Emerging Issues and Needs in Power Plant Cooling Systems

by

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The majority of the electricity generated in the United States is produced by steam-driven turbine-generators. A very important step in this power generation process is the condensation of exhaust steam from the final, low-pressure turbine. When the steam condenses, the rapid decrease in vapor-to-liquid specific volumes creates a vacuum at the turbine outlet (monitored as turbine backpressure) that increases power generation efficiency. The conventional low-pressure steam turbine-generator can operate over a modest backpressure range (typically 1.0 to 5.0 or 5.5 in. Hga), but the design point for optimum efficiency is usually at the lower end of this range (2.0 to 3.5 in. Hga). Operating at backpressures greater than the design point reduces generation efficiency, and operating beyond a maximum backpressure limit is prohibited by warranty terms specified by the turbine manufacturer. Because lower turbine backpressures are achieved when the steam condensate temperatures are lower, designing and operating a cooling system that can consistently and continually remove the heat of condensation at those low temperatures is essential. Therefore, the cooling system should be considered an integral part of the power generation process that can have a major influence on the overall power plant performance and availability.

The “waste” heat removed by the cooling system during the steam condensation step must ultimately be transferred to the surrounding environment. Having a high unit heat capacity, water has been the traditional transfer medium of choice because it has been readily available, relatively inexpensive and reusable up to a point. Wet cooling systems use water to absorb heat via indirect contact with steam in a condenser. The heated water is either discharged to a large surface water body such as a river or lake (once-through cooling) or passed through a cooling tower and recycled back to the condenser (recirculated cooling). In either case, heat absorbed in the condenser is released to the environment through a combination of evaporation and sensible heating of the surroundings. Prior to 1990, virtually all steam-electric power plants used wet cooling systems.

Many of the plants built during the last decade are based on the combined-cycle process for power generation. In the most common 2-on-1 arrangement, electricity is produced by two combustion turbine-generators with the hot exhaust gas from these turbines used to produce steam in a heat recovery steam generator (HRSG) for a single steam-driven turbine generator. Since the combustion turbines produce roughly two-thirds of the overall electrical power and have no steam condensation step, a combined-cycle plant requires only about one-third the amount of cooling needed by a conventional steam-electric plant of equivalent capacity. As such, new combined-cycle power plants are seen as offering a greater degree of flexibility in the type of cooling system that can be used. Several recently built combined-cycle plants use an air-cooled condenser (dry cooling) instead of the traditional condenser/wet cooling system. Still other plants have considered or have used combination wet/dry or hybrid cooling systems.

Over this same period, a number of questions have been raised about the future of wet cooling systems for both existing and new power plants. In some instances, the questions focus on certain site-specific concerns. In other cases, the questions are more universal in nature and may have broader implications for the power industry at large. Nevertheless, for the first time in some time, power plant cooling system technology is being reevaluated in terms of a variety of rapidly evolving issues. The purpose of this paper is to examine those emerging issues (both perceived and real) and the corresponding needs for the electric power industry.

The Perceived Issues

Wet Cooling. Since the advent of steam-electric generation, wet cooling systems have been a de facto component of the power production process. Initially, once-through cooling was the favored approach. The large size of the source water guarantees cold cooling water temperatures with almost no daily variation and usually very modest seasonal variation. However, in the early 1970's, new steam-electric generation began using recirculated cooling. The primary reason for this trend (shown graphically in Figure 1) can be found in the Federal Water Pollution Control Act (FWPCA) enacted by Congress in 1972. Recognizing that industrial cooling, particularly for steam-electric power generation, used large volumes of water, Sections 316(a) and 316(b) were designed to address potential impacts on the aquatic environment. Section 316(a) regulates cooling system thermal discharges and Section 316(b) requires the use of best technology available for minimizing environmental impact in the location, design, construction and capacity of a cooling water intake. With lower makeup (intake) flows and lower discharge (cooling tower blowdown) flows, recirculated cooling systems were increasingly selected in direct response to Sections 316(a) and 316(b).

