Handle Steam More Intelligently

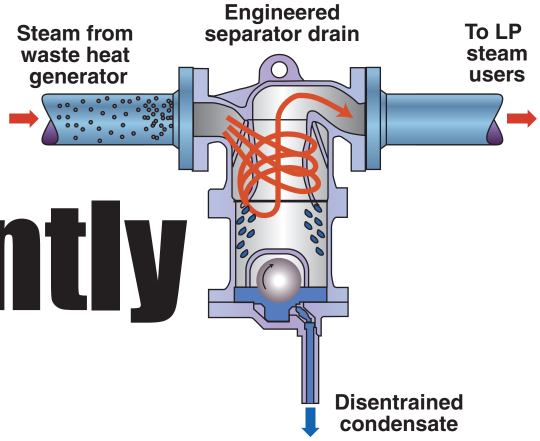

FIGURE 1. Improving the quality of waste heat generatoe steam

With fuel prices at high levels, the diverse energy-conservation techniques outlined in this article make more sense than ever

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The dramatic jump in petroleum and natural prices over the recent years has created much impetus to reduce operating costs at chemical process plants. In processes that use either oil or gas for feedstock, such reduction can come either from improved energy-usage methods or from yield improvements. In either case, the plant's steam resource is often a primary provider of heat or thermodynamic energy to a process. Profit gained from reduction of energy costs through more effective use of steam affects the bottom line in much the same manner as the profit gained through production improvement.

Indeed, in some cases the relationship of productivity improvement is directly tied to a more effective use of the steam supplying the process. This relationship can hold for not merely petrochemical plants but also for ones that employ non-petroleum feedstocks.

Back to basics

The steam circuit can be divided into four basic areas;

- Generation (boiler, waste-heat steam generator or flash vessel)
- Distribution (transportation, turbine generators, and steam-letdown strategy)
- Use (stripping, process heating, turbine drive, furnace atomization, tracing, flaring, HVAC, other)
- Condensate return (recovery of thermal energy and treated water; reduction of environmental impact or costs for sewer treatment)

In today's typical process plants, condensate return provides an especially fruitful opportunity for improving energy efficiency, and much of this article focuses on that area.

To be the most effective, steam generally needs to be dry (such as for process usage), or superheated (for instance, for use in turbines). These requirements dictate utility-system operating procedures to generate the highest quality steam possible, and then distribute it to the points of use without deterioration. Since steam becomes condensate after its heat energy is expended, strategies must be in place to remove condensate as quickly as it is formed, in the steam-supply portion of the circuit and during steam usage alike.

Furthermore, superheated steam is typically desuperheated by injecting hot condensate into the system. As a result, excessive wetness can also occur downstream of the desuperheating station. In either case, if such condensate is not removed from the steam supply, the negative impact on the steam system can be substantial.

Possible outcomes of not removing condensate from a steam supply or process include the following:

- Loss of yield; entrained water does not carry as much heat to a process as does steam
- Damage to nozzles; entrained water erodes nozzles, and can adversely affect vacuum generation or atomization
- Loss of power; entrained water causes turbines to operate less efficiently
- Increase maintenance loading; water hammer can damage equipment such as turbine blades and control-valve packing
- Increased safety risk; water hammer can injure personnel
- Poor process control; flooding exchanges can lead to control swings

At many plants, the operators admittedly realize that condensate must be removed as quickly as it is formed, but a suitable condensate drainage or transportation system is not in place. In such cases, the condensate is often sewered or sent to a field drain. Some possible outcomes of thus removing condensate but not handling it effectively include these;

- Profit loss due to waste of heated and treated condensate
- The extremely wasteful effect of opening bypass valves around process equipment or turbines to prevent waterlogging or damage
- A possible increase in system corrosion because too much makeup water must be treated

Condensate is traditionally removed from steam systems by steam traps or by equipment combinations involving level pots and outlet control valves. In some situations in which high backpressure from the downstream portion of the condensate-return system tends to create a "stall," a different system incorporating both a pump and trap in the design are needed, to drive the condensate while also trapping the steam; this process may be referred to

