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SPECIAL REPORT:

PUT STEAM INTO YOUR EFFORTS

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CONTENTS


167

The importance of steam in the Oil, Gas and Chemical Industry

It is estimated that steam generation accounts for approximately 50% of total energy consumption for a typical refinery, with energy costs accounting for over 50% of total operating expenditure.

The U.S. Department of Energy (DOE) estimates that steam generation, distribution and cogeneration offer the most cost-effective energy efficiencies in the short term with potential energy savings at over 12%. The table below [1] estimates typical savings achieved for the steam distribution system and condensate return of a U.S. refinery.

Further savings also can be achieved in the powerhouse where steam is generated; however, for this article, we will only be looking at steam distribution and condensate return.

Before looking at potential improvements and ways of optimizing the steam system, it is worth understanding the basic properties and characteristics of steam as outlined in the temperature enthalpy diagram in Figure 1: When energy is added to water, the temperature rises until it reaches the point of evaporation (B), which varies with pressure. The energy required to reach point B is known as sensible heat (hf). Any additional energy will convert the water to steam at a constant temperature. At point (D), all water has been completely converted to steam, which is known as dry saturated steam with a steam quality (dryness fraction) of 100%.

The energy added between points B and D is known as enthalpy of evaporation (hfg) and is the energy steam gives out as it condenses back to water. It is the enthalpy of evaporation, which is used in the refining process.

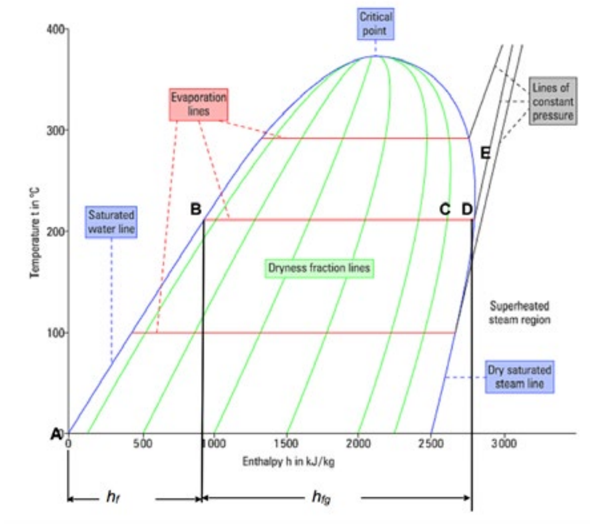
If further energy is added, steam temperature will increase, creating superheated steam (E). It is superheated steam, which is used in a typical powerhouse, (at approximately 100 barg and 450°C), as part of the cogeneration or combined heat and power (CHP) system.

For heating purposes superheated steam offers very little extra energy, and in fact, the steam has to cool to

	Measure	Fuel Saved	Payback Period (years)	Other Benefits
Steam Distribution	Improved insulation	3–13%	1.1	
	Steam trap maintenance	10–15%	0.5	
	Automatic steam trap monitoring	5%	1	
	Leak repair	3–5%	0.4	Reduced requirement for major repairs
	Flash steam recovery/condensate return	Dependent on existing use for flash steam	Variable dependent on application	Reduced water consumption and water treatment costs
	Condensate return alone	10%	1.1	Reduced water consumption and water treatment costs

Steam Energy Savings

Table 1: The table above shows estimates of typical savings achieved for the steam distribution system and condensate return of a U.S. refinery.



Temperature Enthalpy Diagram

Figure 1. The energy added between points B and D is known as enthalpy of evaporation and is the energy steam gives out as it condenses back to water.

saturated temperature before the enthalpy of evaporation can be released. Therefore, using superheated steam instead of saturated steam, at the point of use, actually slows down the heating process.

For the process to achieve maximum efficiency steam needs to arrive at the correct:

- Quality (target dryness fraction of 100%)
- Quantity (to allow the process to meet demand)
- Pressure (which determines saturated steam temperature and specific volume, so affecting thermal transfer).

Steam quality is a measure of dryness fraction. If the dryness fraction is lower than 100% (say point C, Figure 1), then the available energy/kg of steam will be less. Steam quality can be improved by ensuring the mains are well insulated and condensate is removed using steam traps and separators.

The ***quantity of steam*** required is dependent on process energy requirements; however, this relies on correct sizing of the steam distribution lines and control valves serving the application.

Where this can become an issue is when processes are upgraded, or additional assets added, increasing the steam load beyond the steam mains original specification. This results in increasing velocities within the steam system, causing higher pressure losses through the distribution system, leading onto the importance of steam pressure.

