see the froth/soap bubbles being generated.

Repair leaks as they are located. Flange leaks may sometimes be stopped by simply increasing the bolt tension.

- a. If the joint leaks again, then the joint must be unbolted.
- b. Discard the old gasket, insert a new gasket and retighten the bolts.

Re-pressurize the system and repeat the pressure holding test if there were leaks identified and repaired with the first test.

After all the piping/equipment flange joints including instrument tubing screwed joints have been soap tested, all leaks repaired; and the last pressure holding test successful, the pressure holding test is considered complete.

Depressurize the system through various low point drains to help remove any remaining hydro test water or free water remnant from line flushing.

If the pressure holding tests were conducted with nitrogen, depressurize to ~20 KPaG, the system will remain partially air-free, simplifying the air freeing activity covered in Section V, Sub-Section O.

Note: Once the pressure holding tests on different sub-systems in the reactor section have been successfully completed, it will be necessary to perform the pressure holding test on the Oleflex Reactor Section as an Integral System and Feed Fractionation Section as an Integral System. Cold separation system will be bypassed during this integral system pressure holding test. The pressure holding test on the integral system is required because the blinds from the various sub-systems would have been removed and re-assembled to normalize the system in preparation for start-up. The same criterion for pressure holding test applies to the integral system as that applied for the sub-systems.

The integral system in Oleflex reactor section includes- Oleflex fired heaters and reactors, HCFE, reactor effluent contact cooler, REC, REC inter-stage contact cooler, REC discharge drum, chloride treater, reactor effluent driers, reactor effluent filters. Reactor effluent drier regeneration circuit up to and including regenerant gas scrubber is tested separately as another integral system.

The integral system in the fractionation section includes feed treatment section, depropanizer system, de-ethanizer system, propylene-propane splitter system and SHP system. A plant pressure holding test on this integral system is required after the temporary blinds are removed from individual sub-systems and the system is re-assembled and normalized prior to start-up.

Cold separation system pressure holding test, if required, requires understanding of the various plate fin passes and their arrangement; and the maximum differential pressure they can withstand. Further, only nitrogen with less than 1 mol ppm corresponding to less than -76 Deg C (-105 Deg F) atmospheric H₂O dew point shall be used to prevent contamination. Any leak check may require to be performed pass by pass. Follow vendor guidelines/procedures if such test is to be performed. Cold separation system is checked and certified by the vendor before dispatch and therefore generally not included in the pressure holding/ vacuum holding test.

Note: For the C3 Oleflex units designed with the reactor effluent contact cooler, certain process flanges in the section from last reactor outlet to the REC suction are specified with “lip seal welded gaskets”. The lip seal on the gaskets must be welded and bolt tightening completed prior to the pressure holding tests and vacuum holding tests

N. Plant Vacuum Holding Test – Applies only to the Oleflex Reactor Section - Mandatory Test

The advantage of plant pressure holding test in the reactor section to identify the joint leaks is that the leaks can be easily identified by soap test. However, it may not be sensitive enough to identify minor leaks. Therefore, a plant vacuum holding test is recommended to be performed to assure leak free system upon completion of the plant pressure holding test.

Note: The Plant Vacuum Holding Test as described in this sub-section N can be performed earlier during the pre-commissioning activity or combined with the Air Freeing by system evacuation as described later in the sub-section O

As against the pressure holding test performed in sections, the vacuum holding test is generally performed on the whole system in the reactor section after carefully identifying the equipment including instruments that are not designed for vacuum. Typically, it should be possible to perform vacuum holding test covering the Oleflex reactors and heaters, HCFE, reactor effluent contact cooler, REC inter-stage contact

cooler, REC discharge drum, chloride treater, reactor effluent driers and associated piping as an integral system. The REC and cold separation system may not be designed for vacuum and may need to be isolated. If they are designed for vacuum, they can be included in the system.

Note: Each unit must be independently examined for the equipment, piping and instruments that are not designed for vacuum that need to be positively isolated during the vacuum holding test.

For the C3 Oleflex units designed with reactor effluent contact cooler to operate at slightly lower pressure (~15.2 psia or 104.8 KPaA) at the last reactor outlet, plant vacuum holding test is a mandatory requirement in addition to the plant pressure holding test.

This is because in these units, the section between the HCFE and REC suction is anticipated to operate under slight vacuum during normal operations. Air leakage will have to be prevented.

Check and ensure each stage of REC is isolated and under nitrogen blanket since the casings may not be designed for vacuum. Carefully evaluate the process line-up requirements since the piping specifications may vary slightly across the units. The following guidelines “a” through “e” on the process line up prior to vacuum pulling to leak check the system are written for the C3 Oleflex units with the reactor effluent contact cooler which operate under slight vacuum at REC suction during normal operations.

- a. 1st & 2nd stage suction/discharge block valves are shut tightly
- b. Blind on 1st stage suction block valves is swung closed without lip seal welded gasket
- c. Blind on 2nd stage discharge block valve is swung closed
- d. Isolation valves on 1st/2nd antisurge valves are shut tightly
- e. Blinds on isolation valves of 1st/2nd stage antisurge valves are swung closed

Note: In C3 Oleflex units with reactor effluent contact cooler that operate under slight vacuum at REC suction, REC 1st stage suction block valve is specified with lip seal welded gaskets on either side of the blind. Since the blind will be in open position during normal operation, initially test the system with blind in closed position with suitable temporary gaskets. Once successful, swing this blind to open position, install permanent lip seal welded gaskets and repeat vacuum holding test. If successful, proceed with start-up. If unsuccessful, determine and fix the problem if it is internal leakage through the valve (which may be acceptable) or external leakage through the gaskets (which will be unacceptable). There will be situations later in the start-up when air freeing (to inert the system with nitrogen) or nitrogen freeing (to inventory with hydrogen-hydrocarbon) require vacuum pulling. On such occasions the blind with lip-

seal welded gasket on the suction isolation block valve will be retained in open position relying on the block valve to seal.

This line up allows vacuum to be pulled on REC interstage contact cooler, REC discharge cooler and REC discharge drum together with connected piping while maintaining the REC casings isolated. Keep either of the REC casings under nitrogen blanket at 10-20 KPaG.

Reconfirm that the piping and equipment including the instruments not designed for vacuum have been isolated. Pull vacuum on the system using the hogging steam ejector provided for evacuation until about 130 mm Hg Abs system pressure or whatever lowest permitted by the ejector is achieved. Hold vacuum in the system for 2 hours once it has been stabilized by isolating/blocking the ejector suction and then cutting off steam.

If the vacuum is not holding and slowly breaking out, there is air leak into the system. **If the air leak into the system is within 5% of the gauge pressure of the system during the vacuum holding period of two hours, the vacuum holding test is considered successful.** For example, if 150 mm Hg absolute pressure has been achieved after vacuum pulling the corresponding gauge pressure will be -610 mmHg G. A leakage rate corresponding to less than ~30 mmHg increase in system pressure over a two hour period is considered successful vacuum holding test.

Note: Repeat the pressure holding test if the vacuum holding test failed. Identify and fix the leak. Repeat the vacuum holding test.

If the leak cannot be identified in pressure holding test while the vacuum holding test continues to fail, a helium leak test may be performed on select small sub-sections as a last recourse to identify the leaking joint/connection. The critical section in such selection is the section between HCFE and REC suction that operates under slight vacuum. If the seal welded flanges are suspected leaking, recheck them this time with masking tape. If found leaking, the gasket will have to be replaced.

Cold separation system is generally not included in the vacuum holding test due to following reasons--- the equipment may not be mechanically designed for full vacuum; breaking the vacuum with plant nitrogen may let in moisture above permissible level of 1 mol ppm max. The equipment is tested and certified by vendor before dispatch.

O. Air-Freeing ---This activity applies to both the reactor section and fractionation section

This activity must be permitted only after the unit has passed the pressure holding test and vacuum holding test; and the process line up has been verified. The purpose of this activity is to remove all the oxygen from the reactor and fractionation system before introducing hydrogen and hydrocarbon into the unit.

It is necessary to completely air-free all piping and equipment in hydrogen or hydrocarbon service and keep under nitrogen blanket until the unit is ready for start-up. This activity may be done on a section by section basis for convenience.

By Evacuation Method

This method applies only to the Oleflex reactor section provisioned and designed for vacuum as specified. Fractionation section air freeing must be performed by piston-purge with nitrogen described later in this section.

Evacuation is the most efficient and effective way of removing air from the system. This method saves the amount of nitrogen that is required to air free the system compared to the piston-purge method. It is extremely critical that all equipment and instruments in the unit that are not capable of withstanding vacuum be isolated – these must be air freed first by nitrogen purge, isolated and kept under nitrogen blanket. Vacuum holding test and air freeing can be combined when air freeing is done by evacuation of the system.

To air-free by evacuation, commission the evacuation apparatus and draw the system down to the minimum pressure possible. Stop evacuation and introduce nitrogen to break the vacuum. Depending on the amount of vacuum pulled, it may take one or at the most two evacuations to achieve less than 0.5 mol% oxygen in the system when the air freeing is considered complete.

By Piston-Purge Method

In this method the system is pressured and de-pressured with nitrogen 3-4 times to achieve less than 0.5 mol% oxygen in the system after depressure. Unlike evacuation method, this method has an advantage that different sections of the plant can be air freed independently. However, the reactor section air freeing is usually done as one system for convenience except for the reactor effluent drier and feed drier regeneration circuits.

In this method, the system pressure is increased to maximum permissible pressure limited by the equipment/piping design pressure and the supply nitrogen header pressure. Typically the reactor system can be pressurized up to 300 KPaG (~45 psig) limited by equipment design pressure whereas the fractionation section can be pressurized up to 600 KPaG (~87 psig) limited by the nitrogen header pressure. The system is then de-pressured to about 50 KPaG (~7.3 psig). The pressure-de-pressure cycle is repeated for 3-4 times until % oxygen is less than 0.5 mol%.

Nitrogen is vented through various low point drains to help remove any remnant free water from the system. Samples should be taken from several remote points in the system and analyzed for oxygen. If the oxygen content is less than 0.5 volume percent, this section of the plant may be considered air-free. Leave the system under

slight positive nitrogen pressure (~15-20 KPaG or 2-3 psig) to prevent air being pulled in due to ambient temperature changes which can change the system pressure.

UOP does not recommend using steam to air free equipment in an Oleflex unit because all residual water must be removed from the equipment prior to start-up of the unit.

CAUTION: Until now, all activities have been carried out with piping and equipment containing air. With a nitrogen environment now existing in most equipment, a work and entry permit system should be established. A permit system will protect personnel by restricting work in unsafe areas. This system should be maintained for the entire life of the plant.

Any vessels that are loaded with adsorbent/catalyst shall be air freed and leak tested after loading as covered in the Section XII-Special Procedures. Refer to the CCR GOM for info on air freeing the CCR section of the unit.

P. Commissioning of Additional Plant Services

By this time, or in parallel with previous activities, the following critical plant support services shall be commissioned preparing for start-up.

- a. Plant fired water system including deluge/sprinkler/monitor system
- b. Plant drinking water/potable water system; eye wash ; body shower stations
- c. Plant flare system and flare-purge
- d. Plant potable/raw water system
- e. Plant drainage and waste water system
- f. Plant cooling water system
- g. Plant boilers/steam system
- h. Plant utility nitrogen system
- i. Plant utility air system
- j. Plant instrument air system
- k. Plant heat tracing system
- l. Plant raw material and finished product storage and lines
- m. Chlorine supply, storage system pre-commissioning and check-out; inventorying
- n. DMDS supply, storage system pre-commissioning and check out; inventorying
- o. Caustic supply, storage system pre-commissioning and check out; inventorying
- p. Start-Up H2 supply system – pipe line / trolley station system pre-commissioning and check out; inventorying up to battery limit

When flushing, the cooling water lines should be disconnected at exchangers and the exchanger flanges blinded. The cooling water system chemical treatment shall be completed before start-up.

The flare system should be flushed and drained. Also, the flare system must be purged of oxygen down to an acceptable level, generally less than 1.0%. Flare purge should be commissioned if provided.

If desired, the storage tank blanketing header can be commissioned at this time. The steam tracing system should be flushed with steam to verify free flow of steam to all users. If electrical heat tracing system is provided, it should be tested and commissioned. After commissioning, the tracing should be checked to verify that it is hot.

Q. Convection Section Chemical Boil Out and Fired Heater Refractory Dry-Out

Convection section chemical boil-out and fired heater refractory dry-out can begin only after the fuel gas system is fully commissioned and other utilities are available. Procedure for chemical boil out and heater refractory dry-out should be obtained from the heater vendor. Generally Oleflex dry bulk out and heater refractory dry out are often performed together.

VI. Start Up

The various aspects associated with startup of this process, both initial startup, and typical startups following the initial startup are included in this section. The purpose of startup procedures is to provide a safe and reliable way to bring the process on stream. All procedures will be included in a general format which must be modified to be used for a specific operation. This section will address special process considerations, if any, specific to startup conditions which may be required to assure optimum performance.

A. Initial Startup

The initial startup is comprised of the following steps:

1. Leak check, air freeing and drying of Cold Separation System
2. Steam generation system startup
3. Reactor circuit heat up and dry out operations (Bulk Dry out)
4. Reactor and vessel loadings
5. Feed/fractionation section startup long loop circulation and dry out
6. Reactor circuit dry out (Low Temperature Dry out)
7. Feed cut-in to the reactor circuit and subsequent line-out

The initial startup activities for the Feed/Fractionation and Reactor sections can be performed in parallel. The Feed/Fractionation and Reactor sections will be integrated during reactor circuit feed cut-in, covered later in the section. In order to proceed the unit shall be properly commissioned and all the vessels and lines should have been air-freed and leak tested.

The initial start-up steps are discussed in more detail as follows:

1. Leak Check, Air Freeing and Drying of Cold Separation System

Note: Vendor must be consulted for the detailed procedure. Vendor procedure takes precedence over the guide lines contained in this GOM. Flushing, Drying, Air Freeing and Pressure Holding Test can all be clubbed in single activity.

- 1) The cold separation system must be air free and dry before introducing liquid propane and/or hydrogen-propane vapors into the system to chill down in preparation for commissioning the system. Generally the cold separation system is leak tested and dried before dispatch. It is therefore required to air

free the system and perform only confirmatory dry out at site. If the cold separation system is not shipped dry and air free or if moisture has entered the system during site installation or if the system has been shipped dry but not air free, then the cold separation system will need to be made air free and dry as appropriate. The opportunity can also be utilized to re-confirm that the system is leak free by conducting pressure holding test on various passes of the cold separation system. Below is a guideline procedure for drying out and air freeing the cold separation system with nitrogen purge.

- 2) This should preferably be performed simultaneously when the reactor section leak checks and air freeing activities are ongoing. The equipment to be covered in this section include all the plate fin exchangers, turbo expanders, separator vessels, liquid product drum and liquid product pumps. Make sure the reactor effluent inlet, combined feed outlet, net gas outlet, CCR gas outlet, net gas feed to PSA if applicable, liquid product outlet, liquid propane feed inlet, flash gas outlet from liquid product drum and any other process lines to or from cold separation system are positively isolated by installing rated slip blinds.
- 3) Identify suitable nitrogen injection points and blow down low points in the cold separation system to cover each and every pass and equipment/vessel in the system. It is recommended that purging be performed in a down flow direction. It will take multiple flow paths to dry and air free the system.
- 4) The nitrogen used for purging and pressure holding test shall be clean and dry. This will require use of cryogenic liquid nitrogen with a vaporizer. The atmospheric moisture dew point of nitrogen to be used for cold separation system purge shall be lower than -76°C (-105°F) corresponding to less than 1 mol ppm water in nitrogen. The dew point of nitrogen should be confirmed independently with a portable dew point meter and the cleanliness should be checked with blotting paper at the supply point.
- 5) **Pressure Holding Test (Leak Check)**: Cold separation system is generally certified leak tested prior to dispatch and it is not normally necessary to perform a detailed pass by pass pressure holding test or leak check for the system. A simple pressure holding test including all passes and equipment within the system will help confirm if there are any external leaks from the system to the surrounding. It will not be possible to determine and confirm if there are internal leaks within the system between one or more passes.

If it is desired to perform pass by pass internal leak check on the equipment at site, it shall be under vendor supervision or guideline. As against the pressure holding test performed on the rest of the process plant piping and equipment, cold separation system leak check is a complex activity since it is required to be performed pass by pass. Further, each pass may constitute several plate

fin channels making it a challenge to identify which channels in a given pass are leaking. The leak across a given plate fin channel in a given pass may be very small at ambient conditions. For rigorous leak check helium leak test may be required. Reader of this manual is directed to consult the vendor for details of such a test. In this manual simple nitrogen leak test is described as follows.

Fix calibrated pressure gauges with 0.1 Kg/cm² g or lower least count on each pass - at the injection point after the isolation rated slip blind at the inlet of the pass; and at the blow point before the isolation rated slip blind at the outlet of the pass.

Select a pass to be tested - for example reactor effluent pass. Make sure the pass, in this case the combined feed, in contact with the reactor effluent pass is de-pressured to atmospheric pressure and kept positively isolated.

Connect the hose to the injection point (one more points can be used if required) and pressure up the reactor effluent pass to about ~6 Kg/cm² g or its mechanical design pressure or mechanical design differential pressure whichever is lower.

Hold the pressure for about 2 hours. If there is <5% drop in gauge pressure over the two hour period and no increase in pressure on the connected pass observed, the leak test is considered successful. If there is indeed leak, the combined feed pass pressure will gradually increase co-incident with the decrease in the pressure of the reactor effluent pass.

De-pressure the reactor effluent pass to flare header via a suitable point. Repeat two more times. This should complete air freeing and leak check for the reactor effluent pass. Repeat the same procedure to cover the remainder of the passes within the system.

Repeat the leak check if the first test failed. If the second leak check confirmed leak, consult the vendor to identify which channels in a given pass are leaking and fix the leaks under vendor supervision.

- 6) **Flushing and Drying:** Purge each pass of the cold separation system for at least 2 hours and check the dew point of nitrogen leaving the system at blow down point. During purging, the blow down point shall be connected to flare header or discharged at a safe elevated location to prevent personnel from getting exposed to nitrogen. The dew point at blow down point shall be less than -65°C (-85°F) to conclude the system is dry. Calibrated portable moisture analyzers shall be used for dew point measurements. In addition, check with blotting paper or stretched white cotton cloth at blow point if the system is clean and free from manufacturing debris. The system is considered clean if there are no indentations or weld slag particulate sticking to the blotting paper or

cotton cloth. Purging with nitrogen shall continue until both the dew point and cleanliness criterion are satisfied. During purging it is important to stay below the design pressure of all equipment and associated piping. Never exceed the mechanical design differential pressure across the plate fin heat exchanger passes at any stage.

- 7) Up on completion of dry out of all the equipment and passes within the system, stop the nitrogen purge. Re-pressure the system to ~20 KPaG with nitrogen and maintain the system under nitrogen blanket. The blinds inserted at the system boundary must be retained until completion of the "Initial Dry Out" or "Bulk Dry Out" covered later in the section. Disconnect and remove all the temporary hoses and pressure gauges.

2. Commissioning the Steam Generation System

The steam generation section should be in service prior to lighting up any of the Oleflex fired heaters. Failure to do so can cause mechanical damage to the convection section coils. The chemical boil-out of the convection section coils should have been completed as part of pre-commissioning activities by the contractor.

Following is the guideline procedure for commissioning the steam generation system.

1. Commission make-up boiler feed water (BFW) flow passing through the economizer coils into the steam disengaging drum, until a working level is established.
2. Commission the water circulation pumps to fill and circulate the BFW through the steam generation coils. Bring in make-up BFW as required to maintain the level in the steam disengaging drum.
3. Initiate a small flow of steam via the start-up low pressure line sending steam through the steam superheater coils. Vent this steam to atmosphere via the silencer adjusting the hand control valve (HIC) as required. Gradually increase the steam flow. Establish 2.5-3.5 kg/cm²g (35-50 psig) pressure on the steam drum using startup steam line throttling the HIC as required.
4. Prior to lighting any of the main burners on the Oleflex fired heaters, there should be slight flow of make-up BFW through the economizer coils (without overfilling the steam disengaging drum), flow of BFW through the steam generation coil and flow of steam through the superheater coils of the convection section. Once this is established, the pilot burners on the Oleflex fired heaters can be lit.

Note: In the subsequent steps, when the REC is commissioned and certain minimum amount of process gas flow is established through the Oleflex fired heater coils, main burners on the Oleflex fired heaters can be commissioned to

heat up the process gas to the required temperature. As heater firing increases progressively to increase the process gas temperature, radiant section flue gases entering the convection section become progressively hotter. Progressively increasing amount of steam will be produced when the hot radiant section flue gases reject heat to the circulating BFW in the convection section coils. As the steam production increases, the pressure of the steam gradually rises as indicated by the pressure instrument on the steam drum. Adjust the HIC valve on the atmospheric vent silencer as required to gradually build up the steam pressure. When the pressure begins to exceed the pressure of the start-up low pressure supply steam, close the startup steam valve while maintaining venting the steam from the atmospheric vent silencer.

5. Once the steam production commences and system pressure progressively increases, the circulating BFW temperature increases in tandem. When the circulating BFW temperature exceeds the fresh make-up BFW temperature, commission the temperature controller which controls the BFW temperature entering the economizer coils by injecting required amount of circulating BFW. The temperature of the BFW entering the economizer coils must be maintained at least ~10 Deg C (50 Deg F) above the SO_x dew point of flue gases to prevent corrosion of the economizer coils. Make-up BFW flow through the economizer coil gradually needs to increase to maintain the level in the steam dis-engaging drum.
6. When there is sufficient flow of steam issuing from the silencer, slowly start adjusting the HIC valve on the silencer to build up the system pressure further up to the design pressure. When the superheated steam is at design pressure and its temperature within 10° C (18° F) of the design superheated steam temperature, the steam can be routed to the refinery header as explained in the next paragraph.
7. At this stage, open the main block valve to the export steam header to send a small portion of the steam generated to the main refinery high pressure steam header pinching the HIC valve on the atmospheric silencer as required. Commission the steam desuperheater to control the degree of superheat on the steam routed to the export steam header. Fresh BFW is injected into the captive steam export line on temperature control to attain the necessary degree of superheat.
8. Use HIC valves at the outlet of the superheater coils to balance the superheated steam flow such that the superheated steam temperature exiting the respective convection sections is approximately same.
9. At this stage, the HIC valve on the silencer will still be partially open venting a portion of the generated steam to atmosphere. Slowly close the HIC valve to progressively increase the amount of captive steam routed to the main refinery high pressure steam header. Finally close the HIC valve on the atmospheric silencer to route all of the captive steam generated to the refinery header.

Note: The Steam Generation System shall be commissioned only until Step 4 under Section VI A 2 since implementing subsequent steps (increasing steam production, stabilizing pressure, integrating to the export header) will require progress on Reactor Circuit Heat Up and Dry-Out

3. Reactor Circuit Heat up and Dry-Out Operations (Bulk Dry out)

Purpose of Bulk Dry-Out:

Oleflex bulk dry out operation which involves running the reactor effluent compressor (REC) and Oleflex fired heaters circulating hot nitrogen through the reactor system is designed to accomplish two main purposes. The first purpose is to remove all the remnant free liquid phase water from the reactor system in preparation for the subsequent catalyst loading step upon cool down. The second purpose is to identify and fix any thermal expansion issues during the course of heat up; and further carryout reactor internals inspection to identify and fix any mechanical issues upon cool down. It is normal to incorporate heater refractory dry out into Oleflex Bulk Dry Out during the initial commissioning of the Oleflex unit.

Oleflex Cold Separation System shall be positively isolated and bypassed throughout the bulk dry-out operation in all unit configurations to prevent potential contamination with water and/or solvent.

Oleflex bulk dry out operation is carried out during initial start-up of the Oleflex and during each subsequent start-up after unit turnaround or maintenance activity when reactor screen cleaning was performed.

The main source of free water during initial start-up is the remnant liquid water pockets that may have remained from the hydrostatic tests throughout the Oleflex unit. The amount and extent to which such free water is present directly depends on the thoroughness and effectiveness of the pre-commissioning activity covered in Section V Pre-Commissioning.

During subsequent start-ups post Oleflex reactor screen cleaning, the main source of free water is limited to that associated with the remnant neutralization solution from the neutralization step and/or to that associated with the ammonical water from the ammonical water rinsing step which will be covered in more detail in Section X Normal Shutdown. Water from neutralization and/or ammonical water rinsing activities may be lodged in the inner/outer screen channels as also at low points within the reactor.

In either of the situations, the goal shall be to minimize free water in the system. Oleflex catalyst is susceptible to physical damage from free water and therefore, a thorough dry out of the reactor circuit is required prior to initial catalyst loading.

This will be accomplished by circulating hot nitrogen gas at ~480°C through the Oleflex reactor system piping, vessels and equipment draining free water accumulated at various low points in the reactor effluent path starting downstream of the HCFE and ending downstream of the reactor effluent driers (REDs) depending on the unit line-out for the bulk dry-out. The dry out will occur with the reactors empty, but with all the reactor internals in place. The REC discharge pressure and flow shall be maximized within the constraints of the maximum allowable stage temperatures in nitrogen service throughout the bulk dry-out operation.

Unless the quantity of water picked up by the circulating nitrogen stream in the Oleflex heater and reactor section and associated piping results in excess of saturation moisture for the pressure and co-incident temperature conditions existing at the outlet of the HCFE and reactor effluent contact cooler as applicable, water will not condense out into liquid phase water at those locations. This depends on how effectively free water was removed during pre-commissioning for initial start-up and post neutralization and/or ammonical rinsing steps for subsequent start-ups.

Water tends to condense out from the moisture laden circulating nitrogen into liquid phase depending on equilibrium when the vapors are successively compressed and cooled in various REC stages and associated coolers.

In the first phase of bulk dry-out, by circulating hot nitrogen gas at ~480°C while draining free water from various locations, a system free of liquid water will be achieved in preparation for the catalyst loading into the reactors after the subsequent cool down step. This step is considered complete when total free water collected from the various drain points is less than 50 ml/hour.

In the second phase, the temperature at each reactor inlet is increased to ~650°C in a graduated ramp before subsequent cool down to check and fix any thermal expansion issues associated with equipment, vessels and reactor transfer piping. Further, the thermal growth of critical piping and/or equipment are monitored, marked and recorded at approximately every 100°C. Similarly, spring hanger positions are noted. Upon subsequent cool down, reactors will be opened up and accessed from the cover deck manway to inspect the reactor internals. Any issues need to be fixed prior to catalyst loading.

- ❖ **Chloride Treater and REDs Line-Out during Bulk Dry-Out – Oleflex Units WITH the Reactor Effluent Contact Cooler and REC Interstage Contact Cooler if applicable**

In the Oleflex units designed with reactor effluent contact cooler and/or REC inter-stage contact cooler, these direct contact coolers shall be commissioned and put into operation prior to starting up and running the REC.

In such unit configurations special emphasis must be laid on ensuring that all the debris, weld slags and liquid water from hydrotest in the reactor circuit was removed effectively and lines/equipment blown clear of free water during the pre-commissioning activities. This shall also be verified by boroscopic examination and other means at the pre-commissioning stage. This eliminates the chances of large quantities of free water getting blown into the contact coolers during nitrogen circulation which can potentially cause water in oil emulsion in the circulating solvent especially at low reactor effluent (circulating nitrogen) temperature at contact cooler inlet during the initial stages of dry-out.

In addition, since the cold separation system is bypassed during bulk dry-out operation, the equilibrium vapor phase solvent carryover and free solvent droplets carryover with the circulating nitrogen to the Oleflex fired heaters and reactors will need to be minimized and/or eliminated. This is important to minimize/eliminate potential for pyrolytic coking of solvent fraction on the Oleflex fired heater tubes and the reactor screens/internals. The condensed out solvent is removed in REC interstage drum if applicable and discharge drum; and recycled back to contact cooler. Solvent mist is removed in the mist eliminator blanket provided in these drums. It is possible to trap vapor phase solvent in some measure on the adsorbent beds which necessitates the requirement to load the chloride treater and the REDs. Whereas solvent trapped in the chloride treater quickly equilibrates out, that trapped in the RED will have to be removed by cyclical regeneration of the RED beds via start-up lines and taken out via RED regenerant knockout drum.

After inspection and clean out, chloride treater and REDs shall be loaded with adsorbents as per standard procedures and lined out for bulk dry-out operation. During the bulk dry-out, back to back RED regeneration with nitrogen via start-up lines shall commence as soon as practicable but in any case before beginning the temperature ramp on the fired heaters to maximize the trapped solvent removal and minimize solvent carryover with the circulating nitrogen to the reactor section.

It is critical that the solvent loaded into the contact cooler system matches the UOP specifications especially on the initial boiling point (IBP) and the lower carbon number range. Greater amount of lighter fraction will lead to excessive solvent carryover to the reactor section during bulk dry-out operation.

Commissioning the Reactor Effluent Contact Cooler System

- a. Pump fresh solvent to inventory the reactor effluent contact cooler via the fresh solvent injection line. Initially bring-up the level to ~80-85% as seen on the LG/LI.

- b. Commission cooling water to the solvent circulation cooler. Commission the solvent circulation pump, slowly inventory one of the circulating solvent filters, depropanizer feed pre-heater if provided and solvent circulation cooler in sequence. Establish the design solvent circulation rate to contact cooler.
- c. Make up fresh solvent periodically as necessary to maintain ~60-65 % level in the contact cooler.
 - i. Continuous fresh solvent make-up will be commissioned later when the cold separation system has been commissioned
 - ii. At that stage, there will always be an equilibrium carryover of solvent to the fractionation section necessitating fresh solvent makeup to maintain level in the contact cooler.
- d. In the C3 Oleflex units with standalone reactor effluent contact cooler, commission the spent solvent drag later in the start-up once the Oleflex unit has started producing propylene with the Oleflex reactor inlet temperatures in excess of 475° C. The amount of spent solvent withdrawal shall be adjusted to maintain approximately 1wt. % maximum native Oleflex heavies in the circulating solvent derived by comparing the increase in residual heavies' fraction with fresh solvent on the ASTM distillation. Adjust the fresh solvent makeup to compensate for the spent solvent drag as required.

Follow similar line of action and guidelines to commission the REC interstage contact cooler if the unit has been provided with such a facility.

In the C3 Oleflex units with standalone reactor effluent contact cooler, polynuclear aromatic heavies' fraction of the native Oleflex heavies' get purged from the system via spent solvent drag. The lighter fraction of the native Oleflex heavies like benzene, toluene and xylenes will be purged from the system via depropanizer bottoms covered later in this section.

- e. In the Oleflex units provided additionally with the solvent recovery column, further steps need to be taken to commission the system as follows:
 - i. Commission cooling water to the solvent recovery column cooler. Inventory the solvent recovery column overhead pump suction piping via the start-up inventory line to establish ~60-65% level on the solvent withdrawal tray as seen on LG/LI and commission the pump.

- ii. Establish design solvent circulation on flow control to the top packed bed which serves as a “direct contact condenser”.
- iii. Inventory the solvent recovery column bottoms gradually up to ~ 60-65% as seen on LG/LI via slip stream inventory line from the feed to the column.
- iv. Commission the boiler feed water to the de-superheater on superheat control and line-up steam to the column reboiler. Commission the steam condensate flow controller and begin heating up the column bottoms slowly.
- v. When the solvent gets gradually vaporized, it will get condensed in the top direct contact condenser increasing the level on the withdrawal tray. At this point, commission the level controller on the withdrawal tray and establish reflux to the column. Slowly increase reflux co-incident with reboil to design rate and establish stable level-reflux cascade control.
- vi. Commission the net recovered solvent overhead flow controller and start sending the recovered solvent back to the contact cooler on temperature flow cascade control.
- vii. Simultaneously, start slowly bringing in the solvent feed to the column and gradually establish the design feed rate.
- viii. Until the Oleflex unit has been commissioned, there will not be any heavies’ build up in the circulating solvent system. However, the solvent itself will get fractionated leaving behind heavier components in the bottoms, the concentration of which will build-up over time as indicated by the bottoms temperature which controls the net overhead draw. As the temperature increases in the column bottoms, the net overhead draw will get squeezed out increasing the bottoms level. At that point commission the solvent recovery column bottoms pump and start the spent solvent withdrawal on level control.
- ix. Once the Oleflex unit is subsequently commissioned, commission the net heavies’ stream from the depropanizer bottoms stripper or from the depropanizer bottoms (for depropanizer systems with C4 rich side draw) or from the debutanizer bottoms (for debutanizer processing depropanizer bottoms) which constitutes additional feed to the solvent recovery column. Commissioning these systems is covered later in this section.

During normal operation, solvent recovery column is operated with ~5 wt. % residual heavies in the bottoms product and ~ 1wt. % residual heavies in the circulating solvent as determined by ASTM distillation.

Procedure for Bulk Dry-Out:

❖ Pre-Requisites:

Prior to bulk dry-out, confirm the following – [a] Oleflex steam generation system is commissioned and running [b] Pilot burners on the Oleflex fired heaters are lit [c] Cold separation system has been dried out, kept under nitrogen blanket. Reactor effluent inlet and combined feed outlet, liquid propane feed inlet and liquid product outlet; and net gas outlet block valves have been closed to isolate the cold Separation system [d] Reactor effluent contact coolers, REC interstage air/water/contact coolers and REC discharge air/water coolers are running [e] REC is ready to run under nitrogen service [f] Chloride treater and RED vessels are lined out as applicable to the specific unit configuration.

❖ Air-Freeing the Reactor Circuit:

Air freeing is done by pulling vacuum on the system and breaking it with nitrogen. All the process piping, vessels, equipment and instruments not designed for vacuum are isolated which may include, but not limited to the following:

- a. Sulfur injection points
- b. Reactor Effluent Compressor's (REC) casings
- c. RED regenerant knockout drum overheads to the downstream unit
- d. Flash gas recycle from the cold separation system to REC suction
- e. Net gas to the hydrogen purification system and fuel gas header
- f. Solvent injection pumps and any associated piping if applicable
- g. Cold separation system
- h. All instrument connections not rated for vacuum

Open the dry-out bypass valve on reactor effluent feed line to the cold separation system partially which bypasses the reactor effluent to the combined feed outlet line from the cold separation system. Note that it may be necessary to pinch this valve as required for stable REC operation. Install compound pressure gauges at a couple of different locations in the reactor circuit. The gauges should be located at points furthest from the ejector.

Swing the spectacle blinds to open position on the evacuation lines connected to the ejector. These tie-ins to the ejector are located at [a] chloride treater inlet piping [b] reactor effluent drier inlet piping [c] REC first stage suction piping [d] REC second and/or third stage suction piping. Include the regeneration K.O. drum after checking it is designed for vacuum in the reactor circuit by opening the dry out bypass

connection line to the compressor suction drum. Open the block valves located next to the spectacle binds. Commission the ejector and evacuate the reactor circuit.

Pull vacuum until about 130 mm Hg Abs system pressure or whatever lowest permitted by the ejector has been achieved. Check on the compound gauges installed that all sections are covered and indicate stable vacuum. Once identical vacuum has been reached on all the gauges, block in all the evacuation lines connected to the ejector by closing the block valves. Close the block valve on the steam line to the ejector to stop pulling vacuum. Hold the vacuum for ½ hour to reconfirm for leaks as previously outlined in subsection N and O of Section V Pre-commissioning. Then break the vacuum with nitrogen by introducing nitrogen into the reactor loop at the connection provided on the reactor effluent compressor's suction and discharge piping until the system pressure is slightly above (15-20 KPaG) atmospheric. Repeat the steps (without the ½ hour hold) until the oxygen content is less than 0.5 mole-%.

Note: If it takes an exceedingly long time to establish a vacuum, it is likely there are leaks present in the system. The entire reactor circuit should then be leak tested again under positive nitrogen pressure.

Pressure up the reactor circuit to the minimum pressure required to start the REC as confirmed with the REC vendor following the final vacuum break. Typically ~0.5-0.8 kg/cm²g pressure is required before the REC can be started.

❖ **Start the REC and establish Reactor Circuit Gas Circulation:**

Initial startup of the REC should be done under the direct supervision of the vendor's representative. Use the appropriate surge curves for nitrogen case.

- a. Reconfirm that all the compressor sub-systems like lube oil circulation, steam surface condenser, surge protection instrumentation/controls, machine monitoring system etc. are commissioned and running.
- b. Purge the REC casings with nitrogen using the nitrogen connections provided until oxygen content is below 0.5 mole-%. Then pressure up casings to equalize with the rest of the system pressure.
- c. Open the spillback valves on manual per vendor recommendation.
- d. Reconfirm that the reactor effluent air/water/contact cooler, REC interstage air/water/contact cooler, and REC discharge air/water cooler are running.
- e. With the entire reactor circuit pressured up to the required minimum pressure, commission the REC.

Nearly all of the REC discharge will be spilling back to the suction drum and there will be very little forward flow until one begins to close the spill back valves. Start pinching the spill back valves at each stage slowly to force forward flow. Continue to add nitrogen to the reactor circuit to increase the system pressure. With nitrogen as process gas, the compression ratio at each stage and forward flow will be constrained

by the discharge temperature at the outlet of each stage. This is because the temperature rise with nitrogen will be higher than that with the process gas for the same compression ratio. Maximum permissible stage temperatures shall not be exceeded at any stage during the nitrogen run.

Maximize the forward flow and discharge pressure within the above constraints under nitrogen run. Maximizing forward flow will help dry out all the flow paths within the Oleflex reactor circuit quickly and efficiently. Maximizing the discharge pressure will help condense out and remove the moisture picked up from the system in the stage coolers.

A typical bulk dry-out flow path is: REC suction → REC → REC discharge cooler → chloride treater → flow through one reactor effluent drier → cold separation system bypass → HCFE shell side → heaters and reactors → HCFE tube side → reactor effluent cooler/contact cooler → back to the REC suction drum

Once stable flow through the above circuit has been established, the start-up line from the reactor effluent line to the net gas line should be opened. This will allow for a nitrogen flow to the catalyst collectors and surge pots helping dry-out those sections.

In the Oleflex units provided with the reactor effluent contact cooler and/or REC interstage contact cooler, there will be equilibrium solvent vapor carried to the REC in addition to the moisture picked up from the system. The solvent together with water if any will condense out in the REC stage cooler and discharge cooler and flow to the interstage and discharge drums. Commission and establish a stable solvent level in the REC interstage and discharge drum returning back the solvent continuously to reactor effluent contact cooler and/or REC interstage contact cooler as may be the case. Any free water will have to be drained periodically and the solvent free from any phase separated liquid water returned back to the respective contact coolers.

❖ **Perform Phase 1 of Bulk Dry-Out - Start heating up the reactor circuit to remove free water from the system:**

Commission the fuel gas mains on the Oleflex charge heater and interheaters to enable commissioning the main burners. Initially commission 1 main burner on each heater and gradually increase the number of burners in service as heating progresses. Attempting to light too many burners at a time may cause the heaters to trip on low fuel gas pressure at the burner. The reactor inlet temperatures are raised to 480°C (900°F) at a rate not to exceed 20°C/hour (36°F/hour). If refractory dry-out has not been completed consult the heater vendor and incorporate refractory dry-out program into during bulk dry-out. This may necessitate increased hold-up times than

warranted by the bulk dry-out procedural requirements in order to match the refractory dry-out requirements but this is acceptable.

Increase the reactor inlet temperatures at 20°C/hour (36°F/hr) up to 480°C (900°F) using fuel gas pressure controllers. Incorporate the heaters refractory dry-out temperature holds, if any, toward ramp to 480°C. The temperature ramp rate must be limited to 20°C/hr (36°F/hr) maximum to permit sufficient time to monitor and fix any thermal expansion issues before continuing with the ramp.

Free water will get gradually forced out of the heater tubes, piping and equipment. This water will tend to collect at various low points in the dry-out circuit. REC discharge KO drum constitutes the main high pressure, low temperature and low elevation point in the circuit. Other low points may mainly collect swept water until the temperature at the location is high enough that it can no longer hold liquid water. Drain free water from the low points all through the dry-out. Ideally the attempt to check and drain must immediately commence upon establishing the forward flow through REC. Measure and record the amount of water drained off.

When the total water accumulation rate drops below 50 ml/hr, the dry-out is considered complete and all of the free water is considered removed from the system. In the REC stage drum where the water and solvent can co-exist, water will settle at bottom. Collect in glass bottle and allow the sample contents to settle. Continue to drain until the sample contents break into distinct solvent water interphase to measure the amount of water collected. Where no clear distinction is visible and contents indicate an emulsion or milky constitution, continue to drain the material until sample shows clear solvent phase.

In the Oleflex units with the reactor effluent contact cooler, the RED regeneration using start-up lines must immediately commence back to back once the nitrogen circulation is started. In this system, if water – solvent interface is detected in the REC interstage and discharge drums, free water must be drained into the refinery chemical drain system and only solvent must be returned to the contact cooler. Further, the moisture adsorbed by the RED will get removed together with the trapped solvent. Free water collected in the RED regenerant knockout drum must be drained out and only the solvent must be returned back to the contact cooler.

❖ **Perform Phase 2 of Bulk Dry-Out – Ramp to 650°C to check for thermal expansion issues, cool down and perform reactor internals inspection:**

The final phase of the dry-out requires raising the reactor inlet temperatures to 650°C (1200°F) at no more than 20°C/hr (36°F/hr) using fuel gas pressure control and holding at these RITs for 2 hours. Monitor the heater tube skin temperatures to avoid overheating. Monitor all equipment and lines closely for any potential expansion problems. If there is any thermal expansion issue or mechanical issue, immediately stop further heating until the problem is fixed.

- a) Monitor the heater tube skin temperatures to avoid overheating; monitor any thermal expansion issues as outlined below:
 - i. Monitor all equipment and lines closely for any expansion problems. Mark at site expansion of major equipment viz. reactors, HCFE, surge pots etc. at every 100°C for future reference.
 - ii. Check all the fired heater spring supports and spring supports in the transfer piping between hot combined feed exchangers and Oleflex reactors.
 - iii. Tie rods should be nearly hanging plumb and spring position indicators should be at the “hot” position. Mark at site/record spring hanger positions at different temperatures for future reference.
 - iv. Inspect around each reactor for piping and insulation that is restrained from movement due to platforms or other interference
 - v. Check the bolt tensions on the reactor inlet/outlet flanges and HCFE tube side inlet/shell side outlet flanges. Tighten if necessary.
- b) Prior to cooling, if required, the vendor shall tune the surge map for the nitrogen service.
- c) Gradually reduce the heater firing and cool down the reactor circuit at about 20°C/hr (36°F/hr). Shutdown the heaters and continue gas circulation until the reactor inlet and outlet temperatures are less than 50°C (120°F).
- d) When the reactors have been cooled, gradually decrease the forward flow by incrementally and gradually opening the anti-surge (spill-back) valves on each stage of the REC.
- e) If the C3 Oleflex unit with reactor effluent contact cooler and/or REC interstage contact cooler, continue to monitor and maintain the level in these systems. At a certain stage, the spill-back valves will be 100% open with very little forward flow.

- f) In parallel with step e), drain out solvent from the REC interstage and discharge knockout drums to contact cooler monitoring the level.
- g) If applicable, pump out excess to storage either directly or via solvent recovery column bottoms as may be the case to prevent accidental transfer from these drums overfilling the contact cooler while pulling vacuum to air free the system during low temperature dry-out in the subsequent steps.
- h) Shut down the REC and block it in.
- i) Maintain the reactor circuit under a positive nitrogen pressure of 15-20 KPaG.
- j) Just prior to opening the reactors for entry, depressure the system. Make the system safe for man entry by evacuation and breaking the vacuum with dry instrument air.
- k) Perform reactor internals inspection prior to Oleflex catalyst loading

4. Reactor and Vessel Loadings

The Oleflex reactors and vessels need to be loaded before proceeding. Refer to Special Procedures (Section XII) for loading and post dry-out inspection procedures for the following vessels:

- a. Oleflex Reactors
- b. Chloride Treater (if not already loaded)
- c. Reactor Effluent Driers (if not already loaded)
- d. Feed Guard Beds
- e. Mercury Guard Bed (if applicable)
- f. Arsine/Phosphine Metal Guard Beds (if applicable)
- g. Feed Driers
- h. SHP Reactor

5. Feed/Fractionation Section Inventory, Startup Circulation and Dry-Out

While the various phases of commissioning of the Oleflex reactor section are being carried out, the feed/fractionation section is also being prepared for start-up in parallel. Once the Oleflex reactor section and the feed/fractionation section are considered moisture free, commissioning can continue with propane feed sent from

the depropanizer overhead to the Oleflex reactor section. This section provides instructions on propane introduction and dry-out of the feed/fractionation section.

The objective of this section is to inventory and dry all the vessels in the feed/fractionation section. Inventorying will be performed in a stepwise manner with all the vessels pressured with nitrogen prior to introducing propane. Once all the vessels and columns have been inventoried with propane, circulation loops will be established to remove water from the circuit. As various systems are inventoried in sequence, fresh propane is brought from storage as required.

Proper dry-out of this circuit is critical. Any free water and/or excessive moisture in propane (> 1 wt. ppm) feed to the cold separation system will freeze in the cold section requiring unit shutdown to derime the cold separation system.

It is assumed that all the piping, equipment and vessels in the feed/fractionation section have been strength tested, cleaned, leak checked, air-freed and under inert nitrogen blanket. It is further assumed that the fresh feed guard beds have been loaded with the resin and kept under water, feed driers and any other treaters have been loaded with the respective adsorbents and the SHP reactor has been loaded with the catalyst.

In general, when inventorying the lines and vessels with propane, crack open inlet valves slowly to avoid icing of the lines and vessels. When liquid propane flashes, it will auto refrigerate causing chilling of lines and equipment. Lines/equipment should be kept and maintained above the Minimum Design Metal Temperature (MDMT) limits for the pipe class and vessels should be kept above the. Moisture from ambient air will likely condense on the lines/equipment/vessels, but the same freezing to deposit as solid ice shall be prevented.

When inventorying each system, in general, check for any hydrocarbon leaks in the inventoried piping and vessels by running an LEL (Lower Explosion Limit) detector around all the flanges and instrument connections in the included system during the entire course of filling preferably every two hours. Inventorying must be stopped if any leak is identified and the leak fixed before proceeding further. In some situations, this may require de-inventorying the entire system, hydrocarbon freeing by nitrogen piston-purge, fixing the leak and repeating the process of inventory. If there are major flange leaks that require de-inventory to fix the system, the affected flange gaskets shall not be re-used. New gasket must be used.

Inventory and Commission the Feed Guard Beds with Propane

- a. Drain condensate from feed guard beds shortly before inventorying the fractionation section with hydrocarbon.

- b. Purge feed guard beds down flow with nitrogen for ~8 hours to remove as much free water as possible but do not allow to completely dry out. Flush until only water mist is seen at the discharge point.
- c. Pressure the guard beds and feed line with nitrogen to the nitrogen header pressure ~6-7 kg/cm²-g (~85-100 psig).
- d. Fill feed line and feed guard beds and associated piping with propane using the small diameter globe valve and associated crossover line across the main inlet block valve. When pressure reaches ~20 kg/cm²-g (~285 psig) close the filling line globe valve and crack PSV bypass to vent nitrogen to flare. De-pressure to ~15 kg/cm²-g (~213 psig) and repeat until guard bed is liquid full.
- e. Stop filling once liquid is seen in the site flow indicator if provided on the PSV bypass or as evidenced by freezing/icing on the PSV bypass piping downstream of the bypass line globe valve.

Note: Filling and venting should be done slowly to avoid lifting the beds. Sudden changes in pressure could lift the beds. Inventory both the guard beds including the cross over piping.

Inventory and Commission the Mercury Guard Beds with Propane (if applicable)

- a. Pressure the guard beds to nitrogen header pressure ~6-7 kg/cm²-g (~85-100 psig) using nitrogen connections at the bottom of each vessel.
- b. Fill each guard bed from bottom to top using the small diameter globe valve and associated crossover line across the main inlet block valve. When pressure reaches ~20 kg/cm²-g (~285 psig) close the filling line and crack PSV bypass to vent nitrogen to flare. De-pressure to ~15 kg/cm²-g (~213 psig) and repeat until drier bed is liquid full.
- c. Stop filling once liquid is seen in the site flow indicator on the PSV bypass line if provided or as seen by freezing/icing on the bypass line downstream of the globe valve on the PSV bypass line.

Inventory and Commission the Arsine and Phosphine Metal Guard Beds with Propane (if applicable)

- d. Pressure the guard beds to nitrogen header pressure ~6-7 kg/cm²-g (~85-100 psig) using nitrogen connections at the bottom of each vessel.
- e. Fill each guard bed from top to bottom using the small diameter globe valve and associated crossover line across the main inlet block valve. When pressure reaches ~20 kg/cm²-g (~285 psig) close the filling line and crack PSV

bypass to vent nitrogen to flare. De-pressure to $\sim 15 \text{ kg/cm}^2\text{g}$ ($\sim 213 \text{ psig}$) and repeat until drier bed is liquid full.

- f. Stop filling once liquid is seen in the site flow indicator on the PSV bypass line if provided or as seen by freezing/icing on the bypass line downstream of the globe valve on the PSV bypass line. Fill crossover piping with propane.

Inventory and Commission the Fresh Feed Driers and Regeneration System with Propane

- a. Pressure the driers to nitrogen header pressure $\sim 6\text{-}7 \text{ kg/cm}^2\text{g}$ ($\sim 85\text{-}100 \text{ psig}$) using nitrogen connections at the bottom of each vessel.
- b. Fill each drier from bottom to top using the small diameter globe valve and associated crossover line across the main inlet block valve. When pressure reaches $\sim 20 \text{ kg/cm}^2\text{g}$ ($\sim 285 \text{ psig}$) close the filling line and crack PSV bypass to vent nitrogen to flare. De-pressure to $\sim 15 \text{ kg/cm}^2\text{g}$ ($\sim 213 \text{ psig}$) and repeat until drier bed is liquid full.
- c. Stop filling once liquid is seen in the site flow indicator on the PSV bypass line if provided or as seen by freezing/icing on the bypass line downstream of the globe valve on the PSV bypass line. Fill crossover piping with propane.

Note: Filling and venting should be done slowly to avoid lifting the beds. Sudden changes in pressure can lift the beds.

Inventory feed drier regeneration System: This will be applicable only to the closed loop feed drier regeneration system using dry propane as regenerant. Inventory the regenerant vaporizer and spent regenerant receiver/coalescer. Once the coalescer has been inventoried, test the feed drier regenerant pumps. Once pumps have been tested they can be stopped until drier regenerations are started.

Inventory and Commission the Single Depropanizer System with Propane (if unit is a Two Depropanizer System, skip to next step)

- a. Pressure the depropanizer system to approximately nitrogen header pressure $\sim 6\text{-}7 \text{ kg/cm}^2\text{g}$ ($\sim 85\text{-}100 \text{ psig}$). Also drain water from reboilers and coolers to prevent damage to the exchangers due to water freezing.
- b. Slowly bring in propane into the depropanizer. Establish level in the in the depropanizer bottoms.

- c. Commission the column overhead condenser. Commission cooling water to the water cooled condenser. If it is air cooled condenser, commission the air fans.
- d. Start steam reboiler to drive propane overhead. Vent nitrogen through high points and overhead receiver PSV bypass to dry relief header.
- e. As propane vapors rise, condense and accumulate in the receiver building up level in the depropanizer receiver, commission the receiver's level control instrumentation. Vent nitrogen from the depropanizer section to the dry relief header through the PSV bypass.
- f. When the depropanizer overhead pressure is under control venting of nitrogen is complete, close PSV bypass and bring depropanizer overhead pressure to normal operating pressure.
- g. Commission the hot vapor bypass to control the column pressure.
- h. Once sufficient level of propane has accumulated in the overhead receiver, commission the overhead reflux pumps. Send propane back to the depropanizer column. Place the depropanizer column on total reflux.

Inventory and Commission the Two Depropanizer System with Propane

Pressure the Depropanizer system to approximately nitrogen header pressure ~6-7 kg/cm²g (~85-100 psig). Also drain water from the reboilers and coolers. If water freezes during propane filling tube damage could occur.

- a. Slowly bring in propane into depropanizer No. 1. Monitor TIs in depropanizer column. Make sure all locations stay above the MDMT of the column.
- b. Once the column level is established, inventory depropanizer No. 1 bottoms pumps suction line, pump casing and discharge piping.
- c. Start the pump and slowly inventory depropanizer No. 2. Vent nitrogen through high points and overhead receiver PSV bypass to dry relief header as necessary. Keep the pressure below the design pressure of the circuit.
- d. Once bottoms level is established in depropanizer No. 1 and 2, commission the cooling water to the overhead condensers or start the air cooled condenser fans as is the case.

- e. Slowly start the steam reboilers and start heating up the column. Propane vapors will rise through the column and begin condensing in the condenser. Continue to vent non-condensable from the high point vents as necessary.
- f. Allow propane to accumulate and level build up in the depropanizer receiver and commission the receiver's level control instrumentation. Vent non-condensable nitrogen from the depropanizer section to the dry relief header through PSV bypass on the overhead receiver.
- g. When the depropanizer overhead pressure is under control, venting of nitrogen is complete. Close the by-pass on the PSV valve. Bring depropanizer pressure to normal operating pressure.
- h. Commission the hot vapor bypass to control the column pressure.
- i. Once sufficient level of propane has accumulated in the overhead receiver, commission the overhead reflux pumps. Send material back to depropanizer No. 1 and 2. Place the columns on total reflux.
- j. If the depropanizer 2 has C4 rich material side draw, commission the condenser and cooler on the side draw.

Inventory Depropanizer Bottoms Stripper

Skip this section for unit configurations where the depropanizer system is designed with C4 rich side draw product. Stripper shall be inventoried with C4+ material. If this is not available at this stage of start-up, wait until sufficient concentration builds either during the long loop dry-out circulation or until later in start-up when Oleflex unit starts receiving fresh feed.

Fuel gas system typically operates at 200-300 KPaG (29-44 psig), making propane unsuitable to inventory due to risks of icing up the fuel gas headers. The stripper overheads ties into fuel gas preparation system joined in by other sources like net gas, deethanizer off gas, tail gas, natural gas make-up etc. Check process line-up and status of the fuel gas system.

- a. Isolate the root valves on other captive fuel sources if permissible.
- b. Isolate the block valve provided on the combined captive fuel gas line to the fuel gas preparation system if permissible.
- c. Pressure the depropanizer bottoms stripper to approximately nitrogen header pressure ~3-4 kg/cm²g (~43-57psig) or design operating pressure, whichever is lower.

- d. Confirm there is C4+ material that has concentrated in the column bottoms while on total reflux or in long loop circulation.
- e. Start a small amount of flow from the depropanizer bottoms to the depropanizer bottoms stripper.
- f. Establish a level in the stripper column and stop the flow from depropanizer bottoms. Vent off the nitrogen to relief header.
- g. Commission the depropanizer bottoms stripper pumps briefly to confirm operation, and then shut them down.
- h. Establish a flow of fuel gas, if available, at this time to confirm that the stripping hydrogen heater is working properly. If fuel gas line-up is not available, this testing can be postponed until tail gas or the intended stripping gas is available later in the start-up.
- i. Once these pieces of equipment have been confirmed to be operating correctly they can be stopped until a steady flow is established later in the start-up.
- j. Note and normalize system isolations of captive fuel sources as required.

Inventory and Commission the Deethanizer System with Propane

- a. Pressure up the deethanizer stripper system to approximately nitrogen header pressure ~6-7 kg/cm²g (~85-100 psig). Also drain water from reboilers and coolers to prevent damage to the exchangers due to water freezing.
- b. Begin to send propane for the Depropanizer overheads through the feed filters → Cold separation system startup bypass → SHP Reactor bypass (applicable only to conventional C3 Oleflex Units where the SHP is located on the liquid product line from the cold separation system) → deethanizer stripper.
- c. Slowly open the deethanizer stripper feed inlet control valve. Establish a level in the bottom of the deethanizer stripper. Monitor temperatures during filling to prevent freezing and lines from frosting.
- d. As propane enters the system, flashed propane vapors will flow from the deethanizer stripper to the deethanizer rectifier into the deethanizer rectifier receiver. Continue to fill the deethanizer stripper with propane.
- e. Commission the deethanizer stripper condenser. Commission cooling water to the stripper condenser if it is a water cooled condenser. If it is air cooled condenser, commission the air fans.

- f. Once a level is established in the Deethanizer Stripper bottoms, line-up and start steam to the reboilers. Vent nitrogen from the overhead of the deethanizer rectifier receiver, as needed, to maintain the deethanizer system pressure.
- g. Establish a level in the deethanizer rectifier.
- h. Commission the deethanizer stripper reflux pumps to provide reflux back to the deethanizer stripper.
- i. Commission the refrigeration unit as per vendor procedures but limit to virtually no load operation at this stage setting the temperature controller at the condensate outlet at 10°C + at this stage to minimize disturbance to column operating pressure.
- j. Once stable operation is achieved, begin sending material through the hot vapor bypass flow control valve. Bring the system to normal operating pressure.
- k. Continue using the deethanizer rectifier condenser hot vapor bypass to send material to the deethanizer rectifier receiver. Vent non-condensable nitrogen as necessary to maintain and regulate the system pressure. Route the vapors to the rectifier receiver via rectifier condenser bypass to control the pressure.
- l. Slowly load the refrigeration unit to establish the refrigerant circulation through the deethanizer rectifier condenser per vendor guidelines and establish a level in the deethanizer rectifier receiver.
- m. Maintain and regulate the rectifier condenser outlet temperature above 10°C until the dry-out is complete to avoid freezing. This must be controlled by regulating the refrigeration load.

Note: Ensure that the rectifier condenser outlet temperature is maintained all the time above ~10°C during the fractionation dry-out to prevent icing in the lines/column. Any icing may require shut down and deriming. Use the rectifier condenser hot vapor bypass line as necessary to regulate the system pressure during start-up when cracked light ends are not available in the system during start-up.

- n. Use the vent on the overhead line of the rectifier receiver to vent nitrogen from this section to the dry relief header.
- o. Once a level is established, start the deethanizer rectifier reflux pumps to send the material back to the rectifier.

- p. When the operation stabilizes, start sending a slip stream drag to the fresh feed driers via the startup bypass line provided at the discharge of the rectifier reflux pumps.

Note: This will be the water rich stream while circulating propane. A portion of this stream is recycled to feed drier inlet to remove the water captured by the circulating propane in dry out circulation.

Begin back to back fresh feed drier regenerations at this stage to start removing water from the system captured by the circulating propane. Throughout the feed/fractionation section dry-out, feed drier regenerations shall be continuously regenerated back to back until dry-out is complete.

Inventory and Commission the Propylene-Propane (P-P) Splitter System with Propane

PP Splitter System with Two Stage Heat Pump Compressor with Suction Drum for each stage, Heat Recovery Reboiler and Trim Cooler (Figure IV-F3)

As with the previous system, this system also operates under relatively lower pressure and the manner in which lower system pressure is achieved is exactly identical. With independent suction drums for each stage, the liquids from 2nd stage compression vapor condensation are returned to the 2nd stage suction drum operating at relatively higher pressure reducing the amount of flashed vapors. A portion of the 2nd stage suction drum liquids routed to 1st stage spill back helps control temperature rise during start-up. A portion of the 2nd stage vapors routed to the bottom of the 1st stage suction drum helps control excessive liquid level build-up during start-up. Heat recovery reboiler together with the trim cooler provide exit for the adiabatic compression heat in supplement to the reboiler-condensers when the column is initially commissioned on total reflux in closed loop circulation. Therefore, depropanizer system must be stable and running prior to commissioning the PP splitter system.

- Pressure the P-P Splitter system to approximately nitrogen header pressure ~6-7 kg/cm²g (~85-100 psig).
- Slowly open the valve at the deethanizer stripper bottoms to send flow into the P-P splitter bottoms via the start-up lines. Monitor TIs and keep the temperature above the MDMT for P-P splitter and associated equipment.
- Establish a level in the P-P splitter bottoms.
- Inventory both the heat pump compressor (HPC) suction drums through the start-up inventory line at the P-P splitter bottoms.

- e. Vent nitrogen from the column as propane is inventoried. Nitrogen is non-condensable at the operating conditions of the P-P splitter. The P-P splitter system should be nitrogen free prior to starting the HPC. Target <1 mole% nitrogen in the overhead before starting the HPC.
- f. Continue to inventory with propane and vent nitrogen. Frost/ice will build-up downstream of the venting valves once propane is present indicating that the nitrogen has been removed.
- g. Establish a liquid level of at least 50% in both the P-P splitter and the HPC suction drum(s).
- h. Commission utility cooling water to the trim cooler. If it is an air cooled exchanger, commission the air fans.
- i. Commission the sub-systems of the HPC as instructed by the vendor which may include lube oil system, steam surface condenser in case of steam driven HPC, surge control systems etc.
- j. Once nitrogen has been vented from the system, commission the HPC per vendor recommendations. Keep the antisurge (spill back) valves open on either stage as required.
- k. Commission the HPC 1st stage suction drum temperature control loop which sends a portion of the liquids from the HPC 2nd stage suction drum into 1st stage spill back loop to control the HPC 1st stage suction vapor temperature during start-up.
- l. Slowly route the forward flow from the 2nd stage discharge through the heat recovery reboiler/trim cooler circuit without upsetting the depropanizer system. Initially route all the flow through the trim cooler bypassing the heat recovery reboiler using the bypass flow control valve.
- m. Gradually close the bypass valve to force flow through the heat recovery reboiler. These actions will gradually pinch the 2nd stage spill back valve. Route the liquids via propylene trim cooler back to the 2nd stage suction drum.
- n. Depropanizer reboil shall be controlled as appropriate by cutting off steam flow to the steam heated reboiler while increasing the load on the recovery reboiler/trim cooler. At this stage, initiate a small flow of external reflux via the reflux flow controller.
- o. Slowly start heating the P-P Splitter by sending flow to the reboiler/condensers. This will gradually pinch the 1st stage spill back.

- p. Commission the condensate flow controllers on the reboiler/condensers and route condensate as internal reflux to the column. Monitor level in the bottoms of the P-P Splitter and the HPC suction drums. Makeup propane as necessary.
- q. At a given HPC speed when the 1st stage spill back valve is under ~15-20% open or the flow control valves at the outlet of the reboiler-condensers tending to open over ~80-85%, any further increase in the reboil will necessitate increasing the speed of the HPC to increase the reboil/reflux. Increase the HPC speed as required to increase reboil/reflux.
- r. Commission the overhead pressure controller on the 1st stage suction drum. The pressure controller will determine the amount of forward flow from the HPC to the heat recovery reboiler and trim cooler system.
- s. Once the P-P Splitter is stabilized, commission the recycle propane pumps and begin sending the P-P splitter bottoms to the depropanizer (bypassing the SHP reactor if the SHP reactor is located on the recycle propane line).
- t. Initiate a small forward flow to the off spec line to dry the off spec line and tank. Return the material back to the Oleflex via off spec reprocessing line. Once this loop dry out is completed stop the forward flow out of the fractionation system and bringing in material via the off spec line
- u. Continue to makeup propane as required.
- v. After the HPC is running, the reflux and reboiler flows are established, and the suction drum is on automatic pressure control, the P-P Splitter operation can be fine-tuned. Reflux and reboiler flows must be stabilized with the P-P Splitter on total reflux.

Start Dry-Out Circulation Loops to remove water from the Fractionation System bypassing the Cold Separation System

The purpose of the dry-out circulation is to remove all the water that may have still been trapped in equipment/vessels/piping in the system until less than ~1 wt. ppm water is achieved at all inlets/outlets to/from the fractionation system.

This is critical for three main reasons [a] the system provides feed to the cold separation system operating at cryogenic temperatures where water ingress can ice up affecting the performance and potentially damaging the equipment [b] de-ethanizer rectifier system operates with refrigerated condenser where water ingress can ice up in the lines/equipment affecting operability and potentially damaging the condenser tubes [c] PP splitter system constitutes large propane/propylene inventory during normal operation where water ingress can lead to product off specification in water.

Dry-out is accomplished by circulating propane continuously through multiple circulation loops where water is picked up and removing it in the feed driers. Though water has a higher boiling point compared to C2, C3 and C4 light paraffins/olefins; it tends to form azeotrope accumulating in the overheads in distillation columns. This fact is utilized to circulate propane sequentially through the fractionation system allowing it to concentrate in the de-ethanizer rectifier overheads.

A slip stream from the deethanizer rectifier overheads is sent to the feed driers via a start-up line to the feed driers, where water is continuously trapped in adsorption cycle and removed during the regeneration cycle. The feed driers shall be regenerated back to back throughout the feed-fractionation section dry-out and flow through all the dry-out circulation loops in the system shall be maximized to accomplish efficient and quick dry-out. Depending on the amount of water initially present in the system and the circulation rate, the dry-out can take 5 to 15 days.

1st loop: feed driers → depropanizer system → deethanizer stripper via cold separation system start-up bypass → deethanizer stripper → deethanizer rectifier → feed driers via start-up line.

2nd loop: deethanizer stripper bottoms → P-P Splitter bottoms → via SHP start-up bypass → depropanizer.

3rd loop: P-P Splitter overhead → Propylene treaters (if applicable) → on-spec storage → via reprocessing line → deethanizer stripper.

4th loop: P-P Splitter bottoms → off-spec storage → via reprocessing line → deethanizer.

Once all free water from the system has been removed in the feed-fractionation system dry-out loop, SHP reactor can be inventoried with liquid propane stream. However, the SHP reactor will be commissioned at a later stage in the start-up when the PSA H2 is made available.

Once the feed-fractionation long loop circulation through various dry-out loops has been established with the SHP reactor and cold separation system bypassed, there will no longer be need to bring in fresh make-up propane.

The dry-out is considered essentially complete once the moisture in the de-ethanizer slip stream feeding the fresh feed driers, PP splitter overheads and depropanizer overheads is less than ~1 wt.ppm. In addition, onsite and offsite product propylene storage and propane storage shall be dry. Monitor the moisture with 3-4 calibrated portable moisture dew point analyzers at various locations in the system.

Discontinue circulating to on-spec and off-spec storage and returning material through the reprocessing line via 3rd and the 4th loops described earlier once those

sections have been confirmed dry. However, the long loop circulation through the 1st and the 2nd loops described earlier shall be maintained until the Oleflex reactor section is ready for startup. Feed drier back to back regenerations shall continue enabling water removal from the system.

Long loop circulation:

1st loop: feed driers → depropanizer system → deethanizer stripper via cold separation system start-up bypass → deethanizer stripper overheads → deethanizer rectifier overhead liquids → feed driers via start-up line.

2nd loop: deethanizer stripper bottoms → P-P Splitter bottoms → via SHP start-up bypass → depropanizer

3rd loop: deethanizer stripper bottoms → P-P Splitter overheads → Propylene treaters → On spec storage (if applicable) or Dry-out bypass → depropanizer or deethizer stripper via reprocessing line

Feed will no longer be introduced into the system until reactor section start-up. The feed/fractionation section is now ready to be integrated with the Oleflex reactor section. Complete the remainder of the reactor section commissioning procedures for starting feed from the fractionation section to the cold separation system.

6. Reactor Circuit Low Temperature Dry-Out

The purpose of reactor circuit low temperature dry-out is to remove the moisture adsorbed onto the Oleflex catalyst during the catalyst loading activity. Further, any atmospheric moisture that may have entered the system during catalyst loading and reactor internal inspections is removed during the low temperature dry out. Oleflex reactor circuit low temperature dry-out is performed by heating up the Oleflex reactors loaded with catalyst to ~260°C (500°F) under nitrogen circulation.

Prior to this activity, it is assumed at this stage that [a] the Oleflex reactors catalyst loading, chloride treater adsorbent loading and reactor effluent driers (REDs) adsorbent loading activities have been successfully completed [b] the cold separation section has been dried out separately, isolated and kept under nitrogen blanket [c] Oleflex heater refractory dry out and bulk dry-out is completed, convection section is running with Oleflex heater pilots lit up [d] the fractionation system long loop circulation has been going on either with dry out completed or in progress [e] Reactor effluent contact cooler, REC interstage air/water/contact cooler and REC discharge air/water cooler are commissioned [f] Cold separation system is bypassed both on the reactor effluent side as during bulk dry-out and Oleflex liquid propane feed side as during fractionation dry-out [g] Regenerant scrubber has been loaded with packings, inventoried with caustic and; caustic and water circulation to the scrubber commissioned.

Reactor circuit low temperature dry-out must be performed with nitrogen bypassing the cold separation system during the initial start-up of the Oleflex unit. This presents an opportunity to perform safe leak checks on the system under circulating nitrogen rather than under circulating hydrogen and hydrocarbon post reactor internals inspection, catalyst loading and box-up activities.

