SPECIAL REPORT

Steam Turbine Bypass Systems

A robust condenser dump system is critical to a combined-cycle plant's ability to respond to transients. Inattention to detail at the design stage can lead to serious and costly O&M problems

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When a combined-cycle plant is operating at steady-state, 100% load, it's an elegant thing to behold. Well, maybe not to the artist or the fashion designer, but it is to the engineer who can appreciate its unmatched thermal efficiency, small footprint, low water usage, and single-digit air emissions. Unfortunately, during transient and low-load conditions, the marriage of the gas-turbine cycle with the steam-turbine cycle begins to look a bit awkward.

During these conditions—the ones of greatest concern are startup, shutdown, and a steam-turbine trip—the gas turbine (GT) is producing so much exhaust heat at such rapid rates of temperature change that, if it were imposed uncontrolled onto the steam side, thermal ramp-rate limits would be violated in thick-walled components of the heat-recovery steam generator (HRSG) and/or the steam turbine (ST). Such transients are being encountered more frequently today than in the past because of the need to cycle combined-cycle units designed for base-load service. In addition, the transients are more severe in magnitude because the latest combined-cycle plants typically:

■ Feature large GTs with high exhaust flows and temperatures.

■ Operate at high steam temperatures and pressures.

■ Incorporate reheat steam, which significantly increases control complexity during plant startup.

■ Include two or three GT/HRSG blocks supplying a single ST, which complicates both startup and shutdown procedures.

■ Demand more aggressive startup, shutdown, and load-response times.

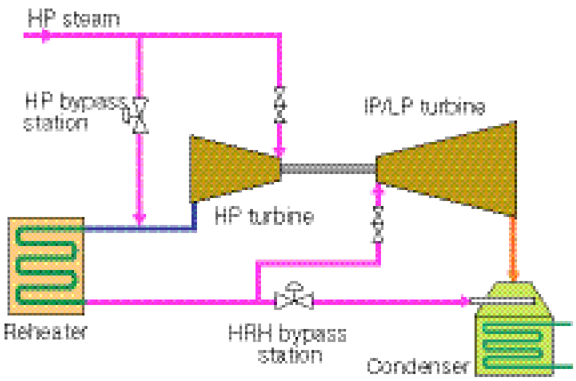
One solution to the imbalance between GT exhaust heat and the steam system's thermal transient limits is to install a bypass damper and a bypass stack upstream of the HRSG, enabling the GT exhaust gas to be vented directly to atmosphere. This permits simple-cycle operation, but can still allow serious thermal transients in the HRSG because it is difficult to precisely modulate the bulky bypass damper and comply with National Fire Protection Association pre-start purge requirements when transitioning from simple- to combined-cycle operation. This solution also is capital- and maintenance-intensive, so it is installed in very few plants.

1. Steam-turbine bypass system is being installed at a 250-MW, 1-by-1 combined-cycle plant. HP (A) and IP (C) valve bodies await receipt of actuators and valve gear. B is spray water manifold for HP desuperheater. Desuperheated steam is routed to sparger in steam-turbine exhaust duct

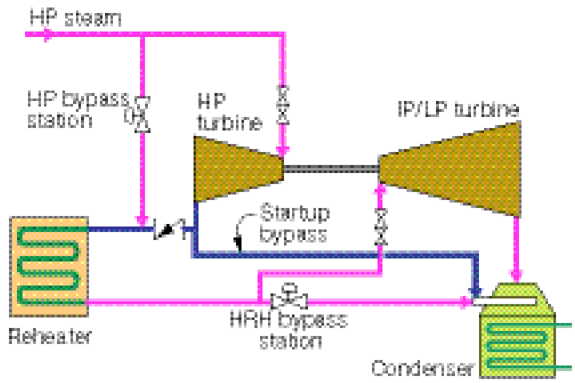
Another solution is to allow the HRSG to generate steam, but to vent it directly to atmosphere until the steam-side metal is properly warmed up. However, the routine use of so-called "sky vents" during every plant startup incurs costly losses of demineralized water, not to mention problems with environmental regulators and plant neighbors who object to the imposing noise and plume.