Hence, environmental impacts became the first concern with wet cooling systems used in power plants. Subsequently, over the next three decades, the related themes of environment and health & safety have been at the center of an increasing number of regulations and factors affecting wet cooling systems, including:

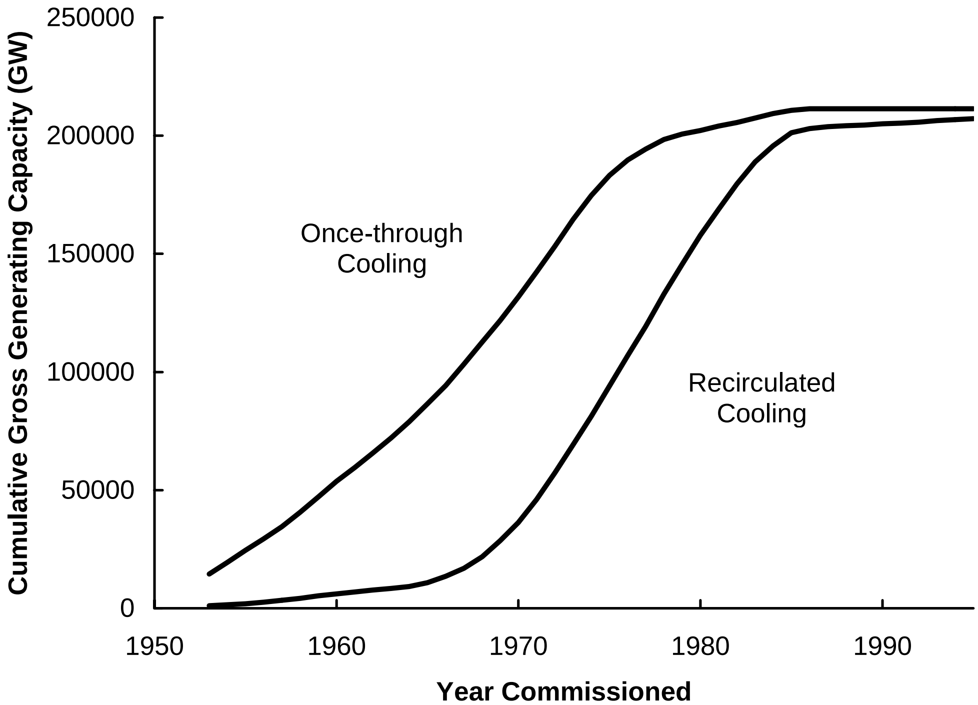

Figure 1
Growth of Once-through and Recirculated Cooling[1]

- Possible pollutant discharges. Amendments to the FWPCA in 1977 (known as the Clean Water Act or CWA) and later promulgated through the National Pollutant Discharge Elimination (NPDES) permit process established specific effluent limitations for certain substances (including chlorine, chromium and zinc). Chromium, an additive used to protect cooling system equipment from corrosion, was ultimately banned entirely. Recent concerns about the presence of certain disinfection byproducts in potable water supplies (notably trihalomethanes or THMs) may eventually be reflected in greater limitations on the use of chlorine in cooling systems.

- Atmospheric plume formation. Depending upon the temperature and humidity of the surrounding air, the saturated exhaust from a cooling tower can form a visible plume which may be unaesthetic or might impair visibility or cause icing on nearby roadways.

- Drift consequences. Initial concerns with potential ground-level salt deposition may have been replaced in some locations with possible contributions to atmospheric particulate levels, measured and monitored in terms of PM_{10} and $PM_{2.5}$.

- Legionnaires' disease. *Legionella*, the freshwater bacteria responsible for Legionnaires' disease, is commonly found in U.S. surface waters, tends to thrive at temperatures typical in wet cooling systems (68-113 °F), and can be transported through the air via aerosols formed in cooling towers. Consequently, cooling towers are viewed as important sources for the potential exposure of workers or persons in the immediate surroundings. Similarly, the use of reclaimed water (treated municipal sewage effluent) has raised some concerns about possible dissemination and exposure to waterborne pathogens.

