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Review Article

Operating Experiences of Glycol Inhibitor for Hydrate and Dew Point Control in Gas Production Facility Offshore and Onshore Mediterranean Sea

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Abstract

Glycols are widely used to prevent hydrate formation in sub sea pipelines and in the gas processing industry to control dew point. Operating experiences of Diethylene glycol and monoethylene glycol for preventing hydrate in gas pipelines and dew point control have been performed to evaluate the unexpected operational problems in gas processing system. Field test and laboratory experiments were carried out to investigate the type of glycol, the fluid solidification condition for Monoethylene glycol and Diethylene glycol in the presence of hydrocarbons and salts. Results led us to make modification in the gas plant and choose the right type of glycol with optimum dose to simplify operation and save costs in gas processing in Egypt. This paper covers all aspects of the process from type of glycol to nozzle placement and locations in low temperature separators to enhance the performance and quality control of gas processing. This study will address the operational issues with practical solutions are presented. These deals with glycol contaminated by a high salt content from completion fluids and hydrate formation in offshore gas line, design modification to process equipment and changing from DEG to MEG for sales gas specification. This paper also addresses the proper glycol type to fit gas composition, proper glycol injection rates, nozzle sizing, placement and location according to actual field data not textbook data that is central in the designed recommended process parameters.

Keywords: Glycol Inhibitor; Gas Production; Diethylene Glycol; Monoethylene Glycol

Introduction

Gupco West Harbour gas plant is a hydrocarbon dew point control plant, Joule Thomson, JT, process, which processes gas from an offshore platform in the Nile Delta area of the Mediterranean. The nominal plant inlet design capacity is 340 mmscfd, achieved via two parallel Joule Thomson processing trains of 160 mmscfd capacity each. The plant was constructed in 1999 - 2000. The raw gas from offshore platform is conditioned at gas plant to produce gas with sales quality specification. The gas hydrocarbon and water dew points are controlled by means of low temperature condensation. Diethylene glycol 80% is injected into the gas at various points, to prevent hydrate formation in offshore and onshore in low temperature parts of the process. This study will attempt to address and clarify the problems that appeared during start up, February 2000 to 2002, in the first years of operation, the gas plant operations reported frequent build-ups of pressure drop in the low temperature separators. This has caused trains to be shut down and sales gas agreement out of specifications. Offshore production platform collects the mixed phase reservoir fluid from six wells in the wellheads manifold. The reservoir fluid is then separated into two streams. Each stream enters one of the two parallel production separators through two 18" headers where water and liquid hydrocarbons are separated from the gas stream. Each production separator can handle up to 160 mmscfd at the minimum wellhead pressure. Separated water is discharged under interface level control to the oily water treatment system where the hydrocarbons liquids are separated by means of a tilted plate interceptor.

Effluent water with the maximum hydrocarbons content of 15 ppm is disposed into sea through a sea sump. Separated hydrocarbons are pumped into the subsea gas pipeline 30". Diethylene glycol 80 wt % is injected from onshore into combined stream before entering the 30" sub sea pipeline in order to prevent hydrates formation. Glycol is transferred to the platform through 3" subsea line from onshore facilities and injected upstream of the instrument and service gas system in order to prevent hydrate formation.

Overview of the process at the West Harbour gas plant

Gas with associated condensate and water, together with injected glycol, arriving onshore plant through 30" sub sea gas pipeline is feed to the slug catcher. A pig receiver is provided upstream of the slug catcher to allow for routine pigging of the sub sea pipeline. Gas from the slug catcher is then fed to two parallel low temperature separation (LTS) modules each consisting of gas/gas exchanger and a Joule Thomson valve and a low temperature separator. Gas from slug catcher is cooled against the cold dry gas from the low temperature separators before being expanded in the Joule Thomson valves in order to reach the hydrocarbon dew point specifications.

Diethylene glycol 80 wt % is injected upstream and downstream of the gas/gas exchangers to prevent hydrates formation. Condensate and injected glycol are separated in the low temperature separators. Dry gas is then discharged to the national grid. Separated hydrocarbon liquids and glycol from slug catcher and low temperature separators are pre-heated in one of the condensate pre-heaters and routed to the glycol/hydrocarbon separator. Separated hydrocarbon liquids are routed to the stabilizer column while the separated glycol is routed to the exhaust glycol storage tank. Gas from the glycol/hydrocarbons separator is discharged to the fuel gas system.

The stabilizer column produces condensate having a maximum Reid vapour pressure of 11 psia. Stabilized condensate is stored in two floating roof tanks after being cooled in the condensate cooler. Condensate is exported to Port Fouad storage facilities using two delivery pumps. Exhaust glycol from the exhaust glycol tank is pumped to two-glycol regeneration package. Each package consists of a surge drum, a glycol/glycol exchanger, a regenerator, circulation pumps and filters. Regenerated glycol is stored in a regenerated glycol tank from which it is pumped to the LTS system and the offshore platform. Figure 1 shows overview of the gas plant simplified process.

