DEA TREATER REVAMP TARGETS FOAMING

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1. INTRODUCTION

A Di-ethanol amine (DEA) Treater processing CCU dry gas experienced infrequent but unpredictable loading events that negatively impacted treating efficiency and capacity. These loading events were characterized by pressure drop excursions attributed to foaming. Rerouting the feed or flaring during these events was undesirable. A full range of options were considered and, during 2008, improvements were implemented targeting upstream knock-out facilities, column internals and amine hygiene, with the intent of improving the reliability and robustness of the treater.

This paper will focus on the equipment improvements that were implemented and compare operation of the tower before and after the revamp. The revamp has been proven to be a success with no significant pressure drop excursions or loading events since start-up. The contributions of Shell site resources and Sulzer Chemtech personnel to this paper are gratefully acknowledged.

2. AMINE TREATERS AND FOAMING

Amine absorbers employ aqueous amine solutions to scrub weak acid gasses like H₂S and CO₂ from process gas streams. The rich amine is regenerated in a stripper or regenerator column and recirculated back to the absorber (hereafter referred to as the ‘treater’). The closed nature of the amine circulation loop can lead to a build-up of solids, salts, amine breakdown products and other surface active species which result in an increased foaming tendency. Amine treaters are normally designed with a severe system or foaming factor in an attempt to provide some robustness towards foaming. Using a foam factor results in bigger tower diameters and larger downcomers. As such, excessive conservatism in selecting a foam factor can add significantly to the cost of a treater and complicate the tray design.

Other measures which can be taken to manage foaming include:

1. Ensure good amine hygiene (monitoring of amine solution strength, visual appearance and sour gas loading; also filtering of solids, capturing of oils and anti-foam with carbon beds)
2. Use of anti-foam
3. Avoid or minimize the presence of liquid hydrocarbons
4. Use of packing rather than trays
5. Intermittent solvent reclaimation (batch) to remove solids/salts
6. Consider the maximum temperature threshold for the solvent
7. Prevent incursions of chemical contaminants borne by the gas inlet

Figure 1 illustrates the impact of amine strength on foaming tendency for clean and dirty amine. The presence of liquid hydrocarbons in a treater, whether through condensation or entrainment, is known to promote foaming and requires careful attention.
Even when all the measures mentioned above are adhered to, foaming excursions can still occur frequently. It is therefore important that the equipment design considers this risk and provides for a flexible and forgiving design with regard to foaming.

An issue with particulate induced foaming was observed in a NGL amine treater located in close proximity to the gas production wells. The treater experienced severe foaming following start-up that limited the gas handling capacity to about 60% of design. The addition of anti-foam did not help. During shutdown and inspection the trays were observed to have various powder and paste-like coatings. Analysis revealed the coating was similar in composition to the drilling mud used by an upstream producer. The inlet separator system was not suitable for removal of fine particulates. After several months of operation the gas wells cleaned up as the drilling mud was expelled and the foaming problem went away. The treater was then able to operate at full design capacity. In this example the foaming problem could not be addressed by the change of any process control variable available to the plant operators.

There are several types of amine solvent problems that are incipient, and might result in occasional process foaming excursions while the plant operates at nearly constant flow conditions.

Some amine treaters suffer foaming that is related to the temperature profile. Heat is liberated when H₂S and CO₂ bond with the amine molecules. It is therefore necessary to have sufficient flow rate of liquid to dissipate the heat of reaction. The temperature profile for the treater reaches a maximum between the top and bottom trays. The gas volumetric flow rate typically peaks at this point because the gas density is a function of the temperature. For some applications, the treater can experience flooding in the middle of the column as a result. There is a threshold peak temperature for operation of treaters that can sometimes be exacerbated by the presence of heat stable salts, metal ions and other contaminants in the amine solvent. This can allow for good operation during a month of steady operation, and poor operation later when operated at the same conditions. It is recommended that the plant conduct periodic laboratory analysis of their lean amine in order to monitor the levels of various contaminants that can accumulate in the solvent.
In the case of plants fed from natural gas pipe lines, there can be instantaneous process related problems with chemical contaminants from the pipeline. These can include the following:

1. Methanol and glycols used to inhibit gas hydrates.
2. Caustic or glycol from an upset of an upstream facility.
3. Carbon particulates from a carbon filter.
4. Silica sand or rust particles from the pipeline.
5. Greases or oils from upstream compressors.
6. Anti-corrosion chemical agents utilized in the pipeline.

