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Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities

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Table of Contents

Chapter 3: Energy Penalty, Air Emissions, and Cooling Tower Side-Effects

Chapter 4: Dry Cooling

Chapter 5: Efficacy of Cooling Water Intake Structure Technologies

Chapter 6: Industry Profile: Oil and Gas Extraction Industry

Chapter 1: Baseline Projections of New Facilities

INTRODUCTION

Chapter Contents

Facilities regulated under the final § 316(b) New Facility Rule are new greenfield and stand alone electric generators and manufacturing facilities that operate a new cooling water intake structure (CWIS) (or a CWIS whose design capacity is increased), require a National Pollutant Discharge Elimination System (NPDES) permit, have a design intake flow of equal to or greater than two million gallons per day (MGD), and use at least 25 percent of their intake water for cooling purposes. The overall costs and economic impacts of the final rule depend on the number of new facilities subject to the rule and on the planned characteristics (i.e., construction, design, location, and capacity) of their CWISs. The projection of the number and characteristics of new facilities represents baseline conditions in the absence of the rule and identifies the facilities that will be subject to the final § 316(b) New Facility Rule.

EPA did not consider the oil and gas industry in the Phase I 316(b) rulemaking for new facilities. The Phase I proposal and its record included no analysis of issues associated with offshore and coastal oil and gas extraction facilities that could significantly increase the costs and economic impacts and affect the technical feasibility of complying with the proposed requirements for land-based industrial operations. Additionally, EPA believes it is not appropriate to include these facilities in the Phase II regulations scheduled for proposal in February 2002; the Phase II regulations are intended to address the largest existing facilities in the steam-electric generating industry. During Phase III, EPA will address cooling water intake structures at existing facilities in a variety of industry sectors. Therefore, EPA believes it is most appropriate to defer rulemaking for offshore and coastal [oil and gas] extraction facilities to Phase III. For further discussion, see Chapter 5: Industry Profile - Oil and Gas Extraction Industry.

This chapter provides a summary EPA's forecasts for the number of new electric generators and manufacturing facilities subject to the final § 316(b) New Facility Rule that will begin operating between 2001 and 2020. The chapter consists of four sections. The first three sections address the forecasts of new facilities and the final section presents a profile of the electricity generation industry. Section 1.1 presents the estimates for the number and characteristics of new electric generating facilities. Section 1.2 presents the estimates for the number of new manufacturing facilities. Section 1.3 summarizes the results of the new baseline projections of facilities. For detailed discussion of the methodology behind the forecasts consult *Chapter 5 of the Economic Analysis*.

1.1 New Electric Generators

EPA estimates that 83 new electric generators subject to the final § 316(b) New Facility Rule will begin operation between 2001 and 2020. Of these, 69 are new combined-cycle facilities and 14 are new coal facilities.[1] This projection is based on a combination of national forecasts of new steam electric capacity additions and information on the characteristics of specific facilities that are planned for construction in the near future or that have been constructed in the recent past. Using these two types of information, EPA developed model facilities that provide the basis for estimating costs and economic impacts for electric generators throughout the remainder of this document. For more detailed information regarding new electric generators, see *Economic Analysis of the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*.

1.1.1 Methodology

EPA used four main data sources to project the number and characteristics of new steam electric generators subject to the final rule: (1) the Energy Information Administration's (EIA) *Annual Energy Outlook 2001* (AEO2001); (2) Resource Data International's (RDI) *NEWGen Database*, (3) EPA's § 316(b) industry survey of existing facilities; and (4) EIA's Form EIA-860A and 860B databases. The following sections provide detail on each data source used in this analysis. The final subsection 5.1.1.e summarizes how EPA combined the information from the different data sources to calculate the number of new combined-cycle and coal facilities.

Annual Energy Outlook 2001

The Annual Energy Outlook (AEO) is published annually by the U.S. Department of Energy's Energy Information Administration (EIA) and presents forecasts of energy supply, demand, and prices. These forecasts are based on results generated from EIA's National Energy Modeling System (NEMS). The NEMS system generates projections based on known levels of technological capabilities, technological and demographic trends, and current laws and regulations. Other key assumptions are made regarding the pricing and availability of fossil fuels, levels of economic growth, and trends in energy consumption. The AEO projections are used by Federal, State, and local governments, trade associations, and other planners and decision makers in both the public and private sectors. EPA used the most recent forecast of capacity additions between 2001 and 2020 (presented in the AEO2001) to estimate the number of new combined-cycle and coal-fired steam electric plants.

The AEO2001 presents forecasts of both planned and unplanned capacity additions between 2001 and 2020 for eight facility types (coal steam, other fossil steam, combined-cycle, combustion turbine/diesel, nuclear, pumped storage/other, fuel cells and renewables). EPA has determined that only facilities that employ a steam electric cycle require significant quantities of cooling water and are thus potentially affected by the final § 316(b) New Facility Rule. As a result, this analysis considers capacity additions associated with coal steam, other fossil steam, combined-cycle, and nuclear facilities only. In its Reference Case, the AEO2001 forecasts total capacity additions of 370 GW

[1]Combined-cycle facilities use an electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine to produce electricity. This process increases the efficiency of the electric generating unit.

from all facility types between 2001 and 2020.[2] Coal steam facilities account for 22 GW, or 6 percent of the total forecast, and combined-cycle facilities account for 204 GW, or 55 percent. The remaining capacity additions, 39 percent of the total, come from non-steam facility types. Based on all available data in the rulemaking record, EPA projects no new additions for nuclear and other fossil steam capacity.

NEWGen Database

The NEWGen database is created and regularly updated by Resource Data International's (RDI) Energy Industry Consulting Practice. The database provides detailed facility-level data on electric generation projects, including new (greenfield and stand alone) facilities and additions and modifications to existing facilities, proposed over the next several years. Information in the NEWGen database includes: generating technology, fuel type, generation capacity, owner and holding company, electric interconnection, project status, on-line dates, and other operational details. The majority of the information contained in this database is obtained from trade journals, developers, local authorities, siting boards, and state environmental agencies.

EPA used the February 2001 version of the NEWGen database to develop model facilities for the economic analysis of electric generators. Specifically, the database was used to:

- calculate the percentage of total combined-cycle capacity additions derived from new (greenfield and stand alone) facilities;
- calculate the percentage of total coal capacity additions derived from new (greenfield and stand alone) facilities;
- estimate the in-scope percentage of new combined-cycle facilities; and
- determine the technical, operational, and ownership characteristics of new in-scope combined-cycle facilities.

§ 316(b) Industry Survey of Existing Facilities

Because the NEWGen database discussed in the previous section contained information on only 16 new (greenfield and stand alone) coal facilities, EPA believes that information from EPA's § 316(b) industry survey of existing facilities (*Industry Screener Questionnaire: Phase I Cooling Water Intake Structures*, *Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures*, and *Industry Short Technical Questionnaire: Phase II Cooling Water Intake Structures*) was more reliable for estimating characteristics of new coal facilities projected over the 2001-2020 analysis period because it included far more plants over a longer time period.

All three survey instruments requested technical information, including the facility's in scope status, cooling system type, intake flow, and source water body. In addition, the screener questionnaire and the detailed questionnaire also requested economic and financial information. For more information on the three survey instruments, see ICR No. 1973.02.

[2]Among other model parameters, the AEO2001 Reference Case assumes economic growth of 3 percent and electricity demand growth of 1.8 percent.

EPA used the following survey data on coal plants constructed during the past 20 years to project the number and characteristics of new (greenfield and stand alone) coal facilities: in-scope status, waterbody type, and cooling system type.[3]

In developing model coal facilities, EPA only considered those existing survey plants that have a once-through system, a recirculating system, or a recirculating system with a cooling lake or pond.

EIA Databases

In addition to the § 316(b) industry survey of existing facilities, EPA used two of EIA's electricity databases (Form EIA-860A, Annual Electric Generator Report – Utility; and Form EIA-860B, Annual Electric Generator Report – Nonutility; both 1998) in the analysis of projected new coal plants. EPA used these databases for three purposes:

- **Identify which of the surveyed electric generators are "coal" plants:** EPA used the prime mover and the primary energy source, reported in the EIA databases, to determine if a surveyed facility is a coal plant. Only plants that only have coal units were considered in this analysis.
- **Identify coal plants constructed during the past 20 years:** Both EIA databases request the in-service date of each unit. Of the surveyed facilities, 111 coal-fired plants began commercial operation between 1980 and 1999.
- **Determine the average size of new coal plants:** The 111 identified coal plants have an average nameplate rating of 475 MW.[4]

Summary of the Number of New Facilities

EPA estimated the number of projected new combined-cycle and coal plants using information from the four data sources described in subsections 5.1.1.a to 5.1.1.d above. EPA used the U.S. Department of Energy's estimate of new capacity additions (combined-cycle: 204 GW, coal: 22 GW) and multiplied it by the percentage of capacity additions that will be built at new facilities (combined-cycle: 88%, coal: 76%) to determine the new capacity that will be constructed at new facilities (combined-cycle: 179 GW, coal: 17 GW). EPA then divided this value by the average facility size (combined-cycle: 741 MW, coal: 475 MW) to determine the total number of potential new facilities (combined-cycle: 241, coal: 35; both in scope and out of scope of today's final rule). Finally, based on EPA's estimate of the percentage of facilities that meet the two MGD flow threshold (combined-cycle: 28.6%, coal: 40.5%), EPA estimates there will be 69 new in-scope combined-cycle facilities and 14 new coal facilities over the 2001–2020 period.

Development of Model Facilities

The final step in the baseline projection of new electric generators was the development of model facilities for the costing and economic impact analyses. This step required translating characteristics of the analyzed combined-cycle and coal facilities into characteristics of the 83 projected new facilities. The characteristics of interest are: (1) the type of water body from which the intake structure withdraws (freshwater or marine water); (2) the facility's type of

[3]Coal plants constructed during the past 20 years were identified from Forms EIA-860A and EIA-860B. See discussion in subsection 1.1.1.d below.

[4]The average capacity for in-scope coal facilities is 763 MW, while the average for out of scope coal facilities is 278 MW.

cooling system (once-through or recirculating system); and (3) the facility's steam electric generating capacity. The following two subsections discuss how EPA developed model facilities for combined-cycle and coal facilities, respectively.

1.1.2 Projected Number of New Electric Generation Facilities

Combined-Cycle Facilities

EPA's analysis projected 69 new in-scope combined-cycle facilities. Cooling water and economic characteristics of these 69 facilities were determined based on the characteristics of the 57 in-scope NEWGen facilities.[5] EPA developed six model facility types based on the 57 facilities' combinations of source water body and type of cooling system. Within each source water body/cooling system group, EPA created between one and three model facilities, depending on the number of facilities within that group and the range of their steam electric capacities.

Based on the distribution of the 57 NEWGen facilities by source water body group, cooling system type, and size group, EPA determined how many of the 69 projected new facilities are represented by each of the six model facility types. Table 1-1 below presents the six model facility types, their estimated steam electric capacity, the number of NEWGen facilities upon which each model facility type was based, and the number of projected new facilities that belong to each type.

Table 1-1: Combined-Cycle Model Facilities

Model Facility Type	Cooling System Type	Source Water Body	Steam Electric Capacity (MW)	Number of NEWGen Facilities	Number of Projected New Facilities
CC OT/M-1	Once Through	Marine	1,031	4	5
CC R/M-1	Recirculating	Marine	489	4	5
CC R/M-2	Recirculating	Marine	1,030	1	1
CC R/FW-1	Recirculating	Freshwater	439	15	18
CC R/FW-2	Recirculating	Freshwater	699	17	21
CC R/FW-3	Recirculating	Freshwater	1,061	16	19
Total				**57**	**69**

Source: EPA Analysis, 2001.

Generally, NEWGen facilities were not always consistent in how they reported their intake flows. Some NEWGen facilities reported design flows, some reported maximum flows and some reported average flows. It was therefore necessary to estimate design flows for those facilities that had reported either maximum or average flows. To do

[5]EPA could determine the water body type for all 57 in-scope facilities but did not have information on the cooling system type for 18 facilities. Since all freshwater facilities with a known cooling system type propose to build a recirculating system, EPA assumed that the 15 freshwater facilities with an unknown cooling system type will also build a recirculating system. For marine facilities, EPA assumed that two of the three facilities with an unknown system type would build a recirculating system in the baseline while one would build a once-through system.

so, EPA assumed estimated design flows to be equivalent to maximum flows, or to three times average flows, based on the results of previous analysis of DQ combined cycle power plants. As was done for the coal-fired plants, EPA normalized estimated design flows for the NEWGen facilities by dividing by MW capacities.

Many NEWGen facilities did not report any intake flow information. EPA developed model facility flow estimates based only on those NEWGen facilities for which flows had been reported. The NEWGen facilities that did not report flows were assumed to follow the same distribution as those which had reported flow information.

EPA grouped the NEWGen facilities according to CWS type (once-through vs. recirculating) and water body type (freshwater vs. marine) to yield several baseline scenarios. The baseline scenarios for combined cycle power plants are listed in Table 1-2 below.

Table 1-2: Baseline Combined Cycle Power Plant Scenarios

Industry Category	Industry Description	Baseline Cooling Technology	Water Body Type
Combined Cycle Power Plants	Includes both Utility and Non-utility facilities	Once-through	Marine
Combined Cycle Power Plants	Includes both Utility and Non-utility facilities	Recirculating with Wet Towers	Marine
Combined Cycle Power Plants	Includes both Utility and Non-utility facilities	Recirculating with Wet Towers	Freshwater

It should be noted that a once-through, freshwater model plant was not developed because none of the NEWGen facilities fell into this baseline scenario. Within each baseline scenario, EPA developed combined cycle model facilities to represent low, medium and high MW capacity plants, using a similar methodology to that used to develop the coal-fired model facilities. Table 1-3 below presents the baseline intake and cooling flow values used in estimating the compliance costs for these model combined cycle power plants.

Table 1-3: Additional Combined Cycle Power Plant Model Facility Baseline Intake and Cooling Flow Values

Model Facility ID	Baseline Cooling Water System	Waterbody Type	Capacity (MW)	Baseline Intake Flow (MGD)	Baseline Cooling Flow (MGD)
CC OT/M-1	Once Through	Marine	1031	613	613
CC R/M-1	Recirculating	Marine	489	8	106
CC R/M-2	Recirculating	Marine	1030	18	223
CC R/FW-1	Recirculating	Freshwater	439	10	198
CC R/FW-2	Recirculating	Freshwater	699	12	230
CC R/FW-3	Recirculating	Freshwater	1061	14	283

Coal Facilities

EPA's analysis projected 14 new in-scope coal facilities. The same approach was used to assign cooling water and economic characteristics to these 14 facilities as was used for combined-cycle facilities (see discussion in the previous section). EPA determined the characteristics of the 14 projected new coal facilities based on the characteristics of the 41existing in-scope coal facilities. EPA developed eight model facility types based on the 41 facilities' source water body and their type of cooling system. Within each source water body/cooling system group, EPA created between one and three model facilities, depending on the number of facilities within that group and the range of their steam electric capacities. Based on the distribution of the 41 survey facilities by source water body group, cooling system type, and size group, EPA determined how many of the 14 projected new coal facilities are represented by each of the eight model facility types. Table 1-4 below presents the eight model facility types, their estimated steam electric capacity, the number of survey facilities upon which each model facility type was based, and the number of projected new coal facilities that are represented by each type.

Table 1-4: Coal Model Facilities

Model Facility Type	Cooling System Type	Source Water Body	Steam Electric Capacity (MW)	Number of Existing Survey Facilities	Number of Projected New Facilities
Coal R/M-1	Recirculating	Marine	812	3	1
Coal OT/FW-1	Once Through	Freshwater	63	3	1
Coal OT/FW-2	Once Through	Freshwater	515	5	1
Coal OT/FW-3	Once Through	Freshwater	3,564	1	1
Coal R/FW-1	Recirculating	Freshwater	173	10	3
Coal R/FW-2	Recirculating	Freshwater	625	7	3
Coal R/FW-3	Recirculating	Freshwater	1,564	8	3
Coal RL/FW-1	Recirculating with Lake[a]	Freshwater	660	4	1
Total				**41**	**14**

[a] For this analysis, recirculating facilities with cooling lakes are assumed to exhibit characteristics like a once-through facility.

Source: EPA Analysis, 2001.

Data taken from the surveys included both design intake flow and average intake flows, where available. With the exception of monitoring costs, all cost components used either the design intake flow or the design cooling water flow (which was estimated from the design intake flow as described in Section 2.3.5 of Chapter 2: Wet Tower Intake Flow Factors) as the input variable for deriving the cost. However, design intake flow data were not available for the SQ and screener facilities. It was therefore necessary to estimate design intake flows for these facilities. To do this, EPA calculated ratios of design to average intake flow (D/A) for those DQ facilities for which both design intake and average intake flows were available. These facilities were then grouped according to cooling water system (CWS) type (i.e., once-through vs. recirculating), and an average D/A ratio was calculated for each CWS type. This yielded average D/A ratios of 1.18 for once-through coal-fired plants and 2.94 for recirculating coal-fired plants. EPA then used these average D/A ratios to estimate design flows for those facilities for which design flows were not available (D/A ratio was multiplied by average flow to yield estimated design flow).

Where design condenser flows were available from EEI 1996 data, EPA compared the estimated design intake flows to the design condenser flows as a check of their reasonableness. For once-through facilities, the design intake flow would be expected to be similar in magnitude to the design condenser flow, while for recirculating facilities with cooling towers, the design intake flows would be expected to be only a fraction of the design condenser flows. In almost all cases, the estimated design flows were found to meet these expectations.

For a few facilities, however (notably, the facilities that had recirculating CWSs with cooling ponds), EPA found the estimated design flows (calculated using the recirculating system D/A ratio of 2.94) to be several times higher than the design condenser flows. Therefore, for these facilities, the design condenser flows were used as being more representative of the design intake flows that might be expected for such facilities (in fact, the design condenser flows were much more in line with estimated design flows calculated using the once-through D/A ratio of 1.18). See Chapter 2 for additional discussion of these recirculating facilities with cooling ponds.

Four survey facilities with estimated design flows less than the regulatory threshold of 2 million gallons per day (MGD) were then eliminated from the flow analysis as being out of scope. The regulatory threshold represents the intake flow rate at which intake systems would be required to comply with the regulation. Only those survey facilities that were in scope (i.e., met the 2 MGD regulatory threshold) were included in the analysis to develop the model facilities.

EPA then normalized the design flows for the in-scope facilities by dividing the design flow for each facility by the corresponding MW capacity for that facility to yield a ratio of design flow to MW capacity (MGD/MW). This was necessary in order to apply the flow values for plants with a range of MW capacities to average capacity model plants.

EPA then grouped the surveyed facilities according to CWS type and water body type to yield several baseline scenarios. The various water body types were divided into two general categories: freshwater, which included facilities located on freshwater rivers, streams, lakes or reservoirs; and marine, which included facilities located on tidal rivers, estuaries and oceans. The baseline scenarios for coal-fired power plants are listed in Table 1-5 below.

Table 1-5: Baseline Coal-Fired Power Plant Scenarios

Industry Category	Industry Description	Baseline Cooling Technology	Water Body Type
Coal-fired Power Plants	Includes both Utility and Non-utility facilities	Once-through	Freshwater (includes freshwater rivers, streams, lakes, and reservoirs
Coal-fired Power Plants	Includes both Utility and Non-utility facilities	Recirculating with Wet Towers	Freshwater
Coal-fired Power Plants	Includes both Utility and Non-utility facilities	Recirculating with Wet Towers	Marine (includes tidal rivers, estuaries, and oceans)
Coal-fired Power Plants	Includes both Utility and Non-utility facilities	Recirculating with Cooling Ponds	Freshwater

It should be noted that EPA did not develop a once-through, marine baseline scenario for coal-fired power plants because none of the surveyed facilities (and therefore none of the projected new facilities) fell into this baseline scenario. It should also be noted that EPA developed a separate baseline scenario for coal-fired power plants that had recirculating CWSs with cooling ponds. The design intake flows and MGD/MW ratios for these facilities were found to be much higher than those for the coal-fired power plants that had recirculating systems with wet cooling towers–more in line with what might be expected for once-through facilities. This would not be entirely unexpected, if the reported flows for these facilities represented the flows of water withdrawn from the cooling ponds for cooling use within the plants, rather than the flows of make-up intake water to the cooling ponds. EPA therefore decided that these recirculating plants with cooling ponds deserved to be treated as a separate baseline scenario. For purposes of cost estimation, these facilities were treated the same as once-through facilities. This represented a conservative approach since, if anything, it would tend to overestimate the size of the baseline cooling water system that would have to be replaced, as well as the corresponding compliance cost.

Within each baseline scenario, EPA ranked the survey facilities in ascending order of their MW capacities. EPA then divided the ranked survey facilities into groups to yield low, medium and high MW capacity model facilities. For baseline scenarios where only a single new facility was projected, only average MW capacities were calculated. EPA developed corresponding average MGD/MW ratios for each grouping. The low, medium and high MW capacities for each baseline scenario were then multiplied by the corresponding average MGD/MW ratios to yield normalized design flow estimates for low, medium and high MW capacity model facilities. EPA then estimated the cooling water flows for the model facilities based on the design intake flows, as described below under Chapter 2, Section 2.3.5: Wet Tower Intake Flow Factors. Table 1-6 below presents the baseline intake and cooling flow values used in estimating the compliance costs for the different model coal-fired plants.

Table 1-6: Coal-Fired Power Plant Model Facility Baseline Intake and Cooling Flow Values

Model Facility ID	Baseline Cooling Water System	Waterbody Type	Capacity (MW)	Baseline Intake Flow (MGD)	Baseline Cooling Flow (MGD)
Coal OT/FW-1	Once Through	Freshwater	63	64	64
Coal OT/FW-2	Once Through	Freshwater	515	420	420
Coal OT/FW-3	Once Through	Freshwater	3564	1550	1550
Coal R/M-1	Recirculating	Marine	812	44	547
Coal R/FW-1	Recirculating	Freshwater	173	5	103
Coal R/FW-2	Recirculating	Freshwater	625	20	405
Coal R/FW-3	Recirculating	Freshwater	1564	77	1538
Coal RL/FW-1	Recirculating with Cooling Pond	Freshwater	660	537	537

1.1.3 Summary of Forecasts for New Electric Generators

EPA estimates that a total of 276 new steam electric generators will begin operation between 2001 and 2020. Of the total number of new plants, EPA projects that 83 will be in scope of the final § 316(b) New Facility Rule. Sixty-nine are expected to be combined-cycle facilities and 14 coal-fired facilities. Table 1-7 summarizes the results of the analysis.

Table 1-7: Number of Projected New Electric Generators (2001 to 2020)

Facility Type	Total Number of New Facilities	Facilities In Scope of the Final Rule						
		Recirculating		Recirc. with Lake		Once-Through		Total
		Freshwater	Marine	Freshwater	Marine	Freshwater	Marine	
Combined-Cycle	241	58	6	0	0	0	5	69
Coal	35	9	1	1	0	3	0	14
Total	276	67	7	1	0	3	5	83

Source: EPA Analysis, 2001.

1.2 New Manufacturing Facilities

EPA estimates that 38 new manufacturing facilities subject to the final § 316(b) New Facility Rule will begin operation between 2001 and 2020. Of the 38 facilities, 22 are chemical facilities, ten are steel facilities, two are petroleum refineries, two are paper mills, and two are aluminum facilities. The projection is based on a combination of industry-specific forecasts and information on the characteristics of existing manufacturing facilities. For more detailed information regarding new manufacturing facilities, see *Economic Analysis of the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*.

1.2.1 Methodology

EPA used several steps to estimate the number of new manufacturing facilities subject to the final rule. For each industry sector, EPA:

- identified the SIC codes with potential new in-scope facilities;
- obtained industry growth forecasts;
- determined the share of growth from new (greenfield and stand alone) facilities;
- projected the number of new facilities;
- determined cooling water characteristics of existing facilities; and
- developed model facilities.

The remainder of this section briefly outlines each of these six steps. The following Section 5.2.2 describes the baseline projections of new manufacturing facilities for each of the five industry sectors.[6]

SIC codes with potential new in-scope facilities

EPA used results from the § 316(b) *Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures* to identify the SIC codes within each of the five industry sectors that are likely to have one or more new (greenfield

[6]This analysis divides the Primary Metals sector (SIC 33) into two subsectors: steel (SIC 331) and aluminum (SIC 333/335). Section 5.2.2 therefore discusses five separate sectors, not four.

and stand alone) facilities subject to the final § 316(b) New Facility Rule. SIC codes that were included in this analysis are those that, based on the Detailed Industry Questionnaire, have at least one existing facility that meets the in-scope criteria of the final rule. Facilities meet the in-scope criteria of the final rule if they:

- use a CWIS to withdraw from a water of the U.S.;
- hold an NPDES permit;
- withdraw at least two million gallons per day (MGD); and
- use 25 percent or more of their intake flow for cooling purposes.[7]

For each SIC code with at least one in-scope survey respondent, EPA estimated the total number of facilities in the SIC code (based on the sample weighted estimate from EPA's § 316(b) industry survey of existing facilities), the number of in-scope survey respondents, and the in-scope percentage.

Industry growth forecasts

Forecasts of the number of new (greenfield and stand alone) facilities that will be built in the various industrial sectors are generally not available over the 20-year time period required for this analysis. Projected growth rates for value of shipments in each industry were used to project future growth in capacity. A number of sources provided forecasts, including the annual *U.S. Industry Trade & Industry Outlook (2000),* the *Assumptions to the Annual Energy Outlook 2001*, and other sources specific to each industry. EPA assumed that the growth in capacity will equal growth in the value of shipments, except where industry-specific information supported alternative assumptions.

Share of growth from new facilities

There are three possible sources of industry growth: (1) construction of new (greenfield and stand alone) facilities; (2) higher or more efficient utilization of existing capacity; and (3) capacity expansions at existing facilities. Where available, information from industry sources provided the basis for estimating the potential for construction of new facilities. Where this information was not available, EPA assumed as a default that 50 percent of the projected growth in capacity will be attributed to new facilities. This assumption likely overstates the actual number of new (greenfield and stand alone) facilities that will be constructed.

Projected number of new facilities

EPA projected the number of new facilities in each SIC code by multiplying the total number of existing facilities by the forecasted 10-year growth rate for that SIC code. The resulting value was then multiplied by the share of growth from new facilities to derive the total number of new facilities over ten years. However, not all of the projected new facilities will be subject to requirements of the final § 316(b) New Facility Rule. Information on the likely water use characteristics of new facilities that will determine their in-scope status under the final rule is generally not available for future manufacturing facilities. EPA estimated that the characteristics of new facilities will be similar to the characteristics of existing survey respondents (i.e., the percentage of new facilities subject to the final rule would be the same as the percentage of existing facilities that meet the rule's in-scope criteria). EPA

[7]For convenience, existing facilities that meet the criteria of the final § 316(b) New Facility Rule are referred to as "existing in-scope facilities" or "in-scope survey respondents." As existing facilities, they will not in fact be subject to the rule. However, they would be subject to the final § 316(b) New Facility Rule if they were *new* facilities.

then calculated the number of new *in-scope* facilities by multiplying the 10-year forecast of new facilities by the in-scope percentage of existing facilities. To derive the 20-year estimate, both the estimated total number of new facilities and the estimated number of new in-scope facilities were doubled. This approach most likely overstates the number of new facilities that will incur regulatory costs, because new facilities may be more likely than existing ones to recycle water and use cooling water sources other than a water of the U.S.

Cooling water characteristics of existing in- scope facilities

EPA used information from EPA's § 316(b) *Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures* to determine the characteristics of the in-scope survey respondents. The survey requested technical information, including the facility's cooling system type, source water body, and intake flow in addition to economic and financial information. Cooling water characteristics of interest to the analysis are the facility's baseline cooling system type (i.e., once-through or recirculating system) and its cooling water source (i.e., freshwater or marine water). In addition, the facility's design intake flow was used in the costing analysis.