Cascading bypass system

The most common method to manage the thermal imbalance during times when the steam turbine cannot use all the steam produced is the "cascading" bypass system (Fig 1). In this scheme, the high-pressure (HP) superheated steam generated



2. In a cascading bypass system, the HP superheated steam generated during startup is diverted around the HP section of the turbine, through a pressure-control valve and an attemperator, and into the cold reheat line. After mixing with IP steam and passing through the reheater, the dump steam is diverted around the IP and LP turbines through a second pressure-control/attemperating station, before it is directed through a dump tube into the condenser



3. A risk introduced by the cascading bypass system is its potential to cause "windage" overheating of the high-pressure steam turbine during startup and shutdown if the pressure-control valves fail to precisely control HP and reheat pressure. To address the problem, designs for some of the combined-cycle powerplants recently installed also include a "startup bypass," which connects the HP turbine vent directly to the condenser, upstream of a check valve in the cold reheat line

during startup is diverted around the HP section of the turbine, through a pressure-control valve (PCV) and an attemperator, and into the cold reheat line. The primary job of the PCV is to control HP drum pressure, thereby limiting thermal stresses on the HP drum—one of the most vulnerable components of the HRSG because of its thick walls.

The attemperated steam then mixes with steam from the intermediate-pressure (IP) drum and is directed through the reheater. After passing through the reheater, the steam is diverted around the IP and low-pressure (LP) steam turbines as it travels through a second pressure-control/attemperating station (hence the name "cascading") located off the hot reheat line, before it is directed through a dump tube (or "sparger") into the condenser. This second PCV's primary job is to control reheat steam pressure, thereby limiting IP drum level swings. The second pressure-control/attemperating station often is referred to as the "hot reheat bypass" or the "LP bypass" (Fig 2).

As the ST satisfies its warm-up requirements, the control valves in both the HP bypass and the hot reheat bypass progressively close and the ST picks up steam load.

Note that a similar solution applied at some combined-cycle units is referred to as "parallel bypass." In this design, the steam generated at startup in the HP and IP drums is attemperated and sent directly to the condenser, without flowing through the reheater. Another feature of the parallel bypass system is that the spray water for the attemperation process comes only from the condensate pumps. By contrast, spray water in the cascading bypass system is taken from the discharge of both the condensate pumps and the feedwater pumps, hence there is a small reduction in the efficiency loss with the parallel design.

But in the parallel design, the reheater remains "dry" during startup and receives no cooling from steam flow. This forces HRSG designers to significantly enhance reheater tube metallurgy, and makes the cascading bypass system the less expensive option.

Other advantages of the cascading bypass system include the following:

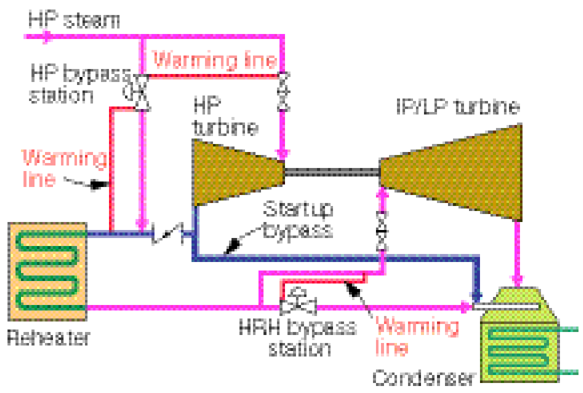
■ Steam flow through the reheater limits the heat input of the HP evaporator (which limits the HP drum transient) during both plant start-up and ST trip.

■ When properly designed and tuned, the cascading bypass system's transient characteristics closely resemble the ST characteristics, which ensures the smallest discontinuities during trip and switch-over situations.

■ The steam produced is used to warm up the reheater headers and main steam lines, instead of being dumped immediately after it has left the HP system.

