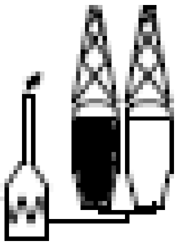
DCU Coking, Fouling, Corrosion, Erosion

Locations & Solutions



REFCOMM ROTTERDAM
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Mitchell J Moloney
Delayed Coking and Process Engineering Specialist
Becht Engineering
mmoloney@becht.com

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Discussion Points:

Purpose: Review where coking, fouling & erosion occurs on DCU's, and discuss solutions that are in play today.

1) Vac resid feed tanks
2) Feed system and preheat exchanger fouling
3) Sediment and Coke build up in the Main Fractionator (MF) bottom
4) Coking & erosion in the Furnace Charge Pump & pass flow control piping
5) Coking, Fouling & Carburization in furnace tubes
6) Coking & Erosion in the transfer line between the furnace and coke drums
7) Coke in the coke drum top dome
8) Coking in the vapor line to the MF
9) Coke Accumulation in the Bottom of the MF
10) Coking & corrosion in the HKGO fractionation zone
11) Coking in the HKGO product and PA circuit

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Discussion Points:

12) Fouling in the Light Distillate System
13) Ammonium Chloride Deposition in the Main Fractionator
14) Cyanides and hydrogen embrittlement in Main Frac and Gas Plant
15) Wet Gas Compressor fouling
16) Gas Hydrate formation in the Fractionating Absorber Coolers
17) Debutanizer Reboiler Shell Side Fouling
18) Coker Gas Amine Treater – Corrosion, Fouling & Foaming
19) Coker Blowdown Contactor - Coke in bottoms
20) Coker Blowdown Fin Fan Condenser Fouling
21) Coker Settler Emulsion
22) Quench water and cutting water piping erosion
23) Furnace Air Preheater Cold End Corrosion

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1) Vacuum Resid Feed Tanks:

- Primary risk is a fire in the tank

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1) Vacuum Resid Feed Tanks:

- Secondary risk is odor emanation
- Causal factors:
  - High operating temperature brings Auto-Ignition Temperature (AIT) risks into play
  - Pyrophoric Iron Sulfide light off in a low-oxygen vapor environment
- History
  - Operating storage temperatures above 400°F (205°C) show an increased frequency of fires
  - Many examples of large resid and asphalt tanks that have ignited over the decades
  - Introduction of emission control devices can worsen the risk, if they limit air intake and outflow
- Mitigations
  - Set operating storage temperature limit at 395°F (202°C)
  - Running higher temperatures requires use of nitrogen blanketing, which has proved to be a reliable risk reduction
  - Some advocate maintaining a steady air flow to prevent iron sulfide from forming and serving as an ignition source, but I do not subscribe to that approach

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2) Resid Feed System Fouling:

- Resid can foul preheat exchangers and piping

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2) Resid Feed System Fouling:

- Causal factors:
  - Coke laydown is time and temperature related; higher temperature, higher fouling
    - Resid transfer piping at 325 - 550^{o}F (163 - 260^{o}C) has low fouling (coke laydown) rates
    - Piping at 650 - 700^{o}F (343-371^{o}C) has an increasing fouling rate as temperature rises
    - As residence time increases, coke laydown increases:
      - Reduced velocity is one reason
      - Increased turbulence (elbows, contractions, expansions , mixing) is the other
- History
  - Significant coke laydown has been seen in systems over the years
  - Long, high-temperature, low-velocity piping has developed very high pressure drops and required installation of flanges for regular pipe decoking
  - Heat exchangers running resid at turndown conditions have fouled rapidly
- Mitigations
  - Design and operate resid preheaters with high velocities (20 – 30 psi, 1.2 – 2.0 bar DP's)
  - In long high temperature transfer piping, set piping diameter to fully utilize available DP, taking into account control valve needs; also install clean-out flanges for hydroblasting in areas of turbulence
  - Consider use of steam purged valves for resid lines over 670 ^{o}F (354 ^{o}C)

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3) Coker Main Frac Bottoms System Fouling from Feed System:

