Originally appeared in:
June 2019, pgs 37-40.
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HP Special Focus | Process Optimization

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Set refinery profitability goals

While the ultimate purpose of operating a refinery is to produce gasoline, diesel or asphalt, key objectives include improving return on investment (ROI), net profitability and cash flow.[1]

Great strides have been made in improving plant efficiency and productivity by implementing online, interactive computer controls. Key segments of refineries have been upgraded, such as vacuum tower steam ejectors and vacuum condensers. Tower resid stripping trays have also been replaced with new types of structured packing.

But has this improved profitability or cash flow? How can the first-line management level know that its cash flow or ROI has been improved?

Setting goals. Process engineers try to keep products on spec and minimize utility consumption and pump outages. What other goals can be set, and what other guidelines can be employed? At the first-line management level, cash flow, net profitability or ROI cannot be easily measured, but they can be determined if things are really improving.

To gauge directionally if cash flow is improving, the following variables, which are listed in order of economic importance, should be monitored:

1. Minimum of 1,050°F (566°C) minus gasoil in vacuum resid, based on ASTM D-1160 test
2. Minimum of 650°F (343°C) minus diesel in fluid catalytic cracking unit (FCCU) feed, based on ASTM D-86 test
3. Minimum of 340°F (171°C) jet fuel (sim distillation) in naphtha
4. Minimum of C_3–C_4 liquefied petroleum gas (LPG) in fuel gas
5. Minimum C_7 toluene precursors in isomerization unit feed
6. Minimum C_6 (i.e., benzene precursors) in reformer feed
7. Minimum of amylenes (C_5) in alkylation feed
8. Minimum butylenes (alky feed) in fluid coking unit (FCU) naphtha
9. Minimize Ni + Va in gasoil to FCU feed hydrotreater
10. Minimize slop production.

Vacuum resid gasoil quality. Considering the diesel diluent needed to add to vacuum resid to meet Goal #6 oil viscosity specs, each barrel of gasoil left in vacuum tower bottoms is a $20 loss. This is particularly true with the new, 5,000-ppm-sulfur spec on bunker fuel oil for ocean-going ships.

However, many plants do not sample the vacuum tower bottoms stream for fear of a fire at the sample point. The auto ignition temperature of the vacuum resid is 320°F (160°C). The sample point is on the run-down stream at 450°F (232°C). The plant safety department may prohibit the use of such a sample station.

However, a sample can be obtained without any hazard, even though the resid solidifies at temperatures below the 320°F (160°C) auto-ignition temperature. The sample can be obtained at the bottom's pump discharge temperature of 680°F (360°C) using a steel bottle, as shown in FIG. 1. The bottle should be allowed to fill with resid, blocked in and cooled, and then unscrewed and sent to the lab.

The seemingly simplest way to reduce gasoil lost to vacuum resid would be to cut back on the wash oil flowrate (FIG. 2) above the grid from approximately 5,000 bpd to 3,000 bpd. However, this will not yield 2,000 bpd of incremental heavy gasoil product. About 80% of the wash oil evaporates in the grid, so the reduced wash oil lost to vacuum tower resid would be only 400 bpd, rather than 2,000 bpd. Additionally, this promotes coke formation due to the lack of wetting of the grid. Over a period of months, the quality of the gasoil product will deteriorate, and the flash zone pressure will increase.

The metals in the gasoil will increase, and these higher amounts of metals will ruin the catalyst in the FCCU feed gasoil hydrotreater, which is contrary to Goal #9 listed here.

Increasing flash zone temperature. The heater outlet could be raised from 760°F (404°C) to the design temperature of 780°F (416°C) if the heater is not over-firing, if the forced draft (FD) air blower is running below rated speed, and

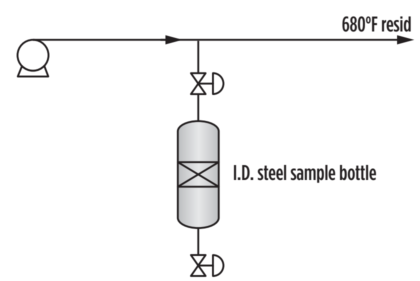

FIG. 1. Sample bottle.

