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2007 Q&A and Technology Forum Questions

FCC

Reliability and Safety

1. Historically, instrument air was used to purge FCC reactor instruments. More recently, dry gas or nitrogen is typically used for this service. Please explain the reasons for moving away from air and provide examples of operating upsets which have occurred when using air to purge instruments.
2. Which type of valve technology or design is typically utilized in units with high catalyst withdrawal rates? Do you continuously withdraw catalyst? From a reliability and safety perspective, what type of hardware are you using for control? What is the best withdrawal line design?
3. Carbonate stress corrosion cracking (CSCC) has been identified as a cause of failure in FCC main fractionator overhead systems. What changes in feed quality, unit operation, or configuration would lead to increased risk of CSCC? What parameters do you monitor to determine whether a system is susceptible to CSCC? While CSCC can be alleviated through post-weld heat treating, has the problem been significant enough to warrant either comprehensive PWHT in potentially affected areas or localized PWHT when problem areas are identified?
4. Does your refinery/company adopt a time-based rather than inspection-based replacement strategy for FCC reactor and regenerator hardware such as feed nozzles, air distributor, cyclones, cyclone support systems, and flue gas expansion joint bellows? If so, what is the planned service life for this equipment?
5. What is the shortest possible time between oil out and entry for maintenance on large inventory, high capacity FCC units? How is this achieved?
6. Some CO and waste heat boilers operate with bypass stacks separated by seal pots or isolation valves. Maintenance of these seal systems can be expensive and these seal systems can be sources of poor reliability. What design upgrades and operating practices have enabled you to eliminate these bypass systems?

Environmental

7. Is your company either considering, or actually implementing, FCC projects that include reduced CO_2 emissions (greenhouse gas reduction-GHGR) as an offset/credit?
8. What level of $PM_{2.5}$ particulate removal do you expect (or have achieved) with flue gas fines separation and removal equipment such as third-stage separators, fourth-stage separators, electrostatic precipitators, or wet gas scrubbers?

Catalysts

9. Are there specific lab studies or commercial examples regarding the effect of regenerator temperature on catalyst deactivation and particle integrity, specifically attrition properties, apparent bulk density, and morphology?
10. What is your recent experience regarding the maximum level of equilibrium catalyst metals (Ni, V, Na, Fe, Ca) in FCC units processing residual feedstocks? Have there been any recent improvements in vanadium passivation technologies? At nickel levels approaching 10,000 ppm, have you experienced increased catalyst deactivation as evidenced by lower equilibrium zeolite surface area?

Process

11. What process or catalyst options are available for shifting yield selectivities from gasoline to distillate while minimizing the impact on light olefin yields? How are the product properties impacted? How does change-out rate impact the viability of the catalyst options?
12. For FCC units with closed riser termination device (RTD)/cyclone systems, do you operate with the primary separator sealed or unsealed in the stripper bed? What differences in performance do you see between these modes? Which do you prefer?
13. With the move toward greater utilization of "opportunity crudes" such as Canadian synthetic crudes, what shifts do you expect in FCC product yield and quality and how will this impact the operation of the FCC unit?
14. What reactions lead to acetone formation and how can they be mitigated? We have measured acetone concentrations between 100 and 1200 ppm in the FCC butanes/butylenes stream.
15. What variables influence gasoline aromatics? In particular, please address feed properties, catalyst, and FCC operating conditions.
16. A number of refiners are adding a chloride dispersant to address FCC main fractionator overhead system plugging issues. What is your experience with these products and have you had issues with downstream gasoline product quality?
17. What minimum nozzle velocities are required in air and steam distributors to prevent catalyst backflow and subsequent erosion? Please consider both upward and downward pointing nozzles.
18. Some refiners have installed gas injection in FCC secondary cyclone diplegs to increase capacity and avoid defluidization problems. Please describe your experience operating with gas addition in the diplegs and any maintenance issues. What advice would you give to others considering this installation?
19. FCC revamps commonly include technology upgrades which increase the catalyst circulation rate which then increases the stripper flux and reduces the stripper residence time. Please describe your experience with the high flux stripper and its performance. What is the maximum flux you have achieved? What is the minimum residence time you have achieved? Will the use of high efficiency stripper internals reduce the required residence time?
20. Several refiners are considering continuous operation of the combustion air heater to maintain a minimum regenerator temperature when processing light, severely hydrotreated feedstocks. What control systems, design features, and other general precautions should be considered?
21. When operating with one or more catalyst coolers on a regenerator, what control philosophy do you employ (e.g. constant heat duty, constant regenerator temperature, etc.)? What are the advantages and disadvantages for each approach? How does operating in full or partial burn impact the control decision?
22. With the introduction of modern riser termination devices (RTD's) and the advent of severe FCC feed hydrotreating, what is your experience (typical values) with the ash content of the main fractionator bottoms (MFB) product (please provide typical values for: wt% ash, BS&W, particle size distribution, etc.)? Please describe the testing methodology utilized and the recommended testing frequency for this stream. What process, practices, and/or equipment changes can be, or have been, employed to reduce the ash content of the MFB product?