A risk introduced by the cascading bypass system is its potential to cause "windage" overheating of the HP turbine during startup and shutdown if PCVs fail to precisely control HP and reheat pressure. Windage occurs when the pressure ratio through a turbine decreases to a point where steam begins to recirculate internally. This recirculation causes a very rapid increase in temperature that can easily exceed the material limits of the ST blading. In certain conditions, windage can occur without any indication of trouble to the operator.

The worst case is a warm start during low-flow conditions. (A hot start allows faster ramp rates,



4. Control-valve reliability and service life can be greatly enhanced by installing a warming connection that, during normal combined-cycle operation, limits the difference between steam temperature entering the respective bypass station and the valve-metal temperature

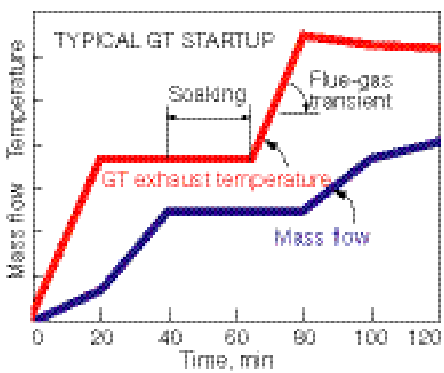
thus higher steam flows, which protect against the overheating effect.)

To address this windage problem, some cascading bypass systems also include a "startup bypass," which connects the HP turbine vent directly to the condenser, upstream of a check valve in the cold reheat line (Fig 3).

Another risk with cascading-bypass systems is the potential to motor the ST if the cold reheat check valves do not seat properly following an ST trip.

Tough on valves. Cascading bypass systems handle an immense amount of energy at elevated temperatures, pressures, and velocities. They also experience harsh temperature and flow changes as PCVs and attemperation valves open suddenly in response to plant transients. The result is severe service for the valves and steam-conditioning equipment, which has led to a host of operations and maintenance (O&M) problems in the field.

At HRSG User's Group meetings, for example, many plant managers report poor reliability of their desuperheater spray valves. A common problem is that these valves have been over-sized or utilize a "linear" trim, leading to erosion, leak-through, and poor control response. Re-trimming with a properly sized "constant percentage" trim can address this problem. At a minimum, an effective preventive-maintenance program for a cycling HRSG will include annual overhaul of these spray valves, and inspection of the block valves, spray nozzles, and thermal liners, if installed.



5. At some plants, the maximum volumetric flows of dump steam occur early in a cold start, during the soaking period, when the GT is at minimum load. But because the architect/engineers based their design on the condition of full GT load/full HRSG pressure, the dump systems end up being undersized

Members of the HRSG User's Group also report great difficulty attaining stable, precise, reliable control from their steam-bypass control valves. That's a particularly critical problem for cycling plants because the bypass system is expected to perform during *every* plant startup and shutdown. In addition to poor process control, the control valves in turbine-bypass systems often experience the following:

- Premature trim and body failure caused by a lack of control of fluid velocity along the flow path, and internal vibration.
- Sluggish operation and sticking because of differential expansion between trim and body.
- Poor shutoff capability. Tight shutoff capability in the HP-bypass control valve must be preserved to minimize HP pressure decay during overnight and weekend shutdowns, and to avoid efficiency losses during normal operation. Tight shutoff capability also is essential in the hot reheat bypass control valve to prevent high-temperature steam from leaking through, unattemperated, into the condenser.

Don't feel like the Lone Ranger if these problems sound familiar. Many owner/operators who were left with low-bid, poor-performing bypass PCVs by their architect/engineer have been compelled to replace these valves with higher quality equipment. Some have even done so within the original valve warranty period.

Valves need warming, too. Many control-valve problems can be attributed to thermal shock, because the valves are designed without any provision for warming. Think about it: The bypass control valves are there to warm up HRSG and ST metal, because we understand the damage that can occur if we shock the HP drum, HP superheater outlet header, or the turbine's steam chest, casing, or rotor—the most vulnerable, thick-walled components. Yet we often make no allowance for the thermal shock that occurs to the bypass control valves themselves.

