WHY AMINE SYSTEMS FAIL – GAS PROCESSING FOCUS

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ABSTRACT

Equipment malfunction or unplanned shutdown of an amine system can have a devastating effect on a production company's profitability. The goal of this paper is to determine and focus the Gas Processing Industry's attention on the highest probability threats to their facilities' reliability. The threats were identified by analyzing 300 cases of amine system failures investigated by Amine Experts over the last 17 years for the root causes of the corrosion, foaming, hydraulic restrictions and specification problems that have limited or crippled gas processing facilities the world over. The most prevalent causes of failure in amine systems, both in general and in gas processing specifically, are determined and strategies to prevent these are given.

INTRODUCTION

Failure of an amine system to deliver its rated capacity of on-specification product can have an adverse effect on engineers' bonuses. In order to avoid this travesty, the authors have analyzed several hundred cases from *Amine Experts'* extensive field troubleshooting history, as well as cases from literature, to ascertain the most frequently occurring root causes of these failures. The intention behind this paper is to use these historical lessons from industry to focus the attention of plant personnel on the best strategies to provide the most significant risk reductions to production reliability.

To the authors' knowledge, this is the first time that such a database has been compiled and published specifically focused on amine systems in gas plants. While the root causes of these failures are not necessarily "new" knowledge to the industry, the frequency and likelihood of specific root causes occurring relative to other common root causes has not previously been qualified to this level of detail.

A generic Amine system is shown in Figure 1. Amine systems work by absorbing the hydrogen sulphide (H_2S) and/or carbon dioxide (CO_2) from hydrocarbon streams into the circulating liquid amine solvent solution. This is done in a contactor/absorber column and allows for the hydrocarbon product to be further processed, transported or sold without the corrosive potential and dangers associated with H_2S and CO_2. The amine solution is then regenerated in the regenerator/still/stripper column by dropping pressure and the addition of heat, which releases the H_2S and CO_2 from the amine solution so that it may be reused. The H_2S and CO_2 may be further processed, reinjected or incinerated.

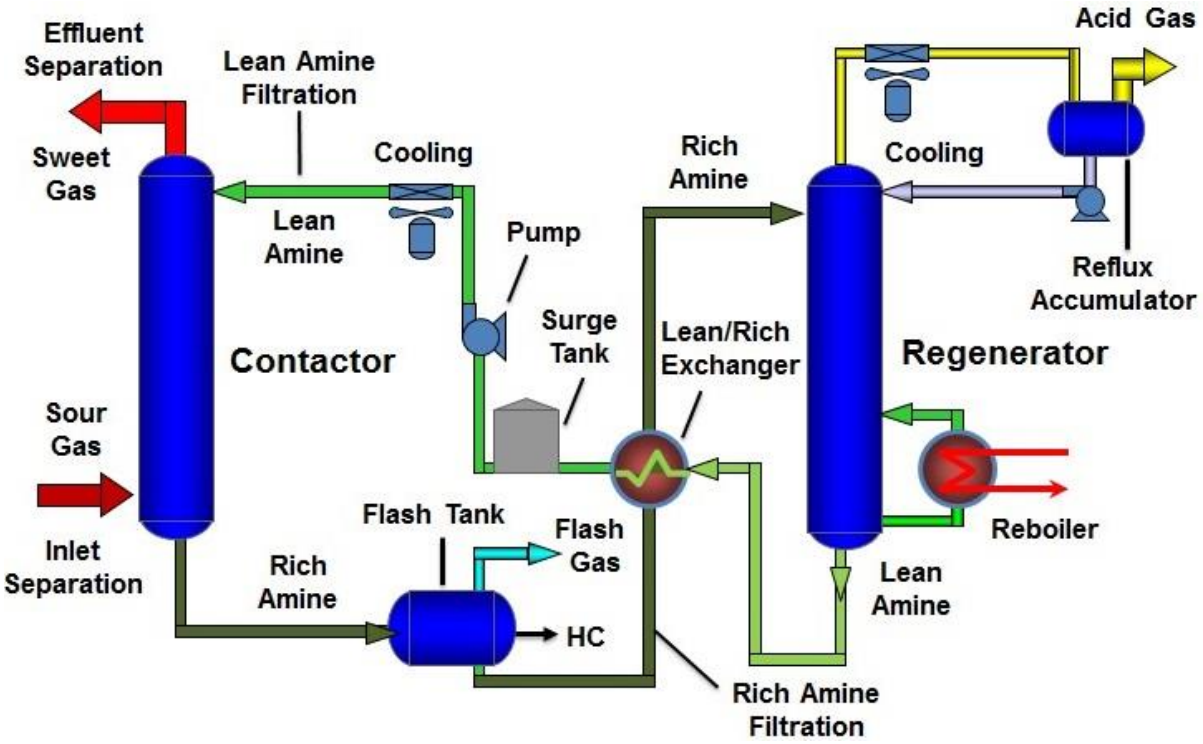


Figure 1: Generic Gas Plant Amine System

Amine solutions typically comprise predominantly of an amine and water. The amines most commonly used are methyl-diethanolamine (MDEA), 2-(2-Aminoethoxy)ethanol (DGA™), diisopropanolamine (DIPA), diethanolamine (DEA) and monoethanolamine (MEA). MDEA is the most prevalent in the gas industry at the time of publication. Other components often added to amine solutions include phosphoric acid (for improved regeneration of the solvent), piperazine (for increased CO_2 removal in MDEA), sulfolane (for COS and mercaptans removal) and anti-foam (for improved operational performance).

Amine systems are widely used throughout the ammonia, steel, oil refining and natural gas industries. They have also started to gain some traction for use in CO_2 capture applications, for instance on coal fired power stations and biogas facilities.

FAILURE TYPES

Of the 300 cases compiled in the study, 243 come from Amine Experts' field troubleshooting reports with an additional 57 being sourced from literature or other industry experts. In consideration of these cases we only looked at situations where production was heavily impacted and there was an in-depth on-site analysis done by the Amine Experts consultant or paper's author. Anecdotes or papers in which it is not apparent that the majority of potential causes were considered were not included in the database. In the cases supplied by Amine Experts, the cost in terms of lost production ranged from USD 250 thousand to 250 million per case. It is easily possible that the lost production from the failures in this database represents several billion dollars.

The types of production failures experienced fall broadly into five categories: off specification hydrocarbon product, corrosion, foaming, flooding and excessive amine loss (excluding loss caused by foaming). Any of these problems can result in expensive losses of production. The relative frequency of their occurrence is shown in Figure 2. These graphs represent the troubleshooting experience on 300 amine plants of all types and 148 amine plants in gas service respectively.

