Energy Research and Development Division

FINAL PROJECT REPORT

Evaluating Cost, Performance and Water Conserving Capability of Hybrid Cooling

California Energy Commission

Edmund G. Brown Jr., Governor

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PREFACE

The California Energy Commission's Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solution, foster regional innovation and bring ideas from the lab to the marketplace. The California Energy Commission and the state's three largest investor-owned utilities — Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company — were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The Energy Commission is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Evaluating Cost, Performance and Water Conserving Capability of Hybrid Cooling is the final report for the Evaluation of Cost, Performance and Water Conserving Capability of Hybrid Cooling project, Grant Number EPC-14-068, conducted by Maulbetsch Consulting. The information from this project contributes to Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

The demand for increasing electricity load while conserving locally limited fresh water supply can sometimes come into conflict, especially with the extended droughts, diminishing snowpack and potential future effects of climate change. Since power plant cooling is the major use of water in most plants, the type of cooling system is important. Traditional wet-cooling systems have good efficiency and low cost but high water consumption; dry cooling virtually eliminates water consumption but at higher cost and reduced efficiency. Hybrid, wet/dry cooling systems have significant water savings, improved efficiency and output but with higher cost compared to wet cooling. When compared to dry systems, however, the hybrid wet/dry usually has lower costs. This report presents quantified tradeoffs between wet, dry, and hybrid cooling systems for typical gas-fired, combined-cycle plants operating in California.

The team developed an Excel spreadsheet-based computer tool specifying the design parameters for closed-cycle wet, direct dry, and parallel wet/dry hybrid cooling systems. To compare costs of the cooling systems, annual operating power requirements, annual steam turbine output reductions, resultant annualized costs, and annual water consumption five California sites representing the range of seasonal and climatic conditions were selected. Calculated results for water consumption were summarized as a percentage of all-wet cooling water usage, cost of water saved, and normalized water. Finally, the tool was used to estimate the economic, power production and water conservation trade-offs provided by the selection of preferred cooling systems for future power development in California.

Keywords: power plant cooling; hybrid cooling; water conservation; alternative cooling systems; efficiency penalty

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EXECUTIVE SUMMARY

Introduction

To conserve water, California power plants must use dry cooling rather than the more conventional closed-cycle wet cooling. However, the switch to dry cooling inevitably leads to reduced power plant efficiency and output, particularly on the hottest, peak load days. Using hybrid cooling instead of all-dry cooling could still achieve significant water conservation while improving plant efficiency and output and, in some cases, reduce cooling system cost. This would reduce the amount of the fuel burned and the amount of greenhouse gas emitted for the same amount of electricity produced.

Hybrid cooling is available as a power plant cooling technology but has had limited use in the United States (only three utility-scale plants) with none in California. This is due, in part, to the lack of information for decision makers to make reliable performance and cost estimates of optimized hybrid systems and to confidently compare these systems with the more conventional wet or dry cooling systems. This study was intended to provide a basis for making such comparisons.

Project Purpose

This project was initiated to develop a tool to analyze the design, performance, and cost of optimized hybrid cooling systems at utility power plant scale to illustrate and compare the potential benefits of hybrid cooling in California. The project team developed a methodology to provide regulators, planners, and potential users with reliable, validated comparative cost, performance, and water use comparisons with alternative all-wet and all-dry cooling systems.

Project Process

The project team used an existing, Excel-based spreadsheet tool to provide estimates of cooling system design, performance, and cost for wet, dry, and hybrid cooling systems to be considered in plant and cooling system selections. Specific cooling system performance quantities estimated included water consumption, steam condensing pressure, and cooling system operating power requirements. Estimates were also provided for plant performance quantities, including turbine exhaust pressure, plant output, and performance penalties for operation with dry or hybrid systems compared to wet cooling.

The study included data acquisition, updating the spreadsheet tool database, validating and calibrating the tool, case study analyses at five sites representative of California climate conditions, and estimates of the statewide benefits of hybrid cooling.

The project team used current design, performance, and cost information for cooling system performance in the spreadsheet tool for all major components of wet, dry, and hybrid cooling systems. In addition, current plant and steam turbine operating characteristics and relevant economic parameters were included.

These data were embedded in the tool to ensure current and appropriate information for the systems considered in this study. In addition, the team input meteorological data that represented the range of conditions in the state, and the procedure was reviewed to ensure consistent comparisons among the alternative cooling technologies.

The tool was validated against design, performance, and operating data obtained from existing plants with the cooling systems of the type being considered in the study; specifically:

- A wet cooled plant in southwestern Arizona.
- Two dry cooled plants in California: one near San Francisco Bay, the other in the Central Valley, north of Sacramento.
- Two hybrid cooled plants: one in southern Washington, the other in southern New Mexico.

Tool estimates were compared with real data from the existing designs and operating characteristics at these plants to ensure the estimates generated by the tool were realistic and representative of current cooling technology.

The team performed case study analyses comparing wet, dry, and hybrid cooling systems on a nominal 530 megawatt (MW) gas-fired, combined-cycle plant at each of five sites. The site locations represent meteorological conditions at Sacramento, Blythe, Long Beach, Bakersfield, and Redding (Figure 1).

Figure 1: Sites Used for Case Study Analyses

Source: Maulbetsch Consulting

The results from the case study analyses were used to estimate the projected future effects on power production costs and water consumption in California, assuming projected growth in power use and forecasted type, capacity, and geographical distribution of power generating facilities.

Project Results

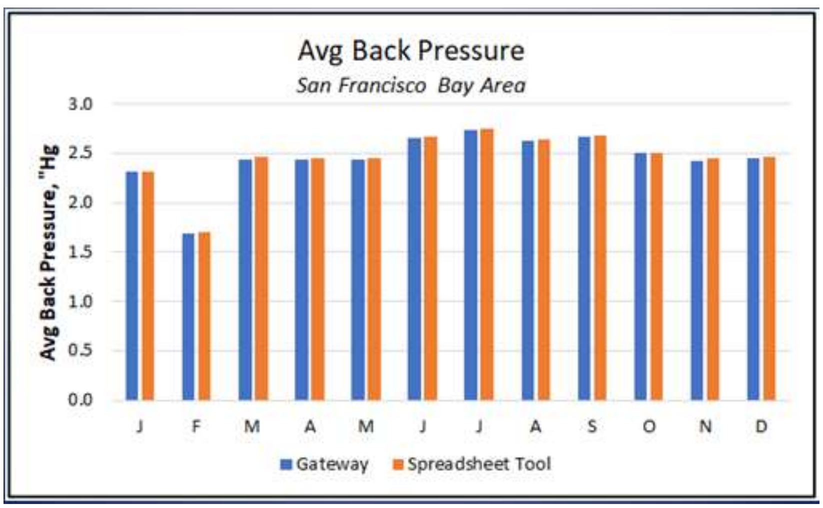
The project results fell into three categories:

- Validating the tool output against existing cooling systems.
- Comparing costs, performance, and water consumption in differing meteorological conditions as illuminated in the case studies.
- Projecting effects of using hybrid cooling at California power plants in the future.

Validation Results

The estimates generated by the tool were comparable to the design and performance of existing systems at full-scale power plants. Systems were sized using the original design specifications of heat load and turbine backpressure at a specific ambient temperature and humidity. The performance of the systems was then calculated on an hourly basis for a year underoperating conditions of heat load and ambient temperature and humidity provided by the plant. In all cases, the equipment sizes and operating power requirements were almost identical to what had been originally provided to the plants by the commercial vendors. Figure 2 displays an example comparison of turbine backpressure at a dry-cooled plant for 2015.

Figure 2: Backpressure Comparisons for Dry-cooled Plant

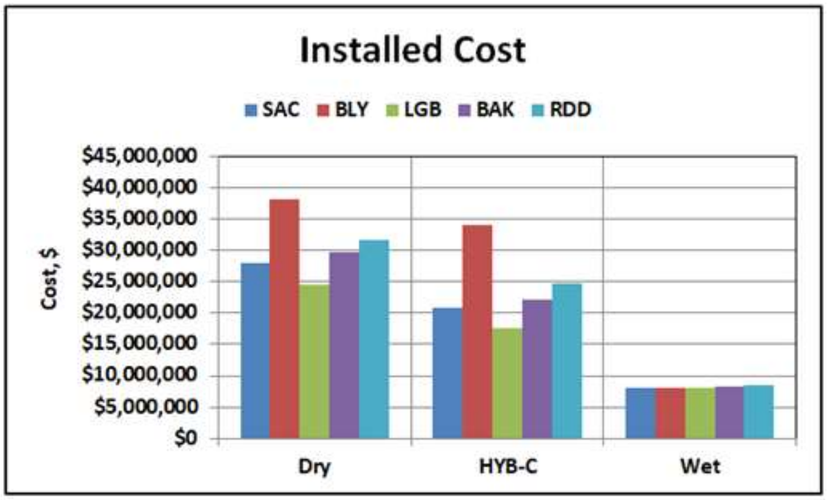


Source: Maulbetsch Consulting

Case Study Results

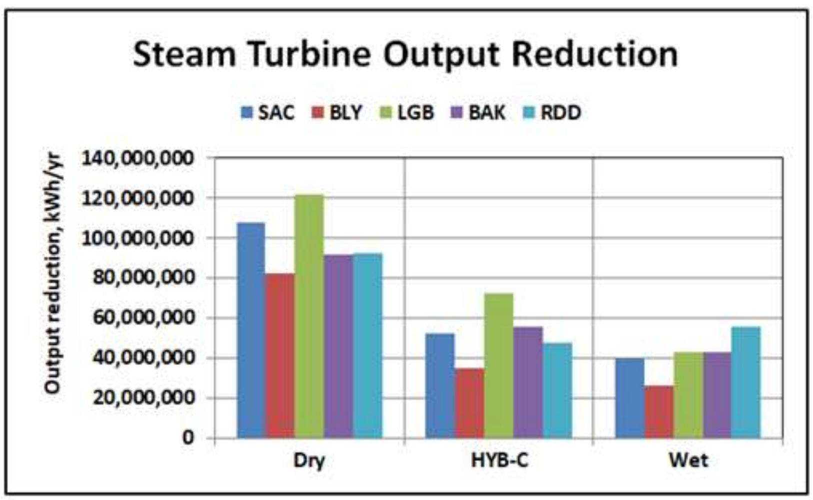
The results of the case studies show distinct effects of meteorological conditions at the site on the comparative performance of the alternative cooling systems. Figures 3 and 4 show the installed cooling system costs and annual turbine output at all five sites for all-wet systems, all-dry systems, and a hybrid system designed to use about half the water required by the all-wet system. The site in Blythe, California has the hottest temperatures and a significantly higher installed cost compared with the other sites. The Long Beach site is the coolest of the selected sites and has the lowest initial cost. Large differences between highest and lowest ambient temperatures throughout a year typically results in a large size of the cooling equipment and low reduction in annual turbine output. Therefore, Blythe has the lowest reduction in annual turbine output, while Long Beach has the highest.

Figure 3: Installed Cost Comparisons by Site



Source: Maulbetsch Consulting

Figure 4: Steam Turbine Annual Energy Output Reduction by Site



SAC – Sacramento, CA; BLY – Blythe, CA; LGB – Long Beach, CA; BAK – Bakersfield, CA; RDD – Redding, CA; Dry – all-dry cooling system; HYB-C – hybrid system with 30% all-dry cooling and 70% all-wet cooling; Wet – all-wet cooling system.

Source: Maulbetsch Consulting

Statewide Effects of Cooling System Choice

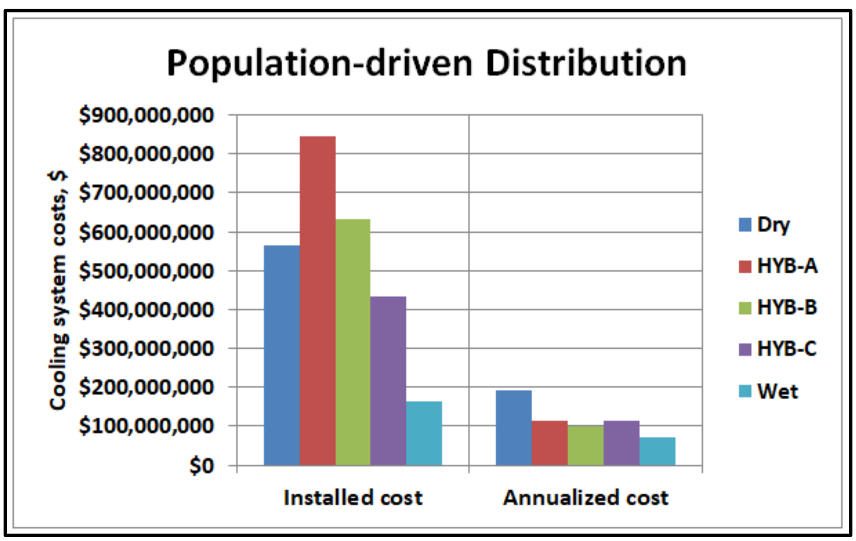
The fundamental results of the study are the projected effects on system cost, energy production, and water consumption aggregated for projected power plant capacity and energy production in 2050. The team assumed, based on projections from other sources [1,2] that approximately 20 gas-fired, combined-cycle plants with capacities of 530 MW would be operating in 2050. The effect from the cooling systems on the overall cost, energy production, and water consumption used for these 20 plants will depend on where the plants are located in regions of differing weather.

The first case considered was a uniform distribution of the 20 plants by siting four plants at each of the five sites; the other, a series of extreme distributions where all 20 plants were sited at each of sites considered separately. A more plausible intermediate distribution is one in which more plants are located in areas of the state with higher population. This results in groups of plants in regions with significantly different meteorology; specifically, the intermediate case included:

- Seven plants in Long Beach.
- Six plants in Sacramento.
- Three plants in Bakersfield.
- Two plants each in Redding and Blythe.

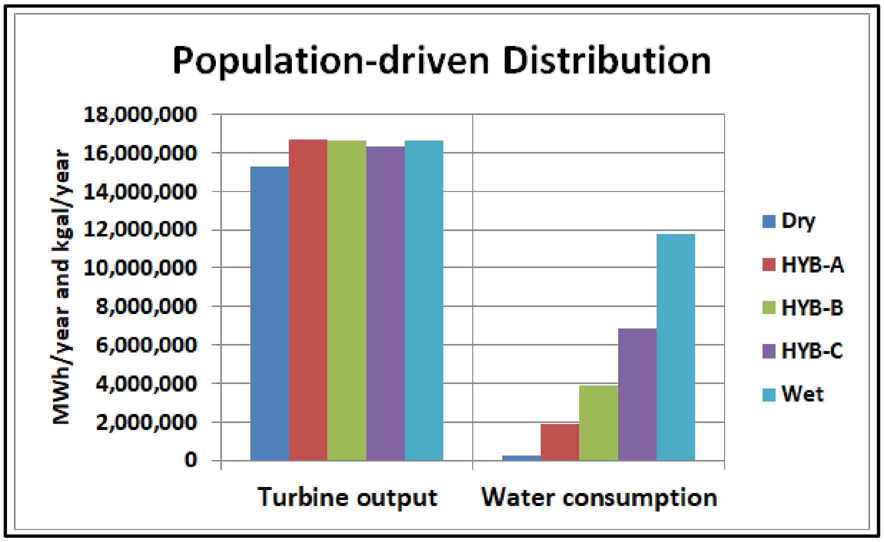
The intermediate distribution is also referred to as a "population-driven" distribution. The project team compared installed costs, annualized costs, turbine energy production, and water consumption for five types of cooling systems under the different cases. The five cooling systems are all-wet, all-dry, and three hybrids designated HYB-A, HYB-B, and HYB-C with respectively 70 percent, 50 percent, and 30 percent of heat load cooled by all-dry system. HYB-C is a design sized to consume approximately one-half the water consumed by an all-wet system. The range of installed and annualized costs for the alternative systems and the range of turbine energy production and water consumption for the population-driven distribution case are shown in Figures 5 and 6. Annualized cost is defined as the initial installed cost amortized at 7 percent plus the lost revenue from the reduced turbine output valued at $70/megawatt hour (MWh).

Figure 5: Variation in Costs by Cooling System Choice for the Intermediate Distribution



Source: Maulbetsch Consulting

Figure 6: Variation in Turbine Output and Water Consumption by Cooling System Choice



Source: Maulbetsch Consulting

The team concluded that while the installed cost and the turbine output reduction vary significantly with cooling system choice, the annualized costs do not.

Benefits to California

Hybrid cooling can save substantial amounts of water compared to the traditional wet cooling systems, although there are increased system costs and potentially reduced hot day generating capacity and annual energy production. The results of this study provide information validated by a computer methodology to determine quantitative estimates of the trade-offs among cooling system cost, annual energy production, and water consumption. State regulatory agencies, power system developers and owners, and community groups can use this information to make informed decisions about the most suitable cooling equipment to use at future steam power generating facilities in California. This will help ensure the appropriate balance among the supply of electrical generation, the cost of electricity, and conserving water resources.

This research project has been supported by numerous Technical Advisory Committee members, including Robert Lotts, manager for water resources at Arizona Public Service, Fred Best, operations and maintenance manager at Goldendale Power Station, Kent Zammit, manager at Electric Power Research Institute, R. David Thurston, senior plant engineer at Gateway Generating Station (Pacific Gas and Electric Company), and Hoc Pfung, project engineer at Pacific Gas and Electric Company.

The results of this work are applicable to a variety of cooling systems in a variety of site conditions and are being distributed to the user community through two scientific articles, presentations and publications at relevant conferences. The findings summarized in first paper *Cost/Performance Tradeoffs Among Wet, Dry and Hybrid Cooling Systems* were presented at the Annual Winter Meeting of the Cooling Technology Institute in Houston on February 5, 2018.

The paper will be published in the CTI Journal in an upcoming issue. The second paper *Wet, Dry and Hybrid Cooling Systems* will be presented at the 2018 Meeting of the International Heat Transfer Conference in Beijing, China in August, 2018 and published in the proceedings of that conference.

Potential users of the research results are:

- the individual electric power companies who specify and select power plant cooling systems.
- the environmental and regulatory community who must consider trade-offs between water conservation and the cost of power generation.
- other researchers and research sponsors seeking to evaluate new concepts against the cost/performance of existing systems.
- vendors of power plant cooling equipment (although to a limited extent since they rely on their own proprietary method).

CHAPTER 1: Introduction

California's goals to reduce greenhouse gas emissions and conserve water have led the state's power plants to use dry cooling rather than the more conventional closed-cycle wet cooling. Dry cooling, however, uses air-cooled condensers and rejects this heat from condensation directly to the atmosphere. This constrains the steam condensing temperature to levels typically 30 to 40 °F above the ambient temperature and with a correspondingly high turbine exhaust pressure. Dry cooling also reduces the turbine output and efficiency during periods of hot weather. Using hybrid cooling instead of all-dry cooling could still achieve significant water conservation while improving plant efficiency and output and, in some cases, reduce cooling system cost. This would reduce the fuel burned and greenhouse gases emitted for the same amount of electricity produced.

Hybrid cooling is currently available as a power plant cooling technology; however, it has seen limited use in the United States and none in California. This is not because of a lack of availability, reliability, or performance of the cooling technology itself, but, to some degree, to the lack of an available way for utility purchasers, state regulators, and other decision makers to make reliable performance and cost estimates of optimized systems and make straightforward comparisons of hybrid systems with the more conventional all-wet or all-dry cooling systems. Even established vendors have described developing an estimate of a hybrid system for a particular plant and site as a "development effort" or a "research project" as opposed to the straightforward estimates routinely done for all-wet and all-dry systems.

This project developed "an analysis of the design, performance, and cost of optimized hybrid cooling systems at utility power plant scale to illustrate the potential benefits of hybrid cooling in California." Successfully achieving these goals would help determine the potential benefit of using hybrid cooling systems in California.

Approach

To provide regulators, planners, and potential users with reliable, validated comparative cost, performance, and water use comparisons with alternative all-wet, all-dry, and hybrid cooling systems, the team designed a methodology, using an existing Excel spreadsheet-based computational tool. This methodology and the tool were used to specify at an "engineering level", design parameters for closed-cycle wet, dry and hybrid cooling systems as they would apply to a gas-fired, combined-cycle power plant in a 2 x 1 configuration.[1] The tool's output was validated against existing systems and then used to conduct case study comparisons of the alternative cooling systems at five sites in California. The results of these case studies were

[1] "2 x 1 configuration" refers to a plant with two combustion turbine-generators each with a heat recovery steam generator (HRSG) feeding a single steam turbine-generator.

then extrapolated to determine the cost, performance, and water use benefits of hybrid cooling at future plants installed in California between now and 2050.

Task 1: Data Acquisition

The team obtained current design, performance, and cost information for cooling system performance to use in the spreadsheet tool; specifically, this included:

- Cost/performance information for all major components of wet, dry and hybrid cooling systems.
- Current turbine operating characteristics relating cooling system performance to power plant performance.
- "Typical" current economic parameters such as inflation rate, amortization rate, fuel cost and electric energy price.

Task 2: Update Spreadsheet Tool

The team explored the data embedded in the tool to ensure they are current and appropriate for the cases in this study; specifically, to:

- Review and replace, where necessary, cooling system component cost information using vendor-supplied data obtained in Task 1.
- Select meteorological data appropriate for the sites representing the range of conditions specific to California.
- Verify and modify, if necessary, the iterative selection procedures to ensure consistent comparisons among the alternative systems.

Task 3: Calibration and Validation of Spreadsheet Tool

The team compared tool estimates against existing designs and operating characteristics at operating utility plants using closed-cycle wet, direct dry, and parallel wet/dry hybrid cooling systems and:

- Obtain design and operating data from selected operating plants.
- Estimate system design values and performance characteristics using the spreadsheet tool.
- Compare the estimates with plant information.
- Adjust the spreadsheet tool data and procedures, if necessary, to demonstrate acceptable consistency with existing system design and performance.
- Discuss results with plant personnel to understand and account for any major, unresolved differences.

Task 4: Case Studies

The team conducted case study analyses comparing the performance of wet, dry and hybrid cooling systems on a nominal 530 MW gas-fired, combined-cycle plant at five sites and

- Selected sites in California representing the range of ambient weather (temperature and humidity) conditions in the state
- Obtained site-specific meteorological data on an hourly basis for a consecutive twelve-month period for each site.

- Estimated an appropriate design for the three cooling systems at each site.
- Conducted estimates of cooling system and turbine performance throughout the year for a typical operating profile.
- Created systematic comparisons of the cooling system cost, performance and water consumption for the alternative systems at each site and for each system for differing ambient conditions at each site.

Task 5: Statewide Benefits Analysis

The team estimated the projected future effects on power production costs and water consumption in California for an assumed growth in power use and forecasted type, capacity, and geographical distribution of power generating facilities:

- Assemble an assumed projection of future power needs, power generating facilities, and economic factors in California through 2050.
- Review assumed projections with California Energy Commission personnel, industry representatives, and environmental groups.
- Analyze future cost, performance, and water use projections under varying assumptions of the degree of utilization of the alternative cooling systems.

Organization of Report

The following sections of the report are organized as follows.

Chapter 2 reports on the acquisition of cost and performance data, including the sources, comparisons, resolution of inconsistencies, and the development of the correlations based on the data embedded in the spreadsheet tool.

Chapter 3 provides a detailed description of the spreadsheet tool, including its input requirements, detailed output results, and explanatory graphs, and the selection of required meteorological data for use in the site-specific validations of existing plants.

Chapter 4 describes the comparisons of the tool estimates with existing plant information and discusses the source and significance of important differences.

Chapter 5 identifies the selected case study sites, defines the relevant ambient conditions and defines the case study plant selection and the operating profile used at all sites. It presents the important cost, performance and water consumption results for each of the cooling systems at each of the sites. System-to-system and site-to-site comparisons and differences are discussed and interpreted in the context of the ambient climate conditions at each site.

Chapter 6 presents future power generation projections for California, the total capacity and number of plants for which alternative cooling systems might be chosen and estimates the comparative costs, hot day capacity, annual energy production and water consumption for different distributions of the plants around the State.

Chapter 7 presents a summary of results and conclusions and suggestions for further study of the topic.

CHAPTER 2: Data Acquisition

Introduction

For the results of the study to be the most relevant and useful, the information must be as consistent as possible with current values used by cooling system vendors and purchasers for their specification, selection and evaluation of competing systems. The information has been solicited from a variety of system vendors. Much of this information had been provided in earlier studies and was adjusted to the present costs using publicly available indices of cost variations over the past few years.

Many data sources were used, including SPX Cooling Systems, Enexio (formerly GEA), Hamon, Holtec, SPIG, TEI, and Evapco. Sensitive cost and performance information in this highly competitive industry is nearly always provided under conditions of confidentiality. Therefore, the sources of the individual data packages will not be specifically identified but rather designated as "Vendor A, Vendor B, etc."

Component information was compiled separately for:

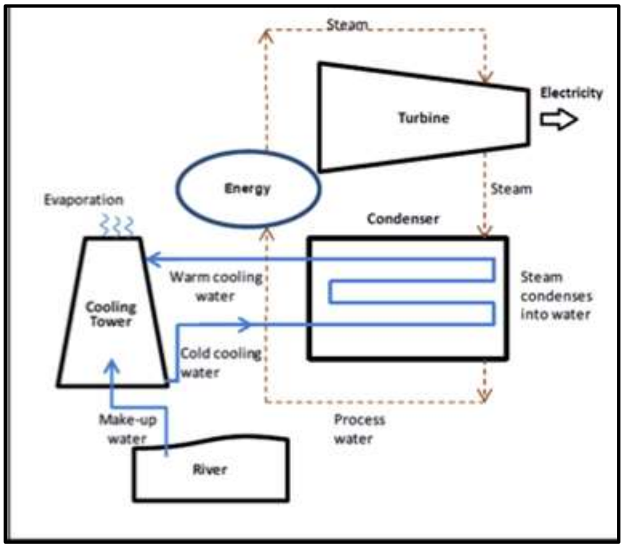
- All-wet systems—Steam surface condensers, wet cooling towers (including fans), allowance for circulating water piping, circulating water pumps
- All-dry systems----Air-cooled condensers (including steam ducts, fans, condensate tanks)
- Hybrid systems---Combination of elements from all-wet and all-dry as described above

Systems can be designed with varying combinations of condenser and cooling tower sizes, circulating water flow rates, pumping power and fan power. The project team requested case study information for a range of operating conditions for each component. For each system, the following sections describe how the information was solicited, how it was provided, and examples of the data as tables or plots.

All-Wet Systems

The all-wet system modeled in the spreadsheet tool consists of a shell-and-tube surface condenser coupled with a mechanical-draft, counter-flow cooling tower. A schematic of the system is shown in Figure 7 with separate cost/performance information for the condenser and the cooling tower.

Figure 7: Schematic of All-Wet Cooling System

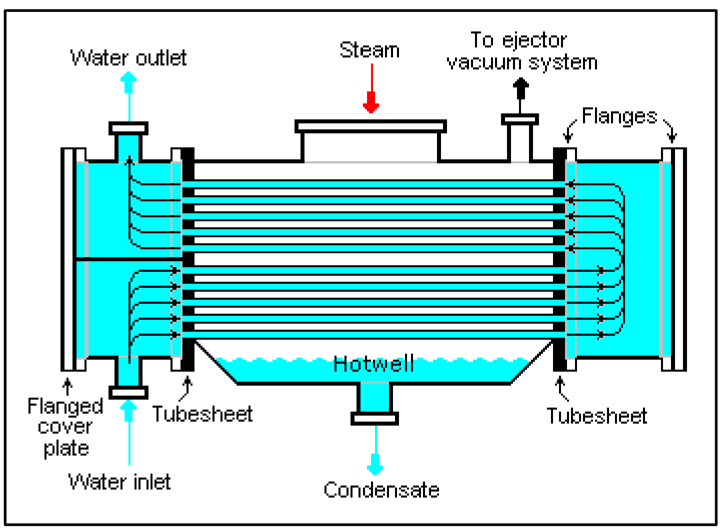


Source: Heat Exchange Institute

Shell-and-Tube Steam Condenser

Figure 8 shows a cutaway sketch of a two-pass, shell-and-tube surface condenser of the type typically used in steam power plants.

Figure 8: Cutaway of Shell-and-Tube Condenser



Source: United States Environmental Protection Agency

Essential design specifications include the steam flow to the condenser, turbine exhaust pressure (or condensing temperature), cooling water inlet temperature and temperature rise. Budget cost estimates and design performance information were selected for condensers sized for a heat duty of 2.375 x 10^9 Btu/hr (steam flow = 2.5 x 10^6 lb/hr) at a condensing pressure =

2.5 in Hg absolute (Hga) over a range of cold water inlet temperatures (75 to 85 ˚F) and cooling water temperature rises (12 to 27 ˚F).

In addition, standard design practice also sets a minimum terminal temperature difference (TTD > 5 ˚F), a maximum tube-side pressure drop (< 10 pounds per square inch (psi)/23 ft H_2O) and velocity (< 10 ft/sec), and a desired water temperature rise (if available within the other constraints). The basis for all design calculations for cooling system condensers are as specified by the Heat Exchange Institute. [4]

The materials selection was based on water quality parameters consistent with cooling tower operation at 10-15 water cycles and assumed that water quality did not require treatment, such as softening. Chemical costs for cooling tower treatment were not calculated and were assumed to be the same for all similar capacity scenarios.

The base design choices were single-shell, single-pressure, divided-flow steam surface condensers with 316/317 stainless steel (SS) tubes and tube sheets, rolled (only) tube-to-tube-sheet joints and a top down steam inlet. The designs had the water cycle either once or twice through depending on the cooling water temperature rise and circulating water flow. The approximate criteria were to maintain the tube-side water velocity at about 8 ft/sec and the tube length below 50 feet.

Included in the price are a main-steam inlet expansion joint and non-stick sliding pads for the support feet. The units are shop-fabricated to the extent allowed by shipping limitations. The price is quoted “ex-works” in the U.S. Midwest.

These design choices and adjustments were considered by the vendor when providing sizing and cost information for the requested example cases. Rather than include these choices in the spreadsheet tool when estimating the various cooling systems at different sites the vendor cost data were consolidated into a generalized cost algorithm[2] used for all cases. Similar choices apply to the wet cooling towers and air-cooled condensers.

Table 1 displays an example of the vendor-supplied information for the several cases. Table 2 summarizes the results of six design cases listing the design specifications, condenser size and tube arrangement and budget prices. The cost of water treatment and disposal are not addressed. Table 3 provides the corresponding operating points and performance data.

