TROUBLESHOOTING MONO ETHYLENE GLYCOL CARRYOVER IN A CANADIAN GAS PLANT[1]

"There is nothing more deceptive than an obvious fact"

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ABSTRACT

The facility in this paper is a gas plant which started operation in 2013 and in the Fort St. John area of British Columbia, Canada. It has a total name plate capacity of 200 MMSCFD sweet natural gas. Liquid carryover of water/MEG/hydrocarbons from the low temperature separator prevented the plant from reaching pipeline water content, hydrocarbon dew point (HCDP) specifications. Initial attempts by the plant's operations team focused on reduction of contaminant ingress to the refrigeration trains. Despite the improved results, the liquid

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carryover continued to occur, resulting in off-spec sales gas. Further troubleshooting efforts took a holistic approach and applied multi discipline involvement, equipment sizing, process simulation, along with stream sampling and analysis allowing the team to uncover a list of equipment design flaws. This paper stresses the importance of proper design data hand over from Projects to Operations, understanding the operating envelope of plant equipment, accessibility to plant historian for remote troubleshooting/monitoring, proper MOC (Management of Change) implementation, documentation, and the need for operations/engineering teams training to identify early signs of deviation from optimal process parameters.

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INTRODUCTION

The facility described in this paper is a 200 MMSCFD sweet natural gas processing plant located in the Montney formation in the Fort St. John area of British Columbia, Canada. About a year after start-up in 2013, the plant began experiencing liquid carryover in the header to the 3rd (sales) stage of compression. This carryover prevented the plant from reaching pipeline water content specifications, required additional operator intervention and created safety concerns and contractual issues with the pipeline company. The carryover also caused problems in the refrigeration section and increased mono ethylene glycol (MEG) losses in the regeneration unit.

PROCESS DESCRIPTION

The facility produces a dehydrated sales gas stream and a stabilized condensate product; it consists of two identical trains with shared inlet/sales reciprocating compressors, overheads systems, and a flare. Train 1 and 2 inlet separators operate at 1,200 kPag (175 psig). Hydrocarbon liquid from the inlet separators is stabilized and sent to atmospheric storage tanks. Produced water from the inlet separators is sent to storage tanks fitted with a hydrocarbon skimmer that returns any condensate to the inlet separators. The condensate is eventually trucked out to sales. The inlet gas is compressed to 6,275 kPag (910 psig) by the first two stages of three parallel 3-stage compressors. After this second stage, the sweet gas streams from the inlet compressors are combined and then sent through two parallel refrigerated hydrocarbon dew point units (HCDPs), which use propane as the chilling medium with mono ethylene glycol (MEG) injection for hydrate prevention. A PFD (Process Flow Diagram) of the identical refrigeration units can be seen below in
Figure 1. MEG is injected at the inlets of the gas-to-gas exchangers and the propane chiller.

The cooled gas-liquid mixture from the chiller is then sent to a three-phase low temperature separator (LTS), operating at -17 ºC (15.4 ºF), which separates the gas, the unstabilized condensate, and the water/MEG mixture for further processing. Condensate from the LTS is processed in a fractionation column and sent to a storage tank. Overheads from the fractionation column are compressed in a single stage compressor and re-circulated to the common suction header of the inlet compressors. The dew pointed sales gas stream is split and sent to the fuel gas header and the 3rd compression stage suction header where the stream is further compressed to 8,000 kPag (1,160 psig) before entering the sales coalescer. Dew point measurement then takes place by Chilled Mirror testing and online analyzers. The sales gas is then sent through a pipeline to the delivery point to the TransCanada Pipeline (TCPL) system.

Sales gas specifications call for a HCDP = -10 ºC (14 ºF) at operating pressure and < 4lb water/MMSCF at > 8,275 kPa (1,200 psia) (TransCanada, 2018).

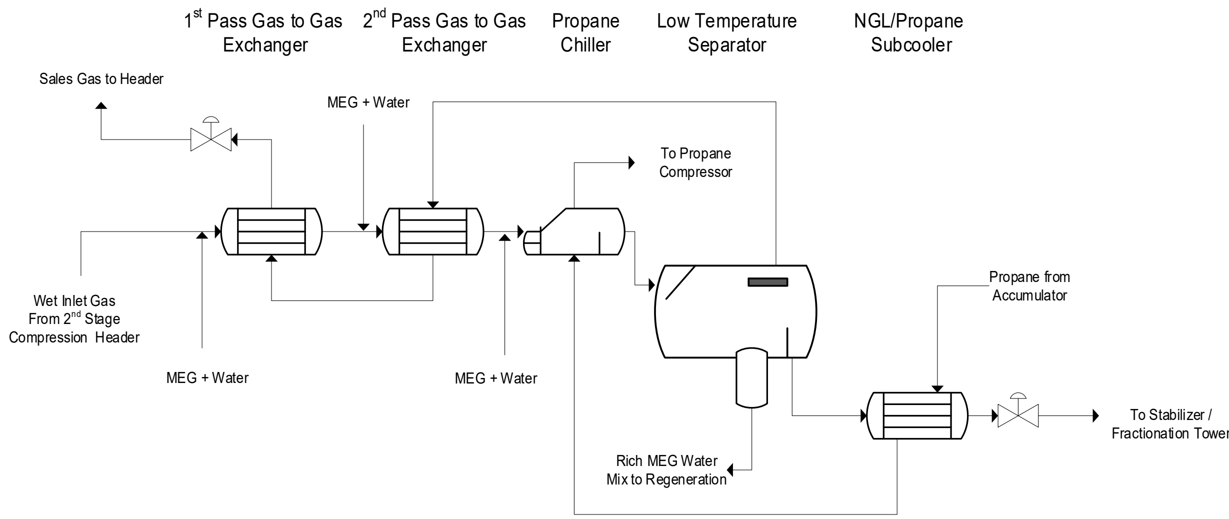


Figure 1 - Hydrocarbon Dew point Unit PFD

A PFD of the identical regeneration units can be seen in Figure 2. Rich MEG/water from the LTS is sent to the regeneration unit where the water-rich glycol mixture is first preheated in the stripping column coil. This coil serves a dual purpose, as it also generates reflux for the top of the column by condensing some of the water/glycol vapours before they exit the column. In order to reduce MEG losses in the overheads, typical overheads temperature is 95 ºC (203 ºF). The pre-heated rich glycol temperature is further increased in the rich/lean (R/L) heat exchanger (plate and frame design) used to reduce reboiler duty. Warm rich glycol is then sent to the flash tank operating at 560 kPag (81 psig) where any light hydrocarbon carry-under from the LTS flashes and is sent to the booster compressor feeding the front end of the plant. Heavy hydrocarbons are manually skimmed in the flash tank.

The rich glycol goes through particle filtration and carbon cannisters to ensure no significant amount of contaminants are sent to the stripping column. The rich glycol is fed to the middle of the two random packing sections where vapours generated in the reboiler can strip the water off the rich glycol to meet the desired lean MEG/Water concentration of 80/20wt%. Lean glycol from the regenerator is then routed to the L/R exchanger to be cooled and then stored in the surge tank, after which plunger pumps raise its pressure to inject the glycol solution into the gas-to-gas exchanger and chiller via injection nozzles. These nozzles are located at the inlet of the exchangers, the lean glycol co-currently distributes into the inlet gas then into the gas-to-gas and chiller tube sheets.