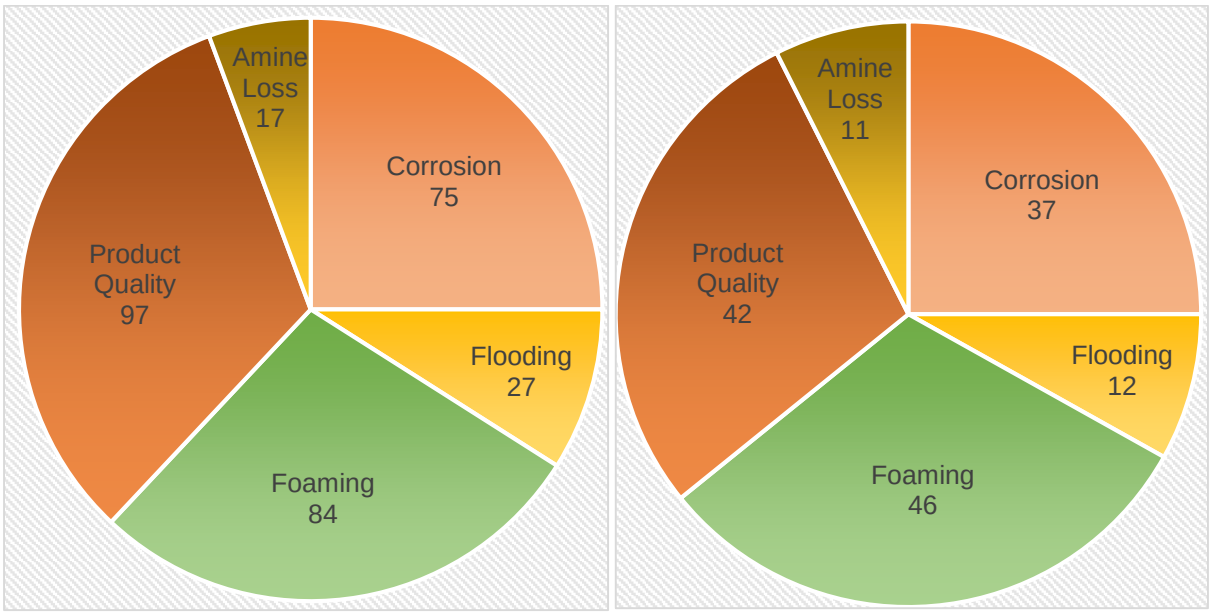


Figure 2: Number of cases of critical failure in all amine systems (left) and gas plants (right)

From the figure, it is clear that the most frequent failure areas facing both the gas processing industry and amine treating in general are foaming, product quality and corrosion. As a result of this relative frequency, these three failure mechanisms will be the primary focus of this paper.

The data shows that foaming and amine loss are slightly more of an issue in gas plants than in the industry in general, however, the differences are too small to be statistically conclusive. Note that amine losses are often also a side effect of a foaming system, however, amine replacement costs are eclipsed by the cost of production losses. For this reason, amine losses caused by foaming were not considered in the amine losses category as these cases were covered in the foaming area and double counting of cases was not considered by the authors to be desirable.

These cases all occurred within the last 30 years, with the bulk of them taking place in the last 15 years. As a result, this database represents a view of current challenges in industry. Historically, other severe problems may have played a larger role (e.g. hydrogen stress corrosion cracking prior to introduction of post-weld heat treating as a standard in amine plants). Since the early 1980s, there has also been a shift from MEA and DEA toward MDEA-based solvents. This shift has impacted on the frequency of certain root causes. Analysis of the frequency of failure of the different amine types will not be undertaken in this paper and may form the topic of future work. There are approximately 60 root causes that are a factor in system failures (45 pertinent to natural gas processing) that are generally accepted in industry. The most prevalent of these, as they pertain to gas plants, are determined and explained in detail in the following sections of this paper.

FOAMING

Foaming occurs when gas is incorporated mechanically into the amine liquid phase, resulting in a froth in which gas bubbles are surrounded by a liquid film. The formation and stability of the foam tends to be more strongly dependent on surface characteristics of the liquid phase than physical conditions like temperature and pressure [1].

A foaming amine plant is characterized by high and erratic differential pressure measurements in the absorber and/or regenerator columns [2]. It may also display fluctuating levels and erratic flow valve positions and generally results in reduced treating efficiency, amine carryover to downstream systems and loss of production capacity.

The common causes of amine plant foaming have been divided into 12 categories. Of the 46 recorded cases of amine system foaming in natural gas treating plants in the database, 36 of these were found to have foam promoting contaminants entering the plant with the feed, see Figure 3. From this finding it seems clear that proper treatment of the feed gas is a key focus area for lowering the foaming risk in gas plants.

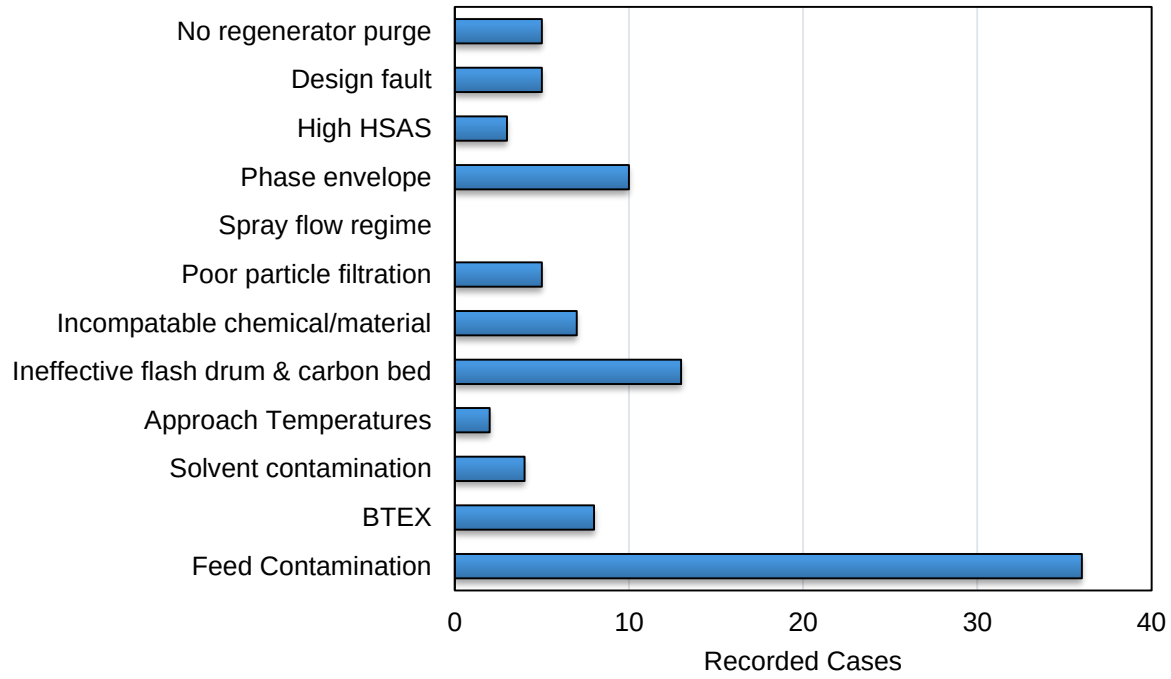


Figure 3: Root Causes of Foaming in Natural Gas Treating Systems

There are numerous potential inlet contaminants in the feed gas (Table 1) that can promote or stabilize foaming, including: compressor lubrication oils, brine water from downhole, drilling and pipeline chemical additives, soap sticks, iron sulphides/oxides, silica and sand. It is critical to remove these before they enter the amine system where they can accumulate and induce foaming incidents. In order to do this, a combination of 3-phase separators, knock out drums, particle filters and coalescing filters is typically used. For certain feed streams with unconventional contaminants, water washes and silica gel beds may also be necessary.

