Chapter B1: Summary of Compliance Costs

INTRODUCTION

This chapter presents the estimated costs to facilities of complying with the Proposed Section 316(b) Phase II Existing Facilities Rule. EPA developed unit costs of complying with the various requirements of the proposed rule and the alternative regulatory options, including costs of section 316(b) technologies, energy costs, and administrative costs. Unit costs were then assigned to the 550 in-scope facilities, based on the facilities' modeled compliance responses, and aggregated to the national level.

CHAPTER CONTENTS

Chapter A1: Introduction and Overview summarizes the requirements of the proposed Phase II rule and five alternative regulatory options considered by EPA. EPA costed four of these options. This chapter discusses the unit costs for the proposed rule and the alternative regulatory options, the compliance years of Phase II facilities, and the total private industry costs of the proposed rule. Compliance years for the alternative options are presented in the appendix to this chapter; costs for the alternative options are presented in *Chapter B7: Alternative Options - Costs and Economic Impacts*.

B1-1 UNIT COSTS

Unit costs are estimated costs of certain activities or actions, expressed on a uniform basis (i.e., using the same units), that a facility may take to meet the regulatory requirements. Unit costs are developed to facilitate comparison of the costs of different actions. For this analysis, the unit basis is dollars per gallon per minute ($/gpm) of cooling water intake flow. All capital and operating and maintenance (O&M) costs were estimated in these units. These unit costs are the building blocks for developing costs at the facility and national levels.

EPA developed cost estimates for a number of alternative regulatory options, based on a variety of technologies for impingement mortality and entrainment reduction. For each regulatory option, individual facilities will incur only a subset of the unit costs, depending on the extent to which their current technologies already comply with the requirements of that regulatory option and on the compliance response they select. The unit costs presented in this section are engineering cost estimates, expressed in 2001 dollars. More detail on the development of these unit costs is provided in the *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule*, hereafter referred to as the *"Phase II Technical Development Document*" (EPA, 2002a).

To characterize the existing facilities' current technologies, EPA compiled facility-level, cooling system, and intake structure data for the 225 in-scope 316(b) Detailed Questionnaire (DQ) respondents and, to the extent possible, for the 314 in-scope 316(b) Short Technical Questionnaire (STQ) respondents. The Agency then used this tabulation of data to make determinations about costing decisions that hinged on the cooling systems and intake technologies in place. Where the STQ responses did not provide sufficient information to make the necessary costing decisions, EPA applied the concept of data projection to the DQ facilities to estimate the missing data pieces for the STQ facilities, as described in the *Phase II Technical Development Document*.

B1-1.1 Technology Costs

Existing facilities that do not currently comply with the Proposed Section 316(b) Phase II Existing Facilities Rule would have to implement one or more technologies to reduce impingement mortality and entrainment. The specific technologies vary for the different alternative regulatory options considered by EPA, but overall these technologies reduce impingement and entrainment (I&E) through one of two general methods:

- implementing design and construction technologies to reduce impingement mortality and entrainment, and
- converting cooling systems from once-through to recirculating operation to reduce the design intake flow.

EPA developed distinct sets of cooling water intake structure compliance costs for existing facility model plants expected to (1) upgrade intake technologies only, (2) upgrade cooling systems and intake structure technologies, and (3) upgrade cooling systems only. The remainder of Section B1-1.1 discusses specific section 316(b) technologies and their respective costs.

a. Intake technologies

All of the regulatory options (with the exception of the dry cooling option) considered by EPA would require some existing facilities to upgrade their cooling water intake structure technologies. Upgrades to intake structure technologies at existing facilities may include retrofitting of impingement technologies, entrainment technologies, or both. In some cases, retrofitting of intake structure technologies may also necessitate modifying the intake structures themselves. For example, retrofitting an intake to entrainment-reducing fine-mesh screens (which would have reduced open cross-sectional area as compared to coarse-mesh screens) may also necessitate expanding, fanning, or adding additional bays to an existing intake structure in order to maintain the required intake flow rate.

❖ ***Fine-Mesh Traveling Screen***

For those model facilities projected to install or upgrade entrainment technologies without flow reduction, EPA based the CWIS technology costs on unit costs developed for fine-mesh traveling screens. Fine-mesh screens are typically mounted on conventional traveling screens and are used to exclude eggs, larvae, and juvenile forms of fish from intakes. Fine-mesh screens generally include those with mesh sizes of 5 mm or less. A detailed explanation of the development of "greenfield" facility traveling screen unit costs can be found in the *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*. The "greenfield" capital costs for fine-mesh traveling screens were then inflated by the "retrofit" capital cost factor of 30 percent. A 10 percent contingency factor and a 5 percent allowance were also applied to account for uncertainties inherent in intake modifications at existing facilities. Therefore, the Agency views the retrofit capital costs developed for upgrading intake screens to be appropriate for existing model plants.

For those plants projected to only incur entrainment related costs of cooling water intake structure upgrades, the Agency estimated that intake fanning/expansion would be necessary for the majority of plants projected to install entrainment-reducing fine-mesh screens. Therefore, the Agency developed capital costs that incorporated the costs of expanding/fanning or adding an additional bay to an existing intake structure to provide an increase in screen area of 50 percent, in order to accommodate the fine-mesh screens. Because fine-mesh screens have reduced open cross-sectional area when compared to coarse-mesh screens, the Agency considers the intake expansion/fanning costs to be appropriate in these cases. Even though there is no set of velocity-based requirements for this proposal, the Agency projected that the model plants expected to upgrade their intake screens from coarse to fine-mesh would reduce their through-screen velocity from the median facility value of 1.5 feet/second to 1.0 foot/second as a result of this rule. The Agency used costs developed for fine-mesh screens with a through-screen velocity of 1.0 foot/second to size the intake for the full design intake flow. The O&M costs of these screens were calculated based on the same principle. The Agency applied a capital cost inflation factor of 30 percent (55 percent for nuclear facilities), in addition to the 30 percent "retrofit" factor, to account for the expansion/fanning of the intake structure, but did not estimate further O&M costs for this one-time activity.

For those plants projected to incur costs of flow reduction and entrainment-reducing fine-mesh screens, the Agency considered the existing intake structures to be of a size too large for a realistic screen retrofit. Therefore, in these cases, the Agency estimated that one-half of the intake bay(s) would be blocked/closed and the retrofitted fine-mesh intake screens would apply to only one-half of the size of the original intake. The Agency considers this a reasonable approach to estimating realistic scenarios where the average plant uses multiple intake bays. In the Agency's view, the plant, when presented an equal opportunity option, would use the potential cost-saving option of installing the fine-mesh screens on only the maximum intake area necessary. The O&M costs were also developed using this size of an intake.

❖ ***Fish Handling and Return System***

For those model plants projected to install or upgrade impingement control or survival technologies, EPA based the CWIS technology costs on unit costs developed for fish handling and return systems. Conventional vertical traveling screens contain a series of wire-mesh screen panels that are mounted end to end on a band to form a vertical loop. As water flows through the panels, debris and fish that are larger than the screen openings are caught on the screen or at the base of each panel in a basket. As the screen rotates, each panel in turn reaches a top area where a high-pressure jet spray wash pushes debris and fish from the basket into a trash trough for disposal. As the screen rotates over time, the clean panels move down, back into the water to screen the intake flow.

Conventional traveling screens can be operated intermittently or continuously. However, when these screens are fitted with fish baskets (also called modified conventional traveling screens or Ristroph screens), the screens must be operated continuously so that fish that are collected in the fish baskets can be released to a bypass/return using a low pressure spray wash when the basket reaches the top of the screen. A detailed explanation of the development of "greenfield" unit costs for fish handling and return systems can be found in the *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*. The "greenfield" capital costs for fish handling and return systems were then inflated by the "retrofit" capital cost factor of 30 percent. A 10 percent contingency factor and a 5 percent allowance were also applied to account for uncertainties inherent in intake modifications at existing facilities.

For those model plants projected only to incur costs of adding fish handling/return systems to existing screens, EPA developed costs by estimating the size of coarse-mesh, 1.0 foot/second screens. The median through-screen velocity for all 316(b) survey respondents was 1.5 feet/second. The Agency thus determined that use of a 1.0 foot/sec metric to size the fish handling/return systems was a conservative assumption (that is, would most likely result in an overestimate of fish handling/return system costs) for the variety of plants projected to incur their capital and O&M costs as a result of the proposed rule.

❖ ***Fine-Mesh Traveling Screens with Fish Handling and Return Systems***

For those plants projected to install or upgrade both impingement and entrainment technologies, EPA based the CWIS technology costs on unit costs for fine-mesh traveling screens with fish handling and return systems, which were developed as noted above.

