Understand real-world problems of vacuum ejector performance

Use these guidelines and case histories to evaluate and troubleshoot ejector systems

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Vacuum ejector system design, operation and performance have a significant impact on crude unit FCC feedstock quality and product yields.[1] Ejector system performance problems are the most frequent cause of low vacuum column distillate yields. Underperforming ejector systems can result from a myriad of potential process and ejector system component problems. Therefore, the correct cause must be identified when troubleshooting vacuum systems. The synergistic effects of process operations, utility system performance and ejector system performance make ejector system troubleshooting a challenge. Three case studies present some process/ejector system problems that reduce vacuum distillate yield.

Refinery crude unit vacuum column ejector performance sets the operating pressure of the first-stage ejector (Fig. 1). First-stage ejector inlet pressure and system pressure drop control the vacuum column distillate yield for a given vacuum column fired heater outlet condition. Ejector system performance has a large impact on the refinery heavy vacuum gas oil (HVGO) and vacuum residue product yields. HVGO/vacuum residue product value differentials vary between \$3 to \$10/bbl, depending on the refinery processing units. Underperforming ejectors can lower HVGO product yield by 2 vol% on whole crude.[2]

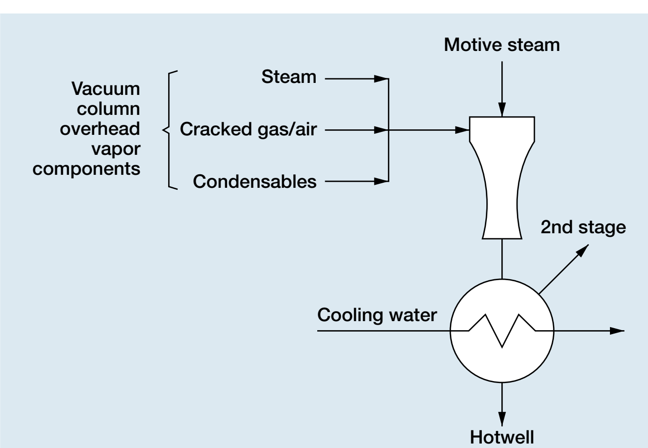

Fig. 1. Vacuum system, first-stage ejector.

EJECTOR SYSTEM COMPONENTS

Major components[3] include the ejector (Fig. 2) and condenser (Figs. 3 and 4). The ejector consists of a steam nozzle, steam chest and diffuser. The steam nozzle design is based on a presumed process gas load (rate and composition), steam pressure and temperature, and maximum discharge pressure. Once the steam nozzle is designed, steam conditions must be controlled at the nozzle design pressure. The steam nozzle is a critical flow orifice; therefore, steam pressure sets the flowrate.

Steam flow to an ejector must be maintained at the design rates, otherwise vacuum column operating pressure may increase. Steam jet-ejectors educt process gases into the steam chest and then through a specially

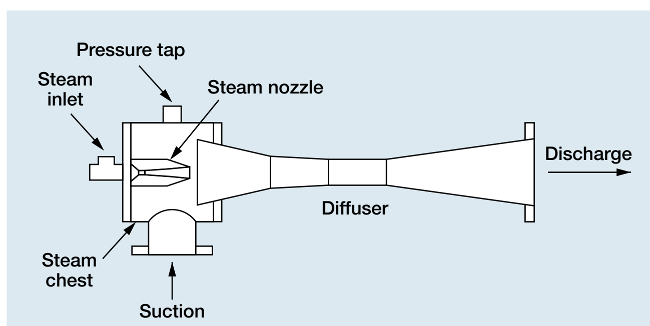

Fig. 2. Ejector.

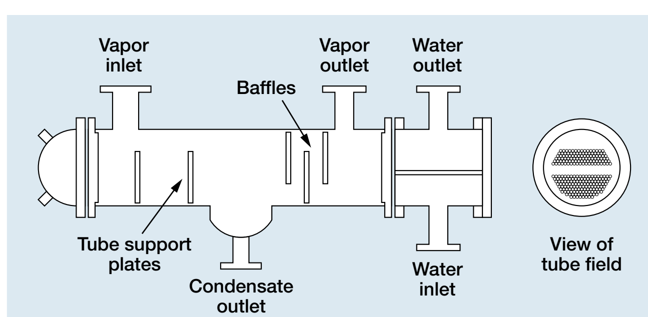

Fig. 3. Condenser (Tema "E" shell).

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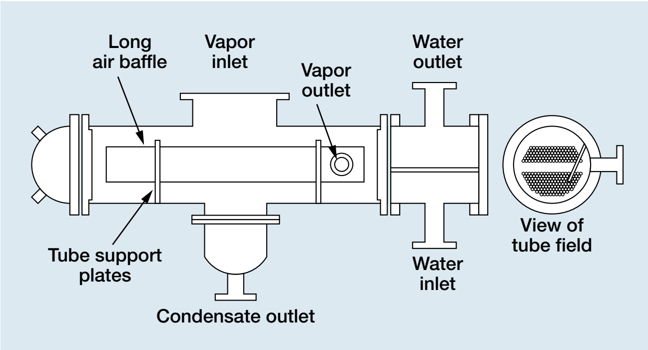

Fig. 4. Condenser (Tema "X" shell).

