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SPECIALREPORT

PLANT SAFETY AND ENVIRONMENT

Pump cavitation caused by entrained gas

Here's how the problem was solved on an FCC main fractionator

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When refinery engineers think of pump cavitation, what first comes to mind is usually insufficient net positive suction head (NPSH) available. Symptoms include erratic pump flow and discharge pressure, a distinct crackling noise coming from inside the pump, and severe suction line vibration. Cavitation is caused when vapor bubbles formed inside the pump or suction line implode as pressure increases inside the pump. Much less frequently, entrained gas in the fluid being pumped causes the same symptoms.

A case study presents troubleshooting an FCC main fractionator revamp including the LCO pumparound (PA) pump that was cavitating due to entrained gas. Here pump cavitation and column flooding caused reduced column heat removal, decreased column capacity, degraded fractionation, lower-than-design unit capacity and high endpoint gasoline. The short-term remedy and longer-term modifications to correct the root cause are discussed.

Background. An FCC revamp failed to meet two of its processing objectives: higher FCC charge and better gasoline/LCO fractionation. After startup, poor fractionation, low LCO PA heat removal, lower than design charge rate and unstable operation were the norm. Gasoline endpoint could not be controlled and logical operating variable changes had no influence on gasoline quality. Attempts to increase LCO PA rate resulted in erratic pump flow and rapidly oscillating discharge pressure, both common symptoms of pump cavitation. Because the LCO PA is used to reboil the gas plant deethanizer, a consequence was poor hydrogen sulfide and C_2 removal from the debutanizer feed. Yet prior to the revamp, the LCO PA pump had operated at much higher flow without showing any cavitation symptoms.

The most significant post-revamp operating problem was unpredictable gasoline endpoint and yield. The refiner had modified the main column internals and PA exchangers to permit undercutting FCC gasoline to LCO product. Decreasing gasoline yield is one option to meet lower refinery pool sulfur levels because half the sulfur[1,2] is contained in the heaviest 10–15% of the FCC gasoline. Changes were made with the expectation of improved fractionation and minimum gasoline yield loss. TOP PA heat removal capability was also increased and high-capacity column internals installed.

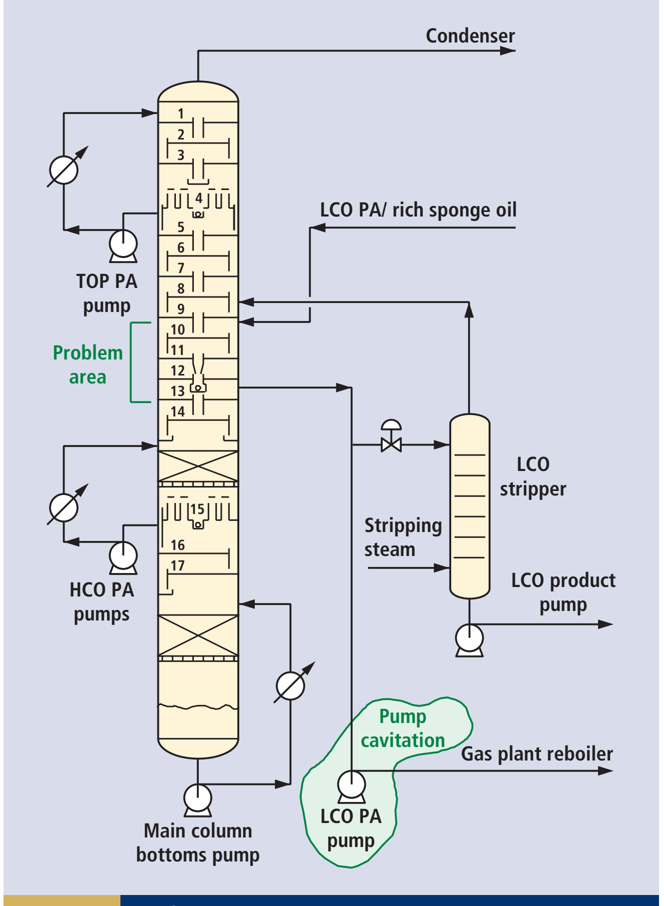

FIG. 1. The four pumparounds include TOP, LCO, HCO and slurry PA.