For a plant with a high feed ingress rate of foam causing contaminants an inlet 3-phase separator followed by a particle filter followed by a coalescing filter (see Figure 4) is thought to be optimal.

It is critical that inlet separation equipment is attentively monitored and well maintained. A good review of these systems and how to operate them correctly is given in the paper "*The Seven Deadly Sins of Filtration & Separation Systems in Gas Processing Operations*" by Sheilan and Engel [3]. Specific areas to be cognizant of:

1) Differential pressure instruments should be in good working order and operating limits not exceeded to prevent particle filter and coalescing cartridge blow out.
2) Lubricants containing surfactants should not be used in element installation.
3) Cartridges that are present in particle filters and coalescers should be installed correctly and securely to prevent bypassing; filter cartridge elements are only as good as the sealing surface between the element and the vessel, so care must be taken during the cleaning and installation stages to ensure very close seals (double O-ring gaskets are preferred in gas phase applications as they provide the best seal).
4) Level control instruments and valves should be maintained in good working order for equipment to function
5) It is important to select a filter cartridge where all of the components in the cartridge are compatible with amine service.
6) Differential pressure over a filter should rise slowly with time, zero differential pressure for long periods of time is not indicative of healthy filter operation and should be investigated.

Table 1: Inlet Contaminants

Solid	Liquid
Scale	Compressor lube oils
Desiccant fines	Hydrocarbon condensates
Corrosion products	Amines
Dirt (silica, sand etc.)	Glycols
Iron sulphides	Pipeline chemicals
Iron oxides	Completion fluids
Adamantane/Diamantane	Condensed water
	Well brines
	Organic acids

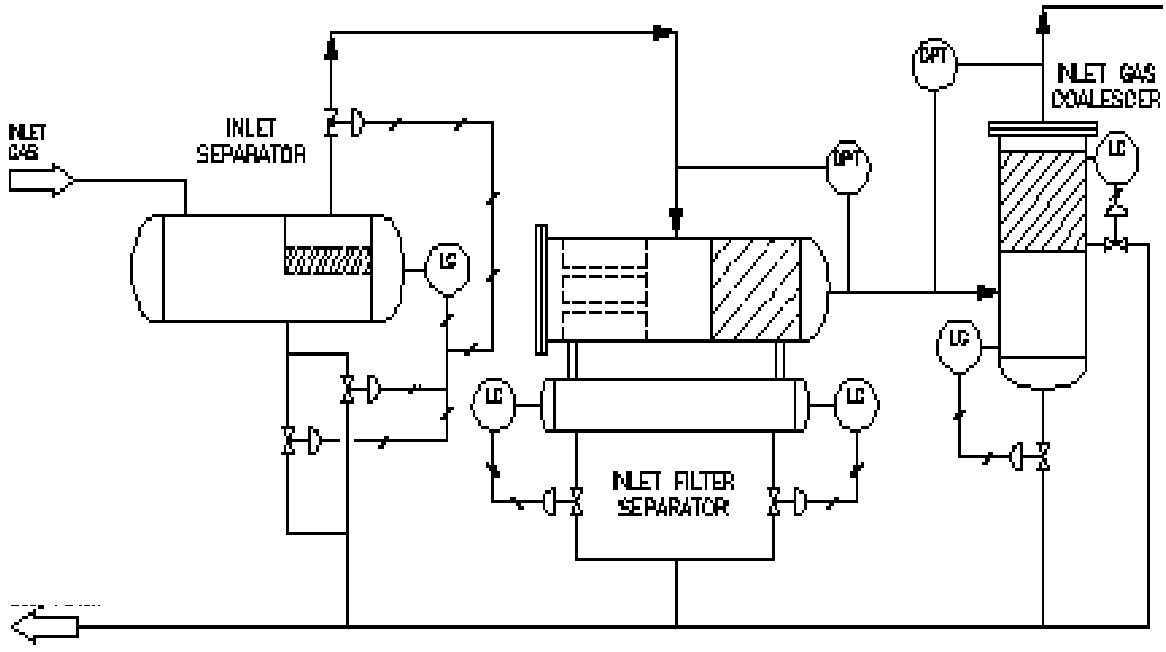


Figure 4: Inlet separation configuration for a natural gas plant with extreme inlet contamination

In gas plant service the majority of foaming incidents occurred in the absorber or throughout the whole system, see Figure 5. There were very few cases of 'regenerator only' foaming recorded in the natural gas industry. This is a result of the large role that inlet contamination plays in foaming incidents as the first area to come into contact with surfactants in an inlet contamination incident is the amine absorber.

Once the amine has been contaminated, foaming will continue in either the absorber or regenerator (or both) until the contaminant has been removed or diluted. In these cases, the flash tank, reflux purges and proper operation/maintenance of the particle filter and carbon bed are critical.

Photos from an inlet contamination incident are shown in Figure 6. In this case, absorber foaming was causing severe carry-under of gas with the rich amine into the amine system flash drum. The excessive gas in the flash drum resulted in high flaring of product gas and frequent pressure safety valve lifting. The cause of the foaming in the absorber was found to be a contaminating aqueous phase surfactant entering with the feed gas. Over the years, the inlet separation system of the plant had been modified from its original design and a line-up allowing the bypassing of the three-phase separator on the plant feed was installed. This bypass was subsequently utilized when the flow meter on the standard line-up developed a fault and an alternative flow meter on the bypass routing was available for accounting purposes. The critical nature of this equipment was not understood by plant management and several months of daily operational grief were endured prior to obtaining management buy-in to restoring the original line up. During this period ~3% of gas processed was flared to atmosphere.