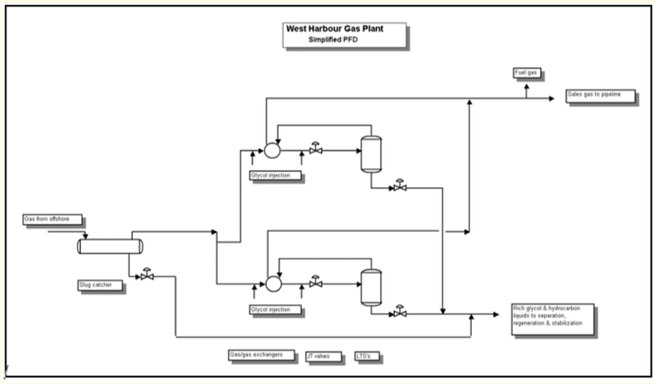

Figure 1: Overview of the gas plant process.

Glycol injection system design and operation

The West Harbour gas plant utilizes glycol injection to inhibit hydrate formation as the feed gas is cooled at high pressure. Water removal from gas which is necessary to meet the sales gas specification requirement of 340 mmscfd is accomplished by condensation of a large portion of the water vapour out of the gas phase by cooling.

System description

Slug catcher operating conditions

Temerature, C: 25 - 30°

Pressure, barg: 93

Saturated gas water content, lb/mmscf: 33

Hydrate temperature, C: 17°.

Outlet from gas/gas exchangers

Temperature, C: 0 - 5°

Pressure, barg: 92

Saturated gas water content, lb/mmscf: 6

Hydrate temperature, C: 17°.

Low temperature separator

Temperature, C: -10 to -15°

Pressure, barg: 72

Saturated gas water content, lb/mmscf: 3

Hydrate temperature, C: 15°.

Glycol injection system operating parameters

The existing glycol injection system at the gas plant utilizes 80 wt % DEG for hydrate inhabitation. Glycol is injected upstream of the gas/gas exchangers and also upstream of the JT valves in each train.

Typical rich glycol concentration 55 - 60 wt %.

Injection rate upstream of gas/gas exchangers 0.019 m^3/mmscfd (0.12 bbl/mmscfd).

Injection rate upstream of JT valves 0.006 m^3/mmscfd (0.038 bbl/mmscfd).

For a nominal train throughput of 160 mmscfd, this corresponds to a lean glycol injection rate of approximately 25 BPD/train. Discussion with plant operations staff indicates that there have been problems with the plants' s glycol injection system since startup. In particular, the glycol regeneration/injection system appears to have been damaged by an accumulation of drilling mud/solids that was produced back through the facilities from the offshore wells. This material has accumulated in the glycol system and caused numerous problems, including loss of glycol injection due to spray nozzle plugging.

Operational problems

A review of the overall operation in West Harbour gas plant revealed a number of abnormal operating conditions. Specifically, low temperature separators liquid carryover problems and the plant is not making the hydrocarbon dew point specification. In addition, high glycol losses due to salt contamination in the system. Since the glycol injection rate was several times higher than necessary, this further aggravated plugging in spray nozzles and poor operation performance it should be borne in mind that complete recovery of the glycol is not feasible. Each day, a small amount of glycol will be lost as a result of vaporization and solubility in the liquid hydrocarbons phase. These losses may be minimized by choice of glycol type and concentration and by maintaining the proper operating conditions. Where hydrocarbons emulsions are especially troublesome owing to the presence of heavy ends in the hydrocarbon condensate.

Glycol contamination

Salt contamination of the glycol is a common problem in low temperature separation. The salt deposits on the tube of the reboiler owing to its reduced solubility at higher temperatures. The salt deposit effectively reduces the heat transfer. If salt contamination cannot be completely prevented, purification of the glycol is required. This may be accomplished by distillation, ion exchange, ion exclusion, or filtration. Other glycol contaminants, which may have a deleterious effect on operation of the unit, include glycol degradation products and gas stream components with surfactant. Usually, these contaminants may be removed by a filtration through activated charcoal, although vacuum distillation may occasionally be required. Filtration of the glycol solution is accomplished by the use of a replaceable type cartridge filter removing particles down to 25 - 50 microns. This type filter can be placed in the cold rich glycol line to conserve pump horsepower. Glycol filters capable of removing particles down to one-micron size should be placed in the hot-lean glycol circuit in order to reduce the pressure drop across the filter due to the lower viscosity of the hot glycol.

Plant operations indicate that there have been problems with plant's glycol injection system since start up 3 February 2000. In particular, the glycol system offshore and onshore appears to have been contaminated by an accumulation of drilling mud/solids that was produced back through the facilities from the offshore wells. This dirt has accumulated in the glycol system and caused numerous problems, including loss of glycol injection due to spray nozzle plugging. The presence of even slight amounts of impurities in glycol system increased the possibility of plugging the glycol nozzle at the upper bundle of gas/gas exchangers. Due to this the first injection point and most critical one, the following actions had taken to solve the problem:

1. Retrieving under pressure the plugged nozzles by using the retrieving tool then clean.
2. Cleaning by back flow through the spray nozzles.
3. Shut down LTS, depressurize and retrieve nozzles and then clean.

