Advanced Cooling Options for Nuclear Power Plants

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EPRI Project Manager

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ABSTRACT

Alternative power plant cooling systems exist that offer significant opportunity for reducing the amount of water used in power plant cooling. These systems include direct dry cooling using air-cooled condensers, indirect dry cooling using air-cooled heat exchangers paired with water-cooled surface condensers, and a variety of hybrid systems incorporating both dry and wet cooling elements. The water savings afforded by the use of these systems, however, comes at a price in the form of more expensive equipment, higher cooling system power requirements, reduced plant efficiency, and limited plant capacity on the hottest days. These systems are used on only about 1% of existing plants (approximately 25 GW capacity) to date, and their application has been limited to fossil-fired plants, both coal-fired steam plants and gas-fired combined-cycle plants, as well as a few solar plants. However, their use on nuclear plants encounters some "nuclear-specific" issues, which have limited their application thus far. There have been no instances of either dry or hybrid cooling on nuclear plants in the U.S., and only two dry cooled nuclear plants world-wide, only one of which is still operating.

It is likely that increasing electric power requirements coupled with the desire to limit greenhouse gas emissions will lead to the construction of new nuclear plants in the U.S. in the near future. Concern over constrained water supply will then create a need for serious consideration of how water-conserving cooling systems can be applied to nuclear plants. This report provides an overview of the options available for dry and hybrid cooling, the issues which must be addressed in order to use them on nuclear plants, and a comparison of the cost and performance of alternative systems. Brief consideration is given to the feasibility of retrofitting existing nuclear plants equipped with once-through or closed-cycle cooling, to dry or hybrid cooling.

Keywords

Cooling system on nuclear plants
Cooling system retrofit
Dry cooling
Heller system
Hybrid cooling
Spray enhanced dry cooling

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

Background

Water use and water conservation are important societal issues in the U.S. and world-wide. In the United States, water for the generation of electric power is an important element in the equation. Steam electric power generation accounts for approximately 48% of the fresh water withdrawals from natural waterbodies in the nation and approximately 3% of the total consumption. Therefore, the availability of water can be an important and contentious issue in power plant siting applications.

At most plants, the major use of water (be it withdrawal or consumption) is for the cooling system with which the turbine exhaust steam is condensed, generically known as "power plant cooling", or "circulating water system". The most common systems currently in use at nearly all (~99%) thermal power plants in the US are once-through cooling and closed-cycle wet cooling. In once-through cooling, water is withdrawn from a natural waterbody adjacent to the plant, passed through a steam condenser where it absorbs heat from the condensing steam, and is returned to the waterbody at a higher temperature. In some cases, the waterbody from which the cooling water is withdrawn and to which it is returned is a cooling pond or cooling lake or cooling canal. These elements are normally connected to a natural waterbody such as a river from which water is withdrawn or diverted to form a reservoir or impoundment from which the cooling water is supplied to the plant. From the standpoint of the plant, this is essentially a once-through system; from the standpoint of the natural waterway, it might be considered recirculating since the only water withdrawn from the natural waterbody is that required to replace water in the pond or lake lost through evaporation or blowdown. At some plants, the discharge flow is passed through a cooling tower (often referred to as a "helper" tower) to reduce the discharge temperature before returning it to the receiving waterbody. For the purpose of the following categorization, all of these arrangements will be considered to be "once-through". "Closed-cycle" will be restricted to mean cooling systems with cooling towers.

In closed-cycle wet cooling, the heated water leaving the condenser, rather than being returned to the environment, is sent to a cooling tower, where it is cooled before being re-cycled to the condenser. The cooling tower can be either a mechanical-draft or natural-draft tower. Withdrawal of water from the environment is limited to the amount required to replace water lost to evaporation, blowdown and drift, and it amounts to typically less than 5% of that withdrawn for once-through cooling.

Alternative cooling systems exist that offer significant opportunity for reducing water use for power plant cooling. These include direct dry cooling using air-cooled condensers, indirect dry cooling using air-cooled heat exchangers paired with water-cooled surface condensers and a variety of hybrid systems incorporating both dry and wet cooling elements. The water savings afforded by the use of these systems, however, comes at a price in the form of more expensive equipment, higher cooling system power requirements, reduced plant efficiency and limited plant capacity on the hottest days. To date, these systems are used on only about 1% of existing plants (approximately 25 GW capacity), and their application has been limited to fossil-fired plants, both coal-fired steam plants and gas-fired combined-cycle plants as well as a few solar plants.

However, their use on nuclear plants encounters some "nuclear-specific" issues which have limited their application to date. There have been no instances of either dry or hybrid cooling on nuclear plants in the U.S. There have been only two dry cooled nuclear plants world-wide and only one is still operating.

It is likely, however, that increasing electric power requirements coupled with the desire to limit greenhouse gas emissions will lead to the construction of new nuclear plants in the U.S. in the near future. Concern over constrained water supply will then create a need for serious consideration of how water-conserving cooling systems can be applied to nuclear plants. This report provides an overview of the options available for dry and hybrid cooling, the issues which must be addressed in order to use them on nuclear plants and a comparison of the cost and performance of alternative systems. Brief consideration is given to the feasibility of retrofitting existing nuclear plants equipped with once-through or closed-cycle cooling to dry or hybrid cooling.

Cooling systems in nuclear plants

There are currently 63 nuclear power plants operating in the U.S. comprising a total of 102 individual units. All use some form of wet cooling. Sixty-six units have once-through cooling; thirty-six have cooling towers. Of those with cooling towers, thirteen have mechanical-draft wet cooling towers; twenty-two, natural-draft wet cooling towers; and one unit with one of each. Of the sixty-six units on once-through cooling, fourteen withdraw cooling water from the oceans; eight from the Great Lakes; twenty-four from rivers; twenty from lakes. The breakdown of nuclear unit cooling systems by type and water source is tabulated in Table 1-1.

As an example of one approach to the conservation of fresh water resources, the Palo Verde Nuclear Power Plant uses reclaimed municipal wastewater, piped in from Phoenix and surrounding towns through a 36 mile pipeline[1] to enable operation of a closed-cycle wet cooling system using mechanical-draft wet cooling towers in the middle of an arid region.

No nuclear plants in the U.S. use dry or hybrid cooling. At least one unit, Dominion's North Anna Unit 3, originally proposed the use of wet/dry hybrid cooling to maintain the water level in Lake Anna while adding a third unit to the existing two-unit plant. However, the project is not currently proceeding.[2]

[1] Palo Verde Nuclear Generating Station Water Reclamation Facility, Palo Verde Energy Information Center, http://www.azein.gov/azein/Shared%20Resources/PVNGS%20Media%20Kit/Water%20Reclamation%20Facility_brochure.pdf

[2] North Anna Power Station Unit 3; https://www.dom.com/about/stations/nuclear/north-anna/north-anna-3.jsp

Table 1-1
Categorization of wet cooling systems in nuclear units

Source water	Nuclear Unit Cooling Systems			
	Once-through (1)	Closed-cycle (with towers)		
		Mechanical-draft	Natural-draft	Both
Ocean (2)	14	0	0	0
Great Lakes	8	1	4	0
Rivers	24	7	15	1
Lakes	20	2	3	0
Reclaimed water	0	3	0	0
Totals	66	13	22	1
		36		
	102			

Notes: (1) Includes units with helper towers and those running off cooling ponds and lakes; (2) Includes bays and estuaries

Elsewhere in the world, two nuclear plants have been built and operated with dry cooling. One is Schmehausen in Germany, a 300 MW thorium, high temperature reactor, which utilized an indirect dry cooling system with a natural-draft tower of a unique design.[3] The plant operated for only a short time and was shut down in 1989; the tower was demolished in 1991. The other, Bilibino, is a small (48 MW plant consisting of four 12 MW units) plant located in Siberia.[4] It is still operating, but little is known about the system. To our knowledge, there are no nuclear plants in the world operating on wet/dry hybrid systems.

Organization of report

The following report is organized into three major sections. Section 2 provides descriptions of a number of potential cooling systems applicable as water conserving alternatives for nuclear power plants. Section 3 discusses some cooling requirements in addition to main condenser cooling of particular relevance to nuclear plants. Section 4 discusses cooling system retrofit issues, again with the emphasis on nuclear installations. Section 5 presents cost performance information on the range of cooling systems of interest. The results and conclusions of the study are summarized in Section 6.

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[3] G. Hirschfelder, *Dry Cooling Tower for the 300 Mw Thtr Nuclear Power Plant Schmehausen*, AEC-TR-7428, 1973

[4] Nuclear Energy Institute, *Source Book, Soviet-Designed Nuclear Power Plants in Russia, Ukraine, Lithuania, Armenia, the Czech Republic, the Slovak Republic, Hungary and Bulgaria, Fifth Edition, 1997*

Two appendices are included. Appendix A is a list of Heller system installations worldwide. Appendix B provides more detailed information on the design, cost and performance of selected cooling systems for each of the three sites.

2
COOLING SYSTEM DESCRIPTIONS

This chapter includes brief descriptions of relevant water conserving cooling systems which might be considered for application to nuclear plants.

Dry cooling systems

Air-cooled condensers—Mechanical-draft, A-frame

The usual direct dry system consists of an air-cooled condenser (ACC), shown schematically in Figure 2-1. Approximately 50 such systems are in operation in the U.S., although none is on a nuclear unit. Direct dry cooling systems utilize ACCs to which turbine exhaust steam is ducted from the turbine exit through a large horizontal duct to a lower steam header feeding several vertical risers. Each riser delivers steam to a steam distribution manifold which runs horizontally along the apex of a set of finned, air-cooled condenser tubes arranged in an A-frame (or delta) configuration. The sets of cells fed by a single steam distribution manifold are referred to as "streets" or "lanes". Each street consists of several cells. The sets of cells adjacent to one another but fed by parallel steam distribution manifolds and aligned in a line perpendicular to the manifolds are called "rows".

Each cell consists of several bundles of finned tubes arranged as parallel, inclined bundles in both walls of the A-frame cell. Steam from the steam distribution manifold enters the tubes at the top, condenses on the inner tube walls and flow downward (co-current with the condensing steam) to condensate headers at the bottom of the bundles. One cell in each street (typically one out of five or six, centrally placed along the street) is a "reflux" or "dephlegmator" cell, included for removal of non-condensable gases from the condenser. Remaining steam exiting from the other cells in the street, along with entrained non-condensable gas, flows along the condensate header to the bottom of the reflux cell tube bundles. An air-removal system (vacuum pumps or steam ejector) removes any non-condensable gases through the top of the reflux cell bundles. Additional condensation takes place in this cell and the condensate runs down (flowing counter-current to the entering steam) into the condensate header. The condensate flows by gravity to a condensate receiver tank from which it is pumped back to the boiler or the heat recovery steam generator (HRSG). A simplified schematic representing a single street containing three cells (two condensing cells and a central reflux cell) is shown in Figure 2-1.

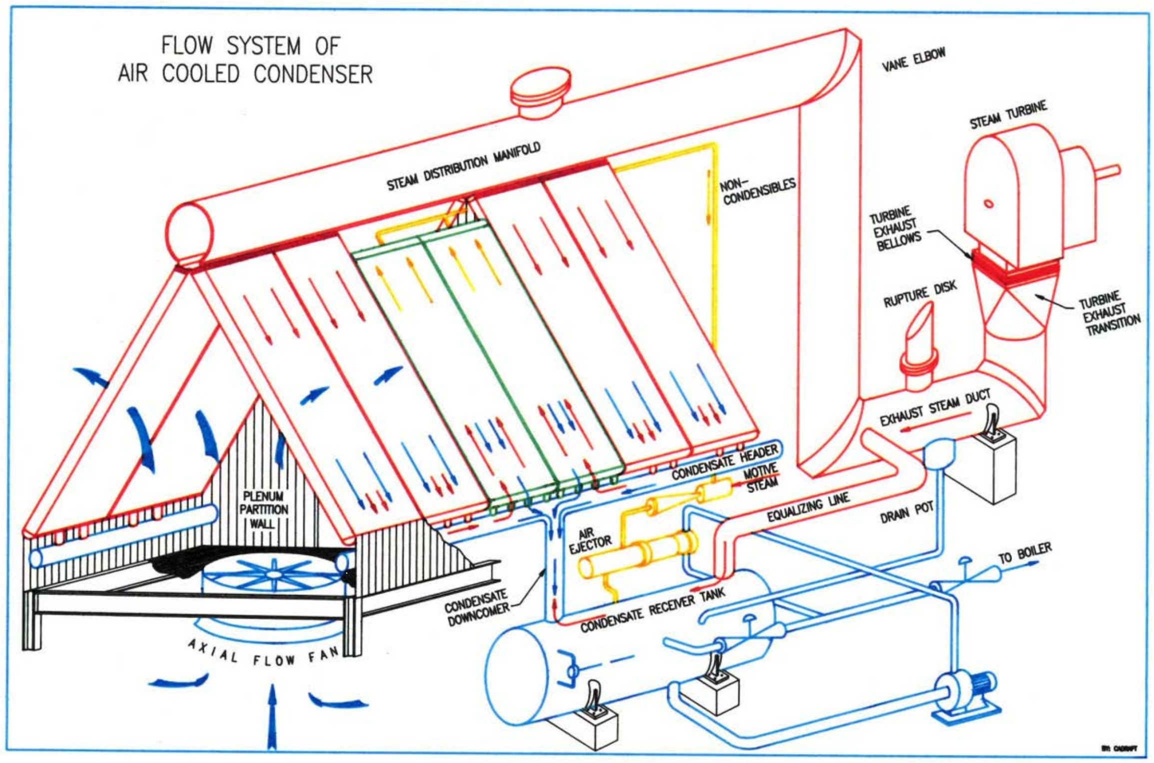

Figure 2-1
Schematic of Air-cooled Condenser (Courtesy of SPX-Marley Cooling Tower Co.)

A 500 MW combined cycle plant, condensing approximately 1 to 1.2 million pounds of steam per hour (125 to 150 kg/s), might typically have 30 to 40 cells arranged in one of several layouts: a 5 x 6 or 8 x 5 or two 4 x 5 clusters. Figure 2-2 shows a 40-cell ACC arranged in two 20-cell (4 x 5) clusters installed on a 520 MW gas-fired, combined-cycle plant. The photograph shows the steam duct, the risers and the distribution manifolds. The cells are surrounded by a windwall to reduce the possibility of hot air recirculation and wind effects. This windwall is not shown in the schematic (Figure 2-1) but is visible in the photograph (Figure 2-2).

Figure 2-2
View of ACC with Steam Risers, Steam Distribution Manifolds, and Windwall

Indirect dry cooling

Mechanical-draft, air-cooled heat exchangers with water-cooled condensers

Indirect systems typically pair a conventional shell-and-tube surface steam condenser with an air-cooled heat exchanger (ACHE). The heated cooling water leaving the condenser is circulated to the ACHE where it is cooled by heat transfer to the atmosphere. An indirect dry cooling system of this type is shown schematically in Figure 2-3.

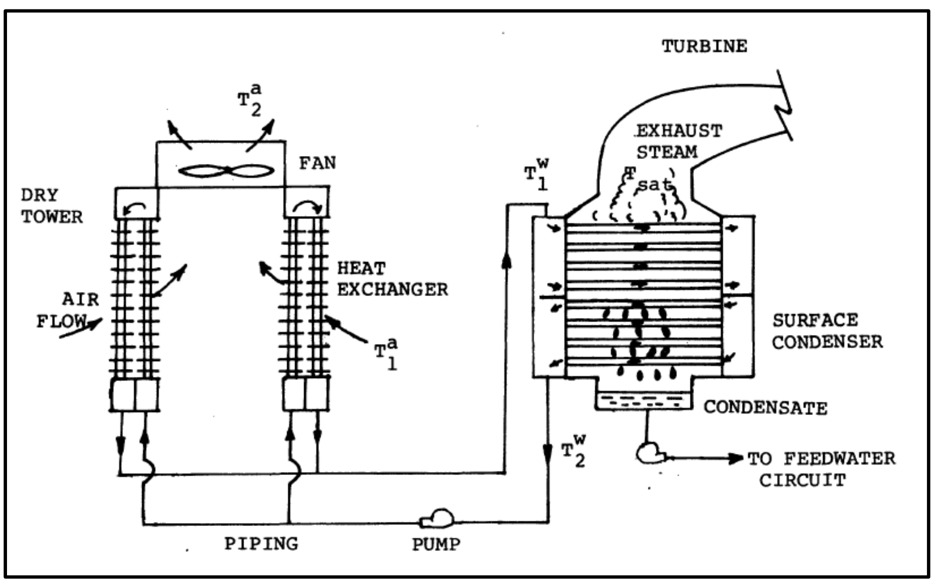

Figure 2-3
Indirect dry cooling with surface condenser and air-cooled heat exchanger

It is more costly and less efficient than the direct dry cooling system because of the two step heat transfer path to the atmosphere, the circulating water pumping power requirement and the temperature rise of the cooling water as an additional temperature difference between the ambient air and the steam condensing temperature. It may be the system of choice for the application of dry cooling to nuclear units, as will be discussed in Chapter 3.

Air-cooled heat exchangers of differing types have been considered for power plant cooling. The first resembles a conventional fin-fan cooler with horizontal finned tube bundles at the top of the unit and forced-draft air circulation from fans underneath, shown schematically in Figure 2-4.

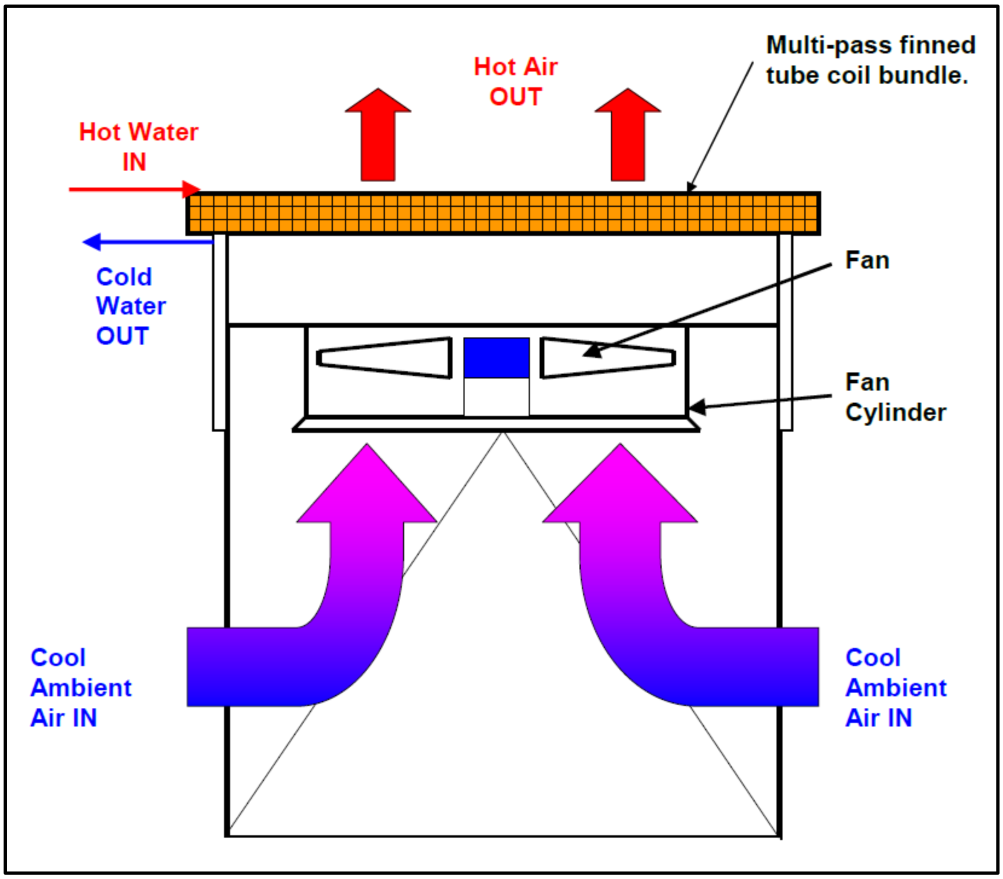

Figure 2-4
Schematic of "fin-fan like" ACHE (Courtesy of SPX)

A sketch of what a large, multi-celled arrangement might look like is shown in Figure 2-5.

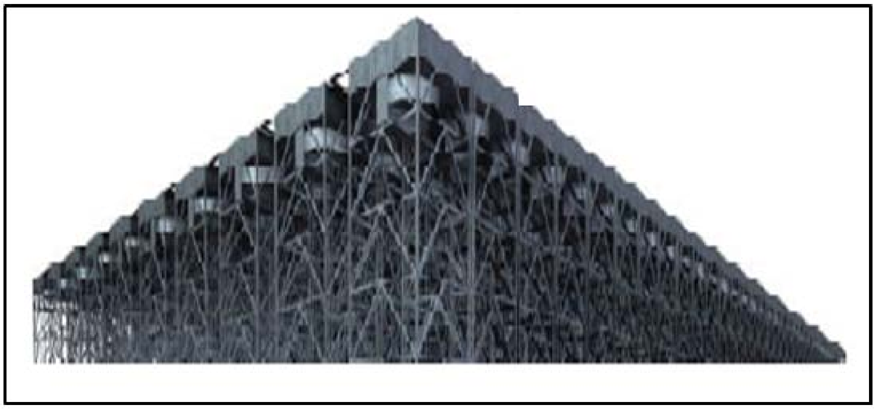

Figure 2-5
Sketch of possible arrangement of "fin-fan-like" ACHE

A second type of ACHE consists of vertical finned tube bundles arranged along the sides of the heat exchanger with air circulation provided by induced-draft fans at the top of the unit. Figure 2-6 shows a 4-fan unit with an exploded view of the bundles of aluminum finned tubes of the so-called Forgo design, named after the Hungarian engineer, Laslo Forgo. The figure also displays a picture of the finned-tube heat transfer surfaces and tubes. They are typically four or six row, staggered tubes connected in a two-pass cross-counter flow arrangement.

These tube bundles are arranged vertically around the bottom of the tower, configured as cooling "deltas". They are self-supporting units with a rigid, triangular frame in which plate-fin heat exchangers are mounted as shown in Figure 2-7. Figure 2-8 shows a full-size ACHE installed on a 800 MW combined-cycle unit at Modugno, Italy as part of a "Heller" cooling system described later in this chapter.

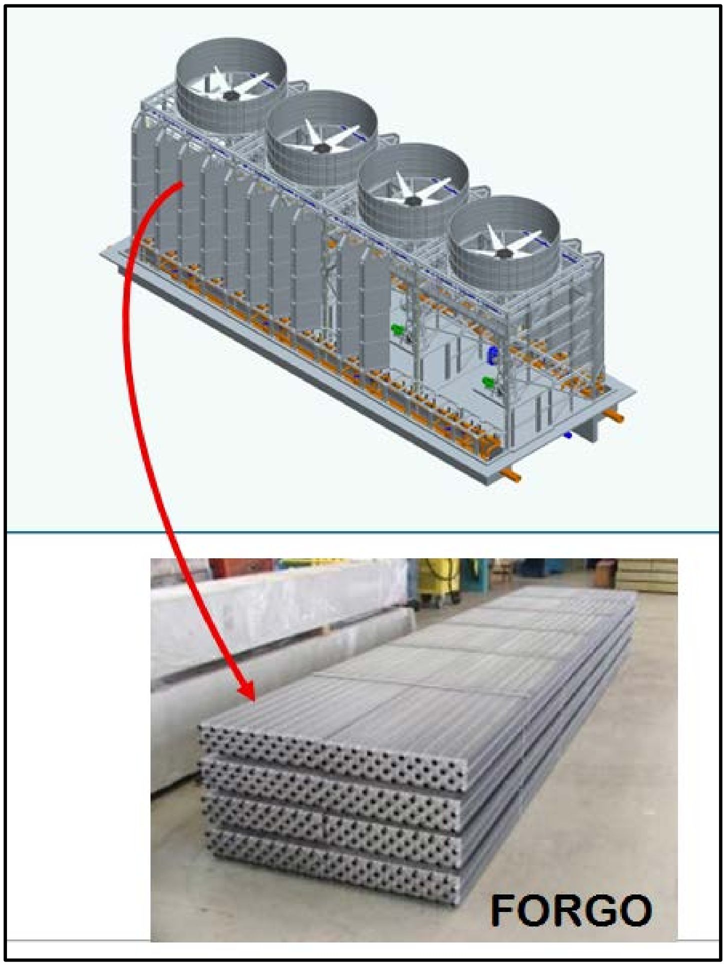

Figure 2-6
Four cell ACHE with “Forgo” heat exchangers

Figure 2-7
Cooling deltas being positioned on side of ACHE

Figure 2-8
Full size ACHE (at Modugno combined-cycle plant, Italy)

Natural-draft ACHEs with water cooled condensers

Indirect dry cooling can be designed with natural-draft ACHEs as well as with mechanical-draft units. Figure 2-9 shows a schematic of such a system. The heat exchanger bundles are sometimes vertical-tube, delta units (of the type described in Figure 2-6 through 2-8) arranged around the periphery of the tower. Photographs of two types of natural-draft towers are shown in Figure 2-10. The tower on the left is constructed with a steel shell, a design commonly used in Europe and the Middle East. The tower on the right is the concrete hyperbolic shell design, as used in the U.S. A different arrangement of the heat exchanger bundles in a horizontal plane inside the tower has been used at the Kendal Station in South Africa (Figure 2-11) and elsewhere.

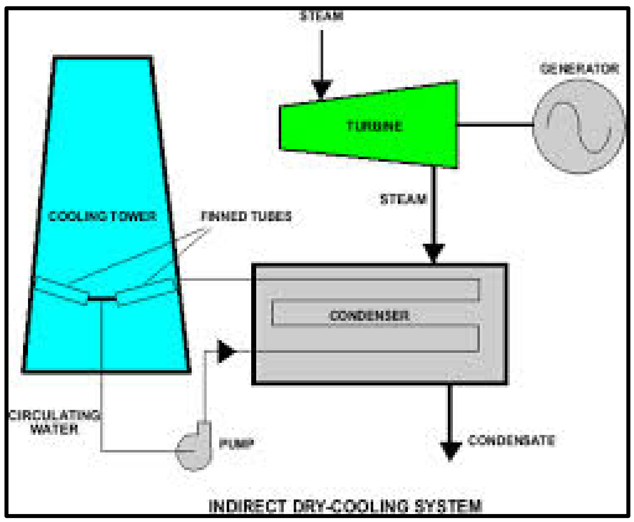

Figure 2-9
Schematic of indirect dry cooling system with natural draft ACHE

While this system has seen limited use in Africa and the Middle East, there are no indirect, all-dry systems operating in the U.S at this time. Figure 2-11 shows the large towers at the Kendal Station in South Africa.

Figure 2-10
Natural-draft towers with peripheral ACHEs

Figure 2-11
Indirect dry cooling system with natural draft towers; Kendal Station, South Africa

Heller system

The Heller system was originally conceived as an alternate approach to dry cooling. It was named after its inventor, Dr. Lazlo Heller, in the 1940's in Hungary and is currently marketed by GEA-EGI. The basic Heller all-dry design approach is conceptually similar to indirect dry cooling but differs in the following two significant ways from the standard indirect dry cooling system:

1. The steam is condensed in a direct-contact (DC) condenser.[5]
2. The air-cooled heat exchangers are installed in a natural-draft tower rather than the more normal fin-fan or mechanical-draft type.

In addition, there are a number of hybrid or wet/dry variations on the all-dry design.

The benefits include:

- a more effective condensation step which achieves a lower condensation temperature and pressure for a given cooling water temperature than does a comparable surface condenser
- lower operating power than is required for a mechanical-draft air-cooled heat exchanger or for a conventional A-frame air-cooled condenser

There are currently over 35,000 MWe of operating plant capacity worldwide in operation or under construction equipped with variations of the Heller cooling system, but there are none currently in the U.S. A partial list is included as Appendix A.

System description

A schematic of the basic all-dry Heller system is presented in Figure 2-12; a photograph of the system installed at the Gebze-Adapazari power plant, a 3 x 777 MW gas-fired, combined-cycle plant located in Turkey, is shown in Figure 2-13. An animated schematic with brief component descriptions is available on the GEA website[6].

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[5] Sometimes referred to as a "barometric" or "spray" condenser.

[6] http://www.gea-energytechnology.com/opencms/opencms/egi/en/cooling/drycooling/

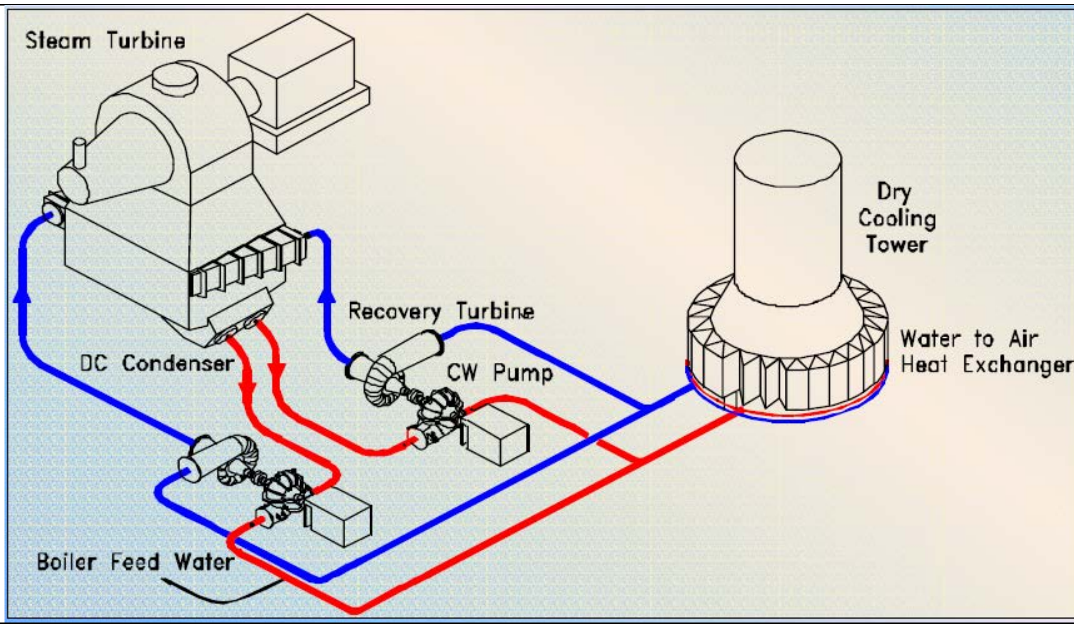

Figure 2-12
Schematic of basic Heller system without wet augmentation

Figure 2-13
Heller system at Gebze-Adapazari plant

The important components of the system are illustrated and discussed in more detail in the following paragraphs. A more detailed schematic of the system circuitry is shown in Figure 2-14.

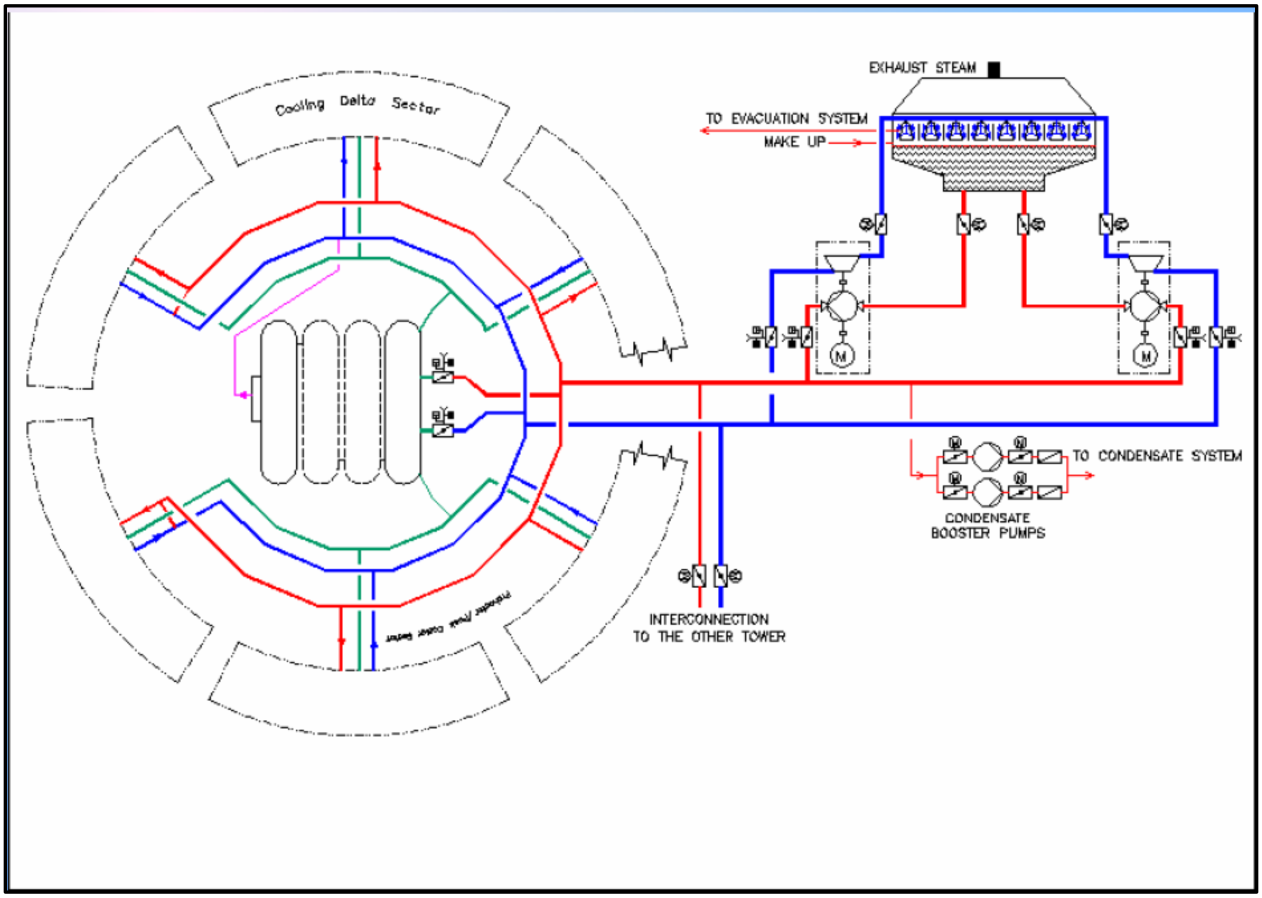

Figure 2-14
Schematic of Heller system flow circuitry

Direct contact condenser

A picture of a DC condenser, shown schematically in the upper, right-hand corner of Figure 2-14, is provided in Figure 2-15. Steam enters at the top (dark arrows), the heated mixture of circulating cooling water and condensate (red arrows) exits at the bottom on its way to the air-cooled heat exchanger. The cooled circulating water returns from the ACHE (light blue arrow) and enters the DC condenser at the side. The cooling water is sprayed into the condenser through nozzles onto impact plates where films are formed on which the steam condenses. Any remaining steam is condensed in a counter-current cascade tray at the bottom where the separation and withdrawal of any non-condensable gases occurs.

