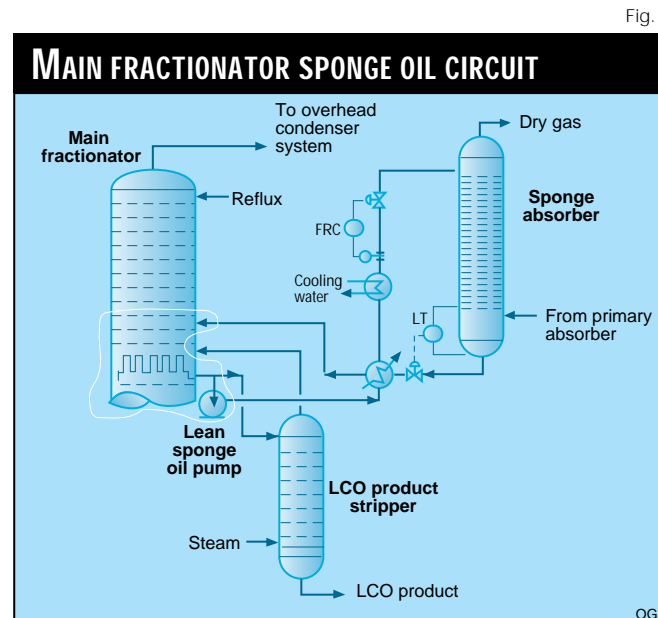FCC REVAMP—1

Case studies reveal common design, equipment errors in revamps

Scott W. Golden   *Process Consulting Services Inc.   Houston*

Revamps of the product recovery section of fluid catalytic cracking units (FCCUs) are common. Failure to thoroughly evaluate the existing process flow scheme and equipment design often results in unit operating problems after a revamp.

This first of two articles discusses FCC revamps and describes a common revamp and its associated problems and solutions. The second article covers two additional revamp situations. The examples of FCC revamps illustrate how fundamental errors in process system design or equipment resulted in performance that did not meet the stated objectives. The examples illustrate recurring problems for refiners in main fractionator and gas plant revamps.

The intent of each revamp was to increase the equipment capacity in order to increase recovery of light products. In each case, the revamp had operating problems after start-up.

Eliminating the bottlenecks in these cases would

Fig. 1

MAIN FRACTIONATOR SPONGE OIL CIRCUIT

have required a very small incremental investment during the revamp.

FCC revamp

FCC revamps will con-

tinue to be the norm in the refining industry. Revamps are, by definition, riskier than grassroots construction.

A revamped unit is pushed closer to several major system or equipment limitations. Once a unit is revamped, unit operation is constrained by the next limitation. Improving return on existing assets means maximizing utilization of existing equipment and running against the next bottleneck.

In recent years, FCC reactor revamps and catalyst technology have significantly changed the yield structure from FCCUs. These yield changes typically involve the production of more gasoline and lighter compounds.

The objectives of converter revamps may be increased conversion, increased production of alkylation unit feed, or addition-

Fig. 2

COMMON MAIN FRACTIONATOR REVAMP

OGJ

Fig. 3

CONVERTING SPONGE OIL CIRCUIT TO PUMPDOWN

OGJ
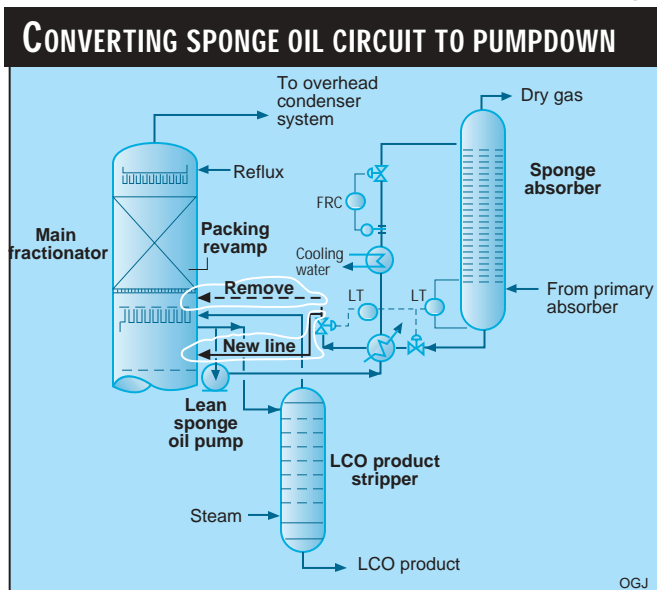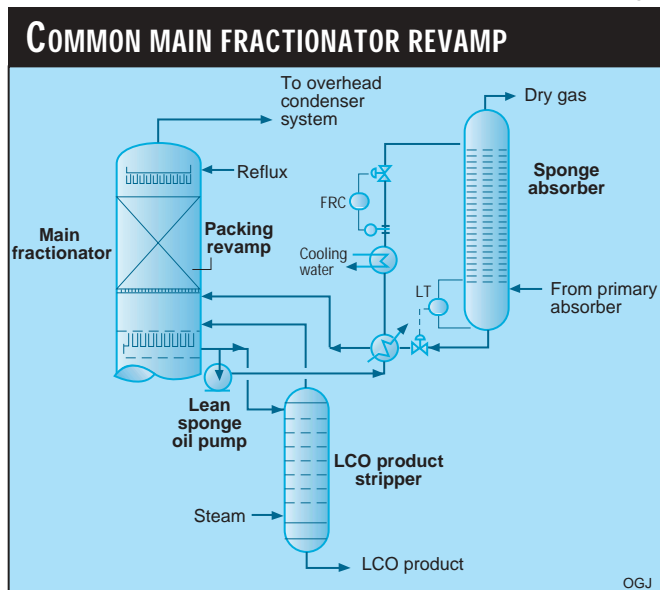
al gasoline yield. Ultimately, the increased quantity of light hydrocarbons must be recovered in the main fractionator and gas concentration unit.

