Staff Report On

Engineering and Economic Aspects of Wet and Dry Cooling Systems

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F O R E W O R D

The study described herein is one of three conducted at the request of Region VIII, Environmental Protection Agency, as a technical contribution to the ongoing, interagency Northern Great Plains Resources Program. In recognition that the findings and approach have interest and application beyond the geographic boundaries and scope of the initiating Program, this Chapter II is made available as a Staff Report.

Other Chapters, similarly available from the Librarian, Pacific Northwest Environmental Research Laboratory, are:

Chapter I	Water Requirements for Power Plants with Wet Cooling Towers, by Guy R. Nelson
Chapter III	Water Usage in the Conversion of Coal to Pipeline Quality Gas, by James P. Chasse

CHAPTER II

Engineering and Economic Aspects of Wet and Dry Cooling Systems

Introduction

This chapter presents an evaluation of the engineering and economic aspects of cooling water systems for 1000MWe coal fired power plants at three sites within the Northern Great Plains study area. (Colstrip, Montana; Gillette, Wyoming; Stanton, North Dakota) Closed-cycle cooling systems with wet and dry mechanical draft cooling towers are selected for analysis. In addition, once-through cooling is evaluated for economic comparison. System design is based upon design meteorological conditions representative of critical summer months. Annual operating characteristics and costs are evaluated using long-term seasonal average weather conditions.

Meteorology

The design and operation of facilities to dissipate waste heat from thermal power plants are dependent to a large degree upon the weather. Therefore, accurate meteorological data are required. Both design and off-design (i.e., annual variations) data must be compiled.

The meteorological variables of significance for this study include:

Wet towers - wet and dry bulb air temperatures
Dry towers - dry bulb temperatures (frequency distribution)
Once-through - water temperatures

Data on wet and dry-bulb temperatures are contained in Table II-1. The design data provided are for temperatures not exceeded more than 5 percent of the time during the summer months. The four seasons consist of the following months:

Winter - December, January, February
Spring - March, April, May
Summer - June, July, August
Fall - September, October, November

The data in Table II-1 were obtained from a compilation of data supplied by Mr. James Shaw, EPA, Region VIII (Ref. II-1). Note that average data for Colstrip and Gillette are also provided.

Table II-1

Wet and Dry Bulb Air Temperatures

	Wet Bulb					Dry Bulb				
Location	Design	Winter	Spring	Summer	Fall	Design	Winter	Spring	Summer	Fall
Colstrip	70.0	22.0	38.9	58.4	42.3	90.0	24.3	44.1	68.9	47.6
Gillete	70.0	21.9	37.0	57.6	41.8	90.0	24.3	42.4	67.9	47.5
Average	70.0	21.9	38.0	58.0	42.0	90.0	24.3	43.2	68.4	47.5
Stanton	70.6	11.9	35.8	59.7	38.7	88.0	14.5	40.7	67.4	44.2

Tables II-2, II-3, and II-4 contain data on the annual frequency distribution of dry bulb temperatures for Bismarck, North Dakota (applied to Stanton), Sheridan, Wyoming (applied to Gillette), and Miles City, Montana (applied to Colstrip). The data in Table II-2 were obtained from Ref II-2, while Tables II-3, and II-4 were developed from information received from Ref II-3.

Data on water temperatures to be expected at the selected sites were not provided, so it was assumed that any surface water which would be available to a power plant would be from a completely mixed water body at equilibrium temperature (i.e., the temperature at which the net exchange of energy across the air-water interface is zero). Data on equilibrium temperatures from Ref II-4 were examined for Casper, Wyoming; Billings, Montana; and Bismarck, North Dakota. The data for these three locations were essentially the same for both design (summer extreme) and average conditions. Thus, the following values of available water temperature were used for all three sites:

Design - 79°F
Winter - 32°F
Spring - 49°F
Summer - 75°F
Fall - 49°F

Economic Considerations

The cost of power generation, i.e. the busbar cost, is expressed in Mills/KWH and is usually broken down into fixed and variable cost components. Fixed charges are those which are unaffected by plant output and include interest on money, amortization of the plant capital cost, interim replacements, insurance, and taxes. The annual fixed charge rate is expressed as a percentage of plant capital cost. It is the sum of the charges alloted to each contributing item noted above. In determining the fixed cost contribution to total busbar cost, the annual cost is calculated in dollars and then converted to Mills/KWH in accordance with plant operation time.