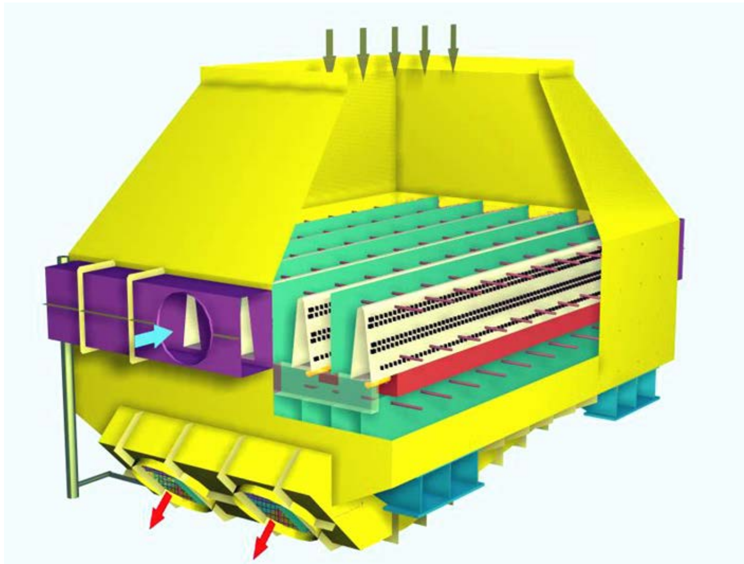

Figure 2-15
Cutaway view of DC Condenser

Air-cooled heat exchanger

The air-cooled heat exchanger in the basic Heller design is a natural-draft tower of the type shown in the left half of Figure 2-10 with the heat exchange element installed around the periphery of the tower at ground level.

Cooling water circuit

The flow leaving the DC condenser is a mixture of circulating cooling water and condensate. The flow is pumped from the DC condenser at condensing pressure (~2 to 5 in Hga) up to the air-cooled heat exchangers at approximately atmospheric pressure. The fraction of the flow corresponding to the condensate (~2 to 3%) is taken from the discharge of the circulating water pumps with booster pumps and returned to the boiler feedwater circuit.

The circulating water pumps are connected through a common shaft to both a hydro-recovery turbine and an electric motor. The power recovered from the circulating water return flow as it drops from atmospheric pressure in the cooling tower to condensing pressure provides part of the pumping power with the remainder supplied by the electric motor. A view of the coupled hydraulic equipment is shown in Figure 2-16.

Figure 2-16
Circulating water hydraulic equipment

Variations on Heller all-dry configurations

Variants on the basic system in all-dry operation include:

- the use of a mechanical-draft cooling tower in place of the natural-draft tower
- the use of a surface (shell-and-tube) steam condenser in place of the DC condenser

The choice of a mechanical-draft tower may be done for aesthetic reasons or to reduce capital cost. The primary effect is to increase the operating power requirements over the life of the plant as compared to the natural-draft system.

Some systems provided by EGI have used a conventional shell-and-tube steam condenser paired with either a natural- or mechanical-draft tower, as shown in Figure 2-17. This, however, essentially reduces the Heller system to a more conventional indirect dry cooling system, which lacks the barometric condenser and the circulating water pump/work recovery turbine which are the defining elements of the Heller system. It is likely that this would be the system of choice for application of dry cooling to nuclear systems as will be discussed in Chapter 3.

The primary disadvantage is an increase in the condensing temperature and pressure for a given condenser cooling water exit temperature due to the higher terminal temperature difference (TTD) in a surface condenser (~5 to 10°F [~2.8 to 5.6°C]) vs. that in a DC condenser (~0.5 to 1°F [~0.3 to 0.6°C]). However, the pumping power required for the circulating water pumps is significantly reduced since the water side of the condenser and the ACHEs are at nearly the same pressure. Further, the complexity of the Heller system hydraulic equipment including the power-recovery hydro-turbine is replaced by conventional circulating water pumps.

Figure 2-17
System with mechanical-draft dry cooling tower

Hybrid systems

The term "hybrid cooling" refers generically to a cooling system with both wet and dry cooling elements. Either or both are available for handling the plant heat load as conditions dictate. The wet and dry elements can be integrated in a single structure or arranged as separate structures operating in series or parallel. Also, hybrid systems can be designed with the objective of either plume abatement or water conservation. The primary emphasis in this report is on water conservation, but a brief discussion of plume abatement systems is included for completeness.

Plume abatement towers

Plume abatement towers are essentially all-wet systems that employ an air-cooled heat exchanger in series with the wet tower. While the dry section rejects some portion of the heat load and, therefore, provides some amount of water conservation, it is typically less than 5%. The primary function of the dry section is to provide a flow of heated dry air which can be mixed with the saturated exhaust plume from the wet portion of the system. This results in a tower exhaust plume in which the psychometric conditions are above the point of saturation during those cold, high-humidity periods of daytime operation when the plume from an all-wet cooling tower is likely to be visible.

A thorough discussion of the several approaches to the design of plume-abatement towers is given in a paper by Lindahl and Jameson[7]. The usual arrangement, in which the wet and dry sections are arranged in a single structure with the dry section on top, is shown schematically in Figure 2-18. Hot water from the condenser flows first through the air-cooled heat portion and

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[7] Lindahl, P.A. and R. W. Jameson (The Marley Cooling Tower Company), "Plume Abatement and Water Conservation with the Wet/Dry Cooling Tower", Proceedings: Cooling Tower and Advanced Cooling Systems Conference, St. Petersburg, FL,EPRI, Palo Alto, CA, pp. 4-37 – 4-51, 1995.

then discharges onto the top of the wet section. A photograph of a modern plume abatement tower with a counter-flow wet section is shown in Figure 2-19.

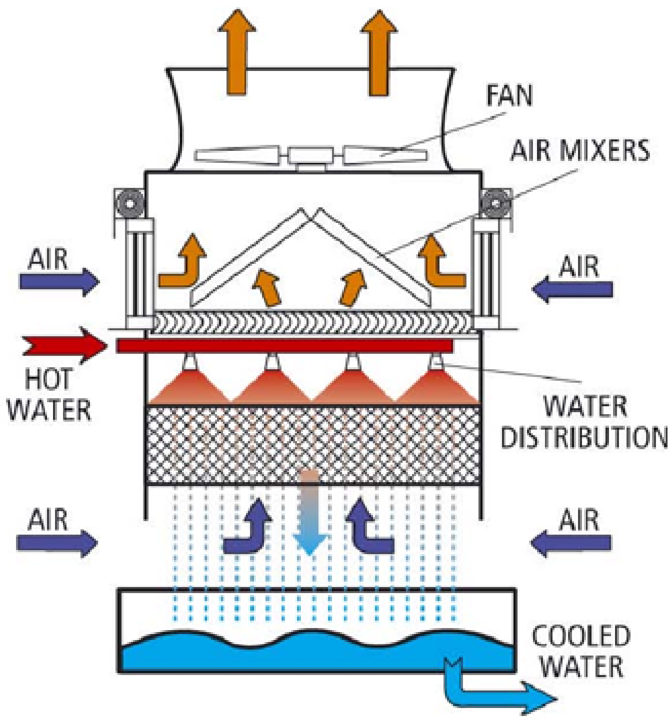

Figure 2-18
Schematic of plume abatement tower

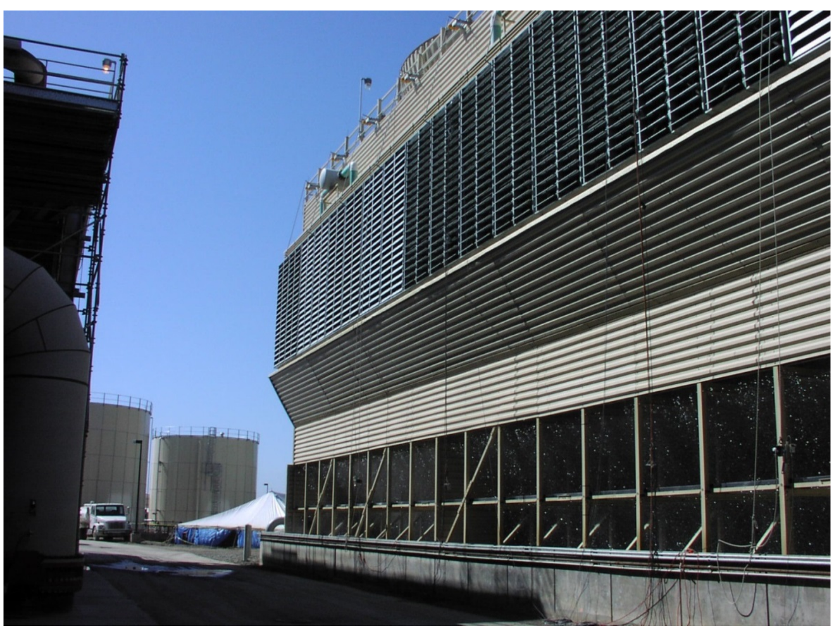

Figure 2-19
Plume abatement wet/dry tower (Courtesy of Metcalf Energy Center)

Hybrid, water-conservation systems

Hybrid systems designed for water conservation have been the subject of increased attention in recent years although to date only a few are installed on U.S. power plants. They are intended to reduce the amount of water required for power plant cooling by using dry cooling during the cooler periods of the year and supplementing the dry capability with wet cooling during hotter periods when dry cooling systems cannot maintain as low a turbine exhaust pressure as is desired. The systems can be configured in a number of ways. A thorough discussion of the several alternatives is contained in an early EPRI report.[8]

Parallel---ACC + wet tower

The most commonly used approach in recent years is that shown schematically in Figure 2-20 in which provision is made to split the steam flow between an ACC and a surface condenser coupled with a mechanical-draft wet cooling tower. A photograph of a small hybrid system is shown in Figure 2-21.

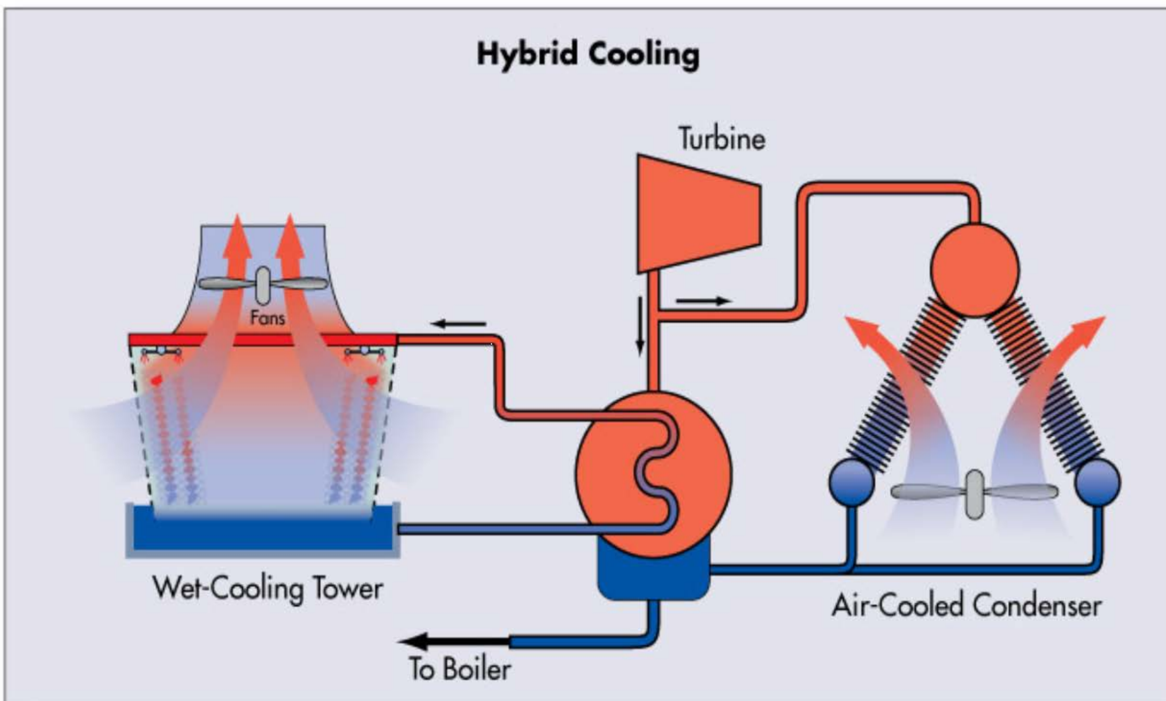

Figure 2-20
Hybrid cooling (shown with parallel wet and dry loops using an air-cooled condenser and a mechanical draft wet cooling tower)

[8] "Survey of Water-Conserving Heat Rejection Systems", EPRI, Palo Alto, CA. EPRI-GS-6252, 1989.

Figure 2-21
Hybrid water-conservation cooling system (shown with a 10 cell air-cooled condenser and a 2 cell wet cooling tower) (from http://www.panoramio.com/photo/2293438)

Series---ACHE + wet tower

As noted earlier, the current common approach to hybrid cooling for water conservation is the parallel system using an ACC for the dry portion. However, as will be discussed in Chapter 3, the use of ACCs on nuclear plants may not be preferred. While this may change in the future, at present it is generally assumed that the presence of a surface condenser as an additional barrier between the steam supply and the environment is desirable. Therefore, hybrid systems for nuclear plants would probably be designed with dry sections based on indirect cooling. Here again, a number of configurations are possible including either series or parallel arrangements of the wet and dry sections and either separate or integrated towers containing the wet and dry elements. These systems are described in an EPRI report[9] and are summarized here for convenience of reference.

[9] op. cit (Footnote 4)

A schematic of a series hybrid system with an indirect dry system and separate wet and dry towers is shown in Figure 2-22. An example of a series, integrated, hybrid system providing significant water conservation exists at the San Juan Generating Station in Farmington, New Mexico. It consists of a conventional, shell-and-tube steam condenser coupled to a hybrid tower with an air-cooled dry section on top which discharges into a wet cooling tower beneath. The integrated hybrid tower is shown schematically in Figure 2-23. A photograph of this tower is shown in Figure 2-24.

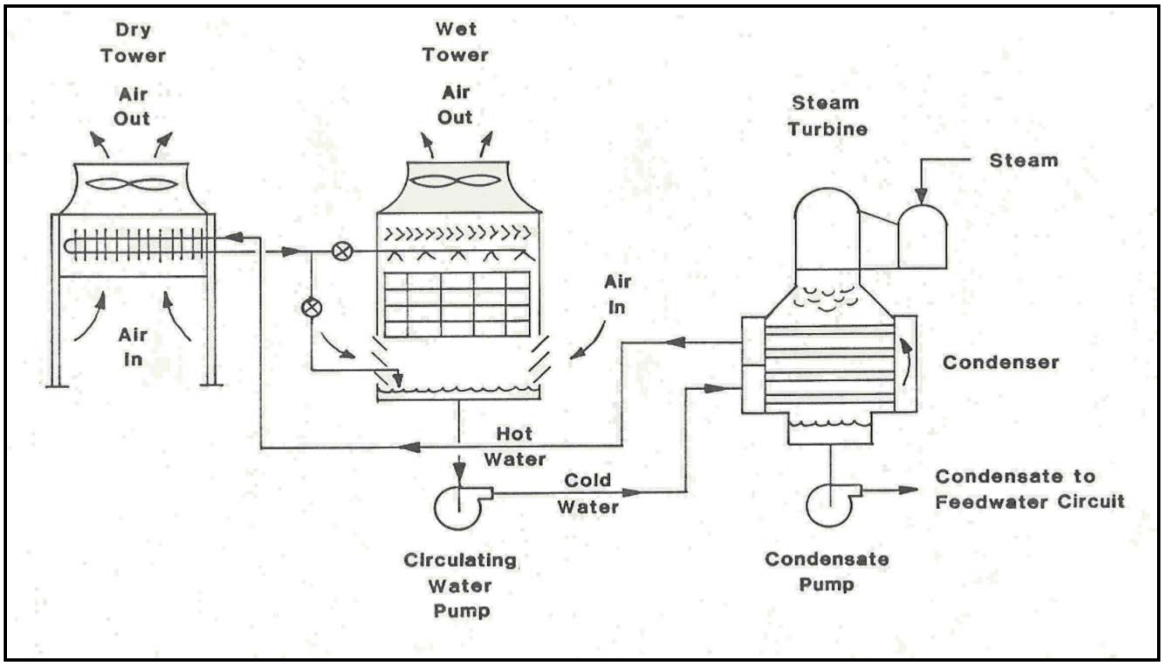

Figure 2-22
Hybrid series system with indirect dry section

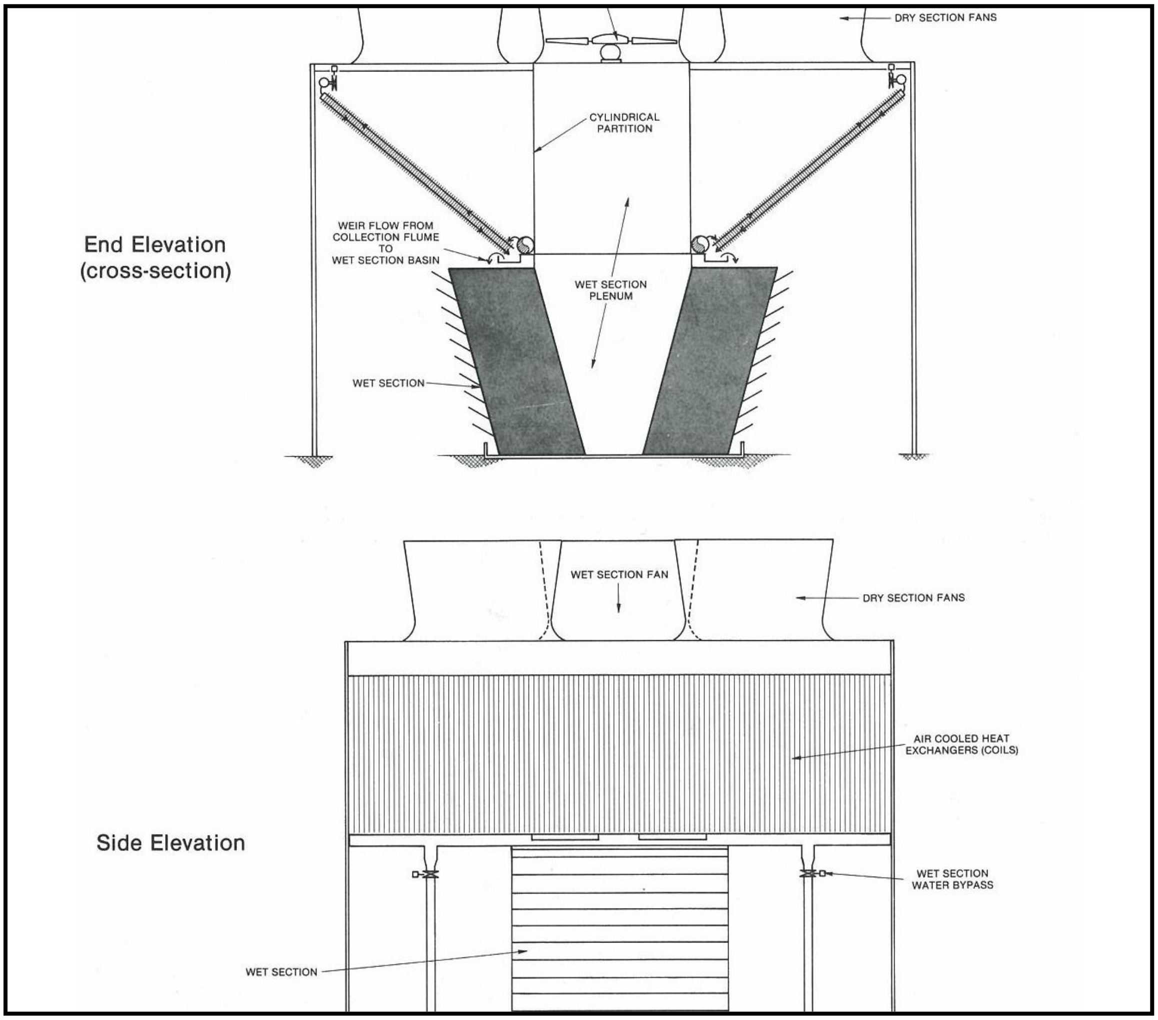

Figure 2-23
Schematic of integrated water-conservation tower

Figure 2-24
Photograph of integrated water conservation tower (Public Service New Mexico San Juan Generating Station Unit 3)

Parallel---ACHE + wet tower

The conceptual approach to indirect hybrid systems with a parallel arrangement is similar. A schematic of an alternative arrangement is shown in Figure 2-25.

An alternative arrangement which can be run in series, parallel, or split (series and parallel) arrangements has been considered for the planned Unit 3 at Dominion's North Anna Nuclear Plant and has been described in recent presentations[10]. The system is illustrated schematically in Figure 2-26 and in an artist's rendition in Figure 2-27.

The system can be operated in either a water-conservation mode or an energy-production mode. In the water-conservation mode, the hot cooling water from the condenser passes first through the dry tower and then to the dry section of the hybrid tower. If the ambient temperature is low enough, the wet section can be by-passed and the flow returned directly to the condenser. At higher ambient temperatures, the flow is directed to the wet section of the hybrid tower and then to the condenser. In an energy-production mode, the fans on the dry tower can be turned off or the dry tower by-passed entirely. In either case, the heat load is then carried primarily by the wet section of the hybrid tower.

[10] Waddill, J., "North Anna 3 Hybrid Cooling", Presented at EPRI Water and Advanced Cooling Workshop, Charlotte, NC, July 8 – 9, 2008.

Figure 2-27 shows both towers in the upper left-hand corner. The round structure is the hybrid tower and the rectangular one is the dry tower. The small four-cell wet tower in the center of the picture is an auxiliary cooling tower for plant service water.

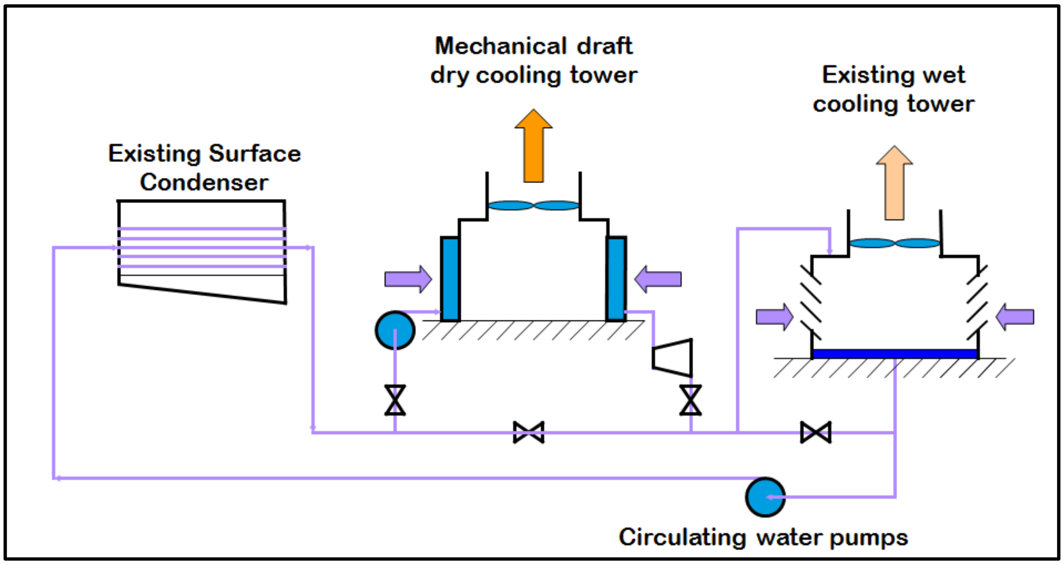

Figure 2-25
Hybrid parallel system with indirect dry section

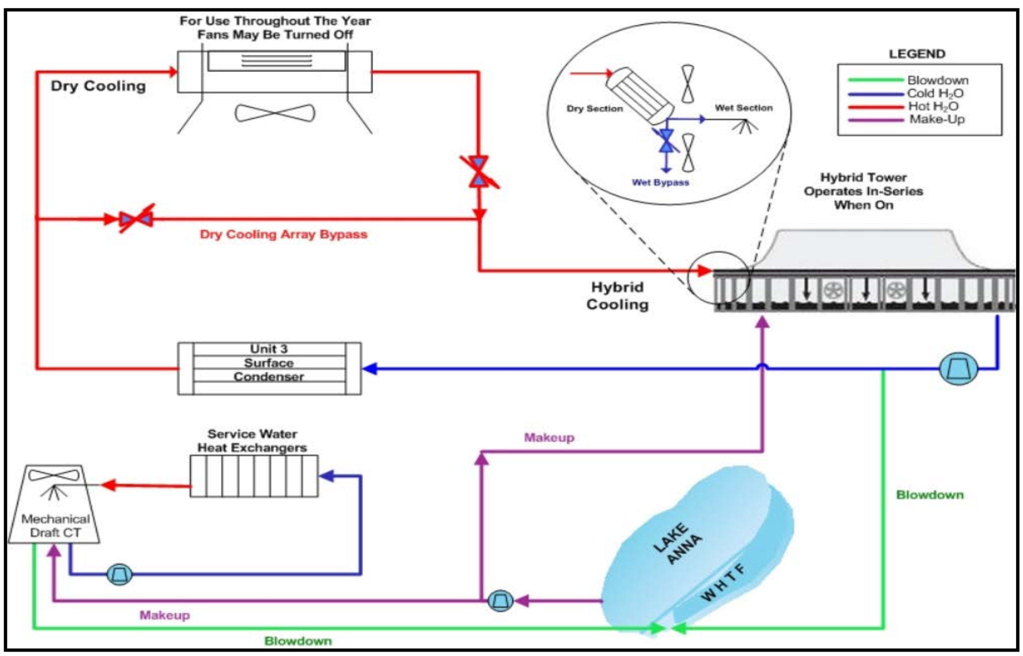

Figure 2-26
Indirect hybrid system for proposed nuclear plant[11]

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[11] Op. cit (Footnote 6)

Figure 2-27
Artist's rendition of indirect hybrid system for proposed nuclear plant[12]

Hybrid Heller systems

Hybrid variants to the Heller system fall in two categories:

- dry systems with some degree of wet enhancement
- combined systems with wet and dry elements in series or parallel

Wet enhanced systems

Two types of wet-enhanced systems exist. These are:

- spray enhancement of the dry heat exchanger deltas
- deluge cooling of supplementary heat exchangers

Spray enhancement

Spray enhancement is provided by spray nozzles mounted on the lower portion of the cooling deltas on the outside of the tower. This arrangement is shown schematically in Figure 2-28 and in a photograph of a mechanical-draft tower in Figure 2-29.

[12] Op. cit. (Footnote 6)

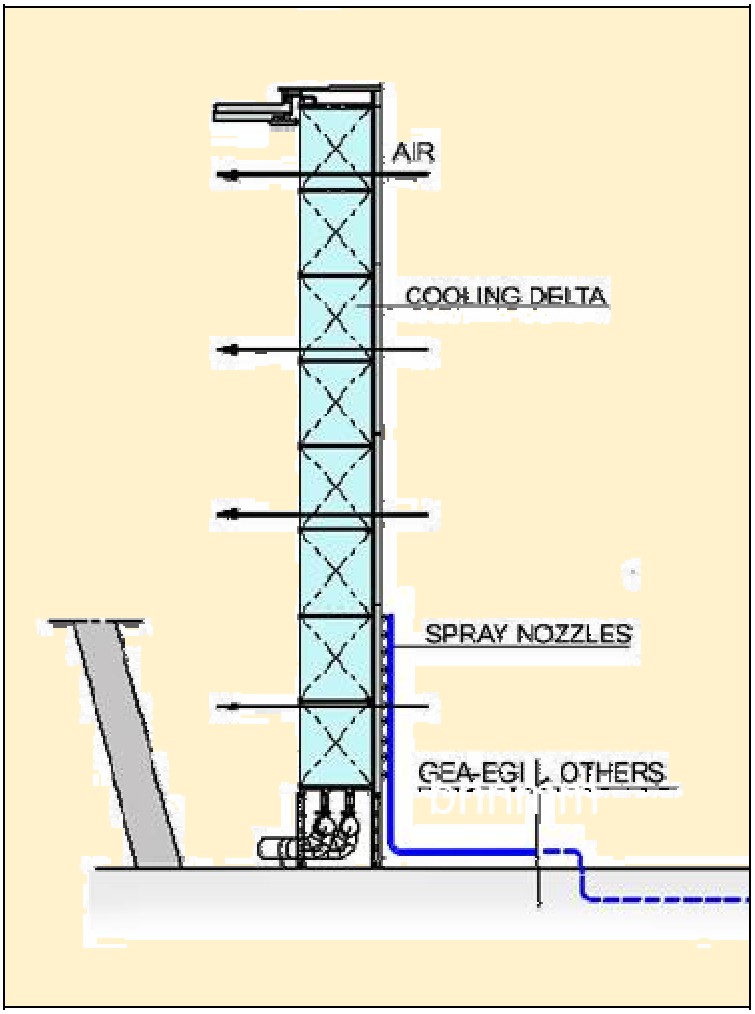

Figure 2-28
Schematic of spray enhancement nozzles

Figure 2-29
Spray enhancement nozzles on mechanical-draft dry tower

The small amount of water required depends on the number of hours per year that performance enhancement is required. The approach is normally used only if necessary to avoid significant reductions in turbine output or turbine shutdown.

Deluge cooling

For systems with natural-draft towers, there are a set of peak coolers arranged around the inside of the tower as shown in Figure 2-30. Known as "HEAD" (Heller Evaporative and Deluge) systems, they differ from the spray enhanced system in that the finned surfaces are flooded with water to maintain a water film on both sides of the plate fins in the supplemental exchangers. Figures 2-31 and 2-32 show the operation of the system schematically.