- Sources of Fouling:
  - Scale in resid feed from piping (usually a start-up issue)
  - Coke from upstream feed piping or surge drum, if operating over 670 ^{o}F (354 ^{o}C)
  - Silicate catalyst deposits if untreated FCC Slurry Oil is part of the feed
    - A portion of catalyst will fall out in the MF, and the rest will carry through into the coke drum, increasing erosion of piping
  - Coke from in foam carryover from the coke drums
    - Related to superficial velocity in the coke drum and foam behavior
- History
  - Typically manageable given that most MF's are designed with equipment to tolerate solid build-up between TA's or to remove solids via agitation and removal systems
- Mitigations
  - Proper standpipe design for the heater charge pump suction
  - Removal systems of various guises
  - Use of a Bechtel total draw tray below the flash zone to catch all foamovers and process through exterior back flush filtration equipment

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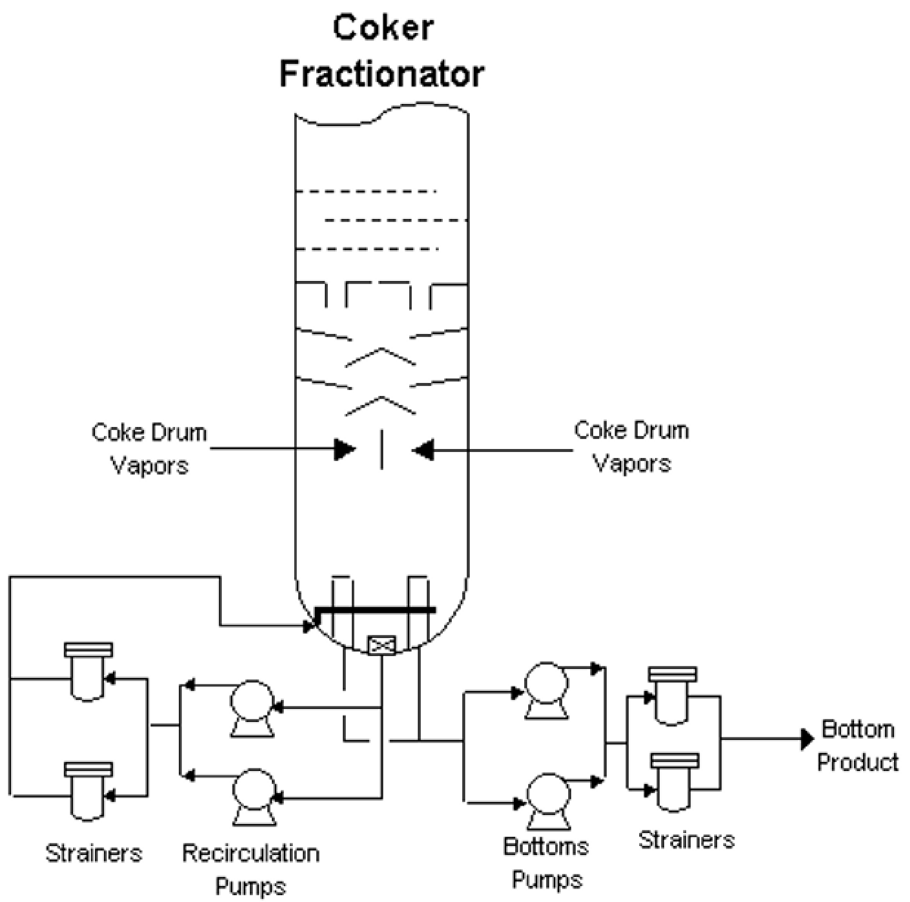
3) Coker Main Frac Bottoms System Fouling:

- Mitigation – One All-encompassing Example to Consider where HCGo is the bottoms product:



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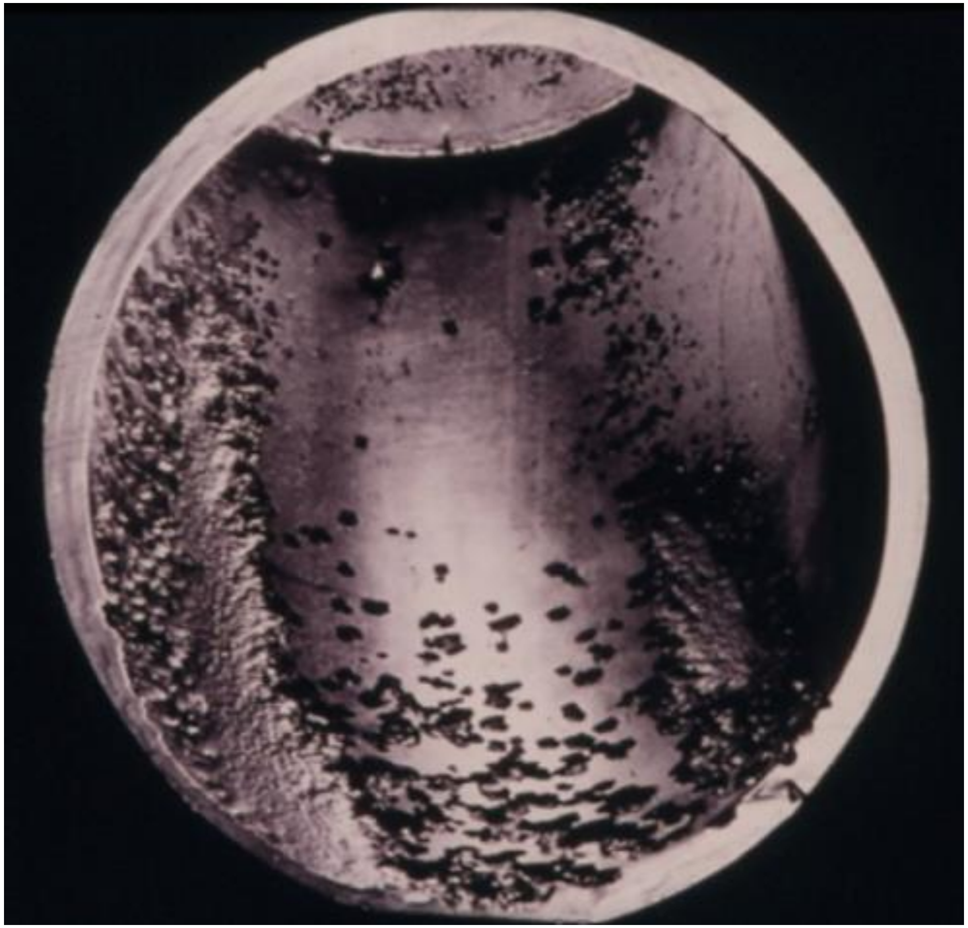
4) Coking & Erosion in the Furnace Charge Pump & Pass Flow control piping:



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4) Coking & Erosion in the Furnace Charge Pump & Pass Flow control piping:

- Sources of Fouling:
  - Solidified resid and coke are the primary causes of fouling, which can restrict flow on the suction side of pumps or through control pass piping
    - can prevent gate valves from properly isolating & inhibit charge pump changeover
    - 325 - 550^{o}F (163 - 260^{o}C) – low coke laydown; 650 - 700^{o}F (343-371^{o}C) - high
- Sources of Erosion:
  - Silicate catalyst is a bad actor due to high hardness, if filtered FCC Slurry Oil is present
  - Coke carrying through is a secondary source of erosion, but typically at a much lower rate
- History
  - Resid solidification occurs with asphaltenic resids
  - Silicate erosion occurs with higher cat slurry in feed (>4 wt%) and higher catalyst concentrations in slurry
- Mitigations
  - Proper piping insulation & tracing & warm-up flow piping design prevents resid solidification
  - Silicate erosion is managed by reducing cat level or planned piping replacements
  - Leakage of resid through control isolation valves is now typically mitigated by using dual block valves; which is a risk when on-line spalling or servicing the control valve

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5) Coking, Fouling & Carburization in Furnace Tubes :

Coked Furnace Tube – Straight Run

Coked Furnace Tube – U-Bend

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5) Coking, Fouling & Carburization in Furnace Tubes :

- Coke formation in furnaces processing heavy oils occurs to varying degrees in crude oil units (atmospheric and vacuum), visbreakers, DCU's and even hot oil heaters
  - Coke forms at the film layer next to the inner tube wall, with the fundamental variables being CCR of the oil, residence time of the film layer, film temperature & sodium concentration
  - Secondary variables - effects of iron sulfide on the wall of the tube and metals concentration in the oil; both contribute to free radical formation and polymeric coke formation
- Inorganic fouling can occur in the convection section tubes due to organic salts (Ca / Mg):
  - Difficult to remove, even with pigging – it is a thin refractory layer of high insulating value.
- Carburization
  - Can often be the end of life determinant for DCU radiant tubes, as opposed to creep
  - Related to high temperature tube operations for chrome and stainless steel tubes
- Mitigations
  - Coke laydown is handled with on-line spalling or off-line pigging, as well as strategies relative to temperature limits and feed selection
  - Inorganics are related to certain crudes (Gulf Coast, African) and/or desalter operatioins; they must be handled with off-line pigging and washing operations
  - Carburization is managed with proper tube metal temperature monitoring & controls

