Attachment A to Chapter 3: Heat Diagram for Steam Power Plant

(Source: Ishigai 1999)

See Hard Copy

Attachment B to Chapter 3: Exhaust Pressure Correction Factors

FOR A NUCLEAR POWER PLANT (Attachment B-1)
(Source: Entergy 2001)

See Hard Copy

FOR A FOSSIL FUEL PLANT (Attachment B-2)
(Source: General Electric. Steam Turbine Technology)

See Hard Copy

FOR A COMBINED CYCLE PLANT (Attachment B-3)
(Source: Litton)

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ATTACHMENT C TO CHAPTER 3: DESIGN APPROACH DATA FOR RECENT COOLING TOWER PROJECTS

(Source: Mirsky 2001)

Table AA-1. Cooling Tower Design Temperature, Range and Approach

STATE	YEAR	FLOW (GPM)	TEMPERATURE (DEG F) HOT WATER	COLD WATER	WET BULB	RANGE (DEG F)	APPROACH (DEG F)	# OF CELLS
AL	2000	208000	85	72	62	13	10	10
OR	2000	152000	98	77.8	68.35	20.2	9.45	11
CA	2000	99746	94.3	72.5	55.5	21.8	17	8
NJ	2000	146000	90.3	75	52	15.3	23	10
AL	2000	278480	105	89	81	16	8	14
AL	2000	147361	112.5	96.7	84.7	15.8	12	7
IL	2000	189041	96.87	85.46	76	11.41	9.46	10
TX	2000	192300	104.3	87	79	17.3	8	12
TX	2000	106400	89.2	78.5	64.2	10.7	14.3	5
MO	1999	60000	85.3	67	52.4	18.3	14.6	4
FL	1999	21500	120	93	80	27	13	1
TX	1999	277190	105	89	81	16	8	14
CA	1999	101000	111.05	89	75	22.05	14	6
AL	1999	50000	107	86	80	21	6	4
MO	1999	25000	98	83	78	15	5	2
MS	1998	230846	106.2	91.2	84.7	15	6.5	12
SC	1998	150000	110	90	80	20	10	11
TX	1998	90000	110	90	83	20	7	5
TX	1998	278480	105	89	81	16	8	14
AL	1998	125000	105.7	85.7	80	20	5.7	10
LA	1998	45000	110	90	82	20	8	3
TX	1998	90400	117.1	94.1	82.68	23	11.42	5
SC	1998	8500	114	95	81	19	14	2
SC	1998	14000	116	95	81	21	14	2
AR	1998	13200	116	95	81	21	14	2
NJ	1998	4400	100	71	66	29	5	4
TX	1998	18000	105	85	72	20	13	2
CA	1998	7000	105	80	71	25	9	1
TX	1998	15000	115	90	81	25	9	2
SC	1998	15000	123	95	81	28	14	1
LA	1998	1000	124	90	80	34	10	1
OH	1998	6400	135	90	77	45	13	2
LA	1997	20000	104	86	81	18	5	2
MO	1997	60000	85.3	67.5	52.4	17.8	15.1	4
PA	1997	30000	105	85	78	20	7	6
AL	1997	16000	114	90	79	24	11	2
OK	1997	8350	112	89	79	23	10	2
WA	1997	14000	120	74	58	46	16	2
MT	1997	12000	96	74	64	22	10	2
GA	1997	3000	97.6	87.6	80	10	7.6	1
OH	1997	6000	118	86	77	32	9	2
MN	1997	7500	106	87	74	19	13	1
LA	1997	12000	110	85	80	25	5	3
NY	1997	4800	103.5	85	78	18.5	7	1
SC	1997	50000	93	81	72	12	9	3
	Maximum	278480	135	96.7	84.7	46	23	14
	Minimum	1000	85	67	52	10	5	1
	Average	75775.42222	106.3	85.2	74.8	21.1	10.4	5
	Median	30000	105.7	87	79	20	10	3
	Mode	278480	105	90	81	20	10	2

ATTACHMENT D TO CHAPTER 3: TOWER SIZE FACTOR PLOT

(Source: Hensley 1985)