For those plants projected to incur costs of both impingement and entrainment technologies, but not flow reduction, EPA developed capital costs that incorporated the costs of expanding/fanning or adding an additional bay to an existing intake structure to provide an increase in screen area of 50 percent, in order to accommodate the fine-mesh screens. The Agency used costs developed for fine-mesh screens with a through-screen velocity of 1.0 feet/second to size the intake for the full design intake flow. The O&M costs of these screens were calculated based on the same principle. Capital and O&M costs for the fish handling and return systems were also based on the size of the larger screens. The Agency applied a capital cost inflation factor of 15 percent (30 percent for nuclear facilities), in addition to the 30 percent "retrofit" factor, to account for the expansion/fanning of the intake structure, but did not estimate further O&M costs for this one-time activity.

For those plants projected to incur costs of flow reduction and both impingement and entrainment technologies, EPA estimated CWIS technology costs based on the assumption that one-half of the intake bay(s) would be blocked/closed. Therefore, the installed capital costs and O&M costs of the intake screens and fish handling/return systems were approximately one-half of those for a full-size screen replacement.

b. Wet cooling towers

Certain of the alternative regulatory options considered by EPA would require some existing facilities to reduce their flow to a level commensurate with a closed-cycle recirculating system. Facilities are not required to install wet cooling towers to reduce their flow to that level. While that level can be achieved by purchasing water from another source or using gray water, EPA has assumed for costing purposes that the facility would recycle their water. Switching an existing facility to a recirculating system involves retrofitting the facility to convert the cooling system from once-through to recirculating operation. Cooling towers are by far the most common type of recirculating system; however, if enough land is available, cooling ponds offer another, and potentially less expensive, approach. For the regulatory options that involved switching to recirculating systems, EPA therefore assumed that all facilities switching to recirculating systems would use cooling towers.

The methodology for estimating costs of these cooling system conversions is based on a set of common principles:

- recirculating systems can be connected to the existing condensers and operated successfully under certain (but not all) conditions,
- condenser flows generally do not change due to the conversions,

- portions of the existing condenser conduit systems can be used for the recirculating tower systems,
- the existing intake structures can be used for supplying make-up water to the recirculating towers,
- tower structures can be constructed on-site before connection to the existing conduit system, and
- modification and branching is generally necessary for connecting the recirculating system to the existing conduits and for providing make-up water to the towers.

❖ *Wet Tower Costs*

Based on the principles outlined above, EPA developed capital cost estimates for cooling system conversions using those developed for new "greenfield" facilities under the 316(b) Phase I Rule for New Facilities. For most model facilities that were projected to install cooling towers, EPA based the cooling tower capital costs on unit costs developed for redwood mechanical draft cooling towers with splash fill, which represents a median tower cost. However, EPA determined that redwood tower unit costs were not appropriate for nuclear facilities. EPA thus based cooling tower capital costs for nuclear facilities on unit costs developed for concrete mechanical draft cooling towers. A detailed explanation of the development of "greenfield" facility cooling tower unit costs can be found in the *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*.

EPA then inflated these capital cost estimates by applying a "retrofit" factor to account for activities outside the scope of the "greenfield" cost estimates. These activities relate to the "retrofit," or upgrade, of existing cooling water systems. Retrofit activities associated with installation of recirculating wet cooling systems may include (but are not necessarily limited to) branching or diversion of cooling water delivery systems, reinforcement of retrofitted conduit system connections, partial or full demolition of conduit systems and/or structures, additional excavation activities, expedited construction schedules, and administrative and construction-related safety precautions. The Agency estimated that a capital cost inflation factor of 20 percent applied to the costs developed for new "greenfield" projects would account for the cooling system retrofit activities described above.

In addition to the 20 percent "retrofit" factor, EPA also used a 10 percent contingency factor for existing facilities. To account for variations in capital construction costs for different locations within the United States, EPA adjusted the capital cost estimates for the existing facilities using state-specific cost factors, which ranged from 0.739 for South Carolina to 1.245 for Alaska. The applicable state cost factors were multiplied by the model-facility cost estimates to obtain location-specific model facility capital costs. The Agency derived the state-specific capital cost factors from the "location cost factor database" in R.S. Means Cost Works 2001 (R.S. Means, 2001). The Agency used the weighted-average factor category for total costs (including material and installation). The RS Means database provides cost factors (by 3-digit Zip code) for numerous locations within each state. The Agency selected the median of the cost factors for all locations reported within each state as the state-specific capital cost factor. Additional detail on the development of the retrofit, contingency, and state-specific cost factors used by EPA can be found in the *Phase II Technical Development Document*.

EPA estimated that O&M costs of wet cooling tower systems for conversion projects would be the same as those developed for new "greenfield" facilities during the 316(b) Phase I Rule for New Facilities. Detail on O&M costs of wet cooling tower systems can be found in the *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*. The Agency notes that recirculating pumping costs included in these O&M costs will roughly equal those of the baseline once-through system, which the Agency deducts from annual costs of cooling system conversion projects. In the end, the O&M costs of cooling tower pumping will roughly cancel between those included within the cooling tower recurring annual costs and those deducted as recurring annual costs of an abandoned system. In EPA's view, this methodology presents a realistic estimate of the actual O&M costs of cooling tower conversion projects.

❖ *Intake Piping Modification Costs*

Conversions from once-through to recirculating cooling systems do not necessarily require construction of new intake structures to provide make-up water to the cooling tower systems. Installation of a fully recirculating cooling system reduces intake flow by upwards of approximately 92 percent as compared to a once-through system. The intake structure designed for a once-through cooling system is oversized for moving flows reduced to this level. Based on example cases, EPA anticipates that most existing facilities will be able to continue to use their baseline intake structures and portions of the associated intake piping systems after converting to recirculating cooling systems. A branch from the original intake conduit system would be needed to provide make-up flow to the cooling tower via a separate pump system. Thus, for purposes of capital cost development, EPA excluded the itemized costs of make-up water pumps in favor of the larger recirculating cooling water pumps inherent in the Agency's cooling tower cost estimates. However, the Agency included capital costs for the conduit system required to bring make-up water to the cooling tower and basin and to discharge blowdown. The Agency estimated that a range of 2000 feet to 4000 feet (depending on intake flow) of concrete-lined steel piping would be used for cooling tower make-up water and blowdown.

The Agency included these costs to account for conversion cases in which significant distances may exist between intake locations and cooling tower sites. While this was not necessarily true for the example cases reviewed by EPA, the Agency views these costs as appropriate for a variety of hypothetical cases. For instance, the Agency is aware of concerns from some existing facilities regarding the need to maintain a reasonably high velocity within the intake structure conduit system to minimize deposition and/or biological growth. By including the make-up water piping capital costs, the Agency's estimates address these concerns by accounting for construction of relatively small-sized intake piping within existing large-sized, once-through intake conduits, closure of a portion of intake bays and/or conduits to maintain in-conduit velocity, and/or branching from the existing intake conduit systems.

As with the wet cooling tower cost estimates, these piping capital costs were further inflated by a "retrofit" factor. The Agency uses a factor of 30 percent to account for construction techniques and situations outside the scope of a typical "greenfield" cost estimate. In addition, EPA applied a 10 percent contingency factor and a 5 percent allowance to account for uncertainties inherent in intake modifications at existing facilities.

❖ ***Intake Pumping Costs***

The Agency did not include the costs of installing pumps for supplying make-up water to the cooling towers. The Agency developed costs for variable-speed pumps for make-up water intakes in its cost development for new facilities, but excluded them from the costs of cooling system conversions. The Agency estimated, based on a set of example cases, that existing intake structures could be reused for the recirculating cooling systems and that a portion of the existing pumping system would be reused.

The Agency used estimates of O&M costs of once-through cooling based on a methodology similar to that used to develop costs for the 316(b) Phase I Rule for New Facilities.

It should be noted that the O&M costs associated with a wet cooling tower do not include consideration of the effects on turbine efficiency resulting from the differences in turbine exhaust pressure caused by changes in the cooling system (see discussion in Section B1-1.2 below).

c. Condensers

For the regulatory options that include wet cooling towers, EPA included costs for premature condenser refurbishments for a portion of the model plants projected to incur costs of cooling tower conversions. The Agency projected premature condenser refurbishments, in part, to alleviate potential condenser tube failures related to cooling tower conversions, such as that experienced at one of the example case facilities. EPA consulted with condenser manufacturing representatives for advice on probable causes for condenser failures due to cooling system conversions, motivations for condenser replacements or refurbishments, useful lives of condensers, and appropriate tube materials for recirculating cooling systems for a variety of water types. The Agency learned from condenser vendors that plants would likely elect to upgrade condenser tube materials to increase the efficiency of the recirculating cooling system. In addition, for plants using brackish or saline cooling water, the Agency judged that the material of the tubes would need to withstand corrosive effects of chemical addition and increased salt content of the cooling water (due to concentration in a recirculating system). Hence, the Agency developed a baseline standard of condenser tube material and based on that determined which model plants would most likely upgrade condenser tube materials.