Pipelines can carry slugs of these contaminants into the amine sweetening plant with little or no advanced warning. Some slugs can overwhelm the capability of the inlet separator causing foaming in the treater and even the regenerator. Minor pipeline excursions could take between a half-hour to two-hours for the plant to re-establish good operation as the contaminants are removed by the filtering system. There are some major excursions at some facilities that could be severe enough to shutdown the facility.

In the investigation of various amine or chemical contaminants that cause foaming, it is necessary to monitor the pressure drop of both the upstream inlet separator and the downstream treater. The review of separator pressure drop can sometimes provide advanced warning to the build up of contaminants in the feed gas that precede foam related contamination in the treater. Sometimes, it is necessary to upgrade the inlet separator with higher performance separator internals in order to provide better protection against specific contaminants known to cause foaming.
4. CASE STUDY: DEA TREATER

Figure 2 provides a simplified flow diagram showing the location of the treater, downstream of a gas plant sponge absorber and upstream of a caustic treater.

The Treater is a 96” diameter trayed tower with originally 29 valve trays, operating at about 150 psig.

The loading events were characterized by differential pressure excursions across the trayed section of the DEA Treater. An example of a severe loading event is illustrated in figure 3 below. Figure 4 illustrates the impact of such an event on throughput and treating efficiency. The loading events were managed by temporarily rerouting feed gas to fuel gas or flare until the differential pressure returned to normal levels. These response mechanisms were not sustainable in the medium to long run.

It proved very difficult to correlate these events to operating and/or physical parameters. As a result it was virtually impossible to predict the onset of these events until they happened. A multi-disciplinary root cause analysis (RCA) team was therefore chartered to investigate and make recommendations to address the issue.

Figure 2: Process Flow Diagram
Figure 3: Example of loading event

Figure 4: Impact of loading event on throughput and treating efficiency
5. ROOT CAUSE ANALYSIS

The RCA team performed extensive data collection and analysis of historical plant data. In the end no single root cause was found, rather a number of contributing factors were identified. The following recommendations were made to address these factors:

1. Minimize the entrainment of liquid hydrocarbons into the treater.
2. Minimize the condensation of liquid hydrocarbons in the treater.
3. Eliminate the intermittent introduction of vents and drains from other process units to the treater feed gas.
4. Improve the tray design to make it more robust with respect to foaming.
5. Closely monitor and control amine hygiene.

6. EQUIPMENT MODIFICATIONS

The rest of this paper will focus on the equipment changes that were implemented to address items 1-4 above. An overview of the modified process flow scheme is provided in figure 5 with changes shown in blue. These will be covered in more detail in the following sections.

![Diagram](image-url)

*Figure 5: Overview of equipment modifications*
6.1 Feed line and KO Pot

In order to decrease entrainment to the Treater and improve the knock-out of condensed hydrocarbons in the feed, the KO vessel was increased in size, provided with an improved mist eliminator pad and a vane inlet device (Schoepentoeter†).

A Schoepentoeter is a robust two-phase feed distributor that effectively disengages vapor from liquid with an almost negligible pressure drop (figure 6). Piping upstream of the inlet nozzle was improved to eliminate bends located close to the inlet. The clearance above and below the feed nozzle was increased as well compared to the old design. Vents and drains were rerouted to the old knock-out drum as shown in figure 5.

<table>
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<th>Old</th>
<th>New</th>
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<td>Inlet device</td>
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<tr>
<td>Load factor, ft/s</td>
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<td>Mist eliminator load factor, ft/s</td>
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<tr>
<td>Mist eliminator thickness, in</td>
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*Table 1: Comparison of old and new KO Pot*

*Figure 6: CFD visualization of feed distribution using a Schoepentoeter.*

6.2 New HiFi Trays

The existing 29 1-pass conventional trays were replaced with 27 Shell HiFi† trays. A HiFi tray is a high capacity multi-downcomer tray with truncated downcomers that maximizes bubbling area and weir length. A mock-up assembly of one half of the tray layout is shown in figure 7.