Crude/Vacuum Distillation and Coking

Process Safety

23. High acid crude processing increases mechanical integrity risk. What steps do you take to ensure piping and vessel integrity when running these crude oils? Please discuss:

- Safe limits of operation (SLO's) for crude acid number, sulfur, temperature and velocity;
- Metallurgy upgrades;
- Chemical additives;
- Inspection techniques, including smart pigging, eddy current testing, UT and inspection frequencies; and
- Inspecting furnace convection sections and other equipment that are difficult to access.

24. How do you manage risk of heater firebox explosion? Please describe your heater shutdown systems. To what extent do you rely on API Recommended Practice 556*, Instrumentation, Control, and Protective Systems for Fired Heaters and Steam Generators*? Do you double block and vent both fuel gas and pilots? Do you use the fuel control valve as a block valve or are these separate valves? How often do you test the components of the heater shutdown system?

25. Coker drum operations have several areas of risk. Please describe your current practices and plans for minimizing risk in the following areas:

- Bottom head;
- Top head;
- Drilling; and
- Switching.

Is remote operation of unheading and drilling operations a feasible target?

Opportunity Crudes

26. What is your experience with crude containing high levels of mercury? What are the operational and safety issues?
27. What are the low-temperature aqueous corrosion impacts of processing high TAN crudes? How do you mitigate those impacts?

Desalting

28. How do you increase the capacity and performance of existing desalter systems without major capital investment?
29. What operating strategies do you employ when desalting high conductivity crudes? What operational and/or equipment changes mitigate the problems caused by high conductivity?
30. What options are available to minimize the impact of high BS&W crudes on desalter operation and wastewater treating?
31. What are the challenges in desalting heavy or synthetic crudes such as those from western Canada or Venezuela? What are your experiences?
32. What are the best practices for minimizing desalter make-up and, consequently, desalter effluent volumes? Is it technically or economically feasible to utilize desalter effluent as make-up water for cooling water or boiler feed water service?

Crude/Vacuum Distillation

33. What resid cut point have you achieved during deep-cut operations? Please comment on vacuum unit design practices and the impact of deep-cut operations on downstream processes.

34. What impacts are oil field additives having on crude unit operations? What mitigation strategies do you use? Please describe your experiences.

Crude Heater

35. Please describe your experience with the latest generation of ultra-low NO_x burners. Please comment on operating performance (NO_x level achieved); flame height; operability; and sensitivity to fuel gas composition variability.
36. During a unit turnaround, how are you assessing remaining life for convection and radiant coils in the short time available?
37. What practices do you currently employ for exterior scale and process side coke removal in process heaters? What criteria are used to determine level of cleanliness?

Coker Heater

38. What mitigation strategies have you used to reduce delayed coker furnace fouling? Were they successful?
39. Is there a correlation between vacuum tower operating severity and delayed coker furnace fouling?
40. Does your refinery (or refineries) have plugged headers (mule ears) on one end or both ends of the heater? Is this common in the industry? Are you planning to phase them out?
41. How do you justify replacing major capital assets such as coker heaters and coke drums?