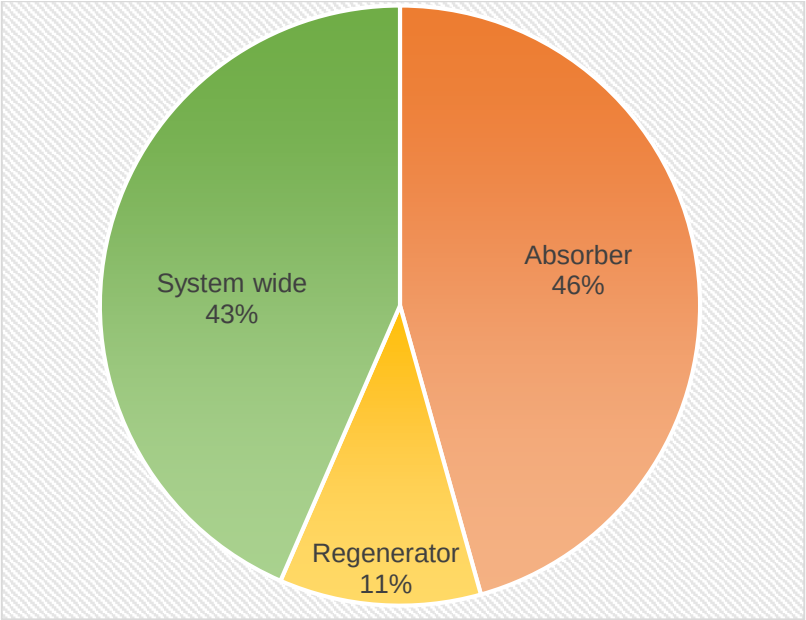


Figure 5: Location of Foaming



Figure 6: Inlet contamination foaming left to right 1) Lean amine entering absorber, 2) rich amine exiting absorber, 3) sample of fluids in gas inlet line & 4) flaring as result of foaming

PRODUCT OFF-SPECIFICATION

Gas leaving an amine absorber must meet certain specifications. What those specifications are depends on the destination of the gas, which is typically to sales, fuel gas or a downstream processing unit. The most common specifications operators are concerned with on a regular basis are:

- H_2S
- CO_2 (or the overall energy value of the gas)
- total sulphur (COS, mercaptans, etc.)

There are many reasons why the amine system may not perform up to expectations and result in off-specification product, and many of the problems are related and intertwined. In general, however, the most common reasons for gas to be off-specification are high lean loading or improper amine temperature (Figure 7).

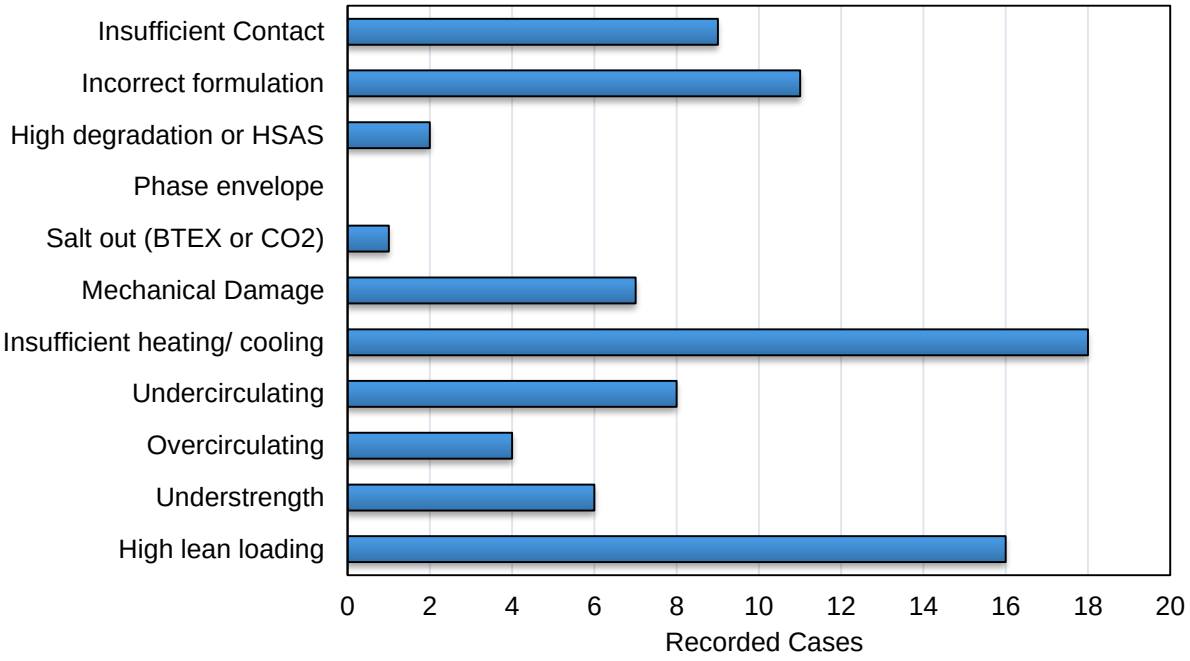


Figure 7: Root Causes of Product going off-specification in Natural Gas Treating Systems

High lean loading: The idea behind the counter-current flow between gas and amine in an absorber tower is that the last thing the gas comes in contact with is the cleanest possible amine. The reason this is important is because the partial pressure of H_2S in the gas phase will be in equilibrium with that of the H_2S in the amine. This means the more H_2S in the lean amine entering the top of the tower, by default, the more H_2S will remain in the treated gas. This effect is more pronounced the lower the overall pressure of the absorber, with tail gas treating units being on the extreme end of the spectrum.

The lean loading in an amine system may be high as a result of insufficient heat transfer in the reboiler, insufficient heat transfer in the lean rich exchanger, insufficient contact with steam in the regenerator column or the contamination of the amine with a strong base. Strong base contamination is often the result of over-vigorous addition of sodium or potassium ions in order to neutralize acidic components that build up in the system over time.

There were 18 cases of improper amine temperatures in the database where there was insufficient heating, cooling or heat transfer (Figure 8). Insufficient heat transfer or steam supply to the reboiler was at the root of more than half the cases, effectively causing high lean loadings and putting the plant off-specification. This implies that high lean loadings are a dominant precursor to off specification production. ***Monitoring and control of the lean loading in an amine system is central to meeting an H_2S specifications.***

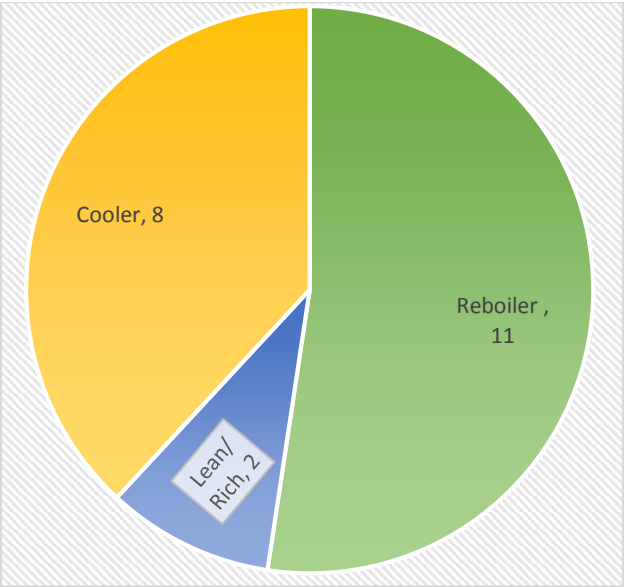


Figure 8: Exchangers where insufficient operational duty put the plant off-specification

Although lean loading is at the root of more (38%) off-specification product problems, there are several other causes which can and often do result in the same issues.

