DESALTING HEAVY CANADIAN CRUDE

Heavy Canadian crudes pose serious challenges during the process of desalting due to their inherent properties. This article presents an overview of critical desalter design and operating considerations to overcome various operational issues.

Tom Collins, *Forum Energy Technologies*

Tony Barletta, *Process Consulting Services*

Heavy Canadian crudes from Alberta and Saskatchewan are some of the most challenging crudes to desalt because of oil properties, composition and contaminants. The geographic location of the producing basin and to some extent the production method determine the degree of desalting difficulty due to variability in filterable solids, viscosity, "cutterstock" composition, asphaltene content, naphthenic acid content, and other contaminants. Even though many of these crudes are between 18.5-22° API gravity, their desalting characteristics are not the same. For example, heavy Canadian crudes such as Cold Lake or Lloydminster B are easier to desalt than bitumen derived blends from northern Alberta. Heavy Canadian crude production is increasing so more refiners will be exposed to increasing volumes of these crudes.

The purpose of the desalter is to remove contaminants and chlorides from raw crude oil. The reduction of chlorides reduces corrosion and thereby improves reliability and run length. Most refiners target a 4-6 year run length between maintenance turnarounds on their crude units. Crude and vacuum unit (CDU/VDU) run length has been materially reduced when processing large percentages of crudes derived from heavy Canadian bitumen, especially from northern Alberta. Poor desalter performance is one of the major contributors to the shortened run length. This paper will present an overview of critical desalter design and operating considerations for heavy Canadian crude processing focusing on salt removal. These same design and operating requirements apply to other heavy opportunity crudes.

Heavy Canadian Crudes

For many years US refiners have processed heavy conventional crudes or heavy synthetic crudes from Venezuela. BCF 17 is an example of conventional crude, whereas Merey is a blend of light crude and Orinoco bitumen. Examples of Venezuelan synthetic heavy crudes are PetroZuata and Hamaca, which are blends of coker products (sometimes hydrotreated) and Orinoco bitumen. Heavy Canadian crudes are similar to the Venezuelan crudes with respect to desalting difficulty with the added challenge of high filterable solids. Two types of heavy Canadian crudes are encountered. They are:

- Conventional heavy crudes – such as Bow River and Lloydminster B
- Bitumens - diluted with synthetic crudes produced from cokers and resid hydrocrackers or diluted with condensate

Bitumens are produced in Cold Lake, Peace River and Athabasca regions with the majority of future production by SAGD methods. Heavy Canadian crudes contain varying amounts of filterable solids, hard to remove chlorides, amines and H2S scavengers from the production process. The filterable solids are iron oxides, iron sulfides, sand and clay.

By definition, bitumens contain high asphaltene concentrations which present problems when they precipitate from the crude oil either in the desalter or the preheat train. Bitumens mixed with paraffinic condensates and other paraffinic type crudes increase the likelihood of asphaltene precipitation and stable rag layer formation in the desalter.

A significant problem with desalting heavy Canadian crude is the generation of a stable emulsion. Large amounts of solids, H_2S scavengers and tramp amines stabilize the emulsion.

Consequences of Poor Desalting

Desalter performance is generally considered good when desalted crude salt content is less than 1 pound of salt per thousand barrels (PTB) of crude. When large percentages of heavy Canadian crude is processed desalted crude salt content can be chronically high (3-5 PTB) or the desalter can have periodic upsets leading to extremely high salt content for short intervals. In either case, high salt content in desalted crude significantly increases crude unit corrosion. Additionally, some heavy Canadian and other opportunity crudes contain difficult to remove organic and inorganic chlorides requiring special treating chemistry.

A portion of the salt leaving the desalter hydrolyzes to HCl in the atmospheric and vacuum heaters. The amount of hydrolysis depends on the heater temperature, the type of salt, and presence of other compounds such as naphthenic acids contained in the crude. Many refiners inject caustic downstream of the desalter to convert chlorides that hydrolyze to more stable sodium chloride (NaCl) to reduce the HCl level in the crude overhead system. This practice helps reduce chlorides. However, if desalted crude salt content is in the 3-6 PTB range even caustic additionl will not materially improve reliability.

A portion of the thermally stable NaCl remaining in the desalted crude which does not hydrolyze in the atmospheric heater will breakdown to HCl in the vacuum heater. Hence, corrosion rates and fouling in the vacuum column overhead system can be very high relative to conventional crudes. Vacuum column overhead system corrosion and salt laydown in the top of the vacuum column have become much more common with heavy Canadian crude processing. This same problem is also common with heavy Venezuelan and other opportunity crudes.