However, with the construction of new power plants in recent years, perhaps the most prevalent concern with wet cooling systems has been water availability. Growing competition from municipal and agricultural users has decreased the amounts and increased the prices of good quality water resources available to industrial users. This competition is most apparent in the southwestern U.S. where the need for new electric power generation is significant, but regional surface water sources are minimal and groundwater sources are highly prized and may have designated use restrictions. But even in areas usually considered "water rich", such as the northeastern U.S., the combination of environmental, safety & health, and resource availability concerns has resulted in an increasing interest in dry and hybrid cooling systems as alternatives to wet cooling systems.

Dry and Hybrid Cooling. Three types of dry and hybrid cooling systems have received the most attention: 1) direct dry cooling (also referred to as an air-cooled condenser or ACC), 2) parallel wet/dry cooling (in which an ACC and a conventional wet recirculated cooling system are operated in combination), and 3) plume abatement cooling (in which the saturated exhaust from a conventional wet cooling tower is passed through an indirect dry cooling system located above it to prevent the atmospheric release of a visible plume). Plume abatement cooling serves a very special need and, assuming that evaporative cooling is not unacceptable for other reasons, this type of cooling will almost certainly be the preferred choice when visible plume abatement is a concern. For that reason, this type of cooling is not discussed further in this paper.

Similarly, indirect dry cooling is not discussed in this paper. For new power plants in the U.S., indirect dry cooling has been dismissed by utilities and architect-engineers as impractical because of the extremely poor thermal performance relative to direct dry cooling. While indirect dry cooling would be more technically suitable than direct dry cooling as a retrofit to an existing wet cooling system, the practicality of such retrofits is questionable for a variety of reasons. The very poor thermal performance of indirect dry cooling systems will likely reduce the generating efficiency too much to justify such a retrofit, especially when combined with other site-specific factors (unit age and anticipated life, space constraints, etc.). An ongoing U.S. Department of Energy study is evaluating some of these retrofit implications and should provide valuable detailed information shortly.

On the other hand, direct dry and parallel wet/dry cooling systems address several of the concerns associated with wet cooling systems. Still, there are other factors that affect their widespread use in power plants. These include:

- Size. By definition, dry cooling involves the transfer of heat to the atmosphere without the evaporative loss of water (i.e., by sensible heat transfer only). Because sensible heat transfer is less efficient than evaporative heat transfer, dry cooling systems must be larger than wet cooling systems. For example, to achieve a comparable heat rejection, one study estimates that a direct dry cooling system (ACC) will have a footprint about 2.2 times larger than a wet cooling tower and a height about 1.9 times greater.[2]

- Operational control. Direct dry cooling and parallel wet/dry cooling systems require the transport of large volumes of steam from the turbine exhaust through ducts into headers for distribution into rows of small-diameter finned tubes grouped in cells. Maintaining the desired steam condensation temperature (turbine backpressure) requires balancing the steam flow into each cell (which can vary with unit load), continuous removal of any noncondensible gases, and elimination of any leaks to assure vacuum conditions throughout the entire network of ducts, headers and tubes. In a parallel wet/dry cooling system, operational control is further complicated by the need to balance steam flow between two separate cooling systems (wet and dry).

- Plume recirculation. In a dry cooling system, forced-draft fans are used to control air flow across the finned tubes and enhance sensible heat transfer. However, forced-draft fans expand the inlet air stream to cover the large finned surface area, which lowers the warm air exit velocity. As a result, a large portion of the warm air plume exiting the top may be drawn back into the intake at the bottom instead of fresh ambient air. The potential for plume recirculation can be exacerbated by variations in wind patterns and the proximity of other structures (such as the turbine building) that could interfere with air flow patterns. In some cases, this problem can be mitigated by appropriately placed windwalls.

- Maintenance. Both direct and indirect dry cooling systems, as well as hybrid cooling systems, are larger and mechanically more complex than corresponding wet cooling systems. In addition to the larger heat transfer surface area, dry and hybrid cooling systems will have more fans, meaning more electrical motors, gearboxes and drive shafts. As such, labor requirements for a large ACC can be substantial. At one site with a 60-cell ACC (three 20-cell bays for three separate steam turbines), the maintenance staff was increased by two people for such activities as cleaning fan blades and heat exchanger tube fins, monitoring lube-oil systems, and leak-checking the vacuum system.[3]

- Energy penalties. Because sensible heat transfer is directly related to the ambient dry-bulb temperature, a dry cooling system must have the flexibility to respond to typical daily temperatures variations of 20-25 °F. A dry system that maintains an optimum turbine backpressure at ambient dry-bulb temperatures of 90-95 °F, may not be able to do so as the temperature increases, meaning a lower generating efficiency. From a design perspective, more surface area (i.e., a larger dry cooling system) can compensate for the decline in heat transfer at high ambient temperatures; but the greater size and associated operational control are also concerns, as previously discussed.