If the ***steam pressure*** is less than the acceptable designed pressures, the process will now be de-rated as the steam will be at a lower saturation temperature, reducing energy transfer rate.

It is impossible to cover every aspect of steam and condensate system design within a couple of magazine articles; therefore, the focus will be on key areas in our experience, which will have the greatest impact in reducing energy costs and improving efficiency.

CHECK THE INSULATION AROUND THE STEAM SYSTEM

First ensure the steam mains, and ancillary equipment are insulated, particularly valves, strainers and separators, which have large surface areas. After any maintenance work on the steam system, check that the insulation has been properly replaced. Good insulation will reduce heat losses by up to 90%.

Putting this into context, just one meter of an uninsulated 100mm steam main operating at ten barg will emit approximately 1.0 kW — equivalent to wasting nearly 16 tons of steam/year. This assumes that the pipe is dry and there is no wind chill!

Good insulation will reduce these loses to approximately 1.6 tons of steam/year. Also, insulating steam mains will reduce the risk of burns compared to bare pipework, where surface temperatures can be well over 400°C on a HP superheated line.

Even with good insulation, a certain amount of steam will condense out during distribution. This needs removed to maintain steam quality, and prevent the possibility of waterhammer.

WHAT IS WATERHAMMER?

As steam begins to condense, the condensate forms droplets on the inside of the walls, which are swept along in the steam flow, merging into a film. The condensate then gravitates towards the bottom of the pipe, where the film begins to increase in thickness.

The buildup of droplets of condensate along a length of steam pipework can eventually form a slug of water which will be carried at steam velocity along the pipework (25–30 m/s). This slug of water will eventually slam into bends in the pipework, valves or separators, in its path (Figure 2).

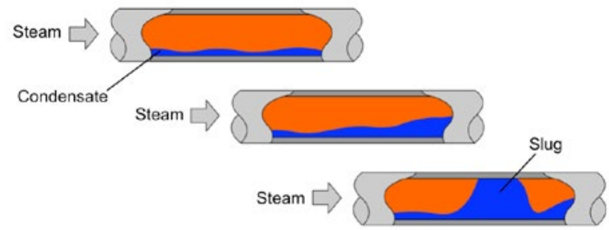
There is also a second cause of waterhammer known as thermal shock (Figure 3). Thermal shock occurs in two-phase systems where water occurs in two states (water and steam) in the same pipe. This can also take place in steam mains, condensate return lines, and heat exchange equipment. Steam bubbles become entrapped within pools of condensate (which have sufficiently cooled below saturated temperature) and immediately collapse.

Since a kilogram of steam occupies several hundred times the volume of one kilogram of water, when the steam collapses the condensate is accelerated into the resulting vacuum. As the void is filled, water impacts the center sending shock waves out in all directions.

Thermal shock therefore can occur where higher temperature return systems containing flash steam are discharged into sub-cooled condensate return lines.

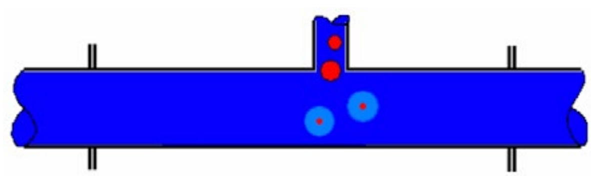
The forces resulting from waterhammer can be immense, resulting in steam mains to physically move, or, in worst cases rupture. We all remember the photo showing downtown New York where a steam main on the central district heating system ruptured. Figure 4, taken from a powerplant in the United States, shows the devastation waterhammer can have on a system:

Waterhammer, at best will increase maintenance costs, and at worst can rupture a steam main, bringing the plant to a halt and possibly killing anyone unfortunate enough to be at the wrong place at the wrong time. Yet, *waterhammer is easily preventable* through good engineering practices and using steam traps at regular intervals, preventing the build up of condensate.



Waterhammer

Figure 2. Waterhammer results when condensate droplets form a slug of water that slams into bends in the pipes, valves or separators in its path.