During subsequent unit start-ups post screen cleaning and/or turnaround, low temperature dry-out can be performed with 50:50 mole ratio hydrogen-propane vapor provided both the REDs in the units with 2 REDs and at least 2 REDs in the units with 3 REDs have been freshly regenerated prior to this dry-out. This is because, after dry-out with hydrogen- propane, cold separation system and reactor section commissioning will commence when it may not be possible to regenerate the REDs due to lack of regenerant risking moisture breakthrough. Depending on the status of the reactor section, the reactor effluent can contain olefinic material and H₂S making it unsuitable as regenerant. There can be coking issues with olefinic regenerant especially if the regenerant heater is an electric heater. Further, in the Oleflex units with reactor effluent contact cooler, the reactor effluent will contain solvent compounds (essentially heavies in Oleflex parlance) making reactor effluent unsuitable as a regenerant because apart from potential coking it can pre-load the REDs with solvent compounds during the cooling step at a stage when the dry-out is still incomplete and all the reactor effluent is routed to the Oleflex reactors bypassing the cold section. For this reason- an alternate source of regenerant-either hydrotreated LPG or sweet-moisture free natural gas or nitrogen is recommended for off-line regeneration during low temperature dry-out with hydrogen-hydrocarbon.

The procedure for low temperature dry-out under hydrogen and propane mixture is identical to that under nitrogen except that external regenerant is used for RED regenerations requiring regenerant effluent line-up via operating regenerant gas scrubber to fuel gas pool or relief header as required at that stage.

The cold separation system is dried out onsite separately as prescribed early in this section and kept isolated throughout the reactor circuit low temperature dry-out. In all types of Oleflex unit configurations, irrespective of whether the low temperature dry-out is performed with nitrogen or hydrogen-propane mixture, cold separation system shall remain bypassed until < 1 mol. ppm H₂O level in the reactor effluent is attained upstream and downstream of the RED in service and remains stable for at least 2 hours and at least 1 freshly regenerated RED is available in stand-by ready to be placed in service. Once this is achieved cold section can be taken in line during nitrogen circulation to dry out cold section if necessary.

- ❖ **C3 Oleflex units with the reactor effluent contact cooler:** In these units, cold separation system shall remain bypassed during low temperature dry out with nitrogen to prevent solvent contaminating/fouling the cold separation system. In nitrogen circulation, there will be no condensed hydrocarbon liquids to wash down the solvent in the cold separation system. Any solvent lodged within the system may tend to freeze out

later during system chill down with propane in passes where no liquids exist. Cold section shall be taken in service later in the start-up when the reactor circuit is inventoried with hydrogen and propane. In these units, dry out of cold separation system constitutes a critical activity during initial startup. When the low temperature dry out is done with hydrogen and propane, it is permissible to take cold separation system in service when $H_2O < 1$ wt.mol ppm at RED inlet/outlet.

During this initial low temperature dry-out, hot nitrogen is circulated at $\sim 260^\circ\text{C}$ (500°F) through the Oleflex reactors, using the same loop as outlined in the reactor circuit bulk dry-out but this time with catalyst loaded in the Oleflex reactors and adsorbents loaded in the chloride treater and reactor effluent driers REDs. The RED placed on stream will adsorb the non-condensable moisture from the circulating gas stream while the other RED will be in regeneration. REDs shall be regenerated back to back during the low temperature dry out with suitable start-up regenerant either hydrotreated dry LPG or sweet and dry natural gas or nitrogen using external alternate RED regenerant lines. If the low temperature dry out is done under hydrogen-propane circulation, sufficient regenerant net gas will not be available until propane dehydrogenation in the Oleflex reactor section is established with reactor inlet temperatures (RITs) running in excess of 600°C and therefore availability of alternate regenerant- either hydrotreated LPG or sweet-moisture free natural gas or nitrogen is recommended.

It may typically take 2-3 days to achieve the atmospheric moisture dew point below -76°C (-105°F) corresponding roughly to ~ 1 mol ppm H_2O in the circulating gas stream downstream of the REDs during low temperature dry-out.

The following procedure applies for reactor circuit low temperature dry-out using nitrogen with cold separation system bypassed:

- 1) Air free the reactor circuit: This step is required since air ingress might have occurred into reactor section during reactor internal inspection post bulk-dry out and cooling and/or during catalyst loading activity. Isolate the reactor circuit and evacuate using the ejector. The line-up and attendant precautions are the same as that described in earlier sections.
 - a. Pull vacuum until ~ 130 mm Hg Abs pressure is attained. Once stable vacuum has been reached, block in all the process lines to the ejector and block in the steam line to the ejector.
 - b. Hold the vacuum for half an hour to check for leaks (for the initial vacuum) and then break the vacuum with nitrogen by introducing nitrogen into the reactor loop at the connection provided on the reactor effluent compressor's suction and discharge piping.

- c. Repeat steps a) and b) (without the half hour hold) until the oxygen content is determined to be less than 0.5 mole-% (estimate 3 times). If it takes an exceedingly long time to establish a vacuum, it is likely there are leaks present in the system. The entire reactor circuit should then be leak tested again under positive nitrogen pressure.
- d. Break the vacuum the third time with nitrogen and pressure up the reactor circuit to the recommended REC start pressure provided by the vendor.

NOTE: If it is desired, in lieu of air freeing by pulling vacuum, air freeing can be done by piston purge of the reactor circuit with nitrogen by pressuring up to ~300 KPaG (~45 psig) and depressuring to ~50 KPaG (~7 psig) in cycles 4-5 times until oxygen is less than 0.5 mol%.

- 2) Purge out the reactor effluent compressor casings with nitrogen to air free.
- 3) Commission the REC as per vendor guidelines for operation in nitrogen service. Initially the anti-surge valves will be 100% open during REC startup. Anti-surge valves will be slowly closed to force flow forward. To establish the required discharge pressure, throttling of the cold separation system bypass will be necessary. Maximize flow while maintaining required discharge pressure.
- 4) Line out the reactor circuit at normal operating conditions at the REC suction drum with a discharge pressure and temperature consistent with nitrogen circulation. Typically the discharge pressure is anticipated to be in the range of 8-9 kg/cm²g (114-128 psig) in nitrogen service.
- 5) Once the nitrogen circulation has been established, check the reactor inlet temperatures (RITs) attained only with the pilots running. Commission the main fuel gas line and low firing mode (LFM) fuel gas lines keeping the respective burners isolated. Initially light only 1 or 2 burners in each heater (or in each cell in case of heaters with dual cells). Either main burner or LFM burner can be chosen for lighting. LFM burner has relatively low heat release compared to main burner enabling more burners to be lit to attain the target temperature ensuring better distribution of heat flux. If main burners are chosen, spatially distribute the burners to attain better distribution of heat flux. Raise the RITs to about 260°C (500°F) in a controlled manner at the rate of 20°C/hr (36°F/hr) on fuel gas pressure

control. A slow heat up will gradually drive off the water adsorbed on the catalyst.

NOTE: During startup, the driers will be regenerated with nitrogen from the cold separation system. Liquid water is collected in the RED regenerant knockout drum and drained out safely into refinery chemical drain, and the gas from the regenerant knockout drum is diverted to the REC suction drum via the dry-out line instead of the downstream regenerant gas scrubber. Regenerations shall be completed as necessary to attain the target dryness. During the nitrogen regenerations, to ensure that sufficient pressure exists in the regenerant knockout drum to effect condensation of water, the start-up regenerant effluent return line to the REC suction can be throttled as required. It is recommended that all the REDs are regenerated before concluding the dry-out and hydrocarbon startup of the reactor section. This will ensure maximum capacity of the driers for H₂S and water during initial startup.

NOTE: In the Oleflex units with the reactor effluent contact cooler, the trapped solvent components on the REDs will get removed and get co-condensed with water and accumulate in the regenerant knock-out drum. In these units, phase separated liquid water must be drained out to refinery chemical drain and only solvent phase must be returned back to the contact cooler. If this is not possible due to the drain material being an emulsion, dispose-off the condensed liquids to the spent solvent storage via safe and suitable temporary means or dispose of the collected liquids as refinery waste oil. One possible means is to attach flanged end of a rated metallic hose (with a flanged connection at one end and filling nozzle contraption at the other end) to the drain point and fill into a carbon steel portable trolley tank (designed for minimum 3.5 barg and having at least 50% LG range equivalent capacity) fitted with a pressure and level gauge; inlet/outlet and drain/vent points. Once filled the trolley tank must be removed to near spent solvent storage yard. Water must be drained and solvent transferred to the spent solvent tank with a temporary unloading pump. If this is not feasible, unload into clean drums purged with nitrogen. Fill the drums leaving ~10% vapor space. Once filled, place the drums on a pallet and move sway with fork lift to storage yard for disposal as waste oil.

- 6) Circulate the gas through the reactor effluent driers (REDs), bypassing the cold separation system. Monitor the moisture level at the inlet/outlet of the online RED. Monitor and establish moisture content is <1 mol ppm at the outlet of the RED.

- 7) Once at <1 mol ppm H₂O at the outlet of the RED, open the start-up line from the reactor effluent to the net gas line. This allows nitrogen to flow through the catalyst collectors, reduction zone/surge pot electric heaters, surge pots and reduction zone; and reactor plug purge lines. Use CCR gas heater startup bypass to route the gas through the Purge Gas heater. Commission the CCR gas heater and Purge Gas heater to aid dry-out those sections.
- 8) Continue hot nitrogen gas circulation around the reactor circuit, the reactor effluent driers via cold separation system bypass. Continuously monitor the moisture level at the inlet of the RED's using the start-up lines for the RED on-line moisture analyzer or portable moisture analyzers.
- 9) Continue RED regenerations until [a] <1 mol ppm H₂O is achieved both at the inlet and outlet for the online RED and remaining stable at least since last 2 hours [b] The off-line REDs are freshly regenerated at least once and ready to be placed in service
- 10) Gradually reduce the heater firing cut off the number of burners in service as required finally cutting off all the burners that were in service. Isolate all the fuel gas block valves at the burners.
- 11) Close the air registers. Shutdown all the pilot burners blocking pilot fuel gas cock valve at each burner.
- 12) Purge the fire box for 15-20 minutes by opening the stack damper and then close the damper.
- 13) Continue the gas circulation permitting the Oleflex reactors to cool down until all the reactor outlet temperatures are approximately 100°C (212°F). Reduce the gas circulation to a minimum operating level by gradually opening the anti-surge valves until they are fully open.
- 14) In parallel with step 13, for C3 Oleflex units with reactor effluent contact cooler and/or REC interstage contact cooler, drain out solvent from the REC interstage and discharge knockout drums to contact cooler monitoring the level. Pump out excess to storage either directly or via solvent recovery column bottoms as may be the case to prevent accidental transfer from these drums overflowing the contact cooler while pulling vacuum during hydrogen-hydrocarbon inventory in the subsequent steps.
- 15) Shut down the REC safely.

- 16) Stop makeup nitrogen and block all the nitrogen injection valves to the reactor circuit.
- 17) De-pressure the reactor system to flare by crack opening the pressure control dump valve in steps of 2% down to a level of approximately 10 KPaG (1.4 psi) above the flare header pressure. Then close the valve.

This dump valve is located on the reactor effluent contact cooler in the case of C3 Oleflex units with the reactor effluent contact cooler. Alternatively the de-pressuring can be performed with the bypass valve on the PSVs from various vessels as available.

The reactor circuit low temperature dry-out, is now considered complete. The reactor system is now in standby mode, ready to be inventoried with hydrogen and hydrocarbon. The unit shall be leak tested prior to and after inventorying with hydrogen and hydrocarbon before proceeding further with start-up.

7. Feed Cut-in to Reactor Circuit and Subsequent Line-out

At this stage it is assumed that: [a] the reactor circuit low temperature dry-out has been successfully completed and the circuit is under dry nitrogen blanket at ~10 KPaG above flare header pressure with <1 mol ppm moisture [b] the REC has been shut down but the reactor effluent/REC interstage air/water/contact coolers and REC discharge cooler are running [c] Oleflex fired heaters have been shut down including the pilots [d] The fractionation section is in long loop circulation with <1 wt.ppm H₂O in the circulating propane [e] Back to back feed drier regeneration is in progress [f] Both the REDs in 2 RED configuration and at least 2 REDs in 3 RED configuration are freshly regenerated [g] The regenerant gas scrubber has been loaded with the packings, inventoried with caustic and the scrubber has been commissioned with caustic and water circulation [h] Net gas compression system if applicable and PSA unit check outs, pre-commissioning have been completed by the vendor and the system is ready for commissioning.

The following procedural steps will bring the Oleflex reactors online

- 1) Isolate all the equipment and instruments not designed for vacuum and line up the system for pulling vacuum as described in the earlier sections.
- 2) Check and ensure each stage of REC is isolated and under nitrogen blanket since the casings may not be designed for vacuum. The reader of this manual must carefully evaluate the process line-up requirements for the specific unit since the piping specifications may vary slightly across the units.

The following guidelines on the process line up prior to vacuum pulling to inventory the system with hydrogen-hydrocarbon, are written for the C3 Oleflex units with the reactor effluent contact cooler which operate under slight vacuum at REC suction during normal operations.

- a. 1st & 2nd stage suction/discharge block valves are shut tightly
- b. Blinds on 1st & 2nd stage suction/discharge block valves swung open
- c. Lip-seal on the 1st stage suction block valve is intact
- d. Isolation valves on 1st/2nd antisurge valves are shut tightly
- e. Blinds on isolation valves in item "d" above swung open

This line up allows vacuum to be pulled on REC interstage contact cooler, REC discharge cooler, REC discharge drum together with connected piping while maintaining the REC casings isolated. Swinging the spectacle blinds to open position before pulling vacuum, even if nitrogen leaks from the pressurized casing side into vacuumed process side, is safer than attempting to swing open the blind later with the process side under pressure risking hydrogen - hydrocarbon leak. Further, it is safer to perform lip-sealing job on the 1st stage inlet block valve early on with the system under nitrogen rather than swing open the blind later and seal weld the lip-seal gasket with hydrogen- hydrocarbon on the process side. Keep nitrogen purge on either of the REC casings continuously venting it to atmosphere while pulling vacuum.

For the conventional Oleflex units with reactor effluent air/water cooler with/without solvent injection system and with/without REC discharge drum, the requirement to isolate the REC casings from being subject to vacuum continue to remain valid though the process line up may slightly vary.

In the C3 Oleflex units with the reactor effluent contact cooler and/or REC interstage contact cooler, check and ensure the solvent is drained out to minimum possible level in the REC interstage contact cooler and discharge knockout drums prior to pulling vacuum. This will prevent accidentally pulling the solvent liquids from these drums into contact cooler(s)/piping during vacuum pulling. Block the solvent outlet valves from these drums prior to vacuum pulling.

3) **Inventorying the Reactor Circuit with Hydrogen and Propane**

Commission steam to the ejector evacuate down to ~130 mm Hg. Re-pressure the reactor system to the required pressure to start the REC (consult vendor for pressure) with a 50:50 mixture of propane and hydrogen. Depending on the unit's piping arrangement one of the following procedures will be used to pressurize the circuit with hydrogen and hydrocarbon:

a. Initial inventory on the units provided with hydrogen and propane flow meters on the inventory lines:

If such provision exists, inject propane and hydrogen simultaneously at the same molar flow rate into the REC suction drum (or reactor effluent contact cooler if applicable) to pressure up the reactor circuit from vacuum to an adequate pressure level as prescribed by the vendor to start the REC. The anticipated initial pressure to start the REC is typically 0.8 -1.3 kg/cm² g (~11.4 -18.5 psig). Adjust the flow rates throttling the globe valves and local flow indicators to achieve a 50:50 molar ratio of hydrogen and propane. Normally the initial inventorying lines are located around the area close to the REC suction. Make sure all the equipment, vessels and piping have been pressured up and inventoried as required. There are pressure gauges located on the REC interstage and discharge stage drums; chloride treater outlet, RED outlet, each Oleflex reactor outlet and reactor effluent contact cooler outlet which serve to check the pressurization.

b. Initial inventory on the units not provided with hydrogen and propane flow meters on the inventory lines:

Pressurize the circuit in steps using equal installments of ~30 KPa (~4.35 psi) alternating between hydrogen and propane. For example, starting with ~130 mm Hg A which corresponds to ~17.33 KPa A (~2.51 psi), break vacuum with hydrogen until pressure increases by ~30 KPa (4.35 psi) to 47.33 KPa A (6.86 psia) and then pressure system by another ~30 KPa (4.35 psi) with propane to 77.33 KPaA (11.21 psia). Repeat until the system is at desired starting pressure for the REC. Make sure all the equipment, vessels and piping are pressured up in each pressurizing step and attain equal and stable pressure before proceeding to the next step. There are pressure gauges located on the REC interstage and discharge stage drums; chloride treater outlet, RED outlet, each Oleflex reactor outlet and reactor effluent contact cooler outlet which serve to check the pressurization. The anticipated initial pressure to start the REC is typically 0.8 -1.3 kg/cm² g (~11.4 -18.5 psig). The last pressure step before starting the REC should be done with propane. This procedure should yield ~50:50 mole mixture of hydrogen and propane.

c. Including the REC circuit in initial inventory:

Upon attaining the required pressure on the rest of the system to start the REC, stop nitrogen purge on the REC casings and switch

to hydrogen purge of casing on each stage. Purge for about ½ hour to 1 hour to ensure all nitrogen is removed. Stop the hydrogen purge. Slowly open the isolation valve(s) at each stage inlet/outlet of the REC. Slowly open the isolation valve(s) upstream and downstream of the antisurge valves. Finally open the antisurge valves if they were previously in closed position.

Note: The propane used during pressuring is routed from the depropanizer overhead line to the REC suction. It is important to monitor operations in the depropanizer column while inventorying the reactor circuit with propane vapor. Make certain that the depropanizer column operations remain stable during this period.

Once REC circuit has been inventoried, check back the system pressure and composition. Depending on the pressure and composition, either make-up with hydrogen-propane or slightly depressure to flare to attain the required pressure and gas composition to start the REC.

4) **Performing Initial Leak Check for Hydrogen-Hydrocarbon at Low Pressure and Temperature**

At this stage, perform the hydrogen-hydrocarbon leak check on the system by running the lower explosive limit (LEL) detector on all the major flanges and connections on the reactor system. This includes the flanges at Oleflex reactor inlet/outlet, HCFE combined feed/reactor effluent inlet/outlet, HCFE manways, Oleflex heater manifold hand holes, Oleflex reactor surge pots/reduction zone body flange, REC stage inlet/outlet flanges, REC reactor effluent air/water/contact cooler flanges/connections, REC interstage air/water/contact cooler flanges connections, REC discharge air/water cooler flanges connections, chloride treater inlet/outlet/bypass, RED inlet/outlet, reactor effluent filter inlet/outlet, cold separation system bypass, REC stage drums, solvent lines etc. Any leaks found at this stage must be fixed.

- 5) Proceed to restart the REC per the vendor guidelines. Normally REC is started with the antisurge valves 100% open.
- 6) Commission the pressure controller that is cascaded to the REC speed controller.

For the C3 Oleflex units with reactor effluent contact cooler, designed to operate at ~105 KPaA (~15.2 psia) at the reactor 4 outlet where the pressure is controlled, set the pressure controller initially to ~138

KPaA (~20 psia) targeting 102-103 KPaA at 1st stage suction of the REC to stay above the local barometric pressure and achieve stable pressure control on automatic control mode. The unit shall be started and lined out initially at this pressure at the outlet of reactor 4. Once stable operations are achieved and established on the unit including the CCR regenerator section, the operating pressure at reactor 4 outlet will be reduced to normal operating pressure level. This will be covered later in this section.

- 7) In order to increase the forward flow through the system and build-up the pressure, the antisurge valves will need to gradually close. While keeping the pressure controller in automatic mode cascaded to the speed controller, this can be achieved either by progressively closing the antisurge valves in manual mode or by placing the antisurge valves in automatic control mode. In either case, it will be required to add hydrogen and propane continuously to the system with pressure controller in automatic mode cascaded to the speed controller to build up system pressure and increase forward flow. Failing to make up this addition will result in either failure to build up the REC discharge pressure or inability to close the REC antisurge valves due to kick-back from the surge controller. The surge protection system will continue to protect the REC irrespective of whether the antisurge valves are on manual mode operation or auto mode operation.
- 8) Monitor the REC's specific gravity analyzer continuously. As the forward flow increases at a given discharge pressure, the REC speed will increase. Adjust the hydrogen and propane vapor flow based on the specific gravity analyzer. If the specific gravity tends to drop off as indicated by the analyzer, decrease hydrogen injection rate and/or increase propane vapor injection rate. If the analyzer begins to trend upwards, decrease propane vapor injection and/or increase hydrogen injection rate.
- 9) The flow path should be the same as the reactor circuit low temperature dry-out bypassing the cold separation system. All the reactor effluent downstream of the RED is routed via the cold separation system bypass block valves to tie-into the combined feed to HCFE. This block valves will have to be throttled as required to build the REC discharge pressure even while maximizing the forward flow.
- 10) **Maximize the forward flow targetting the minimum required back pressure on the combined feed exit (downstream of the bypass valve) as required by the vendor to commission the cold separation system which is covered later in this section.**

- 11) Confirm the moisture analyzer reading at the outlet of the RED's is less than 1 ppm H₂O.
- 12) **Commission the CCR gas heater and establish flow to the catalyst collectors, lift engagers 1, 2 and 3. Flow indication may not be correct at this stage due to gas specific gravity but that is acceptable.**
- 13) **Open the jumper valve on the CCR gas to purge gas heater. Commission the purge gas heater. Route the gas via reduction zone/surge pot electric heaters to reduction zone/surge pots but do not start the electric heaters yet!**

Reduction zone electric heater and surge pot electric heaters will be commissioned later when the cold separation system has been commissioned and net gas of required hydrogen purity is available.

- 14) Establish the reactor plug purges with CCR gas since PSA hydrogen is not available at this stage of the start-up. Open the net gas to reactor plug purges via the startup tie-in line from the CCR Gas Heater.
- 15) Commission the differential pressure controllers between the reduction zone and Reactor 1, and between the surge pots and their respective reactors. Set the differential between 0.10-0.15 kg/cm²g (1.4-2.1 psi) using the PDIC.
- 16) Once stable gas circulation is accomplished, sample the circulating gas. Make sure %N₂ in the circulating gas is <5 mol%. If in excess, depressure the circuit slightly from suitable pressure points to relief header and add makeup hydrogen and propane until N₂ is <5 mol%. Relight the Oleflex heaters and raise the reactor inlet temperatures (RITs) initially to 260°C (500°F) at 20°C/hr (36°F/hr) using fuel gas pressure control.
- 17) Skip this step and proceed to Step 18 if low temperature dry-out has been completed.

Perform Oleflex low temperature dry-out if being performed with hydrogen-hydrocarbon. The procedure will be essentially same as that performed under nitrogen except that external regenerant might be used for RED regenerations.

- 18) **Cold Separation System Commissioning Guidelines:** This system shall be commissioned as per the procedures prescribed by the Cold Separation System vendor and the vendor for the Turbo-Expander machinery. Initial start-up shall be under vendor supervision. If there is any conflict between

the guidelines given below with those of the vendor, vendor guidelines shall prevail.

- a. Confirm that the high pressure turbo expander (HPTE) and low pressure turbo expander (LPTE) inlet block valves are closed tightly. Both the instrumented block valve and manual valve (if provided) must be closed.
- b. Fully open the bypass JT (Joule Thomson) valve around the HPTE and the bypass JT valve around LPTE
- c. Reconfirm that the reactor effluent inlet, combined feed outlet, liquid propane feed inlet, net gas outlet and flash gas return and liquid product outlet valves are closed.
- d. Reconfirm that the various separator vessels outlet and liquid product pump inlet/outlet valves open to permit pressurizing/inventorying the liquid product pass and liquid product drum.
- e. Confirm that the nitrogen purge to through the casing (external non-process area under cold insulation) of the cold separation system has been established at the required rate
- f. Confirm that all the instrumentation on the cold separation system including the seal gas system instrumentation on the turbo expanders is commissioned
- g. Depressure the nitrogen encased in the cold separation system from 15-20 KPaG blanket pressure to ~atmospheric pressure safely to the atmosphere from the vantage points.
- h. Bleeder on the flash gas return, net gas return and liquid product return may be used for venting. Exercise care since nitrogen is can asphyxiate. Minimizing nitrogen hold-up will reduce the amount of nitrogen contaminant in the circulating gas once the cold separation system is taken in service. Once finished, close all the bleed valves and blind.
- i. Fully open the first block valve on the reactor effluent inlet to the cold separation system.
- j. Gradually open the small pressurizing globe valve across the second inlet block valve on the reactor effluent to start pressurizing the system.

- k. Pressurize all the passes/piping/vessels ensuring the maximum allowable differential pressure across the plate fin passes and the design pressure of the equipment is not exceeded at any stage.
- l. Once the system has been pressurized approaching within ~5 KPa of the pressure downstream of the reactor effluent bypass valve bypassing the cold separation section, close the small pressurizing globe valve.
- m. Close the liquid outlet valves on all the separator vessels and liquid product drum.
- n. **Set the PIC on the combined feed exit at a value corresponding to the minimum back pressure as required by the cold separation system vendor.** Commission the PCV/PIC on the combined feed exit on auto while keeping the parallel bypass/block valve in closed position to equalize the pressure with that upstream of the reactor effluent bypass valve.

This PIC shall not be kept on manual as this can compromise integrity of cold section exchangers during start-up.

- o. Fully open the second block valve on the reactor effluent inlet to the cold separation system to establish parallel flow path through the cold separation system with the reactor effluent bypass circuit.
Note that if the pressure upstream of the reactor effluent bypass valve bypassing the cold separation system is lower than the set pressure on the PIC, the control valve on combined feed outlet will remain closed. In order to establish the flow, if necessary, pinch the reactor effluent bypass valve such that the pressure upstream of this valve is above the PIC set point permitting the PCV to open.
- p. Establish hydrogen and hydrocarbon flow through the cold separation system- Reactor Effluent Pass of Cold Combined Feed Exchanger → High Pressure Separator→HPTE Bypass→ Intermediate Pressure Separator→LPTE Bypass →Low Pressure Separator→ Combined Feed Pass of Cold Combined Feed Exchanger.

Target approximately 60% of the design reactor effluent mass flow at REC discharge at this stage maintaining H₂: HC at 1:1

- q. Continue to throttle the reactor effluent bypass valve bypassing the cold separation system slowly to direct more flow through the cold

system permitting gradual opening of the PCV until a point is reached when the PCV reaches about 60-70% open position. At this stage the reactor effluent bypass valve may still remain partially open.

- r. **When the minimum required back pressure on the combined feed pass exists as prescribed by the vendor, liquid propane feed can be introduced to the feed chiller pass of the cold separation system to initiate initial chilling down of the system.**
- s. Crack open the liquid propane feed inlet valve to start chilling the cold separation system by auto refrigeration of propane. The rate of increase in feed propane ($\text{m}^3/\text{hr} / \text{hr}$) is guided by the maximum allowable chilling rates ($^{\circ}\text{C}/\text{hr}$) of the cold separation system specified by the vendor which is typically $10\text{-}20^{\circ}\text{C}/\text{hr}$ ($50\text{-}68^{\circ}\text{F}$). Vendor recommended chilling rate shall not be exceeded.

When liquid propane feed is introduced, the back pressure on the PCV at combined feed exit will gradually start to increase forcing the pressure controller to open the control valve further. If the PCV is over 80% open, crack open the PCV bypass valve to maintain the PCV in good control range. Add make up hydrogen as necessary to contact cooler to maintain the specific gravity of process gas running through the REC.

- t. Continue gradually increasing the feed targetting 60% design rate which may take several hours. It should be possible to commission both the HPTE and LPTE before 60% liquid feed is achieved to permit uniform chill down of the cold separation system.

As to at what stage the expanders could be cut-in, follow prescribed vendor guidelines. There may be minimum process gas inlet temperature specified for HPTE start-up and minimum back pressure prescribed for LPTE start-up.

- u. At this stage, gradually pinch the HPTE bypass JT valve to increase the pressure in the reactor effluent pass to effect condensation of propane. Simultaneously, continue throttling the reactor effluent bypass valve to direct more flow through the cold system ensuring all the time that the minimum necessary combined feed exit back pressure is maintained.

Though no dehydrogenation products are formed at this stage requiring hydrogen to be taken out via net gas, it will be necessary to commission the net gas pressure controller at this stage to preparing for HPTE/LPTE start-up.

- v. When the pressure, temperature and flow at the inlet of the HPTE is appropriate as prescribed by the vendor to start the machine, commission the HPTE. HPTE will initially be commissioned with bypass JT valve partially open on manual. The bypass JT valve will then be progressively closed to load the HPTE. At this stage commission the pressure controller on the HPTE. The REC discharge pressure will now be controlled by this controller.
- w. Once HPTE is commissioned, there will be a large increase in chilling and rapid liquid condensate from the high pressure separator and intermediate pressure separator vessels. Recycle hydrogen purity will increase. Once hydrogen purity has stabilized, open the net gas block valve and close the reactor effluent line to net gas line start-up bypass.
- x. As the chilling progresses and liquid propane gets condensed, liquid level will appear in the various separator vessels. Commission the level controllers on the separator vessels where liquid levels have been seen and start sending the liquids to the liquid product drum. Makeup propane and hydrogen as required.
- y. When the recycle hydrogen purity, flow and pressure and the back pressure on the machine is appropriate as prescribed by the vendor enabling to start the machine, commission the LPTE. LPTE will initially be commissioned with bypass JT valve partially open on manual. The bypass JT valve will then be progressively closed to load the LPTE. At this stage commission the recycle gas flow controller on the LPTE.

Adjust and maintain the ratio of (moles of hydrogen in recycle gas) / (moles of hydrocarbon in the recycle gas + moles of hydrocarbon in Oleflex liquid propane feed) commonly referred to as H₂/HC ratio hereafter, at 1:1 in the Oleflex combined feed throughout the start-up until instructed to reduce later in this section.

Further, though no dehydrogenation products are formed now requiring hydrogen and light ends like methane, ethane and ethylene to exit via net gas, to maintain the net gas pressure controller in good control range, some excess hydrogen may be added to the reactor effluent contact cooler as required.

Once the LPTE has been commissioned, additional cooling will be achieved. Monitor cold end and warm end approach temperatures at each exchanger between adjoining passes in thermal contact. They should be typically within 5-10° C. For example- reactor effluent inlet and combined feed outlet temperatures should be within 5-10° C apart; reactor effluent outlet and combined feed (recycle hydrogen and propane feed) inlet temperatures should be within 5-10° C apart. Wide approach temperatures can exert excessive thermal stresses on the brazed aluminum plate fin joints which over time can lead to inter-pass leaks.

- z. As the liquid level begins to build up in the liquid product drum, proceed to commission the liquid product pumps. The liquid product pumps may require initial chilling before they could be started. Follow vendor guidelines. Start sending the liquids from the drum to the fractionation section on liquid product drum level control via the liquid product pumps and liquid product pass to fractionation. Commission the flash gas pressure controller to start sending the vapors to the REC suction to control the pressure in the liquid product drum.

At this stage, at ~60% design propane feed to the cold separation system, it should be possible to fully close the reactor effluent bypass valve and route all the reactor effluent through the cold separation system.

As the cold section cools, increasing amount of propane will condense out of the system causing the reactor system pressure to begin to drop requiring makeup propane. The makeup propane is added initially to reactor effluent contact cooler during cold separation system start-up but later at some point in this procedure it is achieved by adjusting the propane feed rate.

Further, as the feed rate is increased, the total combined feed circulation rate will increase as well increasing the overall system pressure requiring hydrogen makeup. Add makeup hydrogen at REC suction as required.

Throughout the chill down, add make-up propane and/or H₂ into the circuit to maintain the system pressure and appropriate specific gravity of the circulating gas to maintain stable REC operation.

- 19) Monitor the unit for signs of freezing in the cold separation system. Freezing would result in increased pressure drop across exchangers or temperature imbalance in various exchanger passes.

- 20) Once the liquid propane feed to the cold separation system has been raised and stabilized at ~60% of design, liquid product drum level attained at ~40-60% and the flow through the liquid product pump is established, the start-up line bypassing the cold separation system liquid feed to liquid product line will need to be gradually phased out. This is accomplished by progressively closing the bypass valve coincident with the Oleflex liquid product pump out to maintain the fractionation feed stable at ~60% design which was the rate at which the fractionation dry-out loop was initially established. Phase out the deethanizer rectifier overhead slip stream to feed driers at this stage once the freshly regenerated feed drier is placed online.
- 21) With the Oleflex startup bypass line closed, a long loop circulation with 60% design feed rate is established through the complex. Once a steady net flow is established out of the flash drum, complete phasing out the startup bypass circulation. Establish feed flow through the normal path from the depropanizer overhead receiver. At this point the amount of fresh feed coming into the unit should match the amount of liquid being condensed out. Continue to monitor specific gravity at the REC and if necessary add hydrogen to the system to compensate for any losses of hydrogen. Hydrogen makeup will need to continue until the dehydrogenation reactions start however the amount of hydrogen for makeup should be small once the circulation rate, propane feed rate and system pressure have been established.
- 22) Start raising the RITs from 260°C to 400°C at 20°C /hr. While the RITs are being increased and when the net gas hydrogen purity is ≥ 92.5 mol% H₂, commission the reduction zone and surge pot electric heaters with CCR hydrogen gas that will be at approximately same purity as net gas depending on the cold separation section configuration and increase the temperatures up to 350°C at 55°C/hr using the temperature controller. It is recommended to keep the surge pots at this temperature until PSA hydrogen is available due to concerns of coking the electric heaters with hydrocarbons in the CCR gas hydrogen.

If external PSA hydrogen meeting Oleflex PSA hydrogen quality requirements is available, then the reduction zone and reactor surge pot heaters can be ramped in tandem with the RITs to match the 400°C RITs at this point; and later in the procedure when the RITs are ramped further >400°C later in the procedure, the reduction zone and surge pot temperatures can be ramped in tandem with the RITs until they attain their design temperatures. However, it should be noted that this addition requires that an equal amount must be taken out as net gas. If such

external PSA H₂ is not intended to be used, the reduction zone and surge pot electric heaters shall be maintained at 350°C with CCR hydrogen gas.

23) Performing Leak Checks under H₂-HC Circulation

In the next steps, initial sulfiding program will be performed when the RITs will be raised further and held at 475°C (sulfiding hold), 500°C (sulfiding hold), 550°C (sulfiding hold), 595 – 600°C (hold at stable temperature before ramp plan execution) and finally normal operating temperatures (625°C -650°C). At each of these temperature holds including when the unit is lined out at final RITs, it is critical to perform leak check for H₂ and hydrocarbon on all the major flange joints and process connections outlined earlier in this section and in addition on all the cold separation system flanges/connections with the portable LEL detectors. Flange insulation covers should not be removed unless excessive leakage is detected and hot bolting is to be performed. Contractor shall determine at what temperature hot bolting is required.

24) Perform Initial Sulfiding Program:

Sulfiding shall be performed at H₂/HC mole ratio of 1.0 and 60% design Oleflex feed which shall be maintained throughout the sulfiding schedule by adjusting the required amount of recycle gas accurately accounting for the purity of the recycle gas mol % H₂. This is critical to establish a stable metal sulfide barrier.

- a. When reactor inlet temperatures reach 400°C (752°F), initiate the sulfiding of the reactor circuit by commissioning the DMDS injection pumps. Inject 50 wt. ppm sulfur (based on total liquid feed). All three injection pumps should be operating and each pump should be set at 33% of the desired flow, with the flow of each pump feeding the inlet of the HCFE. Do not hold at 400°C (752°F), instead, continue raising reactor inlet temperatures at 20°C/hr (36°F/hr) to 475°C (887°F). Check and record the reactor effluent H₂S content, using Dräger tubes, every two hours throughout the entire sulfiding procedure.
- b. At 475°C (887°F) maintain DMDS injection between 50-60 wt. ppm sulfur based on total liquid feed. Hold at these conditions for 12 hours or until a stable level of at least 30-40 mol ppm H₂S is present in the reactor effluent section for 6 hours, whichever occurs later.

When the reactor inlet temperatures are in the temperature range of 475°C to 500°C, some propane dehydrogenation products will be formed requiring net gas pressure control valve to open to take out excess hydrogen and light ends from the system. At this stage

any hydrogen addition to the contact cooler that was being done to keep the net gas pressure control valve in good control range may be completely stopped.

- c. Raise the reactor inlet temperatures at 20°C/hr (36°F/hr) to 500°C (932°F) and increase DMDS injection to 60-70 wt. ppm sulfur based on total liquid feed. Hold at these conditions for 12 hours or until a stable level of at least 40-50 mol ppm H₂S is present in the reactor effluent, whichever occurs later.
- d. Raise the reactor inlet temperatures at 20°C/hr (36°F/hr) to 550°C (1022°F) and increase DMDS injection to 75-85 wt. ppm sulfur based on total liquid feed. Hold at these conditions for 32 hours or until a stable level of at least 50-60 mol ppm H₂S is present in the reactor effluent for at least 6 hours, whichever occurs later.

The initial sulfiding schedule shall be repeated in its entirety should the unit trip or shutdown during the course of sulfiding.

- 25) At this point at 550°C stable RITs, H₂/HC mole ratio of 1.0 and 60% design feed rate to the unit, net gas can be established as carrier gas and two-thirds of DMDS can be fed downstream. Commission the net gas purge FIC on the combined feed outlet of HCFE. Swing two of the DMDS injection points to the HCFE outlet from the respective DMDS injection pump.
- 26) When the net gas production starts, the net gas pressure controller can be operated in auto if not already placed in auto. Initially there will not be enough net gas to regenerate the REDs therefore the net gas pressure controller will be overriding the RED regeneration gas flow control. As net gas production increases the regenerant gas flow to the REDs should be increased to the design rate.
- 27) In the meanwhile, even as the sulfiding schedule is in progress, when the RITs are raised in excess of 475°C (887°F); the reaction products will contain increasingly more propylene and cracked light ends. The fractionation section will need to be adjusted accordingly.
- 28) Light ends will be removed in the Deethanizer system. As light ends accumulate, the deethanizer system pressure will increase at which stage the pressure controllers should be set at the normal operating pressure. The Deethanizer Rectifier Condenser should be chilled to design operating temperature to maximize propane/propylene condensation and recovery. Operating at higher rectifier condenser outlet temperature will result in loss of C₃ material.

29) Stabilize the P-P Splitter operation. As the RITs increase propylene production will also increase. Propylene will accumulate in the P-P Splitter overhead as indicated by the decrease in overhead temperatures. Commission the online product analyzer and start diverting propylene to off spec. storage until propylene is on spec which can then be routed to export or on spec. storage.

30) On the Oleflex heaters side, more burners will require to be taken in service as the RITs and/or feed is increased. Once all the burners are online and the fuel gas pressure is stable, transition the fuel gas control from pressure control to flow control.

31) **Commission the PSA Unit, SHP Reactor and begin RED regenerations**

Continue to raise the RITs above 550°C at 20°C/hr once the initial sulfiding schedule has been satisfactorily completed. In the range of 550-585°C (1022-1085 °F) RITs, there should be sufficient net gas production to permit RED regenerations and commissioning of the PSA unit. Start the PSA as per the vendor's recommendations. Commission the SHP reactor- as per the procedure covered later in this section. Start the RED regenerations with net gas regenerant.

32) Once the PSA H₂ is available, close the net gas jumper bypass valve to the purge gas heater at this stage and route PSA hydrogen via the purge gas heater to the reduction zone, reactor surge pots and reactor plug purges. Ramp reduction zone inlet temperature from 350°C to approximately 550°C (1022 °F) at no more than 55°C/hour (131°F) to achieve 540°C on the reduction zone bottom catalyst temperature as indicated by the temperature indicator for optimum catalyst reduction. If necessary adjust the reduction zone heater outlet temperature to achieve 540°C at the reduction zone bottom. Ramp the surge pots on Reactor 2, 3, and 4 from 350°C to their respective design inlet temperatures.

33) At this point the CCR section should be on standby ready to begin catalyst circulation and subsequently catalyst regeneration. Once PSA H₂ is available, start the cold catalyst circulation at ~60-80% design circulation rate without initiating the burn in the Regenerator but with upper regeneration blower and lower regeneration blower running under dry nitrogen circulation and with cooler blower in operation. Establish dust collector operations to start removing fines from the circulating catalyst system. Begin monitoring coke on catalyst by sampling from each lift engager. The coke levels will guide when the catalyst regeneration can be started. Normally stable regenerator burn can be established when the spent coke level builds up to ~1.0 wt. % - 1.5 wt. % over 2-3 cycles of cold catalyst circulation. **When this point is reached, commission the CCR**

regenerator section and vent gas treating system. Please refer to the CCR General Operating Manual for more information.

- 34) Raise the RITs further to about 595°C to 600°C (1094 to 1112 °F) in increments of 5°C all the while maintaining $0.6 < H_2/HC < 1$ adjusting the recycle gas rate and DMDS as required. After this, increase Oleflex propane feed rate from ~60% to ~85%+ of design or whatever is maximum permissible limited by the capacity of the propane recycle pumps and/or REC

During feed increases monitor the H_2/HC ratio and H_2S in the reactor effluent. Allow the H_2/HC ratio to decrease below 1.0 but make sure the ratio stays ≥ 0.6 by adjusting the recycle gas flow as necessary. Adjust the DMDS injection to maintain 50-60 mol ppm H_2S in the reactor effluent.

35) Execute the Oleflex Initial Ramp Plan – Establish Stable Operation

Details of the Oleflex Initial Ramp Plan will be provided by the UOP Chief Technical Advisor. The purpose of the initial severity ramp is to allow the Oleflex catalyst to attenuate in operation permitting normal operation of the Oleflex reactor section and the CCR section with reasonable (<5 wt. %) spent catalyst coke level at design (100%) catalyst circulation rate. Fresh Oleflex catalyst is highly active and prone to generating excess coke until it has been attenuated going through at least 2 catalyst regeneration cycles in the Regenerator.

During the Oleflex initial ramp period, the RITs will be increased and optimized while the H_2/HC ratio will be reduced to 0.5 design in a controlled manner at ~100% catalyst circulation rate while the Oleflex unit feed rate will be maximized throughout. A typical C3 Oleflex ramp chart is shown at the end of this section.

The severities will be adjusted in such a manner so as to yield approximately the same fractional Del T across each reactor as at design throughout the ramp. Coke make on the catalyst from each lift engager (LE) will be monitored and controlled typically to be within 1.0/1.2/1.8/4.0 wt. % failing which the respective RIT may be reduced during the ramp. Goal is to maximize the production at lowest possible RITs at the design H_2/HC ratio (~0.5) by the end of the ramp period. The RITs can be adjusted to target either optimum conversion or selectivity; for more details refer Section VIII, Normal Operations.

Note: The initial ramp plan is prescribed only for startups involving fresh Oleflex catalyst supplied in reduced form. For subsequent startups with the same catalyst the initial ramp is not required

Subsequent to the ramp, the C3 Oleflex units with the reactor effluent contact cooler designed to operate under slight vacuum at REC suction, shall be lined out at ~95% design production rate

36) Continue to monitor the reactor effluent H₂S levels. Increase or decrease DMDS injection to maintain at least 50-60 mol ppm in the reactor effluent throughout the ramp. Maintain H₂/HC at 0.5.

37) Continue to check the flange joints in the reactor circuit for leaks using a portable detector. Flange insulation covers should not be removed unless excessive leakage is detected and hot bolting is to be performed.

38) Commission the SHP Reactor:

The SHP Reactor can be commissioned once the net gas production is sufficient enough to start the PSA unit, RED regenerations are proceeding and the P-P splitter operation has been stabilized. This is anticipated to occur when the RITs are in the range of 550-585°C. At this point the SHP reactor is expected to be loaded with the catalyst, air freed, and under nitrogen blanket pressure.

The SHP reactor will be located either on the liquid product line (in case of conventional C3 Oleflex units designed with reactor effluent air/water coolers) or on the recycle propane line from P-P splitter bottoms (in case of C3 Oleflex units designed with reactor effluent contact cooler and/or REC interstage contact cooler that operate under slight vacuum at REC suction during normal operation).

To inventory and line-up the SHP reactor,

- a. Check and make sure the hydrogen inlet valves are positively isolated
- b. SHP reactor inlet/outlet valves are closed
- c. Check and make sure all the instrumentation- bed TI, inlet/outlet TI, pressure instruments, top LG/LI are commissioned
- d. Steam inlet to the SHP feed pre-heater shall be shut (if applicable) and the condensate flow control valve shall be shut to prevent any feed pre-heat at this stage.
- e. Route the deethanizer stripper bottoms stream bypassing the SHP effluent exchanger and SHP feed exchanger (if applicable) to prevent any feed pre-heat at this stage.

- f. Reconfirm the system is air free by pressurizing to $\sim 6\text{-}7\text{ kg/cm}^2\text{g}$ ($\sim 85\text{-}100\text{ psig}$) and then depressurizing to $\sim 0.5\text{ kg/cm}^2\text{g}$ ($\sim 7\text{ psig}$) with nitrogen cyclically until $<0.5\text{ mol \%O}_2$ is achieved
- g. Pressurize the SHP reactor system with nitrogen to $\sim 6\text{-}7\text{ kg/cm}^2\text{g}$ ($\sim 85\text{-}100\text{ psig}$)
- h. Crack open the small filling globe valve across the inlet block valve and start filling.
- i. Vent the nitrogen via PSV bypass line globe valve to cold relief header when the pressure is $\sim 15\text{-}20\text{ kg/cm}^2\text{g}$ ($\sim 215\text{-}285\text{ psig}$) to depressure to $\sim 10\text{ kg/cm}^2\text{g}$ ($\sim 145\text{ psig}$)
- j. Continue filling watching the level on the top LG/LI and bed temperatures
- k. Fill till the top LG/LI indicate 100% level. Continue filling till the line downstream of the globe valve located on PSV bypass indicates frosting confirming the SHP reactor is liquid full
- l. Close the filling globe valve and open the inlet block valve to equalize with feed pressure. Open the outlet block valves.
- m. Commission the pressure/flow controller and control valve at the outlet initially on manual and establish flow through the SHP reactor in parallel with flow via reactor bypass line.
- n. Gradually start closing the SHP reactor bypass valve to incrementally forcing more flow through the reactor.
- o. Finally close the SHP reactor bypass valves lining up all the flow through the reactor.
- p. Check that the SHP reactor inlet pressure controller is placed on manual, if it is placed in auto it may close the control valve at reactor outlet cutting the flow-path.
- q. Commission the flow controller and establish auto-cascade control mode (Oleflex liquid product drum level-flow cascade in conventional C3 Oleflex units or the P-P splitter bottoms level-flow cascade in the C3 Oleflex units with reactor effluent contact cooler which operate under slight vacuum at the REC suction)

- r. Once SHP reactor is commissioned and online, commission the diolefins rich side draw stream from the P-P Splitter. This will establish recycle of methyl acetylene and propadiene rich stream from the P-P splitter to the SHP where the diolefins will be saturated back to their respective mono olefins.
- s. In the C3 Oleflex units with reactor effluent contact cooler operating under slight vacuum at the REC suction, there will additionally be a pressure controller to control the reactor pressure since the downstream depropanizer pressure will not be enough to ensure hydrogen dissolution during normal operation. In such systems, gradually build-up the SHP reactor pressure by giving incrementally higher pressure set point to the pressure controller until the normal operating pressure has been attained with the controller on auto mode.
- t. Line up hydrogen and commission SHP compressor per vendor recommendations. Purge lines with hydrogen to remove nitrogen.
- u. Start the SHP H₂ compressor per the vendor's recommendations. The SHP H₂ compressor is always started with spill back open. Commission the pressure controller at compressor discharge.
- v. Calculate hydrogen flow that will give H₂: Diolefins mole ratio of 1.1 or 1000 mol-ppm H₂ in the feed whichever is higher. Commission the flow controller. Start injecting the required hydrogen flow to SHP reactor with flow controller on automatic mode.
- w. In the conventional C3 Oleflex units, there will be SHP feed pre-heater heated by steam. Commission SHP feed pre-heater and adjust feed temperature to convert all di-olefins to mono-olefins. In these units, the SHP is located on the liquid product stream.
- x. In the C3 Oleflex units with the reactor effluent contact cooler that operate at slight vacuum at the REC suction, there will be heat recovery exchangers with attendant temperature control system to provide the feed SHP reactor feed pre-heat. Commission the temperature control system to heat up the SHP feed to the required temperature. In these units, the SHP operates at relatively higher concentration of diolefins since the SHP is located on the recycle propane stream which constitutes only about 2/3rd of the liquid product stream.

In either case, target less than 1 mol ppm methyl acetylene and propadiene (MAPD) in the SHP discharge stream. In addition, monitor the olefins retention by checking the propylene content at the inlet and outlet of SHP. If there is loss of propylene across the SHP, reduce

the SHP inlet temperature while maintaining <1mol ppm MAPD at the reactor outlet. The temperature at the reactor inlet must be adjusted accordingly. Monitor SHP bed temperatures for excessive temperature increase during filling and operation. If excessive temperature increase occurs cut hydrogen and heat to SHP reactor.

Note: The procedure above is for the pre-reduced palladium catalyst used in Oleflex SHP units. Please contact UOP Technical Services for procedures if your unit does not use this type of catalyst.

- 39) Once unit is at normal operating flows and conditions, the compressor control system vendor for the REC and Heat Pump Compressor (HPC) should tune the anti-surge controllers' using curves for all operating cases. The REC anti-surge tuning should include RED regeneration cases.

40) Commission the Depropanizer Bottoms Stripper

If the C3 Oleflex unit configuration does not have depropanizer bottoms stripper, skip this step.

In the C3 Oleflex units where butanes recovery is not required, a depropanizer bottoms stripper is provided to strip off the C4s with hydrogen rich tail gas. The tail gas will contain ~50 mol% H₂, ~46 mol% C₁ and ~4 mol% C₂-C₃ components. The overheads from the stripper rich in hydrogen and C₁-C₄ components is sent to the refinery fuel gas pool.

- a. Commission the stripping tail gas flow controller to the depropanizer bottoms stripper via stripping hydrogen heater.
- b. Commission the condensate flow controller on the stripping hydrogen heater and establish the stripping tail gas temperature at design level by commissioning the stripping gas temperature controller.
- c. Once this has been completed, the depropanizer bottoms stream can be routed to the stripper.
- d. Monitor the depropanizer or depropanizer No. 2 (if applicable) bottoms level and temperatures. As the amount of heavies in the system increases the bottoms temperature will increase.
- e. When the depropanizer bottoms temperature approaches the design number, route the bottoms flow to the depropanizer bottoms stripper either on tray temperature control or bottoms level control depending on the control scheme.

- f. Hot tail gas will strip off most of the C3 and C4 material. Overhead vapors are routed to the refinery fuel gas pool.
- g. Left behind predominantly C6+ heavies will cause stripper bottoms level to rise. When the level of heavies is ~60% at the bottom of the stripper, commission the stripper bottom proportioning pump.
- h. Establish the stripper bottoms operation on automatic level control which controls either the stroke length or number of strokes per unit time on the proportioning pumps.
- i. **Start sending the heavies to storage or recovery as covered later in this section in Step 42.**

41) Commissioning the C4+ rich Stream in C3 Oleflex Units

Depropanizer configuration and control schemes can slightly vary across the units depending on the unit specific requirements. After propane has been fractionated out as net overheads, the remainder will be predominantly C4s fraction and C5+ heavies' fraction. In the C3 Oleflex units where butanes recovery is required, C4s are recovered either as a side draw on the specified depropanizer tray temperature control or as net overhead from a debutanizer processing depropanizer bottoms.

❖ **Commissioning the Systems with C4 rich side draw**

- a. Confirm that the C4 rich side draw air/water cooled condenser/cooler utility has been commissioned on the depropanizer No. 2.
- b. Confirm that the depropanizer No.2 bottoms air/water cooler utility has been commissioned on the depropanizer No. 2.
- c. Once the appropriate, tray temperature controlling the side draw has been attained, commission the side draw flow controller.
- d. Start sending the C4 rich stream on temperature control which resets the C4 side draw flow controller.
- e. Allow the C6+ polynuclear aromatic heavies' native to Oleflex together with the C6+ aromatic rich solvent compounds, concentrate to build in depropanizer No. 2 bottoms.
- f. Once ~60% level has been built-up in depropanizer No.2 bottoms, start sending the heavies' via cooler on level control which resets the bottoms flow controller.

- g. **Start sending the heavies to storage or recovery as covered in this section in Step 42.**

42) Processing Heavies' in C3 Oleflex Units:

In the C3 Oleflex units with the reactor effluent contact cooler and/or REC interstage contact cooler, the carryover of solvent compounds into fractionation will be continuous. The heavies' stream will therefore contain substantial solvent fraction in addition to the light aromatic heavies' like benzene, toluene, xylenes and polynuclear aromatic heavies' native to Oleflex. However, in these systems majority of the polynuclear aromatic heavies are expected to be removed in the reactor effluent contact cooler and only minor amounts are anticipated to exit with the heavies' stream in fractionation section. Majority of the solvent fraction in the heavies' stream will be recovered in the solvent recovery column and recycled back to the contact cooler system to minimize solvent consumption in the unit. Light aromatics (benzene, toluene, xylenes) fraction of the native Oleflex heavies will need to be removed as "benzene drag" to prevent accumulation within the system.

- a. Establish the "benzene drag" by setting the ratio controller initially at design ratio of (Recycle Heavies' / Total Heavies') that resets the heavies' recycle to the solvent recovery column. Benzene drag, which constitutes the automatically rejected balance fraction, is combined with the net bottoms from the solvent recovery column, cooled and sent to spent solvent storage.
- b. Route the heavies recycle on flow control to the solvent recovery column stripper section to recover the solvent compounds.

43) Adjusting Benzene Drag during Normal Operations:

A certain fraction of the depropanizer stripper bottoms heavies' is purged from the system as "benzene drag". This "benzene drag" stream is combined with the solvent recovery column bottoms stream and sent to storage as spent solvent. Benzene, toluene and xylenes in trace levels constitute part of the native Oleflex heavies' species in addition to the polynuclear aromatic heavies'. These are produced in trace amounts in the Oleflex reactors. If not purged from the system, these light aromatic compounds will recycle via the solvent recovery column overheads gradually concentrating and building up in the solvent circulation system. On the other hand polynuclear aromatic heavies' get purged from the system via solvent recovery column bottoms.

If not monitored properly and closely, these light aromatic components may get carried in trace levels undetected in the Oleflex feed contributing to screen fouling and coke on catalyst.

These compounds are provided an essential exit as “benzene drag” from the system. Due to variations in feed stock quality, operating severities and variability of the commercial catalysts; the amount of native Oleflex heavies produced can vary from that estimated in design. In commercial operation, the amount of benzene drag will need to be adjusted accordingly. Symptoms of light aromatics build-up are indicated below:

- ❖ Over time the depropanizer bottoms temperature profile is shifting up
- ❖ Solvent recovery column rectification section temperature is shifting down
- ❖ Increasing volume fraction covering 80°C- 144°C boiling point range in ASTM distillation at stable WAIT, H2/HC and LHSV on the following samples:
 - Depropanizer stripper bottoms sample OR
 - Depropanizer bottoms sample on units with C4 side draw.....OR
 - Recovered solvent return to reactor effluent contact cooler

If any of the above symptoms has been noticed, the amount of benzene drag shall be increased until a point is reached when it has started trending down. The unit is initially started and commissioned with the ratio controller setting the benzene drag based on design ratio. Benzene drag is not separately controlled but constitutes the fraction of the heavies' stream not recycled to the solvent recovery column.

Oleflex unit shall not be operated on total heavies' recycle to the solvent recovery column without benzene drag during the normal operation.

44) Establishing normal operating pressure on the C3 Oleflex Units with reactor effluent contact cooler designed to operate at lower pressure at the outlet of Reactor 4 (Low Pressure Mode)

A. Checklist before switching to Low Pressure Mode

- i. Oleflex initial ramp has been completed and the unit is stabilized at 0.5 H2/HC ratio with Oleflex liquid feed maximized yielding ~95% design production with at least 1 cycle of catalyst circulation completed after the last RIT and H2/HC changes.

- ii. Reactor 4 outlet pressure controller (PIC), which resets the REC speed controller, is controlling in automatic mode at ~138 KPa A (~20 psia) targeting 102-103 KPaA at REC 1st stage suction flange.
- iii. A "Set Point Limit" function has been implemented in the DCS to prevent inadvertent, under barometric pressure, set point entry by the operator on the Reactor 4 outlet PIC
- iv. "Low Pressure Limit Controller" has been implemented within the REC antisurge control system and set at ~101.3 KPaA (~14.7 psia) or the local barometric pressure whichever is higher
- v. Reactor effluent compressor (REC) antisurge control system is operating in automatic control on either stages
- vi. The pressure controller at the high pressure turbo-expander (HPTE) inlet and its bypass JT valve are in automatic control; flow controller at the low pressure turbo-expander inlet and its bypass JT valve are in automatic control (LPTE)
- vii. Oleflex reactor screen pressure drops are stable
- viii. DMDS injection has been stabilized to yield stable 50-60 mol ppm H₂S in the reactor effluent
- ix. Oleflex CCR system has been operating with 100%+ catalyst circulation in white burn
- x. Regenerator operations have been optimized with <4 wt. % coke on spent catalyst and <0.1 wt. % coke on the regenerated catalyst
- xi. The core coke count on the regenerated catalyst is less than 2 pills out of 200
- xii. The Oxygen/Moisture/H₂S analyzers at the outlet of the RED are calibrated and functioning normally
- xiii. The CO/Methane infrared (IR) analyzer and Oxygen (O₂) analyzer on the PSA H₂ product stream is calibrated and functioning normally
- xiv. H₂S analyzer at the REC inter-stage is calibrated and functioning normally

- xv. CO/O₂ analyzer on the net gas is calibrated and functioning normally (CO if specified/provided)
- xvi. Moisture analyzer at the RED inlet is calibrated and operating properly (if specified/provided)
- xvii. SHP reactor has been commissioned and operating normally
- xviii. The Oleflex reactor circuit has been checked for hydrogen-hydrocarbon leaks as prescribed and all leaks fixed
- xix. Oleflex reactor effluent drier regeneration control system (DRCS) is operating normal in automatic control mode
- xx. The REC speed/suction pressure control system and RED de-pressure-purge and hydrocarbon load valve ramps have been tuned such that pressure accumulation or evacuation is minimized during RED activities
- xxi. All flanges in the reactor circuit starting from reactor 4 outlet to REC 1st stage suction provided with lip-seal welded gaskets are verified intact.

After the checklist is verified and confirmed, Oleflex reactor 4 outlet pressure can be gradually reduced from ~138 KPaA (~20 psia) to ~104.8 KPaA (~15.2 psia) which constitutes the normal operating pressure in a controlled manner explained later in this section. When the Oleflex reactor section pressure is being reduced, Oleflex liquid feed, catalyst circulation rate, H₂/HC ratio and RITs shall be held constant to detect if there is any air leak into the process via the plant sections operating under vacuum.

B. Detecting and Preventing Air Leak into the System

During the course of the pressure reduction as well as normal operation at reduced pressure, the primary concern is with the air ingress into the system where the system pressure drops below the local barometric pressure in the piping/vessels/equipment. Air leak can cause PSA H₂ turning off spec in CO and/or O₂, overload the REDs with H₂O with potential breakthrough of H₂S and in extreme ice up the cold section if additionally H₂O breakthrough occurred from the REDs. The pressure controller is located at the reactor4 outlet to ensure the reactor circuit pressure is always above atmospheric. Low pressure limit controller should retain reactor4 outlet pressure above atmospheric during process transients like feed reduction or RED activities when inherent compressor dynamics cause temporarily pressure variation before the

control system recovers. During normal operation when the section from HCFE to REC 1st stage is under vacuum, lip-seal welded flanges should help prevent air leak.

There will be a minor amount of air leak into the system during normal operation that can be tolerated by the system. However, it is the increased air leak that needs to be identified and appropriate measures taken during the operation.

Depending on the location of the air leak, it may reflect either as molecular oxygen (O₂) and molecular nitrogen (N₂) or as reaction products - carbon monoxide (CO), carbon dioxide (CO₂) and H₂O or a combination of these components in the reactor effluent. If air leak occurred in cooler sections downstream of the HCFE, it will likely exit unreacted as molecular O₂ and N₂. If air leak occurred in hot sections upstream of HCFE, some O₂ may react out to form CO, CO₂ and H₂O. With ~50+ mol% H₂ in the reactor effluent, CO₂ is expected only in trace amounts.

Since there will be finite CO/H₂O native to Oleflex, those associated with air ingress can be deduced by establishing a baseline of native CO/H₂O in the reactor effluent at 100% catalyst circulation rate while the catalyst reduction zone is in operation reducing the oxidized catalyst from the regenerator with unit lined out at ~138 KPaA (~20 psia) at reactor 4 outlet and then comparing it with the CO/H₂O levels while in low pressure mode during normal operation with reactor4 outlet at ~104.8 KPaA (~15.2 psia).

A portion of the CO in the reactor effluent comes off the net gas in cold section serving as a proxy for CO content in the reactor effluent and can be monitored either by laboratory analysis or with an on line analyzer. Remainder CO comes off the deethanizer off gas. Since H₂O is adsorbed in the REDs, it will have to be measured by atmospheric dew point at the inlet of the RED either with a portable dew point analyzer or an on line analyzer. Trace CO₂ is expected to go with liquid product and get removed via deethanizer rectifier off gas.

Molecular O₂ is directly measured by the online analyzer at RED outlet. A portion of the molecular O₂ will come off the net gas while the remainder comes off the deethanizer off gas.

A consistent and marked shift in the CO/H₂O/O₂ levels over the base line readings, indicates an increase in air leak into the system. H₂O level in the reactor effluent upstream of the REDs may trend with CO in net gas if it is produced due to an air leak. On the other hand, molecular O₂ detected by the online O₂ analyzer confirms air leak. Nitrogen

associated with air leak will pass through as molecular N₂ and will get removed predominantly through the net gas and a small amount through the deethanizer off gas. Any equilibrium level of CO/CO₂/O₂/N₂ that may have passed into liquid product, get removed via de-ethanizer off gas and therefore do not pose immediate threat to operability of the Oleflex unit.

O₂/H₂O/H₂S analyzers at the outlet of the REDs, CO/O₂ analyzer on the PSA H₂ product line together with the net gas CO/O₂ analyzer and RED inlet moisture analyzer (if provided) should help monitor and detect any potential air ingress into the system enabling proper operator response.

In the event of any confirmed air leak into the system, at any stage during the operation, operator shall increase the pressure at reactor4 outlet by an amount such that pressure indicated by the REC 1st stage suction pressure instrument increases and remains approximately in the range ~102-103 KPa A.

C. Switching to Low Pressure Mode after Initial Start-Up

Establish baseline CO in net gas, H₂O at RED inlet, O₂ at RED outlet when the unit is lined out at ~design production with 100% catalyst circulation with reactor4 outlet at ~138 KPaA (~20 psia). Determine CO in net gas by either laboratory analysis or online analyzer and H₂O in reactor effluent at RED inlet either by a portable dew point analyzer or online Panametrics. Collect the laboratory analytical data every 4 hours over a period of at least 3 days to establish a verifiable baseline trend. At least 18-20 consistent data points shall be made available to establish the baseline. Calculate statistical mean X, standard deviation SD for the data set and assign (X+2SD) as maximum permissible CO/H₂O levels covering 95 percentile sample data. Sample catalyst from each lift engager (LE) every 8 hours and establish the average coke levels.

- a. Reduce the set point on the reactor4 outlet PIC by 1 KPa (0.1 psi or 10 mbar)
- b. Allow ~3/4 hour (~30-45 minutes) after the above step change for the unit to line out and stabilize.
- c. Repeat steps a) and b) until the target pressure ~104.8 KPa (~15.2 psia) is attained at reactor4 outlet subject to restrictions imposed under step e).

- d. Approximately 33 steps spread over ~24 hours will be required to attain this final pressure.
- e. All through steps b) to d), monitor the following:
 - 1. Monitor the REC 1st and 2nd stage antisurge valve movement. These are expected to gradually close.
 - 2. Monitor REC speed change. This is expected to gradually increase.
 - 3. Monitor oxygen level on the net gas online analyzer. This is expected to remain stable once target pressure in given step reduction through steps a) and b) is attained at reactor4 outlet. If oxygen is detected at >65 mol ppm after any given step reduction in pressure, stop further pressure reduction and start increasing back the pressure in 1 KPa (0.1 psi) increments until REC 1st stage suction is at 102-103 KPaA (~14.5-14.7 psia) or the oxygen level drops to <65 mol ppm whichever condition is attained first.
 - 4. Monitor the CO in net gas by online analyzer and H₂O dew point at RED inlet sampling every 4 hours or by online analyzer. If 3 consecutive samples or analyzer trends indicate increasing levels of CO/H₂O over the maximum permissible level, it will be due to air leak. When net gas CO>800 mol ppm (typical max CO limit for PSA unit feed), start increasing back the pressure in 1 KPa (0.1 psi) increments until REC 1st stage suction is at 102-103 KPaA (~14.5-14.7 psia) or net gas CO<800 mol ppm whichever condition is attained first.
 - 5. If air leak is causing the H₂O level in reactor effluent to trend up as described in the previous Step 4, this H₂O which is not native to Oleflex will be an additional contaminant load on the REDs. Check REDs are able to cycle through the design adsorption time without H₂S break through. If the RED breaks through in H₂S and/or H₂O, assignable to air leak, then start increasing back the pressure in 1 KPa (0.1 psi) increments until REC 1st stage suction is at 102-103 KPaA (~14.5-14.7 psia) or pre-upset level of H₂O at RED inlet whichever is attained first.

6. Monitor CO and O₂ in PSA H₂ product by the online analyzer continuously. If CO breaks through >1 mol ppm and/or O₂ breaks through >65 mol ppm, temporarily halt the pressure reduction program and try to fix the problem by decreasing the adsorption timer on the PSA unit. Emergency procedure calls for stoppage of catalyst circulation which may interfere with CO/H₂O levels being monitored in the reactor effluent. Confirm CO < 1 mol ppm and O₂ < 65 mol ppm in PSA H₂ product continually for at least 1 hour after the catalyst circulation has been re-established. Resume pressure reduction program after this confirmation.

Note that at captive PSA H₂ having >500 mol ppm O₂ >1 mol ppm H₂O may exist in recycle propane exiting SHP. As an abundant caution SHP may be switched to external PSA grade H₂ from bottled storage if captive PSA H₂ has >100 mol ppm O₂ to prevent potential for icing in feed chiller pass of the cold separation system.

7. Monitor the Del T across each Oleflex reactor. Lower reactor circuit pressure is expected to increase conversion reflected as increase in reactor Del T.
8. Monitor coke level on the catalyst from each lift engager (LE) at 4 hours interval. Coke level on catalyst is expected to increase. Adjust the regenerator operation. If the spent coke level from reactor 4 starts exceeding 5 wt. % continuously over 3 consecutive samples halt further pressure reduction. Catalyst circulation rate may have to be increased to be within 5 wt. % spent coke. Proportionally increase the maximum permissible baseline CO/H₂O levels assigned.
9. Monitor the depropanizer and PP splitter operation. Increased conversion and selectivity will result in increased propylene production with corresponding increase in fresh propane feed and native Oleflex heavies requiring minor adjustments to the column operations. Optimize PP splitter by increasing the reboil/reflux to minimize propylene in the column bottoms.
10. Monitor the SHP reactor Del T. With increased conversion, diolefins concentration will likely increase

marginally. Make sure SHP parameters are adjusted to achieve <1 mol ppm diolefins in the SHP product.

11. Monitor and control the H₂S in Oleflex reactor effluent in the range of 50-60 mol ppm H₂S. There may be minor shifts due to reduction in both hydrogen and sulfur partial pressure.
12. Monitor the Oleflex reactor inner and outer screen pressure drop (Del P) trend to check screen fouling rates. There will likely be slight increase in screen Del P due to hydraulic effect during pressure reduction but if any unusual increase in inner screen fouling has been noticed, temporarily halt pressure reduction and investigate before proceeding further. Watch reactor4 outer screen Del P for any signs of fouling. This screen will be prone to plugging due to heavies' and/or coke.
13. Line out the unit upon attaining ~104.8 KPa (~15.2 psia) at reactor4 outlet. Continue to monitor the unit for air leak into the system as described earlier. At any stage if there is evidence confirming air leak, start increasing back the pressure in 1 KPa (0.1 psi) increments until REC 1st stage suction is at 102-103 KPaA (~14.5-14.7 psia) or O₂/CO/H₂O level drops below the maximum operable levels as discussed earlier in this section.