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Attachment E to Chapter 3: Cooling Tower Wet Bulb versus Cold Water Temperature Typical Performance Curve

(Source: Hensley 1985)

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Attachment F to Chapter 3: Summary and Discussion of Public Comments on Energy Penalties

For the November 2000 proposal, the Agency presented a discussion on energy penalties for dry cooling systems, but did not present detailed estimates of penalties. The Agency also stated that energy penalties at wet cooling towers were negligible in their effect on final cost estimates for the proposed rule. Subsequent to the proposal, the Agency recognized, based, in part, on public comments, that the proposal did not sufficiently consider energy penalties for the regulatory options considered and proposed. In turn, EPA began a thorough program to assess the state of research into energy penalties that would meet its broad needs. After learning that the appropriate energy penalty data did not exist or was not well documented and explained, EPA began a project to assess the energy penalty of a variety of cooling systems for a variety of conditions. In order to notify the public of its intention, the Agency included information in the June 2001 notice of data availability that explained the status of the research project, the types of information the Agency was considering, the methodology for estimating the penalties, and the ultimate methodology for assessing the cost of the penalties and the associated air emissions increases.

In addition to a host of general comments on the proposal and notice of data availability that urged consideration of the energy penalty in the technical, economic, and environmental analyses of the final rule, the Agency primarily received its most technical comments in response to the notice of data availability. The Agency fully considered all of the comments received on the subject of energy penalties (see the response to comment document), which came from all manner of stakeholders. However, due to the detailed technical nature of select comments, the Agency devotes the following discussion to evaluation of public comments received from the Department of Energy (DOE) and the Utility Water Act Group (UWAG) concerning EPA's energy penalty estimates and the methodology presented in the draft report, titled "Steam Plant Energy Penalty Evaluation, April 20, 2001," which was included in the public record for the notice of data availability. For the sake of clarity and simplicity, this discussion will address the commenters by their representative organizations, even though select individuals within, legal firms representing, or contractors hired by the organizations may have prepared the comments.

The DOE comments were the more general of the comments in nature. The Agency addresses these comments first, along with general comments made by UWAG on energy consumption for different cooling systems. The UWAG technical comments (Appendix B of their comments) on the draft energy penalty report are then addressed, followed by a brief discussion of other issues related to EPA's notice of data availability draft report (here after referred to as the "draft report"). Finally, EPA provides conclusions on the comments and their influence on the final energy penalty estimates.

F.1 General Comments from DOE and UWAG

F.1.1 The Components of Energy Penalties

Both the Agency and the commenters agree that the total energy penalty consists of three components: 1) changes in turbine efficiency, 2) changes in cooling water pumping requirements, and 3) changes in cooling system fan energy requirements. The commenters make no references to other significant components, implying that no other additional factors need to be considered.

In the draft report, the Agency estimated the three components and presented them separately to allow flexibility in application and to avoid double counting. For example, the fan and pumping energy costs were incorporated into the Agency estimates for the cooling tower O&M costs. Therefore, the notice of data availability presented each component separately and factored them in separately, where necessary, depending on the analysis being performed. However, from an energy output perspective (i.e., ignoring costs), the DOE comment is correct that for the total energy penalty, all three components should be added together. The Agency intended to do this all along.

F.1.2 Turbine Efficiency and the Presentation of Energy Penalty

The Agency agrees with DOE that the energy penalty should be expressed as a "percentage reduction in plant output." Again, the Agency had intended to do so and, as noted by DOE, presented the pumping and fan power components as such in the draft report. While the Agency intended for the calculated values for changes in turbine efficiency to be representative of percent changes in plant output, the calculation method, as presented by the Agency, unfortunately led to other interpretations. Therefore, for the sake of clarity, the Agency developed a revised method for determining the changes in turbine efficiency, now based on turbine exhaust pressure response curves, for the final rule. This method removes the confusion cited above but does not change results dramatically.