[2] For the steam surface condensers, a single relationship between installed cost and heat transfer area)

Table 1: Example Condenser Specification Sheet (from Vendor A)

Condenser Design Specification Sheet
HEI 10th Edition
Imperial Units

Surface	157,563	sqft		
Tube Count	22,640			
Tube O.D.	1.000	in		
Effective Tube Length	26.5833	ft		
Total Tube Length	26.7500	ft		
Tube Material	316/317 SS			
Tube Thickness	22	bwg		
Backpressure	2.50	in HGA		
Saturation Temperature	108.65	deg F		
Condensate Temperature	108.65	deg F		
Condensate Enthalpy	76.67	btu/lb		
Duty	2,375.000	mbtu/hr		
Steam & Drains	Flow		Enthalpy	
Turbine Exhaust	2,500.000	klbs/hr	-	btu/lb
BFPT Exhaust	-	klbs/hr	-	btu/lb
Drain 1	-	klbs/hr	-	btu/lb
Drain 2	-	klbs/hr	-	btu/lb
Drain 3	-	klbs/hr	-	btu/lb
Drain 4	-	klbs/hr	-	btu/lb
Drain 5	-	klbs/hr	-	btu/lb
Drain 6	-	klbs/hr	-	btu/lb
Cooling Water				
Flow Rate	395,800	gpm		
No. of Passes	1			
Inlet Temp	75.00	deg F		
Outlet Temp	87.00	deg F		
Rise	12.00	deg F		
Tube Velocity	8.01	fps		
Pressure Drop	9.7	ft		
Heat Transfer Coeff	554.01	btu/hr-deg F-ft^2		
LMTD	27.21	deg F		
ITD	33.65	deg F		
TTD	21.65	deg F		
Cleanliness Factor	0.85			
Metal Factor	0.854			
Temp Corr Factor	1.0250			
Velocity Factor	262.97			
Specific Heat	1.000	btu/lb-deg F		
Specific Gravity	1.000			
Uncorr Heat Trans Coeff	744.49	btu/hr-deg F-ft^2		

Source: Maulbetsch Consulting

Table 2: Steam Condenser Budget Price Summary

Case No.	Condensing Pressure	Heat Duty	Inlet Water Temperature	Water Flow	No. of passes	Tube Size[1]	Tube Count	Tube Length	Surface Area	Budget Price	Normalized Price
	in Hga	Btu/hr	F	gpm	np	in. OD x BWG	n	ft	Sq. ft.	$	$/Sq. ft.
1	2.5	2.375E+09	75	395,800	1	1. X 22 BWG	22,640	26.75	157,563	$3,548,000	$22.52
2	2.5	2.375E+09	75	250,000	2	1. X 22 BWG	28,552	25.25	187,495	$3,984,000	$21.25
3	2.5	2.375E+09	75	175,925	2	1. X 22 BWG	20,156	49.00	257,685	$4,434,000	$17.21
4	2.5	2.375E+09	80	339,300	1	1. X 22 BWG	19,474	39.75	201,807	$3,818,000	$18.92
5	2.5	2.375E+09	80	215,900	2	1. X 22 BWG	24,720	43.33	279,361	$4,725,000	$16.91
6	2.5	2.375E+09	85	279,000	2	1. X 22 BWG	32,076	37.08	310,007	$5,198,000	$16.77

1. All tubes 316/317 SS

Source: Maulbetsch Consulting

Table 3: Steam Condenser Design/Operating Points

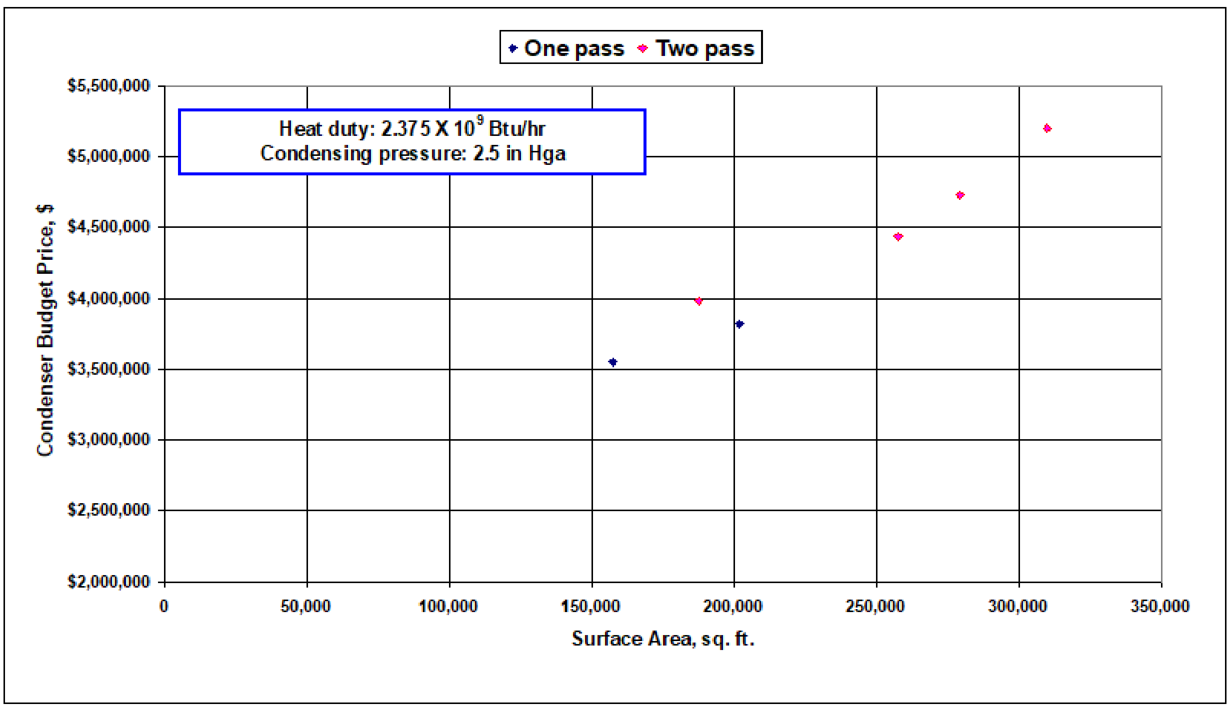
Case No.	Condensing Pressure	Heat Duty	Steam flow	Inlet Water Temperature	Range	LMTD[1]	ITD[2]	TTD[3]	Pressure Drop
	in Hga	Btu/hr	lb/hr	F	F	F	F	F	ft H2O
1	2.5	2.375E+09	2,500,000	75	12	27.2	33.7	21.7	9.7
2	2.5	2.375E+09	2,500,000	75	19	22.9	33.7	14.7	17.1
3	2.5	2.375E+09	2,500,000	75	27	16.7	33.7	6.7	29
4	2.5	2.375E+09	2,500,000	80	14	20.9	28.7	14.7	12.5
5	2.5	2.375E+09	2,500,000	80	22	15.1	28.7	6.7	26.1
6	2.5	2.375E+09	2,500,000	85	17	13.4	23.7	6.7	22.5

Notes: [1] LMTD = Log mean temperature difference
[2] ITD = Initial temperature difference
[3] TTD = Terminal temperature difference

Source: Maulbetsch Consulting

Figure 9 displays a plot of condenser budget price versus condenser surface area, indicating good correlation over a range of design specifications of 75˚F to 85˚F for the inlet cooling water temperature and a factor of x3 in the circulating water flow rate.

Figure 9: Condenser Cost vs. Heat Transfer Area



Source: Maulbetsch Consulting

The one-pass and two-pass cases are shown separately and indicate a difference in cost for equivalent surface area. The two-pass units are slightly more expensive as a result of the greater number of tubes for the same surface area and correspondingly higher labor costs. For the comparisons in this study, a single curve through all six cases was used to develop a convenient normalized correlation on the basis of price-per-square-foot of condenser area.

The budget prices provided include vacuum pumps for air removal, a sacrificial anode cathodic protection system, leak detection trays and a curtain spray system in the neck. They also include typical bypass lines, as required for a combined-cycle plant but do not include any extraction piping.

In past years, permanently installed tube cleaning systems were often requested on once-through cooling systems. The costs range from $250,000 and more, and are almost never purchased in recent years, particularly on recirculating cooling systems with cooling towers, where the water quality is better and more controllable than with once-through systems. These tube cleaning systems are not included in this estimate.

Adjustments to Condenser Cost Estimates

The prices presented include only equipment costs at the supplier's loading dock. Additional costs must be included to account for transportation to the site and for assembly and installation at the site. Obviously these costs depend on site location and on local labor cost and productivity. However, the following adjustment factors have been adopted based on discussions with equipment vendors and architectural and engineering (A&E) firm personnel.

A vendor estimate placed the range of shipping costs for a condenser between 150,000 to 300,000 square-foot size range from as low as $50,000 to as much as "a few hundred thousand" depending on the destination. From an origination point in the Midwest, destinations to the North and East are "expensive" while those to the South and West are "less so." In the absence of more detailed information, the estimate in this study used $125,000 for sites in California. These costs may not be accurate in any individual case, but they account for only a small fraction of the total system cost and are not expected to affect the system cost comparisons in any significant way.

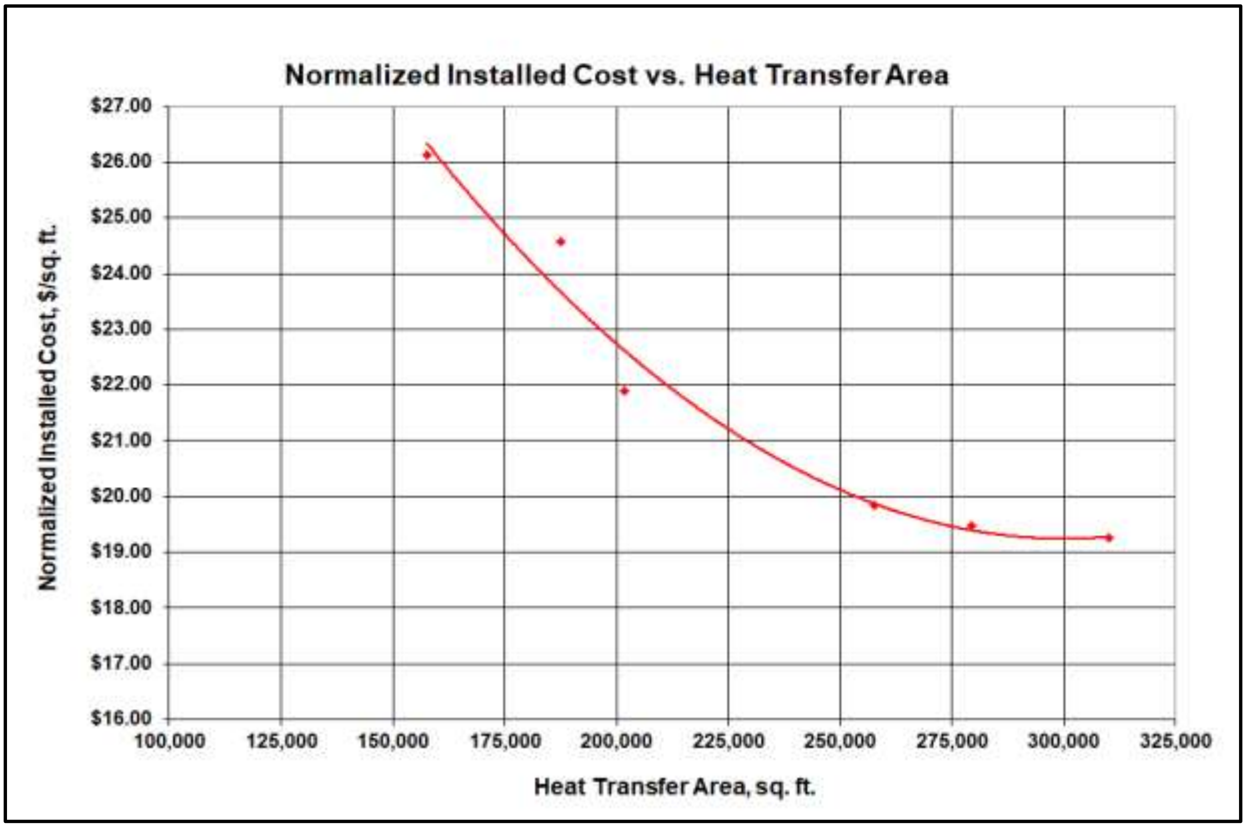
A factor of 12.5% for equipment cost is assumed to account adequately for the assembly and installation costs. These cost adjustments are combined with the base condenser costs and tabulated as total installed costs in Table 4 and plotted in Figure 10.

Table 4: Total Installed Cost Information

Steam Flow	Condensing Pressure	Heat Duty	Inlet Water Temperature	Surface Area	Budget Price	Normalized Price	Ass'y/Install (@12.5%)	Shipping Cost	Total Installed Cost	
lb/hr	in Hga	Btu/hr	F	Sq. ft.	$	$/Sq. ft.	$	$	$	$/Sq. ft.
2.5E+06	2.5	2.375E+09	75	157,563	$3,548,000	$22.52	$443,500	$125,000	$4,116,500	$26.13
2.5E+06	2.5	2.375E+09	75	187,495	$3,984,000	$21.25	$498,000	$125,000	$4,607,000	$24.57
2.5E+06	2.5	2.375E+09	75	257,685	$4,434,000	$17.21	$554,250	$125,000	$5,113,250	$19.84
2.5E+06	2.5	2.375E+09	80	201,807	$3,818,000	$18.92	$477,250	$125,000	$4,420,250	$21.90
2.5E+06	2.5	2.375E+09	80	279,361	$4,725,000	$16.91	$590,625	$125,000	$5,440,625	$19.48
2.5E+06	2.5	2.375E+09	85	310,007	$5,198,000	$16.77	$649,750	$125,000	$5,972,750	$19.27

Source: Maulbetsch Consulting

Figure 10: Total Installed Cost Estimate

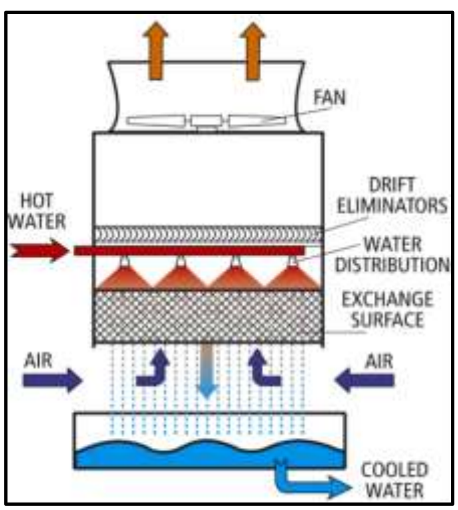


Source: Maulbetsch Consulting

Mechanical-Draft, Counterflow Wet Cooling Tower

The wet cooling systems in this study use mechanical-draft, counterflow wet cooling towers. A schematic of such a tower is shown in Figure 11; a photograph of a large tower at an operating plant is displayed in Figure 12.

Figure 11: Schematic of Mechanical-Draft, Counterflow Cooling Tower



Source: Maulbetsch Consulting

Figure 12: Mechanical-Draft, Counterflow Cooling Tower

Source: Maulbetsch Consulting

Essential design specifications include the heat load on the tower, the circulating water flow, the ambient wet bulb temperature, the cold water temperature leaving the tower, and the site elevation. When incorporated along with a condenser into an all-wet cooling system, the heat loads on the tower and condenser are equal, the circulating water flow in the tower and the tower are equal, and the cold water temperature leaving the tower is the same as the corresponding inlet water temperature to the condenser. The equivalence of the heat loads, the water flow rates, and the cold water temperatures ensures that the hot water temperatures leaving the condenser and entering the tower are the same. Budget cost estimates and design performance information were selected for cooling towers sized for a heat duty of 2.375 x 10^9 Btu/hr (steam flow = 2.5 x 10^6 lb/hr) at a condensing pressure = 2.5 in Hga) over a range of cold water inlet temperatures (75 to 85 ˚F) and cooling water temperature rises (12 to 27 ˚F).

Standard design practice also sets a minimum tower “approach” (the difference between the cold water temperature leaving the tower and the ambient wet bulb) of 5 ˚F, and a maximum water loading of 7 to 8 gallons per minutes (gpm)/ft^2. The materials selection was based on water quality parameters consistent with cooling tower operation at 10-15 cycles of concentration with fresh, good quality make-up water available to the tower.

Towers can be sized in two ways depending upon the purchaser’s preference. One option is a “low first cost” tower, which is physically smaller with less cooling fill volume but high airflow and correspondingly higher fan power and operating cost; the other, referred to as an “evaluated cost tower” is a larger tower, with a higher initial cost but requiring less air flow and ultimately a lower total evaluated cost over the life of the plant. For this study, the cost/performance data for evaluated cost tower designs were chosen.

Estimates were obtained from three separate vendors for several case studies with heat loads from 1 x 10^9 to 2.4 x 10^9 British thermal units (Btu)/hr at ambient wet bulb temperatures from 65 to 80 ˚F, approach temperatures from 7 to 20 ˚F, and tower ranges (hot water inlet temperature minus cold water exit temperature) from 15 to 30 ˚F, all at sea level. The variations in the range and approach exceed likely design points but were requested to obtain information and understanding of the variation in tower size, power requirements, and cost over a wide range. Table 5 is an example of basic information obtained for one set of specifications from Vendor C.

Table 5: Example of Basic Cooling Tower Cost/Performance Data

Wet Cooling Tower								
Counterflow mechanical draft								
Heat Duty = 2.5 x 10^9 Btu/hr								
Low First Cost								
Case No.	Ambient Wet Bulb	Range	Approach	Water Flow	Number of cells	Fan Power	Pump Head	Budget Price
	F	F	F	gpm	n	HP	ft	$
1	70	27	5	185,185	18	242.4	30.9	$7,642,000
2	70	19	8	263,159	18	247.0	28.2	$5,636,000
3	70	12	12	416,667	20	240.6	29.7	$7,181,000
4	75	22	5	227,273	20	249.4	32.5	$7,705,000
5	75	14	8	357,143	20	247.7	30.7	$8,569,000
6	80	17	5	294,118	16	247.0	30.3	$6,083,000
Minimum Evaluated Cost								
Case No.	Ambient Wet Bulb	Range	Approach	Water Flow	Number of cells	Fan Power	Pump Head	Budget Price
	F	F	F	gpm	n	HP	ft	$
1	70	27	5	185,185	19	127.4	20.0	$9,232,000
2	70	19	8	263,159	15	130.7	18.7	$7,062,000
3	70	12	12	416,667	20	129.6	19.2	$8,159,000
4	75	22	5	227,273	20	124.1	20.2	$9,663,000
5	75	14	8	357,143	20	162.0	19.8	$9,884,000
6	80	17	5	294,118	16	123.7	19.0	$7,480,000

Source: Maulbetsch Consulting

In other instances, the team obtained significantly more design detail. Table 6 illustrates such an example for a tower of a size specifically suitable for a 500 MW gas-fired, combined-cycle plant. Table 7 provides more detailed design information for several cases.

Table 6: Supplementary Design Examples

Heat Load: 1.08E+09 Btu/hr				
Design Inlet Air Wet Bulb:	65 °F			
Design Inlet Air Dry Bulb:	99 °F			
Range (°F)	Flow GPM	Approach	CWT	HWT
20.0	108,000.0	19.0	84.0	104.0
22.5	96,000.0	16.5	81.5	104.0
25.0	86,400.0	14.0	79.0	104.0
27.5	78,545.5	11.5	76.5	104.0
Design Inlet Air Wet Bulb:	75 °F			
Design Inlet Air Dry Bulb:	90 °F			
Range (°F)	Flow GPM	Approach	CWT	HWT
15.0	144,000.0	14.0	89.0	104.0
17.5	123,428.6	11.5	86.5	104.0
20.0	108,000.0	9.0	84.0	104.0
22.5	96,000.0	6.5	81.5	104.0

Source: Maulbetsch Consulting

Table 7: Example of Detailed Design Information

Tower Type:	FRP Structure, PVC Coolfilm Fill, 304 SS hardware & connectors. All FRP materials have a flame spread rating of 25 or less
Design Assumptions:	90 mph wind, max zone 2A seismic both per UBC 1997
	Drift Rate 0.005% to 0.003%
	Circ. Water TSS continuous<50 ppm, peak <100ppm
	Single Speed motors - 480v, 3hp, 60 Hz, 250 hp Max.
	Non-union labor for erection.
Excluded from Budget $	Basin, fire protection, bypass lines, valves, piping external to the tower, electrical works and performance, noise & drift testing

	All dimensions are in ft															
RESULTS:	# Cell	Cell Length	Cell Width	Deck Heigh	Stack Height	Fill HT	Fan Dia	# Blad	RPM	Motor Hp	Total ABS Hp	Total Pump	Budget $	Basin Length	Basin Width	Basin Depth
Lowest 1st Cost	7	45.93	39.37	31.00	10	3.28	24	6	148.5	200	1,357	25.5	1,484,800	324.50	47.40	4
Evaluated ($2,500/kW)	5	59.06	52.49	38.00	10	4.92	32	6	98.9	200	791	27.7	1,828,300	298.20	60.50	4
Lowest 1st Cost	7	45.93	39.37	31.00	10	4.10	26	6	137.1	200	1,364	24.5	1,501,600	324.50	47.40	4
Evaluated ($2,500/kW)	6	59.06	52.49	38.00	10	3.28	32	6	98.6	125	744	29.6	2,144,700	357.30	60.50	4
Lowest 1st Cost	8	39.37	39.37	30.00	10	4.92	26	8	137.1	200	1,540	26.5	1,487,400	317.90	47.40	4
Evaluated ($2,500/kW)	6	59.06	52.49	36.00	10	4.92	32	6	98.6	125	741	27.6	2,194,000	357.30	60.50	4
Lowest 1st Cost	7	45.43	45.43	34.00	10	4.92	28	6	127.3	200	1,400	29.0	1,733,000	321.00	53.50	4
Evaluated ($2,500/kW)	7	59.06	52.49	36.00	10	4.92	30	6	118.4	150	902	29.6	2,559,600	416.40	60.50	4

RESULTS:	# Cell	Cell Length	Cell Width	Deck Heigh	Stack Height	Fill HT	Fan Dia	# Blad	RPM	Motor Hp	Total ABS Hp	Total Pump	Budget $	Basin Length	Basin Width	Basin Depth
Lowest 1st Cost	9	39.37	39.37	28.00	10	3.28	26	8	137.1	200	1,799	23.4	1,636,400	357.30	47.40	4
Evaluated ($2,500/kW)	7	59.06	52.49	35.00	10	3.28	32	6	96.6	125	839	24.9	2,502,100	416.40	60.50	4
Lowest 1st Cost	8	45.93	39.37	31.00	10	3.28	28	8	127.6	250	1,969	25.5	1,696,900	370.40	47.40	4
Evaluated ($2,500/kW)	7	59.06	52.49	35.00	10	4.92	32	6	98.6	125	825	28.1	2,559,600	416.40	60.50	4
Lowest 1st Cost	8	45.93	39.37	34.00	10	4.92	28	9	127.5	250	1,991	27.7	1,735,300	370.40	47.40	4
Evaluated ($2,500/kW)	7	59.06	52.49	35.00	10	4.92	32	6	111.2	150	1,030	27.0	2,564,300	416.40	60.50	4
Lowest 1st Cost	9	45.93	39.37	34.00	10	4.92	28	8	127.5	250	2,225	29.5	1,952,200	416.30	47.40	4
Evaluated ($2,500/kW)	8	59.06	52.49	35.00	10	4.92	32	6	98.7	150	1,078	28.6	2,925,300	476.00	60.50	4

Source: Maulbetsch Consulting

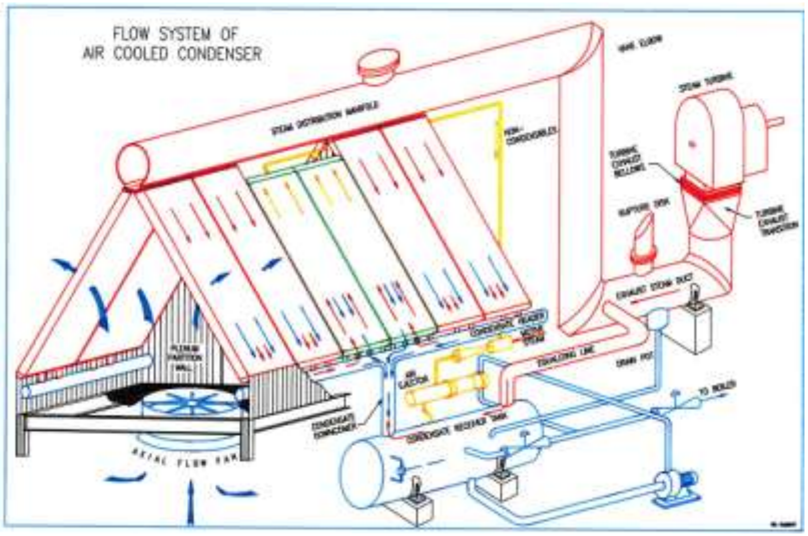
Data from all vendors during the entire range of heat load, tower approach, and range fell within a very narrow range of $114/ft^2 to $124/ft^2 based on tower footprint area. As a result, a cooling tower cost of $120/ft^2 was used, representing the data to within +/- 3% to 5%.

Air-Cooled Condenser

Direct dry cooling systems use air-cooled condensers (ACC) with turbine exhaust steam 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, called bundles. 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 flows downward (co-current with remaining uncondensed 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 device for partial condensation of multicomponent vapor system, “reflux” or “dephlegmator” cell, included to remove non-condensable gases from the condenser. Uncondensed steam 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 the 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 where it is pumped back to the boiler or heat recovery steam generator (HRSG).

A schematic of a dry cooling system with a cutaway view of one of the cells is shown in Figure 13. A photograph of a forty cell ACC at an operating plant in the U.S. Southwest is shown in Figure 14.

Figure 13: Schematic of All-Dry Cooling System with Air-Cooled Condenser



Source: Maulbetsch Consulting

Figure 14: Forty-Cell Air-Cooled Condenser at Southwestern Power Plant

Source: Maulbetsch Consulting

Cost/Performance Information

Essential design specifications are the steam flow from the turbine, the steam quality at the turbine exhaust, the desired turbine exhaust pressure, the ambient temperature, and the site elevation. Information from several vendors had been solicited for an ACC for a given heat duty, steam flow, and turbine exhaust pressure operating at five different sites. The ACC specifications and site conditions are listed in Table 8. Two ambient temperatures are provided. The summer (June through September) average ambient temperature was used as the design ambient at which the 2.5 in Hga turbine exhaust pressure was to be achieved. The 0.4% dry bulb (the temperature which is equaled or exceeded for only 35 hours per year) was used as an alternate rating point to see what performance could be expected at the very hot periods of the year.

Table 9 lists the sizing information for each site as provided by each of three vendors. Information obtained included design values (number of cells, cell configuration and cell dimensions, fan size and power, etc.) and equipment cost. Unlike costs for wet cooling towers, which are bid as an erected, installed unit, air-cooled condenser costs are quoted as equipment cost and erection/installation cost separately.

Table 8: Example ACC Design Cases – Design Points

ACC Cost Information

Design Specifications--Set 1					
Steam Flow, lb/hr			1,100,000		
Turbine Exit Quality, %			95		
Enthalpy, Btu/lb			980		
Heat Duty, MMBtu/hr			993.7		
Design Backpressure, inHga			2.5		
Site Conditions					
	Site 1	Site 2	Site 3	Site 4	Site 5
Elevation, ft	10	10	10	10	10
Summer Av. Temp, F	80.2	78.5	65.4	65.5	69
0.4% Ambient Temp, F	102	95	94	91	89

Design Specifications--Set 2			
Steam Flow, lb/hr		2,500,000	
Turbine Exit Quality, %		95	
Case Conditions			
	Case 1	Case 2	Case 3
Elevation, ft	10	10	10
Design Ambient Temp, F	70	90	100
Turbine Exhaust Pressure, in Hga	2.5	3.5	7.0

Source: Maulbetsch Consulting

Table 9 lists the sizing information for each site as provided by each of three vendors. Information obtained included design values (number of cells, cell configuration and cell dimensions, fan size and power, etc.) and equipment cost. Unlike costs for wet cooling towers, which are bid as an erected, installed unit, air-cooled condenser costs are quoted as equipment cost and erection/installation cost separately

Finally, cost information is listed in Table 10. The costs tabulated include the base equipment cost, the ACC erection cost, cost adjustments for the steam duct, cost of electrical and control systems, and a nominal cost for an auxiliary cooling system in cases where the balance of plant cooling may require lower cooling water temperatures than could be reliably supplied by the ACC at all hours of the year. These extra costs were included by the vendors for completeness but are quite small in relation to the erected cost of the ACC and have no effect on the system comparisons.

A full interpretation of the ACC sizing and cost data is made complex by differences in design and marketing philosophy among competing vendors. In particular, the trade-off between initial capital cost and operating cost (primarily fan power) varies depending on a vendor's view of a potential purchaser's preferences.

Table 9: Example ACC Design Cases – Design Values

	Design Elevation	Design Ambient	Alt. Rating Temp.	Cells	Streets	Cells per street	Length	Width	Height	Plot Area	Fan Dia	Motor Size	Noise @ 400 ft	Fan Power	Fan Power	Power per Fan
	ft	F	F	#	#	#	ft	ft	ft	sq. ft.	ft	HP	dBa	kW	HP	HP
Vendor A																
Site 1	10	80	102	40	8	5	200	312	115	62,400	34	200/50	70	5,475	7,339	183
Site 2	10	79	95	40	8	5	200	312	107	62,400	34	200/50	70	4,640	6,220	155
Site 3	10	65	94	28	7	4	160	273	103	43,680	34	200/50	68	3,415	4,578	163
Site 4	10	65	91	28	7	4	160	273	103	43,680	34	200/50	68	3,415	4,578	163
Site 5	10	69	89	30	6	5	200	234	110	46,800	34	200/50	68	3,660	4,906	164
Vendor B																
Site 1	10	80	102	55	11	5	194.9	428.7	123	83,554	32	200	67.2	7,250	9,719	177
Site 2	10	79	95	55	11	5	191.3	420.8	120.6	80,499	32	200	66.9	6,889	9,234	168
Site 3	10	65	94	35	7	5	187.9	263	104.9	49,418	32	200	65.3	4,467	5,988	171
Site 4	10	65	91	35	7	5	187.9	263	104.9	49,418	32	200	65.3	4,467	5,988	171
Site 5	10	69	89	35	7	5	198.6	278.1	111	55,231	32	200	65.4	4,795	6,428	184
Vendor C																
Site 1	10	80	102	40	8	5	227	344	102	78,088	34	200	65	5,356	7,180	180
Site 2	10	79	95	40	8	5	227	344	102	78,088	34	200	65	5,356	7,180	180
Site 3	10	65	94	24	4	6	172	273	71	46,956	34	200	65	3,066	4,110	171
Site 4	10	65	91	24	4	6	172	273	71	46,956	34	200	65	3,066	4,110	171
Site 5	10	69	89	30	5	6	215	273	71	58,695	34	200	65	2,932	3,930	131

Source: Maulbetsch Consulting

Table 10: Cost Values for Selected Cases

	Eqpt Cost	Eqpt Cost per Cell	Erection Cost	Erection Cost per Cell	Base + Erection	Base + Erection per Cell	Steam duct	Elec. + Cont.	Aux. Cooling	Total Capital
Vendor A	**MM$**	**MM$**	**MM$**	**MM$**	**MM$**	**MM$**	**MM$**	**MM$**	**MM$**	**MM$**
Site 1	**19.6**	**0.490**	**9.6**	**0.240**	**29.2**	**0.730**	**0.15**	**1.2**	**2.3**	**32.8**
Site 2	**19.6**	**0.490**	**9.6**	**0.240**	**29.2**	**0.730**	**0.15**	**1.2**	**2.3**	**32.8**
Site 3	**13.9**	**0.496**	**6.9**	**0.246**	**20.8**	**0.743**	**0.15**	**0.84**	**1.6**	**23.4**
Site 4	**13.9**	**0.496**	**6.9**	**0.246**	**20.8**	**0.743**	**0.15**	**0.84**	**1.6**	**23.4**
Site 5	**14.9**	**0.497**	**7.3**	**0.243**	**22.2**	**0.740**	**0.15**	**0.9**	**1.7**	**25.0**
Vendor B										
Site 1	**23.15**	**0.421**	**9.9**	**0.180**	**33.1**	**0.601**	**0.15**	**1.65**	**2.6**	**37.5**
Site 2	**22.27**	**0.405**	**9.5**	**0.174**	**31.8**	**0.578**	**0.15**	**1.65**	**2.5**	**36.1**
Site 3	**14.19**	**0.405**	**6.1**	**0.174**	**20.3**	**0.579**	**0.15**	**1.05**	**1.6**	**23.1**
Site 4	**14.19**	**0.405**	**6.1**	**0.174**	**20.3**	**0.579**	**0.15**	**1.05**	**1.6**	**23.1**
Site 5	**15.9**	**0.454**	**6.8**	**0.195**	**22.7**	**0.649**	**0.15**	**1.05**	**1.8**	**25.7**
Vendor C										
Site 1	**24**	**0.600**	**10.3**	**0.257**	**34.3**	**0.857**	**0.15**	**1.2**	**2.7**	**38.3**
Site 2	**24**	**0.600**	**10.3**	**0.257**	**34.3**	**0.857**	**0.15**	**1.2**	**2.7**	**38.3**
Site 3	**16**	**0.667**	**6.9**	**0.286**	**22.9**	**0.952**	**0.15**	**0.72**	**1.8**	**25.5**
Site 4	**16**	**0.667**	**6.9**	**0.286**	**22.9**	**0.952**	**0.15**	**0.72**	**1.8**	**25.5**
Site 5	**18**	**0.600**	**7.7**	**0.257**	**25.7**	**0.857**	**0.15**	**0.9**	**2.0**	**28.8**

Source: Maulbetsch Consulting

For example, for the set of five cases for ACCs sized to handle 1.1 x 10^6 lb/hr of steam, Vendor B chose smaller fans and correspondingly smaller cells than did Vendors A and C. However, this resulted in a larger number of cells for the ACC, equipment costs intermediate between Vendors A and C, but significantly higher fan power requirements. Vendor C proposed larger and more costly cells (at some sites fewer cells than Vendor), but the lowest fan power. On an annualized cost basis, defined as the initial capital cost amortized at 7% plus the annual power cost, Vendor B is significantly higher with Vendors A and C quite comparable.