Poor desalting generally leads to very high corrosion rate in the atmospheric crude and vacuum column overhead systems. It is not uncommon for the top of the columns to experience corrosion and/or salting. Peripheral equipment such as top pumparounds and product rundown systems have experienced fouling and corrosion too. Piping, exchangers, ejector equipment and drums have all been severely corroded with loss of containment occurring in several instances. Rapid amine chloride salt laydown in the top of the atmospheric crude column is relatively common, and increasingly, the internals in the top of vacuum columns are fouling with chloride salts. Atmospheric crude columns with top pumparounds can have very high corrosion rates in the piping, pumps, exchangers and control valves.

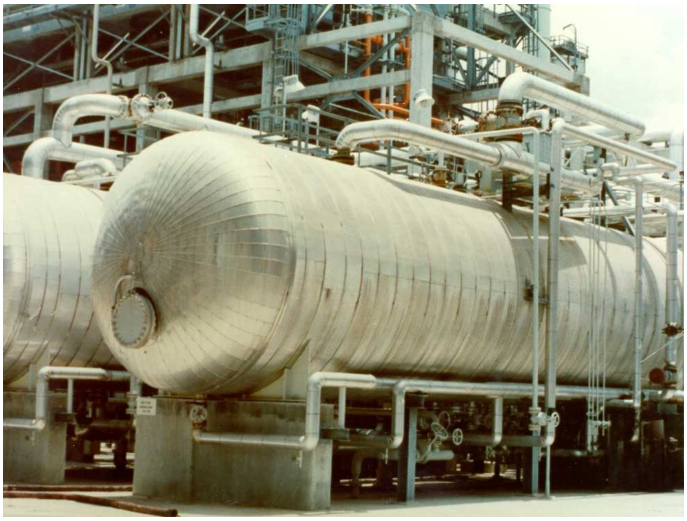
Figure 1 Severe Fouling in Crude Column Top Pumparound

Vacuum column light vacuum gas oil pumparounds (LVGO) and vacuum preflash column top pumparounds have shown high metal loss. These chlorides eventually make their way to downstream hydrotreating equipment where higher corrosion rates have also been observed. Other consequences of poor desalting include severe exchanger fouling from poor filterable solids removal, in conjunction with poor exchanger design.

Desalter Variables

Larger than typical desalters are required to desalt heavy Canadian crude. Most crude units designed for light or even moderately heavy crudes require additional desalter volume to satisfactorily desalt heavy Canadian crude. Some refiners have tried to defer investment in additional desalting by operating the first and second stage desalters in parallel. The trade-off from converting a two-stage desalter to a single stage has been high desalted crude salt content (3-6 PTB), high corrosion rates, and poor reliability. Controlling corrosion with single stage desalting and caustic addition has proven difficult for heavy Canadian crude processing.

Figure 2 Two Stage Desalter System



Because of the difficulties associated with desalting heavy Canadian crude it is equally important to pay special attention to other critical desalter parameters. The overall performance will depend on desalter size as well as attention to these other variables:

- Operating temperature
- Amount and quality of water
- Water and oil mixing
- Mud washing to remove solids
- Brine cooling heat exchanger design
- Chemical treatment
- Desalter design
- Transformer size

Crude preheat trains must have the flexibility to meet the desalter temperature required for optimum performance. The preheat train must have the flexibility to vary desalter temperature irrespective of crude blend changes – this means the ability to shift heat to and from the raw crude exchangers based on the desalter requirements.

Optimum desalter temperature depends on the specific crude or crude blend, and it should be an operating variable, not a consequence of the exchanger network design. Many existing crude units were designed for light or moderately heat crude oils. It is not unusual to have desalter temperatures in the 220-240°F range when these units process heavy crude because the exchanger network has poor flexibility or heat exchanger fouling is high. When the exchangers are clean or the crude is lighter, the desalter temperature may exceed the maximum temperature for the grid insulator bushings causing shorting and damage of some or all of the grid system.

Optimum desalter temperature may be 280-290°F for some heavy crudes. However, with some heavy Canadian crudes the optimum temperature may be as low as 240-260°F to avoid excessive asphaltene precipitation and increases in conductivity that occurs at higher temperatures. When asphaltenes precipitate in the desalter they collect at the oil/water interface and stabilize the emulsion. In some cases rag layer removal headers can be used to remove hard to break emulsions from the desalter.

Some crude units have too many exchanger services and excess surface area in front of the desalters, and others have too little. Unfortunately, CDU/VDU exchanger network designs are increasingly being done by pinch theorists with little understanding of critical operating parameters or challenges associated with heavy Canadian crude processing. The resulting designs do not have the robustness required to deliver optimum desalter temperature required for specific crude blends.

Desalter water rate and make-up water quality must be maintained to properly desalt. With heavy crudes, the total desalter water rate should typically be 7-10 volume % of the crude, and some extreme cases may need as much as 14%. In order to reduce the amount of effluent water, total wash water may consist of a portion of recycle with the make-up water when good quality water is available. For heavy crudes a higher water rate is needed to increase the number of water droplets resulting in better oil and water contact, making the droplets closer together, thus improving coalescing inside the electric field. This will also allow for larger droplets thus reducing settling time.