D. Switching to Low Pressure Mode for Subsequent C3 Oleflex Unit Start-Ups following a shutdown

If the unit is being restarted following a unit shutdown/turnaround when the reactor section was opened up for screen cleaning, the same start-up procedure shall apply including leak checks performed under pressure and vacuum; initial sulfiding etc. For any chosen set of operating conditions, the unit shall be stabilized first at 102-103 KPaA at REC 1st stage suction before switching to the Low Pressure Mode of operation. For operations under identical catalyst circulation rate, feed rate, RITs and H₂/HC it will not be necessary to wait for 3 days to generate again the baseline data. Switch to low pressure mode with the previously set baseline data for CO/H₂O/O₂ at prescribed locations.

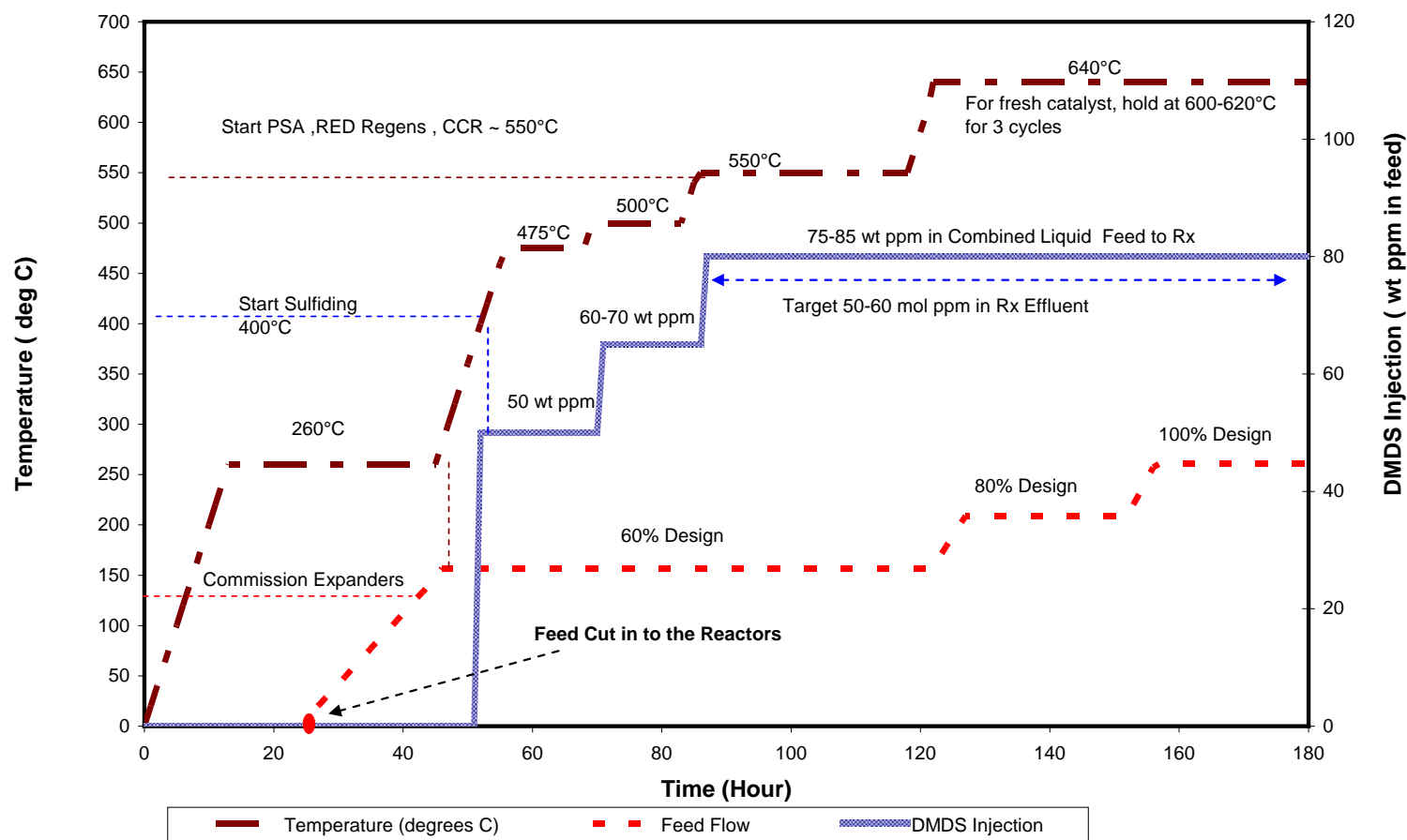
If the unit is being restarted following a unit shutdown/trip, and if the reactor section was not opened up for screen cleaning, perform the leak checks while under positive pressure hydrogen-hydrocarbon in the system. Stabilize first at 102-103 KPaA at REC 1st stage suction before

switching to the Low Pressure Mode of operation applying the same procedure.

Note: The system has been engineered and designed to operate with a finite amount of air leak expected during Low Pressure Operating Mode. The derived baseline limits on CO/H₂O/O₂ will be conservative serving as initial guidelines in switch to the Low Pressure Mode for the Initial Start-Up. The maximum permissible air leak will be defined by the ability of the PSA unit to supply on-spec H₂ and/or the ability of the REDs to sustain operation without H₂S breakthrough and/or the ability of the cold section to sustain the recycle gas flow/purity whichever occurs first.

The maximum permissible limits on CO/H₂O/O₂, initially defined by baseline, will continue to be evolved/revised by the operator based on process response. The limits shall not be relaxed to a point when the PSA and/or RED operate with sustained CO and H₂S breakthrough respectively.

Reactor Section Typical Ramp up plan

Uop C3 Oleflex Process Unit

B. Normal Startup

1. Unit restart following a shutdown - Abbreviated Sulfiding Schedule

For the initial startup of the Oleflex unit and for future unit startups following the reactor disassembly/neutralization, the Initial Sulfiding Schedule prescribed in Section A. earlier must be followed to ensure proper metal passivation.

However, following a unit shutdown either planned/unplanned that did not involve reactor dis-assembly/neutralization, restart the unit in normal manner following the steps after Step 3 in Section A7 post inventory of the reactor circuit with hydrogen-hydrocarbon. Once cold separation system has been commissioned and required net gas purity has been achieved, if warranted trickle mode must be performed (Refer Section XI Emergency Procedures). The Oleflex heaters can be re-lighted to begin the temperature ramp. However, since the reactor section metallurgy has remained in sulfided condition, an abbreviated sulfiding schedule shall be followed as prescribed below:

- 1) When reactor inlet temperatures reach 400°C (752°F), initiate the sulfiding of the reactor circuit by starting the DMDS injection pumps. Inject 50 wt. ppm sulfur (based on total liquid feed). All 3 injection pumps should be operating and each pump should be set at 33% of the desired flow. Check and record the reactor effluent H₂S content, using Dräger tubes, every two hours throughout the entire sulfiding procedure. Continue increasing reactor temperatures at no more than 30°C/hr (54°F/hr).
- 2) At 475°C (887°F) maintain DMDS injection between 50-60 wt. ppm sulfur based on total liquid feed. Hold at these conditions for 8 hours or until a stable level of at least 30-40 mol ppm H₂S is present in the reactor effluent section for 4 hours, whichever occurs later.
- 3) Raise the reactor inlet temperatures at no more than 30°C/hr (54°F/hr) to 550°C (1022°F) and increase DMDS injection to 75-85 wt. ppm sulfur based on total liquid feed. Hold at these conditions for 8 hours or until a stable level of at least 50-60 mol ppm H₂S is present in the reactor effluent for 4 hours, whichever occurs later.
- 4) Raise reactor inlet temperatures to desired operating conditions at no more than 30°C/hr (54°F/hr). Incrementally raise the reactor inlet temperatures to desired conditions. Raise the temperatures to achieve the approximate design conversion levels across the Oleflex reactors. Ensure that the design H₂/HC mole ratio to the reactor inlets is maintained at all times. Maintain the sulfur injection rate at 75-85 wt. ppm based on combined liquid feed rate. Monitor the reactor effluent H₂S level and maintain at least 50-

60 mol ppm H₂S at all times. Increase the sulfur injection rate above 85 wt. ppm, if necessary, in order to maintain at least 50-60 mol ppm H₂S in the reactor effluent.

Though a stable metal sulfide scale, which is chrome sulfide, on the reactor circuit metallurgy had been established prior to the shutdown, the stable metal sulfide scale will be disturbed due to reactor circuit cool down and de-pressure. Therefore, though the sulfide scale exists, the stable metal sulfide barrier will have to be re-established. This is facilitated by performing abbreviated sulfiding. As against this, when the reactors are neutralized, sulfide scale is removed and therefore a longer duration sulfiding included in the Initial Sulfiding Procedure is prescribed for the unit re-start following reactor circuit neutralization. Further, the lower heat up rate of 20°C/hr (36°F/hr) is specified for the initial sulfiding as against 30°C/hr (54°F/hr) for abbreviated sulfiding to ensure better metal passivation while additionally providing adequate time to fix any thermal expansion issues.

The abbreviated sulfiding schedule shall be repeated in its entirety should the unit trip or shutdown during the course of sulfiding.

Note: For the C3 Oleflex units designed with the reactor effluent contact cooler that operate at relatively lower pressure at the outlet of reactor⁴, abbreviated sulfiding shall be performed with the unit under positive pressure. Refer to Section A 7 Step 44 to switch to Low Pressure Mode

2. Future Unit Restarts Following Turnarounds

Following turnarounds where the reactors are neutralized and/or opened for inspection the following steps will need to be completed after the ammoniated water wash and reactor assembly:

- 1) Bulk Dry-Out and ramp to design temperature to remove water and test mechanical integrity (See Section A above)
- 2) Reactor inspection and loading (Refer to Special Procedures XII)
- 3) Low Temperature Dry-Out
- 4) Unit restart

During subsequent restarts, it is permissible to perform low temperature dry-out using a 50:50 mole mixture of hydrogen and propane, as covered in Section VI A6, as long as hydrogen is available and the fractionation section is ready to feed propane to the reactor section and fresh REDs are available.

Performing the low temperature dry-out with hydrocarbon will save time during the startup, but any leaks found during dry-out with hydrocarbon will prove more hazardous than those found during a nitrogen dry-out.

The procedure for low temperature dry-out with hydrogen-hydrocarbon is identical to that performed with nitrogen. A brief outline procedure is given below:

- 1) Air-free the reactor circuit and perform initial inventory with H₂ and propane as prescribed in Section A7. Keep cold separation system bypassed.
- 2) Confirm the reactor effluent air/water/contact coolers, REC interstage air/water/contact cooler and REC discharge air/water coolers have been commissioned.
- 3) Confirm - at least 1 RED and preferably both REDs freshly regenerated are available in units with 2 RED configuration; at least 1 RED and preferably 2 REDs freshly regenerated are available in units with 3 RED configuration.
- 4) Place the freshly regenerated RED online. If adequate supply of suitable start-up regenerant like nitrogen, sulfur and moisture free LPG or sulfur, moisture and CO₂ free natural gas (NG) is available; commission off-line RED regeneration. Drain free water from the regenerant knockout drum returning only solvent to the reactor effluent contact cooler if the C3 Oleflex unit has been designed with that.
- 5) Start the REC and establish hydrogen-propane vapor circulation bypassing the cold separation system.
- 6) Relight the Oleflex heaters and raise the reactor inlet temperatures to 260°C (500°F) at 20°C/hr (36°F/hr) using fuel gas pressure control. 260°C is adequate to drive out moisture adsorbed on the catalyst which is the primary goal of low temperature dry out apart from removing any moisture that may have leaked into the process during catalyst loading or reactor inspections following bulk dry out.
- 7) Circulate the gas through the online reactor effluent driers (REDs), bypassing the cold separation system until <1 mol ppm H₂O is established consistently for at least 2 hours at the outlet of the RED.
- 8) Commission the cold separation system as outlined in Section A7.
- 9) Perform the Initial Sulfiding as required outlined in Section A7.
- 10) Increase the RITs and feed rate to desired levels

For the C3 Oleflex units designed with the reactor effluent contact cooler that operate at relatively lower pressure at the outlet of reactor⁴, the unit shall initially be stabilized under positive pressure with the REC 1st stage suction maintained at the minimum at 101-103 KPa A. Refer to Section A7 Step 44 to switch to Low Pressure Mode

C. Introducing External Streams to Oleflex Unit

In some units there may be external recycle streams designed to be brought into the Oleflex unit. These streams should be brought in only after following conditions are satisfied:

- a. Oleflex reaction and fractionation sections are integrated
- b. Oleflex initial ramp has been completed
- c. Oleflex unit is stabilized and the product rate and quality are established
- d. The recycle streams are on specification

In the following events, recycle streams to the Oleflex unit should be isolated until the unit is stabilized:

- a. REC trip (avoid accumulation of hydrocarbons in reaction circuit)
- b. Unit shut down
- c. Unacceptable impurities or catalyst poisons found in recycle streams
- d. Unit from which the recycle stream originates is shutdown

VII. Normal Operations

This section includes information on how to evaluate, and optimize the process. Process monitoring and data evaluation are important parts of this section. Information from this section will describe the collection of data during normal operations. Data evaluation, calculations, and other programs are explained.

A. Calculations

Following key yield calculations must be performed at the minimum once per day while the Oleflex unit is normal operation. Since the unit configurations can slightly vary, these calculations will be reviewed and modified by the UOP Chief Technical Advisor as applicable to the specific unit.

Raw daily average stream flow, temperature, pressure and composition data is first collected via suitable electronic data acquisition systems from DCS and Laboratory and then processed to arrive at corrected stream flow data by applying the necessary flow meter corrections for the operating temperature, pressure and composition. Corrected stream flow and composition data must be used in unit yield and mass balance calculations. UOP Chief Technical Advisor and Instrument Advisor at the site will provide the flow correction calculations.

To simplify the representation, following definitions and symbology will be used throughout. Subscript "m" for the stream refers to mass or mole rate; subscript(s) on mass or mole fraction X refer to the "stream" and the "component species" in that order. Stream rate and fraction can either be represented on mass or mole basis. Use dimensionally consistent units in calculations:

- | | |
|-----------------------|--|
| 1) RIT _x | Reactor Inlet Temperature for reactor "x" ; x = 1 to 4 |
| 2) ROT _x | Reactor Outlet Temperature for reactor "x" ; x = 1 to 4 |
| 3) X _{X CAT} | M ³ of active catalyst volume in reactor "x" ; x = 1 to 4 |
| 4) F _m | Rate of C3- feed to the cold separation system(CS) |
| X _{F C3-} | Fraction of C3- in C3- feed to the CS |
| X _{F C3=} | Fraction of C3= in C3- feed to the CS |
| X _{F HC} | Fraction hydrocarbon species in C3- feed to the CS |
| X _{F H2} | Fraction H2 in C3- feed to the CS |
| MW _F | Molecular weight C3- feed stream to the CS |
| DEN _F | Density of feed stream in SM ³ |
| 5) LP _m | Rate of liquid product from the CS |
| X _{LP C3-} | Fraction of C3- in liquid product from CS |
| X _{LP C3=} | Fraction of C3= in liquid product from CS |
| 6) RG _m | Rate of recycle gas |
| X _{RG C3-} | Fraction of C3- in recycle gas |

$X_{RG\ C3=}$	Fraction of C3= in recycle gas
$X_{RG\ H2}$	Fraction H2 in recycle gas
$X_{RG\ HC=}$	Fraction hydrocarbon (HC) in recycle gas
7) NG_m	Rate of net gas (include PSA feed; exclude CCR gas)
$X_{NG\ C3-}$	Fraction of C3- in net gas
$X_{NG\ C3=}$	Fraction of C3= in net gas
$X_{NG\ H2}$	Fraction of H2 in net gas
MW_{NG}	Net Gas molecular weight
8) E_m	Rate of external streams to Oleflex downstream (d/s) of HCFE
$X_{E\ C3-}$	Fraction of C3- in external streams to Oleflex d/s of HCFE
$X_{E\ C3=}$	Fraction of C3= in external streams to Oleflex d/s of HCFE
$X_{E\ Z}$	Fraction (H2+C1) in external streams to Oleflex d/s of HCFE
9) P_m	Rate of specification C3= product from the PP Splitter
$X_{P\ C3=}$	Fraction C3= in PP Splitter C3= product
10) FR_m	Rate external recycle stream to fractionation section
$X_{FR\ C3-}$	Faction of C3- in external recycle streams to frac ⁿ section
$X_{FR\ C3=}$	Fraction of C3= in external recycle streams to frac ⁿ section
11) FP_m	Rate of fresh C3- feed to the depropanizer system
$X_{FP\ C3-}$	Faction of C3- in fresh C3- feed to the depropanizer system
$X_{FP\ C3=}$	Faction of C3= in fresh C3- feed to the depropanizer system
12) OG_m	Rate of fresh de-ethanizer off gas
$X_{OG\ C3-}$	Fraction of C3- in de-ethanizer off gas
$X_{OG\ C3=}$	Fraction of C3= in de-ethanizer off gas
13) H_m	Rate of depropanizer bottoms
$X_{H\ C3-}$	Fraction of C3- in depropanizer bottoms
14) B_m	Rate of depropanizer C4 rich side draw (if present)
$X_{B\ C3-}$	Fraction of C3- in depropanizer C4 rich side draw
$X_{B\ C3=}$	Fraction of C3= in depropanizer C4 rich side draw
15) RP_m	Rate of recycle propane stream to depropanizer
$X_{RP\ C3-}$	Fraction of C3- in recycle propane stream to depropanizer
$X_{RP\ C3=}$	Fraction of C3= in recycle propane stream to depropanizer
16) $DMDS$	Rate of DMDS injection
$X_{DMDS\ C1}$	Equivalent methane fraction in DMDS on decomposition
17) SOL_M	Rate of fresh solvent to contact cooler (assume 0% C3- or C3=)
18) SOL_R	Rate of recovered solvent return to contact cooler
$X_{SR\ C3-}$	Fraction of C3- in recovered solvent
$X_{SR\ C3=}$	Fraction of C3= in recovered solvent
19) SOL_S	Rate of spent solvent (for solvent recovery if applicable)
$X_{SS\ C3-}$	Fraction of C3- in spent solvent stream
$X_{SS\ C3=}$	Fraction of C3= in spent solvent stream
20) SRC_B	Solvent Recovery Column (SRC) bottoms+ benzene drag
21) H_{BZ}	Benzene drag stream
22) PSA_{GAS}	PSA H2 gas returned to Oleflex
MW_{PSA}	PSA H2 gas molecular weight
$X_{PSA\ H2}$	Fraction of H2 in PSA gas

$X_{\text{PSA C3-}}$	Fraction of C3- in PSA gas
23) SHP H2_m	H2 injection rate to SHP
MW_{PSA}	PSA H2 gas molecular weight
24) CCR_{GAS}	CCR gas rate
25) CCR	Rate of catalyst circulation
26) $\%C_R$	% carbon on regenerated catalyst
27) $\%C_s$	% carbon on coke on spent catalyst

C3 Oleflex reactor section per pass propane conversion, propylene selectivity and propylene yield per pass are calculated based on the mass balance envelope encapsulating the Oleflex reactor circuit and cold separation system. Mass balance envelope on the fractionation section encapsulates depropanizer, de-ethanizer, PP splitter and SHP systems. For the conventional C3- Oleflex units, ignore the terms associated with the solvent streams setting them to zero.

The calculations are performed and reported based on the mass balance (MB) envelope drawn around the Oleflex unit. For convenience, three MB envelopes are drawn: [a] Oleflex reactor circuit – refer Figure VII A1 [b] Fractionation circuit– refer Figure VII A2 [c] Plant Battery Limit covering entire unit. Additionally, mass balance around each fractionation column must be performed.

Performing the mass balance on the reactor section and fractionation separately helps segregate the section in which the losses, if any, are occurring.

Figure VII-A1
Reactor Circuit Mass Balance Envelope

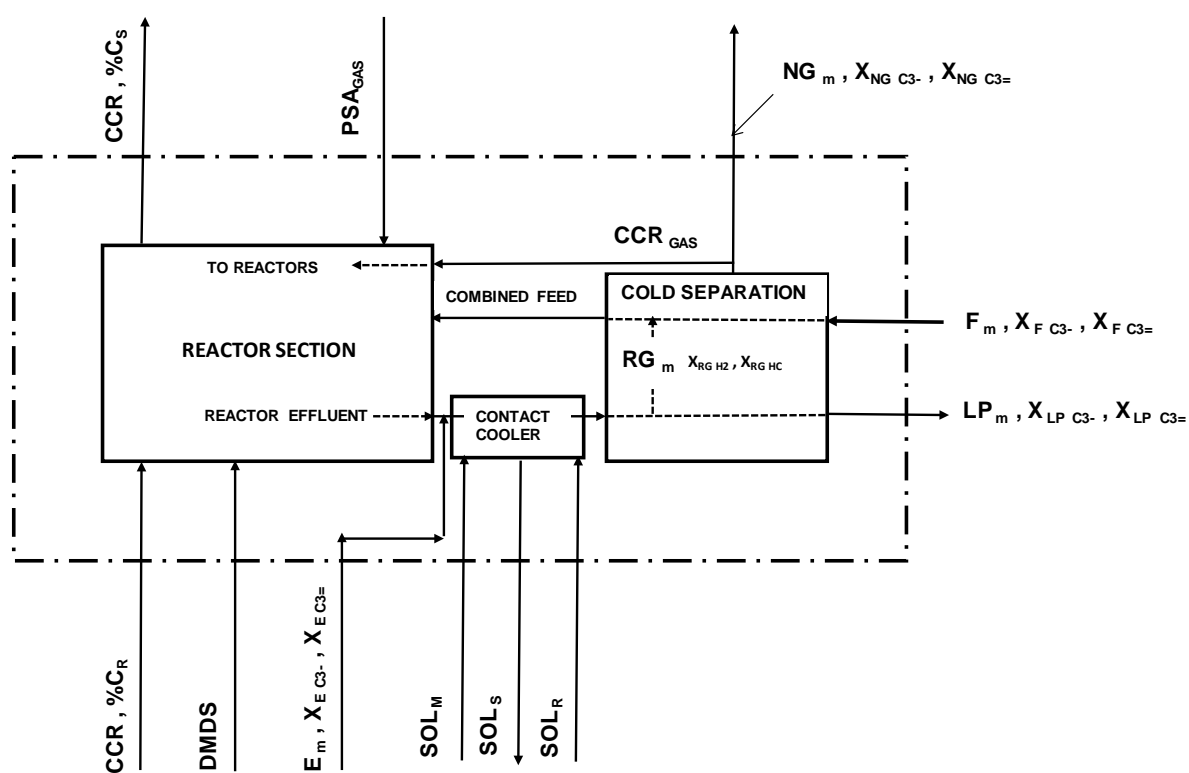
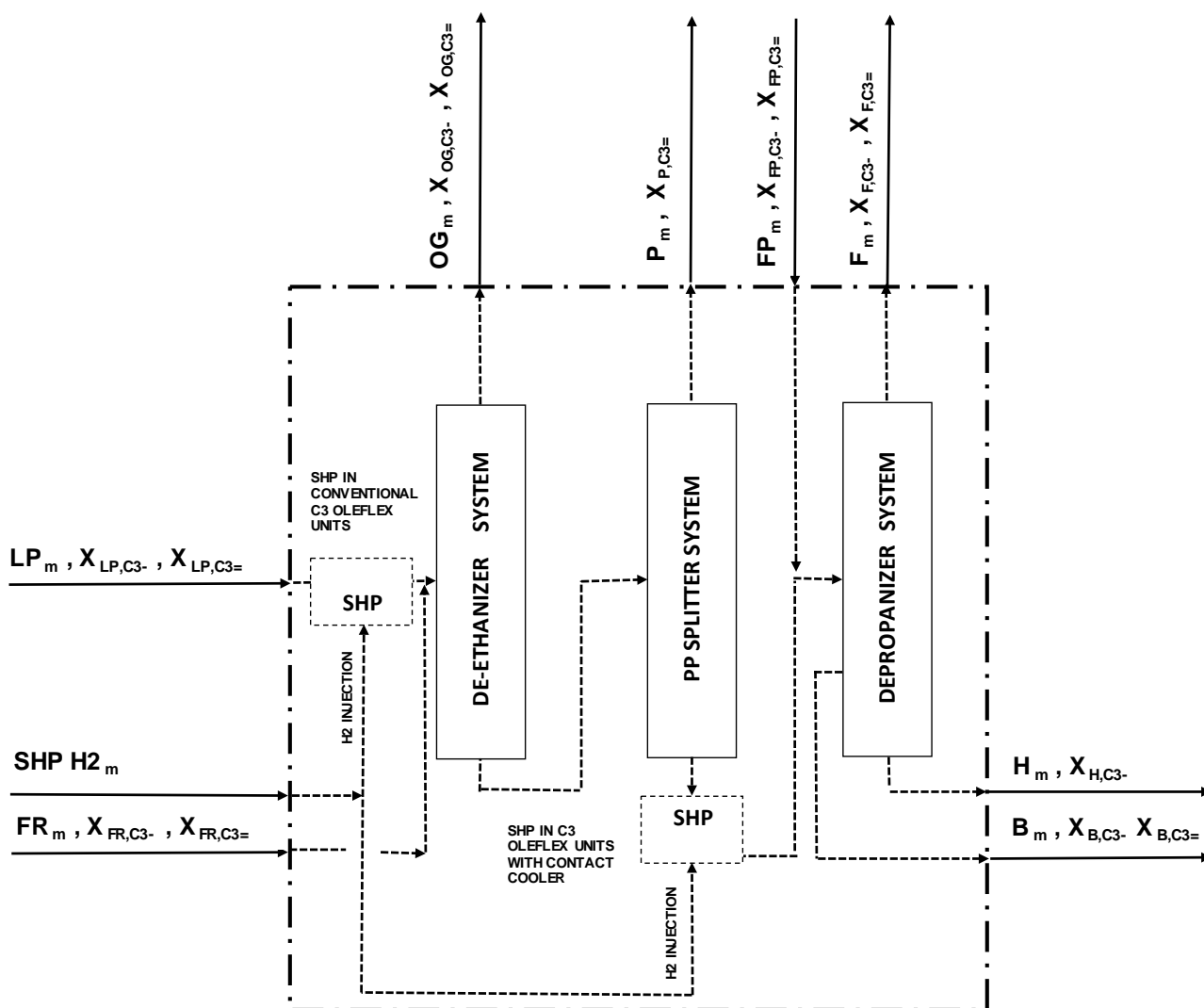


Figure VII-A2
Fractionation Circuit Mass Balance Envelope



1. Conversion

In the context of C3 Oleflex, conversion per-pass is the amount of propane (C3-) that has reacted out in one pass through the reactor section. Conversion can also be defined across each individual reactor, or across the complex. Per-pass conversion in C3 Oleflex typically varies from 20-36 wt. % depending on the process conditions.

$$\text{C}_3\text{-Conversion} = \frac{\text{Mass of Propane Converted per Pass}}{\text{Mass of Propane Charged per Pass}}$$

Calculate C₃-conversion in following steps as follows:

Step a) Calculate (C₃- Charged per Pass) =

$$= (F_m * X_{F C3-})$$

Step b) Calculate (C₃-Converted per Pass) =

$$= (F_m * X_{F C3-}) - [(LP_m * X_{LP C3-}) + (NG_m * X_{NG C3-}) + (SOL_s * X_{SS C3-}) - (SOL_r * X_{SR C3-}) - (E_m * X_{E C3-})]$$

Step c) Calculate % C₃- Conversion per Pass

$$\% [(C_3\text{-Converted per Pass}) / (C_3\text{- Charged per Pass})]$$

The terms associated with solvent and net gas are usually negligible and can be ignored. Conversion is usually expressed in weight percent.

Conversion is expected to gradually decrease over life cycle of the catalyst for a given set of operating conditions and this is the main reason for the concurrent decrease in yield per pass over the life cycle of the catalyst. The unit is designed to produce propylene at the nameplate capacity through the catalyst life cycle.

2. Selectivity

The selectivity of the process is usually also referred to on a per-pass basis and is defined as:

$$\text{C}_3\text{= Selectivity} = \frac{\text{Mass of Propylene Produced Per Pass}}{\text{Mass of Propane Converted Per Pass}}$$

Calculate selectivity in following steps as follows:

Step a) Calculate (C₃-Converted per Pass) =

$$(F_m * X_{F C3-}) - [(LP_m * X_{LP C3-}) + (NG_m * X_{NG C3-}) + (SOL_s * X_{SS C3-}) - (SOL_r * X_{SR C3-}) - (E_m * X_{E C3-})]$$

Step b) Calculate (C₃= Produced per Pass) =

$$[(LP_m * X_{LP C3=}) + (NG_m * X_{NG C3=}) + (SOL_s * X_{SS C3=}) - (SOL_r * X_{SR C3=}) - (F_m * X_{F C3=}) - (E_m * X_{E C3=})]$$

Step c) Calculate $C_{3=}$ Selectivity =

$$\% [(C_{3=} \text{ Produced per Pass}) / (C_{3=} \text{ Converted per Pass})]$$

Terms representing the amount of $C_{3=}$ and $C_{3=}$ associated with net gas and solvent are usually negligible and can be ignored. Per Pass Selectivity to other product species can be calculated in similar manner replacing propylene with the selected species. Selectivity is usually expressed in weight percent.

Selectivity of the catalyst to propylene is expected to remain largely unchanged over the life cycle of the catalyst.

3. Yield per Pass

The yield per-pass (YPP) for each reactor is defined below. It can also be calculated by multiplying conversion and selectivity, as they were defined above.

$$\text{Propylene YPP} = \frac{\text{Mass of Propylene Produced per Pass}}{\text{Mass of Propane Charged per Pass}}$$

Calculate $C_{3=}$ YPP in following steps as follows:

Step a) Calculate $C_{3=}$ Produced per Pass =

$$[(LP_m * X_{LP C_{3=}}) + (NG_m * X_{NG C_{3=}}) + (SOL_s * X_{SS C_{3=}}) - (SOL_r * X_{SR C_{3=}}) - (F_m * X_{F C_{3=}}) - (E_m * X_{E C_{3=}})]$$

Step b) Calculate $C_{3=}$ Charged per Pass =

$$(F_m * X_{F C_{3=}})$$

Step c) Calculate $C_{3=}$ YPP

$$\% [(C_{3=} \text{ Produced per Pass}) / (C_{3=} \text{ Charged per Pass})]$$

The terms representing the amount of $C_{3=}$ associated with net gas and solvent are usually negligible and can be ignored. YPP of other product species can be calculated in similar manner replacing propylene with the selected species. YPP is typically expressed in weight percent. $C_{3=}$ YPP gradually declines from the “Start of Run” (SOR) to “End of Run” (EOR) with catalyst aging. Anticipated YPP change over the catalyst life cycle expressed as $\%[(YPP @ \text{SOR}) / (YPP @ \text{EOR})]$ is ~105% at identical operating conditions.

4. Calculating the Net Gas Yield per Pass

Net Gas yield expressed as amount of net gas produced per unit propane converted across the reactor section can be calculated in the following steps. Stream flows and composition are in mass fractions in the calculations below.

Step a) % Net Gas per Pass Yield (Moles Net Gas / Mol $C_{3=}$ Charge) =

$$\% \left[\left(\frac{NG_m}{MW_{NG}} - \frac{PSA_{GAS}}{MW_{PSA}} - (DMSD * X_{DMSD C1}) - (E_m * X_{EZ}) \right) / (F_m * X_F / 44.1) \right] \dots \text{Mole basis}$$

Step b) % Net Gas per Pass Yield (Nm³ Net Gas / MT C₃- Charge) =

$$\% \left\{ \left[\left(\frac{NG_m}{MW_{NG}} - \frac{PSA_{GAS}}{MW_{PSA}} - (DMSD * X_{DMSD C1}) - (E_m * X_{EZ}) \right) * 22.4 \right] / (F_m * X_F) \right\} \dots \text{Vol. basis}$$

Net Gas yield is another indicator to monitor the unit performance. Over the life cycle of the catalyst, net gas yield per pass is expected to trend with propylene yield per pass. DMSD corrects for C₁ contribution upon decomposition. Assume H₂ and C₁ fractions in stream E exit with net gas while C₂+ fractions exit predominantly with liquid product.

5. Calculating H₂/HC Ratio

The ratio of hydrogen (H₂) to hydrocarbon (HC) designated H₂/HC is calculations below are shown with flows and compositions on mole basis for the cold combined feed exiting the cold separation system in the following steps. Use consistent units.

Step a) Calculate moles H₂ in the cold combined feed (CCF) exiting the cold separation system to Oleflex

$$(R_{G_m} * X_{R_{GH_2}}) + (F_m * X_{F_{H_2}}) = \text{Moles H}_2 \text{ in CCF}$$

Step b) Calculate moles hydrocarbon in the cold combined feed (CCF) exiting the cold separation system to Oleflex

$$(R_{G_m} * X_{R_{GHC}}) + (F_m * X_{F_{HC}}) = \text{Moles HC in CCF}$$

Step c) Calculate the H₂/HC

$$H_2/HC = (\text{Moles H}_2 \text{ in CCF}) / (\text{Moles HC in CCF})$$

6. Mass Balance

The purpose of carrying out unit mass balance is primarily to detect if any physical loss of material has been taking place over a period of time. In addition, it also helps detect flow meter drifts over time and reflects accuracy of measurement. Sum total mass rate of all inlet streams into any given mass balance envelope should equal the sum total mass rate of all outlet streams. It is often convenient to express mass balance (MB) close out as % (Mass Out / Mass In) or as % (Mass In / Mass Out). A close approach to 100% mass balance close out is ideal. In commercial units, 98% to 102% mass balance close out is considered acceptable limited by measurement accuracy.

A gradual drift in the % mass balance close out may indicate physical losses from the system. Physical inspection of the process plant often help identify such losses- for example icing on the sample return lines, liquid hydrocarbon purge lines to flare, equipment/piping leaks. In addition the analysis of flare gas and drift in flare gas flow may indicate the species and quantity being lost. A step change in the MB close out,

on the other hand may indicate a calibration shift of certain flow measurement device requiring maintenance to check and fix the flow meters. Calculating the yields when physical losses have been occurring in the system and when flow metering devices have drifted will provide incorrect and misleading results masking or exaggerating process issues. It is therefore critical to monitor the unit mass balance and/or individual system on a daily basis.

A. Oleflex Reactor Circuit Mass Balance:

$$\text{Oleflex reactor circuit (R}^N\text{) MB} = \frac{\text{MASS OUT from the Oleflex Reactor Circuit}}{\text{MASS IN to the Oleflex Reactor Circuit}}$$

Calculate the MB close out in the following steps as follows:

Step a) Mass in (R^N) = F_m + (SOL_M + SOL_{SR}) + E_m + DMDS + PSA_{GAS} + (CCR/100) * (%C_R)

Step b) Mass out (R^N) = LP_m + NG_m + SOL_{SS} + (CCR/100) * (%C_S)

Step c) (R^N) MB = % [Mass out (R^N) / Mass in (R^N)]

B. Fractionation Circuit Mass Balance:

$$\text{Fractionation circuit (FR}^N\text{) MB} = \frac{\text{MASS OUT from the Fractionation System}}{\text{MASS IN to the Fractionation System}}$$

Calculate the MB close out in the following steps as follows:

Step a) Mass in (FR^N) = LP_m + FP_m + FR_m + SHP H2_m

Step b) Mass out (FR^N) = F_m + P_m + OG_m + (B_m + H_m)

Step c) (FR^N) MB = % [Mass out (FR^N) / Mass in (FR^N)]

C. Overall Plant Mass Balance:

$$\text{Unit Overall MB} = \frac{\text{MASS OUT from the Unit}}{\text{MASS IN to the Unit}}$$

Calculate the MB close out in the following steps as follows:

Step a) Mass into the Unit =

$$FP_m + FR_m + (SOL_M + SOL_{SR}) + DMDS + PSA_{H2} + (CCR/100) * (%C_R)$$

Step b) Mass out from the Unit =

$$OG_m + P_m + (B_m + H_m) + SOL_{SS} + NG_m + (CCR/100) * (%C_S)$$

Step c) (FR^N) MB = % [Mass out (FR^N) / Mass in (FR^N)]

7. Unit Specific Consumption

Specific consumption of propane in the unit is defined as the amount of propane consumed in producing a unit of product propylene generally expressed as (MT C3- / MTC3=)

$$\text{Propane Specific Consumption} = \frac{\text{Mass of Feed Propane into the Unit}}{\text{Mass of Product Propylene Produced by the Unit}}$$

Calculate as follows:

Basis a) Units of 100% propane chemical consumed to produce 1 unit of 100% propylene chemical net of recycle propane and/or propylene.

$$(\text{FP}_m * \text{X}_{\text{FP C3-}} + \text{FR}_m * \text{X}_{\text{FR C3-}} + \text{E}_m * \text{X}_{\text{FR C3-}}) / [(P_m * \text{X}_{\text{P C3=}}) - (\text{FP}_m * \text{X}_{\text{FP C3=}} + \text{FR}_m * \text{X}_{\text{FR C3=}} + \text{E}_m * \text{X}_{\text{FR C3-}})]$$

Basis b) Units of 100% propane chemical consumed to produce 1 unit of propylene product of guaranteed purity $\%(X_{\text{P C3= GA}})$ net of recycle propane and/or propylene.

$$(\text{Specific Consumption calculated by Basis a)}) * [100 / \%(X_{\text{P C3= GA}})]$$

Any external recycle streams must be discounted or credited as appropriate for propane and propylene. Above calculation is based on 100% propane and propylene. Based on the above definition, the theoretical minimum fresh propane consumption is 1.05, assuming a stoichiometric conversion of fresh propane feed to propylene.

Depending on the specific unit, the consumption of fresh propane may be defined slightly differently. The definition of fresh propane consumption as defined in the Guarantee Agreement between UOP and the customer will be considered for the Product Test or Performance Test.

8. Component Yields

In addition to selectivity to propylene, it is often useful to track the selectivity to other component species. Further, it is useful to check and confirm the conversion, selectivity and per pass yield calculations previously discussed by alternate means identified by the superscript "Alt".

Step a) Calculate propane and component "J" in liquid product by material balance around the de-ethanizer, PP splitter and depropanizer as follows:

$$(\text{LP}_m)^{\text{Alt}} = \text{OG}_m + \text{P}_m + \text{RP}_m - \text{FR}_m$$

$$[\text{C3- in } (\text{LP}_m)^{\text{Alt}}] = \text{OG}_m * \text{X}_{\text{OG C3-}} + \text{P}_m * \text{X}_{\text{P C3-}} + \text{RP}_m * \text{X}_{\text{RP C3-}} - \text{FR}_m * \text{X}_{\text{FR C3-}}$$

$$[\text{"J" in } (\text{LP}_m)^{\text{Alt}}] = \text{OG}_m * \text{X}_{\text{OG J}} + \text{P}_m * \text{X}_{\text{P J}} + \text{RP}_m * \text{X}_{\text{RP J}} - \text{FR}_m * \text{X}_{\text{FR J}}$$

Step b) Calculate propane and component "j" in the Oleflex liquid feed by material balance around the depropanizer as follows:

$$[C3- \text{ in } (F_m)^{Alt}] = FP_m * X_{FP C3-} + RP_m * X_{RP C3-} - B_m * X_{B C3-} - H_m * X_{H C3-}$$

$$["J" \text{ in } (F_m)^{Alt}] = FP_m * X_{FP J} + RP_m * X_{RP J} - B_m * X_{B J} - H_m * X_{H J}$$

Step c) Define net reactor effluent (NREF) as follows,

$$NREF^{Alt} = (LP_m)^{Alt} + (NG_m - PSA_{GAS}) - E_m - (SOL_M + SOL_{SR} - SOL_{SS}) - DMDS * X_{DMDS C1}$$

Calculate net reactor effluent propane and component "j" flows from the Oleflex unit as follows,

$$[C3- \text{ in } NREF^{Alt}] =$$

$$[C3- \text{ in } (LP_m)^{Alt}] + (NG_m * X_{NG C3-}) - (E_m * X_{E C3-}) - (SOL_{SR} * X_{SR C3-}) + (SOL_{SS} * X_{SS C3-})$$

$$["J" \text{ in } NREF^{Alt}] =$$

$$["J" \text{ in } (LP_m)^{Alt}] + (NG_m * X_{NG J}) - (PSA_{GAS} * X_{PSA J}) - (E_m * X_{E J}) - (SOL_{SR} * X_{SR J}) + (SOL_{SS} * X_{SS J}) - (DMDS * X_{DMDS J})$$

The solvent terms in $[C3- \text{ in } NREF]$ and $["J" \text{ in } NREF]$ cancel out and therefore can be ignored. Retain, the solvent terms in calculating NREF to account for the solvent fraction in the liquid product. The term $(PSA_{GAS} * X_{PSA C3-})$ is omitted since there is no C3- in PSA H2. However, $(PSA_{GAS} * X_{PSA J})$ is retained to permit net H2 yield calculation. DMDS term corrects for methane species on decomposition of DMDS in NREF mass/mole and NREF component flow.

Step d) Calculate C3- converted per pass and component "J" produced per pass as follows;

$$[C3- \text{ converted}]^{Alt} = [C3- \text{ in } (F_m)^{Alt}] - [C3- \text{ in } NREF^{Alt}]$$

$$["J" \text{ produced}]^{Alt} = ["J" \text{ in } NREF^{Alt}] - ["J" \text{ in } (F_m)^{Alt}]$$

Step e) Calculate per pass propane conversion; selectivity and YPP for component "J" on "Alternate" basis, as follows and report,

$$[C3- \text{ Conversion}]^{Alt} = \% \{ [C3- \text{ converted}]^{Alt} / [C3- \text{ in } (F_m)^{Alt}] \}$$

$$[\text{Selectivity of component "J"}]^{Alt} = \% \{ ["J" \text{ produced}]^{Alt} / [C3- \text{ converted}]^{Alt} \}$$

$$[YPP \text{ of component "J"}]^{Alt} = [C3- \text{ Conversion}]^{Alt} * [\text{Selectivity of component "J"}]^{Alt}$$

Component product species "J" can be hydrogen, methane, ethane, ethylene, propylene, methyl acetylene (MA), propadiene (PD), butanes, butenes, pentanes and pentenes. C4 olefin and di-olefin yields ascribed to propane will include minor contribution from native C4 paraffin in feed, but the trend will still be indicative. Recycle propane will have to be sampled upstream of SHP in C3 Oleflex units with reactor effluent contact cooler to capture MAPD. In conventional C3 Oleflex units, the liquid product should be sampled upstream of SHP before di-olefins stream ties-in.

It is recommended that the component yields be tracked on routine basis as this provides insight into operations of the reactor section. For example, increase in (methane + ethane + ethylene) may point to increased non-selective cracking in the

non-catalytic areas of the reactor section requiring evaluation of fired heater operation.

9. Heavies Yield

In the C3 Oleflex units with the reactor effluent contact cooler and solvent recovery column, calculate heavies yield by material balance around the solvent as follows:

$$\text{Heavies Yield} = (\text{SRC}_B) / (\text{C}_3\text{-Converted per Pass})$$

In the conventional C3 Oleflex units, calculate heavies yield as follows:

Units with C4 rich side draw from the depropanizer system:

$$\text{Heavies Yield} = (\text{H}_m) / (\text{C}_3\text{-Converted per Pass})$$

Units with the depropanizer bottoms stripper:

$$\text{Heavies Yield} = (\text{Heavies' from Depropanizer Bottoms Stripper}) / (\text{C}_3\text{-Converted per Pass})$$

10. Calculated Key Process Variables

Liquid Hourly Space Velocity (LHSV): This is calculated and reported as standard cubic meters (SM³/Hr) of propane feed to the Oleflex unit per cubic meter (M³) of active catalyst volume in the reactors. Use consistent mass units for feed and density.

$$\text{LHSV} = [(\text{F}_m) / (\text{DEN}_F)] / [\text{X1}_{\text{CAT}} + \text{X2}_{\text{CAT}} + \text{X3}_{\text{CAT}} + \text{X4}_{\text{CAT}}] \dots (\text{SM}^3/\text{Hr})/\text{M}^3$$

Weighted Average Inlet Temperature (WAIT): This is calculated and reported in °C or °F as follows:

$$\text{WAIT} = [\text{RIT1} * \text{X1}_{\text{CAT}} + \text{RIT2} * \text{X2}_{\text{CAT}} + \text{RIT3} * \text{X3}_{\text{CAT}} + \text{RIT4} * \text{X4}_{\text{CAT}}] / [\text{X1}_{\text{CAT}} + \text{X2}_{\text{CAT}} + \text{X3}_{\text{CAT}} + \text{X4}_{\text{CAT}}]$$

Weighted Average Inlet Temperature (WABT): This is calculated and reported in °C or °F as follows:

$$\text{WABT} = [((\text{RIT1} + \text{ROT1})/2) * \text{X1}_{\text{CAT}} + ((\text{RIT2} + \text{ROT2})/2) * \text{X2}_{\text{CAT}} + ((\text{RIT3} + \text{ROT3})/2) * \text{X3}_{\text{CAT}} + ((\text{RIT4} + \text{ROT4})/2) * \text{X4}_{\text{CAT}}] / [\text{X1}_{\text{CAT}} + \text{X2}_{\text{CAT}} + \text{X3}_{\text{CAT}} + \text{X4}_{\text{CAT}}]$$

Void Blowing Margin (VBM): Refer to Section VII E.

The calculations mentioned in this section constitute those required to monitor the Oleflex unit process performance on a daily basis. In addition, additional calculations to monitor the energy consumption, chemicals consumption and equipment performance may be performed and trended by the operator as necessary. Void blowing margin calculations have been covered separately in Section VII E.

The calculations are usually set to be performed electronically via a suitable spreadsheet program on the computer with the ability to automatically retrieve process data from the DCS and Laboratory via suitable data acquisition systems. The results are often translated into graphics to monitor the process performance over time.

UOP offers customers with proprietary OpAware process monitoring program that automatically processes the raw data and presents the results saving time and efforts. For more details, contact the local UOP representative.

B. Evaluation and Optimization

1. Managing Oleflex Reactor Screen Fouling

Oleflex reactor screen fouling can affect the unit performance in various ways depending on the amount of fouling, nature of foulants and location briefly outlined as follows [a] excessive inner screen fouling can lead to flow mal-distribution in the catalyst bed impacting reactor performance [b] excessive inner screen fouling can lead to “void blowing” which will be discussed later in Section VII E, generating excessive catalyst fines causing various operating issues [c] reactor 4 outer screen carbonaceous fouling increases the back pressure on the reactor system impacting conversion, selectivity and specific consumption [d] reactor 1 inner screen and/or catalyst bed fouling led by iron sulfide scale may cause catalyst circulation issues and/or impact the catalyst performance due to iron migration.

Reactor inner (I/S), outer screen (O/S) and catalyst bed fouling manifests itself as increase in the reactor differential pressure ($RX \Delta P$) and/or increase in I/S ΔP and/or O/S ΔP during normal operation. When the screen(s) foul affecting the operability, or production/consumption to a point economically unacceptable; the unit will have to be shut down to clean the screens to restore the performance. Generally, the observed frequency between two successive screen cleanings in C3 Oleflex is 2-3 years in commercial units depending on operations.

During normal operation, the extent of fouling on each reactor screen is regularly assessed by calculating the incremental increase in $RX \Delta P$, I/S ΔP and O/S ΔP from the respective recorded baseline values with the new screens. Since the absolute operating ΔP is a function of unit hydraulics as defined by the feed rate, RIT and H_2/HC ; incremental ΔP s should be calculated at approximately identical hydraulic conditions.

At any given time, based on the absolute level of incremental ΔP increase from baseline and current rate of ΔP progression, appropriate actions are planned to achieve the target run length. Increase in operating severity will increase production, but it will also increase the screen fouling rate. Operator will have to balance between the twin objectives of run length and productivity when operating the unit.

Establish the baseline screen Δ Ps upon start-up with new screens when the Oleflex unit has attained:

- a. Design or normal operating throughput
- b. Design or normal operating reactor inlet temperatures (RIT)
- c. Normal operating H_2/HC ratio

It is recommended to exercise extra caution and closer monitoring when the incremental ΔP on the inner screen measured from baseline approaches ~ 3.5 KPa (~ 3.5 mbar or ~ 350 mm H_2O). Though the unit can continue to operate beyond this point, the unit must be monitored for signs of “localized void blowing” discussed later in this section apart from any impact on reactor performance.

Managing Screen Fouling: This constitutes an important exercise throughout the normal operations of the unit.

Reactor inner screen fouling is typically ascribed to:

- a. Feed contaminant(s)
- b. Metal catalyzed coke
- c. Thermal cracking coke
- d. Corrosion products
- e. Mechanical obstruction

Outer screen fouling is typically ascribed to:

- a. Plugging by catalyst fines
- b. For reactor4: Fouling due to heavies condensation / coking

Catalyst bed fouling is typically due to:

- a. Stagnant catalyst
- b. Stagnant hot hydrocarbon
- c. Upstream catalyst containment loss
- d. Sulfur upset

These primary causal factors are explained in more detail below;

❖ Reactor Inner Screen Fouling

- a. Feed impurities: Reactive species like nC_4 , C_4 olefins and methyl acetylene and propadiene (MAPD) in feed lead to the formation of soot coke and heavies in the Oleflex heaters. Olefins in the recycle gas can contribute to coking and related fouling. Control the feed impurities to the Oleflex reactors within allowable limits by optimizing the fractionation and SHP sections. Recycle gas quality must be controlled paying attention to cold separation system performance.

- b. Metal catalyzed coke: It is critical to maintain the required sulfur content in the feed and reactor effluent to minimize the formation of metal catalyzed coke contributing to screen fouling. Sulfur levels substantially lower than prescribed will increase metal catalyzed coke. This coke is characterized by spaghetti like structure with iron at the head of the strand with rest of the strand constituting coke.
- c. Thermal cracking coke: Localized heat flux due to uneven firing in the fired heaters can increase thermal cracking and lead to screen fouling in the downstream Oleflex reactor. Optimize fired heater operations by monitoring and maintaining the quality of the burn pattern in fired heater burners. Monitor the U-tubes for direct flame impingement. Inspect and clean the burner tips regularly.
- d. Corrosion products: This primarily refers to iron sulfide scale which may get formed in HCFE in relatively low temperature sections and get blown into the reactor¹. In addition, if the sulfur injection is excessive for a given temperature, iron sulfide scale can also form in other locations contributing to screen fouling.
- e. Mechanical obstruction: This is characterized by sudden step increase in I/S ΔP which is typically due to inlet guide vane failure of the reactor inlet elbow partially blocking the flow path.

❖ Reactor Outer Screen Fouling

- a. Plugging by catalyst fines: Events like localized void blowing, refer Section VII E for details, can generate fines within the catalyst bed which may traverse across the bed and lodge on the outer screen increasing its ΔP . In addition, inadequate fines removal from the system can cause fines to circulate through the reactor circuit and foul the O/S and/or catalyst bed.
- b. Reactor⁴ O/S fouling: This is typically seen only on reactor⁴. Reactor⁴ has the highest hot residence time and maximum reaction products concentration. Some of the polynuclear aromatic (PNA) type heavies may tend to condense out on the relatively cold O/S causing fouling. This can be controlled by adjusting the reactor⁴ RIT.

❖ Catalyst Bed Fouling

- a. **Stagnant catalyst:** Stagnant catalyst in the reactor while in operation due to catalyst circulation interruption can lead to progressively increasing coke on catalyst. At some point the high coke on stagnant catalyst may start binding with the fines and pills

into nuggets of coke and catalyst. The reactor inlet temperatures are therefore reduced in line with the guide lines provided under Section XI Emergency Procedures.

Stagnant catalyst can also form only in a section of the catalyst bed due to catalyst pills binding with coke, catalyst fines and/or corrosion products. The reactor to catalyst collector catalyst transfer pipe temperature monitoring help detect any catalyst flowing issues and/or stagnant catalyst while in operation. Try and adjust the reactor to catalyst collector ΔP via the pressure differential controller on the catalyst collector vent line to improve the gas assist to induce catalyst flow through the non-moving sections.

- b. **Stagnant hot hydrocarbon:** When the unit experiences an unplanned unit shutdown from the normal operating RITs, the reactors will take to cool down. Further, olefinic rich vapors may migrate from the cold separation system to reactors when the system gets warmed -up. Some reactions may continue to occur on the catalyst forming coke and heavies leading to bed fouling. This may cause high coke catalyst to exit from the reactor during unit restart. Coke from each lift engager is therefore monitored during restart and appropriate actions planned in the regenerator section if a section of the catalyst bearing high coke is passing through the system. Further, the flow path of recycle gas from the cold separation system can be blocked upstream or downstream of the low pressure turbo expander to prevent migration of olefin rich material until the reactors have cooled down. Bed fouling in this manner may or may not cause catalyst flow issues.
- c. **Upstream catalyst containment loss:** If due to mechanical damage, for example outer screen to base plate weld crack or O/S profile wire corrosion at the top of reactor1 outer screen that sees HCl, H₂O and H₂S from reduction zone migrating into reactor via catalyst transfer pipes, catalyst containment is lost which causes catalyst pills to migrate to downstream reactor via the reactor interheaters. Since the gas velocity is high, the catalyst pills may get damaged at impact points while flowing through and deposit as chips on the I/S causing ΔP increase. There exist several symptoms: [a] Increase in the amount of make-up catalyst into the surge hopper as compared to gross fines collected from the dust collector [b] Frequent plugging of the REC seal gas filters with catalyst dust (conventional C3 Oleflex units) [c] Sudden increase in chloride treater ΔP (conventional C3 Oleflex units) [d] Frequent plugging of solvent circulation filters (C3 Oleflex units with reactor effluent contact cooler) has increased [e] Increased amount of

catalyst lifted to the reactor than the amount removed over time. The unit will have to be shutdown to investigate the root cause.

- d. **Sulfur upset:** Excessive amounts of sulfur injected into the system over prescribed levels can cause iron sulfide scale within the austenitic system. The fractious and unstable iron sulfide scale can get dislodged from the parent metal and get blown into the reactor system. Iron sulfide scale may promote metal catalyzed coking within the catalyst bed and/or bind with catalyst pills causing chunks of coke mixed with catalyst pills fouling the bed. Additionally, this may cause catalyst flow issues and drop in reactor performance. Iron sulfide can be detected by magnet test on the catalyst fines. If substantial magnetic particulate are found, this may suggest problems related to sulfiding.

In addition to the primary causal factors for screen fouling described earlier, the other important aspect in monitoring the screen fouling is the propensity for “localized void blowing”, refer to Section VII E for the details, in the reactor while operating with the fouled screens. Void blowing is essentially a hydraulic phenomenon when the reactor inlet vapors exert sufficient hydraulic force on the catalyst pills to push them away creating a void in the catalyst bed leading to catalyst attrition. Calculations in Section VII E providing operating margin from the onset of incipient void blowing for a given set of operating conditions are based on new/clean screens. They provide guide line on the allowable hydraulic load during normal operations. When the screens foul during normal operations, “localized void blowing” can set in earlier than that predicted by the calculation depending on the amount of screen open area plugged by fouling. Therefore, it is important to diagnose and plan remedial actions if there are signs of localized void blowing. Localized void blowing is indicated by one or more of the following symptoms:

- a. Fluctuating and inconsistent reactor ΔP
- b. Decrease in reactor ΔT
- c. Sudden increase in fines generation
- d. Difficulties in catalyst circulation may occur coincident with item c.
- e. Inability to achieve the catalyst level in the surge pot or reduction zone on top of reactor after successive lifts

If localized blowing is occurring, try eliminating the void by decreasing the feed rate in increments of approximately 5%. After each step decrease, assess if symptoms have disappeared before next step decrease in feed. Once symptoms disappeared, try inching up back on the feed. Repeat till stable conditions are achieved.

Monitoring the shape of the ΔP trend, refer to Figure VII-B1, serves as a good tool to assess the potential type of issue related to screen fouling:

- a. Sudden exponential pick up in ΔP after a period of stable ΔP run is a concern
- b. Step change in ΔP may indicate a potential mechanical issue
- c. Gradual increase in ΔP led by process fouling can be optimized

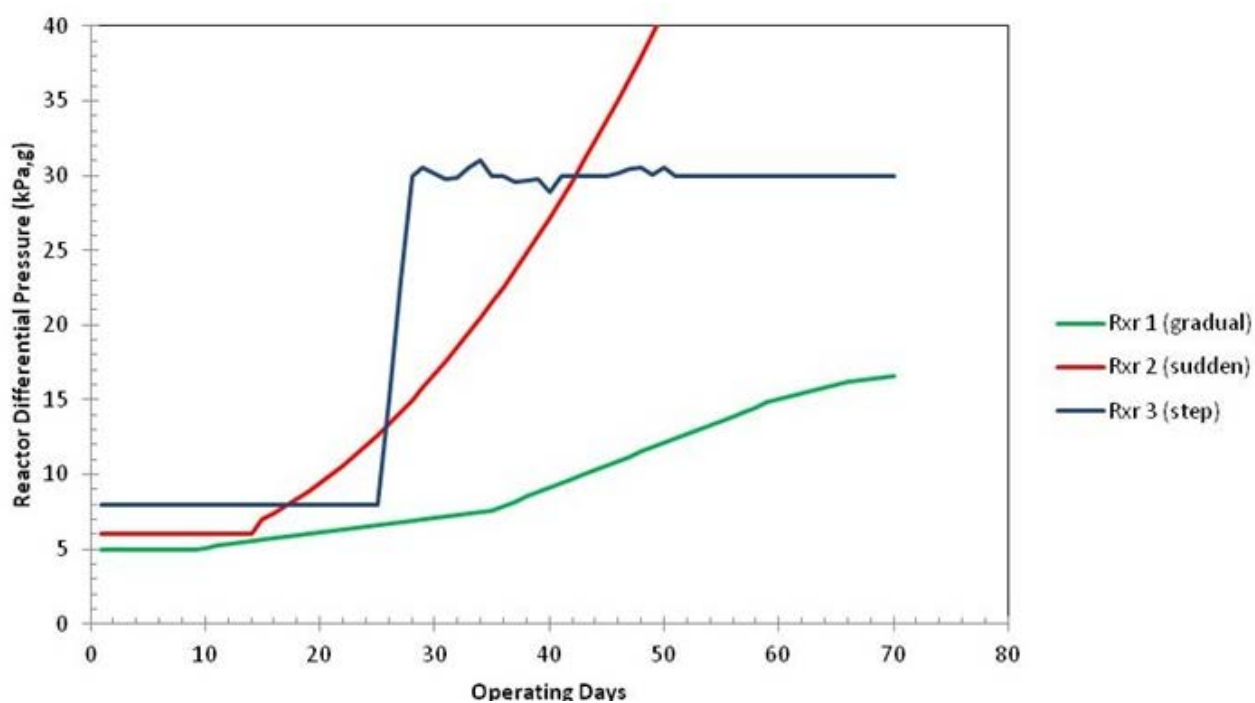
A gradual increase in I/S ΔP as shown in Figure VII-B1 for reactor1 can be mitigated by checking the primary causal factors discussed earlier.

A step increase in I/S ΔP as shown in Figure VII-B1 for reactor2, occurring typically in a short duration of 1 to 5 minutes, is often symptomatic of a mechanical issue like reactor inlet guide vane failure. Often a partially failed component of the inlet guide vane lodged in the reactor inlet elbow flow path can be detected by the distinguishable “rattling” noise when listened-to closely. This issue can only be fixed during shutdown.

A rapid but unexplained I/S ΔP increase as shown in Figure VII-B1 for reactor1 indicates some process deviation from normal operation has occurred which needs to be detected and fixed. This may be due to [a] unanticipated contaminants like oxygenates entering via fresh feed [b] an upset in the depropanizer operation [c] an upset in the SHP operation [d] heavies accumulation in the circulating solvent system when applicable [e] insufficient sulfur injection [f] excessive RIT than that indicated-control issues [g] poor cold separation system performance with consequent loss of recycle gas purity [h] direct flame impingement on heater coils [i] potential catalyst containment loss from the upstream reactor[j] poor dust collector operation circulating large quantities of fines to reactor system [k] onset of localized void blowing.

Finally, the operating absolute I/S ΔP at any stage during normal operation must remain within the external design pressure of the plug distributor which is the weakest component in the reactor internals. If at any stage I/S ΔP tends to approach the plug distributor design pressure, feed must be reduced immediately to bring back the I/S ΔP in acceptable range before any further investigation to protect the plug distributor from getting damaged.

Figure VII-B1
Different Trends for Reactor ΔP Increase



2. Optimizing the Oleflex Unit

The Oleflex unit is normally operated at stable reactor inlet temperatures (RITs), H₂/HC and feed rate. The operating conditions are adjusted and optimized within the operating constraints depending on the user requirements. Requirements are generally one of the following dictated by economics:

- Maximum propylene production
- Minimum propane specific consumption
- Maximum run length between screen cleaning

❖ Maximum propylene production:

During start of the run (SOR), with active catalyst, targeting the design RITs and H₂/HC while maintaining the feed rate corresponding to end of the run (EOR) will maximize the production. Higher amounts of coke generated will need to be managed adjusting the conditions in the regenerator.

The feed rate to the unit can even be increased more than the designated EOR feed rate provided the void blowing margin (VBM) is retained within ~20%. It is acceptable to maximize the feed ensuring the %VBM ≥ 20% on all the reactors.

At any stage during the run, increasing the RIT, decreasing the H₂/HC and maximizing the feed within the constraints of spent catalyst coke, screen fouling and void blowing margin will result in increased production. Propylene make responds faster to RIT rather than H₂/HC in normal operating bands. The advantage of lowering the H₂/HC slightly lies in the ability to push more feed through the reactor circuit.

❖ Minimum propane consumption:

Optimizing propane consumption involves minimizing the propensity for non-selective thermal cracking in the non-catalytic areas of Oleflex which is primarily a function of temperature.

During start of the run (SOR), with active catalyst, it should be possible to achieve the design production rate at EOR feed rate at lower than the design RITs with design H₂/HC. This helps achieve lower specific consumption and relatively lower spent catalyst coke while maintaining the design production rate.

At any stage of the operation, non-selective cracking can be controlled by optimizing the reactor inlet temperature (RIT) profile. Depending on the RIT profile, propane consumption can vary at constant conversion. Changes to the RIT affects the degree of cracking that occurs in each reactor. Amount of thermal cracking of propane decreases with increase in propylene concentration. Therefore, reactor 1 is operated at a lower temperature than the downstream reactors 2, 3 and 4. Since propylene content increases progressively in the downstream reactors, RITs can be increased

to achieve the target conversion with diminishing impact on consumption. However, reactor 4 which has maximum hot residence time, is typically maintained at an RIT slightly lower than reactor 3 to limit spent catalyst coke within acceptable limits.

Non-selective thermal cracking can also increase due to uneven firing in the fired heaters and/or direct flame impingement on the heater tubes with consequent increase in propane consumption. Review and optimize fired heater operation;

- a. Adjust air registers to obtain short stiff and stable flame on each burner
- b. Clean the burner tips regularly to ensure equal heat release per burner
- c. Inspect fired heater U-tubes regularly for hot spots which indicate fouling

A “humped” reactor inlet temperature profile is typically the most efficient in maximizing production and reducing feed consumption. Typical operating range for the RITs is given below:

- a. RIT, reactor 1: 610-625°C (1130-1157°F); to limit thermal cracking.
- b. RIT, reactor 2: > RIT reactor 1 in the range 635-650°C (1175-1202°F); propylene suppresses thermal cracking
- c. RIT, reactor 3: > RIT reactor 2 in the range 635-650°C (1175-1202°F)
- d. RIT Reactor #4: < RIT reactor 3 in the range 630-645°C (1166-1193°F); maximum hot residence time; target < = 5 wt % coke on spent catalyst.

❖ **Maximum run length between screen cleaning:**

Refer to Section VII-B 1 on managing screen fouling for details. In general, the variables that impact screen fouling must be regularly monitored and controlled to extend the run length between successive screen cleanings.

❖ **Other optimization considerations:**

- a. SHP operations must be monitored for olefins retention in addition to selective saturation of diolefins. Optimize reactor inlet temperature and hydrogen addition to minimize propylene conversion to propane while ensuring saturation of diolefins.
- b. Check the loss of propylene and propane in the deethanizer rectifier off gas. Optimize the rectifier condenser temperature within the constraints of the refrigeration compressor to minimize the amount of propylene and/or propane loss through off gas.

- c. Monitor the propane slip through the C4 rich side draw and/or depropanizer bottoms as applicable and try to minimize the loss by adjusting reboil while maintaining overhead purity.
- d. Feed drier regenerations must be checked to ensure that propane is not being lost in any of the various regeneration steps and in particular during the heating and cooling steps. Where an automated drier regeneration control system has been provided, check and ensure that propane is not being lost through the bleed/vent valves into the flare system. The thermal mass flow switch provided on the vents and bleeds must be able to assist in detecting valve leaks.
- e. Regulate the reactor effluent drier (RED) inlet temperature in the normal operating range by adjusting the amount of cooling in the REC stage coolers especially during winter. If RED inlet temperature is allowed to dip below the dew point of the circulating vapors, propylene and/or propane will condense out into liquid phase and lodge in the RED during adsorption. If this is allowed to happen, propylene and propane will come off the bed during subsequent regeneration and will be lost with the regenerant effluent affecting specific consumption.
- f. Adjust PP splitter reboiler-condenser operation to minimize propylene slip into the recycle propane stream. Reducing propylene in the recycle propane will reduce the propylene content in the Oleflex feed creating space for propane and help achieve increased production. Further, propylene in Oleflex feed tends to suppress the dehydrogenation in reactor 1 and therefore shall be minimized.
- g. In the conventional C3 Oleflex units, the reactor effluent contact cooler fouling will tend to increase the back pressure on the reactor system which will affect conversion and selectivity. Solvent cleaning must be performed to enable operation of the reactor section at lowest achievable operating pressure while maintaining REC suction at positive pressure all the time.
- h. In the C3 Oleflex units with the reactor effluent contact cooler, the pressure at the outlet of reactor 4 shall be maintained at the normal operating value. Though reducing the operating pressure, is directionally favorable to optimize the production and consumption, coke make and heavies increase will need to be closely monitored. Air leak into the system will increase when

pressure is reduced and constitutes an additional consideration while reducing the pressure.

- i. Regularly monitor the mass balance around sections of the unit to identify and fix any physical losses that may have been occurring. Sample the flare line to ascertain the components leaking out of the system.

3. Coke on Catalyst

The variables that impact the absolute level of coke on spent catalyst include RIT, H₂/HC, feed contaminants, catalyst age and catalyst circulation rate. Reactor 4 RIT impacts the spent catalyst coke to a greater degree than the RIT on the other reactors due to higher hot residence time. Reactor 4 RIT is therefore adjusted to limit the amount of spent coke on catalyst exiting the reactor system. Decreasing the H₂/HC ratio increases conversion and selectivity but will also tend to increase coke make on the catalyst. In normal operating bands of H₂/HC typically 0.01-0.02 lower than design, the impact on coke is manageable. However, reducing the H₂/HC significantly below design will increase spent catalyst coke and heavies. Absolute coke level on the spent catalyst can be reduced by increasing the catalyst circulation rate and vice versa during normal operations.

Refer to the CCR section General Operating Manual for more details on how to manage and optimize catalyst coke levels.

C. Monitor on a Daily Basis

1. Mass Balance

The following data should be monitored at a minimum of once per day while the Oleflex unit is in normal operation:

- 1) Reactor Section: Mass balance around the Oleflex unit, yield calculations, key calculated operating variables should be conducted on a daily basis and reported as follows.

Mass Balance:

- Oleflex reactor circuit mass balance close out
- Fractionation circuit mass balance close out
- Overall mass balance close out for the unit

Conversion

Selectivity

LHSV

Weighted Average Inlet Temperature (WAIT)

Weighted Average Bed Temperature (WABT)

C₃= Production

H₂/HC ratio - In the event of a unit upset, it is advisable that the H₂/HC ratio be monitored more often.

Percent Void Blowing Margin (%VBM)

Fractionation Section: Mass balances should be performed around each column on a daily basis. From this, the following data can be monitored daily:

Mass Balance Close Out

Reflux/Feed Ratio

2. Lab Results

A detailed laboratory schedule is listed in the 934 Process Specification and discussed in Section VIII. The following lab results should be monitored at least once a day:

- a. Fresh Feed Composition
- b. Combined liquid feed composition (depropanizer overhead)
- c. Product propylene (P-P splitter overhead)
- d. Deethanizer rectifier receiver off gas
- e. Recycle gas composition
- f. Flash drum liquid composition
- g. SHP inlet and outlet liquid composition
- h. PSA H₂ product quality

3. Outside Readings

A set of outside readings should be taken once a day to monitor temperatures, pressures and levels that might not be normally monitored in the control room. The following readings should be taken daily:

- a. Delta pressures across the feed guard beds, fresh feed driers, chloride treater and RED's.
- b. Liquid levels of the various separators in the Separation Section.
- c. DMDS injection rate.
- d. Charge Heater and inter-heater flame patterns.
- e. Pressures at inlet and outlet of reactors and across REC inter-stage and 2nd stage coolers.
- f. Delta pressures across the on-line fresh feed filter, the reactor effluent filter, REC seal gas filter and circulating solvent filter.