When C_3 recovery in an absorber is 75%, compared to a design value of 92%, then C_3 material is being burned in the refinery fired heaters. The differential value between propylene as liquid product vs. fuel is high, and such a problem can be expensive.

Sponge oil circuits

Fig. 1 shows an example of an FCCU main fractionator and sponge oil circuit. The sponge oil circuit is essentially a pumparound. The lean oil is cooled, and the rich oil is returned to the main fractionator.

Rich oil contains light hydrocarbons; therefore, when the pressure is reduced, the rich oil flashes. If the system is not properly designed, this flashing can cause various operating problems in the main fractionator.

Many FCC main fractionator revamps have failed because the process aspects of this system were not understood. Equipment design errors can create unexpected bottlenecks.

Revamp No. 1

A relatively common revamp scheme for FCC main fractionators is to replace trays with structured packing. The objectives of such a revamp are to reduce column pressure drop, increase capacity, and improve separation.

Fig. 2 shows a common type of main fractionator revamp that has been used by several refiners. In each case, the revamp accomplished part of the objective. But each unit had operating problems. This particular error, or a variation of it, has occurred in more than ten FCC revamps.

Fig. 1 shows the main fractionator sponge oil circuit of the FCCU before the revamp.

The lean and rich sponge oil streams form a circulating system that flows between the main fractionator and the sponge (sometimes called secondary) absorber. Lean sponge oil (LSO) is typically main fractionator light cycle oil (LCO), but heavy naphtha-boiling-range material occasionally is used.

The LSO from the main fractionator is cooled by water prior to entering the sponge absorber. The quantity of gas absorbed by the LSO depends on lean oil temperature, lean oil rate,

feed gas composition, and column operating pressure.

The LSO recovers a small amount of C_2s and C_3s, but the absorbed gas is predominantly C_4s and C_5s. Occasionally, poor primary absorber operation results in significant quantities of C_3 recycle from the bottom of the sponge absorber to the main fractionator.

The flow rate of rich sponge oil (RSO) to the main fractionator is a function of the LSO flow rate and the quantity of gas absorbed. RSO flow rate is set by the controller of the bottoms level in the sponge absorber column.

The level-control valve reduces the RSO pressure to slightly more than the main fractionator operating pressure. The absorbed gas vaporizes when the pressure is reduced. This gas has a molecular weight of about 28. While the mass flow rate of the gas is very low, its volume is high because of its low molecular weight.

Sponge absorber circulating systems act essentially as a pumparound. Understanding this is important when troubleshooting and correcting design errors.

The quantity of heat removed by the sponge absorber circuit is a function of the LSO flow rate and the temperature difference be-

tween the LSO and RSO. The major difference between a typical pumparound return (all liquid) and the RSO is that the RSO arrives at the main fractionator as a two-phase stream.

Revamp designs are usually based on process data taken from a flow-sheet model. Liquid and vapor loadings in FCCU main fractionators are generated by computer models.

The computer model of the trayed main fractionator shown in Fig. 1, if correct, would have the RSO returning to the main fractionator one stage above the LSO draw from the column. Accurate modeling of the RSO return to the main fractionator would identify the stream as a mixed-phase (vapor and liquid) stream.

Computer models are a useful tool, but they do not always represent the reality of field-installed equipment. The revamp design shown in Fig. 2 is not the same as the original design (Fig. 1), and the computer models must account for this.
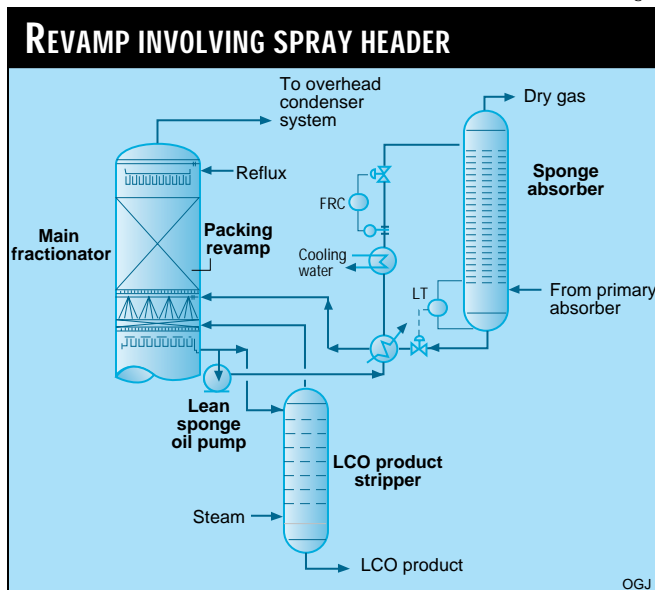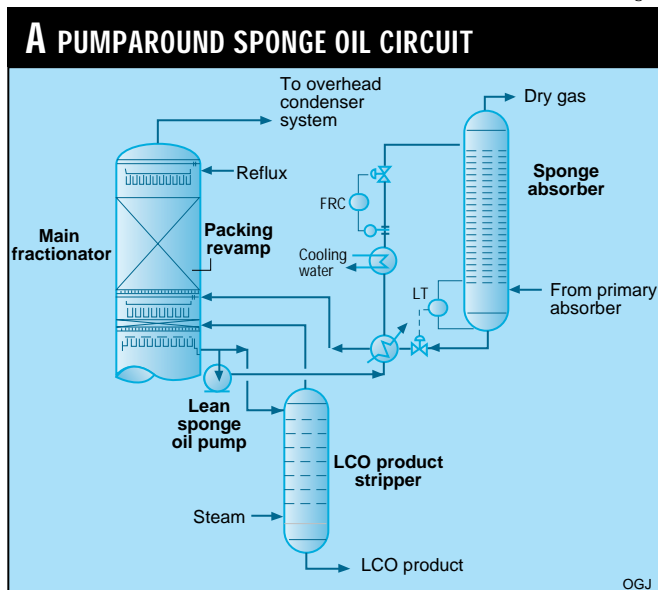
Operating problems