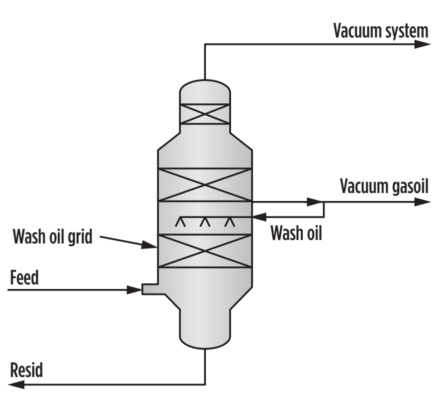

FIG. 2. Wash oil protects the grid from coking.

if the burner flames are not near the tubes. However, the higher flash zone temperature will increase cracked gas flow, which can overload the vacuum system. The tower pressure will increase as a result, and gasoil recovery will drop.

Another option is to increase the steam through the vacuum heater passes concurrently with the higher outlet temperature. The reduced oil soaking time in the tube due to the steam would offset the hotter outlet, decreasing the formation of cracked gas. Also, the coil steam would reduce the hydrocarbon partial pressure in the flash zone. This does place a larger load on the first-stage ejector (**FIG. 3**). However, the extra steam in the heater passes will suppress the average coil temperature by promoting more vaporization in the heater tubes. The lower temperature will also reduce the rate of cracked gas formed in the tubes.

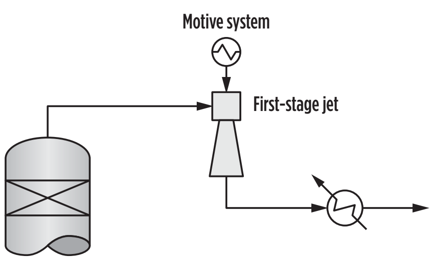

FIG. 3. Extra steam to the vacuum heater overloads the first-stage jet.

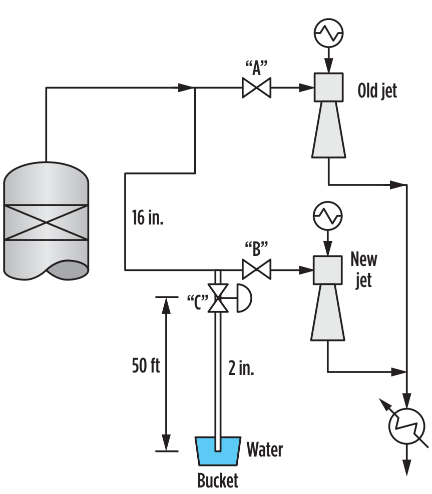

FIG. 4. Commissioning the spare first-stage ejector.

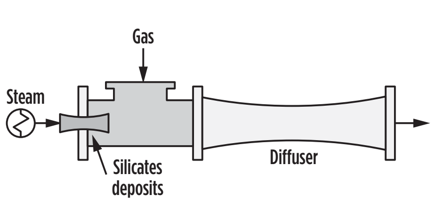

FIG. 5. Silicate fouling is a possible cause cause of poor ejector performance in refineries.

The extra steam may cause an overload of the first-stage ejector capacity and raise the vacuum tower flash zone pressure. Only a plant test can determine the best course of action.

Commissioning spare steam ejector. One option is to commission the spare first-stage ejector. Previously, each time this has been attempted (**FIG. 4**), the vacuum breaks and the tower top increases in minutes by 20 mm Hg. Why? Testing the jet by itself showed that it ran well. The steam nozzle was replaced anyway, but that made no difference to the performance.

Startup of the idle jet was again attempted. However, the new first-stage jet was on an 80-ft elevated platform by itself and was connected to the tower overhead vapor line by 120 ft of 16-in., bare piping. As soon as the outside operator cracked open the inlet gate valve (**FIG. 4**), the local vacuum pressure gauge jumped from 36 mm of Hg to 48 mm of Hg and continued to trend higher.

This repeated each time, and it was noted that the suction line could be full of water. When the operator opened valve B, water would be drawn into both the old and new ejectors, bogging down both jets. It would be necessary to drain down the 16-in. line going to the new jet before opening valve B. However, the 2-in. valve (i.e., valve C) just upstream of valve B could not be opened because the 100-ft-long, 16-in. line was under a vacuum. If opened, it would draw air into the jets and the vacuum would break.

A hose was run from the 2-in. drain to a bucket of water 50 ft below the C drain valve (**FIG. 4**). For this to work, the hose must first be filled (i.e., primed) with water. Then, the 16-in. line can be drained before opening valve B.

The 2-in. drain should have been piped into the seal drum or the initial installation should have been designed to avoid low points in the piping that can gather liquid.