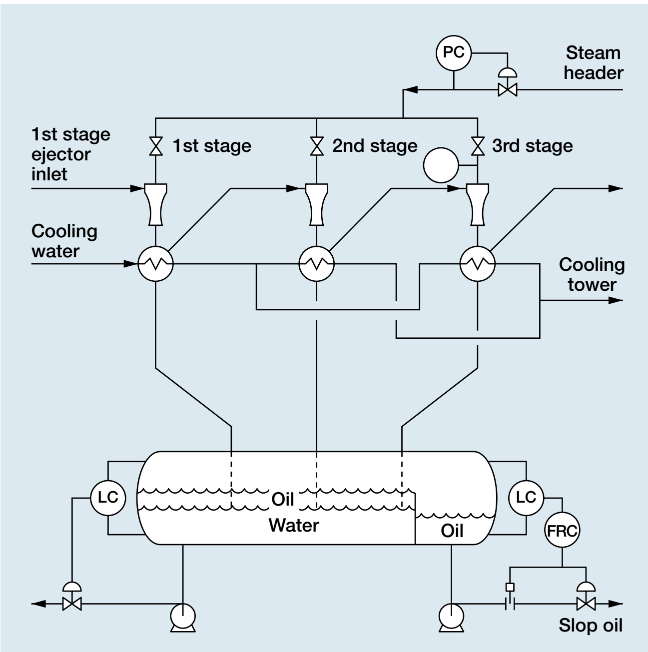

Fig. 5. Vacuum ejector system.

designed converging-diverging device that is part of the diffuser. The diffuser dimensions and throat area are manufactured to meet the system design objectives. An ejector stage is designed with a maximum discharge pressure (MDP). The ejector cannot exceed this MDP or it will "break." Up to this point, gas suction load sets the ejector inlet pressure.

Vacuum ejector systems must compress process gas from the first-stage ejector inlet pressure to the hotwell operating pressure. Typical vacuum ejectors operate from a first-stage suction pressure between 4 and 20 mmHg to a hotwell operating pressure between 810 and 1,050 mmHg. Refinery vacuum unit ejector compression ratios vary from 2.2:1 to 15:1, depending on the application. Meeting overall process gas compression objectives requires multiple ejector stages.

Typically, vacuum unit ejector systems have three series-ejector stages (Fig. 5). Often, larger crude vacuum units will have parallel three-stage ejector systems. Optimizing overall operating and installed costs results in the ejector-condenser pairing seen in most applications. In a few instances, an ejector will follow directly after another ejector without an intercondenser. The shell-and-tube ejector condenser reduces load on the downstream ejector, which reduces overall motive steam consumption.

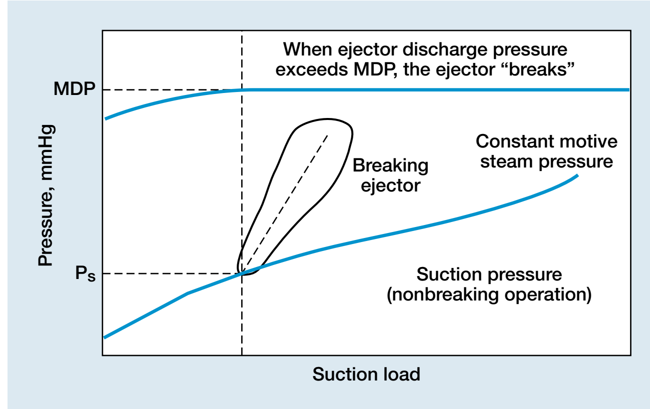

Fig. 6. "Breaking" vacuum ejector curve.

Each ejector is designed for a presumed gas rate, composition, suction pressure and maximum discharge pressure. The condenser is designed for the motive steam rate, steam enthalpy at ejector discharge conditions, process gas load, cooling water flowrate and cooling water temperature. Assuming the ejector/condensers have no mechanical or process problems, the ejector suction pressure will vary with gas load.

Once the ejector maximum discharge pressure is reached, the ejector "breaks." This means the ejector suction pressure is now dependent on gas load, motive steam pressure and discharge pressure.[4] Breaking increases ejector suction pressure and can be dramatic (Fig. 6). Breaking may be accompanied by backfiring or surging. The surging noise is a distinct periodic rumbling. Backfiring does not always occur when an ejector breaks.

Between the ejector basic performance curve and the "broken" operating curve is a region where the ejector system operating pressure is erratic. Fig. 6 shows the measured first-stage ejector suction pressure over time. The pressure is erratic between 4 and 10 mmHg. When the system breaks, the first-stage suction pressure increases to approximately 50 mmHg. In this case, the third-stage ejector noncondensable capacity caused the system to break. Although the first-stage ejector system inlet pressure increased dramatically, the cause was the third-stage ejector capacity.

Process gas load will affect vacuum ejector performance. Each ejector has a design performance curve that correlates process gas load with suction pressure (Fig. 7). The ejector performance curve gas load is represented by equivalent steam load (lb/hr), calculated from the process gas component flowrates to the ejector. Fig. 7 is a typical first-stage ejector curve for a damp vacuum column design. Damp vacuum units have a significant quantity of fired heater coil steam and/or stripping steam used to affect the oil partial pressure and furnace tube velocity/oil residence time. The basic performance curve (unbroken operation) shows how the ejector suction pressure (mmHg) increases as the gas load to the ejector increases. Unfortunately, vacuum unit ejector system first-stage gas loads are not precisely known.

Ejector and condenser component performance, individually, are relatively easy to understand. The ejector suction pressure varies with process load. However, crude vacuum units have three ejector/condenser pairings in series. The system requires that each component perform within a relatively narrow operating band, otherwise the

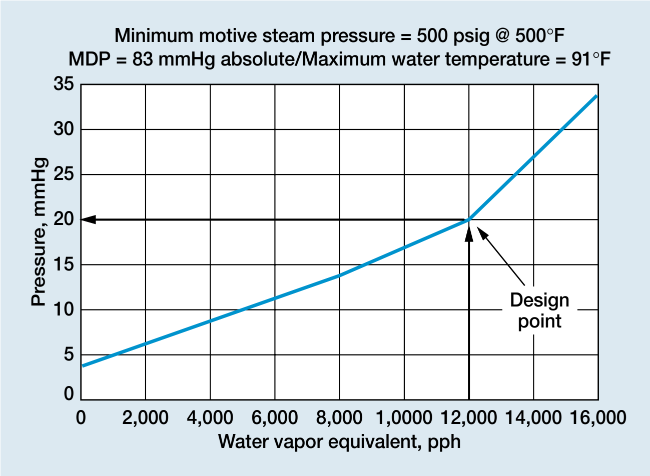

Fig. 7. Ejector performance curve (first-stage ejector).