Variable costs, also called operating costs or production costs, are those associated with the amount of generation and include fuel, payroll labor, and other operating and maintenance expenses. Each of these items is expressed in terms of Mills/KWH.

Both fixed and variable costs are influenced by the heat dissipation system of a plant. The opposite is also true, because general cost factors play a major roll in the optimal design of a plant-cooling system combination. Hence, it is important to establish economic criteria in the early stages of any study of this type.

Table II-2 - Annual Distribution of Air Temperature for Bismarck, North Dakota (Used for Stanton)

Air Temperature Range (°F)	Percent of Time	Air Temperature Range (°F)	Percent of Time
119/115	0	39/ 35	6.89
114/110	0	34/ 30	7.45
109/105	0.01	29/ 25	6.27
104/100	0.07	24/ 20	5.40
99/ 95	0.32	19/ 15	4.23
94/ 90	0.89	14/ 10	3.85
89/ 85	1.72	9/ 5	3.33
84/ 80	2.87	4/ 0	3.17
79/ 75	4.07	- 1/- 5	2.37
74/ 70	5.18	- 6/-10	1.49
69/ 65	6.46	-11/-15	0.88
64/ 60	7.00	-16/-20	0.54
59/ 55	6.91	-21/-25	0.23
54/ 50	6.42	-26/-30	0.10
49/ 45	5.93	-31/-35	0.03
44/ 40	5.91	-36/-40	0.01

Table II-3 - Annual Distribution of Air Temperature for Sheridan, Wyoming (Used for Gillette)

Air Temperature Range (°F)	Percent of Time	Air Temperature Range (°F)	Percent of Time
119/115	0	39/ 35	8.90
114/110	0	34/ 30	8.20
109/105	0	29/ 25	5.99
104/100	.05	24/ 20	4.29
99/ 95	.44	19/ 15	3.12
94/ 90	1.13	14/ 10	2.69
89/ 85	1.99	9/ 5	2.53
84/ 80	2.88	4/ 0	1.31
79/ 75	4.06	- 1/- 5	.29
74/ 70	5.23	- 6/-10	.25
69/ 65	6.16	-11/-15	.10
64/ 60	7.30	-16/-20	.10
59/ 55	8.15	-21/-25	0
54/ 50	8.24	-26/-30	0
49/ 45	8.12	-31/-35	0
44/ 40	8.48	-36/-40	0

Table II-4 - Annual Distribution of Air Temperature for Miles City, Montana (Used for Colstrip)

Air Temperature Range (°F)	Percent of Time	Air Temperature Range (°F)	Percent of Time
119/115	0	39/ 35	7.68
114/110	0	34/ 30	7.11
109/105	.05	29/ 25	5.62
104/100	.30	24/ 20	4.12
99/ 95	.91	19/ 15	3.39
94/ 90	1.68	14/ 10	3.34
89/ 85	2.60	9/ 5	3.52
84/ 80	3.68	4/ 0	2.12
79/ 75	4.60	- 1/- 5	.60
74/ 70	5.70	- 6/-10	.60
69/ 65	6.71	-11/-15	.20
64/ 60	7.24	-16/-20	.19
59/ 55	7.10	-21/-25	0
54/ 50	6.90	-26/-30	0
49/ 45	6.78	-31/-35	0
44/ 40	7.30	-36/-40	0

Data on plant capital costs, fuel costs, and fixed charge rates for power plants to be constructed in the Northern Great Plains Study were provided by EPA's Region VIII (Ref. II-1). Table II-5 gives the low, high, and, if appropriate, medium values for these cost factors. In the economic analysis which follows, several combinations of these cost factors were examined.