Development of model facilities

The final step in the baseline projection of new manufacturing facilities was the development of model facilities for the costing and economic impact analyses. This step required translating characteristics of the existing in-scope facilities into characteristics of the projected new facilities. Again, the characteristics of interest are: (1) the facility's type of cooling system in the baseline (once-through or recirculating system) and (2) the type of water body from which the intake structure withdraws (freshwater or marine water). EPA developed one model facility for each cooling system/water body combination within each 4-digit SIC code. Based on the distribution of the in-scope survey respondents by cooling system type and source water body, EPA assigned the projected new in-scope facilities to model facility types.

EPA developed model manufacturing facilities using DQ data for 178 manufacturing facilities, regardless of their year of construction. Because the DQ manufacturing facilities represent only a sampling of the total population of manufacturing facilities, EPA used survey weights in developing flow estimates for these model facilities.

EPA first sorted the DQ manufacturing facilities according to their 4-digit SIC Codes, and then according to CWS type (once-through vs. recirculating) and water body type (freshwater vs. marine) to yield one or more baseline scenarios within each 4-digit SIC Code. Many of the DQ manufacturing facilities were found to use mixed once-through and recirculating CWSs. For purposes of cost estimation, EPA treated these facilities the same as once-through CWSs. This represented a conservative approach since, if anything, it would tend to overestimate the size of the baseline CWS that would have to be replaced, and thus overestimate the corresponding compliance costs.

Eighteen survey facilities with estimated design flows less than the regulatory threshold of 2 million gallons per day (MGD) were then eliminated from the flow analysis as being out of scope. The regulatory threshold represents the intake flow rate at which intake systems would be required to comply with the regulation. Only those survey facilities that were in scope (i.e., met the 2 MGD regulatory threshold) were included in the analysis to develop the model facilities.

The baseline scenarios for manufacturing facilities are listed in Table 1-8 below.

Table 1-8: Baseline Manufacturing Facility Scenarios

Industry Category	Industry Description	Baseline Cooling Technology	Water Body Type
SIC 2621	Paper and Allied Products - Paper Mills	Once Through	Freshwater
SIC 2812	Chemical and Allied Products - Alkalies and Chlorines	Once Through	Marine
SIC 2812	Chemical and Allied Products - Alkalies and Chlorines	Once Through	Freshwater
SIC 2812	Chemical and Allied Products - Alkalies and Chlorines	Reuse/Recycle	Freshwater
SIC 2819	Chemicals and Allied Products - Industrial Inorganic Chemicals, Not Elsewhere Classified (NEC)	Once Through	Freshwater
SIC 2819	Chemicals and Allied Products - Industrial Inorganic Chemicals, NEC	Reuse/Recycle	Freshwater
SIC 2819	Chemicals and Allied Products - Industrial Inorganic Chemicals, NEC	Once Through	Marine
SIC 2821	Chemicals and Allied Products - Plastics Materials and Synthetic Resins	Once Through	Marine
SIC 2821	Chemicals and Allied Products - Plastics Materials and Synthetic Resins	Once Through	Freshwater
SIC 2821	Chemicals and Allied Products - Plastics Materials and Synthetic Resins	Reuse/Recycle	Freshwater
SIC 2834	Chemicals and Allied Products - Pharmaceuticals	Once Through	Freshwater
SIC 2834	Chemicals and Allied Products - Pharmaceuticals	Reuse/Recycle	Freshwater
SIC 2869	Chemicals and Allied Products - Industrial Organic Chemicals, NEC	Once Through	Marine
SIC 2869	Chemicals and Allied Products - Industrial Organic Chemicals, NEC	Once Through	Freshwater
SIC 2869	Chemicals and Allied Products - Industrial Organic Chemicals, NEC	Reuse/Recycle	Freshwater
SIC 2873	Chemicals and Allied Products - Nitrogenous Fertilizers	Once Through	Freshwater
SIC 2873	Chemicals and Allied Products - Nitrogenous Fertilizers	Reuse/Recycle	Freshwater
SIC 2911	Petroleum Refining	Reuse/Recycle	Freshwater
SIC 2911	Petroleum Refining	Once Through	Freshwater
SIC 3312	Primary Metal Industries - Steel Works, Blast Furnaces and Rolling	Once Through	Freshwater

Table 1-8: Baseline Manufacturing Facility Scenarios

Industry Category	Industry Description	Baseline Cooling Technology	Water Body Type
SIC 3312	Primary Metal Industries - Steel Works, Blast Furnaces and Rolling	Reuse/Recycle	Freshwater
SIC 3316	Primary Metal Industries - Cold-Rolled Steel Sheet, Strip and Bars	Once Through	Freshwater
SIC 3316	Primary Metal Industries - Cold-Rolled Steel Sheet, Strip and Bars	Reuse/Recycle	Freshwater
SIC 3317	Primary Metal Industries - Steel Pipe and Tubes	Once Through	Freshwater
SIC 3317	Primary Metal Industries - Steel Pipe and Tubes	Reuse/Recycle	Freshwater
SIC 3353	Primary Metal Industries - Aluminum Sheet, Plate and Foils	Once Through	Freshwater
SIC 3353	Primary Metal Industries - Aluminum Sheet, Plate and Foils	Reuse/Recycle	Freshwater

Within each baseline scenario, EPA ranked the DQ facilities in ascending order based on their design intake flows. Design intake flows were not available for two of the DQ manufacturing facilities. However, average intake flows were available for these facilities. EPA estimated design intake flows for these facilities by multiplying their average intake flows by the average ratio of design intake to average intake flow for the other facilities within their baseline scenarios.

EPA then divided the DQ facilities within each baseline scenario into thirds. EPA then calculated weighted average design intake flows for the middle third to yield design flow values for medium-sized (as reflected by design flow) manufacturing facilities; the lower and upper thirds were excluding from the averaging to minimize the effects of unusually small or unusually large facilities on the average. Table 1-9 below presents the baseline intake and cooling flow values used in estimating the compliance costs for the different model manufacturing facilities.

Table 1-9: Manufacturing Model Facility Baseline Intake and Cooling Flow Values

Model Facility ID	Baseline Cooling Water System	Waterbody Type	Baseline Intake Flow (MGD)	Baseline Cooling Flow (MGD)
MAN OT/FW-2621	Once Through	Freshwater	24	24
MAN OT/M-2812	Once Through	Marine	94	94
MAN OT/FW-2812	Once Through	Freshwater	265	265
MAN R/FW-2812	Reuse/Recycle	Freshwater	6	60
MAN OT/FW-2819	Once Through	Freshwater	19	19

Table 1-9: Manufacturing Model Facility Baseline Intake and Cooling Flow Values

Model Facility ID	Baseline Cooling Water System	Waterbody Type	Baseline Intake Flow (MGD)	Baseline Cooling Flow (MGD)
MAN R/FW-2819	Reuse/Recycle	Freshwater	2	20
MAN OT/M-2819	Once Through	Marine	27	27
MAN OT/FW-2821	Once Through	Freshwater	78	78
MAN R/FW-2821	Reuse/Recycle	Freshwater	14	140
MAN OT/M-2821	Once Through	Marine	30	30
MAN OT/FW-2834	Once Through	Freshwater	18	18
MAN R/FW-2834	Reuse/Recycle	Freshwater	2	20
MAN OT/FW-2869	Once Through	Freshwater	40	40
MAN OT/M-2869	Once Through	Marine	26	26
MAN R/FW-2869	Reuse/Recycle	Freshwater	4	40
MAN OT/FW-2873	Once Through	Freshwater	33	33
MAN R/FW-2873	Reuse/Recycle	Freshwater	30	300
MAN R/FW-2911	Reuse/Recycle	Freshwater	8	80
MAN OT/FW-2911	Once Through	Freshwater	105	105
MAN OT/FW-3312	Once Through	Freshwater	124	124
MAN R/FW-3312	Reuse/Recycle	Freshwater	85	850
MAN OT/FW-3316	Once Through	Freshwater	23	23
MAN R/FW-3316	Reuse/Recycle	Freshwater	12	120
MAN OT/FW-3317	Once Through	Freshwater	39	39
MAN R/FW-3317	Reuse/Recycle	Freshwater	4	40
MAN OT/FW-3353	Once Through	Freshwater	35	35
MAN R/FW-3353	Reuse/Recycle	Freshwater	6	60

1.2.2 Projected Number of New Manufacturing Facilities

Paper and Allied Products (SIC 26)

This analysis assumes that two new in-scope paper mills (SIC code 2621) will begin operation during the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 88 percent of all existing in-scope paper mills operate a once-through system and withdraw from a freshwater body. EPA therefore assumed that both projected new in-scope paper mills will be freshwater facilities with a once-through system. Table 1-10 below presents the model facility type, the number of in-scope survey facilities upon which the model facility type was based, and the number of projected new facilities that belong to that model type.

Table 1-10: SIC 26 Model Facilities

Model Facility Type	SIC Code	Cooling System Type	Source Water Body	Number of In-Scope Survey Respondents	Number of New In-Scope Facilities
MAN OT/F-2621	2621	Once-Through	Freshwater	47	2

Source: EPA Analysis.

Chemicals Manufacturing (SIC 28)

EPA projected that 22 new in-scope chemical facilities will begin operation during the next 20 years. Based on the distribution of the in-scope survey respondents across water body and cooling system types, EPA assigned the 22 new facilities to 11 different model facility types, by SIC code:

- ***SIC code 2812:*** EPA projects that two new in-scope facilities will begin operation during the next 20 years. The distribution of existing in-scope facilities across water body and cooling system types showed that 36 percent of the existing facilities operate a once-through system and withdraw from a freshwater body and 36 percent operate a once-through system and withdraw from a marine body. EPA therefore projected one new once-through/freshwater facility and new once-through system/marine facility.
- ***SIC code 2819:*** Four new industrial inorganic chemicals, not elsewhere classified are projected to begin operation during the 20-year analysis period. The distribution of existing facilities across water body and cooling system types showed that 47 percent of the existing in-scope facilities operate a once-through system and withdraw from a freshwater body, 39 percent operate a once-through system and withdraw from a marine water body, and 14 percent operate a recirculating system and withdraw from a freshwater body. EPA therefore projected two new once-through/freshwater facilities and two new once-through/marine facilities.
- ***SIC code 2821:*** EPA projects that four new in-scope facilities will begin operation during the next 20 years. The distribution of existing facilities across water body and cooling system types showed that all existing in-scope plastics material and synthetic resins, and nonvulcanizable elastomer facilities operate a once-through system and withdraw from a freshwater body. EPA therefore assumed that all four projected new in-scope facilities will be freshwater facilities with a once-through system.
- ***SIC code 2834:*** EPA projects that two new in-scope facilities will begin operation during the next 20 years. The distribution of existing facilities across water body and cooling system types showed that all existing in-scope pharmaceutical preparation facilities operate a once-through system and withdraw from a

freshwater body. EPA therefore assumed that both projected new in-scope facilities will be freshwater facilities with a once-through system.

- ***SIC code 2869:*** Eight new facilities in the Industrial Organic Chemical, Not Elsewhere Classified sector are projected to begin operation during the 20-year analysis period. The distribution of existing facilities across water body and cooling system types showed that 89 percent of the existing facilities operate a once-through system and withdraw from a freshwater body and 11 percent operate a recirculating system and withdraw from a freshwater body. Therefore EPA projected that seven new once-through/freshwater facilities and one new recirculating/freshwater facility.
- ***SIC code 2873:*** EPA projected that two new in-scope nitrogenous fertilizer facilities will begin operation in the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 50 percent of the existing facilities operate a recirculating system and withdraw from a freshwater body and 50 percent operate once-through systems and withdraw from a freshwater body. EPA therefore projected one new recirculating/freshwater facility and one new once-through/freshwater facility.

Table 1-11 below presents the model facility type, the number of in-scope survey facilities upon which the model facility type was based, and the number of projected new facilities that belong to that model type.

Table 1-11: SIC 28 Model Facilities

Model Facility Type	SIC	Cooling System Type	Source Water Body	Number of Existing In-Scope Facilities	Number of Projected New Facilities
MAN OT/M-2812	2812	Once-Through	Marine	6	1
MAN RE/F-2812	2812	Once-Through	Freshwater	6	1
MAN OT/M-2819	2819	Once-Through	Marine	13	2
MAN OT/F-2819	2819	Once-Through	Freshwater	16	2
MAN OT/F-2821	2821	Once-Through	Freshwater	10	4
MAN OT/F-2834	2834	Once-Through	Freshwater	4	2
MAN OT/F-2869	2869	Once-Through	Freshwater	35	7
MAN RE/F-2869	2869	Recirculating	Freshwater	4	1
MAN OT/F-2873	2873	Once-Through	Freshwater	4	1
MAN RE/F-2873	2873	Recirculating	Freshwater	4	1
Total				**102**	**22**

Source: EPA Analysis.

Petroleum and Coal Products (SIC 29)

EPA projected that two new in-scope petroleum refineries (SIC code 2911) will begin operation during the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 52 percent of the existing petroleum refineries operate a recirculating system and withdraw from a freshwater body and 30 percent operate once-through systems and withdraw from a freshwater body. EPA therefore assumed that the two new projected facilities would have those characteristics. Table 1-12 below presents the model facility type, the number of in-scope survey facilities upon which the model facility type was based, and the number of projected new facilities that belong to that model type.

Table 1-12: SIC 29 Model Facilities

Model Facility Type	SIC Code	Cooling System Type	Source Water Body	Number of Existing In-Scope Facilities	Number of Projected New Facilities
MAN OT/F-2911	2911	Once Through	Freshwater	9	1
MAN RE/F-2911	2911	Recirculating	Freshwater	15	1
Total				**24**	**2**

Source: EPA Analysis.

Steel (SIC 331)

EPA projected that 10 new in-scope steel facilities will begin operation during the next 20 years. Based on the distribution of the in-scope survey respondents across water body and cooling system types, EPA assigned the 10 new facilities to six different model facility types, by SIC code:

- ***SIC code 3312:*** Six steel mills are projected to begin operation during the 20-year analysis period. The distribution of existing facilities across water body and cooling system types showed that 91 percent of the existing facilities operate a once-through system and withdraw from a freshwater body and nine percent operate a recirculating system and withdraw from a freshwater body. Therefore EPA projected that five new once-through/freshwater facilities and one recirculating/freshwater facility.
- ***SIC code 3316:*** EPA projected that two new in-scope cold-rolled steel sheet, strip, and bar facilities will begin operation in the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 67 percent of the existing facilities operate a once-through system and withdraw from a freshwater body and 33 percent operate a recirculating system and withdraw from a freshwater body. EPA therefore projected one once-through/freshwater and one recirculating/freshwater facility.
- ***SIC code 3317:*** EPA projected that two new in-scope steel pipe and tube facilities will begin operation in the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 50 percent of the existing facilities operate a recirculating system and withdraw from a freshwater body and 50 percent operate once-through systems and withdraw from a freshwater body. EPA therefore assumed that the two new projected facilities would have those characteristics.

Table 1-13 below presents the model facility type, the number of in-scope survey facilities upon which the model facility type was based, and the number of projected new facilities that belong to that model type.

Table 1-13: SIC 331 Model Facilities					
Model Facility Type	**SIC Code**	**Cooling System Type**	**Source Water Body**	**Number of Existing In-Scope Facilities**	**Number of Projected New Facilities**
MAN OT/F-3312	3312	Once-Through	Freshwater	32	5
MAN RE/F-3312	3312	Recirculating	Freshwater	3	1
MAN OT/F-3316	3316	Once-Through	Freshwater	6	1
MAN RE/F-3316	3316	Recirculating	Freshwater	3	1
MAN OT/F-3317	3317	Once-Through	Freshwater	3	1
MAN RE/F-3317	3317	Recirculating	Freshwater	3	1
Total				**50**	**10**

Source: EPA Analysis.

Aluminum (SIC 333/335)

EPA projected that two new in-scope aluminum facilities will begin operation in the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 50 percent of the existing aluminum facilities operate a recirculating system and withdraw from a freshwater body and 50 percent operate once-through systems and withdraw from a freshwater body. EPA therefore assumed that the two new projected facilities would have those characteristics. Table 1-14 below presents the model facility type, the number of in-scope survey facilities upon which the model facility type was based, and the number of projected new facilities that belong to that model type.

Table 1-14: SIC 3353 Model Facilities					
Model Facility Type	**SIC Code**	**Cooling System Type**	**Source Water Body**	**Number of Existing In-Scope Facilities**	**Number of Projected New Facilities**
MAN OT/F-3353	3353	Once-Through	Freshwater	3	1
MAN RE/F-3353	3353	Recirculating	Freshwater	3	1
Total				**6**	**2**

Source: EPA Analysis.

1.2.3 Summary of Forecasts for New Manufacturing Facilities

EPA estimates that a total of 380 new manufacturing facilities will begin operation between 2001 and 2020. Thirty-eight of these are expected to be in scope of the final § 316(b) New Facility Rule. Of the 38 facilities, 22 are chemical facilities, ten are steel facilities, two are petroleum refineries, two are paper mills, and two are aluminum facilities. Table 1-15 summarizes the results of the analysis.

Table 1-15: Number of Projected New Manufacturers (2001 to 2020)

Facility Type	Total Number of New Facilities	Facilities In Scope of the Final Rule				
		Recirculating		Once-Through		Total
		Freshwater	Marine	Freshwater	Marine	
Paper and Allied Products (SIC 26)	2	0	0	2	0	2
Chemicals and Allied Products (SIC 28)	282	2	0	17	3	22
Petroleum Refining And Related Industries (SIC 29)	2	1	0	1	0	2
Blast Furnaces and Basic Steel Products (SIC 331)	78	3	0	7	0	10
Aluminum Sheet, Plate, and Foil (SIC 3353)	16	1	0	1	0	2
Total	**380**	**7**	**0**	**28**	**3**	**38**

Source: EPA Analysis, 2001.

1.3 Summary of Baseline Projections

EPA estimates that over the next 20 years a total of 656 new greenfield and stand alone facilities will be built in the industry sectors analyzed for this final regulation. Two hundred and seventy-six of these new facilities will be steam electric generating facilities and 380 will be manufacturing facilities. As Table 1-16 shows, only 121 of the 656 new facilities are projected to be in scope of the final § 316(b) New Facility Rule, including 83 electric generators, 22 chemical facilities, 12 primary metals facilities, two new pulp and paper, and two petroleum facilities. For more detailed information, see *Economic Analysis of the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*.

Table 1-16: Projected Number of New In Scope Facilities (2001 to 2020)

SIC	SIC Description	Projected Number of New Facilities	
		Total	**In-Scope**
	Electric Generators		
SIC 49	Electric Generators	276	83
	Manufacturing Facilities		
SIC 26	Paper and Allied Products	2	2
SIC 28	Chemicals and Allied Products	282	22
SIC 29	Petroleum Refining And Related Industries	2	2
SIC 33	Primary Metals Industries		
SIC 331	Blast Furnaces and Basic Steel Products	78	10
SIC 333 SIC 335	Primary Aluminum, Aluminum Rolling, and Drawing and Other Nonferrous Metals	16	2
Total Manufacturing		*380*	*38*
Total		**656**	**121**

Source: EPA Analysis, 2001.

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Chapter 2: Costing Methodology

INTRODUCTION

This chapter presents the methodology used to estimate the costs to facilities of complying with the final §316(b) New Facility Rule. This chapter presents detailed information on the development of unit cost estimates for a set of technologies that may be used to meet requirements. This chapter describes how the technology unit costs were used to develop facility-level cost estimates for each projected in-scope facility.

2.1 BACKGROUND

Facilities using cooling water may be subject to the final §316(b) New Facility Rule. A facility using cooling water can have either a once-through or a recirculating cooling system.

In a once-through system, the cooling water that is drawn in from a waterbody travels through the cooling system once to provide cooling and is then discharged, typically back to the waterbody from which it was withdrawn. The cooling water is withdrawn from a water source, typically a surface waterbody, through a cooling water intake structure (CWIS). Many facilities using cooling water (e.g., steam electric power generation facilities, chemical and allied products manufacturers, pulp and paper plants) need large volumes of cooling water, so the water is generally drawn in through one or more large CWIS, potentially at high velocities. Because of this, debris, tree limbs, and many fish and other aquatic organisms can be drawn toward or into the CWIS. Since a facility's cooling water system can be damaged or clogged by large debris, most facilities have protective devices such as trash racks, fixed screens, or traveling screens, on their CWIS. Some of these devices provide limited protection to fish and other aquatic organisms, but other measures such as the use of passive (e.g., wedgewire) screens, velocity caps, traveling screens with fish baskets, or the use of a recirculating cooling system may provide better protection

Chapter Contents

and have greater capability to minimize adverse environmental impacts.[1]

In a recirculating system, the cooling water is used to cool equipment and steam, absorbing heat in the process, and is then cooled and recirculated to the beginning of the system to be used again for cooling. The heated cooling water is generally cooled in either a cooling tower or in a cooling pond. In the process of being cooled, some of the water evaporates or escapes as steam. Flow lost through evaporation typically ranges from 0.5 percent to 1 percent of the total flow (Antaya, 1999). Also, because of the heating and cooling of recirculating water, mineral deposition occurs which necessitates some bleeding of water from the system. The water that is purged from the system to maintain chemical balance is called blowdown. The amount of blowdown is generally around 1 percent of the flow. Cooling towers may also have a small amount of drift, or windage loss, which occurs when some recirculating water is blown out of the tower by the wind or the velocity of the air flowing through the tower. The water lost to evaporation, blowdown, and drift needs to be replaced by what is typically called makeup water. Overall, makeup water is generally 3 percent or less of the recirculating water flow.[2] Therefore, recirculating systems still need to draw in water and may have cooling water intakes. However, the volume of water drawn in is significantly less than in once-through systems, so the likelihood of adverse environmental impacts as a result of the CWIS is much lower.[3] Also, some recirculating systems obtain their makeup water from ground water sources or public water supplies, and a small but growing number use treated wastewater from municipal wastewater treatment plants for makeup water.

The final §316(b) New Facility Rule establishes a two-track approach for regulating cooling water intake structures at new facilities.[4] Facilities have the opportunity to choose which track (Track I or Track II) they will follow. Facilities choosing to comply with Track I requirements would be required to meet flow reduction, velocity, and design and construction technology requirements. These requirements include reducing cooling water intake flow to a level commensurate with that achievable with a closed-cycle, recirculating cooling system; achieving a through-screen intake velocity of 0.5 feet per second; meeting location- and capacity-based limits on proportional intake flow; and implementing design and construction technologies for minimizing impingement and entrainment and maximizing impingement survival. Facilities choosing to comply with Track II requirements would be required to perform a comprehensive demonstration study to demonstrate that proposed technologies reduce the level of impingement and entrainment to the same level that would be achieved by implementing the requirements of Track I.

2.2 Overview of Costing Methodology

Based on information provided by vendors and industry representatives, EPA first developed unit costs and cost curves, including both capital costs and operations and maintenance (O&M) costs, for a number of primary technologies such as traveling screens and cooling towers that facilities may use to meet requirements under the final §316(b) New Facility Rule. 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 flow. For most technologies, EPA used the cooling water intake flow as the basis for unit costs; for cooling towers, EPA used the cooling water recirculating flow through the tower as the basis for unit costs. EPA estimated all capital and operating and maintenance (O&M) costs in these units. These unit costs and cost curves are the building blocks for developing costs at the facility and national levels.

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[1] CWIS devices used in an effort to protect fish also include other fish diversion and avoidance systems (e.g., barrier nets, strobe lights, electric curtains), which may be effective in certain conditions and for certain species. See Chapter 5 of this document.

[2] In some saltwater cooling towers, however, makeup water can be as much as 15 percent.

[3] Manufacturer Brackett Green notes that closed loop systems (i.e., recirculating systems) normally require one-sixth the number of traveling screens as a power plant of equal size that has a once-through cooling system.

[4] See *Economic Analysis of the Final Regulations Addressing Cooling Water Intake Structures for New Facilities* (hereinafter referred to as the *Economic Analysis*), Chapter 1: Introduction and Overview for a summary of this rule's requirements.

While EPA developed unit costs for a number of available technologies, EPA used only a limited set of these technologies to develop facility-level capital and O&M cost estimates. For purposes of cost estimation, EPA assumed that facilities would meet the flow reduction requirement by installing cooling towers. EPA assumed that facilities would meet the velocity and design and construction technology requirements by installing traveling screens with fish handling features, with an intake velocity of 0.5 ft/s.

EPA used unit cost curves to develop facility-level capital and O&M cost estimates for 41 model facilities. These model facilities were then scaled to represent total industry compliance costs for the 121 facilities projected to begin operation between 2001 and 2020. Individual facilities will incur only a subset of the unit costs, depending on the extent to which they would have already complied with the requirements as originally designed (in the baseline) and on the compliance response they select. To account for this, EPA established a number of baseline scenarios (reflecting different baseline cooling water system types and waterbody types) so that the unit costs could be applied to the various model facilities to obtain facility-level costs.

The cost estimates developed for various technologies are intended to represent a National "typical average" cost estimate. The cost estimates should not be used as a project pricing tool as they cannot account for all the site-specific conditions for a particular project.

The facility-level capital and O&M costs presented in this chapter represent the net increase in costs for each set of compliance technology performance requirements as compared to the technology the facility would have installed absent this regulation. To calculate net costs for each model facility, EPA first calculated the cost for the entire cooling system for the baseline technology combination, and then subtracted those costs from the calculated cost of the entire cooling system for each compliance technology combination.

Development of the facility-level capital and O&M costs for the final §316(b) New Facility Rule is discussed in detail in Section 2.3 below. In addition to the facility-level cost estimates developed for the preferred two-track option adopted for the final rule, EPA also developed facility-level cost estimates for several additional options that EPA considered but did not adopt for the final rule. Development of the facility-level capital and O&M cost estimates for these options are also discussed in Section 2.3.

In addition, EPA applied an energy penalty cost to those electric generators switching to recirculating systems to account for performance penalties that may result in reductions of energy or capacity produced because of adoption of recirculating cooling tower systems. These performance penalties are associated with reduced turbine efficiencies due to higher back pressures associated with cooling towers, as well as with power requirements to operate cooling tower pumps and fans. EPA's costing methodology for performance penalties is based on the concept of lost operating revenue due to a mean annual performance penalty. EPA estimated the mean annual performance penalty for recirculating cooling tower systems as compared to once-through cooling systems. EPA then applied this mean annual penalty to the annual revenue estimates for each facility projected to install a recirculating cooling tower technology as a result of the rule. It should be noted that EPA took a conservative approach and double-counted some parts of the energy penalty, since fan and pump power costs were included in both the energy penalty and the cooling tower O&M costs. Energy penalties are discussed in detail in Chapter 3 of this document and their costs are presented in the *Economic Analysis*.

Compliance with the final section §316(b) New Facility Rule also requires facilities to carry out certain administrative functions. These are either one-time requirements (compilation of information for the initial NPDES permit) or recurring requirements (compilation of information for NPDES permit renewal, and monitoring and record keeping), and depend on the facility's water body type and the permitting track the facility follows. Development of these administrative costs is discussed in the *Information Collection Request for Cooling Water Intake Structures, New Facility Final Rule* (referred to as the ICR) and in the *Economic Analysis*.

All costs presented in this chapter are expressed in 1999 dollars. For the *Economic Analysis* for the final §316(b) New Facility Rule, EPA escalated these costs to 2000 dollars.

2.3 FACILITY LEVEL COSTS

2.3.1 General Approach

The facility-level cost estimates presented in this section are based on a limited set of the unit costs presented in detail in the following sections of this Chapter. For purposes of cost estimation, EPA assumed that facilities would meet the flow reduction requirement by switching to recirculating systems. EPA assumed that all planned facilities switching to recirculating systems would use cooling towers (the most common type of recirculating system). This is consistent with the requirement of the final section 316(b) New Facility Rule to reduce intake flow to a level commensurate with that which could be obtained by use of a closed-cycle recirculating system. EPA assumed that facilities would meet the velocity and design and construction technology requirements by installing traveling screens with fish handling features, with an intake velocity of 0.5 ft/s. This is a conservative assumption because such technologies are among the more expensive technologies available for reducing velocity and I&E.