When the revamped unit started up, the following operating problems occurred:

• The reflux flow rate in the main fractionator was significantly higher than be-

Fig. 4

A PUMPAROUND SPONGE OIL CIRCUIT

To overhead condenser system

Reflux

Dry gas

FRC

Sponge absorber

Main fractionator

Packing revamp

Cooling water

From primary absorber

LT

Lean sponge oil pump

LCO product stripper

Steam

LCO product

OGJ

Fig. 5

REVAMP INVOLVING SPRAY HEADER

To overhead condenser system

Reflux

Dry gas

FRC

Sponge absorber

Main fractionator

Packing revamp

Cooling water

From primary absorber

LT

Lean sponge oil pump

LCO product stripper

Steam

LCO product

OGJ

fore the revamp.

• The lean oil and LCO product draw temperatures were 60° F. colder.

• The LCO product contained 5 vol % more gasoline-boiling-range material.

• Gasoline yield was slightly less.

• The observed temperature drop across the LCO stripper was zero, and increasing or decreasing LCO stripping steam had no effect on the amount of gasoline-boiling-range material in the LCO product.

The results of similar revamps have been nearly identical. In each case, the same symptoms were observed and the problem was circumvented by reducing the LSO rate, sometimes to zero.

When revamped equipment does not do what the computer model predicted, the tendency is to blame the new equipment. But if computer models do not accurately represent installed equipment, incorrect conclusions are drawn from the model.

Why did the computer model of the revamped system not predict the observed plant operation? In the original plant operation, the RSO enters the column two trays above the lean oil draw. In the revamp, the RSO returns to main frac-

tionator on the collector tray where the LSO (and LCO product) is withdrawn from the main fractionator.

It is important to remember that sponge oil circuits are heat removals. The liquid returns to the column colder than the draw temperature.

In a pumparound, the cold pumparound return liquid is heated to its bubble point by contact with vapor flowing up the column. The column mass-transfer device (trays or packing) exchanges heat between the sub-cooled pumparound return and the rising vapor. Hence, the vapor rate leaving a pumparound section is always lower than the vapor rate entering the section.

In this revamp, RSO returns to the main fractionator on the same tray as the lean oil draw liquid. The cold RSO oil does not contact the vapor entering the LSO draw tray. Without contact between the liquid and vapor, heat cannot be transferred between the column vapor and RSO.

The vapor rate entering the collector tray (LSO and LCO product) is the same as the vapor rate leaving the collector tray. However, heat is transferred between the bubble point liquid leaving the packed bed and the colder RSO.

The RSO and bubble point liquid from the packing combine on the collector tray. The heat transfer results in a sub-cooled liquid (LCO product and lean oil) being withdrawn from the column.

Observations

When troubleshooting, it is necessary to evaluate equipment operation using measured field data. In this unit, the following observations were made:

• Main fractionator reflux increased because the sponge oil circuit no longer exchanged heat with the rising vapor. The column vapor rates entering and leaving the circulating lean/rich sponge oil system were the same. The column reflux rate increased by the amount of duty previously removed by the circulating sponge oil system. If the main fractionator overhead condenser system is limited, as it was in this example, the increased condenser load increases wet gas production. The wet gas compressor must have the capacity to handle this incremental gas load.

• The lean oil and LCO product side-stripper feed are sub-cooled in this unit; therefore, the observed colder draw temperature (60° F. lower than normal) should be expected. The amount of

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sub-cooling is a function of the lean oil rate and the temperature difference between the lean-oil draw and rich-oil return. When the lean-oil rate is reduced to zero, the draw is no longer sub-cooled; the liquid withdrawn from the column is now a bubble point liquid.

• The LCO stripper uses steam to strip a portion of the feed. If the feed to any side stripper is not a bubble point liquid, stripper efficiency is reduced. Steam reduces the oil partial pressure in the vapor phase. Once feed sub-cooling reaches the point where the oil vapor pressure cannot be reduced by steam, no stripping occurs. With little or no stripping, the gasoline-boiling-range material in the LCO product increases.

• If the gasoline-boiling-range material in the LCO increases, the gasoline rate must decrease. The LCO product rate increases by an amount equal to the decrease in naphtha product rate.

Solution

Fig. 3 shows one potential solution to the problem. In this scheme, the sponge oil circuit is converted to a pumpdown. The limitation of this system is that it greatly complicates the column operation.

The internal reflux rate in the column below the LCO product draw is a function of the pumpdown and the internal overflow from the lean-oil collector tray in the main fractionator. The flow rate of the sub-cooled pumpdown cannot exceed the internal overflow on a no-pumpdown basis. The pumpdown flow must be lower than a thermally equivalent amount of bubble point internal-overflow liquid from the LSO draw tray.