To a great extent, most of these concerns are developmental in nature and reflect the U.S. utility industry's lack of experience with the design and operation of dry and hybrid wet/dry cooling systems large enough for most power plants. Although some sources cite as many as 600 power plants using dry cooling systems worldwide, in the U.S. most dry cooling systems are at units that have generating capacities less than 100 MW. During the ten-year period 1990-1999, dry cooling was used at ten new U.S. power plants with a capacity greater than 50 MW; only one of these plants had a generating capacity greater than 200 MW.

The Real Issues

None of the concerns described for wet, dry or parallel wet/dry cooling systems addresses the real issues. Instead, these concerns would be more correctly considered "constraints" rather than "issues". They define the limits in which a cooling system must cost effectively operate. The real issues are economically based and are centered on reliable, cost-effective performance and unit availability. In the evolving deregulated utility industry, electric generating units that are unable to meet consumers' demands for power at the lowest price will be slowly, but inevitably, excluded from the market. So the real issues for all power plant cooling systems are low-cost performance and availability within a set of defined constraints.

Performance. For any cooling system, performance is determined by the system's continuous and consistent ability to reject the heat load necessary to achieve the steam condensate temperature corresponding to the optimum turbine backpressure. In doing so, the cooling system must be designed not only to transfer the maximum heat load, but also to operate over a broad range of anticipated environmental conditions. Failure to meet either of these design considerations usually means higher steam condensate temperatures (higher turbine backpressures) and lower power generation efficiency.

For wet cooling systems with a given condenser design (steam flow and cooling water flow), the temperature of the cold water entering the condenser will determine the steam condensate temperature. Therefore, the cold water temperature is a key design and operating parameter. For a once-through cooling system, plant operators have no control over inlet cold water temperatures. But with adequate historic source water data, once-through systems usually can be designed to provide cold water temperatures suitable for maintaining turbine operation at the optimum design point throughout the year. Assuming some typical values for condenser temperature rise (the increase in cooling water temperature entering and exiting the condenser) and a condenser terminal temperature difference or TTD (the temperature difference between the condensing steam and the hot water leaving the condenser), it is possible to calculate the condensing steam temperature and the corresponding turbine backpressure as shown in Table 1. For this example, Atlanta, Georgia has been chosen as the power plant site.

TABLE 1

Steam Condensate Temperatures and Turbine Backpressures for Typical Cooling System Design Values

	Once-through Wet Cooling	Recirculated Wet Cooling	Direct Dry Cooling (ACC)
Surface water temperature[A]	79 °F		
Condenser temperature rise	20 °F		
Ambient wet-bulb temperature[A]		78 °F	
Ambient dry-bulb temperature[A]			95 °F
Correction for plume recirculation		2 °F	3 °F
Approach to wet-bulb temperature		8 °F	
Cooling tower range		24 °F	
Condenser TTD	6 °F	6 °F	
Condenser ITD[B]			20 °F
Steam condensate temperature	105 °F	118 ° F	118 °F
Corresponding turbine backpressure	2.3 in. Hga	3.3 in. Hga	3.3 in. Hga

A - Maxiumum surface water temperature and 1% ambient wet-bulb and dry-bulb data are for Atlanta, GA.

B - A 20 °F ITD was selected in order to achieve a steam condensate temperature comparable to the recirculated system and ensure adequate performance at the 1% ambient dry-bulb temperature; a more typical, cost-effective ITD would be in the 25-55 °F range.