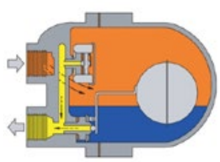
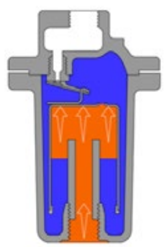
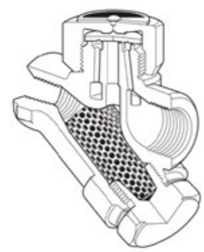
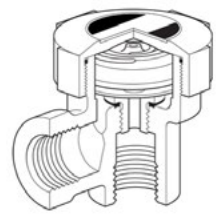
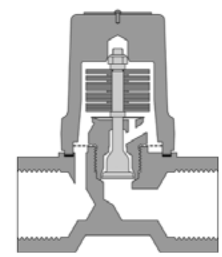


Thermal Shock

Figure 3. Steam bubbles become entrapped within pools of condensate and immediately collapse, causing another form of waterhammer.

Damage from Waterhammer

Figure 4. The damage to this truck bed came from part of a steam main that travelled over 400 m before landing in the car park.

Mechanical		Thermodynamic	Thermostatic	
Principle of operation: Distinguishes between steam and condensate using difference in density between steam and condensate. Removes condensate as it forms.		Principle of operation: Distinguishes between steam and condensate through variation of flow dynamics between the two fluids. Removes condensate as it forms.	Principle of operation: Use difference in temperature between steam and condensate. Condensate has to cool below the steam saturation temperature, before the trap will open, which leads to backing up of condensate.	
Float	Inverted Bucket	Thermodynamic	Balance Pressure	Bimetallic
	IB Trap 			

Types of Steam Straps

Table 2. Most steam traps operate using just three principles of operation.

STEAM TRAPPING

Many people underestimate the impact steam traps can have on the whole steam system and process. Some of the most common problems found in a steam system can be traced back to either the steam trap application or poor condensate removal. These issues can normally be resolved through good engineering practices, selection of the correct steam trap and a steam trap management program.

When selecting steam traps, it is worth remembering that most steam traps operate using just three principles of operation. Dependent on the application will determine which type of steam trap should be used. Tables 2 and 3 summarizes the three major types of traps and typical examples of where used in the oil and petrochemical plant.

Selecting the correct steam trap is just part of the solution, the next question is where should they be installed? Listed below are some general rules and guidelines to consider:

- *Along the steam main* (Figure 5) at approximate every 30–50 meters, using a pocket, which is the same diameter as the steam main up to 100mm. This will ensure that all condensate running along the bottom of the pipe will be captured and removed.
- *At all low points* on the steam main and wherever the steam main rises, at a gantry for example.
- *Before control valves*, in particular serving a process. By also using a separator (discussed later), will ensure that the steam entering the process will be dry saturated steam, so improving the heat exchanger efficiency. It will also minimize the risk of erosion of the control valve, reducing maintenance costs. Finally, it will ensure that condensate is drained when the control valve is in the closed position, preventing the risk of water hammer.
- *Before steam isolation valves*, again to remove the potential build up of condensate when the valve is closed.
- *At the end of each steam main*. This should have either a steam trap with good air venting properties, or a separate air vent.

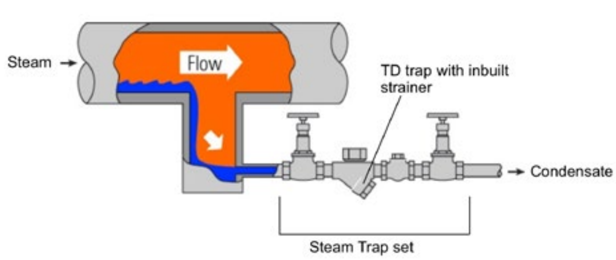
Application	Trap Types	Comments
Process Applications: e.g. Heat Exchangers: • Reboilers • Pre-heaters • Water heaters	Mechanical	Mechanical steam traps will remove the condensate as it forms, regardless of fluctuating loads — ensuring maximum steam space and heating surface area within the heat exchanger. Mechanical steam traps also have the greatest capacity, making them ideal for process applications
Distribution lines: e.g. Steam mains	Thermodynamic	Thermodynamic (TD) traps are robust and relatively low cost. TD's will remove the condensate as it forms, eliminating the risk of condensate backing up into the steam line.
	Thermostatic	Thermostatic traps, by their nature, will back up with condensate; however, they are robust and relatively low cost. Thermostatic traps can be used on distribution mains, provided there is a "cooling leg" between the trap and the steam mains.
Critical tracing: e.g. Sulphur lines	Thermodynamic	Thermodynamic traps will be the first choice, as they are compact, robust and low cost. They remove condensate as it forms, ensuring the traced product does not solidify.
	Mechanical	Mechanical traps are also used, but tend to be less compact.
Non-critical tracing; e.g. Instrumentation	Thermostatic	Thermostatic traps allow the condensate to sub-cool within the tracer before being discharged. This makes use of the sensible heat in the condensate and reduces the release of flash steam, particularly important if the trap is discharging to grade.

