Amine unit cost elements

Two surveys were organised by the Amine Best Practices Group in order to build a database to compare the operating efficiency of different amine units. This article reports the findings of the latest survey, which focused on the question of operating costs and some of the design features affecting them

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The Amine Best Practices Group (ABPG) was formed in 1993 by a group of refiners and consultants who were interested in developing a set of benchmarks for measuring the relative performances of their amine units. They determined that no real-world published data were available against which to measure their own performance, and they therefore agreed to conduct an industry wide survey to generate the necessary data to be able to make benchmarking comparisons. To develop the survey document, the group first defined goals for an amine unit. The four goals were:

—To meet the refinery's specification for treated products
—To produce a steady, clean feed for the sulphur recovery units
—To achieve these two goals reliably
—To achieve all three goals at the minimum cost.

In a previous article, ABPG reported on the results of the survey, carried out in 1994. The database resulting from the survey responses, which at that time included data from 62 refinery amine units, led the Group to the following conclusions:

—There is a potentially large cost differential between a well run unit and a poorly run unit, possibly over $1 million a year
—Amine makeup rates were substantially higher than was to be expected from any previously published data
—There was a clear relationship between the amount of heat input to the regenerator and the frequency of episodes of off-spec product
—There was a weak relationship between the level of amine contamination and the amount of amine makeup.
—More data focusing on the cost of real operating units was needed to provide a benchmark against which to measure the fourth goal.

Reader response was overwhelming. Another 20 refiners asked to join the survey and to receive the resulting database. That database now contains operating data on 82 refinery amine units. Although the database is significantly bigger, and the quartile benchmark values are slightly different the conclusions listed above are still true. Median quartile values from the expanded database are indicated in Table 1.

1996 amine cost survey

It became clear in analysing the results of the amine operating survey that any real benchmarks against which to measure unit operations must include more cost data than was available. Clearly, there are cost related tradeoffs between the various benchmarking parameters chosen from the operating survey.

The relationship between steam usage and off-spec operation mentioned above is a good example: one would not expect the same refinery in the first quartile in both energy costs and on-spec operation.

The meaning of good operation here will depend entirely on the way the refinery values steam and the costs of off-spec operation. If the cost of being off-spec is high and the cost of low pressure is lower than the off-spec cost the refiner will properly choose to incur the high steam cost to avoid the even higher costs of being off-spec. In order to accumulate enough real-world operating cost data to understand the relationships between the various elements of cost in an amine unit the ABPG asked amine operators to respond to another survey. This survey, distributed at the end of 1995, aimed at a number of operating cost parameters and at some of the design features that might influence operating cost elements. The remainder of this article will report on the results of that operating cost survey.

To date, there are 47 separate amine units participating in the survey. Of these 47, there are nine units (19 per cent) using monoethylanolamine (MEA), 25 units (53 per cent) using diethanolamine (DEA) and 13 (28 per cent) using methyldiethanolamine (MDEA) in either generic form or in proprietary blends. The measure of size used in most of the data analysis is the rich amine feed rate to the regenerator.

Throughout this article this measure of unit size will be used to eliminate the impact of size alone on various cost elements. The survey responders range in size from 90gpm to 2900gpm amine circulation rate.

Of the 47 survey responders 39 are refinery units, four are tail gas treating units, three are natural gas processing plants, and one is a chemical plant removing CO_2 only from a gas stream. One of the tailgas treating units is

Updated first and fourth quartile median values

Operations measurement	Units	First	Fourth
Heat to the regenerator	Btu/gal circ	645	1200
Amine makeup rate	lb/equiv MMscf	1.8	24
Off-spec incidents	Times/year	0	18
Downtime	Days/year	0	10
Contamination cost	$/year/gpm	$10	$250
Upsets caused by amine unit	Times/year	0	15

Table 1

combined with the refinery's main amine scrubbing system, using a common regenerator.

The wide range of unit sizes and amine technology applications is both a problem and a benefit to the analysis of the resulting database. A problem in that many of the raw correlations show a wide scatter in the data, making trends somewhat more difficult to recognise and, perhaps, masking subtle interactions that may be unexpected. A benefit in that the wide range covers virtually all the common amine technology applications so that much good information can be obtained by reviewing groups of units with common properties.