Estimates from Vendors A and C were selected for further investigation since they were preferred on a standard trade-off between capital and operating cost and they selected fan sizes more typical of current design. The total cost, normalized by the footprint of the ACC is consistent from vendor to vendor and from case to case, ranging from \$490/ft^2 to \$543/ft^2 with an average of \$522/ft^{2}., +/- approximately 5%.

The three cases for the larger ACC, sized to handle 2.5 x 10^6 lb/hr of steam all had normalized total costs of between \$804/ft^2 and \$818/ft^2. Scaling the normalized cost from the smaller ACC up to the date when the estimates for the larger ACC were made using the Chemical Engineering historical cost data, the corresponding normalized cost is approximately \$850/ft^2 or within 5% of the more recent estimates. This confirms that the basic design of ACCs, using the single-row condenser bundles with galvanized tubes and aluminum fins in an A-frame configuration had remained essentially the same and has remained so to the present time.

Scaling the approximate normalized cost of (say) \$830/ft^2 to the present is less straightforward. Use of the same Chemical Engineering data suggests a value of slightly less from the peak prices of 2008 to approximately \$800/ft^2. For cell footprint dimensions of approximately 40' x 40' this results in a per cell price of nominally \$1,300,000. For purposes of the calculations in the normalization, this was done on the basis of superficial heat exchanger air inlet area per cell. For the A-frame arrangement with a 60° apex angle, condenser tube effective length of 38' and allowance for structural elements between cells and at the top and bottom of the tube bundles, this translates to approximately \$430/ft^2.

Additional System Costs

The cost data presented in the preceding sections covers only the major elements of the cooling systems. To assemble a working system, there are additional costs to connect the elements to the plant and to circulate the cooling water or condensate. For the ACC some of these costs such as the steam duct and risers were included. For the wet cooling towers and the ACCs, the costs of component erection/installation are included. Major additional costs considered in the cost estimates of this study are restricted to the circulating cooling water system pumps and piping.

Circulating Water Piping

The team assumed the wet cooling towers were located 1,000 feet from the turbine hall where the surface condenser is located. The piping was sized to provide a water velocity in the piping of 9 ft/sec. The piping cost including installation was assumed to be $218 per foot of length and per foot of diameter ($218/ft-ft).

Circulating Water Pumps

Circulating water pumps were sized for the pressure drop through 2,000 feet of piping plus a 45' head rise to the top of the cooling tower. Pump cost including the motor was assumed to be $350/hp. These costs were consistent with those reported in the EPA Technical Development Document for the 316(b) Rulemaking [5] and a related report by the Washington Group. [6]

Other costs for the complete installation and interconnection of the systems, in particular for the parallel hybrid system, are generally highly site-specific and believed to be minor. No additional allowance was made for them.

CHAPTER 3
Calibration and Validation

The team validated the data to calibrate the spreadsheet tool and validate the results against actual operating data from existing plants with wet, dry and hybrid cooling systems. Operating data was provided by three participating power plants. The validation analysis was twofold. First, using the design points from existing plants, the tool was used to configure a similar system. For example, for the dry-cooled plant, equipment parameters such as the number of ACC cells, heat exchanger area, air flow, and fan horse power were calculated and compared to the participating plant. Second, operating data, such as back pressure, was calculated by the tool using actual plant load and meteorological data.

Introduction

Validation demonstrates the capabilities of the spreadsheet tool to configure wet, dry and hybrid cooling systems and predict their ability to cool water under different ambient conditions. Three gas-fired combined cycle plants were selected to validate the tool: Gateway Generating Station (Gateway) uses an ACC for cooling; Redhawk Generating Station (Redhawk) is cooled with a wet mechanical draft cooling tower; and Goldendale Energy Center (Goldendale) uses dry/wet hybrid cooling. The principal investigators know key personnel at these plants from past studies, making data acquisition easier.

Gateway is a one-unit plant with a gross output of 530 MW (nominal) and is configured as a 2 x 1 combined-cycle plant. Located in Antioch, California, the facility is owned and operated by Pacific Gas and Electric (PG&E). Operating data for 2015 was collected for validation analysis, and during that time, the plant had a capacity factor of approximately 70% (based on nominal output). The plant, with a 36-cell ACC, operated in duct-fire mode intermittently throughout the year, but more frequently during the peak summer months. .

Redhawk is a two-unit plant; each unit is configured as a 2 x 1 combined-cycle with a gross output of 530 MW (nominal) per unit. The plant is located in Arlington, Arizona (52 miles west of Phoenix) and is owned and operated by Arizona Public Service (APS). Operating data from July 2016 to June 2017 was collected for Unit 2, and during that time, had a capacity factor of approximately 40% (based on nominal output). The plant operated in duct-fire mode infrequently during the peak summer months and has two 10-cell cooling towers (one for each unit).

Goldendale is owned and operated by Puget Sound Energy (PSE) and is located in Goldendale, Washington (115 miles east of Portland, Oregon). The facility is configured as a 1 x 1 combined-cycle plant with a gross output of 277 MW (nominal). Operating data for 2015 was collected for analysis, and based on that data, the plant had a capacity factor of approximately 60% (based on nominal output). The plant, with a 10-cell ACC and a 2-cell cooling tower, operated in duct-fire mode occasionally throughout 2015, but more frequently during the peak summer months.

Plant Configuration Data

Equipment data was obtained from the participating plants to identify how their respective cooling systems were designed. These data were input into the Tool to determine if its output matched the design information provided. Table 11 summarizes of the data requested from the three plants.

Table 11: Plant Configuration Data Used in Validation

Component	Gateway Generating Station, PG&E	Redhawk Generating Station, APS	Goldendale Generating Station, PSE
Cooling System Type	ACC Only	CT Only	Hybrid
Cooling System Design Point	X	X	X
Combustion Turbine(s) Output, MW	X	X	X
Steam Turbine Output, MW	X	X	X
Steam Turbine Exhaust Flow, lbs/hour	X	X	X
Equipment Design Data[2]	X	X	X
ACC Performance Curves	X	N/A[3]	(Note 1)
ACC Cell & Plenum Dimensions	X	N/A	X
ACC Fan Specifications	X	N/A	X
CT Performance Curves	N/A	(Note 1)	X
CT Cell Dimensions	N/A	X	X
CT Fan Specifications	N/A	X	X
Circulating Pump Specifications	N/A	X	X
Wet Surface Condenser Specifications	N/A	X	X

Notes…

1. Data not available.
2. Equipment design includes plant layout drawings, equipment drawings, equipment specs, O&M manuals, etc.
3. N/A = not applicable.

Source: Maulbetsch Consulting

Of special note in Table 11 is the cooling system design point. This was the basis used to size all of the components in a cooling system. For example, an ACC design point is based on thermal load (usually based on maximum steam turbine exhaust flow with a given steam quality) and a desired exhaust back pressure for a given ambient temperature. This data provides enough information to determine the number of cells, heat transfer area, total air flow for an ACC cooling system, system footprint, etc. In the validation exercises, deriving these parameters does not always provide exact results. For example, the size of the heat exchanger can be adjusted to optimize fan power and still meet the design point. The tool is designed to estimate, within typical design constraints, design features that are usually close but not always exactly the same as the compared system. This also applies to wet and hybrid cooling systems.

For a cooling tower, the design point is based on thermal load, desired backpressure, wet bulb temperature (rather than ambient temperature), approach to wet bulb temperature, and cooling range. All of the system components are derived from this data: number of cells, area and depth of fill, air flow, circulating water flow, condenser surface area, and others.

Lastly, the design point for a hybrid system is usually based on the ACC design point. For Goldendale, the ACC was designed to take 40% of the thermal load at the design point; reducing water consumption during the peak summer months from June through September. There was no specific target for water reduction in the design basis. Also, the design basis was to have the wet cooling system offload the ACC to reduce parasitic load. The data show that each system operated all year and somewhat evenly shared the thermal load.

Plant Operating Data

After the tool was used to reproduce the design features of each plant, hourly operating data was input to predict key operating conditions. One year of key plant data was requested to describe how the plant operated under plant load and ambient temperature conditions. Refer to Table 12. Using steam turbine exhaust flow (thermal load), ambient temperature conditions and backpressure, the number of fans required (ACC, wet cooling and hybrid scenarios), and the evaporation rate for wet cooling and hybrid systems. These were then compared to actual plant data. Plant meteorology was used where possible. Gateway had a meteorological station close by and its data was deemed accurate. Redhawk recorded dry bulb and relative humidity onsite (this is somewhat typical for combined cycle plants); however, their humidity data was not useable for a significant period of time. Weather data from a nearby desert site was used instead. Goldendale recorded dry bulb and humidity on site and it was deemed usable when compared to a nearby weather station.

Validation Results

Gateway

Table 13 compares Gateway's ACC design basis to modeling results. With the exception of air flow (11.4% difference), all other parameters are within 1% to 3% of design. The back-pressure comparison shown in Figure 9 is very close. For fan number, which is the average number of fans operating for a given month, the comparison in Figure 10 is reasonably close. The control of fans is based on a control target for back pressure and adjusted automatically; however, plant operators can make changes.

Table 12: Hourly Operating and Meteorological Data Used in Validation

Operating Parameter	Gateway Generating Station, PG&E	Redhawk Generating Station, APS	Goldendale Generating Station, PSE
Cooling System Type	ACC Only	CT Only	Hybrid
Gross Steam Turbine Output, MW	X	X	X
Steam Turbine Exhaust Flow, lb/hour	X	X	X
Steam Turbine Back Pressure, "Hg	X	X	X
Ambient Dry Bulb, ˚F	X	X	X
Ambient Wet Bulb, ˚F	X	X	X
Ambient Relative Humidity[1]	X	X	X
Operating Status for ACC Fans	X	N/A	X
Operating Status for CT Fans	N/A	X	X
Cooling Tower Makeup, gpm	N/A	X	X
Cooling Tower Blowdown, gpm	N/A	X	X

Notes…

1. For some sites, relative humidity was used to calculate wet bub.

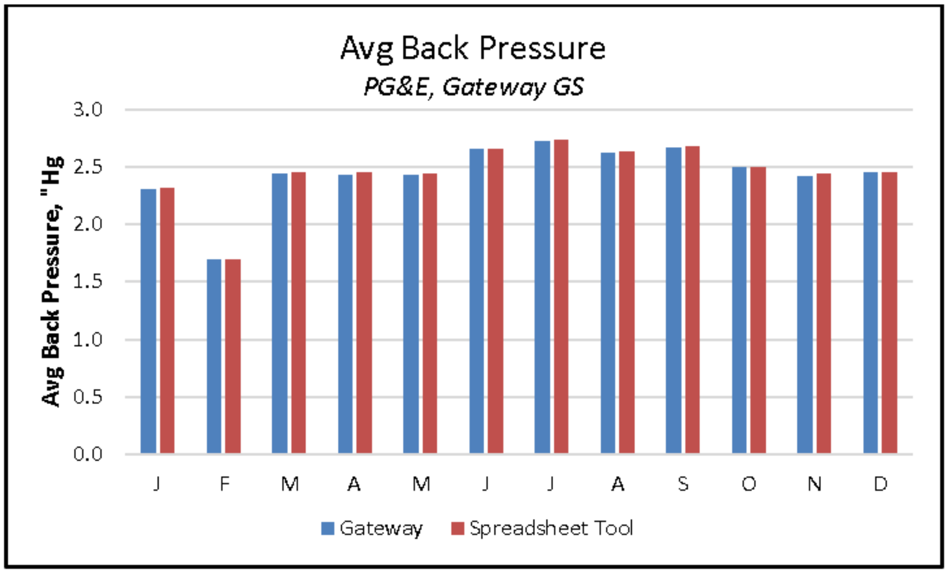
Source: Maulbetsch Consulting

Table 13: Gateway ACC – Design Parameters Validation

Design Parameter	Plant Design	Spreadsheet Tool
Total (ACC + CT) Steam Flow, #/hour	1,420,900	1,420,900
BP (1% DB), "Hg	5.00	5.00
1% DB, F	101.00	101.00
Condensing Temp, F	133.75	133.75
Condensing Enthalpy, BTU/#	1,017.7	1,017.7
ACC Thermal Load, MMBTU/hour (1% DB)	1,382.4	1,382.4
ACC Steam Flow, #/hour	1,358,380	1,358,380
ACC Design (1% DB) ITD, F	32.75	32.75
Total Cells	36	36
D Cells	4	6
K Cells	32	30
Unit Steam (Total) Flow, #/hour/cell	39,469	39,469
Total Air Flow, cfm	62,701,897	55,131,820
Air Flow (K & D), cfm/cell	1,741,719	1,531,439
Fan Power, HP	222.6	217.9
Fan Diameter, feet	36	36
Static Pressure, "H2O	0.466	0.481
Face Area, SF/cell	3,255	3,346
Footprint, SF	66,907	67,631

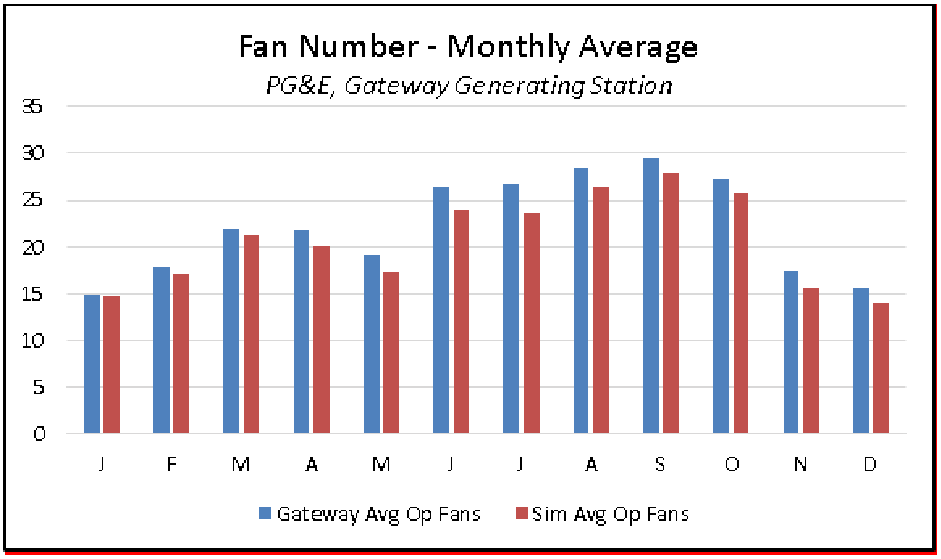
Source: Maulbetsch Consulting

Figure 15: Gateway – Back Pressure Comparison



Source: Maulbetsch Consulting

Figure 16: Gateway – Fan Number Comparison



Source: Maulbetsch Consulting

Redhawk

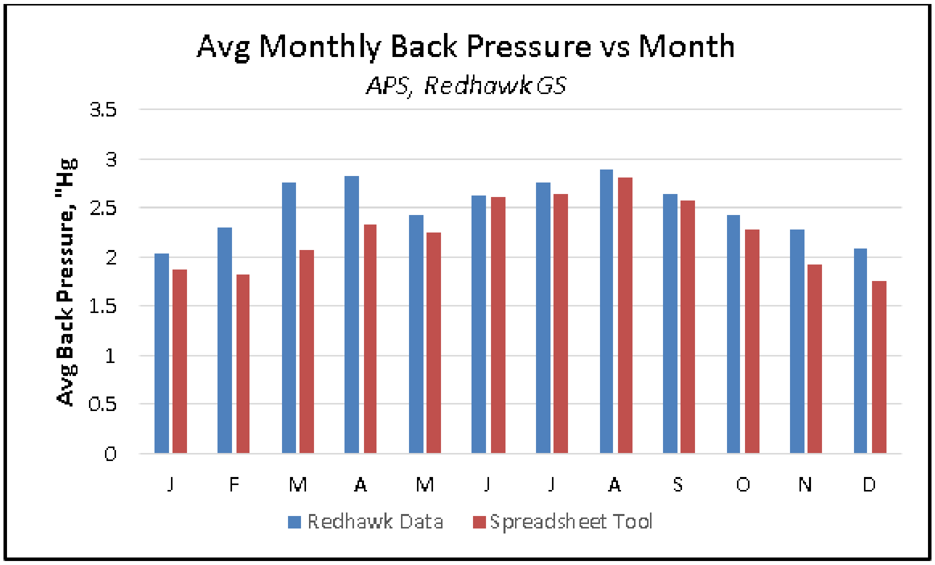
Table 14 compares the actual performance of the Redhawk cooling tower to modeling results. With the exception of air flow (8.1% difference) and cooling tower cross sectional area (11.1%), which is an indirect measure of cooling tower heat exchange surface area, all other parameters are within 3% to 5% of design. Comparison of back pressure found in Figure 17 is close except for February, March, and April and to a lesser extent for November, December, and January. The system was operated in this manner, because the two main bearings of the steam turbine began overheating during the colder months. One of the support piers for the turbine shifted slightly over time, and during cold weather, the frame of the steam turbine would move enough to cause an imbalance in the shaft and the bearings would overheat. Operators at Redhawk found that it was the high back pressure that prevented overheating; the support pier has since been repaired. This was the primary reason for the difference between plant actual performance and the tool prediction. Figure 18 shows a comparison of cooling tower evaporation rates. There is good agreement except for the months of June, July, and August. The plant uses a ZLD (Zero Liquid Discharge) system to manage water use. Five flow meters are used to calculate cooling tower evaporation. There is also a large surge pond that can store water and this can interfere with evaporation measurement. The team assumed there was a problem with flow measurement and/or water storage that created the difference in plant predicted values.

Table 14: Redhawk Cooling Tower – Design Parameters Validation

Design Parameter	Plant Design	Spreadsheet Tool
Heat Load, MMBTU/hour	1,216	1,194
Altitude, feet	1,107	1,107
Design Wet Bulb, F	79.0	79.0
Approach, F	9.0	9.0
Range, F	15.2	15.2
Circulating Water Flow, gpm	160,000	156,834
Cell Depth, feet	60	54
Cell Width, feet	54	54
Fill Depth, feet	5.0	5.0
KaV/L	(no data)	1.552
L/G	1.605	1.701
Cooling Tower Cells	9	9
Total Fill X-Sect Area, SF	29,160	26,244
CT Unit Flow, gpm/SF	5.49	5.98
CT Unit Flow, gpm/cell	17,778	17,426
Total Air Flow, CFM	12,440,000	11,505,031
Air Flow, CFM/Fan	1,382,222	1,278,337
Fan Power, HP	(no data)	125.7
Total Fan Power, HP	(no data)	843
Static Pressure, "H2O	0.330	0.349
Fan Diameter, feet	36	34

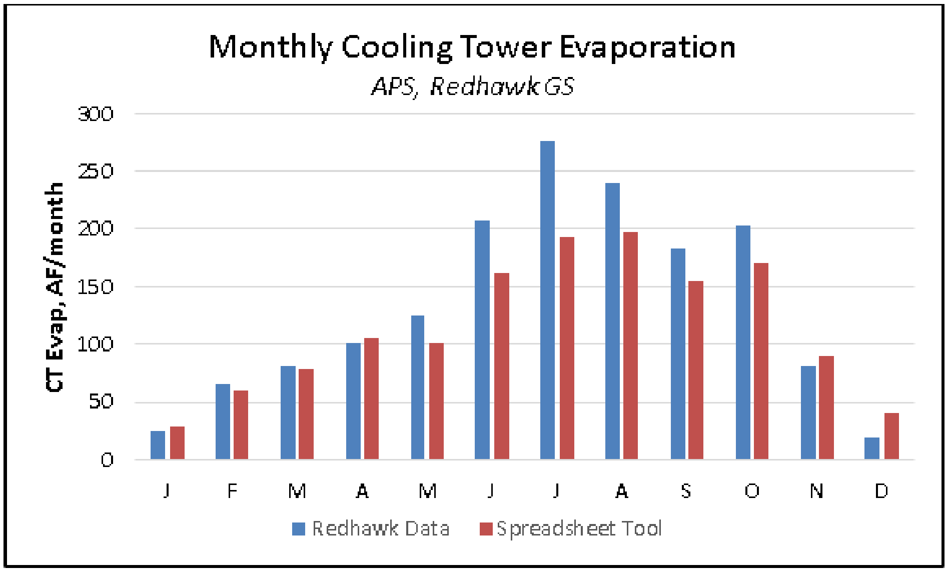
Source: Maulbetsch Consulting

Figure 17: Redhawk – Back Pressure Comparison



Source: Maulbetsch Consulting

Figure 18: Redhawk Generating Station – Cooling Tower Evaporation Comparison



Source: Maulbetsch Consulting

Goldendale

The ACC system design at Goldendale is outdated; heat exchangers in current ACC systems are significantly different and more efficient. Additionally, the physical size of the Goldendale system was smaller than current systems evaluated. As a result, the Spreadsheet Tool had to be modified to duplicate the design and performance of the Goldendale ACC. Refer to Table 15 for a comparison of the Goldendale ACC design basis to tool predictions, which are close to the Goldendale design.

The cooling towers at Goldendale are also somewhat unique in that fan speed and air flow can be varied from 40% to 100% of design using VFD control (variable frequency drive) for the fan motors. Based on information supplied by Goldendale, adjustments were made in 5% increments. Cooling tower fans are usually one speed; some cooling towers have two-speed motors. Adjustments were made to Tool calculations to duplicate this design feature. Table 16 shows the results of the plant design compared to Tool predictions. All design parameters are somewhat close with the exception of air flow (6% difference) and fan power (51% difference). Fan calculations in the Tool are based on a major manufacturer's design data for ACC fans. Parametric analysis was made for a variety of fans typically used in ACC systems and the results (which were relatively close) were averaged. This discrepancy in air flow and fan power was not typical in the other plant validations and cannot be explained.

Table 15: Goldendale ACC – Design Parameters Validation

Design Parameter	Plant Design	Spreadsheet Tool
Total (ACC + CT) Steam Flow, #/hour	666,700	666,700
BP (1% DB), "Hg	4.44	4.44
1% DB, F	90.00	90.00
Condensing Temp, F	129.30	129.30
Condensing Enthalpy, BTU/#	1,020.3	1,020.3
ACC Thermal Load, MMBTU/hour (1% DB)	272.1	285.7
CT Thermal Load, MMBTU/hour (1% DB)	408.1	428.5
Hybrid ACC Steam Flow, #/hour	266,680	266,680
ACC Design (1% DB) ITD, F	39.30	39.30
Total Cells	10	10
D Cells	2	2
K Cells	8	8
Unit Steam Flow, #/hour/cell	26,668	26,668
Total Air Flow, cfm	10,131,425	10,155,719
Air Flow (K & D), cfm/cell	1,013,142	1,015,572
Fan Power, HP	151.9	138.7
Fan Diameter, feet	30	30
Static Pressure, "H2O	0.608	0.525
Face Area, SF/cell	(no data)	1,977
Footprint, SF	14,916	14,448

Source: Maulbetsch Consulting

Figure 19 compares backpressure for the hybrid system to the tool prediction. It is important to note that with a hybrid system, a plant operator can vary ACC and cooling tower load sharing by increasing or decreasing air flow to either system. The variable speed control of cooling tower fans at Goldendale plant correlates with a significant amount of fine control in this area.

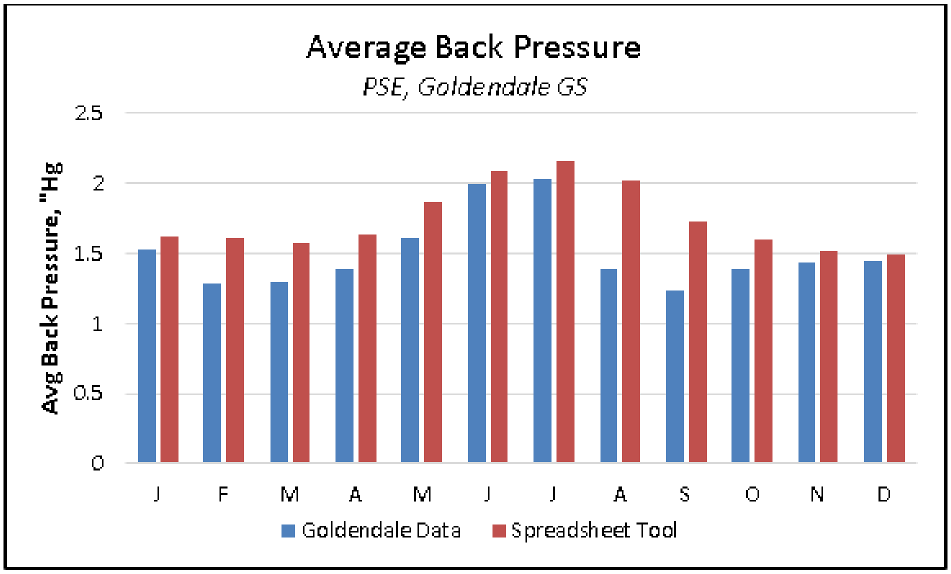
The tool is designed to solve for back pressure based on ambient conditions and the cooling capacities of the ACC and cooling tower; this solution is affected by the specific design of the system and assumes no operator involvement. These predictions are somewhat close for most of the year except for August and September. Figure 20 compares heat load share for the Goldendale ACC and the tool. Predictions are relatively close. Lastly, Figure 21 shows a comparison of actual cooling tower evaporation versus the tool prediction. There is relatively good agreement for most of the data; again, given the plant's ability to adjust load, it is somewhat difficult to predict performance.