Engineering Considerations

The initial requirements for approximating the size and performance of alternative cooling systems are the meteorological and economic data given previously. Based on these data and generalized cost estimates for system components and operation, component sizes and performance characteristics are determined via digital computer programs.

The procedure for designing each cooling device varied according to the source of the computer programs. A computer program developed by the Dynatech Corporation was used as a primary means for analyzing wet cooling towers and once-through systems (Ref. II-5). Design and cost data on mechanical draft dry (Heller) cooling systems were obtained from the analysis provided by R. W. Beck and Associates (Ref II-2).

The Dynatech and R. W. Beck computer programs are the results of EPA research contract efforts. Supplementary cost data on wet towers were obtained from The Marley Company (Ref. II-6) and the literature (Ref. II-7). Cross-referencing and spot checks among Dynatech, R. W. Beck and in-house calculations were made to assure consistency and reasonable agreement of the results despite the varied approaches used in system design.

Detailed discussions of the optimization procedures used are not given here. The interested reader is urged to consult the original source (Refs. II-2, 5) for such details. In addition, a report on alternative cooling systems for the Lake Michigan area (Ref. II-8) contains information on the procedures, as well as numerical results.

The two computer programs used in this study have substantially different input requirements. In order for the reader to properly evaluate the final results of the analyses, the appropriate input data are provided. It should be noted that both programs contain coefficients, constants, etc. which can be changed by the user. Unless noted herein, the program constants used in this study are as contained in the source references.

In addition to the meteorological and economic data given previously, the Dynatech program requires input data on plant capacity on an annual cycle and turbine heat rate.

Table II-5

Cost Factors

Magnitude	Plant Capital Cost ($/KW)	Fixed Charge Rate (%)	Fuel Cost (¢/10^6 BTU)
Low	300	12	16
Medium	---	15	--
High	400	18	19

An average annual plant capacity factor of 0.77 was selected, based on information provided by Region VIII (Ref. II-1). The following distribution of load on the 1000 MWe base plant was selected to correspond to the 0.7 plant capacity factor:

Capacity	1.0	0.8	0.6	0.4	0
Hours/yr	4000	2000	1310	900	550

In order to evaluate the operation of the cooling system throughout the annual cycle, the Dynatech program requires a seasonal distribution of plant capacity; Table II-6 provides such information for this study.

Another important system cost factor is the turbine heat rate and its variation with capacity factor and the condenser operating temperature. Data for typical GE turbine of a 1000 MWe capacity were used with the Dynatech program. Turbine heat rates at several capacity factors were obtained from the manufacturer's heat rate tables (Ref. III-9). Table II-7 provides these data. (Note that these are heat rates for a specific turbine and should not be equated to an overall plant heat rate.)

The Dynatech program contains cost functions for all components of the cooling system, including condenser, pumps, cooling tower, intake and outlet structures, etc. A review of recent literature (Refs. II-6, 7, 10) and manufacturer's data was undertaken to update these cost functions. This review indicated that the cost functions contained in the Dynatech program were still generally applicable. Two changes were made. Condenser costs were increased by 50 percent to account for recent increases in cost. The overall heat transfer coefficient for the condenser was assumed to be 525 BTU/hr-ft^2 - °F. Also, pump costs were increased from \$1/gpm to \$1.70/gpm based on data in Ref. II-10. These changes in cost functions cause relatively minor increases in cooling system cost over the original Dynatech values.

The R. W. Beck program was written for optimizing Heller-type mechanical and natural draft dry tower cooling systems for steam electric power generating plants. The dry tower system is "optimized" with respect to four major cost items: capital cost, auxiliary power cost, plant fuel cost, and cost of replacing lost capacity. The program does not provide an exact cost optimization of a dry cooling tower system at this time because of two major problems: a) unavailability of performance and cost data for high back pressure turbines and b) the proprietary nature of information on cost and performance of cooling coils. Reasonable extrapolations based on the current turbine designs and order of magnitude estimates of prepackaged cooling coil-fan modules are used in the program. The cost information in Ref. II-2 has not been increased due to inflation since 1969.