Fig. 1 shows the main process flow scheme with four pumparounds including TOP, LCO, HCO and slurry PA. The revamp design basis would shift heat removal from lower pumparounds to the TOP PA to raise reflux between gasoline and LCO product draws. Since the HCO and LCO pumparounds are used for gas plant reboiler heat, their duties could not be

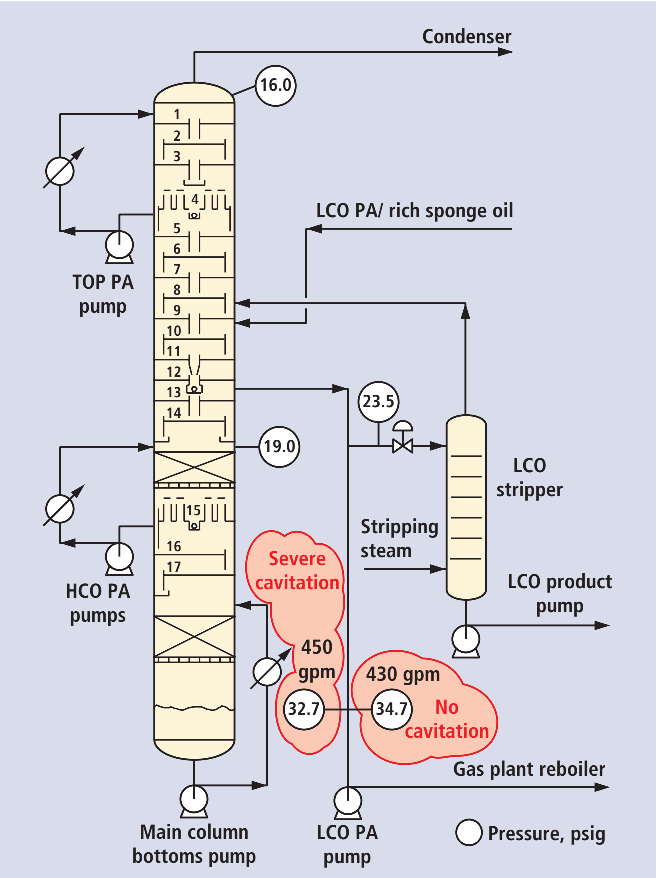

FIG. 2. Pressure and temperature measurements should complement scans when troubleshooting columns.

reduced. Therefore, the slurry PA revamp design basis called for reduced duty so that reflux flow below the TOP PA could be increased. Yet, due to the heat shift up the column, vapor flowrate throughout would increase. But after the revamp, fractionation throughout the column degraded and gasoline endpoint was much worse than before the changes were made.

Post-revamp performance. Gasoline endpoint varied erratically from 450°F to 520°F, yet there were no obvious operating problems other than LCO PA pump cavitation. Normal operating changes, such as lowering overhead vapor temperature, did not reduce gasoline yield or endpoint. These symptoms alone indicate column flooding or damaged column internals.

When a revamp does not meet expectations, often the troubles are blamed on whatever was changed. Conventional trays were replaced with high-capacity trays and packing to allow more charge rate and permit gasoline to be undercut to LCO product. TOP PA cooling was increased to provide additional duty to condense the undercut gasoline and higher reflux. In theory, heat shift changes to TOP PA would decrease gasoline yield, generate higher internal reflux and improve fractionation.

In practice, all the column internals would need to be capable of handling the higher vapor rate, otherwise flooding would actually reduce fractionation rather than improve it. The revamp changed all the column internals with the exception of trays #12–14. These trays were rated by the design engineers and tray vendors, and determined to have sufficient capacity.

Field testing, plant observations and operator input. Troubleshooters need to gather sufficient accurate field data to determine the root cause of poor performance. Plant observations, such as unusual noises, may help find the root cause. Operator know-how is an essential first part of troubleshooting because they are familiar with how the unit responds to operating changes. But increasingly, the first things done when revamp performance is poor is to employ sophisticated techniques such as a gamma scan. Not uncommonly, these sophisticated tests take significant skill to interpret and findings can be inconclusive.

In this case, one of the scans showed the column was beginning to flood at tray #13, while the others showed no signs of flooding. Gamma scans are useful tools. However, they need to be planned, executed and interpreted by an experienced person. And they should not be the sole basis for troubleshooting. Often the troubleshooter must recommend shutdowns to correct design errors. Making a mistake can cost the refinery millions of dollars and not correct the problem's real cause. Temperature and pressure measurements[3] are powerful troubleshooting tools (Fig. 2) and should complement scans when troubleshooting columns.