The above three steps were used as a short term solution to avoid nozzle plugging due to impurities. The majority of solids are iron sulfide, rust, sand, and mud. Solids can erode equipment (pumps, valves) and also can plug exchangers and contactor trays. High salt can enter the glycol solution when produced brines or salt waters carryover inlet separator. Salts, soluble in the glycol, decrease the efficiency of the injection glycol system. Sodium chlorides are usually inversely soluble in glycol. That is, the hotter the glycol the lower the solubility.

The salt will therefore drop out of the solution and crystallize on the hot spots of the system, primarily the pre-heater tubes and the fire tube. As the salt adheres to the fire tub and pre-heater tubes, it forms a heat resistant layer which forces the metal skin temperature to increase to put out the same heat as before the scale was laid down. As in the case of hydrocarbon contamination, oily material can coke and the glycol will thermally degrade. Calcium chloride is less soluble in cool glycol, like most mineral salts, and these types of salts will crystallize in valves, fittings, and coolers. We have found that the majority of salt contamination in West Harbour plant is calcium chloride rather than sodium chloride.

A secondary effect of salt contamination is the possibility of corrosion mechanisms occurring due to its corrosive nature. Salts cannot be filtered out of a glycol solution. In order to prevent plugging problem. We have been developing additional filter unit before gas/gas glycol injections nozzles. The success of such system will hopefully be the subject of design similar plant.

Choosing the proper glycol for gupco gas plant

Operations experience indicates that Mono ethylene glycol is the most logical choice for a hydrate inhibitor due to its advantage over di-ethylene glycol and tri-ethylene glycol. The West Harbour gas plant uses DEG for hydrate inhibition in first years operation.

This is quite unusual glycol injection type. Most refrigeration and JT plants utilize MEG for hydrate inhibition. MEG as it is often referred to, has the following advantages over DEG:

1. Better hydrate point depression per pound due to lower molecular weight.
2. Lower viscosity at low temperatures.
3. Lower solubility of MEG in hydrocarbon condensate.
4. Wider operating range with respect to glycol/water solution freezing points.
5. Lower cost.

The main potential advantage of DEG over MEG is somewhat lower vaporization losses at warmer operating temperatures. For low temperature separator operating conditions of high pressure and low temperature, vaporization losses of MEG should be negligible. Figure 2 and 3 show hydrate temperature and liquid phase freezing point as a function of glycol concentration for both DEG and MEG. Low temperature separator operating temperature of approximately -20°C is required to make the hydrocarbon dew point of 5°C. Figure 2 also indicates that feasible operating window for DEG is very small and would require a lean DEG concentration of around 85 wt% injected at a rate to give less than 10% dilution. This could prove to be very restrictive from an operational point of view. Even at the current typical LTS temperature of around -10°C, operational flexibility with respect to lean glycol concentration and allowable dilution is limited.

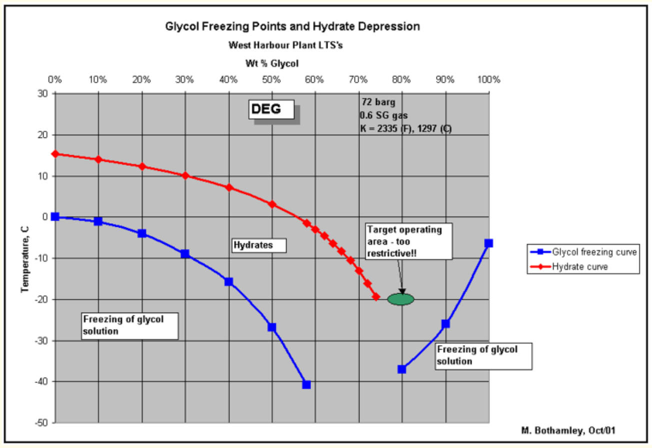

Figure 2: DEG freezing and hydrate curves.

Mon ethylene utilization feasibility study for Gupco gas plant

The purpose of this study is to investigate the feasibility of the existing Regeneration package of handling MEG instead of DEG. The comparison between MEG and DEG as hydrate inhibitors leads to the following consideration:

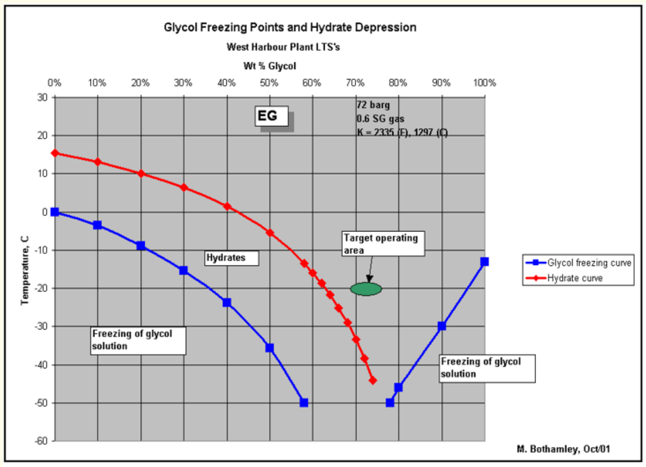

Figure 3: MEG freezing and hydrate curves.