F.1.3 Energy Penalties for Dry Cooling Towers and the Basis of Comparison

The draft report only addressed the energy penalty for once-through versus recirculating wet cooling towers. Subsequent to the draft report, the Agency developed energy penalty estimates for dry towers (air cooled condensers) for comparison to either once-through or wet tower cooling baseline systems. These estimates are presented in section 3.1. The estimates in the draft report were for alternative cooling systems to be installed at new facilities (in other words, they represented a change in design from once-through to wet tower cooling systems). As such, the Agency did not consider factors that would be associated with retrofitting an existing facility, contrary to the commenter's assertion.

F.1.4 Condenser Inlet Temperature

Both the UWAG and DOE comments noted that the Agency only considered the condenser inlet temperature. The commenters correctly point out that condenser inlet temperature is not the only factor that will affect the turbine exhaust pressure. However, in the Agency's view, it is the major driving factor. While condenser inlet temperature is the starting point, temperature rise (or "range") through the condenser and the design of the condenser will influence the exhaust steam pressure. The Agency chose cooling system design parameters that best represent the wide range of systems recently constructed. These same design parameters are used as the basis for the compliance cost estimates for installing recirculating wet towers. The representativeness of these numbers will be discussed in more detail below. The trade-off is that plants with smaller temperature rises must accomplish the cooling by using a larger volume of cooling water flow. UWAG only notes that the method neglects the influence of condenser performance (Comment 2).

F.2 Detailed Technical Comments from UWAG

F.2.1 Turbine Exhaust Pressure, Performance, and Loading

In the Agency's view, UWAG is correct in noting that the exhaust pressure at which condensed moisture may cause damage to the turbine will vary depending upon throttle conditions, the shape of the expansion curve, and blade metallurgy. If the throttle settings are low (that is, the plant is operating much below capacity), then the exhaust pressure at which damaging moisture levels may occur will be lower. Agency evaluation of energy penalty focused primarily on turbines operating close to their capacity, which is supported by the results of the Agency's data collection efforts for the final new facility rule. For instance, the Agency projects that the mean capacity factor at new plants is approximately 85 percent (that is, near to full capacity). See the Economic Analysis.

Condensed moisture is but one of several factors that may prevent more efficient operation at lower exhaust pressures. Another more important factor is the dynamic losses mentioned in UWAG Technical Comment 2. As can be seen in the turbine response graph showing turbine exhaust pressure versus turbine heat rate (included as Attachment B to the draft report), the curve representing the maximum steam loading rates straightens and begins to increase (that is, the efficiency decreases) as the pressure drops below approximately 1.5 inches Hg. This efficiency decrease is, for the most part, due to dynamic exhaust losses which occur when the expansion of steam (due to steam pressure progressively dropping through the turbine) results in an increase in the velocity of the steam as it exits the turbine.

In general, manufacturers design steam turbines to prevent a steam velocity increase by increasing the turbine cross-sectional area as the steam passes through the turbine. However, as the exhaust pressure approaches a vacuum, the amount of area required at the outlet end increases rapidly and the corresponding cross-sectional area needed increases the turbine costs such that the economic trade-off (increased cost vs. increased efficiency) compels the designer to lose efficiency at low exhaust pressures. For standard turbines at low exhaust pressures, the steam velocity increases and a portion of the steam energy is converted to kinetic energy (proportional to the square of the velocity). This increase in the steam kinetic energy reduces the net amount of energy available to the turbine. Thus, the commenters are correct: rather than condensed moisture, it is dynamic exhaust losses that set a practical minimum exhaust pressure (at higher steam loading rates) for turbines of conventional design.

The Agency bases the final energy penalty estimates on actual turbine response curves representing the different types of plants, rather than on theoretical calculations. The Agency developed two sets of values representing maximum load and 67 percent load (that is, 67 percent of maximum steam load). Finally, the Agency bases its estimates for reduced capacity at peak demand periods on the maximum load values and the estimate of mean annual energy penalty (for the purpose of estimating economic impact over the entire year) based on the 67 percent load values. In the Agency's view, the nuclear penalty estimate based on the theoretical calculations is validated by the turbine response curve for that facility. A comparison of this curve with the estimated penalty curve (based on theoretical calculations) showed that the two curves were very close in value. In these estimates, the Agency used the data from Attachment B to these comments (the turbine response curve) for the nuclear power plant penalty estimates.