The R. W. Beck program was run with both summer and winter peaking. In the summer peaking mode, the program provides gas turbine peaking units

Table II-6

Percent of Time at Various Capacities
on a Seasonal Basis

Plant Capacity	Winter	Spring	Summer	Fall
1.0	30	20	30	20
0.8	25	25	25	25
0.6	25	25	25	25
0.4	18	32	18	32
0	0	50	0	50

Table II-7

Turbine Heat Rates* (BTU/KWH)

	Back Pressure (in. Hg)			
Capacity	1.0	2.0	3.0	3.5
1.0	7415	7532	7716	7805
0.8	7483	7659	7855	7941
0.6	7674	7947	8181	8283
0.4	8045	8434	8728	8847

*For a 1000 MWe turbine, cross-compound, 3600/1800 RPM, 3500 PSIG, 1000/1000F, 6 flow, 38 inch last stage blades.

(\$100/KW, 40¢/10^6 BTU fuel cost, 15,000 BTU/KWH heat rate, and \$1.20/KW O&M cost) to make up lost capacity during the summer when excessively high air temperatures occur more than ten hours per year. Since most of the power to be generated in the Northern Great Plains will be exported, summer peaking capacity could be provided by the end user (e.g., a Chicago utility) instead of at the site (e.g., Colstrip). Thus, a winter peaking season, where the advantages of cool temperatures provide low power plant heat rates, was also analyzed. For winter peaking, gas turbines are not required.

For annual operation emphasizing either summer or winter peaking, the plant provides an annual output of 6.56 x 10^6 MWH of electric power. This is based on an average annual plant capacity of 0.75 with the following distribution:

Capacity	1.0	0.75	0
Hours/yr	3750	3750	1260

In order to obtain equivalent power output under both summer and winter peaks, the cost data provided are not truly "optimal," because the data were selected at the specific ITD which gave the desired plant output rather than the "optimal" ITD.

Results

Economic data for the three cooling systems analyzed (i.e., once-through, closed-cycle wet mechanical draft cooling towers, and Heller type dry towers) are presented in tabular form. For once-through and wet towers, the Gillette and Colstrip sites were run as one site, since the relevant meteorological parameters were essentially equal. As stated previously, the Dynatech and R. W. Beck programs were run for several combinations of the economic factors contained in Table II-5.

Only minor variations in wet cooling system design characteristics occurred between the various cases analyzed. For once-through cooling systems, the condenser Δ T varied from a low of 26°F to a high of 31°F with an average of 28°F. For the wet MD tower, the range averaged 26°F and the approach was 19°F.

The cost data for once-through and closed-cycle wet towers are contained in Table II-8. The data for all three sites were averaged, since the slight variation in meteorology did not cause significant differences in cost. The last column in this table shows the overall economic impact of the cooling system on the total busbar cost. It includes fixed charges, O&M costs, and fuel penalties.

Table II-9 provides cost data for dry (Heller type) towers for the three sites. Note that the capital cost of the tower at each site was constant. The three columns in Table II-9 for each site provide the following information:

TABLE II-8

Cost of Wet Cooling Systems

Plant Capital Cost ($/KW)	Fuel Cost (¢/10^6 BTU)	Fixed Charge Rate (%)	Type of Cooling System *	Capital Cost ($/KW) Condenser and Pumps	Capital Cost ($/KW) Cooling Device **	Total Cooling System Cost *** (Mills/KW hr)
300	16	15	OT	4.81	1.25	0.155
			MD	5.13	2.37	0.226
300	16	12	OT	4.97	1.25	0.128
			MD	5.13	2.37	0.182
300	16	18	OT	4.60	1.25	0.180
			MD	5.15	2.37	0.270
300	19	15	OT	4.88	1.25	0.157
			MD	5.13	2.37	0.226
400	19	15	OT	4.81	1.25	0.162
			MD	5.18	2.32	0.244
400	16	15	OT	4.73	1.25	0.160
			MD	5.18	2.32	0.243
400	19	18	OT	4.66	1.25	0.189
			MD	5.13	2.37	0.291