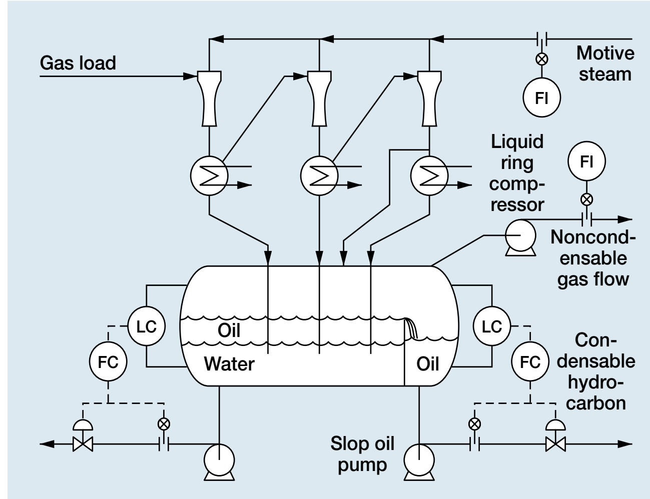

Fig. 8. Process gas load (material balance).

first ejector pressure may be significantly higher than design (broken). Process conditions or ejector system problems often cause high vacuum column operating pressure and lower distillate yields. When an ejector system is underperforming, it is necessary to determine what specific problems cause the high operating pressure.

Field troubleshooting requires basic ejector system knowledge and a thorough understanding of the process conditions that can negatively impact ejector system performance. Sometimes the problem is obvious (Case 1). Often, troubleshooting ejector system performance is by exclusion. The number of potential problems is large; therefore, eliminating those that are not the problem takes time. Case 2 fits into this category (a problem you don't really want to be assigned!). Case 3 is the classic application of doing something and seeing what happens.

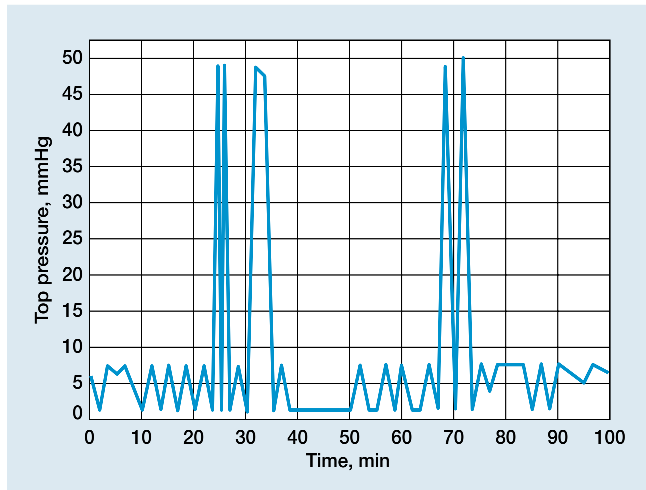

Fig. 9. "Breaking" vacuum ejector.

PROCESS GAS LOAD

Ejector system process gas load affects ejector suction pressure. Higher gas load increases ejector inlet pressure and reduced gas load decreases ejector inlet pressure. Ejectors operating on their basic curve will have a suction pressure that varies with gas load. However, when a downstream ejector inlet pressure increases above the ejector maximum discharge pressure of the upstream stage, the upstream stage operates on a "broken" curve, which is unknown.

Different components of the vacuum column overhead gas load will impact the three stages differently. Process gas load must be reviewed from the perspective of the first-stage gas load; however, an individual gas load component impact on the second and third stages are reviewed. Ejector first-stage gas load consists of:

- Steam
  - Coil/stripping steam flowrate
  - Saturated water in feed
  - Leaking steam/water
- Noncondensable gas
  - Air leakage
  - Cracked gas
  - Instrument purge gas
  - Startup fuel gas lines
- Condensable hydrocarbon.

Ejector steam load typically comes only from the first two sources although, when troubleshooting, all sources must be checked. Coil/stripping steam should be metered, otherwise ejector system gas load can only be qualitatively determined. In some cases, the steam load can be determined by a hotwell material balance if the proper metering is installed (Fig. 8). When the first-stage ejector inlet pressure rises, the process gas load has increased. It is necessary to determine which gas load components are causing the higher operating pressure.

The operating gas load through an ejector system normally decreases from the first to third stages. Ejector gas load reduction is caused by increasing condensation pressure in the first- to third-stage condensers. Higher condenser pressure lowers the amount of water and condensable hydrocarbon to the subsequent ejector. The second-stage ejector suction pressure varies between 65 and 95 mmHg. Gas load to the second-stage ejector is primarily noncondensables, a small amount of steam and a smaller amount of condensable hydrocarbon. The third-stage ejector suction pressure is 250 to 400 mmHg; therefore, the gas load is primarily noncondensable gas. Understanding the qualitative nature of the gas load change across the ejector system is important in interpreting plant measured data. The individual ejector stage design and performance curve information must be known to troubleshoot an ejector system problem.

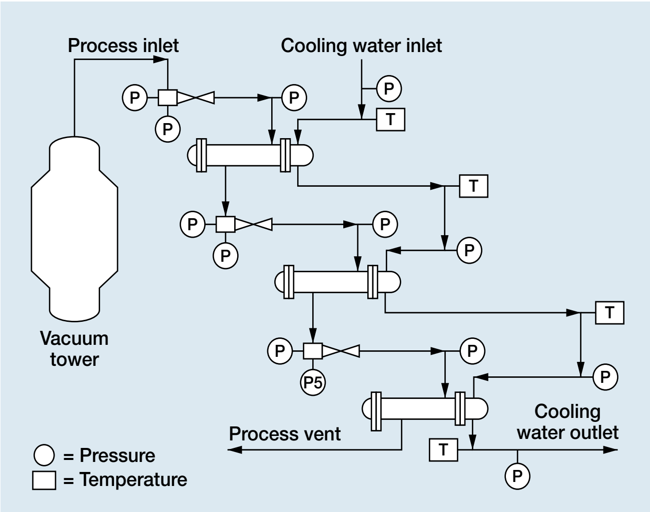

Fig. 10. Vacuum system survey.