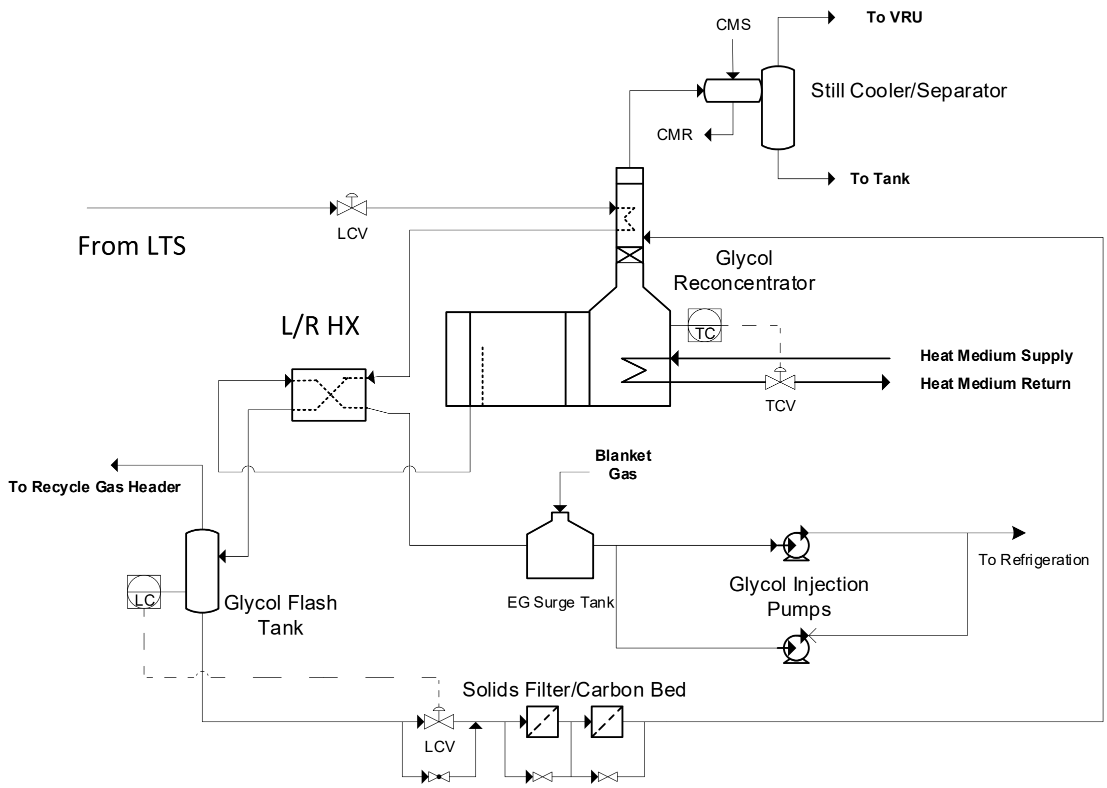


Figure 2 - Regeneration Unit PFD

COMPRESSOR OIL ISSUES

After the plant was commissioned in the fall of 2013, the MEG refrigeration processes began experiencing operational issues at 60% of the design throughput capacity. Initially, lube oil carry-over from second stage compression caused fouling of the tubes in the gas-to-gas exchangers and chillers. This was caused by a compressor oil which was heavier than specified in the original design. The lube oil was injected in the first and second stages of the reciprocating compressors and carried into the refrigeration train. Since the lube oil was heavier than glycol, it accumulated in the glycol closed loop system. The lack of process coalescers after second stage compression meant no barrier existed against contaminant ingress into the refrigeration trains. Operations addressed this in the summer of 2015 by installing process coalescers upstream of the refrigeration trains and changing out the lube oil. This resolved the lube oil carryover/fouling in the refrigeration units .

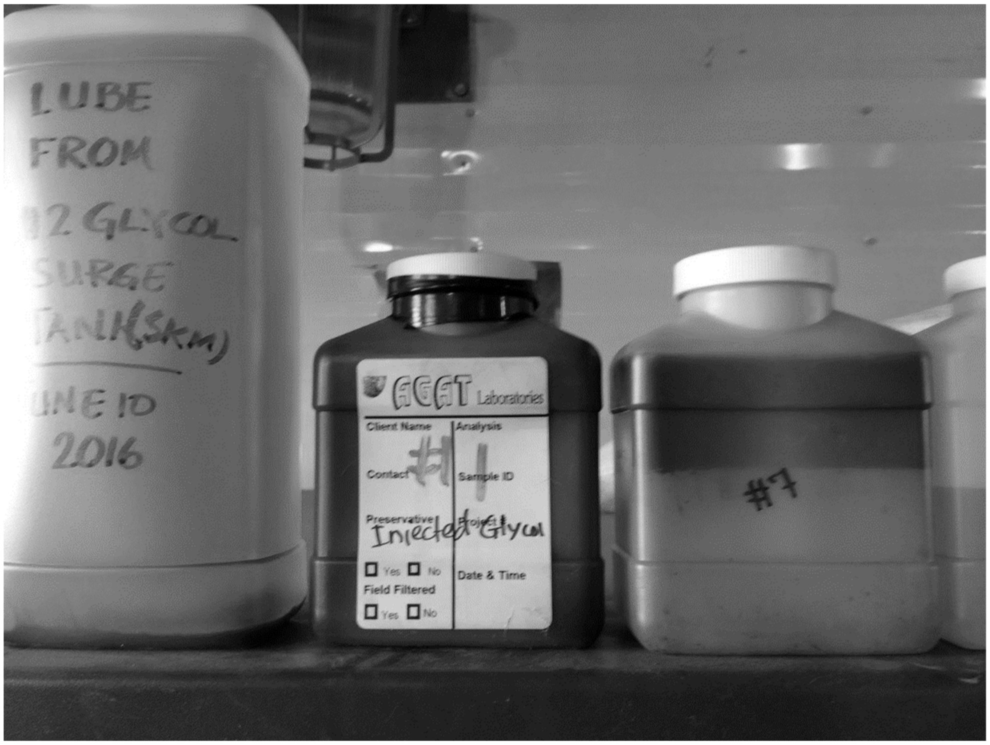


Figure 3 - MEG samples prior to process coalescer installation. Lube oil sample (left), Injected Glycol (centre), skimmed Glycol from flash tank (Right). Prior to June 2015

MEG CARRYOVER ISSUES –INITIAL MODIFICATIONS

After the coalescers were installed, liquid carry over made out of mostly MEG/water through the refrigeration trains was noticed, especially when the flowrate exceeded 60% of the design capacity per train. As a result a root cause analysis (RCA) was requested by the leadership team. The RCA was completed in the winter of 2015 with the participation of the Process Engineering team based in Calgary. The findings of this RCA showed that the internals of the LTS were undersized, and modifications to the inlet device and demisting pad were recommended to prevent excessive liquid carryover. The original LTS operating envelope can be seen in Figure 4. The original design had a diverting plate as inlet device and a standard horizontal mesh pad at the outlet. This was changed to 4 inlet cyclonic devices and a combination of vertical mesh pad/vane pack arrangement. In addition, process simulations showed that the glycol injection rates to the refrigeration exchangers were below the required theoretical minimum, and an increase was recommended. Evidence of the liquid carryover was first spotted due to substantial glycol losses and liquids present in the gas header downstream of the refrigeration trains.