Figure 2-30
Delugeable peak coolers inside natural-draft dry tower

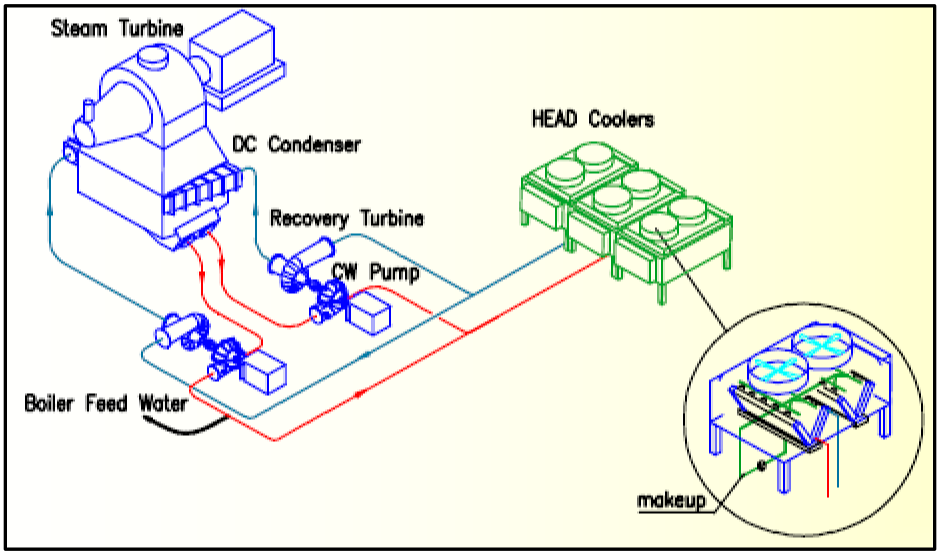

Figure 2-31
Schematic of HEAD system

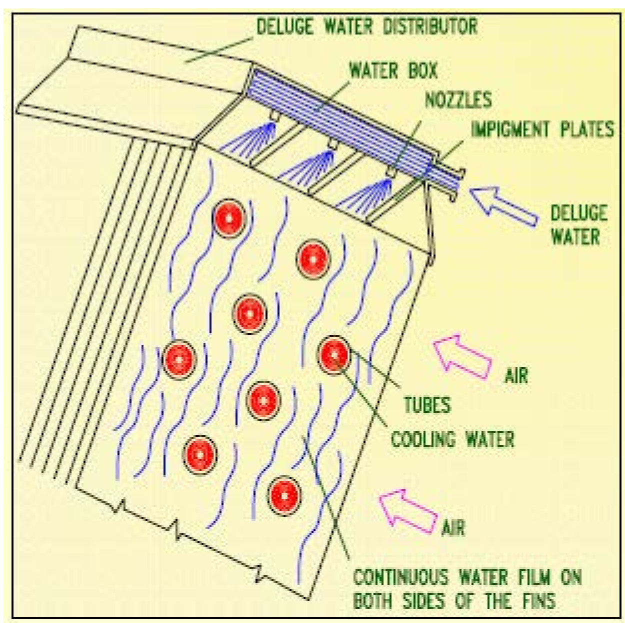

Figure 2-32
Deluge water films on plate fins

Combined wet/dry hybrids

There are a variety of arrangements where an air-cooled heat exchanger, in either natural- or mechanical-draft tower can be combined with a wet cooling tower. The arrangement can be in series or parallel. Typically there is provision for by-passing either the dry or wet element as conditions dictate. All of these arrangements require the use of a surface condenser rather than a DC condenser since when the cooling water is exposed directly to the atmosphere in the wet tower it can no longer be used in a DC condenser without introducing unacceptable contamination into the steam loop.

A number of these arrangements are discussed in EGI publications[13]. A few are illustrated in the following figures but will not be discussed in detail since their principle of operation is the same for all and the same as for the more familiar hybrid systems currently in use in the U.S.

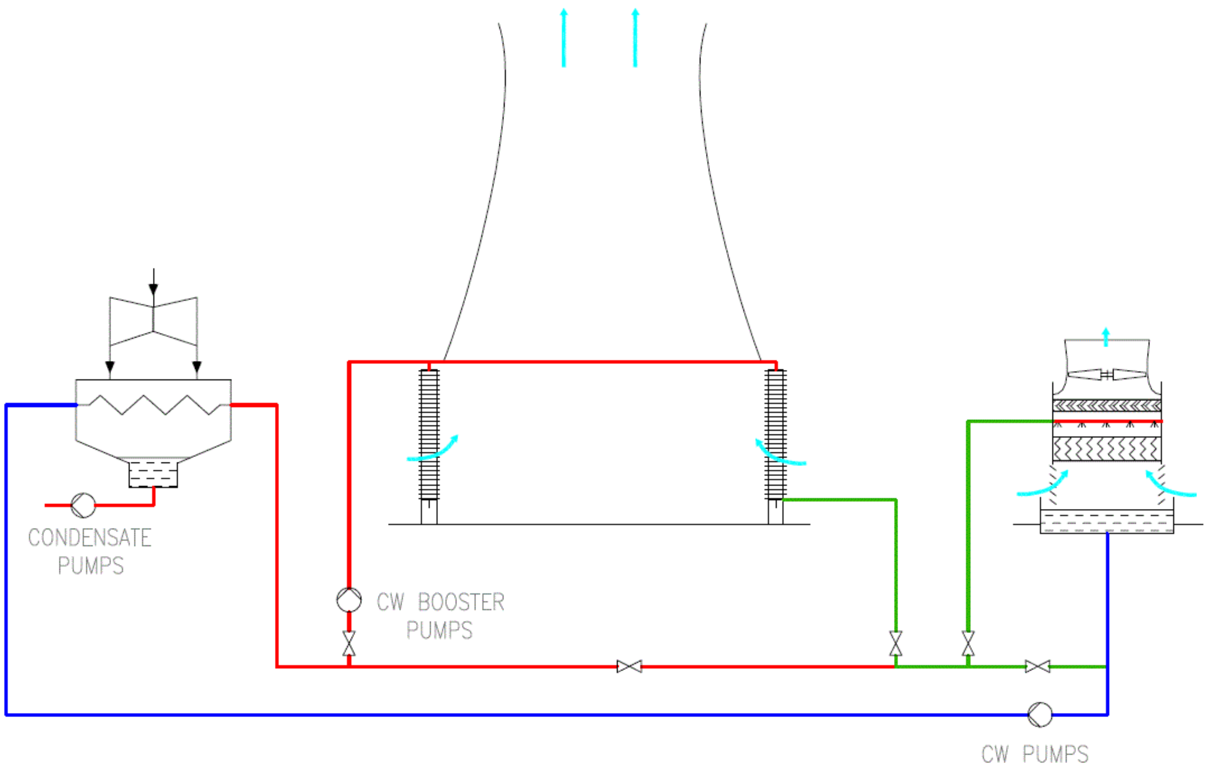

Figure 2-33
Wet/dry hybrid system; series arrangement

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[13] Balogh, A. and Z. Szabo, "Dry and Dry/Wet Cooling May Enhance Economy and Realize Ultimate Environmental Compatibility for Nuclear Power Generation", Presented at 8th Annual China Nuclear Energy Congress, Beijing, China, May, 2012.

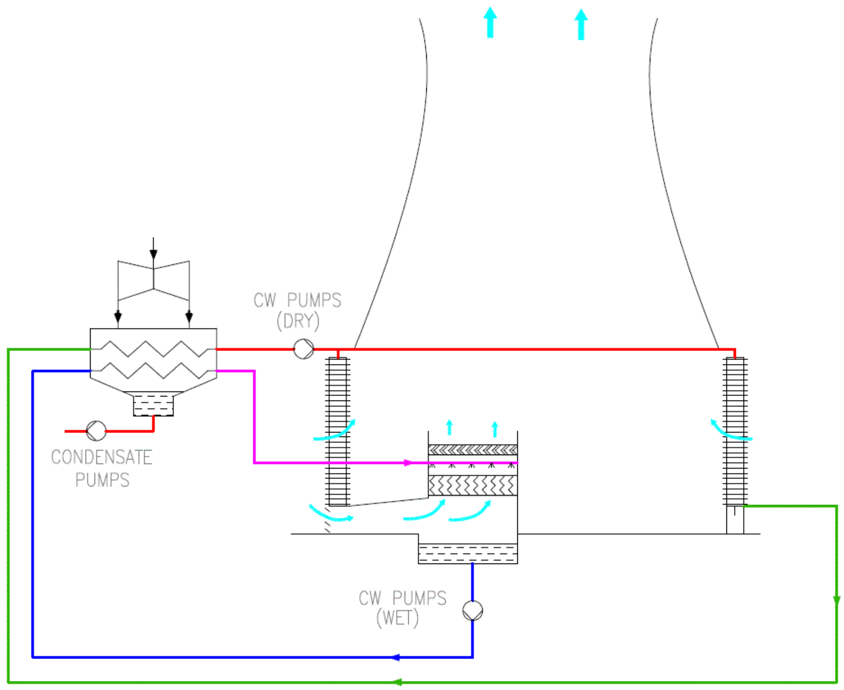

Figure 2-34
Wet/dry hybrid system; parallel arrangement

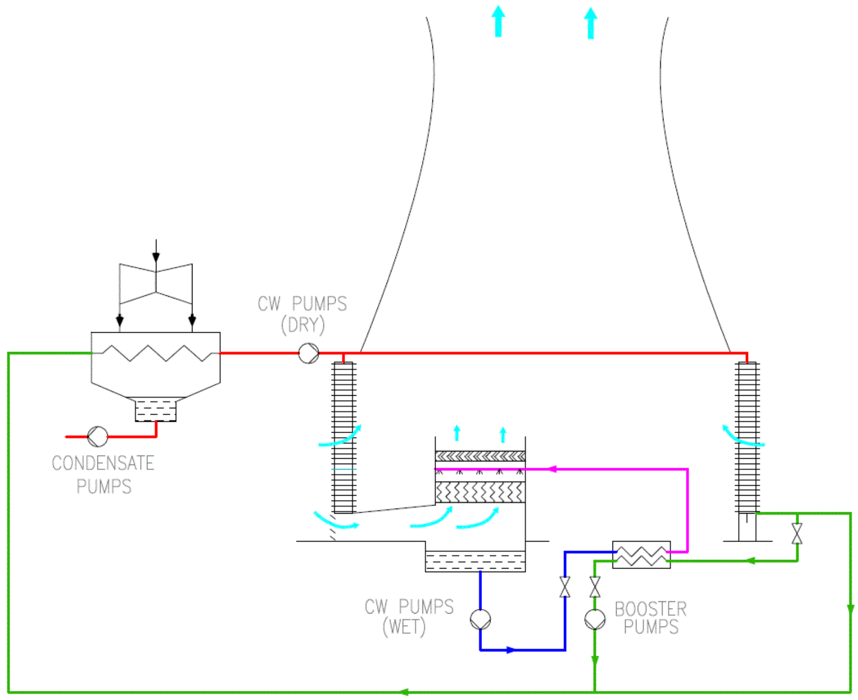

Figure 2-35
Wet/dry hybrid: split series arrangement

Spray enhanced dry cooling

Spray enhancement, illustrated schematically in Figure 2-36 works by reducing the temperature of the inlet air to the ACC. At an essentially constant ITD, this results in a corresponding reduction in condensing temperature and backpressure. Many owner/operators of existing ACC's have installed *ad-hoc* retrofits to obtain better hot weather performance. A few of these installations are illustrated in Figures 2-37 through 2-40

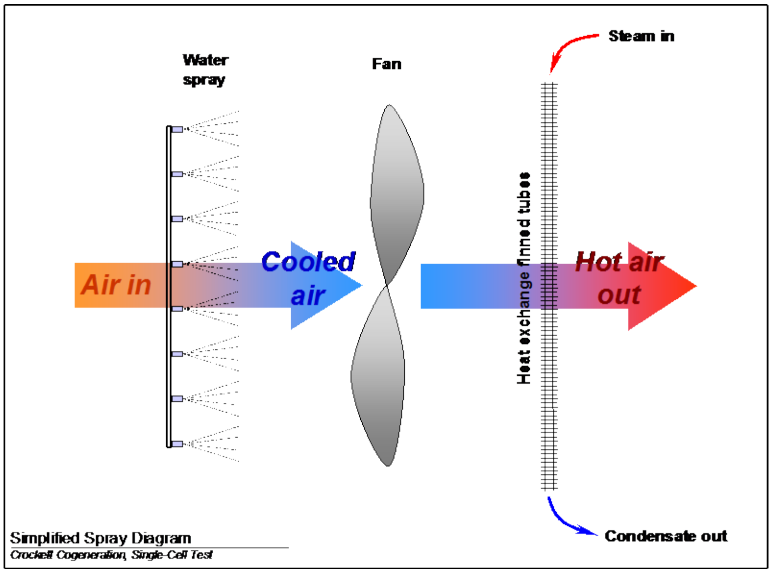

Figure 2-36
Spray enhancement system

Figure 2-37
Sprays in operation at Chinese Station

Figure 2-38
Spray nozzle on El Dorado Energy Center ACC

Figure 2-39
Interior spray nozzles in operation at Crockett Co-Generation

Figure 2-40
Spray nozzle on Linden ACC

In some cases, such as Chinese Station, the use of the sprays has become routine operation for many years. In others, such as El Dorado, the use of sprays, although effective in reducing hot day backpressure, has been discontinued for a variety of reasons ranging from concern over incipient corrosion or scaling of the finned tube surface to water supply limitations. To our knowledge, only a single installation, the Kogan Creek station in Australia, has incorporated spray enhancement into the original design.

An extensive pilot study of spray enhancement of a single, air-cooled heat exchanger (not a condenser cell) at the Crockett Co-Generation plant was conducted in 2001 and reported in earlier reports[14].

Figure 2-41 shows the test spray rig in operation. Figure 2-42 shows performance data from a single test day demonstrating an inlet cooling effect of about 10°F (5.6°C) or approximately 70% of the ambient wet bulb depression (T_{amb} - $T_{amb\ wet\ bulb}$). Finally, Figure 2-43 shows a correlation of the data in the form of the cooling effect vs. the spray flow rate times the wet bulb depression.

[14] Spray Cooling Enhancement of Air-Cooled Condensers, EPRI Report # 1005360 August 2002

Figure 2-41
Crockett spray tests

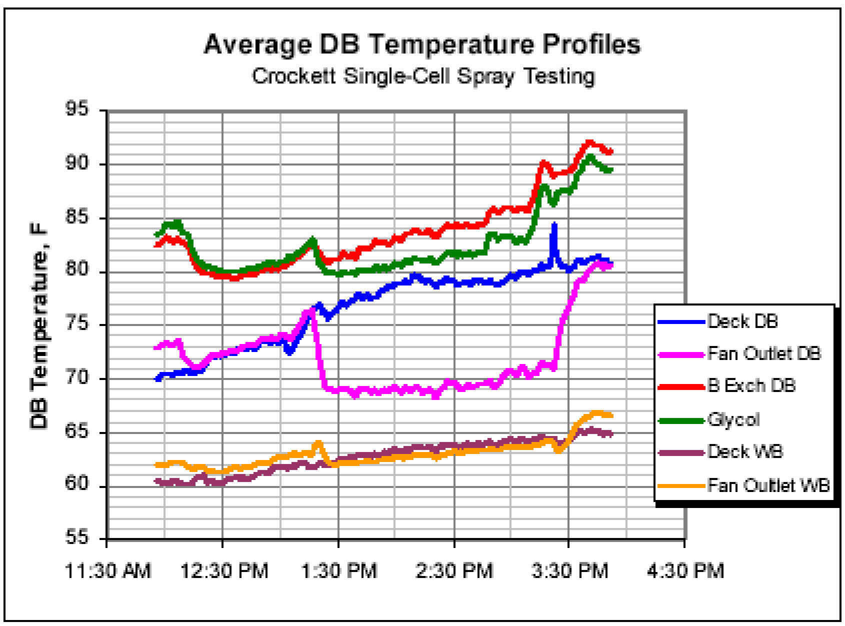

Figure 2-42
Spray system performance at Crockett; September 9, 2001

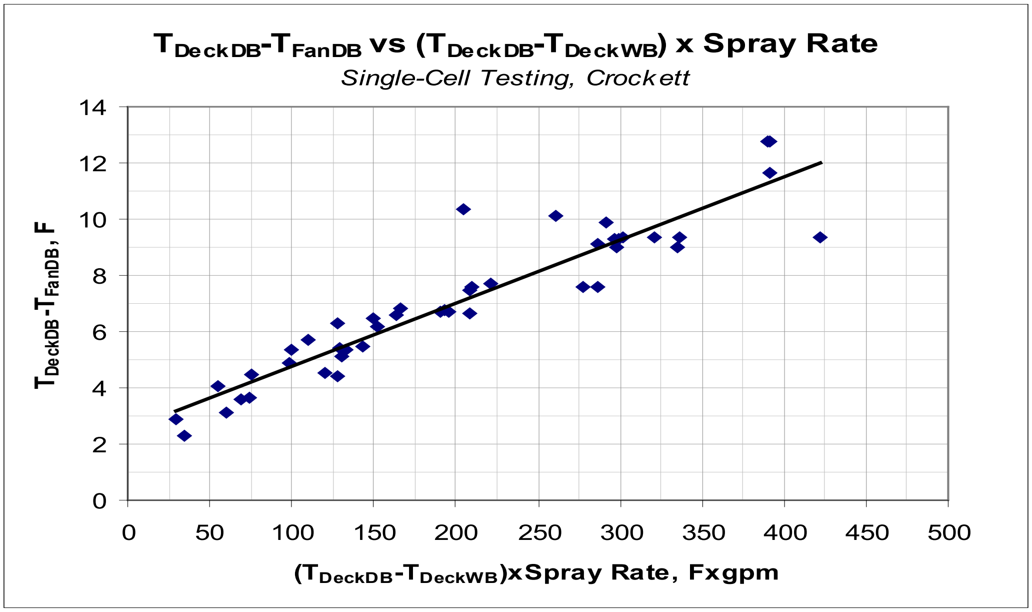

Figure 2-43
Correlation of Crockett spray data

In general, the spray enhancement approach has the advantage of low capital cost compared to a full hybrid system. The disadvantages, however, are the less efficient use of water and potential scaling and corrosion problems. Therefore, the spray enhancement system may be favored for applications where the enhancement would be required for only a few (<100 to 200) hours per year and where the water chemistry has low potential for scale formation and other forms of plugging (i.e., macrofouling). The full hybrid system would be favored when longer duration enhancement periods (100 to 200 hours) are anticipated.

3 ISSUES SPECIFIC TO NUCLEAR UNITS

In recent years, much attention has been directed to the study of alternative cooling systems for water-conservation at thermal power plants. The motivation for this has come largely from the installation of new plants in areas of high electricity demand and limited water resources, such as the southwestern United States. The majority of these plants have been gas-fired, combined-cycle plants. While much of the analysis, methodology and conclusions from these studies are applicable to nuclear plants, there are important differences and nuclear-specific requirements and constraints that affect the specification and evaluation of water-conserving cooling systems in nuclear applications. These differences will be addressed in the following three categories:

- Main plant condenser cooling
- Auxiliary plant component cooling
- Safety system cooling requirements

Power plant main condenser cooling

As in all plants, the cooling requirements are dominated by the main condenser cooling heat load. Adequate cooling of the main condenser is essential to maintain the desired turbine exhaust pressure at the design steam flow in order to maintain plant efficiency and output over the range of ambient conditions. Nuclear plants differ from comparable fossil plants in three ways; specifically:

- The magnitude of the heat load
- The turbine exhaust pressure limitations
- The suitability of direct dry cooling

Main condenser heat load

The condenser heat load per unit output is higher at a nuclear unit than on fossil units. The turbine heat rate is higher for nuclear units due to limitations on the turbine inlet conditions. Therefore, the steam flow to the condenser per MWh of turbine output is higher, ranging from 6,000 lb/MWh to 10,000 lb/MWh depending on unit age and design with an average value of around 8,000 lb/MWh. In comparison, the steam flow on the steam side of combined-cycle plants ranges from 5,000 lb/MWh to 7,000 lb/MWh and from about 4,000 lb/MWh to 6,000 lb/MWh for coal-fired steam plants. This results in a main condenser heat load for nuclear plants which exceeds that for fossil plants by 30 to 50%. This difference is greater than might be inferred from simple comparisons of plant efficiencies due to the fact that fossil units reject a significant fraction of their reject heat through the stack in the form of hot combustion gases.

Turbine exhaust pressure limitations

Nuclear turbines differ in design from those used at coal plants or at gas-fired combined-cycle plants in at least three ways. First, they are often larger due to the economic choice for unit size at nuclear plants vs. fossil (particularly combined-cycle) plants. Second, as discussed above, the steam flow per unit output is higher. Finally, the rotational speed for nuclear turbines is 1,800 rpm as opposed to 3,600 rpm for fossil turbines. This is due to the higher steam flows in the larger turbines requiring large exit areas with long blades. The rotational speed is reduced to maintain allowable tip speeds in the last stages.

As a result, the turbine characteristics as defined by the relationship between turbine exhaust pressure and turbine efficiency and output for a given steam flow are different. This relationship is critical to the selection of a preferred or optimized cooling system for a given unit at a given site as will be discussed in more detail in Section 5.

In addition, the maximum allowable turbine exhaust pressure, above which damage to the last stage blading may occur, is currently more limited for nuclear turbines than for fossil turbines, particularly for those selected for dry cooled combined-cycle plants.

Most dry cooled plants make use of turbine designs which allow operation at exhaust pressures above 5 in Hga (16.9 kPa). Typical backpressure limits for dry-cooled fossil plants are in the range of 7 in Hga (23.7 kPa) (alarm) and 8 in Hga (27.1 kPa) (trip). Some can go to 10 in Hga (33.9 kPa). An early dry-cooled, coal-fired steam plant (Wyodak) uses a high backpressure turbine which can operate up to 16 in Hga (54.2 kPa). These high or extended backpressure turbines are preferred for dry cooled applications because a turbine restricted to 4.5 to 5 in Hga (15.2 to 16.9 kPa) requires that the steam condensing temperature be below 130°F (54.4°C). ACCs with initial temperature differences (ITD defined as the steam condensing temperature minus the ambient air temperature, $T_{condensing}$ - $T_{ambient}$) below about 35°F (19.4°C) become uneconomically large and require unacceptable operating power. Therefore, when the ambient temperature exceeds 95°F (35°C), the condensing temperature exceeds 130°F (54.4°C). At this point, the turbine steam flow, and hence the plant output, must be reduced in order to keep the exhaust pressure below 5 in Hga (16.9 kPa). The consequences of this will be discussed in more detail in Section 5.

However, there is nothing fundamentally preventing the availability of higher exhaust pressure limits on nuclear turbines. As the need for water-conserving cooling systems becomes more severe, it is possible that the turbine vendors will develop an extended backpressure turbine suitable for nuclear designs at the 1000 to 1500 MW scale. Second, if the small modular reactor (SMR) approach gains acceptance, the turbine designs will be closer in size to turbines currently in use on gas-fired combined-cycle plants and could have similar performance characteristics. In fact, current literature on SMRs suggests that they can be dry-cooled.

Suitability of direct dry cooling

The use of direct dry cooling with an air-cooled steam condenser may not be acceptable for use on nuclear units. This may be a particular concern for boiling water reactors (BWRs) since there is an uninterrupted steam path from the reactor core through the turbine to the condenser. While this is not the case for pressurized water reactors (PWRs), direct dry cooling, either in all-dry or hybrid, wet/dry systems, has not been used on a nuclear unit anywhere in the world to our knowledge. Only two nuclear plants (Bilibino in Russia and Schmehausen in Germany, both discussed in Section 1) have been built with dry cooling, and both used indirect dry cooling, not ACCs. Since it may come to pass that, with increasing need for water-conserving systems on nuclear units, direct dry cooling will be proposed and perhaps accepted by licensing agencies. These systems will be covered in the analyses in Section 5; however, the results should be taken as speculative at the present time.

Auxiliary plant component cooling

In addition to main condenser cooling, cooling systems at power plants must handle additional heat loads. This is true for all plants, not just nuclear, and these heat loads are referred to as "auxiliary cooling loads". They generally include such items as lubrication oil cooling, generator cooling, pump cooling and space conditioning chillers among other components. These loads are handled in a closed coolant loop referred to as the component cooling water system. Many of these systems must function whether the plant is operating or shutdown. The heat is discharged to the environment through a separate service water system using a small wet tower or a dry, fin-fan cooler.

As will be discussed further in the following section, in an emergency situation, decay heat from the reactor can be discharged through the component cooling system to the environment through the service water system. A schematic of these auxiliary cooling loops are shown (as arranged on a PWR) in Figure 3-1.

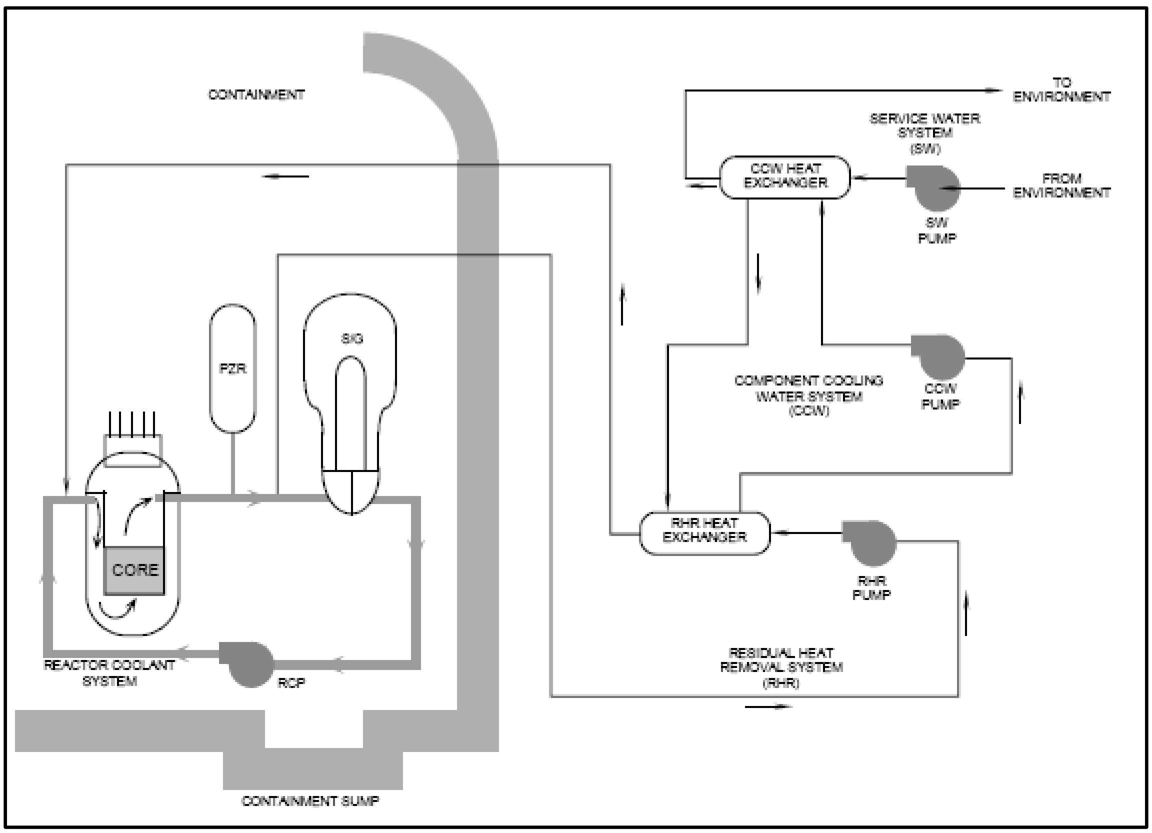

Figure 3-1
Auxiliary cooling loops (excerpted from Reactor Manual[15])

Safety system cooling requirements

Nuclear plant service water systems, component cooling water systems and residual heat removal systems are designed on the basis that some specified cooling water inlet temperature

[15] Reactor Concepts Manual Pressurized Water Reactor Systems; USNRC Technical Training Center

will never be exceeded. At that temperature, critical systems can operate to maintain conditions considered critical to the safe operation or emergency shutdown of the plant. Such conditions include control room habitability conditions in which operators can work, temperatures of fuel cladding, insulation, control systems, valves, and concrete structural members among others. On rare occasions, as for example at the Millstone plant on August 12, 2012, when the temperature of the cooling water intake from Long Island Sound exceeded 75°F (23.9°C), the plant was required to shut down.[16]

Ultimate heat sink

The reliable source of cooling water at the specified temperature is referred to as the "Ultimate Heat Sink" (UHS). The requirements placed on a UHS are described in the U.S. NRC's Regulatory Guide 1.27. This states in part,

> "The ultimate heat sink should be capable of providing sufficient cooling for at least 30 days (a) to permit simultaneous safe shutdown and cooldown of all nuclear reactor units that it serves…" and
>
> "Sufficient conservatism should be provided to ensure that a 30-day cooling supply is available and that design basis temperatures of safety-related equipment are not exceeded. (emphasis added).

While these criteria are normally considered in the context of a large waterbody, Regulatory Guide 1.27[17] lists as "sinks that have been found acceptable by the staff" twelve examples including:

> #11---Two wet/dry forced draft towers[18] and
> #12---Two dry forced draft towers

in addition to large rivers, large lakes, oceans and various combinations of wet cooling towers, ponds and reservoirs.

If the use of water conserving cooling systems in arid areas is extended to the safety related systems and UHS, the performance of the system would need to be evaluated under the most demanding ambient climatological conditions. Again, as specified in Regulatory Guide 1.27,

> "The meteorological conditions considered in the design of the sink should be selected with respect to the controlling parameters and critical time periods unique to the specific design of the sink. For example, consider a dry cooling tower as the sink. The controlling parameter would be a dry bulb temperature, and the critical time period may be on the order of one hour."

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[16] New York Times, August 13, 2012
[17] USNRC Regulatory Guide 1.27; http://pbadupws.nrc.gov/docs/ML0037/ML003739969.pdf
[18] It is not clear whether "forced draft" is intended to exclude the more common "induced draft" designs or is simply meant to specify mechanical-draft (as opposed to natural draft) towers.

Therefore, the maximum one hour dry bulb temperature based on regional climatological information (defined as 30 year history at the site) would be the acceptable design basis meteorological condition. For a hot arid site in the southwestern U.S., the maximum one hour temperature can exceed 120°F (48.9°C). Under such conditions, the available cold water temperature could easily exceed 130°F (54.4°F) making the design and operation of the component cooling systems problematic or impossible. If the main condenser cooling system were to be all-dry, it would seem necessary to provide an alternative capability for the auxiliary systems such as on-site water storage ponds with a 30 day cooling supply. Such an approach was taken at the Palo Verde Nuclear Generating Station in Arizona, for example. Even though that plant is equipped with mechanical-draft wet cooling towers for main plant cooling, the water supply of reclaimed municipal waste water, supplied through a single pipeline from Phoenix could not be certified as "highly reliable" and on-site supply was provided.

Some plants have incorporated some degree of dry cooling into their UHS design and operation. One example is the Waterford Steam Electric Station, Unit 3[19]. The UHS at Waterford Unit 3 consists of a dry cooling tower, a wet cooling tower and the water stored in the wet cooling tower basin. Two 100% capacity trains contain one wet and one dry cooling tower. The dry tower rejects heat from the Component Cooling Water system (see Figure 3-1). An auxiliary component cooling water system is a separate system that provides cooling water to the primary system and uses the wet cooling tower to reject heat to the atmosphere. Each dry tower is sized to dissipate approximately 60% of the heat removed by the CCW after a loss of coolant accident.

Spent fuel pool cooling

All nuclear plants must provide storage capability for the spent fuel assemblies. The assemblies are stored submerged in a spent fuel pool. Cooling of the water in the pool must be provided to remove the decay heat from the assemblies. In the absence of cooling, the temperature of the water could rise to the boiling point in a few hours with subsequent loss of water from the pool and uncovering of the assemblies.

A spent fuel cooling system is provided to remove the decay heat from the spent fuel pool and reject it to the component cooling system. An example of a typical spent fuel cooling system is given in a manufacturer's manual20 and is illustrated in Figure 3-2. The system is designed to maintain a pool water temperature of 140°F (60°C) at the highest expected cooling water temperature at the site under "long term" conditions. Since the average cooling water temperature is well below the maximum expected, the system is capable of removing more than the design heat load most of the time. "Long term" conditions refer to a pool full of assemblies less space reserved for a full core unload and with the most recently added assemblies having been in storage for longer than 11 days. The design heat load can be exceeded for a short time when fresh assemblies are added to the pool during refueling. After 11 days, the decay heat has dropped to the design heat load.

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[19] USNRC Waterford Ultimate Heat Sink; http://pbadupws.nrc.gov/docs/ML1302/ML13025A167.pdf

[20] Westinghouse Technology Systems Manual, Section 14.4, Spent Fuel Cooling and Cleanup System; available at http://pbadupws.nrc.gov/docs/ML1122/ML11223A323.pdf

In addition, during refueling the entire core may be off-loaded to the spent fuel pool. This increases the heat load significantly above the design capability of the spent fuel pool cooling system. In either of these high load conditions, the assistance of the residual heat removal system is required to maintain the pool temperature. The systems are arranged so that one branch of the residual heat removal system can handle a portion of the spent fuel pool heat load.

A water conserving alternative to the base design for the spent fuel pond cooling system, could, in principle, be achieved with air-cooled heat exchangers to maintain the pool water at a maximum temperature of 140°F (60°C) at a maximum and expected ambient dry bulb temperature of 120°F (48.9°C). The unit would require an air-side surface area of about one-half that of a single cell on a conventional air-cooled condenser drawing approximately the same airflow. To our knowledge, this approach has never been taken on a nuclear plant in the U.S. and might encounter acceptance problems, but the thermal performance of a unit of reasonable size would appear to be adequate.