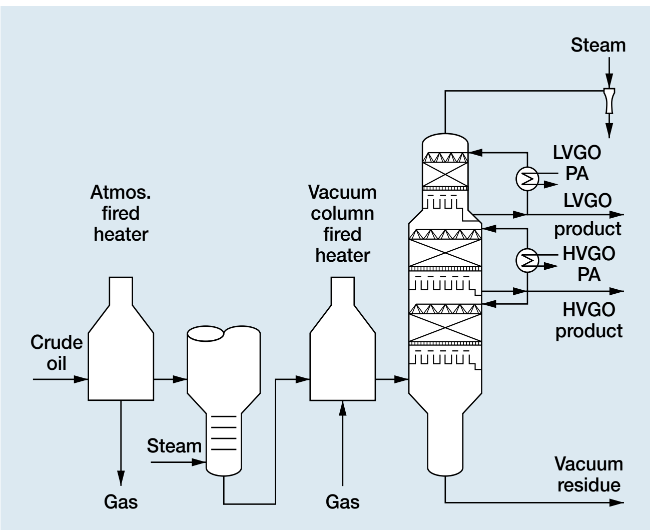

Fig. 11. Atmospheric/vacuum column fired heaters.

NONCONDENSABLE GAS

Ejector system noncondensable gas leaving the hotwell is cracked gas, air and possibly fuel gas. Some refiners use fuel gas or natural gas to purge instruments. Instrument purge should be a small flow controlled with restriction orifices (typically 1/16-in. orifice). Startup fuel gas lines should be blocked to prevent unnecessary ejector noncondensable loading. Air leakage is a function of column pressure, number of flanges and the flange "tightness." Air leakage varies from 50 to 150 lb/hr based on the unit's size. A general rule is that the nitrogen composition in the noncondensable should be less than 10 mol% for typical cracked gas production. Cracked gas production will vary from low for a well-designed heater and low residence time vacuum column design to quite high when significant oil cracking occurs.

Most cracked gas is produced in the vacuum column heater. This is true in most cases; however, when a unit is not performing, all sources of cracked gas must be checked. Cracked gas is produced in the crude unit in these areas:

- Atmospheric column heater
- Atmospheric column liquid inventory
- Vacuum column heater

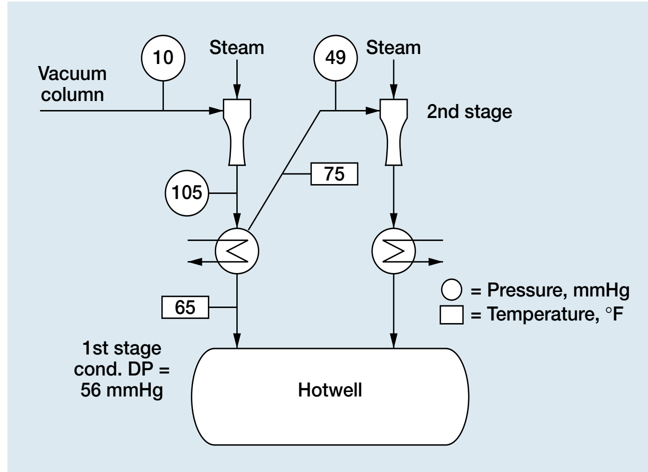

Fig. 12. Vacuum ejector performance (cold weather operation).

- Vacuum column bottom liquid inventory
- Vacuum column "overflash" collector tray.

Depending on specific equipment design and operation, each of these areas can contribute to high cracked gas production. Atmospheric column heater operation can produce 25% to 35% of the total gas. High residence time in the vacuum column's bottom can produce 10% to 20% of the total cracked gas. Vacuum "overflash" collector trays that chronically coke will produce a significant quantity of cracked gas. Minimizing cracked gas production should consider the unconventional sources of cracked gas.

CONDENSABLE HYDROCARBON

Condensable hydrocarbon carryover to the ejectors is a function of vacuum column feed composition, ejector noncondensable/steam load and column overhead temperature. Noncondensable/steam load (assuming it does not adversely affect column pressure) is largely a fixed value for a given operation. Vacuum column overhead temperature is a function of ambient temperature and top pumparound operation (Case 1). Higher vacuum column overhead temperature will increase the condensable carryover to the ejectors. Usually, this is not the major contributor to condensable gas load, although it could be a problem in a situation where the ejector gas capacity is on the edge of breaking an ejector.

Vacuum column feed composition has the largest effect on ejector condensable loading. Atmospheric column operation and equipment performance control vacuum column feed composition. The vacuum column feed ideally contains little 400°F to 550°F boiling-range material. When the atmospheric column operates at a low cutpoint, and/or when the atmospheric column residue stripping trays are damaged, the 550°F and lighter material can increase dramatically. Condensable leaves as hotwell slop oil. When the slop oil rate increases significantly, it indicates a process equipment or operating problem.

EJECTOR PERFORMANCE—PROCESS STEAM CONDITIONS

The motive steam pressure at the steam nozzle affects ejector performance. Dry steam should be supplied at the steam nozzle's design pressure. Pressure gauges should be installed downstream of the steam block valves

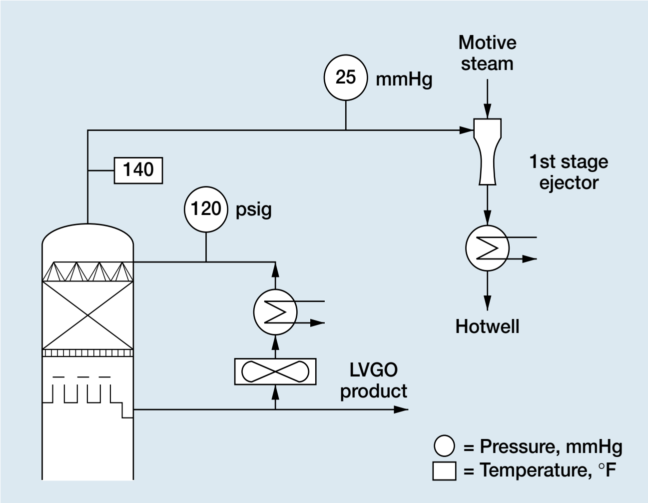

Fig. 13. Vacuum ejector performance (warm weather operation).