4. HCl Dräger Readings

HCl Dräger readings should be taken at the inlet and outlet of the Chloride treater at least once a day to ensure that no HCl breakthrough has occurred.

D. Monitor on a Continuous Basis

The following operating parameters should be monitored continuously while the Oleflex unit is on line.

1. Reactor Section

1.1 Delta Temperature across the Reactors

If the feed and recycle gas rates and reactor inlet temperatures have remained constant, delta T's should also remain constant. A downward shift in reactor delta T at constant processing conditions may be indicative of a catalyst activity problem.

1.2 Delta Pressure across the Reactors

The pressure drop across the Reactors is a critical variable for monitoring the long term operations of the Oleflex unit. At stable feed rate, recycle gas rate and reactor inlet temperatures (RIT); the hydraulics remain unchanged and therefore the reactor delta P should remain stable. Increasing reactor delta P on any given reactor at stable hydraulic conditions signifies reactor screen and/or catalyst bed fouling on that reactor. The delta P across the reactors should be continuously monitored.

1.3 H₂S Dräger Readings

H₂S Dräger readings of the reactor effluent should be taken at least every 8 hours. If the readings show that the H₂S is not within 50-60 ppmv, the DMDS injection should be adjusted accordingly.

1.4 Heater Tube Skin Temperatures

Monitor the tube skin temperatures in each of the heaters for hot spots above 705°C (1300°F). Temperatures in excess of 705°C can lead to excessive non-selective cracking and soot coke formation in the heater tubes, and must be avoided.

1.5 Items to Check around the Reactor Effluent Compressor

a. Temperature of reactor effluent at REC Suction Drum

If temperatures here begin to increase, it could be a sign that the reactor effluent coolers are becoming fouled or, depending on whether the reactor

effluent coolers are fin fans or shell-and-tube, that more fans need to be turned on or cooling water must be increased. In units with the reactor effluent contact cooler, ensure that the solvent circulation rate to the contact cooler is maintained and utilities commissioned properly to the circulating solvent cooler.

b. Temperature of reactor effluent at REC interstage/discharge

Excessive temperatures at the REC discharge could cause the REC to trip. If temperatures begin to increase, check the interstage and second stage cooler operations.

c. Pressures at suction and discharge of REC

The pressure at the suction and discharge of the REC should remain relatively constant.

If the pressure at the REC suction begins to increase, the molar flow rate to REC may be exceeding the design rate. Check to ensure that the feed and recycle gas rate and reactor inlet temperatures have remained constant which should correspond to fairly stable molar vapor rate to the REC suction. On automatic control, depending on the situation, REC antisurge valves will first tend to close followed by increase in the REC speed to accommodate increase in molar flow rate. Once the REC attains its maximum operating speed as set by the vendor, the suction pressure will tend to increase. It is also important to check the pressure controller located at the REC suction drum as in conventional C3 Oleflex units or the reactor 4 outlet pressure controller as in C3 Oleflex units with the reactor effluent contact cooler to ensure the set point is correct and that the transmitter is determining the pressure correctly.

On the other hand, if the REC suction pressure begins to decrease it runs the risk of air leak into the system on the conventional C3 Oleflex units. On these units, the pressure at the REC suction flange as determined by the antisurge control instrumentation, should remain at positive pressure to prevent vacuum. Check to ensure that the feed and recycle gas rate and reactor inlet temperatures have remained constant which should correspond to fairly stable molar vapor rate to the REC suction. If these were held constant, check the pressure controller on the REC suction drum. In the C3 Oleflex units with the reactor effluent contact cooler, the pressure controller at the outlet of the reactor 4 must similarly be checked.

REC discharge pressure is controlled by regulating the pressure at the inlet of the high pressure turbo-expander on a C3 Oleflex unit. Progressive increase in the REC discharge pressure may have been caused by the fouling in the REC interstage and discharge coolers, increase in the pressure drop across the chloride treater and/or increase in the pressure drop across the reactor

effluent drier when the unit is being operated at stable hydraulic conditions. The pressure drop through the narrated process equipment must be checked.

Note: Routinely perform Solvent Injection, as required (applicable only to the conventional C3 Oleflex units with reactor effluent air/water cooler) to remove the heavies deposits that may have been contributing to the increased pressure drop. Refer to the Section XIII – Special Procedures for Solvent Injection Procedure.

REC's RPM must remain relatively constant at given set of operating conditions when the unit is being operated at stable hydraulic conditions.

d. Specific Gravity at the REC Suction Drum

REC interstage specific gravity must be monitored. REC is designed to operate with the gas in a specified density range. Too low a specific gravity will indicate a light gas which may be too rich in hydrogen or other light ends like methane, ethylene and ethane which may tend to speed up the REC due to higher molar rate. On the other hand too high a specific gravity will indicate a heavier gas which may be tend to increase the required power to the REC due to higher mass rate. Specific gravity analyzer proves useful during the initial start-up while trying to make up hydrogen or hydro-carbon as required to remain in the operating range of the REC. During normal operations, it serves as an additional tool to monitor the cracking in Oleflex.

1.6 Monitor the Cryogenic Section

- a. Temperatures exiting both of the turbo-expanders should remain relatively constant during normal operations. However, these temperatures may swing somewhat during the various stages of RED regeneration.
- b. Monitor the warm end and cold end approach temperature for the adjoining streams in each exchanger within the cold separation system. The approach temperatures at either end for the streams in contact should remain typically within 5-6 °C. Diverging approach may signify internal leaks and/or process fouling.
- c. Reactor effluent temperature exiting the cold combined feed exchanger is critical. If this temperature begins to increase, the entire cold section will begin to warm up
- d. The HP and LP Gas Expander RPM's and amps should remain constant where the work is extracted from the expander via a generator. An increase in delta pressure across the expander for a given mass rate will

correspond to increase in extracted work which will show up as an increase in the amps. If the delta pressure is too large, the turbo expanders may trip on high amps.

1.7 Performance of the Reactor Effluent Driers (REDs)

When the Oleflex unit is in normal operation, one of the REDs will be in adsorption step while the other RED(s) will be in various stages of regeneration. It is important that drier regeneration continue smoothly so that H₂S breakthrough does not occur before a freshly regenerated drier could be brought on line. See Section XII, Special Procedures, for RED regeneration sequence.

1.8 Reactor Coke Make / Regenerator Coke Burning Balance

During normal operation on an Oleflex unit, coke is formed on the catalyst as it traverses the reactor system performing its intended dehydrogenation function. The typical Oleflex unit operating range is within approximately 3-4 wt% coke on spent catalyst. Coke will gradually build on catalyst as the catalyst inventory is circulated through the Oleflex reactors. The catalyst inventory will develop a coke profile through the system – from no coke on freshly regenerated catalyst at the top of Reactor No. 1 to the peak spent catalyst coke level at the bottom of Reactor No. 4. When operating at steady state conditions, this coke profile remains relatively unchanged over long term operation.

The rate of coke formation on catalyst is a function of the operating severity in the reactor section. Reactor temperatures play a major role on how quickly coke lays down on the catalyst. An increase in reactor temperature will have a direct increase in coke on the catalyst. Additional operating variables which impact coke level are H₂/HC (lower H₂/HC favors more coke make), feedstock and recycle gas impurities (an increase in impurities such as nC₄ and C₄ olefins result in higher coke levels), residence time of the catalyst in the reactors which is determined by the catalyst circulation rate. This particular variable, especially the catalyst residence time in the last reactor, plays a major role in coke on catalyst. An increase in residence time can result in a substantial increase in coke on catalyst.

The objective of the Continuous Catalyst Regeneration, or CCR, section is to circulate catalyst and thereby burn coke at a fast enough rate to ensure that the coke profile on catalyst in the reactors is less than the threshold for activity loss. This ensures that catalyst in all the reactors has a constant activity and performance. An increase in severity in any of the above operating parameters will generally result in higher coke on catalyst. If the coke level on spent catalyst increases above the threshold where it begins to affect activity,

process performance will decline. Performance can only be recovered when the coke profile on catalyst in the reactors is restored to its desired level.

It is critical during normal operations that coke be burned at the same rate it is formed in the reactors. This is done by maintaining catalyst circulation without interruption while the plant is in operation. When catalyst circulation is interrupted, coke on catalyst could rise quickly. This is considered a potential emergency situation for which corrective action needs to be taken. Refer to Section XI Emergency Procedures of this manual for the guideline for handling a loss of catalyst circulation.

In the event where coke on spent catalyst is higher than desired due to some process upset, recovery from such an event is critical. Coke must be burned at a higher rate than it is being generated to allow coke burning to get 'caught up' with the coke make. This can be done in two ways:

a. Increasing catalyst circulation rate

During steady-state operation, the CCR will generally operate at a catalyst circulation rate below the system's ultimate capacity. Following an upset where coke on catalyst has increased, it is generally recommended that some of the regenerator's idle capacity be utilized by increasing catalyst circulation rate.

Increasing circulation rate will increase the amount of coke burned at a constant or increasing coke level. This will aid in burning coke at a faster rate than it is produced, thus resulting in a decrease in coke on catalyst. When the coke level decreases to its pre-upset level, it may be possible to reduce circulation rate back to what it had originally been.

Any increase in catalyst circulation and coke burning should be done in accordance with normal regenerator operating practices and guidelines as outlined in UOP's CCR Regeneration Section General Operating Manual. It is especially important when coke on catalyst rises that bed temperatures in the regenerator do not exceed their recommended limits. As such, it may not be possible to increase circulation much, if at all, when the coke is abnormally high. It will generally depend on how high the coke has increased.

b. Temporarily reducing severity in the reactors

This will generally require a temporary drop in reactor temperature while the coke level declines. It has been found that the majority of coke on Oleflex catalyst is formed in the last reactor and that coke level is strongly influenced by temperature and catalyst residence time in the last reactor.

When catalyst in the last reactor has a high coke level, the reactor's delta T will drop off. The lower delta T results in an increase in the reactor's average temperature. The higher average temperature the catalyst sees will cause the coke make rate to increase further. This can generate a coke cycle where more and more coke continues to be formed, and the coke on catalyst level continues to increase. It is generally difficult to break this coke cycle without some decrease in last reactor inlet temperature.

If an incident has occurred where coke on spent catalyst has increased appreciably (to, say, well above 5 wt %), it is generally a good idea to reduce the last reactor's inlet temperature until the coke comes back down to its previous level (i.e. below 5 wt %). How much to reduce the last reactor inlet temperature will depend on how high the coke is. Experience has shown that when operating at abnormally high coke levels, a reduction of the last reactor inlet to 620°C (1150°F) typically will bring the coke make/burn back into balance within a couple of days.

2. Fractionation Section

2.1 Product Propylene Purity

The Propylene-Propane Splitter overhead stream should be kept on specification at all times. Off-spec product may be indicative of the analyzer recorder controller being out of range due to too much or too little heat being added to the column from the Heat Pump Compressor.

2.2 C₄+ Olefins in the Depropanizer Overhead

If the amount of C₄+ Olefins is greater than design, there may be a problem with the operation of the depropanizer. Adjust depropanizer operations as required.

2.3 C₂ in the Deethanizer Stripper Bottoms

If C₂ is present in the Deethanizer Stripper Bottoms, the propylene product will be off-specification. Adjust Deethanizer operations as required.

2.4 Performance of Fresh Feed Driers

The on-line moisture analyzer should be monitored continuously to ensure that water breakthrough does not occur. Perform regenerations as required.

E. Special Monitoring - Reactor Hydraulics

The operations staff must continuously be familiar with the normal trends of the unit. This allows for a more rapid identification of reactor circuit problems, and also problems throughout the complex. The intent of this section is to educate operations personnel in how to identify signs indicative of a developing hydraulic problem and what the proper response should be to avoid further problems. Before proceeding with this discussion, however, it is critical to develop an understanding of the hydraulic phenomenon known as void blowing.

1. Void Blowing Theory

Void blowing is defined as a hydraulic phenomenon that occurs when fluid forces are developed large enough to "blow" the catalyst bed away from the reactor inner screen/catalyst interface and form a "void." Void blowing can be caused by excessive throughput and/or localized pluggage of the inner screen, and can be initiated at one or more points along the reactor inner screen/catalyst interface. Churning and turbulent circulation of the catalyst on itself within the void pockets or spaces causes appreciable catalyst breakage, subsequent screen/bed pluggage, and further void propagation. Eventually, these actions will result in a shutdown of the Oleflex reactor section. The original void blowing curve supplied by UOP Mechanical Design is calculated in such a manner as to ensure a void blowing margin of approximately 30% at design unit throughput, or:

$$\frac{W_{VB} - W_{design}}{W_{design}} = 0.3$$

Where W = mass flow rate of the combined feed. The curve itself plots theoretical W at incipient void blowing vs. the density of the reactor vapors at the center pipe (inner screen). These curves will be supplied to the client by the UOP Chief Technical Advisor. Based on the above, it is apparent that the void blowing margin will decrease below 30% only when the unit's combined feed rate (recycle gas + iC_4 feed) is increased above design.

The purpose of the 30% void blowing margin at design throughput is to account for variation of the independent variables involved in the void blowing equation. Thus, UOP does not recommend operation of the Oleflex unit at throughputs above design. It must also be understood that the design void blowing margin is based on a normal hydraulic situation in each reactor and does not apply if the reactor internals have been fouled.

Increasing the mass throughput through a reactor does not proportionally decrease the void blowing margin. This is due to the fact that at higher throughputs, reactor system pressure is increased. At higher pressure, the

vapor density of the reactor inlet gas increases. As the void blowing curve will show, increasing the vapor density at a constant mass throughput will shift an operation away from the void blowing curve. Thus, although an increase in mass flow will reduce the void blowing margin overall, the corresponding increase in vapor density has some negating effect of this void blowing margin reduction.

Void blowing margins for each reactor should be calculated regularly. The data needed for such an evaluation can be obtained from lab results and DCS readings. The following illustrates in detail how the calculation is performed. Note that the pertinent physical properties of the gas stream (used to calculate vapor density) are derived from the conditions at the reactor inlet. Inlet conditions are used due to the philosophy that void blowing begins at the inner screen/catalyst interface.

Definitions

N_P	=	Total Kg moles of products from Oleflex unit, Kg mol/hr
N_F	=	Total Kg moles of feed to Oleflex unit, Kg mol/hr
N_E	=	Total Kg moles produced across the reactor section, Kg mol/hr = $N_P - N_F$
W_t	=	Total mass into reactor (Rx), Kg/hr
W_{VB}	=	Theoretical mass into reactor at incipient void blowing
X	=	Conversion fraction = (delta T of previous reactor) / (total delta T)
M_t	=	Total Kg moles into reactor, Kg mol/hr
m	=	Molecular weight of reactor at inner screen = W_t/M_t
T	=	Reactor inlet temperature, °K = (°C + 273.15)
P	=	Reactor inlet pressure, Kg/cm ² a = (Kg/cm ² g + 1.033227)

2. Procedure to calculate the void blowing margins (VBM)

Calculate each of the above variables using simultaneous unit readings, lab results, and weight balance calculations.

- N_P , N_F , and N_E should first be calculated. This is typically done within the unit's mass balance program, and is done by calculating each streams' molecular weight from GC lab results, followed by calculation of Kg moles/hr from the calculated molecular weights and corrected mass flows. Note that N_F includes all feed to the unit, including purge flows.
- Calculate W_t . This should be done for each reactor, and should include any hydrogen purge flows that enter the unit just upstream of the subject reactor. For example, purge flow to catalyst collector 1 exits to the reactor 1 outlet line and should be included in the W_t value for reactor 2.

- c) Calculate X for each reactor. Note that the X value for the previous reactor is used in calculating the subject reactor's void blowing margin. This is due to the fact that only reactor inlet conditions are used to calculate void blowing margin. In other words, the molar expansion in Rx 1 does not impact the Rx 1 inlet conditions – it affects those of Rx 2.
- d) Calculate M_t for each reactor. As for W_t , this value should include any inter-reactor purge flows. M_t is also affected by molar expansion, and can be calculated as follows:

$$M_t = M \text{ into previous Rx} + M \text{ of inter Rx purge flows} + X (N_E)$$

- e) Calculate m using W_t and M_t for each reactor.
- f) Calculate the vapor density at each reactor inlet as follows:

$$\text{Vapor Density, Kg/ M}^3 = (P * m) / (R * T) \quad (\text{for Kg-moles})$$

$$R = \text{Gas Constant} = 0.08478 \text{ (Kg/cm}^2 \text{ a) (M}^3 \text{) / (Kmol) (}^\circ \text{K)}$$

- g) With the vapor density now calculated, read W_{VB} off of the void blowing curve.
- h) Calculate the void blowing margin for each reactor:

$$\% \text{ margin} = (W_{VB} - W_t) / (W_t) \times 100\% = V_{BM}$$

This equation for void blowing margin is the basis for the design of the Oleflex unit reactors, and should equal approximately 30% at design throughput

3. Void Blowing in Operations

With the concept of void blowing now understood, it is critical for operations personnel to know what the indications of a void blowing occurrence are and what responsive actions to take.

It should be noted that for the Oleflex reactors, a significant restriction must exist before any abnormality in delta P can be measured. In other words, serious pluggage of the reactor internals with catalyst fines (due to void blowing) or coke would have already taken place once an irregular rise in reactor delta pressure (delta P) is observed. For example, Figure VII-E1 shows the relationship between pressure drop across the reactor inner screen and fouling. As can be seen by this graph, noticeable pressure drop does not occur until the inner screen is greater than 90% fouled.

Although monitoring the reactor delta P's is important, other indicators of a developing hydraulic problem must be continuously monitored as well so that a problem can be rectified even before a delta P problem is first observed. Any indications that relate to possible hydraulic problems should be taken seriously. If the indications cannot be attributed to changes in typical process variables, proper precautions as outlined later in this section should be carried out immediately.

An early indication of a possible hydraulic problem within a reactor is the development of an offset in that reactor's catalyst performance. Such an offset can be observed by monitoring the temperature delta of each reactor. The olefin dehydrogenation reaction is endothermic. In fact, about 30 kcals per mole of olefin converted is consumed. The result is a temperature drop across the catalyst bed of each reactor. Further, the temperature drop of a given reactor is approximately constant when taken as a function of % of the total reactor delta temperature. As the temperature of the inlets is increased, the delta temperature of each reactor increases maintaining the same approximate individual reactor percentages. In other words, if Reactor No. 2 has 33% (+/- 1%) of the total delta temperature, it will still maintain 33% when all the reactor inlets are raised equally. The same is true for increasing the feed rate or lowering the H₂/HC ratio. Any function that equally affects the catalyst system will alter the absolute total delta temperature, but not the individual percentage of that delta temperature performed in each reactor. It must be understood, though, that small changes in a reactor percent delta T can be caused by routine changes in process variables. For example, if all three Oleflex reactors are being run at the same inlet temperature and only the Reactor 1 inlet temperature is increased, the percent delta T of Reactor 1 will increase while Reactors 2, 3 and 4 will decrease slightly. The effect of increased system pressure at higher throughputs can also cause some shift in the delta T distribution. Thus, if a sudden shift in reactor percent delta T is observed, ensure that the shift is not due to a change of operating conditions. If the shift occurs at constant process conditions or if the shift is too substantial to have been caused by process variable changes, immediately proceed with precautionary measures as outlined later.

With the above in mind, the operations staff can monitor the delta temperature of each reactor. If these are monitored as a percentage of the total delta temperature, operations can determine if a particular reactor is beginning to run less efficiently (with less dehydrogenation) than it previously did. Such data might look like Figure VII-E2. Notice the data from 0 to 100 days on stream is about 33% of the total reactor delta temperature. However, at 100 days on stream and beyond, the percentage of delta temperature declines steadily even though process conditions were constant. Such indications are symptomatic of vapor bypassing in a reactor due to void blowing.

In addition to a sudden change in a reactor's percent of the total reactor delta temperature being an early indicator of void blowing, a sluggish response of Reactor Surge Pot levels when catalyst is withdrawn during the loading step of their respective lift engagers or lock hopper can be another indicator. This, however, has a significant amount of variability and may not indicate anything conclusive.

Delta pressure indicators (PDI's) specified by UOP for each reactor are also used to assess any suspected hydraulic problems. It has already been stated that significant reactor internals fouling must occur before an abnormal PDI indication is observed. However, if the problem is detected early enough with the PDI's and appropriate actions are taken immediately, a total unit shutdown may be averted. During normal operation when a hydraulic problem does not exist, the PDI indications will trend together. At constant throughput and temperature, the PDI indications should all remain stable. When throughput is increased or decreased, the PDI indications for each reactor should trend up and down together, even though the absolute value of each reactor's change is slightly different. If one reactor develops an upward delta P trend at constant conditions and when the other reactor delta P's are stable, this is an indication of a hydraulic restriction and must be immediately addressed.

If an offset in reactor percent delta T, surge pot level response, or reactor delta P occurs as described in the above paragraphs, the operations group should immediately begin an investigation into why the reactor performance has deteriorated. The investigation should be swift and encompass the following areas:

- 1) The Reactor Surge Pot catalyst transfer line delta pressure is measured and alarmed if the delta pressure drops below the field set values. If the pressure drop is adequate, it is assumed that the catalyst pipes are full and the hydrogen purge is adequate. However, if the delta pressure has declined, check the catalyst level and the hydrogen purge system. Be sure both are functioning properly.
- 2) The individual reactor delta pressure indicators (PDI's) should be reviewed to determine if the problem is located in only one reactor or is general to the circuit.
- 3) The reactor's void blowing margin should be checked to assure that the reactor is not in a void blowing position due to an excessively high combined feed rate. As noted above, the calculated void blowing margin is approximately 30% at design feed rate and H_2/HC , and will decrease as feed rate and/or H_2/HC is increased above design. However, if a hydraulic restriction such as fines or coke pluggage of the reactor internals exists, a calculated void blowing margin does not apply. In such a situation, void blowing may be occurring even though the calculated void blowing margin

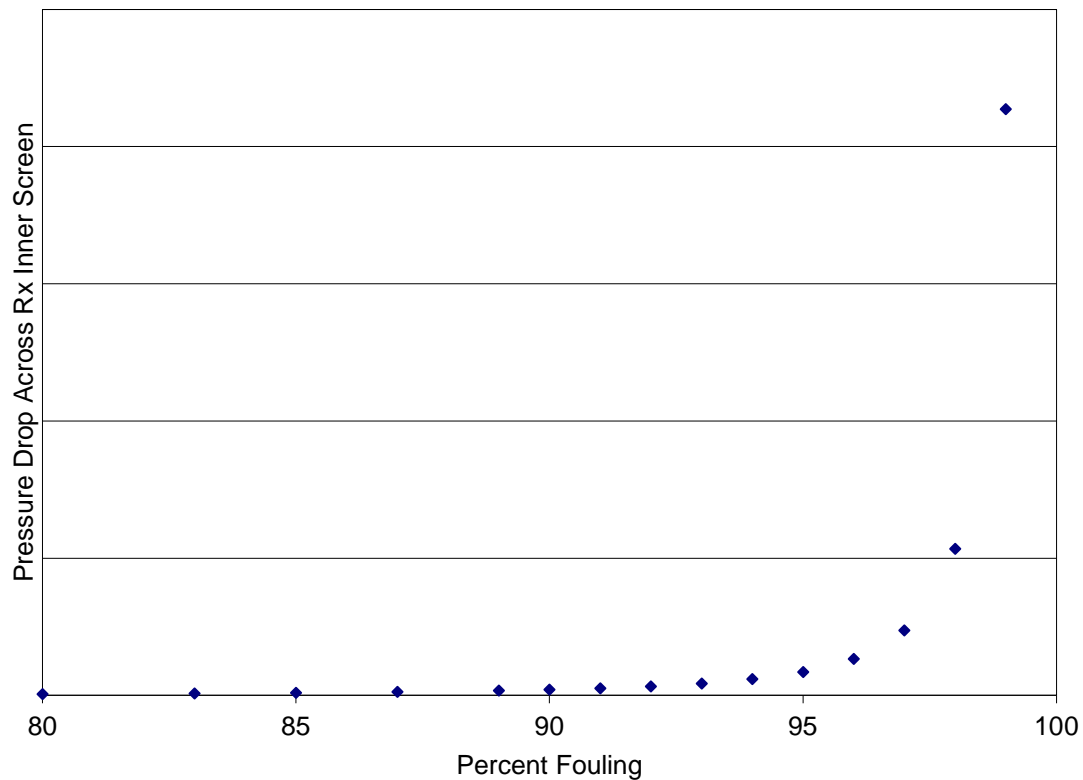
is acceptable. Calculation of the void blowing margin should be done in parallel with Steps 1 and 2 and be done as quickly as possible.

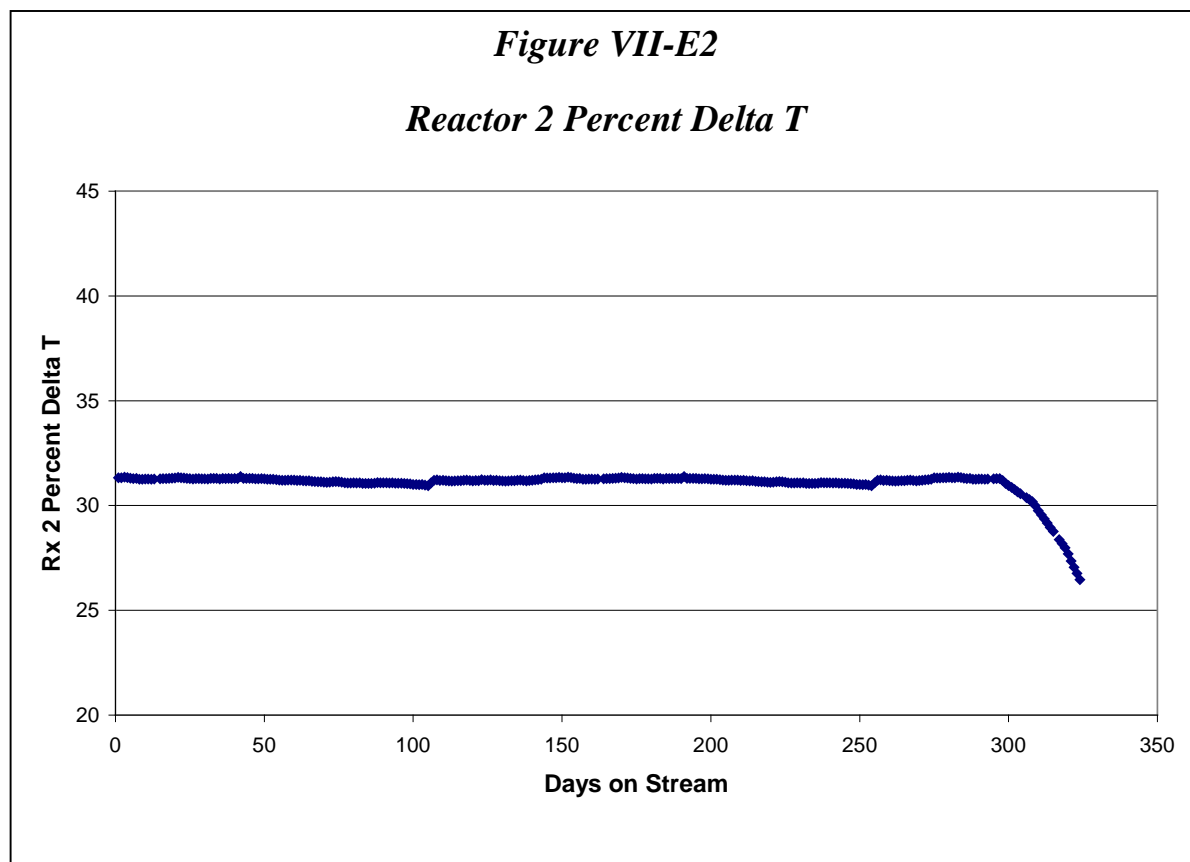
- 4) Check the lift patterns of Lift Engagers #1, 2, and 3. Abnormal lift patterns may develop if void blowing is occurring due to the influence of higher fines containing catalyst. Also check the CCR's Surge Hopper catalyst level. If void blowing is occurring and the volume of these voids becomes appreciable, the level in the Surge Hopper may rise.
- 5) If the calculated void blowing margin is unacceptably low, an unacceptably high pressure drop exists anywhere in the reactor circuit, or one of the other void blowing symptoms can be reasonably attributed to void blowing, immediately decrease the combined feed rate to a level below void blowing conditions. Elimination of the symptoms used to conclude that void blowing is occurring, dictates how low the combined feed rate must be lowered. For example, if an abnormally high delta P exists, stabilization of that delta P is an indication of when void blowing has been stopped.
- 6) Finally, a complete review of the daily unit performance data should be performed to detect any offsets in either conversion or selectivity. If any deviations from the normal historic data trends are observed, note these and report them to UOP with details on all of the above review.

In general, the intent of the immediate review will be to identify the cause of the reactor performance offset, adjust the known parameters to reduce the impact of said offset, and eliminate the potential for high pressure drops to develop in other parts of the circuit. Observance of the monitoring guidelines depicted above and swift action (should an unknown event occur) will meet the previously described intent. Above all, the operations staff must be familiar with the normal trends of the unit. This will allow a more rapid identification of reactor circuit problems, but also problems throughout the complex.

Figure VII-E1

Relationship between Screen Fouling and Pressure Drop Across Reactor Inner Screen





VIII. Analytical

Information in this section lists laboratory analysis that may be included in the required analytical schedule for the process. Typical operating ranges for some of the analysis may be included.

A. General

Samples should be taken on a regularly scheduled basis by authorized personnel knowledgeable in the procedure. Operating company standards must be consulted in determining the proper personnel protective equipment required for the taking and handling of samples.

The general design and specification of the sample points is provided in the Project Specifications.

Sample cylinders should be received from the laboratory properly cleaned and purged consistent with the analysis being performed, e.g. if analysis for oxygenates are being performed then the sample cylinder must be purged of oxygen prior to use.

All samples leaving the process area for the laboratory should be tagged with the following information: sample description, sample source, analyses requested, date and time sampled.

Analytical test methods and standards by UOP and ASTM are available at www.astm.org.

B. Sample Procedures

Sampling procedures will need to be developed in conformance to the operating company's procedures.

1. Closed Flow-Through To Process Sampling (Liquid or Gas)

Sample points are provided that allow a portion of the process stream to be directed through a closed sampling system. The system is used to contain a portion of the stream and allow its transport to the laboratory. This type of system is used when the material sampled is considered to be toxic/hazardous or when taking an open sample would compromise the analysis. Typically such sampling arrangement is provided across a control valve or a pump which provides the necessary Del P to induce flow through the sample bomb.

Instructions for the use of the closed sample system are to be provided by the supplier of the system. The general arrangement of these sample points are included in the Piping and Instrument diagram provided for the project.

2. Closed Flow-Through to Vent/Drain Sampling (Liquid or Gas)

When it is impractical to take a sample through a closed sample system and return it to the process flow stream it may directed to the safe vent system of the unit or sent into the drain system of the unit. The system is used to collect a portion of the stream and allow its transport to the laboratory.

Instructions for the use of the closed sample system are to be provided by the supplier of the system. The general arrangement of these sample points are include in the Piping and Instrument diagram provided for the project.

3. Sample on Vent to Safe Location - Type “DT”

Occasionally analysis is made with gas detection tubes. These devices require a low pressure at their connection to the process in order to provide an accurate reading. After connecting the sample tube to the “DT” connection point on the sample point a small purge of gas is vented through the vent line to atmosphere and the sample is taken following the procedure given by the vendor of the gas detection tube.

Care should be taken so the vent rate is not too high as this may cause a higher flow than intended through the gas detection tube and cause poor analysis accuracy.

C. Analysis

The laboratory schedule, including the required analytical method number and the frequency of sampling, for the specific unit is documented in the 934 specification of the “UOP Schedule A” design book which should be referred to by the reader for his unit. The narrative provided here is informatory only. Stream Data can be found in the Engineering Design Information of the “Schedule A” design book.

1. Oleflex (Propylene) Reactor Section Analytics

Sample Number	Stream and Test Name	Test Method Number	Frequency	
			Normal	Startup
01-SN-01	Blowdown from Steam Drum			
	Total Hardness (as CaCO ₃)	ASTM D1126	Occas.	Occas.
	Sodium	ASTM D4191	Occas.	Occas.
	Copper	ASTM D1688	Occas.	Occas.

Sample Number	Stream and Test Name	Test Method Number	Frequency	
			Normal	Startup
	Iron	ASTM D1068	Occas.	Occas.
	Total Alkalinity (as CaCO ₃)	ASTM D1067	1/D	2/D
	Chloride	ASTM D512	Occas.	Occas.
	Sulfate	ASTM D516	Occas.	Occas.
	Silica	ASTM D859	Occas.	Occas.
	Total Suspended Solids	Std Method 2540D	1/D	2/D
	Total Dissolved Solids	Std Method 2540C	1/D	2/D
	pH	ASTM D1293	1/D	2/D
	Specific Conductance	ASTM D1125	1/D	2/D
	Dissolved Oxygen	ASTM D5543	Occas.	Occas.
	Oil	ASTM D3921	Occas.	Occas.
	Total Organic Compounds	ASTM D4779	Occas.	Occas.
	Phosphates (when used)	ASTM D4327	1/D	2/D
	Hydrazine (when used)	ASTM D1385	1/D	2/D
	Sulfite (when used)	ASTM D5542	1/D	2/D
01-SN-02	Combined Feed to Charge Heater / Reactor No 1 Inlet			
	Composition	UOP 539	As Req'd	As Req'd
	Trace Components	UOP 899	As Req'd	As Req'd
	H ₂ S	Draeger	As Req'd	As Req'd
01-SN-03	Reactor No 1 Effluent to No 1 Interheater / Reactor No 2 Inlet			
	Composition	UOP 539	As Req'd	As Req'd
	Trace Components	UOP 899	As Req'd	As Req'd
	H ₂ S	Draeger	As Req'd	As Req'd
01-SN-04	Reactor No 2 Effluent to No 2 Interheater / Reactor No 3 Inlet			
	Composition	UOP 539	As Req'd	As Req'd
	Trace Components	UOP 899	As Req'd	As Req'd
	H ₂ S	Draeger	As Req'd	As Req'd
01-SN-05	Reactor No 3 Effluent to No 3 Interheater / Reactor No 4 Inlet			
	Composition	UOP 539	As Req'd	As Req'd
	Trace Components	UOP 899	As Req'd	As Req'd
	H ₂ S	Draeger	As Req'd	As Req'd
01-SN-06	Neutralization Solution			
	pH	ASTM D1293	As Req'd	As Req'd
01-SN-07	Fuel Gas to Heaters			

Sample Number	Stream and Test Name	Test Method Number	Frequency	
			Normal	Startup
A	Composition	UOP 539	1/D	1/D
B	H ₂ S	Draeger	Occas.	1/D
	HCl	Draeger	Occas.	1/D
01-SN-08	Reactor Effluent Compressor Interstage			
	Composition	UOP 539	1/D	2/D
	Trace Components	UOP 899	1/D	2/D
	H ₂ S	Draeger	Occas.	1/D
01-SN-09	Reactor Effluent Drier Inlet			
A	Composition	UOP 539	Occas.	1/D
	Trace Components	UOP 899	Occas.	1/D
B	H ₂ S	Draeger	2/D	6/D
	HCl	Draeger	1/D	2/D
C	CO/CO ₂	UOP 603	1/D	2/D
D	H ₂ O	Portable or Online Panametrics Analyzer	1/D	2/D
01-SN-10	Reactor Effluent Drier Outlet			
A	Composition	UOP 539	Occas.	1/D
	Trace Components	UOP 899	Occas.	11D
B	H ₂ S	Draeger	1/D	2/D
	HCl	Draeger	1/D	2/D
C	CO/CO ₂	UOP 603	1/D	2/D
01-SN-11	Regenerant Gas Scrubber Wash Water			
	pH	ASTM D1293	1/D	1/D
	Specific Gravity	ASTM D1298	1/D	1/D
	Total Dissolved Solids	APHA-2540	1/D	1/D
	Total Suspended Solids	APHA-2540	1/D	1/D
01-SN-12	Regenerant Gas Scrubber Caustic			
	Alkalinity as %NaOH & %Spent	UOP 209	1/D	1/D
	pH	ASTM D1293	1/D	1/D
	Specific Gravity	ASTM D1298	1/D	1/D
	Total Dissolved Solids	APHA-2540	1/D	1/D
	Total Suspended Solids	APHA-2540	1/D	1/D
01-SN-13	PSA Hydrogen Product			
	Composition	UOP 539	1/D	2/D
	Trace Components	UOP 899	1/D	2/D
	CO/CO ₂	UOP 603	1/D	2/D

Sample Number	Stream and Test Name	Test Method Number	Frequency	
			Normal	Startup
	O2 Molecular/ N2 Molecular	UOP 539 or ASTM D2504	1/D	2/D
01-SN-14	PSA Tail Gas			
	Composition	UOP 539	1/D	2/D
	Trace Components	UOP 899	1/D	2/D
	CO/CO2	UOP 603	1/D	2/D
	O2 Molecular/ N2 Molecular	UOP 539 or ASTM D2504	1/D	2/D
01-SN-15	Net Gas			
	Composition	UOP 539	1/D	2/D
	Trace Components	UOP 899	1/D	2/D
	CO/CO2	UOP 603	1/D	2/D
	H2S	UOP 212	3/W	1/D
	O2 Molecular/ N2 Molecular	UOP 539 or ASTM D2504	1/D	2/D
01-SN-16	Neutralization Return			
	pH	ASTM D1293	As Req'd	As Req'd
01-SN-17	Steam from Disengaging Drum			
	Silica	ASTM D859	1/D	2/D
	Sodium	ASTM D4191	1/D	2/D
	pH	ASTM D1293	1/D	2/D
	Cation Conductance	ASTM D4519	1/D	2/D
	Specific Conductance	ASTM D1125	1/D	2/D
	Silica	ASTM D859	1/D	2/D
01-SN-18	Scrubbed Regenerant Gas			
	Composition	UOP 539	1/D	1/D
	Trace Components	UOP 899	1/D	1/D
	H2S	Draeger	1/D	1/D
01-SN-19	Fresh Solvent (applicable to units with contact cooler or solvent injection system)			
	Distillation	ASTM D2887	As Req.	As Req.
	Viscosity	ASTM D445 or ASTM D7279	As Req.	As Req.
01-SN-20	Circulating Solvent (applicable only to units with reactor effluent or REC interstage contact cooler)			
	Distillation	ASTM D2887	Occas.	1/D
	Viscosity	ASTM D445 or ASTM D7279	Occas.	1/D

Sample Number	Stream and Test Name	Test Method Number	Frequency	
			Normal	Startup
01-SN-21	Spent Solvent (applicable to units with contact cooler or solvent injection system)			
	Distillation	ASTM D2887	Occas.	1/D
	Viscosity	ASTM D445 or ASTM D7279	Occas.	1/D

2. Oleflex (Propylene) Fractionation Section Analytics

Sample Number	Stream and Test Name	Test Method Number	Frequency	
			Normal	Startup
02-SN-01	Fresh Feed to Feed Guard Bed			
	Composition	UOP 373	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899 or ASTM D2712	1/D	2/D
	Total Sulfur	UOP 923 or ASTM D6667	3/W	1/D
	H ₂ S/COS	UOP 212	3/W	1/D
	Ammonia and Amines	UOP 936	Occas.	3/W
	Alcohols	UOP 960 or ASTM D7423	3/W	1/D
	Oxygenates	UOP 960 or ASTM D-7423	Occas.	3/W
	Chlorides, Fluorides	UOP 991 with LPG adapter or ASTM D7359 with LPG adapter	Occas.	3/W
	Metals	UOP 906	Occas.	3/W
	Copper Strip Corrosion	ASTM D1838	Occas	3/W
02-SN-02	Feed from Feed Guard Bed			
	Ammonia and Amines	UOP 936	Occas.	3/W
	Metals	UOP 906	Occas.	3/W
02-SN-03	Depropanizer Overhead Vapor			
	CO/CO ₂	UOP 603 or ASTM D2504	1/D	2/D
02-SN-04	Depropanizer Reflux			
	Composition	UOP 373	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	1/D	2/D

Sample Number	Stream and Test Name	Test Method Number	Frequency	
			Normal	Startup
02-SN-05	Depropanizer Bottoms			
	Composition	UOP 980	1/D	2/D
	Trace Components: propylene, propane	UOP 373	1/D	2/D
02-SN-06	Separation System Liquid to Deethanizer Stripper			
	Composition	UOP 539	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	1/D	2/D
	Total Sulfur	UOP 923 or ASTM D6667	3/W	1/D
	H2S	UOP 212	3/W	1/D
02-SN-07	Recycle from Polypropylene Plant to Deethanizer Stripper (if applicable)			
	Composition	UOP 539	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	1/D	2/D
	Total Sulfur	UOP 923 or ASTM D6667	3/W	1/D
	H2S	UOP 212	3/W	1/D
	Ammonia and Amines	UOP 936	Occas.	3/W
	Alcohols	UOP 960 or ASTM D7423	3/W	1/D
	Oxygenates	UOP 960	Occas.	3/W
	Chloride, Fluorides	UOP 991 with LPG adapter or ASTM D7359 with LPG adapter	Occas.	3/W
	Metals	UOP 906	Occas.	3/W
	Arsine/Phosphine (by PP Licensor)	TBA	Occas.	3/W
	Organic Aluminum (by PP Licensor)	TBA	Occas.	3/W
	Copper Strip Corrosion	ASTM D1838	Occas.	3/W
	O2 Molecular/ N2 Molecular	UOP 539	Occas.	3/W
02-SN-08	Deethanizer Stripper Bottoms			
	Composition	UOP 373	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	1/D	2/D
02-SN-09	Deethanizer Rectifier Reflux			
	Composition	UOP 539	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	1/D	2/D



02-SN-10	Deethanizer Rectifier Bottoms			
Sample Number	Stream and Test Name	Test Method Number	Frequency	
			Normal	Startup
	Composition	UOP 539	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	1/D	2/D
02-SN-11	Deethanizer Rectifier Receiver Vapor			
	Composition	UOP 539	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	1/D	2/D
	CO/CO ₂	UOP 603	1/D	2/D
	H ₂ S	UOP 212	3/W	1/D
02-SN-12	Propylene-Propane Splitter Bottoms to SHP Reactor			
	Composition	UOP 373	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	1/D	2/D
02-SN-13	Propylene-Propane Splitter Reflux (Propylene Product)			
	Composition	UOP 373 and ASTM D2163	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899 or ASTM D2712	1/D	2/D
	O ₂ Molecular/ N ₂ Molecular	UOP 539 or ASTM D2504	Occas.	3/W
	H ₂ S/COS	UOP 212 or ASTM D5303	Occas.	3/W
	Total Sulfur	UOP 923 or ASTM D6667	Occas.	3/W
	Oxygenates (including Methanol, Isopropanol)	UOP 960	Occas.	3/W
	Ammonia and Amines	UOP 936	Occas.	3/W
	Metals (including Arsine)	UOP 906	Occas.	3/W
	Phosphine (by PP Licensor)	UOP 906* (TBA)	Occas.	3/W
	Cyclopentadiene and Green Oils (by PP Licensor)	UOP 899	Occas.	3/W
	Total Halides	UOP 991 with LPG adapter or ASTM D7359 with LPG adapter	Occas.	3/W

02-SN-14	Propylene-Propane Splitter Diolefin Recycle			
	Composition	UOP 373	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	1/D	2/D
02-SN-15	Off-Spec Material to Deethanizer Stripper			
	Composition	UOP 539	As Req'd	As Req'd
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	As Req'd	As Req'd
	Total Sulfur	UOP 923 or ASTM D6667	As Req'd	As Req'd
	H ₂ S	UOP 212	As Req'd	As Req'd
	Ammonia and Amines	UOP 936	As Req'd	As Req'd
	Alcohols	UOP 960 or ASTM D7423	As Req'd	As Req'd
	Oxygenates	UOP 960	As Req'd	As Req'd
	Chloride, Fluorides	UOP 991 with LPG adapter or ASTM D7359 with LPG adapter	As Req'd	As Req'd
	Metals	UOP 906	As Req'd	As Req'd
	Copper Strip Corrosion	ASTM D1838	As Req'd	As Req'd
02-SN-16	SHP Reactor Effluent			
	Composition	UOP 539	1/D	2/D
	Trace Components: Dienes, Acetylenes, C5+	UOP 899	1/D	2/D
02-SN-17	SHP Reactor Vent to Relief Header			
	H ₂ S	Draeger	As Req'd	As Req'd
02-SN-18	Arsine and Phosphine Guard Bed Effluent			
	Trace Metals	UOP 906	Occas.	3/W
02-SN-19	Heat Pump Compressor Discharge			
	CO/CO ₂	UOP 603 or ASTM D2504	1/D	2/D

3. List of Fresh Feed to Feed Guard Bed

List of Contacts for Non-UOP Test Methods

3.1 ASTM Methods

American Society for Testing and Materials (ASTM)
100 Barr Harbor Drive
West Conshohocken, PA 19428-2959
Tel: 610-832-9585
Fax: 610-832-9555
e-mail: Service@astm.org
Website: <http://www.astm.org>

3.2 Standard Methods for the Examination of Water and Wastewater

Website: <http://www.standardmethods.org>

For additional reference on this publication contact any of the three technical societies listed below who jointly sponsor, publish, and distribute this book.

American Public Health Association
(APHA)
Publication Sales
P.O. Box 753
Waldorf, Maryland 20604-0753
Phone: 301-893-1894
Fax: 301-843-0159
Website <http://www.apha.org>

Water Environmental Federation
(WEF)
601 Wythe Street
Alexandria, VA 22314-1994
Phone: 703-684-2400
Fax: 703-684-2492
Website: <http://www.wef.org>

American Water Works Association
(AWWA)
6666 West Quincy Avenue
Denver, CO 80235
Phone: 303-794-7711
Fax: 303-794-7310
Website: <http://www.awwa.org>

D. Sample Analysis at UOP or Third Parties

In order to comply with U.S. regulatory laws outlined by the Environmental Protection Agency (EPA) and other regulations, UOP must assure that all chemical substances received at our facilities adhere to certain procedures.

Please contact your UOP Regional Service or UOP Sales representative for the latest shipping instructions. Failure to ship samples in accordance with our instructions may result in delay of analysis, refusal of the sample, or confiscation by government agency.

IX. Troubleshooting

For systematic troubleshooting of any process problem reliable and relevant data is essential. Such data is collected from a variety of sources like the unit DCS, electronic process information system, electronic laboratory information management, operator log sheets, maintenance records, material specifications, unit yield/mass balance calculations, proprietary UOP system like OpAware etc. Daily operating data is disseminated to observe any deviations from the normal process before they develop into full blown problems affecting plant availability, capacity utilization and product quality. Any unexplained deviations must be followed-up until the root cause is identified and the necessary corrective actions implemented to eliminate the deviation. It must be noted that there may be overlapping cause and effects between different process related problems.

This section is focused mainly on process related problems. Equipment specific problems such as those with pumps, compressors, filters, fired heaters etc. not included since this information is generally available from the equipment vendors.

A. Table of potential problems and possible solutions

1. Process Symptom: Propylene production has decreased

	Potential Causes	Corrective Actions
A	True reactor inlet temperatures have decreased.	<p>Check operating RIT against set point.</p> <p>Check temperature instrument.</p> <p>Check if insulation has been removed downstream of the RIT control thermocouples. Measure pipe skin temperature to assess true inlet temperature and adjust the RIT</p>
B	The reactor section operating pressure has increased.	<p>Check the operating pressure on the REC suction drum pressure or reactor4 outlet pressure as applicable against set point.</p> <p>Check if the REC speed has attained the maximum operating speed and being impeded by the speed controller.</p>

		<p>Check if Del P has increased across HCFE tube side, reactor effluent cooler or reactor effluent contact cooler as applicable due to process fouling.</p> <p>Check if reactor 4 outlet screen Del P has increased due to carbonaceous fouling.</p>
C	Catalyst performance affected	<p>Make certain that the catalyst is being properly regenerated in the Regeneration Tower:</p> <ol style="list-style-type: none"> 1) Check the coke on regenerated catalyst to make certain that all of the coke is being burned off in the regeneration zone. 2) Check the color of the regenerated catalyst is creamy white. Gray color indicates problems with platinum distribution. 3) Check the chloride level on the regenerated catalyst. A high chloride level on catalyst will favor cracking rather than dehydrogenation. 4) Check core coke pill count has not increased. 5) Check performance of catalyst reduction zone
D	The feed rate has decreased.	<p>Check potential causes for feed decrease:</p> <ol style="list-style-type: none"> 1) Feed control valve malfunction

		<p>2) Incorrect set point on flow controller</p> <p>3) Drift in flow measuring instrument</p> <p>4) Problems in fresh feed supply</p>
E	Increase in reactor Del P.	Check if there has been abnormal increase in the reactor/screen Del P's across any one of the reactors as covered earlier in Section VII B1
F	Leak in the Hot Combined Feed Exchanger (HCFE).	<p>HCFE leak causes a portion of the combined feed to leak into the reactor effluent stream bypassing the reactors. Unless the leak is substantial, it is often difficult to detect.</p> <p>Symptom: A gradual "apparent" decrease in conversion and coincident gradual decrease in reactor del P for <u>all</u> reactors.</p> <p>Check: Under positive pressure, compare HCFE tube side inlet analysis with REC interstage sample debiting flash gas recycle. Special sampling facility with sample cooler may be required for sampling at HCFE. If the REC interstage sample is relatively richer in olefins, this will confirm the leak.</p>
G	Leak in the cold separation system	<p>If there is a leak in the cold combined feed exchanger (CCFE), a portion of the reactor effluent will leak into the combined feed stream to the reactors. Unless the leak is substantial, it is difficult to detect.</p> <p>Symptoms: One more of the listed symptoms can be co-incidental</p>

		<ol style="list-style-type: none"> 1) Increase in spent catalyst coke levels despite stable feed and recycle gas quality 2) Increase in amount of core coke pills for no assignable cause 3) Increase in screen fouling rates for no assignable cause 4) Deterioration in approach temperatures on CCFE over time <p>Check:</p> <ol style="list-style-type: none"> 1) Sample combined feed upstream of HCFE and compare with calculated composition of combined feed. If the sample is richer in MAPD and propylene than that calculated from feed and recycle gas, and if repeatability is established, it will confirm leak
H	Excessive catalyst attenuation by sulfur	<p>Increase in sulfur injection can attenuate the catalyst causing decrease in olefins production.</p> <p>Check the trend for H₂S in reactor effluent and adjust DMDS injection as necessary</p>
I	Poor olefins retention across SHP	<p>Check SHP inlet and outlet composition. If propylene content is decreasing across SHP, check and adjust reactor inlet temperature and hydrogen injection rate as required ensuring di-olefins continue to get saturated.</p>
J	Excessive propylene in recycle propane	<p>Increase in propylene content in recycle propane will cause propylene content to increase in Oleflex feed as well</p>

		<p>affecting yield per pass and net production.</p> <p>Check PP splitter operations. Consider increasing reboiler-condenser duty to strip off propylene more effectively</p>
K	Increase in propylene/propane in de-ethanizer off gas	Check de-ethanizer stripper/rectifier operations if propylene/propane is being lost through off gas. Increase the rectifier reflux and decrease the rectifier condenser outlet temperature as necessary
L	Physical propylene losses	Check unit mass balance for fractionation section. Deteriorating mass balance close out may signify physical loss. Check potential leakage points around the PP splitter system. Check flare gas sample for propylene.

2. Process Symptom: Reactor 1 ΔT has decreased over time; ΔT on downstream reactors have increased

	Potential Causes	Corrective Actions
A.	A decrease in reactor 1 inlet temperature (RIT)	<p>Confirm that the downstream reactor(s) Del T has increased co-incident with the decrease in reactor1 Del T. Total Del T on reactors may remain unchanged initially (downstream reactors compensating fully for the lost endotherm in reactor1) but may gradually reduce subsequently when the reactor 1 Del T decreases beyond a point (downstream reactors compensating partially for the lost endotherm in reactor1).</p> <ol style="list-style-type: none"> 1) If reactor 1 RIT process value is being controlled at set point, confirm the thermocouple indication has not drifted. 2) If reactor 1 RIT process value is being controlled at set point and there is no thermocouple drift, check the insulation

		<p>downstream of the thermocouple. If insulation has been removed, measure inlet elbow pipe skin temperature to confirm actual reactor inlet and adjust the RIT.</p> <ol style="list-style-type: none"> 3) If reactor 1 RIT process value is below the set point, check the fuel gas control valve function - %controller output against field %opening. Fix if it is instrument issue. 4) Check if the combined feed temperature to charge heater has trended down due to potential fouling in HCFE to a point overwhelming the fuel gas control valve. 5) Check if the charge heater burners are plugged or the fuel gas line is plugged increasing the fuel gas control valve back pressure to a point overwhelming the fuel gas control valve.
B	Propylene in the combined feed.	<p>Propylene will suppress the reaction in reactor1 lowering the reactor Del T.</p> <ol style="list-style-type: none"> 1) Check if the source of propylene in Oleflex feed is recycle propane or fresh feed and plan appropriate action. 2) If propylene in Oleflex feed is due to increase in propylene content in the recycle propane, increase the reboiler-condenser duty on PP splitter to strip off propylene. 3) If propylene in Oleflex feed is due to increase in propylene content in the fresh feed, co-ordinate with feed supplier to address the issue.
C	Flow mal-distribution in reactor.	<p>Excessive screen fouling can lead to potential flow mal-distribution issues affecting reactor performance on any of the 4 reactors. However,</p>

		<p>since greater proportion of non-selective cracking occurs in the charge heater, reactor 1 inner screen is relatively more prone to fouling. Though this is not anticipated on the units with LCP, it can potentially happen on the units with conventional screens operating with significantly fouled screens.</p> <ol style="list-style-type: none"> 1) Check and compare the reactor 1 inner screen Del P, reactor bulk Del P and reactor 1 Del T trends. If there is verifiable correlation, plan to replace the screen(s) on reactor 1 during the next opportunity. 2) Monitor the unit fines generation and catalyst transfer pipe temperatures from reactor 1 closely before the deviation develops into localized void blowing problem 3) Try to decrease reactor 1 RIT (which also limits non-selective cracking in charge heater with mal-functioning reactor 1 not adding to incremental conversion) and increase RIT on downstream reactors to recover Total Del T
D	Non-uniform catalyst flow through the reactor annulus or catalyst bridging in the annulus	<p>This can be an offshoot of cause C, or problem developed as a result of [a] catalyst fines circulation through the regenerated catalyst due to improper dust collector operation or [b] catalyst attrition during transport or [c] improper sulfiding generating iron sulfide scale that may have blown into the reactor [d] sulfide scale from the HCFE blown into the reactor</p> <ol style="list-style-type: none"> 1) Check the catalyst transfer pipe temperature trend to confirm catalyst flow issues. List any pipes where the catalyst is not flowing or catalyst flow is suspected relatively less compared with other pipes.

		<p>2) Check if fines are being circulated to reactor1 as result of poor dust collector operation:</p> <p>Review PSD (particle size distribution) on gross fines and adjust dust collector operations. There should be 20% to 40% whole pills in gross fines.</p> <p>3) Check fines being circulated to reactor1 as a result of fines generation in catalyst transfer system to reactor1:</p> <p>Review the PSD on disengaging hopper product, lift engager 5 and lift engager 1 over few days to determine if fines are being circulated to reactor1.</p> <p>Check the on/off automatic valves and manual valves in the catalyst transport system from regenerator to the surge hopper to assess the source of fines and plan corrective action if necessary.</p> <p>Assess lift gas velocity and flux to fix any fines generation mechanism.</p> <p>Assess if the reduction zone purge gas rate has been increased high enough to cause fluidization.</p> <p>4) Check if iron sulfide scale is being generated or circulated to reactor1:</p> <p>Perform magnet test on the gross fines and lift engager1 samples for iron sulfide scale. If there exists appreciable magnetic particulate, it may suggest presence of iron sulfide scale.</p> <p>Check sulfiding program whether the iron sulfide scale was due to improper sulfiding.</p> <p>5) Check fines being generated internal to reactor1 due to localized void blowing:</p>
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		<p>Review the PSD on disengaging hopper product, lift engager 5 and lift engager 1 over few days to determine if fines are being generated within reactor1. If true, it may indicate potential localized void blowing.</p> <p>Check if the downstream reactor inner screen is being plugged with catalyst dust as seen by the screen del P trend and/or physical sampling confirming increased physical dust carryover.</p> <p>6) Try to improve catalyst flow by adjusting the differential pressure between the catalyst collector 1 and lift engager1</p> <p>7) Check and adjust regenerator operations as core coked pills/high coke pills may start to emerge from reactor1</p> <p>8) If localized void blowing is suspected, try reducing feed rate before inching back gradually.</p>
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3. Process Symptom: All the Oleflex reactor ΔT s have decreased at stable RIT, H₂/HC ratio and operating pressure

	Potential Causes	Corrective Actions
A.	Catalyst poisons entering through the feed	<p>As a first step, reconfirm that the RITs, H₂/HC and reactor system pressure are stable. Lower RITs, increased H₂/HC and increased reactor section pressure affect the performance of all the reactors.</p> <p>Next check for catalyst poisons. Heavy metals like lead, arsenic, mercury; chloride or fluoride bearing compounds and oxygenates constitute potential poisons entering via feed. In addition, excessive levels of CO non-native to Oleflex</p>

		<p>entering recycle gas will attenuate Oleflex catalyst.</p> <ol style="list-style-type: none"> 1) Check, analyze and confirm if the listed feed contaminants are entering the system; identify the source to rectify the issue. 2) Check if feed guard bed resin is letting out feed contaminated with lead 3) Check if arsine/phosphine guard beds are poisoned with sulfur causing contaminant breakthrough 4) Check if mercury is entering via feed in units with no mercury trap in feed drier or if the mercury guard bed is breaking through 5) Check on units with reactor effluent contact cooler if air leak into the system is cause of excessive CO in recycle gas 6) Check is PSA H2 product is breaking through in CO
B	Sulfur attenuation	<p>Excessive sulfur levels in the reactor system can attenuate the catalyst. Though this can affect all the reactors, the effect can be reversed by readjusting the sulfur levels.</p> <ol style="list-style-type: none"> 1) Check if sulfur species like H₂S, mercaptans or thiophenes are entering via fresh feed in excessive levels contributing to increase in H₂S levels in the reactor effluent beyond prescribed limits. Plan appropriate action to improve feedstock quality. DMDS injection should not be adjusted to address this issue since DMDS is the only compound that matches the required decomposition profile in Oleflex system.

		<p>2) Check the DMDS injection rate via the calibrated sight glass and confirm the injection rate is as required.</p> <p>3) Excessive H₂S in reactor effluent, despite checks from 1) and 2) being negative, on rare occasions can be caused by either DMDS injection pumps not being turned off when the unit was shut down or excessive iron sulfide scale residing within the reactor system getting reduced to iron.</p> <p>Check the DMDS injection trends during previous shut down and evidence for iron sulfide scale via magnet test on fines.</p>
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4. Process Symptom: Oleflex reactor Δ Ts cycling with catalyst circulation at stable RIT, H₂/HC ratio and operating pressure

	Potential Causes	Corrective Actions
A.	Section of the circulating catalyst fraction activity has been pre-maturely impacted due to tramp metal interaction with metal function on the catalyst and/or core coke.	<p>Symptoms:</p> <ol style="list-style-type: none"> 1) Reactor 1 Del T dips over a period and gradually recovers back. Followed by similar observation on reactors 2, 3 and 4. 2) Spent catalyst coke may increase when the catalyst fraction exits reactor 4 and inch back to normal level when reactor 4 Del T has recovered. 3) Lift engager coke levels may increase when the catalyst fraction exits the respective reactor and inch back to normal level when respective reactor Del T has recovered.

		<ol style="list-style-type: none"> 4) Regenerator burn zone profile shifts down when the catalyst fraction enters the regenerator 5) Regenerator experiences exotherm in the transition zone and/or chlorination zone when the catalyst fraction passes through 6) Regenerator does not permit white burn mode of operation when the catalyst fraction is passing through 7) Appearance of catalyst for the subject fraction may be distinctly different as compared to rest of the catalyst batch 8) Subject catalyst fraction may indicate greater fraction of core coked pills and/or pills with gray rings or gray centers <p>Corrective actions:</p> <ol style="list-style-type: none"> 1) Track the catalyst fraction via flow control hopper counts (FCH CNT). Fix "Head" of the affected catalyst fraction (corresponds to FCH CNT when the reactor 1 Del T starts trending down. Fix "Tail" of the affected catalyst fraction (corresponds to FCH CNT when the reactor 1 Del T starts trending up. 2) If coke make is affected, decrease the respective RIT when the "Head" enters the reactor and increase the respective RIT when the "Tail" exits the reactor. 3) Adjust the regenerator conditions to burn off the core coke under controlled conditions in the lower burn zone. 4) Sample the affected catalyst fraction and the remainder of the unaffected catalyst fraction and ship to UOP to detect root cause of catalyst activity loss and check if it is reversible.
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B.	Inefficient catalyst reduction	<p>1) Check reduction zone temperature</p> <p>2) Check reduction zone hydrogen purge gas flow</p> <p>3) Check PSA feed contaminants</p> <p>4) Check H₂O in CCR instrument air < 5 mol ppm</p>
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5. Process Symptom: Carbon Monoxide breakthrough into the PSA hydrogen product

	Potential Causes	Corrective Actions
A.	PSA adsorption step is too long	<p>If the amount of PSA feed contaminants is within the prescribed component limits for the PSA unit, optimize the adsorption cycle time by progressively decreasing it until the product is on specification.</p> <p>Refer to Section XI-Emergency Procedures, 2.6-Loss of PSA Unit for additional actions in the event of CO breakthrough into PSA hydrogen product.</p>
B.	Oxygenates in the fresh feed, including methanol, CO and CO ₂ .	<p>Oxygenates in the feed will convert to CO via steam reforming type reaction across the Oleflex reactors increasing CO level in the net gas to the PSA unit.</p> <p>Check that the oxygenate level in fresh feed has not increased.</p> <p>One source of excessive methanol presence is the methanol injected into LPG lines to derime the shipping lines of hydrates.</p> <p>CO and/or CO₂ in fresh feed may be due to upsets in the upstream gas processing unit.</p> <p>Refer to Section XI-Emergency Procedures, 2.6-Loss of PSA Unit for additional actions in</p>

		the event of CO breakthrough into PSA hydrogen product.
C.	PSA feed contaminants from other feed sources not native to Oleflex.	<p>If the feed to the PSA unit comes from sources other than the net gas from Oleflex unit, confirm the contaminant levels from these sources remain within the limit. CO will be the first component to break through if the PSA cannot handle the contaminant load.</p> <p>Refer to Section XI-Emergency Procedures, 2.6-Loss of PSA Unit for additional actions in the event of CO breakthrough into PSA hydrogen product.</p>
D.	Check the drying air to the CCR.	<p>If the CCR instrument air driers are not performing properly, this will increase the moisture on the regenerated catalyst returned to the reactor section. Water retained on the catalyst will convert to CO in reactors exiting via the net gas overloading the PSA unit. Check and fix the problem on the CCR air drier system.</p> <p>Refer to Section XI-Emergency Procedures, 2.6-Loss of PSA Unit for additional actions in the event of CO breakthrough into PSA hydrogen product.</p>
E.	Air leak into the system (applicable for C3 Oleflex units designed with reactor effluent contact cooler that operate under slight vacuum at the REC suction)	<p>Depending on the location of the leak, molecular oxygen (O₂) ingress may cause CO and H₂O to form or net gas may additionally contain O₂ and N₂ contaminants. It is also possible that CO, O₂ and N₂ may together constitute additional contaminants, not native to the Oleflex, being present in the net gas feed to the PSA unit. The adsorbents in the PSA unit may not be able to handle these excess contaminants leading to CO breakthrough.</p> <p>Refer to Section XI-Emergency Procedures, 2.6-Loss of PSA Unit for additional actions in the event of CO breakthrough into PSA hydrogen product.</p>

		Refer to Section VI-7 Step 44) B and C - Commissioning
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6. Process Symptom: Reactor No.1 ΔP is gradually increasing

	Potential Causes	Corrective Actions
A.	Check ΔP transmitter.	<ol style="list-style-type: none"> 1) Confirm that the transmitter has not drifted 2) Check transmitter line-up 3) Check leak at low pressure impulse line joint at transmitter and root valve
B.	Flame impingement in charge heater	<p>Flame impingement on tubes can cause excessive soot coke plugging the reactor screen</p> <ol style="list-style-type: none"> 1) Check flame impingement on tubes and fix the problem if present 2) Check heater skin temperatures are <705 Deg C
C.	Improper sulfur injection	<p>Excessive sulfur injection can cause iron sulfide scale which can get blown into the reactor</p> <ol style="list-style-type: none"> 1) Check sulfur injection rate
D.	Feed impurities.	<p>It is possible that some impurities in the feed may have formed soot coke in the Charge Heater and have fouled reactor No.1 inner screen.</p> <ol style="list-style-type: none"> 1) Check the levels of MAPD, nC4's and C4 olefins in Oleflex feed 2) Check impurities in the recycle hydrogen stream 3) Check benzene drag from depropanizer is being operated correctly (applicable to

		C3 Oleflex units with reactor effluent contact cooler)
E.	Circulating fines	<p>If all of the fines are not being removed from the spent catalyst in the Disengaging Hopper, these fines will end up returning to the reactor section and possibly causing fouling of the reactor screens.</p> <p>1) Check gross fines have 20-30% whole pills</p>
F.	Void blowing	Check for void blowing symptoms as discussed in Section VII B1
G.	Leak in cold combined feed exchanger	<p>Leak in cold combined feed exchanger will likely impact reactor 1 first.</p> <p>1) Check as discussed in earlier sections</p>

7. Process Symptom: H₂S breakthrough from RED

	Potential Causes	Corrective Actions
A.	Excess H ₂ S level	<p>RED is designed for certain load of H₂S. If excessive H₂S is sent with reactor effluent, early breakthrough can occur</p> <p>1) Check H₂S level and correct the DMDS injection rate if necessary</p> <p>2) Measure the H₂S in the reactor effluent by both an on-line analyzer and a Draeger tube reading.</p>
B.	Excess H ₂ O ingress	<p>If RED is loaded with excess H₂O, the breakthrough of H₂S will occur first ;</p> <p>1) Check H₂O level in reactor effluent is not excessive</p> <p>2) For C3 Oleflex units with reactor effluent contact cooler, excess air ingress can cause increase in H₂O load. Check for</p>

		<p>air leaks as outlined in Commissioning Section VI- 7 Step 45) B and C</p> <p>3) Check for leak in surge hopper cooling coil</p> <p>4) Check for steam leak in RED regenerant heater. In this case, H₂O may breakthrough first followed by H₂S. Cold separation section may additionally ice-up</p>
C.	Channeling in the RED.	<p>If there is channeling in the adsorbent bed, decreased H₂S capacity will result. In general, the ΔP across each of the RED's should be nearly the same. RED bed fouling can be caused by heavies, adsorbent damage, RED support grid leak leading to high pressure drop and potential bed channeling.</p> <p>1) Confirm if the ΔP of the affected RED is similar to the other RED's.</p> <p>2) If RED grid failed, the reactor effluent filter pressure drop would also increase</p>
D.	Contaminants in regenerant gas	<p>1) If the gas being used for regenerating the RED's contains H₂S, the bed will get pre-loaded</p> <p>2) If there is CO₂ in regenerant gas, the bed would get pre-loaded though to a lesser degree</p> <p>3) If there is H₂O in regenerant gas, the bed would get pre-loaded</p>
E.	HCl breakthrough of the Chloride Treater	<p>The adsorbent in the RED's will also adsorb HCl in the reactor effluent gas. However, the HCl will remain on the adsorbent and decrease the capacity of the adsorbent for H₂S. The HCl cannot be removed during regeneration.</p> <p>1) Check if chloride treater has been breaking through in HCl</p>

		2) Plan and replace chloride treater adsorbent if this has been the problem
F.	Improper regeneration	1) Check regenerant volumetric flow is adequate 2) Check regenerant inlet temperature is ~230-240 Deg C 3) Check regenerant effluent attains a plateau amounting to ~200-210 Deg C at RED outlet for at least 1 hour 4) Check heavies accumulation in the RED regenerant knockout drum has ceased 5) Check the heating step is concluded only after both the criteria under 3) and 4) have been fulfilled

8. Process Symptom: Cold Separation Section Warm-Up

	Potential Causes	Corrective Actions
A.	H2O icing	<p>H2O ingress can cause icing in cold section. Pressure drop through certain passes may increase over time or quickly affecting performance.</p> 1) Check if feed drier has been breaking through in H2O, fix if there is a problem 2) Check if there is H2O breakthrough from RED, fix if there is a problem 3) Try methanol injection under vendor guidance to derime 4) If not successful, depending on the situation, the unit may have to be shut down to derime the cold section

		<p>Allow all temperatures to warm to at least +10 Deg C when unit is shutdown</p> <p>Drain water from all the low points. Purge all passes with nitrogen with a dew point \leq minus 76 Deg C</p>
B.	Heavies' fouling	<p>If the cold section is getting fouled over time due to heavies' ingress the approach temperatures may deteriorate over time;</p> <ol style="list-style-type: none"> 5) Check RED regeneration and ensure optimal regeneration to remove all trapped heavies 6) During opportunity shutdown, Allow all temperatures to warm to at least +10 Deg C when unit is shutdown <p>Drain heavies from all the low points. Collect samples and analyze for the species.</p> <p>Purge all passes with nitrogen with a dew point \leq minus 76 Deg C</p>
C.	CO2 icing	<p>Excessive CO2 ingress via fresh feed may have caused icing in cold section. Pressure drop through certain passes may increase over time or quickly affecting performance.</p> <ol style="list-style-type: none"> 1) Check CO2 in fresh feed, fix if there is a problem 2) Check if CO2 has entered via Red regenerant when removed by RED during adsorption, fix if there is a problem 3) Depending on the situation, the unit may have to be shut down to derime the cold section <p>Allow all temperatures to warm to at least +10 Deg C when unit is shutdown</p> <ol style="list-style-type: none"> 3) Drain any minor amount of heavies from all the low points.