EPA judged that the minimum standard material would be copper-nickel alloy (of any mixture) for brackish water (i.e., for facilities with intakes withdrawing water from estuaries/tidal rivers) and stainless steel (of any type) for saline water (i.e., for facilities with intakes withdrawing water from oceans). The Agency then consulted the 1994 UDI database to determine the condenser tube material for the existing plants projected to incur cooling tower conversion costs. For the units at each plant with condenser tube materials judged to be of a quality below that of the minimum standards, the Agency estimated that the plant would refurbish the condenser (thereby upgrading the condenser tubes) as a result of the cooling system conversion. The Agency projected that tube material for the upgrades would be stainless steel for all model plants receiving upgrade refurbishments. At some plants, EPA projected that only a portion of the site's condensers would require refurbishment.

EPA contacted condenser vendors to obtain cost estimates for refurbishing existing condensers and for full condenser replacements. Using the vendor information, EPA developed unit cost estimates (on a flow basis) for several types of condenser tube materials – copper-nickel alloy, stainless steel, and titanium – as detailed in the *Phase II Technical Development Document*. The capital cost estimates for condenser refurbishing were lower than those for full replacements, and the Agency determined that, given equal opportunity, facilities would make the economic decision to refurbish existing condensers rather than replace the shell and the tubes. The condenser refurbishing costs developed by the Agency account for the tube materials, full labor, overhead, and potential bracing of the shell due to buoyancy changes (related to differences in replacement tube material and, hence, densities).

Power plants will refurbish or replace condensers on a periodic basis. Condenser vendors estimated the average useful life of condenser tubes as 20 years. In order to determine remaining useful life of the condensers at the model plants, the Agency calculated a condenser replacement/refurbishing schedule based on the 20-year useful life estimate and the age of the generating units at the plants. The average useful life remaining for a condenser at the model plants was approximately 9.5 years (in 2001). The Agency rounded this to 10 years and used this figure to represent lost operating years as a result of premature condenser refurbishments. EPA estimated that the baseline condenser material for any plant upgrading a condenser would be copper-nickel alloy. Therefore, plants upgrading condensers in order to install recirculating cooling would incur the costs of the full condenser refurbishment/upgrade to stainless steel. However, 10 years later, they would save the costs of replacing the original condenser, with a new condenser made of the same, lesser material (e.g., copper-nickel alloy). Both the cost of condenser replacement and the savings associated with not having to replace the original condenser 10 years later, are accounted for in EPA's cost analysis.

d. Dry cooling

One of the alternative regulatory options considered by EPA would require some existing facilities to switch to dry cooling (air cooled condensers). EPA developed capital cost estimates for dry cooling system conversions using those developed for new "greenfield" facilities under the 316(b) Phase I Rule for New Facilities. A detailed explanation of the development of "greenfield" facility dry cooling unit costs can be found in the *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*.

The capital cost equations were based on equivalent cooling water flow rates (gpm), using the once-through design intake cooling flow as the independent variable. EPA inflated the "greenfield" capital cost estimates by applying a "retrofit" factor of 5 percent, a contingency factor of 10 percent, and a 5 percent allowance to account for activities outside the scope of the "greenfield" cost estimates. Intake pumping was assumed to decrease to zero or near zero. Therefore, no costs were included for intake or piping modifications. In addition, it should be noted that the dry cooling capital costs do not include any consideration for replacement or modification of the steam turbines. The Agency developed dry cooling costs for new "greenfield" facilities based on the installation of direct dry cooling systems. Since direct dry cooling systems would require existing facilities to replace their steam-turbines, EPA assumed that indirect dry cooling systems would be used instead. Therefore, the Agency has developed facility-level dry cooling costs for indirect systems by using data from direct dry cooling systems.

EPA revised the O&M costs for dry cooling using a different basis than was used for the New Facility Rule compliance cost estimates. Rather than base the technology costs on factors applied to the capital costs as previously done, EPA based the O&M unit costs on energy requirements and cost information obtained from facility personnel and vendors. A detailed explanation of the development of the dry cooling O&M costs can be found in the *Phase II Technical Development Document*. It should be noted that these dry cooling O&M costs do not consider the effects on turbine efficiency resulting from the differences in turbine exhaust pressure caused by changes in the cooling system (see discussion in Section B1-1.2 below). As noted above, the Agency estimates that if dry cooling were used at existing facilities, the indirect dry cooling system would be employed. The Agency developed the size and energy requirements of its new "greenfield" dry cooling systems based on the more efficient (and, therefore, smaller) direct dry cooling systems.

B1-1.2 Energy Costs

Converting a cooling system from a once-through system to a recirculating system with a wet cooling tower or to a dry cooling system could affect a plant's operation in two ways. The first potential effect is an "energy penalty" from the operation of the recirculating or dry cooling system. Energy penalty estimates reflect the long-term reduction in available capacity due to the ongoing operation of the new system. The second potential effect is a one-time, temporary outage of the plant when the new system is connected to the plant's existing cooling system. Both effects are discussed in the subsections below. The third subsection discusses EPA's monetary valuation of the energy penalty and the cost of downtime.

a. Energy penalty

The energy penalty is the long-term reduction in available capacity as a result of operating a recirculating or dry cooling system and is expressed as a percent of generating capacity. The energy penalty consists of two components: (1) a reduction in unit efficiency due to increased turbine back-pressure and (2) an increase in auxiliary power requirements to operate the new system (e.g., for pumping and fanning). EPA estimated energy penalties for different types of generators (nuclear, combined-cycle, and fossil fuel) and different geographic regions (northeast, south, mid-west, and U.S. average). The estimated mean annual energy penalty for a recirculating system with wet cooling towers is 1.70 percent for nuclear units, 1.65 percent for fossil fuel units (including coal, oil, and natural gas), and 0.40 percent for combined-cycle units. The estimated mean annual energy penalty for a dry cooling system is 8.53 percent for nuclear units, 8.58 percent for fossil fuel units (including coal, oil, and natural gas), and 2.09 percent for combined-cycle units. EPA also considered the energy requirements of other compliance technologies, such as rotating screens, but found them insignificant and thus excluded them from this analysis.

As described in Section B1-1 above, EPA's estimates of O&M costs already include the second portion of the energy penalty, the increase in auxiliary power requirements. Therefore, to avoid double-counting these costs, only the turbine back-pressure part of the energy penalty was applied to the national cost estimate.

Table B1-1 below presents EPA's estimate of the energy penalty for wet cooling towers and dry cooling systems by facility type and geographic region.

Table B1-1: Annual Energy Penalty (% of Plant Capacity) by Facility Type and Geographic Region

Region	Nuclear			Fossil Fuel			Combined-Cycle		
	Turbine	Aux. Power	Total	Turbine	Aux. Power	Total	Turbine	Aux. Power	Total
Recirculating Systems with Wet Cooling Towers									
Northeast (MA)	0.73%	0.85%	**1.58%**	0.88%	0.77%	**1.65%**	0.14%	0.26%	**0.39%**
South (FL)	1.03%	0.85%	**1.88%**	0.93%	0.77%	**1.69%**	0.18%	0.26%	**0.44%**
Midwest (IL)	0.96%	0.85%	**1.82%**	1.00%	0.77%	**1.77%**	0.16%	0.26%	**0.41%**
West (WA)	0.67%	0.85%	**1.52%**	0.74%	0.77%	**1.51%**	0.11%	0.26%	**0.37%**
U.S. Average	**0.85%**	**0.85%**	**1.70%**	**0.89%**	**0.77%**	**1.65%**	**0.15%**	**0.26%**	**0.40%**
Dry Cooling Systems									
Northeast (MA)	4.96%	2.40%	**7.36%**	4.69%	2.45%	**7.14%**	0.98%	0.82%	**1.80%**
South (FL)	9.63%	2.40%	**12.0%**	10.06%	2.45%	**12.5%**	2.14%	0.82%	**2.96%**
Midwest (IL)	5.35%	2.40%	**7.75%**	5.26%	2.45%	**7.71%**	1.06%	0.82%	**1.88%**
West (WA)	4.60%	2.40%	**7.00%**	4.50%	2.45%	**6.95%**	0.90%	0.82%	**1.72%**
U.S. Average	**6.13%**	**2.40%**	**8.53%**	**6.13%**	**2.45%**	**8.58%**	**1.27%**	**0.82%**	**2.09%**

Source: Phase II Technical Development Document (U.S. EPA, 2002a).

b. Connection outage

The second energy effect associated with the conversion to a recirculating or a dry cooling system is a one-time, temporary outage of the plant when the new system is connected to the plant's existing cooling system. EPA estimates that the average construction and installation outage would be one month. This is the net outage attributable to the installation. EPA assumes that plants would minimize the disruption to their operations by installing the new system during times of scheduled maintenance outages. Scheduled maintenance outages can range from several weeks to several months, depending on the type of facility and the specific maintenance requirements.[1] Therefore, by scheduling the connection of the new system during maintenance periods, facilities could minimize the net impact to approximately one month but have several months to complete the connection.

c. Monetary valuation of energy cost

The energy penalty and the connection outage represent a cost to the facilities that incur them. For the energy penalty, this cost manifests itself as a reduction in revenues (the same amount of fuel is required to produce less electricity available for sale). For the connection outage, this cost is a loss in revenues offset by a simultaneous reduction in fuel costs (while the plant is out of service, it loses revenues but also does not incur variable costs of production).