1. The MEG injection rate to reach a required hydrate depression is less than DEG.
2. MEG has lower viscosity and more favorable heat transfer properties.
3. Hydrocarbons have a lower solubility in MEG, which leads to lower losses for hydrocarbons vaporization, lower emission, and lower heat requirement for hydrocarbon vaporization.
4. MEG has a lower solubility in condensate, leading to lower losses.
5. MEG is less cost.
6. MEG has a wider operating range regarding freezing point.

The switching from DEG to MEG according to feasibility study requires some.

Modification in the existing regeneration system package supplied by SIRTEC-NIGI. The following recommendations were made based on utilization feasibility study for handling MEG instead of DEG. Change the dehydration chemical from DEG to MEG by using the existing DEG skid unit for improved operability.

The following main changes can be pointed out:

1. Use mixed DEG and MEG in the regeneration package unit.
2. Change the existing regeneration unit or modified for new MEG injection.

Converting the existing DEG facility to MEG can result in appreciable cost savings and this definite step in optimizing our facilities. And excellent dew point control at lower capital cost. Based on these results and study, the glycol injection system should be switched over from DEG to MEG.

Optimum glycol concentration

Most glycol injection plants utilize MEG and regenerate the glycol to achieve a 75 - 85 wt% solution. The main issue here is to produce a glycol solution that Will have a freezing point below the minimum operating temperature in the low temperature separators. The West Harbour plant has been designed to operate somewhat warmer than typical refrig/LTS plants which often operate with LTS temperatures in the -25 to 35°C range. Often these colder plants are designed to achieve significant recovery of natural gas liquids, not just make a hydrocarbon dew point specification. However, because of the West Harbour gas plant warmer operating temperatures, and the reduced inhibition properties of DEG, a lean glycol concentration of Closer to 85 wt% is recommended. Concertation 80 wt% is a good target figure for MEG.

The effect of increasing lean glycol concentration from 80-wt% to 85% should be minimal. The reboiler temperature must be raised about 5°C and the duty increases slightly. Concentration of 85 wt% still allows for sufficient safety margin with respect to glycol-water solution freezing temperature at high concentrations, iven the expected minimum operating temperature, -20°C.

Injection points and spray nozzle design

The West Harbour gas plant has two glycol injection points per each train. The first is upstream of the gas/gas exchangers, and the second is downstream of the gas/gas exchangers, just ahead of the JT valves. The injection point locations and nozzle orientation are less than ideal, particularly with respect to gas/gas exchangers. There should be a separate glycol spray nozzle for each inlet tube sheet. The gas /gas exchangers (one per train) are actually made up of two shell& tube exchangers, one "piggy-backed" on top of the other as shown in figure 4. The initial design had glycol injected upstream of the inlet to the first tube pass only. There are problems with the glycol injection system. As a result there are tubes plugged with hydrates in the tube bundles of both shells for each gas/gas Exchanger. Typically it is the tubes in the upper part of the bundles that plug As they are the ones that usually don't get glycol when there are glycol spray Distribution problems glycol injection system has to modified to give good glycol spray distribution into all the gas/gas tubes in order to run the low temperature separator at much colder temperatures than are currently being achieved, which will the entire sales gas hydrocarbon dew point specification to be made, assuming the LTS liquid carryover problems are fixed. The following recommendations were made based on an overall analysis of glycol system problems.