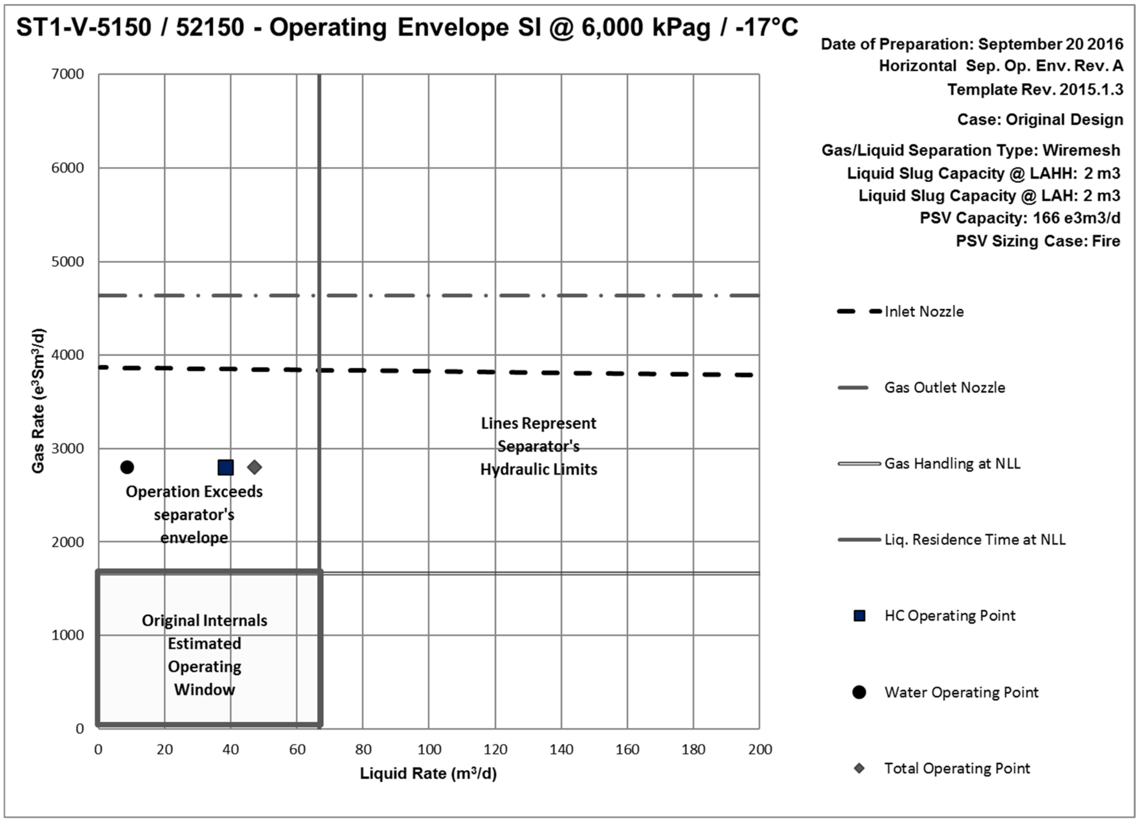


Figure 4 - Simplified LTS Operating Envelope prior to retrofit illustrating different mechanical constraints prior to Q2 2016. Operation exceeds maximum capacity of the separator internals

Hydrocarbon dewpoint measurements (HCDP) at this plant are tested using a Chilled Mirror Test. This test consists of a high-pressure chamber through which the gas to be tested flows. A polished mirror is at one end of the chamber and a viewing window at the other. The operator throttles an expandable gas (propane or carbon dioxide) through a valve cooling the polished mirror until the dew point is observed (liquid droplets on the surface of the mirror). A mercury glass thermometer inserted inside the mirror tube provides an indication of the temperature of the chilled mirror. The dewpoint temperature observed can be translated to a given water content at the operating pressure, e.g. McKetta & Wehe's Water Content Chart (GPSA, 2012).

Chilled Mirror tests, or Chandler tests, resulted in a "stain" appearing at temperatures as high as 10 ºC (50 ºF). This "stain" caused the HCDP test to be considered a failure by the pipeline company. Research has demonstrated that the Chilled Mirror test can be skewed by even trace amounts of MEG (Mono Ethylene Glycol) present in the gas stream (Lokken, 2013) (Lokken, 2012).

To mitigate the liquid stain and monitor effects of process changes, Operations would routinely drain the gas header and perform Chilled Mirror tests every two-hours. It goes without saying these activities put additional load and exposure on operators, increased operating expenditures, and increased the risk for equipment failure (e.g. potential for liquid ingress to compressors, liquid hammer within gas headers, etc.).

Following the recommendations of the Process Team and the EPC contractor outlined in the RCA, the internals of the LTS in both trains were upgraded to a cyclonic inlet separation device and larger vertical mesh pad and vane pack combination, replacing the horizontal mesh pad, during a pit stop in the summer of 2016. After these changes, liquid carryover and first stain did not improve, as Operations continued to see liquid in the gas header and sales coalescer, as well as stains during Chilled Mirror testing between 0 ºC to 5 ºC (32 ºF to 41 ºF).

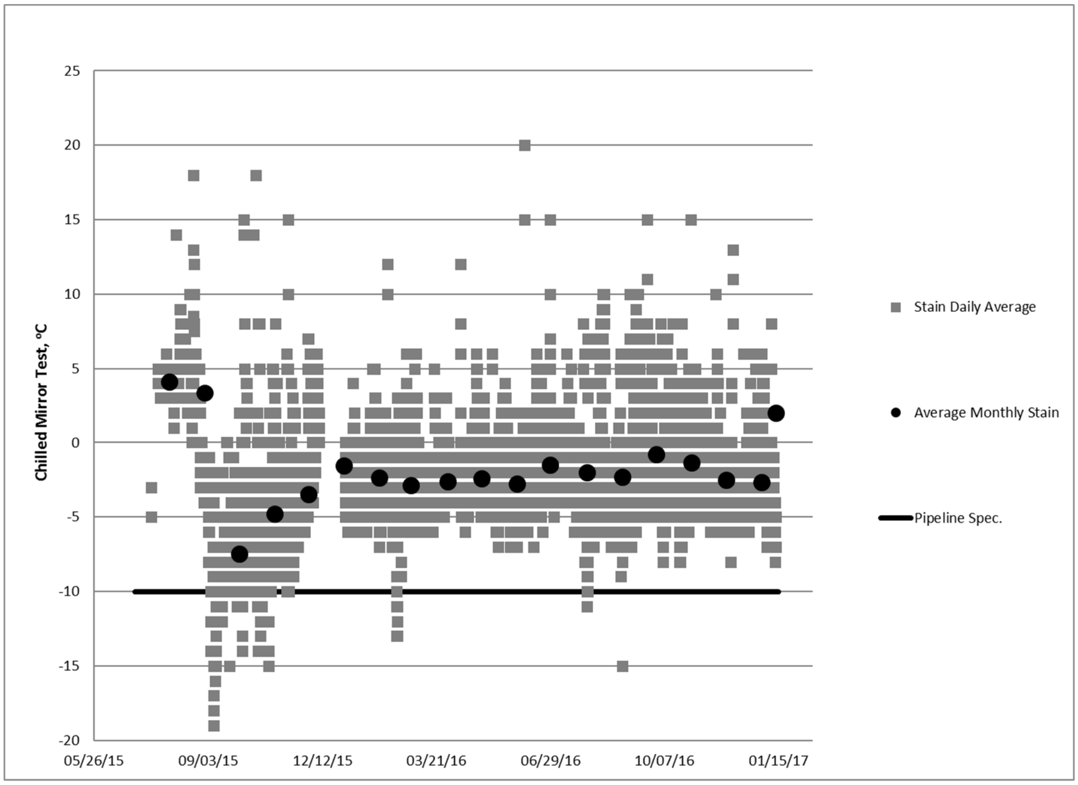


Figure 5 - Chilled Mirror Daily and Monthly Average Results vs. Pipeline Specification from 2013 to Q2 2017

Further investigation by the Process team found that additional operating changes were completed prior to the summer of 2016 with the aim to reduce liquid carryover. MEG injection to the gas-to-gas exchangers was reduced and MEG injection to the chiller was eliminated. These changes led to hydrate formation in the units. In addition, a Management of Change (MOC) completed by Operations reduced the size of the random packing in the glycol regeneration column with the goal of increased capacity and efficiency; however, no hydraulic or process calculations were completed to support this change and its potential consequences. Remote monitoring and troubleshooting of the plant by support teams was also difficult due to the lack of access to the plant historian data outside the facility.