F.2.2 Optimal Turbine Back Pressures

UWAG argues that the use of 1.5 inches Hg as the optimal operating back pressure does not consider that many U.S. plants operate below 1.5 inches Hg during substantial portions of the year. It then states that this assumption is not likely to have a huge effect on the penalty (although it will tend to understate the penalty). As discussed above, the 1.5 inches Hg value corresponds to turbines operating near capacity. Rather than assume that plants will optimize the operation of the cooling system, the turbine efficiency analysis in the Agency's final energy penalty study uses the values from the turbine response curves. Therefore, the Agency avoided setting any minimum exhaust pressure value, about which the commenter expresses concern.

The Agency agrees with the point raised that some U.S. plants operate below 1.5 inches Hg for substantial portions of the year. In some cases, the design of the plant does not provide for control of the cooling system (for example, a once-through system with constant speed pumps). However, unless the plant is specifically designed to operate efficiently at low pressures (with higher turbine capital costs), the turbine response curves indicate that typical turbines operating at low exhaust pressures either operate efficiently but at well below the turbine capacity, or operate in a less than optimal mode near full capacity. In fact, the curves suggest that turbines of standard design operating at exhaust pressures below 1.5 inches Hg and near capacity may be experiencing an energy penalty by not controlling the cooling system such that the exhaust pressure does not drop below the optimum pressure. Turbines operating at low load experience improved efficiency at lower exhaust pressures, but the diminished output tempers the overall effect. Therefore, the Agency's methodology does not underestimate energy penalties as the commenters suggest.

F.2.3 Empirical Data Versus Subtle Effects

The Agency agrees that the estimation methodology simplifies complex relationships including subtle impacts of turbine design. The use of empirical data simplifies the modeling of complex factors with subtle effects. This is the fundamental approach of design engineering and is a reasonable approach for this rule.

The commenter takes exception to the Agency's perceived reliance on a cooling tower manufacturer for comparison of its estimates. The Agency used data in Attachment C of the draft report (to which the commenter questions) only as a benchmark value for comparison/validation. Since the Agency's estimates were derived independently, the qualifications as a cooling tower manufacturer do not affect their validity.

F.2.4 Thermal Design Approach Values

The Agency disagrees that there is a disadvantage with using the median value (it is also the mean and the mode, in this case) for the design approach of the model cooling tower used for the regulatory impact analysis. The data in Attachment G of the draft report represents 45 wet cooling towers installed from 1997 through 2000 in locations throughout the country. The Agency reviewed this data and did not discern any pattern, such as regional trends, that would warrant use of values different than the statistical median. The Agency intended for these estimates to support national estimates. Therefore, the Agency included regional and seasonal differences in the cooling media (surface water, wet bulb, dry bulb) temperatures in the estimates for the final rule. Similar to other construction projects, economic considerations, such as availability of capital and the desired time period to recoup investment, among other factors, influence the selection of the design approach, design range, and other design parameters. The Agency believes it is difficult to estimate these factors and variables and notes that the commenter did not suggest a reasonable way to take these variables into consideration in the national energy penalty estimates. In the Agency's view, the statistical median for recently constructed cooling towers throughout the country best represents the full range of design operating conditions employed throughout the country. In addition, the commenters do not take issue with the validity or representativeness of the data in Attachment G to the draft report. See also Attachment C to Chapter 3 for the data supporting the Agency's estimates of a design approach value of 10 deg F.

The Agency notes that the design approach value is for comparison to ambient wet bulb conditions and not to the wet bulb temperature of the tower inlet, which can be slightly higher when air recirculation occurs. The Agency also notes that air recirculation occurs intermittently and only at times when winds are high and are blowing from a direction perpendicular (broadside) to the tower orientation. Where possible, towers, in their design, are oriented so as to minimize this effect. In general, the installed tower is certified by the manufacturer to perform within the design specifications with a wind velocity of up to 10 mph (Hensley 1985) . Thus, the tower size and other design criteria that apply to the towers used in the cost estimates do include consideration of air recirculation.