Steam Trap Applications

Table 3. The application will determine the type of steam trap used. This table gives examples of applications and preferred trap type.

Modern steam trap stations normally consist of "quick fit connectors," which allow traps to be isolated and changed out in minutes by removing just two bolts.

Quick fit steam traps have had a significant impact in reducing maintenance costs and total cost of ownership of steam traps.



Steam Trap Placement

Figure 5. Placing a steam trap along the steam main ensures that all condensate running along the bottom of the pipe will be captured and removed.

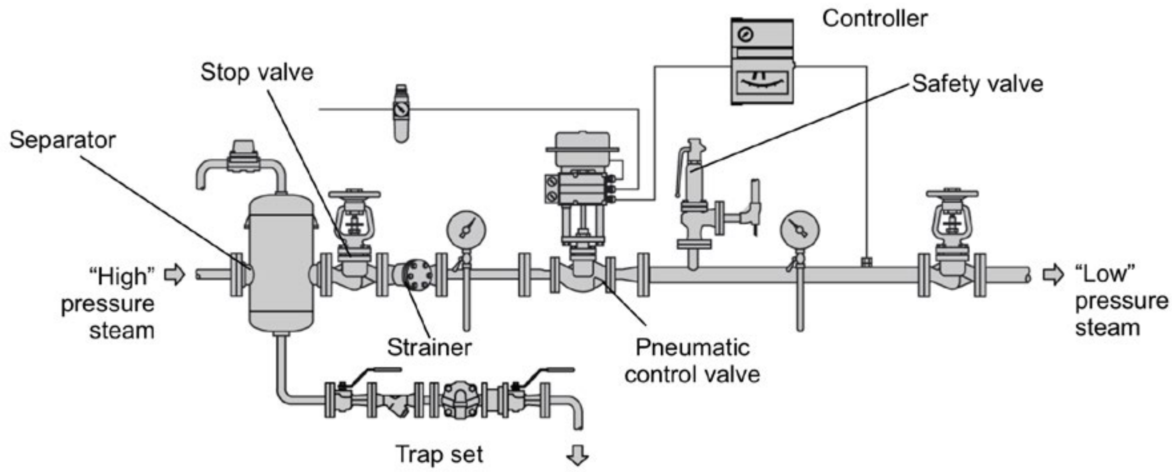
TESTING AND MAINTAINING STEAM TRAPS

Modern steam traps are reliable and robust, assuming that they have been correctly sized and selected for the given application. However, like anything they can fail.

A steam trap has two modes of failure, it can fail either open or closed / blocked.

If a steam trap fails open, there are two major consequences:

1. Steam wastage resulting in higher energy costs/ greater emissions, increased water consumption and boiler feedwater chemicals.
2. If the condensate is being returned, the condensate line becomes pressurized, which can have the effect of de-rating the capacity of any other steam trap discharging into the same condensate line. This is because the differential pressure across the steam trap has been reduced, and therefore less condensate will pass through a given size orifice.



Steam Trap Installation

Figure 6. This illustration depicts a typical separator and trap installation protecting a pressure control valve station.

Table 4 shows typical steam losses from just a single ½-in. thermodynamic (TD) steam trap used on high pressure (HP), medium pressure (MP) and low pressure (LP) steam mains when failed open. Although the figures used are conservative, this clearly shows the need to ensure steam traps are checked regularly and failed traps replaced as soon as possible. HP traps should be checked at least every six months, while MP and LP traps at least once a year.

During a steam trap audit, it is not unusual for Spirax Sarco to find over 10% of the steam trap population failed open, where a customer has not implemented a steam trap management scheme. In value terms, this normally shows potential savings of $ 100,000s/year with a payback of less than 6 months.

Figure 7 gives a couple of examples taken from actual steam trap audits.

Line pressure	Approx. steam loss tons/year* (Discharging into condensate line)	Approx. steam loss tons/year* (Discharging to grade)
100 barg	460	920
20 barg	95	190
5 barg	25	50

* Based on 8,700 hrs/year

Steam Losses

Table 4: This table shows steam loss from a single ½-in. TD steam trap used on high, medium and low pressure steam mains when failed open.