Table 16: Goldendale Cooling Tower – Design Parameters Validation

Design Parameter	Plant Design	Spreadsheet Tool
Heat Load, MMBTU/hour	424.1	428.6
Altitude, feet	1,600	1,600
Design Wet Bulb, F	72.5	72.5
Approach, F	19.00	19.00
Range, F	24.2	24.2
Circulating Water Flow, gpm	35,000	35,838
Cell Depth, feet	48	48
Cell Width, feet	42	42
Fill Depth, feet	5.0	5.0
KaV/L	1.227	1.283
L/G	2.146	2.175
Cooling Tower Cells	2	2
Total Fill X-Sect Area, SF	4,032	4,032
CT Unit Flow, gpm/SF	8.68	8.89
CT Unit Flow, gpm/cell	17,500	17,919
Total Air Flow, CFM	2,239,096	2,110,675
Air Flow, CFM/Fan	1,119,548	1,055,337
Fan Power, HP	105.4	159.2
Total Fan Power, HP	210.7	318.5
Static Pressure, "H2O	0.532	0.552
Fan Diameter, feet	28	28

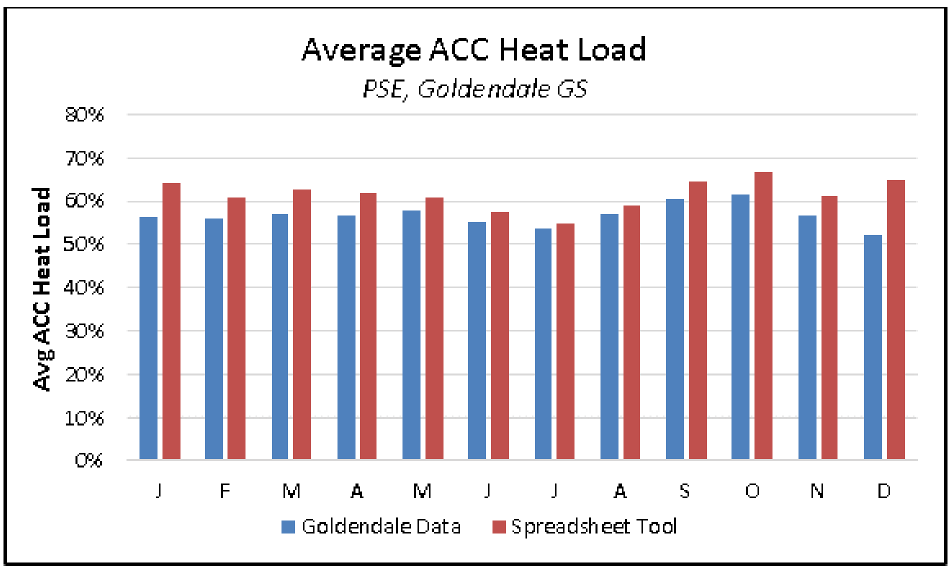
Source: Maulbetsch Consulting

Figure 19: Goldendale – Back Pressure Comparison



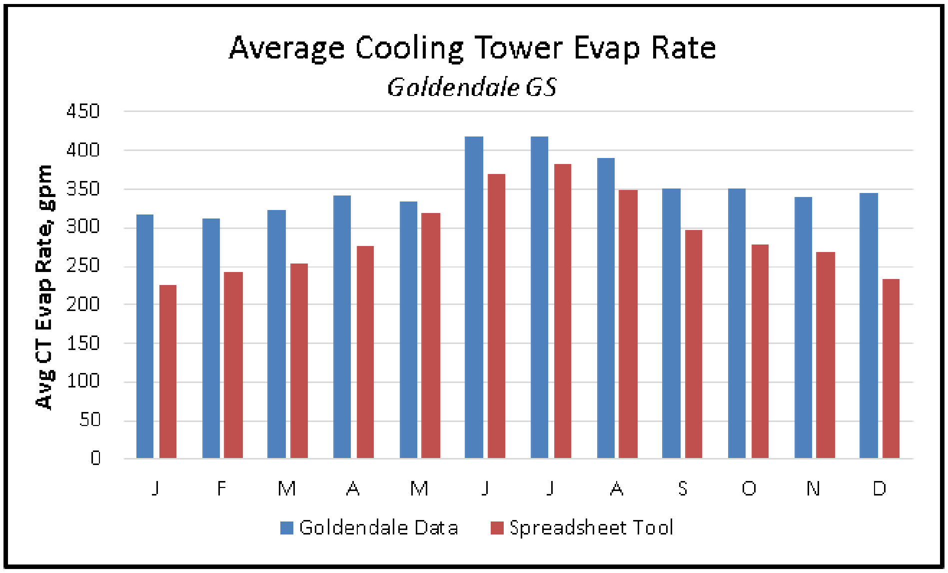
Source: Maulbetsch Consulting

Figure 20: Goldendale – Average ACC heat load



Source: Maulbetsch Consulting

Figure 21: Goldendale – Cooling Tower Evaporation Comparison



Source: Maulbetsch Consulting

CHAPTER 4
Case Studies

Introduction

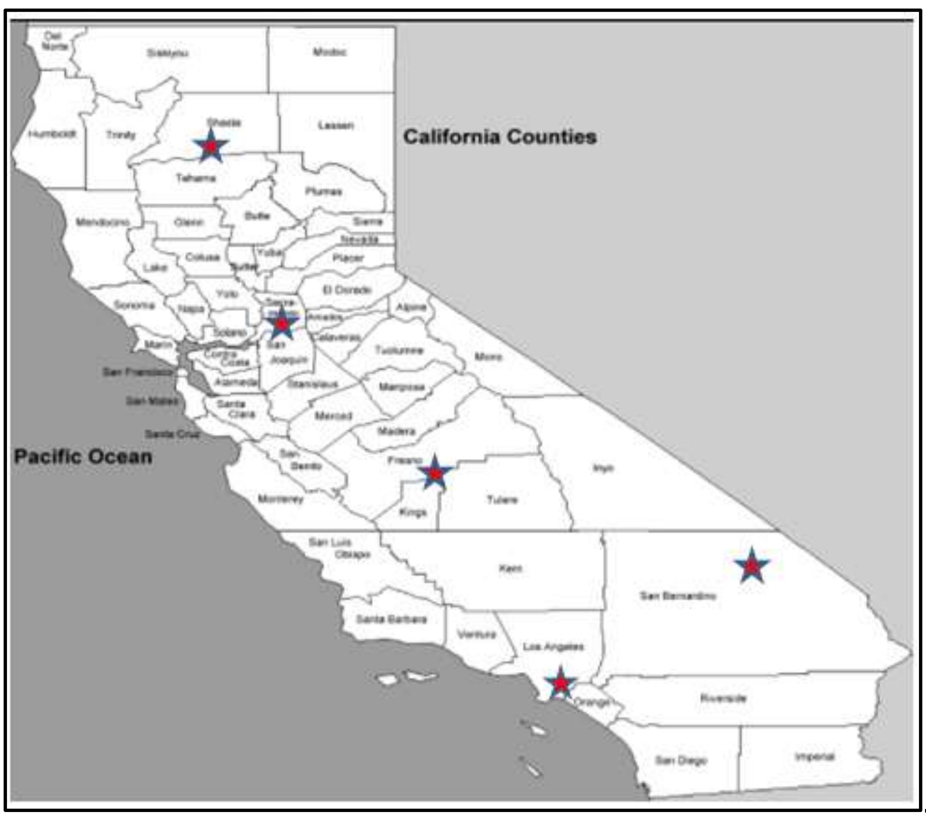
The validated tool was used to conduct case study comparisons of the cost, performance and water consumption of all-wet, all-dry and hybrid cooling systems at several sites. This phase of the work consisted of several tasks:

- Selecting five sites
- Determining site environmental characteristics
- Specifying plant design specifications and operating characteristics
- Specifying specific bases of comparison
- Computing comparable results
- Evaluating site-to-site comparisons

Selection of sites

The five sites were selected to represent the range of climatic conditions found in California. They are Sacramento, Blythe, Long Beach, Bakersfield, and Redding (Figure 22).

Figure 22: Five Case Study Site Location



Source: Maulbetsch Consulting

Site Characteristics

The general environmental characteristics of the sites are listed in Table 17. Detailed meteorological information of the type required for the design and evaluation of the cooling systems are provided in Table 18 and Figures 23 and 24.

Table 17: General Site Characteristics

Site	Location	Characteristics
Sacramento (SAC)	Sacramento/San Joaquin River Delta	Hot, dry summers; damp to wet mild winters
Blythe (BLY)	Near California/Arizona border; Colorado Desert section of Sonoran Desert	Very hot summers; mild winters
Long Beach (LGB)	20 miles south of Los Angeles; 4 miles inland from Pacific Ocean	Mediterranean, semi-arid; mild temperatures throughout year
Bakersfield (BAK)	Southern end of San Joaquin Valley	Long, hot, dry summers; Brief, cool slightly moist winters
Redding (RDD)	Northwestern end of Central Valley/Cascade Foothills	Hot, dry summers; cool, wet winters

Source: Maulbetsch Consulting

Table 18: Site Meteorological Values

Site	Ambient Temperature, ˚F			Ambient Wet Bulb Temperature, ˚F				Elevation, ft
	Max	Min	1%	Max	Min	1%	MCWB @ 1% dry bulb	
Sacramento (SAC)	106	27	98.3	74	26	71.3	68	95
Blythe (BLY)	112	22	110	76	18	76.1	68	1926
Long Beach (LGB)	103	36	91.2	80	33	72	68	10
Bakersfield (BAK)	109	29	100.4	76	28	69.7	70	492
Redding (RDD)	113	24	103.9	70	22	70.2	69	497

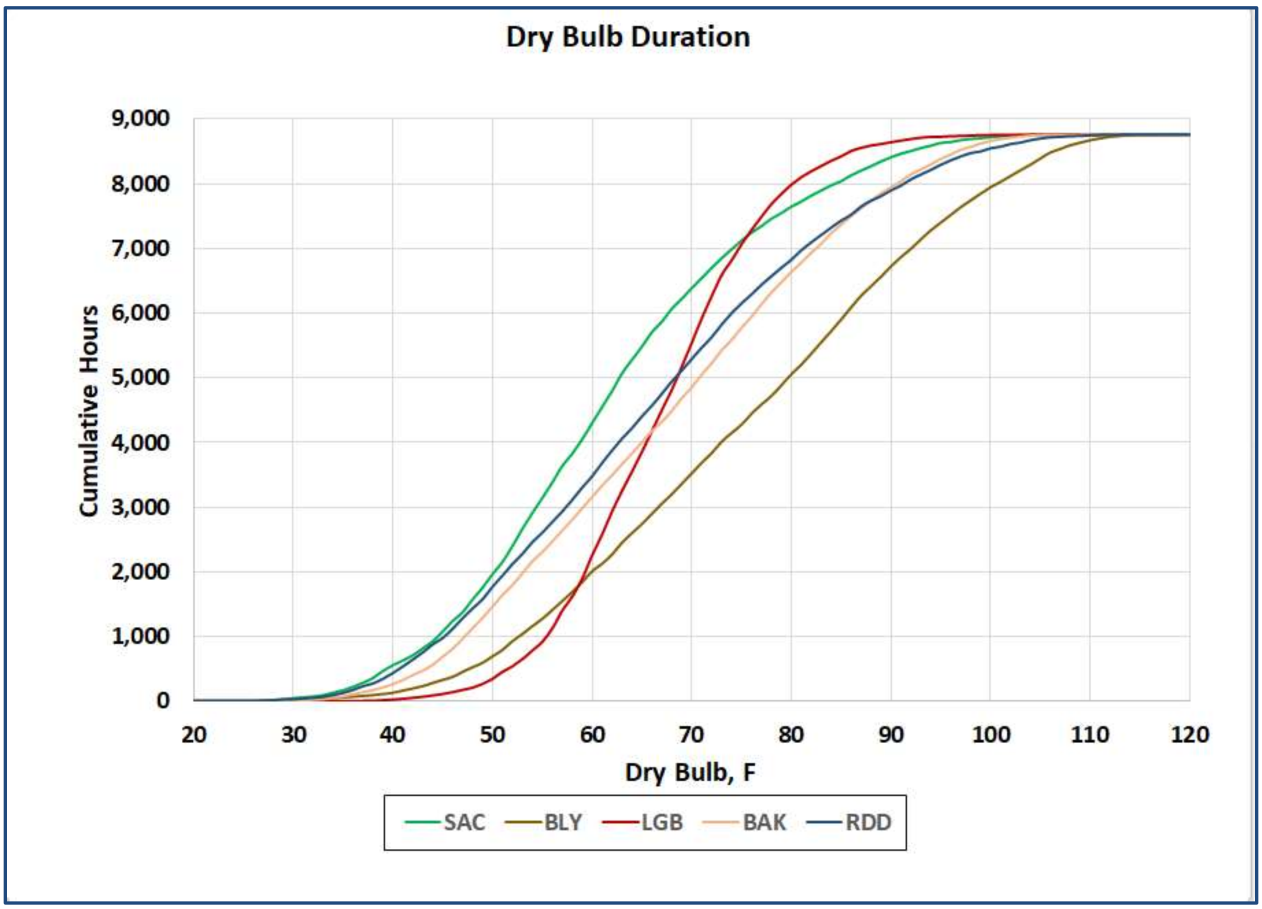
Source: Maulbetsch Consulting

Figure 23 displays the annual duration curves for ambient temperature and is interpreted as the hours on the ordinate represent the number of hours per year when the temperature is **below** the value on the abscissa. For example, this information indicates that the ambient temperature at Blythe is below 80 ˚F for only 5,000 hours per year, whereas the ambient temperature in Sacramento is below 80 ˚F for about 7,600 hours per year. In general, lower curves represent hotter sites.

Figure 24 plots the mean coincident wet bulb (MCWB) versus the ambient dry bulb temperature. The MCWB is relevant for the design of the hybrid systems since the starting point for the design is the 1% dry bulb temperature to size the dry element's ACC. The corresponding wet element's cooling tower must then be sized at the corresponding wet bulb temperature, which is selected as the MCWB at the 1% dry bulb.

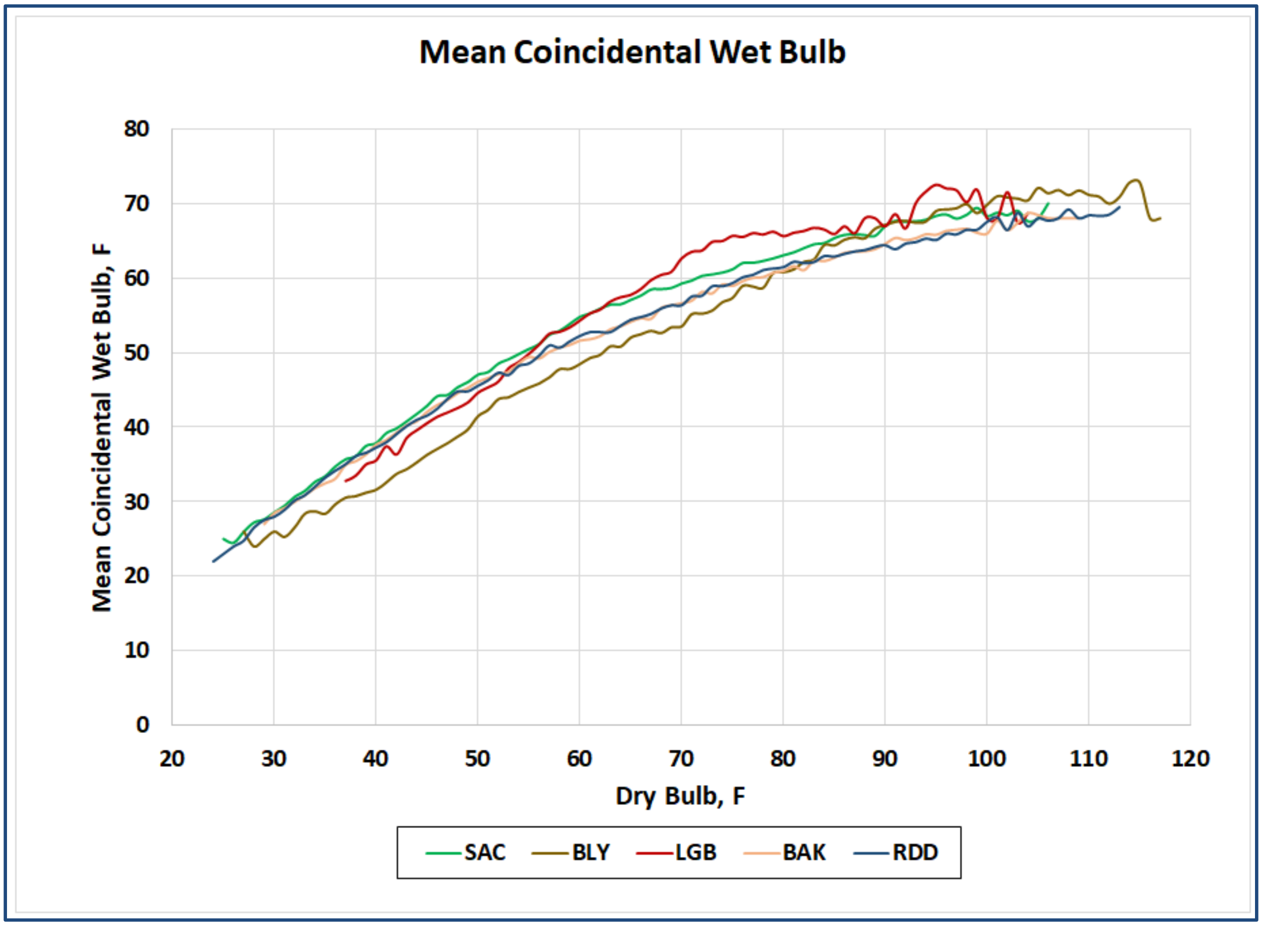
The ambient temperatures, while significantly different from site to site, exhibit reasonably similar seasonal variability for four of the five sites. The exception is Long Beach, the coastal site, which cools rapidly (the most hours below 80 ˚F for all sites) and then stays more moderate for most of the year having the fewest hours below 60 ˚F for all sites. The wet bulb temperature at Long Beach also exhibits different behavior from the other sites, with fewer hours below a wet bulb of 62 ˚F than any of the other sites.

Figure 23: Temperature Duration Curves



Source: Maulbetsch Consulting

Figure 24: Mean Coincident Wet Bulb vs. Ambient Dry Bulb Temperature

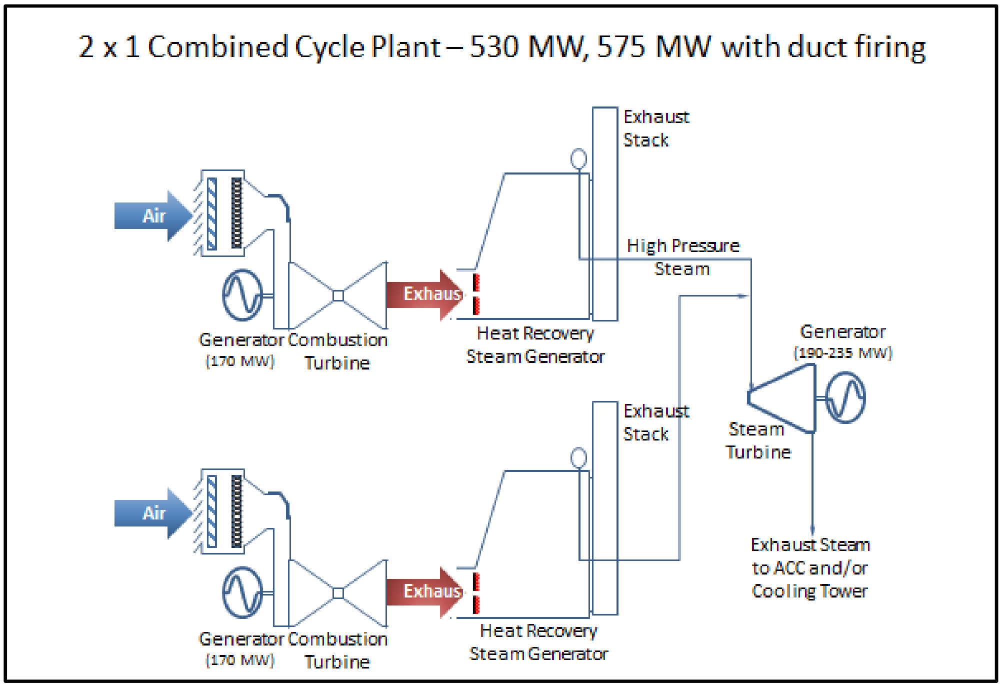


Source: Maulbetsch Consulting

Plant Selection

The same plant design to compare the cooling systems was used at each site and corresponds to the usual plant type and size most common for new plant construction in California and elsewhere, comparable to the Gateway and Colusa plants. It is a 530 MW (gross) gas-fired, combined-cycle plant in a 2 x 1 configuration consisting of two combustion turbines (CT), each rated at 170 MW, two heat recovery steam generators (HSRG) and one steam turbine (ST) rated at 190 MW (Figure 25).

Figure 25: Schematic of Plant for Case Study Analyses

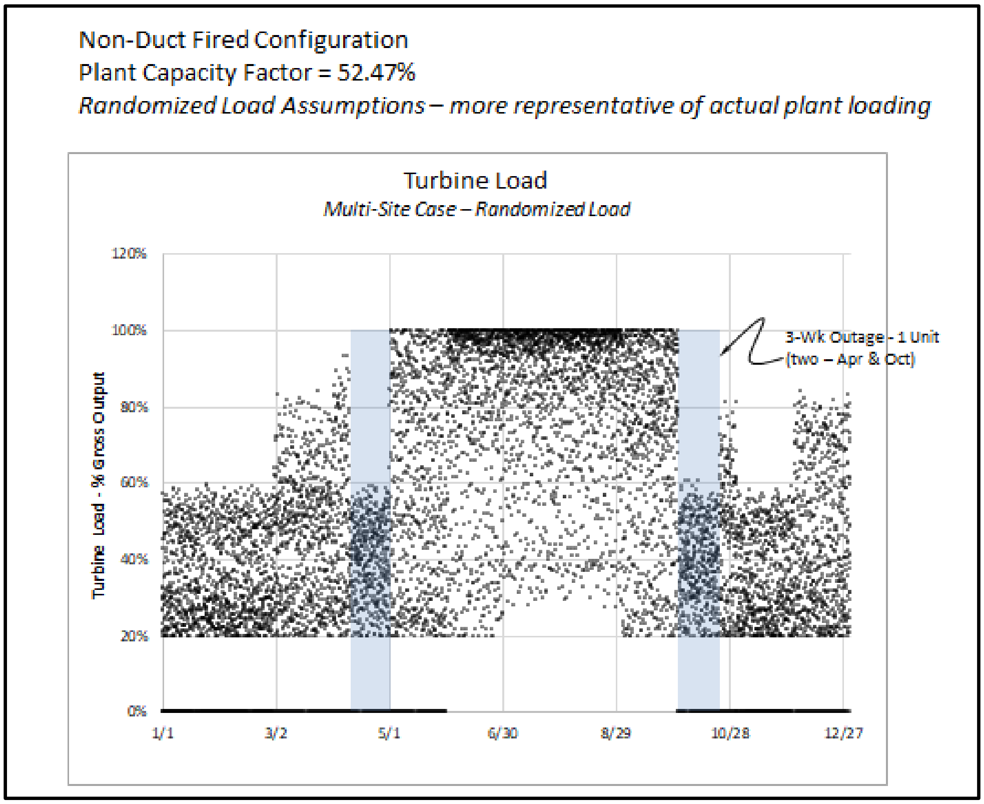


Source: Maulbetsch Consulting

Some plants are equipped with duct burners to increase the heat content of the exhaust gas flow from the CTs to the HRSGs under conditions of high demand or when the CT output is limited. In order to get a more consistent set of operating conditions for the case study comparisons, the use of duct firing will not be considered.

The same annual operating profile is used at each site and tailored to provide an annual capacity factor of more than 52%, which the Energy Commission has indicated is typical for plants of this type in California in recent years [6]. To provide a measure of realism, two brief outages were scheduled; one three week outage for each unit in April and October of the year. This profile, randomized to be representative of plant loading, is illustrated in Figure 25. As noted in the previous chapter, this compares adequately with the operating data from Gateway for 2016.

Figure 26: Plant Operating Profile



Source: Maulbetsch Consulting

Cooling System Design Points

The design points for the three cooling systems are the same for all sites; specifically

- All-wet systems
  - Turbine exhaust steam flow: 1.1 x 10^6 lb/hr
  - Turbine exhaust steam quality: 95%
  - Design ambient wet bulb: 1% wet bulb
  - Turbine exhaust pressure: 3.5 in Hga
  - Constraints
    - Condenser TTD > 5 ˚F
    - Cooling tower approach > 5 ˚F
- All-dry systems
  - Turbine exhaust steam flow: 1.1 x 10^6 lb/hr
  - Turbine exhaust steam quality: 95%
  - Design ambient temperature: 1% dry bulb
  - Turbine exhaust pressure: 7. in Hga
- Hybrid systems
  - Turbine exhaust steam flow: 1.1 x 10^6 lb/hr
  - Turbine exhaust steam quality: 95%
  - Design ambient temperature: 1% dry bulb
  - Design ambient wet bulb: Mean coincident wet bulb @ 1% dry bulb
  - Turbine exhaust pressure: 4. in Hga

- Alternative sizings:
  - Fraction of heat load on dry element at design conditions
    - 70%, 50%, 30% (designated as HYB-A, HYB-B AND HYB-C)

System Designs

The selected designs for the all the cooling systems are presented and discussed below.

All-Wet Cooling

The estimated design values for the all-wet cooling systems at each of the five sites are listed in Table 19.

Table 19: All-Wet Cooling System Design Values

System Designs--Wet Cooling					
	SAC	BLY	LGB	BAK	RDD
ST Output, MW	190				
Steam Flow, #/hour	1,215,000				
Steam Quality, #/#	0.96				
CT 1% WB BP, "Hga	3.50				
1% WB, F	71.3	76.1	72.0	69.7	70.2
Elev, feet	30	272	0	404	564
Approach, F	10.00	10.00	10.00	10.00	10.00
Range, F	20.00	20.00	20.00	20.00	20.00
Cond TTD, F	19.25	14.47	18.57	20.87	20.37
CT Cells	8	8	8	9	9
CT Fan Diam, feet	36	34	36	36	36
Fill X-Sect Area, SF	25,920	23,328	25,920	29,160	29,160
CT Op Fan Motor HP	125	116	115	100	101
Air Flow, CFM/cell	1,394,134	1,250,749	1,351,216	1,300,747	1,305,748
CT L/G	1.274	1.464	1.297	1.236	1.260

Source: Maulbetsch Consulting

The all-wet cooling systems are reasonably similar for all sites. The towers at Bakersfield and Redding are slightly larger (nine cells vs. eight cells at the other three sites) but with a resulting higher cross-section area of fill, less air flow per cell and slightly lower fan power per cell at design. Apparently the differences in site elevation and minor differences in wet bulb temperature throughout the year were enough to tilt the preferred tower design to a slightly different configuration in order to reach the proper trade-off between capital and operating costs.

The cooling system at Blythe operates at a higher Liquid/Gas (L/G) ratio on the cooling tower and a lower TTD in the condenser. This is a result of the significantly higher wet bulb temperature at the design point and of high wet bulb temperatures during the year; there were about 1,500 more hours at wet bulb temperatures above 65 ˚F compared to the four other study sites. For the same heat loads and condensing temperature, this leads to higher hot water and cold water temperatures in the condenser and the tower. The condenser therefore must have a lower TTD to maintain the same condensing temperature (turbine exhaust pressure) and the tower can operate at a higher L/G (less air flow) to reject the same heat load.

All-Dry Cooling

The estimated design values for the all-dry cooling systems at each of the five sites are listed in Table 20.

Table 20: All-Dry Cooling System Design Values

System Designs--Dry Cooling					
	SAC	BLY	LGB	BAK	RDD
ST Output, MW	190				
Steam Flow, #/hour	1,215,000				
Steam Quality, #/#	0.96				
ACC 1% DB BP, "Hga	7.00				
1% DB, F	98.3	110.0	91.2	100.4	103.9
Elev, feet	30	272	0	404	564
ACC ITD, F	48.55	36.85	55.65	46.45	42.95
ACC Cells	20	25	18	20	24
ACC Fan Diam, feet	36	36	36	36	36
ACC HX Ext Area, SF	7,287,337	10,020,089	6,376,420	7,773,160	8,258,982
ACC Op Fan Motor HP	224	223	206	229	218
Air Flow, CFM/cell	1,546,133	1,626,812	1,475,198	1,619,637	1,496,257

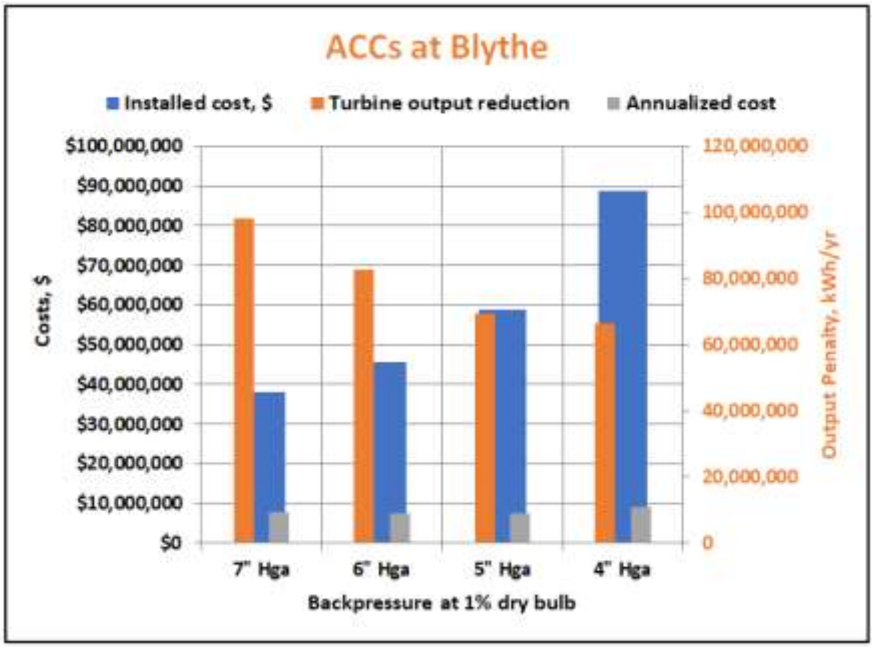
Source: Maulbetsch Consulting

The sizes of the ACCs vary as would be expected for cases with the same heat load and turbine exhaust pressure at different ambient design temperatures. A lower initial temperature difference (ITD) (larger ACC) is required to maintain the same condensing pressure at higher ambient temperatures. It is noteworthy, however, the ACCs selected for these case study locations are significantly smaller than ACCs which are currently installed and operating at locations with similar meteorology; for example, the ACCs at Gateway and Colusa are 36 and 42 cells, respectively, compared to 20 cells selected for the Sacramento case study.

This is the result of specifying a seven in Hga design backpressure at the 1% dry bulb temperature at each site. Figure 27 shows a comparison of initial installed cost, turbine output reduction and annualized cost for four separate design choices of 4, 5, 6 and 7 "Hga at Blythe. As the turbine backpressure design point is reduced from 7 "Hga to 4"Hga, the initial cost rises rapidly. The turbine output reduction is reduced, rapidly at first but then more moderately below 5"Hga. The annualized cost, which represents a balance of the two factors, varies little across the range. The 5"Hga point represents a point at just before a rapid rise in cost and just after the turbine output reduction starts to level off. This is a frequently selected design point and results in ACCs of the general size found at Gateway and Colusa.

The 7 "Hga design point was selected to obtain a low cost all-dry cooling system that could still ensure that the turbine backpressure would not exceed the typical alarm point of 7 "Hga at the hot day design point. While this design choice sacrifices some degree of plant efficiency throughout the year, it provides the minimum cost approach to maximum water conservation to serve as a benchmark comparison with hybrid designs.

Figure 27: Effect of ACC Design Point Choice at Blythe



Source: Maulbetsch Consulting

Hybrid Cooling

The estimated design values for three alternative hybrid cooling systems at each of the sites are listed in Tables 21, 22 and 23.

The three hybrid systems have different splits between the wet and dry capabilities of the systems. They differ in the specification of the fraction of the heat load carried by the dry element **at the design point**; specifically, HYB-A can carry 70% of the total hat load at the 1% dry bulb design temperature; HYB-B, 50% and HYB-C, 30%. As expected, HYB-A results in the largest, and most expensive, ACC but has the lowest water consumption. These “% values” should not be interpreted as a “percent water reduction.” As the fraction of heat load handled by the ACC is increased, the water consumption will be reduced.