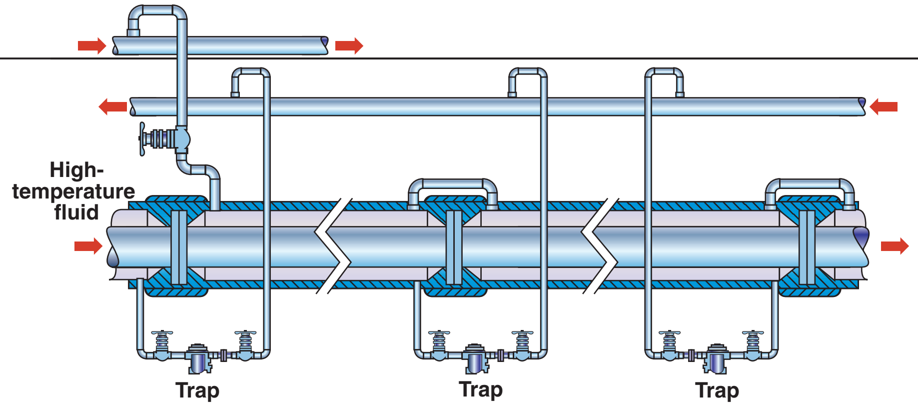

FIGURE 2a. Preferred method to drain jacketed pipe for high temperature fluids such as sulfur

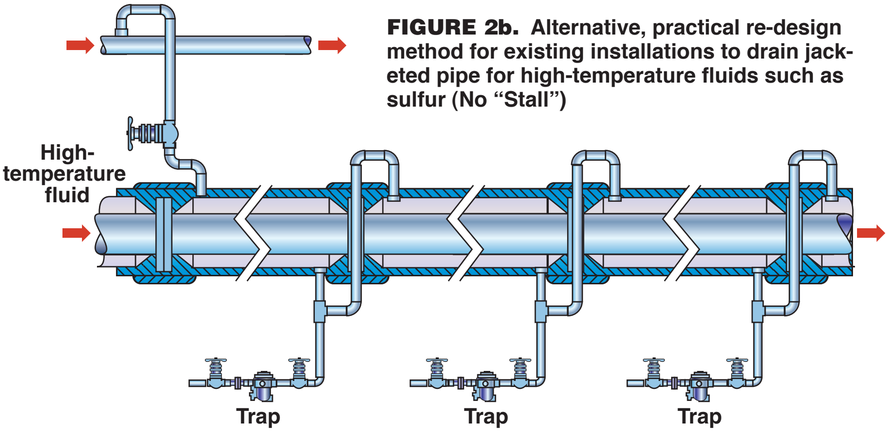

FIGURE 2b. Alternative, practical re-design method for existing installations to drain jacketed pipe for high-temperature fluids such as sulfur (No "Stall")

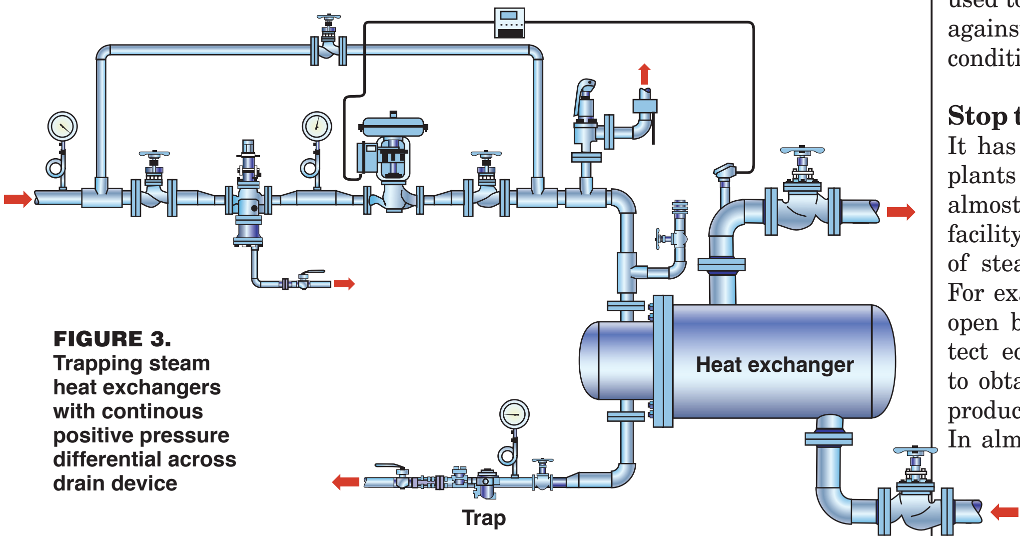

FIGURE 3. Trapping steam heat exchangers with continous positive pressure differential across drain device

as pump-trapping or power-trapping.