Accurate instrumentation was used to measure pressure on the column at two locations simultaneously. Pressure drop from the top of the column across 13 trays to the HCO PA draw was 3.0 psi or an average of 0.23 psi/tray. Trays on 24-in. tray spacing begin to flood at approximately 0.13 psi pressure drop. High pressure drop, when the measurements are accurate, is a definitive indication of flooding irrespective of scanning interpretations. In this example, pinpointing the locations where the column began to flood was not possible because few pressure taps were available. However, in another case, accurate gauges were used to successfully identify the location where flooding was initiated when measuring pressure dropped across only two trays.[4]

Several tests were run to isolate the specific location where column flooding initiated. First, heat removal was increased in the LCO PA by lowering the return temperature. This reduced the vapor load above the LCO pumparound, but column pressure drop did not materially change. However, when either the HCO or slurry PA duties were increased, column pressure drop and gasoline endpoint decreased. These tests clearly showed flooding somewhere on the five trays #10–14 between the HCO and LCO PA return nozzles. Often pumparound/product draws[5] and feed locations, and reboiler systems[6,7] are the source of distillation column flooding. An experienced troubleshooter always looks here first.

Laboratory tests were used to help confirm flooding. The TOP PA stream D86 endpoint was above 600°F and the gravity below 30°API. A column fractionating properly would have a TOP PA endpoint of about 475–500°F and a gravity of about 45°API. When LCO PA heat removal dropped due to pump cavitation, duty would decrease and vapor flowrate above the PA return increased. This caused liquid in the flooded column to be carried with the vapor out the top of the column. Thus overhead receiver gasoline flowrate and gasoline endpoint would increase rapidly during the carry-over. All these are classical column flooding symptoms.

While gamma scan findings indicated the column was *not* flooded, testing and observations all showed it was badly flooded.

Pump NPSH requirements. Pumps require a certain NPSH to operate without exhibiting head or flow loss. Pump manufacturers develop the pump NPSH required curve by lowering feed drum level (NPSH) until the total dynamic head (TDH) decreases by 3% at a given flowrate. This standard test is the basis for pump NPSH required curves. It is estimated that 80% of all pump problems are due to inadequate suction conditions and most suction problems are related to NPSH.[8]

Pump cavitation—entrained gas. Vacuum tower bottoms (VTB) pumps are the most common service in a petroleum refinery where entrained gas causes cavitation. Gas bubbles formed by thermal cracking in the vacuum column bottom are entrained as the fluid flows into the column outlet nozzle feeding the pump suction line. Most vacuum column boots have no quench distribution. Thus, the unquenched flash zone liquid and boot quench do not mix until they reach the outlet nozzle (Fig. 3). Therefore, areas of the column boot are the same temperature as the flash zone.

Cracked gas is formed in the high-temperature areas and the vapor bubbles in many instances cannot vent back into the column because the nozzle and pump suction line are too small. Even though the pump has calculated or measured NPSH available much higher than required, the fluid cavitates—resulting in erratic pump operation and damage.

Often designers will mistakenly increase vacuum column skirt height during design to increase NPSH available intending to eliminate potential for cavitation. However, when the unit starts up cavitation still occurs. This is especially true with deepcut vacuum units that operate at very high flash zone temperatures. Vacuum column boot quench distribution is essential to maintain uniform temperature throughout the boot to suppress cracked gas formation that causes cavitation. While it is possible to make the nozzles and pump suction line self-venting, it is a very high-cost solution.

LCO PA system pressure survey. Several tests and pressure surveys were performed to determine the cause of pump cavitation. First, the LCO PA flowrate was reduced until flow and head were stable. A pressure gauge was installed on the pump suction above and below the pump strainers. This was done to ensure that nothing was plugging the strainers. The pump suction pressure was measured at 34.7 psig with the pump flow and discharge pressure both stable (Fig. 2). The metered LCO PA flowrate was 430 gpm with no signs of cavitation.

LCO PA flow was then increased to determine if the LCO PA draw system capacity was limiting circulation. LCO PA flowrate was slowly increased to 450 gpm, and the pump began to severely cavitate. Cavitation was measured by flow meter and pump discharge pressure variability. Discharge pressure began to bounce just prior to the board flowrate becoming unstable. At these conditions the measured suction pressure had dropped to 32.7 psig, but it was stable. The LCO product draw was increased to try to empty the suction line, yet the pump suction pressure never dropped below 32.7 psig. Thus, the suction line was still full of liquid even though the pump was cavitating. The pump suction pressure showed that the NPSH available was over 45 ft, and the pump required only 16 ft. The pump had sufficient NPSH, but was still cavitating.