For a recirculated system, the cooling tower is designed to produce a specified cold water temperature based on the anticipated climatic conditions. Because evaporation is the dominant means of heat transfer in a cooling tower, the ambient air wet-bulb temperature is the controlling factor. The lower the inlet air wet-bulb temperature (indicating colder air and/or lower humidity), the colder a tower can make the cooling water going to the condenser. As a matter of physics, the cold water temperature can never be lower than the inlet air wet-bulb temperature. The difference in cold water and inlet air wet-bulb temperatures is known as the “cooling approach”. Most cooling towers are designed for an approach between 5 and 10 °F; for power plant cooling towers, the approach is generally 8 °F.

To assure adequate cooling tower performance virtually all of the time, a “worst case” ambient wet-bulb temperature is selected for design purposes. Based on historic climatic data, the design value most frequently used is an ambient wet-bulb temperature that would not be exceeded for more than 29 hours during the months of June through September (approximately 1 percent of the total time for that period). Again, assuming some typical values for a power plant cooling tower range (the temperature difference between the hot water entering and the cold water leaving an evaporative cooling tower) and plume recirculation (the estimated increase in inlet air wet-bulb temperature due to tower plume recirculation), it is possible to calculate the condensing steam temperature and the corresponding turbine backpressure as shown in Table 1.

For dry cooling systems, sensible heat transfer is the only form of heat rejection, so performance depends upon the ambient air dry-bulb temperature instead of the wet-bulb temperature. Because ambient dry-bulb temperatures are usually higher and tend to experience more dramatic daily and seasonal fluctuations than ambient wet-bulb temperatures, designing and operating dry cooling systems to obtain the consistent and continuous performance historically provided by wet cooling systems is possibly the greatest obstacle to the increased use of dry cooling in power plants.

One way to overcome this obstacle is to increase the size of the air-cooled condenser (i.e., when the rate of sensible heat transfer declines due to an increase in the ambient dry-bulb temperature, a larger ACC will still have adequate heat transfer area to reject the design heat load). This can be accomplished in the design phase by specifying a smaller initial temperature difference or ITD (the temperature difference between the condensing steam and the ACC inlet air dry-bulb temperature). Assuming a fairly low design ITD (20 °F) and a typical plume recirculation (the estimated increase in inlet air dry-bulb temperature due to ACC plume recirculation), it is possible to calculate the condensing steam temperature and the corresponding turbine backpressure as shown in Table 1.

The results shown in Table 1 indicate that all three types of cooling systems can be designed to provide acceptable performance (operating turbine backpressures in the range of 2.0-3.5 in. Hga) for environmental conditions that might occur approximately 99.44% of the year. Therefore, performance need not be a limiting factor in the selection and/or use of any of these systems for power plant cooling.

Availability and reliability. In order to be profitable, a commercial enterprise must operate; in the electric generation business that means producing power. If a cooling system cannot operate reliably on-demand, then it can interfere with the production of power for sale. Hence, a cooling system must guarantee suitable performance on a continuous and consistent basis.

When operated and maintained properly, the availability and reliability of wet cooling systems have been excellent. Problems that might impede power production are rare and usually occur because of extremely unusual circumstances. For example, during infrequent periods of very high surface water temperatures, some once-through systems have needed to curtail flow or use helper towers to meet the maximum temperature limits required by site-specific discharge permits. Some recirculated systems have reported partial or complete cooling tower collapses due to ice formation during freezing temperatures or deterioration of the wooden support structure from fungal-based decay. As previously mentioned, the utility industry's experience with dry cooling systems is limited. But potential problems that have been reported in other applications include fouling of the finned tubes from airborne contaminants, and freezing and rupturing of the finned tubes during periods of extremely low dry-bulb temperatures.

Yet, these problems are relatively rare and can usually be avoided with proper operating and maintenance practices. Therefore, availability and reliability should not be a limiting factor in the selection and/or use of any of these systems for power plant cooling.