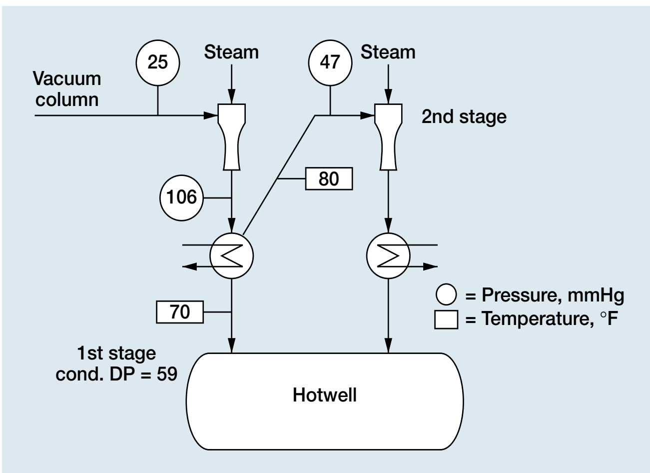

Fig. 14. Vacuum ejector performance.

on each ejector stage. In some cases, throttling steam pressure with the block valves is used to control the ejector first-stage suction pressure. While this may sometimes work, often it results in an erratic first-stage ejector inlet pressure. Throttling steam with parallel ejector stages results in a capacity imbalance between the parallel stages. Performance imbalance can result in backflow from one parallel ejector to the other. This acts like a process load and increases ejector suction pressure.

Steam supplied to the nozzle should be clean and dry. The steam line should be fitted with properly designed strainers. A single Y-type strainer is adequate. Steam line scale and other debris can and will plug the steam nozzle during startup if the line has a poorly designed, damaged or no strainer. To obtain dry steam at the ejector nozzles requires steam traps and possibly a centrifugal steam/water separator. Wet steam can cause steam nozzle, diffuser and downstream piping erosion.

CONDENSER PERFORMANCE—COOLING WATER

Vacuum column operating pressure usually increases in the summer due to changes in condenser performance. Vacuum ejector first-stage discharge pressure is controlled by the steam/condensable hydrocarbon vapor pressure, which is set by the condenser operating temperature. The condenser outlet temperature largely sets

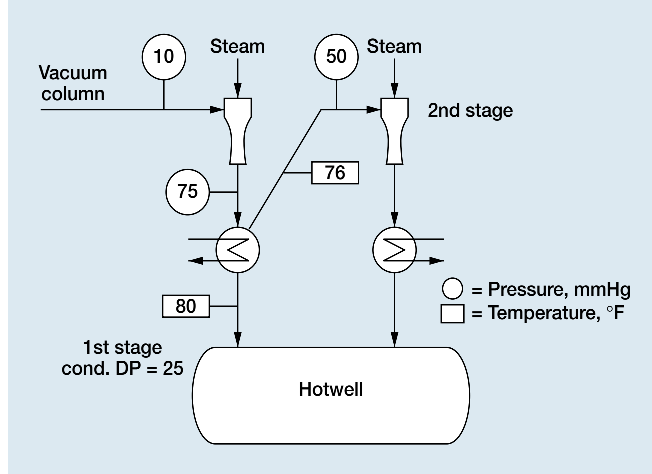

Fig. 15. Vacuum ejector performance clean condenser.

second- and third-stage ejector gas load water and condensable oil content. Cooling water flowrate and temperature and exchanger fouling (process and water side) set the condenser performance. Reduced cooling water flowrates will increase the first-stage condenser discharge pressure. Increased cooling water temperature also increases the condensing pressure.

Exchanger fouling lowers the condenser overall heat transfer coefficient, which increases the gas outlet temperature. Tube-side fouling decreases water flowrate. Shell-side fouling increases exchanger pressure drop, which can increase the first-stage ejector discharge pressure. First-stage condensers operating at a pressure above the ejector MDP will break the first-stage ejector. When an ejector breaks, the vacuum column operating pressure will increase dramatically (Fig. 9).

Condensers are designed so condensate draining from the shell's bottom and exiting gas are separated. The gas is preferentially routed past the coldest cooling water. A properly operating condenser will be cool to the touch in the exchanger's lower portion where the condensate accumulates. The top half will be too hot to touch. However, condensers do not always operate properly. Exchangers are subject to corrosion and salt formation from the HCl neutralizer injected into the system. The drain legs can plug due to corrosion and wax formation in the line. Corrosion usually occurs at the condensate level in the drain line. When either the exchanger or drain-leg plugs, the exchanger will be cold to the touch. This is a good qualitative check of condenser performance.

TROUBLESHOOTING EJECTOR SYSTEMS

Vacuum columns that operate at elevated pressures yield less distillate product. Ejector system troubleshooting must determine whether the ejector system equipment, process gas load or plant utilities cause the problem. Often, a combination of ejector system and process operation causes high vacuum column pressure. Troubleshooting an ejector system requires a complete set of pressure and temperature survey data.[5, 6] Fig. 10 shows a three-stage ejector system with two identical parallel stages with a common condenser system.