During normal operation with the ST loaded, the HP bypass system's valve bodies cool to saturation temperature—approximately 600F. Certainly, some amount of bypass-system warming occurs because of heat conduction. But in many plant designs the HP bypass valve is at the end of a long pipe run, perhaps 12 ft or more, arranged with the valve above the HP steam pipe and with bottom entry of the pipe. This arrangement precludes conduction alone from providing adequate valve-body warming.

During both normal shutdowns and trips of the ST, the 600F bypass valve bodies are suddenly subjected to high flows of steam at 1050F, a temperature differential of around 450 deg F. By comparison, the allowable temperature differentials set by HRSG and ST manufacturers between steam and metal temperatures range from 145 to 200 deg F.

Similarly, when the plant is off-line, the bypass valve bodies cool, all the way down to ambient temperature during a long shutdown. On the subsequent startup, when the bypass valves open, the cold valve bodies experience a high flow rate of hot steam.

Control-valve reliability and service life can be greatly enhanced by installing a warming connection that, during normal combined-cycle operation, limits the difference between steam temperature entering the respective bypass station and the valve-metal temperature (Fig 4). We recommend a differential of 160 deg F before the control valves are allowed to swing wide open.

Bypass valve warming during normal operation can be effectively accomplished without loss of system efficiency or great capital cost. A small-bore pipe connected at one end to the bypass valve just upstream of the seat and the other end connected to the valve's respective main or hot reheat pipe near the ST will supply sufficient steam flow to keep the valves warm, while still delivering the warming steam to where it was going in the first place. The additional warming connections still require the installation of startup and shutdown drain lines to be installed in the bypass piping.

Other design improvements. Valves are not the only design weakness found in the condenser dump systems at many combined-cycle plants. To be sure, the design challenges are formidable, and somewhat unique to this plant type. Condenser dump systems have been operating successfully in North America for many years at nuclear plants, particularly at boiling-water reactor plants, where routine venting of potentially radioactive steam is not permitted. But a nuclear plant's use of saturated steam avoids many of the design challenges found in the superheated, reheat steam systems of a combined-cycle plant. Similarly, many large fossil-fueled North American steam plants have experienced years of successful condenser-dump operation. But their bypass systems typically are sized for less than the full-load condition—a usual value is 30% dump capacity—so the demands on their equipment are less severe.

There has been substantial experience with high-capacity dump systems at steam plants outside of North America. In Europe, South Africa, and Japan, for instance, the majority of steam plants installed over the past 50 years featured Benson-type once-through boilers which required 100%-capacity dump systems. Several useful lessons can be taken from that experience and applied to today's challenges at North American combined-cycle plants.

Design, O&M lessons to learn

Dump undersized for ST trip. Many North American condenser dump systems are undersized, which forces operators to supplement their capacity by opening the sky vents and thereby waste valuable demineralized water. Use of sky vents also makes pressure control less precise.

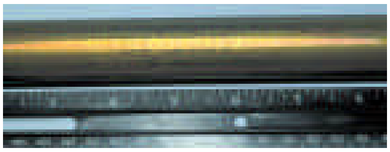
When designing condenser dump systems, engineers typically consider the case where the ST trips from full load. Some assume, logically at first glance, that the mass flow will be 100% of the flow through the fully loaded ST. But when the ST trips, the HP bypass valve opens and attemperating spray is injected to desuperheat the steam from approximately 1050F to 600F. This attemperating spray *adds mass flow* to the fluid stream, perhaps as much as 20% more than the flow through the fully loaded ST.

The fluid stream then flows through the reheater and the second, hot reheat attemperation station, which further reduces steam temperature to approximately 350F. The hot reheat bypass spray flow *adds yet more mass* to the fluid stream, approximately another 20%.