Turndown is sometimes a problem with low NPSH required pumps. But when turndown causes cavitation, reduced flow does not improve pump performance, it makes it worse. Observations showed that lowering LCO pump flowrate by only 20 gpm (less than 5% of total flow) eliminated cavitation, and the pump began to run smoothly, although field measurements showed that when pump flow increased by 20 gpm the pump suction pressure would decrease by only 2 psi, and severe pump cavitation occurred. Pump turndown was not the problem because decreasing LCO PA flow improved pump performance. Nonetheless, the lower pressure—assuming the suction line was full—indicated that the fluid density was changing as pump flow increased.

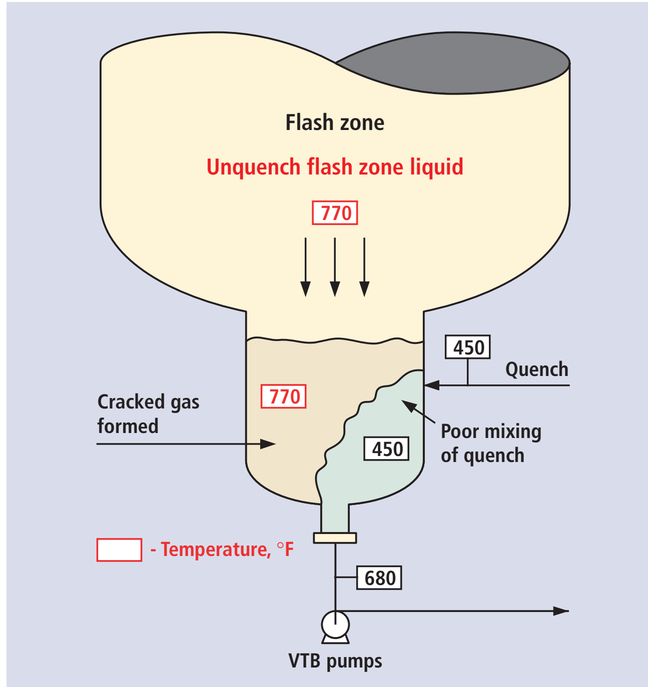

FIG. 3. The unquenched flash zone liquid and boot quench do not mix until they reach the outlet nozzle.

Increasing LCO product draw rate would also cause the PA pump to cavitate. LCO product and PA are both drawn from the same column nozzle with the line feeding the stripper located about 15 ft below the column draw nozzle. During the pump survey, the pressure was also measured at the inlet to the LCO stripper level control valve. Fig. 2 shows the measured pressure that indicated the suction line was full.

At this location, a loud crackling noise could be heard downstream of the stripper level control valve. The noise was typical of vapor degassing from liquid. Calculations showed the total draw rate (LCO PA and product) in the column nozzle and suction piping was above the line self-venting velocity limit.[9]

Another problem was that the draw box entrance below tray #12 had low open area. Hence, once a two-phase fluid entered the draw box, it would not allow vapor to escape through the entrance even if the draw box allowed the phases to separate. Once the self-venting velocity was exceeded or two-phase flow increased into the draw box, gas bubbles were entrained in the pump fluid. Because tray flooding heavily aerates the liquid, entrained vapor bubbles in the pumped fluid caused the pump cavitation.

Short-term fix—eliminating cavitation. If gas was being entrained in the liquid to the pump, then it was hypothesized that the gas could be vented. Hence, a vent was installed by hot tapping the suction line 90° elbow with the vent line routed to the LCO