A better design is shown in Fig. 4, where a heat-transfer zone is added to the column. The RSO is distributed to a packed bed where heat-transfer occurs (pumparound).

The two-phase RSO enters in a specially designed two-phase liquid distributor. If the distributor is not designed for two phases, severe operating problems will be created. Packed column revamps often attempt to distribute RSO with a distributor designed for liquid.

Fig. 5 shows a revamp variation where the sponge oil circuit was returned to a packed column. This revamp did not work.

RSO contains 30-50 vol % vapor. The revamp shown in Fig. 5 used a spray header to distribute RSO to a packed bed. Spray headers are used for liquid distribution and distribute two-phase flow unevenly.

Poor RSO distribution causes nonuniform heat removal in different cross sections of the packed bed. Depending on the heat removal rate of the sponge oil circuit, the problem varies from manageable to severe.

FCCUs with very high sponge-oil circulation rates will have lower gasoline yields because the maldistribution creates composition gradients. ∎

FCC REVAMP—Conclusion

Simple engineering changes fix product recovery problems

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Refiners often try to improve fluid catalytic cracking unit (FCCU) operation and output by revamping the product recovery section. But, following such revamps, unit operations frequently become problematic.

This final article in a two-part series presents two case studies detailing revamp problems. One occurred in an absorber/stripper and the other, in a stripper reboiler.

These cases show how simple measures were used to diagnose and solve the problems. The first article in this series discussed FCC revamps and described the resolution of a problem in an FCCU sponge oil circuit (OGJ, Apr. 7, 1997, p. 62).

Absorber/strippers

Design and operation of FCC absorber/stripper systems affect C_3 recovery from fuel gas and C_2 rejection to fuel gas (Fig. 6). Absorber C_3 recovery is an economic issue, while stripper C_2 rejection affects downstream processing.

Operating problems with these columns are relatively common. Two problem areas common to absorber/stripper revamps are the intercooler draw and stripper reboiler systems. Incorrect design of these systems can cause high C_3 losses and significant downstream unit operating problems.

Absorber columns recover the C_3s and C_4s from the main fractionator wet gas. Absorbers use lean oil to absorb light gases. The lean oil comprises either main fractionator overhead liquid or main fractionator liquid supplemented with debutanizer bottoms. In a few gas plant designs, debutanized gasoline alone is used in the absorber.

Absorber C_3 recovery for a given column temperature and pressure is improved by increasing the liquid-to-vapor (L/V) ratio in the absorber column. The L/V ratio can be increased by increasing the liquid rate or decreasing the vapor rate.

Vapor rate is affected by operation of the stripper, not the absorber. It is possible, however, to increase the liquid rate in the absorber.

Recycling debutanizer bottoms to the absorber increases the L/V ratio. Alternately, bypassing lean oil decreases the L/V ratio and reduces C_3 recovery. By-passing lean oil around the absorber is usually not part of a revamp design, but rather an operational necessity caused by design errors.

C_3 recovery is also improved by lower absorption-oil temperature. C_3 and C_4 absorption raises lean oil temperature, which decreases the lean oil's ability to absorb.

Often, absorber systems are designed with a side draw to a water-cooled exchanger. After cooling, the liquid is returned to the ab-

Fig. 1

FCC ABSORBER/STRIPPER SYSTEM

Fig. 2

PRIMARY ABSORBER
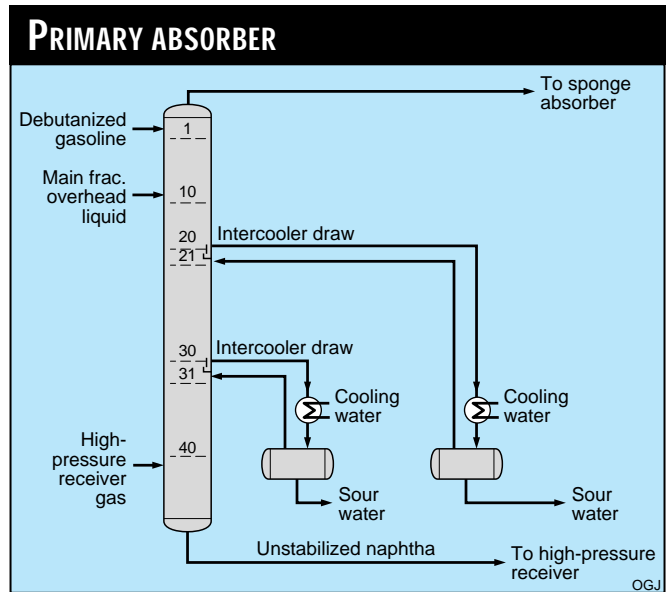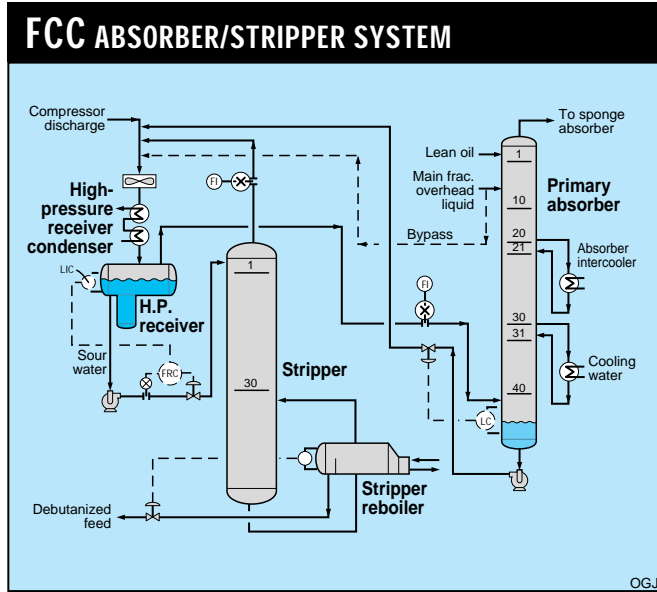
sorber one tray below its draw.