COLD STEAM TRAPS

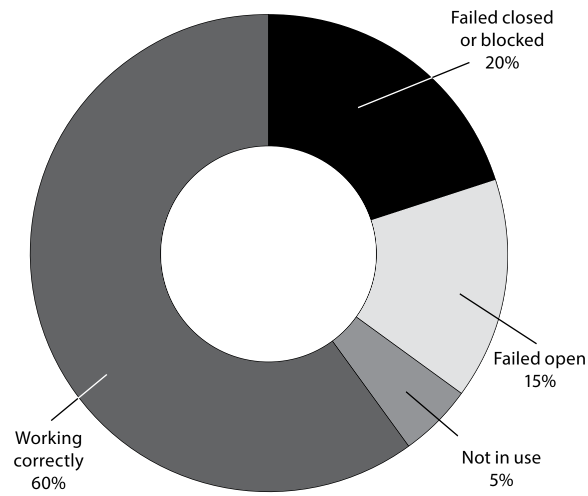
Cold steam traps are either failed closed, blocked, or, have been isolated (having failed open).

Although harder to show a return on investment by repairing these steam traps, the consequences of ignoring this situation can be significantly more costly.

Not replacing or maintaining cold traps can result in:

- Corrosion, leading to system degradation and increased maintenance costs.
- Waterhammer — giving the potential for catastrophic failure of the steam system — a major safety issue with possible fatal results.
- Freezing, leading to pipe ruptures.
- Valve erosion, wire drawing, vibration and failed valve packing, where traps have failed upstream of control valves.
- Corrosion and loss of heat transfer on tracing lines, leading to higher pumping costs or solidification of the product being traced.
- Blade erosion, vibration and drive shaft wear on turbines.

Steam trap audit results from a UK Refinery



Cost of steam wasted from failed open traps from a U.S. Chemical Plant

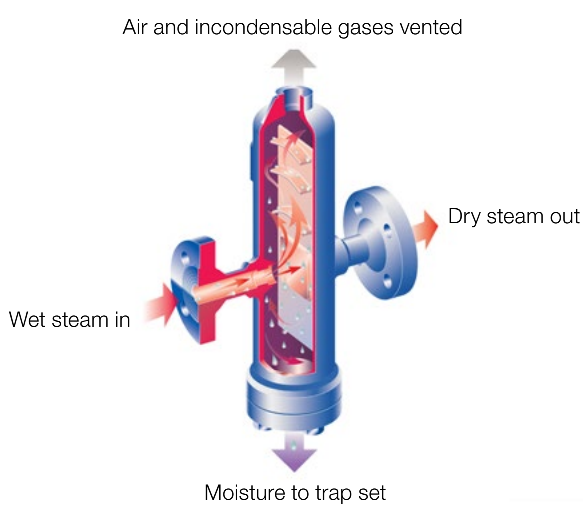
Unit	Steam loss ($)
Aromatics	51,111
Fire Water	6,975
Flare Skid	28,087
Light Olefins	323,847
OSBL PR	58,667
Pipe Rack	45,054
Pyro Naptha	21,932
Cyclohexane	28,811
Air Systems	20,454
Annual Loss	**$ 584,938**

Steam Trap Audits

Figure 7. With proper steam trap management, plants could see potential savings of $100,000s per year with a payback of less than 6 months.

It is advisable to use an external company, such as Spirax Sarco, to carry out steam trap audits and manage the steam trap population.

These companies will have highly trained survey engineers, who will not only check the operation of the steam traps, but will be able to advise on installation and, select and size the correct type of trap for a given application. Also, they can project manage the complete change out and installation process, if required, allowing site maintenance engineers to focus on the process.



Separator

Figure 8. Separators are used to remove entrained water in the steam system to bring the steam quality back up to nearly 100%.