Coke Drums

42. What advances have been made on coke drum life expectancy, either through new drum designs or operating best practices?
43. What on-line inspection techniques (after a drum cut) have you employed on coke drums? Have you used laser ID measurement or video inspection to detect incipient cracks?
44. Which coke drum weld seams are more prone to cracking (cone-to-shell attachment or 2nd or 3rd seam from bottom)? What techniques have you employed to repair these cracks?

Coker Operations

45. Please describe your insulation system best practices for minimizing heat loss from a coke drum. Are there any correlations between coke drum overhead vapor temperature and coke make and/or liquid yield?
46. What procedures do you use (or are considering) to reduce coke drum emissions during the decoking steps?
47. When a full drum is switched to blowdown to begin cooling, we often see a rapid rise in foam level which is immediately reduced once water is introduced into the drum. What may be causing this and how might it be mitigated?

Coker Blowdown System

48. For refiners who have implemented or are implementing coke drum blowdown vapor recovery: How did the additional backpressure on the blowdown drum impact coke drum cooling and vapor recovery to the coker compressor and/or the flare recovery compressor? Were additional relief valves required to maintain the unit's relief capacity?

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Gasoline

Process Safety

49. In the past year, a sulfuric alkylation unit released a significant amount of sulfur dioxide to atmosphere when light hydrocarbon flowed from the reaction zone through the acid blowdown system and into the spent acid tank. What measures do you recommend for preventing this?
50. What is the proper firefighting media to use when putting out a fire when both spent sulfuric acid and heavy hydrocarbon are present (e.g. in a spent acid tank or a diked area which has a layer of hydrocarbon floating on the spent acid)?
51. Reforming unit stabilizer column top trays and overhead condensers can experience fouling with ammonium chloride salts which are commonly removed by on-line water washing of the column overhead. What practices do you employ to reduce the risk of rapid corrosion and the potential failure associated with this fouling and subsequent water washing procedure?
52. Have you found highly condensed aromatics (i.e. red oil) around the reforming unit, especially around heat exchangers and/or valve leaks? What safety precautions do you recommend for handling this material?

Alkylation

53. In a hydrofluoric acid alkylation unit, what can you do to prevent plugging in the acid-soluble oil caustic neutralizer?
54. In a sulfuric acid alkylation unit, what can you do to minimize foaming and/or plugging in caustic wash or water wash systems?
55. Have you incorporated coalescing media into your acid settlers to reduce acid carryover? If so, what were the benefits and/or problems?
56. In a sulfuric acid alkylation unit, there have been problems keeping the acid wash electrostatic precipitator (EP) operational. What steps do you recommend to improve the reliability of the EP?
57. What sulfur concentrations do you have in your alkylate and what have you done to decrease the sulfur content?
58. In a sulfuric acid alkylation unit, the refrigeration compressor's controls maintain a positive suction pressure by opening the anti-surge recycle valve. This limits refrigeration and, therefore, unit capacity. Do you operate the refrigeration compressor in vacuum? Is oxygen entrainment a concern? What have you done to debottleneck the refrigeration section?
59. For a hydrofluoric acid (HF) alkylation unit, what instrumentation do you recommend for controlling HF acid levels throughout the unit?

Isomerization:

60. How do you detect leaks in an isomerization unit's steam charge heater? Have you been able to detect a leak before a significant portion of the catalyst bed was deactivated?
61. Have you found that you needed to install a methanator upstream of a chlorided catalyst isomerization unit to remove carbon monoxide (CO) from the feed? What is the source of the CO and how much of a difference has the addition of the methanator made to catalyst life? What is the expected payout for the cost of the methanator?

Naphtha Hydrotreating:

62. How much coker naphtha can be added to the naphtha hydrotreater feed before you need to add a separate diolefin reactor?