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6) Coking & Erosion in the Transfer Line piping between the furnace and coke drums:

- Coke laydown grows in thickness over time between the furnace outlet and switch valve
- Coke forms downstream of the switch valve, but spalls off due to the thermal cycling of the piping every drum switch
- Additional coke can form due to the following:
  - Spalling operations create a mix point in the outlet piping, where high temperature steam and cracking two-phase hydrocarbon meet. Depending on the piping configuration, and flow rates, a coke donut can form creating significant pressure drop
  - Extended heater circulation (weeks, or months) can form coke if the circulation temperature is over 670^{o}F (354 ^{o}C). This can create significant restrictions to flow, which creates high-velocity impingement and potential hole through of the transfer line
- Impingement erosion of outlet headers and loss of containment can occur as part of the on-line spalling process.
- Carburization
  - Can often be the end of life determinant for DCU radiant tubes, as opposed to creep
  - Due to high tube metal temperatures in presence of vac resid for chrome and stainless steel tubes
- Mitigations
  - Coke must be removed off-line, most typically, by hydroblasting, coincident with tube pigging
  - Proper design, operation and monitoring
  - Impingement erosion can be mitigated with the use of a "flooded tee" design
  - Carburization is managed with proper tube metal temperature monitoring & controls

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7) Coke in the Top Dome of the Coke Drum:

- With certain crudes – Venezuelan Orinoco region crudes, for example - coke will adhere and grow in thickness on the inner wall of the top dome of the coke drum.
  - This tendency appears to be somewhat proportional to the CCR of the resid feed
  - Two risks are:
    - I. Coke detaching and exiting the bottom head of the coke drum during maintenance activities or cyclic bottom head activities if a swing-back or cart system is being used.
    - II. Corrosion of the 410SS liner and base metal
- History
  - Injuries have occurred due to falling coke when working around an open bottom head
  - Corrosion of the 410SS liner & base metal has been reported by one refiner, no details
- Mitigations
  - Both Flowserve and Ruhrpumpen provide "dome clean-out" capabilities with the design of the limit switch protective system to allow removal of coke in the dome following removal of the coke bed. This allows periodic removal (weekly to monthly to quarterly) to prevent accumulation of large coke pieces.
  - Use of a bottom slide valve design addresses the cyclic operational risk, but not special maintenance work activities
  - Corrosion of the 410SS liner has rarely been noted by DCU operators over the years, so the jury is still out on this risk factor

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8) Coking in the Coke Drum Vapor Line to the MF:

- Gradual build-up occurs due to heavy cracked molecules adhering to the inner wall of the vapor line piping and valves and forming polymeric coke
- Foam entrainment or a foam upset carryover are other more severe mechanisms
- Areas of turbulence (thermowell insertion areas, elbows and upstream of quench injection points) form coke, which can create a significant build-up of coke over 1 to 12 months.
  - The increased coke drum pressure reduces liquid yields , increases coke yields and leaves more partially-coked oil in the upper coke bed, increasing ‘hot drum’ frequency/severity
- History
  - Occurs on all DCU’s to varying degrees
- Mitigations
  - Rate of coke build-up can be reduced by:
    - Insulating the vapor lines and injecting a quench oil into the coke drum vapor near the outlet of the drum to reduce vapor temperature by 20 - 30^{o}F (11 - 17^{o}C).
    - Use no quench oil, but install a vapor shield around the vapor line piping, which allows some condensation at the inner wall, preventing coke from adhering; the steam-purged valves can be insulated for personal protection reasons.
    - Hydroblasting of the piping is needed to remove “coke donuts” near the outlet
    - Hydroblasting of the downstream vapor line piping requires a train shutdown and blinding at the Main Frac entrance (either during TA or a train squat for furnace pigging)

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9) Coke Accumulation in the Bottom of the MF from Coke Drum:

- Sources of coke in the bottom of the tower are:
  - Coke spalled off feed piping (function of resid feed temperature)
  - Foam entrainment from the coke drum (superficial vapor velocity, resid crude source, bed outage)
  - Foam upset carryover
  - Coke spalled from the vapor piping / valves
- History
  - Each occurs on all DCU's to varying degrees
- Mitigations
  - Good design and operations procedures
  - Good foam height monitoring and control
  - Standpipe design with top hat
  - Agitation and removal system in the bottom of the tower