		<p>4) CO₂ will release and get purged once the system is de-pressured.</p> <p>5) Purge all passes with nitrogen with a dew point =< minus 76 Deg C if necessary</p>
D.	Feed distributor plugged	<p>Plugged feed distributor within the cold combined feed exchanger may cause improper feed distribution and affect performance</p> <p>1) Check fresh feed filters Del P trend. If the trend indicates an increase and then sudden decrease, the filter elements may have collapsed passing particulate plugging the feed distributor</p> <p>2) Check feed strainer on liquid feed to cold section</p>
E.	Leaks internal to the cold section	<p>Depending on the location of leak(s), the performance may deteriorate</p> <p>1) Check if there has been mercury ingress with the feed. Mercury will form amalgam with brazed aluminum metallurgy and will come off the solid solution if the metallurgy was exposed any time to ambient air leaving behind porous weakened metal which can develop leaks subsequently in operation</p> <p>2) Check if the cold section was subjected to thermal shocks during operation-for example high reactor effluent inlet temperature, temperature swings during RED depressure purge and/or hydrocarbon load steps. Thermal shocks can weaken the joints leading to failure during operation</p>

X. Normal Shutdown

The procedures given in this section are intended for normal shut down situations, when no emergency or special situations exist. The purpose of the shutdown procedures is to provide a safe and reliable way to take the process off stream. This section will address special process considerations, if any, specific to shut down conditions which may be required to assure optimum performance of the process during subsequent operations.

A. Unit Shutdown

The procedure for shutting down the Oleflex unit entails the following guidelines. These procedures are of a general nature and will be supplemented by the UOP Chief Advisor during the initial start-up sequence:

1. Prior to Shutdown

- a. Increase Catalyst Circulation Rate to 100%, if possible, for 1 – 2 Days prior to the shutdown to minimize the amount of coke on catalyst
- b. Ensure one Reactor Effluent Drier (RED) is completely regenerated, if possible, when the unit shuts down

2. Unit Shutdown

The procedure for shutting down the Oleflex unit entails the following guidelines:

1. Gradually reduce the reaction severities in a stepwise manner by lowering the reactor inlet temperatures (RITs) and the feed rate.
2. Start decreasing the RITs from the normal operating level at ~30 °C/Hr to prevent buildup of mechanical stresses. Decrease the RITs to a level of 260 °C at each reactor over a period of ~12-13 hours. During the same period, decrease the feed from the normal operating level (~design feed rate) to 60% design rate.
3. When the RITs and feed are being decreased, the firing load on the Oleflex heaters will also decrease. Start cutting out the burners in operation on each heater as required to maintain the fuel gas pressure at the burners. Switch from the fuel gas flow control to fuel gas pressure control.

It is critical to avoid burner fuel gas pressure dropping too low which can trip the heaters in which case trickle mode operation will be required during unit restart.

4. Allow the H₂/HC mole ratio to increase but retain it in the range 0.6-1.0 by adjusting the recycle gas rate as required to remain within the allowable process gas specific gravity range of the REC.
5. Adjust the sulfur injection based on liquid feed rate and the RITs throughout the RIT and feed reduction as prescribed in this procedure to minimize potential for iron sulfide scaling.

At this stage while the RITs are >550°C, retain the same level of sulfur injection wt. ppm of liquid feed injection rate (anticipated at ~75-85 wt. ppm) when the RITs are being decreased from the normal operating level toward 550°C.

6. While the RITs and feed are being decreased, net gas production will decrease. At some point, when the RITs are in the range of 550-600°C, net gas feed to the PSA unit will be insufficient forcing PSA unit to shut down. When PSA hydrogen is no longer available, stop the catalyst circulation immediately.

Swing from PSA H₂ to CCR gas for the reduction zone, surge pots and reactor plug purges. Reduce reduction zone and surge pot purge gas temperature from normal operating temperature to 350 °C at 55 °C/Hr.

Shut down the SHP reactor by [a] stopping hydrogen injection and SHP hydrogen compressor [b] cutting off the heat to the SHP feed [c] bypassing the SHP reactor

7. Decrease the RITs to 550°C and continue to decrease toward 500°C. Adjust the sulfur injection to 60-70 wt ppm based on liquid feed when the RITs are being decreased from 550°C - 500°C.

While transitioning to this stage and further toward 475°C RITs, the net gas production will decrease to a negligible amount. To maintain the gas specific gravity for stable REC operation and to retain the net gas pressure in the cold separation system, bring in external start-up hydrogen adding it at the REC suction drum or reactor effluent contact cooler as required.

8. Decrease the RITs to 500°C and continue to decrease toward 475°C. Adjust sulfur injection to 50-60 wt ppm based on liquid feed when the RITs are being decreased from 500°C - 475°C.

Decrease the RITs to 475°C and continue to decrease toward 400°C. Adjust sulfur injection to ~50 wt ppm based on liquid feed when the RITs are being decreased from 475°C - 400°C.

For C3 Oleflex Units with Reactor Effluent Contact Cooler that operate at slightly lower pressure at the outlet of reactor 4: On these units, at this stage when all RIT<475°C, gradually increase the reactor 4 outlet pressure

from 136.3 KPa A (~15.2 psia) to an appropriate level such that the pressure at the 1st stage suction flange of the REC as determined by the surge control instrumentation is above the local barometric pressure typically in the range of 1 – 2 KPa G. The pressure increase shall be in gradual and controlled manner without impacting the REC operation. This is because during cool down the equipment and piping tend to shrink and any weak joint has greater risk of failing increasing the potential for air leak.

9. Decrease the RITs further to 400°C and continue to decrease toward 260°C. Cut off the sulfur injection when all the RITs have decreased <400°C. Stop DMDS injection pumps.
10. Adjust the downstream column/unit operations and conditions as throughput is decreased. When the feed rate is decreased, Oleflex liquid product rate and the concentration of the reaction products contained within it will decrease as well. Adjust the depropanizer, de-ethanizer and PP splitter operations as required.
11. Decrease the RITs to 260 °C and feed to 60% design. At this stage crack open the reactor effluent bypass for the cold separation system.
12. Continue to gradually decrease the feed while increasing the flow through the reactor effluent bypassing the cold separation system. Slowly close the combined feed outlet PCV bypass valve permitting PCV to gradually open on pressure control. As liquid propane feed is decreased, back pressure on PCV will decrease forcing the PCV to pinch on automatic control to regulate the pressure. Continue to add make-up hydrogen and/or propane as required to the system. This will be necessary to permit maintaining sufficient gas circulation rate through the REC to ensure there exists required back pressure at the combined feed exit as prescribed by the vendor when the liquid feed is still being added to the cold separation system.
13. Continue to decrease the Oleflex liquid propane feed while continuing to maintain the required back pressure by adjusting the reactor effluent bypass valve. At this point proceed to gradually open the turbo expander bypass valves in small incremental steps toward 50 – 65 % opening or as required to maintain the pressure at the HP turbo expander upstream and recycle gas flow through the LP turbo expander system. The amount of cooling across the expanders will start to decrease and cold section will begin to warm up. The warm-up rate shall be within the rates prescribed by the vendor. Increase the expander bypass valve opening in the range of 50 – 65 % or as required to maintain the flow and pressure.
14. Continue to decrease the liquid feed toward extinction to approximately match the time the turbo expanders are going to be shut down. Shut down both the high

pressure turbo expander and low pressure turbo expander as per the vendor procedures. Normally when the work extracted from the expanders decreases to the minimum permissible, the machines need to be shut down. Cut off liquid propane feed completely at this stage. This action should close the PCV on combined feed outlet.

This will allow sufficient time to have elapsed since the reactions stopped, thus allowing the olefin rich material to pass out of the Oleflex reactor system before the cold section begins to warm up.

Cut off remainder of the main burners if any if they were still switched on to maintain RITs at 260°C. Close burner air registers to retain heat in the firebox.

15. The liquid product rate to fractionation and consequent feed to the downstream fractionators will decrease in tandem with the Oleflex liquid propane feed. Proceed to operate these columns on total reflux once liquid propane feed to Oleflex has been cut off.
16. Continue gas circulation to sweep out the hydrocarbons from the catalyst beds and to decrease the RITs to <100°C. Continue as long as the molecular weight of the circulating gas will allow normal operation of the compressor, even though this will likely not be very long.

Shut down the REC when necessary after confirming the REC suction pressure is positive.

17. Once REC has been shut down, following further actions shall be taken as applicable to the specific unit [a] Air fans on the solvent circulation cooler and REC discharge cooler can be switched off. [b] If REC stage coolers and/or circulating solvent coolers are cooling water based, the cooling water circulation can be blocked off at the specific exchangers – if necessary for maintenance on the exchangers. [c] If the reactor effluent and REC interstage coolers are contact coolers, solvent circulation pump(s) can be shut down if necessary.

If it is necessary to inspect contact cooler equipment, first pump out the solvent to spent solvent storage for once through contact cooler systems before shutting down the circulation pump. If the unit has contact cooler system with solvent recovery column, follow additional steps as required; [I] cut off the steam to the solvent recovery column reboiler allowing solvent to drain down [II] stop reflux pump of the solvent recovery column once the level has been reduced from the draw off well [III] pump out the solvent to spent solvent storage via solvent recovery column utilizing the solvent circulation pump and solvent recovery column bottoms pump [IV] confirm depropanizer bottoms stripper pump has been shut down [V] drain remainder excess solvent from the equipment to the refinery chemical drain safely [VI] perform nitrogen piston purge on the equipment later

in the procedure applied for the entire reactor section [VII] isolate the contact cooler and solvent recovery column systems by installing blinds on reactor effluent inlet and outlet, other process inlet streams to reactor effluent contact cooler, solvent inlet from the depropanizer bottoms stripper to the solvent recovery column and spent solvent outlet from the solvent recovery column [VIII] fill the contact cooler with boiler feed water with temperature $<100^{\circ}\text{C}$ up to $\sim 80\%$ level with a temporary rated metallic hose that can withstand boiler feed water pressure. Make sure a high point vent is open while filling with boiler feed water to prevent accidental over pressure on a closed system. Add wetting agent or detergent as necessary to the contact cooler. [IX] Start the solvent circulation pump to circulate water to the contact cooler for ~ 2 hours. Send a slip stream to the solvent recovery column to wash down the stripping and rectifying section (middle and bottom packed section). Wash down the direct contact condenser section (top packed bed) by introducing boiler feed water safely via solvent recovery column overhead pump suction using temporary rated metallic hose and circulating via top section of the packing. Drain water to refinery chemical drain from the contact cooler and solvent recovery column. Repeat the process 2-3 times as necessary until the drained water is free of solvent. The drain water shall be clear, not milky and dissolved oil/hydrocarbon <10 wt. ppm. Drain all the free water. Repeat the process for solvent recovery column. [x] Piston purge the equipment with nitrogen until moisture free. Use hot nitrogen with temperature $\sim 100^{\circ}\text{C}$ to dry the system. Vent to high point or wet relief system. [XI] Normalize the system by de-blinding [XII] Nitrogen free the system by evacuation and break vacuum with dry instrument air along with the rest of the Oleflex reactor system [XIII] Check the system for safe man-entry for equipment inspection.

18. Send any excess liquid that collected in the various separator vessels in the cold separation system to the flash drum and on to the downstream unit.
19. If equipment is to be accessed, prepare the system as follows. Depressure hydrogen and hydrocarbon to the flare utilizing the dump valve located on the REC suction drum or on the reactor effluent contact cooler as applicable. Hydrocarbon free the system by piston purge with nitrogen by pressuring to ~ 300 KPa G and de-pressuring to ~ 50 KPaG over 3-4 cycles until the hydrogen and hydrocarbon level has dropped corresponding to $<5\%$ lower explosive limit (LEL). Evacuate the system by pulling vacuum keeping the equipment/instruments not designed for vacuum isolated. Break the vacuum with dry instrument air. Repeat the cycle once more to ensure the oxygen level in the system is safe for man entry.

IMPORTANT: Maintain the pilots lit if the unit will be restarted soon. Else the pilots can be shut down. Purge the fire box to remove the combustibles by injecting low pressure purge steam downstream of the stack dampers through the dedicated connection or any other

arrangement as provided by the heater vendor. Close all the air registers. Shut off the fuel gas valves at burners and on the main fuel gas lines.

Sustaining Catalyst Circulation with External Source of PSA H2:

Unless external source of PSA H2 of required purity at required rate is available, catalyst circulation will have to be stopped when the PSA unit shuts down. Otherwise catalyst circulation can continue as follows: check there are provisions to supply external H2 feed to the PSA unit and provision for tail gas recycle to net gas compression with only a small bleed of tail gas. This will enable routing back the net gas from cold section to the PSA unit reducing the amount of external H2 intake. Reduce the surge pot 2, 3 and 4 heater temperatures running with external PSA H2 in tandem with RITs ensuring less than 100°C difference between the surge pot heater outlet and the respective RIT to minimize thermal cycling at the top of the reactor where the catalyst enters the reactor. Reduction Zone will need to continue to be operated at normal temperature of 540 °C while catalyst circulation continues until all the RITs have been dropped to ~440°C - 450°C. At RITs ~440°C - 450°C stop the catalyst circulation to prevent thermal cycling and reduce the reduction zone temperature to match reactor 1 RIT which should be at ~440°C - 450°C which will take ~3 hours at 30 °C/Hr. From this point, with the catalyst circulation stopped, continue decreasing the RITs at 30 °C/Hr toward 260°C. Once the catalyst circulation has been stopped, stop running the PSA unit with external hydrogen. The advantage of being able to circulate the catalyst until RITs ~440°C - 450°C with external PSA H2 as against 550-600°C when the PSA unit shuts down due to lack of native net gas is marginal reduction in hoop stress in addition to the ability to process any high coked (>5 wt. %) catalyst if any from the reactor system. Attempting to circulate the catalyst all the way until ~350°C (below which trickle mode will not be required even if the heater and/or REC tripped) will result in thermal cycling at top of reactor1 for ~3-4 hours since the reduction zone will need to continue to operate. It is conservative approach to avoid such cycling since the consequences are difficult to predict.

If reactor entry is required, neutralization of the austenitic SS should be done. See Section XIII, Special Procedures.

B. Unit Shutdown for Fractionation Section Maintenance

The following general procedure is written to cover a normal planned shutdown as required for periodic inspection of equipment in the feed/fractionation section of the unit. This shutdown must be coordinated with the shutdown of the entire Oleflex complex. The following procedure assumes that the reactor section has already been shut down and the fractionation columns have been placed on total reflux.

Fresh Feed Guard Beds, Feed Driers and Metal Guard Beds

If required, these liquid filled vessels can be isolated and de-pressured to the flare header slowly via the PSV bypass or via any low point liquid drains to the relief system provided ensuring the vessel shells do not get iced up and temperatures dropped to less than the minimum design metal temperature.

Shutdown the Depropanizer system

Slowly reduce the depropanizer reboiler duty and finally stop the reboil by cutting off the reboiler condensate flow and steam; and bypassing the heat recovery reboiler if applicable. Pump out all the material from the receiver vessel to the column to minimize the receiver inventory and then stop the reflux pumps. Allow the column liquids to drain down. Use the pump out line from depropanizer bottoms to the recycle propane pumps to pump out the material to off spec storage. The recycle propane pumps will be available for pump out once the PP splitter system has been shut down.

Shutdown the Deethanizer System

Slowly reduce the deethanizer stripper reboiler heat duty by progressively reducing the condensate flow to a minimum just enough to sustain system pressure if necessary. Further, use the hot vapor bypass and rectifier condenser bypass to try and maintain the deethanizer system pressure. Pump out the material from the deethanizer rectifier receiver to the rectifier column and then stop the rectifier reflux pumps. Allow the rectifier column liquids to drain down. Then, pump out the material from the rectifier column to the deethanizer stripper. Allow the deethanizer stripper column liquids to drain down. Send the material from deethanizer stripper bottoms liquids to PP splitter when it is still in operation at relatively lower pressure. Then terminate the heat input to the stripper reboiler. Shutdown the refrigeration package per the vendor recommendations.

Shutdown the P-P Splitter System

Gradually decrease the reboiler-condenser load by decreasing the Heat Pump Compressor (HPC) load. Stop the Heat Pump Compressor. All the PP splitter column to drain down the liquids. Pump out the material from PP splitter bottoms, HPC suction drum(s) to off spec storage using the recycle propane pump.

Isolate and de-pressure the various sections to flare

Once the liquid inventory in various fractionation section vessels and equipment has been reduced to a minimum, all the heat input has been stopped and heat source isolated, all rotating equipment like pumps and compressors have been shut down safely with power input isolated, the entire system can be safely de-pressured.

Isolate the depropanizer system, deethanizer system, P-P Splitter system, and feed treatment section individually using rated slip blinds (where end blinds are impractical such as on pipe flanges or where spools or valves that can be dropped are not available) or end blinds (if a spool section or control valve or block valve has been dropped) for positive isolation. Closing block valves alone shall not be treated as positive process isolation. Drain all condensate and cooling water from exchangers to avoid freezing during de-pressure. Slow de-pressure the various sections to the relief header via the safety valve bypass. During de-pressuring monitor vessel and lines for icing. Halt de-pressuring temporarily if icing occurred. Always maintain the vessel and lines above the Minimum Design Metal Temperature (MDMT).

Hydrocarbon free by nitrogen purge followed by dry instrument air purge to prepare the system for man-entry.

After the entire fractionation system has been safely de-pressured and all liquid hold-up removed, piston purge each system with nitrogen by pressuring to ~600 KPa G and de-pressuring to flare until ~50 KPa G over 3-4 cycles to remove the remnant hydrocarbons. Pressure and de-pressure sections with nitrogen to remove hydrocarbon. Check lower explosive limit (LEL) < 5 % in each system at different points. After all the piping/equipment/vessels are confirmed hydrocarbon free and isolated from the rest of the section, introduce dry instrument air. Repeat the piston purge but this time with dry instrument air on the system/vessel requiring man-entry by pressuring to ~600 KPa G and de-pressuring to atmosphere at safe and elevated location until ~50 KPa G over 3-4 cycles to remove the nitrogen. Confirm the oxygen level is 20-21 mol% before man-entry. Prepare vessels and equipment for inspection.

It is the responsibility of the operator to follow all the necessary regulatory and refinery guidelines for preparing the system for man-entry.

XI. Emergency Procedures

The purpose of the procedures in this section is to describe a safe manner to shut the process down during emergency situations while minimizing damage to the process. The procedures given in this section are general instructions which cannot be specific because of the variations in the design and construction of the equipment and the variation in operations philosophy of each operating company. The methods should be used by each operating company to develop a detailed set of emergency procedures for the process.

Emergencies must be recognized and acted upon immediately. The operators should be aware of the general steps required to resolve any sudden problem. While some of the emergencies listed in this section may not result in a unit shutdown, they could cause serious trouble on the unit if not handled properly.

Hard and fast rules cannot be written to cover all the possible events that might occur. The following sections outline some of the situations and their respective suggested responses. The following list outlines some of the situations and their respective suggested responses.

A. GENERAL

1. Power Failure
2. Loss of Instrument Air
3. Loss of Steam
4. Loss of cooling water
5. Explosion, fire, line rupture or serious leak

B. REACTOR SECTION

1. Reactor Effluent Compressor Shuts Down
2. Loss of Fired Heaters
3. Loss of Feed to Oleflex Reactors/Depropanizer
4. Loss of One Turbo Expander
5. Loss of Both Turbo Expanders
6. Loss of PSA
7. Loss of One Sulfur Injection Pump
8. Loss of Sulfiding
9. Loss of Net Gas to Sulfur Injection (Carrier Gas)
10. Loss of CCR
11. H₂S breakthrough in the Reactor Effluent
12. CO breakthrough into the PSA Hydrogen Product
13. Air Leak into Oleflex Reactor Circuit

C. FRACTIONATION SECTION

1. Increase in nC4, C4=, and/or C3= Material in Depropanizer Overhead
2. Increase in Methyl Acetylene / Propadiene in Depropanizer Overhead
3. Heat Pump Compressor Shuts Down
4. Deethanizer Refrigeration Failure
5. SHP Unit - High Temperatures Excursion
6. SHP Unit - Loss of Feed
7. SHP Unit - Loss of Hydrogen

A. General

1. Power Failure

The loss of power will almost always results in the shutdown of the Oleflex unit. All motor driven rotating equipment will shut down, which will result in ESD trips of remaining systems. DCS, controllers, and control valves will be maintained by power back-up (UPS) for a short duration, allowing limited capability for controlled de-pressuring or de-inventorying. Operational priority is given to first securing the plant with whatever control is available, sweeping reactor circuit to minimize coking, retaining hydrocarbon inventory as much as possible, and then restart once power is available.

It is recommended to shut down the unit in as controlled a manner as possible.

- 1) Confirm which pumps and air cooler motors have stopped and try to restart them. The turbo expanders will most likely shut down during a short power outage.
- 2) If an emergency power supply is not available or does not work properly, all electrical control instruments will fail. All electronic controllers must be operated manually and temperatures must be read by means of a battery operated potentiometer.
- 3) Switch any motor driven pumps that have been in service over to steam driven spares, where available.
- 4) If the failure affects the cooling water system, restore the normal water flow as soon as possible.

- 5) If the power loss is over a long period of time, shutdown the unit per the normal procedures (as much as possible).
- 6) If fuel gas to the fired heater trips for any reason during the loss of power, block in the primary and secondary burner tips.
- 7) When power is again available, the steps to restart the unit are identical to the steps following a Reactor Effluent Compressor shut down. Follow the restart procedures outlined in Step-12 through Step-24 in the Section 2.1 "Reactor Effluent Compressor Shuts Down", below

2. Loss of Instrument Air

Instrument air failure will most likely result in a unit shutdown unless the instrument air pressure is brought up soon.

Loss of instrument air will result in a gradual decrease in the instrument air header pressure. The rate of header pressure decrease will depend on the tightness (leakage) of the system. In most cases, the header pressure will be maintained only 10 to 15 minutes. A significant loss of instrument header pressure will cause control valves in the unit to go to their fail safe position (fail open, fail closed, fail last position) and control from the DCS will no longer be available. Major rotating equipment such as compressors and expanders will trip. Operators should be familiar with fail safe positions of all control valves in the plant.

Operational priority in this scenario is to begin a controlled shutdown of the Oleflex unit, for as long as control is possible, per normal shutdown procedures. Once instrument air is re-established, startup of the reactor section will be dependent on the state of the system at that time.

There may be multiple instrument air compressors (2 or 3) cycling to supply seamless instrument air supply. Any failure or trip of one compressor should result in load sharing by the running compressors and/or start-up of hot spare. It depends on Instrument Air package system design. In some refineries these compressor systems might have emergency power supply. The impact of Instrument Air failure or partial loss and time taken for recovery depends on the system design.

The following actions must be taken as feed in the event of instrument failure:

- 1) Confirm control valve action and positions. They should go to fail safe positions. In case of Instrument Air header pressure dropping below the minimum supply pressure, some control valve pneumatic actuators may not perform optimally causing difficulty in reaching fail safe position.
- 2) Watch column and vessel pressures and, if needed, vent excess pressure to relief header.
- 3) Confirm the REC is shut down and depressure casing.

- 4) If instrument air failure continues, take steps for "normal" shutdown (Section X).

3. Loss of Steam

Failure of the high pressure steam supply to the turbine drivers of reactor effluent compressor (REC) and Heat Pump Compressor (HPC) will cause the compressors to trip. This will lead to unit shut down. In case the REC trips, follow section 2.1 "Reactor Effluent Compressor Shuts Down" procedure. If the HPC trips, follow section 3.3 "Heat Pump Compressor Shuts Down".

If the compressor drivers are electric motors, the compressors will keep running on false load (anti-surge valves open 100%) if feed was cut off in case the steam is not restored quickly.

Steam failure will result in a loss of duty to the depropanizer reboilers, debutanizer reboiler, deethanizer stripper, depropanizer bottoms stripping tail gas heater, solvent recovery column bottoms reboiler as applicable. The associated equipment will not be able to continue operation. The columns will slump, and liquid may need to be pressured/pumped to off-spec storage to allow a visible level in the column bottom before unit restart.

4. Loss of Cooling Water

It is important to list all the major cooling water consumers and prioritize the critical consumers. This will help divert the flow in the event of partial cooling water failure.

The major/critical service consumers depending on unit configuration could be; [a] solvent circulation cooler [b] solvent recovery column overhead cooler [c] spent solvent cooler [d] reactor effluent cooler [e] REC interstage cooler [f] REC discharge cooler [g] depropanizer overhead condenser [h] deethanizer stripper overhead condenser [i] tail gas compressor skid lube oil coolers [j] net gas compression stage coolers [k] RED regenerant effluent cooler [l] Feed drier regenerant effluent cooler/condenser [m] REC, HPC, Turbo Expander system lube oil coolers [n] mechanical seal fluid coolers on certain pumps [o] surge hopper cooling coils [p] propylene product coolers [q] propylene trim condenser on HPC [r] propane feed cooler [s] deethanizer rectifier refrigeration unit compressor discharge cooler/condenser etc. It is important to recognize that there may be additional cooling water consumers on the other auxiliary systems like HVAC, Boilers, Air Separation Units, etc.

Utility system designs may vary but normally there are at least two or three cooling water pumps running at any given time so that if one pump tripped or shut down, the other(s) pump will share the load to keep the cooling water

system running. There should also be a spare pump in hot stand-by. If the cooling water battery limit supply pressure dropped, try to divert cooling water flow to the more critical consumers drawn from the priority list. There may be consumers where the temperature differential on cooling water side is significantly less than design. On these consumers, throttle the cooling water flow to divert the flow to more critical consumers. Note and mark the valve positions before and after throttling to re-establish normal positions upon restart.

Heat input to the fractionation columns shall be immediately brought down and cut off where the condenser utility is cooling water. REC, HPC, refrigeration package unit compressor, tail gas compressor and net gas compressor units will have to be shut down where the interstage and/or discharge cooling and/or auxiliary systems like lube oil cooling is achieved with cooling water based exchangers. The solvent circulation temperature may start shooting up in units with reactor effluent contact cooler and/or REC interstage contact cooler requiring REC to be shut down. However equipment protection systems should trip these units for such eventuality, operator shall make sure appropriate actions have been taken. Stop the pumps and close discharge valves where the pumps require cooling water utility for safe operation. Watch column and vessel pressures closely. If necessary, vent to the columns/vessels to relief header. If cooling water failure continues for a prolonged period, take the necessary steps for a "normal" shutdown (Section X).

- 1) If cooling water failure occurred, start preparing for unit shut down by reducing reactor temperatures and charge rate.
- 2) For partial cooling water failure or temporary supply disruption, it may be possible to decrease the unit feed rate and/or RITs to a level as necessary to maintain unit operation. At 60% unit feed, maintain RITs no more than 600°C and H₂/HC ratio no less than 0.6 to limit non-selective cracking due to increased hot residence time. Decrease RITs by ~10 °C for every 5% decrease in feed below 60% adjusting DMDS as required corresponding to the RIT.
- 3) For a total loss of cooling water, the unit must be shut down. Follow the normal shutdown procedures, with the exception of stopping heater firing immediately. Operate the REC as long as possible to sweep off hydrocarbon from the heaters and reactors. Maintain unit pressure.

5. Explosion, Fire, Line Rupture of Serious Leak

These guidelines focus on the process requirements for dealing with the scenario of flange leaks or fires in the Oleflex reactor circuit. The safe response/procedure for the fire itself (methods to control, extinguish etc.) is to be determined by the site emergency response teams.

In case of explosion, fire, line rupture or a serious leak, if possible, do the following:

- 1) Stop firing in all heaters. If the heaters or control valves are beyond reach, use the battery limit block valves. Assess the situation and use heater emergency shut down button from the control room if necessary.
- 2) Stop the fresh feed to the reactor circuit.
- 3) Leave the Reactor Effluent Compressor (therefore, recycle gas) running, if possible, while other items are attended to. The flowing gas will help cool the reactor and heaters and sweep the hydrocarbons from the reactor circuit.
- 4) Depressure the unit to the flare using the REC suction drum PIC or reactor effluent contact cooler PIC to flare as applicable.
- 5) Shut down the balance of the plant as circumstances permit or require. Shut down the reactor effluent compressor when its lower operating pressure is reached.

B. Reactor Section

1. Reactor Effluent Compressor (REC) Trip

Loss of REC results in complete shutdown of the reactor section and fractionators being forced to be placed on total reflux. The fired heaters and turbo expanders should automatically trip; and propane feed automatically cut off on the loss of REC. The fractionation section will experience an upset due to the stoppage of Oleflex propane feed and Oleflex liquid product; and eventually stoppage of fresh propane feed, propylene product and deethanizer off gas. Operator priorities will be to confirm that the relevant trip functions have been activated and fractionation section is stabilized. Restart of the reactor section following an REC trip will require additional measures to protect the Oleflex reactor internals. Low Firing Mode and Trickle Mode procedures together facilitate these measures prior to restarting the REC.

In absence of these procedures following scenario is expected during restart subsequent to REC trip. Following the REC trip, the Oleflex fired heaters will shut down. The fired heaters cool at a faster rate than the reactor internals and the catalyst bed. Reactor inner screens (I/S) will shrink slightly drawing in catalyst due to increase in annulus volume. The outer screen will (O/S) will subsequently shrink as well resulting in pressing of the catalyst bed and resultant radial stress (hoop stress). Upon REC re-start, the relatively colder gas from the heaters causes the relatively hotter inner screen (I/S) to radially shrink

at a rate faster than the outer screen (O/S), allowing more catalyst to be drawn into the annulus due to increased annulus volume. As the catalyst bed and the O/S continue to cool down, the O/S will continue to shrink, pressing the catalyst bed increasing the bed pressure and the applied hoop stress (circumferential or radial stress) on the screens further. When the Oleflex heaters are commissioned and heating commenced; relatively hotter gas from the heaters causes the I/S to radially expand at a rate faster than the outer screen (O/S), further increasing the bed pressure and hoop stress applied on the screens. Since the I/S is only free to move up longitudinally as against O/S which is only free to move down, in presence of the applied hoop stress this movement gets restricted (longitudinal or axial stress). If the applied radial force (hoop stress) is severe enough, this will result in radial buckling of the I/S. The magnitude of the applied hoop stress will be proportional to the delta between the heater and reactor temperatures at the time of the reactor effluent compressor (REC) restart. The higher this delta, the higher the resulting hoop stress on the reactor internals. To preclude the possibility of damaging the Oleflex reactor internals during a compressor restart operation, following procedural guidelines have been incorporated by UOP.

The first procedure is termed **Low-Firing Mode (LFM)**. The main objective of the LFM is to heat up the heater metal mass without process gas flow within the heater tubes to a level such that when the REC is restarted the temperature of the process gas hitting the reactor I/S is approximately 50 °C to 100°C lower than the estimated reactor I/S temperature in order to limit the hoop stress from increasing further. In LFM, the low firing burners, rather than the main burners, are used to heat the heater metal mass to a temperature relatively close to that of the reactor. This is done with no process flow through the radiant tubes which is necessary to prevent the need for a long waiting period in which the reactors slowly cool to a safe temperature delta T between the I/S temperature and the gas inlet. LFM is used to quickly reduce this delta T such that the REC can be restarted at will. The maximum heater tip temperature (temperature of the flue gas underneath the convection section coils) which can be used during the LFM mode is 550°C (1020°F) limited by the maximum design metal temperature of the convection section coils.

Trickle Mode(TM) is the second major procedural event designed to preclude any damage to the reactor internals by eliminating the residual bed pressure that may have developed contributing to the hoop stress. Trickle mode is performed after the REC is restarted and is designed to relieve the residual catalyst bed pressure (and thus hoop stress) generated during the REC restart. Although the I/S can tolerate the hoop stress generated by the safe heater/reactor ΔT during REC restart, the axial stress which will be created during heat up of the reactor can cause axial failure of the I/S if there exists residual catalyst bed pressure prior to the heat up. This is the purpose of the TM. Following the REC restart, catalyst is removed from the Oleflex reactors in

very small increments to ensure a uniform decrease in catalyst bed density within the reactor annulus. After completing the TM, any bed pressures above normal are relieved, thereby eliminating the possibility of excessive axial stresses developing during the reactor heat up. Once this is accomplished, reactor section heat up may begin. Trickle mode is accomplished using the existing catalyst transfer equipment and a sub routine within the Catalyst Regeneration Control System (CRCS). Refer to the Oleflex CCR General Operating Manual for a more detailed discussion.

The proper sequential procedure following a Reactor Effluent Compressor trip is described below:

- 1) The Reactor Effluent Compressor shuts down. The REC restart permissive will be disabled until the supervisory switch is activated later in this procedure when conditions that may lead to a reactor internals failure are relieved.

When the REC trips, the recycle gas flow will drop off almost immediately. Confirm the Oleflex propane feed to cold separation system has been cut off.

Note down the time and each reactor RIT at the moment of REC trip. Based on the anticipated time of REC restart and cooling rate for each reactor, calculate the target heater hip temperature for each Oleflex reactor that must be attained prior to REC restart. The target heater hip temperature for a given reactor will be 50 °C - 100 °C below the calculated RIT for that reactor or 550 °C whichever is lower when the REC is restarted. Maximum allowable hip temperature is 550 °C.

The reactor cooling rate is initially estimated by the UOP Chief Technical Advisor (CTA) and then calculated following the first trip or shutdown. Cooling rate for each reactor will be provided by the CTA to the customer.

After a short time delay (about 10 seconds) post REC trip, the Oleflex fired heaters will trip on low recycle gas flow or low reactor effluent flow. Close the primary and secondary fuel gas cock valves at each burner in preparation for low firing mode. Permissive for use of main fuel gas header is disabled until trickle mode is completed later in this procedure. Maintain a minimum hip temperature of 200°C (390°F). The pilot burners should remain lit and will supply sufficient heat to maintain the minimum hip temperature. Monitor the steam generation section in the Oleflex heater area. Adjust the boiler feed water make-up as required. Stop and isolate the boiler feed water to the de-superheater, as well if necessary. Control the steam pressure, if necessary, by venting through the silencer to atmosphere.

- 2) The “Trickle Mode” (TM) indicator on the CRCS panel will illuminate if at the moment of REC trip, any one or more of the RITs was/were above the Trickle Mode switch point which is 350 °C. If all the RITs were <350 °C at the moment of the REC trip, Trickle Mode will not be required.

Further, if the REC can be restarted within 100 °C of all the RITs at the moment of REC trip, TM can be bypassed using the TM Bypass Switch.

- 3) Block in the cold separation system net-gas valve to maintain the reactor circuit pressure.
- 4) Ensure that the REC suction drum or reactor effluent contact cooler dump valve pressure controller (PIC) to flare operates properly and does not depressure the unit completely.
- 5) Close the RED regenerant flow control valve and confirm that the PSA unit has shut down. Confirm SHP hydrogen injection has been stopped and SHP hydrogen compressors shutdown.
- 6) Shut down and isolate the DMDS injection pumps.
- 7) Follow the vendor-recommended shutdown procedures for blocking in the cold separation system equipment.
- 8) With the liquid feed flow to the reactor section stopped and there is no liquid product feed from the cold separation system to the fractionation section, place the depropanizer column, the deethanizer stripper/rectifier columns and the P-P splitter columns on total reflux until the cold separation system is restarted subsequently.
- 9) Allow the CCR to continue to operate even though catalyst circulation to and from the reactors has been stopped with Lock Hopper 1 and Lock Hopper 2 automatically stopped by the CRCS. Allow the Flow Control Hopper (FCH) to cycle approximately 75 counts more to create room in the disengaging hopper for the catalyst received from Lock Hopper 1 when the Trickle Mode is started in subsequent steps. After the FCH has cycled 75 times, place the CCR in Hot Shutdown as outlined in section XI of the Oleflex CCR General Operating Manual.
- 10) With all primary and secondary tips on the main burners isolated but normal combustion air flow (burner air registers opening) to each heater maintained, commission the LFM mode fuel header by activating the LFM

mode permissive switch. In a symmetric fashion and in close communication with the panel operator, begin commissioning the required number of LFM burners in each heater (independent LFM burners may be specified on some units depending on the type of start-up fuel gas composition and lower heating value). If there is no independent LFM burner provided, commission the primary fuel gas tips on the required number of main burners keeping the secondary tips isolated.

- 11) Commission LFM mode while limiting the heater hip temperature ramp rate to 100°C/hr (180°F/hr). The panel operator must closely monitor heater tube skin and hip temperatures and be watchful for any signs of localized overheating. At the same time, the field operator must monitor the firebox for any signs of flame instability and/or flame impingement on the tubes. Adjust the combustion air flow and/or the number of burners to obtain uniform firebox temperatures and a maximum heat up rate of 100°C/hr (180°F/hr). More burners firing should result in a more homogeneous temperature distribution in the firebox. Only primary burner tips are used to limit the amount of heat released from each burner where no dedicated LFM burners are provided.
- 12) From the RIT_{TRIP} for any given reactor at the moment of REC trip, the cooling rate R °C/Hr for that reactor and the elapsed time T Hrs from the moment of REC trip to anticipated re-start, estimate the target hip temperature $T_{Target\ Hip}$ as follows:

$$T_{Target\ Hip} \text{ during LFM} = (RIT_{TRIP} - T \cdot R) - 50^{\circ}\text{C} \text{ maximum..... (A)}$$

$$T_{Target\ Hip} \text{ during LFM} = (RIT_{TRIP} - T \cdot R) - 100^{\circ}\text{C} \text{ minimum..... (B)}$$

If (A) and/or (B) results in a value $>550^{\circ}\text{C}$, 550°C will be the maximum. The maximum allowable heater hip temperature for LFM is 550°C (1020°F) on any given reactor. This shall not be exceeded.

Once the target hip temperatures have been achieved for each reactor, proceed to step 13)

Note: If the REC restart has been delayed or uncertain, and LFM mode operation of the heater for a given reactor is likely to extend beyond 24 hours, cut off the LFM burners and stop LFM for that particular reactor. Low-firing mode should not be maintained for more than 24 hours on any heater.

Approximately 4 hours before the REC is to be restarted, re-commission the low-firing mode fuel header, recalculate and achieve the target hip temperatures. A sample of a calculation sheet for estimating the target heater temperatures is shown in Figure XI-B1.

Do not increase the heater hip temperatures above the estimated reactor temperature. This can result in failure of reactor internals during REC restart. It is critical for the heater to be 50-100°C (90-180°F) below the reactor temperature instead of higher.

- 13) With low firing mode stabilized at the desired heater temperature for at least 15 minutes, reset the REC startup permissive and restart the REC according to normal procedures. After the REC has been restarted and forward flow to reactors exists,
- a) If any RIT is above 475°C (890°F), immediately re-establish DMDS injection at 60-70 ppmw S based on feed rate prior to REC trip.
 - b) If any RIT is below 475°C (890°F), immediately re-establish DMDS injection at 50-60 ppmw S based on feed rate prior to REC trip.
 - c) If any RIT has decreased below 400°C (750°F), cut off DMDS.

Note that in absence of net gas as dispersant the injection must be done at HCFE inlet.

- 14) Reduce DMDS, as necessary, when all the reactor inlet temperatures have reached the stated temperature limits. Since the main burners are not yet lit and the circulating gas flow through the system is being increased simultaneously with cold separation system restart, it is expected that the reactor inlet and outlet temperatures will decrease.
- 15) **Once the REC is restarted, DO NOT increase heat input to any of the heaters (i.e., DO NOT increase the number of firing burners, DO NOT decrease combustion air flow, and DO NOT increase low-firing mode fuel gas header pressure). Allow the RITs to decrease.**

This is to prevent any axial stress from developing at the inner screen and to eliminate the possibility of screen failure. Note the maximum reactor outlet temperature and the associated reactor inlet temperature observed during the restart.

- 16) Once the REC operation is lined out, restart the cold separation system and begin to cool down as per vendor instructions and procedures outlined in this GOM in earlier section on start -up. The activities here include starting up the turbo expanders, introducing liquid propane feed, lining out separator vessels to liquid product drum and commissioning the liquid product pumps to begin sending liquid product to the fractionation section. Be careful not to upset the specific gravity in the Rx section as this may re-trip the REC.

- 17) Once 92.5 to 94 mol% H₂ recycle gas purity is achieved, re-establish purge gas flows to each of the catalyst collectors, reduction zone, surge pot heaters and reactor plug purges. This will require swinging the jumper line to divert net gas through the purge gas heater (this may not be necessary if PSA H₂ of specified quality is made available). Commission the CCR gas heater and purge gas heater if steam was cut off.
- 18) Make sure the reduction zone and surge pot heaters are in shutdown condition. But the purges via these heaters must be established. These heaters will be started later in the procedure. Establish surge pot to reactor differential pressure of ~10 KPa or ~ 100 mbar.
- 19) Start Trickle Mode after the cold separation system has been commissioned (starting up turbo expanders and establishing liquid propane feed) and after the reactor section purges have been lined out. However, gradual increase in liquid feed to cold separation system may continue even as Trickle Mode is being performed.
- 20) Press the Lock Hopper 1 pushbutton on the CRCS panel, Lock Hopper 1 will automatically initiate Trickle Load mode of operations (trickle load mode of operation for the inter-reactor reactor lift engagers is discussed in the appropriate section of the CCR GOM).
- 21) Press the pushbuttons for Lift Engagers 1, 2 and 3 on the CRCS panel. This will initiate Trickle Load operations for these lift engagers automatically. Do not press the pushbutton for Lock Hopper 2. No catalyst will be moved from the Regeneration Tower during Trickle Mode.
- 22) After starting Trickle Mode, the Reduction Zone and Surge Pot Heaters may be restarted. Use the CRCS to enable the heaters, then ramp the temperatures up to 350°C at 55°C/Hr. Do not allow the heaters to go above 400°C while the CCR gas (net gas) is lined up to heaters since impurities in the gas may potentially coke up the electric heater elements.
- 23) After the appropriate amount of catalyst has been removed from each reactor, the "Trickle Mode" indicator on the CRCS panel will turn off.
- 24) Latch the main fuel gas valves open and heat the reactors at 30°C per hour, closing each low firing burner and relighting each main burner as required. Adjust the steam generation system as required. Restart DMDS injection when the RITs are at 400°C. Perform the abbreviated sulfiding procedure following the necessary holds at 475°C and 550°C. When the RITs are in the range of 550°C to 600°C, there will be enough net gas to re-start the PSA unit. When PSA H₂ of specified quality is available; close the CCR gas jumper line to the purge gas heater, and establish PSA H₂ flow to the

reduction zone, surge pots and reactor plug purges. Begin increasing the reduction zone and surge pot heater temperatures to the design temperatures. Re-establish normal operations.

2. Loss of Oleflex Fired Heaters

Oleflex Fired Heaters will shut down in the event of any one of the following.

- a. Loss of circulating water to convection sections of charge heater and inter heaters
- b. Low fuel gas pressure downstream of the fuel gas control valve to charge heater and inter heaters
- c. Low pilot fuel gas pressure
- d. Loss of recycle gas flow
- e. High heater hip temperatures during Low Firing Mode operation
- f. Low reactor effluent gas flow
- g. High cold separation system inlet temperature (if provided)

In the event of fired heater trip, except for the case of low pilot fuel gas pressure, the pilots will remain lit. It is desirable to keep the pilots operating to maintain the hip temperatures near of 200°C. Trickle Mode (TM) will be activated automatically whenever the Oleflex fired heaters trip if any of the RITs > TM switch point which is 350°C. TM will be required to relieve the hoop and axial bed stresses imposed on the reactor screens due to rapid cooling of the process gas. In addition, PSA H₂ will not be available as net gas production ceases forcing the PSA unit to shut down. TM is the only means of moving the catalyst through the reactor when PSA H₂ is not available.

Trickle Mode disables the main fuel gas to the Oleflex fired heaters. Therefore, for the heater re-start, the shift supervisor will need to use the TM Bypass switch in the CRCS cabinet to enable the main fuel gas to heaters if required. TM bypass to restart the heaters is only permissible if the RIT at the moment of heater restart on each reactor is within 100°C of the RIT at the moment of heaters trip or if all the RITs were < TM switch point which is 350°C at the moment heaters tripped. Otherwise TM must be performed. TM bypass is NOT permissible if heaters and/or REC trip occurred 3 consecutive times without circulating catalyst from each reactor at least once even if all the RITs were < 350°C at the moment of each trip.

This procedure is intended to be used during events where the Oleflex fired heaters have tripped while the Reactor Effluent Compressor (REC) continues to run. Confirm that TM has been triggered. In the event that the fired heaters have tripped and the REC has also shut down, refer to the "Reactor Effluent Compressor Shuts Down" emergency procedure, earlier in this section.

- 1) Close the main fuel valves to each heater. Close all main burner gas valves. Pilot valves should remain open and the pilots should remain lit to achieve the heater hip temperatures in the vicinity of 200°C.
- 2) Open the stack damper for 5 minutes to allow any un-combusted fuel gas to be vented from the fired heater box prior to re-lighting burners. Purge the stack with low pressure steam connection at stack. Close the stack dampers. Check the reactor inlet temperatures (RITs). If all the RITs have decreased less than 100°C of the pre-upset temperature, then skip to Step-22 in this section.
- 3) Fully close the burner air registers at each burner. This will prevent the heater hip temperatures and reactor inlet temperatures from cooling down too quickly.
- 4) Monitor the heater hip temperatures. If hip temperatures drop below 200°C at any time during this procedure, then commission the Low Firing Mode (LFM) fuel gas header and ignite the required number of LFM burners (or primary tips on main burners if there are no dedicated LFM burners) to maintain the hip temperatures at ~200°C (if temperatures remain above 200°C, then move to Step-5 below.). To commission the LFM fuel gas header, activate the LFM, line up the LFM PCVs, and activate the LFM fuel reset to open the shutdown valves on the LFM fuel gas header. Adjust the PCVs to about 28 Kpa G (~0.28 kg/cm² g), if necessary, and light up the burners after the respective burner air registers are ~50% open. Light up one burner at time. The stack dampers can remain fully closed while the main fuel gas line is shut down to keep the heat inside the fire box, even if LFM is activated. The pressure inside the fire box shall remain slightly negative. To achieve this, open the stack dampers slightly and adjust as required.
- 5) Maintain the H₂/HC ratio at the same level as before the trip. Note that the recycle gas purity will increase after the heater trip since the dehydrogenation reactions will progressively cease as the reactors cool down.

It will be required to decrease the feed to the unit as necessary limited by the recycle propane pump capacity. Anticipated feed reduction will be from pre-upset level to ~60% if the heater operation cannot be re-established quickly.

- 6) Maintain DMDS injection rate at approximately 60-70 wt ppm sulfur in the feed to achieve 30-40 mol ppm H₂S in reactor effluent when the reactor inlet temperatures are still above 475 °C. Reduce DMDS to 50-60 wt ppm sulfur when the reactor inlet temperature drops down to under 475°C and

cut off completely-when the reactor inlet temperature drops down to under 400°C.

- 7) Allow the CCR to continue operation until the flow control hopper (FCH) has cycled at least 75 times. This creates enough free volume in the disengaging hopper to allow catalyst transfer during TM. Afterwards place the CCR in "Hot Shutdown" mode according to the CCR "Hot Shutdown" procedure in the Oleflex CCR General Operating Manual.
- 8) Monitor the steam generation section in the Oleflex heater area. Adjust the boiler feed water make-up as required. Stop and isolate the boiler feed water to the de-superheater, as well if necessary. Control the steam pressure, if necessary, by venting through the silencer to atmosphere.
- 9) Monitor net gas production. Shutdown the PSA unit or adjust the PSA unit capacity, if applicable, as net gas production tapers off
- 10) Shutdown the SHP H₂ compressors if the PSA H₂ is not available. Adjust and monitor the net gas pressure controller. It should have closed the net gas pressure control valves. If that is not helpful to maintain the pressure (if control valves leak out) then either close the block valves or start adding make up H₂ through start up line.
- 11) If there is no PSA H₂ supply, it is necessary to open the jumper line to allow CCR gas to the purge gas heater. Close the PSA H₂ to the purge gas heater by closing the block valve. Line up CCR gas to the reduction zone, surge pots and reactor plug purges.
- 12) Ensure that the reduction zone and surge pot heaters have shut down if the PSA unit shut down. If CCR gas was lined up before the PSA unit shutdown (in this case, the electric heaters would not have tripped), then decrease the electric heater temperatures to 350 °C at 70 °C /Hr.
- 13) Re-establish and reconfirm the flows to the Reduction Zone, Surge Pots and Reactor Plug Purges.
- 14) Once all flows are stable, begin Trickle Mode. It should take 4-6 Hours to complete Trickle Mode from initiation of the "Trickle Mode" indicator.
- 15) Once Trickle Mode has started, restart the Reduction Zone and Surge Pot heaters. Use the CRCS to enable the heaters, then ramp the temperatures up to 350°C at 55°C /Hr. Do not exceed 400 °C with CCR gas due to increased potential for coking due to impurities.

- 16) Once the "Trickle Mode" indicator has gone off on the CRCS, the main fuel gas to Oleflex heaters will be enabled. Reset the main fuel gas to begin heating up the reactors.
- 17) Ensure the stack dampers are open and begin lighting the main burners while shutting off the low firing burners one at a time. Be sure not to put too many burners on line at a time to avoid overshooting the ramping rate. Begin ramping the reactor inlet temperatures to 400 °C at 30 °C /Hr. **Perform abbreviated sulfiding schedule. Refer to the Abbreviated Sulfiding Procedure in the Normal Start-up section of this manual. Raise the RITs further from 550 °C at 30 °C /Hr upon completion of sulfiding.**
- 18) Commission the net gas to PSA unit and commission the PSA unit (it that had been shut down or tripped) when sufficient net gas is being produced. Re-commission the SHP hydrogen compressors and start injecting hydrogen to the SHP reactor. Swing to PSA H2 for the reduction zone, surge pots and reactor plug purges and increase the electric heater outlet temperatures to design temperatures.
- 19) Re-start the RED regenerations. If using an external start up regenerant, switch to net gas when available.
- 20) Start the catalyst circulation as soon as the PSA H₂ is available. Note that CCR temperatures should be high enough and in standby in the Hot Shutdown condition.
- 21) Ramp the Oleflex unit to normal operating RIT, H₂/HC and feed.
- 22) **If each of the RIT's recorded at the moment of heater restart is within 100°C of the pre-upset temperature, it will be possible to restart the unit without having to perform Trickle Mode.** Trickle Mode disables the main fuel gas to Oleflex fired heaters. Therefore for heater start-up, the shift supervisor will need to use the Trickle Mode bypass switch in the CRCS cabinet to enable the main fuel gas to heaters.

Establish CCR gas to Reduction Zone, Surge Pots and Reactor Plug Purge. Start the electric heaters and ramp to 350 °C. If net gas was lined up before the PSA unit has been shut down (in this case electric heaters would not have tripped as yet), then decrease the electric heater temperatures to 350 °C at 70 °C /Hr. Simultaneously, begin lighting the burners and ramping reactor inlet temperatures at 30°C/Hr or less to the pre-upset RITs and follow through Steps-17 to Step-21 above.

Note that the heaters should be up and running without allowing RIT on any reactor decreasing <100°C below the pre-upset conditions. If

the temperatures drop more than 100°C, then it is required to perform the Trickle Mode.

Figure XI-B1

Target Hip Temperature Calculation Sheet

1. Time of REC trip or Loss of Forward Flow _____
2. Reactor 1 inlet temperature at the time of REC trip: _____ °C
3. Reactor 2 inlet temperature at the time of REC trip: _____ °C
4. Reactor 3 inlet temperature at the time of REC trip: _____ °C
5. Reactor 4 inlet temperature at the time of REC trip: _____ °C
6. Estimated time of REC Restart _____
7. Time between REC Trip and Restart _____ hrs. (#6 - #1)

Estimate that each reactor cools at $\sim X^{\circ}\text{C/hr}$. Calculate the reactor temperature at the time of REC restart:

8. Reactor 1: _____ (#2) - (#7)*X°C/hr = _____ °C
 9. Reactor 2: _____ (#3) - (#7)*X°C/hr = _____ °C
 10. Reactor 3: _____ (#4) - (#7)*X°C/hr = _____ °C
 11. Reactor 4: _____ (#5) - (#7)*X°C/hr = _____ °C

Estimated Hip temperatures at the time of REC restart. Low Side to High Side is the specified target hip temperature range under LFM mode. The maximum allowable hip temperatures is 550°C:

12. Charge Heater = _____ (#8) - 50°C = _____ °C High Side (Max 550°C)
 _____ (#8) - 100°C = _____ °C Low Side
13. Interheater #1 = _____ (#9) - 50°C = _____ °C High Side (Max 550°C)
 _____ (#9) - 100°C = _____ °C Low Side
14. Interheater #2 = _____ (#10) - 50°C = _____ °C High Side (Max 550°C)
 _____ (#10) - 100°C = _____ °C Low Side
15. Interheater #3 = _____ (#11) - 50°C = _____ °C High Side (Max 550°C)
 _____ (#11) - 100°C = _____ °C Low Side

As long as all hip temperatures are in the specified range, the REC can be started to re-establish the flow through the reactors.

3. Loss of Feed

Feed to the Oleflex unit can be lost [a] if fresh propane feed pump feeding the Oleflex trips [b] if the feed control valve fails close or trips or incorrect inadvertent set point entry by operator causes control valve to close [c] if there is a miss operation in the feed drier system where an on-line drier is inadvertently blocked in [d] if the recycle propane pump is lost cutting off majority of depropanizer feed. Depropanizer reflux pump failure is unlikely to cause loss of feed event since there is sufficient pressure to push feed to the cold separation system though column reflux would be impacted increasing impurities in feed which is covered as a separate emergency later in the section. If there is total feed loss which will likely be sudden in case of [b], Oleflex fired heaters should trip automatically by the shutdown logic. Confirm this has happened. Follow emergency guidelines for “Loss of Oleflex Fired Heaters” described in earlier section. If there is a partial feed loss as in case of [a], [c] and [d] depending on depropanizer receiver level or a short window of time, typically ~10 minutes exists before the total loss of feed could set in; do the following;

- 1) Decrease the RITs: A sudden loss of feed will result in a sudden loss of the majority of the mass flow to the heaters and reactors. The heater firing controls will likely not respond quickly enough to a loss of feed, and temperatures in the reactors and heaters could rise rapidly. Excessive reactor inlet temperature shoot-up in a relatively short time, could result in coking in the reactors and/or heaters until the heaters trip subsequently on low recycle gas flow and/or reactor effluent low flow. Therefore, there will be an immediate need to control the heater firing.

Take the heater firing control on fuel gas pressure control or on manual as necessary and start decreasing the RITs toward 550°C while simultaneously decreasing the Oleflex feed to manage depropanizer receiver level to maintain column reflux and overhead purity. Monitor the fuel gas pressure staying above low heater fuel gas pressure heater trip limit by cutting off the burners as required. In the meanwhile, try to fix the cause of feed disruption.

If this is proving to be difficult to manage the above actions and if the reactor temperatures are continuing to shoot up, it is recommended that while the emergency of loss of feed is being sorted out, trip the Oleflex fired heaters manually from the control room using heater emergency stop. If the Oleflex heaters tripped, follow through the “Loss of Oleflex Fires Heaters” emergency procedure discussed in the earlier section.

- 2) Monitor the Reactor Effluent Compressor: Loss of feed will cause the molecular weight of the compressor gas to fall quickly. If the anti-surge valves do not respond quickly as required by the controller tripping the

REC, proceed with the “Reactor Effluent Compressor Shut Down” emergency procedure discussed earlier. On the other hand, if the amount of feed loss causes the anti-surge valves to open enough decreasing the reactor effluent flow and/or the recycle gas flow, Oleflex fired heaters may trip. To prevent this, while the REC is in operation, commission the make-up propane and hydrogen feed quickly to the REC suction drum or reactor effluent contact cooler as applicable to control the specific gravity at the REC and supplement forward flow.

- 3) Quickly remedy the problem and resume feed flow to the reactors as soon as possible, with the REC is running. Re-establish the H₂/HC ratio to where it was prior to the loss of feed. Reestablish stable REC operation and stabilize the reactor section. Once the feed and REC have stabilized, restart the fired heater according to normal heater restart procedures.

4. Loss of One Turbo Expander

If a single turbo-expander is lost, the main concern is losing recycle gas purity, which may lead to increased coking on the reactor internals. Further, due to the increased olefins in the net gas, the PSA unit may become overloaded. It is possible to operate with a single turbo-expander and avoid unit shutdown, but operating severities and production rates may be impacted. The following actions are recommended:

- 1) Determine the root cause of failure. After determining the root cause, remedy the situation and restart the turbo expander as per vendor guideline.
- 2) When the turbo expander trips, it is expected that the bypass valve (JT valve) should open to a preset position. Check whether this has happened. If this opening is not sufficient at a given unit load, manually adjust the valve opening to achieve the desired pressure upstream of the high pressure turbo expander (HPTE) or the desired recycle gas flow through the low pressure turbo expander (LPTE).
- 3) Closely monitor the cold separation system temperature trends. If the recycle gas temperature at the outlet of the low pressure separator downstream of the LPTE increases by more than 20°C above the pre-upset temperature, decrease the reactor inlet temperatures to 600°C within 20 minutes and increase DMDS injection to attain 200 wt ppm sulfur based on liquid feed.
- 4) As cold section warms up due to loss of turbo-expander, recycle gas hydrogen purity issuing from the low pressure separator will drop. It will have increased concentration of olefins. Initially decrease the propane feed rate which also helps maintain the pre-upset H₂/HC. This is because, it

may be necessary to decrease the feed at 600°C RITs to manage the recycle propane rate limited by the recycle pump capacity. This action helps maintain the H₂/HC compensating for the loss of recycle gas hydrogen purity by feed reduction rather than by increasing the recycle gas rate.

- 5) Monitor the net gas purity issuing from the intermediate pressure separator. If cold section continues to warm up due to loss of turbo-expander, net gas hydrogen purity will continue to drop further due to increased concentration of olefins. At this point adjust the recycle gas rate as necessary to maintain the H₂/HC at pre-upset condition.
- 6) Monitor the PSA unit. With cold section warm-up, net gas feed to the PSA unit will have increased level of olefinic impurities. PSA H₂ product may break through in olefins. Olefins in reduction zone gas can impact the catalyst reduction. Further, olefins in PSA H₂ product can coke up the reduction zone and surge pot electric heaters. Due to this concern, stop the catalyst circulation immediately following the turbo-expander trip to prevent potential exposure of incoming oxidized catalyst in reduction zone to olefins. Decrease the reduction zone and surge pot heaters outlet temperature to 400°C over an hour.
- 7) When the PSA H₂ product is on specification with <1 mol ppm in CO and, 1 mol ppm olefins; it is acceptable to ramp back the reduction zone and surge pot heaters to their pre-upset conditions.
- 8) Restart the catalyst circulation.
- 9) If the operation has to continue with the single turbo-expander for an indefinite period, gradually inch back on the Oleflex feed first followed by RITs maintaining the pre up-set H₂/HC until such a point that [a] the recycle gas total olefins are <0.1 mol%, C₃+ olefins are <0.05 mol% and [b] PSA H₂ product is <1 mol ppm in CO and olefins. Gradually decrease the DMDS injection rate as wt.ppm sulfur in Oleflex liquid propane feed to the pre-upset level.
- 10) When the turbo-expander has been restarted and the cold separation section is normalized, readjust the Oleflex feed followed by RITs maintaining the DMDS injection rate and H₂/HC at their pre-upset levels.

5. Loss of Both Turbo-Expanders

The loss of both turbo-expanders will necessitate a unit shutdown. Cold separation system temperatures will climb immediately. As this occurs, the

separation in the various product drums will become increasingly less effective. The result is a lower purity recycle hydrogen stream that can contain excessive olefinic material. Recycling olefinic material to the front end of the reactor section may result in rapid soot coke fouling of the reactor internals. Net gas hydrogen purity will decrease as well due to excessive olefins overloading the PSA unit with possibilities of olefins breakthrough. The key operator response in this case should be to prevent [a] the coking of Oleflex reactor screens [b] potential damage to the incoming oxidized catalyst in the reduction zone [c] potential coking in the reduction zone and surge pot electric heaters

- 1) Determine the cause of the shutdown and attempt to remedy the problem.
- 2) If a long-term shutdown seems likely, warn downstream units of an impending unit shut down.
- 3) Monitor the temperatures, pressures, and flows throughout the product recovery section. If the recycle gas temperature issuing from the low pressure separator rises more than 20°C (36°F) above the pre-upset temperature, decrease reactor inlet temperatures to 600°C (1112°F) within 20 minutes and immediately increase DMDS injection to obtain 200 ppmw sulfur based on liquid feed.
- 4) This would increase the recycle propane due to reduced conversion in Oleflex.

Therefore it will be necessary to simultaneously reduce the liquid feed, as necessary, limited by the recycle propane pump capacity. It will also be necessary at some point to open the reactor effluent bypass on the cold separation system since the amount of hydrocarbons condensed out will progressively decline with cold section warm-up. The reactor effluent bypass shall be opened as required by an amount such that the back pressure on the combined feed outlet is maintained at the level specified by the cold separation system vendor when liquid feed is still continuing to exist.

- 5) Lower the Oleflex feed rate to maintaining the pre-upset H₂/HC ratio rather than by increasing the recycle gas in response to the decreased recycle gas hydrogen purity as the cold separation system warms up. Lower RITs and increased sulfur injection will minimize the possibility of fouling the reactor internals with soot coke due to an excessive amount of olefins in the recycle gas.

- 6) Stop the catalyst circulation immediately to limit the incoming oxidized catalyst from contacting the olefins in the reduction zone due to the PSA H₂ product potentially becoming off spec in olefins.
- 7) Due to increased olefinic level in the Oleflex net gas and the possibility of olefins breakthrough from the PSA unit, shut down the reduction zone heater and surge pot electric heaters to prevent olefins driven coking.
- 8) After the cold separation system operations have stabilized and it is verified that the PSA H₂ product and net gas contain less than 0.5 mol% olefins, it is acceptable to commission the reduction and surge pot heaters either with the PSA H₂ product or with the CCR net gas (this will require switching to the CCR gas on the purge gas heater). But limit the reduction and surge pot electric heater outlet temperatures to 400°C. Catalyst circulation shall not be started at this stage. If the olefins in CCR net gas and/or PSA H₂ product remain >0.5 mol %, these heaters must remain shut down.
- 9) If the turbo-expanders cannot be brought back online quickly, cut the reactor temperatures to below 500°C (932°F) within 30 minutes. This is fairly rapid cut down in heater firing. To prevent Oleflex fired heater trip while executing this temperature reduction, take the heaters on fuel gas pressure control and cut down the number of burners as required to remain above the low fuel gas pressure trip set point. Maintain sulfur injection at 200 wt.ppm based on liquid feed.
- 10) If the turbo-expanders still cannot be restarted after decreasing reactor temperatures to below 500°C, continue to decrease reactor temperatures below 400°C (707°F) within 30 minutes exercising the same cautions described in Step 21 in regulating the heater firing. Maintain sulfur injection at 200 wt.ppm based on liquid feed.
- 11) Once all the reactor inlet and outlet temperatures are below 400°C, cut off the DMDS injection.
- 12) At this stage, the amount of net gas generated will not be sufficient to regenerate the RED's. Therefore it is necessary to decrease the RITs to ≤ 400°C (707°F) so that DMDS injection can be completely stopped which prevents the REDs from being overloaded risking H₂S breakthrough.
- 13) Continue to keep the REC running making up propane and hydrogen as required at the REC suction drum or reactor effluent contact cooler as applicable to manage the specific gravity of the circulating gas.
- 14) When the feed and RITs are decreased, the amount of liquid product that is pumped to the fractionation section and the amount of propylene and

light ends contained in the liquid product will decrease. Adjust the deethanizer stripper and rectifier operations to maintain the system pressure by adjusting the hot vapor bypass and rectifier condenser bypass as required. Adjust depropanizer operations by decreasing the bottoms product and C4 rich side draw as applicable while maintaining the overhead purity. Adjust PP splitter operations by starting to phase out the net product draw while retaining enough propylene in the column to maintain the overhead propylene purity.

- 15) When the Oleflex liquid propane feed has been decreased to ~60% design, slowly open the Oleflex feed bypassing the cold separation section. Slowly phase out the Oleflex feed to the cold separation system while continuing to increase the flow via bypass in equal measure. Finally completely phased out Oleflex feed to the cold separation system while maintaining ~60% feed via the cold separation system bypass.
- 16) Place the reactor section on internal circulation (reactors → REC → chloride treater/RED's → cold separation system + reactor effluent bypass → reactors). Maintain the fractionation section in long loop circulation.
- 17) When the turbo expanders can be restarted, return to the Normal Startup section of this manual to perform the Abbreviated Sulfiding procedure before normalizing the operations.

6. Loss of PSA Unit

Loss of PSA unit results in loss of purge gas hydrogen to the reduction zone, surge pots, lift engager 5 lift gas, lock hopper 2 pressure-up gas, hydrogen for injection to the SHP reactor and reactor plug purges. Operator priority is to initiate the measures to [a] protect the Oleflex reactor plug distributors and internals from coking due to loss of plug purge [b] protect the Oleflex catalyst from building-up excessive coke due to inability to circulate the catalyst and [c] to restart the PSA unit.

On loss of PSA H₂ supply the following should happen automatically: [a] the reduction zone and surge pot heaters trip on low flow [b] SHP hydrogen injection will stop due to the hydrogen compressor stopping or going on spill back [c] catalyst circulation will stop due to inability to run lift engager 5 and lock hopper 2. [d] The differential pressure between the reduction zone and reactor1 and between the surge pot and reactor on reactors 2, 3 and 4 is maintained. In some of the conventional Oleflex units this is achieved by the closure of the vent valve (HV) on the reduction zone and surge pot vent via HIC. In the C3 Oleflex units with reactor effluent contact cooler and in some of the conventional C3 Oleflex units this is achieved by the opening of the XV

valve installed in parallel with the reactor-reduction zone and reactor-surge pot differential pressure control valve (PDCV)

Take the following steps immediately.

- 1) Check if the above actions have happened automatically. If not, shut down the reduction zone and surge pot electric heaters immediately.
- 2) Stop the catalyst circulation by placing the lock hopper 2 in STOP mode. Perform a hot shutdown of the regeneration section. Follow through the emergency procedure for stoppage of catalyst circulation and decrease the RITs as required by the procedure. This will limit coke on the catalyst when the PSA unit has been restarted and catalyst circulation re-established later in the procedure.
- 3) Immediately establish a small flow of the CCR gas through the crossover line to the purge gas heater. Route the CCR gas to the reduction zone, surge pots and reactor plug purges. Check a positive delta P exists between the reduction zone/surge pot and respective reactor preventing process gas migration into the reduction zone/surge pots which can result in severe coking. Restart the reduction zone and surge pot electric heaters and ramp the temperature to 400°C (707°F).
- 4) Start the PSA unit as soon as possible and re-establish PSA product flow to the reduction zone, surge pots, lift engager 5 lift gas, lock hopper 2 pressure-up gas, hydrogen for injection to the SHP reactor and reactor plug purges. This will require routing the PSA H₂ purge gas to purge gas heater and then closing the cross over line block valve that was routing the CCR gas to the purge gas heater. Ensure that the CCR gas crossover block valve is tightly closed. Ramp the reduction zone and surge pot electric heaters to their design temperatures. Re-start the catalyst circulation and normalize the operations.