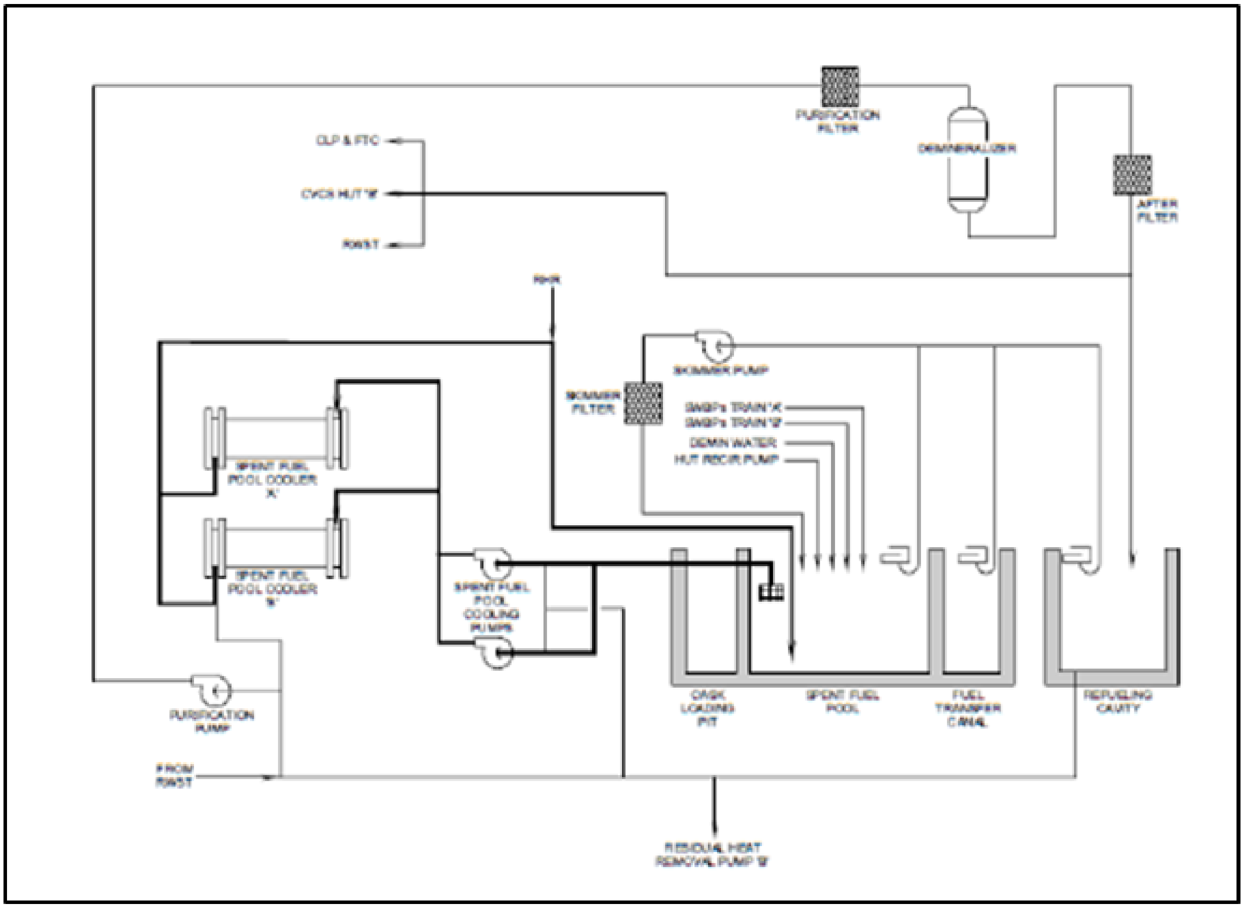

Figure 3-2
Spent fuel cooling pool schematic

4
RETROFIT CONSIDERATIONS

Cooling system retrofits on nuclear plants arise in two contexts. The first is the conversion of once-through cooled plants to closed-cycle wet cooling if it should be required by 316(b) regulations; the second is the modification of closed-cycle wet systems at plants operating on cooling towers, cooling lakes or cooling ponds if reductions in consumptive water use should be necessary.

Once-through to closed-cycle retrofits

The requirement to retrofit once-through cooled plants to closed-cycle cooling is driven by potential regulations under Section 316(b) of the Clean Water Act (CWA). Regulatory developments are underway at both the Federal level and in some states. The following sections provide background information on activities underway at the USEPA and the California State Water Resources Control Board (SWRCB) and the Ocean Protection Council (OPC). In both cases the definition of the eventual requirements is still a "work in progress". Therefore, the specific cooling system environmental performance requirements, the specification of technologies adequate to meet such requirements and associated costs and effects on plant performance and capacity are as yet undetermined. However, background material is presented to provide some indication of what might be proposed. The California material is particularly relevant in that special attention was directed to the two large California nuclear plants--the Diablo Canyon Power Plant and the San Onofre Generating Station[21].

Federal (U.S. EPA) rulemaking

As amended by Congress in 1972, §316(b) of the CWA requires the EPA to ensure that "the location, design, construction and capacity of cooling water intake structures shall reflect the best technology available for minimizing adverse environmental impact."22 EPA's first attempt to promulgate regulations under §316(b) was remanded by the Fourth Circuit court in 1977 on procedural grounds. No new rule was issued for many years until the Agency, under a consent decree, established a schedule for conducting a §316(b) rulemaking proceeding in three phases: Phase 1 covering "new facilities"; Phase II, covering existing steam electric power plants that commenced construction on or before January 17, 2002 and that withdraw more than 50 million gallons per day (MGD) from waters of the United States; and Phase III, covering all existing facilities, including power plants and industrial facilities, not covered by Phase II.

The Phase I rule for new facilities was issued originally on December 18, 2001. A slightly amended version was then issued on June 19, 2003 and has remained the Final Rule for new facilities. The basic requirement is that facilities with an intake flow equal to or greater than 10 MGD are required to install a recirculating system or other technologies that would reduce the design intake flow to a level commensurate with that of a recirculating system OR demonstrate

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[21] At the time of writing, the retirement and closure of the San Onofre Nuclear Generating Station had just been announced.

[22] Federal Water Pollution Control Act, §316 (b), 33 U.S.C §1326(b)

to the Director that the technologies employed will reduce the level of adverse environmental impact from the cooling water intake structures to a level comparable to that which would be achieved with a recirculating system.

The Phase II rule addressed existing facilities and was issued on July 9, 2004[23]. The rule was challenged by a number of environmental groups led by Riverkeeper, Inc. as well as several state environmental agencies, two power companies and the Utility Water Act Group. The challenges were consolidated into a single case which was argued before the United States Court of Appeals for the Second Circuit on June 8, 2006 and a decision was issued on January 25, 2007.

One of the major issues in the case was the role of cost in determining "Best Technology Available" (BTA). Environmental groups and states argued that EPA had violated §316(b) by rejecting closed-cycle cooling as the basis for §316(b) performance standards based on the Agency's weighing of costs and benefits. The Second Circuit decision[24] rejected the use of "cost-benefit" analysis.

Although the Second Circuit Decision held that cost/benefit considerations could not be used to reject closed-cycle cooling retrofits as BTA, retrofits could be rejected if the industry could not bear the cost or if there were significant adverse environmental impacts or impacts to energy production and efficiency.

The Second Circuit's holding prohibiting use of cost-benefit analysis under §316(b) was appealed to the U. S. Supreme Court[25]. The appeal was granted, and the case was argued on December 2, 2008. The Supreme Court issued its decision on April 1, 2009[26] and determined that EPA could consider benefits relative to costs in making the BTA determination.

While that appeal was underway, EPA issued a memorandum dated March 20, 2007 to EPA's Regional Offices announcing withdrawal of the §316(b) Phase II Rule. This was followed by a notice in the Federal Register on July 9, 2007. Specifically, the memorandum and Federal Register notice stated the withdrawal of the Rule was a result of the impact of the Second Circuit's remand on the overall compliance approach. EPA determined that so many of the Rule's provisions were affected by the Decision that the overall Phase II approach was no longer workable for compliance. The memorandum and Federal Register notice further directed EPA Regional Offices and delegated states to implement §316(b) in National Pollution Discharge Elimination System (NPDES) permits on a "best professional judgment" (BPJ) basis, until issues underlying the Second Circuit decision were resolved. EPA then assembled a team to initiate work on a revised §316(b) regulation based on the Second Circuit decision and later on the Supreme Court decision.

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[23] 40 CFR Parts 9, 122 – 125, Final Regulations to Establish Requirements for Cooling Water Intake Structures at Phase II Existing Facilities, 69 Fed. Reg. 41,576, July 9, 2004.

[24] Riverkeeper, Inc. *et al.* vs. United States Environmental Protection Agency; Decision from United States Court of Appeals for the Second Circuit, Docket Nos. 04-6692-ag(L) *et al., January 25, 2007*

[25] United States Supreme Court, Docket No. 07-588, 07-589 and 07-597 (Consolidated), Available at http://www.supremecourtus.gov/docket/07-588.htm), December 2, 2008.

[26] Entergy Corp. *v.* Riverkeeper, Inc., *et al.,* (2009) 129 S.Ct. 1498, 173 L.Ed.2d 369

EPA published a proposed rule for public comment in the Federal Register on April 20, 2011. The "Fact Sheet" issued at the same time summarizing the proposed rule described three important elements. Specifically,

- Existing facilities that have a design flow of greater than 2 MGD would be subject to an upper limit on how many fish can be killed by impingement[27]. The technology to be used to achieve this would be determined by the facility. Alternatively, the facility could reduce their intake velocity to 0.5 feet per second or less.
- Existing facilities withdrawing more than 125 MGD would be required to conduct studies to determine what site-specific controls would be required to reduce entrainment[28] losses.
- New units that add generation capacity to an existing facility would be required to add technology that is equivalent to closed-cycle cooling.

In June, 2012, EPA issued two Notices of Data Availability (NODA) and solicited public comments on both. The first contained new data on the performance of impingement mortality control technologies; the second, the results of their "stated preference" survey which sought to determine the public's Willingness to Pay (WTP) for improvements to fishery resources affected by in-scope 316(b) facilities. Comments were accepted up until July 12, 2012. The data described and the comments received are being used to inform the contents of the final rule which is now scheduled to be issued on June 27, 2013[29].

California ocean plant policy

Concurrent with the Federal activity, the State of California developed and issued policies which will affect the continued use of once-through cooling by plants located on, and withdrawing cooling water from, the Pacific Ocean. The SWRCB issued a final amended version of the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Water for Power Plant Cooling. Two alternative compliance options, known as Track 1 and Track 2 are available to owners or operators of existing power plants.

- Track 1 requires a reduction in intake flow rate at each unit at a minimum to a level commensurate with that which can be attained by a closed-cycle wet cooling system. At least a 93% reduction is required and the through-screen intake velocity cannot exceed 0.5 feet per second.
- Track 2 requires a demonstration to the SWRCB's satisfaction that compliance with Track 1 is not feasible. In this case, the plant must reduce impingement mortality and entrainment to a comparable level that could be achieved under Track 1 using structural or operational controls or both.

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[27] Impingement…..refers to the entrapment of fish and other organisms against the intake screen when water is drawn into the plant cooling system

[28] Entrainment…..refers to the drawing of small organisms <u>into</u> the plant cooling system with the inlet water flow where they can be exposed to elevated pressure and temperature

[29] As of this writing, it is apparent that the issuance of the Rule will be further delayed beyond June 27, 2013. An new expected date of issuance has been announced for early November, 2013.

Portions of those policies directly address nuclear plants. The Global Warming Solutions Act of 2006 requires California to reduce greenhouse gas emissions to 1990 levels by 2020 and then to maintain those reductions. The Diablo Canyon Power Plant and the San Onofre Nuclear Generating Station provide approximately 4,600 megawatts of baseload electricity and do not emit greenhouse gases during energy generation. Energy generation from those plants facilities will be critical to meeting the mandates of the Global Warming Solutions Act and emerging national and international greenhouse gas reduction requirements. In recognition of these considerations and others, the cooling water policy requires special studies for the nuclear power plants to address their unique issues and to evaluate appropriate requirements for them.

The details of these special considerations for nuclear plants are given in the July 2011 policy[30]. Broadly, they state:

- If compliance with the requirements of the Policy would result in a conflict with any safety requirement established by the Nuclear Regulatory Commission (NRC), the SWRCB will make a site-specific determination of a best technology that would not result in a conflict OR establish alternative site-specific requirements.
- Southern California Edison (SCE) and Pacific Gas & Electric Company (PG&E) were required to conduct special studies for submission to the State Water Board.
  - The special studies shall investigate alternatives for the nuclear-fueled power plant to meet the requirements of this Policy, including the costs for these alternatives.
  - The special studies shall be conducted by an independent third party with engineering experience with nuclear power plants, selected by the Executive Director of the State Water Board.
  - The special studies shall be overseen by a Review Committee, established by the Executive Director of the SWRCB and consisting of, at a minimum, representatives of SCE, PG&E, SACCWIS[31], the environmental community, and staffs of the State Water Board, Central Coast Regional Water Board, and the San Diego Regional Water Board.

The Review Committee was to provide a report for public comment detailing the scope of the special studies including the extent to which existing completed studies can be relied on. Based on a final report from the Review Committee to the SWRCB, the Board will base its decision to modify this Policy with respect to the nuclear fueled power plants on the following factors:

- Costs of compliance in terms of total dollars and dollars per megawatt hour of electrical energy produced over an amortization period of 20 years
- Ability to achieve compliance with Track 1 considering factors including, but not limited to, engineering constraints, space constraints, permitting constraints, and public safety considerations
- Potential environmental impacts of compliance with Track 1, including, but not limited to, air emissions.

[30] http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/

[31] Statewide Advisory Committee on Cooling Water Intake Structures

If the State Water Board finds that for a specific nuclear-fueled power plant to implement Track 1, either:

- the costs are wholly out of proportion to the costs considered by the State Water Board in establishing Track 1[32] and/or
- compliance is wholly unreasonable based on the factors listed above,

then the State Water Board shall establish alternate requirements for that nuclear-fueled power plant.

Those requirements shall be no less stringent than justified by the “wholly out of proportion” cost and other factor(s). The burden is on the person requesting the alternative requirement to demonstrate that alternative requirements should be authorized.

In the event the SWRCB establishes alternate requirements for nuclear-fueled power plants, the difference in impacts to marine life resulting from any alternative, less stringent requirements shall be fully mitigated. Mitigation required in such a case shall be a mitigation project directed toward the increase in marine life associated with the State’s Marine Protected Areas in the geographic region of the facility. Funding for the mitigation project shall be provided to the California Coastal Conservancy, working with the Ocean Protection Council to fund an appropriate mitigation project.

Nuclear plant retrofits

Beginning in 2007, EPRI initiated studies to analyze and estimate the potential costs, performance impacts, environmental effects and effects on the power grid that might be imposed upon the industry should widespread retrofits of existing once-through cooled plants with closed-cycle wet cooling be required. The results of these studies are summarized in an EPRI research results summary.[33] One of the studies[34] included the costs of retrofit from additional O&M, from reductions in unit efficiency and capacity, and from lost revenue during plant downtime necessary to complete the retrofit in addition to the capital cost of the retrofit projects themselves. In the study, nuclear plants were analyzed as a group separate from fossil plants. This was done because, for plants of comparable size, retrofit costs are consistently higher for nuclear plants than for fossil plants. This is primarily due to the fact that, as discussed in Section 2, both the steam flows, the reject heat loads and the circulating cooling water flows are higher on a “per MW basis” for nuclear plants than for fossil plants.

An additional factor relates to the fact that designs of closed-cycle wet cooling systems optimize at a lower circulating cooling water flow and hence a higher cooling water temperature rise than do designs for once-through cooled systems. The usual approach to retrofit is to keep the same circulating water flow and the same condenser. While this is the lowest capital cost for a retrofit,

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[32] Costs identified in Tetra Tech, Inc., California’s Coastal Power Plants: Alternative Cooling System Analysis, February 2008 (see pages ES-10 [summary], C-1 - C-2 and C-23 - C-40 [Diablo Canyon Power Plant] and N-1 - N-2 and N-25 - N-42 [San Onofre Nuclear Generating Station])

[33] Clean Water Act Section 316(b) Closed-Cycle Cooling Retrofit Research Program Results Summary. EPRI, Palo Alto, CA. 1023453, August, 2011.

[34] Closed-Cycle Cooling System Retrofit Study: Capital and Performance Cost Estimates, EPRI, Palo Alto, CA. 1022491, January, 2011

it results in a closed-cycle cooling system that is not optimized and incurs higher operating costs for the remaining life of the plant. While this approach is appropriate for smaller plants with modest capacity factors and limited remaining life, it is often not appropriate for large, base-loaded plants with long remaining life. While this is the case for many fossil plants, it is the case for nearly all nuclear plants and the more economical solution is to re-optimize the cooling system, reduce the circulating water flow, modify the condenser and install a more appropriately sized cooling tower. While resulting in a preferred solution with a lower life-cycle cost for the remaining life of the plant, it incurs a higher capital cost, a longer downtime to complete the retrofit, and correspondingly higher cost for replacement capacity and energy during the period that the plant is off-line for the retrofit.

The methodology, analysis and results, are presented in detail in an EPRI report.[35] They are summarized here for convenience of reference.

The EPRI study developed a set of simple, linear relationships of the form:

Capital cost of retrofit ($) = K x Circulating water flow rate (gpm)[36]

between the capital cost of retrofit and the circulating water flow rate in the existing once-through cooling system. These relationships were based on independent cost estimates for individual plants obtained from a variety of sources including very detailed studies of cooling system retrofit options by experienced engineering firms.[37] [38] [39] [40] A total of sixteen estimates were available for nuclear plants.

Figure 4-1 displays the normalized retrofit costs in $/gpm for each of the 16 plants. They are seen to fall roughly into two groups labeled as “Less” or “More” Difficult with one “outlier” considered “extreme”.

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[35] *Ibid.*

[36] gpm…..gallons per minute

[37] *Diablo Canyon Power Plant Cooling Tower Feasibility Study, Enercon Services, Inc. 2009*

[38] *Feasibility Study for Installation of Cooling Towers at San Onofre Nuclear Generating Station,* Enercon Services, Inc. 2009

[39] *Economic and Environmental Impacts Associated with Conversion of Indian Point Units 2 and 3 to a Closed-Loop Condenser Cooling Water Configuration*, Prepared for Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, ENERCON Services, Inc. 2003

[40] *Determination of Cooling Tower Availability for Oyster Creek Generating Station, URS Corporation, 2006*

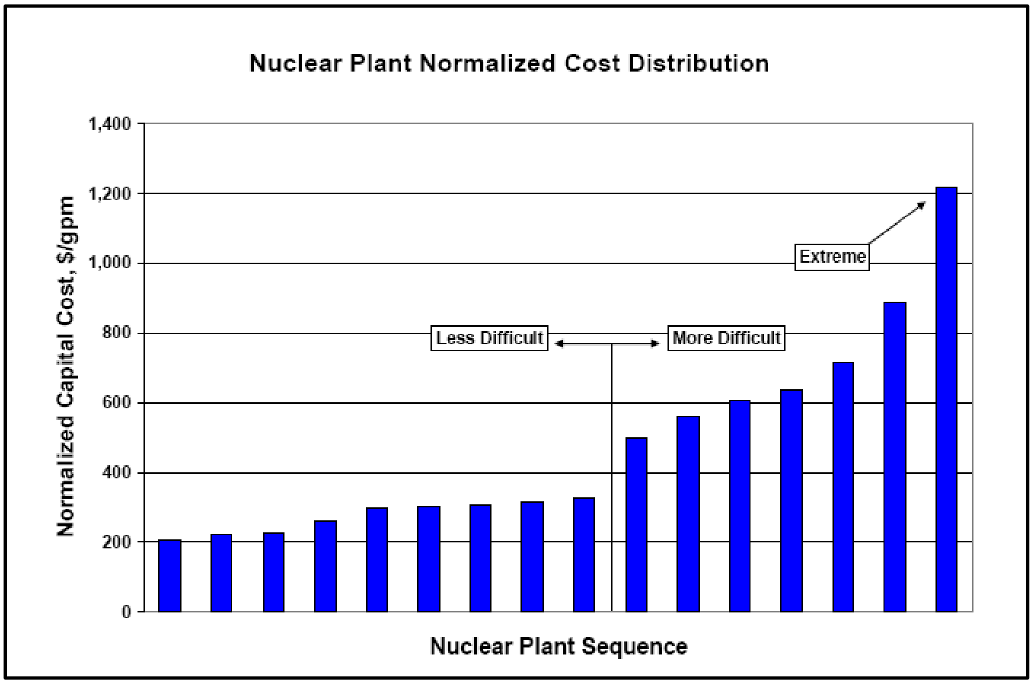

Figure 4-1
Normalized retrofit cost for selected nuclear plants

Figure 4-2 plots the same capital costs of retrofit vs. circulating water flow rate. Fifteen of the values are seen to fall into two clusters each of which is reasonably represented by a linear correlation. The groups represent examples with significantly different retrofit costs for plants with once-through cooling systems of comparable size as represented by their circulating water flows. It was the primary hypothesis of the study that this difference was attributable to site-specific factors which affected the "degree of difficulty" of a cooling system retrofit at a particular site. These groups correspond to the categories categorized as "Less Difficult" and "More Difficult" in Figure 3-1. The coefficients of the linear correlating lines are:

K (for "Less Difficult"):	$274/gpm
K (for "More Difficult"):	$644/gpm

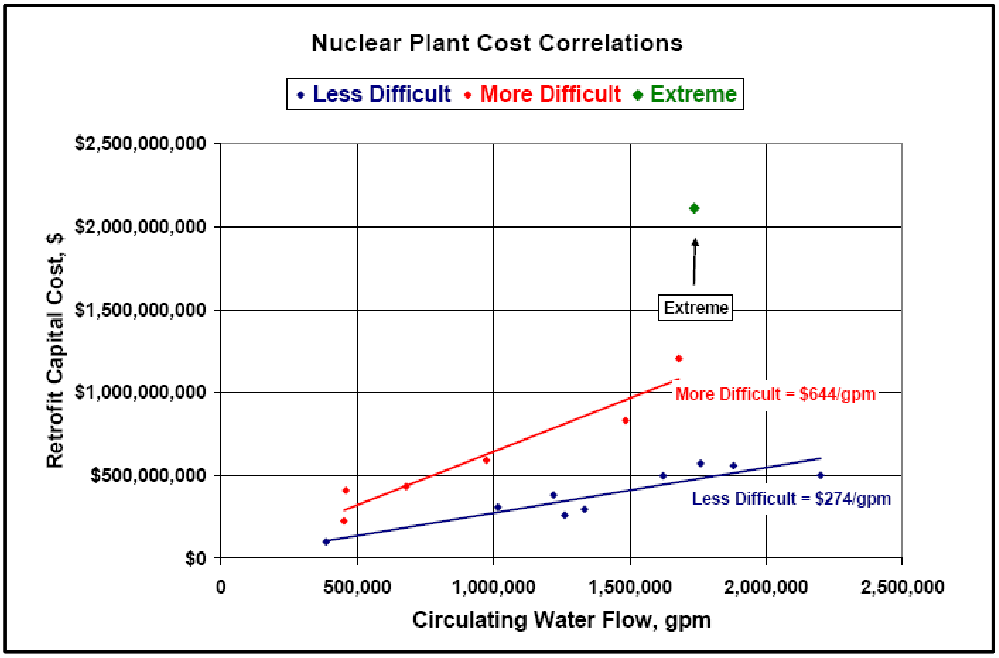

Figure 4-2
Nuclear plant retrofit costs vs. circulating water flow rate

The retrofit cost estimate for one of the plants was significantly higher on $/gpm basis than the others. This value was excluded from the correlation because including it would have distorted the correlating equation to the point where the other plants in the "More Difficult" group which cover a wide range of conditions would have been poorly represented. This does not suggest, however, that extremely high retrofits cannot be encountered at some sites where particularly difficult conditions exist.

These relationships were used to estimate retrofit capital costs at 10 other nuclear plants for which no independent estimates were available. This required a judgment to be made about the "degree of difficulty" of a retrofit at each plant. This judgment was based on considerations of several factors listed in Table 4-1.

Table 4-1
Factors influencing degree of difficulty and retrofit costs

Factor	Description
1	The availability of a suitable on-site location for a tower
2	The separation distance between the existing turbine/condenser location and the selected location for the new cooling tower
3	Site geological conditions which may result in unusually high site preparation or system installation costs
4	Existing underground infrastructure which may present significant interferences to the installation of circulating water lines
5	The need to reinforce existing condenser and water tunnels
6	The need for plume abatement
7	The presence of on- or off-site drift deposition constraints
8	The need for noise reduction measures
9	The need to bring in alternate sources of make-up water
10	Any related modifications to balance of plant equipment, particularly the auxiliary cooling systems, that may be necessitated by the retrofit
11	Re-optimization of the cooling water system or extensive modification or reinforcement of the existing condenser and circulating water tunnels
12	The need for anti-scalant chemical feed systems. Additionally, this can result in added O&M costs of ~$200,000 per year / 850 MWe

Site-specific information on these factors was obtained from questionnaires, Google Earth views, discussions with plant personnel and other public information sources. This set of 10 plants, along with the 16 plants for which independent estimates were available formed a cohort of 26 plants of which 8 plants were considered to be “More Difficult”, an additional 8 to be “Less Difficult” and the remainder to be of intermediate difficulty. Assuming that this distribution of degrees of difficulty would be comparable for the entire family of the 48 nuclear plants in the U.S. on once-through cooling, aggregate cost estimates were calculated as displayed in Table 4-2.

Table 4-2
National retrofit cost estimates for nuclear plants

Plant Type	Degree of Difficulty	Allocation	Capacity	Flow	Cost
		%	MW	Gpm (liter/s)	$ (millions)
Nuclear	Less Difficult	30%	18,000	10,700,000 (675,065)	$3,520
	More Difficult	30%	18,000	10.700,000 (675,065)	$8,270
	Intermediate	40%	24,000	21,400,000 (1,350,130)	$7,860
Total		100%	60,000	42,800,000 (2,700,260)	$19,460

In addition, there are other costs associated with retrofitting operating plants with closed-cycle cooling. For some plants, substantial downtime is incurred while installing the retrofit. Other costs, incurred for the remaining life of the plant include additional cooling system operating power and maintenance and reduced plant efficiency and output incurred because of performance limitations of the new cooling system compared to the existing once-through cooling. A detailed explanation of how these costs were estimated and aggregated is available in the original EPRI 2011 report.[41] The total national cost from each of these cost elements is tabulated in Table 3-3. The capital, downtime and annual costs are combined as both annualized costs and net present value costs in the table as well.

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[41] *op.cit.(Footnote 9)*

Table 4-3
National capital and other costs of nuclear plant retrofits

Plant Type	Source Water	Capacity	Circulating Water Flow	Costs					
				Capital	Operating Power	Heat Rate Penalty	Downtime	Annualized Cost	Net Present Value
		MW	GPM (liter/s)	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
Nuclear	Great Lakes	6,000	3,840,000 (242,266)	$1,760	$13	$16	$740	$200	$2,860
	Lakes/Reservoirs	20,000	13,990,000 (882,632)	$6,420	$46	$60	$2,700	$740	$10,430
	O/E/TR (1)	22,000	17,615,000 (1,111,334)	$8,090	$58	$75	$3,400	$940	$13,140
	Rivers	12,000	7,344,000 (463,334)	$3,370	$24	$31	$1,420	$390	$5,480
	Total	60,000	42,789,000 (2,699,566)	$19,640	$141	$182	$8,270	$2,280	$31,920

Notes: (1) Oceans/Estuaries/Tidal Rivers

Examples of actual retrofits

There are very few examples of once-through cooled plants retrofitting to closed-cycle cooling. Seven, for which some information is available, are:

1. Canadys (South Caroline E&G)
2. Jeffries (Santee Cooper)
3. McDonough (Southern/Georgia Power)
4. Palisades Nuclear Generating Station (Entergy)
5. Pittsburg Unit 7 (Pacific Gas & Electric)
6. Wateree (South Caroline E&G)
7. Yates (Southern/Georgia Power)

Of these seven plants, only Palisades is a nuclear plant. It is a single unit, 725 MW plant operating on two mechanical-draft cooling towers as shown below in Figure 4-3. The plant was commissioned in 1971 and operated on once-through cooling for the first year or so and switched over to cooling towers in 1973. The reason for converting from once-through to closed-cycle cooling is reported to be local environmental concern over thermal discharges with potential "radioactive releases from the radwaste system" and unrelated to any intake issues[42]. Anecdotal information suggests that the decision to go to closed-cycle cooling was made during the last phases of construction, but operation was allowed to begin on once-through cooling while the closed-cycle capability was being installed. The photograph below suggests that there were no serious space constraints for the installation of the towers and that they could be located relatively close to the turbine building. The cost, in 1971 dollars is reported to be $18.8 million.

[42] "California Coastal Power Plants: Alternative Cooling Systems Analysis" Prepared by TetraTech for the California State Water Resources Control Board, February 2008. Available at http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/docs/acs_analysis2008/fullreport.pdf

Figure 4-3
Palisades nuclear plant on Lake Michigan

Retrofits of closed-cycle wet systems

Situations might arise in which nuclear plants, originally designed for and operating on closed-cycle wet cooling with mechanical- or natural-draft cooling towers, could face reductions in the availability (or increases in the cost) of water for cooling system make-up. This possibility has led some plants, both nuclear and fossil, to explore the feasibility and cost of retrofitting an existing closed-cycle wet system to a water-conserving system. Alternatives might include:

- Conversion to all-dry cooling
    - Direct dry (ACC)
    - Indirect dry (ACHE)
- Conversion to hybrid cooling (Addition of dry elements)
    - Parallel
        - Direct (ACC)
        - Indirect (ACHE)
    - Series
        - Indirect (ACHE)

The dry cooling elements that could be used in such retrofits are ACCs and ACHEs and have been described in some detail in Chapter 2. The installation of these elements in a retrofit situation to replace or augment an existing wet system face the same issues on nuclear units as were discussed in Chapter 3 as well as some difficulties directly associated with retrofits. These retrofitting issues are discussed briefly in the following paragraphs.

Conversion to all-dry cooling

In principle, plants with closed-cycle wet systems can be converted to dry cooling, which can be either direct or indirect systems.[43] Retrofit issues for such a conversion include:

- Inappropriate turbine characteristics for dry cooling
- Lack of space to locate an ACC or ACHE
- Difficulty of ducting steam to the ACC

Turbine characteristics

Turbines designed for use with closed-cycle wet or once-through cooling are not well suited for operation with dry cooling. They normally have a design exhaust pressure of 2 to 2.5 in Hga (6.8 to 8.5 kPa) and restrictions on the allowable upper limit of the exhaust pressure. Typical recommendations are "Alarm" at 4.5 in Hga (15.2 kPa) and "Trip" at 5 in Hga (16.9 kPa). Dry cooling systems may not be able to maintain the condensing pressure below these limits during periods of high ambient temperature. A conservatively large ACC with an ITD of 35°F (19.4°C) would result in a turbine alarm condition at an ambient temperature of 95°F (35°C) or above. In hot areas, as the southwestern U.S., temperatures of 95°F (35°C) can occur for several hundred to over one thousand hours per year. During those periods, when the demand for energy from base-loaded nuclear plants is likely to be at its peak, unit output would have to be reduced by perhaps as much as 20% in order to maintain acceptable backpressure levels. Comparative analyses over the course of a year in a hot arid climate further show that for as much as 60% of the year, a large ACC would not achieve as low a backpressure as a conventionally sized wet cooling tower.

For indirect dry cooling, the same difficulty pertains, but the situation is worse. Assuming a typical cooling water temperature rise of 25°F (13.9°C) and terminal temperature differences of 10°F (5.6°C) for both the steam condenser and the ACHE, the condensing temperature would be 45°F (25°C) above the ambient temperature. In this case, the 4.5 in Hga (15.2 kPa) alarm backpressure would be exceeded at temperatures above 85°F (29.4°C).

Lack of space

The physical size of either an ACC or an ACHE capable of handling the heat rejection load from an 1100 MW nuclear plant is very large. An ACC, typically designed to handle 40,000 to 60,000 lb/hr of steam per cell would require, perhaps, 150 cells each measuring 40' x 40' (12.2 m x 12.2 m) for a footprint of about 5.5 acres. An ACC is preferably located within ~100 ft (30.5 m) from the turbine building in order to minimize the steam duct pressure loss and the cost. For most sites, adequate space in the required location would not be available.

For an ACHE in an indirect system, there is more flexibility in that only circulating cooling water need be piped from the existing steam condenser to the ACHE. However, if the available space is far from the turbine building and existing on-site facilities are in between, the

[43] As discussed in Chapter 3, direct dry cooling either as an all-dry system or as the dry part of a hybrid system would not be considered for BWRs.

installation of the underground circulating water piping would likely encounter many interferences and be very costly.

Ducting steam to an ACC

For direct dry cooling, the transport of steam from the turbine exhaust to the externally located ACC requires connecting the turbine exhaust to a large duct or ducts. There are often severe space constraints under the turbine and around the turbine pedestal making removal of the existing condenser and installation of the required duct work difficult, time-consuming and expensive.