EPA calculated facility-level baseline revenues using estimates of facility-specific average annual electricity sales and wholesale electricity prices:

- ***Facility Average Annual Electricity Sales (MWh):*** EPA calculated electricity sales for a "typical" operating year for each in-scope facility. This estimate is based on net generation data for each facility, adjusted to reflect that not all net generation will be sold for revenue. EPA calculated the average annual net generation for each in-scope facility over the five-year period 1995 to 1999 and excluded from this average "outlier" years, i.e., years of unusually low levels of generation. This analysis defines outlier years as net generation of 70 percent or more below the facility's average 1995 to 1999 net generation.[2] To derive electricity sales for a "typical" operating year, EPA adjusted the average net generation estimate to account for generation that is (1) lost due to transmission or distribution inefficiencies, (2) furnished without charge, or (3) used by the utility's own electricity department. The electricity sales adjustment is based on the average (1995 to 1999) percent of utility-level energy disposition that is sold. This percentage was calculated for each facility's owner.[3] For facilities without available utility-level energy disposition information, EPA used the 1995 to 1999 average for all in-scope facilities for which this information was available (95 percent of total energy sold, based on 531 facilities).

- ***Wholesale Electricity Price:*** EPA used utility-level revenues and electricity sales from Form EIA-861 to calculate the utility-specific wholesale price of electricity. EPA calculated each utility's average wholesale price of electricity by dividing revenues from *sales for resale* by the quantity of *sales for resale*.[4] EPA used revenue from sales for resale instead of average revenue per unit sale by the total company for this calculation since sales for resale represents the value of electricity at the generator busbar and does not include the price of additional value-added services provided by the company as it delivers generated electricity to its customers. Thus, the average price received for sales for resale is approximately a wholesale electricity price as received by the company. EPA estimated this price for each year between 1995 and 1999 and adjusted the values to constant year-2001 dollars using the electric power producer price index (PPI).

EPA estimated ***fuel cost per MWh of generation*** for each facility costed with a cooling tower under one of the regulatory options considered based on annual data forms for utility-owned power plants (FERC Form 1 for investor-owned utilities, Form EIA-412 for public electric utilities, and Form RUS 12 for rural electric cooperatives) compiled in OPRI's DataPik Electric Generating Plant Database (as of February 2000 and May 2001).

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[1] For a detailed discussion of scheduled maintenance outages, see the *Phase II Technical Development Document*.

[2] Annual net generation is based on the U.S. Department of Energy's (U.S. DOE) Form EIA-906 (formerly known as Forms EIA-759 and EIA-900). When data were not available from EIA Form-906, EPA used a compilation of annual data forms for utility-owned power plants (FERC Form 1 for investor-owned utilities, Form EIA-412 for public electric utilities, and Form RUS 12 for rural electric cooperatives; compiled in OPRI's DataPik Electric Generating Plant Database, as of February 2000 and May 2001).

[3] EPA used utility-level energy disposition information from the U.S. DOE's Form EIA-861.

[4] When the wholesale price could not be calculated, EPA calculated a price based on all utility-level revenues and electricity sales (including both electricity sales to ultimate consumers and electricity sales for resale).

❖ ***Energy Penalty***

To estimate the monetary value of the energy penalty, EPA calculated the loss in electricity sales by multiplying the facility's average annual electricity sales by the energy penalty percentages in Table B1-1 above. The penalty estimate used in this calculation is the turbine part of the penalty and is based on each facility's type and geographic region. EPA multiplied the loss in electricity sales by each facility's electricity price estimate to calculate the annual revenue loss from the energy penalty.
The following formulas were used to calculate this revenue loss:

$$Annual\ Revenue\ Loss = Annual\ Loss\ of\ Electricity\ Sales \times Electricity\ Price$$

where:

$$Annual\ Loss\ of\ Electricity\ Sales = Annual\ Electricity\ Sales \times Energy\ Penalty$$

❖ ***Connection outage***

The average cost of the connection outage is the revenue loss during the downtime less the fuel expenses that would normally be incurred during that period. EPA calculated the revenue loss due to the connection outage by dividing the facility's average annual sales by twelve and multiplying this value by the facility's electricity price estimate. EPA calculated the fuel cost by dividing the facility's average annual net generation by twelve and multiplying this value by each facility's fuel cost per MWh of generation.

The following formulas were used to calculate the net loss due to downtime:

$$Cost\ of\ Connection\ Outage = Revenue\ Loss - Fuel\ Costs$$

where:

$$Revenue\ Loss = \frac{Average\ Annual\ Electricity\ Sales}{12} \times Electricity\ Price$$

and

$$Fuel\ Costs = \frac{Average\ Annual\ Net\ Generation}{12} \times Fuel\ Cost\ per\ MWh\ of\ Generation$$

This approach may overstate the cost of the connection outage because it uses average electricity sales and prices. If downtime is scheduled during off-peak times, both the loss in electricity sales and the price per MWh could be lower. In addition, variable production costs other than fuel costs may be avoided during downtime. By only including fuel costs, EPA again may have overestimated the cost of the connection outage.

B1-1.3 Administrative Costs

Compliance with the proposed Phase II rule would require facilities to carry out certain administrative functions. These are either one-time requirements (compilation of information for the initial post-promulgation NPDES permit) or recurring requirements (compilation of information for subsequent NPDES permit renewals; and monitoring, record keeping, and reporting). This section describes each of these administrative requirements and their estimated costs.

a. Initial post-promulgation NPDES permit application

The proposed rule would require existing facilities to submit information regarding the location, construction, design, and capacity of their existing or proposed cooling water intake structures, technologies, and operational measures as part of their initial post-promulgation NPDES permit applications. Some of these activities would be required regardless under the current case-by-case cooling water intake structure permitting procedures, so to some extent the permitting costs of this proposed rule are over-costed. Ideally, these costs would be estimated on only an incremental basis. Activities and costs associated with the initial permit renewal application include:

- ***start-up activities:*** reading and understanding the rule; mobilizing and planning; and training staff;

- ***permit application activities:*** developing drawings that show the physical characteristics of the source water; developing a description of the CWIS configuration; developing a facility water balance diagram; developing a narrative of operational characteristics; developing a description of the existing cooling water system; submitting materials for review by the Director; and keeping records;
- ***source water baseline biological characterization data:*** identifying available data and documenting efforts; compiling and analyzing existing data; submitting materials for review by the Director; and keeping records;
- ***proposal for collection of information for comprehensive demonstration study:*** developing a proposal for the collection of information; developing a description of the proposed and/or implemented technologies, operational measures, and restoration measures to be evaluated; developing a description of historical studies that will be used; developing a summary of public participation and consultation with fish and wildlife agencies; developing a sampling plan; submitting data and plans for review; revising plans based on state review; and keeping records;
- ***source waterbody flow information****:* determining the annual mean flow of the waterbody for freshwater rivers/streams; developing a description of the thermal stratification of the waterbody for lakes/reservoirs; preparing supporting documentation and engineering calculations; submitting data for review; and keeping records;
- ***impingement mortality and entrainment characterization study:*** performing biological sampling; developing a taxonomic identification and characterization of species of fish and shellfish and their life stages; documenting impingement mortality and entrainment of all life stages of fish and shellfish; identifying protected species; submitting the study for review; and keeping records;
- ***impingement mortality and entrainment characterization study capital and O&M costs:*** contract laboratory analysis of samples;
- ***design and construction technology plan:*** calculating facility capacity utilization rate; describing in-place or selected technologies and operational measures; documenting efficacy of the technologies; performing design calculations and preparing drawings and estimates; submitting the plan for review; and keeping records;
- ***evaluation of potential cooling water intake structure effects:*** calculating the baseline upon which to assess total reduction in impingement mortality and entrainment; calculating reduction in impingement mortality and entrainment that would be achieved by the technologies and operational measures selected; demonstrating that the location, design, construction and capacity of the intake reflects the best technology available (BTA) for minimizing adverse environmental impact; performing impingement and entrainment pilot studies; submitting data and analysis for review; and keeping records;
- ***impingement and entrainment pilot study capital and O&M costs:*** purchasing, installing and operating pilot study technology; laboratory analysis of samples;
- ***information to support site-specific determination of best technology available (BTA) for minimizing adverse environmental impact:*** performing a comprehensive cost evaluation study; developing a monetized valuation of the benefits of reducing impingement and entrainment; performing engineering calculations and drawings; submitting results for review; and keeping records;
- ***site-specific technology plan:*** describing selected technologies, operational measures and restoration measures; documenting efficacy of the proposed and/or implemented technologies or operational measures; developing site-specific evaluation of suitability of technologies or operational measures; performing design calculations and preparing drawings and estimates; submitting the plan for review; and keeping records;
- ***verification monitoring plan:*** developing a narrative description of the frequency of monitoring, parameters to be monitored, and the basis for determining the parameters and frequency and duration of monitoring; and keeping records;
- ***remote monitoring device capital and O&M costs:*** installation of remote monitoring devices.