Figure 6 - Chilled Mirror test "stain" as observed at sales point from 2013 to Q2 2017

PROCESS TROUBLESHOOTING AND DATA COLLECTION

After the LTS modifications and the continuation of liquid carryover, it became clear there were additional challenges that needed to be addressed. In the past, multiple operational changes were done simultaneously, making the identification of what worked and what did not more difficult. Process simulation and calculations showed that hydrate formation was in part caused by the lower MEG injection rates for 80/20wt% MEG/Water mixture predicted by simulation tools. The plant had the lean glycol water content oscillated between 12 to 30wt% (optimum range is between 20 to 30wt%). In addition the rich water content was between 20 to 35wt% (optimum range is between 35 to 45wt%) (Mercier, Ruiz, Lechelt, & Chu, 2015) an indication of poor retention time/contact in the LTS and spray nozzles. To prove that hydrates were present, a methanol injection test was performed. During the test, gas loads to each train were switched due to field upsets resulting in swings in pressure. However, the results did show a drop in differential pressure that proved that hydrates were present in Train 2. The results of this test can be seen below. Based on this test, it was recommended to increase glycol injection rates to mitigate hydrate formation. Unfortunately, the increase in glycol injection rates led to increased losses and the injection rates were lowered by Operations once again:

Methanol test data results

1. T2 Initial DP @ 2,350 e^3Sm^3/d (83 MMSCFD)
    a. G/G HX = 147 kPad (21 psid)
    b. Chiller = 88 kPad (13 psid)
    c. LTS = 1.4 kPad (0.2 psid)
2. T2 After Test DP @ 2,400 e^3Sm^3/d (85 MMSCFD)
    a. G/G HX = 74 kPad (11 psid)
    b. Chiller = 53 kPad (8 psid)
    c. LTS = 1.4 kPad (0.2 psid)

3. T1 Initial DP @ 2,500 e^3Sm^3/d (88 MMSCFD)
    a. G/G HX = 85 kPad (12 psid)
    b. Chiller = 109 kPad (16 psid)
    c. LTS = 2.4 to 2.8 kPad (0.3 to 0.4 psid)
4. T1 After Test DP @ 2,350 e^3Sm^3/d (83 MMSCFD)
    a. G/G HX = 81 kPad (12 psid)
    b. Chiller = 91 kPad (13 psid)
    c. LTS = 2.4 to 2.8 kPad (0.3 to 0.4 psid)

INJECTION NOZZLES

During investigation, the EPC contractor observed that the injection nozzles were too far from the tube sheets, leading to maldistribution of the injected lean glycol and therefore hydrate formation. The original design had called for retractable nozzles for ease of maintenance an arrangement that was not implemented during the project execution. The original nozzles were solid cone style, these nozzles tend to create medium to large droplets that tend to fall before reaching the upper tubes, which given the excessive distance of the nozzles exacerbated the issues with proper tube sheet coverage. It was recommended to installed impingement style nozzles that generate a fog with smaller droplets (BETE, 2016). Process calculations confirmed the EPC's observation, it was the EPC's opinion that an emulsion was being formed by vigorous mixing in the exchanger tubes which carried through the separator and explained the glycol losses. This mixing was a result of a reduction in available cross-sectional area caused by hydrate formation. It was suggested retrofitting the nozzles would lead to a significant reduction or even elimination of the liquid carryover to the sales line executed during a pit stop in Q4 2016.

MEG FOAMING

During prior testing by Shell Process Engineering and Operations, it was observed that rich glycol samples from the flash tanks were very foamy, but no significant evidence of heavier hydrocarbon residue consistent with the emulsion theory was observed. To further test the emulsion theory, an MOC was completed by site engineering to install an injection pump to dose the system with de-emulsifier as specified by the chemical vendor prior to the installation of new injection nozzles. Rich glycol samples were bottle tested with the demulsifier and after 72 hours no evidence of an emulsion was present. The de-emulsifier injection proved to make an insignificant change to liquid carryover and glycol losses.

The Process Team also conducted a survey of key process indicators for the regeneration system on both trains and discovered that the rich glycol temperature from the R/L exchanger was only 30 ºC (86 ºF) – far below the typical range of 60 to 80 ºC (140 to 176 ºF) (Chu, 2015). The R/L exchanger was a compact plate and frame unit with 1 millimetre spacing between plates. This exchanger was prone to fouling and leaking after cleaning, as it was discovered during the survey this unit had been replaced four times in the past. The rich glycol low temperature at the outlet of the R/L exchanger explained the foaming experienced in the flash tank samples due to hydrocarbons coming out of solution at atmospheric pressure. In addition, more hydrocarbons to the regeneration system led to an increase in the vapour traffic of the still column affecting its performance and exacerbating flooding conditions and likelihood for packing fouling.

WATER BOOT ISSUE

This hydrocarbon carry-under from the LTS was exacerbated in the Train 1 regeneration unit because the LTS' water boot heating coil, in place to aid in the MEG/water and NGL separation, was shut in as a result of a leak. Another consequence of higher hydrocarbon content in the rich glycol was accelerated spending of the activated carbon beds so quickly that they were bypassed and the amount of flashed gas in the particle filters lead to sub-utilization of these filters due to vapour lock. As a result, the Process Team recommended to clean/replace the R/L exchangers with a different design or add filtration prior to the exchangers and fix the LTS heating coil in Train 1.

The data collected to this point helped to conclude that there were two main issues:

a. Liquid carryover affecting the sales gas quality
b. Loss of glycol via the sales gas and the regeneration train, with the latter not affecting the sales gas quality

To collect additional data to pinpoint the root cause of the carryover, Chilled Mirror readings using a portable unit owned by AGAT a testing contractor were taken in three locations: downstream of the vertical mesh pad/vane pack assembly; downstream of the gas-to-gas exchangers; and at the inlet and outlet of the sales coalescer. These readings were done both before and after the glycol injection nozzle retrofit in Q4 2016. Additionally, key plant historian tags were made available for remote monitoring and troubleshooting. The results indicated that the nozzles were not the main cause of the liquid carryover into the sales gas, even though the nozzles did help in ensuring proper glycol/water coverage of the tube sheets and a reduction in the measured pressure drop in the trains due to hydrates. During the injection nozzles change out in Q4 2016, the Process Team requested to have a visual inspection of both the gas-to-gas exchangers and the mesh pad/vane pack assembly for evidence of damage. However, only the LTS internals were partially inspected due to time constraints, confirming that no damage of the internals had taken place.

MEG TEMPERATURES

Another important factor for optimal glycol injection is lean glycol injection temperature. This temperature is important because it affects the viscosity of the mixture and its ability to flow and evenly distribute through the nozzle orifice affecting tube sheet coverage. As part of the troubleshooting, it was identified that the plant's MEG glycol surge tank and associated piping was not insulated. Uninsulated piping is not a problem during the summer, but with temperatures as low as -50 ºC (-58 ºF) during the winter months, it could lead to injection temperatures below the minimum recommended by internal guidelines of 30 ºC (86 ºF), as discovered during a temperature survey of the system. The recommendation was to insulate and heat trace associated piping and surge tank. In addition to the low glycol injection rates, the flow meters used by operations to determine how much MEG was being injected to each heat exchanger were affected by the pulsations coming from the duplex pumps upstream and the meter needles were "jumpy" and impossible to determine the actual flow with some accuracy. Recommendations for the installation of triplex pumps, and the addition of surge dampeners were issued for both trains.