Because there are thus at least three condensate-drainage alternatives, it makes more sense to think in terms of required "condensate discharge locations" rather than referring to condensate removal devices indiscriminately as "steam traps." This mind-set helps avoid any predisposition to install steam traps even in applications that need a different type of condensate drainage solution.

Engineered separator-drains, such as the one in Figure 1, remove condensate that is entrained in a moving steam supply (including flash or regenerated steam). The result is highest quality steam delivered for plant use. On the other hand, steam traps remove condensate that has already fallen out of the steam. By their name, steam traps remove condensate and "trap steam." Level pots can be used in certain instances where steam traps can not meet the high pressure or capacity requirements.

There can be many situations in a plant where effective condensate removal requires specialized drainage designs. For instance, Figures 2a and 2b show two options for condensate drainage from jacketed pipe that conveys high-melting-point materials, such as liquid sulfur or high-boiling hydrocarbons

Other examples of specialized applications include options to effectively drain steam-heated heat exchangers. A key consideration is to first determine whether a stall condition exists or not; when it does, condensate will not drain effectively through a simple steam trap. Such a situation typically arises when modulating steam pressure creates a negative pressure differential across the condensate drain device. So-called "Type II" secondary pressure drainers of the pump-trap type are used on equipment with negative pressure differential (Figure 3), whereas "Type I" secondary pressure drainers of a "pump only" type are used to recover and power condensate against an even higher-backpressure condition (Figure 4).

Stop the bleeding

It has become such a habit in some plants to open bleed valves that it is almost impossible to walk through the facility and not find multiple sources of steam being bled to atmosphere. For example, many operators tend to open bleed lines in an effort to protect equipment from overheating or to obtain higher product throughput, product consistency, or line fluidity. In almost every case, bleeding steam is a symptom of an improper drainage design at the given condensate-discharge location. There is usually a causal relationship with poor operation of a process. Typical areas to search for steam bleeds include process heat exchangers (under stall condition), steam tracers on high-temperature lines or jacketed pipe, and turbine supply lines.

Hidden bleeding of steam at a process heat exchanger is usually the most damaging. This can occur whenever a bypass line is opened around equipment in order to maintain process throughput. The bleeding may be invisible to those in the area, but it continues daily nevertheless. In such instances, the production rate may be maintained, but the cost of the steam input is usually far greater than needed. Such a loss will often occur continuously until an improved design solution is implemented.

With respect to bleed lines at the inlets to a turbines, plant personnel are in many cases so concerned about turbine trips due to water damage that the feel that opening bleed valves at the inlet is only way to remove potentially damaging condensate. As for pipe tracing or jacketing, in many cases it turns out that the low-first-cost original design did shave the installation cost, but at the expense of frequent waterlogging in the jackets, so, the bleeders are opened to remove the condensate and improve the product flow.

In virtually all cases of bleed steam on the above applications, it is better to find the cause of the "need-to-bleed" steam in the first place, so that an improved drainage solution can be installed to reduce steam loading while maintaining or improving performance. Bleed steam is costly.

Incidentally, plant air systems in many plants incur the ill consequences of excessive air-bleed loss – for similar reasons. Often, the cause of bleeding plant air is that the drainage devices cease operating, due to contaminants in the system. An improved condensate drain design for the air system usually provides noticeable gains (Figure 5).