Table 21: Hybrid Cooling System (HYB-A) Design Values

System Designs--Hybrid Cooling --HYB-A					
	SAC	BLY	LGB	BAK	RDD
ST Output, MW	190				
Steam Flow, #/hour	1,215,000				
Steam Quality, #/#	0.96				
1% DB, F	98.3	110.0	91.2	100.4	103.9
1% WB, F	71.3	76.1	72.0	69.7	70.2
Elev, feet	30	272	0	404	564
Dry Portion					
ACC Thermal Load at 1% DB	70%	70%	70%	70%	70%
ACC 1% DB BP, "Hg	4.00	4.00	4.00	4.00	4.00
ACC ITD, F	27.14	15.44	34.24	25.04	21.54
ACC Cells	25	45	20	25	30
ACC Fan Diam, feet	36	36	36	36	36
ACC HX Ext Area, SF	9,716,450	17,489,609	7,773,160	10,931,006	12,752,850
ACC Op Fan Motor HP	237	230	217	240	234
Air Flow, CFM/cell	1,630,991	1,619,266	1,577,415	1,747,639	1,711,658
Wet Portion					
CT Cells	3	3	3	3	3
CT Fan Diam, feet	32	32	32	32	32
Fill X-Sect Area, SF	7,776	7,776	7,776	7,776	7,776
CT Op Fan Motor HP	111	77	105	125	120
Air Flow, CFM/cell	1,145,276	1,005,912	1,123,708	1,197,110	1,181,522
CT L/G	1.274	1.464	1.297	1.236	1.260

Source: Maulbetsch Consulting

Table 22: Hybrid Cooling System (HYB-B) Design Values

System Designs--Hybrid Cooling --HYB-B					
	SAC	BLY	LGB	BAK	RDD
ST Output, MW	190				
Steam Flow, #/hour	1,215,000				
Steam Quality, #/#	0.96				
1% DB, F	98.3	110.0	91.2	100.4	103.9
1% WB, F	71.3	76.1	72.0	69.7	70.2
Elev, feet	30	272	0	404	564
Dry Portion					
ACC Thermal Load at 1% DB	50%	50%	50%	50%	50%
ACC 1% DB BP, "Hg	4.00	4.00	4.00	4.00	4.00
ACC ITD, F	27.14	15.44	34.24	25.04	21.54
ACC Cells	18	30	15	18	24
ACC Fan Diam, feet	36	36	36	36	36
ACC HX Ext Area, SF	6,922,970	12,752,850	5,465,505	7,651,710	8,744,808
ACC Op Fan Motor HP	219	226	195	237	218
Air Flow, CFM/cell	1,574,969	1,682,186	1,465,952	1,714,894	1,542,914
Wet Portion					
CT Cells	4	4	4	5	5
CT Fan Diam, feet	32	32	32	32	32
Fill X-Sect Area, SF	10,368	10,368	10,368	12,960	12,960
CT Op Fan Motor HP	217	150	205	125	120
Air Flow, CFM/cell	1,431,595	1,257,390	1,404,635	1,197,110	1,181,522
CT L/G	1.274	1.464	1.297	1.236	1.260

Source: Maulbetsch Consulting

Table 23: Hybrid Cooling System (HYB-C) Design Values

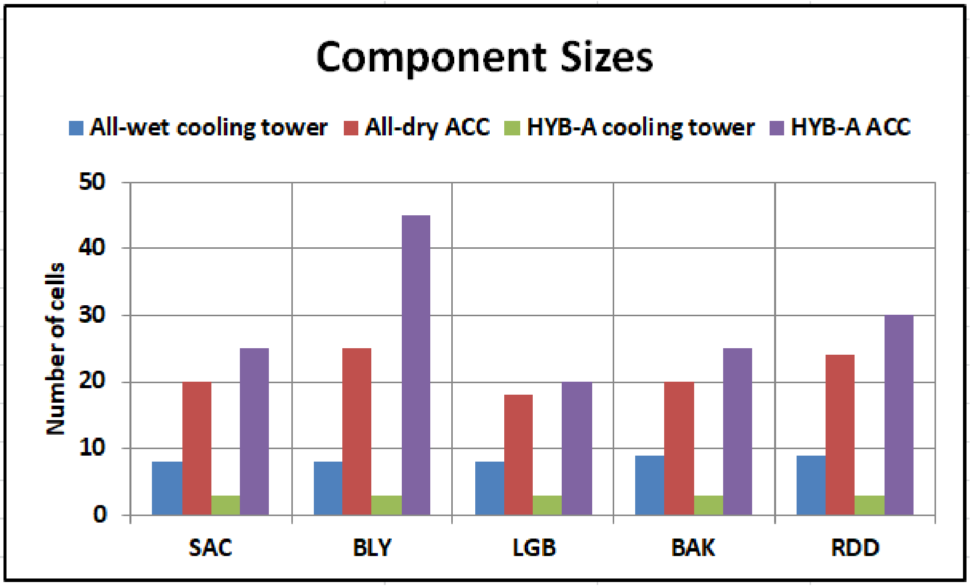
System Designs--Hybrid Cooling --HYB-C					
	SAC	BLY	LGB	BAK	RDD
ST Output, MW	190				
Steam Flow, #/hour	1,215,000				
Steam Quality, #/#	0.96				
1% DB, F	98.3	110.0	91.2	100.4	103.9
1% WB, F	71.3	76.1	72.0	69.7	70.2
Elev, feet	30	272	0	404	564
Dry Portion					
ACC Thermal Load at 1% DB	30%	30%	30%	30%	30%
ACC 1% DB BP, "Hg	4.00	4.00	4.00	4.00	4.00
ACC ITD, F	27.14	15.44	34.24	25.04	21.54
ACC Cells	12	18	10	12	15
ACC Fan Diam, feet	36	36	36	36	36
ACC HX Ext Area, SF	4,129,488	7,469,521	3,522,210	4,372,404	5,283,315
ACC Op Fan Motor HP	161	221	102	206	174
Air Flow, CFM/cell	1,325,367	1,649,282	1,134,713	1,506,388	1,393,637
Wet Portion					
CT Cells	6	6	6	6	6
CT Fan Diam, feet	32	32	32	32	32
Fill X-Sect Area, SF	15,552	15,552	15,552	15,552	15,552
CT Op Fan Motor HP	176	122	167	199	191
Air Flow, CFM/cell	1,336,155	1,173,564	1,310,993	1,396,628	1,378,442
CT L/G	1.274	1.464	1.297	1.236	1.260

Source: Maulbetsch Consulting

The variation in the cooling system designs from site to site are for the same reasons as those discussed for the all-wet and all-dry systems. The site-to-site differences for all the systems in component size, expressed as the number of cells in the wet cooling towers and the ACCs, are shown in Figures 28, 29 and 30.

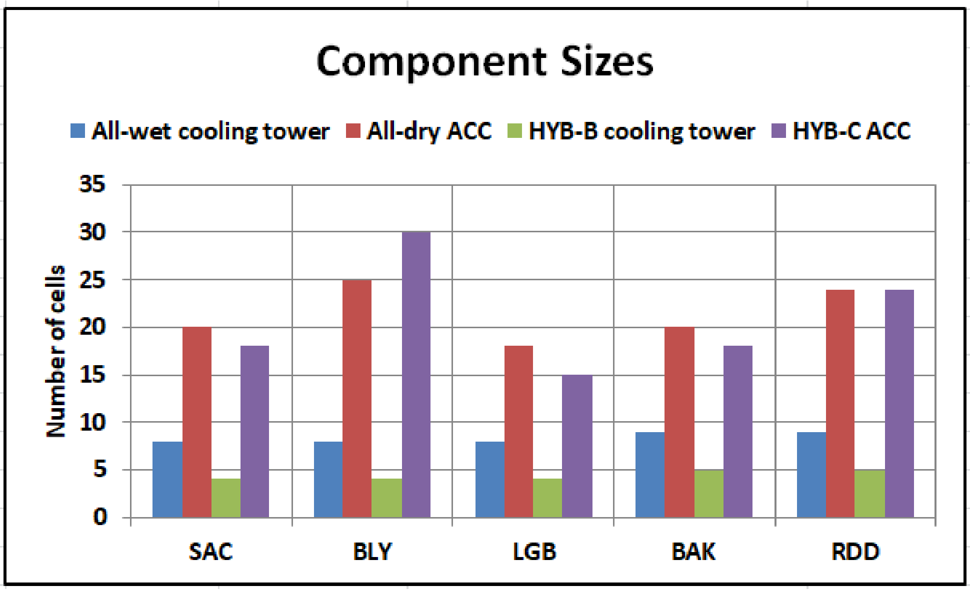
For HYB-A and HYB-B, the ACCs associated with the hybrid systems are larger than those for the all-dry systems. This would be unusual for competitive designs at actual plants, but is the case for these studies for two reasons. First, as mentioned, the all-dry system ACCS are smaller than the usual choices because of the choice of a seven in Hga design point. Second, the hybrid systems are designed for a design backpressure of four in Hga which requires a larger ACC for an equivalent heat load. Finally, HYB-A and HYB-B are designed for much greater amounts of dry operation and correspondingly much greater reductions in water consumption than typical. This was done to explore the limits of water conservation achievable. HYB-C corresponds more closely to the “typical” 50% water consumption compared to all-wet systems. For those cases both the wet cooling towers and the ACCs are smaller than the corresponding components for the all-wet and all-dry systems.

Figure 28: Component Sizes for All-Wet, All-Dry and Hybrid (HYB-A)



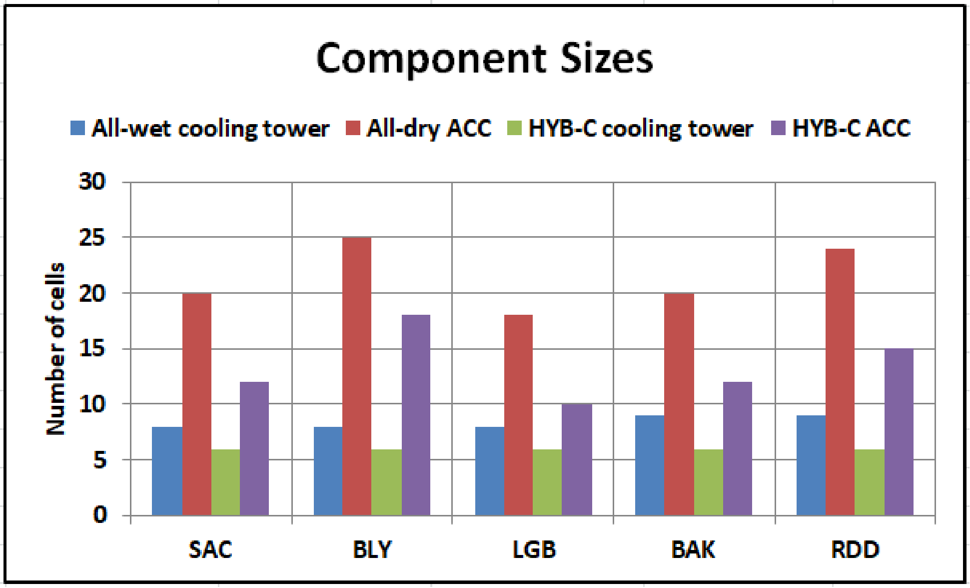
Source: Maulbetsch Consulting

Figure 29: Component Sizes for All-Wet, All-Dry and Hybrid (HYB-B)



Source: Maulbetsch Consulting

Figure 30: Component Sizes for All-Wet, All-Dry and Hybrid (HYB-C)



Source: Maulbetsch Consulting

Operating results

Tables 24 through 28 provide the performance results for the alternative cooling systems whose designs are listed in the preceding tables for each of the five sites. The important comparisons are

- System operating power requirement (pumps and fans).
- Reduction in steam turbine output (at design point and annual average).
- Total reduction in plant output (steam turbine output reduction plus power requirement).
- Annual water consumption.

Wet Cooling Systems:

The performance results for all-wet systems are displayed in Table 24.

Table 24: All-Wet System Operating Points

	Operating Points--All-wet cooling				
	SAC	BLY	LGB	BAK	RDD
Plant Oper, hrs/year	8,185	8,185	8,185	8,185	8,185
Avg BP, "Hg	1.97	2.05	2.11	2.02	2.00
BP >5"Hg, hours/year	6	9	5	42	16
CT Oper, hrs/year	8,185	8,185	8,185	8,185	8,185
Avg CT Evap, gpm	1169.0	1317.7	1165.4	1235.0	1270.4
CT Evap, kgal/year	574,117	647,122	572,310	606,506	623,888
CT Evap, AF/year	1,761.9	1,985.9	1,756.4	1,861.3	1,914.6
Avg CT Op Fans	5.74	5.75	5.73	6.16	6.44
CT Power, kWhr/year	15,935,124	15,581,561	15,518,732	15,256,993	15,482,255
Total Power, kWhr/year	15,935,124	15,581,561	15,518,732	15,256,993	15,482,255
ST Penalty, kwh/year	-23,656,833	-26,116,149	-27,662,219	-27,723,528	-40,208,607
Avg ST Output Penalty, MW	-2.89	-3.19	-3.38	-3.39	-3.18
Output at 2 "Hga, MWh/yr	873,601	874,364	873,769	873,236	873,548
Adjusted output, MWh/yr	834,009	832,666	830,588	830,255	818,283

Source: Maulbetsch Consulting

The performance of the all-wet cooling systems varies little from site to site.

- The annual plant output varies from 818,238 MWh/yr at Redding to 834,009 MWh/yr at Sacramento, a variation among the five sites of less than +/- 1%.
- The average turbine exhaust pressure varies from a minimum of 1.97 in Hga at Sacramento to a maximum of only 2.11 in Hga at Long Beach.
- The total operating power requirements vary from 15,256 MWh/yr. at Bakersfield to 15,935 MWh/yr at Sacramento, a difference of just over 4%.
- The steam turbine output reduction due to cooling system limitation varies significantly from 23,657 MWh/yr at Sacramento to 40,209 MWh/yr at Bakersfield, a difference of just over +/- 25%.
- The total reduction in plant output is the sum of the operating power requirements and the steam turbine output reduction. This varies from 39,592 MWh/yr at Sacramento to 55,691 MWh/yr at Redding, a difference of 40%.

All-Dry Cooling Systems:

The performance results for all-dry systems are provided in Table 25.

Table 25: All-Dry System Operating Points

	Operating Points--All-dry cooling				
	SAC	BLY	LGB	BAK	RDD
Plant Oper, hrs/year	8,185	8,185	8,185	8,185	8,185
Avg BP, "Hg	3.83	3.47	4.43	3.38	3.23
BP >5"Hg, hours/year	168	118	140	64	96
Avg ACC Fan Number	21.89	28.93	19.66	22.87	26.33
ACC Power, kWh/year	12,063,244	15,828,556	9,922,252	12,475,580	14,066,726
Total Power, kWhr/year	12,063,244	15,828,556	9,922,252	12,475,580	14,066,726
ST Penalty, kwh/year	-95,429,488	-82,190,565	-112,255,249	-79,353,134	-73,089,762
Avg ST Output Penalty, MW	-11.66	-10.04	-13.71	-9.69	-8.93
Output at 2 "Hga, MWh/yr	873,601	874,364	873,769	873,236	873,548
Adjusted output, MWh/yr	766,109	776,345	751,591	781,407	786,392

Source: Maulbetsch Consulting

- The annual plant output varies from 751,591 MWh/yr at Long Beach to 786,392 MWh/yr at Redding, a variation among the five sites of less than +/- 3%.
- The average turbine exhaust pressure varies from a minimum of 3.23 in Hga at Redding to a maximum of only 4.43 in Hga at Long Beach.
- The total operating power requirements vary significantly from 9,922 MWh/yr. at Long Beach to 15,829 MWh/yr at Blythe. The other sites are all in the 12,000 to 14,000 MWh/yr range.
- The steam turbine output reduction due to cooling system limitation varies significantly from 73,090 MWh/yr at Redding to 112,255 MWh/yr at Long beach, a difference of over 50%.
- The total reduction in plant output is the sum of the operating power requirements and the steam turbine output reduction. This varies from 87,156 MWh/yr at Redding to 122,177 MWh/yr at Long Beach, a difference of over 40%.

Hybrid Cooling Systems:

Hybrid systems of three different designs were analyzed. They differed in the fraction of the total cooling system heat load that could be handled by the dry element at the design point. As this fraction is increased, the number of hours per year that can be operated with the cooling system in an all-dry mode increases and more the annual water consumption is reduced. The “driest” of the three hybrid systems (HYB-A) is sized to handle 70% of the heat load with the ACC at design; HYB-B, 50%; and HYB-C, 30%.

The performance results of the hybrid cooling systems are shown in Tables 26, 27, and 28.

Table 26: Hybrid System (HYB-A) Operating Points

	Operating Points--Hybrid Cooling --HYB-A				
	SAC	BLY	LGB	BAK	RDD
Plant Oper, hrs/yr	8,185	8,185	8,185	8,185	8,185
Avg BP, "Hg	2.19	2.26	2.31	2.26	2.21
BP >5"Hg, hours	22	18	63	25	35
CT Oper, hrs/yr	2,584	2,951	4,470	3,106	2,489
Avg CT Op Fans	0.70	0.83	1.21	0.88	0.70
CT Evap, kgal/yr	72,100	88,708	118,663	95,057	76,183
CT Evap, AF/yr	221.3	272.2	364.2	291.7	233.8
Avg ACC Fan Number	27.79	49.01	20.88	26.96	33.44
ACC Power, kWh/yr	15,909,645	26,379,826	10,773,666	15,281,693	18,807,626
CT Power, kWhr/yr	1,540,647	1,591,754	2,637,638	1,941,745	1,527,263
Total Power, kWhr/yr	17,450,291	27,971,580	13,411,304	17,223,439	20,334,889
ST Penalty, kwh/yr	-17,674,969	-22,955,576	-26,550,665	-23,076,030	-19,138,896
ST Output Penalty, MW	-2.16	-2.80	-3.24	-2.82	-2.34
ST Out Penalty rel to CT, MW	0.73	0.39	0.14	0.57	2.57
ST Out Penalty rel to CT, kWhr	5,981,864	3,160,573	1,111,554	4,647,497	21,069,711
Output at 2 "Hga, MWh/yr	873,601	874,364	873,769	873,236	873,548
Adjusted output, MWh/yr	838,476	823,436	833,807	832,937	834,074

Source: Maulbetsch Consulting

- The annual plant output varies from 823,238 MWh/yr at Blythe to 838,476 MWh/yr at Sacramento, an overall variation of less than 2%.
- The average turbine exhaust pressure varies from a minimum of 2.19 in Hga at Sacramento to a maximum of only 2.31 in Hga at Long Beach.
- The total operating power requirements vary from 13,411 MWh/yr. at Long Beach to 27,972 MWh/yr at Blythe, or more than a doubling from the lowest to the highest sites.
- The steam turbine output reduction due to cooling system limitation varies significantly from 17,675 MWh/yr at Sacramento to 26,551 MWh/yr at Bakersfield, a difference of about +/- 25%.
- The total reduction in plant output is the sum of the operating power requirements and the steam turbine output reduction. This varies from 35,125 MWh/yr at Sacramento to 50,927 MWh/yr at Blythe, a difference of just over 40%.

Table 27: Hybrid System (HYB-B) Operating Points

	Operating Points--Hybrid Cooling --HYB-B				
	SAC	BLY	LGB	BAK	RDD
Plant Oper, hrs/yr	8,185	8,185	8,185	8,185	8,185
Avg BP, "Hg	2.26	2.29	2.45	2.32	2.26
BP >5"Hg, hours	13	11	51	18	29
CT Oper, hrs/yr	3,539	3,609	5,952	3,995	3,255
Avg CT Op Fans	1.24	1.29	2.03	1.77	1.44
CT Evap, kgal/yr	154,155	172,214	246,492	190,396	155,412
CT Evap, AF/yr	473.1	528.5	756.5	584.3	476.9
Avg ACC Fan Number	16.93	27.83	11.49	16.09	23.07
ACC Power, kWh/yr	8,397,946	13,934,715	5,026,012	8,452,129	11,423,147
CT Power, kWhr/yr	4,100,280	3,636,525	6,752,195	4,095,152	3,283,351
Total Power, kWhr/yr	12,498,226	17,571,240	11,778,208	12,547,281	14,706,498
ST Penalty, kwh/yr	-22,945,924	-25,614,835	-34,156,661	-27,465,013	-22,865,321
ST Output Penalty, MW	-2.80	-3.13	-4.17	-3.36	-2.79
ST Out Penalty rel to CT, MW	0.09	0.06	-0.79	0.03	2.12
ST Out Penalty rel to CT, kWhr	710,909	501,315	-6,494,442	258,515	17,343,286
Output at 2 "Hga, MWh/yr	873,601	874,364	873,769	873,236	873,548
Adjusted output, MWh/yr	838,157	831,178	827,834	833,224	835,976

Source: Maulbetsch Consulting

- The annual plant output varies from 827,834 MWh/yr at Long Beach to 838,157 MWh/yr at Sacramento, a variation among the five sites of just over 1%.
- The average turbine exhaust pressure varies from a minimum of 2.26 in Hga at Sacramento and Redding to a maximum of only 2.45 in Hga at Long Beach.
- The total operating power requirements vary from 11,778 MWh/yr. at Long Beach to 17,571 MWh/yr at Blythe, a difference of just under 50%.
- The steam turbine output reduction due to cooling system limitation varies significantly from 22,865 MWh/yr at Redding to 34,157 MWh/yr at Long Beach, a difference of just under 50%.
- The total reduction in plant output is the sum of the operating power requirements and the steam turbine output reduction. This varies from 35,444 MWh/yr at Sacramento to 45,935 MWh/yr at Long Beach, a difference of 30%.

Table 28: Hybrid System (HYB-C) Operating Points

	Operating Points--Hybrid Cooling --HYB-C				
	SAC	BLY	LGB	BAK	RDD
Plant Oper, hrs/yr	8,185	8,185	8,185	8,185	8,185
Avg BP, "Hg	2.62	2.46	3.17	2.66	2.49
BP >5"Hg, hours	501	9	1343	454	200
CT Oper, hrs/yr	5,483	4,746	7,505	5,680	4,797
Avg CT Op Fans	2.62	2.38	3.62	2.76	2.35
CT Evap, kgal/yr	300,193	295,072	406,482	340,246	288,407
CT Evap, AF/yr	921.3	905.5	1,247.4	1,044.2	885.1
Avg ACC Fan Number	7.38	12.33	4.09	7.01	10.34
ACC Power, kWh/yr	2,698,967	6,017,289	1,055,519	3,211,910	4,065,706
CT Power, kWhr/yr	8,207,607	6,313,108	11,115,194	8,917,550	7,411,838
Total Power, kWhr/yr	10,906,574	12,330,397	12,170,713	12,129,460	11,477,544
ST Penalty, kwh/yr	-41,051,194	-34,555,055	-60,142,508	-43,587,384	-35,890,198
ST Output Penalty, MW	-5.02	-4.22	-7.35	-5.33	-4.38
ST Out Penalty rel to CT, MW	-2.13	1.03	-3.97	-1.94	0.53
ST Out Penalty rel to CT, kWhr	-17,394,361	-8,438,856	-32,480,289	-15,863,856	4,318,409
Output at 2 "Hga, MWh/yr	873,601	874,364	873,769	873,236	873,548
Adjusted output, MWh/yr	821,643	827,478	801,456	817,519	826,180

Source: Maulbetsch Consulting

- The annual plant output varies from 801,456 MWh/yr at Long Beach to 827,478 MWh/yr at Blythe, an overall variation of about 3%.
- The average turbine exhaust pressure varies from a minimum of 2.46 in Hga at Blythe to a maximum of only 3.17 in Hga at Long Beach.
- The total operating power requirements vary from 10,907 MWh/yr. at Sacramento to 12,330 MWh/yr at Blythe, a difference of just over 12%.
- The steam turbine output reduction due to cooling system limitation varies significantly from 34,555 MWh/yr at Blythe to 60,143 MWh/yr at Long Beach, a difference of almost 75%.
- The total reduction in plant output is the sum of the operating power requirements and the steam turbine output reduction. This varies from 46,885 MWh/yr at Blythe to 72,313 MWh/yr at Long Beach, a difference of 54%.

From the design and operating values listed, the project team calculated overall performance comparisons=. These include:

- Initial installed cooling system cost.
- Annualized cooling system cost.
- Annual water savings, compared to all-wet cooling.
- Percent of all-wet system water use required.
- Cost of water saved.
- Normalized water use.

The quantities are tabulated for all cooling systems at all five sites in Table 29.

Table 29: Overall Cost Performance Comparisons

	Sacramento				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$27,870,000	$40,070,000	$30,880,000	$20,900,000	$8,110,000
Annualized cooling system cost, $	$9,475,391	$5,263,668	$4,642,690	$5,100,044	$3,339,137
Annual water saving, kgal/yr	562,635	502,017	419,962	273,924	0
% Water Consumed	2.0%	12.6%	26.9%	52.3%	100.0%
Cost of water saved, $/kgal	$16.84	$10.49	$11.06	$18.62	NA
Normalized Water Use, gal/MWh	15	86	184	365	688
	Blythe				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$38,180,000	$69,180,000	$49,860,000	$34,110,000	$8,160,000
Annualized cooling system cost, $	$9,533,938	$8,407,501	$6,513,225	$5,669,678	$3,490,040
Annual water saving, kgal/yr	634,179	558,414	474,908	352,049	0
% Water Consumed	2.0%	13.7%	26.6%	45.6%	100.0%
Cost of water saved, $/kgal	$15.03	$15.06	$13.71	$16.10	NA
Normalized Water Use, gal/MWh	17	108	207	357	777
	Long Beach				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$24,420,000	$32,770,000	$24,680,000	$17,680,000	$8,160,000
Annualized cooling system cost, $	$10,261,825	$5,091,238	$4,943,041	$6,299,525	$3,593,867
Annual water saving, kgal/yr	560,864	453,647	325,818	165,828	0
% Water Consumed	2.0%	20.7%	43.1%	71.0%	100.0%
Cost of water saved, $/kgal	$18.30	$11.22	$15.17	$37.99	NA
Normalized Water Use, gal/MWh	15	142	298	507	689
	Bakersfield				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$29,710,000	$44,590,000	$33,430,000	$22,210,000	$8,380,000
Annualized cooling system cost, $	$8,507,710	$5,942,263	$5,140,961	$5,454,879	$3,595,236
Annual water saving, kgal/yr	594,376	511,450	416,110	266,260	0
% Water Consumed	2.0%	15.7%	31.4%	56.1%	100.0%
Cost of water saved, $/kgal	$14.31	$11.62	$12.35	$20.49	NA
Normalized Water Use, gal/MWh	16	114	229	416	731
	Redding				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$31,540,000	$51,410,000	$38,040,000	$24,790,000	$8,420,000
Annualized cooling system cost, $	$8,679,651	$6,361,865	$5,292,827	$5,051,042	$4,457,940
Annual water saving, kgal/yr	602,504	538,617	459,388	326,393	0
% Water Consumed	2.0%	12.4%	25.3%	46.9%	100.0%
Cost of water saved, $/kgal	$14.41	$11.81	$11.52	$15.48	NA
Normalized Water Use, gal/MWh	16	91	186	349	751

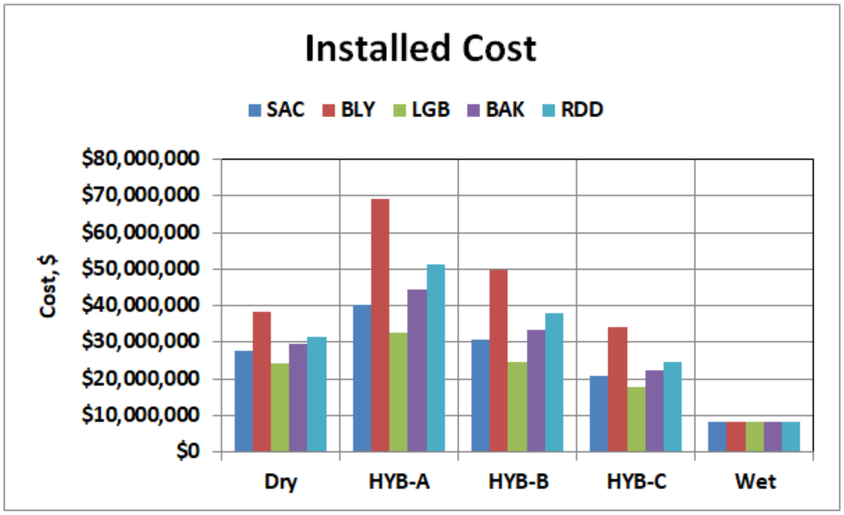
Source: Maulbetsch Consulting

The cooling system installed costs for all systems at all sites are shown in Figure 31. The cost variation from system to system and from site to site is directly related to the equipment sizes and the required number of ACC and cooling tower cells. Blythe and Long Beach have the largest and smallest equipment sizes respectively and are similarly the most and least expensive across all five systems.

The costs of the all-wet cooling systems vary from between $8.1 million and $8.4 million for all sites. These costs vary roughly with the cooling tower size which was discussed earlier with some adjustment for related condenser costs.

The costs of the all-dry cooling systems vary from about $24 million for Long Beach to $38 million at Blythe with intermediate costs at the other three sites. These costs vary with ACC size (roughly with the number of cells) for the reasons discussed above. The all-dry system costs range from three to five times the costs of all-wet systems which is consistent with prior analyses.

Figure 31: Cooling System Installed Costs—All Systems, All Sites



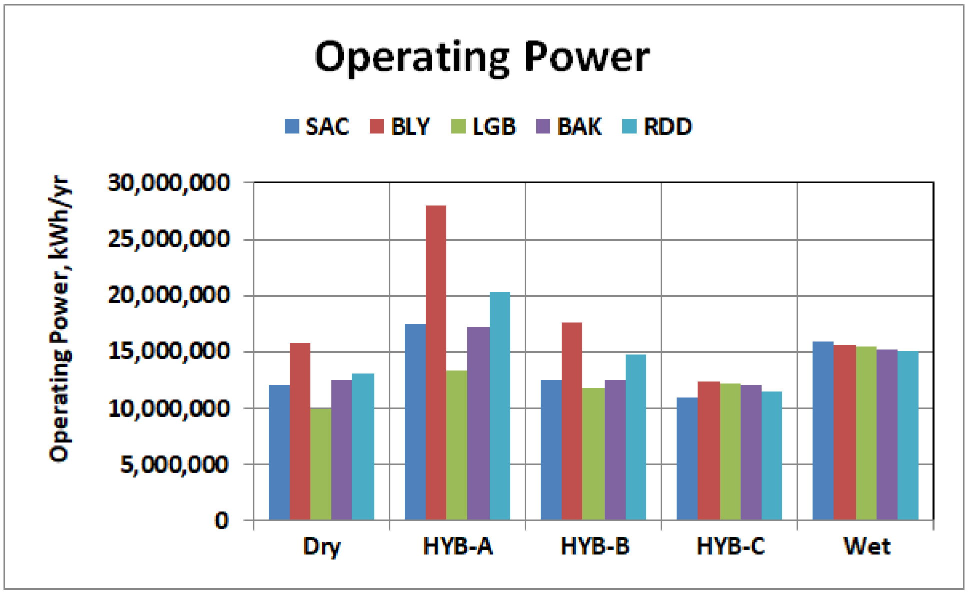
Source: Maulbetsch Consulting

The additional costs of cooling systems, in the form of cooling system related performance penalties, are shown in Figures 33 and 34. The operating power requirements in Figure 33 include the fan power for the air-cooled condensers in the all-dry and hybrid systems and the combined fan and circulating water pump power in the all-wet and hybrid systems.

- The all-wet systems are essentially equal at all sites as would be expected. For the same heat load and range (Table 18), the circulating water flow is identical at all sites and the head losses through the condenser, the circulating water piping and the rise to the distribution deck of the cooling tower are all identical or very close.
- The all-dry system annual power consumption varies with design point specifications and, more importantly, with the annual temperature variation at each site.
    - Sites with higher design ambient temperatures are designed with more cells and higher airflow to maintain the design turbine exhaust pressure and condensing temperature.
    - During the rest of the year, sites with more hours at colder temperatures can operate with fewer fans running more of the time and hence save power.
    - The average number of fan operating throughout the year (Table 19) corresponds very closely to the variation in annual operating power in Figure 26.

- Similar explanations apply to operating power consumption by the hybrid systems. The site-to-site variation from HYB-A, which is dominated by the ACC in the dry element, is very similar to the variation for the all-dry system. HYB-C, on the other hand, which has a large wet element at each site, varies more similarly to the all-wet system with generally lower power consumption due to the reduction of the circulating water flow and the fewer hours of wet tower operation. HYB-B, as would be expected, displays intermediate behavior.