* OT = once-through; MD = closed-cycle, wet mechanical draft towers
** For once-through systems, this cost covers intake and outlet structures
*** Average annual cost

TABLE II-9. Cost Data for Mechanical Draft Dry Cooling Systems

Peaking Season	Plant Capital Cost ($/KW)	Fixed Charge Rate (%)	Fuel Cost (¢/10^6 BTU)	Colstrip (Tower Capital Cost = $16.5/KW) Total Plant Fuel Cost * (Mills/KWH)	Colstrip Total System Cost ** (Mills/KWH)	Colstrip Cooling System Penalty (Mills/KWH)	Gillette (Tower Capital Cost = $16.0/KW) Total Plant Fuel Cost * (Mills/KWH)	Gillette Total System Cost ** (Mills/KWH)	Gillette Cooling System Penalty (Mills/KWH)	Stanton (Tower Capital Cost = $15.4/KW) Total Plant Fuel Cost * (Mills/KWH)	Stanton Total System Cost ** (Mills/KWH)	Stanton Cooling System Penalty (Mills/KWH)
		12	16	1.488	2.184	.696	1.488	2.149	.661	1.483	2.132	.649
	300		19	1.767	2.463	.696	1.767	2.428	.661	1.761	2.410	.649
		18	16	1.488	2.494	1.006	1.488	2.445	.957	1.483	2.421	.938
Summer			19	1.767	2.773	1.006	1.767	2.724	.957	1.761	2.699	.938
		12	16	1.488	2.222	.734	1.488	2.186	.698	1.483	2.167	.684
	400		19	1.767	2.501	.734	1.767	2.465	.698	1.761	2.445	.684
		18	16	1.488	2.551	1.063	1.488	2.499	1.011	1.483	2.474	.991
			19	1.767	2.830	1.063	1.767	2.778	1.011	1.761	2.752	.991
		12	16	1.493	1.938	.445	1.493	1.923	.430	1.493	1.905	.412
	300		19	1.773	2.218	.445	1.773	2.203	.430	1.773	2.185	.412
		18	16	1.493	2.149	.656	1.493	2.124	.631	1.493	2.098	.605
Winter			19	1.773	2.429	.656	1.773	2.404	.631	1.773	2.378	.605
		12	16	1.493	1.979	.486	1.493	1.959	.466	1.493	1.940	.447
	400		19	1.773	2.259	.486	1.773	2.239	.466	1.773	2.220	.447
		18	16	1.493	2.202	.709	1.493	2.178	.685	1.493	2.152	.659
			19	1.773	2.482	.709	1.773	2.458	.685	1.773	2.432	.659

* Exclusive of peaking fuel cost

** Includes total plant fuel cost, including peaking costs

Total plant fuel cost - The average annual plant fuel cost including the cost of fuel to run the auxiliary equipment for the cooling systems, but excluding the fuel used in gas turbine peaking units. For the conditions examined in this report, the auxiliary energy required is 1 to 2 percent of the total plant energy generated. This information is reflected in the annual plant fuel cost.

Total system cost - The average annual cost for the cooling system, including fixed charges, O&M, and peaking costs, plus the total plant fuel cost.

Cooling system penalty - The difference between the first two columns; this column provides the total cost attributable to the cooling system, exclusive of fuel penalties for auxiliaries. As is noted below, this column cannot be directly compared with the last column in Table II-8.

The ITD values used in the dry tower analyses are: Colstrip, 61.3°F; Gillette, 63.5°F; Stanton, 64.5°F.

Summary and Conclusions

The different methods of optimization used by the two programs makes it difficult to make a direct comparison between the two outputs. For example, the Dynatech program directly provides the total cost penalty associated with the cooling system (i.e., the last column in Table II-8), while the R. W. Beck program computes cooling system cost including plant fuel cost. In order to provide a direct comparison of costs between wet and dry tower systems, it was necessary to determine the total plant fuel cost for the wet systems and add it to the cooling system cost, thus providing a total system cost comparable to total system cost column in Table II-9 for dry towers. Using a nominal plant heat rate of 9000 BTU/KWH, plant fuel costs of 1.44 Mills/KWH for 16¢/10^6 BTU coal and 1.71 Mills/KWH for 19¢/10^6 BTU coal were obtained. These values were added to the last column in Table II-8 to obtain total system cost. Table II-10 contains total system cost information for each of the three cooling systems for several combinations of cost factors (Table II-5) and thus provides a direct measure of comparison among the systems.