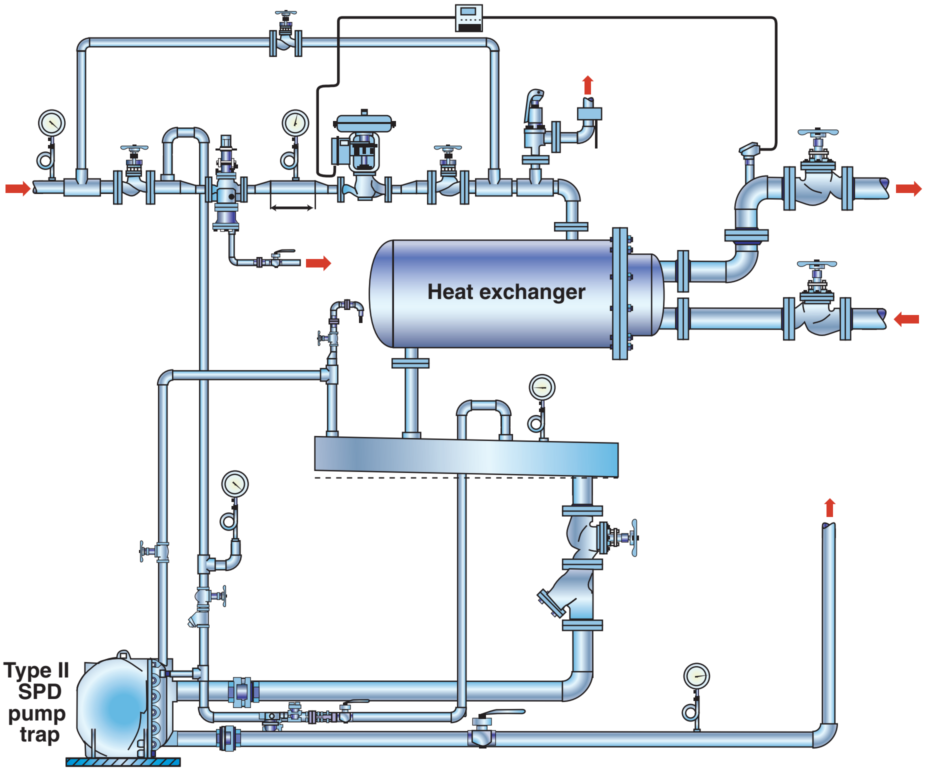

FIGURE 4. "Power-trapping" steam heat exchangers with possible negative pressure differential across drain device ("stall")

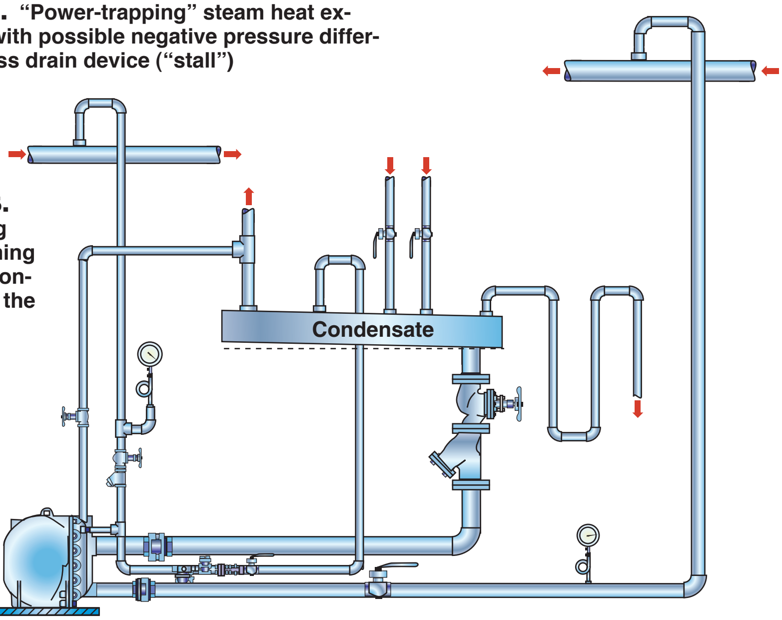

FIGURE 5. Recovering and Returning Valuable Condensate to the Boiler

Steam trap management

How long should steam traps last? Some companies talk of 4% trap failure rates. For a mature plant, however, that figure implies, on average, a 25 year trap life! Is it really expected that an entire steam trap population will survive the challenging environment of a process plant for 25 years on average? Such statements indicate the need for a measurable method to quantify trap population life. One such method is to total all replacement trap purchases over one 12 month period, then add this amount to the change in trap failures recorded from the previous survey, while correcting all values to an annual basis. The addition of newly failed traps to replaced traps over a year period will provide an estimate of the annual failure rate of a site.