Figure 33: Cooling System Operating Power Consumption—All Systems, All Sites



Source: Maulbetsch Consulting

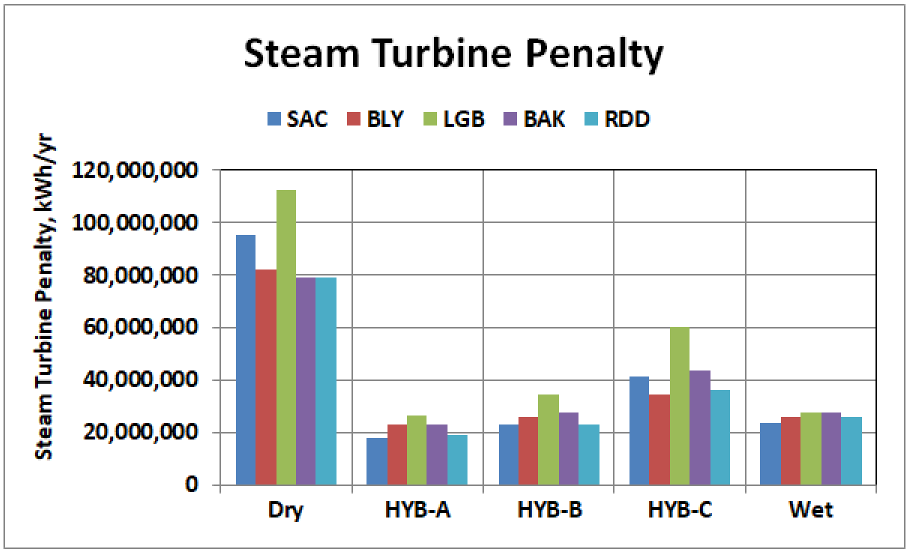
Figure 34 displays the performance penalty incurred by the steam turbine as a result of cooling system performance capabilities that limit turbine exhaust pressure to values above the turbine design level of 2 "Hga for much, or all, of the year.

The penalty at the design point is set by the design backpressure which is 7"Hga for the all-dry systems; 4 "Hga for the three hybrid systems and 3.5"Hga for the set systems at all sites. Therefore, the hourly variability in both the ambient temperature, which controls the ACCs in the all-dry and hybrid systems and the ambient wet bulb, which controls the wet cooling towers in the all-wet and hybrid systems govern the hours per year at any given turbine exhaust pressure for all systems at all sites. The annual average turbine backpressures (Tables 24 through 28) give excellent indications of the relative turbine penalties from site to site.

This is illustrated by comparing the situations for the all-dry systems at Blythe and Long Beach. The ACCs at both sites are designed for a turbine exhaust pressure of 7"Hga with the corresponding condensing temperature of 147 °F at the 1% dry bulb temperature. At Blythe, where the design ambient temperature is 110 F, this give an ITD of 37 F (147 F – 110 F); at Long beach the ITD is 56 F. A reasonable approximation for ACC performance at off-design temperatures is that, for the same heat load, the ITD is essentially the same. Therefore, whenever the temperature difference between Blythe and Long Beach is less than 19 F (56 F – 37

F), the condensing temperature and, hence, the turbine exhaust pressure at Blythe will be lower than at Long Beach. The temperature duration curves demonstrate the temperature difference between Blythe and Long Beach is less than 19 °F for almost 8,000 hours per year. Therefore, the steam turbine penalty at Blythe is less than it is at Long Beach, except for those hours when the temperature at Blythe exceeds 100 °F.

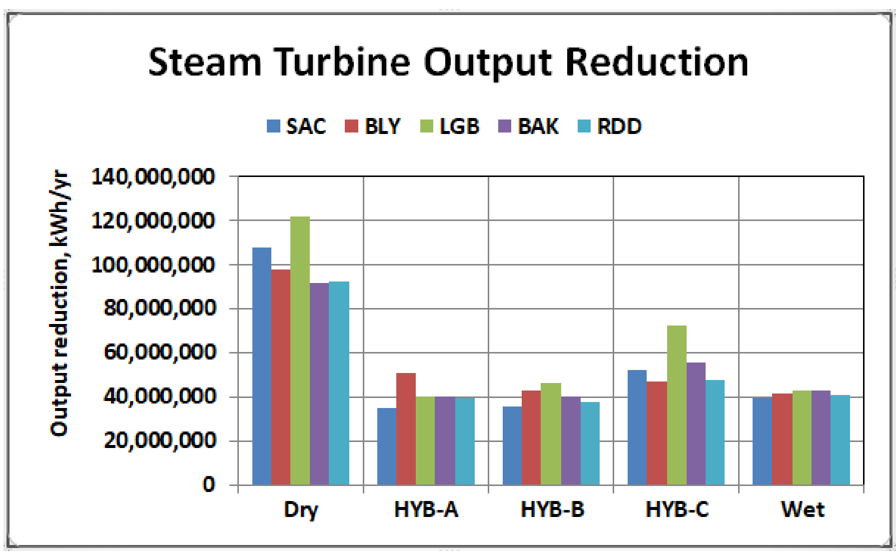
Figure 34: Steam Turbine Performance Penalty—All Systems, All Sites



Source: Maulbetsch Consulting

Figure 35 represents the sum of the power requirements and the turbine output penalty, which is the total reduction in steam turbine energy output from its ideal operating condition of 2 "Hga for the entire year.

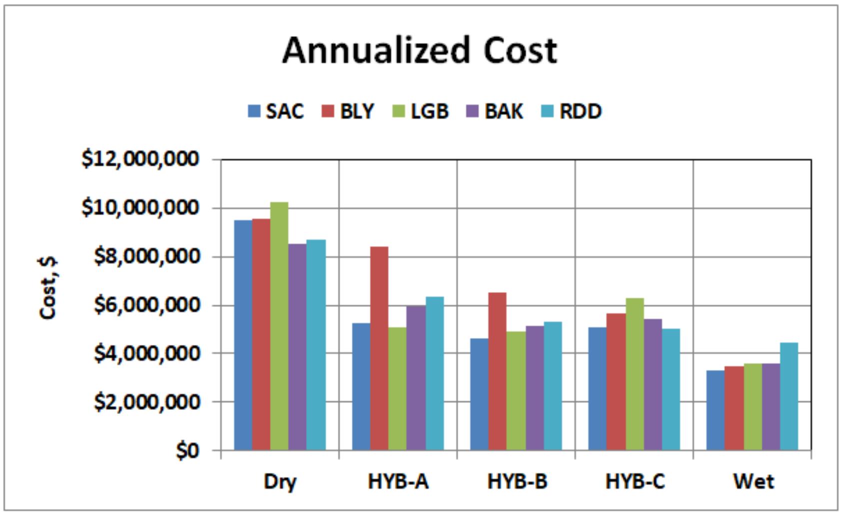
Figure 35: Steam Turbine Output Reduction—All Systems, All Sites



Source: Maulbetsch Consulting

The annualized cooling system cost is defined as the initial installed cost amortized at 7% plus the total annual reduction in turbine output evaluated at $70/MWh. The annualized cost is plotted in Figure 36. The annualized cost of each cooling systems is reasonably similar at each site with the exception of Blythe which, because of the long duration of very high ambient temperatures, incurs higher costs for the two “driest” hybrid systems. Again, with the exception of Blythe, the annualized costs of the three hybrid systems are all quite close.

Figure 36: Cooling System Annualized Cost—All Systems, All Sites

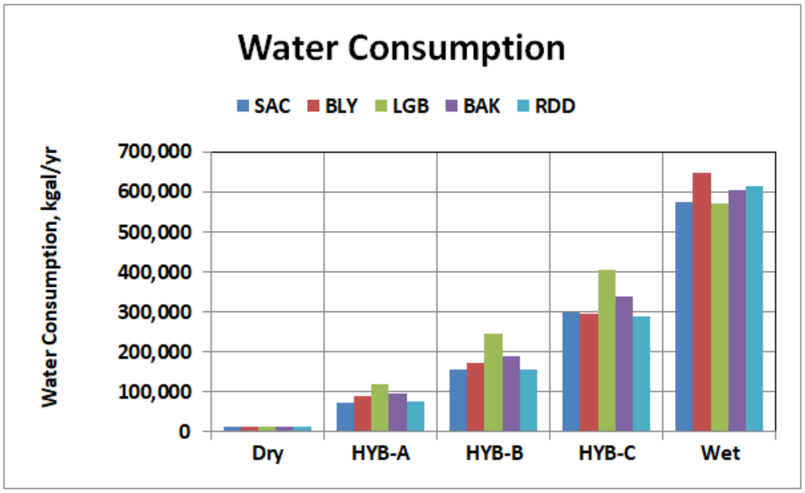


Source: Maulbetsch Consulting

The water consumption and water savings for the several cooling systems are displayed in different ways in Figures 30, 31, and 32. Figure 37 shows the annual water consumption of each system in kgal per year. The amount of water consumed in the all-wet cooling systems is nearly the same (approximately 572,000 kgal/yr) at Sacramento and Long Beach and significantly more (approximately 647,000 kgal/yr) at Blythe. Bakersfield and Redding consume intermediate amounts.

The high evaporation rate at Blythe results from the fact that the inlet ambient air is very hot and dry. As a result, the air stream is actually cooled as it passes through the cooling tower. Therefore, the sensible contribution to the heat load is **negative**, whereas at more typical ambient conditions it can account for 10% or more of the total heat load. At Blythe, additional water must be evaporated to carry not only the imposed heat load from the condenser but the additional load from cooling the air.

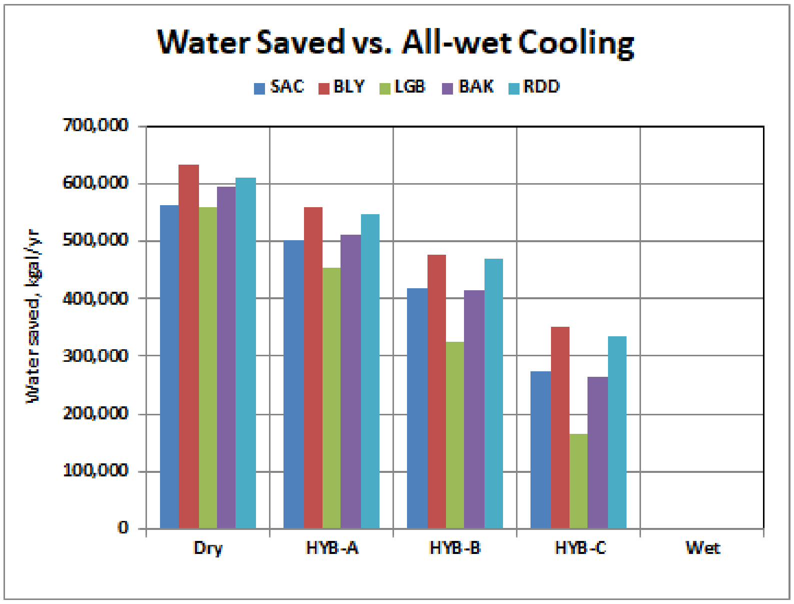
Figure 37: Annual Water Consumption—All Systems, All Sites



Source: Maulbetsch Consulting

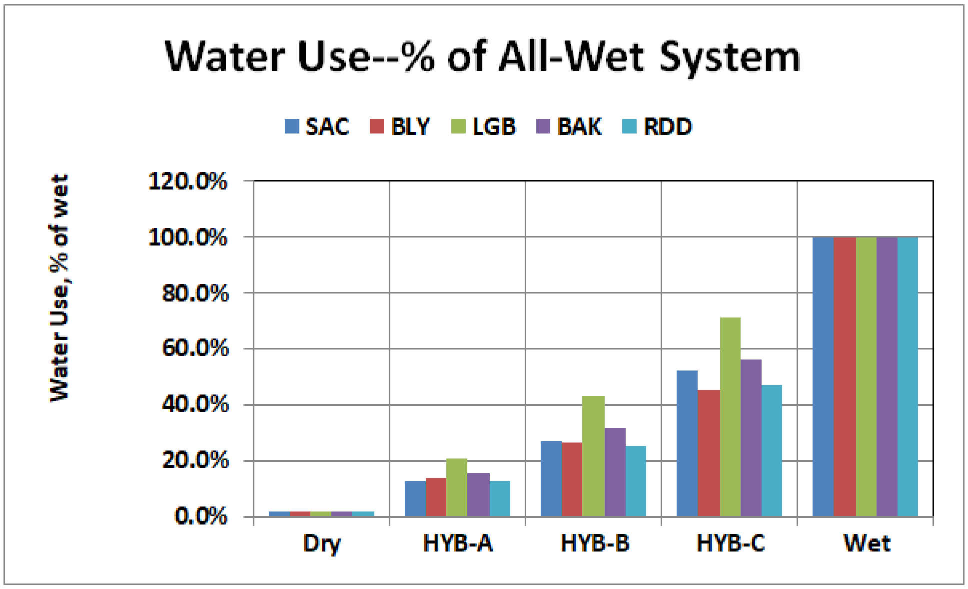
Figure 38 displays the amount of water saved compared to the amount of water used by an all-wet cooling system for each of the four water-conserving systems at each site. Figure 39 displays the water use for each system at each site as a percentage of the amount of water used by the all-wet cooling system.

Figure 38: Water Saved Relative to All-Wet Cooling—All Systems, All Sites



Source: Maulbetsch Consulting

Figure 39: Percent Water Use—All Systems, All Sites

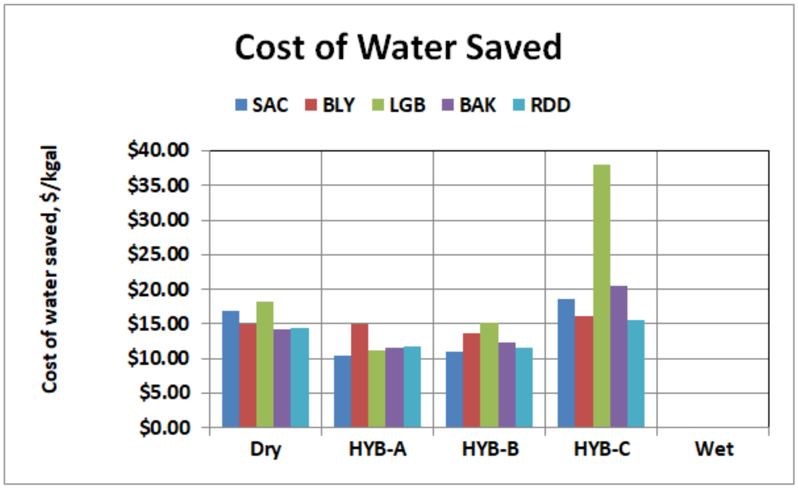


Source: Maulbetsch Consulting

The cost of saving water can be estimated by dividing the annualized cost of the cooling system by the amount of water saved. This value for the dry and hybrid systems is shown in Figure 40. It varies from $10/kgal to $15/kgal for the all-dry and hybrid systems HYB-A and HYB-B. The increased cost for HYB-C is regulated primarily to the fact that significantly less water is saved than either of the other two hybrid systems and their annualized cost is very similar.

The significantly higher cost of water saved at Long Beach for the HYB-C system results from the combined effect of a somewhat higher annualized cost and significantly less water saved. Because of the temperature and wet bulb duration curves, the ACC is less effective at Long Beach for much of the year and additional wet tower capacity is required to maintain an acceptable turbine backpressure.

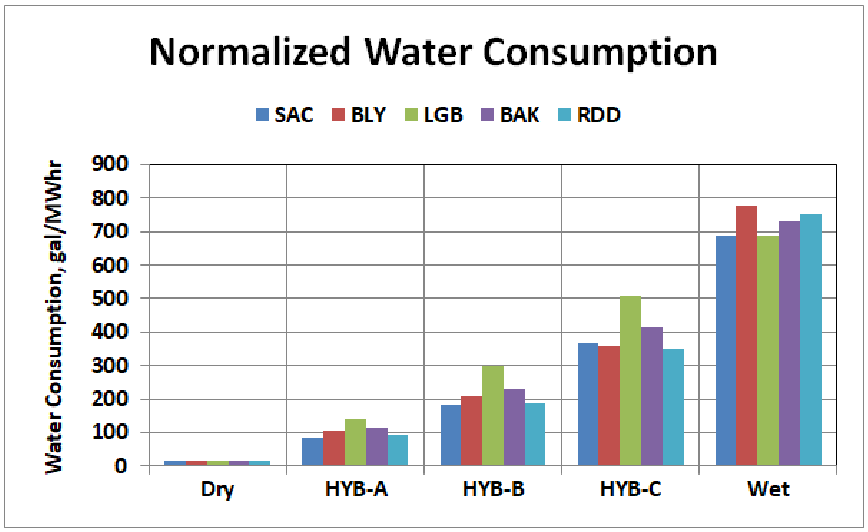
Figure 40: Cost of Water Saved—All Systems, All Sites



Source: Maulbetsch Consulting

Figure 41 presents the normalized water consumption defined as the amount of water consumed annually divided by the adjusted annual energy output. The normalized water consumption with all-wet cooling varies from 688 g/MWh at Sacramento to 777 g/MWh at Blythe, which is a typical range for wet cooling systems noted in other analyses. Since the adjusted energy output for the all-wet and hybrid systems at the different sites varies little as seen in Table 24 and Tables 26 through 28, the normalized water consumption follows the pattern of the annual water consumption. Again, Long Beach is a larger consumer of water because of the unusual annual variation of the dry and wet bulb temperatures.

Figure 41: Normalized Water Consumption—All Systems, All Sites



Source: Maulbetsch Consulting

CHAPTER 5: Statewide Benefits

Introduction

A statewide benefits analysis was performed to estimate the comparative effect of alternative cooling system use on power production, water consumption, and cost in California for an assumed growth in power use and forecasted type, capacity, and geographical distribution of power generating facilities. The intent is to provide electric power system planners and decision makers with a basis for evaluating the trade-offs among wet, dry, and hybrid cooling systems and to assess the benefits of hybrid cooling under varying expectations for the future of power production in California.

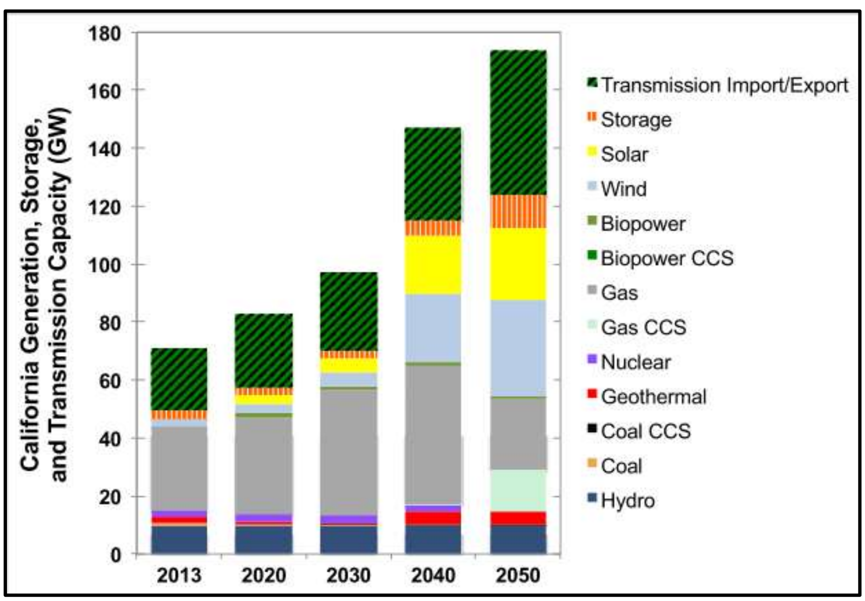
The analysis was carried out in several tasks:

- Establish an assumed power system capacity growth and distribution.
- Develop a basis for projecting cost, water consumption and production penalty.
- Calculate the results for alternative cooling system scenarios.
- Display alternatives showing the effects of hybrid cooling adoption.

Power System Projections

A recent study of potential projections for required California electric power production capacity through 2050 was conducted for the California Energy Commission in 2013. [1],[2] Figure 42 shows the growth in the generation, storage, and transmission capacity from 2013 to 2050 in ten-year intervals.

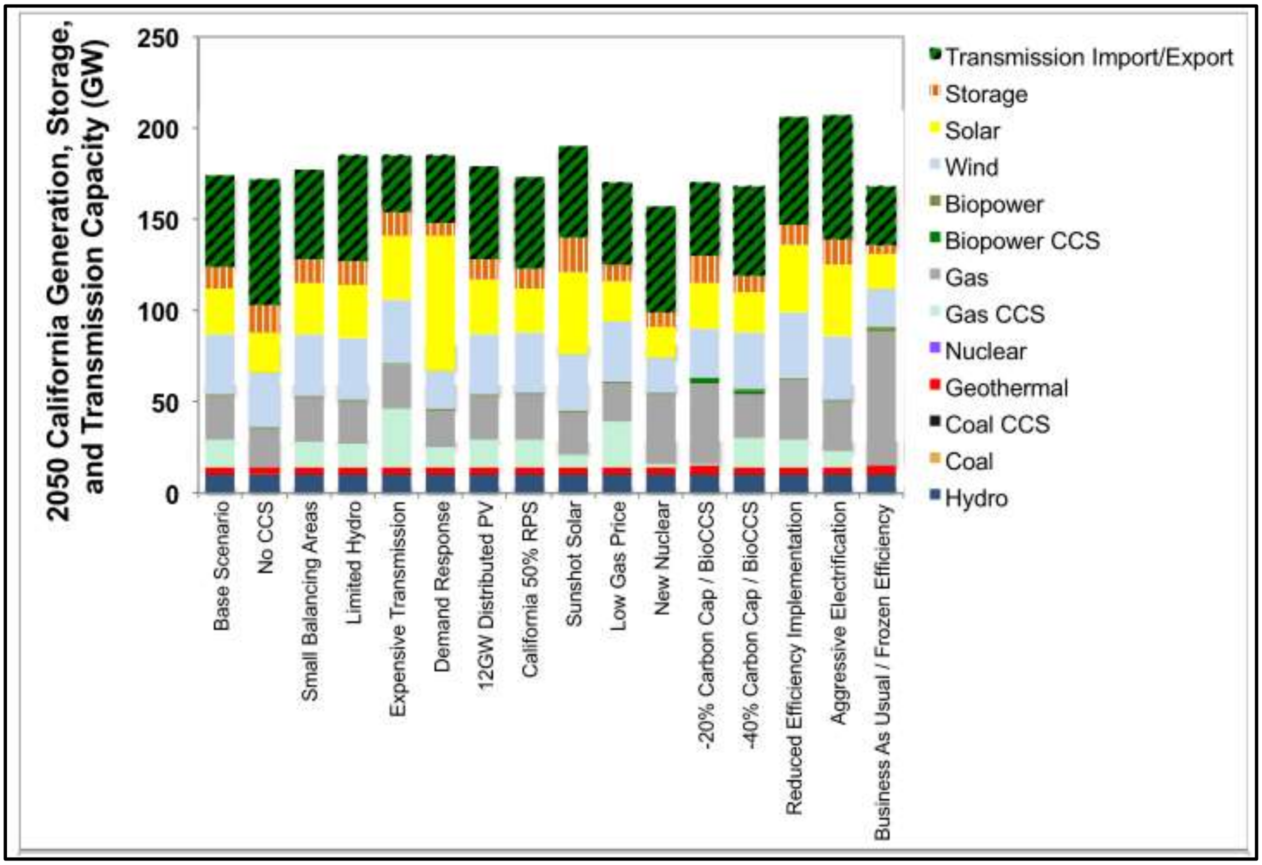
Figure 42: Capacity Projections for California 2013 - 2050



Source: Maulbetsch Consulting

Figure 43 displays the mix of sources of the required capacity for 16 different scenarios based on a wide variety of assumptions of future technological and policy trends.

Figure 43: Capacity Projection for California in 2050-Alternative scenarios



Source: Maulbetsch Consulting

For ease of reference, Table 30 contains the numerical values from which Figure 44 was constructed.

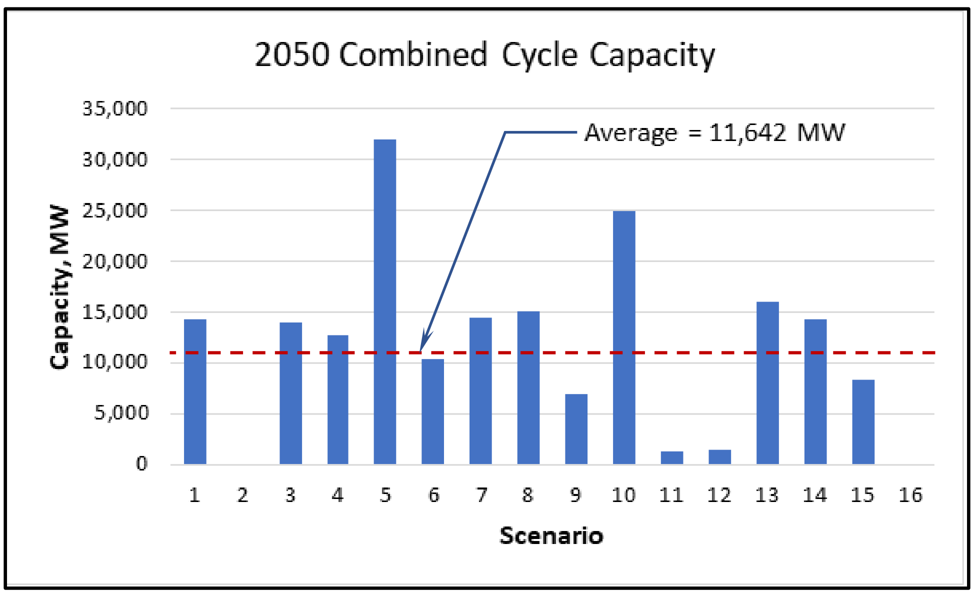
Table 30: Values for Figure 44

	Coal	Gas	Geothermal	Solar	Wind	Biopower	Hydro	Nuclear	Coal CCS	Gas CCS	Biopower CCS	Storage	Transmission Import/Export
Base Scenario	0	24684	4548	24733	33007	989	9890	0	139	14308	0	11447	50176
No CCS	0	20788	4548	22011	29663	989	9890	0	0	0	0	15442	68616
Small Balancing Areas	0	23959	4548	28039	33256	989	9890	0	139	14009	0	13558	48582
Limited Hydro	0	22845	4548	28828	34290	989	9890	0	139	12690	0	12946	58312
Expensive Transmission	0	23539	4548	35026	35190	989	9890	0	247	31968	0	13103	30320
Demand Response	0	20021	4548	73986	21540	989	9890	0	139	10387	0	7065	36223
12GW Distributed PV	0	24276	4548	29490	32948	989	9890	0	139	14444	0	11885	50379
California 50% RPS	0	24358	4548	24487	32999	989	9890	0	139	15072	0	10987	50051
Sunshot Solar	0	23059	4548	45018	30300	989	9890	0	79	6903	0	19399	49734
Low Gas Price	0	20685	4548	22219	32646	989	9890	0	79	24972	0	8612	45703
New Nuclear	0	38722	4548	17355	18360	986	9890	0	139	1316	0	8044	57600
-20% Carbon Cap / BioCCS	24	43747	4548	25686	26349	799	9890	0	361	1473	2712	14598	39829
-40% Carbon Cap / BioCCS	0	23322	4548	21291	31290	799	9890	0	79	16015	2716	9258	48856
Reduced Efficiency Implementation	0	33196	4548	37237	36270	989	9890	0	139	14335	0	10238	58820
Aggressive Electrification	0	27133	4548	38314	35580	989	9890	0	79	8381	0	14229	67562
Business As Usual	139	72858	4548	19225	21120	3254	9890	0	300	0	0	4309	31969

Source: Maulbetsch Consulting

Figure 44 extracts from Table 30 the capacity projected to be provided by gas-fired, combined-cycle plants for each of the scenarios.

Figure 44: Gas-Fired, Combined-Cycle Plant Capacity for Alternate Scenarios



Source: Maulbetsch Consulting

The average of the gas-fired, combined-cycle capacity in each of the 16 scenarios is 11,642 MW. For the purposes of the following analysis, an assumed capacity of 10,600 MW will be used corresponding to 20 plants of 530 MW capacity of the type used for the case study analyses.

The effect of the choice of cooling systems used for these 20 plants on the overall cost, energy production, and water consumption in California will depend on how the plants are distributed around the state in regions of differing meteorology.

Three different assumptions of how the plants might be distributed will be analyzed. These are

- Uniform distribution: Four of the twenty plants will be located at each of the five case study sites.
- "Population-driven" distribution: More power plants will be located in the more populous areas of the state; specifically:
    - Seven plants in Long Beach.
    - Six plants in Sacramento.
    - Three plants in Bakersfield.
    - Two plants each in Redding and Blythe.
- "Extreme" distribution: Five separate situations in which all 20 plants are located at each of the five sites.

The term "population-based" distribution is not intended to imply that plants are located based on population patterns. Other factors including proximity to fuel source, water source, transmission access, and other factors are typically dominant. This is simply a way of defining a plausible intermediate distribution of future generation between the bounding cases of "uniform distribution" and "extreme distribution."

The various distributions will be evaluated and compared on the bases of initial installed cooling system cost, annualized cooling system cost, hot day capacity, annual electric energy production, and annual water consumption.

Table 31 lists, for each system at each site, the values for installed capital cost, annualized cost, reduction in turbine capacity below the turbine design value when operating at the at the 1% dry bulb design point, the annual turbine energy production, and annual water consumption in both kilo-gallons and acre-feet per year.