In sum, the total mass flow that the condenser-dump system must be sized to handle for the case of an ST trip is not 100% of the turbine's full-load steam flow, but as much as 140%. In addition to suitably sizing the piping, valves, steam inlets to the condenser, and condenser-tube nest, this 140% mass-flow condition requires adequately sized condensate pumps that can remove the larger volume of water from the condenser.

Dump undersized for cold start, LP conditions. Another common cause of undersizing condenser dump systems lies in the analysis of startup transients. When evaluating startup scenarios, designers often assume that the highest steam flow will occur during the latter part of a startup, when the GT is at full load and the HRSG is at 100% rated pressure. But a characteristic of GTs is that they produce a high percentage of their full-load exhaust energy during both ramp-up and operating at low load—perhaps up to 70%. This means that the HRSG is capable of achieving near rated steam production, often at lower-than-design steam pressures.

During a cold start, the GT is quickly brought to and held at minimum load for heat soaking of the HRSG (Fig 5). During this soak period, steam temperature and pressure are low, therefore its specific volume is very high (the steam is less dense). At several plants analyzed, the maximum volumetric flows occur at these conditions—early in a cold start when the GT is at minimum load. But because the designers of these plants sized the condenser dump system for the condition of full GT load/full HRSG pressure, the operators must open the sky vents to supplement their undersized dump system. Realize that the operators must open these vents



6. North American guidelines, in contrast to European practice, require that steam dumping into a condenser must be superheated. But the tube-support spacing in condensers generally is designed to handle the lower velocities of 90% quality steam exiting from an operating turbine. Tube damage, shown here on shiny area, was caused by tubes hammering against each other during turbine-bypass operation

during *every* cold start, so the cumulative waste of demineralized water during a cycling plant's 20-yr service life is going to be enormous.

If the sky vents are not opened, then pressure ramp-rate limits in the HP drum will be violated. So the Hobson's Choice is to waste demineralized water, or shorten HP drum life.

Location, location. . .saturation. Another design lesson that can be learned from overseas experience concerns the location of the bypass station, and the quality of steam that is dumped into the condenser.

The common practice overseas is to locate the hot reheat (HRH) bypass station close to—typically just a few feet away from—the condenser neck. The North American practice, by contrast, has been to locate the HRH bypass station closer to the boiler (that is, more remote from the condenser) to minimize the use of expensive P91 piping. But the resulting longer piping runs of HRH discharge piping, which could be several hundred feet in length, necessitate either the use of larger diameter piping or higher steam pressures at the HRH bypass to yield the correct steam pressure entering the condenser.

Closely related to the location issue, is the issue of steam quality as it is dumped into the condenser. The industry standard in other parts of the world is to dump *saturated steam* of approximately 90% quality. This is to emulate the fluid that is normally discharged into the condenser from the ST exhaust. Makes sense.

In North America, however, recommended guidelines published by the Heat Exchange Institute (HEI) and the Electric Power Research Institute (EPRI) require that steam dumped into the condenser from a turbine bypass system must be *superheated*. HEI, whose members include condenser manufacturers, is concerned about erosion that may occur from "wet" steam. In our experience, this concern is overblown, and is the cause of considerable mechanical damage and process-control problems at North American combined-cycle plants.

The specification of superheated steam leads to several problems. For starters, superheated steam has a lower heat-transfer coefficient, so the condenser, which was sized for 100% ST load, often ends up with too little surface area in its cooling tubes to handle the condenser-dump flow. The result, during condenser-dump operation, is a loss of condenser vacuum. In a 2-by-1 combined-cycle plant, if one power block is operating at load and the other is dumping steam through the bypass system, there is a significant risk of tripping the ST on high condenser pressure (inadequate vacuum).

Another potential problem with the North American practice is that superheated steam has a higher specific volume, and therefore a greater velocity than 90% quality steam, for the same mass flow rate. The tube-support spacing in condensers is generally designed to handle the lower velocities of 90% quality steam exiting from an operating ST, hence the supports often are unable to prevent the condenser tubes from hammering against each other when they encounter high-velocity steam from the dump system. In a marginal case, damaging steam velocities may only occur during cold-weather operation, when lower condenser pressures further increase the steam velocity into the tube nests.