For a site that has not had a proactive trap management program with annual surveys and repair, it is not uncommon to have 50% of the trap population (or more) in a current state of failure. If those failures are equally divided between failed open or failed shut, then about 25% of the population can be leaking steam. Even with a simple steam-loss estimate of $1,500 per trap leakage, multiplying the failed-leaking trap population by a leakage estimate can quickly make a good case for remedying the situation. At least one trap manufacturer provides software that can clearly estimate the value of leaking steam from a failed steam trap. Such software can provide data that will justify the cost of setting up maintenance response on a cost/return basis. Basic summary values from a condition-monitoring program

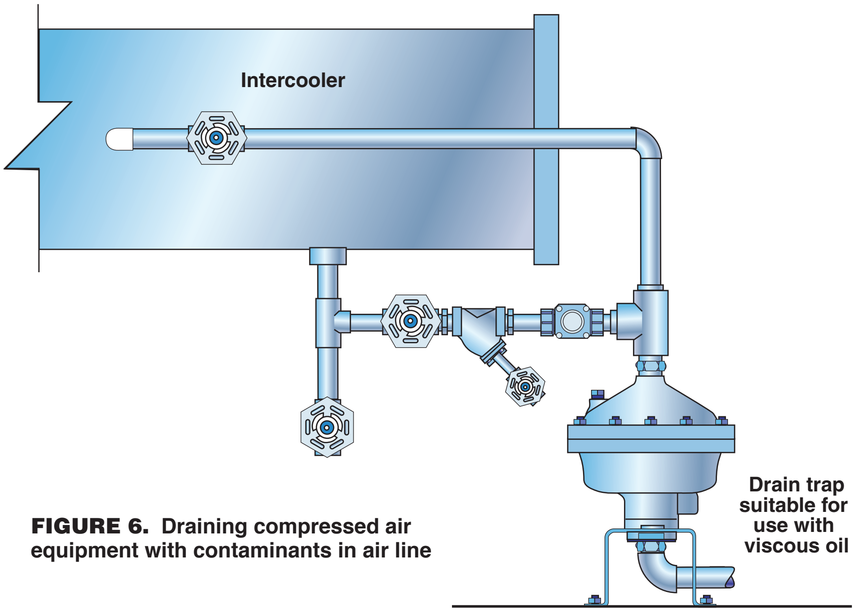

FIGURE 6. Draining compressed air equipment with contaminants in air line

TABLE 1. CONDITION OF INSTALLED STEAM TRAP POPULATION				
Category		**Quantity**	**Percentage**	**Monetary Loss**
Failed	Blowing	124	5.0%	$243,025
	Leaking	307	12.5%	$211,700
	Blocked	179	7.3%	$0
	Low Temp.	294	12.0%	$0
	Total	904	36.8%	$454,725
Good		1180	48.1%	$0
Unknown Condition		371	15.1%	$0
Total		2455	100.0%	$454,725

TABLE 2. THRESHOLD VALUES FOR REPLACEMENT OPTIONS WITH BUDGET ALLOCATIONS		
BUDGET REPLACEMENT THRESHOLD VALUES		
Annual Blocked Trap Replacement Value		**$1,500**
Leaking Trap Replacement Thresholds		
Pressure		Annual Value $
650 psig	≥	$1,600
250 psig	≥	$800
150 psig	≥	$800
< 50 psig	≥	$600

for the steam-trap population at one process plant appear in Table 1.

Decisions regarding "Out of Service" or "No Service" traps can be made based on the expected trap condition. If the steam service is turned on but a given trap is found to have been valved out, then that trap is probably failed in a leaking mode (if the trap were instead blocked, there would usually be no need to valve it out). If the steam service is instead turned off (perhaps during a turnaround or when winterization steam is not needed) then the trap condition is unknown. For unknown-condition traps, it is usually common to assume a failure rate comparable to that for traps of known condition in similar application service.