EPA used 41 model facilities to develop facility-level capital and O&M cost estimates for the 121 facilities projected to begin operation between 2001 and 2020. The development of model facilities is described in Chapter 1. Individual facilities subject to the regulation will incur differing costs depending on site specific conditions, technologies projected to be installed in the baseline (i.e., regardless of this regulation), and on the compliance response they select. To account for this, EPA established a number of baseline scenarios (reflecting different baseline cooling water system types and waterbody types) so that the unit costs could be applied to the various model facilities to obtain facility-level costs.

In this analysis, the baseline technology represents an estimation of the technologies that would be constructed at new facilities prior to implementation of the final New Facility Rule regulatory requirements. Specifically, the costs presented in the cost tables represent the net increase in costs for each set of compliance technology/monitoring requirements as compared to the baseline technology. EPA accomplished this by calculating the cost for the entire cooling system for the baseline technology combination and then subtracting those costs from the calculated cost of the entire cooling system for each compliance technology combination.

The final New Facility Rule allows for facilities to comply with one of two alternative sets of permitting requirements (Track 1 and Track 2). Facilities choosing to comply with Track 1 permitting requirements would be required to meet flow reduction, velocity, and design and construction technology requirements. Facilities choosing to comply with Track 2 permitting requirements would be required to perform a comprehensive demonstration study to confirm that proposed technologies reduce the level of impingement and entrainment mortality to the same level that would be achieved by implementing the flow reduction, velocity, and design and construction technology requirements of Track I.

EPA assumed that facilities that were projected to have recirculating baseline cooling water systems would follow Track I. EPA developed cost estimates for these facilities based on the assumption that they would already be installing cooling towers, and thus would only have to install velocity reducing design and construction technologies of traveling screens with fish handling features.

EPA assumed that facilities that were projected to have once-through baseline cooling water systems would follow Track II. EPA developed cost estimates for these facilities based on the assumption that they would perform comprehensive demonstration studies, but would still have to install cooling towers and design and construction technologies of traveling screens with fish return systems to meet the regulatory requirements. This is a conservative assumption that may overestimate compliance costs if a significant number of Track II facilities are able to demonstrate that lower cost alternative technologies will reduce the level of impingement and entrainment to the same level that would be achieved by implementing the flow reduction, velocity, and design and construction technology requirements of Track I.

Some facilities were projected to have mixed once-through and recirculating baseline cooling water systems. EPA treated these facilities the same as facilities with baseline once-through cooling water systems. This represents a conservative approach since it will tend to overestimate the size of the baseline cooling water system that would have to be replaced, and thus overestimate the corresponding compliance cost. In addition, one coal facility was projected to have a recirculating system with a cooling pond. This facility was also costed to switch to a cooling tower.[5]

2.3.2 Capital Costs

Capital cost estimates used in calculating the net compliance costs include individual estimates for the following initial one-time cost components where applicable:

- Once-through system including intake structure, pumps, and piping costs.
- Recirculating wet towers.
- Intake for wet tower make-up water including intake pumps and piping.
- Intake screens.

EPA summed these individual cost elements together to derive the total capital costs for each baseline and compliance scenario. EPA then subtracted the total baseline cost from the total compliance cost to determine the incremental cost of compliance with the final §316(b) New Facility Rule.

EPA concluded that the cooling water flow through the condenser at a given facility to be the same when switching from once-through to wet towers because the design specifications of surface condensers for both types of systems are similar enough that the condenser costs would also be similar. Thus, when comparing wet cooling systems, differences in costs from baseline for the surface condensers were assumed to be zero.

2.3.3 Operation & Maintenance Costs

O&M cost estimates used in calculating the net compliance costs include individual estimates for the following cost components where applicable:

- Operating costs for pumping intake water.
- O&M costs for operating recirculating wet towers.
- O&M cost for operating intake screen technology.
- Annual post-compliance operational monitoring.

EPA summed these individual cost elements together to derive the total O&M costs for each baseline and compliance scenario. EPA then subtracted the total baseline cost from the total compliance cost to determine the incremental cost of compliance with the final §316(b) New Facility Rule.

It should be noted that EPA overcosted the costs of post-compliance operational monitoring, since these costs were also included in the annual administrative costs as described in the ICR and the *Economic Analysis*.

[5]In some states, a cooling pond is considered a water of the U.S. In these states, a plant with such a cooling system would have to comply with the recirculating requirements of the final section 316(b) New Facility Rule. In those states where a cooling pond is not considered a water of the U.S., a plant would not have to comply with the recirculating requirements of this final New Facility Rule. This costing analysis made the conservative assumption that facilities with a cooling pond would have to comply with the recirculating requirements. These facilities were therefore costed as if they had a once-through system in the baseline.

2.3.4 Development of Model Facilities

EPA developed cost estimates for 41 model facilities within three industry categories: coal-fired power plants, combined cycle power plants and manufacturers. These model facilities were developed to reflect a range of potential design intake flows and (for power plants) megawatt (MW) capacities. The methodology for developing model facilities for each of these three industry groups is described in Chapter 1.

2.3.5 Wet Tower Intake Flow Factors

EPA based all model facility flow values, including both intake and cooling water, upon projected intake flows for the baseline technology. When switching from baseline once-through to recirculating wet tower cooling systems, EPA assumed that the recirculating cooling flows through the wet towers would be equivalent to the baseline once-through flows. When either the intake flow or the cooling flow had been projected for wet towers, EPA then calculated the corresponding cooling flow or intake flow using a wet tower make-up water intake flow factor.

EPA used different make-up flow factors for power plants versus manufacturers, as well as for facilities using marine versus freshwater source waters. Since seawater and brackish water in marine cooling water sources have higher dissolved solids (TDS) content than freshwater, the blowdown rate should be higher to avoid the build-up of high TDS in the recirculating water as the cooling water evaporates in the tower. The build-up of high TDS can affect the performance of the cooling system, increase corrosion, and create potential water quality problems for the blowdown discharge. Therefore, the portion of the cooling water that must be removed (blowdown) and replaced is greater for higher TDS source waters. Note that seawater represents the worst-case scenario, but in most cases the intakes within the group of facilities attributed to this water body type will be withdrawing brackish water (i.e., the TDS content will be somewhere between that of seawater and freshwater).

The make-up water must replace all cooling water losses, which include blowdown, evaporation, drift, and other uses. One measure of the blowdown requirement is the "concentration factor," which is the ratio of the concentration of a conservative pollutant, such as TDS, in the blowdown divided by the concentration in the make-up water. For freshwater, the concentration factor can range from 2.0 to 10 (Kaplan 2000) depending on site-specific conditions. For marine sources including brackish and saltwater, the concentration factor can range from 1.5 to 2.0 (Burns and Micheletti 2000).

Cooling Tower Fundamentals (Hensley, 1985) provides a set of equations and default values for estimating the rate of evaporation, drift, and blowdown using the temperature rise (20 °F) and concentration factor. The make-up volume is the sum of these three components. Input values in this calculation include the concentration factor and the temperature rise. The temperature rise used (20 °F) is consistent with the design values used throughout the wet tower cost estimation efforts. Since the estimate was for national average values, the default values for estimating evaporation and drift presented in the reference were used. Table 2-1 provides the calculated make-up and blowdown rates as a percentage of the recirculating flow for different concentration factors ranging from 1.1 to 10.0, for a wet tower with a recirculating rate of 100,000 gpm. Note that the selection of the recirculating flow rate is not important, since the output values are percentages which would be the same regardless of the flow rate chosen.

Table 2-1: Make-Up and Blowdown Volumes for Different Wet Tower Concentration Factors

Concentration Factor	Evaporation[a] (gpm)	Drift[b] (gpm)	Blowdown (gpm)	Blowdown (%)	Make-Up (gpm)	Make-Up (%)
1.1	1600	20	15,980	16.0%	17,600	17.6%
1.2	1600	20	7980	8.0%	9600	9.6%
1.25	1600	20	6380	6.4%	8000	8.0%
1.3	1600	20	5313	5.3%	6933	6.9%
1.5	1600	20	3180	3.2%	4800	4.8%
2	1600	20	1580	1.6%	3200	3.2%
3	1600	20	780	0.8%	2400	2.4%
5	1600	20	380	0.4%	2000	2.0%
10	1600	20	158	0.2%	1778	1.8%

Based on methodology presented in *Cooling Tower Fundamentals* (Hensley 1985).
[a]Evaporation = 0.0008 x Range (°F) x Recirculating Flow (gpm)
[b]Drift = 0.0002 x Recirculating flow (gpm)
Range = 20 °F
Recirculating Flow = 100,000 gpm

To be conservative, EPA selected the lower concentration factor for each of the two ranges of literature values (2.0 for freshwater and 1.5 for marine water). Note that a lower concentration factor results in a higher make-up rate. EPA used the equations presented in Hensley 1985 to derive the make-up water rates that correspond to the selected concentration factors of 1.5 and 2.0. This method generated make-up rates of 3.2 percent and 4.8 percent for freshwater and marine water, respectively. These factors were then compared to intake flow and generating capacity values of existing facilities. The resulting estimated cooling water flow rates were somewhat high for the plant generating capacity. To correct for this observation and to account for site variations and other cooling water uses, EPA increased the calculated make-up factors by approximately 50 percent and rounded off, resulting in factors of 5 percent and 8 percent for freshwater and marine water, respectively. These values produced estimated cooling flow values that were consistent with data from power plants with similar generating capacities.

Manufacturers use cooling water for numerous processes, some of which may not be amenable to use of recirculating wet towers or to reuse/recycle. While wet towers are being used as a model for estimating cooling system water reduction technology costs for manufacturers, the aggregate make-up water rates may be greater due to these limitations. In order to account for these potential limitations, EPA set the make-up rates for manufacturers equal to twice the rate for power plants using similar water source types. Thus, the makeup water rates for manufacturers were estimated at 10 percent and 16 percent for freshwater and marine water, respectively.

2.3.6 Baseline Cost Components

EPA selected the baseline technologies based upon the projected type of baseline cooling system and the type of facility. The type of water body affects the costs, but not the selection of technologies. The basic components and assumptions for each baseline technology are described below:

2.3.7 Baseline Once-through Cooling

- The intake is located near shoreline and water is pumped using constant speed pumps through steel pipes to and from a surface condenser and is then discharged back to the water body. The once-through cost estimate includes the intake structure, pumps and piping costs. The development of these costs is described in greater detail below.
- For all types of power plants, baseline intakes are equipped with traveling screens (without fish handling systems) with an intake velocity of 1.0 fps. For manufacturing facilities, intakes are equipped only with trash racks which were assumed to be included in the cost of the intake system. Cost curve charts at the end of this chapter were used to generate the intake screen cost estimates.

2.3.8 Baseline Recirculating Wet Towers

- The cost estimates are for recirculating wet towers with redwood construction and splash fill. This is not the most common construction material for cooling towers, it represents a median cost for cooling tower construction. The wet tower approach was 10 ºF with a temperature rise of 20 ºF. Cost curve Charts presented at the end of the chapter were used to generate the wet tower capital cost estimates.
- O&M costs are based on Scenario 1 described in Section 2.2.2.1, in which make-up water is withdrawn from the surface waterbody and blowdown is treated and discharged. Cost curve charts at the end of this chapter was used to generate the wet tower O&M cost estimates.
- EPA assumed that the make-up water volume would be a proportion of the recirculating flow. A separate cost estimate for an appropriately sized cooling water intake with constant speed pumps was added to serve this purpose. EPA developed intake costs in the same manner as for once-though intakes and included costs for an appropriately sized surface condenser.
- For all types of power plants, baseline intakes are equipped with traveling screens (without fish handling systems) with an intake velocity of 1.0 fps. For manufacturing facilities, intakes are equipped only with trash racks which were assumed to be included in the cost of the intake system. Cost curve charts at the end of this chapter were used to generate the intake screen cost estimates.

2.4 Compliance Cost Components

2.4.1 Recirculating Wet Towers

- EPA developed costs for recirculating wet towers as the compliance technology using the same assumptions as for baseline recirculating wet tower costs as described above, with the exception of the intake screen technology and the use of variable speed pumps at the intake. All compliance costs included the cost of traveling screens with fish baskets and fish returns with an intake velocity of 0.5 fps at the intake structure. EPA derived costs for traveling screens with fish baskets and fish returns from cost curve data found at the end of this chapter.
- As described above, the make-up water (intake flow) factors used for power plants were 5 percent for freshwater and 8 percent for marine water.

2.4.2 Reuse/recycle

- Water reuse/recycle technologies at manufacturing facilities are expected to produce reductions in intake water use of a similar degree as recirculating wet towers. However, due to the integrated nature and variable uses of cooling water at manufacturing facilities, EPA did not consider the development of a model technology other than recirculating wet towers to be practical. Since it is possible to use recirculating wet towers as a replacement for once-through cooling at manufacturing facilities, the costs for reuse/recycle technologies were estimated to be similar to the cost of using recirculating wet towers. Therefore, at manufacturing facilities, EPA developed the costs for water reuse/recycle and the water intakes using recirculating wet towers as the model. EPA used the same methodology as described above for recirculating wet towers, with the exception that the make-up factors used for reuse/recycle were set at twice the rate used for power plants (10 percent for freshwater and 16 percent for marine water). The higher rate is intended to account for possible limitations in the degree of water use reduction that may be attained by reuse/recycle.

2.5 Cost Estimation Assumptions and Methodology

The assumptions and cost data sources for each of the technologies is described below.

2.5.1 Once-through Capital Costs

The capital costs for the once-through system includes costs for the following:

- Intake structure
- Pumps, pump well, and pump housing
- Piping to and from the condenser
- Service road to the intake structure adjacent to the cooling water pipes

The maximum cooling flow value used to develop the once-through cost equations was 350,000 gpm. If the model facility flow value exceeded this maximum by 10 percent (i.e., > 385,000 gpm), EPA costed multiple parallel once-through units. Assumptions for each of the cost components are described below:

Intake Structure

- Size equivalent to a box with one side equal to the area needed for a traveling screen with an intake velocity of 1.0 fps. 10 ft were added to the height and the minimum side dimension was 8 ft. An adjacent pump well was also added.
- Concrete thickness of 1.5 ft.
- Excavated volume equal to 2.5 times box and pump well volume.
- Dredged volume equal to 2.5 times box and pump well volume.
- Installation of temporary bulkhead with 20 ft added to width.
- Installation of temporary sheet piling to shore up excavation equal to 1.5 times side area for intake and pump well.
- Area cleared was assumed to be 6 times intake and pump well area.

Service Road

- The service road for the intake was made of 6-inch thick reinforced concrete, and a 12-ft width was assumed. An estimated length of road (which is also the cooling water piping distance) was assigned to different intake volumes. EPA based the lengths on the cooling water flow, since the cooling water flow should be proportional to the plant size and does not change between types of cooling systems. The cooling flow corresponding to a freshwater system was used in the case of wet towers, since it represented the greatest flow. For intake volumes corresponding to a cooling flow of 500 to 10,000 gpm, a 1,000 ft length was assigned, for >10,000 gpm to 100,000 gpm a 1,500 ft length was used, and for >100,000 gpm a length of 2,000 ft was used.

- Area cleared was assumed to be length times 24 ft.

Pumps and Pump Well

- Assumed 3 pumps with each pump sized at 50 percent of design flow (i.e., one pump served as a back-up). Constant speed pumps were used for baseline costs and variable speed pumps were used for compliance costs.
- Pump installation was set equal to 40 percent to 60 percent of pump and motor costs (60 percent at 500 gpm scaled to 40 percent at 350,000 gpm).
- Pump and motor costs were from vendor quotes based on a 50 ft pumping head. Purchase costs were increased by 15 percent to account for taxes, insurance, and freight.
- Pump housing unit cost was estimated at $\$130/ft^2$.
- Pump and pump well area was established using the per pump footprints in Table 2-2 below.

Table 2-2: Assumed Pump Pad and Well Area

Pump Design Flow (gpm)	Footprint (ft)
250	5x5
500	5x5
2,500	7x6
5,000	7x7
25,000	10x10
50,000	11x11
175,000	12x12

Piping to and from the Condenser

- Pipe length in one direction is equal to service road length, which is described above. Total length is twice this distance.
- Pipe diameters were selected to correspond to pipe velocities ranging from 6 fps for smaller diameter (i.e., 6 inch) to 12 fps for larger diameter pipe.
- Pipe unit cost ranged from $5.50 /in. dia - ft length for smaller pipe to $7.50 /in. dia - ft length for larger pipe.

Intake Screens

As described in Section 2.2.2.3 above, EPA developed cost curves for intake screens of varying widths. The cost curves for each screen width covered a range of flow volumes that tended to overlap those with larger and smaller widths. For purposes of estimating intake screen costs, EPA sized the intake screens according to intake flow volumes. Table 2-3 below summarizes the screen width sizes that were selected for each intake flow volume for the given technology and design specification. Note that the maximum flow volume listed is approximately 10 percent greater than the maximum cost curve input value. For intake flow volumes that exceeded this maximum value, multiple parallel screens of the maximum width listed are costed.

Table 2-3: Intake Flow Volume Criteria for Screen Width Selection

Screen Width	Intake Flow for Traveling Screens @ 1.0 fps (gpm)	Intake Flow for Traveling Screens @ 0.5 fps (gpm)
2 - Foot	0 - 10,000	0 - 5,000
5 - Foot	>10,000 - 24,000	>5,000 - 12,000
10 - Foot	>24,000 - 60,000	>12,000 - 30,000
14 - Foot	>60,000 - 220,000	>30,000 - 110,000
Maximum Flow*	220,000	110,000

* Intake volumes above this value were costed for multiple parallel screens using the maximum screen width shown.

Additional Unit Costs

Table 2-4 below summarizes additional unit costs that were used in deriving the capital costs for the items described above.

Table 2-4: Additional Unit Costs

Cost Item	Unit	Cost/Unit	Comment
Foundation Concrete	Cubic Yard	$259	RS Means Cost Works 2001
Structural Concrete	Cubic Yard	$1,125	Based on 16 in column costs- RS Means Cost Works 2001
Excavation	Cubic Yard	$26	RS Means Cost Works 2001
Bulkhead	Linear foot	$254	RS Means Cost Works 2001
Sheet Piling	Square Foot	$15	RS Means Cost Works 2001
Area Clearing	Acre	$2,975	Clear, grub, cut light trees to 6 in.- RS Means Cost Works 2001
Road Paving	Square Yard	$23.30	Concrete pavement 6 in. thick with reinforcement -RS Means Cost Works 2001

Miscellaneous Costs

EPA factored the following miscellaneous costs into the estimated capital costs as a percentage of the total capital cost. Values were selected from the ranges given in Section 2.2.1.2 above:

- Mobilization and demobilization was estimated to be 3 percent.
- Process engineering was estimated to be 10 percent.
- Contractor overhead and profit are included in the unit cost estimates.
- Electrical was estimated to be 10 percent.
- Site work was estimated to be 10 percent.
- Controls were estimated to be 3 percent.
- The contingency cost was estimated at 10 percent.

2.5.2 Once-through O&M

- The O&M costs are estimated using the cooling water intake pumping energy requirements.
- Pumping head was assumed to be 50 ft for all systems.
- Pump and motor efficiency was 70 percent.
- Annual hours of operation was assumed to be 7860.
- Energy cost was estimated at $0.08/KWH. Note that this value is set near the average consumer costs and is higher than the energy cost to the power plant. This overestimation of the unit energy cost is intended to account for other O&M costs, such as for intake cleaning and maintenance and pumping equipment maintenance, that are not included as separate items.

2.5.3 Recirculating Wet Tower Capital Costs

- For wet towers, it is assumed that recirculating (i.e., cooling) flow would be same as baseline once-through flow.
- Capital costs for the recirculating wet tower include costs for all basic tower components, such as structure, foundation, wiring, piping and recirculating pump costs. Wet tower costs are based on cost data for redwood towers with splash fill and an approach of 10 °F taken from chart at the end of this chapter.
- The maximum cooling flow value used to develop the wet tower cost equations (both Capital and O&M) was 204,000 gpm. If the model facility flow value exceeded this maximum by 10 percent (i.e., > 225,000 gpm), EPA costed multiple parallel wet tower units.
- Costs include installing an inlet structure and pumps using the same assumptions as the once-through intake, except they are sized based on the make-up water requirements described above. Similarly, EPA developed the pipe and service road lengths using same method as for once-through intakes except that road and piping length were based on a recirculating flow corresponding to a freshwater system.

2.5.4 Wet Tower O&M Cost

- Wet tower O&M costs have two components; one for the intake and one for the wet tower. EPA took wet tower O&M costs from cost charts at the end of this chapter. Intake O&M costs were based on intake pumping energy requirements in a similar manner as for once-through pumping described above.
- EPA based the intake O&M costs on cooling water intake pumping energy requirements using the same cost assumptions as for the once-through O&M costs. As with the once-through costs, the energy costs were inflated to account for O&M costs in addition to the pumping energy requirements.

2.6 Alternative Regulatory Options

In addition to the preferred two-track option adopted for the final §316(b) New Facility Rule, EPA also developed facility-level cost estimates for several additional options that EPA considered but did not adopt for the final rule. These additional regulatory options include the following:

- Option 1: Technology-Based Performance Requirements for Different Types of Waterbodies. Under this option, only facilities located on marine waterbodies would be required to reduce intake flow commensurate with the level that can be achieved using a closed-cycle recirculating wet cooling system. For all other waterbody types, the only capacity requirements would be proportional flow reduction requirements. In all waterbodies, velocity limits and a requirement to study, select and install design and construction technologies would apply.

- Option 2A: Flow Reduction Commensurate with the Level Achieved by Closed-Cycle Recirculating Wet Cooling Systems. Under this option, all facilities would be required to reduce intake flow commensurate with the level that can be achieved using a closed-cycle recirculating cooling water system, regardless of the type of waterbody from which they withdraw cooling water. In addition, facilities would need to meet velocity limits, comply with proportional flow requirements, and study, select and install design and construction technologies.

- Option 2B: Flow Reduction Commensurate with the Level Achieved by Use of a Dry Cooling System. Under this option, all steam electric power plants would be required to reduce intake flow commensurate with zero or very low-level intake (i.e., dry cooling). Manufacturing facilities would be required to comply with the national requirement of capacity reduction based on closed-cycle recirculating wet cooling. This option does not distinguish between facilities on the basis of the waterbody from which they withdraw cooling water.

- Option 3: Industry Two-Track Option. Under this option, an applicant choosing Track I would install "highly protective" technologies in return for expedited permitting without the need for pre-operational or operational studies in the source waterbody. Such fast-track technologies might include technologies that reduce intake flow to a level commensurate with closed-cycle recirculating wet cooling and that achieve an average approach velocity of no more than 0.5 ft/s, or any technologies that achieve a level of protection from impingement and entrainment within the expected range for a closed-cycle recirculating wet cooling system. Examples of candidate technologies include: (a) wedgewire screens, where there is constant flow, as in rivers; (b) traveling fine mesh screens with a fish return system designed to minimize impingement and entrainment; and (c) aquatic filter barrier systems, at sites where they would not be rendered ineffective by high flows or fouling. Track II would provide an applicant who does not want to commit to any of the above technology options with an opportunity to demonstrate that site-specific characteristics would justify another cooling water intake structure technology, such as once-through cooling.

EPA used the same model facilities and baseline technologies that were used for the preferred two-track option to develop cost estimates for the alternative regulatory options. In general, EPA used the same assumptions as described above when developing cost estimates for the alternative regulatory options. Exceptions are noted below for each of the alternative regulatory options.

2.6.1 Option 1: Technology-Based Performance Requirements for Different Types of Waterbodies

Freshwater Facilities

- Compliance cooling system remains the same as baseline, but with variable speed intake pumps.
- Compliance intake screen technology consists of traveling screens with fish handling features with an intake velocity of 0.5 fps.

Marine Facilities

- Compliance cooling system consists of recirculating wet towers with variable speed intake pumps.
- Compliance intake screen technology consists of traveling screens with fish handling features with an intake velocity of 0.5 fps.

Administrative costs for this option will differ from the preferred two-track option, as noted in the *Economic Analysis*.

2.6.2 Option 2A: Flow Reduction Commensurate with the Level Achieved by Closed-Cycle Recirculating Wet Cooling Systems

Compliance technologies for this option are the same as for the preferred two-track option adopted in the final rule. Therefore, EPA did not develop separate capital and O&M costs for this option. Administrative costs for this option will differ from the administrative costs for the preferred two-track option, as noted in the *Economic Analysis*.

2.6.3 Option 2B: Flow Reduction Commensurate with the Level Achieved by Use of a Dry Cooling System

Power Plants

- Compliance cooling system consists of dry cooling towers (air cooled condensers).
- No surface water intakes are needed.

Manufacturing Facilities

- Compliance cooling system consists of recirculating wet towers with variable speed intake pumps.
- Compliance intake screen technology consists of traveling screens with fish handling features with an intake velocity of 0.5 fps.

Capital Costs

The use of air cooled condensers (dry cooling system) instead of wet cooling involves the substitution of the surface condenser as well as the cold water system. Thus, the cost of surface condensers needs to be included in the baseline capital costs for once-through and wet tower cooling systems for this option. For baseline once-through systems, EPA incorporated the condenser capital costs into the cooling system cost component that includes intake structure, pumps, pipes, etc. For baseline wet towers, EPA incorporated the condenser costs into the intake system cost component that includes intake structure, pumps, pipes, etc. In the case of wet tower intake costs, the cost equation uses the intake flow as the input variable. Since the condenser cost is based on the cooling water flow, EPA developed a separate intake/condenser cost curve for each scenario that uses a different make-up water factor. For the dry cooling compliance systems, EPA included the air cooled condenser cost in the cooling cost.

Wet Cooling Surface Condensers

- EPA obtained equipment costs for condensers sized to handle 12 cooling flow values ranging from 4,650 gpm to 329,333 gpm from a condenser manufacturer (Graham Corporation). Condenser capital costs include an air removal package plus accessories.
- Condenser installation was set equal to 40 percent to 60 percent of condenser equipment costs (60 percent at 500 gpm scaled to 40 percent at 350,000 gpm).

Air Cooled Condensers

- Costs for dry cooling are based on steel towers sized to handle the equivalent heat rejection rate of the replaced cooling water flow. This conversion is factored into the cost formula, which uses the replaced cooling water flow as the input variable. Development of the unit costs and cost curves for dry cooling systems is discussed in Chapter 4 of this document.
- Dry cooling systems do not require water intakes.

O&M Costs

While EPA explicitly included consideration of surface condenser costs in the capital cost estimates where dry cooling systems were involved, EPA did not directly incorporate corresponding costs for operation and maintenance of the surface condensers into the O&M costs. In general, O&M costs for the condensers will involve maintenance only, since the condensers are static and any energy or other consumable material is already considered in other cost components. Some maintenance, including cleaning of fouled tubes and replacement of damaged tubes may be necessary. However, EPA has concluded that such costs are a small portion of baseline operation of a power plant and would be similarly offset with O & M costs of drying cooling condenser tubes.

2.6.4 Option 3: Industry Proposed Two-Track Option

Facilities with Baseline Once-through Cooling

- Compliance cooling system consists of once-through cooling with variable speed intake pumps.
- Compliance intake screen technology consists of wedgewire (passive) screens with an intake velocity of 0.5 fps.

Facilities with Baseline Recirculating Wet Towers

- Compliance cooling system consists of recirculating wet towers with variable speed intake pumps.
- Compliance intake screen technology consists of traveling screens with fish handling features with an intake velocity of 0.5 fps.