† Shell Group Trademark
“Vapor crossflow channeling” (VCC) is the name given to a hydraulic condition that results in vapor preferentially passing through the outlet region of the active area whilst liquid weeping takes place near the inlet. Kister [1] and Resetarits [2] suggested that the following factors may contribute to poor hydraulic performance, excessive weeping and premature flooding:

1. Contoured or venturi-type valves,
2. High open area (low dry tray pressure drop),
3. Long flow path lengths (FPL/TS > 2-2.5),
4. High weir loadings (>5.6-6.6 gpm/in), and
5. Inlet inactivity caused by unaerated liquid exiting downcomers.

The old tray design satisfied criteria 3-5. HiFi trays are well suited to eliminate concerns with respect to VCC since they allow for shorter flow path lengths, longer weir length and thus reduced weir loading. By perforating under the downcomer outlet slots, inlet area inactivity can be eliminated as well.

The differences between the new and old trays are summarized in table 2 below.
Table 2: Comparison of old to new tray design

Other improvements included a liquid collector tray beneath the bottom mass transfer tray. The purpose of the liquid collector tray was to reduce the risk of foaming by collecting the liquid from the bottom tray downcomers and directing it via downpipes to the sump liquid below without interaction with the feed vapor and to minimize splashing.

In order to further increase the robustness to foaming, the 2nd and 4th trays from the bottom were removed, to allow for increased tray spacing (from 24 to 48”). The additional spacing would make it more difficult for foam to propagate up the tower.

Since the old column shell had to be replaced, the column internals were installed into the new shell at the fabricator’s workshop and the fully dressed column was lifted into place during the turn-around. Careful inspection revealed that the installed trays were not affected by the column transport and erection.

6.3 Other internals

In addition to the 27 new HiFi trays, the vapor feed arrangement was optimized by replacing the previous inclined baffle with a perforated pipe feed sparger to help diffuse the inlet momentum and avoid aeration of the sump liquid. See figure 8.
A baffle was also provided in the sump to allow for intermittent skimming of liquid phase hydrocarbons, if required.

7. PERFORMANCE AFTER REVAMP

The Treater has performed very well in the four months after the revamp with no significant pressure drop excursions in spite of swings in feed rate, temperature and composition and lean amine temperature. Treating efficiency has been excellent even with 2 fewer trays installed and a lean amine feed rate 20% lower than design. The H₂S content of the treated gas is so low that it is essentially determined by the stripping efficiency of the amine regenerator. By maintaining an appropriate steam-to-feed ratio on the amine regenerator, the treated gas H₂S content can be maintained well below the specification. Hydrocarbon skimming has not been required. Figure 9 compares the differential pressure response over a similar time period before and after revamp.
It is interesting to note that after the revamp the column differential pressure response to changes in the lean amine feed temperature is now as expected. A slow but small increase in pressure drop is reversed by an increase in the lean amine inlet temperature, consistent with the evaporation of liquid hydrocarbons that promote foaming. Such an event is reproduced in figure 10.

8. CONCLUSIONS

A revamp of a DEA Treater to reduce its sensitivity to foaming has been successfully executed. A variety of factors contributing to the problem were addressed including operational measures and equipment modifications. These included minimizing the amount of entrained hydrocarbon liquid introduced to the tower, providing an improved tray design and minimizing shear and turbulence in the column sump. Since start-up there has been no significant pressure drop excursions. H₂S removal efficiency is limited by residual H₂S in the lean amine rather than tray count or lean amine rate.
Figure 10: Effect of lean amine feed temperature increase on pressure drop

REFERENCES


The companies in which Royal Dutch Shell plc directly and indirectly owns investments are separate entities. In this publication the expressions “Shell”, “Group” or “Shell Group” are sometimes used for convenience where references are made to Group companies in general. Likewise, the words “we”, “us” and “our” are also used to refer to Group companies in general or those who work for them. These expressions are also used where there is no purpose in identifying specific companies.