Survey analysis can also be used to select effective maintenance response recommendations. When setting up such a program, the plant management should assign threshold values that signal when a leaking trap is to be replaced, and that also provide an estimate of the replacement value associated with a trap being blocked (Table 2). Then, the plant can apply the threshold values each individual trap's diagnosis to determine the maintenance decision. Based on such a program in action, Table 3 demonstrates how a simple spreadsheet analysis using IF/THEN statements can provide a recommended action for each steam trap location. The strategy underlying this spreadsheet analysis is as follows: "IF the '$ Loss' is greater than the Threshold Value on leaking steam traps, THEN replace' the trap; OTHERWISE, no action is to be taken."

Much attention is focused on replacement of leaking traps; and for good reason. Steam-trap leaks, like other instances of leaking steam, represent the low-hanging fruit of a plantsite for quick, high return opportunity. However, additional savings can be gained by evaluating the reliability record of the entire installed trap population. At some process plants, historical maintenance and survey records provide adequate data; and once annual surveys are conducted, there will be a factual record of the site's trap failures. Then, when the total failures (those corrected, plus those just surveyed but not yet corrected) over the testing period add up to the total trap population, then the trap population has "turned" one time, in a manner analogous to inventory turns. Using such a method will provide one method to measure trap life. Such analysis may, of course lead to the replacement of existing traps with more-reliable versions.

Don't ignore cold traps

In light of that the just-mentioned high return opportunity with leaking traps, plants tend to give higher priority to replacing such steam traps than to dealing with blocked or cold steam traps. But a cold steam trap can be a harbinger of an imminent disastrous event. There have been cases where cold traps – and, therefore, cold condensate-discharge locations – caused critical turbines to go out of service, or caused main compressors to shut down a plant for days. Keep in mind that the original designer of the system decided that the installed condensate drain point – with a steam trap to drain – was needed to maintain the desired performance and safety of the system.

In short, all cold traps should be repaired or replaced. If, in some instances, it truly seems that a trap is not needed at the intended discharge location, then a proper management-of-change (MOC) procedure should be executed to permanently remove the trap from service. The MOC must carefully considers all potential consequences of such an action, and assure that the removal of the drain point is an absolutely safe decision.

Keep in mind that technology is not frozen in time. Plants must increasingly develop more-efficient ways to manage their the steam trap populations. Best practices should be reviewed and modified (if appropriate) at once or more often per year to select the most effective condensate drainage device for the discharge location. At least one trap manufacturer offers an annual service to review applications, with up-to-date recommendations for "best practices" consideration. Engineering consultants may also be fruitful sources for improved condensate-drainage practices.

TABLE 3. MAINTENANCE RESPONSE DECISIONS

Trap	Application	Pressure	Test Result	#/hr.	$ Loss	Action
Trap 1	Drip	650	Small Leak	23.2	$1,837	Replace
Trap 2	Drip	650	BLOWING	133.92	$10,605	Replace
Trap 3	Drip	250	BLOWING	77.12	$4,810	Replace
Trap 4	Drip	250	Large Leak	50.46	$3,147	Replace
Trap 5	Tracer	250	Medium Leak	21.21	$1,323	Replace
Trap 6	Drip	150	Small Leak	14.13	$962	Replace
Trap 7	Tracer	50	NOT IN S	0	$0	-
Trap 8	Drip	50	BLOCKED	0	$0	Replace
Trap 9	Drip	50	Large Leak	25.66	$1,011	Replace
Trap 10	Tracer	50	Medium Leak	18.98	$748	Replace
Trap 11	Tracer	50	Small Leak	6.11	$241	-
Trap 12	Drip	25	BLOCKED	0	$0	Replace
			Leak Value Blocked Value Totals	370.79	$24,684 $3,000 $27,684	