When ejector suction pressure increases due to process gas load increase, it is necessary to determine which component is causing the ejector-loading problem. When

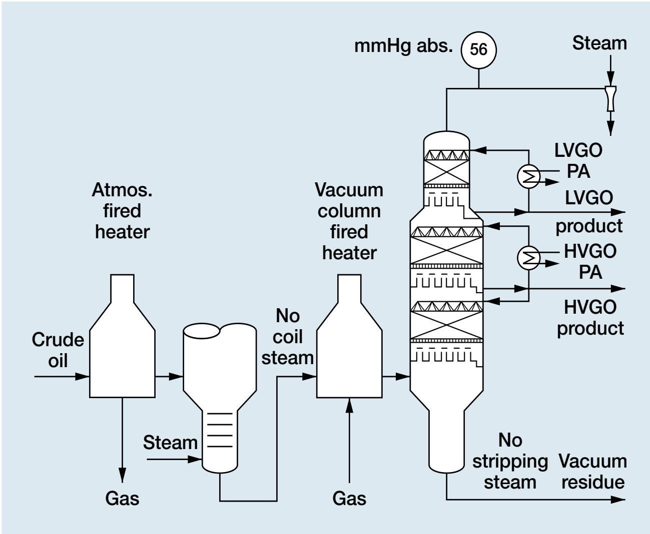

Fig. 16. Atmospheric/vacuum column fired heater.

coil/stripping steam is used on damp vacuum unit designs, it constitutes the majority of the first-stage ejector load. The second- and third-stage gas load is primarily cracked gas and air leakage. Condensable hydrocarbon loading is a function of feed composition, column overhead temperature and the total steam/noncondensable load. Vacuum feed composition is controlled by atmospheric column cutpoint and residue stripper performance (Fig. 11). Troubleshooting a gas load increase first requires determining where the high load comes from.

CASE 1: EJECTOR INTERCONDENSER FOULING

High operating pressure decreased this vacuum column's HVGO product yield by 2,000 bpd. During cold weather, the vacuum column operated at 10-mmHg ejector inlet pressure (Fig. 12). When the ambient temperature increased above 70°F, the column overhead pressure increased from 10 to 25 mmHg. During the same period, the vacuum column top pumparound spray header plugged. The vacuum column top pumparound temperature increased from 120°F to 140°F due to the spray header plugging (Fig. 13). The vacuum system hotwell liquid increased from 40 to 80 bpd. The assumption was that the plugged light vacuum gas oil (LVGO) pumparound (PA) spray header pressure drop caused a heat removal problem, which increased the overhead temperature. This caused the hotwell slop oil production to double. Thus, it was assumed that the increased slop oil overloaded the first-stage ejector.

Troubleshooting. Complete ejector system temperature and pressure data is required to troubleshoot most ejector systems. Often, the ejector system does not have the necessary pressure connections and thermowells to gather a complete set of data. And partial ejector system operating data often is insufficient to troubleshoot the problem. Occasionally, the operating problem is relatively simple to find. Fig. 14 shows the pressure survey of the first-stage ejector and condenser. Measured first-stage condenser pressure drop is 59 mmHg. This pressure drop is extremely high considering that condensers are normally designed for 5 to 10 mmHg pressure drop. The first-stage ejector outlet pressure was operating at the ejector's maximum discharge pressure of 105 mmHg.

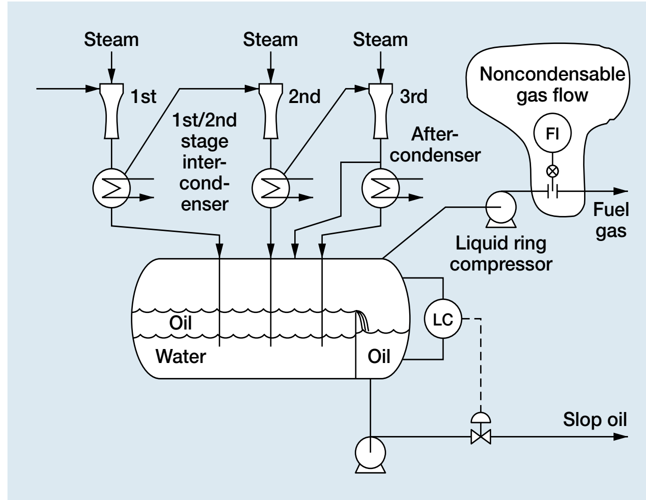

Fig. 17. Ejector system.

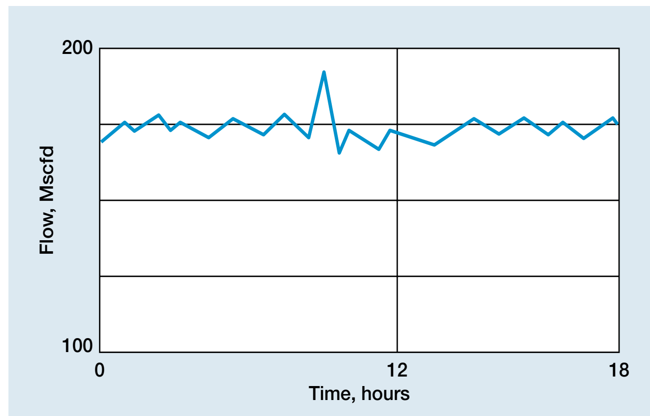

Fig. 18. High noncondensable production.

When troubleshooting, the following observations were made:

- First-stage ejector condenser condensate drain line was cold.
- First-stage ejector condenser was cold except for the exchanger's very top section.
- Exchanger was full of cold condensate.

Conclusion. The cause of the ejector problem was first-stage breaking due to a high discharge pressure. The high condenser pressure drop was caused either by a plugged drain leg or plugged exchanger. A hydraulic "snake" was used to clean out the drain leg. After this was done, there was no change in the ejector system performance. The drain-leg and exchanger shell were still cold. A neutron back-scatter of the exchanger showed no significant condensate level. When the vacuum unit had an unscheduled outage, the exchanger was opened. It was plugged with a black gelatinous substance (typical of chemical neutralizer salts and corrosion products). Fig. 15 shows the clean exchanger pressure drop. A clean condenser pressure of 25 mmHg is still too high. However, the first-stage ejector discharge pressure is well below the maximum discharge pressure. Unfortunately, this exchanger fouls quickly, causing a chronic vacuum column high-pressure problem.