Desalter water should be of good quality which generally means low hardness, suspended solids and ammonia (pH). Ideally, the desalter make-up water pH should be maintained between 5-7. Because heavy Canadian crudes can have significant amounts of amines and stripped sour water is often used as make-up, water pH can be high making it necessary to inject acid into the make-up water for pH control. High pH water, in conjunction with high naphthenic acid results in formation of soaps, harder to break emulsions and poor desalting.

Proper oil and water mixing is essential. The mix valve must create enough shear to produce a small enough droplet size to allow the water to contact the oil allowing contaminants to be dissolved in the water. The objective is to try and make wash water droplets the same, or similar size as the brine droplets, so that when coalescence occurs the brine will be removed with the make-up water. If the mix valve pressure drop is too low the oil and water will not mix properly. Hence salt, filterable solids and amines removal will be poor. Optimum mix valve pressure drop will vary, and it must be determined through adjustment and desalter performance monitoring.

Filterable solids content vary significantly depending on the specific crude source. It is not uncommon to have filterable solids above 100 PTB and sometimes higher than 300 PTB. These solids tend to stabilize the oil/water emulsion leading to a large rag layer. The desalter size is often a function of the emulsion layer resolution rather than the droplet coalescing. The filterable solids accumulate in the bottom of the desalter must be removed through intermittent or continuous mud washing. If the solids are not removed, they reduce residence time leading to poor brine effluent quality. Mud washing is recommended in both first and second stage desalters.

Make-up water must be heated to the desalter temperature and brine cooled sufficiently to allow further effluent treating. Because the amount of solids removed during mud washing foul conventional heat exchangers, it is not unusual for make-up water rate to be limited by the amount of brine that can be pressured from the system. When the brine/make-up water and brine/CW exchangers foul, they can limit water make-up. Fouling resistant spiral heat exchangers are needed in the brine service.

Good chemical treatment is essential and the types of chemicals used are important. New chemicals are being developed to deal with the challenges of desalting heavy Canadian crude oils such as oil soluble emulsion breakers and wetting agents. A thorough review of the type of chemicals used is required to process these crudes effectively.

Optimum Desalter Design
Each desalter should be specifically designed for the crude type or blend, based on operating conditions and process specifications.

The most important factor in designing for heavy Canadian crude is controlling the interface emulsion. These crudes tend to be "emulsion sensitive" making resolution of the interface very difficult. Stokes Law does not factor this component into sizing calculations, and it can only be derived emperically. Most desalters are sized based on gravity and viscosity, typically making the desalter too small to resolve the interface emulsion at a rate as fast as it is being created. This leads to increased upsets, oily effluent water, increased chemical consumption, and frequent use of interface draw-off, creating additional slop and associated operating costs to treat this material.

Along with vessel sizing, distribution of the oil can also be improved the environment for resolving the interface emulsion. Having the proper distribution, and the ability to control residence time for the interface can have a huge impact to overall performance.

Due to the conductivity of these type crudes, voltage gradient must also be optimum for steady state operation. Lower voltages tend to provide more flexibility than conventional desalter secondary outputs. A range of voltage outputs is selected so optimization for any particular crude can be realized.

Figure 3 Large Power Transformer

Mudwashing, or sediment removal is also critical to good, long term operation and should be closely evaluated for the proper design, use and water treating plant limitations.

Figure 4 Large Accumulation of Sludge

There are several types of interface level control devices avalible and sometimes multiple technologies may be considered. This should be discussed with the desalter designer to ensure a proven technology is utilized for that particular application and location of the interface.

While the proper design emulsifying valve is required, the proper size is also needed. The industry standard for measuring mixing is the delta P across the valve, however, if a valve is too small, it may have a large amount of pressure drop, but is not providing efficient mixing. As an example, if an 8" valve has 10 psi pressure drop and a 12" valve on the same crude has the same 10 psi delta P, they are not providing the same mixing. The 8" valve may be 50% closed while the 12" valve may be 75%. The 12" with the 75% closure will provide a much more efficient and uniform distribution of the water droplets than the 8" with 50% closure. The valve position, along with pressure drop should be monitored to make sure good mixing is occurring.

Conclusions
Desalting heavy Canadian crude is proven to be very challenging. Effective desalting requires large desalters and attention to all variables associated with good desalter performance. Specialty tailored desalter chemicals may be needed to further improve salt removal and/or effluent water quality. In addition to problems they create in the desalter tramp amines and H2S scavengers contained in heavy Canadian crude pose additional reliability concerns in the top of the crude column and its overhead system. It is becoming clear that these sections of the unit must be robustly designed to minimize lay-down of high salt point amine chlorides in order to achieve reliability targets.

About the author
Tom Collins is with Forum Energy Technologies
Tony Barletta is with Process Consulting Services ■