Costs. If performance, availability and reliability appear to be equal, then the single issue that will most likely govern the selection and use of a power plant cooling system is cost. Unfortunately, the economics of power plant cooling systems are complex, which means cost estimates are frequently mistaken, misunderstood or misrepresented. This complexity results from the complicated relationships of three key costs: installed equipment capital cost, annual operating and maintenance or O&M cost, and energy penalty cost. For most manufacturing processes, the first two costs can be fairly well defined and, to a certain extent, contractually guaranteed by the vendor/supplier. But the energy penalty cost is somewhat unique to power plant cooling systems because it reflects a direct performance link between the cooling system and the low-pressure turbine-generator. Consequently, the potential for and the magnitude of an energy penalty cost can dictate cooling system design and operating changes that directly affect the capital and O&M costs. So in a competitive market, generating power in the most cost-effective manner depends upon a company's ability to balance all three key costs and optimize the overall life-cycle cost of the cooling system.

For wet cooling systems, decades of experience have helped establish the optimum design and O&M practices. As a result, the relationships of the three key costs are well understood and documented. Ongoing innovations (such as the introduction of film fill about 15 years ago and the increasing replacement of wood by fiberglass) may cause some changes in capital and O&M costs. But these changes are not likely to influence the current design practice of specifying performance based on the maximum source water temperature (for once-through cooling) or the 1% ambient wet-bulb temperature (for recirculated cooling). The daily and seasonal variations in source water and wet-bulb temperatures are too small to justify a lower performance that could produce a higher energy penalty cost.

For dry cooling systems, the U.S. power plant experiential database is extremely small. Hence, the relationships between the three key costs are not well understood or documented. An important difference from wet cooling systems is the greater sensitivity of dry cooling system performance to ambient conditions. The larger daily and seasonal variations in ambient dry-bulb temperatures indicate that energy penalties for dry cooling systems are more likely to occur, particularly during the hottest times of the year. Because these times would typically coincide with periods of peak electricity consumption, a decline in power production could represent a serious difficulty in meeting customer demand and a potentially significant revenue loss.

Determining reasonable energy penalty cost estimates is problematic due to the hour-to-hour and day-to-day variations that occur in ambient dry-bulb temperatures and the market price of electrical power. Using daily averages for both of these parameters is an approach commonly suggested to simplify the energy penalty cost calculation. But daily averages for dry-bulb temperatures cannot account for extreme energy penalties that might occur briefly during the hottest times of the day. Continuing with the example presented earlier in Table 1, Figure 2 shows the change in turbine backpressure as a function of ambient dry-bulb temperature for four different ITD design values. For an ITD of 40 °F and the average daily dry-bulb temperature for Atlanta during the summer, the turbine backpressure is within the typical operating range and well under the maximum operating limit. Consequently, the estimated energy penalty cost would be very low. But at the 1% dry-bulb design value, an ACC with an ITD of 40 °F will be unable to maintain the turbine backpressure below the maximum operating limit. Even though the 1% dry-bulb design value will definitely occur during the summer, the associated energy penalty cost, which could be substantial, would not be reflected in an estimate based on daily averages for summer dry-bulb temperatures.