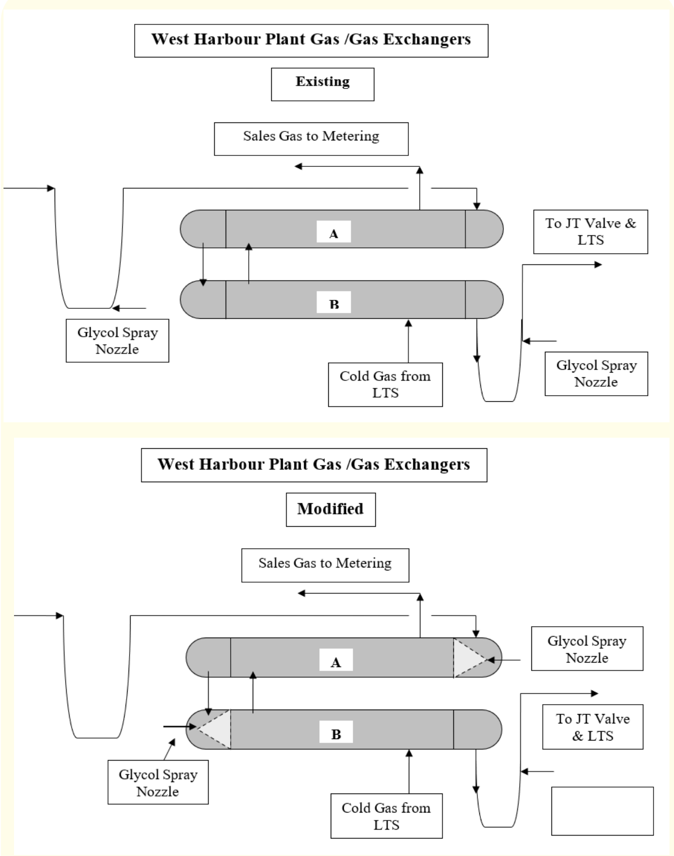

Figure 4: Shows existing and modified spray nozzles injection locations.

Modify glycol injection nozzle placement to mitigate hydrate tendencies:

1. The spray nozzles relocated inside the channel head and positioned to provide full spray coverage of the entire tube side.
2. The nozzles should be of the hollow cone type in order to provide a finer aerosol spray as opposed to the full cone type.
3. The spray nozzles should be sized to provide al least 100 psia pressure drop at least expected injection rates.

As a result of these recommendations, operating problems in the glycol system were Completely fixed.

Glycol injection rate calculation

The required glycol injection rate is a function of the several factors, glycol type, lean glycol concentration, minimum operating temperature required, and the amount of water condensed out of the feed gas. The key relationship is the following equation which is presented below:

T = KX/mw (1-x)

Where: T = Hydrate temperature depression, C

K = 1297

mw = Molecular weight of inhibitor

x = Weight fraction of the inhibitor in the aqueous phase.

For a given hydrate temperature depression requirement, the necessary glycol concentration in aqueous phase can be calculated from the above equation. However, because of the uncertainties involved in the calculations, the variability of West Harbour plant operating conditions, and in particular the difficulty achieving good glycol distribution, a significant safety margin is typically included. It is quite common in refrigeration and JT plants, to inject 80 - 85 wt% lean glycol and the injection rate is controlled to achieve a 70% rich glycol concentration at the coldest part of plant. Many glycol injection plants operate with LTS temperature of -25 - 35°C in order to maximize natural gas liquids recovery. These temperatures are somewhat colder than the West Harbour plant requirements -15 to -20°C. Per cited equation; colder temperatures require higher rich glycol concentration to prevent hydrates. A combination of factors, including hydrate formation conditions, glycol freezing point, and allowance for uncertainly, makes the 80 - 85 wt% lean glycol 10% dilution rule-of thumb convenient and reasonable for these lower temperature applications. This guideline is applicable for West Harbour as well. Figure 5 shows lean glycol injection rate in gal/mmscfd VS operating temperature for 85 wt% glycol DEG and 80 wt % MEG assuming an allowable dilution of 10wt %. Note that the glycol injection rates shown in figure 5 are much higher than the injection rates that have been historically used at the West Harbour gas plant 6.7 gal/mmscfd. The injection rate calculation had been adjusted based on GPSA engineering data book and Cample gas condition and processing.

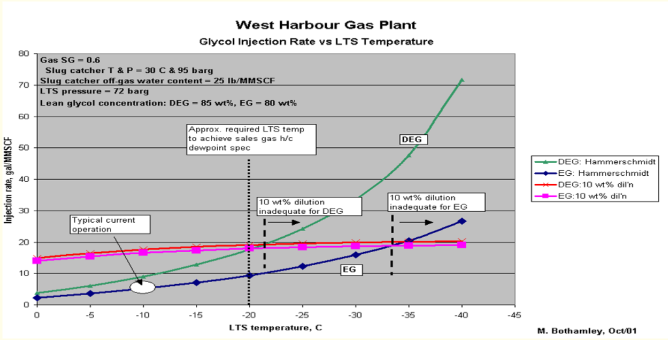

Figure 5: DEG and MEG injection rate and LTS temperature.

Gas plant hydrocarbon dew point control

The West Harbour sales gas contract hydrocarbon dew point specification stipulates that the delivered gas shall form no hydrocarbon condensates or hydrates above 5 degrees Celsius) at any pressure below the delivery pressure. In order to meet the hydrocarbon dew point specification, heavy hydrocarbons, typically C6+ must be removed from the feed gas stream. A JT plant does this by condensing out the heavy hydrocarbons at low temperatures and high pressures.

The required cooling effect is achieved via Joule-Thompson expansion of the gas across a control valve in conjunction with back exchange of the cold residue gas against the warm inlet gas in gas/gas exchangers. Two things are required to achieve the sales gas hydrocarbon dew point of 5°C. First, the low temperature separators must be operated at around -20°C. This requires the gas/gas exchangers and glycol injection system to operate properly. Second, Liquid carryover from the low temperature separators must be fixed.