Wedgewire (Passive) Screens

- Where applicable, compliance costs included the cost of wedgewire (passive) screens at the intake structure. Intake velocity was 0.5 fps.
- Costs for passive screens were derived from cost curve data presented at the end of this chapter.
- Table 2-5 below summarizes the screen width sizes that were selected for each intake flow volume for the given technology and design specification. Note that the maximum flow volume listed is approximately 10 percent greater than the maximum cost curve input value. For intake flow volumes that exceeded this maximum value, multiple parallel screens of the maximum width listed are costed.

Table 2-5: Intake Flow Volume Criteria for Screen Width Selection

Screen Width	Intake Flow for Wedgewire Screens @ 0.5 fps (gpm)
2 - Foot	0 - 5,000
5 - Foot	>5,000 - 12,000
10 - Foot	>12,000 - 25,000
Maximum Flow*	25,000

* Intake volumes above this value were costed for multiple parallel screens using the maximum screen width shown.

Administrative costs for this option will differ from the administrative costs for the preferred two-track option, as noted in the *Economic Analysis*.

2.7 Summary of Costs by Regulatory Option

2.7.1 Final Rule

Table 2-6 summarizes the baseline, compliance and net technology costs for each model facility for the preferred two-track option adopted for the final rule. These costs are presented in 1999 dollars. For the *Economic Analysis*, EPA escalated these values to 2000 dollars. Note that not all of the manufacturing model facility costs are used in the economic analysis model.

Table 2-6: Baseline, Compliance and Incremental Technology Costs for Model Facilities Preferred Two-Track Option (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
Coal-Fired Power Plants:						
Coal OT/FW-1	$2,310,000	$389,000	$3,766,000	$600,000	$1,456,000	$211,000
Coal OT/FW-2	$9,991,000	$2,522,000	$19,967,000	$3,423,000	$9,976,000	$901,000
Coal OT/FW-3	$33,411,000	$9,280,000	$68,135,000	$12,141,000	$34,724,000	$2,861,000
Coal R/M-1	$25,265,000	$4,396,000	$25,739,000	$4,484,000	$474,000	$88,000
Coal R/FW-1	$5,546,000	$849,000	$5,641,000	$919,000	$95,000	$70,000
Coal R/FW-2	$19,148,000	$3,241,000	$19,365,000	$3,311,000	$217,000	$70,000
Coal R/FW-3	$66,928,000	$11,970,000	$67,698,000	$12,054,000	$770,000	$84,000
Coal RL/FW-1	$11,372,000	$3,219,000	$24,585,000	$4,296,000	$13,213,000	$1,077,000
Combined Cycle Power Plants:						
CC OT/M-1	$15,989,000	$3,673,000	$28,273,000	$4,979,000	$12,284,000	$1,306,000
CC R/M-1	$5,796,000	$890,000	$5,911,000	$971,000	$115,000	$81,000
CC R/M-2	$10,936,000	$1,819,000	$11,133,000	$1,899,000	$197,000	$80,000
CC R/FW-1	$9,650,000	$1,585,000	$9,776,000	$1,655,000	$126,000	$70,000
CC R/FW-2	$10,968,000	$1,831,000	$11,106,000	$1,902,000	$138,000	$71,000
CC R/FW-3	$12,999,000	$2,223,000	$13,157,000	$2,294,000	$158,000	$71,000
Manufacturing Facilities:						
MAN OT/FW-2621	$1,012,000	$141,000	$1,871,000	$281,000	$859,000	$140,000
MAN OT/M-2812	$6,420,000	$1,556,000	$13,717,000	$2,349,000	$7,297,000	$793,000
MAN OT/FW-2812	$2,814,000	$552,000	$5,450,000	$877,000	$2,636,000	$325,000
MAN R/FW-2812	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000
MAN OT/FW-2819	$875,000	$112,000	$1,598,000	$236,000	$723,000	$124,000
MAN R/FW-2819	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/M-2819	$1,094,000	$159,000	$2,117,000	$328,000	$1,023,000	$169,000
MAN OT/FW-2821	$2,419,000	$458,000	$4,639,000	$741,000	$2,220,000	$283,000
MAN R/FW-2821	$7,367,000	$1,175,000	$7,616,000	$1,254,000	$249,000	$79,000
MAN OT/M-2821	$1,172,000	$176,000	$2,277,000	$354,000	$1,105,000	$178,000
MAN OT/FW-2834	$848,000	$106,000	$1,550,000	$228,000	$702,000	$122,000
MAN R/FW-2834	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/FW-2869	$1,440,000	$235,000	$2,713,000	$419,000	$1,273,000	$184,000
MAN OT/M-2869	$1,067,000	$153,000	$2,062,000	$319,000	$995,000	$166,000
MAN R/FW-2869	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000
MAN OT/FW-2873	$1,253,000	$194,000	$2,342,000	$358,000	$1,089,000	$164,000
MAN R/FW-2873	$13,997,000	$2,424,000	$14,435,000	$2,506,000	$4,380,000	$82,000
MAN R/FW-2911	$4,564,000	$683,000	$4,743,000	$758,000	$179,000	$75,000
MAN OT/FW-2911	$3,079,000	$617,000	$5,959,000	$966,000	$2,880,000	$349,000
MAN OT/FW-3312	$3,527,000	$728,000	$6,866,000	$1,123,000	$3,339,000	$395,000

Table 2-6: Baseline, Compliance and Incremental Technology Costs for Model Facilities Preferred Two-Track Option (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
MAN R/FW-3312	$35,922,000	$6,664,000	$39,993,000	$7,000,000	$4,071,000	$336,000
MAN OT/FW-3316	$985,000	$135,000	$1,815,000	$272,000	$830,000	$137,000
MAN R/FW-3316	$6,449,000	$1,012,000	$6,711,000	$1,092,000	$262,000	$80,000
MAN OT/FW-3317	$1,414,000	$229,000	$2,658,000	$410,000	$1,244,000	$181,000
MAN R/FW-3317	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000
MAN OT/FW-3353	$1,306,000	$206,000	$2,445,000	$375,000	$1,139,000	$169,000
MAN R/FW-3353	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000

2.7.2 Option 1: Technology-Based Performance Requirements for Different Types of Waterbodies

Table 2-7 summarizes the baseline, compliance and net technology costs for each model facility for alternative regulatory Option 1. These costs are presented in 1999 dollars. For the *Economic Analysis*, EPA escalated these values to 2000 dollars. Note that not all of the manufacturing model facility costs are used in the economic analysis model.

Table 2-7: Baseline, Compliance and Incremental Technology Costs for Model Facilities Option 1 (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
Coal-Fired Power Plants:						
Coal OT/FW-1	$2,310,000	$389,000	$2,964,000	$470,000	$654,000	$81,000
Coal OT/FW-2	$9,991,000	$2,522,000	$14,110,000	$2,689,000	$4,119,000	$167,000
Coal OT/FW-3	$33,411,000	$9,280,000	$49,121,000	$9,741,000	$15,710,000	$461,000
Coal R/M-1	$25,265,000	$4,396,000	$25,739,000	$4,484,000	$474,000	$88,000
Coal R/FW-1	$5,546,000	$849,000	$5,641,000	$919,000	$95,000	$70,000
Coal R/FW-2	$19,148,000	$3,241,000	$19,365,000	$3,311,000	$217,000	$70,000
Coal R/FW-3	$66,928,000	$11,970,000	$67,698,000	$12,054,000	$770,000	$84,000
Coal RL/FW-1	$11,372,000	$3,219,000	$16,733,000	$3,423,000	$5,361,000	$204,000
Combined Cycle Power Plants:						
CC OT/M-1	$15,989,000	$3,673,000	$28,273,000	$4,979,000	$12,284,000	$1,306,000
CC R/M-1	$5,796,000	$890,000	$5,911,000	$971,000	$115,000	$81,000
CC R/M-2	$10,936,000	$1,819,000	$11,133,000	$1,899,000	$197,000	$80,000
CC R/FW-1	$9,650,000	$1,585,000	$9,776,000	$1,655,000	$126,000	$70,000
CC R/FW-2	$10,968,000	$1,831,000	$11,106,000	$1,902,000	$138,000	$71,000
CC R/FW-3	$12,999,000	$2,223,000	$13,157,000	$2,294,000	$158,000	$71,000
Manufacturing Facilities:						
MAN OT/FW-2621	$1,012,000	$141,000	$1,386,000	$221,000	$374,000	$80,000

Table 2-7: Baseline, Compliance and Incremental Technology Costs for Model Facilities Option 1 (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
MAN OT/M-2812	$6,420,000	$1,556,000	$13,717,000	$2,349,000	$7,297,000	$793,000
MAN OT/FW-2812	$2,814,000	$552,000	$4,058,000	$657,000	$1,244,000	$105,000
MAN R/FW-2812	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000
MAN OT/FW-2819	$875,000	$112,000	$1,193,000	$190,000	$318,000	$78,000
MAN R/FW-2819	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/M-2819	$1,094,000	$159,000	$2,117,000	$328,000	$1,023,000	$169,000
MAN OT/FW-2821	$2,419,000	$458,000	$3,484,000	$558,000	$1,065,000	$100,000
MAN R/FW-2821	$7,367,000	$1,175,000	$7,616,000	$1,254,000	$249,000	$79,000
MAN OT/M-2821	$1,172,000	$176,000	$2,277,000	$354,000	$1,105,000	$178,000
MAN OT/FW-2834	$848,000	$106,000	$1,154,000	$183,000	$306,000	$77,000
MAN R/FW-2834	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/FW-2869	$1,440,000	$235,000	$1,984,000	$320,000	$544,000	$85,000
MAN OT/M-2869	$1,067,000	$153,000	$2,062,000	$319,000	$995,000	$166,000
MAN R/FW-2869	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000
MAN OT/FW-2873	$1,253,000	$194,000	$1,723,000	$277,000	$470,000	$83,000
MAN R/FW-2873	$13,997,000	$2,424,000	$14,435,000	$2,506,000	$438,000	$82,000
MAN R/FW-2911	$4,564,000	$683,000	$4,743,000	$758,000	$179,000	$75,000
MAN OT/FW-2911	$3,079,000	$617,000	$4,448,000	$724,000	$1,369,000	$107,000
MAN OT/FW-3312	$3,527,000	$728,000	$5,122,000	$841,000	$1,595,000	$113,000
MAN R/FW-3312	$38,851,000	$6,898,000	$39,993,000	$7,000,000	$1,142,000	$102,000
MAN OT/FW-3316	$985,000	$135,000	$1,348,000	$215,000	$363,000	$80,000
MAN R/FW-3316	$6,449,000	$1,012,000	$6,674,000	$1,089,000	$225,000	$77,000
MAN OT/FW-3317	$1,414,000	$229,000	$1,947,000	$314,000	$533,000	$85,000
MAN R/FW-3317	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000
MAN OT/FW-3353	$1,306,000	$206,000	$1,798,000	$289,000	$492,000	$83,000
MAN R/FW-3353	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000

2.7.3 Option 2A: Flow Reduction Commensurate with Closed-Cycle recirculating Wet Cooling Systems

Baseline, compliance and incremental technology capital and O&M costs for this option are the same as for the preferred two-track option.

2.7.4 Option 2B: Flow Reduction Commensurate with Dry Cooling Systems

Table 2-8 summarizes the baseline, compliance and net technology costs for each model facility for alternative regulatory Option 2B. These costs are presented in 1999 dollars. For the *Economic Analysis*, EPA escalated these values to 2000 dollars.

Table 2-8: Baseline, Compliance and Incremental Technology Costs for Model Facilities Option 2B (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
Coal-Fired Power Plants:						
Coal OT/FW-1	$3,757,000	$389,000	$9,397,000	$2,363,000	$5,640,000	$1,974,000
Coal OT/FW-2	$17,139,000	$2,522,000	$62,634,000	$11,427,000	$45,495,000	$8,905,000
Coal OT/FW-3	$59,509,000	$9,280,000	$234,182,000	$38,505,000	$174,673,000	$29,225,000
Coal R/M-1	$34,738,000	$4,396,000	$79,792,000	$16,882,000	$45,054,000	$12,486,000
Coal R/FW-1	$7,643,000	$849,000	$14,892,000	$3,669,000	$7,249,000	$2,820,000
Coal R/FW-2	$26,241,000	$3,241,000	$60,315,000	$11,173,000	$34,074,000	$7,932,000
Coal R/FW-3	$94,286,000	$11,970,000	$232,222,000	$38,355,000	$137,936,000	$26,385,000
Coal RL/FW-1	$20,397,000	$3,219,000	$81,323,000	$13,074,000	$60,926,000	$9,855,000
Combined Cycle Power Plants:						
CC OT/M-1	$26,663,000	$3,673,000	$93,582,000	$13,790,000	$66,919,000	$10,117,000
CC R/M-1	$7,933,000	$590,000	$15,277,000	$3,757,000	$7,344,000	$2,867,000
CC R/M-2	$14,985,000	$1,819,000	$32,319,000	$7,177,000	$17,334,000	$5,358,000
CC R/FW-1	$13,298,000	$1,585,000	$28,513,000	$6,486,000	$15,215,000	$4,901,000
CC R/FW-2	$15,137,000	$1,831,000	$33,374,000	$7,362,000	$18,237,000	$5,531,000
CC R/FW-3	$18,025,000	$2,223,000	$41,410,000	$8,677,000	$23,385,000	$6,454,000

Baseline, compliance and incremental technology capital and O&M costs for manufacturing facilities for this option are the same as for the preferred two-track option.

2.7.5 Option 3: Industry Two-Track Option

Table 2-9 summarizes the baseline, compliance and net technology costs for each model facility for alternative regulatory Option 2B. These costs are presented in 1999 dollars. For the *Economic Analysis*, EPA escalated these values to 2000 dollars. Note that not all of the manufacturing model facility costs are used in the economic analysis model.

Table 2-9: Baseline, Compliance and Incremental Technology Costs for Model Facilities Option 3 (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
Coal-Fired Power Plants:						
Coal OT/FW-1	$2,310,000	$389,000	$2,595,000	$440,000	$285,000	$51,000
Coal OT/FW-2	$9,991,000	$2,522,000	$12,178,000	$2,530,000	$2,187,000	$8,000
Coal OT/FW-3	$33,411,000	$9,280,000	$41,751,000	$9,168,000	$8,340,000	$0*
Coal R/M-1	$25,265,000	$4,396,000	$25,739,000	$4,484,000	$474,000	$88,000
Coal R/FW-1	$5,546,000	$849,000	$5,641,000	$919,000	$95,000	$70,000
Coal R/FW-2	$19,148,000	$3,241,000	$19,365,000	$3,311,000	$217,000	$70,000
Coal R/FW-3	$66,928,000	$11,970,000	$67,698,000	$12,054,000	$770,000	$84,000
Coal RL/FW-1	$11,372,000	$3,219,000	$14,247,000	$3,219,000	$2,875,000	$0*
Combined Cycle Power Plants:						
CC OT/M-1	$15,989,000	$3,673,000	$19,289,000	$3,677,000	$3,300,000	$4,000
CC R/M-1	$5,796,000	$890,000	$5,911,000	$971,000	$115,000	$81,000
CC R/M-2	$10,936,000	$1,819,000	$11,133,000	$1,899,000	$197,000	$80,000
CC R/FW-1	$9,650,000	$1,585,000	$9,776,000	$1,655,000	$126,000	$70,000
CC R/FW-2	$10,968,000	$1,831,000	$11,106,000	$1,902,000	$138,000	$71,000
CC R/FW-3	$12,999,000	$2,223,000	$13,157,000	$2,294,000	$158,000	$71,000
Manufacturing Facilities:						
MAN OT/FW-2621	$1,012,000	$141,000	$1,229,000	$206,000	$217,000	$65,000
MAN OT/M-2812	$6,420,000	$1,556,000	$8,632,000	$1,631,000	$2,212,000	$75,000
MAN OT/FW-2812	$2,814,000	$552,000	$3,608,000	$617,000	$794,000	$65,000
MAN R/FW-2812	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000
MAN OT/FW-2819	$875,000	$112,000	$1,059,000	$177,000	$184,000	$65,000
MAN R/FW-2819	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/M-2819	$1,094,000	$159,000	$1,331,000	$234,000	$237,000	$75,000
MAN OT/FW-2821	$2,419,000	$458,000	$3,108,000	$523,000	$689,000	$65,000
MAN R/FW-2821	$7,367,000	$1,175,000	$7,616,000	$1,254,000	$249,000	$79,000
MAN OT/M-2821	$1,172,000	$176,000	$8,632,000	$1,631,000	$2,212,000	$75,000
MAN OT/FW-2834	$848,000	$106,000	$1,025,000	$171,000	$177,000	$65,000
MAN R/FW-2834	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/FW-2869	$1,440,000	$235,000	$1,821,000	$300,000	$381,000	$65,000
MAN OT/M-2869	$1,067,000	$153,000	$1,297,000	$228,000	$230,000	$75,000
MAN R/FW-2869	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000

Table 2-9: Baseline, Compliance and Incremental Technology Costs for Model Facilities Option 3 (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
MAN OT/FW-2873	$1,253,000	$194,000	$1,528,000	$259,000	$275,000	$65,000
MAN R/FW-2873	$13,997,000	$2,424,000	$14,435,000	$2,506,000	$438,000	$82,000
MAN R/FW-2911	$4,564,000	$683,000	$4,743,000	$758,000	$179,000	$75,000
MAN OT/FW-2911	$3,079,000	$617,000	$3,945,000	$682,000	$866,000	$65,000
MAN OT/FW-3312	$3,527,000	$728,000	$4,577,000	$793,000	$1,050,000	$65,000
MAN R/FW-3312	$38,851,000	$6,898,000	$39,993,000	$7,000,000	$1,142,000	$102,000
MAN OT/FW-3316	$985,000	$135,000	$1,195,000	$200,000	$210,000	$65,000
MAN R/FW-3316	$6,449,000	$1,012,000	$6,674,000	$1,089,000	$225,000	$77,000
MAN OT/FW-3317	$1,414,000	$229,000	$1,787,000	$294,000	$373,000	$65,000
MAN R/FW-3317	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000
MAN OT/FW-3353	$1,306,000	$206,000	$1,595,000	$271,000	$289,000	$65,000
MAN R/FW-3353	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000

*For this model facility, O&M costs for wedgewire screens are actually less than the O&M costs for the baseline traveling screens. To be conservative, EPA has set the incremental O&M cost at $0; this does not reflect potential savings to the facility associated with switching intake screen types.

2.8 Technology Unit Costs

2.8.1 General Cost Information

The cost estimates presented in this analysis include both capital costs and operations and maintenance (O&M) costs and are for primary technologies such as traveling screens and cooling towers. Facilities may install these technologies to meet requirements of the final §316(b) New Facility Rule. Cooling tower cost estimates are presented for various types of cooling towers including towers fitted with features such as plume abatement and noise reduction. Estimated costs for traveling screens were developed mainly from cost information provided by vendors. The cost of installing other CWIS technologies such as passive screens and velocity caps are calculated by applying a cost factor based on the cost of traveling screens. All of the base cost estimates are for new sources.

To provide a relative measurement of the differences in cost across technologies, costs need to be developed on a uniform basis. The cost for many of the CWIS and flow reduction technologies depends on many factors, including site-specific conditions, and the relative importance of many of these factors varies from technology to technology. The factor that is most relevant is the total flow. Therefore, EPA selected total flow as the factor on which to base unit costs and thus use for basic cost comparisons. EPA developed cost estimates, in $/gallons per minute (gpm), for most of the technologies for use at a range of different total intake flow volumes. For cooling towers, EPA developed cost estimates for use at a range of different total recirculating flow volumes.

EPA assumed average values or typical situations for the other factors that also impact the cost components. For example, EPA assumed an average debris level and an intake flow velocity of 0.5 feet per second (fps); EPA also used 1.0 fps for cost comparison purposes. EPA separately assessed the cost effect of variations from these average conditions as add-on costs. For instance, if the water being drawn in has a high debris level, this would tend to increase cost by about 20 percent.

EPA determined the specifications for each factor based on a review of information about the characteristics most likely to be encountered at a typical facility withdrawing cooling water. Cost factors used in this analysis and the assumed values/scenarios are listed below in Table 2-10. EPA's unit cost estimates for the selected technologies are based on the information provided by vendors, industry representative, and published documents.

Table 2-10. Basis for Development of Unit Costs

Base Factor for Developing Unit Costs	Assumed Values of Other Factors for Base Costs
Costs were developed for flows of: [1] < 10,000 gpm - 4 flows 10,000 to < 100,000 gpm - 20 flows 100,000 to 200,000 gpm - 4 flows > 200,000 gpm - 1 flow.	Intake flow velocity = 0.5 fps, and 1.0 fps for comparison Amount and type of debris = average/typical Water quality = fresh water Waterbody flow velocity = moderate flow Accessability to intake = average/typical (no dredging needed, use of crane possible)

Cost Elements

Cost estimates of screens include non-metallic fish handling panels, a spray system, a fish trough, housings and transitions, continuous operating features (intermittent operation feature for traveling screens without fish baskets), a drive unit, frame seals, engineering, and installation. EPA separately estimated costs for spray wash pumps, permitting, and pilot studies.

Cooling towers cost estimates are based on unit costs that include all costs associated with the design, construction, and commissioning of a standard fill cooling tower. Costs of cooling towers with various features, building materials, and types are calculated based on cost comparisons with standard cooling towers.

O&M costs were estimated for each type of technology. These costs were estimated, in part, using a percent of capital costs as a basis and considering additional factors.

Potential Add-Ons to Cost

Amount and type of debris = high or need for smaller than typical openings
Depth of waterbody = particularly shallow or deep
Water quality = salt or brackish water (extra cost for non-corrosive material for device and shorter life expectancy/higher replacement cost)
Waterbody flow velocity = stagnant or rapidly moving
Accessability to intake = cost of difficult installation (extra cost for dredging, extra cost for unusual installation due to site-specific conditions)
Existing intake structure = costs associated with retrofit and what existing structure(s) or conditions would cause the extra costs. For example, if an existing structure has an intake flow of 2.0 fps and the intake velocity will be reduced to 0.5 fps with a new device, additional equipment or changes to other equipment/structures of that part of the intake system may increase capital costs (albeit minimally) when compared to installing a new system.

1) Cost estimates were developed for selected flows in each range (e.g., 4 different flows less than 10,000 gpm). 10,000 gpm = 14.4 MGD

The costs estimated for fish protection equipment are linked to both flow rates and intake width and depth. Cooling towers costs are based on the recirculating flow rate, temperature approach (defined later), and the type of cooling tower. Several industry representatives provided information on how they conduct preliminary cost estimates for cooling towers. This is considered to be the "rule of thumb" in costing cooling towers (i.e., $/gallons per minute). Regional variations in costs do exist. However, EPA has based its cost estimates on average flow designs representing model facilities. EPA often used conservative (i.e. high cost) assumptions in order to develop model facility costs that accurately represent average costs applicable to affected facilities across the country. In addition to the costs presented below, cost curves and equations are provided at the end of this chapter. The cost curves and equations can be used to estimate costs for implementing technologies or taking actions for facilities across a range of intake flows. Additional supporting information can be found in *Cost Research and Analysis of Cooling Water Technologies for 316(b) Regulatory Options* (SAIC, 2000).

2.8.2 Flow

EPA determined preliminary intake flow values for the base factor based on data from the ICR (Information Collection Request) for the §316(b) industry questionnaire, a sampling of responses to the §316(b) industry screener questionnaire, a Utility Data Institute database (UDI, 1995), and industry brochures and technology background papers.[6] Data from these sources represent utility and nonutility steam electric facilities and industrial facilities that could be subject to prospective §316(b) requirements and are provided in Table 2-11. EPA used these data to determine the range of typical intake flows for these types of facilities to ensure that the flows included in the cost estimates were representative. Through data provided by equipment vendors, EPA determined the flows typically handled by available CWIS equipment and cooling towers. Facilities with greater flows would generally either use multiple screens, towers, or other technologies, or use a special design. Considering this information together, EPA selected flows for various screen sizes, water depths, and intake velocities for use in collecting cost data directly from industry representatives.

Table 2-11. Flow Data for Unit Costs

ICR (average intake flows by utility/industry category)

Steam electric utilities:	178 MGD (124,000 gpm) for 1,093 facilities
Steam electric non-utilities:	2.8 MGD (1,944 gpm) for 1,158 facilities
Chemicals & allied products:	0.339 MGD (235 gpm) for 22,579 facilities
Primary metals:	0.327 MGD (227 gpm) for 10,999 facilities
Petroleum & coal products:	0.461 MGD (320 gpm) for 3,509 facilities
Paper & allied products:	0.148 MGD (103 gpm) for 9,881 facilities

UDI Database (design intake flow for steam electric utilities) (UDI, 1995)

Up to 11,219 gpm (16.15 MGD)	401 units
11,220-44,877 gpm (16.16-64.62 MGD)	465 units
44,878-134,630 gpm (64.63-193.9 MGD)	684 units
134,631-448,766 gpm (194-646.2 MGD)	453 units
More than 448,766 gpm (646.2 MGD)	68 units

Sampling of Responses from Industry Screener Questionnaire (daily intake flow for non-utilities)

Up to 0.5 MGD (347 gpm)	6 facilities	>20-30.0 MGD (13,890-20,833 gpm)	2 facilities
>0.5-1.0 MGD (348-694 gpm)	1 facilities	>30-40.0 MGD (20,834-27,778 gpm)	2 facilities
>1-5.0 MGD (695-3,472 gpm)	3 facilities	>40-50.0 MGD (27,779-34,722 gpm)	1 facility
>5.0-10.0 MGD (3,473-6,944 gpm)	8 facilities	>50-100.0 MGD (34,723-69,444 gpm)	0 facilities
>10-20.0 MGD (6,945-13,889 gpm)	2 facilities	>100 MGD (>69,444 gpm)	1 facility

US Filter/Johnson Screens Brochure (ranges for flow definitions) (US Filter, 1998)

Low flow:	200 to 4,000 gpm (0.288 to 5.76 MGD)
Intermediate flow:	1,500 to 15,000 gpm (2.16 to 21.6 MGD)
High flow:	5,000 to 30,000 gpm (7.2 to 43.2 MGD)

Background Technology Papers (SAIC, 1994; SAIC, 1996)

"Relatively low intake flow":	1-30 MGD (694-20,833 gpm)
"Relatively small quantities of water":	up to 50,000 gpm (70 MGD)

[6]EPA sent the *Industry Screener Questionnaire: Phase I Cooling Water Intake Structures* to about 2,500 steam electric non-utility power producers and manufacturers. This sample included most of the non-utility power producers that were identified by EPA and a subset of the identified manufacturers in industry groups that EPA determined use relatively large quantities of cooling water.

2.8.3 Additional Cost Considerations Included in the Analysis

The cost estimates include costs, such as design/engineering, process equipment, and installation, that are clearly part of getting a CWIS structure or cooling tower in place and operational. However, there are additional associated capital costs that may be less apparent but may also be incurred by a facility and have been included in the cost estimates either as stand-alone cost items or included in installation and construction costs. EPA included the following costs as part of the unit cost estimates:

- Mobilization and demobilization,
- Architectural fees,
- Contractor's overhead and profit,
- Process engineering,
- Sitework and yard piping,
- Standby power,
- Electrical allowance,
- Instrumentation and controls, and
- Contingencies
- Installation.

Following is a brief description of these miscellaneous capital cost items to provide an indication of their general effect on capital costs. These descriptions are also intended to help economists adjust costs to account for regional variations within the U.S. EPA notes that for the costs of cooling towers, each of these items is included the total installed capital costs estimates, but these specific items are not necessarily itemized due to EPA's use of a total inclusive cost per gallon estimate for cooling towers.