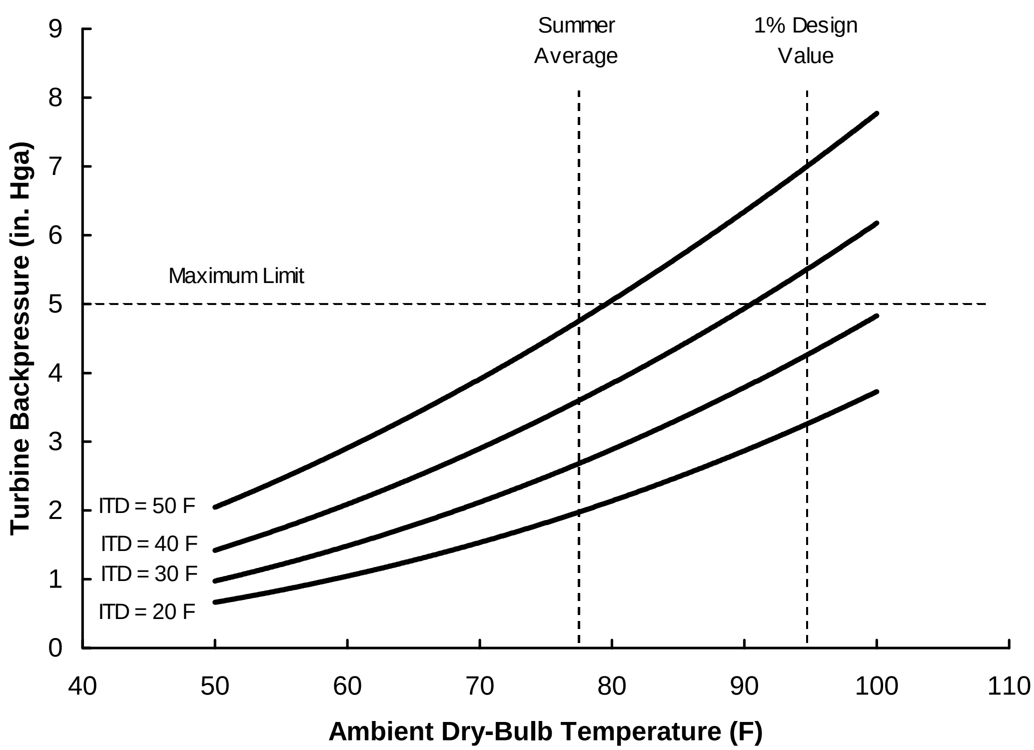

Figure 2
Ambient Dry-Bulb Temperature vs Turbine Backpressure

A misconception about the new generation of combined-cycle plants may also be contributing to incorrect energy penalty cost estimates for dry cooling systems. The confusion stems from an assumption that the cooling system can affect only the steam turbine-generator, which is not necessarily true. If a cooling system cannot provide adequate heat rejection, then steam flow from the HRSG through the turbine to the condenser may need to be reduced. Since the exhaust gases from the combustion turbines must pass through the HRSG, a limit on the boiler's steam production could also make it necessary to reduce the flow of exhaust gases by "trimming" operation of the combustion turbines. Through this domino affect, reduced cooling system performance could have energy penalty cost implications for both the steam and combustion turbines in a combined-cycle power plant.

Several methods have been proposed to mitigate possible energy penalty costs when dry cooling is used at power plants. In addition to different cost implications, each method has certain characteristics that may be viewed as advantages or disadvantages depending upon site-specific constraints. Furthermore, although presented separately here, a combination of two or more of these methods could prove to be the most cost-effective dry-cooling system design.

- Larger ACC (smaller ITD). As shown in Table 1, an ACC with a large heat transfer surface area (low ITD) will provide adequate performance at the 1% ambient dry-bulb temperature (which is comparable to the performance standard typically required for wet cooling towers based on the 1% ambient wet-bulb temperature) to eliminate the energy penalty cost. Doing so, however, will appreciably increase both the installed equipment capital cost and the annual O&M cost. A larger ACC may also encounter site-specific space constraints and difficulties with operational control.

- Turbine redesign. The maximum backpressure range of 5.0-5.5 in. Hga for conventional steam turbines could be extended to a higher value enabling more flexible operation over a wider range of backpressures. This could be done by modifications to existing turbine designs or by development of a new turbine. One modification that has been widely discussed includes removing the last row of blades or final stage and introducing steam downstream of the initial stage during periods of high ambient dry-bulb temperatures. Because these changes would reduce the efficiency of the turbine across the entire range of backpressures, enlargements in the steam flow area of both the high-pressure and intermediate-pressure turbines have been suggested to help compensate.

  A different modification would not remove the last row of blades, but would adjust the lengths and increase the structural strength of blades in the last several rows; no changes would be made to the high or intermediate-pressure turbines. As before, this redesign would reduce the efficiency of the turbine across the entire range of backpressures.

  A more radical approach would be the design of a completely new turbine. More than thirty years ago, one study suggested that by shortening the last-stage blades, strengthening all of the stages to pass more steam flow and extensively altering the exhaust structure, a turbine could be designed to operate at backpressures ranging from 2.0 to 14.0 in. Hga.[4] While such a design might be 10-12% less efficient than conventional low-pressure turbine (based on a comparison of heat rates), the efficiency would be relatively constant across the entire range of backpressures, making it desirable to operate at the higher end. Since that time, no serious efforts have been made to design such a high-backpressure turbine primarily because the investment from manufacturers would be significant and the demand from utilities was not.