The commenters take issue with the use of a constant approach value throughout the year. The approach value that the Agency used for the draft report represents design conditions which generally apply to the worst-case design (i.e., summer) conditions. As such, the use of a constant value throughout the year will not result in inaccurate estimates for the maximum penalty value. After further review of this issue, the Agency agreed that the commenters are correct that it is inappropriate to use the design approach value for estimating the average energy penalty throughout the year. EPA has found within the suggested reference (Hensley 1985) a graph for the relation between wet bulb temperature and cold water temperature for a tower that can be used as the basis for estimating the approach at wet bulb temperatures other than the design temperature. The revised penalty estimates in the final report incorporate this suggestion for estimating seasonal changes in the approach values.

F.2.5 Turbine Exhaust Pressure and Cooling Water Inlet Temperatures

For the final energy penalty report, the Agency investigated whether the Heat Exchange Institute Standards for Steam Surface Condensers assist in more "precisely" estimating the relationship between turbine exhaust pressure and cooling water inlet temperatures. The Agency notes that a revised method would in itself require assumed values (for example, condenser heat transfer coefficient, number and arrangement of tubes, etc.) that given the nature of the comments are then subject to the same arguments made by the commenter that they do not represent the full variety of condenser designs being employed. In the end, the revised method suggested by the commenter generated very similar results to EPA's method in the draft report, and, therefore, was not used.

F.2.6 Fan Energy Requirements

UWAG implicitly agrees with the EPA methodology for estimating wet cooling tower fan energy requirements. The commenters only take issue with using an "optimistic" motor efficiency of 95 percent instead of 92 percent, and failure to include a factor for fan gear efficiency (typically 96 percent). The factors used in the draft report, including a fan usage factor of 93 percent, were obtained from a cooling tower manufacturer (Fleming 2001). Incorporation of the UWAG suggestions increased the fan energy component by a total of 7.6 percent of a component that itself is less than 1 percent of plant output. Regardless, the Agency incorporated the factors suggested by the commenter.

F.2.7 Recirculating Water Pumping Velocity

UWAG's comments dispute the use of a cooling water velocity of 5.7 ft/s in the circulating water pipes, reporting that their past observation was that cooling water velocities in all three types of power plants were in the range of 8 to 11 ft/s. EPA notes that the 5.7 ft/s value was used as the minimum design starting point. The draft report showed that the results of piping designs resulting in three different flow velocities of 5.8, 7.7, and 11.6 ft/s, along with three different piping distances, were used in the analysis.

As a follow-up, the Agency contacted a Bechtel power systems engineer to obtain typical values for pumping head and learned that a 50 ft total pumping head was typical for a once-through system (Taylor 2001). The notice of data availability analysis shows that for a pumping distance of 1,000 ft, the total calculated pumping heads were 49 ft and 58 ft at pipes sized to produce velocities of 7.7 and 11.6 ft/s, respectively. These values compare favorably with the Bechtel estimate. Final Agency estimates for once-through pumping costs use this 50 ft pumping head value.

F.2.8 Static Head

UWAG states that the two static head values assumed by the Agency are inaccurate based upon reference to Power Engineering sources. The commenters did not specify in what way the values used by the Agency were inaccurate except to imply (as indicated in comment 10 below) that they may be overstated. The Agency reviewed the cited reference (Handbook of Energy Systems Engineering) to see if useful data was available for inclusion in the final analysis. As such, the implication made by commenters, as elsewhere, is that Agency's draft report estimates would tend to understate the penalty.

After review of the data, the Agency determined that it disagrees with the assertion made by the commenter regarding understated static head values. The Agency estimates that the siphon will continue from pump inlet to an open channel outlet, and, as a consequence, the static head would be the elevation difference between these two. In many cases this static head difference would be relatively small. Thus, the Agency's estimates of static head in the notice of data availability are reasonable. The Agency also notes that the static head is a site-specific value.