Mobilization and Demobilization

Mobilization and demobilization costs are costs incurred by the contractor to assemble crews and equipment on-site and to dismantle semi-permanent and temporary construction facilities once the job is completed. The equipment that may be needed includes backhoes, bulldozers, front-end loaders, self-propelled scrapers, pavers, pavement rollers, sheeps-foot rollers, rubber tire rollers, cranes, temporary generators, trucks (including water and fuel trucks), and trailers. Mobilization costs also include bonds and insurance. To account for mobilization and demobilization costs, a range of 2 percent to 5 percent is was added to the total capital cost, depending on the specific site characteristics.

Architectural Fees

Estimates need to include the cost of the building design, architectural drawings, building construction supervision, construction engineering, and travel, not to exceed 8 percent of the capital cost.

Contractor's Overhead and Profit

This element includes field supervision, main office expenses, tools and minor equipment, workers' compensation and employer's liability, field office expenses, performance and payment bonds, unemployment tax, profit, Social Security and Medicare, builder's risk insurance, and public liability insurance. This was estimated at 12 percent of the capital cost.

Process Engineering

Costs for this category include treatment process engineering, unit operation construction supervision, travel, system start-up engineering, study, design, operation and maintenance (O&M) manuals, and record drawings. These costs were estimated by adding a range of 10 percent to 20 percent to the estimated capital cost.

Sitework and Yard Piping

Cost estimates for sitework include site preparation, excavation, backfilling, roads, walls, landscaping, parking lots, fencing, storm water control, yard structures, and yard piping (interconnecting piping between treatment units). These costs were estimated by adding a range of 5 percent to 15 percent to the estimated capital cost for sitework and a range of 3 percent to 7 percent for yard piping.

For installation of CWIS technologies (e.g., screens), a yard piping cost of 5 percent of the total capital cost is sometimes used based on site-specific conditions. Cooling towers require a significant amount of piping (for both new facilities and retrofits to existing facilities) and these costs are already included in the capital cost estimate for cooling towers so an additional 5 percent was not applied.

Standby Power

Standby generators may be needed to produce power to the treatment and distribution system during power outages and should be included in cost estimates. These costs are estimated by adding a range of 2 percent to 5 percent to the estimated construction cost.

Electrical Allowance (including yard wiring)

An electrical allowance should be made for electric wiring, motors, duct banks, MCCs, relays, lighting, etc. These costs are estimated by adding a range of 10 percent to 15 percent to the estimated construction cost.

Instrumentation and Controls

Instrumentation and control (I&C) costs may include a facility control system, software, etc. The cost depends on the degree of automation desired for the entire facility. These costs are estimated by adding a range of 3 percent to 8 percent to the estimated construction cost.

Contingencies

Contingency cost estimates include compensation for uncertainty within the scope of labor, materials, equipment, and construction specifications. This uncertainty factor is estimated to range from 5 percent to 25 percent of all capital costs, with an average of 10 percent for general engineering projects.

Contingency costs can range from 2 percent to 20 percent for construction projects. CWIS technology projects are not typical construction projects since most of the construction is done at the manufacturing facility and site work mainly involves installation. So some of the uncertainties that could occur in typical construction projects are less likely in CWIS projects. Design and manufacture of the technology can be around 90 percent of the total cost for a project that involves a straightforward installation (e.g., no dredging). The approach used in this cost estimate is conservative and is considered to cover contingencies for typical CWIS technology or cooling tower projects.

In its 1992 study of cooling tower retrofit costs, Stone and Webster (1992) included, in its line item costs, an allowance for indeterminates (e.g., contingencies) of 15 percent for future utility projects. The Stone and Webster study involved major retrofit work on existing plants (i.e., converting a once through cooling system plant to recirculating), so the contingencies allowance fell in the higher end of the typical range.

Installation costs

Installation costs are estimated at 80 percent of cooling tower equipment cost based on information provided by equipment vendors. See the end of this chapter for cost curves and equations.

2.8.4 Replacement Costs

Cooling towers may require replacement of equipment during the financing period that is necessary for the upkeep of the cooling tower. These costs tend to increase over the useful life of the tower and constitute an O&M expenditure that needs to be accounted for. Therefore, EPA factored these periodic equipment replacement costs into the O&M cost estimates presented herein. However, EPA has not included the replacement costs for other equipment because the life expectancy is generally expected to last over the financial life of the facility.

2.9 Specific Cost Information for Technologies and Actions

The following sections present information on potential compliance actions that a facility might take, including the installation of certain technologies, in order to meet requirements under the §316(b) New Facility Rule. The information presented includes the cost curves and unit costs developed for each potential compliance action. Estimated costs are presented in 1999 dollars. The cost equations and cost curves can be used to estimate costs. The equations and cost curves generally use flow as the basis for determining estimated costs (i.e., unit costs are in $/gpm). For screens, since flow is dependent on the flow velocity through the screen, different equations and cost curves are included for the two velocities of 0.5 fps and 1.0 fps.

2.9.1 Reducing Design Intake Flow

Switching to a recirculating system

As noted earlier, in a recirculating system cooling water is used to cool equipment and steam, and absorbs heat in the process. The cooling water is then cooled and recirculated to the beginning of the system to be used again for cooling. Recirculating the cooling water in a system vastly reduces the amount of cooling water needed. The method most frequently used to cool the water in a recirculating system is putting the cooling water through a cooling tower. Therefore, EPA chose to cost cooling towers as the technology used to switch a once-through cooling system to a recirculating system.

The factors that generally have the greatest impact on cost are the flow, approach (the difference between cold water temperature and ambient wet bulb temperature), tower type, and environmental considerations. Physical site conditions (e.g., topographic conditions, soils and underground conditions, water quality) affect cost, but in most situations are secondary to the primary cost factors. Table 2-12 presents relative capital and operation cost estimates for various cooling towers in comparison to the conventional, basic Douglas Fir cooling tower as a standard. EPA notes that based on its data collection for recent cooling tower projects, for most cases, environmental considerations such as plume abatement and noise abatement are rarely installed. Therefore, EPA is presenting costs in the following sections for comparison purposes only and these types of costs are not uniformly applicable to a national rule.

Table 2-12. Relative Cost Factors for Various Cooling Tower Types[1]

Tower Type	Capital Cost Factor (%)	Operation Cost Factor (%)
Douglas Fir	100	100
Redwood	112[2]	100
Concrete	140	90
Steel	135	98
Fiberglass Reinforced Plastic	110	98
Splash Fill	120	150

Table 2-12. Relative Cost Factors for Various Cooling Tower Types[1]

Non-Fouling Film Fill	110	102
Mechanical draft	100	100
Natural draft (concrete)	175	35
Hybrid [Plume abatement (32DBT)]	250-300	125-150
Dry/wet	375	175
Air condenser (steel)	250-325	175-225
Noise reduction (10dBA)	130	107

1) Percent estimates are relative to the Douglas Fir cooling tower.
2) Redwood cooling tower costs may be higher because redwood trees are a protected species, particularly in the Northwest.

Sources: Mirsky et al. (1992), Mirsky and Bauthier (1997), and Mirsky (2000).

There are two general types of cooling towers, wet and dry. Wet cooling towers, which are the far more common type, reduce the temperature of the water by bringing it directly into contact with large amounts of air. Through this process, heat is transferred from the water to the air which is then discharged into the atmosphere. Part of the water evaporates through this process thereby having a cooling effect on the rest of the water. This water then exits the cooling tower at a temperature approaching the wet bulb temperature of the air.

For dry cooling towers, the water does not come in direct contact with the air, but instead travels in closed pipes through the tower. Air going through the tower flows along the outside of the pipe walls and absorbs heat from the pipe walls which absorb heat from the water in the pipes. Dry cooling towers tend to be much larger and more costly than wet towers because the dry cooling process is less efficient. Also, the effluent water temperature is warmer because it only approaches the dry bulb temperature of the air (not the cooler wet bulb temperature). Development of unit costs and cost curves for dry cooling towers is discussed in Chapter 4 of this document.

Hybrid wet-dry towers, which combine dry heat exchange surfaces with standard wet cooling towers, are plume abatement towers. These towers tend to be used most where plume abatement is required by local authorities. Technologies for achieving low noise and low drift can be fitted to all types of towers.

Other characteristics of cooling towers include:

C ***Air flow***: Mechanical draft towers use fans to induce air flow, while natural draft (i.e., hyperbolic) towers induce natural air flow by the chimney effect produced by the height and shape of the tower. For towers of similar capacity, natural draft towers typically require significantly less land area and have lower power costs (i.e., fans to induce air flow are not needed) but have higher initial costs (particularly because they need to be taller) than mechanical draft towers. Both mechanical draft and natural draft towers can be designed for air to flow through the fill material using either a crossflow (air flows horizontally) or counterflow (air flows vertically upward) design, while the water flows vertically downward. Counterflow towers tend to be more efficient at achieving heat reduction but are generally more expensive to build and operate because clearance needed at the bottom of the tower means the tower needs to be taller.

C ***Mode of operation***: Cooling towers can be either recirculating (water is returned to the condenser for reuse) or non-recirculating (tower effluent is discharged to a receiving waterbody and not reused). Facilities using non-recirculating types (i.e., "helper" towers) draw large flows for cooling and therefore do not provide fish protection for §316(b) purposes, so the information in this chapter is not intended to address non-recirculating towers.

- ***Construction materials*:** Towers can be made from concrete, steel, wood, and/or fiberglass.

Generally, all cooling towers with plume abatement features are hybrid towers. According to the Standard Handbook of Power Plant Design, attempts to modify towers with special designs and construction features to abate plumes has been tested but not accepted as an effective technology. Natural draft towers are concrete towers, although some old natural draft wood cooling towers do exist. Therefore, for costing purposes, concrete is assumed to be the material used for building natural draft cooling towers.

Capital Cost of Cooling Towers

Typically, the cost of the project is determined based on the following factors: type of equipment to be cooled (e.g., coal fired equipment, natural gas powered equipment); location of the water intake (on a river, lake, or seashore); amount of power to-be-generated (e.g., 50 Megawatt vs. 200 Megawatt); and volume of water needed. The volume of water needed for cooling depends on the following critical parameters: water temperature, make of equipment to be used (e.g, G.E turbine vs. ABB turbine, turbine with heat recovery system and turbine without heat recovery system), discharge permit limits, water quality (particularly for wet cooling towers), and type of wet cooling tower (i.e., whether it is a natural draft or a mechanical draft).

Two cooling tower industry managers with extensive experience in selling and installing cooling towers to power plants and other industries provided information on how they estimate budget capital costs associated with a wet cooling tower. The rule of thumb they use is \$30/gpm for a delta of 10 degrees and \$50/gpm for a delta of 5 degrees.[7] This cost is for a "small" tower (flow less than 10,000 gpm) and equipment associated with the "basic" tower, and does not include installation. Ancillary costs are included in the installation factor estimate listed below. Above 10,000 gpm, to account for economy of scale, the unit cost was lowered by \$5/gpm over the flow range up to 204,000 gpm. For flows greater than 204,000 gpm, a facility may need to use multiple towers or a custom design. Combining this with the variability in cost among various cooling tower types, costs for various tower types and features were calculated for the flows used in calculating screen capacities at 1 ft/sec and 0.5 ft/sec.

To estimate costs specifically for installing and operating a particular cooling tower, important factors include:

- ***Condenser heat load and wet bulb temperature (or approach to wet bulb temperature)*:** Largely determine the size needed. Size is also affected by climate conditions.

- ***Plant fuel type and age/efficiency*:** Condenser discharge heat load per Megawatt varies greatly by plant type (nuclear thermal efficiency is about 33 percent to 35 percent, while newer oil-fired plants can have nearly 40 percent thermal efficiency, and newer coal-fired plants can have nearly 38 percent thermal efficiency).[8] Older plants typically have lower thermal efficiency than new plants.

- ***Topography*:** May affect tower height and/or shape, and may increase construction costs due to subsurface conditions. For example, sites requiring significant blasting, use of piles, or a remote tower location will typically have greater installation/construction cost.

- ***Material used for tower construction*:** Wood towers tend to be the least expensive, followed by fiberglass reinforced plastic, steel, and concrete. However, some industry sources claim that Redwood capital costs might be much higher compared to

[7]The delta is the difference between the cold water (tower effluent) temperature and the tower wet bulb temperature. This is also referred to as the design approach. For example, at design conditions with a delta or design approach of 5 degrees, the tower effluent and blowdown would be 5 degrees warmer than the wet bulb temperature. A smaller delta (or lower tower effluent temperature) requires a larger cooling tower and thus is more expensive.

[8]With a 33 percent efficiency, one-third of the heat is converted to electric energy and two-thirds goes to waste heat in the cooling water.

other wood cooling towers, particularly in the Northwest U.S., because Redwood trees are a protected species. Factors that affect the material used include chemical and mineral composition of the cooling water, cost, aesthetics, and local/regional availability of materials.

- ***Pollution control requirements*:** Air pollution control facilities require electricity to operate. Local requirements to control drift, plume, fog, and noise and to consider aesthetics can also increase costs for a given site (e.g., different design specifications may be required).

Summaries of some EPRI research on dry cooling systems and wet-dry supplemental cooling systems note that dry cooling towers may cost as much as four times more than conventional wet towers (EPRI, 1986a and 1986b).

Table 2-13: Estimated Capital Costs of Cooling Towers without Special Environmental Impact Mitigation Features (1999 Dollars)

Flow (gpm)	Basic Douglas Fir Cooling Tower Cost[1]	Redwood Tower	Concrete Tower	Steel Tower	Fiberglass Reinforced Plastic Tower
2000	$108,000	$121,000	$151,000	$146,000	$119,000
4000	$216,000	$242,000	$302,000	$ 292,000	$238,000
7000	$378,000	$423,000	$529,000	$ 510,000	$416,000
9000	$486,000	$544,000	$680,000	$ 656,000	$535,000
11,000	$594,000	$665,000	$832,000	$ 802,000	$653,000
13,000	$702,000	$786,000	$983,000	$ 948,000	$772,000
15,000	$810,000	$907,000	$1,134,000	$1,094,000	$891,000
17,000	$918,000	$1,028,000	$1,285,000	$1,239,000	$1,010,000
18,000	$972,000	$1,089,000	$1,361,000	$1,312,000	$1,069,000
22,000	$1,148,400	$1,286,000	$1,608,000	$1,550,000	$1,263,000
25,000	$1,305,000	$1,462,000	$1,827,000	$1,762,000	$1,436,000
28,000	$1,461,600	$1,637,000	$2,046,000	$1,973,000	$1,608,000
29,000	$1,513,800	$1,695,000	$2,119,000	$2,044,000	$1,665,000
31,000	$1,618,200	$1,812,000	$2,265,000	$2,185,000	$1,780,000
34,000	$1,774,800	$1,988,000	$2,485,000	$2,396,000	$1,952,000
36,000	$1,879,200	$2,105,000	$2,631,000	$2,537,000	$2,067,000
45,000	$2,268,000	$2,540,000	$3,175,000	$3,062,000	$2,495,000
47,000	$2,368,800	$2,653,000	$3,316,000	$3,198,000	$2,606,000
56,000	$2,822,400	$3,161,000	$3,951,000	$3,810,000	$3,105,000
63,000	$3,175,200	$3,556,000	$4,445,000	$4,287,000	$3,493,000
67,000	$3,376,800	$3,782,000	$4,728,000	$4,559,000	$3,714,000
73,000	$3,679,200	$4,121,000	$5,151,000	$4,967,000	$4,047,000
79,000	$3,839,400	$4,300,000	$5,375,000	$5,183,000	$4,223,000
94,000	$4,568,400	$5,117,000	$6,396,000	$6,167,000	$5,025,000
102,000	$4,957,200	$5,552,000	$6,940,000	$6,692,000	$5,453,000
112,000	$5,443,200	$6,096,000	$7,620,000	$7,348,000	$5,988,000
146,000	$7,095,600	$7,947,000	$9,934,000	$9,579,000	$7,805,000
157,000	$7,347,600	$8,229,000	$10,287,000	$9,919,000	$8,082,000
204,000	$9,180,000	$10,282,000	$12,852,000	$12,393,000	$10,098,000

1) Includes installation at 80 percent of equipment cost for a delta of 10 degrees.

Using the estimated costs, EPA developed cost equations using a polynomial curve fitting function. Table 2-14 presents cost equations for basic tower types built with different building materials and assuming a delta of 10 degrees. The cost equations presented in Table 2-13 include installation costs. The “x” in the presented cost equations is for flow in gpm and the “y” is in dollars.

Table 2-14. Capital Cost Equations of Cooling Towers without Special Environmental Impact Mitigation Features (Delta 10 degrees)

Tower Type	Capital Cost Equation[1]	Correlation Coefficient
Douglas Fir	$y = -9E\text{-}11x^3 - 8E\text{-}06x^2 + 50.395x + 44058$	$R^2 = 0.9997$
Redwood	$y = -1E\text{-}10x^3 - 9E\text{-}06x^2 + 56.453x + 49125$	$R^2 = 0.9997$
Steel	$y = -1E\text{-}10x^3 - 1E\text{-}05x^2 + 68.039x + 59511$	$R^2 = 0.9997$
Concrete	$y = -1E\text{-}10x^3 - 1E\text{-}05x^2 + 70.552x + 61609$	$R^2 = 0.9997$
Fiberglass Reinforced Plastic	$y = -1E\text{-}10x^3 - 9E\text{-}06x^2 + 55.432x + 48575$	$R^2 = 0.9997$

1) x is for flow in gpm and y is cost in dollars.

Using the cost comparison information published by Mirsky et al. (1992), EPA calculated the costs of cooling towers with various additional features. These costs are presented in Table 2-15. Table 2-15 presents capital costs of the Douglas Fir Tower with various features. The costs for other types of cooling towers were calculated in a similar manner.

Table 2-16 presents cost equations for Douglas fir cooling towers with special environmental mitigation features, built with different building materials and assuming a delta of 10 degrees. The cost equations presented in Table 2-16 include installation costs. The “x” in the presented cost equations is for flow in gpm and the “y” is in dollars. The final costs were based on cost curves constructed for redwood splash fill towers. Costs and cost equations for Douglas fir towers are listed here as an example of how cost equation curves were developed, although these are not the costs used to develop the facility costs.

At the end of this chapter, cost curves with equations are also presented for other types of cooling towers.

Table 2-15: Capital Costs of Douglas Fir Cooling Towers with Special Environmental Impact Mitigation Features (Delta 10 degrees) (1999 Dollars)

Flow (gpm)	Douglas Fir Cooling Tower	Splash Fill	Non-fouling Film Fill	Noise Reduction 10 dBA	Dry/wet	Hybrid Tower (32DBT Plume Abatement)
2000	$108,000	$130,000	$119,000	$140,000	$405,000	$324,000
4000	$216,000	$259,000	$238,000	$281,000	$810,000	$648,000
7000	$378,000	$454,000	$416,000	$491,000	$1,418,000	$1,134,000
9000	$486,000	$583,000	$535,000	$632,000	$1,823,000	$1,458,000
11,000	$594,000	$713,000	$653,000	$772,000	$2,228,000	$1,782,000
13,000	$702,000	$842,000	$772,000	$913,000	$2,633,000	$2,106,000
15,000	$810,000	$972,000	$891,000	$1,053,000	$3,038,000	$2,430,000
17,000	$918,000	$1,102,000	$1,010,000	$1,193,000	$3,443,000	$2,754,000
18,000	$972,000	$1,166,000	$1,069,000	$1,264,000	$3,645,000	$2,916,000
22,000	$1,148,400	$1,378,000	$1,263,000	$1,493,000	$4,307,000	$3,445,000
25,000	$1,305,000	$1,566,000	$1,436,000	$1,697,000	$4,894,000	$3,915,000
28,000	$1,461,600	$1,754,000	$1,608,000	$1,900,000	$5,481,000	$4,385,000
29,000	$1,513,800	$1,817,000	$1,665,000	$1,968,000	$5,677,000	$4,541,000
31,000	$1,618,200	$1,942,000	$1,780,000	$2,104,000	$6,068,000	$4,855,000
34,000	$1,774,800	$2,130,000	$1,952,000	$2,307,000	$6,656,000	$5,324,000
36,000	$1,879,200	$2,255,000	$2,067,000	$2,443,000	$7,047,000	$5,638,000
45,000	$2,268,000	$2,722,000	$2,495,000	$2,948,000	$8,505,000	$6,804,000
47,000	$2,368,800	$2,843,000	$2,606,000	$3,079,000	$8,883,000	$7,106,000
56,000	$2,822,400	$3,387,000	$3,105,000	$3,669,000	$10,584,000	$8,467,000
63,000	$3,175,200	$3,810,000	$3,493,000	$4,128,000	$11,907,000	$9,526,000
67,000	$3,376,800	$4,052,000	$3,714,000	$4,390,000	$12,663,000	$10,130,000
73,000	$3,679,200	$4,415,000	$4,047,000	$4,783,000	$13,797,000	$11,038,000
79,000	$3,839,400	$4,607,000	$4,223,000	$4,991,000	$14,398,000	$11,518,000
94,000	$4,568,400	$5,482,000	$5,025,000	$5,939,000	$17,132,000	$13,705,000
102,000	$4,957,200	$5,949,000	$5,453,000	$6,444,000	$18,590,000	$14,872,000
112,000	$5,443,200	$6,532,000	$5,988,000	$7,076,000	$20,412,000	$16,330,000
146,000	$7,095,600	$8,515,000	$7,805,000	$9,224,000	$26,609,000	$21,287,000
157,000	$7,347,600	$8,817,000	$8,082,000	$9,552,000	$27,554,000	$22,043,000
204,000	$9,180,000	$11,016,000	$10,098,000	$11,934,000	$34,425,000	$27,540,000

Table 2-16. Capital Cost Equations of Douglas Fir Cooling Towers with Special Environmental Impact Mitigation Features (Delta 10 degrees)

Tower Type	Capital Cost Equation[1]	Correlation Coefficient
Douglas Fir	$y = -9E\text{-}11x^3 - 8E\text{-}06x^2 + 50.395x + 44058$	$R^2 = 0.9997$
Splash Fill	$y = -4E\text{-}05x^2 + 62.744x + 22836$	$R^2 = 0.9996$
Non-fouling Film Fill	$y = -1E\text{-}10x^3 - 9E\text{-}06x^2 + 55.432x + 48575$	$R^2 = 0.9997$
Noise Reduction 10 dBA	$y = -1E\text{-}10x^3 - 1E\text{-}05x^2 + 65.517x + 57246$	$R^2 = 0.9997$
Dry/Wet	$y = -0.0001x^2 + 196.07x + 71424$	$R^2 = 0.9996$
Hybrid Tower (Plume Abatement 32DBT)	$y = -3E\text{-}10x^3 - 2E\text{-}05x^2 + 151.18x + 132225$	$R^2 = 0.9997$

1) x is flow in gpm and y is cost in dollars.

Validation of Cooling Tower Capital Cost Equations

To validate the cooling tower capital cost curves and equations, EPA compared the costs predicted by the cooling tower capital cost equations to actual costs for cooling tower construction projects provided by cooling tower vendors. EPA obtained data for 20 cooling tower construction projects: nine Douglas fir towers, eight fiberglass towers, one redwood tower, and two towers for which the construction material was unknown (for purposes of comparison, EPA compared these last two towers to predicted costs for redwood towers). In some cases, the project costs did not include certain components such as pumps or basins. Where this was the case, EPA adjusted the project costs as follows:

- where project costs did not include pumps, EPA added $10/gpm to the project costs to account for pumps.
- where project costs did not include pumps and basins, EPA doubled the project costs to account for pumps and basins.

Chart 2-7 at the end of this chapter compares actual capital costs for wet cooling tower projects against predicted costs from EPA's cooling tower capital cost curves, with 25 percent error bars around the cost curve predicted values. This chart shows that, in almost all cases, EPA's cost curves provide conservative cost estimates (erring on the high side) and are within 25 percent or less of actual project costs. In those few cases where the cost curve predictions are not within 25 percent of the actual costs, the difference can generally be attributed to the fact that the constructed cooling towers were designed for temperature deltas different than the 10 °F used for EPA's cost curves.

Operation and Maintenance (O&M) Cost of Cooling Towers

EPA has included the following variables in estimating O&M costs for cooling towers:

- Size of the cooling tower,
- Material from which the cooling tower is built,
- Various features that the cooling tower may include,
- Source of make-up water,
- How blowdown water is disposed, and
- Increase in maintenance costs as the tower useful life diminishes.

For example, if make-up water is obtained from a lesser quality source, additional treatment may be required to prevent biofouling in the tower.

The estimated annual O&M costs presented below are for cooling towers designed at a delta of 10 degrees. To calculate annual O&M costs for various types of cooling towers, EPA made the following assumptions:

- For small cooling towers, the annual O&M costs for chemical costs and routine preventive maintenance is estimated at 5 percent of capital costs. To account for economy of scale in these components of the O&M cost, that percentage is gradually decreased to 2 percent for the largest size cooling tower. EPA notes that, while there appear to be economies of scale for these components of O&M costs, chemical and routine preventive maintenance costs represent a small percentage of the total O&M costs and EPA does not believe there to be significant economies of scale in the total O&M costs.

- 2 percent of the tower flow is lost to evaporation and/or blowdown.

- To account for the costs of makeup water and disposal of blowdown water, EPA used three scenarios at proposal, as documented in the *Economic and Engineering Analyses of the Proposed §316(b) New Facility Rule* (EEA). The first scenario is based on the facility using surface water sources for makeup water and disposing of blowdown water either to a pond or back to the surface water source at a combined cost of $0.5/1000 gallons. The second scenario is based on the facility using gray water (treated municipal wastewater) for makeup water and disposing of the blow down water into a POTW sewer line at a combined cost of $3/1000 gallons. The third scenario is based on the facility using municipal sources for clean makeup water and disposing of the blowdown water into a POTW sewer line at a combined cost of $4/1000 gallons. For the final §316(b) New Facility Rule, EPA based all cooling tower O&M costs on Scenario 1 (use of surface water sources for makeup water and disposal of blowdown water either to a pond or back to the surface water source).

- Based on discussions with industry representatives, the largest component of total O&M costs is the requirement for major maintenance of the tower that occurs after years of tower service, such as around the 10th year and 20th years of service. These major overhauls include repairs to mechanical equipment and replacement of 100 percent of fill material and eliminators.

To account for the variation in maintenance costs among cooling tower types, a scaling factor is used. Douglas Fir is the type with the greatest maintenance cost, followed by Redwood, steel, concrete, and fiberglass. For additional cooling tower features, a scaling factor was used to account for the variations in maintenance (e.g., splash fill and non-fouling film fill are the features with the lowest maintenance costs).

Using the operation cost comparison information published by Mirsky et al. (1992) and maintenance cost assumptions set out above, EPA calculated estimated costs of O&M for various types of cooling towers with and without additional features. EPA then developed cost equations from the generated cost data points, as documented in the proposal EEA. In preparing O&M cost estimates for the final rule, EPA discovered an error in how the costs for major maintenance were calculated in the proposal EEA. In the proposal EEA, these costs were calculated as annual costs following the years that they were to occur. However, some of these costs actually represent one-time costs. This calculation error caused the O&M cost estimates in the proposal EEA to be in error on the high side. EPA's total O&M cost estimates in the proposal EEA were (for Douglas fir cooling towers, for example) about 25-30 percent of the cooling tower capital cost. EPA's revised calculations indicate that the correct value for total O&M costs should be about 50 percent lower. EPA updated the O&M cost curves for the first scenario for the redwood towers which were used in developing cost estimates for the final rule, and for the concrete towers which were used in the sensitivity analysis for the final rule cost estimates. The updated equations and costs are shown in Tables 2-17 through 2-20 for the first scenario for redwood towers with various features. Updated cost curves and equations for O&M costs for redwood and concrete cooling towers are also presented at the end of the chapter. O&M cost curves and equations contained in the EEA for other types of towers and for the other scenarios would need to be updated in a similar manner before being used to develop cost estimates.