Silicas in steam nozzle. Months before, the vacuum was suddenly deteriorating. A common cause is silicate deposits in the steam nozzle (**FIG. 5**). The steam quality may have suffered, contaminated with carry-over from a kettle waste heat boiler. The entrained moisture can be 10,000 ppm of total dissolved solids (TDS). This is mainly silicates, which precipitate out in the steam nozzle. A plug on the back of the jet can be used to clear the steam nozzle with a wire brush. This cannot be done while the jet is running. Once the new ejector is online, the old jet can be cleaned. This plug is intended to check the internal diameter (ID) of the steam nozzle, but it can also be used as a clean-out access to the steam nozzle. Note that larger ejectors may not be supplied with this connection. In this case, the motive steam chest would need to be removed to check and clean the nozzle.

Wet steam. Water in steam degrades jet performance and damages the ejector. A cyclonic steam separator will help to prevent the problem. The condensate drains through a bucket trap. They work similar to a centrifugal separator.

The effect of wet motive steam to an ejector can be observed. The temperature of the ejector discharge line drops by 15°F–30°F within a few feet of the jet discharge. If the steam blowing out of a bleeder is invisible for an inch or more, the steam is dry. If the steam blows out white, it may still be reasonably dry (i.e., a few percent moisture). If water accumulates at a low-point drain every few minutes, the steam is likely wet enough to adversely affect vacuum. As a test, 30 ft of a 2-in. steam supply line were wrapped with rags and insulation, and several mm of Hg were gained.

Cooling water flow. It was observed that the cooling water flow to the first-stage vacuum condenser was gradually falling and the tubes were chemically cleaned to remove scale, but it failed to help.

The problem was not fouling, but air that evolves out of the water at the condenser outlet. The evolved air chokes off the flow of water through the tubes. As the water rises 80 ft to the elevated surface condensers, it loses head pressure and liberates air. The dissolved air content of the cooling water should be constant, but why was the loss of cooling water getting worse?

Investigation showed that the suction piping of the cooling water pumps was 7 ft above the water level in the sump. That means that the suction piping to the water pump was under a vacuum of 3 psi, or 12 psia—2.3 ft of water are in a psi. If small holes develop in the carbon-steel suction piping due to corrosion, the air is sucked into the pump's suction. At the 60-psig pump discharge pressure, the air dissolves in the water. In that way, the dissolved air content of the cooling water can increase by a factor of four. Furthermore, the problem could grow worse with time.

One temporary solution is to wrap the suction line in duct tape or a fiberglass wrap, which will also help the pump discharge pressure. Duct tape has also been used to temporarily mitigate an air leak on the steam ejector diffusor. **Note:** While duct tape does a good job of sealing a vacuum leak, using it for more than a temporary patch is not advised. If the metal is thin enough to develop a hole, it could be uniformly thinning and could collapse on itself.

Tube material selection. One of the first intercondensers was re-tubed due to wear, and that condenser is now presenting issues. Condensers often need to be re-tubed at least once during their operational life, and they normally work better after new, clean tubes have been installed. In this case, the condenser operated well for the first few months, but it should have operated more effectively due to the material change: the stainless tubes were replaced with carbon-steel tubes, which appeared to be a better option. Not only were the carbon-steel tubes readily available and cheaper, but carbon steel also has a better heat transfer rate than stainless tubes. The improved heat transfer rates should give the condenser more capacity.

However, for this service, carbon-steel tubes are a bad choice. The carbon-steel tubes are exposed to cooling water that is rich in oxygen on one side, and oxygen-containing vapors on the other side. These cause the carbon steel to oxidize and rust. While the tubes do work well at first, it does not take long for them to rust over, impeding heat transfer. That rust buildup can choke off the cooling water flow over time, further degrading performance. Carbon-steel tubes generally do not last more than 1 yr–2 yr before developing major cooling water leaks.

This also explains the increase in hotwell condensate rates and the reduction in condenser performance.

In addition to negatively affecting performance, carbon-steel tubes must be replaced more often because they fail so quickly. This requires additional work and time, so the carbon steel ends up not being as cheap as first thought. Stainless-steel tubes, brass tubes or duplex-stainless tubes are preferred in vacuum condensers.

Recycle line control. The vacuum system's recycle pressure control caused the tower pressure to fluctuate when it was put into service, but inspection failed to find anything wrong with the control valve. The P&IDs were reviewed, and it was determined that the recycle line was installed correctly (FIG. 6).

However, the recycle line is piped from the discharge of the last-stage ejector back to the suction of the first-stage ejector. Most of the load at the end of the ejector system is noncondensables. When the recycle flows back to the suction of the first-stage ejector, it not only adds load to the first-stage ejector but also overloads the second- and third-stage ejectors. Ordinarily, a significant amount of load is needed to change the suction pressure of the first-stage ejector, but the third-stage ejector is designed to handle only the noncondensable loading at the tail end of the system. When the entire system is recycled, the last ejector is overloaded, causing it to break performance. This causes the tower top pressure to fluctuate and the recycle control valve to cycle between fully open and fully shut.