Table B1-2 below lists the estimated maximum costs of each of the initial post-promulgation NPDES permit application activities described above. The specific activities that a facility will have to undertake depend on the facility's source water body type, whether it exceeds capacity utilization rate and proportional flow thresholds, and whether it chooses to meet the proposed rule's performance standards or to make a site-specific determination of BTA. Certain activities are expected to be more costly for marine facilities than for freshwater facilities. Some activities will apply to all facilities, while other activities will apply only if the facility exceeds the capacity utilization rate or proportional flow thresholds or chooses to make a site-specific determination of BTA. The maximum cost a facility that implements all the activities would incur for its initial post-promulgation NPDES permit application is estimated to be approximately $1.4 million.

Table B1-2: Cost of Initial Post-Promulgation NPDES Permit Application Activities ($2001)					
Activity	Estimated Maximum Cost per Permit				
	Freshwater River/ Stream	Lake	Great Lake	Estuary/ Tidal River	Ocean
Start-up activities	$2,014	$2,014	$2,014	$2,014	$2,014
Permit application activities[a]	$9,571	$9,571	$9,571	$9,571	$9,571
Source water baseline biological characterization data[a]	$11,372	$11,372	$11,372	$11,372	$11,372
Proposal for collection of information for comprehensive demonstration study	$12,407	$12,407	$12,407	$12,407	$12,407
Source waterbody flow information[a]	$3,370	$3,894	$0	$0	$0
Impingement mortality and entrainment characterization study[b]	$243,483	$243,483	$302,061	$302,061	$302,061
Impingement mortality and entrainment characterization capital and O&M costs[b]	$118,500	$118,500	$118,500	$199,230	$199,230
Design and construction technology plan[a]	$5,310	$3,807	$5,310	$5,310	$5,310
Evaluation of potential cooling water intake structure effects[a]	$122,246	$76,893	$145,338	$145,338	$145,338
Impingement and entrainment pilot study capital and O&M costs[a]	$321,600	$280,000	$280,000	$350,210	$350,210
Information to support site-specific determination of BTA[a]	$32,823	$32,823	$32,823	$32,823	$32,823
Site-specific technology plan[a]	$7,038	$7,038	$7,038	$7,038	$7,038
Verification monitoring plan[a]	$6,489	$6,489	$6,489	$6,489	$6,489
Remote monitoring device capital and O&M costs[a]	$280,000	$280,000	$280,000	$280,000	$280,000
Total Initial Post-Promulgation NPDES Permit Application Cost	**$1,176,223**	**$1,088,291**	**$1,212,923**	**$1,363,863**	**$1,363,863**

[a] The costs for these activities are incurred in the year prior to the permit application.
[b] The costs for these activities are incurred in the three years prior to the permit application.

Source: U.S. EPA, 2002b.

b. Subsequent NPDES permit renewals

Each existing facility will have to apply for NPDES permit renewal every five years. Subsequent permit renewal applications will require collecting and submitting the same type of information as required for the initial permit renewal application. EPA expects that facilities can use some of the information from the initial permit renewal. Building upon existing information is expected to require less effort than developing the data the first time especially in situations where conditions have not changed.

Table B1-3 lists the maximum estimated costs of each of the NPDES repermit application activities. The specific activities that a facility will have to undertake depend on the facility's source water body type, whether it exceeds the capacity utilization rate and proportional flow thresholds, and whether it chooses to meet the proposed rule's performance standards or to make a site-specific determination of BTA. Certain activities are expected to be more costly for facilities located on a

Great Lake, estuary, tidal river, or ocean than for freshwater facilities. The maximum cost a facility that implements all the activities would incur for its NPDES repermit application is estimated to be $53,000.

Table B1-3: Cost of NPDES Repermit Application Activities ($2001)

Activity	Estimated Maximum Cost per Permit				
	Freshwater River/ Stream	Lake	Great Lake	Estuary/ Tidal River	Ocean
Start-up activities[a]	$542	$542	$542	$542	$542
Permit application activities[a]	$6,265	$6,265	$6,265	$6,265	$6,265
Source water baseline biological characterization data[a]	$4,076	$4,076	$4,076	$4,076	$4,076
Proposal for collection of information for comprehensive demonstration study[a]	$4,579	$4,579	$4,579	$4,579	$4,579
Source waterbody flow information[a]	$1,981	$2,138	$0	$0	$0
Impingement mortality and entrainment characterization study[a]	$14,733	$14,733	$15,023	$15,023	$15,023
Design and construction technology plan[a]	$2,797	$2,011	$2,797	$2,797	$2,797
Evaluation of potential CWIS effects[a]	$7,138	$7,138	$7,138	$7,138	$7,138
Information to support site-specific determination of BTA[a]	$8,011	$8,011	$8,011	$8,011	$8,011
Site-specific technology plan[a]	$2,623	$2,623	$2,623	$2,623	$2,623
Total NPDES Repermit Application Cost	**$52,745**	**$52,116**	**$51,054**	**$51,054**	**$51,054**

[a] The costs for these activities are incurred in the year prior to the application for a permit renewal.

Source: U.S. EPA, 2002b.

c. Monitoring, record keeping, and reporting

All existing facilities subject to the proposed rule will be required to monitor to show compliance with the requirements set forth in the proposed rule. Facilities must keep records of their monitoring activities and report the results in a yearly status report. Monitoring, record keeping, and reporting activities and costs include:

- ***impingement sampling:*** collecting monthly samples for at least two years after the initial permit issuance; enumerating organisms; and keeping records;
- ***entrainment sampling:*** collecting biweekly samples during the primary period of reproduction, larval recruitment, and peak abundance for at least two years after the initial permit issuance; enumerating organisms; and keeping records;
- ***entrainment sampling capital and O&M costs:*** contract laboratory analysis of entrainment samples;
- ***visual or remote inspections:*** conducting weekly visual inspections or employing remote monitoring devices to ensure that design and construction technologies continue to function as designed; and keeping records;
- ***verification study:*** conducting technology performance monitoring; submitting monitoring results and study analysis; and keeping records;
- ***yearly status report activities:*** detailing biological monitoring results; reporting on visual or remote inspection; compiling and submitting the report; and keeping records.

Table B1-4 lists the estimated costs of each of the monitoring, record keeping, and reporting activities described above. Certain activities are expected to be more costly for marine facilities than for freshwater facilities. The maximum cost a facility will incur for its monitoring, record keeping, and reporting activities is estimated to be $110,000.

Table B1-4: Cost of Annual Monitoring, Record Keeping, and Reporting Activities ($2001)

Activity	Estimated Cost				
	Freshwater River/ Stream	Lake	Great Lake	Estuary/ Tidal River	Ocean
Impingement sampling	$16,985	$16,985	$21,623	$21,623	$21,623
Entrainment sampling	$37,369	$37,369	$46,044	$46,044	$46,044
Entrainment sampling capital and O&M costs	$8,300	$8,300	$10,640	$10,640	$10,640
Visual or remote inspections	$9,094	$9,094	$9,094	$9,094	$9,094
Remote monitoring capital and O&M costs	$250	$250	$250	$250	$250
Verification study	$6,427	$6,427	$6,427	$6,427	$6,427
Yearly status report activities	$15,656	$15,656	$15,656	$15,656	$15,656
Total Monitoring, Record Keeping, and Reporting Cost	**$94,081**	**$94,081**	**$109,734**	**$109,734**	**$109,734**

Source: U.S. EPA, 2002b.

B1-2 Assigning Compliance Years to Facilities

This section discusses the methodology used to estimate the compliance years of facilities subject to Phase II regulations. The estimated compliance years of facilities are important for two reasons: (1) they determine by how much compliance costs are discounted in the national cost estimate and (2) for options that include cooling tower requirements, a high concentration of facilities estimated to be out of service for cooling tower connection in the same region and at the same time could lead to temporary energy effects in that region.