- Water spray enhancement. The temporal nature of dry cooling energy penalties means that ACC heat transfer might be cost-effectively enhanced for limited, intermittent periods by evaporating water sprays directed on the hot surfaces of the finned tubes or into the hot ambient inlet air. Besides the practical difficulty of achieving a uniform spray to all sections of a large ACC, both techniques would consume some amount of water, which may be contrary to one or more of the constraints that originally made dry cooling an attractive option. Further, both techniques would need to use relatively pure water to prevent the formation of surface deposits on the ACC finned tubes that would interfere with heat transfer and further decrease system performance. Water sprayed into the inlet air could also leave surface deposits on the induced draft fans. Any water that falls to the ground would need to be collected and treated either for recycle to the spray enhancement equipment, reuse in other power plant processes or discharge/disposal. The additional equipment and pure water requirements will mean increased capital and O&M costs. But, a successful water spray enhancement technique could likely have both new and retrofit applications.

- Parallel wet/dry cooling. The most highly promoted aspect of the parallel wet/dry cooling system is the design capability for distributing the overall heat rejection load between an ACC (at low ambient dry-bulb temperatures) and a conventional wet cooling tower (at high ambient dry-bulb temperatures). By using wet cooling to supplement dry cooling during periods of high ambient dry-bulb temperatures, this system attempts to limit the energy penalty costs. However, the operational control of this hybrid system is even more complex than either a direct or indirect dry cooling system. For example, a 37-MW unit reportedly uses automatic setpoint functions and a neural network to achieve a desired turbine backpressure by simultaneously monitoring and controlling the variable speed fans on the ACC and the cooling tower, as well as the recirculated cooling water flow.[5] In addition, the difficulty of constructing a large, low-pressure-drop, bifurcating ductwork from the turbine exhaust to both an ACC and a water-cooled condenser may limit this type of system to small power applications. For instance, a 400 MW turbine in a fossil plant would typically use a 20 ft. x 20 ft. exhaust. The capital costs for a parallel wet/dry system are reported to be about the same as for a direct dry system (ACC); the O&M costs are not well documented, but are suspected to be comparable or higher.

Needs

Following decades of experience and refinement, wet systems (either once-through or recirculated) have become the standard for cost-effective, reliable cooling of steam turbine generators in electric power plants. Even as the number of constraints affecting the design and operation of these systems has grown over this time, wet cooling has continued to be the dominant choice in power plants.

Recently, federal regulatory activity under Section 316(b) of the Clean Water Act and widespread construction in the semi-arid southwestern U.S. have increased interest in dry and parallel wet/dry systems as alternatives. But the power industry's lack of experience with dry and parallel wet/dry cooling may raise doubts about the cost-effective, reliable performance of these systems. Until these doubts are addressed, the roles for dry and parallel wet/dry cooling in power plants will be ill defined, and the acceptance and use of these technologies will most likely be slow and erratic. Therefore, the following tasks need to be done:

1. Develop methods for improving the performance of dry cooling at high ambient dry-bulb temperatures.

2. Establish a procedure for estimating a representative energy penalty. When variations in important environmental factors are minor, a reasonable estimate can be determined using daily averages. This approach should be adequate for wet cooling systems because variations in hourly surface water temperatures (once-through cooling) and hourly ambient wet-bulb temperatures (recirculated cooling) are minor. However, due to the more significant variations in hourly ambient dry-bulb temperatures, for dry cooling a simple approach based on daily averages would substantially underestimate the energy penalty. Instead, an approach that uses hourly ambient dry-bulb temperature data with a corresponding series of system performance calculations should be used to estimate the energy penalty on an hour-by-hour basis. These values can then be summed for presentation as daily, monthly or annual energy penalties. Without this procedure, it will be difficult to measure the performance improvements achieved in Item 1 above or to estimate the true system cost discussed in Item 3 below.

3. Establish a protocol for optimizing a cooling system design based on site-specific constraints and data, and the three key costs (installed equipment capital cost, annual O&M cost and energy penalty cost). Such a protocol is critical if the utility industry is to make wise economic decisions in an unregulated, competitive market and to avoid unwarranted mistakes in selecting power plant cooling systems.

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