When the condenser at a North American combined-cycle plant suffered tube failures shortly after commissioning, a root-cause analysis showed that tubes hammering against each other, particularly the first four tubes closest to the dump-tube inlet, was the cause. Extra supporting elements had to be retrofit to this unit to dampen the tube movement caused by the condenser dump system (Fig 6).

It appears that many North American designers are not even adhering to the HEI and EPRI guidelines when it comes to the steam enthalpies that they are allowing to enter the condenser. HEI 5.4.2 states: "Limit the enthalpy of entering steam to no more than 1200-1225 Btu/lb except in the case of high-flow steam dumps where the enthalpy shall be limited to 1190 Btu/lb. Acceptance of flows with enthalpy higher than 1225 Btu/lb may be considered depending upon specific conditions of service."

The EPRI guidelines define "high flow" as greater than 20,000 lb/hr. A typical F-class 2-by-1 power block is configured with two dump systems of 717,000 lb/hr each, one per HRSG, dumping into a single condenser. During startups and shutdowns, dump-steam flow rates from each HRSG typically range from 250,000 to 500,000 lb/hr, or more.

Clearly, these flow rates far exceed EPRI's 20,000-lb/hr threshold, thus the HEI limit of 1190 Btu/lb for "high-flow" systems must apply. However many designers are allowing enthalpies of 1250 Btu/lb. They rationalize this by citing the HEI exception, which "may be considered upon specific conditions of service." But the mechanical damage and process-control problems being experienced in North American plants strongly suggest that this exception does not apply to F-class combined-cycle condenser dump systems.

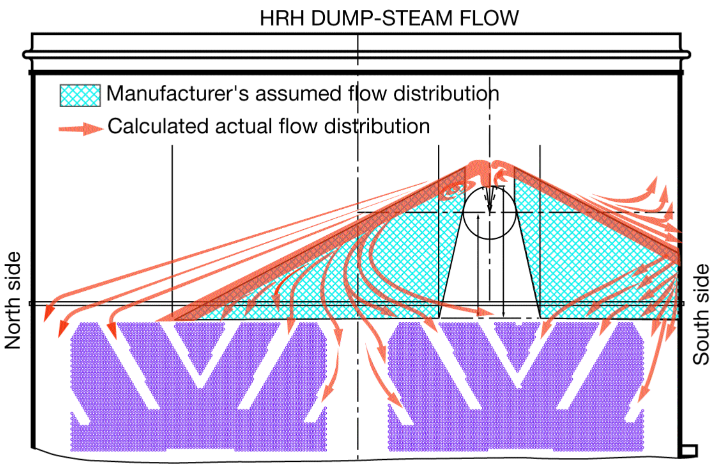
At a minimum, then, owner/operators need to ensure that their designers are adhering to the 1190-Btu/lb enthalpy limit set by HEI and EPRI. To further enhance condenser-dump design, we propose that the requirement for superheated steam published in the HEI and EPRI guidelines be re-evaluated, and that the use of saturated steam, commonly practiced in other parts of the world, be considered. Of course, effectively managing the effects of high-velocity water impingement within the condenser remains important, but we think this is a less troublesome problem than managing highly superheated steam.

HEI published its latest edition (the ninth) of "Standards for Steam Surface Condensers" in 1995, plus an addendum that included new material on turbine bypass in December 2002. The related EPRI publication is "Recommended Guidelines for the Admission of High-Energy Fluids to Steam Surface Condensers," which was last updated in 1982.