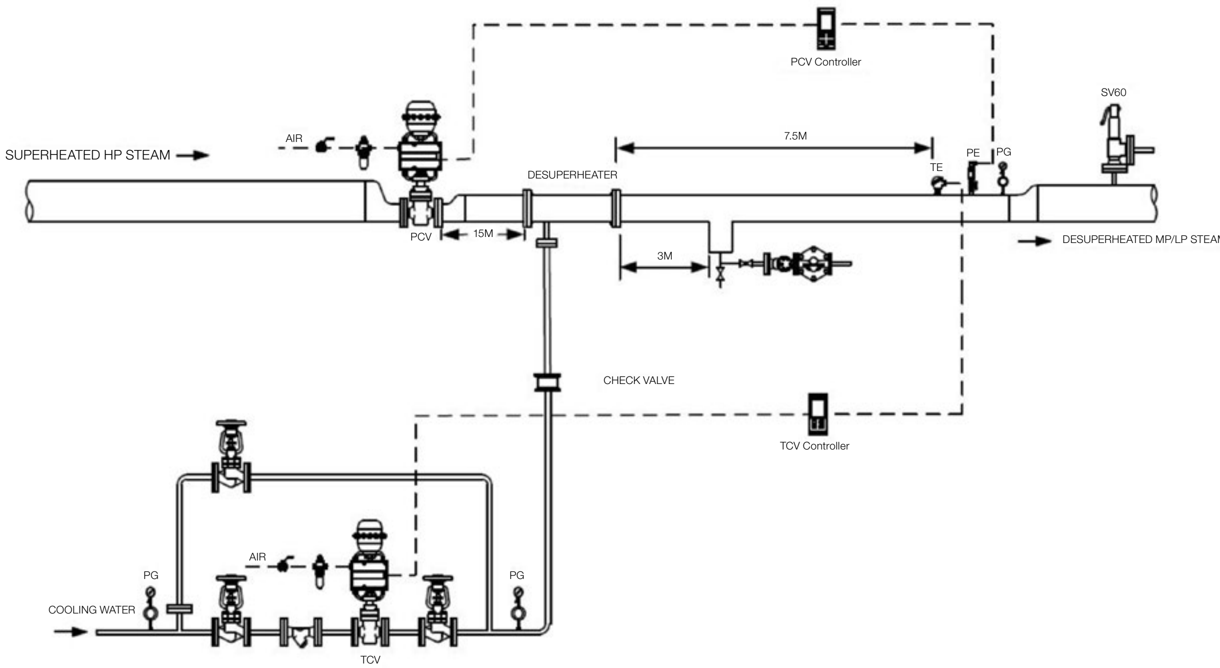
SEPARATORS ON A STEAM SYSTEM

Separators are used to remove entrained water in the steam system to bring the steam quality back up to nearly 100%. They consist of baffle plates, which separate out the water droplets from the steam flow as shown in Figure 8.

WHERE SHOULD SEPARATORS BE USED?

Separators should be installed in the following applications:

- *Upstream of control valves*, particularly just before a process, where they:
    - Protect steam equipment from erosion caused by wet steam
    - Ensure the process receives dry saturated steam, improving performance.



Desuperheater Station

Figure 9. This diagram shows a typical desuperheater application on a let down station.

- Drains the build up of condensate upstream of the control valve when in the closed position.

- *Boiler off take* to knock out any carryover, before distribution.
- *Downstream of desuperheater stations* to remove any remaining water which was not absorbed by the superheated steam.
- *Upstream of steam turbines*, so preventing the risk of damage through water droplets or water hammer.

DESUPERHEATER STATIONS

Superheated steam is generated in most plant powerhouses as part of the cogeneration, or CHP process, as already stated. These pressures and temperatures are far too high to be used on most refining and petrochemical processes. Therefore this high pressure superheated steam is “let down” to the medium and low pressure distribution lines, using turbines or pressure reducing stations.

All steam desuperheaters work on the same principle of injecting water into the superheated steam, where it evaporates absorbing the excess energy resulting in steam with approximately 5°C of superheat. This remaining superheat is soon lost as the steam is distributed to the point of use.

Figure 9 shows a typical desuperheater application on a let down station.

The quantity of water required to de-superheat the steam is controlled by maintaining steam temperature downstream of the desuperheater to between 5°C and 10°C above the steam saturation temperature.

If the temperature is too close to the saturation curve, there is a very real risk that too much water will be injected into the system leading to poor steam quality and all the problems associated with this, already discussed.

If the temperature is too high, excessive superheat will remain, affecting the performance of the downstream process.

Although there is little to go wrong with the average desuperheater, it is worth checking the required set points for temperature and pressure are correct, and, if the desuperheater is still correctly sized, particularly if any conditions or parameters have changed.

This article has covered the importance of ensuring steam reaches the point of use at the correct quality, quantity and pressure, and has looked at some of the key areas to consider in reducing maintenance costs and energy losses, namely, the impact poor steam quality will have on the steam system and how this can be improved through:

- Ensuring the steam system is properly insulated;
- Removing condensate promptly from the distribution system;
- Using the correct steam trap for a given appliction;
- Putting in place a steam trap management program;
- The use of separators; and,
- Checking the installation and performance of desuperheater stations. □

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Steam projects provide fast payback

Louisiana petrochemical complex significantly cuts energy consumption

By Jason W. Gathright, The Dow Chemical Co.