Feed gas composition

The feed gas composition used for simulation is shown in table 1. Unfortunately, the Hysis phase envelope algorithm was having difficulty with gas plant composition and could not generate a proper phase envelope as shown in figure 6. It is very important that the heavy ends in the gas be characterized properly, as this will have a large impact on this portion of the envelope. This phase envelope indicates one of the potential problems associated with high pressure, low temperature condensation processes. Operation near the top of the phase envelope where the dew point curve/liquid lines flatten out is not ideal, as conditions are fairly unstable. This is the reason why it is necessary to achieve low temperature like -20°C in LTS to make the sales gas hydrocarbon dew point specification of 5°C.

Gas/gas exchangers

The design and performance of the gas/gas exchangers is critical to the operation of the gas treatment plant. For a given JT valve delta P, the effective overall heat transfer coefficient multiple exchanger area, UA, of the gas /gas exchangers will determine the achievable minimum low temperature separator operating temperature.

Gas/gas exchanger original design

Inlet gas flow/train mmscfd: 160

Tube side temperature inlet, C: 25

Tube side pressure inlet, barg: 95

Tube side temperature outlet, C: 10

Tube side pressure outlet, barg: 94.7

Component	Mole %
N2	0.140
CO2	0.135
H2S	0.000
C1	94.4848
C2	3.620
C3	1.017
IC4	0.230
NC4	0.135
IC5	0.110
NC5	0.010
C6	0.040
Benzene	0.0003
C7	0.025
Toluene	0.0007
C8	0.020
Ethyl benzene	0.001
Meta and Para xylene	0.0005
Ortho xylene	0.0007
C9	0.0007
C10	0.004
C11	0.002
C12	0.005
C13	0.005
C14	0.003
C15	0.002
C16	0.002
	100.000

Table 1: Feed gas composition.

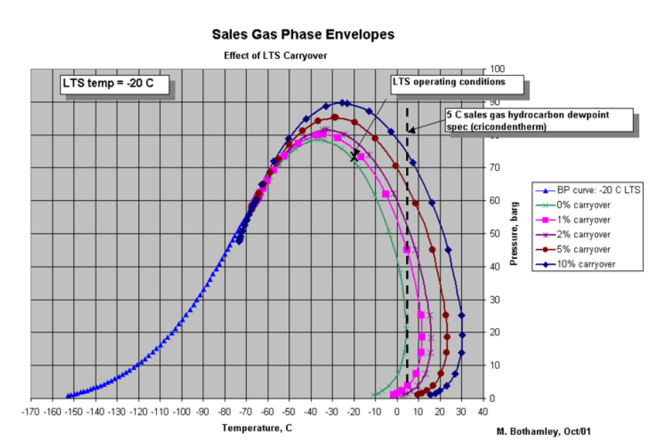

Figure 6: Phase envelopes indicating the effect of carry over for LTS of -20°C.

Shell side temperature inlet, C: 22

Shell side pressure inlet, barg: 71.5

Shell side temperature outlet, C: 15

Shell side pressure outlet, barg: 71

LTS pressure, barg: 71.5

LTS temperature, C: 22

Calculated hydrocarbon dew point, C: 5

Calculated exchanger duty, mmbtu/hr: 13.2

Calculated original design UA, btu/hr-F: 6.8 E05

Total surface area for each gas/gas

Exchanger based on tube OD: 40,500 sq.ft.

Solving for the overall heat transfer coefficient, U0, gives 16.8 btu/hr-F. It is unclear why such a low value has been used for original design. Well designed shell and tube exchangers overall heat transfer for high-pressure gas/gas exchanger with glycol injection, U0, is 60 btu/hr-F. However, the West Harbour gas plant gas/gas exchangers do not appear to be particularly well designed. The calculated heat transfer coefficients for the West Harbour gas plant high Pressure gas/gas exchangers with glycol injection is 40 btu/hr-F. The difference between calculated and well design heat transfer coefficient are mainly due to the low velocity of the West Harbour units.

Gas plant data gives the following results

Inlet gas flow rate, mmscfd: 240

Flow rate, mmscfd: 120

Overall heat transfer coefficient X exchanger, UA: 409,000 btu /hr-F

Overall heat transfer coefficient, Uo: 10 btu /hr-F-Sq ft

The Uo = 10 btu/hr-sq.ft F value is much lower than the theoretical value of Uo= 40 btu /hrsq.ft-F . The estimated actual Uo value based on 282 mmscfd is 14-16 btu/ hr -sq ft -F.

Simulations runs for a shell and tube exchanger highlight a couple of problem areas:

1. The tube side velocity is far too low. Calculations indicate a tube side velocity of approximately 5 ft/sec. The recommended for this service is in the range of 10-16 ft/sec. low velocities will lead to poor gas-liquid distribution in the tubes, including accumulation of liquid in the lower tubes. This will reduce heat transfer coefficients and also impair hydrate inhibition efficiency

2. The shell side of gas/gas exchanger has a calculated pressure drop of 2.5 bar which is high.

3. Some of the tubes in the exchangers are hydrated off. This effectively takes exchanger Heat transfer area out of service.
4. The performance of the gas/gas exchangers is impaired due to accumulation of Liquids on the shell side of the exchanger due to carryover from the LTS's.