CASE 2: HIGH CRACKED GAS PRODUCTION

A dry vacuum column (Fig. 16) processing a blend of Canadian crude oils showed an increase in vacuum column

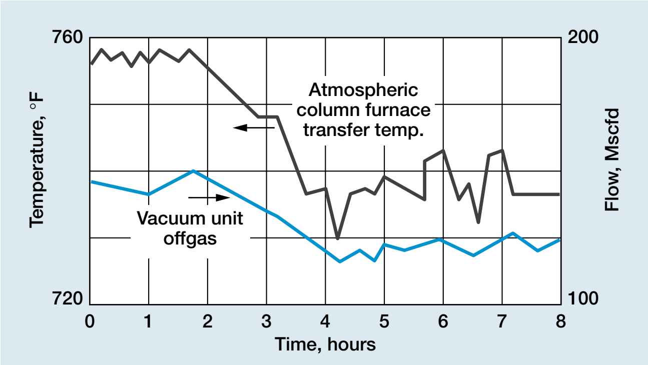

Fig. 19. High noncondensable production.

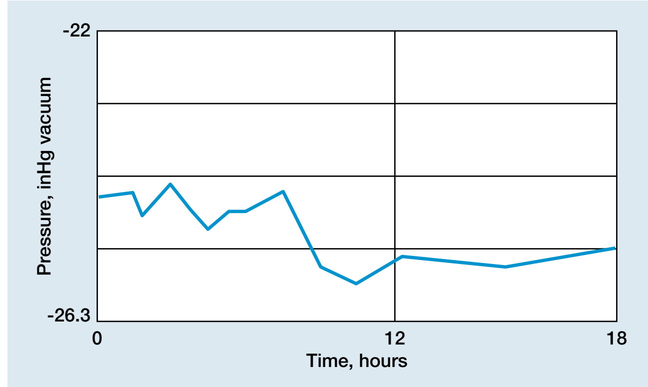

Fig. 20. Heater temperatures and offgas.

ejector inlet pressure from 30 to 56 mmHg. The first-stage ejector operating pressure periodically increased to 100 mmHg. These large pressure increases significantly decreased the HVGO product yields. The increase in ejector inlet pressure correlated with an increase in noncondensables from the vacuum system hotwell. Dry vacuum units do not use coil steam; therefore, 90% to 95% of the first-stage ejector load is noncondensables.

Troubleshooting. The vacuum system is a three-stage ejector system. A liquid ring compressor is used to compress the hotwell gas to the sour fuel gas system operating pressure (Fig. 17). High chronic noncondensable production is usually associated with vacuum unit fired heater cracking (Fig. 18). However, when the vacuum heater outlet temperature was reduced by 30°F, the noncondensable gas production decreased by only 15%. A 30°F reduction in furnace outlet temperature should lower noncondensable production by half. Noncondensable gas results from air leakage and cracked gas production.

The hotwell gas from the liquid ring pump discharge was sampled. The analysis showed less than 8 mol% nitrogen. It contained less than 100 lb/hr of air. Therefore, air leakage was not the problem. There were no fuel gas or steam/water tie-in leaks. After a considerable amount of work, the problem was determined to be increased noncondensables production due to heavier crude processing.

Pressure surveys across the vacuum column wash zone packed bed indicated that the packing was coked. Several pressure surveys were conducted each time the measured pressure drop was 8 to 9 mmHg when operating at higher column pressures and 13 to 15 mmHg at the lower column pressures. After achieving a lower column pressure, the HVGO color became much darker—this is another indication that the wash zone was not performing properly. The overflash collector tray was also coking. When hydrocarbon material cokes, it forms coke (carbon) and light hydrocarbon gas. This definitely was one of the sources of additional offgas flow, which loaded up the ejectors.

A high vacuum-column bottoms level and poor quench system design will also result in cracked gas formation. A furnace is designed to minimize residence time to reduce cracked gas formation. But the residence time in the furnace and transfer line is only seconds compared to a much longer residence time in the vacuum column boot. This vacuum column was designed with the quench returning to the very bottom of the boot. All of the liquid above this point is at the flash zone temperature (unquenched). The suction pressure to the bottoms product strainers was measured for use in back-calculating the liquid head. When the level indication was at 10%, the liquid head indicated that the bottoms level was 21 ft above the gauge location. The level was up into the column's large diameter section just below the transfer line. The bottoms residence time was nearly 8 min. Using a gauge, the bottoms level was reduced to approximately halfway up the boot. The offgas make was reduced by 5% to 10%, but the load reduction was insufficient.

A test was conducted to evaluate the impact of reducing the percentage of medium-heavy crude in the crude slate, on vacuum tower offgas production. Offgas production was approximately 170 Mscfd. After the crude slate was switched to a lighter crude, the offgas make dropped to 140 Mscfd and the first-stage ejector suction pressure reduced from 56 mmHg absolute to 42 mmHg.

The reduced crude samples from the atmospheric column showed a stable foam layer, which indicates oil instability (cracking). This is a likely sign of coking in the crude tower bottom/heater tubes. Samples after the desalter did not form a foam layer, although they are more likely to foam since naphtha and lighter compounds have not been removed.

If cracking occurred in the atmospheric column heater, then reducing the heater transfer temperature should decrease gas production. After reducing the atmospheric column heater transfer temperature by approximately 20°F, the vacuum unit offgas dropped to 120 Mscfd and a stable first-stage ejector suction pressure of 26 mmHg absolute was obtained (Fig. 19). The lower temperature reduced the cracked gas formation (Fig. 20), which enabled operators to increase the vacuum heater transfer temperature to yield more gas oil without significantly increasing the vacuum unit offgas (Fig. 21).