Table 31: Summary of Cost, Performance and Water Use-All Systems, All Sites

	Sacramento				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$27,870,000	$40,070,000	$30,880,000	$20,900,000	$8,110,000
Annualized cooling system cost, $	$9,475,391	$5,263,668	$4,642,690	$5,100,044	$3,339,137
Reduction in turbine capacity at 1% dry bulb, MW	37.2	20.6	20.6	20.6	16.6
Annual turbine energy production, MWh/yr	766,109	838,476	838,157	821,643	834,009
Annual water consumption, kgal/yr	11,482	72,100	154,155	300,193	574,117
Annual water consumption, acre-feet/yr	35	221	473	921	1,762
	Blythe				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$38,180,000	$69,180,000	$49,860,000	$34,110,000	$8,160,000
Annualized cooling system cost, $	$9,533,938	$8,407,501	$6,513,225	$5,669,678	$3,490,040
Reduction in turbine capacity at 1% dry bulb, MW	37.2	20.6	20.6	20.6	16.6
Annual turbine energy production, MWh/yr	776,345	823,436	831,178	827,478	832,666
Annual water consumption, kgal/yr	12,942	88,708	172,214	295,072	647,122
Annual water consumption, acre-feet/yr	40	272	529	906	1,986
	Long Beach				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$24,420,000	$32,770,000	$24,680,000	$17,680,000	$8,160,000
Annualized cooling system cost, $	$10,261,825	$5,091,238	$4,943,041	$6,299,525	$3,593,867
Reduction in turbine capacity at 1% dry bulb, MW	37.2	20.6	20.6	20.6	16.6
Annual turbine energy production, MWh/yr	751,591	833,807	827,834	801,456	830,588
Annual water consumption, kgal/yr	11,446	118,663	246,492	406,482	572,310
Annual water consumption, acre-feet/yr	35	364	757	1,248	1,756
	Bakersfield				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$29,710,000	$44,590,000	$33,430,000	$22,210,000	$8,380,000
Annualized cooling system cost, $	$8,507,710	$5,942,263	$5,140,961	$5,454,879	$3,595,236
Reduction in turbine capacity at 1% dry bulb, MW	37.2	20.6	20.6	20.6	16.6
Annual turbine energy production, MWh/yr	781,407	832,937	833,224	817,519	830,255
Annual water consumption, kgal/yr	12,130	95,057	190,396	340,246	606,506
Annual water consumption, acre-feet/yr	37	292	584	1,044	1,861
	Redding				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$31,540,000	$51,410,000	$38,040,000	$24,790,000	$8,420,000
Annualized cooling system cost, $	$8,679,651	$6,361,865	$5,292,827	$5,051,042	$4,457,940
Reduction in turbine capacity at 1% dry bulb, MW	37.2	20.6	20.6	20.6	16.6
Annual turbine energy production, MWh/yr	781,093	834,074	835,976	826,180	832,430
Annual water consumption, kgal/yr	12,478	76,183	155,412	288,407	623,888
Annual water consumption, acre-feet/yr	38	234	477	885	1,915

Source: Maulbetsch Consulting

The differences in cost, performance, and water consumption among the alternative systems and among the five sites were highlighted and discussed in the previous section describing the case studies. For the statewide benefit analysis, it is the site-to-site comparisons that are most relevant because it is the meteorological conditions at a site that determine the severity of meeting the cooling requirement at the "hot day" design point and the cooling system performance, steam turbine output, and water consumption for the rest of the year.

An illustrative way to view the comparisons is to consider how the systems differ from all-wet and all-dry cooling at each site. In comparison to all-wet cooling, the hybrid and all-dry systems cost more, reduce turbine output, and consume less water. Conversely, in comparison to all-dry systems, the hybrid and all-wet systems cost less, increase turbine output, and consume more water. The magnitude of these differences varies from site-to-site.

As indicated in Table 32, the increase in installed cost above wet cooling averages about $22 million for all–dry cooling and $15.7 million for HYB-C. The cost differences for dry cooling range from $30 million at Blythe to $16.3 million at Long Beach.; for HYB-C, they range from $25.9 million at Blythe to $9.5 million at Long Beach.

In comparison to systems with all-wet cooling, turbine capacity on the hot (1% dry bulb) day is reduced by over 20 MW at all sites with dry cooling and 4 MW at all sites with HYB-C. The annual output reduction averages 60,700 MWh with all-dry cooling, varying from 79,000 MWh at Long Beach to 48,850 MWh at Bakersfield. However, significant water savings are realized averaging 592,000 kgal per year (1,820 acre-feet/year) with all-dry systems ranging from 634,000 kgal/year (1,950 acre-feet/year) at Blythe to 561,000 kgal/year (1,720 acre-feet/year) at Long Beach.

Similar comparisons can be made with all-dry cooling to indicate savings in capital costs and increases in hot day capacity and annual energy production that can be achieved through the use of varying amounts of water. These comparisons are listed in Table 33.

The average savings in installed cost of all-wet cooling compared to all-dry cooling is $22.1 million ranging from $30. Million at Blythe to $16.3 at Long Beach; for HYB-C, the average savings are $6.4 million, ranging from $7.5 million at Bakersfield to $4.1 million at Blythe. The increase in hot day turbine capacity is 20.6 MW for all-wet cooling and 16.6 MW for HYB-C at all sites.

The annual turbine output with all wet cooling increases by an average of 60,680 MWh over all-dry cooling, ranging from 79,000 MWh at Long Beach to 48,850 MWh at Bakersfield; with HYB-C, the average increase is 47,500 MWh ranging from 55,500 MWh at Sacramento to 36,100 at Bakersfield.

However, the increase in water consumption to achieve these reduced costs and increased capacity and output averages 592,700 kgal/year (1,820 acre-feet/year) , ranging from 634,200 kgal/year (1,946 acre-feet/year) at Blythe to 561,000 kgal/hear (1,721 acre-feet/year) at Long Beach for all-wet cooling; for HYB-C, the average increase in water consumption is 314,000 kgal/year (967 acre-feet/year) ranging from 395,000 kgal/year (1,212 acre-feet/year) at Long Beach to 276,000 kgal/year (847 acre-feet/year) at Redding.

Table 32: Cost, Performance and Water Use Differences From Wet Cooling

	Sacramento				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Additional installed cost, $	$19,760,000	$31,960,000	$22,770,000	$12,790,000	0
Additional annualized cooling system cost, $	$6,136,254	$1,924,531	$1,303,554	$1,760,907	0
Additional reduction in turbine capacity at 1% dry/wet	20.6	4.0	4.0	4.0	0
Reduction in annual turbine energy production, MWh	67,901	-4,467	-4,148	12,366	0
Reduction in annual water consumption, kgal/yr	562,635	502,017	419,962	273,924	0
Reduction in annual water consumption, acre-feet/yr	1,727	1,541	1,289	841	0
	Blythe				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Additional installed cost, $	$30,020,000	$61,020,000	$41,700,000	$25,950,000	0
Additional annualized cooling system cost, $	$6,043,899	$4,917,461	$3,023,185	$2,179,638	0
Additional reduction in turbine capacity at 1% dry/wet	20.6	4.0	4.0	4.0	0
Reduction in annual turbine energy production, MWh	56,321	9,229	1,488	5,188	0
Reduction in annual water consumption, kgal/yr	634,179	558,414	474,908	352,049	0
Reduction in annual water consumption, acre-feet/yr	1,946	1,714	1,458	1,080	0
	Long Beach				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Additional installed cost, $	$16,260,000	$24,610,000	$16,520,000	$9,520,000	0
Additional annualized cooling system cost, $	$6,667,959	$1,497,371	$1,349,174	$2,705,659	0
Additional reduction in turbine capacity at 1% dry/wet	20.6	4.0	4.0	4.0	0
Reduction in annual turbine energy production, MWh	78,996	-3,219	2,753	29,132	0
Reduction in annual water consumption, kgal/yr	560,864	453,647	325,818	165,828	0
Reduction in annual water consumption, acre-feet/yr	1,721	1,392	1,000	509	0
	Bakersfield				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Additional installed cost, $	$21,330,000	$36,210,000	$25,050,000	$13,830,000	0
Additional annualized cooling system cost, $	$4,912,473	$2,347,026	$1,545,724	$1,859,643	0
Additional reduction in turbine capacity at 1% dry/wet	20.6	4.0	4.0	4.0	0
Reduction in annual turbine energy production, MWh	48,848	-2,681	-2,969	12,736	0
Reduction in annual water consumption, kgal/yr	594,376	511,450	416,110	266,260	0
Reduction in annual water consumption, acre-feet/yr	1,824	1,570	1,277	817	0
	Redding				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$23,120,000	$42,990,000	$29,620,000	$16,370,000	0
Annualized cooling system cost, $	$4,221,711	$1,903,925	$834,887	$593,102	0
Reduction in turbine capacity at 1% dry bulb, MW	20.6	4.0	4.0	4.0	0
Annual turbine energy production, MWh/yr	51,338	-1,644	-3,546	6,250	0
Annual water consumption, kgal/yr	611,410	547,705	468,476	335,481	0
Annual water consumption, acre-feet/yr	1,876	1,681	1,438	1,030	0

Source: Maulbetsch Consulting

Table 33: Cost, Performance and Water Use Differences From Dry Cooling

	Sacramento				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Reduction in installed cost, $	0	-$12,200,000	-$3,010,000	$6,970,000	$19,760,000
Reduction in annualized cooling system cost, $	0	$4,211,723	$4,832,701	$4,375,347	$6,136,254
Additional turbine capacity at 1% dry bulb, MW	0	16.6	16.6	16.6	20.6
Additional annual turbine energy production, MWh/yr	0	72,367	72,049	55,535	67,901
Additional annual water consumption, kgal/yr	0	60,618	142,673	288,711	562,635
Additional annual water consumption, acre-feet/yr	0	186	438	886	1,727
	Blythe				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Reduction in installed cost, $	0	-$31,000,000	-$11,680,000	$4,070,000	$30,020,000
Reduction in annualized cooling system cost, $	0	$1,126,438	$3,020,713	$3,864,260	$6,043,899
Additional turbine capacity at 1% dry bulb, MW	0	16.6	16.6	16.6	20.6
Additional annual turbine energy production, MWh/yr	0	47,092	54,833	51,134	56,321
Additional annual water consumption, kgal/yr	0	75,765	159,271	282,130	634,179
Additional annual water consumption, acre-feet/yr	0	233	489	866	1,946
	Long Beach				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Reduction in installed cost, $	0	-$8,350,000	-$260,000	$6,740,000	$16,260,000
Reduction in annualized cooling system cost, $	0	$5,170,587	$5,318,784	$3,962,300	$6,667,959
Additional turbine capacity at 1% dry bulb, MW	0	16.6	16.6	16.6	20.6
Additional annual turbine energy production, MWh/yr	0	82,216	76,243	49,864	78,996
Additional annual water consumption, kgal/yr	0	107,217	235,045	395,036	560,864
Additional annual water consumption, acre-feet/yr	0	329	721	1,212	1,721
	Bakersfield				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Reduction in installed cost, $	0	-$14,880,000	-$3,720,000	$7,500,000	$21,330,000
Reduction in annualized cooling system cost, $	0	$5,170,587	$5,318,784	$3,962,300	$6,667,959
Additional turbine capacity at 1% dry bulb, MW	0	16.6	16.6	16.6	20.6
Additional annual turbine energy production, MWh/yr	0	51,529	51,816	36,112	48,848
Additional annual water consumption, kgal/yr	0	82,927	178,266	328,116	594,376
Additional annual water consumption, acre-feet/yr	0	255	547	1,007	1,824
	Redding				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Reduction in installed cost, $	0	-$19,870,000	-$6,500,000	$6,750,000	$23,120,000
Reduction in annualized cooling system cost, $	0	$2,317,786	$3,386,824	$3,628,609	$4,221,711
Additional turbine capacity at 1% dry bulb, MW	0	16.6	16.6	16.6	20.6
Additional annual turbine energy production, MWh/yr	0	52,981	54,883	45,087	51,338
Additional annual water consumption, kgal/yr	0	63,705	142,934	275,929	611,410
Additional annual water consumption, acre-feet/yr	0	196	439	847	1,876

Source: Maulbetsch Consulting

The information in the preceding two tables can be consolidated into overall cost, performance, and water use estimates for the three cases of plant distribution in 2050 introduced earlier. Table 34 considers the “uniform distribution” case where four of the 20 plants are located at each of the five sites. For the State as a whole, the use of hybrid cooling (HYB-C) in preference to all-wet cooling results in:

- An installed cost increase of $327 million.
- A reduction in hot day generating capacity of 80 MW.
- A reduction in annual energy production of 263 GWh.
- A reduction in water consumption of just under 5.6 million kgal/yr (17,000 acre-feet/year).

In comparison to all-dry cooling, the use of hybrid cooling (HYB-C) results in:

- An installed cost savings of $128 million.
- An increase in hot day generating capacity of 332 MW.
- An increase in annual energy production of 969 GWh.
- An increase in water consumption of just under 6.3 million kgal/yr (19,280 acre-feet/year).

Table 34: Statewide Cost, Performance and Water Use-Uniform Distribution Case

	California Totals--Uniform Distribution				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$606,880,000	$952,080,000	$707,560,000	$478,760,000	$164,920,000
Annualized cooling system cost, $	$185,834,064	$124,266,139	$106,130,978	$110,300,674	$73,904,879
Reduction in turbine capacity at 1% dry bulb, MW	744	412	412	412	332
Annual turbine energy production, MWh/yr	15,426,179	16,650,921	16,665,475	16,377,108	16,639,794
Annual water consumption, kgal/yr	241,915	1,802,843	3,674,675	6,521,603	12,095,773
Annual water consumption, acre-feet/yr	742	5,533	11,278	20,015	37,123

Source: Maulbetsch Consulting

Table 35 considers the "population-driven distribution" case. For the State as a whole, the use of hybrid cooling (HYB-C) in preference to all-wet cooling results in:

- An installed cost increase of $292 million.
- A reduction in hot day generating capacity of 80 MW.
- A reduction in annual energy production of 339 GWh.
- A reduction in water consumption of just under 5 million kgal/yr (15,280 acre-feet/year).

In comparison to all-dry cooling, the use of hybrid cooling (HYB-C) results in:

- An installed cost savings of $133 million.
- An increase in hot day generating capacity of 332 MW.
- An increase in annual energy production of 992 GWh.
- An increase in water consumption of just under 6.6 million kgal/yr (20,250 acre-feet/year).

Table 35: Statewide Cost, Performance and Water Use-Population-Driven Case

	California Totals--Population-driven Distribution				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$566,730,000	$844,760,000	$634,130,000	$433,590,000	$164,080,000
Annualized cooling system cost, $	$190,635,432	$114,586,195	$101,492,415	$112,503,018	$71,873,557
Reduction in turbine capacity at 1% dry bulb, MW	744	412	412	412	332
Annual turbine energy production, MWh/yr	15,316,888	16,681,336	16,657,760	16,299,926	16,639,127
Annual water consumption, kgal/yr	236,248	1,878,194	3,876,814	6,834,230	11,812,412
Annual water consumption, acre-feet/yr	725	5,764	11,898	20,975	36,253

Source; Maulbetsch Consulting

Finally, the "extreme distribution" case of placing all 20 plants at each site separately or the equivalent of siting all plants in a region with the same annual weather conditions. Tables 36 through 40 provide the values for each of the five sites.

In comparison to all-wet cooling:

- The largest increase in installed cost of all-dry cooling is $600 million at Blythe.
- The largest increase in installed cost of hybrid cooling is $519 million, also at Blythe.
- The reduction in hot day generating capacity is 412 MW with dry cooling and 80 MW with hybrid cooling at all sites.
- The largest reduction in annual turbine energy production with all dry cooling is 1,580 GWh at Long Beach.
- The largest reduction in annual turbine production with hybrid cooling is 583 GWh, also at Long Beach.
- The largest reduction in water consumption with all-dry cooling is 12,684,000 kgal/year (38,900 acre-feet/year) at Blythe.
- The largest reduction in water consumption with hybrid cooling is 7,040,000 kgal/year (21,600 acre-feet/year) at Blythe.

Table 36: Cost, Performance and Water Consumption-All Plants at Sacramento

	California Totals--Extreme Distribution at Sacramento				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$557,400,000	$801,400,000	$617,600,000	$418,000,000	$162,200,000
Annualized cooling system cost, $	$189,507,824	$105,273,365	$92,853,810	$102,000,876	$66,782,739
Reduction in turbine capacity at 1% dry bulb, MW	744	412	412	412	332
Annual turbine energy production, MWh/yr	15,322,170	16,769,520	16,763,142	16,432,870	16,680,186
Annual water consumption, kgal/yr	229,647	1,442,000	3,083,108	6,003,868	11,482,345
Annual water consumption, acre-feet/yr	705	4,426	9,462	18,426	35,240

Source: Maulbetsch Consulting

Table 37: Cost, Performance and Water Consumption-All Plants at Blythe

	California Totals--Extreme Distribution at Blythe				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$763,600,000	$1,383,600,000	$997,200,000	$682,200,000	$163,200,000
Annualized cooling system cost, $	$190,678,768	$168,150,018	$130,264,504	$113,393,563	$69,800,795
Reduction in turbine capacity at 1% dry bulb, MW	744	412	412	412	332
Annual turbine energy production, MWh/yr	15,526,890	16,468,730	16,623,551	16,549,565	16,653,318
Annual water consumption, kgal/yr	258,849	1,774,159	3,444,275	5,901,448	12,942,434
Annual water consumption, acre-feet/yr	794	5,445	10,571	18,112	39,721

Source: Maulbetsch Consulting

Table 38: Cost, Performance and Water Consumption-All Plants at Long Beach

	California Totals--Extreme Distribution at Long Beach				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$488,400,000	$655,400,000	$493,600,000	$353,600,000	$163,200,000
Annualized cooling system cost, $	$205,236,502	$101,824,757	$98,860,816	$125,990,510	$71,877,332
Reduction in turbine capacity at 1% dry bulb, MW	744	412	412	412	332
Annual turbine energy production, MWh/yr	15,031,830	16,676,141	16,556,683	16,029,116	16,611,752
Annual water consumption, kgal/yr	228,924	2,373,262	4,929,832	8,129,636	11,446,200
Annual water consumption, acre-feet/yr	703	7,284	15,130	24,950	35,129

Source: Maulbetsch Consulting

Table 39: Cost, Performance and Water Consumption-All Plants at Bakersfield

	California Totals--Extreme Distribution at Bakersfield				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$594,200,000	$891,800,000	$668,600,000	$444,200,000	$167,600,000
Annualized cooling system cost, $	$170,154,199	$118,845,256	$102,819,211	$109,097,581	$71,904,729
Reduction in turbine capacity at 1% dry bulb, MW	744	412	412	412	332
Annual turbine energy production, MWh/yr	15,628,146	16,658,731	16,664,474	16,350,383	16,605,102
Annual water consumption, kgal/yr	242,603	1,901,136	3,807,926	6,804,920	12,130,127
Annual water consumption, acre-feet/yr	745	5,835	11,687	20,885	37,228

Source: Maulbetsch Consulting

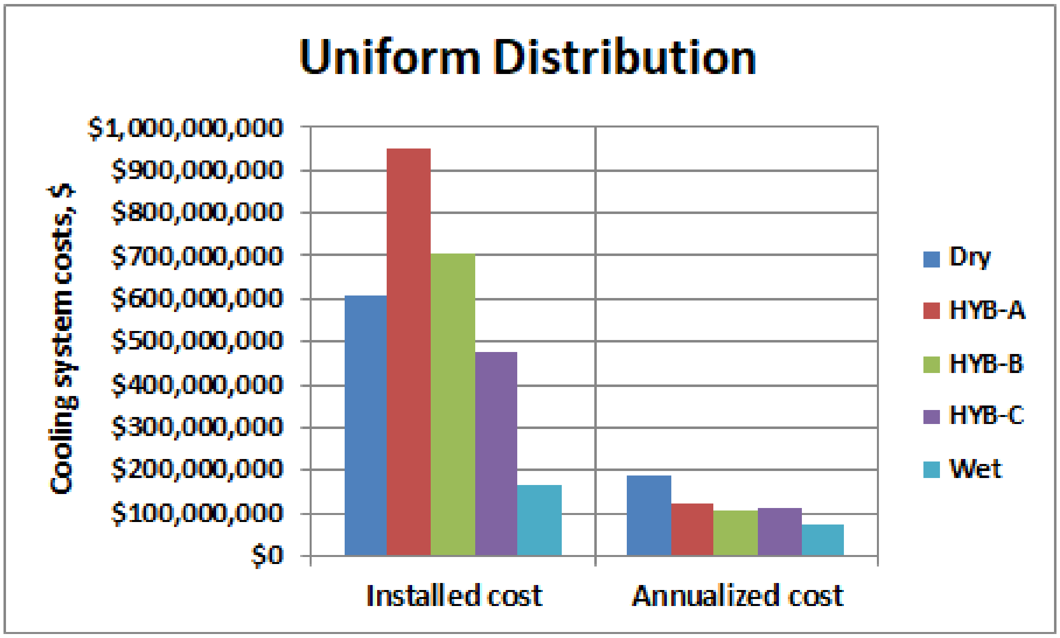
Table 40: Cost, Performance and Water Consumption-All Plants at Redding

	California Totals--Extreme Distribution at Redding				
	Dry	HYB-A	HYB-B	HYB-C	Wet
Installed cost, $	$630,800,000	$1,028,200,000	$760,800,000	$495,800,000	$168,400,000
Annualized cooling system cost, $	$173,593,028	$127,237,299	$105,856,547	$101,020,838	$89,158,801
Reduction in turbine capacity at 1% dry bulb, MW	744	412	412	412	332
Annual turbine energy production, MWh/yr	15,621,860	16,681,484	16,719,524	16,523,605	16,648,610
Annual water consumption, kgal/yr	249,555	1,523,659	3,108,235	5,768,141	12,477,760
Annual water consumption, acre-feet/yr	766	4,676	9,539	17,703	38,295

Source: Maulbetsch Consulting

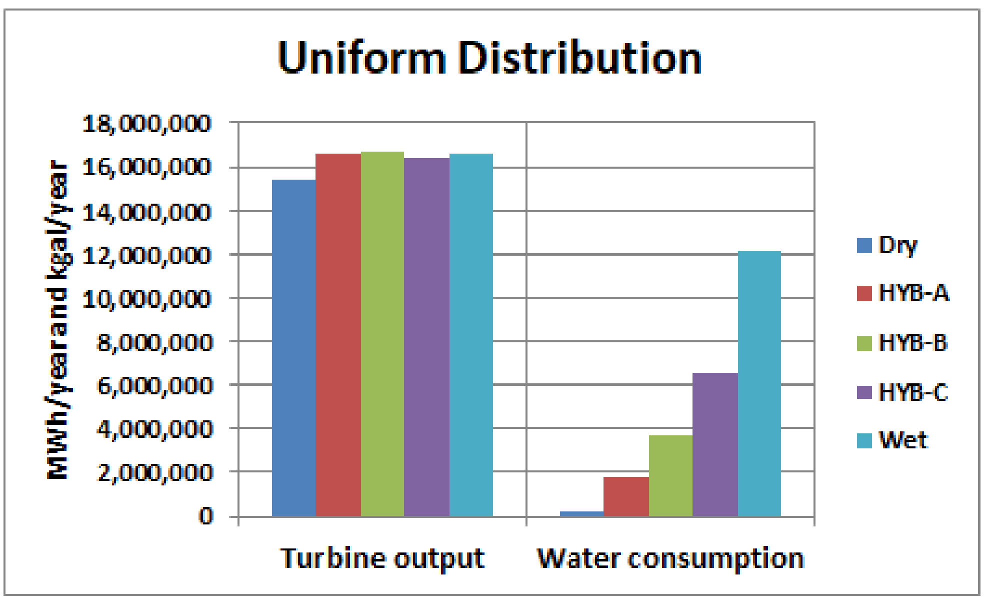
To present the results in a form easier to visualize, Figures 45 through 50 provide selected examples of the extensive information contained in the preceding tables.

Figure 45: Statewide Costs for Uniform Distribution Case



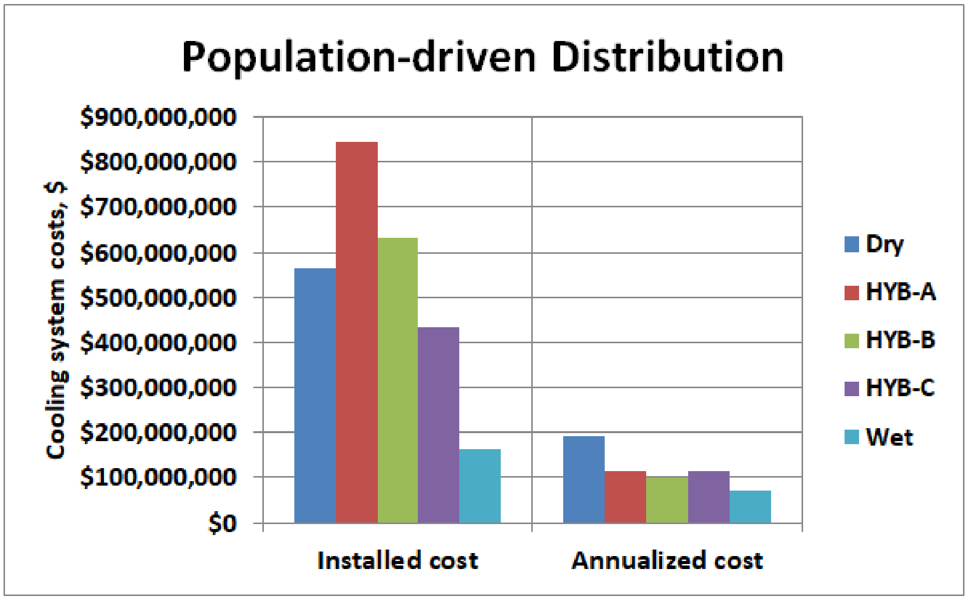
Source; Maulbetsch Consulting

Figure 46: Statewide Turbine Output and Water Consumption for Uniform Distribution Case



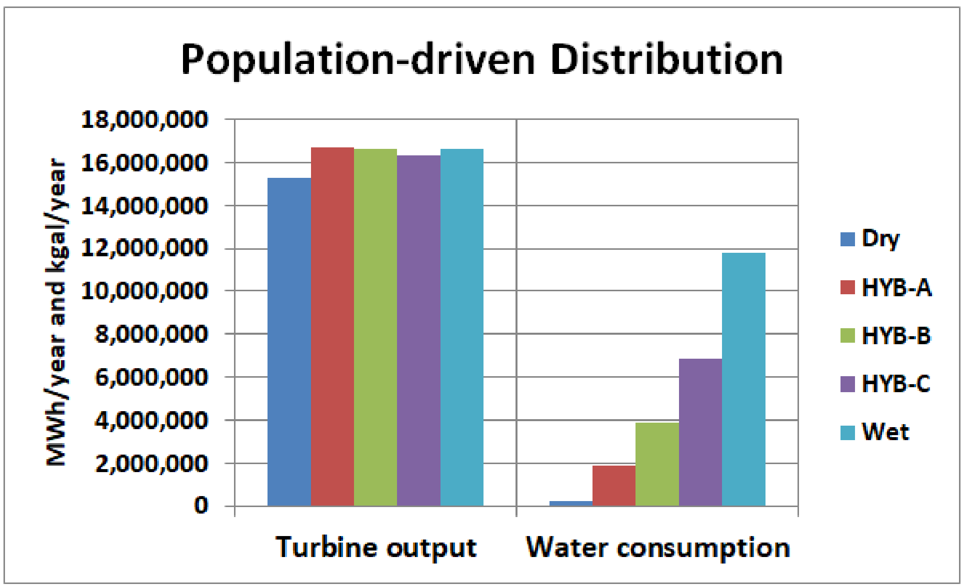
Source; Maulbetsch Consulting

Figure 47: Statewide Costs for Population-Driven Distribution Case



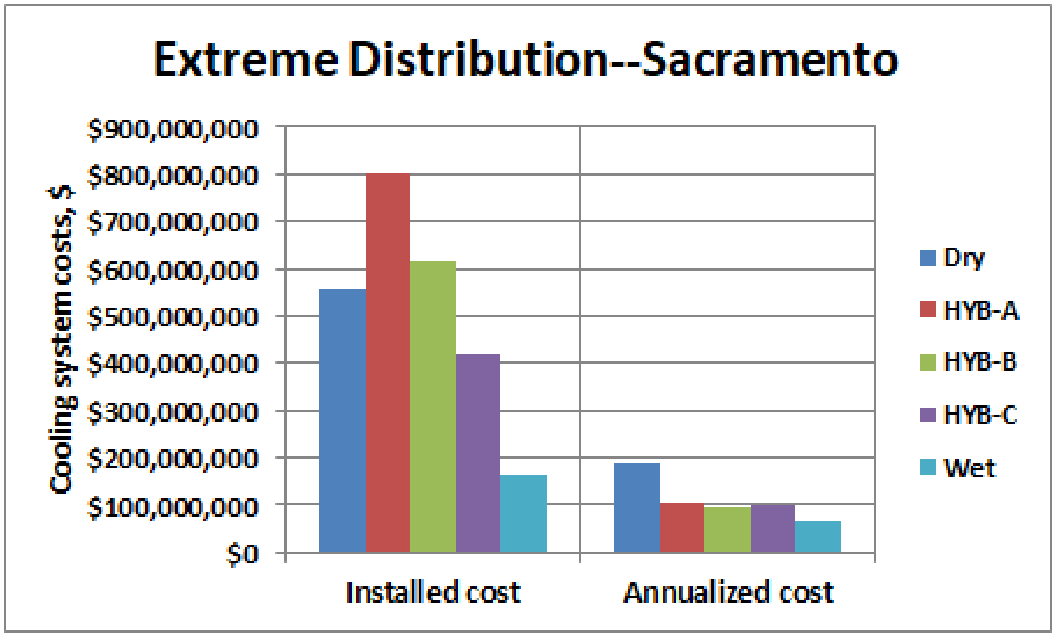
Source; Maulbetsch Consulting

Figure 48: Statewide Turbine Output and Water Consumption for Population-Driven Case



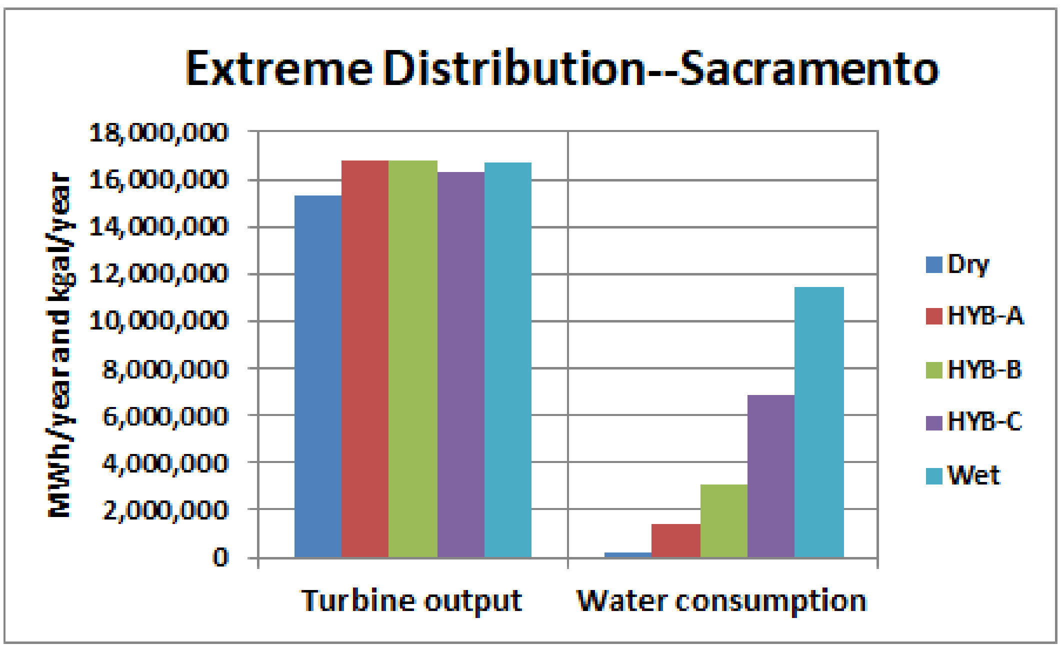
Source; Maulbetsch Consulting

Figure 49: Statewide Costs for Extreme Distribution Case—Sacramento Climate



Source; Maulbetsch Consulting

Figure 50: Statewide Turbine Output and Water Consumption for Extreme Case—Sacramento



Source; Maulbetsch Consulting

In summary, it is clear that hybrid cooling can save substantial amounts of water compared to the traditional wet cooling systems, although at increased cooling system cost and reduced hot day generating capacity and annual energy production. Three additional comparisons are of interest.