The cost of operating an amine unit can be broken into five different classifications for purposes of analysis and control. These are as follows:

Energy costs, in this survey considered to be the heat input to the regenerator, either through the reboiler, the reclaimer, or by direct injection. The electrical energy cost for pumping the amine is relatively small and is generally outside the direct control of the unit operator and so is not included here.

Make up costs for replacing lost amine. This is simply the total annual cost of amine purchased for the plant.

Contamination costs, in this survey considered to be all the costs of removing foreign materials from the amine inventory. This includes the non-energy cost of reclaiming, filtration, and additives injected to control HSS or foaming.

Corrosion and maintenance costs. Much attention was given to corrosion as it is the only part of maintenance costs that is somewhat under the control of the unit operator, being related to amine condition and to the way the unit is operated.

Indirect cost of unit upsets and maloperation, including Claus unit upsets, limitations in the feed to upstream units, and the cost of off-spec operation.

Energy costs

By a large margin the primary controllable energy cost is the steam used in the stripper reboiler to regenerate the rich amine. This steam must provide the energy to accomplish three essentials. These are: the heat necessary to raise the rich amine to its boiling temperature at the pressure in the bottom of the regenerator, the chemical heat required to break the chemical bond between the amine and the acid gas, and heat to boil up enough steam to carry the acid gas out of the top of the regenerator. Below this minimum the lean amine will be under stripped, while above the minimum stripping is slightly improved but with increased energy costs. Data from the present survey confirms the data from the earlier survey in the relationship between steam rate and off-spec treated product. Below a break point of about 800–850Btu/gpm of rich amine fed to the regenerator the likelihood of an off-spec incident increases rapidly. That is, units using more steam than this break point all have relatively few off-spec incidences while those operating at lower than the break point steam usage include all the units having significant problems with off-spec products.

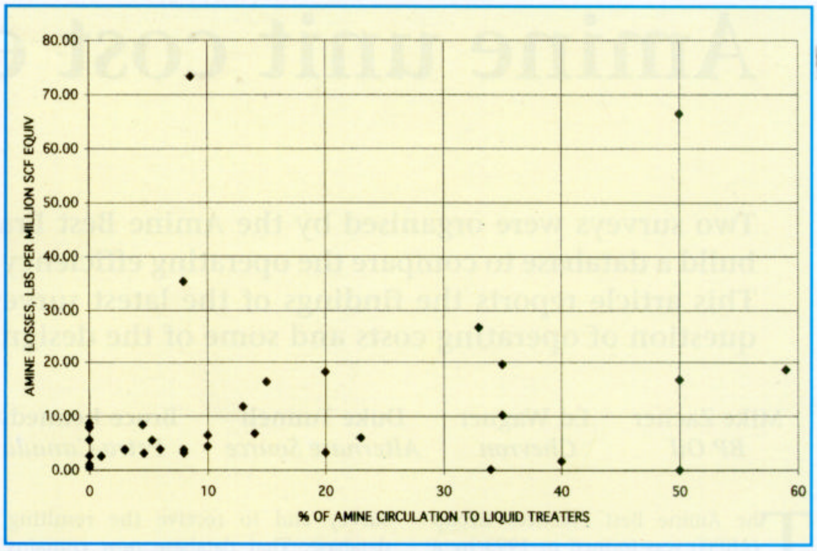

***Figure 1** Amine loss rate vs amount of liquid treating*

This suggests that high steam rates are a form of insurance against off-spec product. The appropriate operating strategy for a refiner depends on the relative values placed on steam and on not meeting the refinery specification for treated products. Note that in the survey the products are the sweet fuel gas or hydrogen recycle or the like, and LPG fed to a caustic pretreater or Merox unit. The specification is the one set by the refinery for the particular application.

In principle, this relative valuation of steam and product quality would set the refiner's steam flow control strategy as well as helping set the desirable rate. In a unit with low cost steam and high off-spec, costs would be more likely to use a low tech control system, perhaps a simple steam flow controller, with the rate maintained at some comfortable rate.

High cost steam and low cost of off-spec operation would argue for a high tech control – for example, a regenerator vapour line temperature controller to maintain a constant rate of stripping steam in the overhead regardless of regenerator feed quality.