In recognition of these difficulties, both EPA[44] and EPRI[45] have stated that retrofitting from either once-through or closed-cycle wet cooling to dry cooling is generally infeasible.

Conversion to hybrid cooling

A conversion from all-wet cooling to hybrid cooling is less problematic than conversion to all-dry cooling but still has many of the same issues. If adequate water is available to operate the existing wet cooling tower during the hot, peak load periods of the year, the problem related to the exhaust pressure upper limits of 4.5 and 5 In Hga (15.2 to 16.9 kPa) no longer exists. The conversion consists of installing a dry cooling element either in series of in parallel with the existing tower and providing the necessary piping, valving and additional pumping capacity, if required, to operate the system in either an all-wet, all-dry or combined mode as conditions dictate. Once a chosen system is installed, the amount of water conserved can be traded off against the amount of energy produced by using the wet and dry element in differing proportions as water availability and ambient temperature conditions permit.

Some of the constraints discussed above in relation to all-dry systems still pertain.

- An ACC would not be considered for the dry element in a hybrid system for a BWR. It may be acceptable for a PWR.
- A parallel arrangement can make use of either an ACC or an ACHE as the dry element. A series arrangement would obviously require an ACHE.
- The physical size of the dry elements depends on the amount of water conservation desired in the particular situation. If an ACC is used in a parallel arrangement on a PWR, the requirement that it be located close to the turbine still applies and may eliminate the arrangement from consideration.

There is at least one instance where such a conversion has been carried out, albeit on a very small fossil plant. The Cedar Falls Utility's Streeter Station, Unit 7 is a 37 MW coal fired unit originally equipped with a 2 cell cross-flow wet cooling tower. In the late 1980's, a state highway was constructed to the south and east of the plant. Prevailing winter winds from the Northwest would have carried the plume and drift over the highway creating potential visibility problems and icing hazards. After various options to reduce, redirect or eliminate the plume

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[44] § 316(b) Phase II Final Rule – Technology Development Document; http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/devdoc_index.cfm

[45] *Closed-Cycle Cooling System Retrofit Study: Capital and Performance Cost Estimates.* EPRI, Palo Alto, CA: 2011. 1022491.

were considered, the choice was made to add an air-cooled condenser in parallel with the re-circulating wet cooling system capable of carrying the entire load during the cold winter months during which plumes would form on the wet tower.

The ACC, installed in 1993, was sized to maintain a 3 in Hga (10.2 kPa) turbine exhaust pressure at full load at an ambient air temperature of 55°F (12.8°C) (the typical operating range for the existing L-P turbine is 3.0 - 3.5 in Hga (10.2 to 11.9 kPa), and the trip point is 8.0 in Hga (27 kPa)). This resulted in a five-cell ACC (four condensing and one reflux or dephlegmator cell) each with a 28-foot (8.5 m) diameter fan, each equipped with a 150-hp (112 kW) motor and a variable speed drive. The designer/supplier was GEA.

The ACC is located adjacent to the south wall of the turbine hall close to a river bounding the plant property. The motor control center is in a room between the turbine hall and the ACC. The steam ducting consists of four 48" (1.2 m) diameter pipes that are connected to rectangular transitions attached to openings cut in the top casing of the steam condenser. The limited space between the L-P turbine exhaust and the steam condenser made connecting such large steam ductwork directly to the existing turbine exhaust casing very complex and expensive.

The operation of the system has been satisfactory and adequate plant cooling has been available. However, installation costs were approximately $5 million in 1993 for a 5-cell ACC servicing a 37 MW fossil plant.

In addition, at least two site-specific feasibility analyses and cost/performance estimates have been conducted of which we are aware: one for a coal plant; the other, for a nuclear plant. While the specifics of the studies are proprietary, the conversions, while technologically possible, were complex and very costly.

Recent in-depth Studies

In accordance with the California Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Water for Power Plant Cooling discussed in detail earlier in this chapter, two studies were conducted by independent third parties for PGE's Diablo Canyon and SCE San Onofre Nuclear Generating Station (SONGS) plants. These reports[46],[47] are available at:

http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/

While these reports do not contain complete cost analyses, they indicate the complexity of a cooling system retrofit at a large nuclear plant. With the recent retirement of SONGS, this report will presumably not be completed. However, the construction details and cost estimates for the Diablo Canyon Power Plant may be available at a later date.

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[46] Independent Third-Party Final Technology Assessment for the Alternative Cooling Technologies or Modifications to the Existing Once-Through Cooling System for the Diablo Canyon Power Plant, Bechtel Power Corporation, Report No. 25762-000-30R-G01G-000010, 2013

[47] Independent Third-Party Final Technology Assessment for the Alternative Cooling Technologies or Modifications to the Existing Once-Through Cooling System for the San Onofre Nuclear Generating Station, Bechtel Power Corporation, Report No. 25761-000-30R-G01G-000010, Rev. 2, November, 2012

5
COST/PERFORMANCE COMPARISONS

Scope of comparisons

The following chapter provides cost/performance comparisons of alternative, water-conserving cooling systems. The systems are compared on the basis of capital and operating cost and on performance penalties resulting from performance/capacity limitations imposed by limitations of the cooling system. Cost performance analyses are conducted and the results described for several alternative cooling systems which might be considered for nuclear power plants. While the primary emphasis is on water-conserving alternatives, closed-cycle wet cooling with mechanical-draft wet cooling towers is established as the base case for comparison purposes.

There are certain characteristics of nuclear plants which influence the choice of systems to be considered; specifically,

- the applicability of direct dry cooling with ACCs and
- the effect of nuclear turbine characteristics on the allowable range of operating conditions.

Use of air-cooled condensers

Most water-conserving cooling system concepts in use today, either dry or hybrid, are based on air-cooled condensers. However, virtually all of these systems are installed on fossil plants, either coal-fired steam plants or gas-fired, combined-cycle plants. Air-cooled condensers have never been used on nuclear plants. As noted in Section 1, only two nuclear plants have been built with dry cooling, and both used indirect dry cooling, not ACCs.

It is considered unlikely that ACCs would ever be used on BWRs given the direct connection between the reactor and the turbine exhaust and ACC. However, it is possible that ACCs might find application on PWRs and the Canadian-designed CANDU plants given the additional barrier in the steam generator between the reactor and the turbine. Therefore, analyses of dry and hybrid systems using ACCs will be included.

Turbine characteristics

Most dry cooled plants make use of turbine designs which allow operation at exhaust pressures above 5 in Hga (16.9 kPa). Typical backpressure limits for dry-cooled fossil plants are in the range of 7 in Hga (23.7 kPa) (alarm) and 8 in Hga (27.1 kPa) (trip). Some can go to 10 in Hga (33.9 kPa). An early dry-cooled, coal fired- steam plant (Wyodak) uses a high backpressure turbine which can operate up to 16 in Hga (54.2 kPa). These high or extended backpressure turbines are preferred for dry cooled applications because a turbine restricted to 4.5 to 5 in Hga (15.2 to 16.9 kPa) requires that the steam condensing temperature be below 130°F (54.4°C). ACCs with initial temperature differences (ITD defined as the steam condensing temperature minus the ambient air temperature, $T_{condensing}$ - $T_{ambient}$) below about 35°F (19.4°C) become uneconomically large and require unacceptable operating power. Therefore, when the ambient temperature exceeds 95°F (35°C), the condensing temperature exceeds 130°F (54.4°C). At this point, the turbine steam flow, and hence the plant output, must be reduced in order to keep the exhaust pressure below 5 in Hga (16.9 kPa).

The analysis adopts two approaches. The estimates are initially done assuming a backpressure limit of 5 in Hga (16.9 kPa) consistent with existing nuclear turbine characteristics. However, additional estimates will be developed based on a 7 in Hga (23.7 kPa) limit for two reasons. First, as the need for water-conserving cooling systems becomes more severe, it is possible that the turbine vendors will develop an extended backpressure turbine suitable for nuclear designs at the 1000 to 1500 MW scale. Second, if the small modular reactor approach gains acceptance, the turbine designs will be closer in size to turbines currently in use on gas-fired combined-cycle plants and could have similar performance characteristics. Current literature on SMRs suggests that they can be dry-cooled[48].

Cost/performance analyses

The following sections provide cost/performance comparisons of some alternative, water-conserving cooling systems. Comparisons will be made for three sites at Yuma, Arizona, Jacksonville, Florida and Green Bay, Wisconsin in order to establish the effect of site climatology on cooling system selection and evaluation. The sites represent hot, arid conditions, hot, humid conditions and moderate humidity conditions with a wide temperature range.

The systems discussed include:

- Closed-cycle wet cooling
    - Mechanical-draft towers
    - Natural-draft towers

- Direct dry cooling
    - Air-cooled condensers
        - Mechanical-draft, A-frame condensers
        - Natural-draft towers

- Indirect dry cooling
    - Mechanical-draft dry towers (air-cooled heat exchangers)
    - Natural-draft dry towers

- Hybrid wet/dry cooling (separate structures)
    - Series or parallel
    - Alternative wet elements
        - Mechanical-draft
        - Natural-draft
    - Alternative dry elements
        - Direct dry (ACCs)
        - Indirect dry (ACHEs)
            - Mechanical-draft

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[48] http://www.world-nuclear.org/info/Current-and-Future-Generation/Cooling-Power-Plants/#.UeNHGo21EXs

        - Natural draft

- Hybrid wet/dry cooling (integrated single structure)
    - Mechanical-draft
    - Natural-draft assisted

- Special topics
    - Dry Heller system
        - Heller system with spray assist and deluge coolers
    - Spray-assisted dry cooling
        - ACCs with spray inlet cooling

Available information/data for analysis

While cost and performance information is readily available for mechanical-draft wet cooling towers and mechanical-draft, A-frame ACCs, it is less so for other elements.

- Natural-draft wet cooling towers, while in wide use throughout the US, are only now being built after a nearly 20-year hiatus. Therefore, current information is limited and not publically available.
- Air-cooled heat exchangers at the sizes required for utility systems have not been built in the U.S. in either mechanical-draft or natural-draft designs.
- Only a single hybrid system on an integrated structure was ever built in the U.S. (San Juan Generating Station, Unit 3) and that was in 1979. No current cost information is available nor has the system been recently proposed.
- Heller systems, while also widely used abroad, have not been built in the US so verifiable costs under US market conditions are difficult to obtain.

Therefore, the analysis of wet, dry and hybrid systems using mechanical-draft wet cooling towers and ACCs will be presented and discussed in detail based on vendor-supplied information and applied in a variety of situations to illustrate the effects of design choice, water availability and site characteristics. The discussions of the other systems will be based on limited information of performance and cost for a single system at a single location obtained either from published papers at industry conferences or restricted documents prepared for client projects for which attribution cannot be made. While this is less than satisfactory, attempts will be made to establish the "reasonableness" of these estimates based on comparisons to related systems for which documentable information is available.

Plant characteristics

The plant specifications used for comparisons are typical values for a current PWR in the 1,100 MW range. The relevant system values are shown in Table 5-1.

Table 5-1
Plant characteristics

Pressurized Water Reactor	
Capacity (Gross), MWe	1100
Capacity (Net), MWe	1045
Turbine steam flow, lb/hr (kg/s)	7.43 x 10^6 (936)

Turbine characteristics

The base case turbine is a conventional ~1100 MW turbine designed for nuclear service. Table 5-2 gives typical operating values and Figure 5-1 shows a typical performance curve of % capacity loss vs. exhaust pressure.

Table 5-2
Turbine characteristics

Capacity (design)	1100 MW
Inlet steam pressure	~ 1100 psia (7,584 kPa)
Design exhaust pressure	3.5 In Hga (11.9 kPa)
Maximum exhaust pressure	5 in Hga (16.9 kPa)
Rotation	1800 rpm

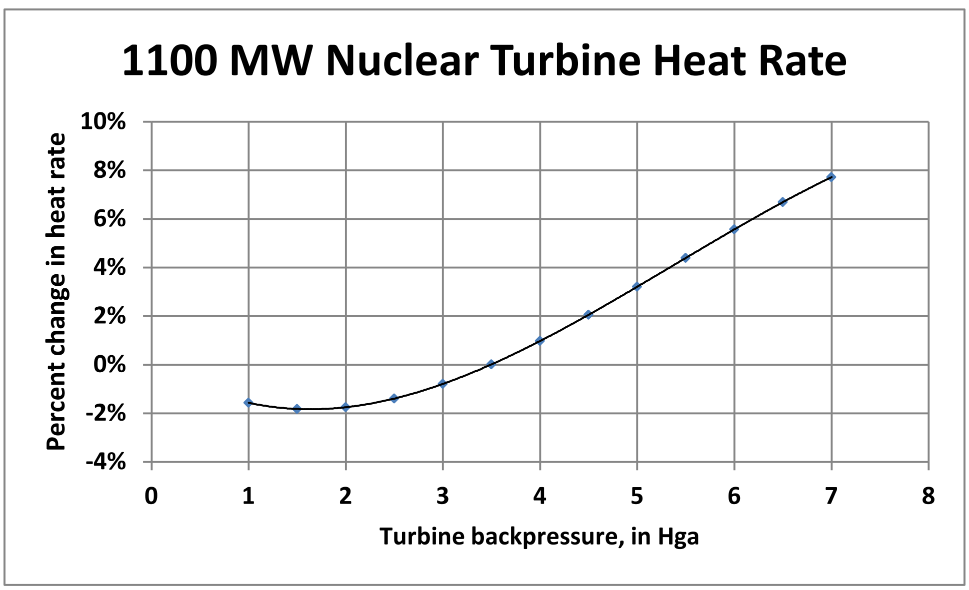

Figure 5-1
Representative turbine characteristic curve

Establishment of base cases

The initial estimates will establish baseline cost/performance estimates based on conventional, closed-cycle wet cooling systems.

Closed-cycle wet cooling with mechanical draft wet towers

Mechanical-draft, counterflow wet cooling towers of FRP construction were sized for each of the three sites. Table 5-3 lists the design specifications for each case and Table 5-4 lists the capital costs, operating power requirements, water consumption and a measure of the annual average and hot day unit performance.

Table 5-3
Wet cooling system design specifications

	Yuma, AZ	Green Bay, WI	Jacksonville, FL
Heat load, Btu/hr	7×10^9	7×10^9	7×10^9
1% DB, F	109	85	93
Mean Coincident WB, F	72.4	72.9	77.9
1% WB, F	76	74	78
Mean Coincident DB, F	96	83	88
Backpressure @ MCWB, in Hga	3.5	3.5	3.5
Condensing Temperature, F	120.5	120.5	120.5
Circulating flow rate, gpm	467,460	467,460	500,850
Range, F	30	30	28
Approach, F	7	7	7
Condenser TTD, F	7.5	9.5	7.5

Table 5-4
Wet cooling system cost/performance results

	Yuma, AZ	Green Bay, WI	Jacksonville, FL
Performance			
Water consumption, acre-feet/yr	20,317	15,980	17,653
Operating power, MW	13.6	12.5	11.4
Energy consumption, MWh/yr	102,837	97,080	90,702
Lost output (penalty), MWh/yr	159	78	12
Costs			
Capital cost, $	34,800,000	35,490,000	37,800,000
Annualized capital cost, $/yr	2,790,000	2,850,000	3,060,000
Power cost, $/yr	9,255,000	8,736,000	8,163,000
Turbine penalty cost, $/yr	15,000	6,000	0
Total annualized cost, $/yr	12,060,000	11,592,000	11,223,000

Since wet cooling tower performance is limited by the ambient wet bulb temperature rather than the dry bulb temperature, the differences among the three sites are less than might be imagined given the radically different climate characteristics. The most demanding conditions are at the Jacksonville site due to the higher wet bulb temperature. However, in order to achieve the same desired condensing temperature and pressure at an acceptable tower approach (> 7°F [3.9°C]) and condenser terminal temperature difference (TTD) (also > 7°F [3.9°C]), it was necessary to increase the circulating water flow slightly to achieve a slightly lower range (28°F [15.6°C] vs. 30°F [16.7°C]).

The cost/performance estimates were developed using the EPRI cooling system spreadsheet tool[49]. The cooling system costs include the cooling tower, the surface condenser and generalized factors for typical circulating cooling water lines, pumps and valves. While a range of tower configurations were considered in order to find a minimum cost solution, no optimization over a range of circulating water flows or tower approaches was performed. Given this and the level of confidence in the numerous cost elements, the costs of the three sites tabulated in Table 5-4 are essentially equivalent, varying by less than +/- 5% for both the capital and annualized costs.

Closed-cycle wet cooling with natural-draft towers

There has been a historical preference for natural-draft towers for large nuclear plants because of the lower operating power requirements over the life of the plant. Although there had been a long hiatus in the construction of natural-draft towers in the U.S., the use of natural-draft towers has continued elsewhere in the world. Recently announced new nuclear units, Units 3 and 4 at Georgia Power's Plant Vogtle, will use natural-draft towers, although the proposed Units 3 and 4 at SCANA's V. C. Summer plant chose round, concrete mechanical-draft towers.

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[49] Hybrid Cooling System Selection and Analysis Tool (HCSSAT) Version 1.; EPRI #1024544

However, there is little or no publically available information on the current costs of natural-draft towers. Historical assumptions have estimated that the cost of natural-draft towers is about double that of mechanical-draft towers for the same service. [50,51]

There are also limited indications from engineering studies related to the retrofitting of once-through cooled plants with closed-cycle cooling systems. For example, estimates for alternative cooling tower systems at a nuclear plant in the Northeast indicate costs for natural-draft towers ranging from 16% to 23% above the costs for equivalent mechanical-draft towers.[52] Recent information at one site indicated that the cost differences for new plant construction had narrowed almost to the point where the costs were nearly the same. One possible source of the difference from historically assumed cost ratios is that they may have been based on mechanical-draft towers of wood or FRP construction, while individual estimates may have been based on round, concrete towers which are more robust, have greater assumed longevity and are presumably more costly.

If the cost differential is minimal, the operating cost savings associated with natural-draft cooling are significant. Typical fan power requirements can be from 0.75 to 1% of plant output. For a 1000 MWe unit, this amounts to at least 5 MW. Evaluated at $90/MWh for a year at 90% capacity factor, the annual cost of fan power is over $5 million and amounts to an important element in the annual evaluated cost (see Table 5-4).

Water-conserving cooling options

Dry cooling

In order to bound the estimates, all-dry systems of various configurations will be considered. The system for which the most performance and cost information is available is direct dry cooling using forced-draft ACCs of the A-frame design. Additional possible types are natural-draft ACCs and mechanical and natural-draft indirect-dry systems using air-cooled heat exchangers (ACHEs).

Direct dry cooling with mechanical-draft, A-frame air-cooled condensers

ACCs of the conventional, forced-draft, A-frame type were sized for each of the three sites. Two sets of assumptions were made. First, the ACCs were sized to maintain a 5 in Hga (16.9 kPa) limit at the 1% dry bulb temperature; second, that they were sized for 7 in Hga (23.7 kPa), assuming that a suitable turbine could be available. This issue was discussed in an earlier section of this chapter. As in the case of the wet cooling systems, the cost/performance estimates were developed using the EPRI spreadsheet tool.

The design specifications and cost/performance results are shown in Tables 5-5 and 5-6 for the 5 in Hga (16.9 kPa) cases and in Tables 5-7 and 5-8 for the 7 in Hga (23.7 kPa) cases.

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[50] General background statement from "Cooling System Study Report" to Indiana-Michigan Power Company, Inc., December, 2010

[51] Personal communication, J.P. Libert, EvapTech, July, 2013

[52] Millstone Power Station: An Evaluation of Cooling Water System Alternatives", Dominion Nuclear, Connecticut, August, 2001

Table 5-5
ACC design specs/design estimate

	Yuma, AZ	Green Bay, WI	Jacksonville, FL
Heat load, Btu/hr	7×10^9	7×10^9	7×10^9
Steam flow, lb/hr	7.25×10^6	7.25×10^6	7.25×10^6
1% DB, F	109	85	93
Backpressure @ 1% DB, in Hga	5.0	5.0	5.0
Design ITD, F	24.8	48.8	40.8
No. of cells	270	135	150

Table 5-6
ACC cost/performance results

	Yuma, AZ	Green Bay, WI	Jacksonville, FL
Performance			
Water consumption, acre-feet/yr	0	0	0
Operating power, MW	45.3	22.6	25.2
Energy consumption, MWh/yr	300,819	169,881	213,945
Lost output (penalty), MWh/yr	13,092	8,835	19,533
Costs			
Capital cost, $	355,350,000	181,680,000	216,900,000
Annualized capital cost, $/yr	28,650,000	14,640,000	17,490,000
Power cost, $/yr	27,075,000	15,288,000	19,254,000
Turbine penalty cost, $/yr	1,179,000	795,000	1,758,000
Total annualized cost, $/yr	56,904,000	30,723,000	38,502,000

It should be noted that the design for the Yuma, AZ site is unrealistically large. Maintaining a 5 in Hga (16.9 kPa) turbine exhaust pressure at the 1% dry bulb temperature of 109°F (42.8°C) results in an ITD of 11.5°F (6.4°C) which is far lower than the normal lower limits of ITD in the range of 25°F to 30°F (13.9°C to 16.7°C). Both the capital costs and the power costs for the 270 fans are exorbitantly high. The designs at the other sites while less extreme still represent very high cost solutions. It is likely that, given the constraints of current nuclear turbine designs, all-dry cooling would not be selected for a large nuclear plant.

Relaxing the turbine backpressure constraints to 7 in Hga (23.7 kPa) results in the systems tabulated in Tables 5-7 and 5-8. Since the Yuma and Green Bay sites bracket the system costs and performance, the Jacksonville site was not estimated for this case.

Table 5-7
ACC design specs

	Yuma, AZ	Green Bay, WI	Jacksonville, FL
Heat load, Btu/hr	7×10^9	7×10^9	
Steam flow, lb/hr	7.25×10^6	7.25×10^6	
1% DB, F	109	85	
Backpressure @ 1% DB, in Hga	7.0	7.0	
Design ITD, F	37.9	61.9	
No. of cells	180	105	

Table 5-8
7" ACC cost/performance results

	Yuma, AZ	Green Bay, WI	Jacksonville, FL
Performance			
Water consumption, acre-feet/yr	0	0	
Operating power, MW	30.2	17.6	
Energy consumption, MWh/yr	258,915,000	154,341,000	
Lost output (penalty), MWh/yr	76,692,000	84,909,000	
Costs			
Capital cost, $	226,980,000	140,700,000	
Annualized capital cost, $/yr	18,300,000	11,340,000	
Power cost, $/yr	23,301,000	13,890,000	
Turbine penalty cost, $/yr	6,903,000	7,641,000	
Total annualized cost, $/yr	48,504,000	21,531,000	

Both the ACC sizes, costs and power requirements are significantly less for these 7 in Hga (23.7 kPa) cases than for the 5 in Hga (16.9 kPa) cases. The size of the Yuma ACC scales reasonably well on the basis of steam flow from much smaller units installed on gas-fired combined-cycle units with similar turbine backpressure limitations in the Las Vegas area where the climatic conditions are comparable.

Because of the much colder annual average temperatures in Green Bay than in Yuma, the Green Bay ACC optimizes at a much higher ITD, has fewer cells and a correspondingly higher steam loading per cell. In both instances, a significantly higher turbine penalty is incurred compared to the 5 in Hga (16.9 kPa) cases, but the total annualized costs are much lower. It should be noted, however, that the "hot day" reduction in output will be greater when the turbine backpressure is allowed to rise to 7 in Hga (23.7 kPa) by as much as 4% or about 40 MW.

Comparing the all-dry cases with the all-wet base cases, the capital cost ratios (ACHE/ACC) range from 6.5 at the Yuma site to about 4 at the Green Bay site. The annualized cost ratios are 4 and 1.9 at Yuma and Green Bay, respectively.

Direct dry cooling with natural-draft ACCs

There are no direct dry cooling systems on natural-draft towers operating in the U.S. or, to our knowledge, anywhere in the world on a power plant. One is under construction by SPX at the Upington-Khi Solar One, a 50 MW concentrating solar plant in South Africa and is scheduled for completion in 2013. No cost or performance information is available at this time. Given the nuclear industry's historical preference for natural-draft towers over mechanical-draft towers, this "first-of-a-kind" installation should be monitored to understand its potential for application elsewhere.

Indirect dry cooling with mechanical- or natural-draft towers

Indirect dry cooling is rarely chosen in preference to direct dry cooling due to generally higher initial costs and turbine heat rate penalties, although there are two plants in South Africa and several in China with indirect dry cooling systems. As noted earlier, there have been only two dry cooled nuclear plants in the world and both used indirect dry systems.

Mechanical-draft indirect dry towers

Limited cost estimates were made for indirect dry systems in an earlier EPRI report.[53] The cost estimates were developed for both a 500 MW coal plant and a 600 MW nuclear plant at five sites. Two of the sites (Yuma, AZ and Jacksonville, FL) are the same as used in previous sections of this report. A third (Burlington, VT) is reasonably comparable to the Green Bay, WI site used in this study. At the coal-fired plant, estimates for both an indirect dry system and a direct dry system are provided; for the nuclear plant, only the indirect system is estimated.

The procedure for developing the estimated sizes, costs and power requirements for indirect dry cooling systems are discussed in detail in the referenced report. In general terms, the size/performance estimates are scaled from ACC data by scaling up the frontal area and air flow proportionally to keep the airside heat transfer coefficients and fan power comparable. A set of curves for cost and fan power requirements was obtained from a variety of sources including vendor websites, vendor-supplied information, a previous water conservation study for a utility client and formal bid packages for related applications using similar equipment.

The results for the sites for a 500 MW coal-fired plant are given in Table 5-9 along with the comparable ACC costs. The corresponding ACHE/ACC cost ratios are given in Table 5-10 and indicate increased capital costs for indirect dry systems over direct dry systems in the range of 5% to 26% and annualized cost ratios ranging from 58% to 72% due in part to the significantly higher operating and penalty costs.

Indirect dry system costs were also estimated for a 600 MW nuclear plant and are displayed in Table 5-11. These values, when scaled simply on the basis of steam flow, are a factor of 1.75 to 2 higher than the costs of the 7 in Hga (23.7 kPa) direct dry cooling in Table 5-7. The level of confidence that can be placed in this comparison is low since the estimates were made with different methodologies, for different design assumptions and using data from different times. However, the point remains that the cost of indirect systems is likely to be substantially higher than those for direct systems.

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[53] Economic Evaluation of Alternative Cooling Technologies, EPRI Report No. 1024805, December, 2011.

Table 5-9
Comparative costs of direct and indirect dry cooling

500 MW Coal Plant						
Cost element	**Direct dry cooling with ACC**			**Indirect dry cooling with ACHE**		
	Yuma	**J'ville**	**Burlington**	**Yuma**	**J'ville**	**Burlington**
Capital cost, $	97,200,000	87,000,000	62,300,000	108,600,000	91,200,000	78,600,000
Operating cost, $/yr	4,800,000	4,200,000	2,800,000	8,800,000	10,500,000	8,600,000
Penalty cost, $/yr	4,000,000	2,500,000	3,000,000	12,000,000	5,800,000	2,400,000
Maintenance, $/yr	1,500,000	1,300,000	940,000	1,600,000	1,400,000	1,200,000
Annualized capital, $/yr	7,800,000	7,000,000	5,000,000	8,700,000	7,300,000	6,300,000
Total annual cost, $/yr	18,100,000	15,000,000	11,740,000	31,100,000	25,000,000	18,500,000

Table 5-10
ACHE/ACC cost ratios

ACHE/ACC cost ratios			
Cost element	**Yuma**	**Jacksonville**	**Burlington**
Capital cost, $	1.12	1.05	1.26
Operating cost, $/yr	1.83	2.50	3.07
Penalty cost, $/yr	3.00	2.32	0.80
Maintenance, $/yr	1.07	1.08	1.28
Annualized capital, $/yr	1.12	1.04	1.26
Total annual cost, $/yr	1.72	1.67	1.58

Table 5-11
Costs of indirect dry cooling at 600 MW nuclear plant

600 MW Nuclear Plant with ACHE			
Cost element	**Yuma**	**Jacksonville**	**Burlington**
Capital cost, $	217,900,000	175,500,000	146,300,000
Operating cost, $/yr	12,400,000	7,080,000	8,520,000
Penalty cost, $/yr	6,640,000	4,780,000	2,210,000
Maintenance, $/yr	3,270,000	2,630,000	2,200,000
Annualized capital, $/yr	17,430,000	14,040,000	11,710,000
Total annual cost, $/yr	39,720,000	28,540,000	24,640,000

Another source of comparison between direct and indirect dry systems is a recent study of alternative cooling system retrofits at a nuclear plant in the Southwest. An ACC was sized for a steam flow of about 9.3 x 10^6 lb/hr for a design backpressure of 7.4 in Hga (25.1 kPa) at an ambient temperature of 122°F (50.0°C). A corresponding indirect cooling system with an ACHE was sized for the same heat load and ambient temperature but for a backpressure of 5 in Hga (16.9 kPa). The comparative cost comparisons are listed in Table 5-12.

Table 5-12
ACC/ACHE cost estimates

System	Backpressure in Hga (kPa)	Capital cost ($ millions)	Cost ratio (ACHE/ACC)
ACC	7.4 (25.1)	361	--
ACHE	5 (16.9)	690	1.91
ACC adjusted[54]	5 (16.9)	562	1.22

This may be a more realistic ratio than the higher values discussed in the previous paragraph since the estimates were made by experienced vendors for the same assumed conditions at the same time.

Natural-draft indirect dry towers

The comparisons of indirect to direct dry cooling systems given above were for mechanical-draft systems of both kinds. While no direct dry systems currently operate on natural-draft towers, there are examples of indirect-dry systems that do.

Results from a recent study of hybrid cooling systems for a large nuclear unit considered both mechanical- and natural-draft towers for the dry elements of the systems. Extrapolating the costs of the two tower types to the “0% Water Use” point provides an approximate comparison of the

[54] Adjusted using 7 in Hga/5 in Hga ratios from Tables 5-6 and 5-8

costs for an ACHE for an indirect dry cooling system with either a mechanical- or natural-draft tower. These extrapolations are shown in Figure 5-2.

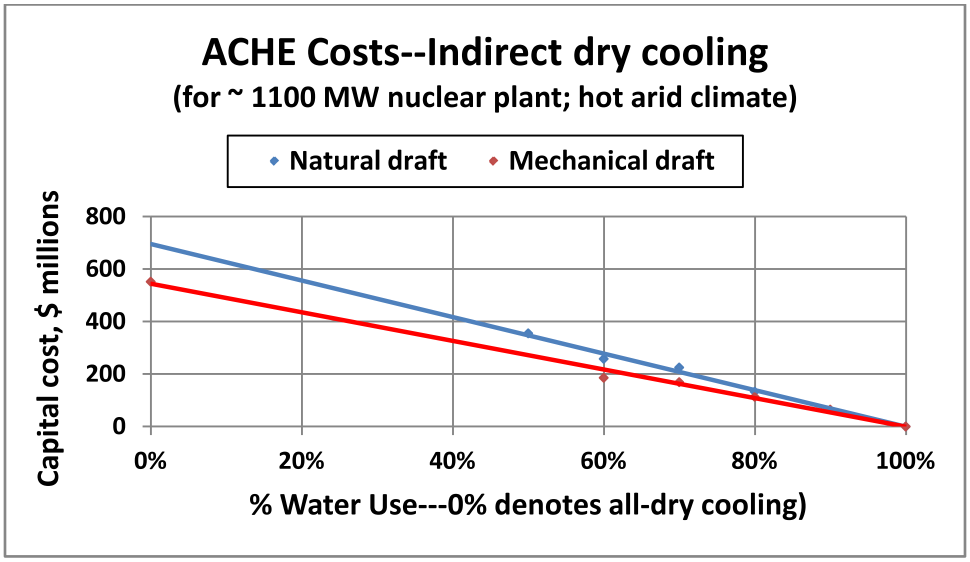

Figure 5-2
ACHE tower costs

The cost ratio is approximately 1.28 which is reasonably consistent with the ratio of natural- to mechanical-draft wet towers from the Millstone retrofit study referred to in an earlier section.

Mechanical-draft direct vs. natural-draft indirect

A more complicated comparison can be considered between a direct dry cooling system with a mechanical-draft ACC and an indirect dry cooling system with a natural-draft ACHE. Two coal-fired plants in South Africa of approximately the same size, age and with similar climatological conditions are the Matimba Power Station (3,990 MW; 1982; mechanical-draft, direct) and the Kendal Power Station (4,116 MW; 1983; natural-draft, indirect). The plants are shown in Figures 5-3 and 5-4.

Figure 5-3
Matimba Power Station

Figure 5-4
Kendal Power Station

While detailed cost comparisons are not available, anecdotal information suggests the capital cost of the natural-draft, indirect system at Kendal was 30% to 40% higher while an evaluated life-cycle cost was somewhat lower due to the significantly lower operating power and reduced maintenance cost. Given the likely preference for indirect dry systems for nuclear units (particularly BWRs) and natural-draft towers, the Kendal technology should be given careful consideration in future studies. Systems of this general type are discussed in a later section dealing with modified Heller systems.