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10) Coking & Corrosion in HKGO Fractionation Zone:

- DCU’s are unique in that resid feed surge inventory is typically in the lower part of the Main Fractionator, allowing low-value recycle liquid from the flash zone (FZ) and HKGO fractionation zone to comingle with the resid feed
  - However, some cokers invest in separate feed surge drums and recycle collection drums
  - De-entrainment and fractionation internals vary considerably in the industry
  - Contacting the 770 - 800^{o}F (410 - 427^{o}C) vapors for de-entrainment and then backend HCGO fractionation occurs above the FZ using a varied selection of sheds or grid, or vapor distributors and tray; then spray wash or trays
  - Internals below the FZ can range from nothing to a total draw tray (Bechtel proprietary), and/or a vapor shield.
- History - Coking occurs on all internals to varying degrees
  - Coking of spray nozzles (and trays) during power failures and other unit upsets
  - Coke deposits and naphthenic/sulfidic acid corrosion under the HCGO chimney have been reported, which is linked most likely to resid entrainment
- Mitigations
  - Prevent entrainment of resid from bottom pool (proper design and/or vapor shield)
  - Proper control of foam level in the coke drum
  - Proper temperature control above and below the HCGO fractionation zone
  - Proper tray design and spray header design relative to internals reliability, HCGO quality and recycle rate control over the desired coker feed rate range (typically 2:1)

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11) Coking in the HKGO product and PA circuit:

- Poor HCGO backend fractionation can result in coke forming in the high residence time zones on the HCGO chimney draw tray
  - This coke can spall during tower operational “transients” and migrate into the pumparound and product heat exchangers, causing high pressure drops and shutdowns for cleaning
  - The coke formation rate can be worsened by entrainment of resid molecules through the fractionation zone
  - Running minimum recycle operations increases the probability of this phenomenon
- History
  - This has occurred on delayed cokers in the industry
  - Cokers with spray wash zones are more prone than those with tray designs
- Mitigations (same as the previous slide)
  - Prevent entrainment of resid from the bottoms pool (proper design and/or vapor shield)
  - Proper temperature control above and below the HCGO fractionation zone
  - Proper tray design and spray header design relative to internals reliability , HCGO quality and recycle rate control over the desired coker feed rate range (typically 2:1)

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12) Fouling in the Light Distillate System:

- It is almost always the fault of what is going on in the upper trays above
- Ammonium chloride salt deposition requires water washing or use of salt dispersant chemical addition, which moves salts and corrosion products into this zone of the MF
- The salts and corrosion products can corrode/foul the middle distillate pumpround and/or product systems
- … so let’s go to the next slide…..

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13) Ammonium Chloride Deposition in the MF:

- The DCU thermal cracking process makes plenty of ammonia, the limiting component is the amount of chlorides (Cl^-) that can react with the NH_4^+ to form NH4Cl
- The chloride level is set by the amount of organic salts that get through the desalter plus the amount of hydrolyzed chloride salts that are not removed by desalting or separation in the crude unit towers.
- Salt deposition temperature is set by the combination of NH_4 and Cl concentrations
- If the local temperature on the upper trays is less than the deposition temperature, these salts will deposit and corrode the 410SS trays or carbon steel shell of the tower
  - In addition to corrosion, the salts can foul tray sieve holes or valves, increasing pressure drop in the tower's upper naphtha-LCGO fractionation zone
  - Salting in the overhead condensers is usually not a problem due condensation/injection of H2O
- History
  - MF's operating at low pressure (8 – 12 psig, 0.6 – 0.9 barg) are most prone to salt deposition.
  - As naphtha cut point is lowered, top tray temperature is reduced and salt deposition probability increases; towers with top pumparound designs (rare) would be much more likely to deposit salts
  - Larger diameter towers have more risk, since turndown operations have low velocity tray regions
- Mitigations
  - Use a salt dispersant chemical (available from major process chemical vendors)
  - Perform a controlled water wash of the upper trays (requires slopping products and cutting rate)
  - Compromise on naphtha cut point, if possible / economic

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14) Cyanides and Hydrogen Attack in Main Frac and Gas Plant:

- Cyanide (HCN), if at a high enough concentration, can cause hydrogen blistering of metalsand creates the tell-tale Prussian Blue color on the vessel internal walls
- DCU's feeding certain high nitrogen crudes (California San Joaquin Valley is one example) will see this phenomenon
- History
  - MF's overhead drums, WGC vessels and naphtha stabilizers with CN- levels <20 wppm in the water do not suffer from CN- hydrogen blistering
  - Risks with CN- levels >25 wppm should be evaluated
- Mitigations
  - Do nothing
  - Inject additional water to dilute the cyanides and reduce the mass transfer rate of hydrogen into the steel
  - Inject ammonium polysulfide into the water systems (which is the typical mitigation employed on Fluid Cat Crackers and Fluid/Flexicokers) with proper knowledge and precautions

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15) Wet Gas Compressor Fouling:

- Polymeric foulants can form on the internal rotor components of Wet Gas Compressors
- As discharge temperature of the WGC stage increases, rate of polymeric fouling increases.
- Polymeric foulant is related to the amount of butadiene, which forms free radicals that can polymerize and foul internals
- History
  - Foulant and loss of WGC compression efficiency has been seen in many WGC applications – FCC, Flexicoking, Delayed Coking.
  - The degree of fouling is highly variable in regard to severity, given the chemistry variables, operating temperature variables and the machinery operating conditions and effects
- Mitigations
  - Periodic rotor “wheel washing” is a proven method to prevent foulant build-up; a naphtha (FCC cracked naphtha, reformate and coker naphtha) is typically injected, on some frequency, into the compression machinery
  - The manner in which it functions is debatable – some maintain that the liquid solubilizes and dissolves the deposits; others say that the naphtha strikes the deposit and fractures it; still others say it can be a combination of both
  - Many refiners have claimed improved compressor performance from wheel washing, and continue to use it on a regular frequency (weekly to monthly)

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16) Gas Hydrate formation in the Fractionating Absorber Coolers:

- Gas Hydrates form when water and methane or ethane gases hydrolyze
- They form at low temperatures, typically around 35 - 40 ^{o}F (2 - 4^{o}C) and are notorious in natural gas production systems, which operate with compositions and conditions similar to DCU gas plants.
- History
  - Can happen in the winter with clean air fin coolers in DCU Gas Plants.
- Mitigations
  - Set proper operating temperature limits to prevent "overcooling" of the gas feeding the Fractionating Absorber

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17) Debutanizer Reboiler Shell Side Fouling:

- DCU cracked naphtha (diene molecules) will react and polymerize if the film temperature of the reboiler is high enough
- The foulant can be bad enough to prevent removal of the tube bundle for cleaning
- Low Risk Operating Temperature Range:
  - 400 – 475^{o}F (204 - 234^{o}C)
- High Risk Operating Temperature Range:
  - 525 – 625^{o}F (274 - 329^{o}C)
- History
  - Consistently occurs on reboilers using a high temperature reboiler medium (e.g., HCGOPA)
  - The film temperature on the shell (naphtha) side of the reboiler is the determinant
- Mitigations
  - Use a lower temperature reboiler medium, such as LCGOPA
  - Switch from counter-current to co-current HX shell-tube flow arrangement
  - Switch the order of pumparound heat removal to lower the temperature

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18) Coker Gas Amine Treater:

- DCU Fuel Gas has many reactive components that can increase corrosion products (which can stabilize foam) and heat stable salt (HSS) formation in the circulating amine solution
  - DCU Contaminants are O_2, SO_2, COS, CS_2, NH_3, HCN, formic acid, acetic acid, oxalic acid)
  - HSS over 0.8 wt% should be managed; with 2.0 wt% typically being the maximum allowed.
  - Iron levels in the lean amine over 25 wppm indicate unacceptable corrosion in the circuit
  - Sodium should be 0 – 0.2 wt% (2000 wppm); chlorides 0 – 1000 wppm; all others less than 100 wppm, unless metals passivation chemicals being used
  - TSS < 100 wppm; solution color => clear water-white to yellow to green
- History
  - Amine utility operators must be ready to handle the higher corrosion product (iron sulfides) and HSS's that DCU gas treating brings
- Mitigations
  - Proper amine concentration control, rich and amine loadings, metallurgies and temperatures
  - An amine filter should always be present. It may be full flow or slip stream, on the lean or the rich side of the system. Most systems apply lean slipstream cartridge or bag filters. A 25% slipstream is the recommended minimum. 20 micron max and 5 micron minimum.
  - Carbon treater if hydrocarbon is in the amine.
  - HSS control – amine purging (expensive) or reclaiming (a kettle reboiler with 316SS tubes and provision for easy addition of caustic or soda ash).