This "intercooler" removes the latent heat from the absorbed C_3s and C_4s. This heat of absorption manifests as a temperature increase from the top of the absorber to the bottom.

Most absorbers use one or two intercoolers. These intercoolers can be either gravity or pumped systems. In either case, the systems must be designed so the unit can be operated if the intercoolers are taken out of service.

The stripper column removes C_2s and hydrogen sulfide from the column bottoms stream. In most gas plants, the stripper bottoms stream feeds the debutanizer.

The debutanizer overhead product stream is a C_3/C_4 mixture. This stream is processed in alkylation, MTBE, and cumene units, or is fractionated in downstream columns. In all cases, there is a maximum C_2 composition in the debutanizer overhead that, if exceeded, causes operating problems.

Stripper columns are difficult to operate efficiently, even under the best conditions. The C_2 content of the stripper-column bottoms stream is controlled by the reboiler duty. If the reboiler surface area or available heat input (typically from main fractionator pumparound) is

limiting, the C_2 content in the stripper bottoms increases.

Stripper reboiler duty must be sufficient to achieve the heat input necessary to meet the target C_2 composition.

Revamp No. 2

The absorber system in Fig. 1 was revamped to increase gas-handling capacity. Prior to the revamp, 25% of the lean oil bypassed the absorber. The bypass lean oil went directly to the high-pressure receiver.

Attempts to increase the lean oil rate to the absorber

resulted in large quantities of lean oil carry-over to the downstream sponge absorber. The rich sponge oil (RSO) containing primary absorber lean oil was returned to the main fractionator. The recycled lean oil from the primary absorber (gasoline) vaporized in the main fractionator.

Vaporization of entrained gasoline in the rich oil acts as heat removal in the main fractionator. Increased heat removal in the sponge oil circuit reduces main fractionator overhead temperature, thus increasing gasoline losses to LCO.

Carry-over of primary absorber lean oil to the main fractionator will cause unstable operation in the main fractionator. This is often the first symptom of primary absorber flooding.

First fix

An engineering study was conducted to identify the problem in the absorber. The study also evaluated an increase in the FCCU charge rate.

The absorber problem was studied via computer modeling and vendor hydraulic calculations. No field tests were conducted to

Fig. 3

RETURN LOCATIONS*

*Intercooler draw

Fig. 4

PROBLEMS*

*Intercooler draw

Fig. 5

REVAMPED UNIT
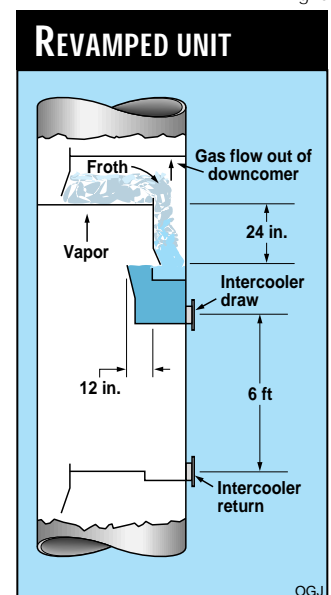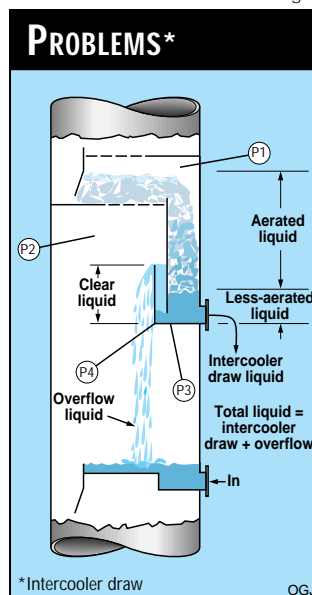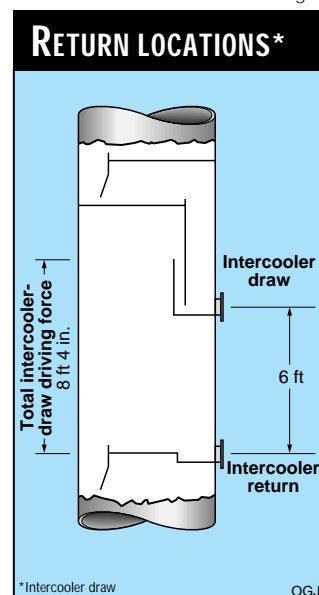
provide a basis for either type of study.

The computer study determined that the column flooded because gas was flowing up the downcomer. Gas flow up the downcomer reduced downcomer capacity, which caused the column to flood at reduced lean oil rates.

The revamp involved replacing the absorber-column valve trays. The new valve-tray design had fewer valves on the tray active panel and reduced downcomer clearances.

After the revamp, the lean oil by-pass had to be increased from 25 to 50% to keep the column from flooding at the same unit charge rate as before the revamp. The revamp actually reduced C_3 recovery by 10%.

A second computer modeling study was conducted to determine the cause of the problem. The results of the study indicated that the cause was an unknown phenomenon reducing the system factor to 0.33 (a system factor of 0.33 indicates severe foaming).