Hybrid wet/dry systems

The choice of hybrid cooling is motivated by the desire or need to conserve water without incurring the severe hot day capacity penalties which can occur with all-dry cooling. Wet and dry elements can be in series, parallel or split configurations. Wet elements can be mechanical or natural-draft wet towers. Dry elements can be direct-dry ACCs or indirect-dry ACHEs. Each of these can be mechanical or natural-draft.

The most complete information on the cost and performance of such systems is for parallel elements with ACCs as the dry element. Some general observations regarding the expected cost/performance characteristics of these systems are:

- Typical water savings objectives for the few operating parallel hybrid cooling systems in the U.S. have been about 50% of the annual all-wet system consumption.
- Typical "hot day" backpressure specifications have been generally midway between at typical wet cooling level (~2.5 to 3 in Hga [8.5 to 10.2 kPa]) and a dry cooling level (~5 to 7 in Hga [16.9 to 23.7 kPa]).
- System costs for systems with water saving objectives below 80 to 85% are usually lower than all-dry system costs but still significantly above wet system costs.

The largest parallel hybrid system in the U.S. is installed on Unit 3 at Excel's Comanche Station in Pueblo, Colorado. The plant site, shown in Figure 5-5, can be used to illustrate some features of the system. The hybrid system for Unit 3, a 750 MW coal-fired unit, includes a wet cooling tower with 9 cells and an ACC with 45 cells in a 9 x 5 array. By comparison, the all-wet cooling system for Unit 2, a 350 MW unit shown in the photograph on the right hand side, also has a 9 cell wet cooling tower for less than half the unit capacity. Similarly, a 45 cell ACC is required to cool the 175 MW steam portion of the gas-fired, combined-cycle plant at the Front Range plant located in Colorado Springs. For a hybrid system, the individual wet and dry elements can be much smaller than either would be in an all-wet or all-dry system.

Figure 5-5
Aerial view of Comanche site, Pueblo, Colorado

This system is in increasing use on gas-fired, combined-cycle plants and on one coal-fired steam plant in the U.S. Descriptions of these units are given in an EPRI report on Hybrid Technology.[55] Cost/performance discussions of these alternative arrangements follow.

Parallel wet/dry systems with direct dry cooling

The parallel wet/dry hybrid system with a mechanical-draft A-frame ACC paired with a mechanical-draft wet tower and a shell-and-tube surface condenser is described in Section 1. The selection and design are determined by the specification of the design backpressure under "hot day" conditions and the amount of water available on an annual basis. A systematic selection and design methodology is described in detail in an earlier EPRI report[56] and is summarized briefly here for convenience of reference.

The procedure takes the following steps:

1. Select a design backpressure to be achieved at "hot day" (1% dry bulb temperature) conditions.

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[55] *Hybrid Cooling Systems: Technology Overview.* EPRI, Palo Alto, CA 2011 1024710
[56] *Economic Evaluation of Alternative Cooling Technologies.* EPRI, Palo Alto, CA: 2011. 1024805.

2. Select a fraction of the heat load to be carried by the dry element of the hybrid system at "hot day" conditions.
3. Size the dry and wet components for each combination of design backpressures (Step 1) and hot day dry element performance (Step 2).
4. For each case, calculate system performance including turbine backpressure, plant output and water consumption on an hour-by-hour basis throughout the year. In the calculations for this step, a variety of operating strategies can be selected which the vary the rate at which the wet element is turned down as the ambient temperature decreases and the dry element carries more and more of the total heat load.
5. Plot the relevant system design, performance and cost characteristics as a function of annual water savings.

The resultant curves can be used to determine system design, performance and cost values required to meet an annual water target and a desired hot day performance level

A more complete optimization can be performed with two additional iterations.

1. The tradeoff between ACC size and "hot day" backpressure can be explored until a minimum annualized cost including the cost of operating power and turbine penalty is achieved.
2. The wet system can be further optimized by exploring a variety of circulating water flow rates, cooling water temperature rise and condenser size. It should be noted that the wet element is by far the lower cost element of the system and this additional optimization provides little overall system benefit.

In calculating the hourly water consumption rate and the turbine output penalty and system operating power under changing environmental conditions throughout the year, a variety of operating strategies can be selected which the vary the rate at which the wet element is turned down as the ambient temperature decreases and the dry element carries more and more of the total heat load.

In the following discussion of comparative results, the example cases which were developed at each of the three sites included:

- "Hot day" backpressure, in Hga: 3.5, 5, 6, and 7 (11.9, 16.9, 20.3, and 23.7 kPa)
- Fraction of hot day load taken by the ACC: 30, 50, 67 and 85%
- The operating strategy used was to operate the wet element at full capability until the turbine exhaust pressure reached 2 in Hga . At this point, the wet portion was taken out of service and the cooling system operated in an all-dry mode.

Results for the range of conditions at the Yuma site are shown in the following figures and tables. They display the size of the ACC (number of cells), the installed cost of the total cooling system, the annual cost of the operating (fan) power and the output reduction penalty and the total annualized cooling system cost. More detailed tabular data sets for the three sites are included in Appendix B.

In Figure 5-6, the size of the ACC for the range of design conditions, expressed as the number of cells, is plotted against the annual water savings, expressed as the percentage of the all-wet cooling water consumption. The number of cells for the all-dry system (100% water savings) correspond to the sizes tabulated in Tables 5-5 and 5-7.

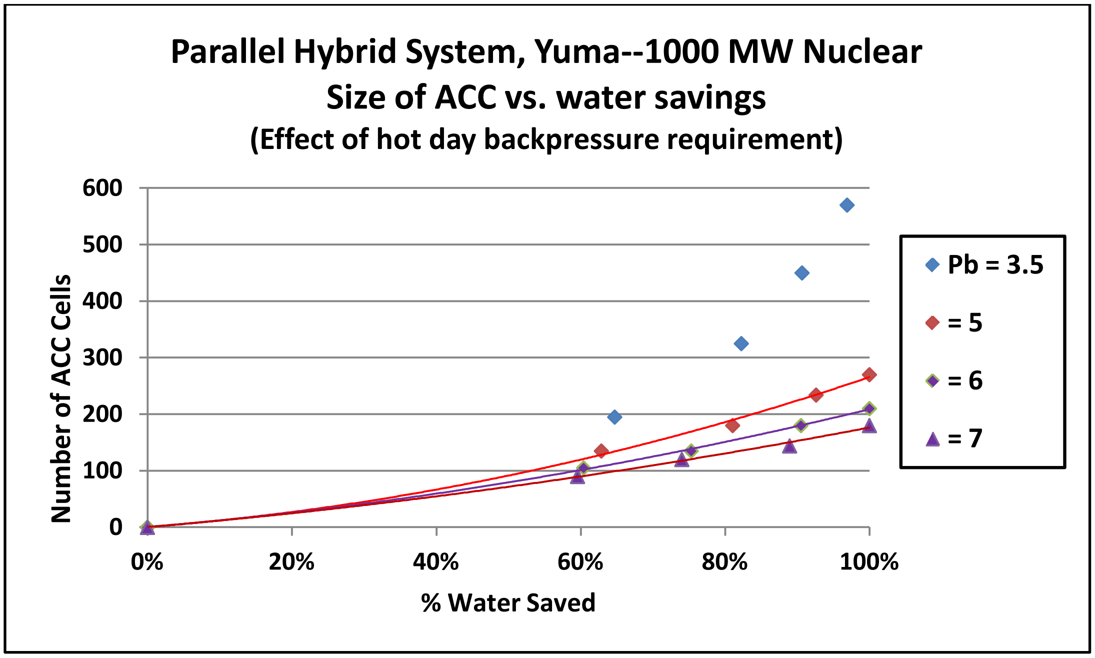

Figure 5-6
ACC Size Comparisons for dry element of parallel wet/dry hybrid system

For design hot day backpressures of 5, 6 or 7 in Hga (16.9, 20.3, or 23.7 kPa) at a hot day design temperature of 110°F (43.3°C), the required size increases by a factor of 2 to 3 as the water savings rise from 50% to 100%. For a design hot day backpressure of 3.5 in Hga (11.9 kPa) the condensing temperature is 120°F (48.9°C) and the required ACC size, air flow and fan power are extremely high (approaching an infinite limit at a backpressure of 2.6 in Hga (8.8 kPa) for which the condensing temperature is equal to the design ambient temperature. The installed cost of the cooling system in Figure 5-7 follows the same pattern and, as noted earlier, becomes exorbitantly high for water saving above about 80%. Again, the costs for the all-dry systems correspond to the values tabulated in Tables 5-6 and 5-8.

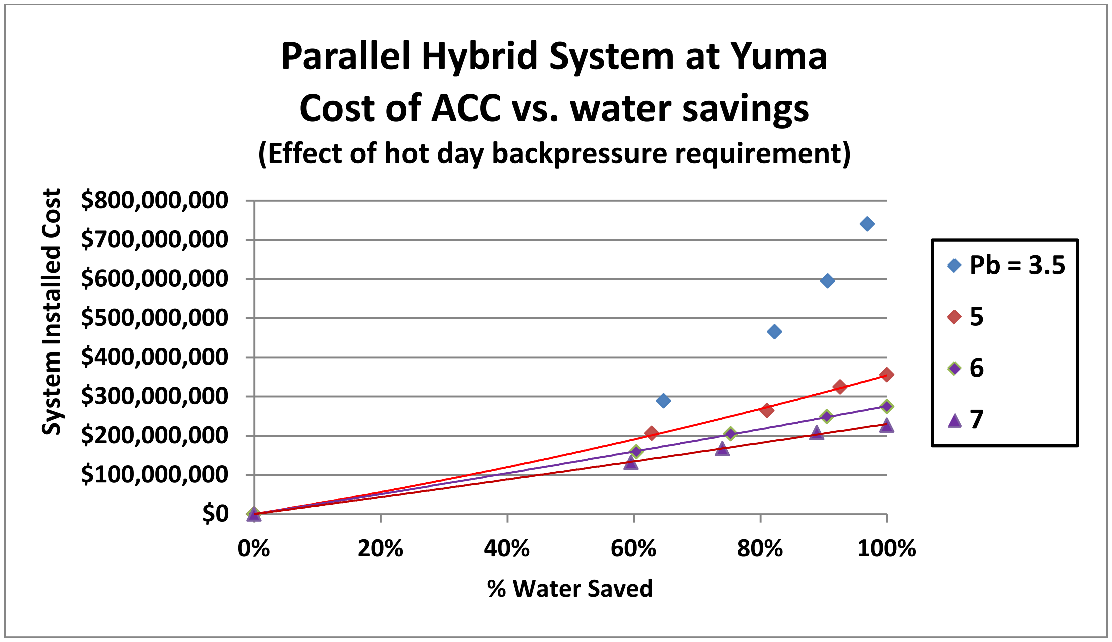

Figure 5-7
ACC Installed Cost Comparisons

Table 5-13 sheds light on the source of the cost/performance benefits of hybrid cooling. The hybrid systems maintain a low turbine output penalty with the selective use of the wet tower during the hotter hours without excessive use of ACC fan power resulting in very similar power penalty costs of a range of water savings and a range of hot day backpressures. This is illustrated in Table 5-13 for the cases of a 5 in Hga hot day backpressure at Yuma. The all-dry system, on the other hand, experiences both high penalty costs and high fan power costs to meet the desired hot day backpressure levels with power penalty costs 2 to 5 times those of the hybrid systems.

Table 5-13
Variation in cost components for hybrid system

System	Yuma Site---5 in Hga Hot Day Backpressure				
	Power Cost	Penalty Cost	Annualized Cost	Installed Cost	% Savings
All-wet	$9,255,000	$0	$12,060,000	$34,800,000	0.00%
Hybrid--50%	$21,651,000	$1,824,000	$40,095,000	$206,250,000	62.9%
Hybrid--67%	$23,034,000	$1,644,000	$45,978,000	$264,270,000	81.1%
Hybrid--85%	$24,729,000	$1,470,000	$52,329,000	$324,240,000	92.6%
All-dry 5"	$27,075,000	$1,179,000	$56,904,000	$355,350,000	100.0%
All-dry 7"	$23,301,000	$6,903,000	$48,504,000	$226,980,000	100.0%

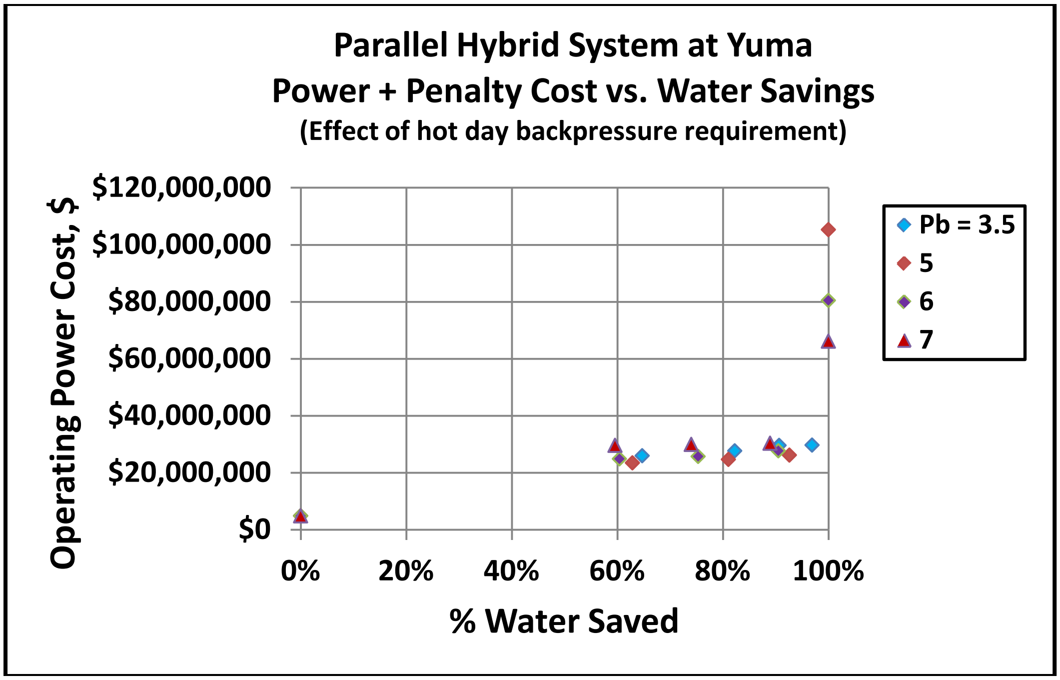

Figure 5-8
Power and Penalty Cost Comparisons

Finally, the annualized costs (Figure 5-9), which include the amortized cost of capital plus operating and penalty costs merge more smoothly with the all-dry costs and are 20 to 30% less at 60% water savings.

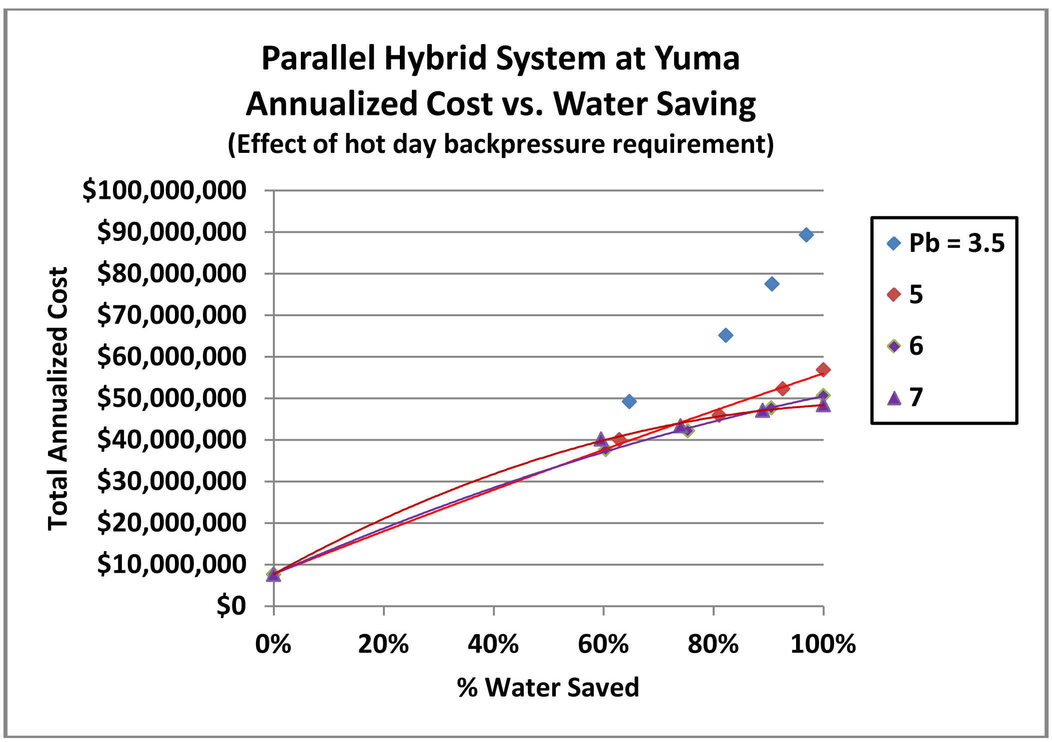

Figure 5-9
Annualized Cost Comparisons

Similar trends are seen for the cooling systems at Jacksonville and Green Bay. Illustrative comparisons among the three sites are displayed for the cases of a 5 in Hga hot day backpressure and hot day dry element capabilities of 50%, 67% and 85%. Figures 5-10 through 5-12 present comparisons of the installed costs, the power and penalty costs, and the annualized cost, respectively. The all-wet and the all-dry cases (sized for a 7 in Hga hot day backpressure) are both included on each chart. The tabulated values are listed in Table 5-14.

The discontinuities between the curves defined by the all-wet and hybrid system costs and the all-dry system cost are a result of differences in the choice of design points. The hybrid systems are sized for a hot day backpressure of 5 in Hga while the all-dry system is sized for a hot day backpressure of 7 in Hga. These design choices were selected to be those that were considered to be the most likely for each system type.

For the hybrid system with the greatest water savings, the ACC required to carry 85% of the load at 5 in Hga is larger, and hence more costly, than the ACC capable of carrying the full load at 7 in Hga. At water savings in the range of 80%, the cost of hybrid systems is similar to or greater than the cost of an all-dry system. The only advantage to a hybrid system in those situations is the ability to deliver maximum unit output at the hottest (peak-load) hours of the year.

The more relevant comparison on Figures 5-10 through 5-12 is that among the three sites. The large increase in installed cost for the Yuma site compared to the other two sites is the result of the significantly higher hot day ambient temperature requiring a much larger ACC for the same heat load capability. The leveling off or diminishing of the power/penalty costs is related to the temperature distribution curves for each site. Green Bay, for example, has long periods when the ambient temperature is low enough to allow the larger ACCs (those for the hybrid systems with greater water savings) to operate with some fans shut off while still maintaining a 2 in Hga backpressure.

The discontinuity in the annualized costs at the all-dry points differ between Yuma and Green Bay because the annualized cost for Yuma is dominated by the high capital cost while at Green Bay, the operating costs have a greater effect.

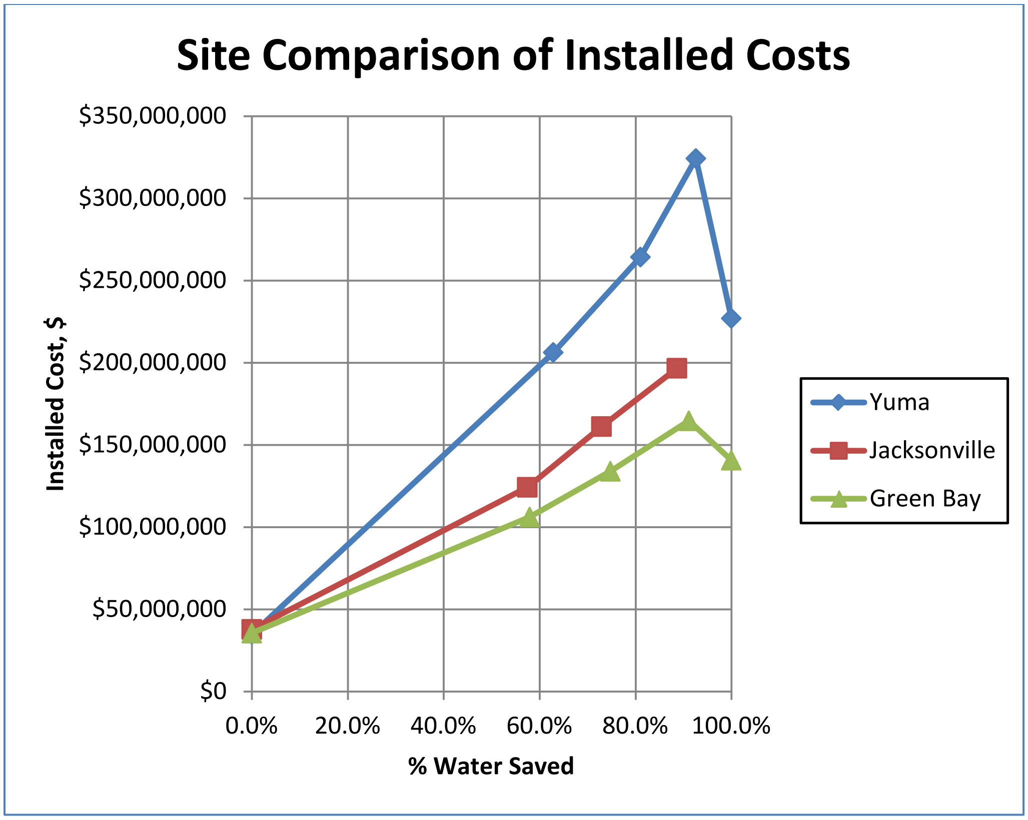

Figure 5-10
Installed Cost Comparisons for All Sites

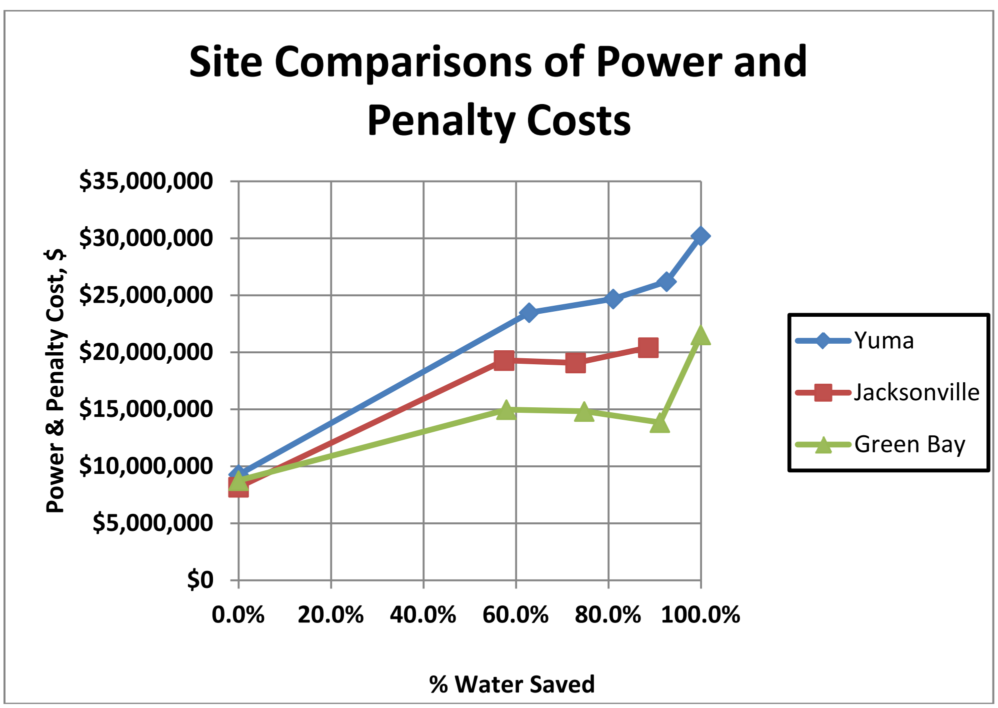

Figure 5-11
Power and Penalty Cost Comparisons for All Sites

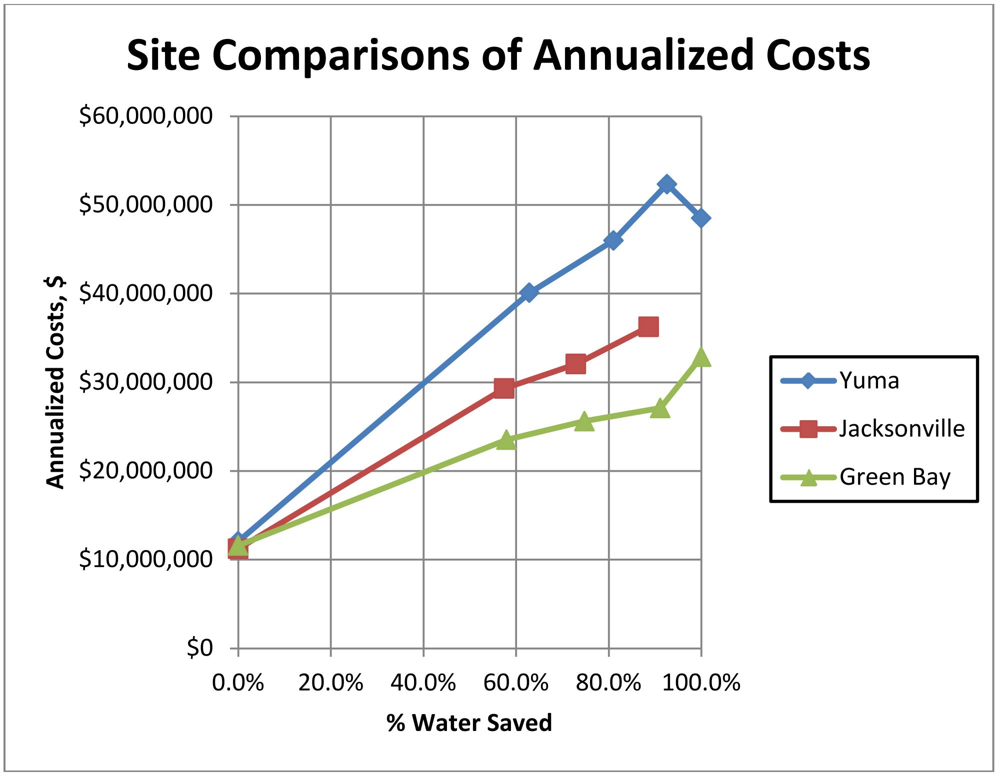

Figure 5-12
Annualized Cost Comparisons for All Sites

Table 5-14
Cost comparison among sites

Site/Cost	Wet---3.5 in Hga	Hybrid---5 in Hga			Dry---7 in Hga
		50%	67%	85%	
Yuma					
Installed cost	$34,800,000	$206,250,000	$264,270,000	$324,240,000	$226,980,000
Power + Penalty	$9,270,000	$23,475,000	$24,678,000	$26,199,000	$30,204,000
Annualized	$12,060,000	$40,095,000	$45,978,000	$52,329,000	$48,504,000
Jacksonville					
Installed cost	$37,800,000	$124,230,000	$161,190,000	$196,650,000	
Power + Penalty	$8,163,000	$19,278,000	$19,068,000	$20,406,000	
Annualized	$11,223,000	$29,298,000	$32,058,000	$36,246,000	
Green Bay					
Installed cost	$35,490,000	$106,140,000	$133,950,000	$164,670,000	$140,700,000
Power + Penalty	$8,742,000	$14,973,000	$14,811,000	$13,833,000	$21,531,000
Annualized	$11,592,000	$23,523,000	$25,611,000	$27,093,000	$32,871,000

Figures 5-13 and 5-14 present additional detail on the breakdown of the installed and operating costs into the several components of each and the variation with the amount of water saving. The installed costs are dominated by the cost of the ACC in all cases even at moderate water conservation. Similarly, the operating cost of the ACC significantly exceeds the turbine penalty in all cases. However, it is noteworthy that most of the turbine penalty for the all-dry case occurs on the hottest days of the year where the demand for energy is typically the greatest. For the hybrid cases, the turbine penalty on the hot days is essentially eliminated on the hot days by the wet element but accumulates during the year at intermediate ambient temperatures and increases as the water savings decrease because of the reduced size of the ACC.

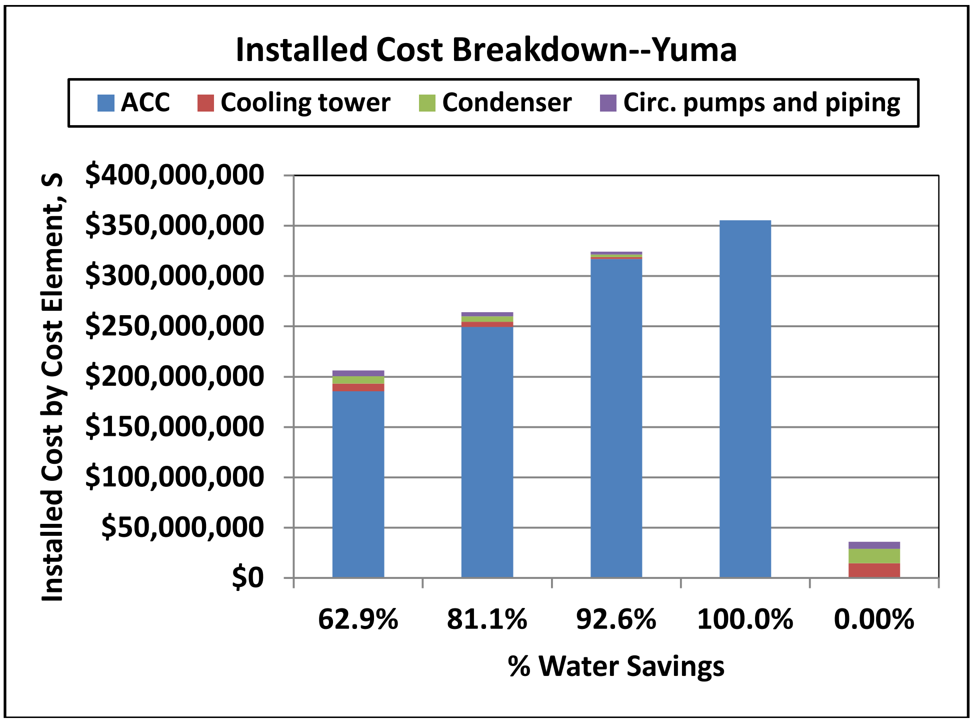

Figure 5-13
Installed Cost Components at Yuma

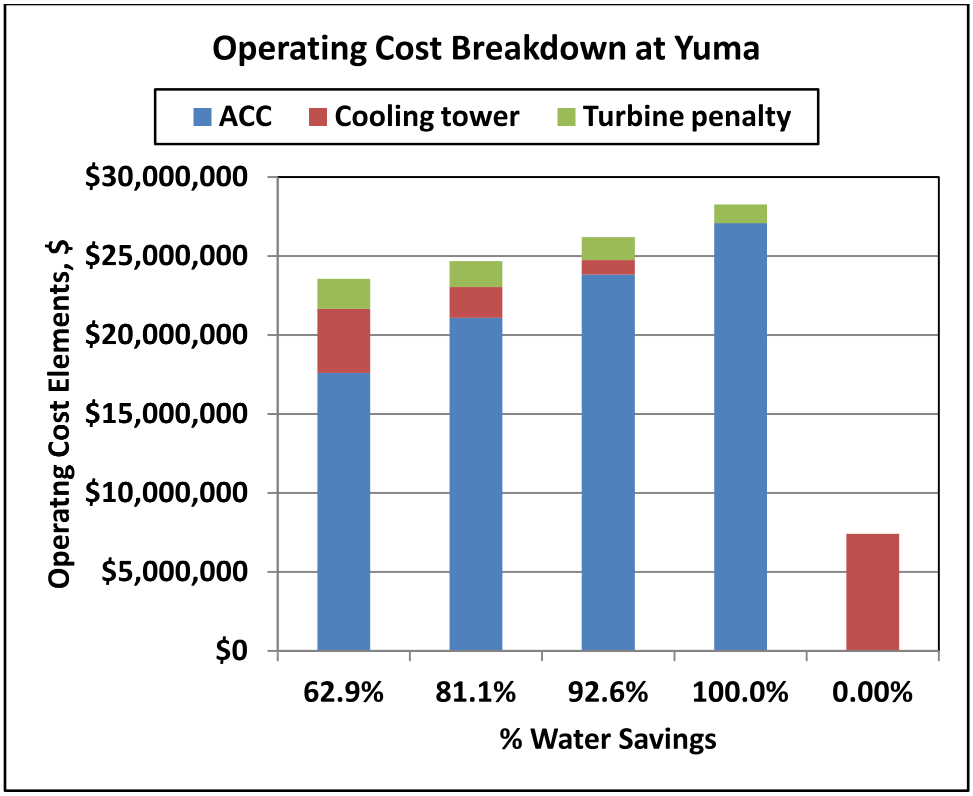

Figure 5-14
Operating Cost Components at Yuma

Wet/dry systems with indirect dry cooling elements (ACHEs)

Given the questions raised previously about suitability of direct dry cooling with ACCs on nuclear plants, the preferred hybrid system may be designed with ACHEs for the dry elements. A stand-alone hybrid tower with the wet and dry elements in a single structure has operated on a fossil plant since the 1970's and was described earlier (see Figures 2-23 and 2-24).