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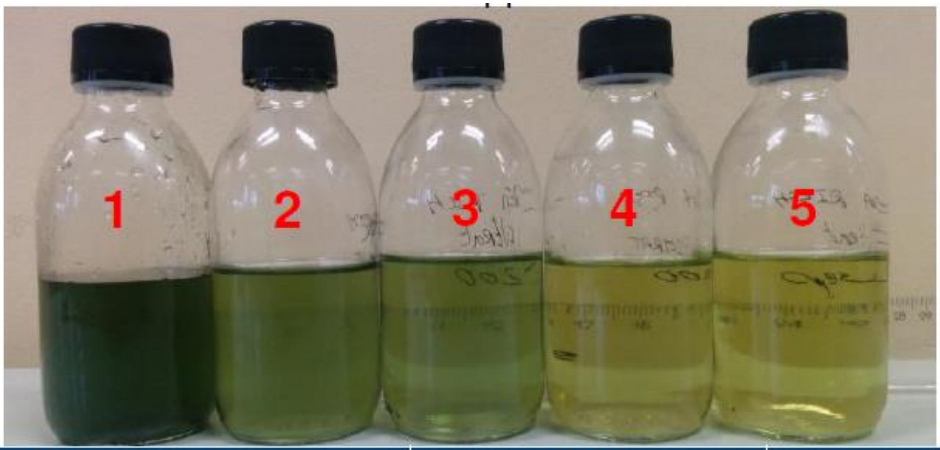
18) Coker Gas Amine Treater:



Sample	Description	TSS	Remarks
1	Unfiltered	>> 5 ppmw	Green/black, cloudy
2	40 µm, β = 5000	2 ppmw	Green, cloudy
3	20 µm, β = 5000	< 1 ppmw	Green, partially cloudy
4	10 µm, β = 5000	< 1 ppmw	Pale yellow, clear
5	10 µm, β = 5000 & L/L coalescer	< 1 ppmw	Pale yellow, clear

Courtesy of Pall Corp Laurance Reid Gas Conditioning Conference Amine Systems: Corrosion Overview, Impact of Solids on the Corrosion-Fouling Cycle feb-2018

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19) Coker Blowdown Contactor - Coke in Bottoms:

- The coker blowdown contactor is the vessel that receives coke drum vapor effluent cyclically during the latter stage of steam stripping (‘Big Steam”), and the water cooling stage (“Sludge”, “Little Water” and “Big Water”)
- All modern designs (last 20 years) also must be designed to simultaneously handle coke PRV relief should coking vapor flow be restricted or blocked (PRV discharge direct to contactor)
- There are several facilities designs – 1) “Low temperature bypass”; 2) “Flow-through with Heating”; 3) Use of two drums – low and high temperature (little used)
- All designs must deal with coke particle carryover to some degree…
  - Foam entrainment from coke drum (superficial vapor velocity, crude type, bed outage)
  - Foam upset carryover or “refoams”
  - Coke spalled from the vapor piping / valves
- History
  - All BD contactors see coke in their bottoms pumping system at some point
- Mitigations
  - Good foam level control and good water level control during quenching
  - Good design parameter control
  - Installation of dual basket strainers on the pump suction
    - ✓ (1000 – 2000 micron holes; 1/16 – 1/32 inch)
    - ✓ Double block and bleed on each side of the strainer basket

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20) Coker Blowdown Fin Fan Condenser Fouling:

- The coker blowdown fin fan condenser receives vapors leaving or bypassing the contactor
- It can be fouled with coke, corrosion products or waxy condensed hydrocarbon
- As mentioned, all modern designs (last 20 years) also must be designed to handle coke PRV relief should coking vapor flow be restricted or blocked (PRV discharge direct to contactor)
- History
  - All BD condensers will typically suffer fouling over time
  - Enhanced control/monitoring technologies are reducing problems with fouling
- Mitigations
  - Proper control of the vapor outlet temperature to the fin fans
    - ✓ 325 - 375 ^{o}F (163 - 191^{o}C) is recommended
    - ✓ This prevents waxy hydrocarbon fouling
  - Proper control of the outlet temperature from the fin fan bays
    - ✓ 160 - 140 ^{o}F (60 - 71^{o}C) is recommended
  - Calculation of total heat transfer coefficient for each bay
    - ✓ Monitoring of outlet temperature from each fin fan bay (local TI's)
    - ✓ Maintaining cleanliness of the exterior tube fins
  - Provision of isolation block valves to allow LGO flushing and steaming
  - Required to maintain PRV relief capacity