MEG STILL COLUMN

After the nozzle replacements, there was confidence that the glycol injection rates could be ramped up to recommended values; however, a dramatic increase in the still packed column pressure showed that flooding was taking place. Glycol samples from the bottom of the still overheads condenser/separator showed that it had a MEG concentration as high as 58 wt.% - in normal operation it should be mostly water. Hydraulic calculations confirmed that the column was grossly undersized for the service after the MOC implementation for random pall ring packing changeout from the original 1” to 5/8”. In a survey of other regeneration units from other plants and standard vendor skids showed that the existing 8” columns for a 100MMSCFD train were too small. Typical vendor designs called for 12” to 14” columns for a similar train capacity. To address this problem, the glycol feed line to the middle of the columns were partially re-routed directly to the reboiler. This modification helped to reduce glycol losses, eliminated the flooding condition in the column, and still achieved the desired lean glycol concentration. The difference in still column pressure before and after this modification can be seen below in Figure 7. Despite the above modifications, liquid carryover to the sales gas continued.

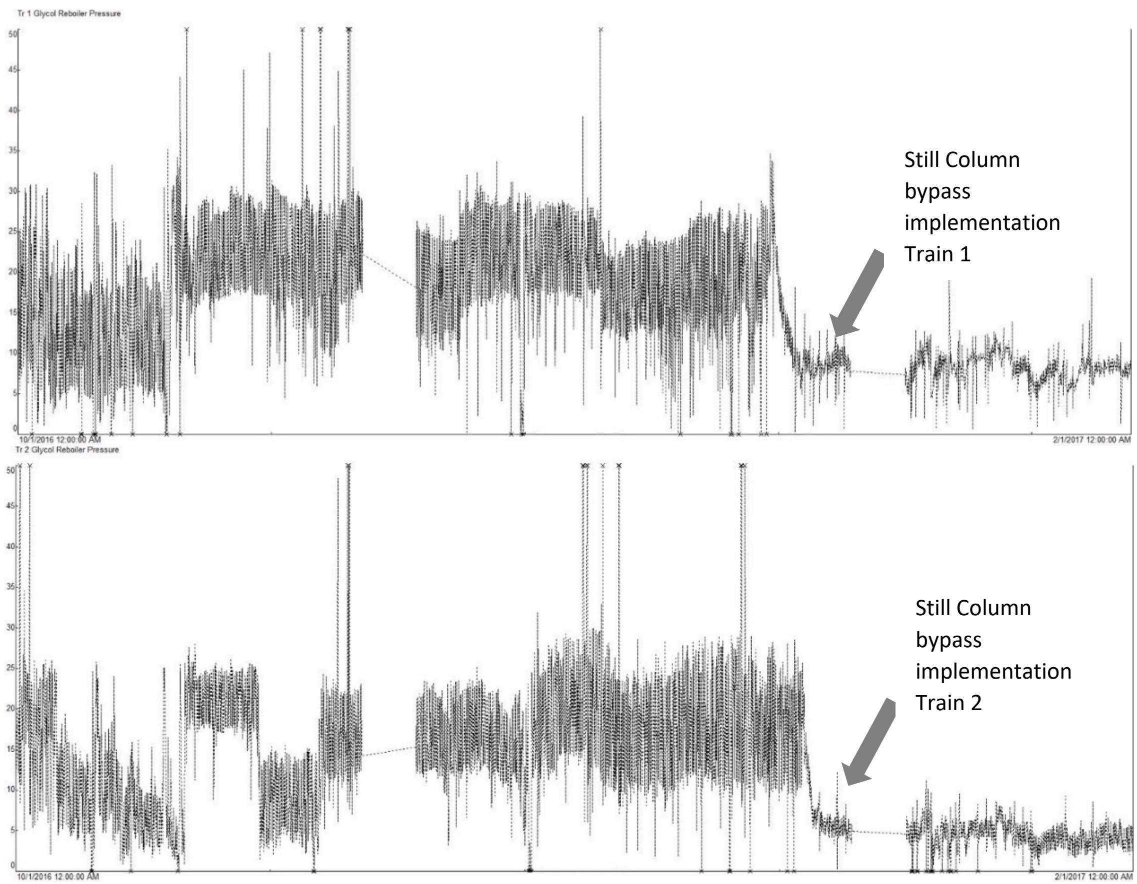


Figure 7 - Glycol regeneration still column pressure (Train 1 above, Train 2 Below) before and after bypass installation in Q4 2016

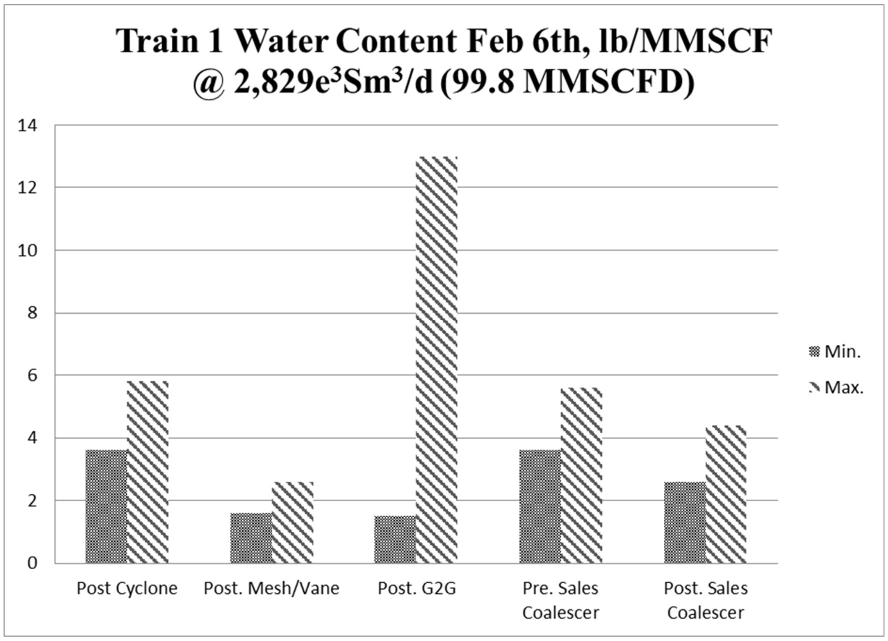
ONLINE ANALYZERS

As part of the plant's monitoring routine, water content and hydrocarbon dew points were being tracked with an online monitor. Water content was reported at less than 1 lb water/MMSCF on average; however, given the amount of liquids in the sales header and the continuous dump from the sales coalescer, the analyzer accuracy was called into question. A second analyzer was dedicated to measure HCDP and this reading was within the expected values for the LTS operating temperature. Similarly, there were concerns that hydrocarbons were also leaving with the sales gas, as was the case with the glycol/water mix, and that the analyzer was not measuring HCDP properly. Since there was glycol/water carryover into the sales gas and glycol/water have higher mass density than the hydrocarbons in the LTS, it was logical to expect a significant amount of hydrocarbons also being entrained and affecting the HCDP specification. The appearance of the "stain" during the Chilled Mirror test affected both the HCDP and water content measurement. Recommendations for analyser inspection and calibration were issued by the Process Team.

NEW INVESTIGATION APPROACH

The process modifications discussed above were aimed to bring the plant back to a typical mode of operation (e.g. MEG/water injection rates to acceptable levels, no hydrates, no flooding on the regeneration column and proper LTS internals to minimize liquid carryover at design gas rates). As the carryover in the sales gas continued, the team had to find a different way to understand the cause and its effect on the target specifications, given that the plant analyzers could not be relied upon based on the evidence collected up to this point. Moreover, there was an urge to fix these issues to be able to continue selling gas to the sales pipeline and identify the plant modifications required to be included in the turnaround scheduled for the summer of 2017.