Facilities not costed with a cooling tower have to come into compliance with the proposed Phase II rule during the year their first post-promulgation NPDES permit is issued. Since NPDES permits are renewed every five years, all facilities not costed with cooling towers will come into compliance between 2004 and 2008. Table B1-5 below presents the distribution of Phase II facilities by North American Electric Reliability Council (NERC) region and compliance year. The NERC regions presented in the table are:

- ASCC – Alaska
- ECAR – East Central Area Reliability Coordination Agreement
- ERCOT – Electric Reliability Council of Texas
- FRCC – Florida Reliability Coordinating Council
- HI – Hawaii
- MAAC – Mid-Atlantic Area Council
- MAIN – Mid-America Interconnect Network
- MAPP – Mid-Continent Area Power Pool
- NPCC – Northeast Power Coordinating Council
- SERC – Southeastern Electric Reliability Council
- SPP - Southwest Power Pool
- WSCC – Western Systems Coordinating Council

Table B1-5: Weighted Number of Phase II Facilities by NERC Region and Compliance Year

Compliance Year	NERC Region												
	ASCC	ECAR	ERCOT	FRCC	HI	MAAC	MAIN	MAPP	NPCC	SERC	SPP	WSCC	Total
2004	0	14	18	8	3	6	10	6	10	13	5	5	**99**
2005	1	20	4	10	0	11	16	6	11	20	10	16	**125**
2006	0	30	8	2	0	16	13	16	18	21	3	7	**133**
2007	0	21	7	3	0	6	5	6	12	28	5	2	**94**
2008	0	15	15	7	0	5	7	10	12	13	9	4	**97**
Total	**1**	**100**	**52**	**30**	**3**	**44**	**51**	**44**	**62**	**95**	**32**	**34**	**550**

Source: U.S. EPA analysis, 2002.

The appendix to this chapter presents EPA's methodology for assigning compliance years to facilities costed with cooling towers, and the compliance year assignment for regulatory options that include cooling tower requirements for some or all facilities.

B1-3 Total Private Compliance Costs

EPA estimated the total private pre-tax compliance costs for the proposed Phase II rule and the alternative regulatory options based on the unit costs discussed in Section B1-1 and the compliance years discussed in Section B1-2. Technology compliance costs were developed in 1999 dollars and converted to year-2001 dollars using the construction cost index (CCI). Administrative costs were developed in 2001 dollars.

B1-3.1 Methodology

The private cost of the Phase II rule represents the total compliance costs of the 550 in-scope section 316(b) Phase II facilities. Under the proposed rule, facilities are expected to comply over a five-year period between 2004 and 2008; under policy options that include a cooling tower requirement, the compliance period is between 2004 and 2012. EPA estimated the total private cost of the rule by calculating the present value of each facility's one-time costs as of 2004. To derive the constant annual value of the one-time costs, EPA annualized the costs of each compliance technology over its expected useful life, using a seven percent discount rate. EPA then added the annualized one-time costs to the annual costs to derive each facility's total annual cost of complying with the Phase II rule. EPA estimated the post-tax value of private compliance costs by applying state-specific corporate income tax rates to privately-owned facilities (government-owned entities and cooperatives are not subject to income taxes).

a. Present value of compliance costs

EPA calculated the present value of the one-time capital, downtime, and initial permit costs using a seven percent discount rate. The following assumptions were made regarding the timing of these one-time costs:

- ***Cooling Tower Capital Costs:*** This cost is incurred over a two-year period. EPA assumed that in the first year, engineering work would be completed and in the second year, the facility would install the cooling tower. The first year of this cost is the year before the facility installs a cooling tower.

- ***Other Capital Costs:*** For facilities that do not require cooling towers, this cost is incurred in the year that the facility's first post-promulgation permit is issued. For facilities requiring cooling towers, this cost is incurred in the year that the facility installs the cooling tower.

- ***Condenser Improved Material Costs:*** This cost is incurred by facilities that require cooling towers to comply with the regulation. This cost is incurred in the year that the facility installs a cooling tower.

- ***Condenser Existing Material Costs:*** This is a cost that would have been incurred by the facility ten years after installing their cooling tower if the facility had not upgraded to an improved condenser material.

- ***Cost of Connection Outage:*** EPA estimates that the average outage to construct and install a cooling tower would be one month. A more detailed description of this cost is presented in Section B1-1.2 above. This cost is incurred in the year that the facility installs the cooling tower.

- ***Baseline Characterization Study:*** This is a three-year study required for facilities with a cooling tower requirement under the waterbody/capacity-based option that decide to take Track II. The cost of this study is incurred over three years. The first year of costs is in the year that the facility's first post-promulgation permit is issued.

The following formula was used to calculate the net present value of the one-time costs as of 2004:[5]

$$Present\ Value_x = \frac{Cost_{x,t}}{(1 + r)^{2004-t}}$$

where:

$Cost_{x,t}$	=	Costs in category x and year t
x	=	Cost category
r	=	Discount rate (7% in this analysis)
t	=	Year in which cost is incurred (2004 to 2012)

b. Annualization of compliance costs

Annualized compliance costs include all capital costs, O&M costs, administrative costs, energy penalty costs, and plant outage costs of compliance with the proposed Phase II rule and alternative regulatory options. O&M costs include the cost of auxiliary power requirements as a result of the operation of recirculating cooling towers. To derive the constant annual value of the capital costs and the value of the cooling tower construction and/or connection plant outage, EPA annualized them over 30 years, using a seven percent discount rate. The costs of condenser upgrades were annualized over 20 years. Other capital costs, which include fine-mesh traveling screens with and without fish handling as well as fish handling and return systems, were annualized over 10 years. EPA calculated the annualized capital costs using the following formula:

$$Annualized\ Capital\ Cost = Total\ Capital\ Costs \times \frac{r \times (1 + r)^n}{(1 + r)^n - 1}$$

where:

r	=	Discount rate (7% in this analysis)
n	=	Amortization period (useful life of equipment; 30 years for cooling tower equipment; 20 years for condensers; 10 years for other flow reduction and I&E technologies)

EPA then added the annualized capital and outage costs to annual O&M, administrative costs and energy penalty costs to derive each facility's total annual cost of complying with the proposed Phase II rule.

c. Consideration of taxes

Compliance costs associated with the section 316(b) regulation reduce the income of facilities subject to the rule. As a result, the tax liability of these facilities decreases. The net cost of the rule to facilities is therefore the compliance costs of the rule less the tax savings that result from these compliance costs. EPA estimated the tax savings by developing a total tax rate that integrates the federal corporate income tax rate (35 percent) and state-specific state corporate income tax rates. The total effective tax rate was calculated as follows:

$$Total\ Tax\ Rate = State\ Tax\ Rate + Federal\ Tax\ Rate - (State\ Tax\ Rate * Federal\ Tax\ Rate)$$

[5] Calculation of the present value assumes that the cost is incurred at the end of the year.

The amount by which a facility's annual tax liability would be reduced is the annualized compliance cost of the rule multiplied by the total tax rate.[6]

B1-3.2 Total Private Costs of the Proposed Rule

EPA estimates that the total annual facility compliance cost of the proposed Phase II rule for the 550 in-scope facilities is $182 million annually. Table B1-6 presents annualized facility compliance costs by cost category and NERC region. The annualized cost by NERC region ranges from approximately $200,000 for facilities located in ASCC to $33 million for facilities located in ECAR.[7]

Table B1-6: Private (Post-Tax) Annualized Facility Compliance Costs by NERC Region (in millions, $2001)

NERC Region	One-Time Costs			Recurring Costs				Total
	Capital Technology	Connection Outage	Initial Permit Application	O&M	Monitoring, Record Keeping & Reporting	Energy Penalty	Permit Renewal	
ASCC	$0.0	$0.0	$0.1	$0.0	$0.1	$0.0	$0.0	**$0.2**
ECAR	$15.2	$0.0	$6.5	$3.6	$5.9	$0.0	$1.4	**$32.6**
ERCOT	$4.6	$0.0	$3.7	$1.2	$3.4	$0.0	$0.8	**$13.8**
FRCC	$7.2	$0.0	$2.5	$1.8	$2.1	$0.0	$0.5	**$14.1**
HI	$1.2	$0.0	$0.2	$0.2	$0.2	$0.0	$0.0	**$1.9**
MAAC	$9.3	$0.0	$2.9	$1.8	$2.5	$0.0	$0.6	**$17.1**
MAIN	$6.4	$0.0	$3.3	$1.4	$3.0	$0.0	$0.7	**$14.8**
MAPP	$2.0	$0.0	$3.1	$0.4	$2.9	$0.0	$0.7	**$9.1**
NPCC	$13.3	$0.0	$4.3	$2.7	$3.7	$0.0	$0.8	**$24.9**
SERC	$14.7	$0.0	$6.4	$3.9	$5.9	$0.0	$1.4	**$32.3**
SPP	$1.3	$0.0	$2.2	$0.4	$2.1	$0.0	$0.5	**$6.4**
WSCC	$8.2	$0.0	$2.6	$1.5	$2.2	$0.0	$0.5	**$15.1**
Total	**$83.5**	**$0.0**	**$37.8**	**$19.0**	**$34.1**	**$0.0**	**$8.0**	**$182.4**

Source: U.S. EPA analysis, 2002.