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21) Coker Settler Emulsion:

- The coker settler is a horizontal three-phase separator vessel that generates, ***by design***, a non-condensable gas, a wide boiling range light gas oil and sour water (cyclic concentrations of H_2S and NH_3)
- Oil water separation is challenged if heavy oil or coke fines are present
- History
  - All BD settlers will suffer from emulsion formation to varying degrees over their lives
- Mitigations
  1) Proper control of the vapor outlet temperature to the fin fans
  2) Proper control of the outlet temperature from the fin fan bays
  3) Proper design of the settler vessel to separate oil and water
     - There are several options to choose from and all can work
     - Emulsion sampling taps on side of settler should be provided
  4) Use of a reliable level indication system for the water and oil
  5) Use of de-emulsifier if having issues with 1 – 3

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22) Quench & Cutting Water Piping Erosion:

- Corrosion/erosion of these systems is well documented in the industry
  - One DCU (1000 wppm coke fines) used CS NPS 8 piping with 0.500“ (12.7 mm) nominal thickness, the internal corrosion rate was around 0.040 in/yr (40 mils per year, or 1 mm/yr).
  - At another industry coker with coke fines levels of 5000 wppm and larger particles, the loss of metal occurred at twice the rate
  - Dissolved oxygen and coke fines are the primary causes; other dissolved contaminants can worsen the situation depending on concentration
- History
  - All DCU's suffer from erosion/corrosion to varying degrees
  - Cutting water systems operating at over 4000 psig pressure (275 barg) can see “coke line cutting” in the horizontal runs => the start-up acceleration pushes the coke fines along the bottom of the piping causing an erosive cut of the CS piping
- Mitigations
  1) Minimization of coke fines concentration and particle size
  2) Minimization of circulating water temperature
     – higher temperatures (>140^{o}F, 60^{o}C) increases corrosion rate non-linearly
  3) Use of oxygen scavenger can be done, but can be expensive
  4) Increased metal thickness in elbows and areas of turbulence
  5) Increased metal hardness (typically expensive)
     - Use 300 series stainless steel with extreme caution since it is susceptible to chloride SCC

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23) Furnace Air Preheater (APH) Cold End Corrosion:

EXAMPLES OF PREHEATER FOULING

Severe fouling of fin tube surfaces in steam coil air preheaters

Severe Fouling of element channels in rotary air preheaters

1. Loosely adhered rust flakes bridge gaps between fins

3. Early stages of salt accumulation on finned tubes

2. Insulation from an upstream liner failure is wiped away exposing fins underneath

4. **Sticky sulfur deposits,** the consistency of peanut butter, have plugged finned tubes

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23) Furnace Air Preheater (APH) Cold End Corrosion:

- Corrosion of systems is well documented in the industry
  - The flue gas acid dew point depends on sulfur level of the fuel, and can range roughly between 240 to 300^{o}F (116 - 150^{o}C)
  - Severe corrosion will occur just below those numbers
- History
  - Most furnaces seeking to maximize heat recovery from the flue gas will suffer corrosion of unprotected steel internals since localized film temperature effects due to non-ideal heat transfer and mixing across tube bundles.
  - Loss of APH operation usually occurs for several years, with very high energy cost and often furnace feed rate limitations => this probabilistic loss needs to compared to alternate operating and design cases
- Mitigations
  1) Set flue gas operating temperatures for steel tubes with enough allowance, say 50 - 75^{o}F (28 - 42^{o}C), above the dew point to prevent localized non-deal corrosion
  2) Perform soda or potash washing of steel tubes when shutdown
  3) Consider a specialty APH design to prevent cold-end corrosion of the tubes
     - ✓ Glass-lined tubes (Chinese patented designs)
     - ✓ Polymer tube construction (HeatMatrix patent)

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Questions and Comments are Very Welcome

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DCU Commissioning and Start-Up Key Considerations

Mitchell J Moloney
Heavy Oil Upgrading and Process Engineering Specialist
Becht Engineering
mmoloney@becht.com