Incorrect lean amine temperature: Depending on the desired specification between H_2S and CO_2, the lean amine temperature can play a large role in treated gas composition. Simply put, higher amine temperatures will result in higher H_2S and lower CO_2 values in the treated gas. Lower amine temperatures result in the opposite. Usually, the H_2S specification is much lower and more strictly adhered to compared to CO_2. For this reason, the industry standard is to maintain lean amine temperatures at 50°C (122°F) or lower (although there are plenty of exceptions). Higher pressure absorbers and better regenerated amines are more resistant to temperature effects.

The temperature bulge within the absorber can also determine the rate at which the amine will remove H_2S. Excessive temperature bulges in effect render large portions of the tower useless for removing H_2S from the gas, as the amine loses capacity for any sort of absorption. As shown in Figure 9, the amine does not absorb any H_2S in the hottest sections of the absorber. The temperature bulge is usually controlled by the circulation rate and lean amine temperature.

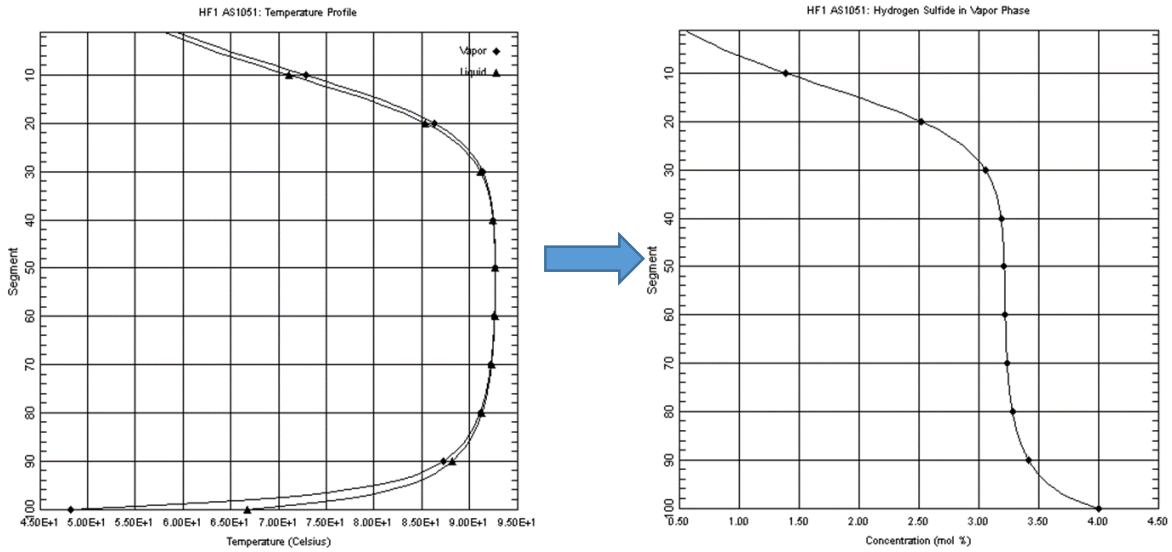


Figure 9: Effect of absorber temperature bulge on H_2S removal from gas systems

Insufficient contact between gas and amine: the contact time between gas and amine is determined by either the height of packing, or the number of trays (and each tray's weir height) in the absorber. Many MDEA systems are designed with multiple feed points, in which the operator can decide which tray to inject the lean amine onto. These feed points are designed to fine-tune the CO_2 slip, but beware that injection onto too low of a tray can result in H_2S slippage as well.

Incorrect formulation: There are many different types of amine on the market, and the correct choice of solvent depends on the specific plant's required specifications, equipment availability and, to a large extent, the ambient temperature in the plant's location. By installing the incorrect amine – or if the inlet gas composition, flow or pressure change over time – possibly the desired specification cannot be met no matter what the operators do with the plant.

High degradation or HSAS: degradation products typically do not react well with either H_2S or CO_2, so they do nothing but take up room in the solution, effectively reducing either the amine or water strength. They add to the viscosity of the amine, reducing the absorption rate of acid gasses into the solvent and as well increase the boiling point in the reboiler. Degradation products can also increase the **foaming tendency** of amine, which is another reason plants can go off-specification.

Heat stable salts have the effect of weakening the bond between H_2S and amine. In small amounts, this helps with regeneration and the operators will notice improvements in H_2S removal. Once the heat stable salt levels climb above a certain value the capacity loss from the tying up of active amine sites starts to have an impact on the ability of the system to absorb acid gas species.

Salting out effect: in very low pressure systems, the amine cannot physically hold a large combination of both H_2S and CO_2. In MDEA-based tail gas systems, the "salting out" effect can occur if excessive carbonic acid is allowed to form and subsequently bond to the amine. Carbonic acid is the product of the reaction between CO_2 and water. CO_2, being a stronger acid than H_2S, will ultimately replace H_2S with itself in the amine solution. The H_2S, which reacts faster but weaker with MDEA, then returns to the gas phase. This effect can be minimized, if not prevented altogether, by minimizing the contact time between the gas and the amine.

Mechanical damage: corrosion, fouling, incorrect installation, valve damage or tray/packing displacement can all result in flow-paths in which the gas and amine follow independent of the other. When the gas rises and amine falls without proper contact, this is called channelling. There is no transfer of acid gases when channelling occurs.

Mechanical damage can also include the gas and amine distributors. If these are not properly designed, installed and kept clean then maldistribution can also result in significant loss of contact between the gas and amine.

Over or under-circulating: the circulation rate of the amine should be set by a ratio. The moles of acid gas per mole of amine is referred to as the rich loading. Most plants target a rich loading of 0.40-0.55 moles of acid gas per mole of amine. If the amine is being under-circulated, then the absorber may be overwhelmed by acid gases which will then lead to H_2S and CO_2 breakthrough in the treated gas.

Over-circulation of amine can also be a problem, especially in CO2 slip systems where the amine will tend to remove more CO_2 and therefore less H_2S (due to the salting out effect). In more typical upstream systems, over-circulation of amine decreases the efficiency of the reboiler and lean amine cooler which could raise both the lean loading and the lean amine temperature.