An intermediate control system might use rich amine flow rate to set reboiler steam rate through a ratio controller.

Cost survey responders were asked what regenerator reboiler steam control system they used. Most of the responders – 24 (56 per cent) of the 43 providing this data – use a simple steam flow control system, and average 1.03lb of steam per gallon of rich amine fed to the regenerator. Some of the responders – 13 (30 per cent) – use a flow ratio control system, and these average 0.88lb of steam per gallon.

The remainder of the units providing data for this question – six (14 per cent) – use an overhead temperature controller to set steam flow. These average 1.16lb per gallon.

It is interesting to note that the six units using the more advanced overhead temperature control system have about twice the frequency of off-spec operation, despite their higher steam usage, than those using the other two control systems, which appear about equal in this respect.

The survey data do not provide a reason for this anomaly. It may be that since the overhead temperature control is a feedback system it may be unable to respond to changes in the amine rapidly enough to prevent the product stream from going off-spec, or has some other inherent instability. No tailgas units, which might have explained the anomaly by their more stringent limitations, are included in the six advanced control applications.

Amine makeup costs

The 1994 survey data revealed unexpected high amine loss rates. The updated average volume of makeup amine was 3.1 system inventory changeouts a year. The data in the present survey support this high loss rate, averaging about 2.8

inventory changes a year. Expressed in pounds of amine per year used per equivalent million standard cubic feet (scf) of gas treated, the value is about 12lb, compared with about 13lb in the previous survey.

Note that equivalent cubic feet includes a simplified correction to try to include the impact of LPG treating on this correlation. The liquid treated is assumed to be propane and this volume is expressed as if it were vaporised. A factor of 36scf per gallon of liquid treated was used in computing the above use rates.

The present survey data suggest (as did the 1994 survey) one of the major causes of amine losses is treating of liquids. Figure 1 illustrates this. While the data are scattered and there are one or two serious outliers there is a clear indication that units that have a high proportion of liquid treating have higher loss rates than those with little or no liquid treating.

Note that three of the responding refiners have water wash devices on the effluent LPG from their liquid amine treaters. These three average 3.6lb per equivalent million scf compared with about 12 for all responders. While the sample is too small from which to draw a firm conclusion, it does suggest this may be an excellent way to reduce amine losses from liquid treaters

Filter changeouts also seem to play a role in amine losses. Survey data indicate a weak correlation between these factors, showing that plants with a high frequency of filter changeouts tend to have a higher loss rate.

Comparing loss rate against the amine circulation rate of the responding unit suggests that large units are somewhat tighter than small ones. This is as expected because of the higher absolute cost of losses from large units compared to small.

There is a virtually no correlation between amine losses and the frequency of absorber foaming or the amount of antifoam used. Contrary to expectations absorber foaming does not appear to be a significant cause of amine losses. This finding, coupled with the correlation between unit size and losses, suggests that most units, particularly large ones, are equipped with amine collection devices, such as knockout pots, to collect the amine carried out of the absorber during a foaming episode.

Refiners that use a prewash of some sort on the sour gas feed to the absorber report slightly lower loss rates, averaging about 10lb per equivalent million scf compared to 12 for the entire survey. Twelve refiners report data on this process configuration. Only three of the 12 responding units are above the average circulation rate, and two of the 12 are tailgas units.

Contamination costs

The cost of contamination, as used in this report, include everything in the amine solution except the amine and the water. These might include HSS, degradation products, oxidation products, oils and other liquid hydrocarbons, various surfactants, and solids. The costs incurred by the refiner by the presence of these contaminants include reclaiming of the amine to remove HSS, particle filtration to remove solids, carbon filtration to remove surface active agents, and the cost of additives used to mitigate foaming, corrosion and HSS problems in the amine solution.

On the whole, the cost of contamination reported by the responders was lower than expected.

It is interesting that the concentration of HSS in the amine solution does not correlate at all with reported corrosion rate data, maintenance cost data, or filtration costs. Virtually all of the responders report HSS levels well below the rule of thumb maximum of 10wt% of the total amine. The data may be verifying that this is a reasonable threshold value; below the 10 per cent threshold there is no cost correlation, above the limit there may actually exist a correlation with one of these cost elements.