Table B1-7 presents total annual facility compliance costs by cost category and steam plant type. The annual compliance costs range from approximately $2 million for waste facilities to $91 million for coal facilities.

[6] This calculation is a conservative approximation of the actual tax effect of the compliance costs. For capital costs, it assumes that the total annualized cost, which includes imputed interest and principal charge components, is subject to a tax benefit. In effect, the schedule of principal charges *over time* in the annualized cost value is treated, for tax purposes, as though it were the depreciation schedule *over time*. In fact, the actual tax depreciation schedule that would be available to a company would be accelerated in comparison to the principal charge schedule embedded in the annualized cost calculation. As a result, explicit accounting for the deprecation schedule would yield a slightly higher present value of tax benefits than is reflected in the analysis presented here.

[7] See definitions of NERC regions in section B1-2.

Table B1-7: Private (Post-Tax) Annualized Facility Compliance Costs by Steam Plant Type (in millions, $2001)

Steam Plant Type	One-Time Costs			Recurring Costs				Total
	Capital Technology	Connection Outage	Initial Permit Application	O&M	Monitoring, Record Keeping & Reporting	Energy Penalty	Permit Renewal	
Coal	$38.8	$0.0	$20.1	$9.4	$18.3	$0.0	$4.3	**$90.9**
Combined Cycle	$1.7	$0.0	$1.2	$0.5	$1.0	$0.0	$0.2	**$4.6**
Nuclear	$15.4	$0.0	$3.7	$3.0	$3.3	$0.0	$0.8	**$26.2**
Oil/Gas	$27.2	$0.0	$12.2	$6.0	$10.9	$0.0	$2.5	**$58.9**
Waste	$0.3	$0.0	$0.6	$0.1	$0.5	$0.0	$0.1	**$1.6**
Unspecified	$0.0	$0.0	$0.1	$0.0	$0.1	$0.0	$0.0	**$0.1**
Total	**$83.5**	**$0.0**	**$37.8**	**$19.0**	**$34.1**	**$0.0**	**$8.0**	**$182.4**

Source: U.S. EPA analysis, 2002.

The total costs of the alternative regulatory options are presented in Chapter B7: Alternative Options - Costs and Economic Impacts.

B1-4 Uncertainties and Limitations

EPA's estimates of the compliance costs associated with the proposed Section 316(b) Existing Facilities Rule are subject to limitations because of uncertainties about the number and characteristics of the existing facilities that will be subject to the rule. Projecting the number of existing facilities that meet the design intake flow threshold is subject to uncertainties associated with the quality of data reported by the facilities in their DQ and STQ surveys, and with the accuracy of the design flow estimates for the STQ facilities. Characterizing the cooling systems and intake technologies in use at existing facilities is also subject to uncertainties associated with the quality of data reported by the facilities in their surveys and with the projected technologies for the STQ facilities. The estimated national facility compliance costs may be over- or understated if the projected number of Phase II existing facilities is incorrect or if the characteristics of the Phase II existing facilities are different from those assumed in the analysis.

There is additional uncertainty about the valuation of the energy penalty and the connection outage. EPA's analysis used historical information on electricity generation, electricity sales, electricity prices, and fuel costs, which may not be representative of conditions at the time when facilities comply with Phase II regulation.

Limitations in EPA's ability to consider a full range of compliance responses may result in an overestimate of facility compliance costs. The Agency was not able to consider certain compliance responses, including the costs of using alternative sources of cooling water, the costs of some methods of changing the cooling system design, and the costs of restoration. Costs will be overstated if these excluded compliance responses are less expensive than the projected compliance response for some facilities.

Alternative less stringent requirements based on both costs and benefits are allowed under the proposed rule. There is some uncertainty in predicting compliance responses because the number of facilities requesting alternative less stringent requirements based on costs and benefits is unknown.

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Appendix to Chapter B1

APPENDIX CONTENTS

B1-A.1 Assignment of Compliance Years for Cooling Tower Options

This section discusses the methodology used to estimate the compliance years of facilities subject to alternative regulatory options that include cooling towers as compliance requirements for some facilities. Under the waterbody/capacity-based option (Option 1), facilities that withdraw cooling water from oceans or estuaries and have certain intake flow characteristics are required to reduce flow to a level commensurate with that of wet cooling towers; EPA costed 54 facilities with cooling towers under this option. The all cooling towers option (Option 4) requires that all facilities that do not currently have a cooling tower to install one; EPA costed 426 facilities with cooling towers under this option. Due to the longer lead-time required to design and install cooling towers, facilities that install cooling towers have a longer time frame within which to comply with a policy option. Facilities not costed with a cooling tower have the same compliance years as described in Section B1-2 of this chapter.

B1-A.1.1 Methodology

Under a regulatory option that would require facilities to reduce their flow to a level commensurate to a closed-cycle recirculating system, a facility installing a cooling tower would have to comply by the end of the first permit issued after the Phase II promulgation date (August 28, 2003). Facilities that got their last NPDES permit in 1999 would receive their first post-promulgation permit in 2004 and would have until the end of that permit term, 2008, to comply with the rule.[8] Similarly, facilities that get a new permit in 2003 would receive their first post-promulgation permit in 2008 and have until the end of that permit term, 2012, to comply with the rule. Therefore, for facilities costed with a cooling tower, the latest possible year of compliance with the proposed rule ranges from 2008 to 2012. Since facilities have the option to comply earlier, the potential compliance period for facilities costed with a cooling tower would be between 2004 and 2012. This analysis assumes that each facility costed with a cooling tower would comply during the five-year term of its first post-promulgation permit.

At a large electric generating plant, a cooling tower takes approximately two years to design, construct, and then connect (U.S. EPA-U.S. DOE personal correspondence, 2002). In the first year, engineers prepare for the construction of a cooling tower. In the second year, the cooling tower is installed. A facility that is issued its first post-promulgation permit in 2004 could do the preparation work in that year and install their cooling tower in 2005. Therefore, the compliance period for facilities costed with a cooling tower is 2005 to 2012. EPA obtained NPDES permit information from its Permit Compliance System (PCS) database, using NPDES permit ID's from the 1994 UDI database or Envirofacts.[9]

Table B1-A-1 below presents the five-year compliance period for facilities costed with a cooling tower, based on the year of their last NPDES permit.

[8] The dates used for this analysis are based on a five-year permit term. For the purpose of analysis simplicity, we assume that each facility's permit period will begin on January 1st and end on December 31st.

[9] NPDES permit IDs could not be identified for eight facilities. EPA randomly assigned these facilities to a compliance year.

Table B1-A-1: Compliance Schedule for Facilities Costed with Cooling Towers			
Year of Last NPDES Permit	Compliance Period		
	Year of First Post-Promulgation Permit	First Year of Cooling Tower Installation	Last Year of Cooling Tower Installation
1999	2004	2005	2008
2000	2005	2005	2009
2001	2006	2006	2010
2002	2007	2007	2011
2003	2008	2008	2012

Source: U.S. EPA analysis, 2002.

The following subsections explain how a specific compliance year was identified from the five-year compliance period available to each facility.

a. Nuclear facilities

Periodic in-service inspections (ISIs) are typically performed at nuclear power plants at five- and ten-year intervals. Five-year ISIs are scheduled for the 5^{th}, 15^{th}, 25^{th}, and 35^{th} years of a plant's operation, and ten-year ISIs are performed in the 10^{th}, 20^{th}, and 30^{th} years. Each of these outages typically requires two to four months of downtime for the plant. EPA assumed that all nuclear facilities costed with cooling towers will install them at times that coincide with their ISIs. This analysis used Forms EIA-860A and EIA-860B to identify the year that each non-retired nuclear unit began operation. When a facility has more than one unit, it was assumed that the ISIs would occur during five-year intervals from the time that the earliest unit began operation. The compliance year used in the analysis is therefore a five-year multiple of the first year of operation of each nuclear facility. The compliance year is additionally constrained by the NPDES permitting schedule, as described above. For example, for a facility which has two active generating units that began operation in 1983 and 1984, EPA assumed that the facility is on an inspection schedule which began in 1983, with inspections occurring in five-year intervals. The facility's current NPDES permit expires in 2005. Therefore, this analysis assumes that the facility would install a cooling tower in 2008, which is 25 years after the facility began operation and occurs during its first post-promulgation permit period (2005 to 2009).

b. Other facilities

Information on routine maintenance shut-downs is not available for non-nuclear facilities, so the algorithm used to determine the compliance year of nuclear facilities could not be used for non-nuclear facilities. Instead, EPA used NPDES permit expiration dates to estimate compliance years. EPA assigned the non-nuclear cooling tower facilities to compliance years so that the capacity and steam electric generating capacity that would be out of service at one time in any NERC region was evenly distributed over the compliance period (2005-2012). In doing so, EPA also took into account the nuclear capacity that would be out of service.