F.2.9 Gravity Versus Siphon Flow of Cooling Water

The commenters contest the Agency's estimate that cooling water will flow by gravity back to the source. The Agency was aware of the use of the siphon effect (with vacuum pumps at the high point) in condenser piping, but was not certain of its wide-spread use and therefore did not include it in the analysis for the notice of data availability. The estimate was intended to produce a more conservative (i.e., higher) pumping head. In this case, the effect of the estimate for gravity flow was a conservative estimate.

The Agency subsequently obtained information concerning head losses within condensers (Hess 2001). The pumping head component for condenser loss in the final estimates reflects consideration of this data. The addition of condenser losses offset the reduction in static head that results from the siphon effect outlined above. This appears to explain why, despite the comments, that the draft report estimates for total pumping head are similar to the estimate provided by Bechtel (Taylor 2001).

F.2.10 Pumping Head as a Function of Tower Height

UWAG disagrees with the pumping head estimates for cooling towers in the notice of data availability report, citing the Agency's lack of varying the tower height, using a small dynamic head, and neglecting to include losses in the tower spray nozzles. The Agency's based the pumping head calculations on a single cooling water flow value and therefore it is not necessary to consider variations in the tower height. The Agency chose a single tower design and a total pumping head value for an actual tower reported by a tower manufacturer (Fleming 2001) which included all of these pumping head components in combination. The tower chosen is actually sized for a slightly more conservative flow than that used in the calculations. Therefore, the tower design specifications are consistent with the tower design used in other energy penalty components and in the cost analysis.

F.2.11 Plant Operating Capacity

The commenters are correct that at times when the plant is operating near its engineering or regulatory limits, the penalty will effectively reduce capacity. They also point out that the energy penalty is not just an economic concern (that is, the penalty will require use of additional fuel or purchase of replacement power), but can also limit plant capacity during peak demand periods. However, this comment has no bearing on the penalty estimates themselves. The Agency also notes that for wet cooling tower systems, the magnitude of even the peak-summer shortfall penalties do not approach a level that will impact plant capacity at peak demand periods. The commenters make a similar statement in Appendix C of their comments to the notice availability. The same is not true for dry cooling systems, based on the Agency's estimates.

F.2.12 Turbine Efficiency Adjustment Factors

The turbine efficiency estimation methodology used in the final energy penalty analysis eliminates the need to use the 17 percent factor to which the commenters object. However, the Agency's final method continues to estimate that the steam turbine contributes approximately 1/3 of the total plant capacity for a combined-cycle plant. The commenters did not take issue with the 1/3 capacity assumption.

F.2.13 Fan and Pumping Costs

The Agency wishes to clarify the estimated fan and pumping costs, in particular, the use of an electricity cost of $0.08/kWh rather than $0.03-$0.04/kWh. The Agency uses an electricity cost value that represents the average cost to the consumer. This value was chosen as a conservative value (on the high side) to ensure that the estimates compensated for other minor O&M cost components associated with the operation of the cooling fans and pumps that the Agency has not directly included.

F.3 Conclusions Regarding Public Comments

The Agency, as described above, fully considered the substance of the comments submitted and has incorporated revisions in its final analysis based on a portion of the arguments, as noted. However, the Agency notes that the commenters generally did not present detailed data to support their positions or that would assist the Agency in revising its estimates. In turn, the Agency sought out additional reference material from a variety of sources, in addition to some references cited by the commenters, to determine the most accurate final estimates possible. These references are included in the record for the final rule.

Many of the comments take issue with the simplification of a very complex system. One of the greatest challenges of this effort for the Agency was to balance the many design and operating variables that apply to a variety of design-specific conditions with the need to develop national estimates that are valid for all of these situations. Thus, where possible, the Agency employed statistical estimates and empirical data to best represent the site-specific conditions and engineering relationships. The Agency points to the DOE comment which states that the draft report methodology "is an approach based on historical correlations, but for most plants and locations it is approximately correct." After incorporation of the revisions outlined above (which the Agency conducted in response to comment and for confirmatory reasons) the Agency's final energy penalty estimates are reasonable and defensible national estimates.

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