A different approach was then selected using Dehydration Experts for the sampling and analysis work to ensure the root cause was determined in Q1 2017 by collecting detailed data including gas/liquid samples, perform GC analysis on site, and to additionally take water content readings. The samples point included upstream/downstream (U/D) of the process coalescers before the refrigeration trains, U/D of the LTS mesh pad/vane pack assemblies, downstream of the gas-to-gas exchangers, and U/D of the sales coalescer, using a hand held device to pinpoint the source of the carryover. In the interim and to minimize liquids in the TCPL separator located approximately 1 km (0.6 mi) away at the sales receipt point, the plant decided to install an additional separator upstream of the TCPL vessel to collect as much liquids as possible while troubleshooting continued at the plant. The water content readings collected using the hand-held moisture analyzers showed that the internals were effectively removing liquids from the gas phase as expected, and that it was after the gas-to-gas exchangers where liquid content in the sales gas increased. The results of this testing can be seen below in Figure 8. This information confirmed an early suspicion of potential exchanger tube damage due to hydrates caused by low glycol injection rates and nozzle maldistribution; despite the evidence, there were doubts on whether to include inspection of the exchangers during the turnaround.



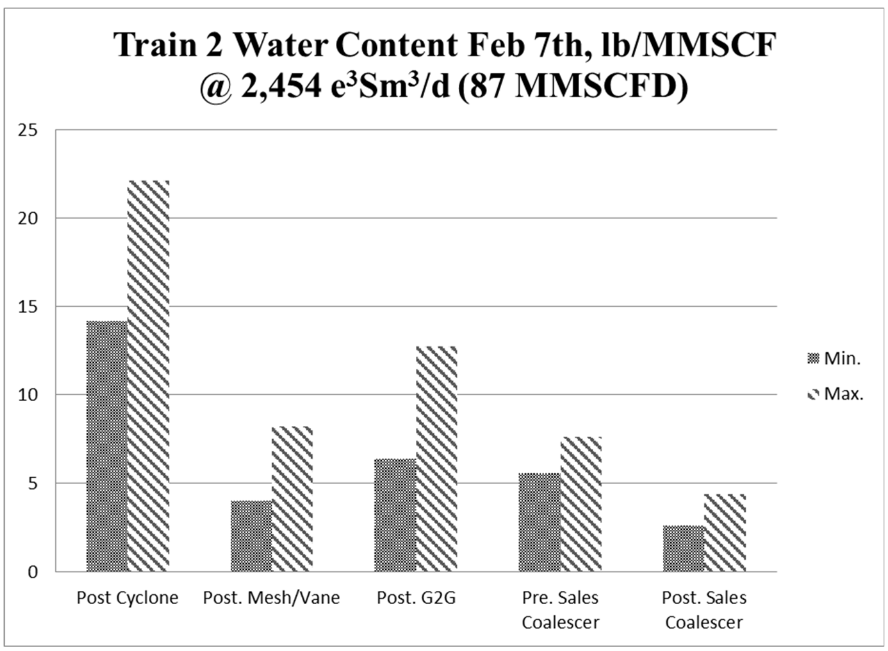


Figure 8 - Water Content Results Pre-Turnaround for both Trains in Q1 2017

The water content values at sample points downstream of the Mesh/Vane pack further backed up the theory that there were leaks in the gas-to-gas exchangers. At this point of the investigation, a key piece of information was shared that the original mesh pads were found collapsed during inspection in 2015 as illustrated in Figure 9. The failure appeared to coincide approximately when glycol injection rates were cut below recommended/simulated values. Unfortunately, it was a missed opportunity to check if there was a leak at that time because the exchangers were not inspected during the LTS internals upgrade, as mentioned previously. This information provided further support for possible tube damage and emphasized the importance of an exchanger inspection during the turnaround. During the scheduled plant turnaround in Q2 2017, the exchangers, chillers, and LTS were inspected, similarly the regeneration column was cleaned and the 5/8” packing was replaced with the original 1” packing.

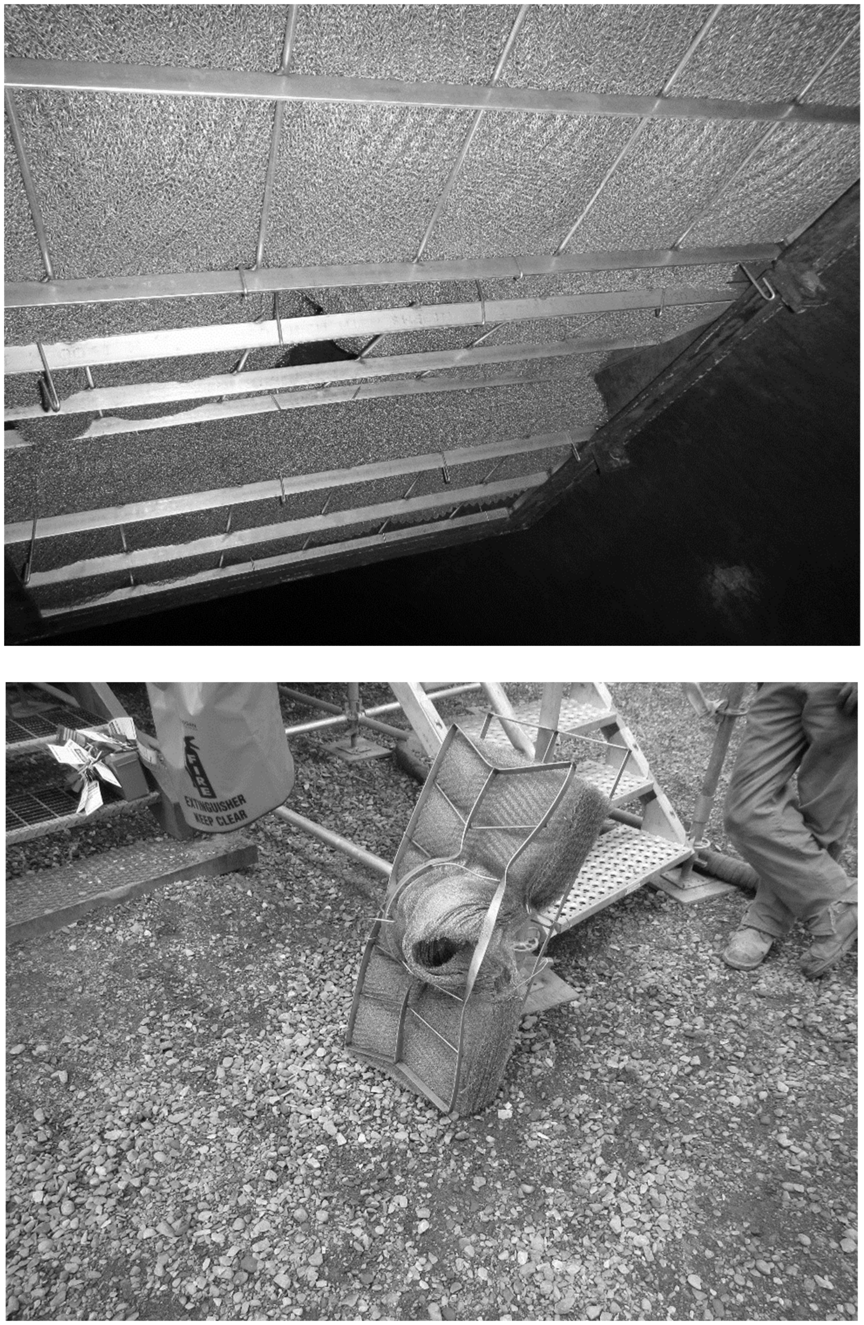
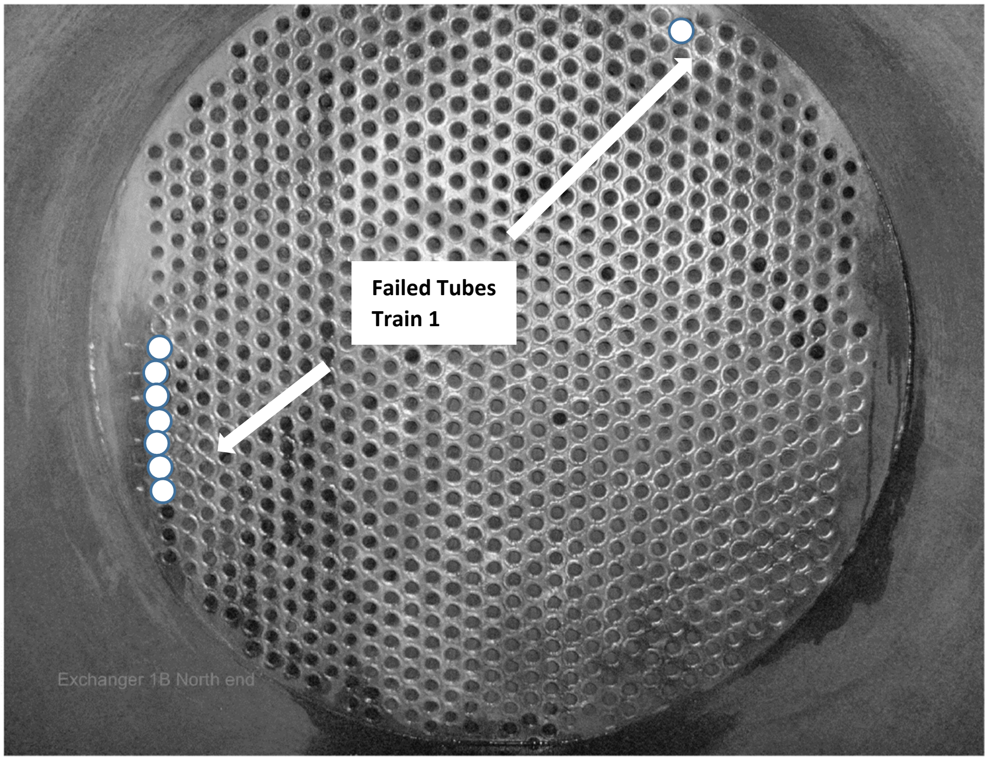