The system factor is an arbitrary number set by the designer. It is used to derate column capacity because of foaming. The calculated flood divided by the system factor equals the derated flood. A calculated tray

flood of 33% (no foaming) divided by a system factor of 0.33 equals 100% flood.

A primary absorber is generally considered a mildly foaming system. Mildly foaming systems use a system factor of 0.9.

A system factor of 0.33 is evidence of a previously unknown physical reaction unique to this plant. Because this explanation is highly unlikely, an alternate solution was sought.

The real reason

The most likely cause of FCC primary absorber problems occur in the bottom of the column or at the intercooler draw or returns. High liquid level can flood the bottom tray. Intercooler draw or return systems can restrict flow and flood the column.

Fig. 2 shows the intercooler draw and return arrangement.

A gravity-flow system must have enough elevation difference between the draw and the return to overcome pressure drop and hydrocarbon density changes resulting from the intercooler system. In this unit, the elevation difference between the top of the draw sump and the overflow from the seal pan is about 8 ft.

This height represents the available driving force

for flow in the system. If the intercooler pressure drop exceeds 8 ft, liquid overflows the seal pan.

Troubleshooting

After determining the problem, data were obtained to ascertain the cause. First, the liquid level in the bottom of the column was lowered. Then the lean oil bypass was decreased (lean oil flow was increased).

If flooding of the bottom tray were causing the problem, lowering the bottom liquid level should allow increased lean oil flow. When the lean oil rate was increased, the column pressure drop increased; therefore, high bottoms liquid level was not the cause of flooding in the column.

The lean oil flow rate to the absorber was reduced and 50% was bypassed. A pressure survey was performed to identify the normal pressure profile. After the pressure profile was established, the lean oil flow rate was increased.

The pressure survey indicated that the flooding began at the lower intercooler draw (Fig. 3). The trays above the lower intercooler began to fill with liquid, resulting in high column pressure drop.

The lower intercooler draw is expected to flood

before the upper one (assuming the tray arrangements are identical) because the vapor rate entering the lower intercooler draw is higher than that entering the upper one.

Normal column operation was re-established. The lean oil rate was set at about 50% bypass. The measured pressure drop in the absorber column was normal.

Another test was conducted to determine the impact of the intercooler draw rate on column flooding. The draw to the lower intercooler was closed. When the intercooler draw was blocked, the column began to flood, even with 50% lean oil bypass. This test confirmed that column flooding was caused by problems at the intercooler draw.

Refinery engineers generally believe that trays flood as a result of high vapor rates. This is the case for main fractionators that operate slightly above atmospheric pressure. But tray operation in FCC gas plants is different than in the main fractionator. Vapor density in the main fractionator is around 0.35 lb/cu ft, while vapor density in the primary absorber is about 1.2 lb/cu ft.

Liquid flowing across the tray deck is contacted with vapor rising through the

Fig. 6

STRIPPER REBOILER REVAMP DESIGN

Tray No. 30
10 ft
Liquid level (design)
7 ft
0 ft
7 ft
LIC
LCO pump-around
Top pumparound
FRC
OGJ

Fig. 7

OPERATION OF REVAMPED REBOILER

Tray No. 30
10 ft
6 ft 6 in.
Liquid level (actual)
6 ft 6 in.
7 ft
0 ft
7 ft
LIC
LCO pump-around
Top pumparound
FRC
OGJ
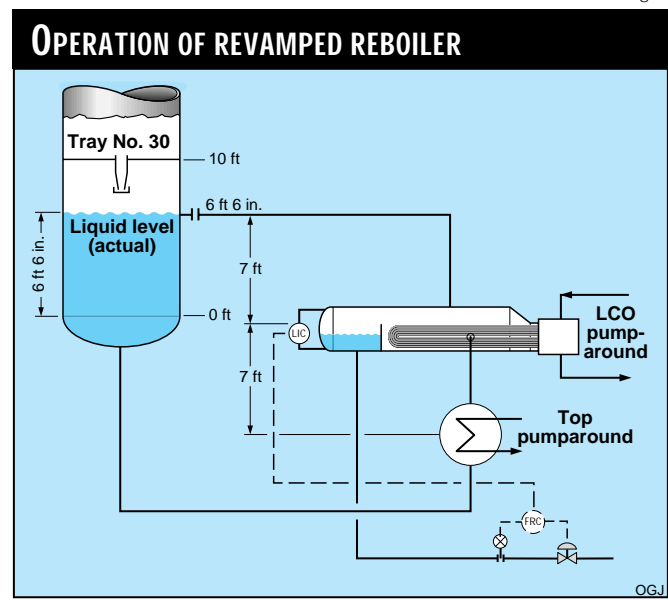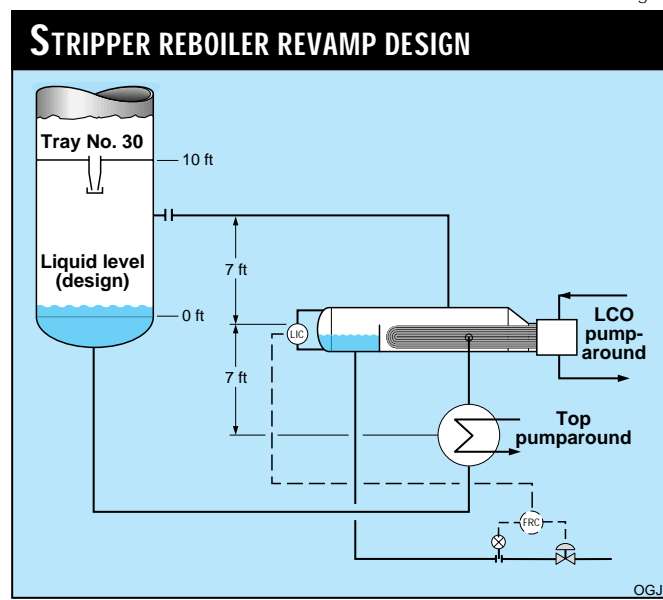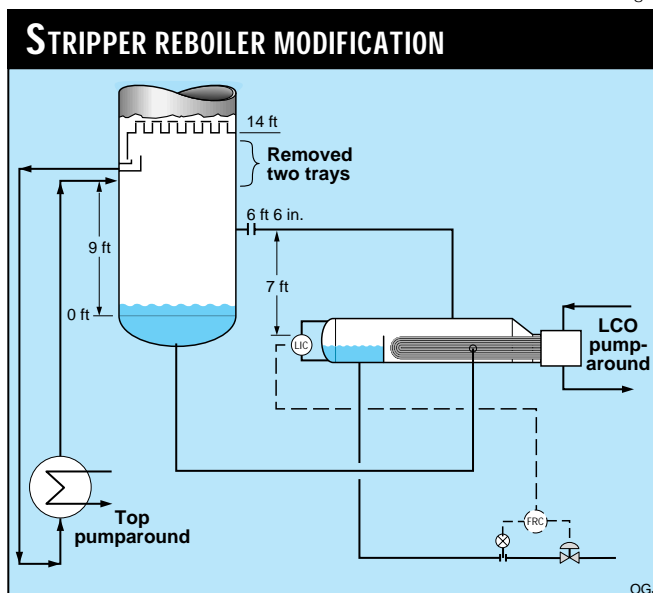
valves. The liquid entrains some of the vapor with the two-phase fluid flowing into the downcomer. The quantity of gas entrained is a function of equipment design and system physical and transport properties, but some gas always enters the downcomer with the liquid.