This is a common error. By recycling from the third-stage ejector discharge back to the first-stage suction, a large pressure differential exists compared to the correct configuration, which is recycling from the first-stage ejector discharge back to the first-stage suction. The larger pressure differential allows the sizing of a smaller line and control valve, which is cheaper to install (FIG. 7).

Rather than controlling the tower pressure with a recycle line, nitrogen can be bled into the system. A nitrogen line was on the tower for purging, as well as a small connection at the tower top where the nitrogen could be introduced. Controlling how much nitrogen is introduced allows the control of the vacuum. Steam is also available to bleed into the system and can be used in place of the nitrogen.

Unfortunately, in this case, nitrogen would not work. The system was a three-stage system, and bleeding in nitrogen would overload the last-stage ejector. Steam could be bled to the first-stage ejector suction to control the load and suction pressure, but this would require a significant amount of steam. Also, the operating cost of doing so can be expensive. Bleeding in steam is not a good long-term solution. A properly installed recycle line is ideal for the installation because it has added no operating costs.

Corrosion control inhibitors. One unusual way to improve vacuum is to shut down the corrosion control spray being used to help reduce corrosion. At the tower top pressure of 10 mm Hg, water will flash at 52°F (11°C). If the corrosion inhibitors are being diluted with water and injected into the system, that water will flash and load the system.

The best way to prevent this is to chill the inhibitor mixture before it is injected; this will avoid flash off and system overload. Equipment can also be built out of more corrosion-resistant material.

Drain leg leak. To identify air leaks, the offgas composition should be examined for unusually high levels of oxygen and nitrogen. An air leak will cause the third-stage ejector pressure to be lower than design. In this case, the leak was in the second condenser's condensate drain leg, about 10 ft above the condensate drum.

How would air ever leak into the condensate drain leg, as those drain legs are filled with liquid? The legs are also at a subatmospheric pressure down to the liquid level in the condensate receiver. If the line were to develop a hole, it would pull air into the system, not leak out as would a line under positive pressure. If air was being pulled into those lines, why did it not flow down into the hotwell with the condensate? The answer is that the flow through the seal legs is low compared to the line sizes, which are designed to vent back to the condensers. Any air that gets pulled into a leak would rise toward the ejectors, which operate at a low pressure. If the leak is large enough, the air being pulled in can prevent the condensate from draining and cause the condenser to flood.

Takeaway. When the goals were reviewed, it was determined that the 1,050°F minus content of the vacuum residue had dropped from 18% to 10%. This had reduced the vacuum resid production rate by about 2,000 bpd, with a concurrent increase in vacuum gasoil yield of 2,000 bpd. The delta value was worth $40,000/d.

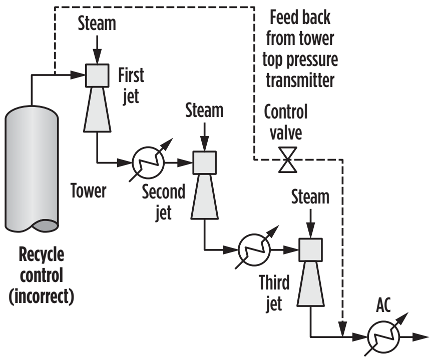

FIG. 6. The vacuum system's recycle pressure control caused the tower pressure to fluctuate when it was put into service, but a P&ID review determined that the recycle line was installed correctly.

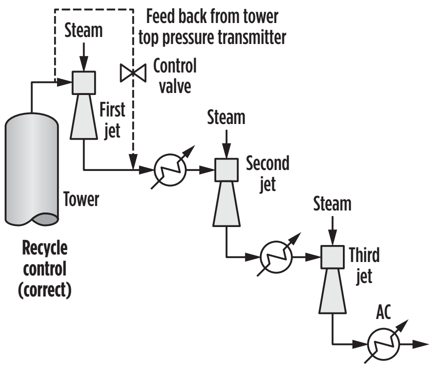

FIG. 7. A larger pressure differential allows the sizing of a smaller line and control valve.

This achieved the goal of improving cash flow by $14 MM/yr with better vacuum tower operation, and ROI and net profitability were significantly advanced. HP

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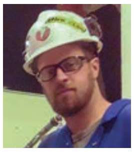

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