There are several ways to control the level of HSS in the amine solution. The usually seen ones are dump and charge, atmospheric or vacuum distillation, and merchant reclaiming by either ion exchange or electrodialysis techniques. In this survey no one reported vacuum reclaiming while one reported using a dump and charge strategy for controlling HSS in DEA at a cost of about $1.50/year per gallon of circulating inventory. Two responders use atmospheric distillation to thermally reclaim MEA at a cost of about $0.50/year per gallon.

The survey data do not reveal the relative use of the two types of merchant reclaiming. The cost of merchant reclaiming of DEA, reported by seven refiners averages about $0.70/year per gallon of circulating inventory, with little variation in the data. The three responders who merchant reclaim MDEA report an average cost of about $2.75/year per gallon of inventory. It must be noted that two of these three are tail gas treating units with relatively low tolerance for HSS.

Clearly, the rate of buildup of HSS is not uniform among the survey responders, nor is the plant limit set for HSS content in the amine. No conclusion can be drawn from this limited cost of reclaiming data except that the available methods of controlling HSS in amine solutions are expensive.

Efforts to keep the contaminants out of the amine in the first place may pay significant dividends compared to reclaiming costs. Those refiners using a water wash on the sour gas before the absorber, excluding the tail gas units, average only $0.27/year per gallon. The water wash technique would seem to be effective in reducing reclaiming costs.

The previous survey indicated that most refiners use antifoam only in shots as needed. The present survey looked at the cost of using antifoam as well as other additives and found them to be minimal compared with other amine unit cost elements.

It is interesting to note that five MEA plants report an average antifoam cost of $4.20/year per gpm of circulation. The corresponding amount for DEA is $2.00 and for MDEA is just over $20.00/year per gpm. There is no indication in the survey data why the cost for MDEA should be out of line with the other amines. There appears to be no correlation between water washing sour gas and foaming or cost of antifoam.

The median cost of amine filtration is about $41/year per gpm of total amine circulation. Here again, the presence of a prewash facility on the sour gas seems to have no impact on amine filtration.

Corrosion costs

The amine cost survey asked the responders to comment on the worst corrosion area in the unit. Thirty-two refiners provided corrosion data in response to this query. The regenerator overhead system seems to be the worst corrosion problem with 14 refiners (44 per cent) indicating this area as their worst. In close second was the regenerator bottoms system, with 13 refiners (41 per cent) indicating this area.

Most of the remainder of the responders voted for the regenerator feed system as the worst area. Only two responders indicted other areas of serious corrosion.

Corrosion rates reported for the worst area ranged from about 10 mils/year (mpy) to over 100mpy, with most of the higher rates reported to be in the overhead system. Corrosion rates in other parts of the plant averaged substantially lower, generally well below 10mpy.

Metallurgy in the areas of concern for corrosion around the regenerator is carbon steel in about three-quarters of the responding units and stainless steel in the remaining quarter of the plants. In general, DEA units use slightly more stainless steel than do either MEA or MDEA units. Stainless is used more often in the regenerator reboiler and feed systems than in other locations. Plants using stainless steel report lower corrosion rates in these areas, as would be expected.

Corrosion inhibitor use appears to be low, averaging about $75/year per gpm of circulation for the plants that use it, but only 11 of the 34 providing data use inhibitor. Figure 2 compares the average corrosion rate reported for each unit with the inhibitor cost. This illustration, although with few data points because few responders provided adequate corrosion rate data, suggests that inhibitor programs are effective in preventing corrosion. Plants reporting no inhibitor cost tend to have higher corrosion rates than those who report a cost. The overall median corrosion rate for all plants responding is about 2mpy.

The correlation between corrosion rates and total amine unit maintenance costs appears to be inverse; that is, plants reporting high corrosion rates seem to have lower maintenance costs than those reporting low corrosion rates. This suggests that corrosion is not a significant factor in determining overall maintenance cost. There seems to be no correlation between the use of stainless steel and overall maintenance costs. The average of all units reporting maintenance costs is $735/year per gpm of circulation.