The fluid density in the downcomer may vary from clear liquid (no entrained gas) at the bottom of the downcomer to a highly aerated frothy fluid at the top (Fig. 4). Ultimately, the entrained vapor must flow out of the downcomer to the tray above, or flow under the downcomer with the liquid.

In the original design, the downcomer on the intercooler draw tray fed the draw nozzle directly. No changes to the draw were made during the revamp.

Understanding the tray hydraulics at the intercooler draw is important. The fluid density in the downcomer is variable. The liquid entering the downcomer contains vapors.

Depending on the downcomer top area, the aeration in the downcomer may be such that clear liquid (no aeration) is found only in the very bottom of the seal-pan. If all the liquid flowing down the column is not drawn to the intercooler, it will overflow the seal pan.

The clear liquid on the overflow side of the seal pan has a higher density than the average fluid density in the downcomer. This clear liquid may cause the downcomer to back up and flood.

Fig. 4 shows a pressure balance for the system.

Downcomer back-up must supply enough static head to overcome the pressure at the bottom of the downcomer created by the clear liquid on the overflow side of the seal pan. In this unit, the absorber flooded because the intercooler hydraulics did not allow 100% of the liquid flowing down the column to be withdrawn. Some liquid always flowed over the seal-pan.

Fig. 8

STRIPPER REBOILER MODIFICATION

14 ft — Removed two trays
6 ft 6 in.
9 ft
7 ft
0 ft
LIC
LCO pumparound
Top pumparound
FRC
OGJ

This was confirmed by a tower scan.

When the intercooler was blocked in, the column flooded at even lower lean oil rates than when the intercooler was in service. This happened because the area between the downcomer and the seal pan was not big enough for all the column internal liquid and entrained gas. The restriction created additional pressure drop that caused the tray downcomer to flood even sooner.

The solution

Fig. 5 shows the modified design of the intercooler draw system.

The active trays above the downcomer were replaced with a collector tray. The collector tray minimizes gas entrainment to the downcomer because it is not active (it has no vapor-liquid contact).

The downcomer of the collector tray is separated from the seal pan on the intercooler draw by a new downcomer seal pan. The liquid in the bottom of the downcomer overflows its seal pan. This liquid flows into the seal pan of the intercooler draw-off. The liquid in the seal pan feeding the intercooler draw nozzle is clear.

The area between the edge of the downcomer seal pan and the intercooler draw pan should be sized for 100% of the column's internal liquid flow. Sizing for full internal flow allows for proper column operation with the intercooler out of service. While this is a conservative sizing method for the top of the seal pan, it will work all of the time.

Why did column performance worsen after the new tray active areas were installed? A tray hydraulic analysis showed that the tray vendor was correct in assuming that there were too many valves on the tray.

Before the revamp, the trays were weeping (liquid was leaking through the valves). Tray weeping was allowing higher lean oil flow rates, even though the intercooler draw was designed incorrectly.

Liquid flowed through the valves on the tray deck because of low vapor velocity. The liquid leaking through the tray decks kept the intercooler draw tray from flooding, even at higher liquid rates with only 25% lean oil bypass.

When the column was revamped and the number of valves was reduced, the vapor velocity through the valves increased. The new tray design no longer allows liquid to leak through the valves.

While installing trays with fewer valves was an appropriate measure to improve efficiency, it was the wrong thing to do, given the operating problems in this column. Incomplete solutions often make problems worse. A revamp should always be checked against plant performance to verify that the fix makes sense.