Case histories

Liquid carryover problems

The West Harbour plant has experienced liquid carryover problems from its LTS's since the plant started up in February 2000. Liquids were recovered from downstream piping and equipment including facilities owned and operated by the sales gas company, Gasco. It is not known exactly how much liquid was carried over but volumes of 200 - 600 GPD have been recovered down stream. This equates to 0.75 - 1.3 gal/mmscfd of processed gas. Most of the recovered liquid is glycol with some hydrocarbon condensate. It is believed that there is significantly more liquid carried out of the LTS'S than is actually recovered from the downstream piping/equipment. Figure 7 shows the liquids carry over and sales gas. This is because most of the carried over liquid hydrocarbons are reappraise as they are warmed up passing back through the gas/gas exchangers. There are two main problems associated with the liquid carryover from the LTS'S:

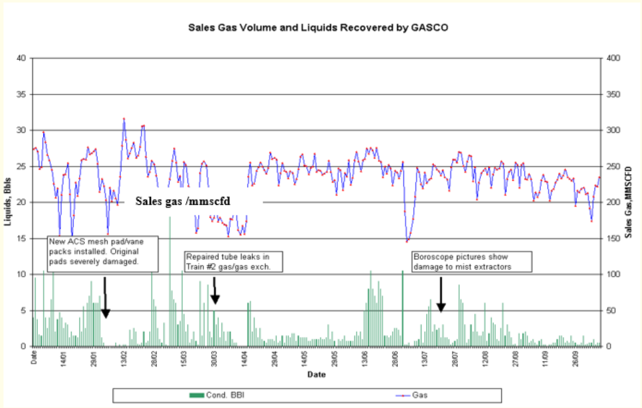

Figure 7: Liquids carry over and sales production.

1. Customer does not want liquids carried into their pipeline system.
2. The hydrocarbon liquid carryover puts the plant sales gas off spec relative to the sales gas contract hydrocarbon dew point specification. Comparison of the sales gas composition from an actual sample obtained on July 2001, with that predicted by Hysis indicates substantial hydrocarbon liquid carry over from the LTS'S. From that time, plant throughput was curtailed because of the first problem. In addition, process simulation work indicated that the plant is not making the hydrocarbon dew point spec. There was also some evidence to indicate that condensate liquids were condensing out of the gas upon pressure letdown into the downstream power plants fuel gas reception facilities. Carryover of liquids from LTS's has a negative impact on the sales gas hydrocarbon dew point specification as shown in the table below.

	Liquid carryover, vol %				
LTS temperature –10°C	**0**	**1**	**2**	**5**	**10**
Rich glycol carry over, bpd	0	2	9	1	7
Hydrocarbon liquid carryover, bpd	0	3	6	14	27
Total liquid carryover bpd	0	5	10	23	44
Sales gas h/c dew point, C	10	14	17	23	29

Table 2

	Liquid carryover, vol %				
LTS temperature –20°C	**0**	**1**	**2**	**5**	**10**
Rich glycol carry over, bpd	0	2	4	9	17
Hydrocarbon liquid carryover, bpd	0	4	8	19	38
Total liquid carryover bpd	0	6	12	28	55
Sales gas h/c dew point, C	2.5	9	13	21	28

Table 3

Liquid carryover volumes in BPD based on 150 mmscfd/train.

Glycol volumes based on lean DEG 85wt% and approximately 10 wt% dilution.

From the above table, carryover of hydrocarbon liquids from the LTS'S has significant effect on the sales gas hydrocarbon dew point. Only the 0% carryover case with an LTS temperature of -20°C actually meets the sales gas specification. Operation staff recommended the approval budget for the remediation of LTS liquid carryover from the West Harbour gas plant. The West Harbour facility has a history of problems with the carry over from process trains. Gupco/BP process Engineering support have jointly developed remedial recommendation to mitigate the liquid carry over and sales gas spec. The agreed scope of work to resolve the carryover problems:

1. Convert glycol system from DEG system to MEG.

2. Install new nozzles in the heat exchangers to achieve full coverage.
3. Install internal diffuser in the low temperature separator.
4. Replace the existing mist pads in the low temperature separator.
5. Install new filter coalecers.

As the result of this scope of work, we have had no liquid carryover problems from LTS's and operated at -20C. and the sales gas hydrocarbon dew point specification was achieved. Figure 8 shows sales gas without liquids.

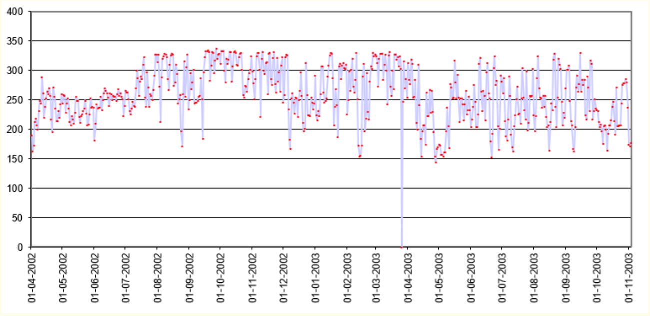

Figure 8: Liquids carry over and sales production.