Note that these cost estimates and equations are for total O&M costs. Stone and Webster (1992) presents a value for additional annual O&M costs equal to approximately 0.7 percent of the capital costs for a retrofit project. Stone and Webster's estimate is for the amount O&M costs are expected to *increase* when plants with once-through cooling systems are retrofit with cooling towers to become recirculating systems, and therefore do not represent total O&M costs.

Table 2-17. Total Annual O&M Cost Equations for Redwood Towers - 1st Scenario

Cooling Tower Material Type	Total Annual O&M Cost Equations[1]	Correlation Coefficient
Redwood	$y = -4E\text{-}06x^2 + 10.617x + 2055.2$	$R^2 = 0.9999$

1) x is flow in gpm and y is annual O&M cost in dollars.

Table 2-18. Total Estimated Annual O&M Costs for Redwood Towers - 1st Scenario (1999 Dollars)

Flow (gpm)	Redwood Tower
2000	$22,000
4000	$43,000
7000	$76,000
9000	$97,000
11,000	$119,000
13,000	$140,000
15,000	$162,000
17,000	$184,000
18,000	$194,000
22,000	$234,000
25,000	$265,000
28,000	$297,000
29,000	$308,000
31,000	$329,000
34,000	$361,000
36,000	$382,000
45,000	$469,000
47,000	$490,000
56,000	$584,000
63,000	$657,000
67,000	$699,000
73,000	$761,000
79,000	$809,000
94,000	$963,000
102,000	$1,045,000
112,000	$1,147,000
146,000	$1,496,000
157,000	$1,580,000
204,000	$2,015,000

Table 2-19. Total Annual O&M Cost Equations - 1st scenario for Redwood Towers with Environmental Mitigation Features[1]

Type of Tower	O&M Cost Equations[2]	Correlation Coefficient
Non-Fouling Film Fill tower	$y =-4E-06x^2 + 11.163x + 2053.7$	$R^2 = 0.9999$
Noise reduction (10dBA)	$y = -5E-06x^2 + 12.235x + 2512.5$	$R^2 = 0.9999$
Hybrid tower (Plume Abatement 32DBT)	$y = -1E-05x^2 + 21.36x + 5801.6$	$R^2 = 0.9998$
Splash Fill tower	$y = -4E-06x^2 + 11.163x + 2053.7$	$R^2 = 0.9999$
Dry/wet tower	$y = -1E-05x^2 + 25.385x + 7328.1$	$R^2 = 0.9998$

1) Features include non-fouling film, noise reduction, plume abatement, or splash fill
2) x is flow in gpm and y is annual O&M cost in dollars.

Table 2-20. Total Estimated Annual O&M Costs - 1st scenario for Redwood with Environmental Mitigation Features (1999 Dollars)

Flows (gpm)	Splash Fill Tower	Non-Fouling Film Fill Tower	Hybrid Tower (Plume abatement (32DBT	Dry/Wet Tower	Noise Reduction (10dBA)
2000	$24,000	$23,000	$44,000	$25,000	$52,000
4000	$47,000	$45,000	$88,000	$50,000	$104,000
7000	$83,000	$79,000	$153,000	$87,000	$182,000
9000	$106,000	$102,000	$197,000	$112,000	$234,000
11,000	$130,000	$125,000	$241,000	$137,000	$286,000
13,000	$153,000	$148,000	$284,000	$162,000	$339,000
15,000	$177,000	$170,000	$328,000	$187,000	$391,000
17,000	$201,000	$193,000	$372,000	$212,000	$443,000
18,000	$212,000	$204,000	$394,000	$224,000	$469,000
22,000	$256,000	$245,000	$469,000	$269,000	$558,000
25,000	$290,000	$279,000	$533,000	$306,000	$634,000
28,000	$325,000	$312,000	$597,000	$342,000	$710,000
29,000	$337,000	$323,000	$619,000	$354,000	$735,000
31,000	$360,000	$346,000	$661,000	$379,000	$786,000
34,000	$395,000	$379,000	$725,000	$416,000	$862,000
36,000	$418,000	$402,000	$768,000	$440,000	$913,000
45,000	$514,000	$493,000	$935,000	$539,000	$1,110,000
47,000	$537,000	$515,000	$977,000	$563,000	$1,159,000
56,000	$640,000	$613,000	$1,164,000	$671,000	$1,381,000
63,000	$720,000	$690,000	$1,309,000	$755,000	$1,554,000
67,000	$766,000	$733,000	$1,392,000	$803,000	$1,652,000
73,000	$834,000	$799,000	$1,517,000	$875,000	$1,800,000
79,000	$888,000	$849,000	$1,598,000	$928,000	$1,893,000
94,000	$1,057,000	$1,010,000	$1,901,000	$1,104,000	$2,253,000
102,000	$1,147,000	$1,096,000	$2,063,000	$1,198,000	$2,445,000
112,000	$1,259,000	$1,203,000	$2,265,000	$1,315,000	$2,684,000
146,000	$1,642,000	$1,569,000	$2,953,000	$1,714,000	$3,499,000
157,000	$1,737,000	$1,655,000	$3,088,000	$1,806,000	$3,654,000
204,000	$2,219,000	$2,109,000	$3,900,000	$2,298,000	$4,607,000

Variable speed pumps

For a power plant operating at near constant power output (e.g., at or near capacity), the amount of heat rejected through the cooling system will also remain nearly constant regardless of changes in ambient conditions. In cooling systems where heat from steam condensation is transferred to cooling water (i.e., those that use surface condensers), the amount of heat rejected can be measured as the product of the cooling water flow rate times the difference in temperature of the cooling water between the condenser inlet and outlet. If the cooling water flow rate remains constant, then the temperature difference will also remain relatively constant regardless of changes in the inlet temperature. Therefore, a decrease in the cooling water temperature at the condenser inlet will result in a similar decrease in the condenser outlet temperature and a corresponding decrease in the temperature of the condenser surface where steam is condensed.

As described in Chapter 3 on the energy penalty, a decrease in condenser temperatures will produce a decrease in the turbine exhaust, which can result in an increase in the turbine efficiency. Thus, seasonal changes in ambient source water temperature will result in changes in the condenser temperatures, which can affect the steam turbine efficiency. However, as the ambient and condenser temperatures progressively drop, the system performance can approach a point where turbine efficiency no longer increases and may begin to decrease. In addition, significantly reduced turbine exhaust pressures can result in condensed moisture within the turbine, which can damage turbine blades and further reduce turbine efficiency. Thus, progressive reductions in the cooling water temperature in a cooling system operating at a constant cooling water flow rate may approach a point where continued reduction in ambient temperatures results in detrimental or less than optimal operating conditions. The ambient conditions at which this begins to occur will be dependent on the cooling and turbine system design, which is often subject to site-specific and economic considerations.

In a once-through cooling system, one method of controlling the steam condenser temperature is to control the cooling water flow rate. If the heat rejection rate remains relatively constant (near constant plant output), a reduction in the cooling water flow rate will result in an increase in the difference in temperature of the cooling water between the condenser inlet and outlet (referred to as the “range”). An increase in the range will result in an increase in the temperature of the steam condensing surface. Therefore, through careful control of the cooling water flow rate, the condenser temperature can be controlled such that the power plant turbine performance does not degrade and damaging conditions are avoided. Thus, the ability to reduce cooling water flow rate can provide for improved plant operation as well as reducing the environmental impacts of cooling water withdrawals from surface waters.

Use of variable speed pumps is an efficient method for attaining control of the cooling water flow rate and thus the condenser performance. Variable frequency drives are used to vary the pump speed, which in turn allows the flow rate to be adjusted through a range from zero to its maximum output.

There are some limitations on the range of flow rates that can be used. Most once-through cooling systems discharge to surface waters under an NPDES permit, which often includes discharge limits on both the maximum temperature (a concern during the warmer months) and the temperature increase of the discharge over the intake temperature (a concern if flow rates are adjusted). Exceedence of the maximum temperature limit can be avoided by operating at the maximum cooling water flow rate and, when necessary, reducing the plant output (i.e., the heat rejection rate). The limit on temperature increase may create an effective lower limit on the cooling water flow rate (at a given heat rejection rate) in the sense that further reduction in cooling water flow rate would result in a temperature rise that exceeded the NPDES temperature increase limitation. These constraints, however, do not prevent varying the cooling water flow rate; rather, they set the range in flow rates (for a given plant power output level) over which the system may operate. Note that varying the cooling water flow rate does not change the amount of heat being discharged. Rather, it only affects the “concentration” of the heat. Limitation of the temperature increase is intended to reduce detrimental impacts on entrained organisms, as well as on those in the mixing zone downstream.

EPA chose to include the cost of variable frequency drives as part of the pump costs for the post-compliance cost estimates for all once-though systems and for wet tower system intakes. While condenser performance is not affected by using variable speed pumps in the wet tower make-up water intake, EPA included them to provide greater process control. For the baseline system costs to which post-compliance costs are compared, EPA used the costs for constant speed pumps even though facilities may install variable speed pumps regardless of the rule's implementation. EPA chose this approach as a means for generating a conservative (on the high side) compliance cost estimate.

A recent evaluation of the equipment cost for variable speed pumps indicates that EPA may have underestimated the cost for the variable frequency drive component of the pumping system. Recent investigation of estimated costs for VFDs from other sources indicates that the unit cost of $100/Hp obtained from the original contact is lower than estimates from these other sources. EPA has re-evaluated the costs for addition of VFDs using data from these other sources. See DCN 3-3038. EPA finds that the contribution to capital cost from the uncertainty of variable speed drive costs is not appreciable for the final annualized compliance costs of the effected facilities. Analogous to the sensitivity analysis performed on the material of construction of the cooling towers of coal-fired plants (i.e., concrete vs. redwood), the percentage of capital cost due to the uncertainty, when amortized over the appropriate period would not significantly influence total annualized compliance costs.

Pump Equipment Cost Development

The distinction between constant and variable speed pumping systems is the presence of variable frequency drives (VFD). A pump supplier estimated that the unit cost of the variable frequency drives was approximately $100/Hp (Flory 2001). This unit cost is consistent with the cost of a VFD of $20,000 to $30,000 cited for a 200 Hp fan for an air cooled condenser (Tallon 2001). Table 2-21 provides a summary of the data that EPA used to develop the equipment costs for constant speed and variable speed pumps.

Table 2-21: Pump Cost Data (Source: Flory 2001)

Flow (gpm)	Brake-Hp at 50 ft Pumping Head[1]	Pump and Motor with Freight and Tax[2]	Variable Frequency Drive	Total with Variable Frequency Drive
5,000	90	$23,000	$9,015	$32,015
50,000	902	$115,000	$90,150	$205,150
250,000	3,606	$402,500	$360,600	$763,100

[1] Based on flow and a pumping head of 50 ft.
[2] Includes 15 percent for cost of freight and tax.

EPA also included pump installation costs, with the value scaled from 60 percent of equipment costs at 500 gpm to 40 percent at 350,000 gpm.

Table 2-22 presents cost equations for estimating capital costs for variable speed pumps. Cost curves and equations for variable speed pumps are also presented at the end of this chapter.

Table 2-22. Capital Cost Equations for Constant Speed and Variable Speed Pumps

Pump Type	Capital Cost Equation[1]	Correlation Coefficient
Constant Speed	$y = 1.6859x + 13369$	$R^2 = 0.9998$
Variable Speed	$y = 3.1667x + 16667$	$R^2 = 1$

1) x is flow in gpm and y is cost in dollars.

Using non-surface water sources

A facility may be able to obtain some of its cooling water from a source other than the surface water it is using (WWTP gray water, ground water, or municipal water supply) and thereby reduce the volume of its withdrawals from the surface water and meet the percent of flow requirements. Some facilities may only need to use this alternate source during low flow periods in the surface water source. To use this option, a facility would need to build a pond or basin for the supplemental cooling water.

A facility using gray water may need to install some water treatment equipment (e.g., sedimentation, filtration) to ensure that its discharge of the combined source water and gray water meets any applicable effluent limits. For costing purposes, EPA has assumed that a facility would only need to install treatment for gray water in situations where treatment would have been required for river intake water. Therefore, no additional (i.e., "new") costs are incurred for treatment of gray water after intake or before discharge.

See the end of this chapter for cost curves and equations for estimating gray water and municipal water costs.

2.9.2 Reducing Design Intake Velocity

Passive screens

Passive screens, typically made of wedge wire, are screens that use little or no mechanical activity to prevent debris and aquatic organisms from entering a cooling water intake. The screens reduce impingement and entrainment by using a small mesh size for the wedge wire and a low through-slot velocity that is quickly dissipated. The main components of a passive screening system are typically the screen(s), framing, an air backwash system if needed, and possibly guide rails depending on the installation location.

Passive screens vary in shape and form and include flat panels, curved panels, tee screens, vee screens, and cylinder screens. Screen dimensions (width and depth) vary; they are generally made to order with sizing as required by site conditions. Panels can be of any size, while cylinders are generally in the 12" to 96" diameter range. The main advantages of passive intake systems are:

- They are fish-friendly due to low slot velocities (peak <0.5 fps), and
- They have no moving parts and thus minimal O&M costs.

New passive intake screens have higher capacity (due to higher screen efficiency) than older versions of passive screens. Wedge wire screens are effective in reducing impingement and entrainment as long as a sufficiently small screen slot size is used and ambient currents have enough velocity to move aquatic organisms around the screen and flush debris away.

The key parameters and additional features that are considered in estimating the cost of passive/wedge wire screening systems on CWIS are:

- Size of screen and flow rate (i.e., volume of water used),
- Size of screen slots/openings,
- Screen material,
- Water depth,
- Water quality (debris, biological growth, salinity), and
- Air backwash systems.

The size and material of a screen most affect cost. Branched intakes, with a screen on each branch, can be used for large flows. Screen slot size also impacts the size of a screen. A smaller slot opening will result in a larger screen being required to keep the peak slot velocity under 0.5 fps.

Site-specific conditions significantly affect costs of the screen(s). The water depth affects equipment and installation costs because structural reinforcement is required as depth increases, air backwash system capacities need to be increased due to the reduced air volume at greater depths, and installation is generally more difficult. The potential for clogging from debris and fouling from biogrowth are water quality concerns that affect costs. The amount and type of debris influence the size of openings in the screen, which affects water flow through the screen and thus screen size. Finer debris may require a smaller slot opening to prevent debris from entering and clogging the openings.

Generally, speed and flow of water do not affect the installation cost or the operation of passive intakes, however there must be adequate current in the source water to carry away debris that is backwashed from the screen so that it does not become (re)clogged. It is recommended as good engineering practice that the axis of the screen cylinder be oriented parallel with the water flow to minimize fish entrainment and to aid in removal of debris during air backwash. The effects of the presence of sensitive species or certain types of species affect the design of the screen and may increase screen cost. For example, the lesser strength of a local species could result in the need for a peak velocity less than 0.5 fps which would result in a larger screen. Biofouling from the attachment of zebra mussels and barnacles and the growth of algae may necessitate the use of a special screen material, periodic flushing with biocides, and in limited cases, manual cleaning by divers. For example, the presence of zebra mussels often requires the use of a special alloy material to prevent attachment to the screen assembly.

The level of debris in the water also affects whether an air backwash system is needed and how often it is used. Heavy debris loadings may dictate the need for more frequent air backwashing. If the air backwash frequency is high enough, a larger compressor may be required to recharge the accumulator tank more quickly.

Another water quality factor that affects screen cost is water corrosiveness (e.g., whether the intake water is seawater, freshwater, or brackish). Most passive screens are manufactured in either 304 or 316 stainless steel for freshwater installations. The 316L stainless steel can be used for some saltwater installations, but has limited life. Screens made of copper-nickel alloys (70/30 or 90/10) have shown excellent corrosion resistance in saltwater, however they are significantly more expensive than stainless steel (50 percent to 100 percent greater in cost, i.e., can be double the cost).

Capital Costs

EPA assumed that the capital cost of passive screens will be 60 percent of the capital cost of a basic traveling screen of similar size. This assumption is based on discussions with industry representatives. The lower capital cost is because passive screen systems have lower onshore site preparation and installation costs (no extensive mechanical equipment as in the traveling screens) and are easier to install in offshore situations. The estimated capital costs for passive screens are shown in Table 2-23, corresponding to the flows shown in Table 2-31 for a through screen velocity of 0.5 fps. Passive screens for sizes larger than those shown in Table 2-23 will generate flows higher than 50,000 gpm. For flows greater than 50,000 gpm, particularly when water is drawn in from a river, the size of the CWIS site becomes very big and the necessary network fanning for intake points and screens generally makes passive screen systems unfeasible.

Table 2-23 Estimated Capital Costs for a Through Flow Passive Water Screen Stainless Steel 304 - Standard Design[1] (1999 Dollars)

Well Depth (ft)	Screen Panel Width (ft) 2	5	10	14
10	$34,200	$56,100	$91,800	$128,700
25	$49,800	$84,900	$140,400	(2)
50	$74,400	$122,700	(2)	(2)
75	$99,000	(2)	(2)	(2)
100	$135,600	(2)	(2)	(2)

1) Cost estimate includes stainless steel 304 structure.
2) Not estimated because passive screen systems of this size are not feasible.

As noted above, the capital costs for special screen materials (e.g., copper-nickel alloys) are typically 50 percent to 100 percent higher.

Table 2-24 presents cost equations for estimating capital costs for passive screens. The "x" in the equation represents the flow volume in gpm and the "y" value is the passive screen total capital cost. Cost equations associated with a flow of 1 fps are provided for comparative purposes.

Table 2-24. Capital Cost Equations for Passive Screens

Screen Width (ft)	Passive Screens Velocity 0.5 ft/sec: Equation[1]	Passive Screens Velocity 0.5 ft/sec: Correlation Coefficient	Passive Screens Velocity 1ft/sec: Equation[1]	Passive Screens Velocity 1ft/sec: Correlation Coefficient
2	$y = 3E\text{-}08x^3 - 0.0008x^2 + 12.535x + 11263$	$R^2 = 0.9991$	$y = 5E\text{-}09x^3 - 0.0002x^2 + 6.5501x + 9792.6$	$R^2 = 0.9991$
5	$y = 0.0002x^2 + 1.5923x + 47041$	$R^2 = 1$	$y = 4E\text{-}05x^2 + 1.0565x + 43564$	$R^2 = 1$
10	$y = 3.7385x + 58154$	$R^2 = 1$	$y = 1.8x + 59400$	$R^2 = 1$

1) x is the flow in gpm y is the capital cost in dollars.

See the end of this chapter for cost curves and equations.

Operation and Maintenance (O&M) Costs for Passive Screens

Generally, there are no appreciable O&M costs for passive screens unless there are biofouling problems or zebra mussels in the environment. Biofouling problems can be remedied through the proper choice of materials and periodic mechanical cleaning. Screens equipped with air backwash systems require periodic compressor/motor/valve maintenance. Therefore, EPA has estimated zero O&M costs for passive screens.

Velocity Caps

The cost driver of velocity caps is the installation cost. Installation is carried out underwater where the water intake mouth is modified to fit the velocity cap over the intake. EPA estimated capital costs for velocity caps based on the following assumptions:

- Four velocity caps can be installed in a day,
- Cost of the installation crew is similar to the cost of the water screen installation crew (see Box 2-1),
- To account for the difficulty in installing in deep water, an additional work day is assumed for every increase in depth size category, and
- Equipment cost for a velocity cap is assumed to be 25 percent of the velocity cap installation cost. In our BPJ, this is a conservatively high estimate of the cost of velocity cap material and delivery to the installation site.

Based on these assumptions, EPA calculated estimated costs for velocity caps, which are shown in Tables 2-25 and 2-26. EPA calculated the number of velocity caps needed for various flow sizes based on a flow velocity of 0.5ft/sec and assuming that the intake area to be covered by the velocity cap is 20 ft^2 which is the area comparable to a pipe diameter of about 5 feet. For flows requiring pipes larger than this, EPA assumed, for velocity cap costing purposes, that multiple intake pipes with a standard, easy-to-handle pipe diameter will be used rather than larger-diameter, custom made pipes (based on BPJ). Cost curves and equations are at the end of the chapter.

Table 2-25. Estimated Velocity Cap Installation Costs (1999 Dollars)

Flow (gpm) (No. of velocity caps)	**Water Depth (ft)**				
	8	**20**	**30**	**50**	**65**
Up to 18,000 (4 VC)	$8000	$12,500	$17,000	$21,500	$26,000
18,000 ≤ flow <35,000 (9 VC)	$12,500	$17,000	$21,500	$26,000	$30,500
35,000≤ flow <70,000 (15 VC)	$21,500	$26,000	$30,500	$35,000	$39,500
70,000≤ flow <100,000 (23 VC)	$30,500	$35,000	$39,500	$44,000	$48,500
157,000 (35 VC)	$44,000	$48,500	$53,000	$57,500	$62,000
204,000 (46 VC)	$57,500	$62,000	$66,500	$71,000	$75,500

Table 2-26. Estimated Velocity Cap Equipment and Installation Costs (1999 Dollars)

Flow (gpm) (No. of velocity caps)	Water Depth (ft)				
	8	20	30	50	65
Up to 18,000 (4 VC)	\$10,000	\$15,625	\$21,250	\$26,875	\$32,500
18,000 ≤ flow <35,000 (9 VC)	\$15,625	\$21,250	\$26,875	\$32,500	\$38,125
35,000≤ flow <70,000 (15 VC)	\$26,875	\$32,500	\$38,125	\$43,750	\$49,375
70,000≤ flow <100,000 (23 VC)	\$38,125	\$43,750	\$49,375	\$55,000	\$60,625
157,000 (35 VC)	\$55,000	\$60,625	\$66,250	\$71,875	\$77,500
204,000 (46 VC)	\$71,875	\$77,500	\$83,125	\$88,750	\$94,375

Table 2-27. Cost Equations for Velocity Cap Capital Costs

Flow (gpm) (No. of velocity caps)	Velocity Cap Capital Cost Equation	Correlation Coefficient
Up to 18,000 (4 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 4212.7$	$R^2 = 0.9962$
18,000 ≤ flow <35,000 (8 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 9837.7$	$R^2 = 0.9962$
35,000≤ flow <70,000 (16 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 21088$	$R^2 = 0.9962$
70,000≤ flow <100,000 (24 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 32338$	$R^2 = 0.9962$
157,000 (35 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 49213$	$R^2 = 0.9962$
204,000 (46 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 66088$	$R^2 = 0.9962$
1) x represents the water depth in feet and y is the capital cost in dollars.		

Installation of Gunderboom Marine Life Exclusion Systems (MLES)

A Gunderboom Marine Life Exclusion System (MLES) utilizes a stationary double-layered filter barrier curtain to prevent entrainment and impingement of aquatic organisms around the CWIS. The MLES consists of a patented filter curtain made of polypropylene/polyester fabric suspended through the full depth of the water column.

Gunderbooms allow for the passage of water, while preventing the passage of aquatic life and particulates into the CWIS. This is achieved by surrounding the intake structure with the filter curtain and sealing the curtain against the seafloor and shoreline structures. Water passing through the curtain does so at a lower velocity than that of the surrounding stream or water body. The MLES system is designed to allow a through-fabric velocity of approximately 0.01 to 0.05 feet/second (fps), yielding an average velocity of approximately 0.02 fps. The system may be designed for lower or higher flows, as needed.

The Gunderboom is enhanced by an automated "Air Burst" cleaning system. This system uses periodic bursts of air between the two fabric layers to free any organisms or debris caught against the filter curtain.

Based on information provided by the manufacturer, the main advantages of the MLES system are:

- The system has been demonstrated to reduce entrainment by at least 80 percent. According to Gunderboom, the MLES can produce up to 100 percent exclusion for many applications.
- The Gunderboom fabric consists of a minute fiber matting with an Apparent Opening Size (AOS) of approximately 20 microns. As such, the system has been shown to significantly reduce turbidity, suspended solids, coliform bacteria, and other particulate-associated contaminants. For MLES systems, perforations ranging in diameter from 0.4 mm to 3.0 mm or more are added to increase the flow of water through the fabric. Perforation size can be customized to prevent entrainment of the specific eggs or fish larvae that are present at the installation site.
- The double fabric layer system with an "Air Burst" Technology cleaning system reduces overall O&M costs. Since debris and sediment are excluded, the Gunderboom may also help reduce O&M costs for intake screens, condensers and other parts of the cooling water system.
- Once the anchoring and "Air Burst" Technology have been installed, deployment of the MLES can be achieved in two to three weeks, barring logistics or weather problems, and requires no or minimal plant shutdown.

Gunderbooms are designed and engineered for the specific site at which they are to be installed. The designs may include plant intakes, floating walkways, pile-supported structures, concrete submerged structures, removable panels and solid frames. However, and in general, the key parameters that may have a significant impact on estimating the cost of the Gunderboom system are:

- CWIS flow rates,
- Physical factors of the water body and facility intake structure,
- Target species and life stages,
- Water body characteristics, including elevation changes, currents, wind-induced wave action and suspended sediment concentrations,
- Degree of automation, and
- Water quality

Factors such as the CWIS flow rates and physical factors of the water body and intake structure affect the capital cost because they determine the required size of the Gunderboom filter curtain. Other factors such as water quality and degree of automation contribute to greater O&M costs.

Installation

The Gunderboom MLES installation cost is largely a function of site conditions. Strong current flow, winds, wave action, and low accessibility can make installation more difficult. However, for the purpose of developing national cost estimates, EPA did not consider abnormal conditions in developing its cost equations and cost curves.

Capital Costs

EPA estimated capital costs of the MLES system based on information submitted by representatives of Gunderboom, Inc. Low and high capital cost estimates were provided for flows of 10,000, 104,000, and 347,000 gpm. EPA then calculated average capital costs as shown in Table 2-28. For purposes of estimating costs, EPA assumed that a simple floating configuration, as opposed to a rigid configuration, would be used.

Table 2-28. Estimated Capital Costs for a Simple Floating Gunderboom Structure

Flow (gpm)	Low Cost	High Cost	Average Cost
10,000	$500,000	$700,000	$600,000
104,000	$1,800,000	$2,500,000	$2,150,000
347,000	$5,700,000	$7,800,000	$6,750,000

According to the manufacturers, the cost of a fixed system for a CWIS of 10,000 gpm capacity ranges between $0.7M and $1.5M while the cost of a complete independent system can be greater than $2M.

Operation and Maintenance (O&M) Costs

EPA also estimated O&M costs of the MLES system based on information submitted by representatives of Gunderboom, Inc. Low and high O&M cost estimates were provided for flows of 10,000, 104,000, and 347,000 gpm. EPA then calculated average O&M costs as shown in Table 2-29. Again, a simple floating configuration was assumed.

Table 2-29. Estimated O&M Costs for a Simple Floating Gunderboom Structure

Flow (gpm)	Low Cost	High Cost	Average Cost
10,000	$100,000	$300,000	$200,000
104,000	$150,000	$300,000	$225,000
347,000	$500,000	$700,000	$600,000

EPA plotted the high, low and average capital as well as the average O&M costs, then fitted equations and curves to the data as shown in Chart 2-30. In the cost equations, "x" represents the flow volume in gpm, and "y" represents the total capital or annual O&M cost.

Branching the intake pipe to increase the number of openings or widening the intake pipe

Branching an intake pipe involves the use of fittings to attach the separate pipe sections. See the end of this chapter for costs curves and equations.

2.9.3 Design and Construction Technologies to Reduce Damage from I&E

Installation of traveling screens with fish baskets

Single-entry, single-exit vertical traveling screens (conventional 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 around, 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 continuously or intermittently. 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. Once the fish have been removed, a high pressure jet spray wash is typically used to remove debris from the screen. In recent years, the design of fish baskets has been refined (e.g., deeper baskets, smoother mesh, better balance) to decrease chances of injury and mortality and to better retain fish (i.e., prevent them from flopping out and potentially being injured). Methods used to protect fish include the Stabilized Integral Marine Protective Lifting Environment (S.I.M.P.L.E.) developed by Brackett Green and the Modified Ristroph design by U.S. Filter.