Incorrect amine strength: if the amine strength is too low, this is then similar to under-circulation where the absorber can be overwhelmed with acid gas. Low amine strength must be countered by increasing the circulation rate. Conversely, the amine strength can be too high as well. In this case, the amine becomes so viscous that acid gases cannot properly dissolve into the solution. There are recommended strength ranges for each type of amine. These are based on not only maximizing acid gas removal but also minimizing corrosion.

CORROSION

Corrosion is described in many ways, but primarily, it is 'the destruction of a metal by the electrical or electrochemical reaction with its environment'. In the case of amine units, the *environment* includes a number of serious corrosion promoters, such as acid gases (H_2S and CO_2), heat stable salts and their acid precursors, chelants (that can remove any protective films that may be formed), velocity and high temperature. Steel is also prone to corrosion because it is not the natural state of iron in the environment. Iron is found as iron oxide in nature, so its tendency to oxidize (corrode) is simply the iron returning to its natural state. For iron to corrode is a completely natural process.

The problem with corrosion is that there are multiple types of corrosion that can occur and many times it is a combination of several factors, rather than a single factor, that generates the corrosive environment in the plants. In no particular order and not in any order of frequency, it is possible to find the following types of corrosion in an amine unit:

- General corrosion
- Galvanic corrosion
- Crevice corrosion
- Under-deposit corrosion
- Pitting corrosion
- Erosion corrosion
- Oxygen-related corrosion
- Stress corrosion cracking
- Hydrogen damage
- Acid attack

Except for ionization, corrosion in amine units is always highly localized. The reason why overall corrosion is not seen is because amines are excellent corrosion inhibitors, and if left contaminant-free, provide excellent inhibition of all amine wetted surfaces. The key to troubleshooting corrosion incidences is to try to determine the logical mechanism, and then determine why that particular part of the plant failed to be protected from corrosion. In natural gas plants, the majority of corrosion is related to acid gas breakout and the subsequent attack of the metal surface, usually at areas of elevated temperature. Since corrosion is a chemical reaction, high temperatures will always accelerate corrosion activity because reactions occur faster and more aggressively at higher temperatures.

Historically, hydrogen embrittlement or hydrogen-induced cracking (HIC) has been a frequent cause of corrosion in the amine industry. In this process the steel becomes brittle and fractures as a result of the introduction and subsequent diffusion of atomic hydrogen into the metal. In amine service, this corrosion is manifested as blisters or cracks in the steel walls of vessels and piping. Atomic hydrogen, which is formed by a number of mechanisms in an amine system, is a small enough atom that it can diffuse through the steel wall to the environment and then re-combine with another atomic hydrogen to form the more stable molecular hydrogen gas. If, however, atomic hydrogen finds an anomaly in the steel (discontinuity or crack caused from an impurity in the manufacturing and forming process) it may stay in the crack until another atomic hydrogen enters the same location causing the unstable atoms to combine to form the stable H_2 molecule. This H_2 molecule is now too large to diffuse through the steel matrix so it is trapped within the steel walls of the vessels where it develops a gas pressure. Ultimately, if enough hydrogen diffuses into and forms hydrogen gas in this discontinuity, the gas pressure exceeds the tensile strength of the steel, leading to the cracking and blistering seen in Figure 10.

Following numerous failures and a particularly tragic incident in 1984 in which an amine LPG treater at a USA refinery ruptured, causing an explosion and fire that killed 17 people [6,7] a NACE survey [10] of 294 amine units was conducted. The survey focused on refineries (272 out of 294 cases), which were predominantly operating MEA and DEA. The survey found that in 98% of the cases the cracking was linked to the use of non-Post Weld Heat Treated (PWHT) steels.

Most facilities built post-1990 use HIC resistant steels. Typically, the plate is tested to meet the requirements of TM0284, which is the NACE standard for the "evaluation of pipeline and pressure vessel steels for the resistance to hydrogen-induced cracking". The most common grade of HIC-

resistant steel plate is A516-to ASME/ASTM standards, certified to grades 60, 65 and 70 (A516 60/65/70 + HIC). Reputable steel manufacturers have full control of the entire process, from the steel's metallurgy to rolling, stress relieving and annealing



Figure 10 – Hydrogen-Induced Cracking and Blistering

Figure 11 provides a summary of the probable conditions that led to the corrosion failures. Having a 'high' (20:1) CO_2:H_2S ratio in the feed gas was seen to be the most common condition associated with corrosion. H_2S in an amine system will react with carbon steel to form a passivating iron sulphide layer that prevents further corrosion [4]; this phenomenon and the protection it provides is not available in amine plants where there is no H_2S present. For this reason, amine plants removing only CO_2 are often built entirely from stainless steels in order to limit corrosion. Stainless steels have a natural chrome oxide passivation layer which provides protection to the system.

Figure 12 provides a summary of the corrosion locations where localized failures have occurred. Almost 75% of the locations are related to zones in the plant where temperatures are higher with almost 50% of corrosion incidents occurring in the reboiler and bottom section of the amine regenerator column, which is connected to the reboiler. From an operational perspective the conditions that contribute to corrosion in amine systems can be grouped into three sections: design, amine hygiene and process conditions.

Design factors include: choice of metallurgy, pressure drops and design loading selection. Hydraulic design can play a large role in corrosion as pressure loss due to friction creates a situation in which some of the absorbed acid gases may flash out of solution. An in depth analysis of this has been published by Sheilan and Smith [5]. Similarly, high amine loadings will also increase the likelihood and severity of acid gas break out. It is important to re-assess a system, both hydraulically and in terms of acid gas loading of the amine, prior to increasing feed rates to above design conditions. Similarly, increasing the amount of H_2S and CO_2 in the feed should be preceded by a check on the resulting acid gas loadings.

In carbon steels the following design limits are normally used in the industry:

- Maximum Lean Loading: 0.04 mol acid species / mol amine
- Maximum Rich Loading: 0.35 to 0.55 mol acid species / mol amine
- Maximum amine velocity: 3m/s
- Wide radius elbow bends on all piping
- Minimizing the distance between the control valve on the rich amine entering the regenerator and the column.