Offshore installation with DEG

The unit involved in the offshore case study consisted of Hapy platform facilities With DEG glycol injected at the fuel gas skid and 30" subsea pipeline. The glycol was recovered in a West Harbour gas plant and piped back via the glycol 3" to the system to be injected over again. The following are the operating difficulties Such as hydrocarbon contamination of the glycol solution, resulting in the plugging of fuel gas system and hence complete shut down of platform, glycol entrainment of the sales gas, pipeline problem during pigging operation and carry over, the formation of solids, with jamming of pumps valves and control devices, high consumption of fresh glycol, and problem with glycol storage tanks. A review of the overall operation revealed a number of abnormal operation conditions. Specifically, an excessively high amount of glycol and condensate went to the sales gas. Since the injection rate was several times higher than necessary, this further aggravated plugging by the solids resulting from the crystallization of the glycol solution. The following recommendations were made based on an overall analysis of the offshore platform and plant operating difficulties:

1. Drain and clean the lean and exhaust glycol tanks.
2. Reduce the injection rate after recharge with fresh 80-wt% glycol.
3. Installed additional filter units before injection nozzles.
4. Changed out the contaminated glycol with a new batch of glycol.

In order to have a sufficient glycol injection and recovery process.

As a result of these recommendations, operating difficulties in offshore.

Facilities were completely cleared up.

Other potential problems

Damage to the mist extraction equipment

The damage mesh pad/vane pack combination was installed as per a recommendation from ACS industries inc., in Houston. ACS claims to have successfully implemented this system in numerous applications. These mist extraction internals were installed in February 2001 in an attempt to minimize/eliminate carryover, which was being experienced with the original mesh pads. The new mist extraction internals worked for a while; with low carryover liquids seen down streams carryover increased back up to levels similar to as before.

The West Harbour LTS's have several negative liquid properties with respect to mist elimination equipment performance such as low surface tension, low density of the hydrocarbon liquids, and high viscosity of the rich glycol phase. The ACS mesh pad that was installed in the West Harbour plant LTS.s consists of three layers of different mesh types. Based on operation experience, the actual gas velocity in the LTS vessels and through the mist extraction equipment was poor and corrected to maximize capacity and separation efficiency of the LTS's. Figure 9 shows low temperature separator (LTS) simplified schematic. There is information available that the mist extraction internals are being subject to mechanical damage while in service:

1. Photographs of original mist extractors, mesh pads, showing severe damage
2. Boroscope photos of the new ACS internals showing damage.
3. Evidence that indicates that the existing internals worked for a period of time after installation then started o experience carryover again.
4. There are known design and operational problems associated with the glycol

5. Injection system.
6. Similar problems are known to have occurred at other plants of this type.

Insufficient filtration system

Good clean glycol should be used for best nozzle performance. A filter or fine strainer should be installed ahead of the spray nozzle to remove solids that could plug the spray nozzle and change the spray patterns. Poor filtration system of glycol is caused by, solid particles less than mesh of filter, heavy hydrocarbons can build up and cause plugging, and bad design of filter system. Frequent filter change outs can increase daily operating costs substantially. Hence, the observed filtration system performance corresponds very well with fluid property actual data and laboratory work. After implemented modification and redesign and revised operation parameters, the filtration system the performance has improved significantly. The following recommendations were made based on an overall analysis of the plant operating difficulties. Specifically, strong consideration to change from DEG to MEG to make the sales gas hydrocarbon dew point spec. Install glycol spray nozzles that achieve good coverage of both inlet tube sheets for each exchanger. This will require the spray nozzles to be located inside the exchanger channel heads. It is quite likely that a large number of tubes are hydrates off in these exchangers because of poor glycol distribution and inadequate injection rates. As a result of these recommendations, abnormal operating conditions were cleared up. Gas plant is currently making the sales gas hydrocarbon dew point specification [1-3].

Conclusion

1. Converting an existing DEG facility to MEG can result in appreciable cost savings and this definite step in optimizing facilities to achieve sales gas dew point control at lower capital cost.
2. The new mist pads have significantly reduced the carry over problem and all agree that West Harbour gas meets the sales contract specifications. The cost of change paid out very quickly and significant gas sales revenue.
3. Further operating experience will reveal the full potentials of implementation modification to the West Harbour gas plant.
4. Widely published data in the literature on glycol regeneration that is found in design handbooks and manual should be used with great care as they otherwise can lead to plant malfunctions
5. Revised operation parameters have been verified in actual plant operations. As a result of the various field operation studies have formed the basis for successful improvement of the performance and operability of a large-scale gas processing plant in Egypt.

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