7. Loss of One Sulfur Injection Pump

The sulfur injection system is made up of three independent pumps, lines, and low flow alarms. The parallel nature of the system should give adequate protection under any normal failure such as loss of 1 pump, plugging of 1 line, or failure of 1 flow alarm. The total DMDS injection should always be split equally between the three injection routes. One third of the total required flow is injected at the common combined feed inlet to the hot combined feed exchangers. Two thirds of the total required flow is injected at the common outlet of the hot combined feed exchangers (HCFEs). In the event of a single DMDS injection route failure (pump trip or line plug), DMDS injection through

the remaining injection routes should immediately be increased to compensate such that the total DMDS injection requirement is maintained:

- 1) **Immediately** increase the injection rate of the other two pumps to 50% to provide the normal combined rate of the three pumps. Insure that at least 50% of the flow is going upstream of the HCFE.
- 2) If this is not done, or cannot be done within 5 minutes, **immediately** reduce the reactor inlet temperatures to 600°C (1112°F) over a span of 20 minutes.
- 3) Determine the cause of the loss of DMDS flow and correct.
- 4) Once the normal DMDS flow can be re-established and the cause is determined to be not a chronic issue, begin raising reactor temperatures to normal operating levels at 30°C/hr (54°F/hr).
- 5) If the total design DMDS flow cannot be re-established, proceed with a normal shutdown.

8. Loss of Sulfiding

The loss of sulfur injection results in severe coke formation that fouls the internals of the reactor system requiring a shutdown and complete disassembly of the reactors for cleaning. In the event that total sulfur injection is lost, the following steps must be taken **immediately**:

- 1) Reduce the reactor inlet temperatures to 550°C (1022°F) within 30 minutes followed by further reduction in temperature to 500°C (932°F) at 50°C/hr (120°F/hr).
- 2) If the DMDS flow can be re-started and the cause is determined not to be a chronic issue, re-establish the desired injection level of 75 to 85 wt ppm based on combined liquid propane feed. Monitor the reactor effluent H₂S level using Dräger tubes and stabilize the operation in excess of 50-60 mol ppm H₂S at all times. Once the desired injection level has been reduced and the effluent H₂S content is consistently greater than 50 mol ppm, begin raising reactor temperatures to normal operating levels at 30°C/hr (54°F/hr).
- 3) If the DMDS flow cannot be re-established, proceed with a normal shutdown.

9. Loss of Net Gas (carrier Gas) for Sulfur Injection

Injection upstream of the HCFE net gas is used as a carrier gas to assist in the vaporization and injection of DMDS into the hot gas stream downstream of the HCFE. Without a proper carrier gas, the DMDS will coke the injection nozzle potentially to the point where DMDS injection to that location will cease. In case of loss of net gas to sulfur injection, the following actions must be taken:

Immediately switch all DMDS injection to upstream of the HCFEs. If this is not done, or cannot be done within 5 minutes, **immediately** reduce the reactor inlet temperatures to 600°C (1112°F) over a span of 20 minutes.

When net gas to sulfur injection is available, re-establish flow to downstream of the HFCE.

10. Loss of Catalyst Circulation

The following actions shall be taken in the event that catalyst circulation is stopped.

- 1) Immediately reduce any reactor inlet temperature that is above 640°C (1184°F) to 640°C (1184°F). Further, reduce the last reactor's inlet temperature, if above 620°C (1148°F) to 620°C (1148°F)
- 2) Increase the recycle gas rate to maintain 0.60 H₂/HCBN minimum in the combined feed to the reactors, reducing the Oleflex liquid propane feed rate to the reactors as necessary to maintain a 20% minimum void blowing margin in each reactor.
- 3) Increase DMDS injection such that H₂S concentration in the reactor effluent is between 70 and 80 mole ppm.
- 4) Once catalyst circulation has been stopped for 12 hours, reduce the last reactor inlet temperature to 600°C (1112°F)
- 5) Once catalyst circulation has been stopped for 18 hours, reduce all other reactor inlet temperatures to 620°C and maintain the last reactor inlet temperature at 600°C (1112°F)
- 6) Once catalyst circulation has been stoppage for 48 hours, reduce all reactor inlet temperatures to 600°C (1112°F).

- 7) When catalyst circulation can be restarted, restart circulation. The regeneration tower shall be initially started in "Black Burn" mode, switched to "Dual Zone Burn" mode and then to "White Burn" mode in sequence. This permits a controlled re-start enabling checks on the burn profile and prevent any core coked or high coked catalyst migrating to the regenerator causing either hot shut down if the burn zone temperature excursion occurred or cold shut down if the transition zone and/or chlorination/drying zone temperature excursion occurred. The switch to "White Burn" mode shall be done after confirming that the coke on regenerated catalyst is <0.2 wt%, and the core coke pill count is <200. Refer to the Oleflex CCR General Operating Manual for more details.
- 8) Once catalyst circulation is resumed, sample the spent and regenerated catalyst every four (4) hours. Once it has been determined that the catalyst which had been in the last reactor during the period of loss of catalyst circulation has passed through the regeneration tower, and it has been confirmed that the regenerated catalyst has less than 0.1 wt% carbon, normalize the reactor section operating conditions with respect to RITs, Oleflex feed rate, H₂/HCBN ratio and DMDS injection rate as necessary.

UOP recommends the following steps be taken in the event of a loss of catalyst circulation when fresh (new) catalyst is present in the reactors. "Fresh catalyst" is any catalyst which has experienced less than three complete regeneration cycles since initially loaded into the unit (other than normal makeup of less than 5 drums at the Surge Hopper).

- 1) Immediately reduce all reactor inlet temperatures to 610°C.
- 2) Increase the recycle gas rate to maintain 0.60 H₂/HCBN minimum in the combined feed to the reactors, reducing the Oleflex liquid propane feed rate as necessary to maintain a 20% minimum void blowing margin in each reactor.
- 3) Increase DMDS injection such that H₂S concentration in the reactor effluent is between 70 and 80 mole ppm.
- 4) Once catalyst circulation has been stopped for 12 hours, reduce the last reactor inlet temperature to 600°C (1112°F).
- 5) Once catalyst circulation has been stopped for 18 hours, reduce all other reactor inlet temperatures to 600°C (1112°F) and maintain the last reactor inlet temperature at 600°C (1112°F).
- 6) When catalyst circulation can be restarted, restart the catalyst circulation. The regeneration tower shall be initially started in "Black Burn" mode,

switched to “Dual Zone Burn” mode and then to “White Burn” mode in sequence. This permits a controlled re-start enabling checks on the burn profile and prevent any core coked or high coked catalyst migrating to the regenerator causing either hot shut down if the burn zone temperature excursion occurred or cold shut down if the transition zone and/or chlorination/drying zone temperature excursion occurred. The switch to “White Burn” mode shall be done after confirming that the coke on regenerated catalyst is <0.2 wt%, and the core coke pill count is <200/200. Refer to the Oleflex CCR General Operating Manual for more details.

- 7) Once catalyst circulation is resumed, sample the spent and regenerated catalyst every 4 hours. Once it has been determined that the catalyst which had been in the last reactor during the period of no catalyst circulation has passed through the regeneration tower, and it has been confirmed that the regenerated catalyst has less than 0.01 wt% carbon, resume prior operating conditions with respect to reactor inlet temperatures, H₂/HCBN ratio and DMDS injection rate.

11. H₂S Breakthrough in the Reactor Effluent

The main concern with the H₂S breakthrough from the REDs is its potential impact on the SHP catalyst, fuel gas contamination and potential impact on propylene product quality.

H₂S is a temporary poison for the SHP catalyst. In the conventional C3 Oleflex units where the SHP is located on the Oleflex liquid product, bypass the SHP reactor immediately if any sulfur break through from the reactor effluent drier (RED) occurs in the effluent section of the unit. A drop in temperature differential (Del T) across the SHP and/or the SHP reactor bed exotherm moving down the catalyst bed may indicate potential H₂S breakthrough poisoning the SHP catalyst.

In the C3 Oleflex units with the reactor effluent contact cooler where the SHP is located on the recycle propane stream, if the H₂S breaks through from the RED it will most likely get removed in the deethanizer system via the deethanizer rectifier off gas. If this gas joins the fuel gas pool, then it can result in the refinery fuel gas getting contaminated with H₂S. This will ultimately reflect as SO_x emission from the heater stacks appearing as white smoke during night time. The concern with SO_x emission is general corrosion around the area due to acid gas formation when in contact with humid air. Local regulatory standards on stack emissions shall be governing factor whether or how long this is permissible. When not permissible, the deethanizer off gas will have to be routed to flare which offers better dispersion of the fumes. Though almost all the H₂S is expected to get removed via deethanizer rectifier off gas in these unit configurations, minor amount of equilibrium carryover to PP splitter system will

take place. Therefore, in addition, monitor the H₂S in PP splitter overhead remains within specification and that recycle propane does not have H₂S which can act as temporary poison for the SHP. Monitor the SHP reactor bed temperature profile and Del T and make sure the SHP reactor performance is not decreasing as seen by decreasing Del T and/or exotherm moving down the catalyst bed. In the meanwhile it will be required to correct the problem on RED as soon as possible to prevent breakthrough.

If the SHP reactor has been poisoned by sulfur, a hot hydrogen strip may be warranted. Refer to the SHP Hot Hydrogen Stripping procedure in the Special Procedures section of this manual.

H₂S breakthrough from the REDs can occur due to a variety of causes as listed below. Plan appropriate action as necessary eliminating each potential root cause one by one.

- 1) RED is not being regenerated properly due to lack of regenerant flow. If the regenerant flow is <0.1 psi/foot (2.3 KPa/Meter) of adsorbent bed, there will be greater potential for channeling within the bed causing improper regeneration.
- 2) RED regenerant gas inlet temperature is inadequate. Normal regenerant temperature is ~230°C (446°F).
- 3) Heating step is being concluded before the required bed outlet temperature is attained. At the end of the heating step, the regenerant effluent temperature should plateau out at ~200°C – 210°C (392°F – 410°F) for at least 1 hour before concluding the heating step for effective regeneration.
- 4) Heating step is being terminated prematurely before all the solvent and/or heavies contaminants from the bed have been removed. This is reflected as cessation of collection of heavies/solvent in the RED regenerant knockout drum. If these components are not removed properly, the bed capacity may progressively decrease over time ultimately causing premature H₂S breakthrough.
- 5) Leaks in the RED regenerant steam heater. Where steam heater is employed, any leak of steam will pre-load the RED bed while in cooling step reducing its capacity during adsorption step.
- 6) There exist polar regenerant feed contaminants like CO₂, H₂S and H₂O etc. Such contaminants depending on the source of regenerant can pre-load the bed
- 7) Chloride treater HCl breakthrough: HCl will be adsorbed by the RED adsorbent permanently but will not get removed efficiently at the design

regenerant temperature. This will over a period of time cause pre-mature breakthrough of H₂S

- 8) RED regeneration steps like depressure, purge, heating, cooling, hydrocarbon loading together are taking more time than the pre-set adsorption cycle time. Investigate why the cycle time is high and take appropriate measures.
- 9) There is air leak into the system generating excess CO and H₂O in reactor effluent. Follow the emergency guidelines on "Air leak into the Oleflex reactor circuit"

12. CO breakthrough into the PSA Hydrogen Product

PSA unit is used to purify the native hydrogen stream from the Oleflex unit and provide essentially 100% pure hydrogen to the SHP and CCR units. One of the most serious contaminants in the PSA product hydrogen stream is carbon monoxide (CO). The Oleflex and CCR units require that the PSA hydrogen contain less than 1 mol ppm CO. However, even less than 1 mol ppm should be avoided. The PSA unit should be operated to provide as low a level of CO as can be detected.

CO levels at or above 1 mol ppm will permanently deactivate the oxidized regenerated catalyst being received into the catalyst reduction zone on top of reactor1 from the CCR regenerator section. In the event of CO breakthrough from the PSA H₂ product, following actions should be immediately initiated.

- 1) Stop the catalyst circulation by placing lock hopper 2 in STOP mode to prevent oxidized catalyst transfer to the reduction zone.
- 2) Start cooling the reduction zone electric heater to 350°C over a 1 hour period. This will limit the amount of catalyst reduction on the residual oxidized catalyst residing in the reduction zone.
- 3) Since the catalyst circulation has been stopped, follow through the emergency guidelines for "Loss of Catalyst Circulation" as discussed earlier.
- 4) Place the CCR in "Hot Shut Down" condition. In this condition, the regenerator will continue to operate with [a] upper and lower burn zone heaters; and the lower air heater running [b] air injection cut off to the burn zones and the chlorination/drying zone [c] chlorine injection stopped to the upper burn zone and at the outlet of the lower air heater. Refer to the CCR General Operating Manual for the procedural details.

- 5) Once the PSA unit performance issue has been resolved, and CO is confirmed to be <1 mol ppm, increase back the reduction zone temperature to achieve 540°C catalyst bed temperature at the bottom of the reduction zone.
- 6) Restart lock hopper 2 by switching to RUN mode once the necessary reduction zone temperature has been achieved.
- 7) Restart the regenerator switching from “Black Burn” to “Dual Zone Burn” and then to “White Burn” when the regenerated catalyst coke is <0.2 wt. % and core coke pill count is <200200.

13. Air Leak into the Oleflex Reactor Circuit

This emergency is applicable only to the C3 Oleflex units with the Reactor Effluent Contact cooler that operate at slightly lower pressure at the outlet of Reactor 4.

Air leak into the Oleflex reactor circuit on these units is possible through the section of the unit piping and equipment starting downstream of reactor 4 outlet nozzles leading to the 1st stage suction flange on the REC. Depending on the location of the air leak, temperature and pressure the rate at which the air has been leaking into the system can vary. Further, molecular oxygen (O₂) contained in the air can exit from the REC discharge as O₂ or as reaction products namely CO and H₂O with trace levels of CO₂. Molecular nitrogen (N₂) associated with the air leak is expected to exit unconverted in native form.

REDs are expected to capture the non-native H₂O in the reactor effluent. A portion of the CO and O₂ exit through net gas and the remainder through deethanizer off gas. N₂ is expected to get removed predominantly via the deethanizer off gas.

Progressive increase in air leak can lead to

[A] H₂S and/or H₂O breakthrough from the REDs

[B] O₂ and/or CO breakthrough from the PSA unit

[C] Trace CO₂ reacting with H₂S and converting to COS in the RED with potential COS contamination of product propylene.

Respective emergency procedures outlined earlier in either case must be followed for H₂S breakthrough from the RED and CO breakthrough from the PSA unit. This procedure will limit to O₂ breakthrough in PSA H₂ product, COS in propylene product and H₂O breakthrough from the RED as follows:

13.1 Oxygen Breakthrough in PSA H2 Product:

In the PSA unit is required to deliver product hydrogen within certain permissible oxygen contaminant level (typically <1 mol ppm max oxygen), oxygen breakthrough will constitute an emergency. The operator response will depend on the economic drivers.

- 1) Decrease the adsorption cycle timer on the PSA unit until the oxygen level in the product is within the specification limit. This will result in decreased hydrogen product recovery in the PSA.
- 2) If the impact on hydrogen recovery is unacceptable while obtaining the on spec hydrogen product, then gradually inch up on the operating pressure at reactor 4 outlet by gradually increasing the pressure in 1 KPa increments while monitoring the reduction in oxygen level in the reactor effluent, net gas and PSA hydrogen product until the PSA hydrogen product is consistently on spec.
- 3) Maximum permissible level of oxygen in the PSA hydrogen supply to Oleflex is limited to 65 mol ppm. If oxygen > 65 mol ppm in PSA hydrogen being returned to Oleflex, the operator shall gradually inch up on the operating pressure at reactor 4 outlet further by gradually increasing the pressure in 1 KPa increments. After each increment, monitor the reduction in oxygen level in the reactor effluent, net gas and PSA hydrogen product. Keep decreasing the pressure until the PSA hydrogen product is consistently on spec or REC suction flange stable pressure is 1-3 KPaG (positive pressure) whichever occurs first.
- 4) Potential impact of oxygen contaminated PSA H2 product on SHP must be addressed. If the oxygen in PSA H2 >500 mol ppm it can result in recycle propane H₂O >1 mol ppm potentially causing problems in feed chiller pass of cold separation system. Switch to alternative bottled PSA grade H₂ injection.

13.2 COS Breakthrough from RED:

CO₂ is expected only in trace levels in the reactor effluent. CO₂ can react with H₂S to form COS which can then potentially turn up in the propylene product. COS limit on the polymer grade propylene feeding the downstream polypropylene (PP) unit is typically <0.1 mol ppm. Typically the PP unit should be having a COS guard bed. If the propylene product is indicating COS contaminant over the acceptable limit for the Oleflex unit, perform the following checks

- 1) Confirm the COS level in product propylene stream from PP splitter.

- 2) Confirm CO₂ is not there in the RED regenerant gas. CO₂ can get adsorbed onto the bed while in cooling and generate COS while in adsorption. COS being less polar can then start breaking through.
- 3) Confirm there is no CO₂ in any external recycle streams to the reactor section downstream of HCFE and upstream of REC. If CO₂ is present in these streams, it can get adsorbed on the RED beds and convert to COS and cause COS breakthrough.
- 4) Check for COS at RED outlet with Draeger tubes. Confirm repeatability.
- 5) Check for CO₂ in reactor effluent upstream of RED. Establish repeatability of analysis.
- 6) If the COS breakthrough from RED has been established consistently and CO₂ at RED inlet assigned as the root cause, try inching up on the operating pressure at reactor 4 outlet pressure and check if COS level decreased. Keep decreasing the pressure until the COS level in the reactor effluent disappears.

13.3 H₂O Breakthrough from RED:

H₂O in reactor effluent to cold separation system constitutes a major emergency and requires immediate action. Icing in cold section can damage the equipment and lead to unit shut down.

- 1) It is essential to establish the root cause of H₂O breakthrough from RED. Eliminate all the potential root causes identified under the emergency guideline 2.11 "H₂S Breakthrough in Reactor Effluent" other than that assigned to air leak.
- 2) It is expected that H₂S will always breakthrough first before H₂O breakthrough can be seen. The exception to this rule is when there is moisture in the RED regenerant gas pre-loading the RED bed.
- 3) If it is confirmed that CO/H₂O increase in the reactor effluent has been caused by the air leak, inch up on the reactor 4 outlet pressure until the H₂O in reactor effluent stream at RED inlet drops to pre-upset level. Note that the pre-upset level is established from the baseline to segregate native H₂O from non-native H₂O at RED inlet at a given catalyst circulation rate.

C. Fractionation Section

1. Increase in nC_4 and $C_4=$ in the Depropanizer Overhead

Normal butane and C_4 olefins ($nC_4+C_4=$) can turn into coke material in the Charge Heater and cause fouling of the inner screen of the reactors. This may result in premature shutdown of the unit and complete disassembly of the reactor screens for cleaning. In case increased $nC_4+C_4=$ is observed in the Depropanizer overhead, steps must be taken to mitigate the potential for coke formation in the reactor section.

- 1) If the combined amount of nC_4 and $C_4=$ in the depropanizer overhead stream reaches 100 wt.ppm, decrease all reactor inlet temperatures to 630°C within 30 minutes. If the problem has been caused by the upset in PP splitter system, such as heat pump compressor (HPC) trip, follow the emergency guidelines for “The Loss of Heat Pump Compressor” in this section.
- 2) Increase DMDS injection to 200 wt.ppm sulfur based on the liquid feed immediately.
- 3) Increase H_2/HC to a minimum of 0.8 within 30 minutes. Decrease the Oleflex liquid propane feed as necessary to maintain the pressure on the REC suction drum or at the outlet of the reactor effluent contact cooler as applicable.
- 4) Increase the depropanizer bottoms flow and/or the C_4 side draw as applicable with the goal of decreasing the C_4+ contaminants in the stripping section of the column. This can be done by decreasing the tray temperature set point on the temperature controller that reset these stream flows. If the control scheme does not have tray temperature control, then decrease the reboil rate slightly let the propane slip into the side draw and/or depropanizer bottoms drag as applicable. Continue this until the concentration of nC_4 's and $nC_4=$'s in the Depropanizer overhead decreases to <100 wt.ppm.
- 5) Once the concentration of nC_4 's and $nC_4=$'s has remained below 100 wt.ppm in the depropanizer overhead for at least past 2 hours, return reactor operating conditions to pre-upset conditions.

2. Increase in Methyl Acetylene/Propadiene in Depropanizer Overhead

Methyl Acetylene/Propadiene (MAPD) can turn into coke material in the Charge Heater and cause fouling of the inner screen of the reactors. This could result in premature shutdown of the unit and complete disassembly of the reactor screens for cleaning. At all times care must be taken to mitigate the potential for coke formation in the reactor section.

- 1) If the combined amount of MAPD in the depropanizer overhead stream reaches 50 mol ppm, decrease all reactor inlet temperatures to 600°C within one hour.
- 2) Increase DMDS injection to 200 wt.ppm sulfur based on the liquid feed immediately.
- 3) Increase H₂/HC to a minimum of 0.8 within 30 minutes.
- 4) Confirm the origin of the MAPD. Potential sources are slumping in the P-P Splitter, MAPD breakthrough of the SHP reactor, or increased MAPD in fresh feed.
- 5) If the origin of the MAPD is from the PP splitter bottoms, begin routing recycle propane to an off-specification tank and increase fresh feed to the unit to 60% of the design reactor liquid feed rate. If less than 60% of the design feed is available as fresh feed, the unit can be operated, but it is recommended that reactor inlet temperatures be decreased further by 5°C for every 5% reduction in feed rate. This is a nominal target intended to provide operating flexibility when limited off-specification storage is available. Make the necessary operational changes to reduce the amount of MAPD in the PP splitter bottoms.
- 6) If the SHP reactor is suspected of not saturating MAPD, check the SHP H₂ flow and determine if the SHP feed heater is operating between 40 °C (SOR) and 60°C (EOR). Adjust operation of heater and addition of H₂, if necessary, to saturate MAPD. Confirm the PSA H₂ CO content is less than 1 mol ppm. If not, then proceed to Loss of PSA emergency procedure. Confirm that the SHP reactor is liquid full. If not, vent any non-condensable to flare. If the activity of the catalyst appears suppressed, then it's possible that the catalyst has been contaminated with sulfur. Refer to Special Procedures for the SHP hot hydrogen stripping procedure, if sulfur contamination is suspected.
- 7) If the origin of the MAPD is the fresh feed, it is not necessary to route P-P Splitter bottoms flow to off-specification storage. However, reactor

conditions will have to remain at the lower severity (600°C reactor inlet temperatures, minimum H₂/HC of 0.8 and 200 wt.ppm sulfur based on liquid feed) until the fresh feed purity issue is resolved. Note that at the lower reactor severity, the amount of propane conversion in the reactor section will decrease, the recycle propane flow will increase, and the fresh feed flow will decrease. This may result in the concentration of MAPD in the depropanizer overhead stream to drop below 50 mol ppm. It is not recommended to return to pre-upset conditions until the cause for high MAPD in the fresh feed has been resolved.

- 8) Once the cause for the high MAPD's has been resolved and the concentration of MAPD's has remained below 50 wt.ppm in the depropanizer overhead for at least 2 hours, return reactor operating conditions to pre-upset conditions.

3. Heat Pump Compressor (HPC) Shut Down

Units which have the depropanizer heat recovery reboiler heated with the HPC discharge vapors, will have partial loss of heat input into the depropanizer. Refer to Section 3.1 and 3.2. During normal operation, small amounts of methyl acetylene and propadiene (MAPD) not removed in the SHP reactor build on the trays in the PP splitter column. These compounds are coke precursors that can cause the Oleflex reactor internals to become fouled if high enough levels are sent to the reactor section. During normal operation, the equilibrium level of MAPD in the PP splitter bottoms is low enough to not be a concern. However, during a PP splitter upset, large quantities of these potential foulants may slump into the column bottoms and be sent to the reactor section. Therefore, if the HPC shuts down and column reflux is reduced significantly, for any reason, action needs to be taken immediately. The following actions are recommended:

- 1) When the P-P Splitter reflux drops to less than 70% of the design flow, immediately stop all recycle propane back to the depropanizer. Route the PP Splitter bottoms flow to off-spec storage.
- 2) In the C3 Oleflex units where the SHP is located on the recycle propane stream, cut off the hydrogen injection to the SHP and discontinue feed heating.
- 3) Increase the fresh feed to the unit to 60% of the design reactor liquid feed rate.
- 4) If less than 60% of the design feed is available as fresh feed, the unit can be operated, but it is recommended that reactor inlet temperatures be reduced further by 5°C for every 5% reduction in feed rate. This is a

nominal target intended to provide operating flexibility when limited off-spec storage is available.

- 5) At the same time as Steps 1 to 3 above, reduce Oleflex reactor inlet temperature to 600°C and increase DMDS injection to target 200 mol ppm H₂S in the reactor effluent stream. This is a precautionary step to prevent any fouling initiated due to potential MAPD that is sent to the reactor section.
- 6) Adjust the operation of the unit for the new feed rate.
- 7) Pump out the PP splitter column until the levels falls below 100 % before restarting HPC. Once the Splitter reflux is re-established at the design rate, sample the recycle propane. In addition, the Splitter bottoms can be purged of any high MAPD containing liquid by venting to flare at a convenient point.
- 8) Once recycle propane is clean (less than 1.5 wt% propylene and less than 100 ppm total MAPD), begin sending recycle propane to the depropanizer(s). Eventually increase to the pre-upset rate.
- 9) With recycle propane at its original flow rate and the unit stable, increase the reactor inlet temperatures to the desired severity levels and return the DMDS injection rate to the target normal H₂S levels in the reactor effluent.
- 10) Route propylene product to storage when it is on specification.

4. Loss of Refrigeration Unit in the Deethanizer System

The loss of cooling utility on the deethanizer rectifier condenser will lead to increased amount of propylene and propane in the rectifier off gas constituting net product and raw material loss. The following actions are recommended:

- 1) Maximize the cooling to the deethanizer rectifier by closing hot vapor bypass to limit the heat input. Reduce steam to deethanizer stripper as required to control column pressure.
- 2) Monitor levels in deethanizer rectifier and deethanizer rectifier receiver. Reduce rectifier reflux as needed to prevent loss of level in the rectifier receiver.
- 3) Monitor the deethanizer overhead composition and check for high propane and propylene levels in the deethanizer rectifier off gas. If the off

gas was being used as a regenerant gas in applications where excessive olefins cannot be tolerated, route the off gas to flare.

4) If refrigeration on the Deethanizer cannot be re-started, it may be desirable to shut down Oleflex unit. The decision to shut down should weigh the following risks versus lost production during a shutdown:

- Loss of propane & propylene to off gas
- Stability of operating pressure in the deethanizer system
- Propylene contamination due to excessive amounts of C₂'s slipping out from the deethanizer stripper bottoms

5. SHP Unit – High Temperature Excursion

Note: Whenever the SHP unit is taken out from service, monitor MAPD content in the stream feeding the SHP unit closely. MAPD builds up in the PP splitter at several thousand ppm around the diolefins side stream withdrawal tray. In the event of PP splitter upset, MAPD will slump to the column bottom ending up in the depropanizer overhead. Maximum allowable MAPD in depropanizer overhead is 50 mol ppm. Refer to emergency procedure in the previous sections in case of high MAPD in the Depropanizer overhead.

Reactor temperatures in the SHP should not exceed 70°C at any time. Temperatures higher than the maximum constitute a high temperature excursion emergency condition. The SHP interlock system protects the unit against high temperature excursions. In case of a high temperature excursion in the SHP:

- 1) Verify heat input to SHP feed heater has been cut off
- 2) Hydrogen injection to the SHP reactor has been cut off
- 3) Verify the SHP H₂ Compressor has tripped, if not shut it down.
- 4) If temperature continues to increase, open the SHP reactor bypass and then isolate the SHP reactor to routing all the feed via reactor bypass.
- 5) Isolate heat input source:
 - a) In units provided with steam heater, close the block valves on the steam supply line. Drain condensate from the tube-side and keep the low point drain open until re-start.
 - b) In units provided with alternate heating medium such as deethanizer stripper bottoms stream, fully open the SHP feed exchanger bypass

- 6) If the temperatures are still increasing immediately proceed to depressure the reactor routing the contents via PSV bypass to flare
- 7) Continue to de-pressure slowly ensuring there is no icing seen on the SHP reactor shell while monitoring the bed temperatures. If the line-up is such that the hydrocarbon content in shell side of feed heater is included in de-pressuring, make sure condensate side drain is kept open to prevent potential icing leading to tube rupture.
- 8) After the pressure has been reduced to ~ 50 KPa G (~7 psig), open the nitrogen connection at the bottom of the reactor and begin to sweep the reactor with nitrogen sending the contents to relief header via PSV bypass.
- 9) Continue the sweep for at least ½ hour or as necessary until all the bed temperatures have decreased to <100°C whichever occurs last.
- 10) Then close the PSV bypass and pressure up the SHP reactor with nitrogen to ~600 KPaG. Stop and positively isolate the nitrogen injection point.
- 11) Confirm that the root cause of temperature excursion has been eliminated for example- HPC trip requiring PP splitter bottoms pump out and subsequent restart to re-establish PP splitter operations; routing diolefins stream to flare as necessary to remove accumulated diolefins from the enriched tray sections
- 12) Liquid fill and restart according to the normal SHP start up procedure.

6. SHP Unit – Loss of Feed

Note: Whenever the SHP unit is down, monitor MAPD content very closely in system. The MAPD builds up in the P-P splitter at several thousand ppm at around the diolefins side stream withdrawal tray. In case of a PP splitter upset, the MAPD will slump to the bottom and end up in the depropanizer overhead. The maximum allowable MAPD in depropanizer overhead is 50 mol ppm. Refer to emergency procedure in the previous sections in case of high MAPD in the Depropanizer overhead.

The loss of liquid feed to the SHP results in a sudden increase of H₂ to di-olefin ratio. This in turn can cause the onset of rapid and complete saturation of dienes and even olefins to paraffins in the SHP reactor, as well as a loss of liquid which normally helps absorb the heat released by the saturation reactions. The end result of this situation is a potential high temperature excursion. The reactor temperatures in the SHP should not exceed 70°C at any time. Temperatures higher than the maximum constitute a high

temperature excursion emergency condition (see above procedure on SHP Unit High Temperature Excursion). In case of loss of SHP feed, the following actions are recommended:

- 1) Cut out hydrogen immediately
- 2) Cut steam to the feed heater
- 3) If feed cannot be restored within 24 hours, shut down the SHP. Depressure the reactor and purge with nitrogen. Keep under inert conditions until restart.

7. SHP Unit – Loss of Hydrogen

The loss of hydrogen to the SHP increases the ability of the diolefins and olefins to react with each other over time and gradually promote the formation of gum-like deposits on the catalyst surface (permanent deactivation).

- 1) Confirm that hydrogen is lost
- 2) Cut heat input to the SHP feed heater by cutting off steam or routing the heating medium via SHP feed exchanger bypass as applicable
- 3) If feed cannot be restored within 24 hours, shut down the SHP. Depressure the reactor and purge with nitrogen. Keep under inert conditions until restart.

XII. Special Procedures

This section includes procedures not covered in other sections of the General Operating Manual or other documentation provided by UOP.

A. Reactor Maintenance

Whenever austenitic stainless steel cannot be adequately protected by maintaining temperatures above the dew point of water or by an adequate nitrogen or dry air purge, a protective neutralizing environment should be established in this equipment prior to exposure to air. An effective neutralizing environment can be provided by washing with a dilute soda ash solution.

The Oleflex Reactors, Fired Heaters, Hot Combined Feed Exchangers and associated piping are all constructed of austenitic stainless steel. This section of the manual describes the steps required to prepare these vessels prior to them being exposed to the air. The basic steps required for preparing these pieces of equipment are as follows:

- 1) Shutdown the Oleflex Unit
- 2) Hydrocarbon free the Oleflex Reactor Section
- 3) Unload Oleflex catalyst from the Reactors
- 4) Neutralize reactors and equipment to be opened
- 5) Protection of fired heaters
- 6) Perform reactor maintenance
- 7) Ammoniated water wash following neutralization

1. Shutdown the Oleflex Unit

The shutdown of the Oleflex unit is covered in Section X-Normal Shutdown, of this manual.

2. Hydrocarbon Free the Reactor Section

- 1) Following shutdown, make certain that the feed valve from the depropanizer overhead column is shut.
- 2) Slowly de-pressure the reactor section to flare through the pressure control valve on the REC suction drum or reactor effluent contact cooler as necessary.
- 3) Once the reactor section is de-pressured, it will have to be pressured and de-pressured 2-3 times with nitrogen to remove the remaining

hydrocarbons. Pressure up the reactor section to $\sim 3 \text{ kg/cm}^2\text{g}$ ($\sim 300 \text{ KPa G}$ or 44 psig) with nitrogen, and then de-pressure to flare. Do not pressure any equipment past its design pressure.

Note: The Nitrogen used for the purging and protection of austenitic stainless steels should be dry with an atmospheric dew point less than -65°C (-85°F) and the oxygen content should be limited to a maximum of 100 ppm. The oxygen content of the nitrogen used should be specified by the supplier, since the analysis for oxygen in this low concentration range requires elaborate analytical equipment which may not normally be available in the refinery laboratory. At the user's discretion, 5000 ppm of ammonia may be added to the nitrogen to compensate for nitrogen containing oxygen or water. It is added at the nitrogen injection point.

- 4) As the reactor section is being de-pressured, sample the material being vented and analyze for hydrocarbons. Continue to pressure and de-pressure the reactor section with nitrogen until the hydrocarbon concentration is $<0.5 \text{ mol}\%$.
- 5) Once the reactor section has been hydrocarbon freed, the reactor section must be positively isolated from the fractionation section to prevent hydrocarbon ingress. Since there can be variations in unit configurations, check for the specific unit the type and locations of process isolation. The locations include but are not limited to the following list:
 - Any external regenerant streams to the RED regeneration system.
 - Oleflex propane feed to the cold separation system.
 - Oleflex liquid product to the cold separation system
 - Reactor effluent inlet to the cold separation system.
 - Combined feed outlet from the cold separation system.
 - Start-up external hydrogen injection line to REC suction drum or reactor effluent contact cooler as applicable
 - Fresh solvent inlet line to contact cooler, if applicable
 - Spent solvent outlet line from contact cooler or solvent recovery column bottoms, if applicable
 - Depropanizer bottoms stripper or debutanizer bottoms to solvent recovery column, if applicable
 - Any external recycle streams from other units to the Oleflex reactor section.
- 6) Once it has been confirmed that the reactor section has been isolated, hydrocarbon freed and under a slight nitrogen purge, catalyst unloading can start.

3. Unload Oleflex catalyst from the Reactor Section

For the Oleflex Reactor Unloading procedure refer to Section C, Step 1.

4. Perform Neutralization of the Reactors and Equipment

4.1 Prepare Neutralization Solution

Aqueous neutralizing solutions of soda ash (Na_2CO_3) should be prepared in the range of 1.5-2.0% by weight. Excess concentration could lead to carbonate corrosion. In this range, a sufficiently high level of alkalinity will be provided to neutralize any polythionic acids that may be formed.

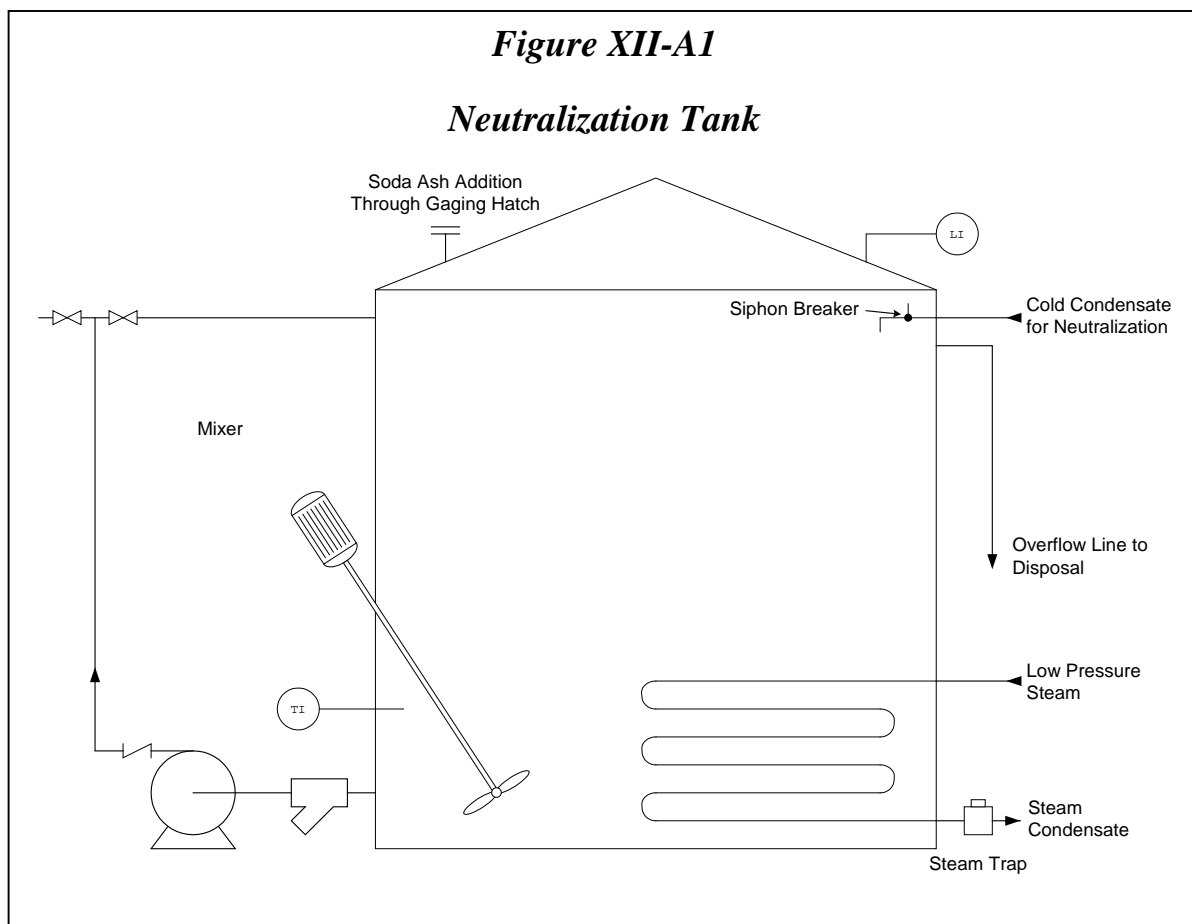
It is important that the solution have a pH >9. To avoid exposing the austenitic stainless steel equipment to a concentration of chlorides, it is recommended that the chloride content of the final soda ash solution must be less than 150 mol ppm based on lab analysis.

As added protection against chloride attack from the small amount of chloride present in the neutralizing solution, 0.5% by weight of sodium nitrate should be added to the soda ash solution. Sodium nitrate concentrations much above 0.5% should not be used, however, in order to avoid the possibility of stress corrosion cracking of carbon steel piping and equipment in the system.

Finally, a wetting agent for use in alkaline solutions is recommended to promote penetration of coke, scale, or oil films. Typically, dosage does not exceed 1 gallon of additive per 1000 gallons of soda ash solution (0.2 wt% max). The objective of adding a wetting agent is to achieve a higher degree of penetration, thus these additives have surfactant properties. Types of compounds used include ethoxylated linear alcohols and alkyl ether phosphate esters. Usually clients desire a wetting agent that is biodegradable and has low foam tendencies. The choice of wetting agent is generally made by the contractor doing the cleaning. UOP is not in a position to recommend a specific product. However, the following products have been used before for this service:

- a. Pen 88 - an ethoxylated compound containing C_8 alcohols.
- b. Alphonics 810-60 – is a 60 wt% ethylene oxide solution containing alcohols in the C_8 - C_{10} range.
- c. Alphonics 1012-60 - a 60 wt% ethylene oxide solution, but contains alcohols in the C_{10} - C_{12} range.
- d. Aztron Surfactant No. 5 - a neutralized alkyl ether phosphate ester.

Figure XII-A1 shows the mixing tank used for preparing the neutralizing solution. The tank is equipped with a mixer and heater.



To prepare the neutralization solution, do the following:

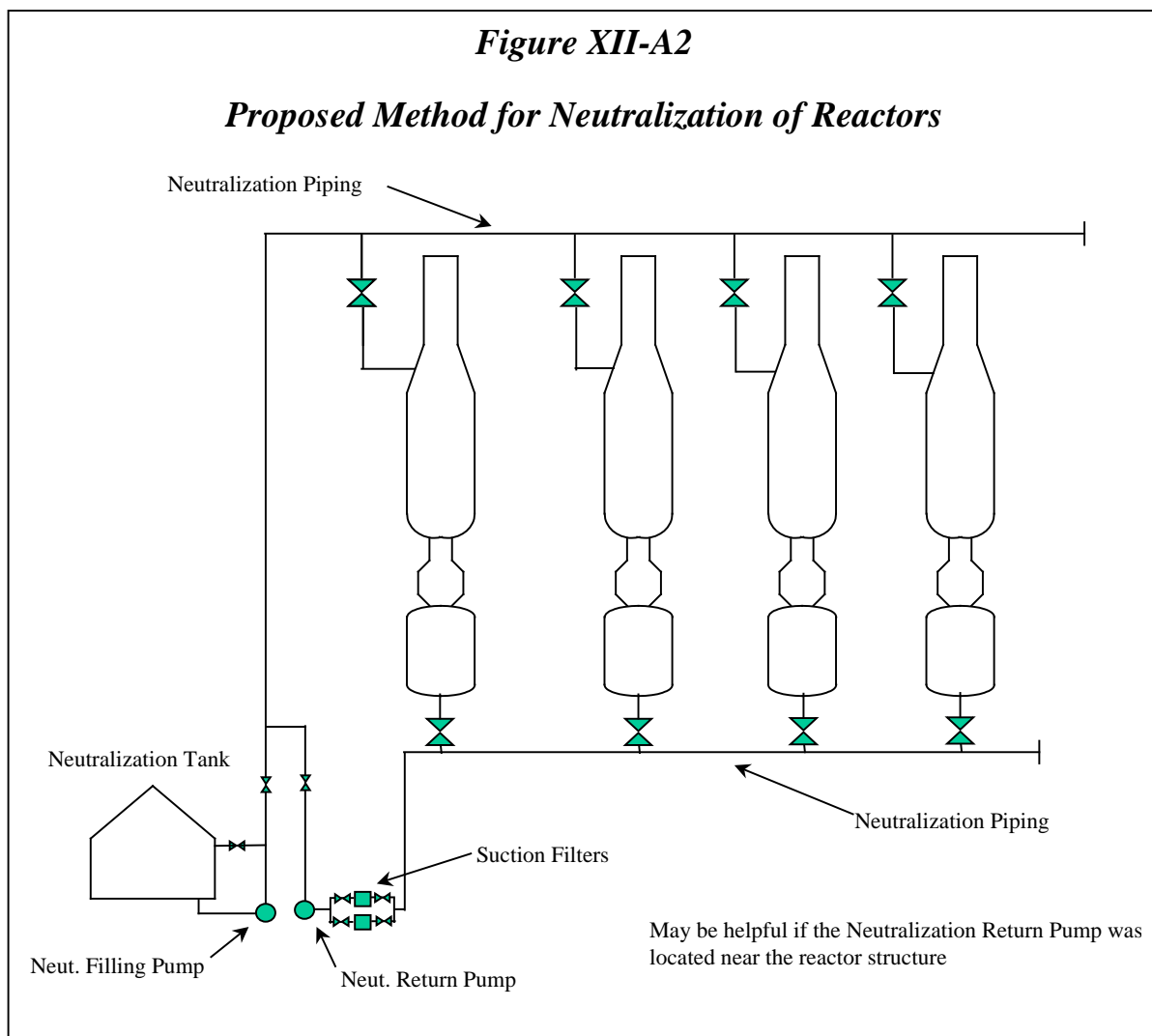
- 1) Fill the neutralization tank with about 15% more water than will be required to fill the particular reactor that is going to be neutralized. The extra neutralization solution can be used to spray the reactor internals intermittently while they are exposed to the atmosphere. A fresh batch of neutralization solution should be used for each reactor and HCFEs. Neutralization solution should not be reused in other vessels or piping.
- 2) Commission the tank heater and begin warming up the water. Preheating the water to about 38°-50°C (102-122°F) will facilitate dissolving all the soda ash.
- 3) Commission the tank mixer and the circulating pump.
- 4) Based on the amount of water in the neutralization tank, calculate the amount of soda ash, sodium nitrate and wetting agent that must be added to the solution. Target between 1.5-2.0 wt% Na_2CO_3 , and 0.5 wt% sodium nitrate and wetting agent in the final solution.

- 5) Begin to slowly add the soda ash, sodium nitrate and wetting agent into the tank from the gauging hatch.
- 6) Allow the material to circulate for ~2 hours. Take a sample of the material and confirm that the pH of the material is >9. If the pH is <9, add more soda ash to the solution and allow it to mix for an additional 2 hours before taking another sample. Depending on the amount of additional soda ash, it may be necessary to add more water so that the final solution is within 1.5-2.0 wt% Na₂CO₃. When solution has been mixed verify that total chlorides are less than 150ppm.

NOTE: A 1.5-2 wt% soda ash solution will provide a sufficient level of residual alkalinity on metal surfaces after the solution drains from the equipment. This low concentration will also facilitate solution preparation.

4.2 Perform Neutralization of Reactors

Whenever a soda ash solution is used for neutralizing and protecting austenitic stainless steel, the piping or piece of equipment involved should be filled completely full with the solution. The equipment should then be allowed to soak for a minimum of two hours before the soda ash solution is drained and the equipment is exposed to the air. Preferably, circulation of the solution should be done to ensure better contacting on the surfaces. **Additionally, the solution should be hot.** For example, circulation for 2-4 hours at 38-50°C (102-122°F) should result in effective contacting. This circulation should be continued for a minimum period of two hours before draining and exposing the equipment to air. A proposed piping diagram of the neutralization system is shown in Figure XII-A2.



Please refer to the procedure below for neutralizing the Oleflex reactors.

- 1) The Oleflex Reactor should be under a slight nitrogen purge.
- 2) Install the appropriate blinds on the reactor. The following blinds must be installed:
 - Reactor inlet and outlet
 - Reduction Zone/Surge Pot inlet piping, downstream of the electric heater
 - Reduction Zone/Surge Pot outlet piping
 - Equalization line at the top of the Reduction Zone and each of the Surge Pots
 - Plug purge line between the flow control valve and the downstream gate valve

- Catalyst Collector inlet and outlet purge line (if the Catalyst Collector is going to be neutralized with the reactor). UOP recommends that the catalyst collector be included in the neutralization of the reactor.
- Each Catalyst transfer line from the bottom of the reactor to the Catalyst Collector (if the Catalyst Collector is not going to be neutralized with the reactor)

3) The following piping modifications must be made:

- If Reactor #1 is being neutralized, remove the catalyst lift line and the manual B-valve from the top of the Reduction Zone.
- If the other reactors are being neutralized, remove the catalyst lift line, the manual B-valve and the automated B-valve from the top of the Surge Pot.
- Install at the top reactor flange a T-connection with a pressure gauge on one side and a gate valve on the other side. The pressure gauge is for monitoring the pressure in the reactor. The other valve is for determining when the reactor is filled with neutralization solution and also used for preventing a vacuum when the neutralization solution is being drained from the reactor.
- A flex hose connection must be made from the reactor structure neutralization piping to the reactor plug purge inlet line.
- A flex hose connection must be made from the reactor structure neutralization piping to the reactor inlet elbow.
- If the Catalyst Collector is to be neutralized, the manual V-ball valve below the Catalyst Collector must be removed and a flex hose connection must be made at this location.

- 4) Line-up the reactor that will be neutralized to the neutralization system. Pump neutralization solution from the neutralization tank to only the plug distributor using the neutralization filling pump. Do not attempt to fill the reactor with neutralization solution from the reactor inlet elbow. If the reactor was filled with liquid from the bottom without the plug distributor filled with liquid, the buoyancy forces would damage the plug distributor.
- 5) Keep the valve on the T-assembly at the top of the Surge Pot open at all times. Once the reactor is filled with liquid, neutralization solution will shoot out from this location. When this occurs, shut off the neutralization filling pump and block in the neutralization piping gate valve at the plug distributor. Also isolate the gate valve on the discharge of the neutralization filling pump.
- 6) Open the 3/4" gate valve that is on the Catalyst Collector outlet elbow to bleed off the air pocket that collects in this location. Keep the gate valve open until neutralization solution leaks out, and then close the valve.

- 7) An air pocket will also collect just below the bottom of the Surge Pot. Once the reactor manway has been opened, it is recommended that the bottom section of the Surge Pot be rinsed with neutralization solution.
- 8) Allow the neutralization solution to soak in the reactor for at least 2 hours.
- 9) After two hours, the neutralization solution should be circulated through the reactor for an additional two hours. The neutralization return pump should be used for circulating the neutralization solution through the reactor. The suction to the neutralization return pump is at the bottom of the reactor, either from the Catalyst Collector or the reactor inlet elbow. The discharge of the neutralization return pump is sent to the reactor plug distributor.
- 10) Filters should be installed on the suction of the neutralization return pump to protect the pump from catalyst chips, pills, etc. that will flow from the reactor during circulation. One filter should be on-line at all times. When the ΔP across the on-line filter increases, the back-up filter should be placed on-line. The first filter should be taken off-line and the filters cleaned.
- 11) The neutralization solution will collect coke, dust, catalyst chips and pills as it passes through the reactor. To prevent from fouling the neutralization tank, it is not recommended to allow neutralization solution to return to the neutralization tank once it has been sent to the reactor. The discharge piping on the neutralization fill pump to the reactors should remain closed.
- 12) After the neutralization solution has circulated through the reactor for two hours, it can be dumped to disposal. The neutralization solution should be drained from the bottom of the reactor first. Once all of the neutralization solution has been drained from the bottom of the reactor, pressure up the reactor with nitrogen to 3 kg/cm²g and siphon out the neutralization solution in the plug distributor by opening the gate valve on the plug distributor piping. This may have to be repeated 2-3 times until all of the neutralization solution (or as much as possible) has been removed from the plug distributor.

4.3 Performing Neutralization of Hot Combined Feed Exchangers (if required)

- 1) The HCFE's should be maintained under a slight nitrogen purge.
- 2) Install blinds at the combined feed inlet and outlet flanges of the HCFE.
- 3) Connect a flex hose from the neutralization supply piping to the neutralization filling flange at the bottom of the exchanger. Remove the

blank flange from the neutralization vent flange, but do not connect flex hosing to this flange yet.

- 4) Commission the neutralization filling pump and begin filling the shell side of the exchanger.
- 5) Once the exchanger is filled, neutralization solution will be seen flowing from the neutralization flange at the top of the exchanger.
- 6) Shut off the neutralization filling pump and block in the discharge valve. Allow the neutralization solution to soak in the HCFE for at least 2 hours.
- 7) After two hours, the neutralization solution should be circulated through the exchanger for an additional two hours. The neutralization return pump should be used for circulating the neutralization solution through the exchanger. The suction to the neutralization return pump is at the bottom of the exchanger. The discharge of the neutralization return pump is sent to the top of the exchanger.
- 8) Filters should be installed on the suction of the neutralization return pump to protect the pump from any debris that may be in the exchanger. One filter should be on-line at all times. When the ΔP across the on-line filter increases, the back-up filter should be placed on-line. The first filter should be taken off-line and the filters cleaned.
- 9) To prevent from contaminating the neutralization tank, it is not recommended to allow neutralization solution to return to the neutralization tank once it has been sent to the HCFEs. The discharge piping on the neutralization fill pump to the reactors should remain closed during this step.
- 10) After the neutralization solution has circulated through the exchanger for two hours, it can be dumped to disposal. It is acceptable to drain the neutralization solution from the bottom of the exchanger.
- 11) An identical method can be used for neutralizing the tube side of the HCFE's.
- 12) After the solution is drained from the equipment, the surfaces should be allowed to dry so that a film or fine deposit of soda ash remains on all surfaces for added protection against polythionic acid formation. Therefore, after draining the soda ash solution, do not rinse the system with steam or water.

Following reactor inspection and reassembly activities the reactor internals need to be rinsed to remove the soda ash. Please see Part 7 for the ammoniated water wash procedure.

5. Protection of Fired Heaters

The austenitic stainless steel tubes in the fired heaters can best be protected by maintaining the pilot burners lit in the heater box, even when there is no circulation of process material through the tubes. The pilot burners should be adjusted to keep the tubes warm and dry, to maintain the environment inside the tubes above the dew point of water. As a general rule, about 205°C (400°F), as measured by thermocouples placed in the hip sections of the heater and directly below any convection coils that may exist, will usually be sufficient for this purpose. Only fuel gas firing should be used for this operation because of the difficulty in controlling and maintaining sufficiently small flames when burning fuel oil.

It is important during this period of heater operation that the heater firing is under strict control and that the firing pattern is properly established to provide good heat distribution. Sufficient thermocouples should be installed throughout the hip sections of the heater to provide a good measurement of the firebox temperatures and to monitor the distribution of heat in the firebox. These thermocouples should be located below any convection bank in the heater and should be connected to a continuous recorder provided with high and low alarm points. The low alarm point should be set at about 150°C (302°F) and the high alarm point at about 232°C (450°F). Stack temperatures should never be used to control firebox temperatures.

If during a unit shutdown the heater hip temperatures cannot be maintained above 205°C (400°F) or the pilot burners must be shut off, action must be taken to prevent polythionic acid attack of the heater tubes. This section of the manual describes how to protect the process-side of the heater tubes in the event the heater box is going to be cooled below 205°C (400°F).

The heater-side of the heater tubes does not require neutralization as long as the fired heaters are firing fuel gas. The typical Oleflex unit uses fuel gas and will not be required to neutralize the outside of the heater tubes. While it is true that excess oxygen during normal operation could react with sulfur in the fuel gas to form sulfur scale on the outside of the tubes, the scale that forms on the tube surface will be a sulfate, not a sulfide. If water condenses on the surface during turnaround activities, the sulfate will not react to form polythionic acid, as will happen with a sulfide. Of course, this assumes that enough sulfur is present in the fuel gas to form a sulfate in the first place. Most often the sulfur concentration in fuel gas is much lower.

On the occasions when the fired heaters are shut down, it is convenient to also schedule inspection of the tubes. Inspection should include measuring the tube outside diameters for comparison to the original new tube O.D.'s, dye penetrant checking of welds and heat affected zones for cracks, and random ultrasonic flaw

detection of the heat affected zones around welds. Periodic radiographic inspection should be conducted to check for scale or deposits inside the tubes.

5.1 Protection of Process-Side of Heater Tubes

When pilots are shutdown it is important that the process side of the heater tubes does not contain oxygen and water (or water vapor). If the heater pilots must be shut down during normal operation, oxygen should not be present because as the heater tubes cool, there may be very small amounts of water condensing inside the tubes. However, water will not be harmful in the absence of oxygen.

If the heater must be cooled down and it is suspected that trace quantities of oxygen might be present, then before cooling the heater, the system should be de-pressured to flare. Continue to maintain 205°C (400°F) firebox temperatures while de-pressuring.

After the system has been de-pressured, pressure the reactor circuit with nitrogen to a pressure below the PSV set pressure at the REC Suction Drum. Repeat this de-pressuring/pressuring procedure as many times as required to reduce the oxygen concentration, by dilution, to as much below 100 mol ppm as is possible. Maintain the process side of the tubes under a positive nitrogen pressure until heater firing can be re-established.

5.2 Exterior Surfaces of Heater Tubes

Whenever heater fires must be shut down and the tubes are allowed to cool, it is recommended that the fire-box be prepared suitably for man-entry. Instrument air or dry plant air can be continuously blown into fire-box keeping the stack damper, all burner air registers, and all doors and ports in the heater box closed to minimize air consumption while maintaining sufficient oxygen level suitable for man-entry.

Following confined space entry requirements, when the heater fires are shut down, it is convenient to also schedule inspection of the tubes. Inspection should include measuring the tube outside diameters for comparison to the original new tube O.D.'s, dye penetrant checking of welds and heat affected zones for cracks, and random ultrasonic flaw detection of the heat affected zones around welds. Periodic radiographic inspection should be conducted to check for scale or deposits inside the tubes.

5.3 Neutralization of Heater Tubes (if required)

Typically heater tube neutralization is not required during turnarounds. However, neutralization is necessary when process side of tubes will be exposed to oxygen at temperatures below the dew point of water such as when a tube or tubes are cut out of the coil, or any time heater piping is exposed to atmosphere. During heater tube neutralization the tubes should be filled with fresh neutralization solution and allowed to soak for a minimum of two hours. With vertical coils, where it is not possible to completely fill the unvented upper return bends, it is necessary instead to vigorously circulate the soda ash solution through the tubes for a minimum of two hours to assure contact of all surfaces. After draining the soda ash solution, do not flush with steam or water but, instead, allow a film of protective soda ash to remain in the tubes.

Prior to unit restart perform ammoniated water wash of heater tubes to remove the soda ash. Please see Part 7 for more information.

6. Perform Reactor Maintenance

Perform reactor maintenance as required. The activities include but not limited to reactor internals dis-assembly, reactor inner and outer screen cleaning and reactor internals re-assembly.

7. Ammoniated Water Wash following Neutralization

This activity is carried out subsequent to reactors re-assembly following maintenance works on the Oleflex reactors and reactor section equipment. Since the procedure requires that soda ash film be maintained all the time on the austenitic equipment removed for maintenance; the reactor shell, inner and outer screens, plug distributor, reduction zone and surge pots, catalyst transfer piping within the reactor, catalyst transfer piping from reactor to catalyst collector and catalyst collectors would have soda ash layer adhered to the surface. In addition, if the Oleflex heaters and/or HCFEs neutralization has been done, these would have leftover sodas ash film after draining the neutralization solution.

The soda ash adhered to the austenitic metal surface must be removed completely from the reactors, catalyst collectors, heaters, HCFE and affected piping. The soda ash can potentially affect the activity of the Oleflex catalyst and must be prevented from contact with the catalyst.

The ammoniated water rinse is used to remove the soda ash film and to protect the passivated metal surfaces prone to PTA attack once soda ash layer is washed down. It is not desirable to leave soda ash inside the reactor circuit since sodium salts can contaminate the catalyst. Additionally any soda ash solution left would release carbon dioxide when heated and leave sodium hydroxide on the metal exposing the austenitic metallurgy to potential caustic embrittlement. Further any chloride in the

soda ash film could concentrate and cause chloride stress corrosion cracking. Wiping off the soda ash film from shell, screens, and surge pots, followed by vacuuming will create a clean metal surface that can be sprayed with ammoniated water.

Due to accessibility constraints (reactor inlet and outlet have been blinded and catalyst transfer pipes between the reactors and catalyst collectors has been removed) the heaters and catalyst collectors will need to be filled with ammoniated water, left for 2 hours and drained out to remove the soda ash film. Vacuum suckers can be used to remove the water from the heater tubes and dispose-off to the refinery effluent treatment system since no drain points exist at the bottom U section. Catalyst collectors can be drained to chemical drain system.

HCFEs, need to be filled with ammoniated water on the shell side followed by tube side, left for 2 hours (or ammoniated water circulated using a pump if provisions exist) and removed to the refinery effluent treatment system. Therefore these activities will be independent of the reactors.

Perform the following steps for each reactor after reassembly of the reactor internals:

- 1) Prepare ammoniated water wash solution. The pH must be above 9 if ammoniated condensate is used.
- 2) Fill up the reactors and catalyst collectors starting with plug distributor all the way until the water comes off the top vent from the reduction zone and surge pots in the same manner as that followed for filling up with the neutralization solution. The ammoniated water should be allowed to drain from the bottom of the reactor.
- 3) Install catalyst transfer pipes and close reactors in preparation for bulk dry out.

Bulk dry out will need to be performed following the reassembly of the reactors in order to remove free water. See Section VI-Normal Startup, for more details. In preparation for bulk dry out, air free and pressure reactor circuit with nitrogen.

B. Loading Reactors and Vessels

During initial startup and following reactor or vessel unloading refer to the procedure below. The Reactor and Vessel Loading section is broken into the following parts:

- 1) Oleflex Reactors
- 2) Chloride Treater
- 3) Reactor Effluent Driers
- 4) Feed Guard Beds
- 5) Feed Driers
- 6) SHP Reactor

During vessel loading all confined space regulations shall be followed. Also the loading team should review the Material Safety Data Sheet (MSDS) and process hazards to determine the personal protective equipment that is needed to perform the loadings.

1. Oleflex Reactor Loading

The Oleflex reactors are loaded one at a time, using catalyst loading equipment (loading and receiving hoppers) to lift the catalyst into the reactor catalyst surge pot/reduction zone. The catalyst free falls from the surge pot, through feeder pipes, into the reactor catalyst annular space. The side manway at the top of the reactor will be opened to allow entry and observation of the loading. The following general procedures are employed in the loading.

- 1) Sample the reactor environment to confirm that safe entry is possible. Make sure all necessary safety precautions are taken for confined space entry.
- 2) Initiate and maintain an instrument air purge at the connection located on the reactor outlet pressure gauge.
- 3) Confirm that the nuclear level indicators are operational. However, prior to entry into any vessel with a nuclear level indicator, confirm that the radiation source has been blocked out and is locked. Generally, this is verified or supervised by the refiner's plant safety personnel.
- 4) Open reactor manway.
- 5) Prior to beginning the loading procedure, an inspection of the reactor internals should be performed to verify that there is not damage and that the reactors are free of pipe scale and/or debris. Suggested inspection points include: Cover deck inspection: nuts, bolts, catalyst transfer pipes, etc.; Annulus inspection from cover deck inspection ports and boroscope; Boroscope inspection of reactor inlet and outlet piping.
- 6) A hoist or crane is used to lift catalyst to the top of each reactor. The catalyst is loaded into large hoppers located at grade. These hoppers are equipped with a slide valve in the outlet line. The hoppers are raised to the top of the reactor and unloaded into the surge pot. Monitor the catalyst bed through the inspection ports in the cover deck to ensure that catalyst is flowing evening through catalyst transfer pipes and there is no debris in the catalyst bed.
- 7) The loading crew will estimate the required catalyst for each reactor. Once the catalyst level is near the cover deck height, the loading rate should be

closely controlled via the hopper slide valve. Once the catalyst level is into the reactor surge pot the following should be verified and/or performed:

- Each catalyst transfer pipe is filled with catalyst
 - Check catalyst level in reactor via the cover deck inspection ports.
 - Close cover deck inspection ports when finished.
 - Check cover deck for catalyst pills, debris, tools, etc.
 - Clean cover deck and close reactor manway.
- 8) Slowly load until the nuclear level indicator at the top of the reactor indicates that the normal catalyst level is reached. Check catalyst outage.
 - 9) For initial startup or after a nuclear level instrument has been replaced. Perform nuclear level calibration.
 - 10) Calibrate the lift engager and lock hopper below reactor being loaded. Refer to nuclear level calibration procedure provided by the Instrument Advisor.
 - 11) Load catalyst used during lift engager or lock hopper calibration into the top of the reactor from which it was removed. Only load until surge pot nuclear level instrument indicates catalyst level.
 - 12) Fully document the loading and record the exact catalyst quantities loaded. Further, composite samples of catalyst should be retained.
 - 13) Close the reactor manway and reinstall Reduction Zone/Surge Pot catalyst transfer pipes. Maintain dry instrument air purge to reactor.

2. Chloride Treater Loading

The Chloride Treater is loaded in the conventional manner. Refer to the detailed loading procedure provided by the UOP Chief Technical Advisor. The following procedure assumes that the vessel is isolated, unloaded, hydrocarbon freed, cleaned and under nitrogen pressure.

- 1) Positively isolate and de-pressure the vessel to flare through the PSV bypass.
- 2) Pressure the vessel with dry instrument air and de-pressure. Pressure and de-pressure the vessel until it is safe for entry.

- 3) Open the vessel bottom manway. Remove inlet elbow and inlet distributor. Verify that vessel is safe for entry.
- 4) Check the inside for cleanliness and clean as required. Check that the outlet distributor has been correctly installed. Mark the vessel tangent location on 4 sides and the required ceramic ball layer height for each specified size of ceramic ball.
- 5) Load the ceramic balls of each specified size through the bottom manway until the marked height is attained. Close the bottom manway and bolt it up.

Note: It is recommended to perform a leak test following the closure of the bottom manway. If the manway leaks after the vessels are completely loaded then the vessel will need to be unloaded to fix the manway leak.

- 6) Prepare a loading platform at the top placing the conical bottom loading hopper such that the bottom of the hopper is at least 600 mm above the inlet nozzle flange.
- 7) Attach a knife edge valve together with pipe spool to the bottom nozzle of the loading hopper. Attach a canvas sock to the pipe spool down-stream of the valve. The sock should be long enough for the person loading to distribute the adsorbent around the vessel.
- 8) Start loading the adsorbent through the top of the vessel through the loading hopper. Control the loading with the knife edge valve.
- 9) Level the adsorbent every 300 mm to get uniform loading density. Record loading density.
- 10) Stop when adsorbent reaches the proper level. Fully document the loading and record the exact adsorbent quantities loaded. Retain composite samples of adsorbents.
- 11) Install the hold down grid. Load the top 19 mm ceramic balls for hold down.
- 12) Install the inlet distributor and inlet elbow. Keeping the vessel isolated, piston purge with nitrogen until all the air is removed. This can be achieved by successively pressuring with nitrogen to ~600 KPaG (~87 psig) and depressuring to ~50 KPaG (~7 psig) for 3-4 times. Maintain 15-20 KPa G (~2-3 psig) nitrogen blanket.
- 13) Perform the following steps to put the chloride treater back in service

- De-pressure nitrogen to flare.
- Slowly pressure the treater using small pressure up line at bed inlet.
- Depressure bed to flare. Repeat pressure/depressure two times.
- Increase the pressure in the Chloride Treater to the same pressure as the inlet pressure.
- Open inlet and outlet block valves. After inlet and outlet valves are open close the bypass valves.

3. Reactor Effluent Driers (REDs) Loading

The Reactor Effluent Driers (REDs) are loaded in the conventional manner. Refer to the detailed loading procedure provided by the UOP Chief Technical Advisor. REDs must be loaded while the unit is shutdown. The procedure is very similar to chloride treater loading except that REDs have profile wire support screen at the bottom rather than outlet distributor. The following procedure assumes that vessels are isolated, unloaded, hydrocarbon freed, and under nitrogen pressure.

- 1) Positively isolate and de-pressure the vessel to flare through the PSV bypass.
- 2) Pressure the vessel with dry instrument air and de-pressure. Pressure and de-pressure the vessel until it is safe for entry.
- 3) Open the vessel bottom manway. Remove inlet elbow and the inlet distributor. Verify that vessel is safe for entry.
- 4) Check the inside for cleanliness and clean as required. Check clearance between the vessel shell and the profile wire grid banding plate. Check the ceramic rope packing has been installed as specified correctly.
- 5) Mark the vessel tangent location on 4 sides and the required ceramic ball layer height for each specified size of ceramic ball.
- 6) Load the ceramic balls of each specified size through the bottom manway until the marked height is attained. Close the bottom manway and bolt it up.

Note: It is recommended to perform a leak test following the closure of the bottom manway. If the manway leaks after the vessels are completely loaded then the vessel will need to be unloaded to fix the manway leak.

- 7) Prepare a loading platform at the top placing the conical bottom loading hopper such that the bottom of the hopper is at least 600 mm above the inlet nozzle flange.

- 8) Attach a knife edge valve together with pipe spool to the bottom nozzle of the loading hopper. Attach a canvas sock to the pipe spool down-stream of the valve. The sock should be long enough for the person loading to distribute the adsorbent around the vessel.
- 9) Start loading the adsorbent through the top of the vessel through the loading hopper. Control the loading with the knife edge valve.
- 10) Level the adsorbent every 300 mm to get uniform loading density. Record loading density.
- 11) Stop when adsorbent reaches the proper level. Fully document the loading and record the exact adsorbent quantities loaded. Retain composite samples of adsorbents.
- 12) Install the hold down grid. Load the top 19 mm ceramic balls for hold down.
- 13) Install the inlet distributor and inlet elbow. Keeping the vessel isolated, piston purge with nitrogen until all the air is removed. This can be achieved by successively pressuring with nitrogen to ~600 KPaG (~87 psig) and depressuring to ~50 KPaG (~7 psig) for 3-4 times. Maintain 15-20 KPa G (~2-3 psig) nitrogen blanket.
- 14) Perform the following steps to put the reactor effluent drier (RED) back in service
 - De-pressure nitrogen to flare.
 - Slowly pressure the RED using small pressure up line at bed inlet.
 - Depressure bed to flare. Repeat pressure/depressure two times.
 - Increase the pressure in the RED to the same pressure as the inlet pressure.
 - Open inlet and outlet block valves. After inlet and outlet valves are open close the bypass valves.