63. What is the upper limit for mercury in catalytic reformer feed? What level of mercury in naphtha is removed in a naphtha hydrotreater? Does the use of cobalt/molybdenum (CoMo) or nickel/molybdenum (NiMo) catalyst make a difference in mercury removal? What is the typical hydrotreating catalyst capacity for mercury loading? If the mercury content in the naphtha is particularly high, is there an alternate method of mercury removal?
64. For an FCC heavy gasoline hydrotreater, how much arsenic (ppbw) do you see in the feed and how do you handle it?
65. Have you been successful in reducing naphtha hydrotreater reactor pressure drop by the use of chemical injection to the reactor? What were the keys to success, and how much time did the chemical injection procedure add to cycle length?
66. We have experienced ammonium chloride fouling at several of our sites with the location of the deposits varying from unit to unit. Of particular concern are deposits around the recycle gas compressors. What washing fluid do you recommend for eliminating these deposits from the compressors? Can you mitigate these deposits by modifying the operating conditions? What is the best strategy to minimize ammonium chloride formation?
67. Have you seen increased catalyst deactivation in FCC gasoline hydrotreaters due to CO getting into the unit? What is the deactivation mechanism? What was the source of the CO and how did you mitigate its effects? How much deactivation did you experience?
68. Please discuss coalescer operation and rating for naphtha service including the impacts that large swings in feed water content and inorganic solids contamination have on coalescer performance. Are there any good references on this topic? From a diagnostic standpoint, how can free and dissolved water contents be accurately sampled and measured? Are any commercial data available which show a component water balance around a coalescer where the balance actually closes?

Reforming

69. How do you address polymer deposits on combined feed exchangers in continuous regeneration reformers? Do you have parallel exchangers equipped with valving that enables one heat exchanger to be taken off-line and cleaned while the unit continues to operate? This problem has resulted in reduced rates or reduced hydrogen to hydrocarbon (H_2/HC) ratio.
70. A continuous reformer running at very high temperature and low H_2/HC ratio has sulfur injected as recommended by the licensor. However, there is still a large amount of coke build up between the scallops and the reactor wall. What is the likely cause of this coke formation and what steps do you recommend to resolve this problem?
71. Do you use an oxygen stripper upstream of naphtha hydrotreater/continuous regeneration reforming units to remove absorbed oxygen found in purchased naphtha or naphtha that has been in storage? If so, what are the operating parameters of the oxygen stripper? Are there additive alternatives?
72. The mandatory addition of high ethanol concentrations to gasoline is reducing the reformate's required octane. What changes need to be made to a regenerator to allow it to run in a low coke mode?
73. With the new stronger scallop designs, what is the next weakest link that will break when the catalyst bed pressures build to the point where something has to break? What causes high reactor bed pressure and what are you doing to address the problem?

Hydroprocessing

Safety

74. What are your best practices for mitigating the risk of hydrogen back flow to tankage during a hydrotreater feed pump trip?
75. How do you protect against heater tube failures? Are operator observations adequate or must design and other monitoring features be incorporated? What are these features?
76. How are you applying API RP 579, Recommended Practice for Fitness-for-Service, to hydroprocessing unit fired heaters and steam/methane reformers? Are the inspection techniques and asset life modeling sufficient for improving turnaround management and extending turnaround cycles?
77. With the increasing number of larger, multi-bed reactors installed for high severity operation (ULSD, FCC feed treating, heavy crude, etc.), how are you managing the additional time required to prepare the reactors for unloading (lower explosive limit (LEL), inert atmosphere, etc.)?
78. Are you using partial stroke testing on critical service high rate depressuring valves to ensure valve availability in hydrocrackers and hydrotreaters? What do you do to test other emergency shutdown valve systems?

Hydrogen Management

79. Given ULSD-related increases in hydrogen consumption, sulfur/nitrogen removal, and the associated impact on existing downstream processes such as amine system, sour water stripper (SWS), and sulfur recovery units (SRUs), how have you changed your FCC feed treater operating strategy?
80. Do you have experience operating PSA (pressure swing absorption) units for hydrogen recovery from purge gases with significant quantities of H_2S? Does the H_2S cause any problems? Are maintenance intervals affected? What is a typical valve service interval for a PSA unit in hydrogen recovery operations?