Figure 9 - LTS Failed Mesh pads as found during LTS internals replacement in Q2 2016

A water leak test was followed by visual inspection of the gas-to-gas exchangers revealed several ruptured tubes on the second pass exchangers where the cold sales gas enters from the LTS. These are 5/8” OD 16 BWG welded tubes, the site inspections team confirmed that most of tube failures were at first row of tubes at shell inlet on first pass from the Low Temperature Separator, second pass from inlet process coalescer heat exchanger in series of each train. The inspection identified eight failed tubes in Train 1 and sixteen in Train 2 as shown in Figure 10. All tubes at nozzle inlet were sheared at the back side of the tube sheet. This was consistent with the likelihood of impact failure due to dislodged hydrates from the original LTS mesh pads. There was however one tube that failed on the opposite end of the nozzle. An illustration and photograph of the damaged tube locations can be seen below in Figure 10. To understand the cause for the tube failures, an HTRI model was set up by the heat transfer group. However, the vendor data sheet and mechanical drawings were incomplete, and the vendor did not supply the missing information upon request. This made the troubleshooting more difficult and Tubular Exchanger Manufacturers Association (TEMA) guidelines were used to fill in the blanks.



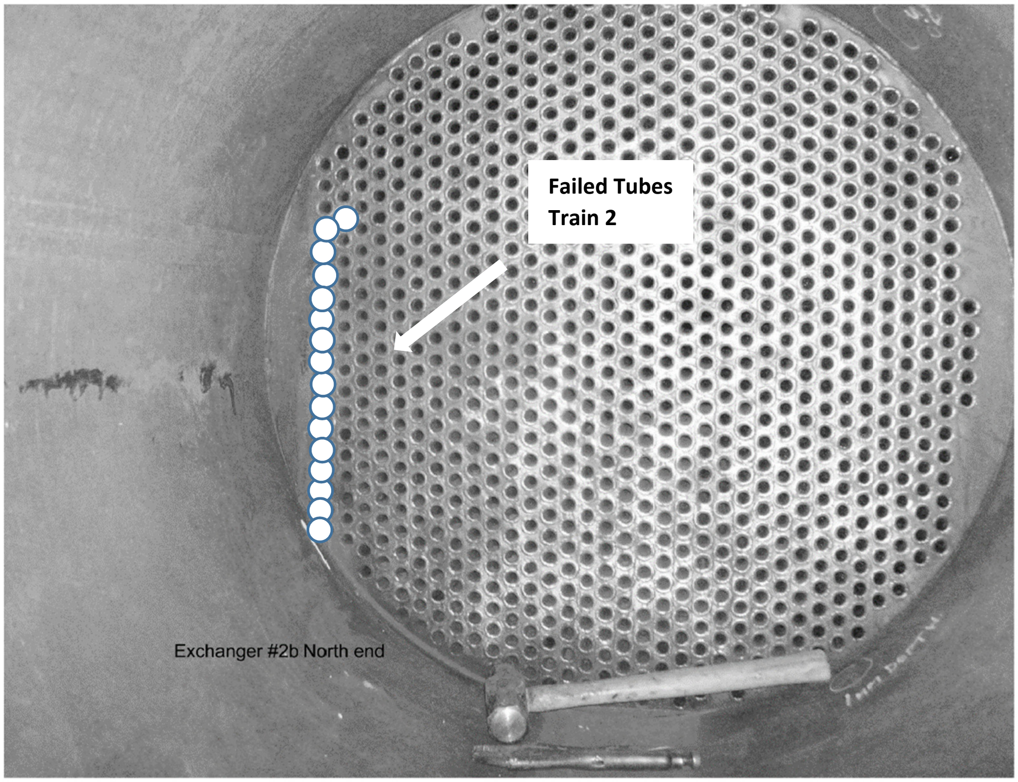


Figure 10 - Train 1 (top) and Train 2 (bottom) Gas-to-Gas 2nd Pass Tube Failures as found during Turnaround in Q2 2017

The HTRI evaluation indicated vibration warning messages for the shell entrance, tube bundle entrance velocity and cross velocity into bundle were flagged for excessive vibration in the heat exchangers. High velocity predictions were calculated at normal gas flow rates with mechanical vibration being quite high on the partially supported and close to the impingement plate tubes on the shell side. This could lead to fretting type failure (tubes hitting each other). However, a more detailed mechanical inspection of the exchangers was not possible due to turnaround time constraints. The gas to gas exchangers are TEMA NEN which have their tubes sheets welded to the shell and to gain access to the shell inlet nozzles for inspection it required a great deal of time and effort to remove the piping attached to them leading to an extended turnaround e.g. scaffolding, cranes etc. A maximum gas flow limit was issued to Operations as well as guidelines of things to look for if something similar happens in the future, the failed tubes on both trains were plug welded and hydrotested during the turnaround.

SUMMARY OF MODIFICATIONS

After the plant turnaround repairs and modifications, the facility is currently able to operate at 105% of the name plate capacity with no excessive liquid carryover to the sales line (no separator is 100% efficient), no manual draining of the sales header, and no hourly Chilled Mirror testing. The online analyzers were confirmed to be damaged and were sent to the supplier for repair and calibration. On the regeneration side, no excessive glycol losses through the still column were observed after the partial bypass and the random packing change out. The replacement of the R/L exchangers on both trains increased the rich glycol temperature to the flash tanks from less than 30 ºC (86ºF) prior to the turnaround to above 60 ºC (140ºF). Further evidence is provided below in Figures 11 and 12.