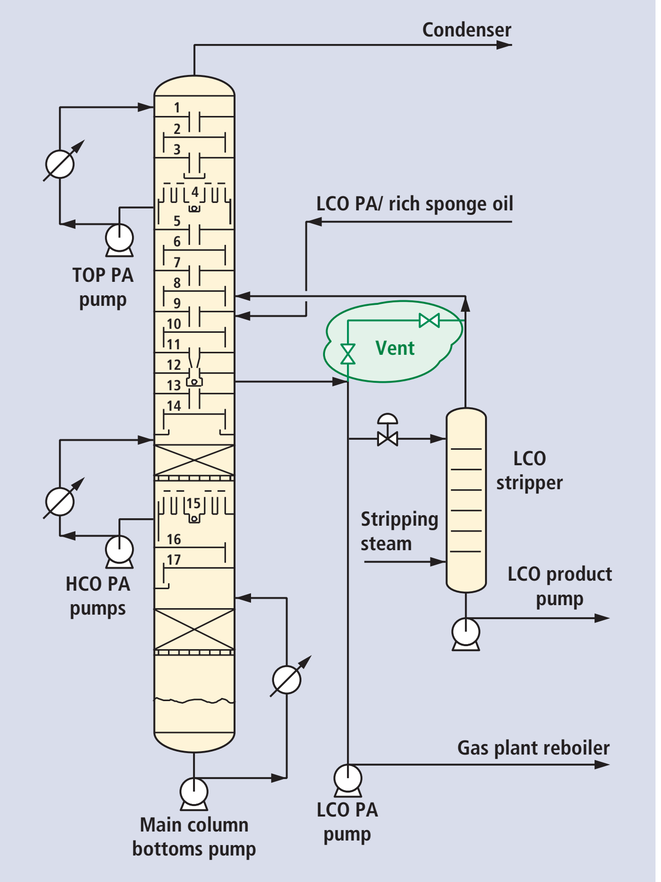

FIG. 4. A vent was installed by hot tapping the suction line.

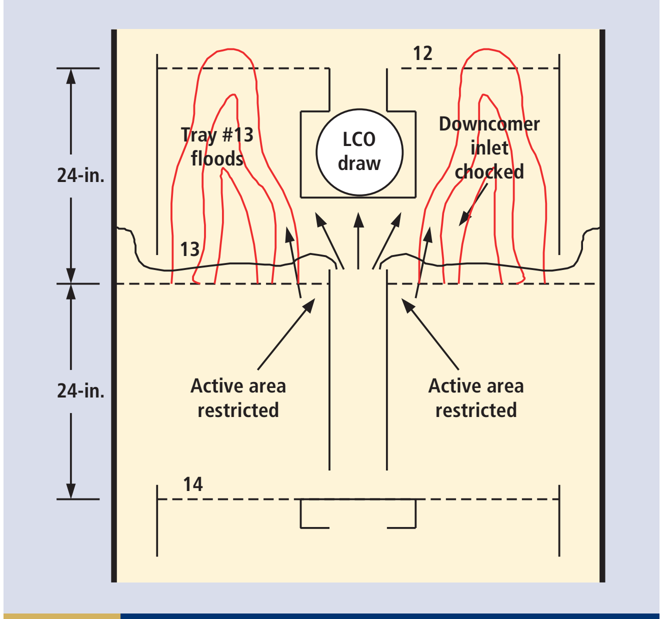

FIG. 5. The tray #12 draw box restricts the active area of tray #13.

stripper vapor return line running next to the pump suction line (Fig. 4). When the vent line was put in service, the pump began to operate stably at flowrates 25–30% higher without any indications of cavitation. The vent allowed the entrained vapor bubbles to flow to the stripper vapor line rather than the pump, which allowed the pump to operate smoothly. While this solved one problem, it did not address column flooding. Even at higher LCO PA flowrate, the column was still flooded, and the gasoline endpoint was high.

Cavitation caused by gas entrainment occurs in heavy oil fractionator PA pump service, although vacuum tower bottoms (VTB) pumps much more commonly have this problem. Because most PA draw nozzles are submerged and vapor/liquid disengagement in draw boxes (sump) feeding the draw nozzles is sufficient to separate the phases, entrained gas cavitation rarely takes place. Furthermore, as elevation change raises suction line pressure, the process fluid can absorb vapor bubbles before it reaches the pump suction. Nevertheless, in the event a column is operated flooded and the draw sump design prevents phase separation, these vapor bubbles can reach the pump inlet and cause cavitation.

Column internals design—root cause. Field testing showed that flooding could be eliminated by increasing either the HCO or slurry PA flowrates. Furthermore, one of the gamma scans confirmed that the column was full of liquid from tray #13 to the top of the column. Fig. 5 is a schematic of the tray #12 draw box arrangement. The tray #12 draw box restricts the active area of tray #13 and chokes liquid flow into the tray #13 downcomer.

Normally tray spacing is increased by 12–18 in. at draw locations to eliminate draw box (sump) interferences with the tray below. However, draw box modifications to reduce blockage of the tray #13 active area and downcomers are possible without increasing tray spacing. Fixing the problem requires a shutdown to modify the draw box. Small details often are the difference between success and failure. In the interim, the slurry PA duty was operated high enough to keep the column from flooding and gasoline on-specification. **HP**

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