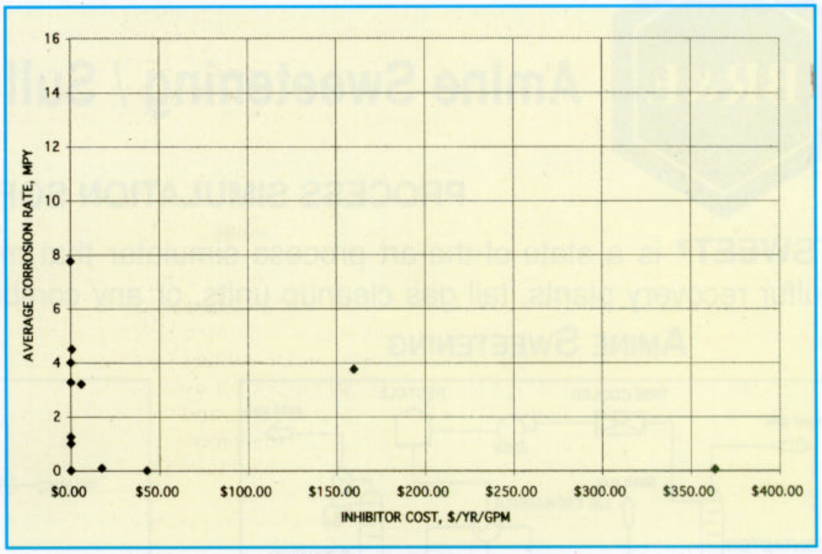

***Figure 2** Corrosion rate vs inhibitor cost*

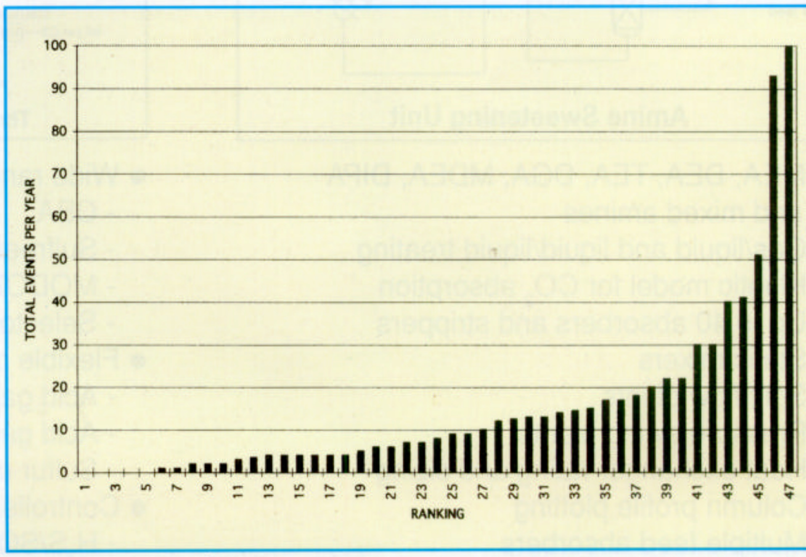

***Figure 3** Frequency of events*

Other operating costs

All the cost elements discussed here are easily quantifiable; that is, somebody writes a cheque to an amine vendor or charges hours to a maintenance work order. There are other, potentially very significant costs of operating an amine treating unit. These result when maloperation or misfortune in the amine unit have an impact on the process plants depending on the amine unit for their operation.

When the amine unit is not able to operate at the needed capacity, then upstream units, like cat crackers, cannot operate at full capacity and the resulting lost production costs money. When the products being treated are off-spec, other costs are incurred, ranging from the cost of retreating products or increased treating costs elsewhere in the refinery, to shutting in natural gas production or the risk of incurring an air violation fine.

If the amine unit produces a feed for the sulphur plant that is loaded with hydrocarbons or water, it can cause upsets or emergency trips. These sulphur plant events carry with them a risk of damage to the plant, or other potentially expensive incidents. These unquantifiable costs should be guesstimated in each plant and the results used in making operating decisions about the unit. The survey data suggest that these events are disturbingly common. Figure 3 illustrates the frequency of all the events mentioned above, totalled. It indicates that the median refiner has a total of eight potentially costly events a year caused by his amine unit. While it is impossible to estimate the cost of these events here, clearly there is the potential for large costs which should be recognised and assigned to the amine unit when attempting to analyse or optimise amine unit operations.