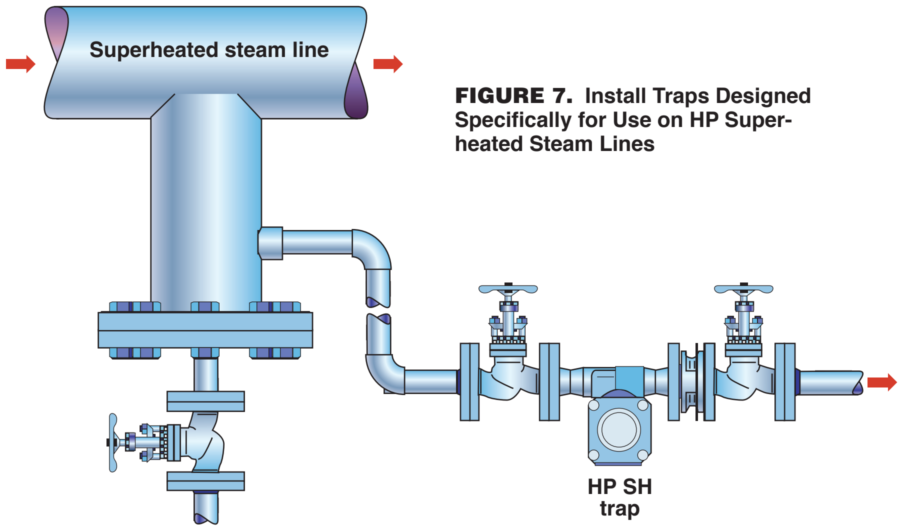

FIGURE 7. Install Traps Designed Specifically for Use on HP Superheated Steam Lines

Balances and audits

While better condensate management is indeed the most promising strategy for improving steam-system efficiency at today's typical process plant, periodic review of the facility's overall steam balance can in many cases uncover unanticipated opportunities for improvement. For one thing, the steam balance not only tracks the steam flow per se, but also can be useful for spotting new load imbalances that may be amenable to re-balancing to save vent steam.

For example, one primary goal is to always seek a use for otherwise vented/wasted steam. One such use might be pre-heating of a nearby fluid. Another example consists of incorporating pump-trap technology, in order that low-pressure steam becomes suitable for some heat exchange equipment that previously could use only medium-pressure steam. Such "power-trapping" the condensate prevents equipment flooding when low pressure steam is used, and can improve the system yield and availability.

In still other applications of the steam balance, an evaluation of the first and second (highest and next-highest) steam pressures can help identify expensive "missing steam" – a major portion of which can often be readily recovered. In many instances, this missing steam is the result of leaking high-pressure steam traps – for which an immediate replacement or repair can be readily justified at the first available opportunity (Figure 6).

For practical information on setting up and maintaining a steam balance, see Steam Balances Save Money, CE, July 2004, pp. 36–41.

A related valuable exercise is an audit of all the plant's condensate. Whereas it may not have been cost-effective to recover certain sources of lost condensate in the past, today's high energy prices may have tilted the scales. With every rise in energy prices, particularly of Fuel Oil Equivalents (FOES), it becomes important to evaluate every potentially collected source of condensate on a cost/return basis, to determine if installing a recovery system may have become justifiable.

Capital or expense budgets?

An all too common situation arises in process plants: An energy-efficiency taskforce uncovers an opportunity, but there is no funding to support the required improvement project. And in those cases where funding does happen to be available, the money is in a maintenance budget – and, therefore, saddled with various constraints that limit the amount of investment that can be made.

One alternative consists of establishing special energy-improvement budgets in stages, with strict requirements that expected gains be realized at any given stage before additional funds are released. Such a "stage gate" release approach can provide necessary funds to improve a plant performance.

A company's financial teams may want to evaluate energy projects' expected return with other performance projects to select the best return on investment. Some steam-system improvement projects do meet capital-funds requirements, and can improve a plant's profitability while achieving a desired reduction in operating costs. Focused business/energy consultants and individuals with Certified Energy Manager (C.E.M.) training can help evaluate the financial aspects of a particular project to determine feasibility for the site.

Final thoughts

Well-run process plants consider all input resources in their operating-cost analyses. Some resource costs, notably plant labor, generally do not incur drastic changes from year to year. Other resources, like energy or steam, are closely tied to the cost of a FOE. While much effort may be expended to obtain a more economic supply of fuel or energy, profit can also be achieved at most plants from a focused effort to improve the steam system quality. ■

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