An energy assessment at Dow Chemical's St. Charles Operations in Hahnville, La., has led to a 272,000-million-Btu/yr reduction in natural gas use, providing $1.9 million in annual savings; costs to improve operations were paid back in about six weeks. The U.S. Department of Energy (DOE) named the petrochemical complex a 2007 Energy Champion Plant, an honor awarded only to the top energy savers in the country.

The 2,000-acre St. Charles facility, which has been in operation since 1966, produces more than 40 different products that go into a variety of consumer goods, and relies heavily on steam — for electricity generation and process duties. Dow has an active energy-management program, which includes the corporate 2015 sustainability goal of reducing energy intensity by 25% from 2005 baseline. Therefore, we took advantage of a "Save Energy Now" assessment sponsored by DOE's Industrial Technologies Program to gain insights on potential energy saving opportunities. A specialist qualified on DOE's Steam System Assessment Tool (SSAT), Riyaz Papar of Hudson Technologies, came to the site and worked with an empowered team comprised of plant operators and engineers. Once SSAT was installed on their computers, the team members modeled the facility and investigated a variety of what-if scenarios for energy savings.

This led to the identification of both near- and medium-term opportunities, based on payback periods. Implementing all of these could result in a more than $5 million annual savings.

Energy Champion Plant

Figure 1. Dow Chemicals' St. Charles Operations in Hahnville, La., reduced its natural gas use, resulting in $1.9 million in annual savings.

NEAR-TERM INITIATIVES

With the help of SSAT, the team pinpointed four efforts to undertake first:

Implementing a steam-trap repair project. An audit performed before the assessment had identified all failed steam traps. SSAT enabled us to quantify the value of implementing a repair program — annual savings exceeding 112,000 million Btu of natural gas and $880,000 in costs.

Upgrading the steam-leak management program. Initial estimates from the assessment proved overly optimistic due to inaccurate measurements taken during data gathering. However, upon verifying the measurement system and performing quantitative analysis, the revised figures still pointed to savings greater than steam trap repair alone.

Improving insulation. Inspection revealed that several areas of the steam distribution network lacked sufficient insulation per Dow standards. Using 3EPlus, DOE's insulation calculation program, the team

Insulation Improvements

Figure 2. Adding insulation, stopping leaks and repairing steam traps played key roles in achieving energy savings.

estimated insulation losses to be about 1%, Reducing such losses to 0.1% promised savings in gas of more than 3,000 million Btu and $25,000 in costs.

Boosting condensate recovery. At the time of the assessment, Dow was recovering about half of the low pressure condensate. The SSAT indicated that a site-wide recovery rate of 75% was possible. This would cut gas use by nearly 88,000 million Btu and costs by almost $650,000.

MEDIUM-TERM OPPORTUNITIES

The team also identified a number of other projects that offered somewhat longer payback but were definitely worth considering:

Adding a blowdown heat-recovery exchanger. Blowdown was going to a flash tank to recover low pressure steam but lack of heat exchangers in the system meant that lots of thermal energy was still being lost. Putting in an exchanger upstream of the tank would enable capture of significant heat that could be used to preheat boiler makeup water. This would save about 31,000 million Btu of gas and $200,000.

Preheating reactor feed with 75-psig steam. Replacing some of the 600-psig steam being used wouldn't save natural gas but would allow more on-site electricity generation from the higher-pressure steam. This would reduce electricity purchases by almost 1,280 M Wh and nearly $80,000.

Installing a back-pressure turbine drive. The site generates 600-psig steam but most applications only require 200-psig steam. Putting in a back-pressure turbine drive could generate electricity to power some critical equipment and save around 1,950 M Wh and more than $120,000.

IMPRESSIVE RESULTS

The estimates the team developed using SSAT came very close to the benefits Dow actually achieved for the near-term projects. The steam-trap repair project provided annual energy savings of 109,000 million Btu and about $800,000 in costs. Efforts to combat leaks led to annual savings of 163,000 million Btu and more than $1.1 million. Implementation costs for both programs totaled about $225,000, so payback was achieved in little more than six weeks! Steam trap maintenance and leak management are now ongoing programs.

In the short-term, insulation inspection and repair is still being conducted with a minimum mandatory visual inspection of all plant distribution lines every three years. In addition, a condensate project has been planned and is part of the new capital spending plan for implementation in 2009.

Medium-term and additional long-term Dow driven energy efficiency and conservation projects have been captured in an opportunity tracking system and will be made part of the plant specific technology plan. These OPPORTUNITIES will be further developed and could be part of future capital spending plans. □

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Ensuring steam system reliability

Midwest specialty chemical plant increases steam system reliability and efficiency by replacing steam traps and conducting annual surveys.