The methodology used to assign compliance years to facilities may not accurately predict the actual shut-down time for any given facility, but it is unbiased and provides a reasonable estimate of national costs.

B1-A.1.2 Summary of Cooling Tower Facilities by Compliance Year

a. Waterbody/capacity-based option

This option would require existing facilities located on estuaries and tidal rivers to reduce intake capacity commensurate with the use of a closed-cycle recirculating cooling system. EPA analyzed two different cases of the waterbody/capacity based option: the first case assumes that all 54 facilities with recirculating cooling system-based requirements would comply with Track I and install a wet cooling tower (Option 1); the second, more likely, case assumes that 21 of the 54 facilities with recirculating cooling system-based requirements would comply with Track II. These 21 facilities would conduct a comprehensive waterbody characterization study and install technologies other than wet cooling towers (Option 2). The following tables and discussion present only the Option 1 analysis. The 33 facilities assumed to install a wet cooling tower under Option 2 are a subset of the 54 facilities analyzed with the wet cooling tower technology in Option 1 and the compliance results for the Option 2 case are less than those presented for the Option 1 case.

The 54 facilities that were costed with a cooling tower in Option 1 account for 62,500 MW of baseline steam capacity. The following three tables present the distribution of capacity costed with a cooling tower by (1) NERC region and steam plant type, (2) NERC region and estimated compliance year, and (3) steam plant type and estimated compliance year.

Table B1-A-2: Weighted Baseline Steam Capacity (MW) by NERC Region and Steam Plant Type

NERC Region	Steam Plant Type					
	Coal	Combined-Cycle	Nuclear	Oil	Other Steam	Total
ERCOT	0	0	0	0	3,902	**3,902**
FRCC	6,651	0	1,700	3,132	0	**11,483**
HI	0	0	0	1,085	0	**1,085**
MAAC	4,346	219	4,211	1,769	0	**10,544**
NPCC	2,927	600	3,076	4,842	3,529	**14,974**
SERC	2,612	0	3,485	0	2,051	**8,148**
WSCC	0	0	4,555	0	7,807	**12,362**
Total	**16,537**	**819**	**17,027**	**10,827**	**17,289**	**62,497**

Source: U.S. EPA analysis, 2002.

Table B1-A-3: Weighted Baseline Steam Capacity (MW) by NERC Region and Compliance Year

Compliance Year	NERC Region							
	ERCOT	FRCC	HI	MAAC	NPCC	SERC	WSCC	Total
2005	0	1,112	610	1,829	0	2,301	1,656	**7,508**
2006	0	1,700	0	1,229	0	3,426	2,396	**8,751**
2007	0	1,320	475	2,382	1,695	1,295	1,317	**8,483**
2008	0	3,333	0	1,767	812	2,254	625	**8,791**
2009	426	0	0	768	2,051	1,447	2,591	**7,283**
2010	514	0	0	1,059	1,790	1,639	3,326	**8,327**
2011	647	1,998	0	801	1,800	0	1,124	**6,370**
2012	2,315	2,019	0	710	0	0	1,940	**6,984**
Total	**3,902**	**11,483**	**1,085**	**10,544**	**8,148**	**12,362**	**14,974**	**62,497**

Source: U.S. EPA analysis, 2002.

Table B1-A-4: Weighted Baseline Steam Capacity (MW) by Steam Plant Type and Compliance Year						
Compliance Year	Steam Plant Type					
	Coal	Combined-Cycle	Nuclear	Oil	Other Steam	Total
2005	987	0	4,129	1,722	669	**7,508**
2006	1,229	0	1,700	1,516	4,306	**8,751**
2007	1,320	0	4,898	475	1,790	**8,483**
2008	5,694	819	2,254	0	25	**8,791**
2009	768	0	0	1,242	5,273	**7,283**
2010	0	0	3,032	3,142	2,152	**8,327**
2011	4,599	0	1,013	0	758	**6,370**
2012	1,940	0	0	2,730	2,315	**6,985**
Total	**16,537**	**819**	**17,027**	**10,827**	**17,289**	**62,497**

Source: U.S. EPA analysis, 2002.

b. All cooling towers option

To comply with the all cooling towers option, EPA estimated that 426 facilities would need to install cooling towers. These facilities account for 353,750 MW of baseline steam capacity. The following three tables present the distribution of capacity costed with a cooling tower by (1) NERC region and steam plant type, (2) NERC region and estimated compliance year, and (3) steam plant type and estimated compliance year.

Table B1-A-5: Weighted Baseline Steam Capacity (MW) by NERC Region and Steam Plant Type

NERC Region	Steam Plant Type					
	Coal	Combined- Cycle	Nuclear	Oil	Other Steam	Total
ASCC	28	0	0	0	0	**28**
ECAR	55,762	0	3,503	1,953	0	**61,218**
ERCOT	7,237	110	2,430	22,940	0	**32,717**
FRCC	7,666	3,402	1,700	10,252	0	**23,021**
HI	0	0	0	1,189	0	**1,189**
MAAC	8,685	219	7,155	6,664	262	**22,985**
MAIN	25,661	0	4,921	0	0	**30,581**
MAPP	12,702	0	3,075	197	0	**15,973**
NPCC	7,867	1,105	10,430	20,104	282	**39,787**
SERC	57,496	127	23,699	16,050	0	**97,373**
SPP	6,456	0	0	2,149	0	**8,605**
WSCC	2,183	344	4,555	13,186	0	**20,267**
Total	**191,742**	**5,306**	**61,468**	**94,685**	**543**	**353,745**

Source: U.S. EPA analysis, 2002.

Table B1-A-6: Weighted Baseline Steam Capacity (MW) by NERC Region and Compliance Year

Compliance Year	NERC Region												
	ASCC	ECAR	ERCOT	FRCC	HI	MAAC	MAIN	MAPP	NPCC	SERC	SPP	WSCC	Total
2005	0	7,090	5,559	3,245	714	2,312	6,588	948	3,711	9,288	1,309	3,497	**44,263**
2006	28	6,832	4,789	1,842	0	2,425	5,159	2,233	4,262	12,312	816	3,937	**44,636**
2007	0	8,439	3,179	1,551	475	5,295	4,137	784	3,337	12,736	386	3,866	**44,186**
2008	0	6,423	3,708	3,414	0	2,603	3,004	2,995	4,332	14,026	562	3,824	**44,892**
2009	0	6,078	3,238	2,250	0	4,279	4,265	2,634	8,574	10,763	654	2,373	**45,109**
2010	0	8,480	2,998	2,852	0	4,105	2,085	2,055	7,205	13,738	2,044	1,639	**47,200**
2011	0	8,573	3,442	3,361	0	1,256	1,605	1,431	4,461	15,987	1,220	25	**41,362**
2012	0	9,304	5,803	4,504	0	710	3,737	2,893	3,905	8,523	1,613	1,105	**42,098**
Total	**28**	**61,218**	**32,717**	**23,021**	**1,189**	**22,985**	**30,581**	**15,973**	**39,787**	**97,373**	**8,605**	**20,267**	**353,745**

Source: U.S. EPA analysis, 2002.

Table B1-A-7: Weighted Baseline Steam Capacity (MW) by Steam Plant Type and Compliance Year

Compliance Year	Steam Plant Type					
	Coal	Combined-Cycle	Nuclear	Oil	Other Steam	Total
2005	25,795	127	9,416	8,924	0	**44,263**
2006	27,043	0	7,229	10,364	0	**44,636**
2007	22,078	1,430	8,069	12,354	254	**44,186**
2008	23,793	1,162	7,383	12,444	110	**44,892**
2009	14,851	218	16,045	13,925	68	**45,109**
2010	20,501	0	9,872	16,827	0	**47,200**
2011	29,028	382	3,454	8,386	111	**41,362**
2012	28,651	1,986	0	11,460	0	**42,098**
Total	**191,742**	**5,306**	**61,468**	**94,685**	**543**	**353,745**

Source: U.S. EPA analysis, 2002.

c. Dry cooling

Compliance year assignments for the dry cooling option (Option 5) are identical to those for facilities in the waterbody/capacity-based option (Option 1), assuming that all facilities will go track 1 and install cooling towers.

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