Operation of a primary absorber column is relatively simple. Maximizing lean oil flow will minimize C_3 losses to fuel gas. Conventional absorbers (those without lean oil chillers) will achieve recoveries of 92-94% when processing only FCC gases.

Revamps are more complicated than grassroots designs because the existing equipment might not be designed per accepted standards. Existing equipment must be thoroughly evaluated, otherwise problems similar to this one can result.

Stripper reboiler

Increasing unit conversion and LPG production increases the stripper bottoms-product rate for a given unit charge. Increased stripper bottoms product requires higher stripper reboiler duty.

Revamps of stripper reboiler systems and available heat sources must be thoroughly reviewed. In several cases, refiners have had to install an additional column downstream of the FCC debutanizer to remove C_2s not removed by the stripper.

These secondary de-ethanizers use a partial condenser system and recycle the vapor to the high-pressure receiver. They are a classic example of treating the symptom rather than the problem. Secondary strippers cost $2-4 million installed, and they greatly complicate operation of the FCCU gas plant.

Increasing stripper reboiler duty first requires a source of heat (Fig. 6). The stripper reboiler duty is a good place to sink a portion of the low-temperature heat

in the main fractionator or the gas plant.

The stripper reboiler inlet temperature is approximately 65° F. lower than the outlet. Utilizing two reboilers in series (the first using low-temperature heat) is feasible. The top and heavy-naphtha pump-around draw temperatures in the main fractionator are, respectively, about 300° F. and 365° F.

Debutanized gasoline is another possible heat source. Any of these heat sources will supply as much as 60% of the required stripper reboiler duty. It is relatively common revamp practice to use a series reboiler system to supply the total reboiler heat.

Revamp No. 3

Fig. 7 shows a reboiler system installed on an FCCU. While there is nothing inherently wrong with the series reboiler concept, there is relatively little flexibility in the system.

The unit shown operated well at the design conditions, but when the unit charge rate was increased and the stripper bottoms-flow increased, stripper column operation was poor.

Design of piping systems for a stripper series-reboiler must be thoroughly evaluated to determine if there are limitations. Fig. 7 shows the relative elevation differences between the two reboilers.

Technically, the first reboiler is a thermosyphon with the feed coming from a nozzle on the bottom of the column. The thermosyphon discharge feeds the two-phase stream into the side of the kettle about halfway up the tube bundle.

Kettle reboilers have a baffle at the end of the bundle to keep the reboiler tubes submerged. The elevation of the top of the baffle sets the minimum liquid level in the bottom of the column.

The actual level in the bottom of the column is set by pressure drop through the reboiler circuit. In this example, the revamp system was designed with only 6 ft 6 in. of vessel height from the column tangent line to the center line of the vapor return nozzle.

The available height of liquid, or static head, to feed the reboiler system is a critical design parameter. Once the liquid level in the column reaches the kettle reboiler return nozzle, liquid from the bottom of the column will flow into the kettle reboiler. The kettle reboiler then will have vapor flowing to the column and liquid flowing from the column. As a result, the pressure drop in the reboiler return line will increase.

Overcoming the increased pressure drop requires an increase in the liquid level in the bottom of the column. At some point, the liquid level in the bottom of the column floods the bottom trays. The stripper column then will begin to fill with liquid.

In cases of very severe stripper flooding, massive amounts of liquid carry over from the top of the column. While this is an extreme result, it is not that unusual.

The pressure drop in the reboiler system includes line losses, the thermosyphon reboiler, the kettle reboiler, and the reboiler vapor return line to the column. The liquid density in the bottom of the column is approximately 0.63. The density of the mixed-phase fluid in the line leaving the reboiler is less than that of the feed to the thermosyphon, and this helps circulation. Nevertheless, the system has 6 ft 6 in. of driving force, which represents less than 2 psi.

Most FCC units operate at significantly higher charge rates than the original design. It is not unusual, therefore, to have stripper bottom flow rates that are 25-50% higher than design. In the author's opinion, the design shown in Fig. 7 is poor because it includes no safety margin.

Complex hydraulic calculations for reboiler systems (such as shell-side, two-phase-flow pressure drop) have significant correlation errors. Two-phase vertical flow calculations are, by definition, estimates.

The solution to the reboiler problem is relatively straightforward. The reboiler piping system must be modified to supply more driving force to the existing reboilers. Column height can be used to increase the hydraulic capacity of the reboiler system by modifying the reboiler draw arrangement.

Stripper columns often are designed with more than 25 trays. The stripper column boil-up required for low bottoms C_2 composition is at a minimum when the column has about 25 well-designed trays.

The solution

The revamped system is shown in Fig. 8. The reboiler system was modified so that liquid is withdrawn from a seal-welded collector located three trays above the bottom tray.

The thermosyphon reboiler discharges to the bottom of the column. The liquid flowing from the column bottom feeds the kettle reboiler. The liquid height in the bottom of the column is now related only to the pressure loss through the kettle and through the kettle vapor return line to the column.

The thermosyphon provides about 65% of the boil-up; hence, the vapor rate leaving the kettle is much lower than the original design. Pressure drop through the existing kettle vapor line is negligible.

The revamped reboiler system has the following advantages:

1. The thermosyphon hydraulics do not affect the bottoms liquid level because the thermosyphon loop is decoupled from the kettle reboiler.

2. The bottom liquid level is reduced.

3. The heat-transfer coefficient of the kettle reboiler increases because the two-phase stream is eliminated. (Two-phase flow into the side of a kettle disturbs the boil-up by causing some tubes to contact only vapor rather than liquid.)

The revamp process must address small details. Without attention to detail, revamps will continue to be risky. ∎