U.S. Filter's conventional (through flow) traveling screens are typically manufactured in widths ranging from two feet to at least 14 feet, for channel depths of up to 100 feet, although custom design is possible to fit other dimensions.

Flow

To calculate the flow through a screen panel, the width of the screen panel is multiplied by the water depth and, using the desired flow velocities (1 foot per second and 0.5 foot per second), is converted to gallons per minute assuming a screen efficiency of 50 percent. The calculated flows for selected screen widths, water depths, and well depths are presented in Tables 2-30 and 2-31. For flows greater than this, a facility would generally install multiple screens or use a custom design.

Well depth includes the height of the structure above the water line. The well depth can be more than the water depth by a few to tens of feet. The flow velocities used are representative of a flow speed that is generally considered to be fish friendly particularly for sensitive species (0.5 fps), and a flow speed that may be more practical for some facilities to achieve but typically provides less fish protection. The water depths and well depths are approximate and may vary based on actual site conditions.

Table 2-30. Average Flow Through A Traveling Water Screen (gpm) for a Flow Velocity of 1.0 fps

Well Depth (ft)	Water Depth (ft)	Basket Panel Screening Width (ft)			
		2	5	10	14
10	8	4000	9000	18,000	25,000
25	20	9000	22,000	45,000	63,000
50	30	13,000	34,000	67,000	94,000
75	50	22,000	56,000	112,000	157,000
100	65	29,000	73,000	146,000	204,000

Table 2-31. Average Flow Through A Traveling Water Screen (gpm) for a Flow Velocity of 0.5 fps

Well Depth (ft)	Water Depth (ft)	Basket Screening Panel Width (ft)			
		2	5	10	14
10	8	2000	4000	9000	13,000
25	20	4000	11,000	22,000	31,000
50	30	7000	17,000	34,000	47,000
75	50	11,000	28,000	56,000	79,000
100	65	15,000	36,000	73,000	102,000

Capital Costs

Equipment Cost

Basic costs for screens with flows comparable to those shown in the above tables are presented in Tables 2-32 and 2-33. Table 2-32 contains estimated costs for basic traveling screens without fish handling features, that have a carbon steel structure coated with epoxy paint. The costs presented in Table 2-33 are for traveling screens with fish handling features including a spray system, a fish trough, housings and transitions, continuous operating features, a drive unit, frame seals, and engineering. Installation costs and spray pump costs are presented separately below.

Table 2-32. Estimated Equipment Cost for Traveling Water Screens Without Fish Handling Features[1] (1999 Dollars)

Well Depth (ft)	Basket Screening Panel Width (ft)			
	2	5	10	14
10	$30,000	$35,000	$45,000	$65,000
25	$35,000	$45,000	$60,000	$105,000
50	$55,000	$70,000	$105,000	$145,000
75	$75,000	$100,000	$130,000	$175,000
100	$115,000	$130,000	$155,000	$200,000

1) Cost includes carbon steel structure coated with epoxy paint and non-metallic trash baskets with Type 304 stainless mesh and intermittent operation components.

Source: Vendor estimates.

Table 2-33. Estimated Equipment Cost for Traveling Water Screens With Fish Handling Features[1] (1999 Dollars)

Well depth (ft)	Basket Screening Panel Width (ft)			
	2	5	10	14
10	$63,500	$73,500	$94,000	$135,500
25	$81,250	$97,500	$133,000	$214,000
50	$122,500	$152,000	$218,000	$319,500
75	$163,750	$210,000	$283,000	$414,500
100	$225,000	$267,500	$348,000	$504,500

1) Cost includes carbon steel screen structure coated with epoxy paint and non-metallic fish handling panels, spray systems, fish trough, housings and transitions, continuous operating features, drive unit, frame seals, and engineering (averaged over 5 units). Costs do *not* include differential control system, installation, and spray wash pumps.

Source: Vendor estimates.

Installation Cost

Installation costs of traveling screens are based on the following assumptions of a typical average installation requirement for a hypothetical scenario. Site preparation and earth work are calculated based on the following assumptions:

- ***Clearing and grubbing*:** Clearing light to medium brush up to 4" diameter with a bulldozer.
- ***Earthwork*:** Excavation of heavy soils. Quantity is based on the assumption that earthwork increases with screen width.
- ***Paving and surfacing*:** Using concrete 8" thick and assuming that the cost of pavement attributed to screen installation is 6x3 yards for the smallest screen and 25x6 yards for the largest screen.
- ***Structural concrete*:** The structural concrete work attributed to screen installation is four 12"x12" reinforced concrete columns with depths varying between 1.5 yards and 3 yards. There is more structural concrete work for a water intake structure, however, for new source screens and retrofit screens, only a portion of the intake structural cost can be justifiably attributed to the screen costs. For new screens, most of the concrete structure work is for developing the site to make it accessible for equipment and protect it from hydraulic elements, which are necessary for constructing the intake itself. For retrofits, some of the structural concrete will already exist and some of it will not be needed since the intake is already in place and only the screen needs to be installed. All unit costs used in calculating on-shore site preparation were obtained from *Heavy Construction Cost Data 1998* (R. S. Means, 1997b).

Table 2-34 presents site preparation installation costs that apply to traveling screens both with and without fish handling features. The total onshore construction costs are for a screen to be installed in a 10-foot well depth. Screens to be installed in deeper water are assumed to require additional site preparation work. Hence for costing purposes it is assumed that site preparation costs increase at a rate of an additional 25 percent per depth factor (calculated as the ratio of the well depth to the base well depth of 10 feet) for well depths greater than 10 feet. Table 2-35 presents the estimated costs of site preparation for four sizes of screen widths and various well depths.

Table 2-34. Estimated Installation (Site Preparation) Costs for Traveling Water Screens Installed at a 10-foot Well Depth (1999 Dollars)

Screen Width (ft)	Clearing and Grubbing (acre)	Clearing Cost[1]	Earth Work (cy)	Earth Work Cost[1]	Paving and Surfacing Using Concrete (sy)	Paving Cost[1]	Structural Concrete (cy)	Structural Cost	Total Onshore Construction Costs
2	0.1	$250	200	$17,400	18	$250	0.54	$680	$19,000
5	0.35	$875	500	$43,500	40	$560	0.63	$790	$46,000
10	0.7	$1,750	1000	$87,000	75	$1,050	0.72	$900	$91,000
14	1	$2,500	1400	$121,800	150	$2,100	1.08	$1,350	$128,000

ft = feet, cy=cubic yard, sy=square yard
1) Clearing cost @ $2,500/acre, earth work cost @ $87/cubic yard, paving cost @ $14/square yard, structural cost @ $1,250/cubic yard.

Source of unit costs: *Heavy Construction Cost Data 1998* (R.S. Means, 1997b).

Table 2-35. Estimated Installation (Site Preparation, Construction, and Onshore Installation) Costs for Traveling Water Screens of Various Well Depths (1999 Dollars)

Well Depth (ft)	Screen Panel Width (ft) 2	5	10	14
10	$19,000	$46,000	$91,000	$128,000
25	$31,000	$75,000	$148,000	$208,000
50	$43,000	$104,000	$205,000	$288,000
75	$55,000	$132,000	$262,000	$368,000
100	$67,000	$161,000	$319,000	$448,000

Source: R.S. Means (1997b) and vendor estimates.

EPA developed a hypothetical scenario of a typical underwater installation to estimate an average cost for underwater installation costs. EPA estimated costs of personnel and equipment per day, as well as mobilization and demobilization. Personnel and equipment costs would increase proportionately based on the number of days of a project, however mobilization and demobilization costs would be relatively constant regardless of the number of days of a project since the cost of transporting personnel and equipment is largely independent of the length of a project. The hypothetical project scenario and estimated costs are presented in Box 2-1. Hypothetical scenario was used to develop installation cost estimates as function of screen width/well depth. Installation costs were then included with total cost equations. To cost facilities, EPA selected appropriate screen width based on flow.

As shown in the hypothetical scenario in Box 2-1, the estimated cost for a one-day installation project would be $8,000 ($4,500 for personnel and equipment, plus $3,500 for mobilization and demobilization). Using this one-day cost estimate as a basis, EPA generated estimated installation costs for various sizes of screens under different scenarios. These costs are presented in Table 2-35. The baseline costs for underwater installation include the costs of a crew of divers and equipment including mobilization and demobilization, divers, a barge, and a crane. The number of days needed is based on a minimum of one day for a screen of less than 5 feet in width and up to 10 feet in well depth. Using best professional judgement (BPJ), EPA estimated the costs for larger jobs assuming an increase of two days for every increase in well depth size and of one day for every increase in screen width size.

Box 2-1. Example Scenario for Underwater Installation of an Intake Screen System

This project involves the installation of 12, t-24 passive intake screens onto a manifold inlet system. Site conditions include a 20-foot water depth, zero to one-foot underwater visibility, 60-70 °F water temperature, and fresh water at an inland. The installation is assumed to be 75 yards offshore and requires the use of a barge or vessel with 4-point anchor capability and crane.

Job Description:
Position and connect water intake screens to inlet flange via 16 bolt/nut connectors. Lift, lower, and position intake screens via crane anchored to barge or vessel. Between 4 and 6 screens of the smallest size can be installed per day per dive team, depending on favorable environmental conditions.

Estimated Personnel Costs:
Each dive team consists of 5 people (1 supervisor, 2 surface tenders, and 2 divers), the assumed minimum number of personnel needed to operate safely and efficiently. The labor rates are based on a 12-hour work day. The day rate for the supervisor is $600. The day rate for each diver is $400. The day rate for each surface tender is $200. Total base day rate per dive team is $1,800.

Estimated Equipment Costs:
Use of hydraulic lifts, underwater impact tools, and other support equipment is $450 per day. Shallow water air packs and hoses cost $100 per day. The use of a crane sufficient to lift the 375 lb t-24 intakes is $300 per day. A barge or vessel with 4-point anchor capability can be provided by either a local contractor or the dive company for $1,800 per day (cost generally ranges from $1,500-$2,000 per day). This price includes barge/vessel personnel (captain, crew, etc) but the barge/vessel price does not include any land/waterway transportation needed to move barge/vessel to inland locations. Using land-based crane and dive operations can eliminate the barge/vessel costs. Thus total equipment cost is $2,650 per day.

Estimated Mobilization and Demobilization Expenses:
This includes transportation of all personnel and equipment to the job site via means necessary (air, land, sea), all hotels, meals, and ground transportation. An accurate estimate on travel can vary wildly depending on job location and travel mode. For this hypothetical scenario, costs are estimated for transportation with airfare, and boarding and freight and would be $3,500 for the team (costs generally range between $3,000 and $4,000 for a team).

Other Considerations:
Uncontrollable factors like weather, water temperature, water depth, underwater visibility, currents, and distance to shore can affect the daily production of the dive team. These variables always have to be considered when a job is quoted on a daily rate. Normally, the dive-company takes on the risks for these variables because the job is quoted on a "to completion" status. These types of jobs usually take a week or more for medium to large-size installations.

Total of Estimated Costs:
The final estimated total for this hypothetical job is nearly $4500 per day for personnel and equipment. For a three-day job, this would total about $13,500. Adding to this amount about $3,500 for mobilization and demobilization, the complete job is estimated at $17,000.

Note: Costs for a given project vary greatly depending on screen size, depth of water, and other site-specific conditions such as climate and site accessibility.

Table 2-36. Estimated Underwater Installation Costs for Various Screen Widths and Well Depths[1] (1999 Dollars)

Well Depth (ft)	Basket Screening Panel Width (ft)			
	2	5	10	14
10	$8,000	$12,500	$17,000	$21,500
25	$17,000	$21,500	$26,000	$30,500
50	$26,000	$30,500	$35,000	$39,500
75	$35,000	$39,500	$44,000	$48,500
100	$44,000	$48,500	$53,000	$57,500

1) Based on hypothetical scenario of crew and equipment costs of $4,500 per day and mobilization and demobilization costs of $3,500 (see Box 2-1).

Table 2-37 presents total estimated installation costs for traveling screens. Installation costs for traveling screens with fish handling features and those without fish handling features are assumed to be similar.

Table 2-37. Estimated Total Installation Costs for Traveling Water Screens[1] (1999 Dollars)

Well Depth (ft)	Basket Screening Panel Width (ft)			
	2	5	10	14
10	$27,000	$58,500	$108,000	$149,500
25	$48,000	$96,500	$174,000	$238,500
50	$69,000	$134,500	$240,000	$327,500
75	$90,000	$171,500	$306,000	$416,500
100	$111,000	$209,500	$372,000	$505,500

1) Includes site preparation, and onshore and underwater construction and installation costs.

Total Estimated Capital Costs

The installation costs in Table 2-37 were added to the equipment costs in Tables 2-32 and 2-33 to derive total equipment and installation costs for traveling screens with and without fish handling features. These estimated costs are presented in Tables 2-38 and 2-39. The flow volume corresponding to each screen width and well depth combination varies based on the through screen flow velocity. These flow volumes were presented in Tables 2-30 and 2-31 for flow velocities of 1.0 fps and 0.5 fps, respectively.

Table 2-38. Estimated Total Capital Costs for Traveling Screens Without Fish Handling Features (Equipment and Installation)[1] (1999 Dollars)

Well Depth (ft)	Screening Basket Panel Width (ft) 2	5	10	14
10	$57,000	$93,500	$153,000	$214,500
25	$83,000	$141,500	$234,000	$343,500
50	$124,000	$204,500	$345,000	$472,500
75	$165,000	$271,500	$436,000	$591,500
100	$226,000	$339,500	$527,000	$705,500

1) Costs include carbon steel structure coated with an epoxy paint, non-metallic trash baskets with Type 304 stainless mesh, and intermittent operation components and installation.

Table 2-39. Estimated Total Capital Costs for Traveling Screens With Fish Handling Features (Equipment and Installation)[1] (1999 Dollars)

Well Depth (ft)	Screening Basket Panel Width (ft) 2	5	10	14
10	$90,500	$132,000	$202,000	$285,000
25	$129,250	$194,000	$307,000	$453,000
50	$191,500	$287,000	$458,000	$647,000
75	$253,750	$381,500	$589,000	$831,000
100	$336,000	$477,000	$720,000	$1,010,000

1) Costs include non-metallic fish handling panels, spray systems, fish trough, housings and transitions, continuous operating features, drive unit, frame seals, engineering (averaged over 5 units), and installation. Costs do *not* include differential control system and spray wash pumps.

Tables 2-40 and 2-41 present equations that can be used to estimate costs for traveling screens at 0.5 fps and 1.0 fps, respectively. See the end of this chapter for cost curves and equations.

Table 2-40. Capital Cost Equations for Traveling Screens for Velocity of 0.5 fps

Screen Width (ft)	Traveling Screens with Fish Handling Equipment: Equation[1]	Correlation Coefficient	Traveling Screens without Fish Handling Equipment: Equation[1]	Correlation Coefficient
2	$y = 6E\text{-}08x^3 - 0.0014x^2 + 28.994x + 36372$	$R^2 = 0.9992$	$y = 5E\text{-}08x^3 - 0.0013x^2 + 20.892x + 18772$	$R^2 = 0.9991$
5	$y = 1E\text{-}09x^3 - 8E\text{-}05x^2 + 12.223x + 80790$	$R^2 = 0.994$	$y = 2E\text{-}09x^3 - 0.0001x^2 + 9.7773x + 54004$	$R^2 = 0.9995$
10	$y = 5E\text{-}10x^3 - 9E\text{-}05x^2 + 12.726x + 88302$	$R^2 = 0.9931$	$y = 5E\text{-}03x^3 - 9E\text{-}05x^2 + 10.143x + 63746$	$R^2 = 0.9928$
14	$y = 6E\text{-}10x^3 - 0.0001x^2 + 15.874x + 91207$	$R^2 = 0.995$	$y = 5E\text{-}10x^3 - 0.0001x^2 + 12.467x + 65934$	$R^2 = 0.9961$

1) x is the flow in gpm y is the capital cost in dollars.

Table 2-41. Capital Cost Equations for Traveling Screens for Velocity of 1 fps

Screen Width (ft)	Traveling Screens with Fish Handling Equipment: Equation[1]	Traveling Screens with Fish Handling Equipment: Correlation Coefficient	Traveling Screens without Fish Handling Equipment: Equation[1]	Traveling Screens without Fish Handling Equipment: Correlation Coefficient
2	$y = 8E\text{-}09x^3 - 0.0004x^2 + 15.03x + 33044$	$R^2 = 0.9909$	$y = 8E\text{-}09x^3 - 0.0004x^2 + 10.917x + 16321$	$R^2 = 0.9911$
5	$y = 2E\text{-}10x^3 - 3E\text{-}05x^2 + 6.921x + 68688$	$R^2 = 0.9948$	$y = 3E\text{-}10x^3 - 4E\text{-}05x^2 + 5.481x + 44997$	$R^2 = 0.9962$
10	$y = 5E\text{-}11x^3 - 2E\text{-}05x^2 + 6.2849x + 88783$	$R^2 = 0.9906$	$y = 5E\text{-}11x^3 - 2E\text{-}05x^2 + 5.0073x + 64193$	$R^2 = 0.9902$
14	$y = 5E\text{-}11x^3 - 2E\text{-}05x^2 + 7.1477x + 113116$	$R^2 = 0.9942$	$y = 5E\text{-}11x^3 - 2E\text{-}05x^2 + 5.6762x + 81695$	$R^2 = 0.9952$

1) x is the flow in gpm y is the capital cost in dollars.

Operation and Maintenance (O&M) Costs for Traveling Screens

O&M costs for traveling screens vary by type, size, and mode of operation of the screen. Based on discussions with industry representatives, EPA estimated annual O&M cost as a percentage of total capital cost. The O&M cost factor ranges between 8 percent of total capital cost for the smallest size traveling screens with and without fish handling equipment and 5 percent for the largest traveling screen since O&M costs do not increase proportionately with screen size. Estimated annual O&M costs for traveling screens with and without fish handling features are presented in Tables 2-32 and 2-33, respectively. As noted earlier, the flow volume corresponding to each screen width and well depth combination varies based on the through screen flow velocity. These flow volumes were presented in Tables 2-42 and 2-43 for flow velocities of 1.0 fps and 0.5 fps, respectively.

Table 2-42. Estimated Annual O&M Costs for Traveling Water Screens Without Fish Handling Features (Carbon Steel - Standard Design)[1] (1999 Dollars)

Well Depth (ft)	Screen Panel Width (ft): 2	5	10	14
10	$4560	$6545	$7650	$12,870
25	$5810	$9905	$14,040	$17,175
50	$8680	$12,270	$17,250	$23,625
75	$11,550	$16,290	$21,800	$29,575
100	$13,560	$16,975	$26,350	$35,275

1) Annual O&M costs range between 8 percent of total capital cost for the smallest size traveling screens with and without fish handling equipment and 5 percent for the largest traveling screen.

Table 2-43. Estimated Annual O&M Costs for Traveling Water Screens With Fish Handling Features (Carbon Steel Structure, Non-Metallic Fish Handling Screening Panel)[1] (1999 Dollars)

Well Depth (ft)	Screen Panel Width (ft) 2	5	10	14
10	$7240	$9240	$10,100	$17,100
25	$9048	$13,580	$18,420	$22,650
50	$13,405	$17,220	$22,900	$32,350
75	$17,763	$22,890	$29,450	$41,550
100	$20,160	$23,850	$36,000	$50,500

1) Annual O&M costs range between 8 percent of total capital cost for the smallest size traveling screens with and without fish handling equipment and 5 percent for the largest traveling screen.

The tables below present O&M cost equations generated from the above tables for various screen sizes and water depths at velocities of 0.5 fps and 1 fps, respectively. The "x" value of the equation is the flow and the "y" value is the O&M cost in dollars.

Table 2-44: Annual O&M Cost Equations for Traveling Screens Velocity 0.5 fps

Screen Width (ft)	Traveling Screens with Fish Handling Equipment: Equation[1]	Correlation Coefficient	Traveling Screens without Fish Handling Equipment: Equation[1]	Correlation Coefficient
2	$y = -3E{-}05x^2 + 1.6179x + 3739.1$	$R^2 = 0.9943$	$y = -2E{-}05x^2 + 1.0121x + 2392.4$	$R^2 = 0.9965$
5	$y = -1E{-}05x^2 + 0.8563x + 5686.3$	$R^2 = 0.9943$	$y = -7E{-}06x^2 + 0.6204x + 4045.7$	$R^2 = 0.9956$
10	$y = -2E{-}06x^2 + 0.5703x + 5864.4$	$R^2 = 0.9907$	$y = 9E{-}11x^3 - 1E{-}05x^2 + 0.8216x + 1319.5$	$R^2 = 0.9997$
14	$y = 5E{-}12x^3 - 1E{-}06x^2 + 0.4835x + 10593$	$R^2 = 0.9912$	$y = 8E{-}12x^3 - 2E{-}06x^2 + 0.3899x + 7836.7$	$R^2 = 0.9922$

1) x is the flow in gpm and y is the annual O&M cost in dollars.

Table 2-45. Annual O&M Cost Equations for Traveling Screens Velocity 1 fps

Screen Width (ft)	Traveling Screens with Fish Handling Equipment: Equation[1]	Traveling Screens with Fish Handling Equipment: Correlation Coefficient	Traveling Screens without Fish Handling Equipment: Equation[1]	Traveling Screens without Fish Handling Equipment: Correlation Coefficient
2	$y = -8E\text{-}06x^2 + 0.806x + 3646.7$	$R^2 = 0.982$	$y = -4E\text{-}06x^2 + 0.5035x + 2334$	$R^2 = 0.9853$
5	$y = -3E\text{-}06x^2 + 0.4585x + 5080.7$	$R^2 = 0.9954$	$y = -2E\text{-}06x^2 + 0.3312x + 3621.1$	$R^2 = 0.9963$
10	$y = -6E\text{-}07x^2 + 0.2895x + 5705.3$	$R^2 = 0.9915$	$y = 1E\text{-}11x^3 - 3E\text{-}06x^2 + 0.4047x + 1359.4$	$R^2 = 1$
14	$y = -3E\text{-}13x^3 - 4E\text{-}08x^2 + 0.2081x + 11485$	$R^2 = 0.9903$	$y = 4E\text{-}13x^3 - 3E\text{-}07x^2 + 0.1715x + 8472.1$	$R^2 = 0.9913$

1) x is the flow in gpm and y is the annual O&M cost in dollars.

Adding fish baskets to existing traveling screens

Capital Costs

Table 2-46 presents estimated costs of fish handling equipment without installation costs. These estimated costs represent the difference between costs for equipment with fish handling features (Table 2-33) and costs for equipment without fish handling features (Table 2-32), plus a 20 percent add-on for upgrading existing equipment (mainly to convert traveling screens from intermittent operation to continuous operation).[9] These costs would be used to estimate equipment capital costs for upgrading an existing traveling water screen to add fish protection and fish return equipment.

Table 2-46. Estimated Capital Costs of Fish Handling Equipment (1999 Dollars)

Well Depth (ft)	Basket Screening Panel Width (ft): 2	5	10	14
10	$40,200	$46,200	$58,800	$84,600
25	$55,500	$63,000	$87,600	$131,400
50	$81,000	$99,000	$135,600	$209,400
75	$106,500	$132,000	$183,600	$287,400
100	$132,000	$165,000	$231,600	$365,400

Source: Vendor estimates.

Installation of Fish Handling Features to Existing Traveling Screens

As stated earlier, the basic equipment cost of fish handling features (presented in Table 2-46) is calculated based on the difference in cost between screens with and without fish handling equipment, plus a cost factor of 20 percent for upgrading the existing system from intermittent to continuous operation. Although retrofitting existing screens with fish handling

[9]This 20 percent additional cost for upgrades to existing equipment was included based on recommendations from one of the equipment vendors supplying cost data for this research effort.

equipment will require upgrading some mechanical equipment, installing fish handling equipment generally will not require the use of a costly barge that is equipped with a crane and requires a minimum number of crew to operate it. EPA assumed that costs are 75 percent of the underwater installation cost (Table 2-36) for a traveling screen (based on BPJ). Table 2-47 shows total estimated costs (equipment and installation) for adding fish handling equipment to an existing traveling screen.

Table 2-47. Estimated Capital Costs of Fish Handling Equipment and Installation[1] (1999 Dollars)

Well Depth (ft)	Basket Screening Panel Width (ft)			
	2	5	10	14
10	$46,200	$55,575	$71,550	$100,725
25	$68,250	$79,125	$107,100	$154,275
50	$100,500	$121,875	$161,850	$239,025
75	$132,750	$161,625	$216,600	$323,775
100	$165,000	$201,375	$271,350	$408,525

1) Installation portion of the costs estimated as 75 percent of the *underwater* installation cost for installing a traveling water screen.

The additional O&M costs due to the installation of fish baskets on existing traveling screens can be calculated by subtracting the O&M costs for basic traveling screens from the O&M costs for traveling screens with fish baskets. See the end of this chapter for cost curves and equations.

2.10 Additional Cost Considerations

To account for other minor cost elements, EPA estimates that 5 percent may need to be added to the total cost for each alteration. Minor cost elements include:

- Permanent buoys for shallow waters to warn fishing boats and other boats against dropping anchor over the pipes. Temporary buoys and warning signs during construction.

- Additional permit costs. Permit costs may increase because of the trenching and dredging for pipe installation.

- Facility replanning/redesign costs may be incurred if the facility is far enough along in the facility planning and development process. This cost would likely be minimal to negligible for most of the alterations discussed above, but could be much higher for switching a facility to a recirculating cooling system.

- Monitoring costs (e.g., to test for contaminated sediments).

As noted earlier, if the intake structure installation involves disturbance of contaminated sediments, the permitting authority may require special construction procedures, including hauling the sediments to an appropriate disposal facility offsite. This may increase the cost of the project by more than two to three times the original cost estimate.

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In addition to the references listed below, EPA recognizes contributions from the following individuals and organizations: Russel Bellman and Brian Julius, Acting Chief, Gulf Coast Branch NOAA Damage Assessment Center, Silver Spring, MD, of the National Oceanic and Atmospheric Administration; Adnan Alsaffar, Arman Sanver, and John Gantnier, Bechtel Power Corporation, Fredrick, MD; Gary R. Mirsky Vice President, Hamon Cooling Towers, Somerville, NJ; Jim Prillaman, Prillaman Cooling Towers, Richmond, VA; Ken Campbell GEA Power Systems, Denver, CO and David Sanderlin, GEA Power Systems, San Diego, CA; Michael D. Quick, Manager - Marketing / Communications, U.S. Filter - Envirex Products, Waukesha, WI; Trent T. Gathright, Fish Handling Band Screen Specialist, Marketing Manager, Brackett Geiger USA, Inc., Houston, TX; Richard J. Sommers, U.S. Filter Intake Systems, Chalfont, PA; Ken McKay, VP Sales/Marketing, USF Intake Products; and Larry Sloan, District Representative, Sloan Equipment Sales Co.,Inc., Owings Mills, MD.