A large number of cost comparisons can be made using Table II-10: Once-through vs wet MD, once-through vs dry MD (at each of the three sites), and wet MD vs dry MD (at each of the three sites). These comparisons are made simply by obtaining the difference between the relevant total system cost values. For example, the difference in cost between wet and dry MD towers for Gillette given a \$300/KW plant cost, 16 percent fixed charge rate, 12¢/10^6BTU fuel cost, and assuming a summer peaking season, is (2.15 Mills/KWH minus 1.62 Mills/KWH) 0.53 Mills/KWH. This value represents the difference in total busbar cost due to the selection of a dry tower over a wet tower.

Table II-10

Summary of Cooling System Cost

Peaking Season	Plant Capital Cost ($/KW)	Fixed Charge Rate(%)	Fuel Cost (¢/10^6BTU)	Total System Cost* (Mills/KWH)				
				Once-Through	Wet MD	Dry MD		
						Colstrip	Gillette	Stanton
Summer	300	12	16	1.57	1.62	2.18	2.15	2.13
Summer	300	18	16	1.62	1.71	2.49	2.45	2.42
Summer	400	18	19	1.90	2.00	2.83	2.78	2.75
Winter	300	12	16	1.57	1.62	1.94	1.92	1.91
Winter	300	18	16	1.62	1.71	2.15	2.12	2.10
Winter	400	18	19	1.90	2.00	2.48	2.46	2.43

*Cost of cooling system plus plant fuel cost.

Table II-11

Cooling System Cost Comparison for Gillette

Peaking Season	Plant Capital Cost ($/KW)	Fixed Charge Rate (%)	Fuel Cost (¢/10^6BTU)	Cost Differential*(Mills/KWH) Once-through vs Wet MD	Once-through vs Dry MD	Wet MD vs Dry MD
Summer	300	12	16	0.05	0.58	0.53
Summer	300	18	16	0.09	0.83	0.74
Summer	400	18	19	0.10	0.88	0.78
Winter	300	12	16	0.05	0.35	0.30
Winter	300	18	16	0.09	0.50	0.41
Winter	400	18	19	0.10	0.56	0.46

*The cost differentials represent the higher busbar cost which would result from the selection of the more expensive of the two competing systems.

Table II-11 provides several comparisons for the Gillette site using data obtained from Table II-10. It is important to recognize that the data in Table II-11 represent the economic consequence (expressed in additional busbar cost) of selecting one type of cooling system over another.

This chapter admittedly contains a large amount of data, some of it in a form not amenable to simple evaluation. Hopefully, the data contained in the tables, especially Tables II-10 and II-11, are described with enough clarity to allow the reader to make a reasoned judgment concerning the costs of power plant cooling systems in the Northern Great Plains Study Area. With that hope in mind, no attempt will be made here to list all of the conclusions which can be extracted from the data. However, three general conclusions do bear mentioning:

1. For both wet and dry systems, the variation in fixed charge rate has a much greater effect on cooling system cost than the variations in either fuel cost or plant capital cost.

2. Providing for winter peaking rather than summer peaking substantially reduces the cost of dry towers.

3. A direct comparison of wet MD vs dry MD costs requires the cost of water (if significant) to be evaluated. Chapter I indicates that 1.97 M^3/MWH of make-up water is required for a wet MD system using base level water conservation control. Using this value along with a range of water costs of $100 to $300 /ac-ft., water cost of 0.16 to 0.48 Mills/KWH are obtained. Adding these values to the cost of wet MD systems (Table II-10) shows that at the higher water costs and for winter peaking, dry MD systems become economically attractive and indeed may be less expensive than wet MD systems.

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