First, an alternative measure of cooling system cost is the annualized cost, which combines the initial installed cost with the cost of reduced energy production as described in an earlier section. The annualized cost values for the state assuming the “uniform”, “population–driven” and “extreme” distributions previously shown. The variations across the several cooling systems are much less than they are for the installed costs.

Second, the annualized cost can be used to calculate a “cost of water saved” defined as the annualized cost divided the difference in water consumption for the system and that for the corresponding all-wet system. Those costs range from $14 to $18/kgal for all-dry systems at all sites, with the highest cost at Long Beach. For hybrid systems (HYB-C), the costs are slightly higher in the range of $15 to $20/kgal at all sites except for Long Beach, where the cost is close to $40/kgal. This high cost of water saved in Long Beach is due to the unusual variation in dry and wet bulb temperature over the course of the year, making water conservation with a hybrid system difficult, as was discussed in the earlier section.

Finally, the effect of cooling system choice on the annual energy production has a direct consequence on the level of greenhouse gas emissions. For example, considering the relative energy output for the 20 plants located as in the “population-driven” distribution, the values range from 16, 639,000 MWh for wet cooling to 15,317,000 MWh for all plants on dry cooling. Assuming this difference of 1,322,000 MWh would be made up with additional generation from other gas-fired, combined-cycle plants operating at an average heat rate of 7,304 Btu/kWh [7], gas would be burned to produce an additional 9.66×10^{12} Btu. Assuming CO_2 emissions from the combustion of natural gas of 117 lb $CO_2/10^6$ Btu [8], this would result in an additional 1.13×10^9 lb CO_2 per year. If hybrid cooling, as represented by HYB-C were used in place of dry cooling, the additional CO_2 emissions would be reduced to 2.9×10^8 lb CO_2 per year. For comparison, the total CO_2 emissions from all natural gas-fired plants in California during 2015 were estimated at 9.7×10^{10} lb CO_2 per year.

CHAPTER 6: Summary and Conclusions

Summary

This study examined using hybrid cooling as an alternative to traditional, closed-cycle wet cooling and the increasingly common direct dry cooling. Wet cooling is the least expensive system and achieves the highest plant capacity and efficiency, but at the expense of consuming large amounts of water. Conversely, dry cooling consumes virtually no water but is expensive and imposes capacity limitations and efficiency reductions on the steam power plants. The premise was that hybrid cooling could provide a balanced contribution to California's goals of providing adequate, economical electric power, conserving water and minimizing greenhouse gas emissions.

The work used an existing spreadsheet tool with the capability of estimating the size and performance of all-wet, all-dry, and hybrid cooling systems for specified design points and of determining the performance of these systems over a range of heat loads and ambient conditions. The effort proceeded in several steps:

- Acquisition of current data on the cost and performance of major cooling system components and embedding this most up-to-date information into the tool.
- Comparison and validation of estimates generated by the tool against data and information from existing power plants equipped with each of the alternative cooling systems.
- Development of cost, performance and water use comparisons among all-wet, all-dry, and hybrid systems at five sites representing the range of meteorological conditions in California.
- Estimation of the effects on total cooling system cost, annual energy output, and annual water consumption for future power plant requirements in 2050.

Conclusions

The estimates generated by the tool compared well to the design and performance of existing systems in operation at full-scale power plants. Systems were sized using the original design specifications of heat load and turbine backpressure at a specific ambient temperature and humidity. The performance of the systems was then calculated on an hourly basis for a year for operating conditions of heat load and ambient temperature and humidity provided by the plant. In all cases, the system sizes and performance were in satisfactory agreement with the data and information provided by the plants. In instances in which the performance differed over certain periods, the differences were satisfactorily explained by operating decisions made by the plant that altered the expected performance.

The results of the case studies gave a clear indication of the effects of the differing meteorological conditions at the five sites on the comparative cost, performance, and water consumption of the alternative cooling systems. This information was adequate to understand how the projected location of future power plants in different regions of California with different climatic conditions would affect the future costs, energy production, and water conservation of electricity generation.

Projected effects of cooling system choice on system cost, energy production, and water consumption aggregated for the state's projected power plant capacity and energy production in 2050 were estimated based on the assumption that 20 gas-fired, combined-cycle plants with capacities of 530 MW would be operating in 2050. The project team considered three different cases with differing assumptions for the geographic distribution of these 20 plants throughout the state in regions of differing meteorology. Two bounding cases, including a "uniform" distribution of the 20 plants by siting four plants at each of the five sites and an "extreme" distribution where all 20 plants were sited at each of sites, were considered. The more plausible distribution is one in which more plants were located in areas of the state with higher population.

It was established that hybrid cooling can save substantial amounts of water compared to the traditional wet cooling systems, although at increased cooling system cost and reduced hot day generating capacity and annual energy production. The results of this study provide information generated by a validated computational methodology for determining quantitative estimates of the trade-offs among cooling system cost, annual energy production, and water consumption. State regulatory agencies, power system developers and owners, and community groups can use this information to make informed decisions about requirements for cooling equipment at future steam power generating facilities in California. This can be a significant factor to ensure California will have the appropriate balance among the supply of electrical generation, the cost of electricity, and the conservation of water resources.

The results of this work are being distributed to the user community through two scientific articles, presentations and publications at relevant conferences. The findings summarized in first paper *Cost/Performance Tradeoffs Among Wet, Dry and Hybrid Cooling Systems* were presented at the Annual Winter Meeting of the Cooling Technology Institute in Houston on February 5, 2018. The paper will be published in the CTI Journal in an upcoming issue. The second paper *Wet, Dry and Hybrid Cooling Systems* will be presented at the 2018 Meeting of the International Heat Transfer Conference in Beijing, China in August, 2018 and published in the proceedings of that conference.

Potential users of the research results are:

- the individual electric power companies who specify and select power plant cooling systems.
- the environmental and regulatory community who must consider trade-offs between water conservation and the cost of power generation.
- other researchers and research sponsors seeking to evaluate new concepts against the cost/performance of existing systems.
- vendors of power plant cooling equipment (although to a limited extent since they rely on their own proprietary method).

GLOSSARY

Term	**Definition**
ACC	Air-cooled condenser
APS	Arizona Public Service Company
Btu/hr	British thermal unit per hour
CO_2	Carbon Dioxide
CT	Cooling Tower or Combustion Turbine
ft H_2O	Foot of water column
Dephlegmator	A devise for partial condensation of multicomponent vapor system
ft/sec	Foot per second
GEA	*GEA Group Aktiengesellschaft* (now Enexio) Cooling system vendor
gpm	Gallon per minute
Hga	Hg absolute, pressure in millimeter of mercury (Hg)
HRSG	Hear Recovery Steam Generator
ITD	Initial temperature difference (Condensing temperature – Ambient air temperature)
lb/hr	Pounds per hour
L/G	Liquid/Gas ratio
LMTD	Log mean temperature difference
MW	Megawatt
MWh	Megawatt hours
PG&E	Pacific Gas & Electric Company
PSE	Puget Sound Energy
psi	Pounds per square inch
SPIG	Cooling system vendor (now owned by Babcock & Wilcox)
SS tubes	Stainless steel tubes
ST	Steam Turbine
TEI	Thermal Engineering International (USA), Inc. A cooling equipment vendor
TTD	Terminal temperature difference
ZLD	Zero Liquid Discharge

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APPENDIX A:
Description of Spreadsheet Tool

The analyses presented in this study are based on estimates of the design, performance and cost of hybrid cooling systems in comparison to closed-cycle wet and dry cooling systems. These estimates are developed using an existing Excel-based spreadsheet tool. A brief description of the tool is provided in this section

Scope and Limitations

For a given cooling system design point (heat load, turbine exhaust pressure, ambient temperature and humidity, site elevation and turbine performance information), the tool will provide estimates of cooling system component size and cost. Performance information such as turbine exhaust pressure, cooling system power requirements, and turbine output and cooling system water consumption throughout the year and the annual totals of energy production and water use are calculated and displayed.

Cooling system types: The tool provides output information for closed-cycle all-wet and all-dry systems as well as parallel hybrid systems; specifically

- All-wet systems: Shell-and-tube steam surface condenser in series with mechanical-draft, counter-flow wet cooling tower
- All-dry systems: Mechanical-draft air-cooled condenser of the forced-draft, A-frame configuration
- Parallel hybrid system: Parallel, self-balancing arrangement of an all-wet system and an all-dry system of the types described above

Excluded from consideration in the current version of the tool are:

- Natural-draft wet and natural-draft dry cooling towers
- All-dry or hybrid systems using indirect dry cooling (air-cooled heat exchangers) of either the conventional “plume abatement” type or the water-conservation type
- Wet-enhanced dry cooling such as inlet air spray cooling of air-cooled condensers

General Arrangement

The tool is constructed in an Excel spreadsheet displaying four visible worksheets—one introductory, informational worksheet and three operational worksheets. In addition, there are ten additional worksheets which are locked and hidden in which the underlying computations and results compilations are performed.

Informational worksheet:

1. “Tool Content” worksheet containing brief descriptions of the tool and the three operational worksheets

Operational worksheets:

1. Input
2. Output
3. Site Index

Computational worksheets:

1. Summary
2. Hybrid System
3. Hybrid-CT Select
4. Hybrid CT
5. Hybrid ACC
6. ACC-Full Load
7. CT-Full Load-Select
8. CT-Full Load
9. Steam Turbine
10. Met Library

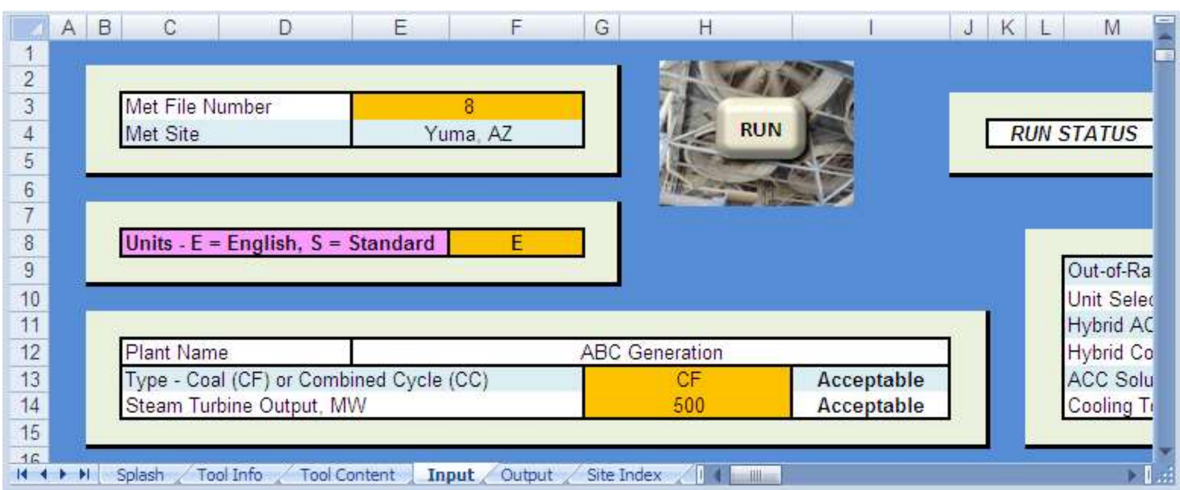
The following sections contain detailed descriptions and operating instructions for the three operational worksheets.

Input Worksheet

The Input Worksheet contains input data cells in which to enter user/case identifiers, site and plant characteristics, cooling system design specifications and relevant economic quantities.

The opening (Input) screen, showing the Tabs of the four visible worksheets is displayed in Figure A-1.

Figure A-1: Spreadsheet Title Frame/Worksheet Tabs



Site/Plant Information

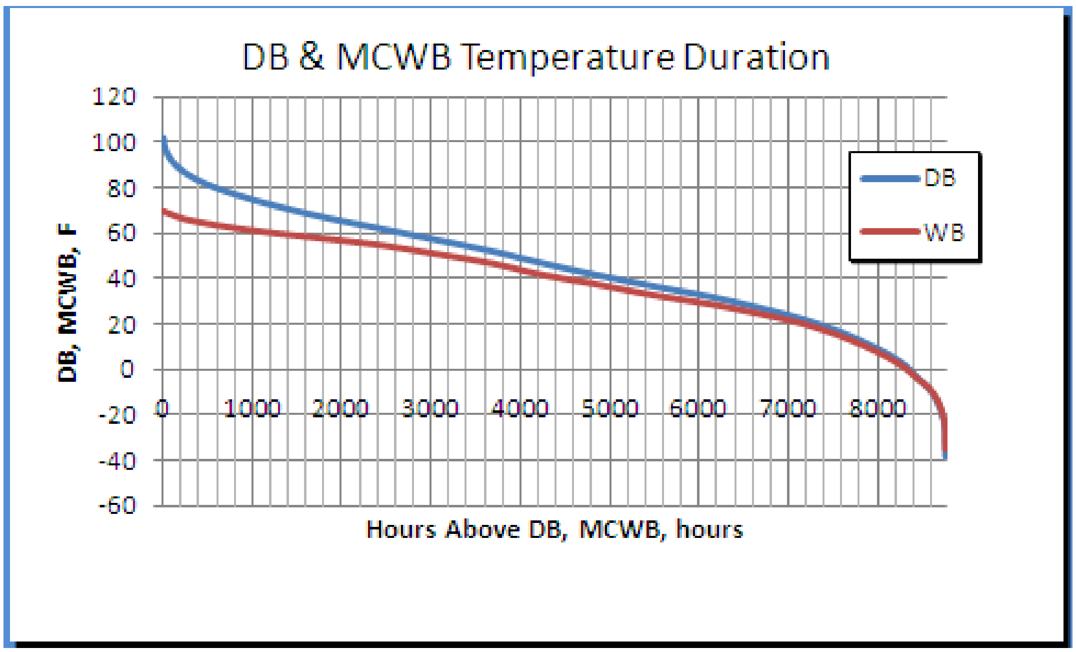
Site and plant information is entered first.

1. Select the site ID number from the dropdown list in Row 3, Columns E and F to create the appropriate meteorological data file. The site name will appear in Row 4, Columns E and F.

    a. A list of sites with the location and corresponding site ID number is found in the "Site Index" tab. Choose a location with meteorological conditions closest to your site.

    b. In order to assist in choosing an available location with meteorological conditions closest to the site of interest, a graph of the dry- and wet-bulb duration curves for the selected site is displayed on the Input Worksheet when a Site ID number is entered as shown in Figure A-1.

Figure A-2: Example Dry- and Wet-Bulb Temperature Duration Curves



2. The tool will accept input and display output in either English (lb., feet, Btu, etc.) or SI (kg, meters, joules, etc.) units. Your preferred system of units is selected in Row 8, Column F by selecting "E" or "S" for English or SI units respectively.

3. Enter Plant Identifiers in Rows 12 through 14, Columns G and H. These items are for your reference purposes only and do not affect the calculations

    a. Enter a plant name in Row 12, Columns G & H

    b. Select a plant type (CF for a fossil (coal)-fired steam plant; CC for a gas-fired combined-cycle plant) in Row 13, Columns E to I.

    c. Enter the nameplate capacity of the steam turbine (Plant capacity for coal plants; steam turbine only capacity for combined-cycle plants) in Row 14, Columns G & H.

Cooling Systems

Input for the three separate cooling systems (all-wet, all-dry and hybrid) are entered separately. Cooling system performance input blocks: Each of the required input variables is listed along with the required units in which the values must be specified. An "Acceptable" range of values is given for each along with an "Advisory" or "Warning" column which notes if the entered value is outside the acceptable range. If a value outside the "Acceptable" range is entered, the calculation will not proceed. Additionally, if there is no solution for an ACC or cooling tower, the program will not run but will indicate that no solution can be found.

Hybrid Cooling System

This input block is divided into three sections.

Overall system characteristics

1. Enter desired turbine backpressure for hybrid system cooling at the 1% ambient dry bulb temperature in Row 19, Column F. (1% DB equals that temperature exceeded at the site for only 1% of the hours in a year). Values lower than 4 in Hga (135 millibars) or higher than 8 in Hga (270 millibars) are not acceptable and, if entered, the tool will not run.
2. Enter full-load, design turbine steam flow in Row 20, Column F. Values lower than 500,000 lb./hr (63 kg/sec) or higher than 3,500,000 lb./hr (440 kg/sec) are not acceptable and, if entered, the tool will not run. Note: Enter the total steam flow (not the dry saturated steam flow) from the steam turbine to the cooling system at full load.
3. Enter desired turbine steam exit quality in Row 21, Column F. Values lower than 0.85 or higher than 1. are not acceptable and, if entered, the tool will not run. If this value is not known precisely, a value of 0.98 is recommended. The effect on the final results is minimal.
4. Enter the site elevation in Row 22, Column F. Values below 0. (sea level) or above 8,000 feet (2440 meters) are not acceptable and, if entered, the tool will not run. Note that the value for your site may be different from the nominal Site ID chosen on the basis of the closest fit to the ambient temperature and humidity profiles. Therefore, it should be entered separately.

Hybrid system dry component

1. Enter the percentage of the total heat load to be carried by the air-cooled condenser at the 1% dry bulb design point in Row 24, Column F. Values below 15% or above 85% are not acceptable and, if entered, the tool will not run. Note: It is this input variable that sets the size of the dry portion of the hybrid system. Higher values will use less water but generally give a higher average backpressure throughout the year, a higher power requirement and a higher cost. To arrive at a preferred design, a range of values of this input should be tried until the desired annual water consumption is arrived at. A reasonable starting point is 50%.

Hybrid system wet component

1. Enter a design approach temperature for the wet cooling tower in Row 27, Column F. Values below 5 ˚F (2.8 C) or above 25 ˚F (14 C) are not acceptable and, if entered, the tool

will not run. **Note: This value and the next value for cooling tower range are those that set the size and performance of the wet component of the hybrid system. They can be varied to obtain a preferred system design. A recommended starting point for the approach is 7 ˚F (4 C).**

2. Enter a design range for the wet cooling tower in Row 28, Column F. Values below 10 ˚F (5.5 C) or above 30 ˚F (16.6 C) are not acceptable and, if entered, the tool will not run. **Note: This value and the previous value for cooling tower approach are those that set the size and performance of the wet component of the hybrid system. They can be varied to obtain a preferred system design. A recommended starting point for the range is 20 ˚F (11 C).**

3. Enter the desired cycles of concentration at which the tower will be operated in Row 29, Column F. Values below 1.5 or above 25 are not acceptable and, if entered, the tool will not run. **Note: This choice of cycles of concentration does not affect the performance or cost of the system. It is used only to convert the amount of water consumed through evaporative loss into a "make-up" requirement which will account for blowdown as well as evaporation.**

All-dry system input

Full-load ACC characteristics

1. Enter desired turbine backpressure for all-dry system cooling at the 1% ambient dry bulb temperature in Row 35, Column F. Values below 2 in. Hga (85 millibars) or above 8. in. Hga (270 millibars) are not acceptable and, if entered, the tool will not run.

All-wet system input

Full-load wet cooling tower characteristics

1. Enter a design approach temperature for the wet cooling tower in Row 39, Column F. Values below 5 ˚F (2.8 C) or above 15 ˚F (8.3 C) are not acceptable and, if entered, the tool will not run. **Note: This value and the next value for cooling tower range are those that set the size and performance of the cooling tower for an all-wet system. They can be varied to obtain a preferred system design. A recommended starting point for the approach is 7 ˚F (4 C).**

2. Enter a design range for the wet cooling tower in Row 40, Column F. Values below 10 ˚F (5.5 C) or above 30 ˚F (16.6 C) are not acceptable and, if entered, the tool will not run. **Note: This value and the previous value for cooling tower approach are those that set the size and performance of the cooling tower for an all-wet system. They can be varied to obtain a preferred system design. A recommended starting point for the range is 20 ˚F (11 C).**

3. Enter desired turbine backpressure for all-wet system cooling at the 1% wet bulb temperature in Row 41, Column F. (1% WB equals that temperature exceeded at the site for only 1% of the hours in a year). Values lower than 1.5 in Hga (50 millibars) or higher than 5 in Hga (170 millibars) are not acceptable and, if entered, the tool will not run.

4. Enter the desired cycles of concentration at which the tower will be operated in Row 43, Column F. Values below 1.5 or above 25 are not acceptable and, if entered, the tool will

not run. **Note: This choice of cycles of concentration does not affect the performance or cost of the system. It is used only to convert the amount of water consumed through evaporative loss into a "make-up" requirement which will account for blowdown as well as evaporation.**

Economic Input

These parameters are used to establish the costs associated with varying plant efficiency and output penalties over the course of a year's operation and to put capital and operating and penalty costs on a common basis.

1. Enter the assumed price for energy output (expressed in $/kWh) in Row 47, Column F. Values below $0.01 or above $0.20 are not acceptable and, if entered, the tool will not run.
2. Enter the assumed cost of capital (expressed in %) in Row 48, Column F. Values below 1% or above 15% are not acceptable and, if entered, the tool will not run. A recommended value is 7%.
3. Enter the assumed project "life" (expressed in years) in Row 49, Column F. Values below 5 or above 50 are not acceptable and, if entered, the tool will not run.

"RUN"

When a satisfactory set of input values has been entered, click on the "RUN" button at the top of the Input worksheet. You may notice that many of the calculations are completed as the input is entered prior to clicking "RUN". However, the "RUN" feature is required to update the graphical output on the Output worksheet.

Messages and Alerts

1. At the end of each input row, an "Out of Range" warning is posted if the input value entered is outside of the "Acceptable" range.
2. It is possible that some combinations of input values will result in an unachievable or unacceptable system specification even if each input value itself is within the "Acceptable" range. For example, for the wet cooling tower components, a combination of low backpressure, high wet bulb temperature, high range and high approach may results in an unacceptably low (< 7°F (3.8 C)) or even negative condenser terminal temperature difference (TTD). In such a case the calculated value of the TTD is displayed with the advisory note to "Increase Design BP".
3. In the upper right hand corner of the Input worksheet, the "Out of Range" entries are categorized and summarized. If the input values to not result in a converged solution for any one of the cooling system components, this will be noted in the lower four rows (Rows 11 – 14; Column O) of the message box.

Output Worksheet

The Output Worksheet displays all of the spreadsheet results (selected design specifications, performance parameters and costs) for the all-wet, all-dry and hybrid cooling systems selected for the specified case along with comparisons among the three cooling system types. The results and comparisons are displayed in both tabular and graphical format. In addition, the corresponding Input tables are reproduced on the Output page in Columns B through J for convenience of reference.

Tabular Display

The Output worksheet displays the results in tabular format in Columns L through R expressed in the selected system of units. Tables are available that 1) summarize the design, performance and cost results for each of the three cooling systems, 2) list detailed design, performance and cost information for the dry elements (all-dry ACC; hybrid ACC) and 3) list detailed design, performance and cost information for the wet elements (all-wet cooling tower; hybrid cooling tower).

Graphical Display

For the graphical output, each plot is presented in two adjoining plots in the two different systems of units regardless of which system of units was used for the input data. For each pair of plots, the English units display is on the left; the SI units display, on the right.

The first group of plots, displayed in Columns S through AJ, provides three sets of comparisons among the three cooling systems; specifically

- Backpressure vs. $T_{ambient}$
- Water evaporation rate by month
- Backpressure by month

The second group, displayed in columns AK through AY, provide site meteorological information (mean coincident wet bulb vs. dry bulb temperature) as well as monthly performance information for the hybrid system; specifically,

- Average backpressure by month
- Evaporation rate by month
- Fan number by month

Additional performance information for the individual elements of the hybrid system is displayed in Columns AZ through BO; specifically,

- Backpressure vs. $T_{ambient}$
- Hybrid ACC fan number vs. $T_{ambient}$
- Hybrid cooling tower approach vs. $T_{wet\ bulb}$

Performance information for the all-wet cooling system is given in Columns BP through CD.

- Turbine backpressure vs. ambient wet bulb
- Cooling tower approach vs. ambient wet bulb

Site Index

The Site Index is simply a list of the sites for which meteorological data are embedded in the tool. Each site is assigned an ID Number for use in the Input sheet. Table A-1 shows the currently listed sites.

Table A-1: List of Sites with Meteorological Data Embedded in Spreadsheet

Index of Sites in Met Data Library...

Site #	Site
1	Atlanta, GA
2	Dover, DE
3	Bismarck, ND
4	Cincinnati, OH
5	Toledo, OH
6	Charlotte, NC
7	Green Bay, WI
8	Yuma, AZ
9	San Bernardino, CA
10	Burlington, VT
11	Galveston, TX
12	Portland, OR
13	Jacksonville, FL
14	St. Louis, MO
15	Pueblo, CO
16	Dallas-Fort Worth, TX
17	Farmington, NM
18	Paris, France
19	Madrid, Spain
20	No site information

Computational Worksheets

The following computational worksheets are hidden. They contain the underlying computations and results compilations that are displayed in the Output worksheet. These worksheets are listed here for reference.

Summary

The Summary Worksheet contains a complete aggregation of all input and output values along with many intermediate results and all default and embedded parameters as well as a more detailed set of graphical results and comparisons. The Worksheet is intended for use by the spreadsheet developers for debugging and tracking down anomalous results.

Hybrid System

Based on the information and correlations developed in the Hybrid CT and Hybrid ACC Worksheets, this Worksheet performs the calculations of the hybrid system performance including turbine backpressure, heat load on both the wet and dry elements, water consumption and power consumption of both the cooling tower and the ACC at off-design conditions throughout the year and aggregates the results into the appropriate annual performance metrics.

Hybrid-CT-Select

This Worksheet selects the size, operating conditions and cost of the cooling tower to be used as the wet element of the hybrid cooling system. The wet tower is sized to meet the heat load allocated to the wet component on the Input Worksheet (Total heat load [Rows 21 and 22/Column F] minus the allocated dry component heat load [Row 24/Column F] and deliver a cold water temperature consistent with the specified range [Row 28/Column F], approach [Row 27/Column

F] and turbine exhaust pressure [Row 19/Column F] at the ambient design condition (1% dry bulb at the selected site [Rows 3 and 4/Columns E and F]. From a set of towers of differing size, a subset is selected which meet various design criteria (water flow per cell, water loading, fan motor horsepower, etc.). Of the designs meeting all criteria, the smallest tower (fewest cells) is selected.

Hybrid CT

The Hybrid CT Worksheet calculates the operating curves of the wet tower specified in the Hybrid-CT Select Worksheet. The Worksheet uses information from the Met Library Worksheet to define, for each month of the year, a set of ambient conditions (dry bulb and corresponding mean coincident wet bulb) at 5 ˚F increments from the highest to the lowest monthly temperature. For each of these ambient conditions, the cold water temperature is determined for a range of heat loads. This information is used in the Hybrid System Worksheet to calculate the performance of the wet element of the hybrid system.

Hybrid ACC

The Hybrid ACC Worksheet selects the size, operating conditions and cost of the ACC to be used as the dry part of the hybrid cooling system. The operating curves for the ACC are also generated in this Worksheet. Hybrid ACC performs the same functions for the ACC portion of the hybrid system that the two worksheets (Hybrid CT-Select and Hybrid CT) do for the wet element.

The ACC is sized to achieve the desired turbine backpressure [Row 19/Column F] at the design dry component heat load [Row 24/Column F] at the design ambient condition (1% dry bulb at the selected site [Rows 3 and 4/Columns E and F]. As was done for the wet component, a set of ACCs of differing size is established from which a subset of those meeting several design criteria (steam flow per cell, air flow per cell, fan power per cell, etc.) are selected. Of those meeting all criteria, the smallest ACC is chosen.

ACC-Full Load

The ACC-Full Load Worksheet selects the size, design, and operating conditions of an ACC suitable for use as an all-dry cooling system using the same approach as described above for the Hybrid ACC. The annual off-design calculations, such as are done for the hybrid system in the Hybrid System Worksheet are also carried out in this Worksheet for the all-dry system.

CT-Full Load-Select

The CT-Full Load-Select Worksheet selects the size, operating conditions and cost of a cooling tower suitable for use as an all-wet cooling system using the same approach as described above for the Hybrid CT.

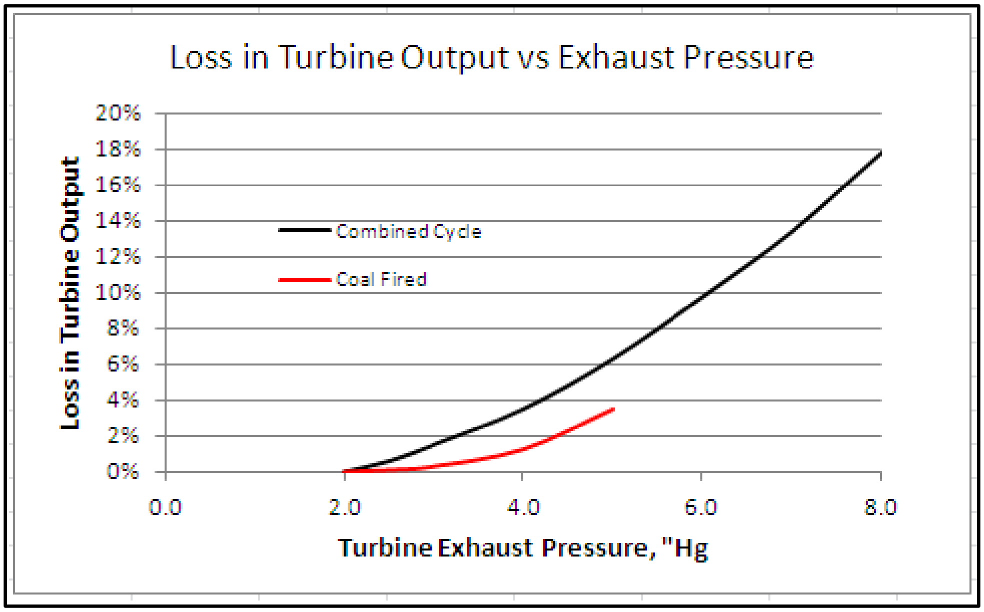
CT-Full Load

The CT-Full Load Worksheet performs the functions of generating the off-design performance curves for the tower selected and sized in CT-Full Load-Select and performing the off-design calculations throughout the year and determining the required annual performance and water consumption metrics.

Steam Turbine

The Steam Turbine Worksheet contains the turbine performance curves for representative turbines used on coal-fired steam plants and gas-fired, combined-cycle plants. Data in the form of "% Loss in Turbine Output" for a range of turbine exhaust pressures from 2 to 8 in Hga are converted into a polynomial curve used in the turbine output calculations at off-design conditions throughout the year. The default curves used in the computation are shown below in Figure A-3.

Figure A-3: Default turbine characteristic curves



Met Library

The Met Library contains the detailed data for ambient temperature and ambient wet bulb for each site in the Site Index. For each month, the temperature data for that month is separated into bins of 5 ˚F starting with the bin which contains the highest reading for the month and ending with the bin containing the lowest reading. The data gives the number of hours that temperatures in that bin were recorded during the month and the mean coincident wet bulb (MCWB) for those hours. The data is taken from the Engineering Weather Data CD assembled by the Air Force Office of Scientific Research (AFOSR).