Conclusion. As crude gets heavier, residence time in the atmospheric furnace and vacuum tower furnace will increase, resulting in additional cracked gas formation. The medium-heavy crude API gravity had decreased from about 25.5 to 23.8 during the period when the ejector problems occurred. Not only was the medium-heavy crude getting heavier, but the plant was processing a higher percentage of this crude.

Poor vacuum performance was a result of the noncondensable gas load exceeding the ejectors' capacity. Vacuum unit offgas make was operating between 170 and 180 Mscfd, with a first-stage ejector suction pressure of about 56 mmHg. Periodically, the offgas rate climbed above 185

Mscfd and the first-stage suction pressure increased to as high as 100 mmHg. After changing the crude slate and reducing the atmospheric heater outlet temperature—to reduce cracking—the offgas make lowered to 120 Mscfd and a stable first-stage suction pressure of 26 mmHg absolute was obtained. The increase in noncondensable load was caused by high atmospheric crude column furnace operating temperature and oil residence time.

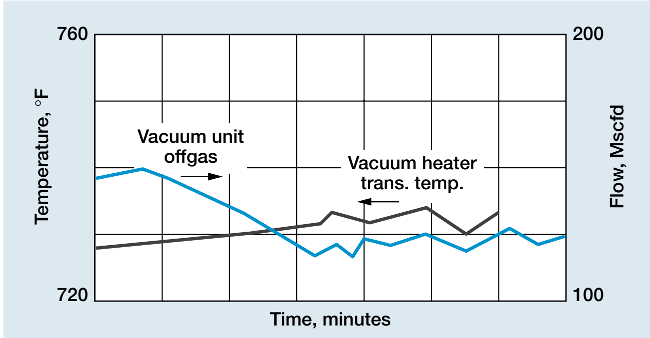

Fig. 21. Heater temperatures and offgas.

CASE #3: PLUGGED EJECTOR STEAM NOZZLE/HIGH CONDENSABLE LOADING

This vacuum tower vacuum system had problems maintaining a vacuum since the refiners' last turnaround. The column top pressure varied from 25 mmHg or higher during the heat of the day to 9 mmHg during the cooler night. In an effort to improve the column vacuum, the vacuum furnace outlet temperature was reduced to limit cracking and stripping steam to the atmospheric column residue stripper was increased.

Field survey. During the field troubleshooting, pressure surveys were conducted around the vacuum tower to find the operating problem. The column pressure survey indicated that the high flash zone pressure was a problem with ejector system operation. Pressure surveys (Fig. 22) were conducted on the ejector system along with temperature surveys (by hand). The thermocouple in the overhead line typically measured a temperature of about 102°F, which was absolutely wrong! Measured by hand, the overhead temperature was at least 130°F. Existing instruments are not always correct. Feeling equipment by touch to evaluate relative temperatures never lies.

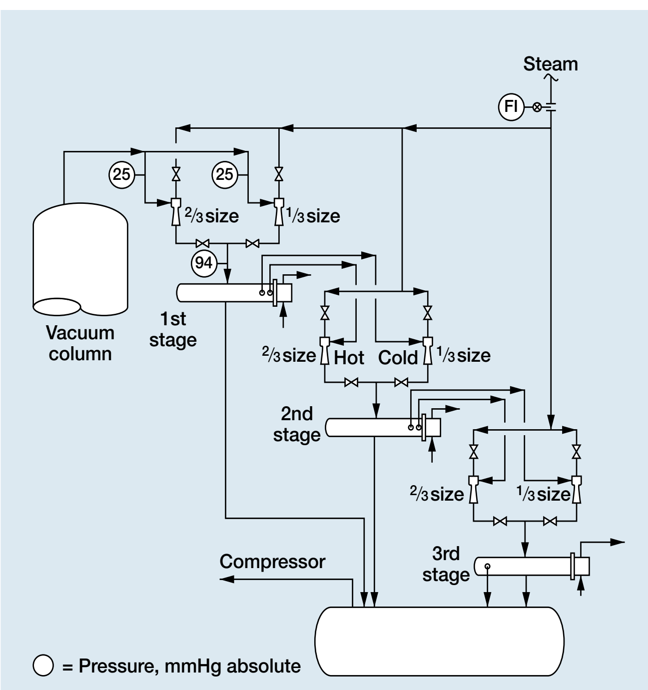

Fig. 22. Vacuum tower survey.

The first-stage intercooler was hot at the inlet, cool toward the middle and slightly warmer at the opposite end. The second-stage ejector is actually two ejectors in parallel with one ejector designed to handle ⅔ of the load and the other ⅓. The suction line to the ⅓ size ejector was slightly warm and the suction line to the ⅔ ejector was hot. This can only occur if the ⅔ ejector is backing steam into the first-stage intercooler. The ⅔ ejector was probably plugged.

To verify this, the ⅔ ejector suction line block valve was closed. Column pressure dropped and the first-stage ejectors started surging. Column top pressure originally at 16 to 17 mmHg (it was a cool, cloudy day) started varying between 8 and 11 mmHg. Steam to the ⅔ second-stage ejector was blocked in, which unloaded the second-stage intercooler and third-stage ejectors. Column overhead pressure locked in at 7.3 mmHg. The ⅔ second-stage ejector was later disassembled and the ejector was found to be plugged, as believed. With the column vacuum system working properly, heater outlet was increased to 730°F.

Performance improvement. The ejector performance problem was a result of a plugged ejector. The plugged second-stage ejector forced additional motive steam back into the first-stage intercondenser, resulting in high condensable loading to the parallel second-stage ejector.

Comparison of operating data indicated that the vacuum bottoms was reduced from 23.9% to 17.6% of crude. This represents an additional 6.3% increase in gas oil recovery based on whole crude. These numbers were based on meters that may not have been exactly correct and the comparison did not take into account potential variations in crude slate. However, it is clear that fixing an ejector system such as this one has a significant impact on refinery economics.

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