Description	Before	After
Maximum Plant Capacity, MMSCFD	173*	210
Average Glycol Injection T1 / T2, m^3/h (gpm)	0.38 / 0.32 (1.67 / 1.41)	0.41 / 0.43 (1.81 / 1.89)
Average Chilled Mirror Stain, ºC (ºF)	-1.5	NA
Average Still Reboiler Pressure T1 / T2, kPag (psig)	23 / 16 (3.3 / 2.4)	0.5 / 0.8 (0.1 / 0.11)
Rich Glycol Temperature to Flash Tanks, ºC (ºF)	28 (82)	65 (149)
Proper Lean Glycol Injection Nozzle Tube Sheet Coverage	No	Yes
Pressure Drop T1 / T2, kPad (psid) Gas to Gas Chiller	 85 / 147 (12 / 21) 109 / 88 (16 / 13)	 60 / 60 (9 / 9) 40 / 50 (6 / 7)
Lean Glycol Injection Temperature in Winter, ºC (ºF)	< 20 (68)	>30 (86)
Manual Draining of Header, times/day	16+	NA

* 120 MMSCFD above which liquid carryover increased significantly

Table 1 - Summary of Results Pre/Post Q2 2017 Turnaround

Glycol samples from the flash tanks were not foamy as was the case prior to the modifications, with the carbon beds back in service and the particle filters not experiencing vapor lock due to excessive flashed hydrocarbons. The plant modifications performed to achieve proper operation were:

Added inlet coalescers
Corrected LTS Internals
Corrected MEG injection rates
Optimized MEG temperatures
Corrected still column issues
Plugged leaking exchanger tubes
Online analyzers sent for repair
Remote access to plant historian for troubleshooting

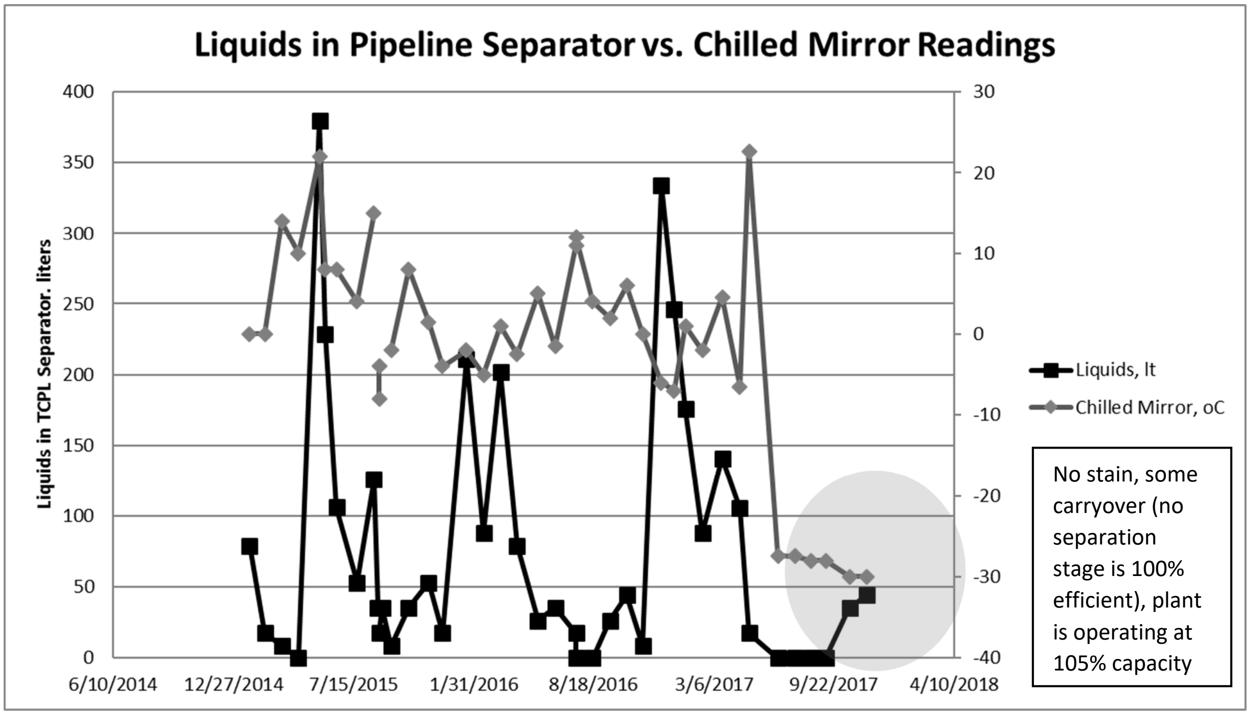


Figure 11 - TCPL Scrubber Liquids Pre/Post Turnaround

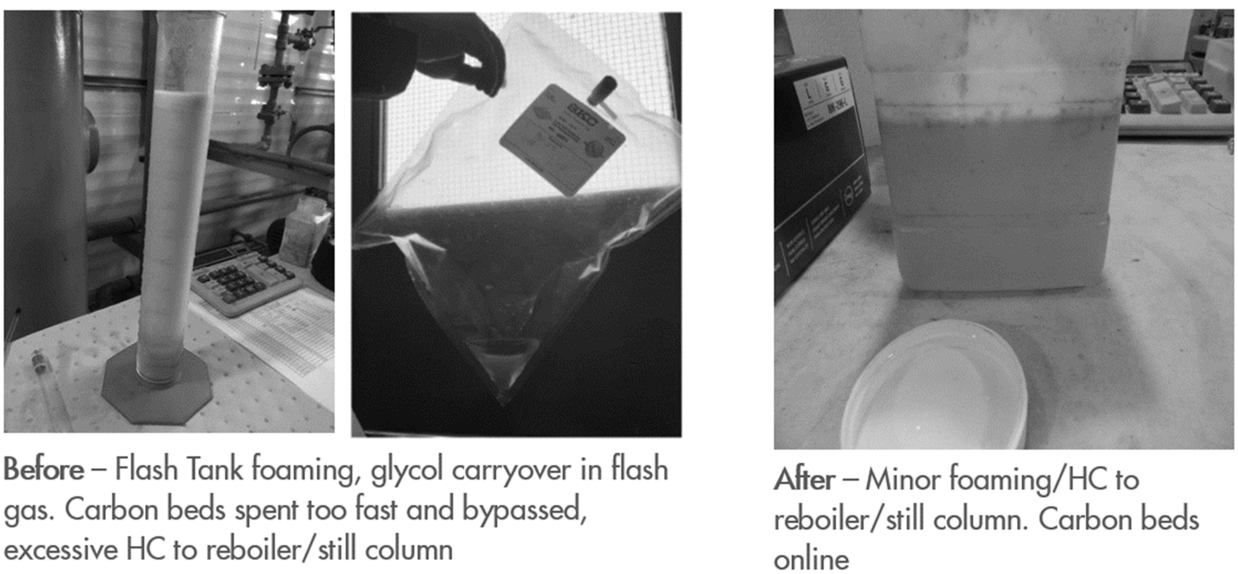


Figure 12 - Flash Tank Rich Glycol Foaming Tendency Pre/Post Turnaround

CONCLUSIONS

This troubleshooting exercise demonstrates the importance of information sharing between different teams, the understanding of potential consequences to plant reliability and performance from cost saving decisions during the project phase, the need to understand the process holistically, appropriate data documentation, and performing troubleshooting in a structured manner to determine the causes and effects of changes. Similarly, this experience shows the need for adequate engineering assurance during project execution and the value the process discipline brings to plant operations.

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