Note: If the unit has start-up regenerant meeting the required quality specification is available; which can be natural gas (NG) or vaporized LPG or nitrogen, then offline RED regenerations are possible when net gas from cold separation is not available. The regenerant should be moisture free (<1 mol ppm), free of CO₂ (<5 mol ppm), R-SH (<1 mol ppm) and H₂S (<1 mol ppm) to be used as a regenerant. Regenerate both the REDs with the start-up regenerant gas (Nitrogen or NG or LPG from vaporizer) after fresh adsorbent loading to remove any moisture adsorbed during the process of loading onto the adsorbent material. This will minimize the potential for moisture breakthrough during the low temperature dry-out.

4. Feed Guard Bed Loading

The resin used in the feed guard beds is shipped water wet and all efforts should be made to store it in a warm dry location to prevent freezing. The feed guard beds can be loaded while the unit is in operation. The following procedure assumes that vessels are isolated, unloaded, hydrocarbon freed, and under nitrogen pressure.

- 1) De-pressure the vessel to flare using the PSV bypass.
- 2) Pressure and de-pressure the guard bed with dry instrument air until it is safe for entry.
- 3) The inlet and outlet valves must be closed. Remove the inlet elbow and remove the inlet profile wire distributor/resin trap.
- 4) Install the outlet strainer or inspect it if it has already been installed.
- 5) The loading hopper shall be in stainless steel construction to prevent the resin from contacting rust while being loaded. Additionally check for cleanliness to prevent the foreign material being dropped into the vessel.
- 6) The vessel should be rinsed with clean condensate and water drained. Insert a hose through the inlet nozzle wetting the walls by moving it around. Continue the rinsing until the drained out water appears as clear as the water used for rinsing. The purpose of rinsing is to remove any adhered loose rust which can contaminate the resin.

Then fill up the vessel with the cooled condensate to the design bed height. The condensate must meet the following requirements or else demineralized water must be used.

- pH 7.0-7.5
- Conductivity <4.0 micro mho/cm
- Iron <0.2 mg/L
- Temperature 48°-50°C (118°-122°F) max.

- 7) Provide a flexible hose to establish a small continuous stream of condensate into the hopper during loading to wet the hopper walls and prevent the resin from dry out.
- 8) Start loading the resin into the vessel through the loading hopper, simultaneously drain the liquid to the chemical drain at the outlet while maintaining the level of water over the resin. The resin density is such that some of it will appears to float on the water.

- 9) Continue loading until the specified quantity of resin has been loaded into feed guard beds.
- 10) Continue to flush the resin bed in down flow with condensate to remove the any manufacturing residue and free acidity from the resin. Initially the effluent water may appear milky with pH as low as 1.5-2.0.
- 11) Flush through the bed and drain the liquid to the chemical drain until the condensate leaving the vessel is clear with pH in the range 6-7. This typically requires 3-4 resin volumes of condensate.
- 12) Stop condensate water flushing. Allow ~ ½ hour for the resin to settle out. Confirm the water level extends above resin that has just been loaded.
- 13) Reinstate the inlet profile wire distributor/resin trap and reconnect the piping at the top of the vessel.
- 14) Purge the free board section of the vessel (the section above water level) with nitrogen to prevent flash corrosion on the free surface.
- 15) The guard bed can be left full of water, under positive N₂ pressure until ready for start-up.
- 16) Prior to inventorying the guard bed with propane, drain and purge the feed guard beds down flow with nitrogen for ~8 hours to remove as much free water as possible. At the blow point at bottom, a wet gas mist should be seen but not free water stream and gas mix nor a completely dry gas. Dry gas will indicate potentially dried out resin which can cause resin shrinkage and damage; and lead to high bed pressure drop in operation due to resin attrition. On the other hand, retaining too much free water can cause prolonged dry-out of the fractionation section.
- 17) Pressure the guard beds and feed line with nitrogen to the nitrogen header pressure ~6-7 kg/cm²g (~85-100 psig).
- 18) Fill feed line and Feed Guard Beds and associated piping with propane using the small diameter filling lines. When pressure reaches ~20 kg/cm²g (~285 psig) close the filling line and crack PSV bypass to vent nitrogen to flare. De-pressure to ~15 kg/cm²g (~213 psig) and repeat until guard bed is liquid full. Stop filling once liquid is seen in the site flow indicator. Filling and venting should be done slowly to avoid lifting the beds.
- 19) Inventory any inlet and outlet piping where hydrocarbon has been removed.

5. Feed Drier Loading

The feed driers are loaded in the conventional manner. Refer to the detailed loading procedure provided by the UOP Chief Technical Advisor. If the feed is water washed prior to sending to the feed driers during normal operations, then the feed driers must be loaded while the unit is shutdown. This is because in such units the feed will always be water saturated requiring the driers to run back to back limiting the adsorption cycle time to design cycle time typically ~24 hours within which it may not be possible to replace the driers online. The design basis for the feed driers is water saturated feed; whereas many a time feed is not water saturated which enables the feed driers to run longer in adsorption cycle in which case there is sufficient time to change the adsorbent in the driers online. The following procedure assumes that vessels are isolated, unloaded, hydrocarbon free, and under nitrogen pressure.

- 1) De-pressure the vessel to flare through the PSV bypass.
- 2) Pressure the vessel with dry instrument air and de-pressure. Pressure and de-pressure the vessel until it is safe for entry.
- 3) Open the bottom manway and the inlet piping. Verify that vessel is safe for entry.
- 4) Check the inside for cleanliness and clean as required.
- 5) Install inlet screen, mark the bottom vessel tangent and ceramic ball layer height for each type of ceramic ball. Load the ceramic balls through the bottom manway. Close the bottom manway and bolt it up.

Note: It is recommended to perform a leak test following the closure of the bottom manway. If the manway leaks after the vessels are completely loaded then the vessel will need to be unloaded to fix the manway leak.

- 6) Load the adsorbent through the top of the vessel. Stop when adsorbent reaches the proper level. Fully document the loading and record the exact adsorbent quantities loaded. Retain composite samples of adsorbents.
- 7) Install the top mesh screen and load the top 19mm bed hold down ceramic balls layer.
- 8) Close the top manway.
- 9) Pressure vessel with nitrogen and de-pressure to flare. Repeat until vessel is oxygen free. Keep vessel under nitrogen pressure until it is put back into service.

10) Check the feed driers for leaks by running the LEL (lower explosive limit) probe around the flanges and pipe and/or instrument joints. Confirm there is no hydrocarbon leak.

11) Perform the following steps to put the driers back in service:

- Pressure the driers to nitrogen header pressure $\sim 6\text{--}7\text{ kg/cm}^2\text{g}$ ($\sim 85\text{--}100\text{ psig}$) using nitrogen connections at the bottom of each vessel.
- Start filling each drier from bottom to top using the small diameter filling lines.
- When pressure reaches $\sim 20\text{ kg/cm}^2\text{g}$ ($\sim 285\text{ psig}$) close the filling line and crack PSV bypass to vent nitrogen to flare. Depressure to $\sim 15\text{ kg/cm}^2\text{g}$ ($\sim 213\text{ psig}$).
- Repeat until drier bed is liquid full. Stop filling once liquid is seen in the site flow indicator if provided or if the line downstream of the PSV bypass frosts up.
- Fill crossover piping with propane.

Note: Filling and venting should be done slowly to avoid lifting the beds. Sudden changes in pressure could lift the beds.

6. SHP Reactor Loading

The SHP reactor can be loaded either during the shutdown or while the unit is in operation. The SHP reactor is isolated and the hydrocarbon flow is routed around the SHP reactor bypass during loading. The following procedure assumes that vessels are isolated, unloaded, hydrocarbon free, and under nitrogen pressure.

- 1) De-pressure reactor to flare using PSV bypass. Pressure and de-pressure using dry instrument air until the reactor is safe to enter.
- 2) Confirm the reactor inlet and outlet blinds are in place and the respective block valves closed. This is necessary for safe loading.
- 3) Clean dirt, scale, and any foreign material found in the reactor.
- 4) Remove the bed thermocouples if they have already been in place.
- 5) Install the catalyst support plate in each of the catalyst unloading nozzles. Install a coil of $1/2\text{''}$ ceramic fiber rope on the top of the support plate after it has been positioned in the unloading nozzles. Refer figure XII-B3.

- 6) Clean the mating surface and install a blind flange on the catalyst unloading nozzle.
- 7) Install the reactor outlet basket screen. Install the extension sleeve in the catalyst unloading nozzle. Refer figure XII-B3. Load the catalyst unloading nozzle and sleeve per the Withdrawal Nozzle Standard Drawing. Typically the catalyst unloading nozzle and sleeve are filled with 6mm (1/4") ceramic balls until the top 100mm. The top 100mm is filled with 3mm (1/8") ceramic balls.
- 8) Use manometer and chalk to mark loading depth of the 19 mm, 6 mm and 3 mm support balls.
- 9) Load 19mm (3/4") ceramic balls through the bottom manway using buckets. Ceramic balls should be spread uniformly across the reactor cross-section. Keep retains for future reference. Compare measurement from top flange to bed to the measurement shown in the loading diagram.
- 10) Load 6mm (1/4") ceramic balls through the bottom manway using buckets. Ceramic balls should be spread uniformly across the reactor cross-section. Keep retains for future reference. Compare measurement from top flange to bed to the measurement shown in the loading diagram.
- 11) Load 3mm (1/8") ceramic balls through the bottom manway using buckets. Ceramic balls should be spread uniformly across the reactor cross-section. Keep retains for future reference. Compare measurement from top flange to bed to the measurement shown in the loading diagram.
- 12) All loading hoppers and socks shall be clean prior to loading the SHP catalyst. Transfer SHP catalyst from the drums into transfer hoppers at grade level. Record the net catalyst weight, lot, and drum number printed on each drum. Keep a small sample of catalyst from each drum. After emptying the contents of each drum of catalyst, replace the foam rubber seal and re-bolt the top back on the drum. Keep these drums in a dry location for future handling of SHP catalyst.
- 13) Lift hoppers to top of SHP reactor and begin loading catalyst into the reactor. Empty the contents into the loading hopper anchored at an adequate elevation from the reactor top manway. On the bottom of the loading hopper, install a 1000 mm long, 100 mm diameter flexible rubber hose. This hose should be fixed to the hopper by bolting to avoid it dropping off into the reactor during the loading.

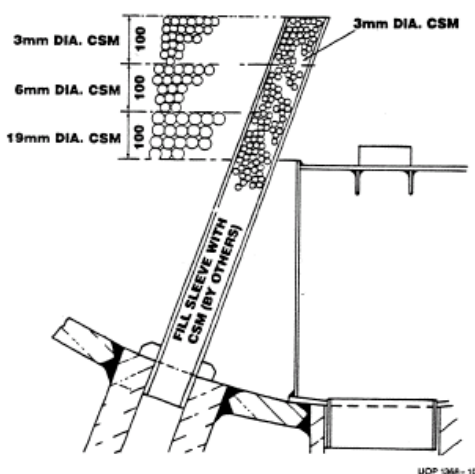
- 14) Swing the flexible rubber hose back and forth in the manway as the catalyst flows through it. This will eliminate the formation of a mound in the center of the catalyst bed. The bed will be loaded more evenly and the possibility of flow channeling during normal operation will be reduced.
- 15) Take a 10 ml sample from each drum of catalyst loaded and combine them into a 1000 ml bottle. Label the samples to indicate what position of the bed they represent. These samples will be held for future reference.
- 16) Halt loading temporarily to level the bed every time after loading 10% drums. Allow the dust to settle and then lower lights into the reactor. Level the catalyst bed.

Further, when the catalyst height reaches to the level of the bed thermocouple, halt the loading temporarily to reinstall the thermocouple.
- 17) Measure and record, on the form provided, the distance between the top surface of the catalyst bed and the reference point and calculate the average bed density all through the loading. Typically loading density variation should be <5%. If it is more, increase the frequency of bed levelling.
- 18) Complete loading the required quantity of catalyst. Do not try to overload since the free board from the inlet liquid distributor to the top ceramic ball layers will have to be maintained to ensure uniform liquid distribution and bed capacity utilization.
- 19) Load the top 6mm (1/4") ceramic balls to the elevation shown in the loading diagram. Ceramic balls should be spread uniformly across the reactor cross-section. Keep retains for future reference. Compare measurement from top flange to bed to the measurement shown in the loading diagram.
- 20) Finally load the top 19mm (3/4") ceramic balls to the elevation shown in the loading diagram. Ceramic balls should be spread uniformly across the vessel cross-section. Keep retains for future reference. Compare measurement from top flange to bed to the measurement shown in the loading diagram.
- 21) Inspect inside of reactor for tools and debris. Install the inlet feed distributor and the vapor/liquid distribution tray (if specified). Box up the reactor.
- 22) Piston purge the reactor with nitrogen by successive pressuring up to ~600 KPaG (~87 psig) and de-pressuring to ~50 KPaG (~7 psig) 3-4 times until oxygen is <0.5 mol%. Maintain ~15-20 KPaG (~2-3 psig) nitrogen blanket until strat-up.

- 23) Remove the blinds at the outlet of the reactors and the outlet of the reactor feed heater. Pressure the reactor to 1.0 kg/cm²g (14 psig) with dry nitrogen. Maintain this slight positive pressure until the plant is ready for startup.
- 24) If SHP catalyst is loaded while the rest of the unit is operating follow the SHP startup procedure provided in Section VI-Normal Startup.

Figure XII-B1

Catalyst Unloading Nozzle Sleeve Extension and Outlet Screen



7. Arsine (As) & Phosphine (Ph) Metal Guard Bed (MGB) Loading (if required)

The As/Ph MGBs where provided are loaded in the conventional manner. Refer to the detailed loading procedure provided by the UOP Chief Technical Advisor. The MGBs can be loaded while the Oleflex unit is in operation. Normally the facility is engineered to safely isolate and bypass the vessel during normal operation to facilitate loading and unloading while the Oleflex unit is in operation. It is assumed here that the vessel has been safely isolated, de-pressured to flare, hydrocarbon freed by nitrogen piston purge until <5%LEL and kept under inert nitrogen blanket.

There may be 2 MGBs to operate in series with crossover piping or a single MGB with bypass depending on the design.

- 1) De-pressure the vessel to flare through the PSV bypass.
- 2) Pressure the vessel with dry instrument air and de-pressure. Pressure and de-pressure the vessel until it is safe for entry.
- 3) Open the side manway at the bottom and the inlet elbow. Verify that vessel is safe for entry.
- 4) Check the inside for cleanliness and clean as required.
- 5) Install outlet screen, mark the bottom vessel tangent and ceramic ball layer height for each type of ceramic ball. Load the ceramic balls through the bottom manway. Close the bottom manway and bolt it up.

Note: It is recommended to perform a leak test following the closure of the bottom manway. If the manway leaks after the vessels are completely loaded then the vessel will need to be unloaded to fix the manway leak.

- 6) Load the adsorbent through the top of the vessel. Stop when adsorbent reaches the proper level. Fully document the loading and record the exact adsorbent quantities loaded. Retain composite samples of adsorbents.
- 7) Install the top mesh screen and load the top 19mm bed hold down ceramic balls layer.
- 8) Close the top manway.
- 9) Pressure vessel with nitrogen and de-pressure to flare. Repeat until vessel is oxygen free. Keep vessel under nitrogen pressure until it is put back into service.
- 10) Check the MGB for leaks by running the LEL (lower explosive limit) probe around the flanges and pipe and/or instrument joints. Confirm there is no hydrocarbon leak.
- 11) Perform the following steps to put the MGB back in service:
 - Pressure the MGB to nitrogen header pressure $\sim 6-7 \text{ kg/cm}^2\text{g}$ ($\sim 85-100 \text{ psig}$) using nitrogen connections at the bottom of each vessel.
 - Start filling each MGB using the small diameter filling lines.

- When pressure reaches ~20 kg/cm²-g (~285 psig) close the filling line and crack PSV bypass to vent nitrogen to flare. Depressure to ~15 kg/cm²-g (~213 psig).
- Repeat until MGB is liquid full. Stop filling once liquid is seen in the site flow indicator if provided or if the line downstream of the PSV bypass frosts up.
- Fill crossover piping with propane.
- Place the MGBs in lead lag if applicable. The freshly loaded shall always be placed in lag position.

Note: Filling and venting should be done slowly to avoid lifting go the beds. Sudden changes in pressure could lift the beds.

8. Mercury Removal Bed Loading (if provided) and Spent Regenerant Treater Loading (if provided)

In some Oleflex units, the fresh propane feed is treated in a mercury removal bed to trap mercury in the feed prior to sending to the arsine and phosphine metal guard beds (MGBs) and/or feed driers since mercury is a poison to Oleflex catalyst apart from causing corrosion issues in the cold separation system aluminum metallurgy. The adsorbent in the spent regenerant treater is typically UOP GB-346S which is a proprietary metal sulfide based adsorbent. On exposure to ambient air the sulfide can turn to sulfate deactivating the adsorbent. The adsorbent supplied in the drums has an outer heavy plastic bag and an inner plastic bag containing the adsorbent. The inner bag has a heat sealed loading neck.

In some Oleflex units the feed driers provided with mercury removal bed, typically UOP HgSIV, in addition to the adsorbent bed to remove water, typically UOP ODG-442; cooled the regenerant effluent is passed through a spent regenerant treater to trap the elutriated mercury prior to routing the regenerant effluent to the fuel gas pool. The adsorbent in the spent regenerant treater is typically GB-562S which is a proprietary metal sulfide based adsorbent. On exposure to ambient air the sulfide can turn to sulfate deactivating the adsorbent. The adsorbent supplied in the drums has an outer heavy plastic bag and an inner plastic bag containing the adsorbent. The inner bag has a heat sealed loading neck.

In either of the above two cases, the adsorbent will require loading under inert nitrogen atmosphere to prevent adsorbent from losing activity in contact with air.

Refer to UOP Standard Drawing 3-356 and 9-123 for details of the material handling equipment and sealed catalyst loading equipment respectively.

It is assumed at this point that the vessel has been hydrocarbon freed, positively isolated and purged with nitrogen to ensure %O₂ is <<5 mol% and is kept under nitrogen blanket pressure at 10-20 KPa G (~1.5-3.0 psig). The spent regenerant treater and mercury removal bed can be changed online provided the arrangement to safely bypass and positively isolate these vessels while in operation have been engineered.

Following general guidelines apply for loading the mercury removal bed and spent regenerant treater:

- 1) Reconfirm the vessel cleanliness, positive isolation and inerting with nitrogen.
- 2) Depressure the vessel to relief header via PSV bypass
- 3) Piston purge with instrument air to nitrogen free the vessel by successive pressuring to ~600 KPaG (~87 psig) and de-pressuring to atmosphere to ~50 KPaG (~7 psig) 3-4 times until %O₂ >20 mol%. De-pressure the vessel.
- 4) Remove inlet elbow and inlet distributor (if specified) and immediately wrap them in plastic.
- 5) Open bottom side man-way.
- 6) Check the vessel is safe for man-entry by testing %O₂ at least at 3 levels through the vessel depth.
- 7) Commission air blower to blow air up through the vessel taking the chute into the vessel from bottom side man-way.
- 8) Mark the vessel tangent on 4 sides of the vessel. Mark bottom ceramic ball layers height for the specified sizes around 4 locations on the circumference of the vessel.
- 9) Install the outlet distributor / adsorbent trap as applicable.
- 10) Load the inert ceramic balls to required height as specified for each size. Level the ceramic ball layer to spread evenly across the vessel.
- 11) Close the side man-way at the bottom.
- 12) At this point stage the inert loading assembly as specified in UOP Standard Drawing 9-123.

- 13)Piston purge the vessel with nitrogen by successive pressuring to ~600 KPaG (~87 psig) and de-pressuring to ~50 KPaG (~7 psig) 3-4 times to reassure the vessel is oxygen and moisture free.
- 14)Start nitrogen purge to loading assembly. Additionally institute a nitrogen purge from the bottom of the vessel.
- 15)Prepare a special drum lid with a ~2" to 3" size hole cut off center at ~1" from the edge of the drum lid. Remove and blunt the sharp edges of the hole to prevent it cutting the plastic liner. The lid shall be provided with quick connect to secure it to the drum throughout the process of loading.
- 16)Remove the lid from the adsorbent drum and unwrap the heavy outer plastic bag. Pull out the loading neck of the inner plastic bag.
- 17)Pull out the loading neck of the inner plastic bag through the special drum lid and then place the lid on the drum and secure it with quick connect. Twist and secure the loading neck to the surface of the lid with a tape.
- 18) Hoist the drum to the loading stage.
- 19)Cut the heat seal on the loading neck and connect the loading neck to the loading assembly
- 20)Remove the wire crimp on the loading neck to load the adsorbent. The loading assembly has a deflector cone which distributes the adsorbent across the vessel eliminating the need for frequent man-entry to level the adsorbent under inert entry.
- 21)Keep log of loading. Once the required quantity has been loaded, stop the nitrogen purge to the loading assembly while keeping the bottom purge on and then remove the loading assembly.
- 22)**Prepare a trained person for inert entry. The person shall have self-breathing apparatus (air-line) throughout the duration of entry into the vessel. Confined space entry regulations shall be followed. Safety watch shall be provided. Inert entry time shall be minimized by proper job planning.**
- 23) Quickly level the adsorbent, place top mesh blanket and load the bed holding 19 mm inert ceramic balls or that specified on the loading diagram.
- 24) Make sure the person has exited the vessel safely.
- 25) Install the inlet distributor and inlet elbow.

- 26) Piston purge 2-3 times with nitrogen venting via PSV bypass through the bottom nitrogen injection point.
- 27) Disconnect the bottom nitrogen purge. Blank off the injection point.
- 28) If it is a spent regenerant treater, once the vessel is de-pressured, slowly open the inlet to the vessel to pressurize it to the same pressure as regenerant effluent bypassing the vessel. Then open the vessel outlet to start the flow through the vessel and bypass in parallel. Then close the bypass to place the spent regenerant online.

If the vessel loaded is a mercury removal bed, then perform the following steps to put the mercury removal bed back in service:

- Pressure the mercury removal bed to nitrogen header pressure ~6-7 kg/cm²g (~85-100 psig) using nitrogen connections at the bottom of each vessel.
- Start filling each mercury removal bed using the small diameter filling lines.
- When pressure reaches ~20 kg/cm²-g (~285 psig) close the filling line and crack PSV bypass to vent nitrogen to flare. Depressure to ~15 kg/cm²-g (~213 psig).
- Repeat until mercury removal bed is liquid full. Stop filling once liquid is seen in the site flow indicator if provided or if the line downstream of the PSV bypass frosts up.

Note: Filling and venting should be done slowly to avoid lifting go the beds. Sudden changes in pressure could lift the beds.

C. Unloading Reactors and Vessels

During vessel unloading all confined space regulations shall be followed. Also the loading team should review the Material Safety Data Sheet (MSDS) and process hazards to determine the personal protective equipment that is needed to unload the various vessels.

1. Oleflex Reactor Unloading

The following procedure assumes that the reactor circuit has been hydrocarbon freed, safely isolated and under nitrogen blanket.

- 1) Confirm that [a] the spacer blinds have been installed at the reactor inlet and reactor outlet, reactor effluent inlet to cold separation system, combined feed outlet from the cold separation system [b] all connecting lines to the reduction zone and/or surge pot for the subject reactor have been isolated by closing the block valves and installing blinds [c] All external streams to the reactor section must be positively isolated by closing the block valves and installing the blinds [d] external hydrogen and propane vapor inlet to the REC suction drum or reactor effluent contact cooler as applicable are positively isolated [e] plug purge line has been isolated [f] PSA hydrogen product inlet to Oleflex has been isolated (critical for units designed to process external raw hydrogen in addition to native net gas in which case the unit may be running even as Oleflex has been shut down) [g] Oleflex liquid propane feed inlet to the cold separation system has been positively isolated [h] Cold separation system is de-pressured of hydrocarbons and kept under dry nitrogen blanket as necessary [i] Fractionation section can be kept under long loop circulation or shut down as necessary following the guidelines provided under the unit shut down section of this manual.

It is absolutely critical to ensure that all possibilities for air, hydrogen and/or hydrocarbon ingress into the system have been eliminated prior to unloading the catalyst.

- 2) Disconnect the catalyst inlet nozzle on the reduction zone or surge pot as applicable, and swing the transfer piping away. Blank off the disconnected piping. Attach a 2" pipe spool on the manual B valve with a 2" gate valve and a temporary compound pressure gauge (PG); to serve as vent in case no other high point vent is available on the reduction zone/surge pot.
- 3) Commission a nitrogen purge via reactor inlet piping introduced via a suitable connection. The amount of nitrogen purge shall be adjusted such that a slight positive pressure is always maintained in the reactor all the way by reading positive pressure on the compound PG throughout the process of unloading. Note that too much nitrogen injection can interfere with the process of catalyst unloading either holding up the catalyst in the reactor or too much nitrogen issuing out from the catalyst drums.
- 4) Confirm that the following equipment is available:
 - a) Enough clean, dry catalyst drums and lids to unload the catalyst.
 - b) Enough heavy gauge transparent plastic bags to hold and contain the catalyst within the drums
 - c) Enough labels and markers so that each drum of catalyst can be labeled as it is unloaded from the reactor.
 - d) Stationary roller for moving the loaded catalyst drums. The rollers should be located below each of the catalyst collectors.

- e) Hose connected to nitrogen supply.
 - f) Dust masks and gloves for the workers.
 - g) At least 2 calibrated weighing machines each capable of weighing at least 300 lb (~136 Kg)
-
- 5) Maintain the reactor under a slight nitrogen purge during the entire catalyst unloading procedure.
 - 6) Jumper open the V-ball and B-ball valves below the catalyst collector. For the last reactor, jumper open the V-ball and two B-ball valves above and below the lock hopper.
 - 7) Open the manual B-ball and V-ball valves below the catalyst collector.
 - 8) Locate the drum at the collection point and insert the nitrogen lance into the drum. Introduce a slight nitrogen purge into the drum. Too much nitrogen can asphyxiate the personnel handling catalyst unloading.
 - 9) Remove the catalyst sample pot from the 2" B-valve located at the bottom of the lift engager. Make certain the 2" V-valve and B-valve are closed at this time.
 - 10) If the distance from the lift engager to grade is greater than 2 meters, connect a clean, dry canvas hose to the 2" B-valve. The canvas hose should be long enough to reach the top of the catalyst drums.
 - 11) Open the 2" B-valve first. Then open the 2" V-valve to begin unloading catalyst from the reactor into the empty catalyst drums.
 - 12) After each catalyst drum is filled, remove the nitrogen lance inserted into the drum and immediately secure the lid on the drum.
 - 13) On the side of each drum, record the reactor from which the catalyst was unloaded. Also, sequentially number each drum of catalyst. This information will be necessary when reloading the catalyst back into the reactor.
 - 14) Remove the filled catalyst drum away from the reactor structure. Store the catalyst drums in a warehouse or have them adequately covered to protect them from the weather.

Continue to keep the Oleflex Reactor under a slight nitrogen purge until it has been neutralized.

2. Chloride Treater Unloading

Use one of the following procedures to unload the adsorbents from the chloride treater: [a] Vacuuming- Removing the adsorbents by vacuuming requires special equipment and is performed by an experienced contractor [b] Gravity- Unload the adsorbent by gravity following the provisions required under UOP Standard Drawings 3-356 and 9-101 [c] Steam out to safe the vessel followed by adsorbent unloading either by vacuuming from top or by gravity from the bottom side man-way.

In addition all the safety equipment forming part of UOP 903 specifications shall be followed at the minimum unless the refinery practices exceed the requirements specified.

[a] Unloading the Chloride Treater by Vacuuming the Adsorbent from Top under continuous up flow nitrogen purge

This procedure will require inert-entry for a limited duration initially to remove the top 19 mm ceramic balls layer and the floating mesh screen. The adsorbent material shall be removed by vacuuming process employing an experienced contractor. The process involves inserting through the top inlet nozzle a moveable sock connected to the hard vacuum piping which in turn is connected to a collection hopper to which vacuuming apparatus is attached. The material collected in the hopper will be removed to the drums periodically. While removing the adsorbent by vacuuming, there will be some air ingress into the vessel despite the nitrogen purge and therefore it is critical to hydrocarbon free the vessel properly for safe unloading. Following is a guideline procedure that must be followed. The required safety regulations in this procedure must be adhered to all the time and shall not be relaxed without proper discussion/approval process. If the owner refinery standards and/or local regulations exceed the requirements contained in this procedure, they must additionally be complied with.

- 1) Open chloride treater bypass valves. This should be done slowly to not upset the REC.
- 2) Block in the treater inlet and outlet lines with the two gate valves provided. Open the 3/4" bleeders between the two gate valves at the inlet and between the two gate valves at the outlet. The treater is isolated from the process with double block and bleed at both the inlet and outlet.
- 3) Install a blind between each of the block valves at the top and bottom of the vessel. At the top the blind should be installed just downstream of the first block valve. At the bottom the blind should be installed just upstream of the second block valve.

- 4) With the treater blinded from the process, de-pressure it to the flare by opening the PSV bypass.
- 5) Attach a nitrogen hose at the bottom outlet of the vessel using a rated metallic hose suitable for the refinery utility nitrogen header pressure. Attach a 2" pipe spool with temporary compound pressure gauge (PG) and a block valve on the vessel vent.
- 6) Hydrocarbon free the vessel by piston purge with nitrogen by successive pressuring to ~600 KPa G (~ 87 psig) and de-pressuring to ~50 KPaG (~7 psig) for 3-4 times. Use the injection point at the bottom of the vessel and purge from the top high vent point.
- 7) **Then use the ejector and break vacuum with nitrogen. Repeat the process for 8-10 times to ensure vessel is hydrocarbon and H₂S free.**
- 8) **Re-establish the slight nitrogen purge from bottom. Make sure the purge rate is adjusted such that the compound PG at vent point reads <5 KPaG (<0.7 psig). Sample the vent gas for H₂S and hydrocarbon to ensure H₂S<10 mol ppm (shall be below OSHA Permissible Exposure Limit- PEL or the local regulatory limit whichever is binding) and Lower explosive Limit (LEL) < 5%. A special sampling apparatus may be required to sample the gas at low pressure.**
- 9) **If H₂S>10 mol ppm and/or if LEL>5%, repeat Steps 7) and 8) --- vacuuming and vacuum breaking cycles until these requirements have been fulfilled.**
- 10) Stop the nitrogen purge. Depressure the vessel to ~atmospheric pressure. Wait for 2 hours. Check for H₂S and LEL levels again and confirm they are within the prescribed limits. This is because there may be slow release of H₂S and/or hydrocarbon from the adsorbent material.
- 11) Restart the nitrogen purge just enough to maintain positive pressure within the vessel.
- 12) Prepare for inert-entry into confined space following the local regulatory guidelines and refinery safety guidelines. The personnel entering the vessel must be provided with a tested Self Contained Breathing Apparatus (SCBA) that has been tested and approved. Continuous safety watch by the trained personnel must be provided for any emergency rescue while inert-entry into confined space is being performed.

- 13) Remove the inlet elbow and inlet distributor while maintaining slight nitrogen purge from the vessel bottom. Adjust the purge such that a slight draft of nitrogen can be felt at the inlet nozzle.
- 14) Insert the vacuuming sock/lance and vacuum out the 19mm ceramic balls top layer. A person may perform inert entry to move the chute around to ensure proper removal of the material if necessary.
- 15) Remove the top wire mesh under inert-entry.
- 16) **Once this has been accomplished, it is expected that inert entry may no longer be required while removing the adsorbent material by vacuuming.**
- 17) **Confirm the personnel inside the vessel have exited safely.**
- 18) Cover the large inlet nozzle of the vessel with spliced sheet metal permitting enough gap to move around the vacuuming sock/lance. This limit the air ingress. Make sure nitrogen purge is maintained which is enough to get sucked out by vacuuming apparatus while permitting minimal air ingress into the vessel.
- 19) Unload the adsorbent by vacuuming until the adsorbent level in the vessel reaches approximately until the bottom of the side man-way.
- 20) **While vacuuming out the adsorbent, periodically empty the hopper contents into the spent adsorbent collection drums. A nitrogen hose with lance shall be inserted into each drum before dropping the adsorbent. Keep a water hose nearby ready. If the drums tend to become hot, immediately pour water.**
- 21) Upon completion of removal of material by vacuuming until the level dropped below the bottom of side man-way on the vessel, arrange to remove the remainder via side man-way. At this time the nitrogen purge to the vessel can be stopped.
- 22) Provide proper ventilation for the vessel using blowers. Air flow through the vessel must be directed from bottom to top. The blower must suck air through a chute inserted from the vessel inlet at the top.
- 23) Check the oxygen content in the vessel for safe man-entry.
- 24) Stage a supply of containers for the spent absorbent near the treater.

- 25) Using personnel protective equipment as necessary, unload remainder of the adsorbent.
- 26) Install a temporary unloading assembly with slide valve at the end of an unloading chute attached to the manway. Canvas socks can be connected to these if desired.
- 27) As the drums are filled, remove them immediately with fork lift to park in safe laydown area. The drums shall be parked in a single layer in an open but restricted entry area at least 10 meters away from the live hydrogen and/or hydrocarbon carrying piping and equipment.
- 28) **All the drums shall be filled with the adsorbent with a nitrogen hose/lance immersed into the drum continuously purging the drum. The personnel handling this job shall wear all the necessary personnel protective equipment like appropriate gloves, dust mask, fire retardant clothing like NOMEX, safety goggles and safety shoes. After the drum has been filled place the lid and then remove the nitrogen hose.**
- 29) **The adsorbent removed under nitrogen purge by vacuuming will need to be deactivated prior to land fill by an experienced contractor. To deactivate the adsorbent, the adsorbent needs to be wetted with water in a suitable arrangement like an open bin prior to disposal. The adsorbent can warm up due to heat of adsorption with water. The land fill shall follow all local regulatory and statutory requirements.**
- 30) After unloading, clean the vessel and inspect.
- 31) **Follow the loading procedure in Part B of Section XII-Special Procedures.**

[b] Unloading the Chloride Treater by Gravity under continuous up flow nitrogen purge

- 1) Follow through Step 1) to Step 8) in the previous procedure Section XII C 2 [a].
- 2) Re-confirm nitrogen purge from bottom up through the vessel. Vent from the PSV bypass.
- 3) Prepare the side-way withdrawal chute following the UOP Standard Drawings 3-356 and 9-101.

- 4) Keep a rated metallic hose attached to plant nitrogen utility and a rated utility water hose attached to plant water utility.
- 5) Line up the spent adsorbent drums on a roller. Place the nitrogen lance in the first drum in the line-up on the roller and keep a slight nitrogen purge.
- 6) Carefully loosen the bolts on the side man-way starting with bottom half.
- 7) Loosen the bolts below the bottom davit more than those in the top half as required to open up the space between the flange and man-way cover.
- 8) Control the opening carefully to limit the rate at which the adsorbent drops out from the opening.
- 9) Collect the adsorbent in the drum, remove the nitrogen lance. If there are fumes or the drum becomes hotter, pour water onto the adsorbent.
- 10) Complete unloading up to the side man-way nozzle.
- 11) **All the drums shall be filled with the adsorbent with a nitrogen hose/lance immersed into the drum continuously purging the drum. The personnel handling this job shall wear all the necessary personnel protective equipment like appropriate gloves, dust mask, fire retardant clothing like NOMEX, safety goggles and safety shoes. After the drum has been filled place the lid and then remove the nitrogen hose.**
- 12) **The adsorbent removed under nitrogen purge by vacuuming will need to be deactivated prior to land fill by an experienced contractor. To deactivate the adsorbent, the adsorbent needs to be wetted with water in a suitable arrangement like an open bin prior to disposal. The adsorbent can warm up due to heat of adsorption with water. The land fill shall follow all local regulatory and statutory requirements.**
- 10) Stop nitrogen purge on the vessel by closing the utility nitrogen block valve. Disconnect the hose.
- 11) Open the inlet elbow and inlet distributor.
- 12) Attach the same hose to instrument air utility and start purging the vessel with dry instrument air. Purge at sufficiently large rate.
- 13) Check the oxygen level in the vessel at bottom, middle and top. It shall be minimum 20 mol% at all the three levels.

- 14) Once the vessel is declared safe for man-entry, remove the remainder of the adsorbent, floating screen and ceramic balls from the bottom side man-way.
- 32) As the drums are filled, inerted with nitrogen, remove them with fork lift to park in safe laydown area. The drums shall be parked in a single layer in an open but restricted entry area at least 10 meters away from the live hydrogen and/or hydrocarbon carrying piping and equipment. The drums shall be maintained under inert nitrogen.
- 15) Clean the vessel and inspect.
- 16) **Follow the loading procedure in Part B of Section XII-Special Procedures.**

[c] Steam out to Safe the Chloride Treater Vessel followed by Adsorbent Unloading either by Vacuuming or by Gravity

Adopting this procedure will require that the engineering specifications for the vessel include the steaming operation. Confirm the vessel in your unit has been specified for steaming service before deciding to proceed with this procedure.

Steaming has an advantage that the hydrogen and hydrocarbons together with any HCl and H₂S will get purged out of the vessel more effectively as compared to relatively cold nitrogen purge. Under nitrogen purge it may be more challenging to attain the H₂S < 10 mol ppm (shall be below OSHA Permissible Exposure Limit-PEL or the local regulatory limit whichever is binding) and hydrocarbon < LEL (lower explosive limit). Therefore, where refinery local regulations or statutory regulations do not permit confined space vessel entry even with self-contained breathing apparatus (SCBA) under prescribed inert entry guidelines, steam purging will facilitate contaminant removal prior to vessel entry to the required level.

Following guideline procedure must be followed:

- 1) Follow through Step 1) to Step 6) in the previous procedure Section XII C 2 [a].
- 2) Confirm the PSV bypass is firmly closed.
- 3) Attach a rated pipe spool minimum 2" NB size with 2" NB globe valve to the top vent nozzle on the vessel. The spool shall have a temporary PG suitable to read 0-15 barg range. Attach a rated steam hose minimum 2" NB size to the pipe spool connected to the top vent nozzle on the vessel. Attach a steam hose of the same rating and minimum 2" NB size (with matching gate valve if drain valve is not existing) to the bottom drain nozzle on the vessel.

- 4) Secure and support both the steam hoses by metallic wires as required so that they do not snap off in service.
- 5) Connect the top metallic hose securely to the utility LP steam (~3-4 barg or ~44-58 psig) or MP steam (~8-10 barg or ~116-145 psig) to the top pipe spool attached to the top vent. A slightly higher pressure steam will ensure the steam blowing through the vessel is superheated limiting the amount of condensed steam.
- 6) Route the bottom hose to a secure blow down point. Since contaminants will escape from the blow down point, it is recommended to route the blow point at safe location and secure the area around with restricted entry by barricading as necessary.
- 7) It is acceptable to use hard piping with hot insulation in lieu of metallic hoses.
- 8) Check the arrangement for safe operation.
- 9) Start the steam flow through the vessel in down flow.
 - a) Initially most of the steam will be adsorbed by the adsorbent in the vessel and no steam may be seen from the blow point.
 - b) After a few hours, once the adsorbent is saturated, steam will start slowly blowing out together with condensed out water.
- 10) Operate with maximum steam flow practicable while flushing the vessel.
- 11) Continue the steam purge through the vessel for a minimum of 3-4 hours after the steam has been seen exiting the blow point.
- 12) Stop the steam purge at this point.
- 13) Quickly disconnect the hose at the utility steam connection
- 14) Connect the hose to the portable oil free air compressor or utility instrument/plant air header as required (the latter can be used if they can provide sufficient flow).
 - a) This should be done as quickly as permissible to prevent the vessel from cooling down and condensing out the steam which will make the adsorbents soggy.
 - b) If this activity is being done while the Oleflex unit is in operation, the instrument air header pressure may suddenly drop and there exists possibility of tripping the Oleflex unit. Therefore, a portable air

compressor with a capacity to sweep through at least 3-4 total vessel volumes per minute is recommended.

- c) If this activity is being done while the Oleflex unit is shut down, if instrument air header or instrument air header is used, it will take a much longer time to flush down any condensed out water.
- 15) Start blowing down the air through the vessel in down flow. This will flush down and remove any condensed out water. Continue to blow down with air until the water dripping out from the blow point stops or when only a mist can be seen.
- 16) At this point stop the down flow air blow down by stopping the air compressor.
- 17) Disconnect the top air/steam injection spool and hose. Open the vent valve on the vessel. Reconfirm PSV bypass is firmly closed.
- 18) Connect the bottom drain hose to utility air point. Switch to up flow air purge using only utility air connection. Vent through the top vent valve.
- 19) Disconnect and remove the inlet elbow on the top of the vessel. Remove the inlet distributor. Continue air purge from bottom up.
- 20) Test the oxygen content in the vessel. Check H₂S and LEL levels for reassurance.
- 21) **At this stage, the vessel is ready to be unloaded either by vacuuming from top or by gravity from the side man-way at bottom following the prescribed general procedures in Section XII C 2 [a] and [b] with the exception that nitrogen purge and inert entry will not be required.**

Note that nitrogen purging of the drums is not required in this procedure since the adsorbent has already been deactivated.

- 22) After unloading, dry the vessel by purging with air and then proceed to clean the vessel and inspect.
- 23) **Follow the loading procedure in Part B of Section XII-Special Procedures.**

3. Reactor Effluent Driers Unloading

The reactor effluent driers (RED) will need to be unloaded and reloaded when the unit is shutdown. This is because the unloading and reloading will take long enough

time and the RED in adsorption cycle will most likely breakthrough in H₂S. If it is desired to replace it on line during operations, it will most likely be necessary to reduce the Oleflex feed rate to 60% and decrease the reactor inlet temperatures below 400° C eliminating the DMDS injection to permit completion of the unloading and reloading activities. **Prior to unloading, the reactor effluent driers should be regenerated. This is a critical requirement for safe unloading.** Best practice is to incorporate RED regeneration into the scheduled shutdown procedure.

Use one of the following procedures to unload the adsorbents from the chloride treater: [a] Vacuuming- Removing the adsorbents by vacuuming requires special equipment and is performed by an experienced contractor. [b] Gravity- Unload the adsorbent by gravity following the provisions required under UOP Standard Drawings 3-356 and 9-101[c] Steaming followed by unloading the adsorbents by either vacuuming from top or by gravity from the bottom side man-way.

In addition all the safety equipment forming part of UOP 903 specifications shall be followed at the minimum unless the refinery practices exceed the requirements specified.

[a] Unloading the RED by Vacuuming the Adsorbent from Top under continuous up flow nitrogen purge:

This procedure will require inert-entry for a limited duration initially to remove the top 19 mm ceramic balls layer and the floating mesh screen. The adsorbent material shall be removed by vacuuming process employing an experienced contractor. The process involves inserting through the top inlet nozzle a moveable sock connected to the hard vacuum piping which in turn is connected to a collection hopper to which vacuuming apparatus is attached. The material collected in the hopper will be removed to the drums periodically. While removing the adsorbent by vacuuming, there will be some air ingress into the vessel despite the nitrogen purge and therefore it is critical to hydrocarbon free the vessel properly for safe unloading. Following is a guideline procedure that must be followed. The required safety regulations in this procedure must be adhered to all the time and shall not be relaxed without proper discussion/approval process. If the owner refinery standards and/or local regulations exceed the requirements contained in this procedure, they must additionally be complied with.

Use the following procedure to unload the Reactor Effluent Drier.

- 1) **Regenerate the RED which has to be unloaded by performing heating and cooling steps.**
- 2) Discontinue the regeneration cycle immediately after completing the cooling step.
- 3) Isolate the RED by closing the inlet and outlet block valves.

- 4) Install a blind between each of the block valves at the top and bottom of the vessel. At the top the blind should be installed just downstream of the first block valve. At the bottom the blind should be installed just upstream of the second block valve.
- 5) With the adsorber positively isolated from the process, de-pressure it to the flare by opening the PSV bypass.
- 6) Attach a nitrogen hose at the bottom outlet of the vessel using a rated metallic hose suitable for the refinery utility nitrogen header pressure. Attach a 2" pipe spool with temporary compound pressure gauge (PG) and a block valve on the vessel vent.
- 7) Hydrocarbon free the vessel by successive piston purge with nitrogen by pressuring to ~600 KPa G (~87 KPaG) and de-pressuring to ~50 KPaG (~7 psig) for 3-4 times.
- 8) **Then use the ejector and break vacuum with nitrogen. Repeat the process for 8-10 times to ensure vessel is hydrocarbon and H₂S free.**
- 9) **Re-establish the slight nitrogen purge from bottom. Make sure the purge rate is adjusted such that the compound PG at vent point reads <5 KPaG (<0.7 psig). Sample the vent gas for H₂S and hydrocarbon to ensure H₂S<10 mol ppm (shall be below OSHA Permissible Exposure Limit- PEL or the local regulatory limit whichever is binding) and Lower explosive Limit (LEL) < 5%. A special sampling apparatus may be required to sample the gas at low pressure.**
- 10) **If H₂S>10 mol ppm and/or if LEL>5%, repeat Steps 7) and 8) --- vacuuming and vacuum breaking cycles until these requirements have been fulfilled.**
- 11) Stop the nitrogen purge. Depressure the vessel to ~atmospheric pressure. Wait for 2 hours. Check for H₂S and LEL levels again and confirm they are within the prescribed limits.
- 12) If not within limits, repeat Steps 7, 8 and 11. This is because there may be slow release of H₂S and/or hydrocarbon from the adsorbent material.
- 13) Restart the nitrogen purge just enough to maintain positive pressure within the vessel.
- 14) Prepare for inert-entry into confined space following the local regulatory guidelines and refinery safety guidelines. The personnel entering the

vessel must be provided with a tested Self Contained Breathing Apparatus (SCBA) that has been tested and approved. Continuous safety watch by the trained personnel must be provided for any emergency rescue while inert-entry into confined space is being performed.

- 15) Remove the inlet elbow and inlet distributor while maintaining slight nitrogen purge from the vessel bottom. Adjust the purge such that a slight draft of nitrogen can be felt at the inlet nozzle.
- 16) Insert the vacuuming sock/lance and vacuum out the 19mm ceramic balls top layer. A person may perform inert entry to move the chute around to ensure proper removal of the material if necessary.
- 17) Remove the top wire mesh under inert-entry.
- 18) **Once this has been accomplished, it is expected that inert entry may no longer be required while removing the adsorbent material by vacuuming.**
- 19) **Confirm the personnel working inside the vessel have exited safely.**
- 20) Cover the large inlet nozzle of the vessel with spliced sheet metal permitting enough gap to move around the vacuuming sock/lance. This limit the air ingress. Make sure nitrogen purge is maintained which is enough to get sucked out by vacuuming apparatus while permitting minimal air ingress into the vessel.
- 21) Unload the adsorbent by vacuuming until the adsorbent level in the vessel reaches approximately until the bottom of the side man-way.
- 22) While vacuuming out the adsorbent, periodically empty the hopper contents into the spent adsorbent collection drums.
- 23) **All the drums shall be filled with the adsorbent with a nitrogen hose/lance immersed into the drum continuously purging the drum. The personnel handling this job shall wear all the necessary personnel protective equipment like appropriate gloves, dust mask, fire retardant clothing like NOMEX, safety goggles and safety shoes. After the drum has been filled place the lid and then remove the nitrogen hose.**
- 24) **The adsorbent removed under nitrogen purge by vacuuming will need to be deactivated prior to land fill by an experienced contractor. To deactivate the adsorbent, the adsorbent needs to be wetted with water in a suitable arrangement like an open bin prior to disposal. The**

adsorbent can warm up due to heat of adsorption with water. The land fill shall follow all local regulatory and statutory requirements.

- 25) Upon completion of removal of material by vacuuming until the level dropped below the bottom of side man-way on the vessel, arrange to remove the remainder via side man-way. At this time the nitrogen purge to the vessel can be stopped.
- 26) Provide proper ventilation for the vessel using blowers. Air flow through the vessel must be directed from bottom to top. The blower must suck air through a chute inserted from the vessel inlet at the top.
- 27) Check the oxygen content in the vessel for safe man-entry.
- 28) Stage a supply of containers for the spent absorbent near the treater.
- 29) Using personnel protective equipment as necessary, unload remainder of the adsorbent.
- 30) Install a temporary unloading assembly with slide valve at the end of an unloading chute attached to the manway. Canvas socks can be connected to these if desired.
- 31) As the drums are filled, remove them with fork lift to park in safe laydown area. The drums shall be parked in a single layer in an open but restricted entry area at least 10 meters away from the live hydrogen and/or hydrocarbon carrying piping and equipment. The drums shall be maintained under inert nitrogen.
- 32) After unloading, proceed to clean the vessel and inspect the vessel and the profile wire grid support.
- 33) **Follow the loading procedure in Part B of Section XII-Special Procedures.**

[b] Unloading the RED by Gravity under continuous up flow nitrogen purge

- 1) Follow through Step 1) to Step 9) in the previous procedure Section XII C 3 [a]
- 2) Re-confirm nitrogen purge from bottom up through the vessel. Vent from the PSV bypass.
- 3) Prepare the side-way withdrawal chute following the UOP Standard Drawings 3-356 and 9-101.

- 4) Keep a rated metallic hose attached to plant nitrogen utility and a rated utility water hose attached to plant water utility.
- 5) Line up the spent adsorbent drums on a roller. Place the nitrogen lance in the first drum in the line-up on the roller and keep a slight nitrogen purge.
- 6) Carefully loosen the bolts on the side man-way starting with bottom half.
- 7) Loosen the bolts below the bottom davit more than those in the top half as required to open up the space between the flange and man-way cover.
- 8) Control the opening carefully to limit the rate at which the adsorbent drops out from the opening.
- 9) Collect the adsorbent in the drum, remove the nitrogen lance. If there are fumes or the drum becomes hotter, pour water onto the adsorbent.
- 10) Complete unloading up to the side man-way nozzle.
- 11) **All the drums shall be filled with the adsorbent with a nitrogen hose/lance immersed into the drum continuously purging the drum. The personnel handling this job shall wear all the necessary personnel protective equipment like appropriate gloves, dust mask, fire retardant clothing like NOMEX, safety goggles and safety shoes. After the drum has been filled place the lid and then remove the nitrogen hose.**
- 12) **The adsorbent removed under nitrogen purge by vacuuming will need to be deactivated prior to land fill by an experienced contractor. To deactivate the adsorbent, the adsorbent needs to be wetted with water in a suitable arrangement like an open bin prior to disposal. The adsorbent can warm up due to heat of adsorption with water. The land fill shall follow all local regulatory and statutory requirements.**
- 10) Stop nitrogen purge on the vessel by closing the utility nitrogen block valve. Disconnect the hose.
- 11) Open the inlet elbow and inlet distributor.
- 12) Attach the same hose to instrument air utility and start purging the vessel with dry instrument air. Purge at sufficiently large rate.
- 13) Check the oxygen level in the vessel at bottom, middle and top. It shall be minimum 20 mol% at all the three levels.

- 14) Once the vessel is declared safe for man-entry, remove the remainder of the adsorbent, floating screen and ceramic balls from the bottom side man-way.
- 33) As the drums are filled, remove them with fork lift to park in safe laydown area. The drums shall be parked in a single layer in an open but restricted entry area at least 10 meters away from the live hydrogen and/or hydrocarbon carrying piping and equipment. The drums shall be maintained under inert nitrogen.
- 15) Clean the vessel. Inspect the vessel and the profile wire support grid.
- 16) **Follow the loading procedure in Part B of Section XII-Special Procedures.**

[c] Steam out to Safe the RED Vessel followed by Adsorbent Unloading either by Vacuuming or by Gravity

Adopting this procedure will require that the engineering specifications for the vessel include the steaming operation. Confirm the vessel in your unit has been specified for steaming service before deciding to proceed with this procedure.

Steaming out RED is relatively less advantageous compared to the chloride treater because the RED is regenerable and therefore the contaminants can be effectively removed prior to adsorbent unloading rendering the spent adsorbent safe to unload. It is still necessary to check that the $H_2S < 10$ mol ppm (shall be below OSHA Permissible Exposure Limit- PEL or the local regulatory limit whichever is binding) and hydrocarbon < LEL (lower explosive limit) as best and safe practice. If the local refinery regulations or statutory requirements do not permit inert entry and/or further require that the spent adsorbent shall be deactivated prior to unloading and/or disposal, then steam out procedure can be followed.

Steaming out the RED shall follow the same guidelines as those provided in Section XII C 2 [c]. After unloading, dry the vessel by purging with air followed by cleaning and inspection of the vessel and profile wire grid support. Follow the loading procedure in Part B of Section XII-Special Procedures.

4. Feed Guard Beds Unloading

The following procedure should be used to unload the feed guard beds by gravity assist. Refer UOP Standard Drawings 3-356 and 3-360 for the equipment and facility planning. In addition all the safety equipment forming part of UOP 903

specifications shall be followed at the minimum unless the refinery practices exceed the requirements specified.

Feed guard beds can be unloaded and reloaded while the Oleflex unit is in operation.

- 1) Isolate the feed guard bed (FGB) by closing the inlet, outlet and bypass gate valves. De-blind the de-inventorying line. Close the gate valve on the sample collection line. If one of the FGBs is going to be dumped while the Oleflex unit is still operating, make certain that all of the feed is flowing through the other FGB.
- 2) Slowly vent the hydrocarbon contained in the vessel to dry relief header using the de-inventorying line followed by de-pressuring the remainder vapors via the globe valve located on the PSV bypass. Then close both the valves to relief header.
- 3) Once the hydrocarbons have been vented and the vessel de-pressured to ~flare header back pressure, pressurize the vessel with nitrogen to ~600 KPaG(~87 psig) and then de-pressure to ~50 KPaG(~7 psig). Repeat 3-4 times to eliminate most of the gaseous hydrocarbon contained in the vessel (LEL<5%).
- 4) Install blind just upstream of the second block valve at top inlet, just downstream of the first block valve at top outlet and just downstream of the first block valve on the cross over line. Install blind downstream of the second block valve (on nitrogen side) on the other cross over line.
- 5) Start filling the vessel with cold clean condensate venting out the nitrogen as required.
- 6) Once the vessel is filled up, stop the vent and start flushing the vessel from top to bottom with clean condensate and draining the water to the refinery chemical drain providing a water wet environment for the resin. Flush until the effluent water meets the following parameters:

pH	7.0-7.5
Temperature	Above freezing (>20° C or >68 ° F)

- 7) Then stop flushing and allow the water to drain out from the bottom as much as practicable to limit the amount of water removed together with resin.
- 8) Stage enough clean, empty 55-gallon drums (with covers) near the treaters to store the spent resin.

- 9) Remove the inlet elbow from the vessel and inlet profile wire distributor if the vessel is going to be re-loaded soon after completion of unloading. If not, then the assembly need not be removed.
- 10) Remove the blank flanges and support plate from the withdrawal nozzles and begin unloading the vessel into the drums. If the resin is intended to be reloaded back into the vessel, stainless steel drums shall be used and drums shall be filled with water (or cooled condensate) until the level is seen above the resin prior to placing the cover onto the drum. This will ensure that the resin remains water wet.
- 11) Some resin may stick to the walls of the vessel and it may be required to wash the walls of the vessel with water to ensure that it is all removed.
- 12) Once all the resin has been unloaded, clean the vessel and prepare for inspection. Inspect the vessel and the outlet strainer at the bottom.
- 13) Follow the loading procedure in part B of Section XII-Special Procedures to re-load the bed.
- 14) If the vessel is not going to be loaded, then it should be dried with nitrogen and left under a slight nitrogen pressure until it is loaded.

5. Feed Driers Unloading

The Feed Driers are typically unloaded and reloaded when the unit is shutdown. It is possible to unload and reload while the Oleflex unit is in operation provided the normal feed to the driers is not water saturated which provides sufficient time to carry out the unloading and reloading activities before the online drier bed breaks through in moisture. If unloading/loading is to be done during the normal operations, then the lead feed drier is taken off service for regeneration followed by unloading/loading after which the freshly loaded drier will be placed in lag position. During operation the molecular sieve can pick up trace contaminants in addition to water for example mercury depending on the unit specific design. Therefore it is critical to regenerate the drier prior to unloading.

Use one of the following procedures to unload the adsorbents from the chloride treater: [a] Vacuuming- Removing the adsorbents by vacuuming requires special equipment and is performed by an experienced contractor. [b] Gravity- Unload the adsorbent by gravity following the provisions required under UOP Standard Drawings 3-356 and 9-101 [c] Steam out followed by adsorbent unloading either by vacuuming from top or by gravity from bottom side man-way [d] Flooding the vessel with water followed by drain down and adsorbent unloading either by vacuuming from top or by gravity from bottom side man-way.

In addition all the safety equipment forming part of UOP 903 specifications shall be followed at the minimum unless the refinery practices exceed the requirements specified.

[a] Unloading the Feed Drier by Vacuuming the Adsorbent from Top under continuous up flow nitrogen purge:

This procedure will require inert-entry for a limited duration initially to remove the top 19 mm ceramic balls layer and the floating mesh screen. The adsorbent material shall be removed by vacuuming process employing an experienced contractor. The process involves inserting through the top inlet nozzle a moveable chute connected to the hard vacuum piping which in turn is connected to a collection hopper to which vacuuming apparatus is attached. The material collected in the hopper will be removed to the drums periodically. While removing the adsorbent by vacuuming, there will be some air ingress into the vessel despite the nitrogen purge and therefore it is critical to hydrocarbon free the vessel properly for safe unloading. Following is a guideline procedure that must be followed. The required safety regulations in this procedure must be adhered to all the time and shall not be relaxed without proper discussion/approval process. If the owner refinery standards and/or local regulations exceed the requirements contained in this procedure, they must additionally be complied with.

- 1) **Regenerate the feed drier until completion of the cooling step. Stop the regeneration cycle at this stage.**
- 2) Once the drier has been cooled down, block in the inlet, outlet, and cross-over gate valves. Also block in all gate valves on the regeneration lines leading to that drier and the valves leading to the moisture analyzer. De-blind the de-inventorying line to relief header.
- 3) Depressure the vessel to ~flare header back pressure by venting the hydrocarbon liquids to the relief header via de-inventorying line. Once all the liquids are removed, de-pressure the remainder vapors to relief header via PSV bypass. Then close both the valves to relief header.
- 4) **Hydrocarbon free the vessel by successive pressurizing to ~600 KPaG(~87 psig) and then de-pressurizing to ~50 KPaG(~7 psig) with nitrogen for 3-4 times to eliminate most of the gaseous hydrocarbon contained in the vessel (LEL<5%).**
- 5) Install a blind between each of the block valves at the top and bottom of the vessel. At the top the blind should be installed just downstream of the

first block valve. At the bottom the blind should be installed just upstream of the second block valve. Insert the blind just downstream of the first block valve on the cross over piping from the drier that has just been purged with nitrogen. Insert the blind downstream of the second isolation block valve (nitrogen side) on the other cross over line.

- 6) De-pressure to ~flare header back pressure.
- 7) **Wait for 2 hours and sample the gas contained within the vessel (special low pressure sampling apparatus may be required for this) to confirm the vessel contents have LEL<5%**
- 8) **Repeat the steps 4), 6) and 7) until LEL is <5%.**
- 9) When the purging is complete, partially open the PSV bypass valve and commence a small, continuous nitrogen purge into the bottom of the treater. Adjust the purge flow rate to ensure the vessel has a very small positive pressure (only slightly higher than the flare pressure). Maintain this continuous purge throughout the unloading process.
- 10) Prepare for inert-entry into confined space following the local regulatory guidelines and refinery safety guidelines. The personnel entering the vessel must be provided with a tested Self Contained Breathing Apparatus (SCBA) that has been tested and approved. Continuous safety watch by the trained personnel must be provided for any emergency rescue while inert-entry into confined space is being performed.
- 11) Remove the outlet elbow at top while maintaining slight nitrogen purge from the vessel bottom. Adjust the purge such that a slight draft of nitrogen can be felt at the inlet nozzle.
- 12) Insert the vacuuming sock/lance and vacuum out the top 19mm ceramic balls top layer. A person may perform inert entry to move the chute around to ensure proper removal of the material if necessary.
- 13) Remove the top wire mesh under inert-entry.
- 14) **Once this has been accomplished, it is expected that inert entry may no longer be required while removing the adsorbent material by vacuuming.**
- 15) **Confirm the personnel working inside the vessel have exited safely.**

- 16) Cover the large inlet nozzle of the vessel with spliced sheet metal permitting enough gap to move around the vacuuming chute/lance. This limit the air ingress. Make sure nitrogen purge is maintained which is enough to get sucked out by vacuuming apparatus while permitting minimal air ingress into the vessel.
- 17) Unload the adsorbent by vacuuming until the adsorbent level in the vessel reaches approximately until the bottom of the side man-way.
- 18) While vacuuming out the adsorbent, periodically empty the hopper contents into the spent adsorbent collection drums.
- 19) Upon completion of removal of material by vacuuming until the level dropped below the bottom of side man-way on the vessel, arrange to remove the remainder via side man-way. At this time the nitrogen purge to the vessel can be stopped.
- 20) Provide proper ventilation for the vessel using blowers. Air flow through the vessel must be directed from bottom to top. The blower must suck air through a chute inserted from the vessel inlet at the top.
- 21) Check the oxygen content in the vessel for safe man-entry.
- 22) Stage a supply of containers for the spent absorbent near the treater.
- 23) Using personnel protective equipment as necessary, unload remainder of the adsorbent.
- 24) Install a temporary unloading assembly with slide valve at the end of an unloading chute attached to the manway. Canvas socks can be connected to these if desired.
- 25) As the drums are filled, remove them with fork lift to park in safe laydown area.
- 26) **Normalize by re-instating blind on the de-inventorying line. The other blinds should be removed and re-instated after loading.**
- 27) Clean the vessel and carry out inspection including the profile wire support screen at the bottom.
- 28) **Follow the loading procedure in Part B of Section XII-Special Procedures.**

[b] Unloading the Feed Drier by Gravity under continuous up flow nitrogen purge

- 1) Follow through Step 1) to Step 8) in the previous procedure Section XII C 5 [a].
- 2) Re-establish nitrogen purge from bottom up through the vessel. Vent from the PSV bypass.
- 3) Prepare the side-way withdrawal chute following the UOP Standard Drawings 3-356 and 9-101.
- 4) Keep a rated metallic hose attached to plant nitrogen utility and a rated utility water hose attached to plant water utility.
- 5) Line up the spent adsorbent drums on a roller. Place the nitrogen lance in the first drum in the line-up on the roller and keep a slight nitrogen purge.
- 6) Carefully loosen the bolts on the side man-way starting with bottom half.
- 7) Loosen the bolts below the bottom davit more than those in the top half as required to open up the space between the flange and man-way cover.
- 8) Control the opening carefully to limit the rate at which the adsorbent drops out from the opening.
- 9) Collect the adsorbent in the drum, remove the nitrogen lance. If there are fumes or the drum becomes hotter, pour water onto the adsorbent.
- 10) Complete unloading up to the side man-way nozzle.
- 11) Stop nitrogen purge on the vessel by closing the utility nitrogen block valve. Disconnect the hose.
- 12) Open the outlet elbow.
- 13) Attach the same hose to instrument air utility and start purging the vessel with dry instrument air. Purge at sufficiently large rate.
- 14) Check the oxygen level in the vessel at bottom, middle and top. It shall be minimum 20 mol% at all the three levels.

- 15) Once the vessel is declared safe for man-entry, remove the remainder of the adsorbent, floating screen and ceramic balls from the bottom side man-way.
- 16) As the drums are filled, remove them with fork lift to park in safe laydown area.
- 17) Clean the vessel. Inspect the profile wire distributor at the bottom.
- 18) **Normalize by re-instating blind on the de-inventorying line. Follow the loading procedure in Part B of Section XII-Special Procedures.**

[c] Steam out to Safe the Feed Drier Vessel followed by Adsorbent Unloading either by Vacuuming or by Gravity

Adopting this procedure will require that the engineering specifications for the vessel include the steaming operation. Confirm the vessel in your unit has been specified for steaming service before deciding to proceed with this procedure.

Steaming out feed drier is relatively less advantageous compared to the chloride treater because the feed drier is regenerable and therefore the contaminants can be effectively removed prior to adsorbent unloading rendering the spent adsorbent safe to unload. It is still necessary to check that the hydrocarbon < 5% LEL (lower explosive limit) as best and safe practice. If the local refinery regulations or statutory requirements do not permit inert entry and/or further require that the spent adsorbent shall be deactivated prior to unloading and/or disposal, then steam out procedure can be followed.

Steaming out the feed drier shall follow the same guidelines as those provided in Section XII C 2 [c]. However, note that the feed driers are not designed for vacuum.

Therefore, upon completion of steaming, the blow down point and vent shall be left open to prevent the vessel collapsing under vacuum due to condensation of steam. The air purge shall therefore follow quickly upon completion of steaming keeping the blow down or vent open as necessary to permit air to leak-in.

Normalize by re-instating blind on the de-inventorying line. Dry the vessel by purging with air after unloading is finished followed by cleaning and inspection including the profile wire inlet support screen at the bottom.

Once completed follow the loading procedure in Part B of Section XII-Special Procedures.

[d] Water flooding the bed to Safe the Feed Drier Vessel followed by Adsorbent Unloading either by Vacuuming or by Gravity

Unlike the alumina based adsorbents in the chloride treater and the RED, the feed drier adsorbent is a molecular sieve which can withstand free water. To this extent, the concerns related to steam condensate contacting the adsorbent materials and damaging their structure making unloading potentially problematic as in case of chloride treater or RED are not relevant to feed drier. Further, the advantage is that there is no risk of vacuum collapse of the vessel as with steaming apart from the fact that the adsorbent can be deactivated safely in contact with water prior to disposal.

This fact can be utilized to safe the feed drier vessel by water flooding.

- 1) Follow the Steps 1) to Step 8) in the previous procedure Section XII C 5 [a].
- 2) Make sure the PSV bypass is firmly closed.
- 3) Connect a rated utility water hose at the bottom drain point and fill up the feed drier vessel bottom up venting out nitrogen as required from the top vent valve.
- 4) Fill up the vessel completely until water over flows from the vent.
- 5) At this stage stop water injection by closing the block valve at the vessel bottom attached to the hose and allow the vessel contents to settle.
- 6) Disconnect the hose attached to the bottom drain after closing the utility water root valve.
- 7) Drain out all the water through the bottom drain to the refinery chemical drain. Once finished, close the drain valve. Re-insert the blind flange.
- 8) Disconnect and open the outlet elbow at the top.
- 9) Dry the vessel by purging with air.
- 10) Normalize by re-instating blind on the de-inventorying line. Once completed, clean and inspect the vessel including profile wire inlet support screen at the bottom.
- 11) Follow the loading procedure in Part B of Section XII-Special Procedures.**

6. SHP Reactor Unloading

The following procedure should be used to unload the SHP. It is assumed here that the activity is being carried out while the Oleflex unit is in operation. SHP reactor unloading can also be done during the unit shut down. Refer UOP Standard Drawings 3-356 and 3-360 for the details of the unloading facility planning.