A specialty chemicals plant located in the Midwest U.S. uses steam for its heat tracing, vats, heat exchangers, steam dryers, and other chemical manufacturing processes throughout the facility.

The industrial insulator at the company began to notice that insulation surrounding the heat tracing was wet and flashing steam. “The traps were freezing,” he said. “The traps weren’t working; they were leaking and making the insulation wet. I kept having to replace the traps and the insulation.”

According to the industrial insulator, Paul Turner, sales engineer at Michigan Steam Equipment Inc., Farmington Hills, Michigan, explained that the chemical company was losing energy (money) at each failed steam trap. “Until then, we really didn’t look at the traps unless it was obvious they were defective,” the insulator said.

The industrial insulator said that the enlightenment he gained from Turner, a Spirax Sarco independent representative, encouraged him to become more interested in heat tracing and steam traps within the steam system. “That’s when I started getting more involved,” he said. “That’s how I became the trap guy at the plant. If he had not come in and pushed, we probably would not be where we are today because nobody really thought about the traps. Unless they were obviously broken, I don’t think we ever really paid attention to them.”

FIRST THINGS FIRST—IT BEGINS WITH THE SURVEY

Turner began with a steam trap survey which indicated that around 20% of the facility’s more than 300 steam traps had failed. In addition, the survey revealed that the plant was not following steam piping best practices. Steam traps were failing and no one was managing them. The plant had a mix of steam traps from multiple manufacturers which were primarily thermostatic traps.

Turner explained how failed steam traps directly correlate to the three crucial issues of energy, safety, and reliability. “Turner trained me,” said the insulator. “He gave us a list of traps to be replaced. I started working on them and learning about them.”

OVERCOMING CHALLENGES

The use of an efficient and reliable tracing system ensures that optimum pumping viscosity is maintained, product solidification or spoilage does not occur, and damage from adverse ambient conditions is avoided. For example, if a particular process requires the material to be maintained at a temperature of 266°F, ambient temperature is insufficient to keep the product at that temperature. In addition, pipes containing chemical products have a tendency to freeze, depending on the nature and temperature requirements of the specific materials. At the Midwest chemical plant, most of the pipes that carry the chemical products are outdoors, requiring freeze protection during the winter months. Steam tracing keeps product in piping from freezing and to maintain process-required temperatures. According to Turner, the failed steam traps directly caused poor tracing system performance.

PUTTING STEAM TRAPS TO WORK

After convincing the chemical company's decision makers to implement the proposed solutions, Michigan Steam Equipment supplied approximately 60 USTS-II compact universal-connection steam trap stations and UTD52 universal thermodynamic steam traps from Spirax Sarco.

The USTS trap station incorporates inlet and outlet isolation valves, an integral strainer with blowdown, and a test valve. It is designed to be a complete steam main drip or a tracer steam trap station. While the USTS station is not a steam trap, it supports all Spirax Sarco universal connection steam traps. If steam trap replacement becomes necessary, maintenance is simplified: close and isolate the station, then remove only two bolts, which free the steam trap — a significant time saver. Typically, a trap can be replaced in less than 5 minutes.

SAVINGS AND NO TRACE OF FREEZING

The Spirax Sarco steam traps turned out to be a good investment. The payback period was around 9 months. A year after replacing the failed steam traps, costs associated with annual steam loss were reduced from $33,746 to $19,564 — an impressive 58% — proving that doing an annual steam trap survey that identifies trap problems saves money. Spirax Sarco has surveyed the chemical plant's steam traps annually, and now the facility's trap failure rate is less than 3%, according to the industrial insulator. And the initial issue of frozen tracing lines was eliminated.

"I took it upon myself to become the trap guy and started taking care of them," the insulator said. "And over the years, I have continued to learn more about them. I listen to the traps now and I can hear the differences. Now I'm not just an insulator — I wear many hats here at the plant. I have been sharing the knowledge I have gained about traps with the maintenance staff."

According to Turner, the most compelling aspect of this project is witnessing the benefits over the years: the reduced steam costs, the reduced labor costs, and the increased reliability of the system — seeing the plan come together. "The company's continuing implementation of the products and best practices is key to making everything a success," he said. "The customer continues to be very pleased with our support and products."

"Whenever there is a problem we can't solve, we call Paul," said the insulator. "We are very happy with the service he provides us." ◻