One common rule of thumb suggests a large residence time in the rich amine flash drum is the key to reducing the frequency of upsets. The ABPG cost survey looked at flash drum residence time. This variable does not correlate at all with sulphur plant trips or any of the common upset causes: hydrocarbon excursions, regenerator foaming or flow rate swings.

Plants with small drums having only a few minutes residence time seem to have the same number of upsets as plants with large drums. One can only speculate that this may be due to a change in the design of flash drums. Newer, larger flash drums usually have internal baffles to control the level of amine and have relatively little surge volume beyond the baffle for amine flowing to the regenerator. Older, smaller drums usually had no internals except a skim nozzle and the whole drum provided surge volume for the amine.

Thus the newer design can introduce some control instability causing fluctuating flow to the regenerator, and thus upset the Claus unit.

Conclusions

A review of the cost survey database leads to some interesting conclusions. There are several cost elements to be considered in analysing amine unit operations, and they all seem to be inter-related. Energy costs affect off-spec product costs. Amine cleanup costs may affect corrosion and maintenance costs. Maintenance costs may affect the frequency and thus the cost of upsets or lost production. Facilities costs may affect amine makeup costs.

Without some consideration of all these cost elements it becomes difficult to make the right decisions about the operation of an amine unit.

There is a very high degree of scatter in the raw data taken from the survey responses proving once again that the cost elements for an individual amine unit are dependent on the situation inside the plant itself. There are no magic bullets for controlling operating costs or improving operations to be found in a gross review of the survey data. There is much benefit and assistance to be had from a review of individual units in the database. This allows units operating in the same mode to be found and operating and cost data to be compared and useful conclusions to be drawn from the analysis.

In an attempt to provide some information on the magnitude of the cost difference between a well run first quartile and a poorly run fourth quartile unit each of the responding plants was ranked on its total cost of operations. Some of the operating cost data is included in the survey responses.

Survey responders were asked to provide data on their cost of filter changeouts, additive costs, costs of controlling HSS, and maintenance costs. They provided information on the volume of amine makeup, the heat input to the regenerator reboiler and the frequency of upsets. By applying some generic cost factors for the remaining elements it is possible to estimate the total operating cost differential between various units.

To eliminate the impact of plant size the total cost figures were divided by the amine circulating rate. The final unit costs were ranked and broken into quartiles. The median first quartile amine unit costs, on this arbitrary basis, about \$1400/year per gpm of circulation. The fourth quartile plant costs about \$3400 on the same basis.

The difference, about \$2000, when applied to the average size plant in the survey, with 669gpm circulation, represents \$1.338 million/year lost to poor operation. For an average plant this is not chicken feed, and will well repay the efforts of the process engineer or the operating superintendent to understand and control costs.

The survey responses helped determine the relative proportion each element plays in the overall cost of operating a typical amine unit. Energy cost was by far the largest at about 72 per cent of the total quantifiable cost. Maintenance and corrosion cost takes 15 per cent, amine losses consume about 8.5 per cent and contamination costs are 4.5 per cent. It is impossible to estimate the total cost of maloperation from the survey data.

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Operators who choose to participate in the ABPG cost survey will receive the complete survey database, with the identities of the participants masked. To receive a copy of the survey questionnaire, contact Bruce Scott Inc at 182 Irwin Street, San Rafael CA 94901, USA, or by phone/fax +1-415-485-5626.

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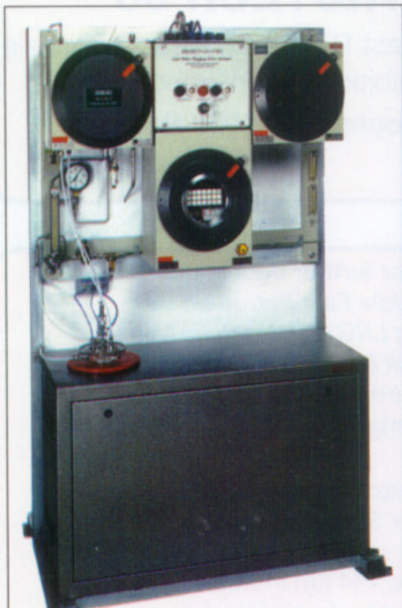

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