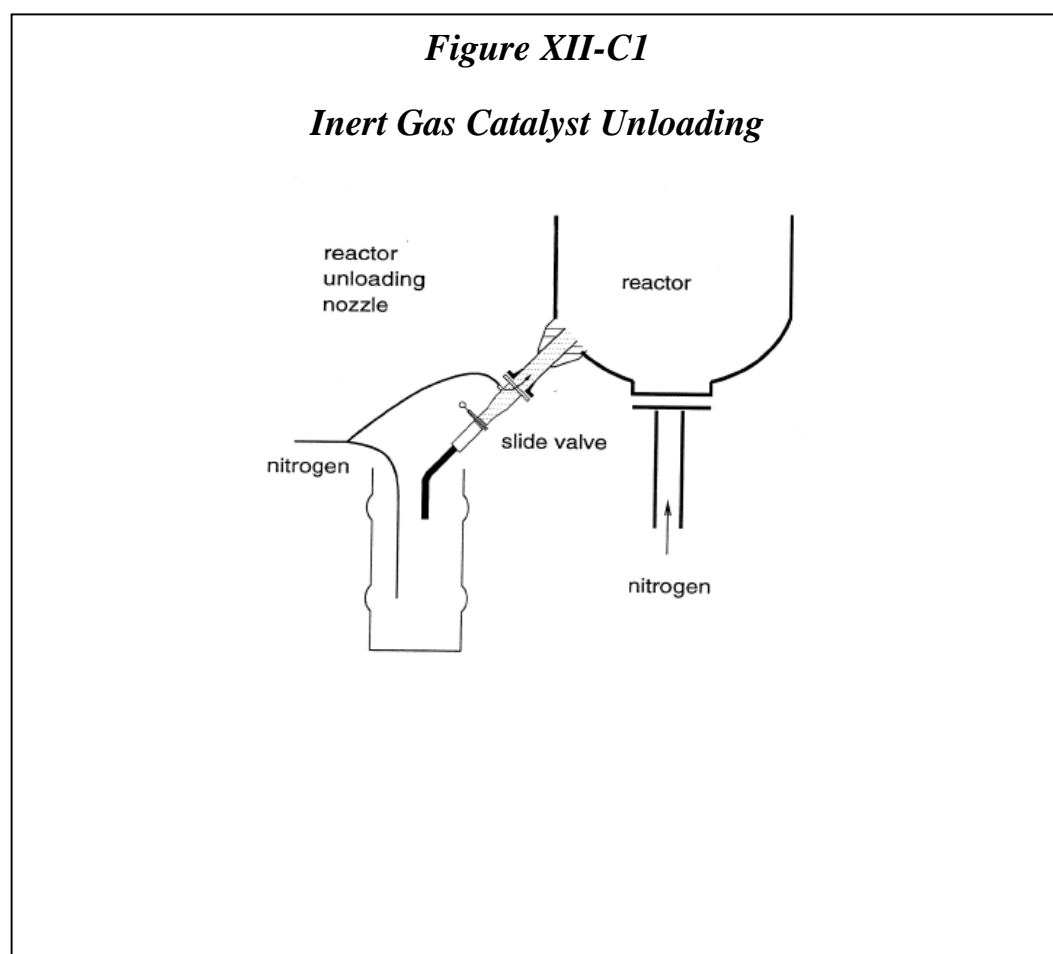
In addition all the safety equipment forming part of UOP 903 specifications shall be followed at the minimum unless the refinery practices exceed the requirements specified.

- 1) Cool the SHP Reactor by slowly stopping heat input to the SHP feed.
- 2) After the bed has cooled down, stop hydrogen flow to the reactor. Continue hydrocarbon flow over the catalyst bed until bed temperatures cool at least 54°C (130°F).
- 3) Open the SHP reactor bypass valves and then close the SHP reactor isolation valves. Hydrocarbon flow should continue bypassing the SHP Reactor.
- 4) Drain condensate for the SHP feed heater if provided with one. This is to prevent condensate icing up in the heater tubes with potential to rupture the tubes during the SHP reactor de-pressuring.
- 5) Slowly vent the hydrocarbon in the SHP reactor to flare using the globe valve at the top of the SHP reactor. During venting monitor piping and vessel for frosting. Stop venting if line and/or vessel upstream of the vent valve start to frost-up. Always maintain the lines and equipment above the Minimum Design Metal Temperature (MDMT).
- 6) Once SHP Reactor has been de-pressured, pressure-up the reactor to ~600 KPa G (~87 psig) with nitrogen and de-pressure to ~50 KPaG (~7 psig) over 3-4 cycles until LEL<5%.
- 7) When the purging is complete, partially open the PSV bypass valve and commence a small, continuous nitrogen purge into the bottom of the reactor. Adjust the purge flow rate to ensure the reactor has a very small positive pressure (only slightly higher than the flare pressure). Maintain this continuous purge throughout the unloading process.
- 8) Prepare a nitrogen hose near the unloading nozzle of the vessel. For now, leave the valve on the hose closed.
- 9) Stage a supply of containers for the spent catalyst near the reactor. Provide proper safety equipment: masks, gloves, protective eyewear, etc. to all the

participants in the unloading. Workers should avoid contact with the catalyst as it is unloaded.

Note: During operation the SHP catalyst may be exposed to sulfur and hence could be pyrophoric. The presence of CO₂ type fire extinguishers is desirable during unloading operations as insurance against spontaneous combustion. Any ignition of catalyst contained in the drums can be smothered by inert nitrogen gas or by closing the container.

- 10) Open catalyst unloading nozzles and install the unloading assembly with slide valve at the end of the nozzles. Canvas socks can be connected to these if desired. See an example of an unloading nozzle in Figure XII-C1.



- 11) Remove the support plate and begin unloading catalyst. While unloading, keep the nitrogen purge through the drum and the vessel. Fill each drum

with catalyst and nitrogen. Remove nitrogen hose and cover drum. Seal the drum with a proper cover and rubber gasket to keep out moisture.

- 12) As the drums are filled, remove them with a crane or fork lift. Put them on a truck and take drums to a safe disposal location. Continue unloading and removing full containers until catalyst does not flow anymore

Note: Near the end of the unloading, ceramic balls from the top of the bed will be mixed with the absorbent. The sacks which contain absorbent and ceramic balls should be kept separate from the others. This material can be later screened and the ceramic balls recovered.

- 13) When the unloading is complete, close the unloading nozzles and piston purge the vessel with nitrogen 3-4 times by successive pressure up to 600 KPaG (~87 psig) and de-pressure to ~50 KPaG (~7 psig) for 3-4 times to remove any remnant hydrocarbons (LEL < 5 %). Confirm by sampling.

- 14) Block in the PSV bypass and stop the nitrogen purge. Double block and bleed the PSV and the bypass line then chain lock its block valves and the bypass valve closed.

- 15) Remove the top manway on top of the vessel. Store the top manway attached to the inlet distributor in a safe place, protected from the elements.

- 16) If the hydrocarbon level is acceptably low in all points of the vessel, disconnect the nitrogen hose and purge the vessel from the bottom 3/4" drain out through the top with instrument air. Purge with dry instrument air until the vessel has a safe atmosphere of fresh air (21% oxygen). Measure the oxygen content of the atmosphere down the entire vessel, and monitor its quality continuously.

Note: If the hydrocarbon content of the purge gas cannot be made acceptably low, do not put air inside the vessel. Instead, all further activities will have to be done with the vessel under an inert atmosphere.

- 17) Inspect vessel and make sure all of the catalyst and ceramic balls have been removed from the vessel.

- 18) **Follow the loading procedure in part B of Section XII-Special Procedures.**

7. Unloading Arsine (As) & Phosphine (Ph) Metal Guard Bed (MGB) - if applicable

The MGB can typically be unloaded and reloaded online when there exist two MGBs operating in lead/lag mode. The lead MGB is unloaded and reloaded. The freshly reloaded MGB shall then be placed in lag position.

Use one of the following procedures to unload the adsorbents from the MGB: [a] Vacuuming- Removing the adsorbents by vacuuming requires special equipment and is performed by an experienced contractor. [b] Gravity- Unload the adsorbent by gravity following the provisions required under UOP Standard Drawings 3-356 and 9-101.

The spent adsorbent must be disposed of following the local regulatory and/or statutory guidelines for safe waste disposal. Consult local UOP CAS if required.

In addition all the safety equipment forming part of UOP 903 specifications shall be followed at the minimum unless the refinery practices exceed the requirements specified.

[a] Unloading the MGB by Vacuuming the Adsorbent from Top under continuous up flow nitrogen purge:

This procedure will require inert-entry for a limited duration initially to remove the top 19 mm ceramic balls layer and the floating mesh screen. The adsorbent material shall be removed by vacuuming process employing an experienced contractor. The process involves inserting through the top inlet nozzle a moveable chute connected to the hard vacuum piping which in turn is connected to a collection hopper to which vacuuming apparatus is attached. The material collected in the hopper will be removed to the drums periodically. While removing the adsorbent by vacuuming, there will be some air ingress into the vessel despite the nitrogen purge and therefore it is critical to hydrocarbon free the vessel properly for safe unloading. Following is a guideline procedure that must be followed. The required safety regulations in this procedure must be adhered to all the time and shall not be relaxed without proper discussion/approval process. If the owner refinery standards and/or local regulations exceed the requirements contained in this procedure, they must additionally be complied with.

- 1) Place the lead-lag MGBs in parallel operation.
- 2) Isolate the lead MGB closing the inlet, outlet, and cross-over gate valves. Close the block valve to sample collection. De-blind the de-inventorying line to relief header.
- 3) Depressure the hydrocarbon liquids from the vessel to ~flare header back pressure by venting to the relief header via the de-inventorying line. Once

all the liquids are removed, de-pressure the vapors via PSV bypass to relief header.

- 4) **Hydrocarbon free the vessel by successive pressurizing to ~600 KPaG(~87 psig) and then de-pressurizing to ~50 KPaG(~7 psig) with nitrogen for 3-4 times to eliminate most of the gaseous hydrocarbon contained in the vessel (LEL<5%).**
- 5) Install a blind between each of the block valves at the top, cross over and bottom of the vessel. At the top, the blind should be installed just upstream of the second block valve. At the bottom and cross over the blind should be installed just downstream of the first block valve. On the other cross over piping, install the blind on the block valve on the nitrogen side.
- 6) De-pressure to ~flare header back pressure.
- 7) **Wait for 2 hours and sample the gas contained within the vessel (special low pressure sampling apparatus may be required for this) to confirm the vessel contents have LEL<5%**
- 8) **Repeat the steps 4), 6) and 7) until LEL is <5%.**
- 9) When the purging is complete, partially open the PSV bypass valve and commence a small, continuous nitrogen purge into the bottom of the treater. Adjust the purge flow rate to ensure the vessel has a very small positive pressure (only slightly higher than the flare pressure). Maintain this continuous purge throughout the unloading process.
- 10) Prepare for inert-entry into confined space following the local regulatory guidelines and refinery safety guidelines. The personnel entering the vessel must be provided with a tested Self Contained Breathing Apparatus (SCBA) that has been tested and approved. Continuous safety watch by the trained personnel must be provided for any emergency rescue while inert-entry into confined space is being performed.
- 11) Remove the inlet elbow while maintaining slight nitrogen purge from the vessel bottom. Adjust the purge such that a slight draft of nitrogen can be felt at the inlet nozzle.
- 12) Insert the vacuuming sock/lance and vacuum out the top 19mm ceramic balls top layer. A person may perform inert entry to move the chute around to ensure proper removal of the material if necessary.
- 13) Remove the top wire mesh under inert-entry.

- 14) **Once this has been accomplished, it is expected that inert entry may no longer be required while removing the adsorbent material by vacuuming.**
- 15) **Confirm the personnel working inside the vessel have exited safely.**
- 16) Cover the large inlet nozzle of the vessel with spliced sheet metal permitting enough gap to move around the vacuuming chute/lance. This limit the air ingress. Make sure nitrogen purge is maintained which is enough to get sucked out by vacuuming apparatus while permitting minimal air ingress into the vessel.
- 17) Unload the adsorbent by vacuuming until the adsorbent level in the vessel reaches approximately until the bottom of the side man-way.
- 18) While vacuuming out the adsorbent, periodically empty the hopper contents into the spent adsorbent collection drums.
- 19) Upon completion of removal of material by vacuuming until the level dropped below the bottom of side man-way on the vessel, arrange to remove the remainder via side man-way. At this time the nitrogen purge to the vessel can be stopped.
- 20) Provide proper ventilation for the vessel using blowers. Air flow through the vessel must be directed from bottom to top. The blower must suck air through a chute inserted from the vessel inlet at the top.
- 21) Check the oxygen content in the vessel for safe man-entry.
- 22) Stage a supply of containers for the spent absorbent near the MGB.
- 23) Using personnel protective equipment as necessary, unload remainder of the adsorbent.
- 24) Install a temporary unloading assembly with slide valve at the end of an unloading chute attached to the manway. Canvas socks can be connected to these if desired.
- 25) As the drums are filled, remove them with fork lift to park in safe laydown area.
- 26) Clean the vessel. Inspect profile wire outlet support screen.

27) Normalize by re-instating blind on the de-inventorying line. The other blinds can be removed after the loading has been completed.

28) **Follow the loading procedure in Part B of Section XII-Special Procedures.**

[b] Unloading the MGB by Gravity under continuous up flow nitrogen purge

- 1) Follow through Step 1) to Step 8) in the previous procedure Section XII C 7 [a].
- 2) Re-establish nitrogen purge from bottom up through the vessel. Vent from the PSV bypass.
- 3) Prepare the side-way withdrawal chute following the UOP Standard Drawings 3-356 and 9-101.
- 4) Keep a rated metallic hose attached to plant nitrogen utility and a rated utility water hose attached to plant water utility.
- 5) Line up the spent adsorbent drums on a roller. Place the nitrogen lance in the first drum in the line-up on the roller and keep a slight nitrogen purge.
- 6) Carefully loosen the bolts on the side man-way starting with bottom half.
- 7) Loosen the bolts below the bottom davit more than those in the top half as required to open up the space between the flange and man-way cover.
- 8) Control the opening carefully to limit the rate at which the adsorbent drops out from the opening.
- 9) Collect the adsorbent in the drum, remove the nitrogen lance. If there are fumes or the drum becomes hotter, pour water onto the adsorbent.
- 10) Complete unloading up to the side man-way nozzle.
- 11) Stop nitrogen purge on the vessel by closing the utility nitrogen block valve. Disconnect the hose.
- 12) Open the inlet elbow.
- 13) Attach the same hose to instrument air utility and start purging the vessel with dry instrument air. Purge at sufficiently large rate.

- 14) Check the oxygen level in the vessel at bottom, middle and top. It shall be minimum 20 mol% at all the three levels.
- 15) Once the vessel is declared safe for man-entry, remove the remainder of the adsorbent, floating screen and ceramic balls from the bottom side man-way.
- 16) As the drums are filled, remove them with fork lift to park in safe laydown area.
- 17) Clean the vessel. Inspect the profile wire support screen at the outlet.
- 18) Normalize by re-instating blind on the de-inventorying line. The other blinds can be removed and normalized after loading has been completed.
- 19) **Follow the loading procedure in Part B of Section XII-Special Procedures.**

8. Mercury Removal Bed Loading (if provided) and Spent Regenerant Treater Loading (if provided)

These beds can typically be unloaded and reloaded online. When mercury removal bed is to be unloaded and reloaded online, the respective vessel can be bypassed.

Since there exists potential for mercury contamination of the feed, the feed being processed during this duration shall be free of mercury to prevent damage to the Oleflex catalyst and/or cold separation section metallurgy. If this cannot be guaranteed, then the Oleflex unit must be ramped down to less than 400°C (752°F) to stop fresh feed intake temporarily until the vessel can be unloaded and reloaded.

On the other hand, the spent regenerant treater can be bypassed to facilitate unloading/loading when the feed drier regeneration has just been completed and there exists sufficient window of time until the next regeneration cycle commences. This may not always be possible on the units where the fresh feed is water saturated and the window of time to unload/re-load the spent regenerant treater inadequate. In the latter case, it may be necessary to ramp down the Oleflex unit to less than 400°C (752°F) to stop fresh feed intake temporarily until the vessel can be unloaded and reloaded.

The spent adsorbent must be disposed of following the local regulatory and/or statutory guidelines for safe waste disposal. Consult local UOP CAS if required.

Use one of the following procedures to unload the adsorbents from the mercury removal bed or spent regenerant treater: [a] Vacuuming- Removing the adsorbents by vacuuming requires special equipment and is performed by an experienced

contractor. [b] Gravity- Unload the adsorbent by gravity following the provisions required under UOP Standard Drawings 3-356 and 9-101.

In addition all the safety equipment forming part of UOP 903 specifications shall be followed at the minimum unless the refinery practices exceed the requirements specified.

[a] Unloading the mercury removal bed or spent regenerant treater by Vacuuming the Adsorbent from Top under continuous up flow nitrogen purge:

This procedure will require inert-entry for a limited duration initially to remove the top 19 mm ceramic balls layer and the floating mesh screen. The adsorbent material shall be removed by vacuuming process employing an experienced contractor. The process involves inserting through the top inlet nozzle a moveable chute connected to the hard vacuum piping which in turn is connected to a collection hopper to which vacuuming apparatus is attached. The material collected in the hopper will be removed to the drums periodically. While removing the adsorbent by vacuuming, there will be some air ingress into the vessel despite the nitrogen purge and therefore it is critical to hydrocarbon free the vessel properly for safe unloading. Following is a guideline procedure that must be followed. The required safety regulations in this procedure must be adhered to all the time and shall not be relaxed without proper discussion/approval process. If the owner refinery standards and/or local regulations exceed the requirements contained in this procedure, they must additionally be complied with.

- 1) Open the bypass on the vessel to route the process flow via vessel and bypass in parallel.
- 2) Isolate the vessel by closing the inlet and outlet gate valves. Close the block valve to sample collection if applicable. De-blind the de-inventorying line to relief header if applicable. The process flow is now routed through the bypass and vessel isolated.
- 3) Depressure the hydrocarbon liquids (applicable only to mercury removal bed) from the vessel to ~flare header back pressure by venting to the relief header via the de-inventorying line (if provided) or via PSV bypass. Once all the liquids are removed, de-pressure the vapors via PSV bypass to relief header.
- 4) **Hydrocarbon free the vessel by successive pressurizing to ~600 KPaG(~87 psig) and then de-pressurizing to ~50 KPaG(~7 psig) with nitrogen for 3-4 times to eliminate most of the gaseous hydrocarbon contained in the vessel (LEL<5%).**

- 5) Install blind at inlet and outlet block valves at the top and bottom of the vessel. At the top inlet, the blind should be installed just upstream of the second block valve. At the bottom outlet the blind should be installed just downstream of the first block valve.
- 6) De-pressure to ~flare header back pressure.
- 7) **Wait for 2 hours and sample the gas contained within the vessel (special low pressure sampling apparatus may be required for this) to confirm the vessel contents have LEL<5%**
- 8) **Repeat the steps 4), 6) and 7) until LEL is <5%.**
- 9) When the purging is complete, partially open the PSV bypass valve and commence a small, continuous nitrogen purge into the bottom of the vessel. Adjust the purge flow rate to ensure the vessel has a very small positive pressure (only slightly higher than the flare pressure). Maintain this continuous purge throughout the unloading process.
- 10) Prepare for inert-entry into confined space following the local regulatory guidelines and refinery safety guidelines. The personnel entering the vessel must be provided with a tested Self Contained Breathing Apparatus (SCBA) that has been tested and approved. Continuous safety watch by the trained personnel must be provided for any emergency rescue while inert-entry into confined space is being performed.
- 11) Remove the inlet elbow while maintaining slight nitrogen purge from the vessel bottom. Adjust the purge such that a slight draft of nitrogen can be felt at the inlet nozzle.
- 12) Insert the vacuuming sock/lance and vacuum out the top 19mm ceramic balls top layer. A person may perform inert entry to move the chute around to ensure proper removal of the material if necessary.
- 13) Remove the top wire mesh under inert-entry.
- 14) **Once this has been accomplished, it is expected that inert entry may no longer be required while removing the adsorbent material by vacuuming.**
- 15) **Confirm the personnel working inside the vessel have exited safely.**
- 16) Cover the large inlet nozzle of the vessel with spliced sheet metal permitting enough gap to move around the vacuuming chute/lance. This limit the air ingress. Make sure nitrogen purge is maintained which is

enough to get sucked out by vacuuming apparatus while permitting minimal air ingress into the vessel.

- 17) Unload the adsorbent by vacuuming until the adsorbent level in the vessel reaches approximately until the bottom of the side man-way.
- 18) While vacuuming out the adsorbent, periodically empty the hopper contents into the spent adsorbent collection drums.
- 19) Upon completion of removal of material by vacuuming until the level dropped below the bottom of side man-way on the vessel, arrange to remove the remainder via side man-way. At this time the nitrogen purge to the vessel can be stopped.
- 20) Provide proper ventilation for the vessel using blowers. Air flow through the vessel must be directed from bottom to top. The blower must suck air through a chute inserted from the vessel inlet at the top.
- 21) Check the oxygen content in the vessel for safe man-entry.
- 22) Stage a supply of containers for the spent absorbent near the vessel.
- 23) Using personnel protective equipment as necessary, unload remainder of the adsorbent.
- 24) Install a temporary unloading assembly with slide valve at the end of an unloading chute attached to the manway. Canvas socks can be connected to these if desired.
- 25) As the drums are filled, remove them with fork lift to park in safe laydown area.
- 26) Clean the vessel. Inspect profile wire outlet support screen.
- 27) Normalize by re-instating blind on the de-inventorying line (if applicable). The other blinds can be removed after the loading has been completed.
- 28) **Follow the loading procedure in Part B of Section XII-Special Procedures.**

[b] Unloading the mercury removal bed and spent regenerant treater by Gravity under continuous up flow nitrogen purge

- 20) Follow through Step 1) to Step 8) in the previous procedure Section XII C 7 [a].

- 21) Re-establish nitrogen purge from bottom up through the vessel. Vent from the PSV bypass.
- 22) Prepare the side-way withdrawal chute following the UOP Standard Drawings 3-356 and 9-101.
- 23) Keep a rated metallic hose attached to plant nitrogen utility and a rated utility water hose attached to plant water utility.
- 24) Line up the spent adsorbent drums on a roller. Place the nitrogen lance in the first drum in the line-up on the roller and keep a slight nitrogen purge.
- 25) Carefully loosen the bolts on the side man-way starting with bottom half.
- 26) Loosen the bolts below the bottom davit more than those in the top half as required to open up the space between the flange and man-way cover.
- 27) Control the opening carefully to limit the rate at which the adsorbent drops out from the opening.
- 28) Collect the adsorbent in the drum, remove the nitrogen lance. If there are fumes or the drum becomes hotter, pour water onto the adsorbent.
- 29) Complete unloading up to the side man-way nozzle.
- 30) Stop nitrogen purge on the vessel by closing the utility nitrogen block valve. Disconnect the hose.
- 31) Open the inlet elbow.
- 32) Attach the same hose to instrument air utility and start purging the vessel with dry instrument air. Purge at sufficiently large rate.
- 33) Check the oxygen level in the vessel at bottom, middle and top. It shall be minimum 20 mol% at all the three levels.
- 34) Once the vessel is declared safe for man-entry, remove the remainder of the adsorbent, floating screen and ceramic balls from the bottom side man-way.
- 35) As the drums are filled, remove them with fork lift to park in safe laydown area.
- 36) Clean the vessel. Inspect the profile wire support screen at the outlet.
- 37) Normalize by re-instating blind on the de-inventorying line. The other blinds can be removed and normalized after loading has been completed.

38) Follow the loading procedure in Part B of Section XII-Special Procedures.

D. Hot Hydrogen Strip (SHP)

When the catalyst in the SHP reactor has become deactivated by polymer deposition or by temporary poisons, the catalyst can be partially restored to fresh conditions using the Hot Hydrogen Strip. During Hot Hydrogen Strip PSA or electrolytic grade hydrogen is used to physically desorb contaminants such as H₂S and organic heavies.

Hot Hydrogen Strip can be performed during normal operation of the unit. The procedure has three main steps.

1) Prepare SHP Reactor for Hot Hydrogen Strip

- a) Cool the SHP Reactor by slowly stopping condensate flow from SHP feed heater or bypassing the feed exchanger as applicable.
- b) Stop hydrogen flow to the reactor.
- c) Open the SHP reactor bypass valves and then close the SHP reactor isolation valves. Hydrocarbon flow should continue normally bypassing the SHP reactor.
- d) If provided with a steam heater for heating the feed, drain condensate for the SHP feed heater to prevent icing in the tubes while de-pressuring the SHP reactor which can cause tube rupture.
- e) Slowly vent the hydrocarbon in the SHP reactor to flare using the globe valve at the top of the SHP reactor. During venting monitor piping and vessel for frosting. Stop venting if lines frost. Always keep the lines and equipment above the Minimum Design Metal Temperature (MDMT).
- f) Once SHP reactor has been de-pressured, pressure the reactor with nitrogen and de-pressure again. Repeat pressing with nitrogen and de-pressuring until the hydrocarbon is removed from the reactor. Generally this takes two times.
- g) All process lines should be isolated and blinded during hot hydrogen strip. Confirm line up and isolation for stripping hydrogen. Typically MP or HP Steam is required to provide the stripping temperature at the required H₂ flow rate. If applicable, switch the SHP feed heater to

MP/HP steam and isolate the LP Steam connections. In some units an independent steam heater is provided for the hot hydrogen strip.

- h) Stripping hydrogen should enter upstream of the SHP Reactor bottom
→ through the reactor to the relief header.
- i) Activate the hot hydrogen strip key switch. This switch bypasses the high temperature interlock, which is required for normal operation. Bypassing the interlock is required since the stripping temperature is above the interlock trip point.

2) Perform Hot Hydrogen Strip

- a) Initiate flow of stripping hydrogen through the SHP reactor. Adjust hydrogen flow to desired flowrate using globe valve and flow indicator. Maintain a minimum of approximately 250 GHSV (gas hourly space velocity) calculated at actual flowing conditions through the SHP reactor bed during the hot hydrogen strip.
- b) Commission the SHP feed heater or stripping hydrogen heater as applicable to heat up the stripping hydrogen gas.
- c) Raise stripping hydrogen temperature slowly to 150°C (300°F) using the heater.
- d) Once the catalyst bed and reactor outlet temperatures have lined out at their maximum temperature, hold for 48 hrs. At least every 8 hours, check the H₂S evolution via Dräger tubes at the reactor overhead. More frequent H₂S sampling will give a better indication of the amount of sulfur contamination and when the stripping step is complete.
- e) Hot hydrogen strip is complete after 48 hours or when H₂S evolution stops, whichever is longer.
- f) Upon completion of the hot hydrogen strip, decrease hydrogen temperature. Stop heat input to the stripping hydrogen stream. Steam flow to the SHP feed heater or stripping hydrogen heater as applicable and isolate. Drain condensate from the heater.
- g) Continue sending hydrogen over the SHP bed until bed temperatures cool down to 40°C (104°F) or less.
- h) Deactivate the hot hydrogen strip key switch. This switch engages the high temperature interlock, which is required for normal operation to protect against high temperature excursions in the SHP reactor.

- i) Stop hydrogen flow and isolate stripping hydrogen from SHP reactor circuit.

3) Bring the SHP Reactor back online

- a) Pressure SHP reactor to nitrogen header pressure $\sim 7 \text{ kg/cm}^2\text{g}$ ($\sim 100 \text{ psig}$).
- b) Slowly introduce hydrocarbon via filling valve located downstream of the SHP feed heater. Monitor temperatures and avoid freezing the lines and reactor. When the SHP reactor pressure reaches the inlet pressure stop feed introduction and depressure to approximately $15 \text{ kg/cm}^2\text{g}$ (214 psig). Slowly bring in more hydrocarbon. Repeat until level instrument at top of reactor indicates a full liquid level and frosting is present downstream of the reactor vent. Close the reactor vent valve.
- c) Line up reactor inlet and outlet. Slowly close bypass valves to route flow through SHP reactor.
- d) Line up hydrogen and commission SHP H_2 compressor per vendor recommendations.
- e) Calculate hydrogen flow that will give 1000 mol-ppm H_2 in the feed. Start required hydrogen flow to SHP reactor.
- f) Commission SHP Feed Heater and adjust feed temperature to convert all di-olefins to mono-olefins.

Note: Monitor SHP bed temperatures for excessive temperature increase during filling and operation. If excessive temperature increase occurs cut hydrogen and heat to SHP reactor.

E. Reactor Effluent Drier Operation during Pre-commissioning

During normal operations, hydrogen rich net gas from the Cold Separation System is used as regenerant. However, while pre-commissioning activities are taking place, hydrogen may not be readily available since it is not being produced by the process.

During dry-out and sulfiding operations the activated alumina adsorbent in the Reactor Effluent Driers (REDs) will capture water and sulfur. Depending on the amount of water and H_2S present the REDs may become saturated before net gas is available. Some unit configurations allow the REDs to be regenerated using clean LPG or natural gas (NG) from an appropriate source within the complex and or nitrogen. Depending on the unit configuration a vaporizer and heater from a different regeneration system within the complex are used or a dedicated startup system may be needed. In any case, the reactor effluent driers can be regenerated during any shutdown or startup situation with C_3 such that water and/or sulfur breakthrough is

avoided before the normal net gas regenerant stream becomes available. The UOP Chief Technical Advisor will supply detailed procedures for this type of regeneration.

F. Antisurge Valve Maintenance

The unit has been designed to allow the antisurge valves for the Reactor Effluent Compressor (REC) to be serviced while the unit is in operation. Performing maintenance on the antisurge valves during operation is a risky procedure because it will eliminate the means of the antisurge controller from protecting the compressor during a surge event. If antisurge valve maintenance is necessary during operation then the compressor should be brought to a safe mode of operation away from the surge curve. Consult with the compressor vendor. This will require reducing unit throughput, increasing the last reactor outlet pressure, and opening the process spillback.

Please contact UOP Technical Services group prior to performing such maintenance.

G. Changing Feed and Reactor Effluent Filters

1. Feed Filters

The delta pressure across the Feed Filter should be monitored on a daily basis. Over time, the filter elements will become plugged with debris and the pressure drop will increase. Once it is noticed that the pressure drop is gradually increasing, it is recommended to clean or replace the filters. The allowable pressure drop for a clean and dirty filter should be available from the filter supplier. Below is the recommended procedure to switch to the spare Feed Filter when the delta pressure across the on-line filter begins to increase.

- 1) Confirm that there are filter elements in the spare feed filter.
- 2) Slowly open the inlet gate valves on the spare feed filter. Pressure the vessel up to operating pressure.
- 3) Open the $\frac{3}{4}$ ' bypass valves around the PSV to purge out any nitrogen or air that may be in the vessel. It may be helpful to pressure and de-pressure the vessel 2-3 times to make certain that the vessel is completely filled with propane feed.
- 4) Once the vessel has been inventoried with propane, close the PSV bypass valves and open the outlet gate valves. At this time, both of the Feed Filters should be on-line. The delta pressure transmitter across the Feed Filters should decrease.
- 5) Close the inlet and outlet gate valves on the feed filter being taken off-line.

- 6) Slowly vent the contents of the feed filter to flare using the PSV bypass. Monitor line and equipment for frosting. Stop venting if frost occurs.
- 7) Once the liquid contents have been drained, connect a nitrogen hose to the $\frac{3}{4}$ " connection provided and purge the vessel to flare through the PSV bypass line. It may be helpful to remove hydrocarbons by pressuring and de-pressuring the vessel several times with nitrogen.
- 8) Continue to purge the vessel until the gas to flare LEL is <5%. The gas can be checked at the $\frac{3}{4}$ " bleed valve outlet line from the filter.
- 9) Once it is confirmed that the hydrocarbons have been purged from the vessel, the filter elements can be removed and/or replaced per vendor recommendations.
- 10) After replacement filters are installed, pressure the offline filter with nitrogen.

2. Reactor Effluent Filters

The delta pressure across the reactor effluent filter should be monitored on a daily basis. Over time, the filter elements will become plugged with debris and the pressure drop will increase. Once it is noticed that the pressure drop is gradually increasing, it is recommended to clean or replace the filters. The allowable pressure drop for a clean and dirty filter should be available from the filter vendor. Below is the recommended procedure to switch to the spare filter when the delta pressure across the on-line filter begins to increase.

- 1) Confirm that there are filter elements in the spare reactor effluent filter.
- 2) Slowly open the inlet gate valves on the spare reactor effluent filter. Pressure the vessel up to operating pressure.
- 3) Open the $\frac{3}{4}$ " bypass valves around the PSV to vent any nitrogen or air that may be in the vessel. It may be helpful to pressure and de-pressure the vessel 2-3 times to make certain that the vessel is completely filled with reactor effluent vapor.
- 4) Once the vessel has been inventoried with vapor, close the PSV bypass valves and open the outlet gate valves. At this time, both of the reactor effluent filters should be on-line. The delta pressure transmitter across the reactor effluent filters should decrease.
- 5) Close the inlet and outlet gate valves on the reactor effluent filter being taken off-line.

- 6) De-pressure the vessel to flare by opening the PSV bypass line.
- 7) Once the vessel has been de-pressured, connect a nitrogen hose to the $\frac{3}{4}$ " connection provided and purge the vessel to flare through the PSV bypass line. It may be helpful to remove hydrocarbons by pressuring and de-pressuring the vessel several times with nitrogen.
- 8) Continue to purge the vessel until the gas to flare LEL is <5% of the lower explosion limit. The gas can be checked at the $\frac{3}{4}$ " bleed valve outlet line from the filter.
- 9) Once it is confirmed that the hydrocarbons have been purged from the vessel, the filter elements can be removed and/or replaced per vendor recommendations.
- 10) After replacement filters are installed, pressure the offline filter with nitrogen.

H. Fresh Feed Drier Regeneration (without HG SIV)

The liquid feed driers are sized to operate at least 24 hours each before requiring regeneration. A drier is to be regenerated once the moisture analyzer on the effluent indicates an upward trend in moisture content. The driers are operated such that one drier is in the lead position, while the other is either in the guard (or standby) position, or is being regenerated.

The drying periods may be extended as operating experience is gained and provided that a water breakthrough does not occur. However, even if the moisture content on the lead drier effluent does not increase from the baseline reading, the molecular sieve in each drier must be regenerated at least one time per week. The following guidelines can be followed to take a drier off line, regenerate it, and bring it back on line.

Note that there may be slight variations from unit to unit in the regeneration system valve sequence configuration. The reader is directed to the Drier Regeneration and Control Systems (DRCs) manual provided by the UOP Process Information & Control (PIC) group for the exact sequence applicable to their process unit.

Assume feed is flowing through driers, i.e., the driers are in series with the "A" drier first ("lead" position) and the "B" drier second ("guard" position). The moisture analyzer sample is from the outlet of the "A" drier. At this stage: Valves A-10, A-9, A-1, A-7, A-8, B-5 and B-6 are open and all others are closed.

When the moisture analyzer indicates a need to regenerate or when the scheduled regeneration time arrives, drier "A" will be isolated, regenerated, cooled and put back in the "Guard" position. The liquid feed drier regeneration sequence will be as follows:

1) Start Flow to the "B" Drier

Open the "B" drier inlet valves (B-9 and B-10).

Open the moisture analyzer inlet valve from the "B" drier effluent (B-1), and close the moisture analyzer sample from the "A" drier (A-1). Flow is now essentially going through the "B" drier since this is the path of least resistance.

2) Open the "B" drier inlet valves (B-9 and B-10).

Open the moisture analyzer inlet valve from the "B" drier effluent (B-1), and close the moisture analyzer sample from the "A" drier (A-1). Flow is now essentially going through the "B" drier since this is the path of least resistance.

3) Block In the "A" Drier

Close the inlet valves to the "A" drier (A-9 and A-10). Close the valves on the crossover line (A-7 and A-8). The crossover bleeder should be checked at this time to verify that the crossover valves A-7 and A-8 are not leaking.

4) Pressure up the Regeneration System

Open the equalization line between the vaporizer and the coalescer. Pressure up the regenerant system to the "A" drier pressure by slowly opening the bypass valve around the fresh regenerant flow control valve (upstream of the vaporizer). Once the regenerant system and drier pressures are equal, close the equalization line valves and the regenerant FCV bypass valve.

5) Line up Regenerant Flow to the "A" Drier

Open the regenerant inlet valve (R-15) and the regenerant outlet valve (R-16). Ensure the cooling inlet and outlet valves (R-17 and R-18) are closed. Open the "A" drier regenerant outlet valves (A-11 and A-12) and regenerant inlet valves (A-3 and A-4). Commission the regenerant condenser. After ensuring that the regenerant pumps' minimum flow spillback line is open, start one of the regenerant pumps.

Line up flow of dried fresh feed to the regenerant vaporizer. Liquid fill the vaporizer and send flow forward through the superheater and establish the design regenerant flow rate.

6) Increase the Regenerant Temperature

Start a flow of steam to the regeneration vaporizer and establish a stable, normal level in it. The vapors generated will displace the liquid in the electric superheater.

Note: It is very important that the electric superheater is not commissioned until all liquid hydrocarbon in it has been displaced by the vapors from the vaporizer. When the superheater outlet thermometer reaches a maximum temperature (same as the vaporizer outlet temperature), all liquids have been cleared out.

Commission the superheater and increase the outlet temperature at a rate of 70°C/hr (125°F/hr) to 230°C (450°F).

7) Hot Soak the Drier Sieves

Monitor the outlet temperature of the drier. As the water is driven off of the sieves, the temperature will gradually increase. Hold the outlet temperature at 230°C (450°F) for 4 hours.

8) Reduce the Drier Temperature

After the 4 hour hold, reduce the superheater outlet temperature to 175°C (350°F) over one hour and shut down the heater. Continue to circulate vaporized regenerant with only the vaporizer in service until the "A" drier outlet temperature is approximately the same as the vaporizer outlet temperature. This step will prevent rapid generation of vapors during the following liquid phase cool down.

9) Cool the Drier with Liquid (up flow)

After the drier has reached the approximate temperature of the vaporizer outlet, the sieves are further cooled with liquid regenerant. Shut off the steam to the vaporizer. Open the liquid coolant inlet valve (R-18) and the liquid coolant return valve (R-17). Close the regenerant inlet valve (R-15) and the regenerant return valve (R-16). Cool the drier sieves until the outlet regenerant return temperature recorder is less than 38°C (100°F).

10) End the Cool Down Period

Slowly close and isolate the regenerant FIC control valve station. Shut down the regenerant pump. Close the liquid coolant inlet valve (R-18) and the liquid coolant return valve (R-17). Close the "A" drier regenerant inlet

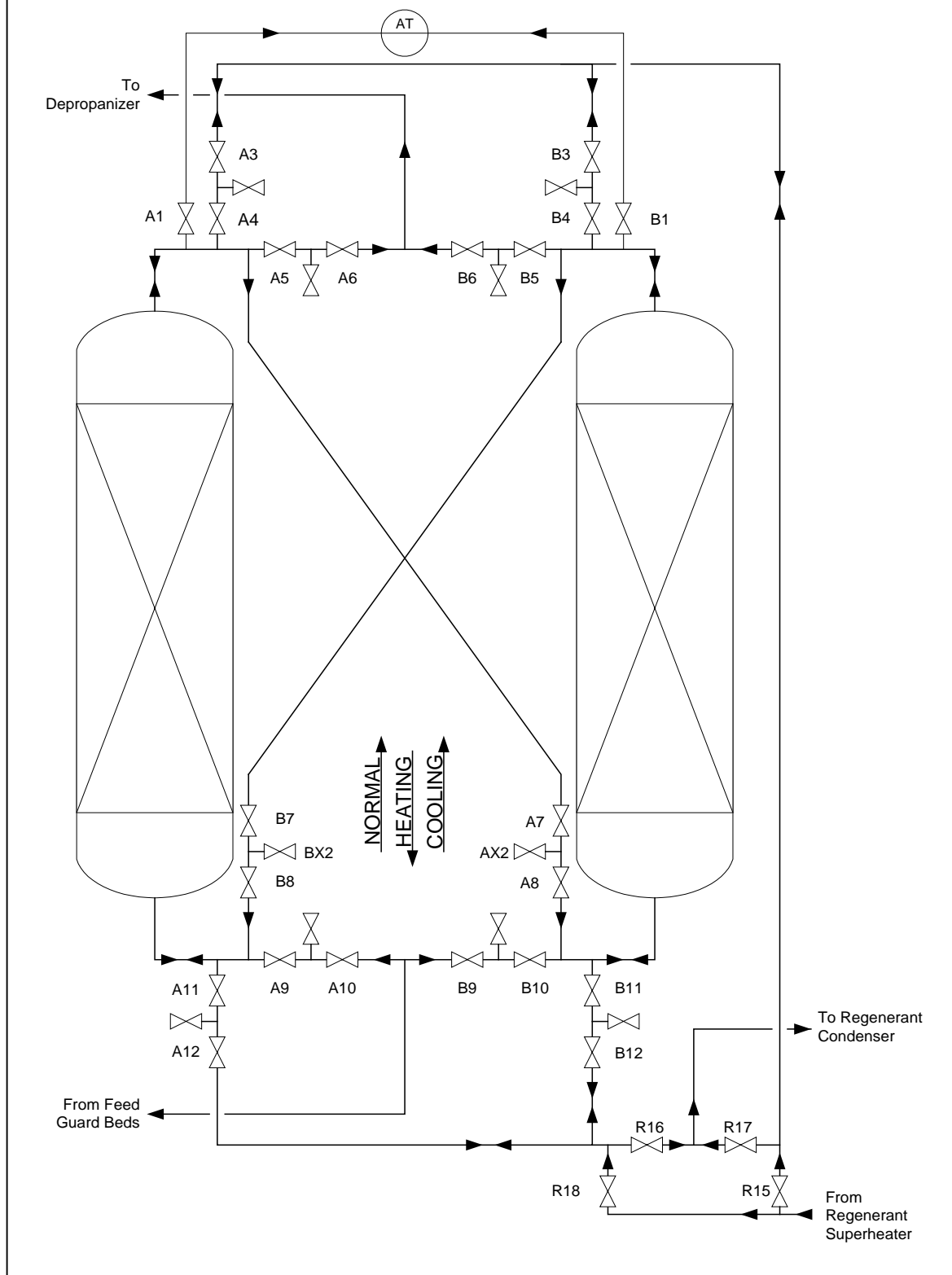
valves (A-3 and A-4) and the "A" drier regenerant outlet valves (A-11 and A-12).

11) Pressure up the "A" Drier

Open the upstream "A" drier inlet valve (A-10). Then open the $\frac{3}{4}$ " bypass valve around the other inlet valve (A-9) to allow the "A" drier to pressure up. After the "A" drier is pressured up to the same pressure as the "B" drier, close the $\frac{3}{4}$ " bypass valve around the "A" drier inlet valve (A-9). Then close the other "A" drier inlet valve (A-10).

12) Place the "A" Drier in the Guard (Lag) Position

Open the "A" drier outlet valves (A-5 and A-6). Open the "B" drier effluent crossover valves (B-7 and B-8). Close the "B" drier outlet valves (B-5 and B-6). When this is done, "B" drier effluent is forced through the "A" drier, thus placing the "B" drier in the lead position and the "A" drier in the lag position. When it is necessary for regeneration of the "B" drier, the entire procedure will then be repeated with respect to the "B" drier.

Figure XII-I1**Feed Drier Regeneration**

I. Fresh Feed Drier Regeneration (with HG SIV)

The liquid feed driers are sized to operate at least 24 hours each before requiring regeneration. A drier is to be regenerated once the moisture analyzer at the outlet of the lead drier bed indicates moisture breakthrough. The driers are operated such that one drier is in the lead position, while the other is either in the guard (or standby) position, or is being regenerated.

Note: Although feed driers containing HgSiv also remove mercury, the need to regenerate is generally set by the water breakthrough.

The drying periods may be extended as operating experience is gained and provided that a water breakthrough does not occur. However, even if the moisture content on the lead drier effluent does not increase from the baseline reading, the molecular sieve in each drier must be regenerated at least one time per week. The following guidelines can be followed to take a drier off line, regenerate it, and bring it back on line.

Note that there may be slight variations from unit to unit in the regeneration system valve sequence configuration. The reader is directed to the Drier Regeneration and Control Systems (DRCs) manual provided by the UOP Process Information & Control (PIC) group for the exact sequence applicable to their process unit.

Assume feed is flowing through driers, i.e., the driers are in series with the “A” drier first (“lead” position) and the “B” drier second (“guard” position). The moisture analyzer sample is from the outlet of the “A” drier.

1) Drier ‘A’ in lead position and Drier ‘B’ in lag position

There is no natural gas flowing to the Regenerant Superheater at this time.

Valves Open:

Drier A: 1A, 2A, 6A, 9A, 12A, 15A, 24

Drier B: 7B, 8B, 3B, 4B, 5B, 12B, 15B

PIC-2 should be set slightly below the pressure of the natural gas.

LIC-5 should be set at ~20%. FV-3 should be cascaded to LIC-5.

Valves Closed:

Drier A: 3A, 4A, 5A, 7A, 8A, 10A, 11A, 13A, 14A

Drier B: 1B, 2B, 6B, 9B, 10B, 11B, 13B, 14B, 25

Others: FV-1, PV-2, FV-3, FV-4, 16, 17, 18, 19, 20, 21, 22

When moisture analyzer on the outlet of Drier 'A' begins to trend upwards, operator will manually start the regeneration.

2) Open Drier 'B' Inlet Valves

Close Valves: 3B

Open Valves: 1B, 2B

3) Stop Flow through Drier "A"

Close Valves: 7B, 8B

Open Valves: 9B

3) Isolate Drier "A"

Close Valves: 1A, 2A, 24

Open Valves: 3A, 25

4) Equalize Pressure between Drier 'A' and the Regeneration Section

Close Valves: 15A

Open Valves: 13A, 14A, 17

Confirm that the regenerant condenser fin fan is operating and that FV-3 is cascaded to LIC-5. Allow the pressure at PT-3 to equalize with PT-5.

5) Pressure-up Regeneration Section to Regenerant Pressure and Drain Drier 'A'

Close Valves: 12A

Open Valves: 10A, 11A, 16

Ramp Open Valve: FV-1

FV-1 25% over a 10 minute period. Allow the regenerant to push out any remaining propane from Drier 'A.' Once FV-3 closes and level in regenerant separator level stops increasing, it can be assumed that liquid propane has been removed from the drier.

6) Increase Regenerant Flow to Drier 'A'

Ramp Open Valve: FV-1

Ramp open FV-1 until the design regeneration flow rate is reached.

7) Heat-up

After regeneration flow rate has been lined out at the design rate, begin ramping TIC-1 to 230°C at 70°C/hr.

8) Hot Soak

When TI-2 reads >200°C, hold for 4 hours. Monitor water level in Feed Drier Regenerant Separator via LT-6, drain water as necessary. However do not completely drain water from the boot.

9) Reduce Regenerant Temperature

Ramp down TIC-1 at 70°C/hr until Regenerant Superheater shuts off.

10) Cool Down

Once Regenerant Superheater has been shut off, switch flow of natural gas from down flow through drier to up flow by doing the following:

Open valves: 19, 20

Close valves: 16, 17

Continue to cool drier until TI-2 is within 5°C of TIC-1

11) Stop Natural Gas Flow through Drier 'A'

Close Valves: FV-1 over a 10 minute period, then close 13A, 14A

Open Valves: 15A

12) Liquid Fill Drier 'A'

Close Valve: 9A

Open Valve: 7A, 21

A portion of fresh feed from Drier 'B' will be sent to fill Drier 'A'. It is important to make certain the drier is liquid filled prior to placing it on-line. The adsorbent will still be warm upon entering this step and some of the propane may vaporize when it comes into contact with the adsorbent. The only way to confirm that the drier is liquid full is to monitor the temperature of the material coming off the drier. If TI-2 is stable for an extended period of time (~20 minutes), then it can be assumed that the drier is liquid full.

13) End Liquid Filling

Close Valves: 20, 10A, 11A, 21

Open Valves: 12A

14) Open Cross Over Lines from Drier 'B'

Open Valves: 8A

Confirm that PT-7 is equivalent to PT-6 before proceeding to the next step.

15) Place Drier 'A' in Lag Position

Close Valves: 6A

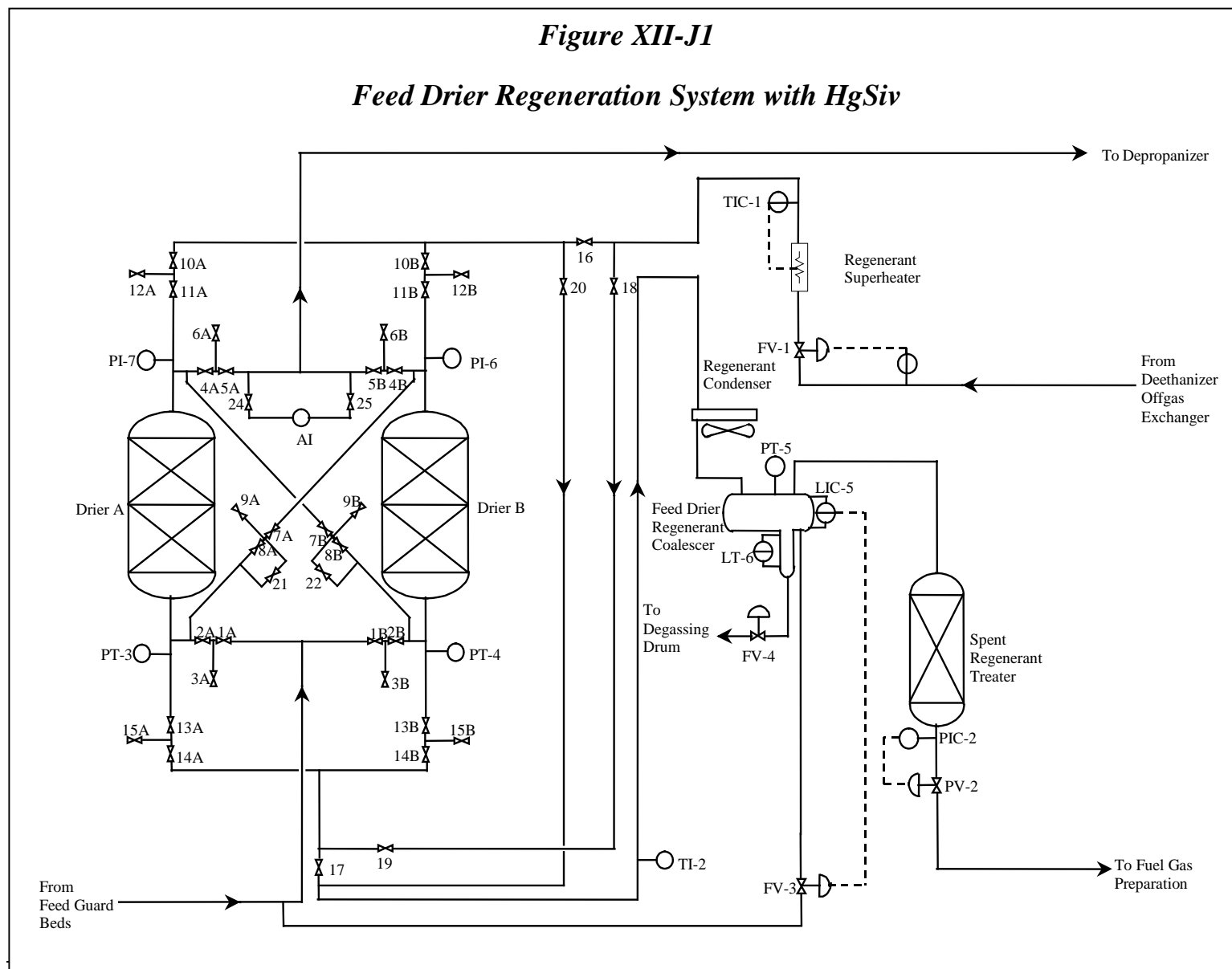
Open Valves: 4A, 5A

16) Place Drier 'B' in Lead Position

Close Valves: 4B, 5B

Open Valves: 6B

When it is necessary to regenerate the “B” drier, the entire procedure will be repeated with respect to the “B” drier.

Figure XII-J1**Feed Drier Regeneration System with HgSiv**

J. 2-Bed Reactor Effluent Drier Regeneration

The reactor effluent driers are specified to remove H₂S and water from the Oleflex reactor effluent stream. Typically, the driers are operated such that one drier is on line while the other is being regenerated. The drying periods may be extended slightly as operating experience is gained and provided that a water or H₂S breakthrough does not occur. Normal drying periods are 24 to 30 hours per drier. The following guidelines can be followed to take a drier off line, regenerate it, and bring it back on line. Note the design net gas regenerant flow through the regenerant flow controller is continuous, even during periods when regenerant is not needed. This is to eliminate any bumps to the net gas pressure control, which would arise if the regenerant flow had to be started and stopped each regeneration.

Note that this procedure is written for up flow heating, cooling and hydrocarbon loading. There may be slight variations from unit to unit in the regeneration system valve sequence configuration. The reader is directed to the Drier Regeneration and Control Systems (DRCs) manual provided by the UOP Process Information & Control (PIC) group for the exact sequence applicable to their process unit.

Assume reactor effluent is flowing down flow through the drier “A”, and drier “B” is ready to be placed on line. Valves A-4, A-5, A-6 and A-7 are open allowing reactor effluent to flow through Drier “A”. Valves B-4 and B-5 are open connecting drier B to the reactor effluent line. Regenerant is bypassing the driers through valve R-14. All other valves are closed.

When the start button is pressed, Drier “B” will be placed on line and Drier “A” will be isolated, regenerated and placed in the standby position. The reactor effluent drier regeneration sequence will be as follows:

1) Establish effluent flow through Drier “B”

Close the bleed, then open Valves B-6 and B-7.

2) Isolate Drier “A”

Close valves A-4 and A-5 then open the bleed.

Close valves A-6 and A-7 then open the bleed.

3) De-pressure Drier “A”

Close the bleed, and then open valves A-8 and A-9.

Open valve R-13.

Slowly open valve R-12 so as not to upset the Reactor Effluent Compressor.

4) Purge Drier “A”

Close the bleed, and then open valves A-2 and A-3.
Slowly open valve R-1 to establish the desired purge. The purpose of the purge is to remove heavy hydrocarbons from the drier. Wait an hour.

5) Pressure Drier "A" with regenerant

Slowly close valve R-12 so as not to upset the Reactor Effluent Compressor then close valve R-13.
Wait for Drier A to rise to the same pressure as the regenerant supply.

6) Establish regenerant flow up through Drier "A"

Open valve R-10
Close valve R-1
Open valve R-11
Slowly close valve R-14 to establish flow up through the drier bed

7) Regenerate Drier "A"

Raise the temperature of the regenerant at 70°C/hr until the desired regenerant temperature is reached
Hold this temperature until the Drier "A" regenerant outlet temperature is 210°C
Lower the set point on the regenerant heater at 70°C/hr until the regenerant is no longer being heated
Wait until the regenerant outlet of Drier "A" has reached 49°C

8) Stop regenerant flow to Drier "A"

Open valve R-14
Close valves A-2 and A-3 then open the bleed
Close R-10 and R-11.

9) Re-pressure Drier "A"

Close the bleed, then open valve A-5
Slowly open A-14. Wait until Drier "A"'s pressure is the same as the reactor effluent
Open valve A-4
Close valve A-14

10) Hydrocarbon Loading of Drier "A"

Open valve R-13
Slightly open valve R-12 to establish a flow of reactor effluent through the drier. Limit this flow so as not to upset the Reactor Effluent Compressor. Wait for an hour

11) Place Drier "A" in the standby position

Slowly close valve R-12

Close valve R13

Close valve A8 and A9 then open the bleed.

Drier "A" is now in the standby position. It can be placed on line when it is time to regenerate Drier "B".

K. Oleflex “On the Fly” Catalyst Change Out Procedure

This procedure summarizes the activities required to change out the Oleflex catalyst inventory while the reactor section remains in operation. This allows any deactivated catalyst to be removed whenever necessary, regardless of turnaround or shutdown scheduling. However, an on-the-fly change out should not be considered as a replacement for periodic scheduled reactor section turnarounds when reactor disassembly is warranted.

Preparation

1. Transport the drums of fresh catalyst to be loaded to a convenient location at the bottom of the CCR structure. The full drums will be hoisted to the catalyst loading hopper platform within the CCR structure during the loading. Record the lot and drum number of each drum of catalyst. Transport as many fresh catalyst drums as possible to the Loading Hopper platform while still allowing for some working area on the platform.
2. Collect enough clean, empty Oleflex catalyst drums to allow for unloading the catalyst to be replaced. The number of empty drums needed will be about the same as the number of fresh catalyst drums to be loaded. Pallets and a forklift will be needed to move the drums away as catalyst is unloaded. Keep the empty drums and drums full of fresh catalyst clearly separated so that the drums filled with the used catalyst during the unloading are not mixed or confused with the fresh catalyst drums. An alternate approach is to use large unloading bins. A typical size holds approximately 3000 pounds (1300 kg) of catalyst.
3. Rig up a flexible, high-temperature, hose from the Flow Control Hopper platform down the CCR structure to grade. This hose will direct the used catalyst being unloaded into drums. The hose should run to grade at a steep angle so that catalyst will flow through it (at least 45 degrees if possible). The top end of the hose should be fabricated to allow for a connection to the V-valve below the Flow Control Hopper. The bottom end of the hose should be directed to the area at grade where the empty drums and pallets are located.
4. Connect a flexible hose from the Surge Hopper unloading nozzle and direct it to grade where the empty drums and pallets are located. This hose will provide a means of unloading the used catalyst from the Surge Hopper.

Catalyst Loading and Unloading

1. Stop catalyst circulation and put the Regeneration Tower into a hot shutdown condition. If catalyst circulation is shut down for 4 hours or more before restarting catalyst circulation later in this procedure, reduce reactor section severity as outlined in the UOP Core Coke Advisory.
2. Shut down the Air Heater. Maintain normal Regeneration Heater outlet temperature. Stop chlorine injection. The Regeneration Blowers should remain in operation, and design nitrogen flow should be maintained to the Drying Zone.
3. Remove the expansion bellows from the catalyst transfer line between the Flow Control Hopper and Surge Hopper. Connect the unloading hose assembly to the bottom of the valve below the Flow Control Hopper. Cover up the top nozzle on the Surge Hopper.
4. Ensure that personnel required to load and/or move catalyst drums are ready to start work and are properly equipped to safely handle the hot, (100-300°C) drums containing the used catalyst from the Flow Control Hopper.
5. If catalyst drums are to be used for unloading, place 4 drums on a pallet. Place another pallet with 4 drums next to this one. Position the unloading hose so it can be moved easily from drum to drum. A forklift truck can then move the empty and full pallets around without interrupting unloading.
6. Unload all used catalyst from the Surge Hopper to drums at grade.
7. Clean the Surge Hopper, if necessary. UOP recommends that the Surge Hopper be cleaned nominally once a year as dust and fines tend to accumulate on the bottom of the Surge Hopper. If dislodged, these materials can cause problems in Lock Hopper No. 2, Lift Engager No. 4 or 5, the Reduction Zone and Reactor No. 1. In addition, clean out the catalyst transfer pipe (Y-spool piece) beneath the Surge Hopper. Dust and fines could settle in this line when unloading catalyst from the Surge Hopper.

CAUTION: PROPERLY ISOLATE AND AIR PURGE THE SURGE HOPPER AND VERIFY A SAFE ATMOSPHERE IS PRESENT BEFORE ENTRY FOR CLEANING.

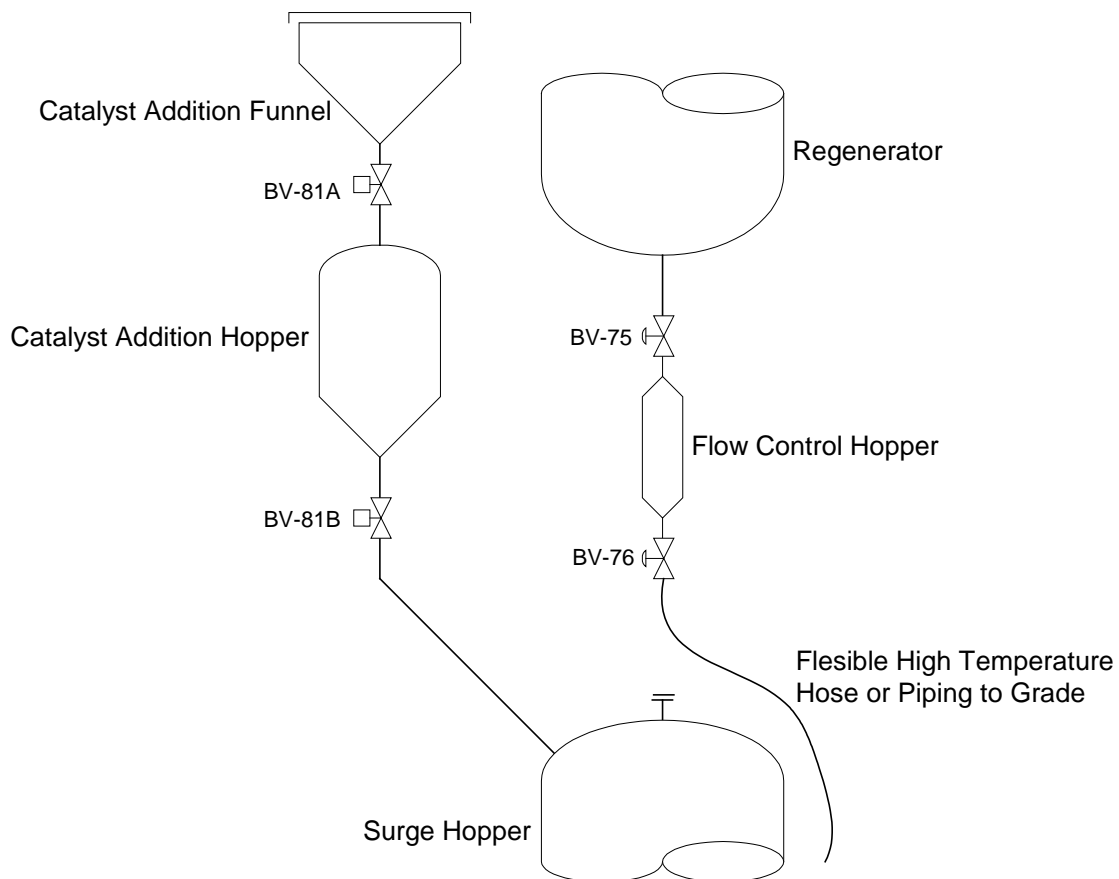
Following cleaning, close the Surge Hopper manway and establish an N₂ atmosphere in Surge Hopper. Maintain normal N₂ purge flow.

8. Have an instrument technician open both of the catalyst loading valves above and below the Catalyst Loading Hopper. Make sure the Surge Hopper nitrogen

purge is set at its design value. A small N₂ purge should be flowing out at the Loading Hopper.

9. Load fresh catalyst into the Surge Hopper. During the entire on-the-fly loading procedure, maintain the Surge Hopper catalyst level 1-2 feet above the panel coils. The catalyst level can be determined using the manual tape gauge at the top of the Surge Hopper.
10. After at least 1 hour has elapsed since the Air Heater was shut down and after all previous steps in this procedure have been completed, begin black burn operations and restart catalyst circulation at a design rate (initially about 50% which later can be increased depending on the ability of the change out crew to keep pace with regenerated and oxidized catalyst removal and equivalent reduced fresh catalyst addition). Adjust upper air injection rate to control the desired O₂ level at the burn zone inlet. As catalyst circulation proceeds, one Flow Control Hopper load of catalyst will flow down through the unloading hose to grade with each cycle of the Flow Control Hopper. The catalyst will be HOT, so take necessary precaution.
11. Fill up the empty drums with catalyst from the Flow Control Hopper. As the Flow Control Hopper cycles, small loads of catalyst will flow into the drums or bins approximately every 60 seconds. Place a nitrogen hose (with a small flow of nitrogen coming from it) into each drum as the catalyst is unloaded into the drum. After each drum is filled up, remove the nitrogen hose and seal the drum immediately. As a drum fills, it is an easy task to move the catalyst unloading hose between drums. However, if it is desired to give some control to the works at grade, a temporary instrument air-line can be hooked up to BV-76. The worker can then shut off air flow to BV-76. Since the Regeneration Tower is in black burn operations, the Boardman should be notified whenever the outside workers close BV-76.
12. It is recommended that the individual Oleflex reactor inlet temperatures be reduced one at a time, as the leading edge of the new catalyst enters each respective reactor. Normally this is limited to 595°C - 600 °C for the first cycle when fresh catalyst enters each reactor. This should minimize the propensity for generating any high coke on the new catalyst during its first pass through the reactors and will serve as a good base case from which operating conditions can be further adjusted to achieve desired production targets. Contact UOP for specific reactor inlet temperature targets.
13. Continue loading catalyst to the Surge Hopper and unloading catalyst from the Flow Control Hopper until the target amount of catalyst has been replaced. The final Surge Hopper level should be approximately 6-12 inches above the panel coils.

14. When the catalyst change out is completed, stop catalyst circulation and discontinue upper air injection to the burn zone. Normally it is recommended to load at least 103% of original inventory as fresh catalyst to make sure that all of the old catalyst has been purged out of the system. Stop the catalyst circulation at this stage. Restart the Air Heater, and begin raising the heater outlet temperature to ~535°C - 540°C. If catalyst circulation is shut down for 4 hours or more, reduce reactor section severity as outlined in the emergency procedure for stoppage of catalyst circulation under the section for fresh catalyst.
15. Simultaneously remove the unloading hose below the Flow Control Hopper and reinstall the expansion bellows.
16. Have an instrument technician return the Catalyst Loading Hopper valves to their normal, closed position.
17. When design air heater outlet temperature is reached in the Regeneration Tower, proceed with a black catalyst CCR startup and resume catalyst circulation. Switch to white burn operations once the tower has established a satisfactory carbon profile with regenerated catalyst carbon levels of less than 0.1 wt% coke. Begin Cl₂ injection in accordance with normal guidelines.

Figure XII-L1**Oleflex “On the Fly” Catalyst Change Out**

XIII. Safety

The process unit and its operation may present hazards to the operators and the environment. This section outlines some of the proper controls expected to be implemented. Since the use of UOP products by others is beyond UOP control, no guarantee, expressed or implied, is made and no responsibility assumed for the use of this material or the results obtained therefrom. Moreover, the recommendations contained in this manual are not to be construed as a license to operate under, or a requirement to infringe, any existing patents, nor should they be confused with state, municipal or insurance requirements, or with national safety codes.

The owner is responsible for establishing and following all pertinent safety procedures for the start-up, shut-down, operation and maintenance of this process unit. As UOP does not perform the final design work for the unit, it is expected that the owner will perform a process hazard analysis or similar investigation of the final process design.

A. UOP Provided Information

This process unit may contain hazards due to chemicals and materials including flammable hydrocarbons, hydrogen and other materials. A listing of the chemicals and materials present and recommended safety equipment can be found in the UOP Engineering Project Specification 903, "Safety Equipment" issued for this process unit.

Safety Data Sheets (SDS) for UOP supplied catalysts and adsorbents may be obtained by UOP at www.uop.com. For the SDS of all other catalysts and chemicals used in this process, contact the vendor.

The General Operating Manual provided by UOP is not considered sufficient operational guidance and the owner must develop operating instructions for the plant.

For safety procedures specific to the technologies presented in this manual, if applicable, please refer to section XII. Special Procedures.

B. General Elements of Process Safety Management

The owner is expected to develop and establish policy and procedures for the following:

- a. Detailed unit specific operating procedures
- b. Employee training related to the process and its operation
- c. Contractors
- d. Mechanical integrity of equipment
- e. Preparing equipment or piping for introduction of hazardous materials

- f. Removal of hazardous materials from equipment or piping in preparation for inspection or maintenance of said equipment or piping.
- g. Line Breaking Procedures
- h. Confined Space Entry
- i. Energy control (Lock-out and Tag-out of Equipment)
- j. Fall Protection for Personnel.
- k. Hot Work Procedures

Operating procedures presented in this manual are general in nature. The steps required to start-up, operate, and shut down the unit will broadly apply to units for which this manual applies. Stepwise procedures that identify specific equipment are to be developed by the owner. Operating procedures may be reviewed with the UOP representative present for start-up and vendor representatives present for commissioning of specific equipment. The owner of the unit may also implement procedures and policies that govern the modification of or deviations from the normal operating procedures.

The owner will manage the training of the personnel and contractors who enter and operate the plant.

A regular plan of inspection and testing will be required to maintain the physical integrity of the equipment of the unit. Process equipment has an expected design life which can be altered by process and other environmental conditions. Procedures and practices should monitor the process equipment to determine if it is fit for service.

Many materials can be considered toxic or hazardous. Procedures and policy must be implemented to insure the safe handling of the materials used in the plant.

Confined spaces are a recognized hazard in most process units. Procedures for access control, entry, and work in confined spaces are implemented by the owner to protect personnel from hazardous encountered in confined spaces.

Energized equipment is also a recognized hazard in most operating units as unexpected operation of equipment may cause injury. The control of equipment and sources of other energy will need to be managed for the purposes of maintenance and inspection.

Falls constitute a hazard in most units when work is performed outside of the normal platforms and walk ways designed to be occupied by workers. Policy to reduce injuries as a result of falls is normally a part of the safety management system of the unit.

As most units contain flammable materials, a system to reduce accidental ignition of flammable materials is implemented. Such systems are commonly referred to as "hot work" systems to protect against ignition of flammable materials by open flames and other ignition sources.

Additional information regarding certain industrial hazards is available at the below website:

www.osha.gov – The website for the United States Department of Labor Occupational Safety and Health Administration.

www.cdc.gov/niosh – The website for the Centers for Disease Control and Prevention National Institute for Occupational Safety and Health.

C. List of Technology Specific Potential Hazards

Please refer to the 903 project specification in the Schedule A from UOP which lists the unit specific chemicals and materials requiring specific safety equipment and special handling procedures.