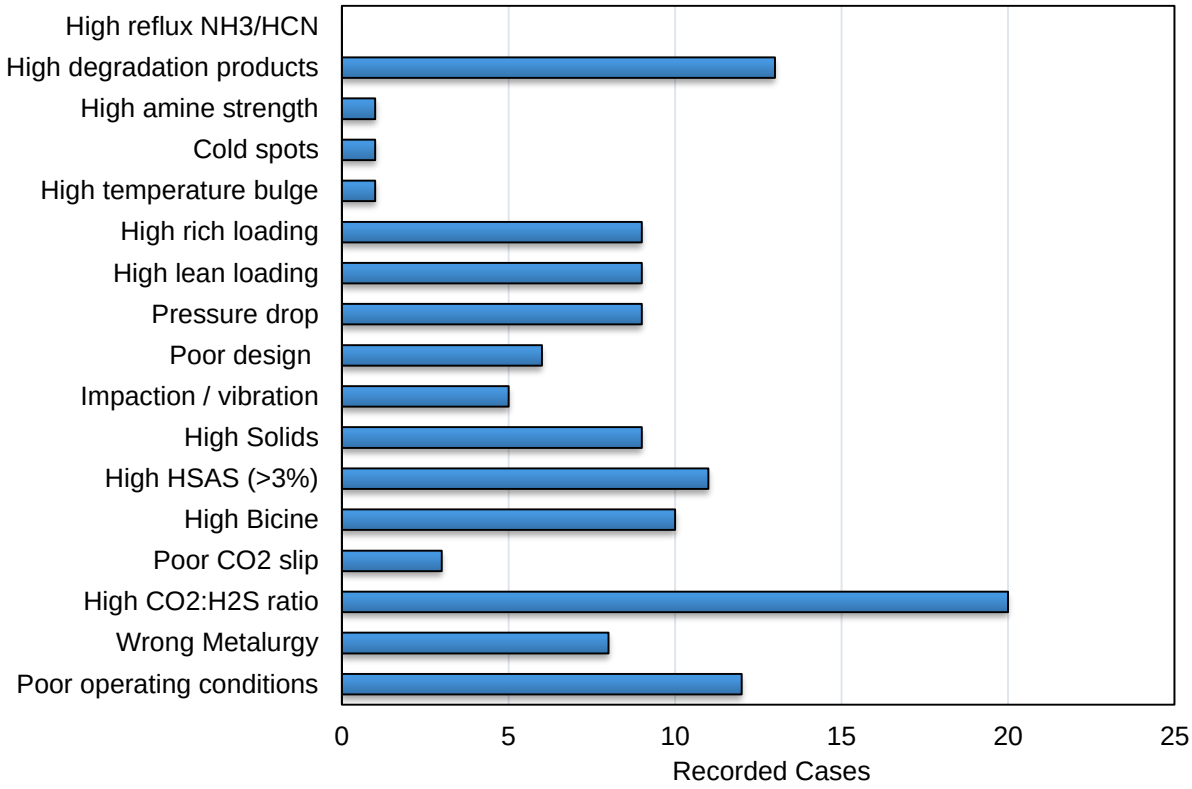


Figure 11: Root Causes of Corrosion in Natural Gas Treating Systems

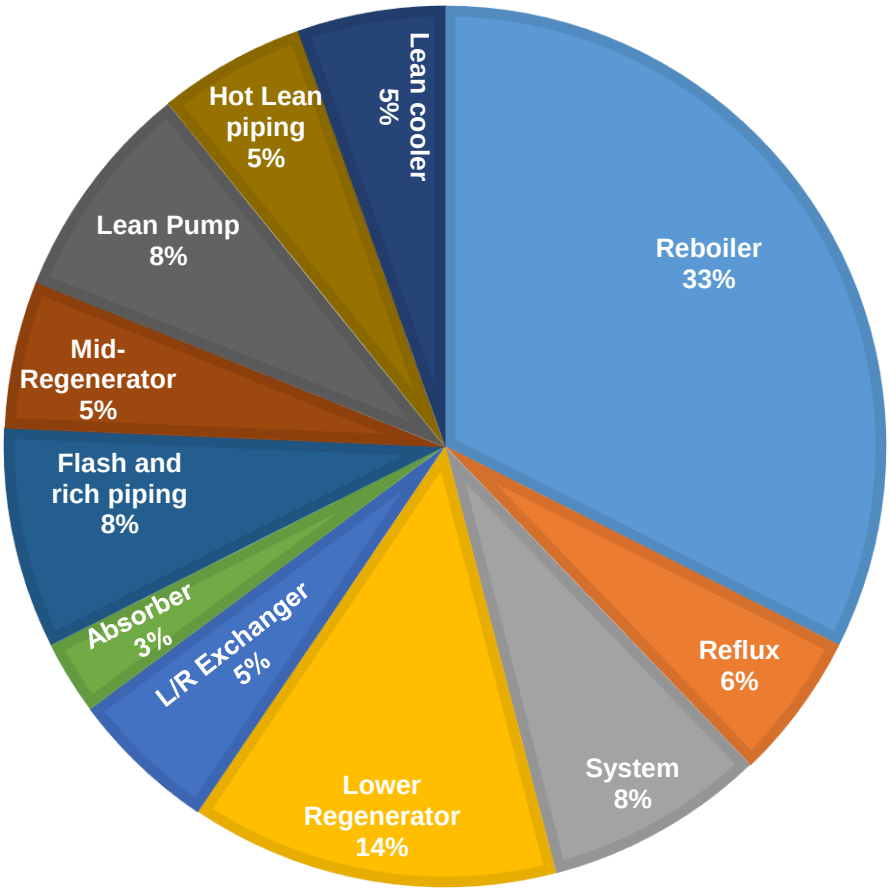


Figure 12: Corrosion Locations in Natural Gas Treating Systems

Amine system hygiene effectively requires limitation of other potentially corrosive contaminants. These contaminants include: solids, degradation products, heat stable amine salts and amino acids (including bicine).

1) Solids in the amine system can contribute to corrosion via erosion of the metal or passivation layers protecting it. Total suspended solids should ideally be kept below 10 ppmw based on use of a 0.45µm absolute filter to test the solution. Note that actual solids levels in the system will differ as a result of increased solubility of many solid precipitates with agitation and temperature. Adequate mechanical filtration and maintenance of the filters is indispensable in maintaining solution quality [3].

2) Heat Stable Amine Salts (HSAS) form via reaction of the amine with a contaminant acid that typically enters the system with the feedstock. The resulting acid-amine salt that forms is not readily regenerable at normal amine system stripping conditions and is hence given the name 'heat stable'. While the acid precursors that enter the unit may be present only at trace levels the HSAS that forms will continue to build up in the system until they are removed.

   Above 3 wt% HSAS in the amine the corrosiveness of the amine rapidly increases. Figure 13 shows a section from the bottom part of a corroded regenerator which was replaced as a result of HSAS based corrosion, salts had been allowed to build up in the system to approximately 5 wt%. This is a standard industry guideline that is generally consistent with the information in the database, however, there were some cases where corrosion was observed at 2 wt% HSAS. The cases where corrosion occurred at lower than the industry recommended guideline were all in systems with a high CO_2:H_2S ratio in the feed and utilizing MDEA, which is the weakest bonding amine used in the gas processing industry.