Catalyst

81. With the newer regeneration/rejuvenation processes for catalysts with Type II active sites, what has been your experience with reuse of these catalysts in ULSD or other services?
82. What are the primary catalyst concerns when restarting the unit after a total power failure?

Process

83. What are the “best in class” practices for ensuring adequate reserve quench in both ULSD hydrotreaters and hydrocrackers? How do you determine the reserve quench requirement?
84. With tightening fuel regulations and the increased severity of distillate hydrotreater operations, have you experienced any unanticipated problems such as corrosion, fouling or catalyst issues?
85. Please identify the possible causes of increased pressure drop in middle and lower catalyst beds. What solutions have you implemented to prevent pressure drop events?
86. Given that FCC product yields can usually be improved significantly by feed hydrotreating, what level of performance (e.g., hydrogen uptake, basic nitrogen removal, desulfurization, etc.) might justify a new FCC feed treater installation?
87. With the projected shift to making more diesel and less gasoline, have you modified the FCC feed treater to add conversion capability and make more diesel? What changes in catalyst type, reactor volume, pressure, or product separation are needed to do this?

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88. Operating a FCC feed treater in aromatic saturation mode generally increases FCC liquid yields. Have you found that this increased severity leads to more refractory sulfur species in the LCO? If so, what options do you have to compensate?
89. When co-processing diesel and VGO for ULSD and FCC feed treating respectively, does this require a specialty catalyst and/or a modification of operating parameters? What is the impact on the FCC unit?
90. What levels of arsenic have you observed in opportunity crudes and how are the arsenic levels distributed through the various crude distillation fractions?
91. As these opportunity crudes are being processed and the use of arsenic trap catalysts is becoming increasingly common, higher levels of arsenic remain behind on spent catalyst. Are there special or additional precautions and procedures that need to be implemented for the safety of the personnel that handle this spent catalyst?
92. Are you aware of any "runaway" reactions in ULSD hydrotreaters (a runaway is defined as a self-perpetuating reaction characterized by a large temperature increase)? Please discuss the factors that can cause such a runaway.
93. The recommended hydrogen circulation rate for ULSD service is typically higher than in pre-ULSD days (i.e. > 5:1 hydrogen available/hydrogen consumed). How are units operating at ratios less than 3:1 performing compared to predictions?
94. In hydrotreaters with high heat release (i.e. hydrocrackers, FCC feed treaters, and ULSD units) what criteria are used to determine distribution throughout the beds during the entire cycle? Is there a recommended thermocouple arrangement and density? Is there an optimal or "best in class" arrangement?
95. Are you using advanced control techniques to optimize ULSD unit operations? Have you utilized feedback/feed forward controls successfully? What variables have you considered in these advanced control schemes? Are there specific analyzer recommendations for this service?

ULSD

96. What best practices do you employ for the use of diesel fuel additives such as lubricity, conductivity, pour point stability, and cetane improvement?
97. How are you dealing with previously processed diesel streams that don't meet ULSD specifications (e.g. diesel from FCC feed treaters, ARDS, H-Oil or LCFiner units and biodiesel)?
98. What factors affect ULSD hydrotreater end of run (EOR)? Have there been any issues (other than color specification) due to high temperature at EOR? How do LCO percentage, operating pressure, feed gravity, and feed endpoint affect the EOR color?

99. Initially, common carrier pipelines established very strict ULSD sulfur maximums to ensure that the product met end-use specifications. More than a year later, these same pipeline operators are considering relaxing their specifications. What options would you consider to take advantage of these changes?
100. How do you manage or avoid contamination due to the swing between jet fuel (up to 3000 ppm sulfur) and seasonal production of ULSK (ultra-low sulfur kerosene, <15 ppm sulfur)?
101. New North American hydrocracker units have been designed to make ULSD rather than gasoline (typical of older designs). What design, catalyst, and process changes have been implemented to make this product shift and ensure that the more stringent ULSD specifications are met?