HRH attemperation control. The control scheme for the desuperheating spray valve is another common design weakness at combined-cycle plants. Most control schemes use a simple *feedback loop* with steam temperature as the single variable. This temperature-control method works fine for the HP bypass station, but not for the HRH bypass station, where the steam is close to the saturation point. The results of closed-loop temperature control during transients in HRH bypass stations are excessive hunting of the desuperheat-spray valve, and frequent control excursions. If the excursion is large enough, it can cause the condenser dump system to trip on high-temperature limit, and force the sky vents to open; or excessive spray to be emitted, leading to pipe erosion and condenser damage.

A more precise, reliable method of attemperation control for HRH bypass transient conditions is a *feed-forward* scheme that measures pressure and temperature upstream of the PCV, and pressure downstream of the PCV. From these parameters and an understanding of the sparge tube's pressure/flow characteristic, we calculate dump-system inlet enthalpy and dump-steam flow rate, which enables the precise determination of required attemperation spray. This enthalpy-control method, extensively applied in European, South African, and Japanese designs, has been retrofit to some North American plants during routine outages, and has eliminated the hunting problems that previously plagued these facilities.

Sometimes a combination of control schemes can be used, with the temperature-control scheme handling steady-state conditions, while transients are handled by the enthalpy-control which more rapidly positions both the PCV and attemperation valve to yield the correct enthalpy in the bypass. After a short time delay, the valves are released back to steady-state, closed-loop temperature control.



7. Condenser designers typically assume that dump steam will be evenly distributed across the entire area of the tube nests. But unless the sparge tube is carefully designed and located, this will not occur. The result is higher localized steam velocities that cause localized heating, excessive vibration, and other mechanical damage

Sparge tube design. Several cases have surfaced where condenser tube damage was caused by the design of the sparge tube that distributes dump steam into the condenser. Condenser designers typically assume that dump steam will be evenly distributed across the entire area of the tube nests. Unless the sparge tube is carefully designed and located, this will not occur, resulting in higher localized steam velocities than anticipated. It is best if sparge tubes extend the full width of the condenser and are oriented perpendicular to the direction of the condenser tubes, so that the dump-steam jets from the sparger are parallel to the condenser tubes.

One style of sparge tube that can be particularly troublesome is represented in Fig 7. This tube has relatively large holes arranged between the 11:00 and 1:00 o'clock positions, with a "hood" positioned above these holes to deflect the steam to each side of the tube. Depending upon hole size, hole location, and hood height, this style of tube can produce very powerful, potentially supersonic jets of steam that impinge on localized areas of condenser tubes, support structures, and side walls—causing localized heating, excessive vibration, and other mechanical damage.

Noise problems. Excessive noise is a final design weakness that we'll discuss in this article. Excessive noise can be generated in the vicinity of the condenser because the condenser casing is typically constructed of thermally uninsulated, thin materials compared to that of the turbine-bypass valves and piping. For the majority of the applications, the noise is addressed using noise attenuating trim in the turbine bypass valve and a downstream dump tube (or sparger) inserted into the condenser.

The increasing use of air-cooled condensers further aggravates the noise problems. In an air-cooled condenser arrangement, the steam is dumped into a main steam duct that then distributes the steam to finned tube banks located over the forced-draft fans. This steam duct is a very large, thin-walled (typically 0.5-in.-thick wall) piece of pipe that runs along the outside of the condenser support structure. The noise generated in such thin-walled ducts can be enough to cause a plant to exceed noise-permit limits.

To eliminate or reduce the noise, several factors must be considered. First, is the noise generated by the control valve itself? Noise is generated here because the majority of the system pressure drop occurs inside the control valve. The next noise formation mechanism that must be accounted for is the sparger. A smaller pressure drop occurs at this point, but the noise must be tightly controlled as the flow dumps into the condenser duct. Finally, as multiple turbine bypass valves are used in the majority of condenser-dump designs, the noise from each separate valve and sparger combination must be considered.

For one application with a direct air-cooled condenser and multiple turbine bypass valves where noise from the condenser ducting and air-cooled condenser was of particular concern, we designed a solution that included four stages of multi-port pressure-reduction plates, with two stages of attemperation, and lead-lined acoustic insulation on the bypass valves and piping.

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