   Heat stable salts can be removed from an amine system by several methods:
   1) Amine replacement
   2) Ion-exchange
   3) Electrodialysis
   4) Vacuum distillation
   5) Thermal reclamation (traditionally only MEA and DGA™)

   HSAS may also be neutralized via the addition of strong base species (usually sodium or potassium containing) to form Heat Stable Salts (HSS). There are, however, limits to the amount of HSS that a system may contain before HSSs precipitate out of the solution and plug parts of the unit. Neutralization also has implications for the HSAS removal methods listed above and is best applied intelligently as part of a heat stable salt management strategy that takes into account the system size, geographic location and HSAS build-up rate.

3) Degradation Products will build up within the amine system over time as a result of thermal exposure and the reaction of amine with CO_2 or Oxygen. Some of these products may be corrosive and they should be monitored regularly and kept within vendor recommended limits. Limiting reboiler tube temperatures to less than 165°C (330°F) will largely eliminate thermal degradation in an amine system. Degradation products are normally removed via installed thermal reclaimers in MEA and DGA™ systems. For DEA, DIPA and MDEA, vacuum distillation or inventory replacement are the established options. MDEA is extremely resistant to chemical degradation and degradation rates in DIPA are lower than MEA, DEA or DGA™.

4) Amino Acids develop in amine systems as a result of the ingress of oxidizing components e.g. O_2, SO_2 and S_X into an amine system causing oxidative degradation of the amine followed by subsequent reaction to amino acids. Bicine (one of several amino acids found in amine systems) has been linked to corrosion in several amine systems [11,12,13]. Bicine functions as a chelant, increasing the solubility of iron in amine by a factor of just under 500 [13]. More recently, several other amino acids have also been linked to corrosion in amine systems [13,14]; with hydroxyethyl sarcosine (HES) being thought to be the most frequently occurring [14].

While several industry limits have been proposed for bicine, review of the data does not reveal any consistency in the level at which bicine will corrode a system. This is likely due to the role of other amino acids (e.g. HES) that have historically not been analyzed for in amine systems.

Amino acids are zwitterions, neutral molecules with both positive and negative charge, and can thus be removed or partially removed by ion exchange and electrodialysis techniques. Neutralisation is not considered an effective method for amino acid removal. Amine replacement or vacuum distillation will also remove amino acids.



Figure 13: Severe acid attack in regenerator bottom section, opposite reboiler return line.

Process Conditions (listed as 'poor operating conditions' in Figure 11) in gas plants is effectively a situation where a large amount of the acid gases absorbed in the rich amine are stripped in the reboiler rather than in the regenerator column. Typical industry guidelines vary between advising that 95 to 99% of the acid gases present in the rich amine be stripped in the regenerator rather than the reboiler.

Excessive amine stripping in the reboiler will often result in pitting type corrosion in the reboiler and lower regenerator. This is avoided by maintaining adequate heat medium flow to the reboiler. This will also generally allow the unit to operate at lower lean loadings which may in turn be beneficial in terms of meeting specification.

Figure 14 shows examples of reboilers that have been corroded due to excessive acid gas break out in the reboiler. In both cases, a large proportion of the stripping was occurring in the reboiler rather than the regenerator.

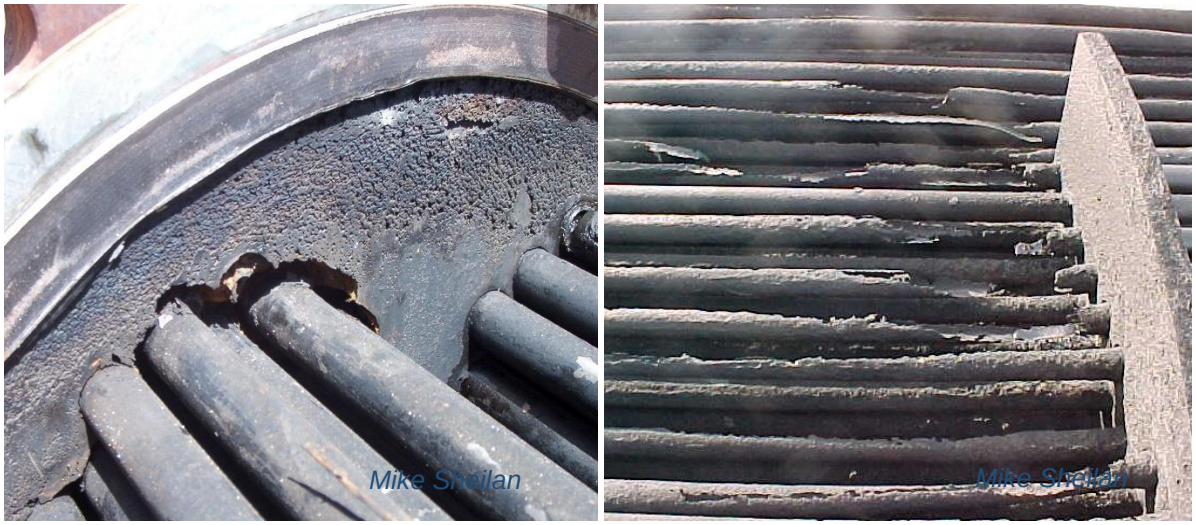


Figure 14: Reboilers corroded by excessive acid gas breakout.

CONCLUSION

Foaming, off specification product and corrosion are the three biggest challenges in reliably operating amine units and have cost the industry billions of dollars over the last 30 years.

Foaming problems in gas plants have been found to be due predominantly (75%) to inlet contamination of the feed with impurities that have surface tension affecting properties. Adequate inlet separation equipment and proper maintenance of existing equipment is critical.

Product not meeting its H_2S specification is most commonly caused by high lean amine loadings, though several other factors may also play an important role.

Corrosion was the result of a range of conditions and is by far the most complex operational issue to address as well as the biggest safety risk to staff. In a well-designed system, that does not have significant prior history of corrosion, the biggest risk factors are the amine solution quality and excessive reduction of the heat medium to the reboiler.

Review of the catastrophic failures of 148 gas plants showed that approximately 50% of the failures could have been eliminated if the following had been in place/performed:

1) Adequate and well maintained inlet separation equipment
2) Proper regeneration of the solvent such that lean amine loading is low and the bulk of the regeneration occurs in the regenerator
3) Regular solvent quality monitoring and having a strategy to maintain HSAS, degradation products, amino acids and solids within acceptable limits.

Based on these findings it is advised that plant operators recite the following mantra on a daily basis:
"FILTERS ON, STEAM IN, SALTS OUT"

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Amine Experts, a division of Sulphur Experts Inc., offers expert process engineering and evaluation services for Amine systems around the world. Since 1998, Amine Experts has performed projects in over 50 countries, involving many different styles and types of amine and glycol plants, MEROX and sour water stripper systems.

We provide on-site sampling and analytical services to troubleshoot performance issues and solve process problems. Our experts also provide technical training at our internationally recognized Amine Seminars to ensure both plant engineers and operators understand the intricacies of effective design and operation to get the most out of their systems. We also provide specialized on-site training tailored to meet the specific needs of our clients.