A system of this type for use on a nuclear unit was considered for the proposed Unit 3 at Dominion's North Anna plant. The system has been described in a presentation by Dominion and consisted of an all-dry ACHE in series with a hybrid wet/dry tower with an ACHE at the top discharging into a wet cooling tower underneath. A schematic and an artist's rendition of the proposed North Anna configuration were displayed in Figures 2-26 and 2-27. Both systems allow for a bypass of the wet portion of the hybrid tower for all dry operation when feasible.

These wet/dry (indirect) systems can be arranged with the elements in series or in parallel as shown schematically in Figures 5-15 and 5-16. In the series arrangement (Figure 5-15), provision is made to allow bypassing the wet tower when it is not required. Similarly, in the parallel arrangement (Figure 5-16) both the wet and the dry elements can be bypassed if conditions warrant. Also, the arrangements, as shown, are divided into three independent "trains" and the system can be operated on all three, two or only one if "full" train bypass capability (not shown) is provided. For designs for which less water saving is desired, the dry elements can be omitted for one (or even two) of the trains as shown in Figure 5-17.

Previous analyses conducted by the authors have shown that the preferred configuration is always a series arrangement where the highest temperature cooling water coming from the condenser passes first through the dry portion in order to achieve the highest possible temperature difference between the cooling water and the ambient temperature prior to any wet cooling. Therefore, the following discussion will focus on the series arrangement.

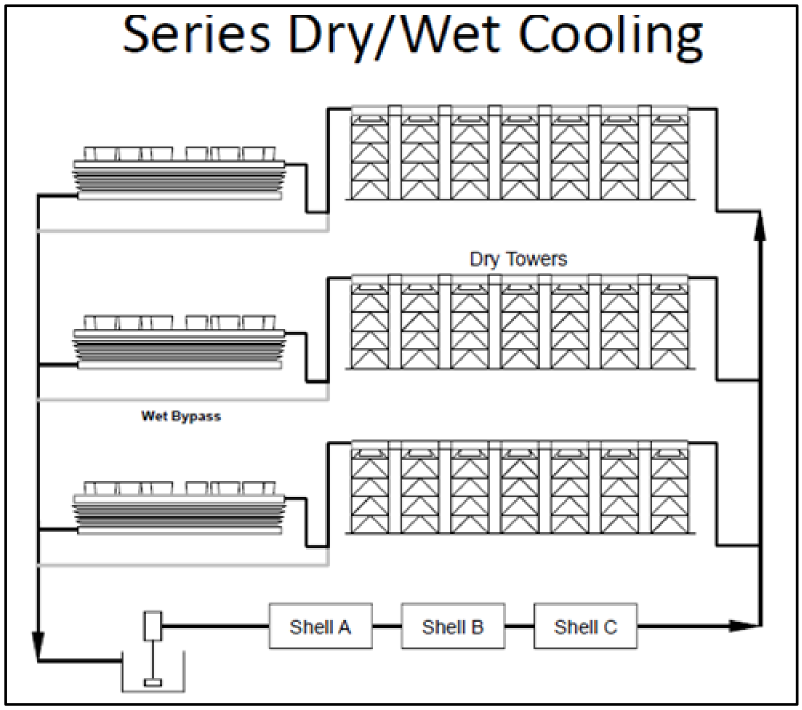

Figure 5-15
Schematic of series wet/dry (indirect) hybrid

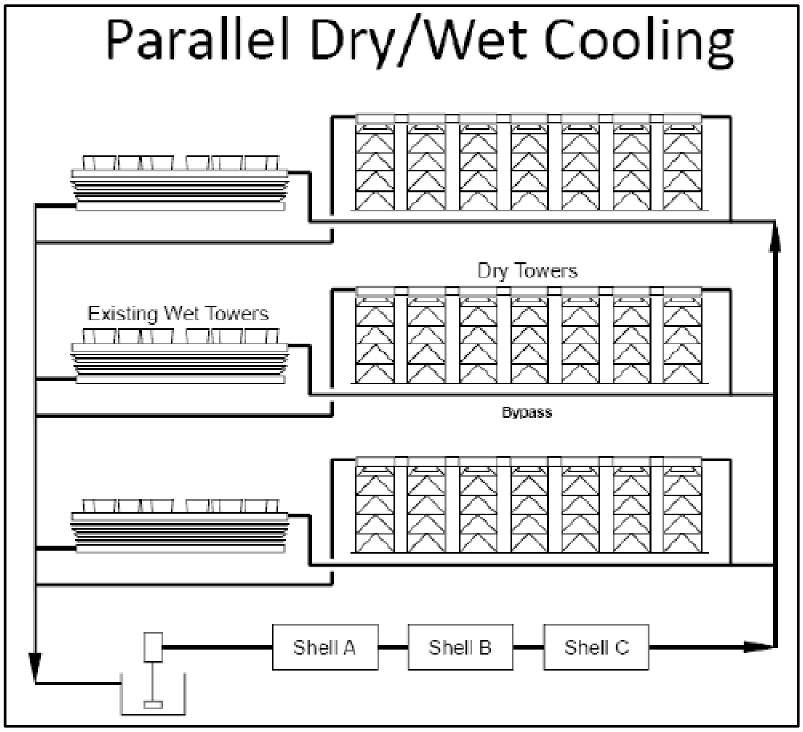

Figure 5-16
Schematic of parallel wet/dry (indirect) hybrid

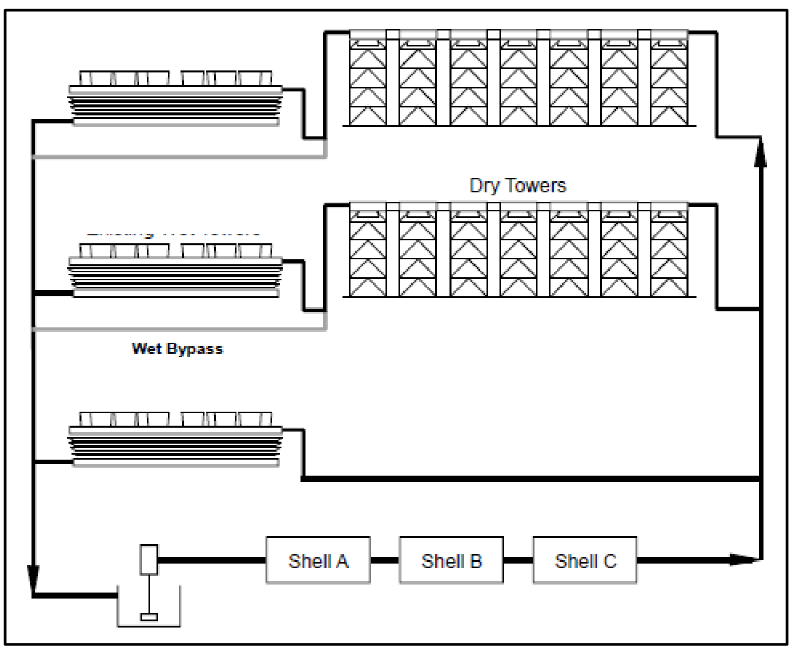

Figure 5-17
Alternate arrangements with reduced dry capability

Figures 5-18 through 5-21 show comparisons among the two configurations and two alternative operating strategies, identified as “seasonal” and “daily”. These options recognize the fact that, even during the hot summer days, there can be periods during the night where the temperature drops to the point that the dry elements can maintain design performance. However, re-directing the large circulating flows on a "daily" basis can be a formidable operating and maintenance challenge. The "seasonal" option keeps the wet elements in service full time during all the months during which the ambient temperature exceeds some specified temperature even if only for a few hours. For all other months, the wet elements are by-passed and returned to service only when the hot weather returns in the spring or early summer.

Figure 5-18 compares the annual water use for a large nuclear unit in the southwestern United States. Three observations are noteworthy. First, the series arrangement provides the greatest water savings in all configurations with the greatest savings achieved with the greatest number of dry elements. Second, the seasonal operation is essentially the same for all cases since the operating strategy specifies that the wet towers be kept in operation for the same period of time for all cases and, in the cases where one or two of the trains have no dry elements, the wet elements are run the entire year. Finally, the "daily" operating strategy can always take advantage of more hours per year of dry operation if it can be implemented, but may not be a practical operating method.

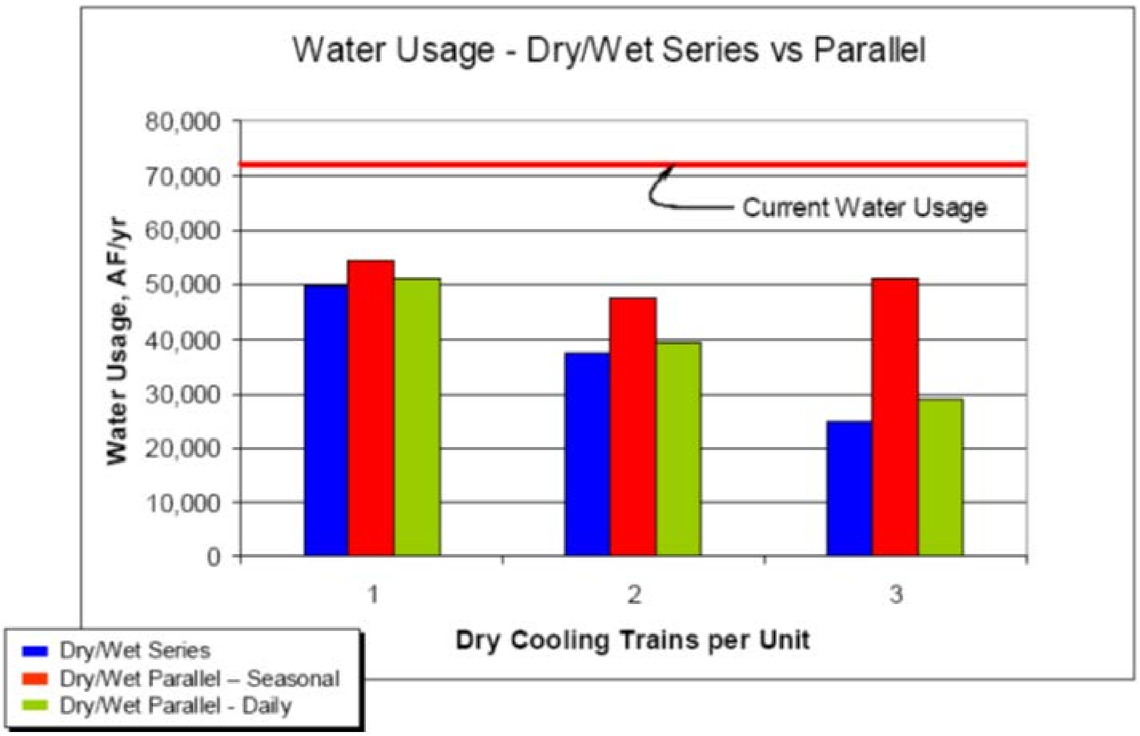

Figure 5-18
Comparative water usage for alternate hybrid systems

Figure 5-19 compares the annual <u>gross</u> output of the different cases. While both the series and the "seasonal" parallel arrangements are consistently higher than any of the "daily" parallel arrangements, it is noted that the differences, as a percentage of gross output are very small and not significantly less (about 0.25%) than the all-wet output.

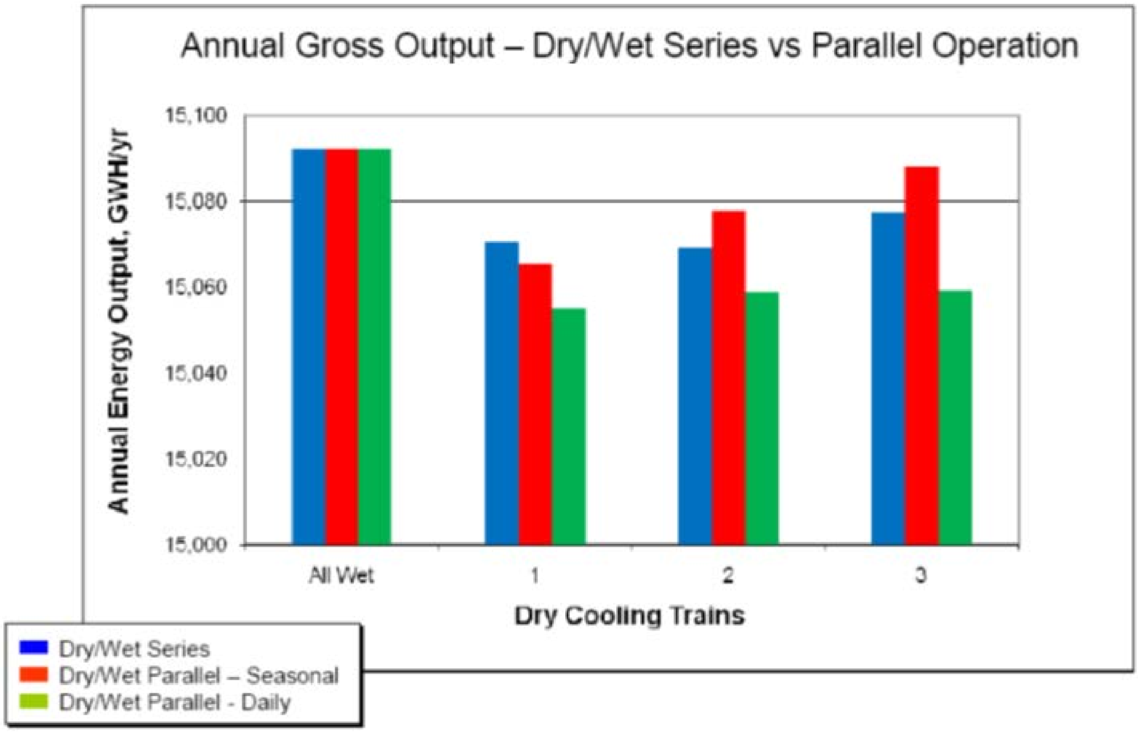

Figure 5-19
Comparative annual output for alternate hybrid systems

A more significant difference among the systems results from the operating power requirements which result in a reduction of the net output. These differences are shown in Figure 5-20. As would be expected, the series arrangement where the entire cooling water flow must be pumped through the ACHE all the time requires higher annual operating power than either of the parallel arrangements where the dry system is bypassed for some portion of the year.

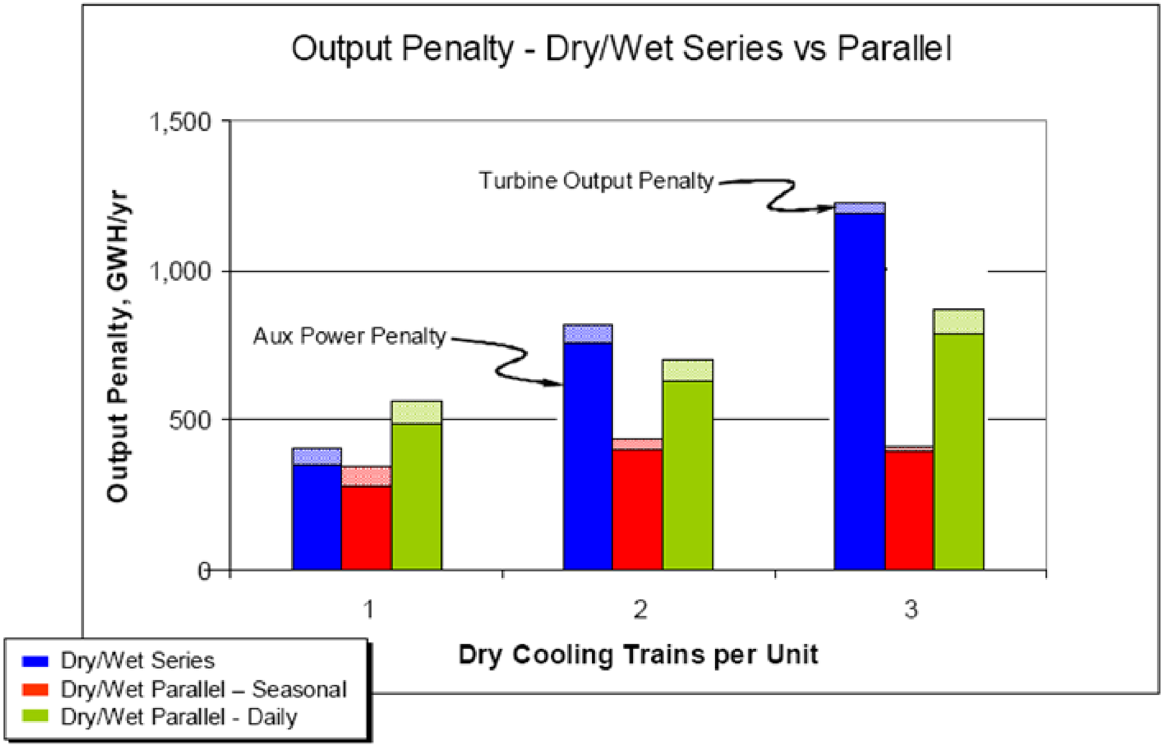

Figure 5-20
Comparative output penalty for alternate hybrid systems

The system costs are tabulated in Table 5-15. The cost is the same for either the series or parallel arrangement.

Table 5-15
Estimated capital cost of hybrid system with indirect dry elements

Cost Element	Capital Costs of Installation ($)		
	1 Train	2 Trains	3 Trains
Dry Cooling System	230,000,000	460,000,000	690,000,000
System Installation	173,000,000	311,000,000	466,000,000
Building Relocation	13,000,000	90,000,000	90,000,000
Circ. Pump Upgrade	1,000,000	1,000,000	1,000,000
Pipe and Valve Vaults	2,300,000	4,600,000	7,000,000
Estimated Total	419,000,000	866,000,000	1,254,000,000

Heller system

The Heller system was originally conceived as an alternate approach to dry cooling. It was named after its inventor, Dr. Lazlo Heller, in the 1940's in Hungary. The basic Heller all-dry design approach is conceptually similar to indirect dry cooling where turbine exhaust steam is condensed in a water cooled condenser and the heated condenser cooling water is cooled in an air-cooled heat exchanger.

It differs in two significant ways from the standard indirect dry cooling system.

1. The steam is condensed in a direct-contact (DC) condenser.[57]
2. The air-cooled heat exchangers are installed in a natural-draft tower rather than the more normal fin-fan or mechanical-draft type.

The benefits include:

- a more effective condensation step which achieves a lower condensation temperature and pressure for a given cooling water temperature than does a comparable surface condenser
- lower operating power than is required for a mechanical-draft air-cooled heat exchanger or for a conventional A-frame air-cooled condenser.

In addition, there are a number of hybrid or wet/dry variations on the all-dry design.

An extensive discussion of the application of this system to nuclear plants is given in a recent paper.[58] An important point which was emphasized in that paper is the need to maintain or increase the isolation between the primary nuclear circuit and the environment. Figure 5-21, excerpted from that paper, compares four alternative cooling systems on the basis of the degree of that isolation provided. The two systems on the left, direct dry cooling and the "conventional" Heller system both extend the steam cycle footprint or the region to which contaminated steam might spread, to the final cooling element. In the case of the ACC, the time in which the spreading occurs is measured in seconds. In the Heller system, it proceeds more slowly but occurs in a few minutes. The all-wet system on the upper right is commonly used on nuclear plants throughout the world. In this case, the cooling water is in direct contact with the environment but is separated from the steam during normal operation by the tubes of the surface condenser. The modified Heller system on the lower right is completely isolated by the tubes in the air-cooled heat exchanger where the final discharge of the reject heat to the environment occurs.

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[57] Sometimes referred to as a "barometric" or "spray" condenser.
[58] Balogh, A. and Z. Szabo, "Dry and Dry/Wet Cooling May Enhance Economy and Realize Ultimate Environmental Compatibility for Nuclear Power Generation", Presented at 8th Annual China Nuclear Energy Congress, Beijing, China, May, 2012.

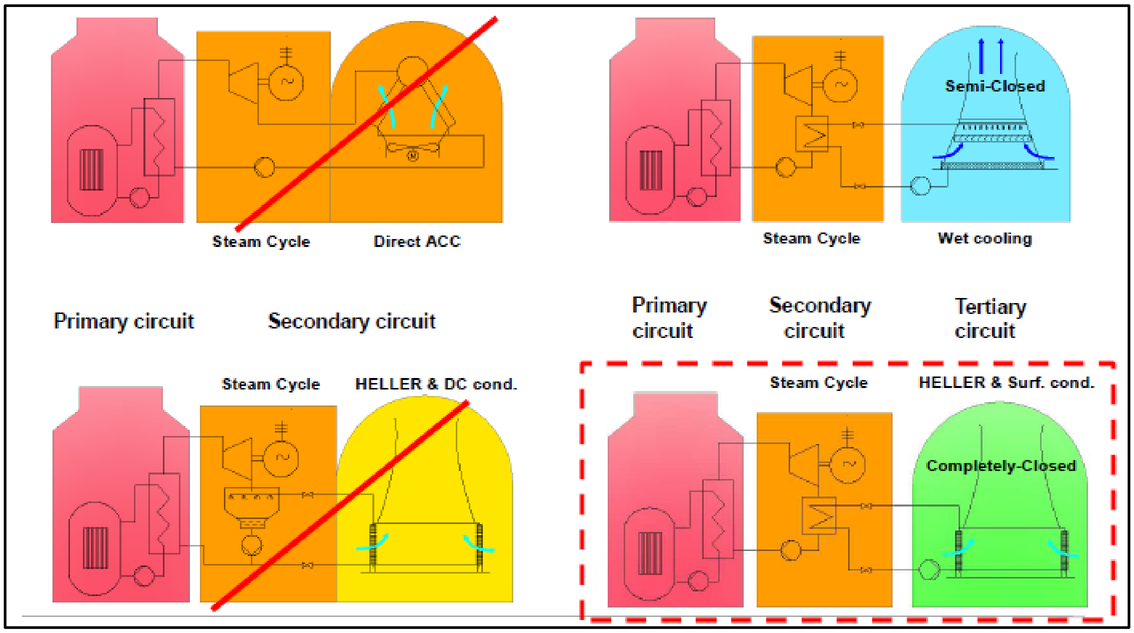

Figure 5-21
Preferred arrangement for Heller/Indirect dry cooling

However, in the all-dry configuration the system is simply an indirect dry cooling system with a natural-draft tower as was described and discussed in an earlier section. A number of options for enhancing the dry system performance with wet enhancement are also discussed. Figure 5-22, also excerpted from the EGI paper, illustrates four possibilities.

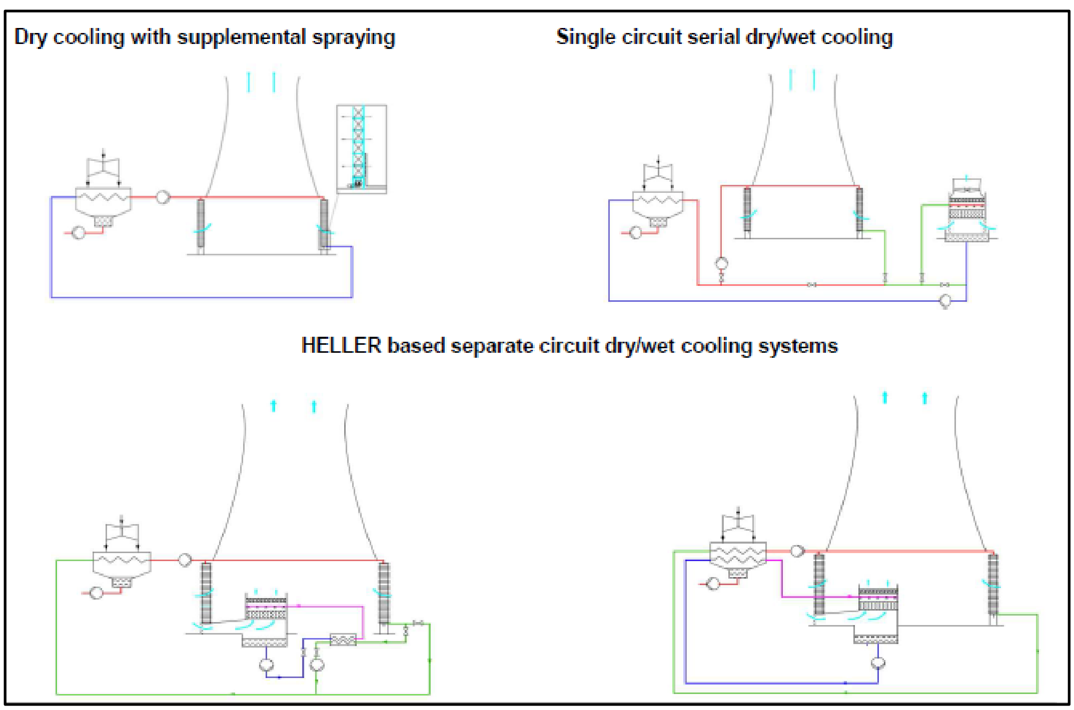

Figure 5-22
Wet augmented dry systems

The schematic at the top right represents a hybrid, wet/indirect dry system with a natural draft tower which can be run with either element by-passed. The one on the top left is an indirect dry system with spray enhancement. This approach will be discussed briefly in the next section in connection with spray-enhanced ACCs.

The two on the bottom represent hybrid combinations of indirect dry and wet cooling systems with the innovative approach of using the draft of the large dry tower to provide air to the wet elements. Figures 5-23 and 5-24 provide some overall cost performance comparisons but no detailed data is available to understand or confirm the results.

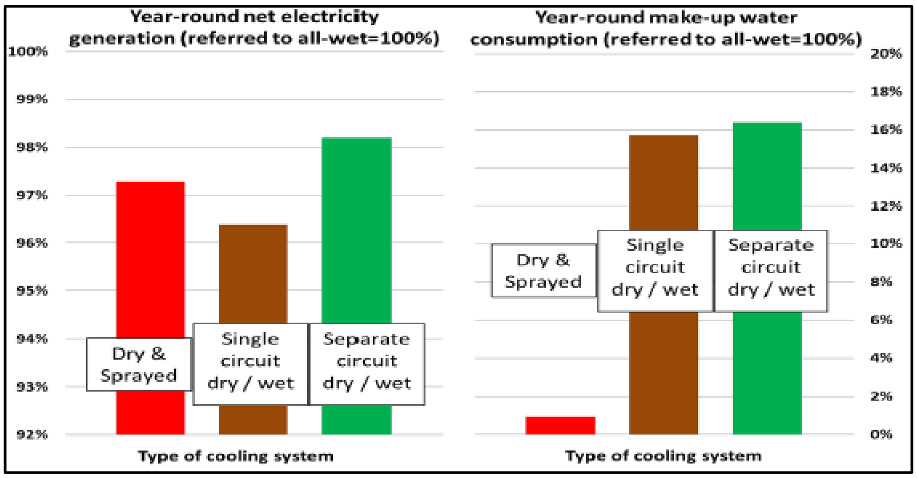

Figure 5-23
Comparative output and water use for alternate Heller systems

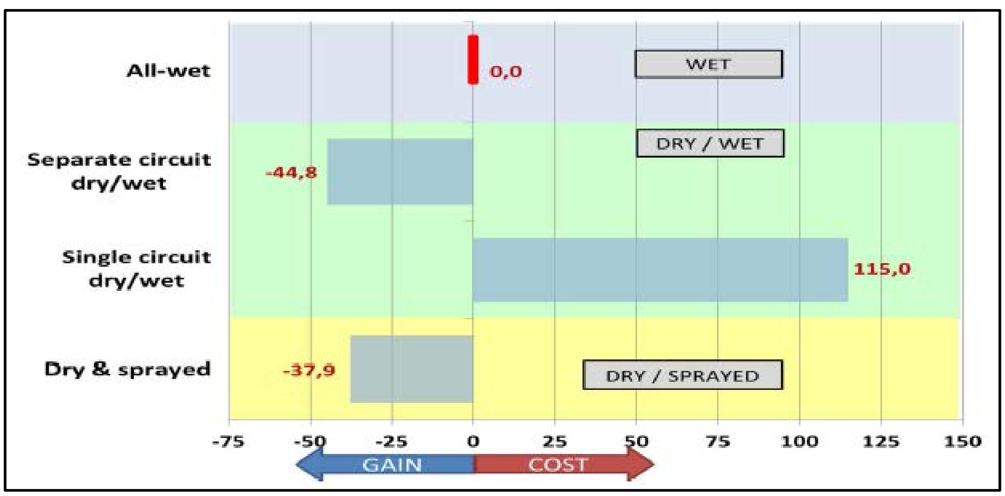

Figure 5-24
Annualized cost comparisons for alternate Heller systems

Spray-enhanced dry cooling

An extensive discussion of wet-enhanced dry cooling in which spray water is introduced into the inlet air stream was provided in Section 2. The usual approach taken with this system is to enhance the performance of an ACC originally designed for all-dry operation and to reduce the achievable backpressure during the hotter hours of the year. In one instance at the Kogan Creek plant in Australia, the spray system was included in the original design and the benefit was taken in the form of a smaller ACC. While no direct information is available on the savings achieved with the addition of sprays, there is one instance of a vendor-estimated comparison of a conventional ACC against one with spray enhancement. Both were designed to the same hot day backpressure, and a much smaller and less expensive ACC was enabled with the use of sprays.

Table 5-16 shows the comparative size and costs of the two systems. While, as noted in previous studies of spray enhancement[59], there are a number of practical issues related to maintenance, water treatment and the environmental effects of water falling to the ground, the system has attractive costs at comparable performance. It is a low capital cost system but one which is inefficient in the use of water in comparison to the more engineered parallel or series hybrid systems. Therefore, it is most suitable for situations in which the enhancement is necessary for only a few (~hundreds) hours per year.

Table 5-16
Cost elements for ACC and ACC with spray enhancement

Cost/performance elements	ACC	ACC with Inlet Spray (AIFS)
Design ambient temperature	122	
Design backpressure, in Hga	7.4	
No. of cells	300	150
Capital cost, $ millions	361.	181.
Replacement cost, $ millions/yr	15.	7.5
O & M cost, $ millions/yr	36.	18.
Annual water use, acre-feet	0	251
Water savings (vs. wet), ac-ft	24,362	24,111 (% of all-dry)
Net generation, GWh	11,750	11,627 (% of all-dry)

[59] Crockett and Bighorn

6
SUMMARY AND CONCLUSIONS

Current systems

Nuclear plant cooling systems require significant amounts of water. Of the 102 nuclear units currently operating at 63 plants in the U.S., 66 are on once-through cooling and 36 on closed-cycle wet cooling with cooling towers.

The units on once-through cooling withdraw from 500 to 1000 gpm per MWe of water which is heated 20 to 30°F (11.1 to 16.7°C) in the steam condenser and then returned to the environment. The units on closed-cycle wet systems cool the condenser discharge water in a cooling tower and recycle the cooled water back to the condenser inlet. The cooling in the tower is achieved by evaporating a small fraction (typically 2 to 3%) of the circulating water. Therefore, the water withdrawn from the environment is only that required to make-up for evaporation and blowdown, typically less than 5% of the water withdrawn for once-through cooling. However, most of water withdrawn is evaporated and therefore lost to the local environment. Once-through cooling incurs some consumptive loss due to increased evaporation from the surface of the receiving waterbody as a result of the heated water discharge. Estimates of this consumptive loss vary but are often less than one-half of that for closed-cycle systems.

Advanced cooling systems

Advanced or modified cooling systems are considered in two contexts: new plant construction and existing plant retrofit.

Retrofit

Consideration of cooling system retrofits for nuclear plants is limited to the retrofit of once-through cooled plants to closed-cycle wet cooling. The retrofit of closed-cycle cooling systems to water-conserving systems of the all-dry or hybrid type is unlikely. Limited studies have shown such conversions to be extremely costly and would likely be considered only in exigent circumstances where a valued plant might be forced to close unless its consumptive water use could be dramatically reduced.

The retrofit of once-through cooled plants to closed-cycle cooling is receiving attention as a result of regulatory pressure under Section 316(b) of the Clean Water Act. Estimates of the capital costs of retrofit, assuming conversion to closed-cycle wet cooling using mechanical-draft cooling towers, range from $200/gpm to $850/gpm (based on the circulating water flow rate of the existing once-through cooling system) with one extreme case estimated to exceed $1200/gpm.

The total capital cost of retrofit of the 48 nuclear plants on once-through cooling was estimated at just under $20 billion. This, plus additional costs including increased cooling system operating power, plant performance penalties of increased heat rate and reduced hot weather output and replacement energy during plant downtime during the retrofit project, are estimated at $3 billion in annualized cost and just under $32 billion in net present value.

New plant construction

Many alternate water-conserving cooling systems were considered. The list of these systems from Chapter 5 is reproduced here for convenience of reference.

- Closed-cycle wet cooling
  - Mechanical-draft towers
  - Natural-draft towers
- Direct dry cooling
  - Air-cooled condensers
    - Mechanical-draft, A-frame condensers
    - Natural-draft towers
- Indirect dry cooling
  - Mechanical-draft dry towers (air-cooled heat exchangers)
  - Natural-draft dry towers
- Hybrid wet/dry cooling (separate structures)
  - Series or parallel
  - Alternative wet elements
    - Mechanical-draft
    - Natural-draft
  - Alternative dry elements
    - Direct dry (ACCs)
    - Indirect dry (ACHEs)
      - Mechanical-draft
      - Natural draft
- Hybrid wet/dry cooling (integrated single structure)
  - Mechanical-draft
  - Natural-draft assisted
- Special topics
  - Dry Heller system
    - Heller system with spray assist and deluge coolers
  - Spray-assisted dry cooling
    - ACCs with spray inlet cooling

Cost/performance and water consumption estimates were made for an 1100 MWe (gross) nuclear unit .for those cooling systems for which adequate data were available. Estimates were made at three sites (Yuma, AZ, Green Bay, WI and Jacksonville, FL) with differing climates.

The results are briefly summarized as follows.

- Closed-cycle wet cooling…mechanical-draft towers

  Capital costs ranged from $35 million at Yuma to $38 million at Jacksonville; total annualized costs, from $12 million at Yuma to 11 million at Jacksonville. The Yuma site, which had the lowest capital cost, incurred the highest annualized cost as a result of higher operating and unit penalty costs. Water consumption for cooling was highest in Yuma at 20,300 acre-feet per year and lowest in Green Bay at 16,000 acre-feet per year.

- Closed-cycle wet cooling…natural-draft towers

  Capital cost estimates ranged from nearly equal to mechanical-draft systems to as much as 25 to 50% higher. No reliable cost information on natural-draft towers is currently available in the public domain. Annual savings in power cost can be as high as $5 million.

- All-dry (direct) cooling…mechanical-draft ACCs

  Capital cost ratios of all-dry to all-wet systems with mechanical-draft towers ranged from 5 in Jacksonville to 10 in Yuma for units equipped with conventional nuclear turbines with backpressure limit of 5 in Hga. Annualized cost ratios varied from 2.8 to 4.8. If turbines with extended backpressure capability up to 7 in Hga were available, the cost ratios would be significantly reduced to 4 in Green Bay to 6 in Yuma. Annualized cost ratios varied from 2 to 4 with the extended backpressure turbines.

- All-dry (direct) cooling…natural-draft ACCs

  None exists. One is in construction, but no cost or performance information is available.

- All-dry (indirect) cooling…mechanical-draft ACHEs

  Cost estimates from prior EPRI studies are based on comparisons of direct and indirect dry cooling for both a 500 MWe coal plant and a 600 MWe nuclear plant. The capital costs of the indirect dry systems ranged from 5% to 25% higher than the comparable direct dry systems, but the total annualized costs were 60% to 70% higher due to significantly higher operating power requirements and unit performance penalties. Operating costs were 1.8 to 3 times higher for the mechanical-draft indirect systems and the unit penalties were 2.3 to 3 times higher.

- All-dry (indirect) cooling…natural-draft ACHEs

  A recent study of indirect dry cooling at a large nuclear plant included both mechanical- and natural-draft systems. The results indicated costs of the natural draft towers to be 25% to 30% higher than the mechanical-draft towers. The reduction in operating per compensated for the higher capital costs and indicated that the annualized total costs of the two systems were nearly equal.

- Hybrid wet/dry systems

  Hybrid systems, consisting of both wet and dry elements, can be configured in several ways. The wet and dry sections can be in parallel or in series. The dry element can be direct dry cooling with an ACC or indirect dry cooling with an ACHE. Both elements can be either mechanical- or natural-draft.

  The most common arrangement to date is a parallel wet/dry system with an ACC for the dry element. For the case of 50% water savings and hot day back pressures ranging from 5 to 7 inHga, the system installed costs are approximately 60% of those of an all-dry system. Total annualized costs show similar comparison with all-dry cooling.

Hybrid systems for nuclear units may be constrained to use indirect dry cooling with ACHEs. In these systems the wet and dry elements can be arranged in series or in parallel. While a number of design trade-offs are possible, the series arrangement typically provides more water saving at comparable gross energy output. The installed system cost of the series arrangement with indirect dry cooling is slightly higher than the cost of the parallel wet/dry system with direct dry cooling.

- Special systems

  Additional options for water-conserving systems are the Heller system which is available in several configurations and spray-enhanced air-cooled condensers.

  The Heller systems typically save up to 85% of the water consumed by all-wet systems while delivering 96 to 98% of the net annual energy output. While these systems are used in numerous applications throughout the world (See Appendix A), there are none currently operating on power plants in the US. No directly comparable cost estimates are available, but several presentations indicate that they are reasonably competitive with air cooled condenser systems.

  Spray enhancement which historically has been used to boost performance of an existing ACC on hot days can also be incorporated into the design of a new unit to reduce the size and cost of the ACC. One estimate indicated that the ACC size and cost could be reduced by 50% providing a 99% reduction in water use with annual energy output essentially identical to that of an all-dry system.

Nuclear-specific issues

Cooling systems for nuclear units face some constraints and demands over and above those for fossil units. For the main plant condenser cooling system:

- The heat load per unit of plant energy output is higher.
- Nuclear turbines of currently available designs have lower backpressure limits and a higher sensitivity to increases in backpressure than do fossil turbines.
- The use of direct dry cooling with air-cooled condensers on nuclear units, especially BWRs, may not be acceptable.

In addition, special cold water temperature requirements and system reliability standards for nuclear plant systems including the ultimate heat sink, the spent fuel storage pool and other auxiliary cooling loads may necessitate extra equipment and cooling capability beyond the conventional main plant condenser cooling system.

A
APPENDIX

Heller System Installations

Ref. No.	Description	Country	Unit Power (MW)	Date Commissioned	Remarks
1.	Pilot plant	Hungary	0.8	1954	Mechanical draft
2.	Dunaújváros Steel Mill	Hungary	16	1962	Natural draft, with louvers
3.	Rugeley Power Station, Unit V.	UK	120	1962	Natural draft Decommissioned in 1994
4.	Eilenburg Chemical Works	Germany	5.3	1964	Mechanical draft
5.	Karaganda Steel Mill, Unit No. 1	Kazakhstan	6	1968	Mechanical draft, with movable shutter
6.	Karaganda Steel Mill, Unit No. 2	Kazakhstan	6	1968	Mechanical draft, with movable shutter
7.	Ibbenbüren Power Station	Germany	150	1967	Natural draft, with louvres
8.	Mátra (Gagarin) Power Station, Unit I.	Hungary	100	1969	Natural draft, with louvres and DC heater
9.	Mátra (Gagarin) Power Station, Unit II.	Hungary	100	1970	Natural draft, with louvres and DC heater
10.	Razdan Power Station, Unit I.	Armenia	210	1970	Natural draft steel tower with louvres
11.	Razdan Power Station, Unit II.	Armenia	210	1971	Natural draft steel tower with louvres
12.	Razdan Power Station, Unit III.	Armenia	210	1971	Natural draft steel tower with louvers
13.	Flötzersteig Incinerator	Austria	3	1970	Natural draft
14.	Mátra (Gagarin) Power Station, Unit IV.	Hungary	220	1972	Natural draft, with louvres and DC heater
15.	Mátra (Gagarin) Power Station, Unit V.	Hungary	220	1972	Natural draft, with louvres and DC heater
16.	Bilibino Nuclear Power Station Unit I.	Russia	12	1972	Mechanical draft , preheating, recirculation, surface condenser
17.	Bilibino Nuclear Power Station, Unit II.	Russia	12	1972	Mechanical draft , preheating, recirculation, surface condenser
18.	Bilibino Nuclear Power Station, Unit III.	Russia	12	1973	Mechanical draft , preheating, recirculation, surface condenser
19.	Bilibino Nuclear Power Station, Unit IV.	Russia	12	1973	Mechanical draft , preheating, recirculation, surface condense
20.	Razdan Power Station, Unit IV.	Armenia	210	1974	Repeat order, see Nos. 10 through 12
21.	Kaneka	Japan	60	1974	Induced mechanical draft dry tower with supplementary spraying
22.	Ivanovo Power Station, Unit V.	Russia	60	1978	Deluged dry tower with louvres
23.	Mátra (Gagarin) Power Station	Hungary	—	1981	LOTHUS system, green house heating

Ref. No.	Description	Country	Unit Power (MW)	Date Commissioned	Remarks
24.	Mátra (Gagarin) Power Station	Hungary	—	1983	LOTHUS system, green house heating
25.	Great Isfahan Power Station, Unit I.	Iran	210	1984	Steel tower with louvres and deluged peak coolers
26.	Great Isfahan Power Station, Unit II.	Iran	210	1985	Steel tower with louvres and deluged peak coolers
27.	Great Isfahan Power Station, Unit III.	Iran	210	1985	Steel tower with louvres and deluged peak coolers
28.	Great Isfahan Power Station, Unit IV.	Iran	210	1986	Steel tower with louvres and deluged peak coolers
29.	Solar Power Station	Ukraine	5	1986	Mechanical draft tower with surface condenser
30.	Trakya Power Station, Unit A.	Turkey	300	1986	One tower for two units deluged peak coolers
31.	Trakya Power Station, Unit B.	Turkey	300	1987	One tower for two units deluged peak coolers
32.	Datong Power Station, Unit V.	China	210	1987	Natural draft concrete tower with preheating system, three condensers per unit
33.	Datong Power Station, Unit VI.	China	210	1988	Natural draft concrete tower with preheating system, three condensers per unit
34.	Shahid Rajai Power Station, Unit I.	Iran	250	1992	Natural draft steel tower, with louvres and deluged peak coolers
35.	Shahid Rajai Power Station, Unit II.	Iran	250	1993	Natural draft steel tower, with louvres and deluged peak coolers
36.	Shahid Rajai Power Station, Unit III.	Iran	250	1993	Natural draft steel tower, with louvres and deluged peak coolers
37.	Shahid Rajai Power Station, Unit IV.	Iran	250	1994	Natural draft steel tower, with louvres and deluge coolers
38.	Trakya Power Station, Unit C.	Turkey	300	1988	Repeat order, see Nos 30 and 31
39.	Trakya Power Station, Unit D.	Turkey	300	1988	As above, see Nos 30 and 31
40.	Teshrin Power Station, Unit I.	Syria	210	1993	Natural draft steel tower, with louvres and deluged peak coolers

Ref. No.	Description	Country	Unit Power (MW)	Date Commissioned	Remarks
41.	Teshrin Power Station, Unit II.	Syria	210	1993	Natural draft steel tower, with louvres and deluged peak coolers
42.	Fengzhen Power Station, Unit III.	China	210	1993	Built by the Chinese licensee
43.	Fengzhen Power Station, Unit IV.	China	210	1994	Built by the Chinese licensee
44.	Privodino Compressor Station	Russia	15.8	1995	Mechanical draft with louvres
45.	Great Isfahan Power Station Extension, Unit V.	Iran	210	1995	Natural draft concrete tower with louvres
46.	Fengzhen Power Station, Unit V.	China	210	1995	Built by the Chinese licensee
47.	Fengzhen Power Station, Unit VI.	China	210	1996	Built by the Chinese licensee
48.	Great Isfahan Power Station Extension, Unit VIII.	Iran	210	1997	Natural draft concrete tower
49.	Kaneka	Japan	60	1997	T60 heat exchangers, 62 000m²
50.	Kaneka	Japan	60	1998	T60 heat exchangers, 62 000m²
51.	Mátra Power Station	Hungary	220	1998	Retrofitting
52.	Great Isfahan Power Station Extension, Unit VI.	Iran	210	1998	Natural draft concrete tower
53.	Great Isfahan Power Station Extension, Unit VII.	Iran	210	1999	Natural draft concrete tower
54.	Bursa Power Station Unit A.	Turkey	700	1999	Natural draft concrete tower for 700 MW CCPP with louvres and deluged peak coolers
55.	Bursa Power Station Unit B.	Turkey	700	1999	Natural draft concrete tower for 700 MW CCPP with louvres and deluged peak coolers
56.	Arak Power Station Unit I.	Iran	325	1999	Natural draft concrete towers with louvres designed by EGI, built by others
57.	Arak Power Station Unit II.	Iran	325	1999	Natural draft concrete towers with louvres designed by EGI, built by others
58.	Arak Power Station Unit III.	Iran	325	2000	Natural draft concrete towers with louvres designed by EGI, built by others

Ref. No.	Description	Country	Unit Power (MW)	Date Commissioned	Remarks
59.	Arak Power Station Unit IV.	Iran	325	2001	Natural draft concrete towers with louvres designed by EGI, built by others
60.	Montazer Ghaem Unit I.	Iran	320	1999	Natural draft concrete tower for 320 MW CCPP designed by EGI, built by others
61.	Montazer Ghaem Unit II.	Iran	320	2000	Natural draft concrete tower for 320 MW CCPP designed by EGI, built by others
62.	Montazer Ghaem Unit III.	Iran	320	2001	Natural draft concrete tower for 320 MW CCPP designed by EGI, built by others
63.	Additional Iranian power units, 18 pcs. similar CCPP	Iran	Σ = ~5760	2001-	Constructed by Iranians based on GEA EGI Montazer Ghaem CCPP cooling system design
64.	Al-Zara Power Station Unit I.	Syria	220	2001	Natural draft steel tower for 220 MW
65.	Al-Zara Power Station Unit II.	Syria	220	2001	Natural draft steel tower for 220 MW
66.	Al-Zara Power Station Unit III.	Syria	220	2001	Natural draft steel tower for 220 MW
67.	Újpest 100 MW CCPP	Hungary	100	2001	Forced mechanical draft dry/ deluged seasonal and auxiliary cooling tower
68.	Gebze 770 MW CCPP Unit I.	Turkey	770	2002	Natural draft concrete tower for 770 MW CCPP with louvres
69.	Gebze 770 MW CCPP Unit II.	Turkey	770	2002	Natural draft concrete tower for 770 MW CCPP with louvres
70.	Adapazari 770 MW CCPP Unit I.	Turkey	770	2002	Natural draft concrete tower for 770 MW CCPP with louvres
71.	CAN 160 MW CFB based Thermal Power Station, Unit 1.	Turkey	160	2004	Natural draft single concrete tower shell for 2 units, with louvres and deluged peak coolers
72.	CAN 160 MW CFB based Thermal Power Station, Unit 2.	Turkey	160	2004	Natural draft single concrete tower shell for 2 units, with louvres and deluged peak coolers
73.	Vértes CHP Seasonal Cooler	Hungary	18	2004	Forced mechanical draft dry seasonal cooling tower
74.	Sochi 72 MW CHP Unit 1.	Russia	72	2004	Mechanical induced draft fan cells with supplementary spraying and applying surface condenser
75.	Mátra Power Station, Unit IV.	Hungary	220+20	2006	Unit power augmentated also by converting all-dry cooling to a separate circuit dry-wet cooling system
76.	Mátra Power Station, Unit V.	Hungary	220+20	2007	Unit power augmentated also by converting all-dry cooling to a separate circuit dry-wet cooling system
77.	Yangcheng Phase II. Unit 7 600 MW Plant Extension	China	600	2007	Natural draft concrete cooling tower with louvers and surface condenser
78.	Yangcheng Phase II. Unit 8 600 MW Plant Extension	China	600	2007	Natural draft concrete cooling tower with louvers and surface condenser

Ref. No.	Description	Country	Unit Power (MW)	Date Commissioned	Remarks
79.	MMDC Moscow City 130 MW Town heating CCPP	Russia	130	2008	Forced draft steel tower with TA-67 fins, winterization louvers and surface condensers
80.	Al Nasserieh 510 MW CCPP	Syria	510	2008	Natural draft steel tower for 160 MW with DC Jet Condenser
81.	Zayzoun 510 MW CCPP	Syria	510	2008	Natural draft steel tower for 160 MW with DC Jet Condenser
82.	Modugno 800 MW CCPP	Italy	800	2009	Low noise mechanical induced draft fan cells with DC Jet Condenser
83.	Deir Ali 750 MW CCPP	Syria	750	2009	Natural draft steel tower with DC Jet Condenser
84.	Tereshkovo 340 MW CHP PS	Russia	340	2011	Mechanical induced draft fan cells with TA-67 fins, winterization louvers and surface condenser
85.	Kojuhovo 340 MW CHP PS	Russia	340	2012	Mechanical induced draft fan cells with TA-67 fins, winterization louvers and surface condenser
86.	Szakoly 20 MW Biomass Power Plant	Hungary	20	2009	Low noise mechanical induced draft fan cells with DC Jet Condenser
87.	Strogino 130 MW CCPP Unit 1.	Russia	130	2009	Mechanical induced draft fan cells with winterization louvers and surface condenser
88.	Strogino 130 MW CCPP Unit 2.	Russia	130	2009	Mechanical induced draft fan cells with winterization louvers and surface condenser
89.	Bao Ji 660 MW SC PP Unit 5.	China	660	2010	Natural draft concrete cooling tower with louvers; DC jet condensers also serving the boiler feed pump turbines; FGD in tower.
90.	Bao Ji 660 MW SC PP Unit 6.	China	660	2011	Natural draft concrete cooling tower with louvers; DC jet condensers also serving the boiler feed pump turbines; FGD in tower.
91.	Pervomaysk 180 MW PP Unit 1.	Russia	180	2010	Supply of Heller dry cooling system of special outfit to the extension of Pervomaysk District Heating Plant No. 14 of St. Petersburg - 3 winter, 1 summer fan - cell rows for 2 units
92.	Pervomaysk 180 MW PP Unit 2.	Russia	180	2010	Supply of Heller dry cooling system of special outfit to the extension of Pervomaysk District Heating Plant No. 14 of St. Petersburg - 3 winter, 1 summer fan - cell rows for 2 units
93.	Sochi 72 MW CHP Unit 3.	Russia	72	2010	Mechanical induced draft fan cells with supplementary spraying and applying surface condenser
94.	Shanyin 300 MW PP, Unit 1	China	300	2012	Single natural draft concrete cooling tower for 2 units with louvers; DC jet condensers also serving the boiler feed pump turbines; FGD in tower.
95.	Shanyin 300 MW PP, Unit 2.	China	300	2012	Single natural draft concrete cooling tower for 2 units with louvers; DC jet condensers also serving the boiler feed pump turbines; FGD in tower.
96.	Shuidonggou 660 MW SC PP Unit 1.	China	660	2011	Natural draft concrete cooling tower with louvers, supplementary spraying and surface condenser
97.	Shuidonggou 660 MW SC PP Unit 2.	China	660	2011	Natural draft concrete cooling tower with louvers, supplementary spraying and surface condenser

Ref. No.	Description	Country	Unit Power (MW)	Date Commissioned	Remarks
98.	Razdan 510 MW SC CCPP Unit V.	Armenia	510	2011	Single natural draft steel structure cooling tower for 330+300=630 MW steam units, DC jet condensers, deluged peak coolers
99.	Razdan 300 MW SC PP Unit VI.	Armenia	300	not in operation yet	Single natural draft steel structure cooling tower for 330+300=630 MW steam units, DC jet condensers, deluged peak coolers
100.	Novy Urengoy 120 MW CCPP	Russia	120	2012	Mechanical induced draft fan cells with winterization louvers and surface condenser
101	Adler 180 MW CCPP Unit 1.	Russia	180	2012	Mechanical induced draft fan cells with supplementary spraying
102.	Adler 180 MW CCPP Unit 2.	Russia	180	2012	Mechanical induced draft fan cells with supplementary spraying
103.	Deir Ali II 750 MW CCPP	Syria	750	2012	Natural draft steel tower with DC Jet Condenser
104.	Tishreen 200 MW PP, Unit 3	Syria	200	2013	Natural draft steel tower with DC Jet Condenser
105.	Tishreen 200 MW PP, Unit 4	Syria	200	2013	Natural draft steel tower with DC Jet Condenser
106.	Tufanbeyli 150 MW PP Unit 1.	Turkey	150	2015	Single natural draft concrete cooling tower for 3 units, DC jet condensers, peak coolers, CFB gases exhausted via cooling tower
107.	Tufanbeyli 150 MW PP Unit 2.	Turkey	150	2015	Single natural draft concrete cooling tower for 3 units, DC jet condensers, peak coolers, CFB gases exhausted via cooling tower
108.	Tufanbeyli 150 MW PP Unit 3.	Turkey	150	2015	Single natural draft concrete cooling tower for 3 units, DC jet condensers, peak coolers, CFB gases exhausted via cooling tower
109.	Jinchang 330 MW PP Unit 1.	China	330	2014	Natural draft concrete cooling tower with louvers, supplementary spraying and surface condenser
110.	Jinchang 330 MW PP Unit 1.	China	330	2014	Natural draft concrete cooling tower with louvers, supplementary spraying and surface condenser

B
APPENDIX

System Cost/Performance Tables

Yuma						
System Summary	Units	CT-Only	Hybrid			7" ACC
			50%	67%	85%	
Site characteristics						
Altitude	feet	0				
1% DB	F	109				
1% WB	F	76				
Cooling system specs						
Steam flow	#/hour	7,426,600				
Steam quality	#/#	0.91				
1% DB backpressure	"Hg	---	5.00	5.00	5.00	7.00
1% WB backpressure	"Hg	3.50	---	---	---	---
Cooling elements						
ACC cells		---	135	180	234	180
Cooling tower cells		51	27	18	9	---
Performance						
Max BP (hottest hour)	"Hg	3.56	5.29	5.35	5.39	8.21
Backpressure > 5"Hg	hours	---	18	18	18	1,209
Summer (J-J-A) Turbine penalty	%	0.01%	0.66%	0.60%	0.53%	2.24%
Yearly average turbine penalty	%	0.00%	0.21%	0.19%	0.17%	0.80%
CT operating hours	hours	8,760	8,324	5,974	5,099	---
Water usage summary						
Water usage	acre-feet/yr	20,317	7,544	3,849	1,501	---
Water savings	acre-feet/yr		12,773	16,468	18,816	20,317
Water Savings	%		63%	81%	93%	100%
Cost summary						
Total installed cost	$	$34,800,000	$206,250,000	$264,270,000	$324,240,000	$226,980,000
Capitalized installed cost	$	$2,790,000	$16,620,000	$21,300,000	$26,130,000	$18,300,000
Total operating cost	$/year	$9,270,000	$23,475,000	$24,678,000	$26,199,000	$30,204,000
Total operating/capitalized cost	$/year	$12,060,000	$40,095,000	$45,978,000	$52,329,000	$48,504,000
Capital cost elements						
ACC	$	---	$185,700,000	$249,600,000	$316,860,000	$226,980,000
Cooling tower	$	$14,130,000	$7,470,000	$4,980,000	$1,920,000	---
Operating cost elements						
Cost of power	$/kWh	$0.09	$0.09	$0.09	$0.09	$0.09
ACC	$/year	---	$17,616,000	$21,102,000	$23,820,000	$23,301,000
Cooling tower	$/year	$9,255,000	$4,035,000	$1,932,000	$909,000	---
Turbine penalty	$/year	$15,000	$1,824,000	$1,644,000	$1,470,000	$6,903,000

Yuma				
System Summary	Units	100% 8 "Hg ACC	100% 3.5 "Hg CT	System
Site characteristics				
Altitude	feet	0		
1% DB	F	109		
1% WB	F	76		
Cooling system specs				
Steam flow	#/hour	7,426,600		
Steam quality	##	0.91		
1% DB backpressure	"Hg	8		
1% WB backpressure	"Hg		3.5	
Cooling elements				
ACC cells		144		144
Cooling tower cells			51	51
Performance				
Max BP (hottest hour)	"Hg	9.34	3.56	
Backpressure > 5"Hg	hours	4,271	---	
CT operating hours	hours	0	8,760	5,142
Summer (J-J-A) Turbine penalty	%	3.46%	0.01%	
Yearly average turbine penalty	%	1.31%	0.00%	
Water usage summary				
Water usage	acre-feet/yr	---	20,317	11,299
Water savings	acre-feet/yr	20,317	---	9,019
Water Savings	%	100%	---	44.4%
Cost summary				
Total installed cost	$	$203,070,000	$34,800,000	$237,870,000
Capitalized installed cost	$	$16,350,000	$2,790,000	$19,140,000
Total operating cost	$/year	$10,024,940	$4,885,003	$14,909,943
Total operating/capitalized cost	$/year	$26,374,940	$7,675,003	$34,049,943
Capital cost elements				
ACC	$	$203,070,000	---	$203,070,000
Cooling tower	$		$13,620,000	$13,620,000
Operating cost elements				
Cost of power	$/kWh	$0.09	$0.09	$0.09
ACC	$/year	$9,456,456	---	$9,456,456
Cooling tower	$/year	---	$9,255,000	$4,870,483
Turbine penalty	S/year	$568,484	$14,520	$583,003

Jacksonville						
System Summary	Units	CT-Only	Hybrid			5" ACC
			50%	67%	85%	
Site characteristics						
Altitude	feet	0				
1% DB	F	93				
1% WB	F	78				
Cooling system specs						
Steam flow	#/hour	7,426,600				
Steam quality	#/#	0.91				
1% DB backpressure	"Hg	---	5.00	5.00	5.00	5.00
1% WB backpressure	"Hg	3.50	---	---	---	---
Cooling elements						
ACC cells		---	90	105	135	150
Cooling tower cells		36	18	12	6	---
Performance						
Max BP (hottest hour)	"Hg	3.69	5.41	5.50	5.58	6.04
Backpressure > 5"Hg	hours	---	22.00	22.00	33.00	35.00
Summer (J-J-A) Turbine penalty	%	0.00%	0.99%	0.80%	0.66%	0.56%
Yearly average turbine penalty	%	0.00%	0.36%	0.29%	0.24%	0.20%
CT operating hours	hours	8,760	8,759	8,594	8,112	---
Water usage summary						
Water usage	acre-feet/yr	17,653	7,466	4,751	1,991	---
Water savings	acre-feet/yr	---	10,080	12,795	15,555	17,653
Water Savings	%	---	57.4%	72.9%	88.7%	100%
Cost summary						
Total installed cost	$	$37,800,000	$124,230,000	$161,190,000	$196,650,000	$216,900,000
Capitalized installed cost	$	$3,060,000	$10,020,000	$12,990,000	$15,840,000	$17,490,000
Total operating cost	$/year	$8,163,000	$19,278,000	$19,068,000	$20,406,000	$21,012,000
Total operating/capitalized cost	$/year	$11,223,000	$29,298,000	$32,058,000	$36,246,000	$38,502,000
Capital cost elements						
ACC	$	---	$103,950,000	$146,520,000	$188,670,000	$216,900,000
Cooling tower	$	$15,000,000	$6,300,000	$4,200,000	$2,100,000	---
Operating cost elements						
Cost of power	$/kWh	$0.09	$0.09	$0.09	$0.09	$0.09
ACC	$/year	---	$11,907,000	$13,812,000	$17,274,000	$19,254,000
Cooling tower	$/year	$8,163,000	$4,143,000	$2,709,000	$1,044,000	---
Turbine penalty	S/year	$0	$3,228,000	$2,547,000	$2,088,000	$1,758,000

Jacksonville				
System Summary	Units	100% 8 "Hg ACC	100% 3.5 "Hg CT	System
Site characteristics				
Altitude	feet	0		
1% DB	F	93		
1% WB	F	78		
Cooling system specs				
Steam flow	#/hour	7,426,600		
Steam quality	#/#	0.91		
1% DB backpressure	"Hg	6.00		
1% WB backpressure	"Hg		3.5	
Cooling elements				
ACC cells		135		135
Cooling tower cells			36	36
Performance				
Max BP (hottest hour)	"Hg	7.01	3.69	3.69
Backpressure > 5"Hg	hours	3,081	---	
CT operating hours	hours	0	8,760	5,142
Summer (J-J-A) Turbine penalty	%	1.19%	0.00%	
Yearly average turbine penalty	%	0.48%	0.00%	
Water usage summary				
Water usage	acre-feet/yr	---	17,653	9,459
Water savings	acre-feet/yr	20,317	---	8,194
Water Savings	%	100%	---	46.4%
Cost summary				
Total installed cost	$	$180,420,000	$37,800,000	$218,220,000
Capitalized installed cost	$	$14,550,000	$3,060,000	$17,610,000
Total operating cost	$/year	$7,431,138	$4,787,103	$12,218,241
Total operating/capitalized cost	$/year	$21,981,138	$7,847,103	$29,828,241
Capital cost elements				
ACC	$	$180,420,000	---	$180,420,000
Cooling tower	$		$15,000,000	$15,570,000
Operating cost elements				
Cost of power	$/kWh	$0.09	$0.09	$0.09
ACC	$/year	$7,252,575	---	$9,456,456
Cooling tower	$/year	---	$4,786,142	$4,870,483
Turbine penalty	S/year	$178,563	$960	$179,524

Green Bay						
System Summary	Units	CT-Only	Hybrid			7" ACC
			50%	67%	85%	
Site characteristics						
Altitude	feet	0				
1% DB	feet	85				
1% WB	feet	74				
Cooling system specs						
Steam flow	#/hour	7,426,600				
Steam quality	#/#	0.91				
1% DB backpressure	"Hg	---	5.00	5.00	5.00	7.00
1% WB backpressure	"Hg	3.50	---	---	---	---
Cooling elements						
ACC cells		---	72	90	108	105
Cooling tower cells		42	21	18	9	---
Performance						
Max BP (hottest hour)	"Hg	3.73	5.54	5.65	5.73	9.28
Backpressure > 5"Hg	hours	---	26	26	26	1230
Summer (J-J-A) Turbine penalty	%	0.00%	0.55%	0.47%	0.41%	2.54%
Yearly average turbine penalty	%	0.00%	0.16%	0.14%	0.12%	0.88%
CT operating hours	hours	8,760	8,424	7,597	5,697	---
Water usage summary						
Water usage	acre-feet/yr	17,653	6,719	4,029	1,415	---
Water savings	acre-feet/yr	---	9,261	11,951	14,565	17,653
Water Savings	%	---	58.0%	74.8%	91.1%	100%
Cost summary						
Total installed cost	$	$37,800,000	$106,140,000	$133,950,000	$164,670,000	$140,700,000
Capitalized installed cost	$	$2,850,000	$8,550,000	$10,800,000	$13,260,000	$11,340,000
Total operating cost	$/year	$8,742,000	$14,973,000	$14,811,000	$13,833,000	$21,531,000
Total operating/capitalized cost	$/year	$11,223,000	$23,523,000	$25,611,000	$27,093,000	$32,871,000
Capital cost elements						
ACC	$	---	$85,650,000	$119,220,000	$157,260,000	$154,341,000
Cooling tower	$	$13,740,000	$7,350,000	$4,980,000	$1,920,000	---
Operating cost elements						
Cost of power	$/kWh	$0.09	$0.09	$0.09	$0.09	$0.09
ACC	$/year	---	$9,459,000	$11,301,000	$11,835,000	$13,890,000
Cooling tower	$/year	$8,736,000	$4,101,000	$2,304,000	$948,000	---
Turbine penalty	S/year	$6,000	$1,413,000	$1,206,000	$1,050,000	$7,641,000

Green Bay				
System Summary	**Units**	**100% 7 "Hg ACC**	**100% 3.5 "Hg CT**	**System**
Site characteristics				
Altitude	feet	0		
1% DB	F	85		
1% WB	F	74		
Cooling system specs				
Steam flow	#/hour	7,426,600		
Steam quality	#/#	0.91		
1% DB backpressure	"Hg	7.00		
1% WB backpressure	"Hg		3.50	
Cooling elements				
ACC cells		105	---	
Cooling tower cells		---	42	
Performance				
Max BP (hottest hour)	"Hg	9.28	3.73	3.73
Backpressure > 5"Hg	hours	3,810	---	---
CT operating hours	hours	---	8,760	5,136
Summer (J-J-A) Turbine penalty	%	2.64%	0.00%	0.00%
Yearly average turbine penalty	%	0.90%	0.00%	0.00%
Water usage summary				
Water usage	acre-feet/yr	---	15,929	9,242
Water savings	acre-feet/yr	15,929	---	6,688
Water Savings	%	100%	---	42.0%
Cost summary				
Total installed cost	$	$140,700,000	$35,490,000	$176,190,000
Capitalized installed cost	$	$11,340,000	$2,850,000	$14,190,000
Total operating cost	$/year	$7,166,118	$4,556,431	$11,722,548
Total operating/capitalized cost	$/year	$18,506,118	$7,406,431	$25,912,548
Capital cost elements				
ACC	$	$140,700,000	---	$140,700,000
Cooling tower	$	---	$13,740,000	$13,740,000
Operating cost elements				
Cost of power	$/kWh	$0.09	$0.09	$0.09
ACC	$/year	$6,926,318	---	$6,926,318
Cooling tower	$/year	---	$4,550,725	$4,550,725
Turbine penalty	$/year	$239,800	$5,705	$245,505

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