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LIST OF COST CURVES AND EQUATIONS

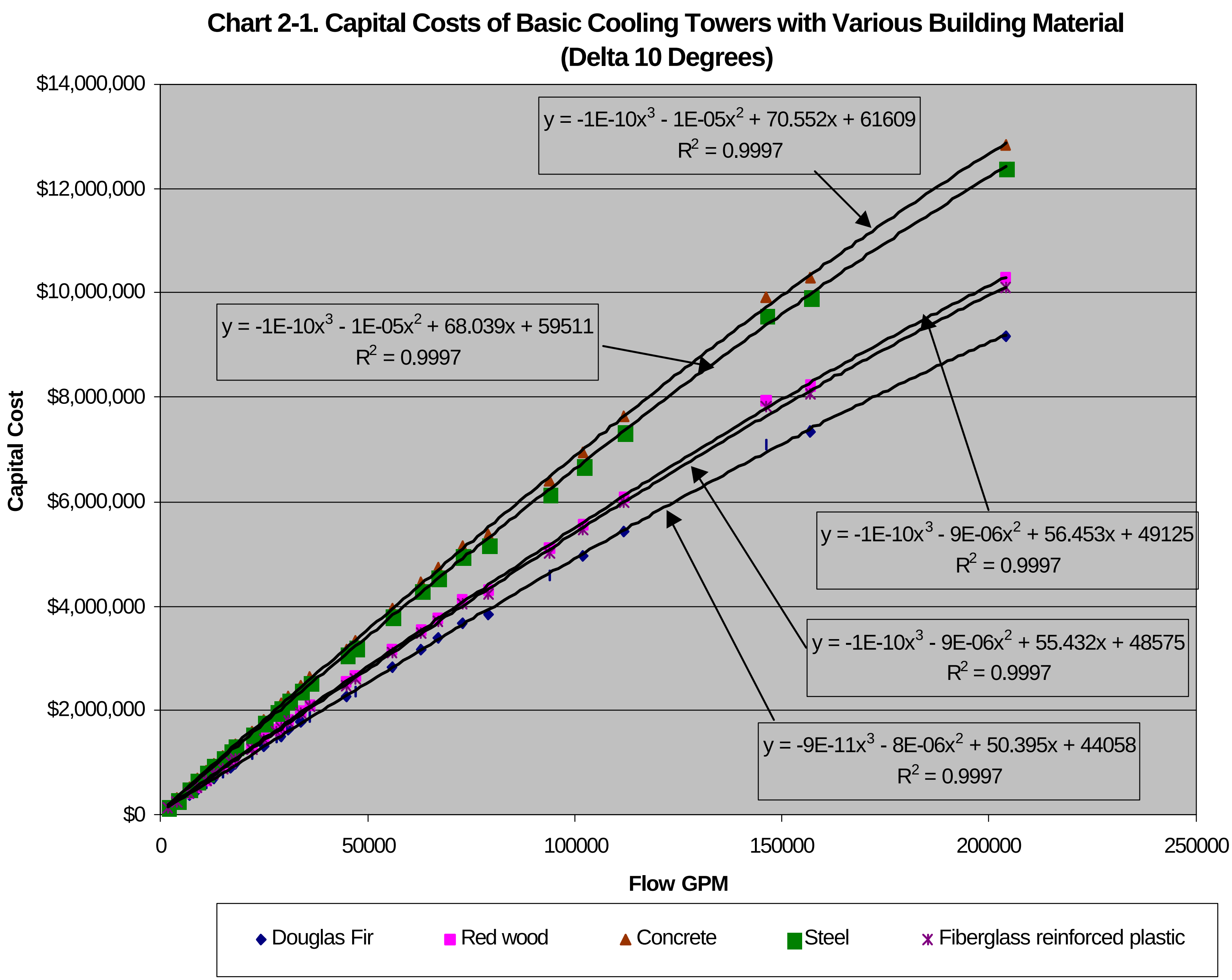
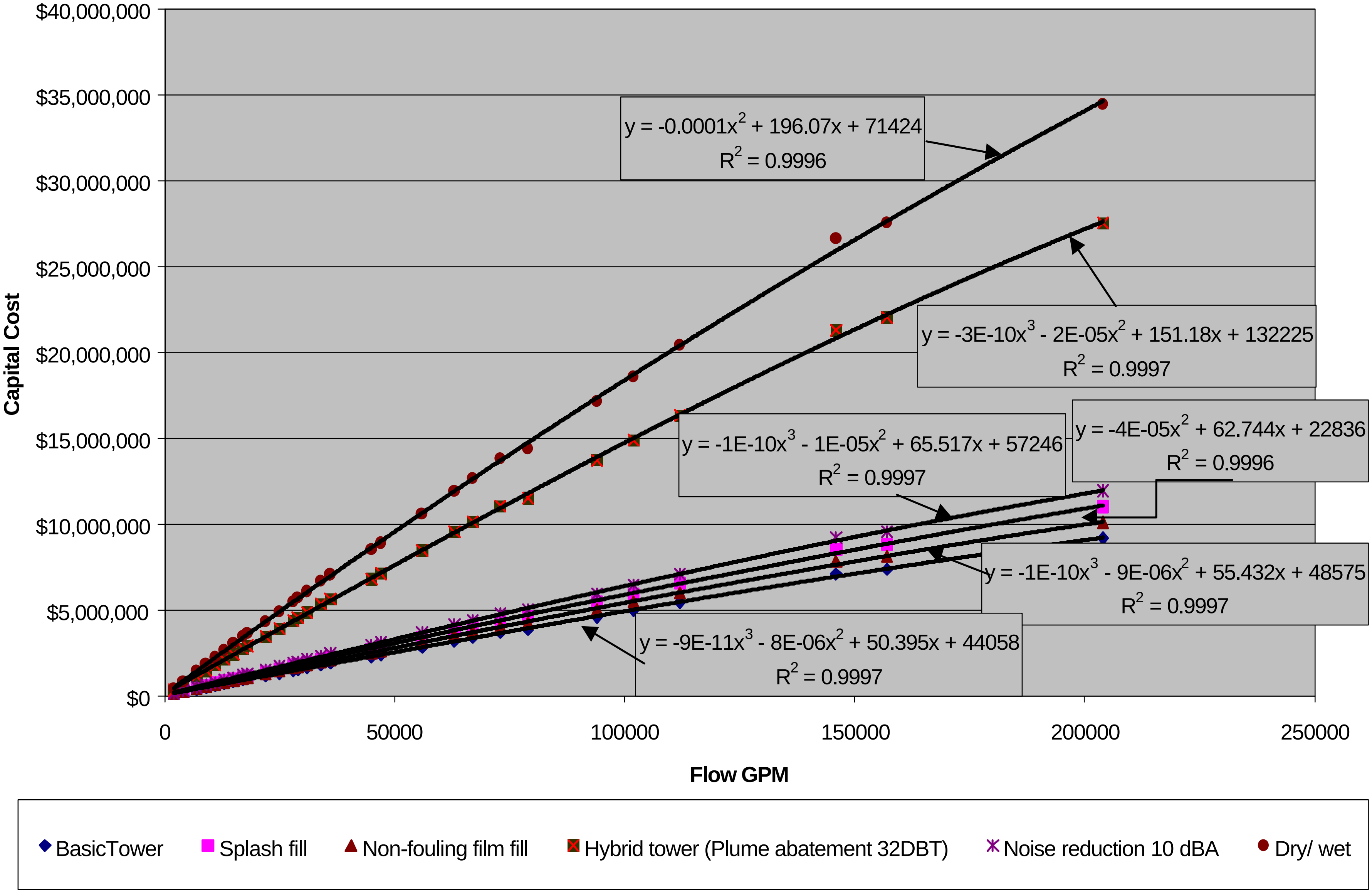


Chart 2-1. Capital Costs of Basic Cooling Towers with Various Building Material
(Delta 10 Degrees)
y = -1E-10x^3 - 1E-05x^2 + 70.552x + 61609
R^2 = 0.9997
y = -1E-10x^3 - 1E-05x^2 + 68.039x + 59511
R^2 = 0.9997
y = -1E-10x^3 - 9E-06x^2 + 56.453x + 49125
R^2 = 0.9997
y = -1E-10x^3 - 9E-06x^2 + 55.432x + 48575
R^2 = 0.9997
y = -9E-11x^3 - 8E-06x^2 + 50.395x + 44058
R^2 = 0.9997
Capital Cost
$14,000,000
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$0
0
50000
100000
150000
200000
250000
Flow GPM
Douglas Fir
Red wood
Concrete
Steel
Fiberglass reinforced plastic

Chart 2-2. Douglas Fir Cooling Tower Capital Costs with Various Features (Delta 10 Degrees)



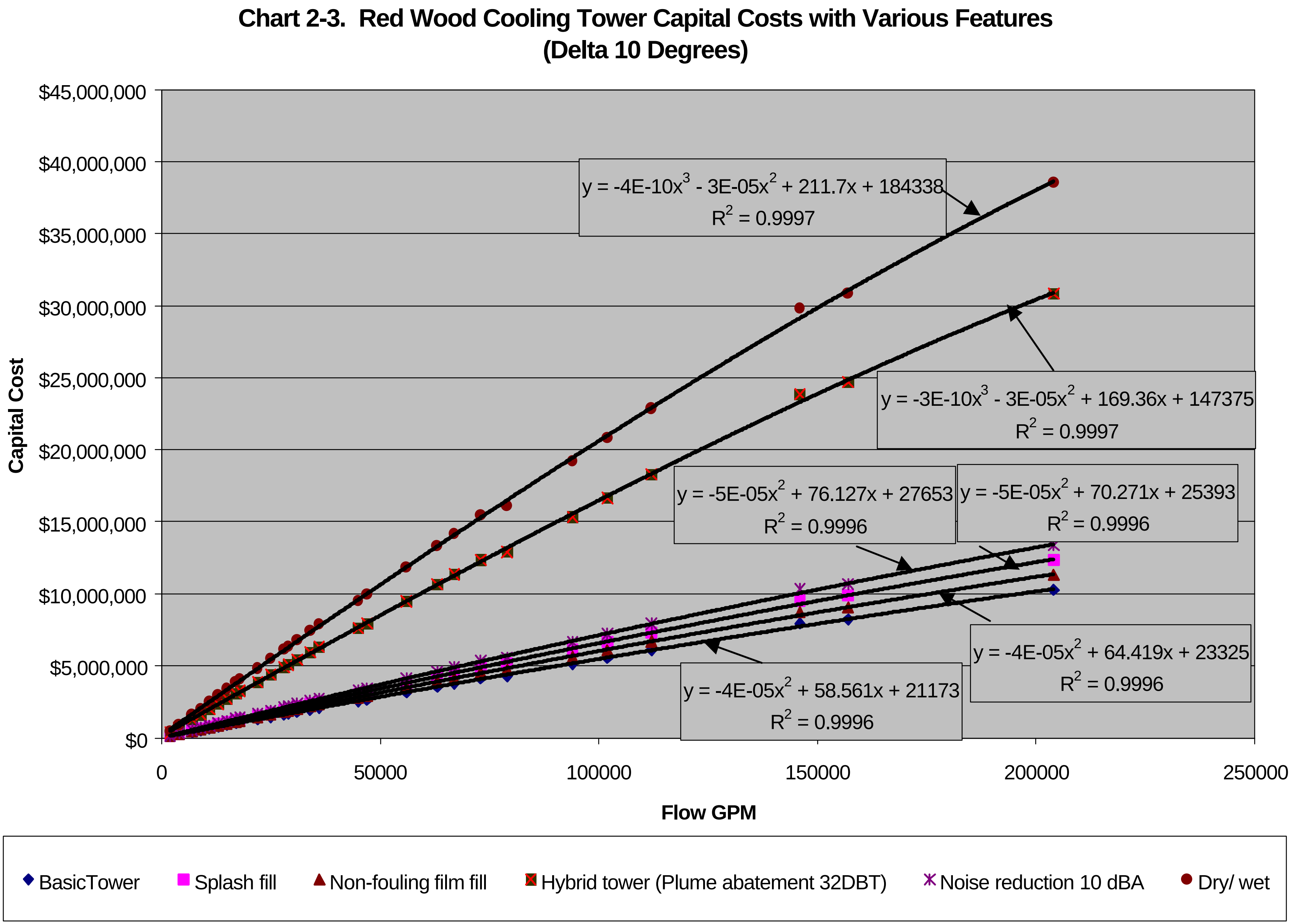


Chart 2-3. Red Wood Cooling Tower Capital Costs with Various Features
(Delta 10 Degrees)
$45,000,000
$40,000,000
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$0
Capital Cost
0
50000
100000
150000
200000
250000
Flow GPM
y = -4E-10x3 - 3E-05x2 + 211.7x + 184338
R2 = 0.9997
y = -3E-10x3 - 3E-05x2 + 169.36x + 147375
R2 = 0.9997
y = -5E-05x2 + 76.127x + 27653
R2 = 0.9996
y = -5E-05x2 + 70.271x + 25393
R2 = 0.9996
y = -4E-05x2 + 64.419x + 23325
R2 = 0.9996
y = -4E-05x2 + 58.561x + 21173
R2 = 0.9996
BasicTower
Splash fill
Non-fouling film fill
Hybrid tower (Plume abatement 32DBT)
Noise reduction 10 dBA
Dry/ wet

Chart 2-4. Concrete Cooling Tower Capital Costs with Various Features (Delta 10 Degrees)

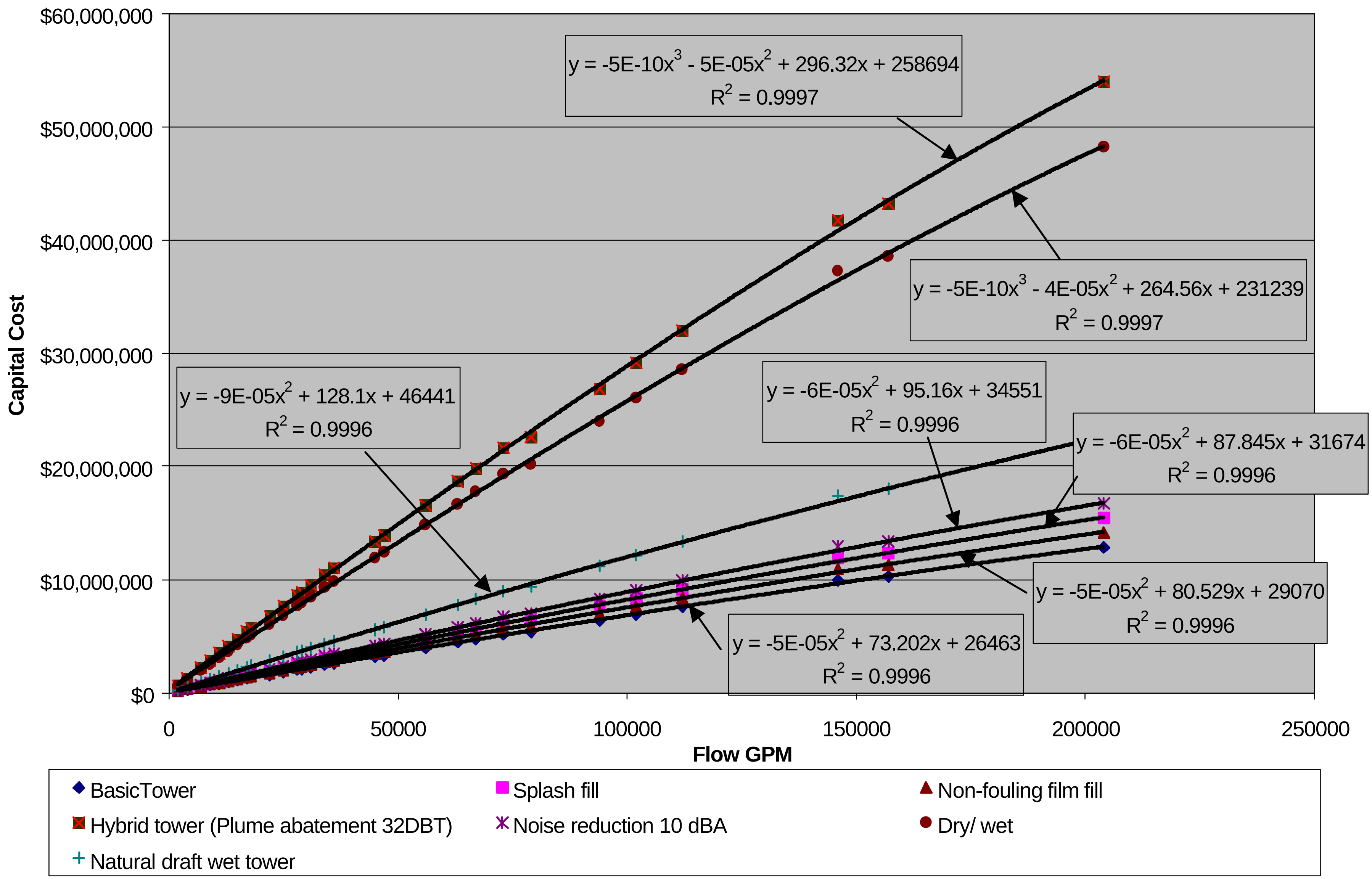


Chart 2-5. Steel Cooling Tower Capital Costs with Various Features (Delta 10 Degrees)

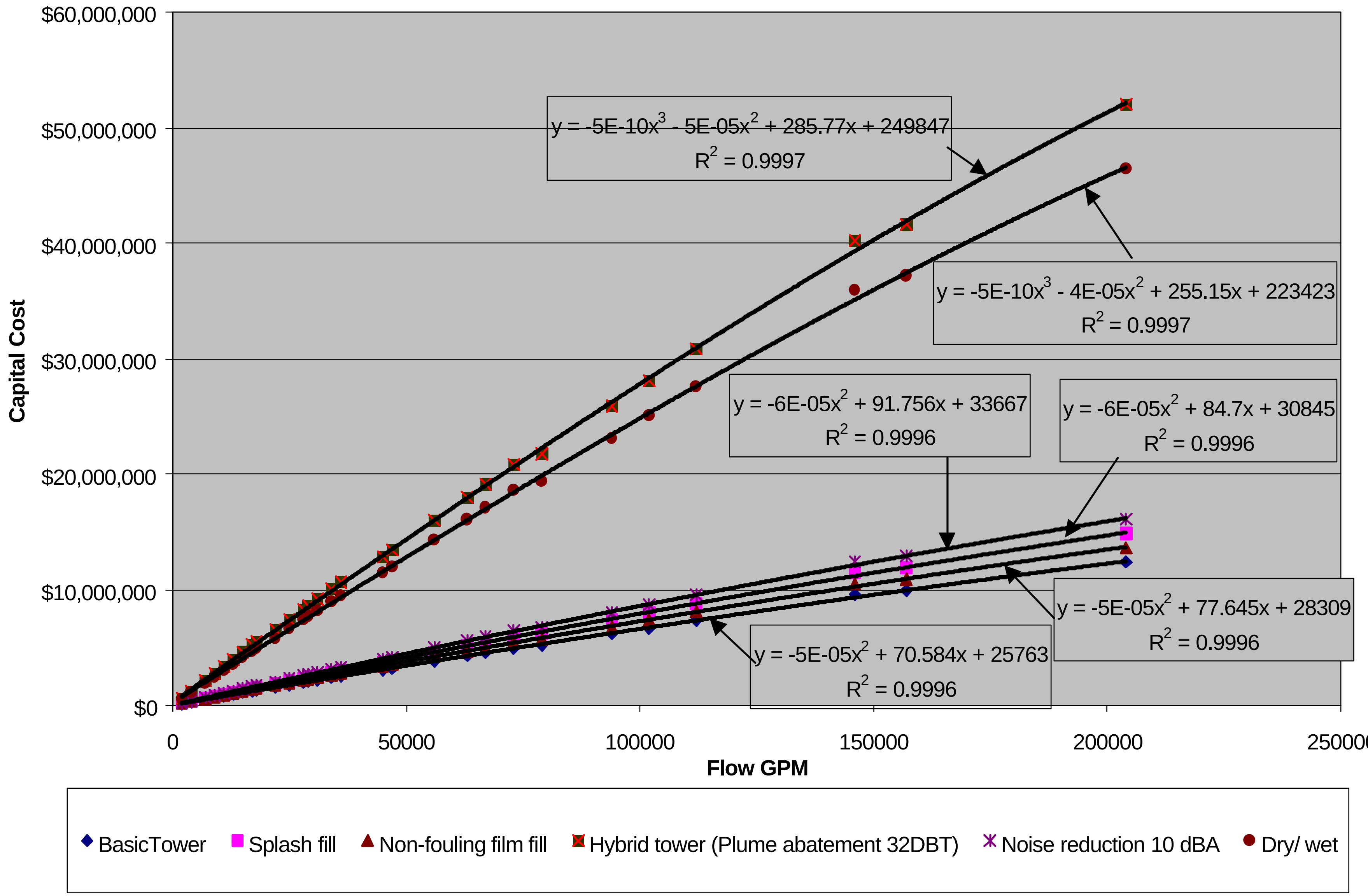


Chart 2-6. Fiberglass Cooling Tower Capital Costs with Various Features (Delta 10 Degrees)

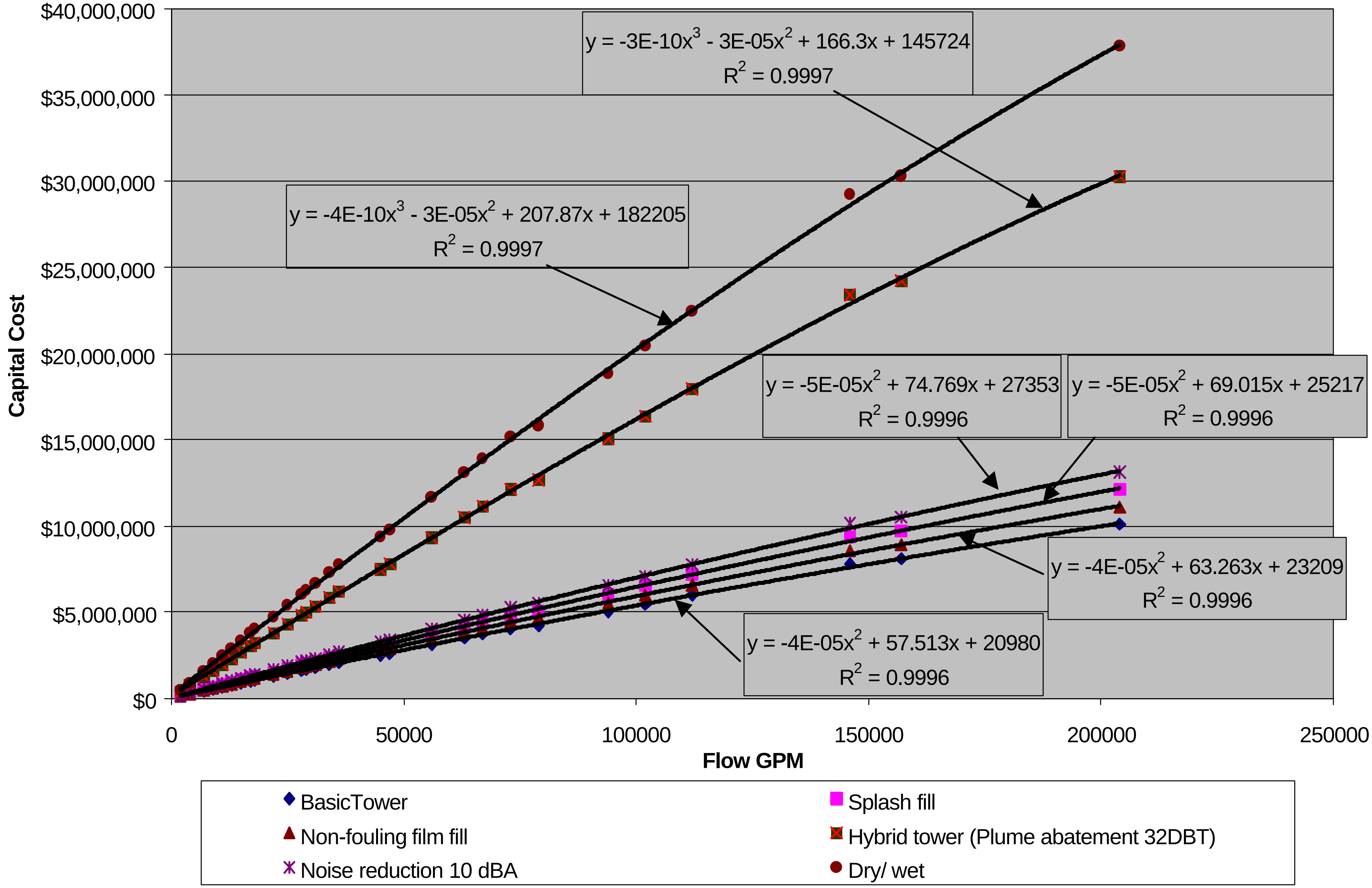


Chart 2-7. Actual Capital Costs for Wet Cooling Tower Projects and Comparable Costs from EPA Cost Curves

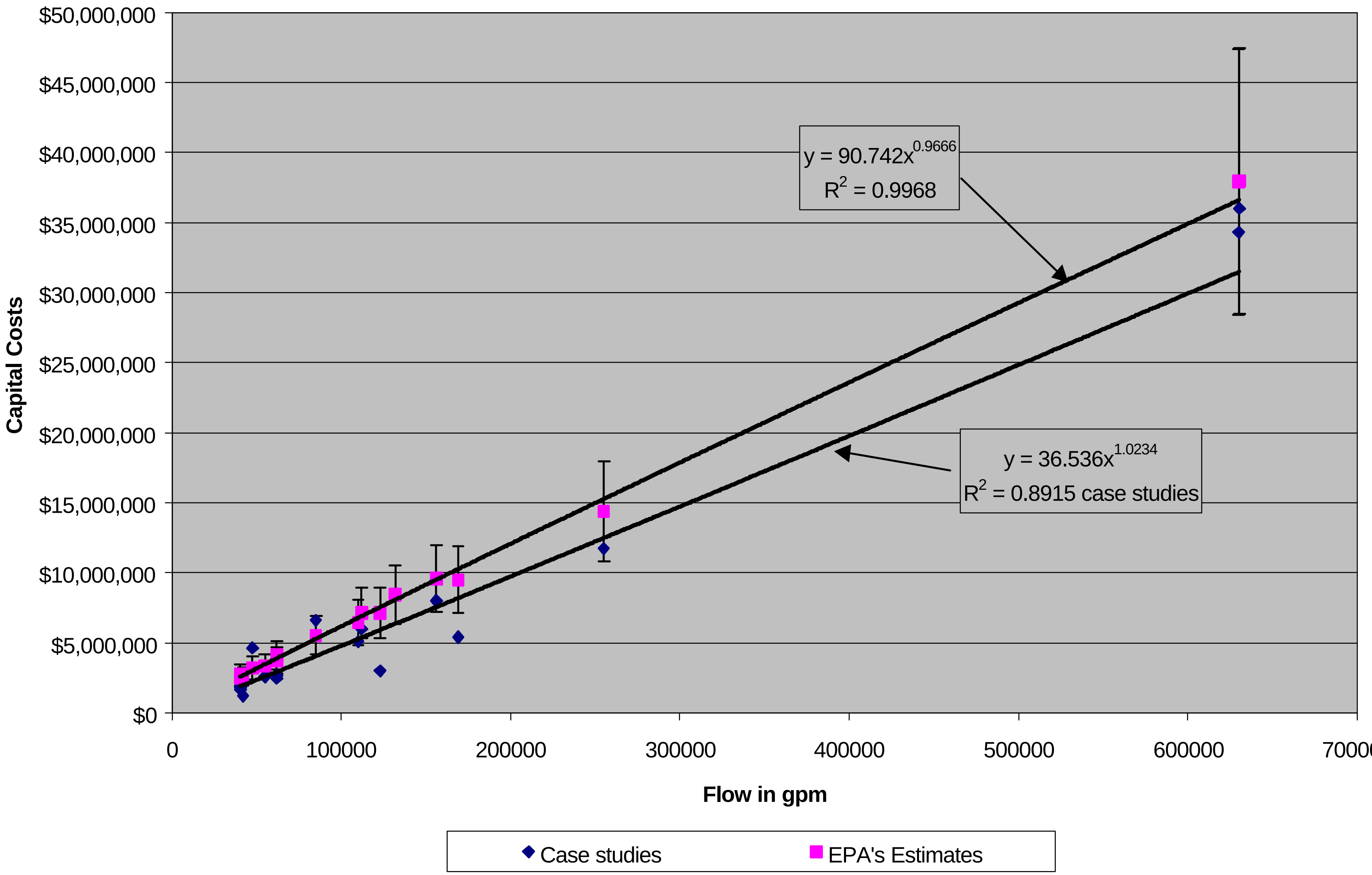


Chart 2-8. O&M Redwood Tower Annual Costs - 1st Scenario

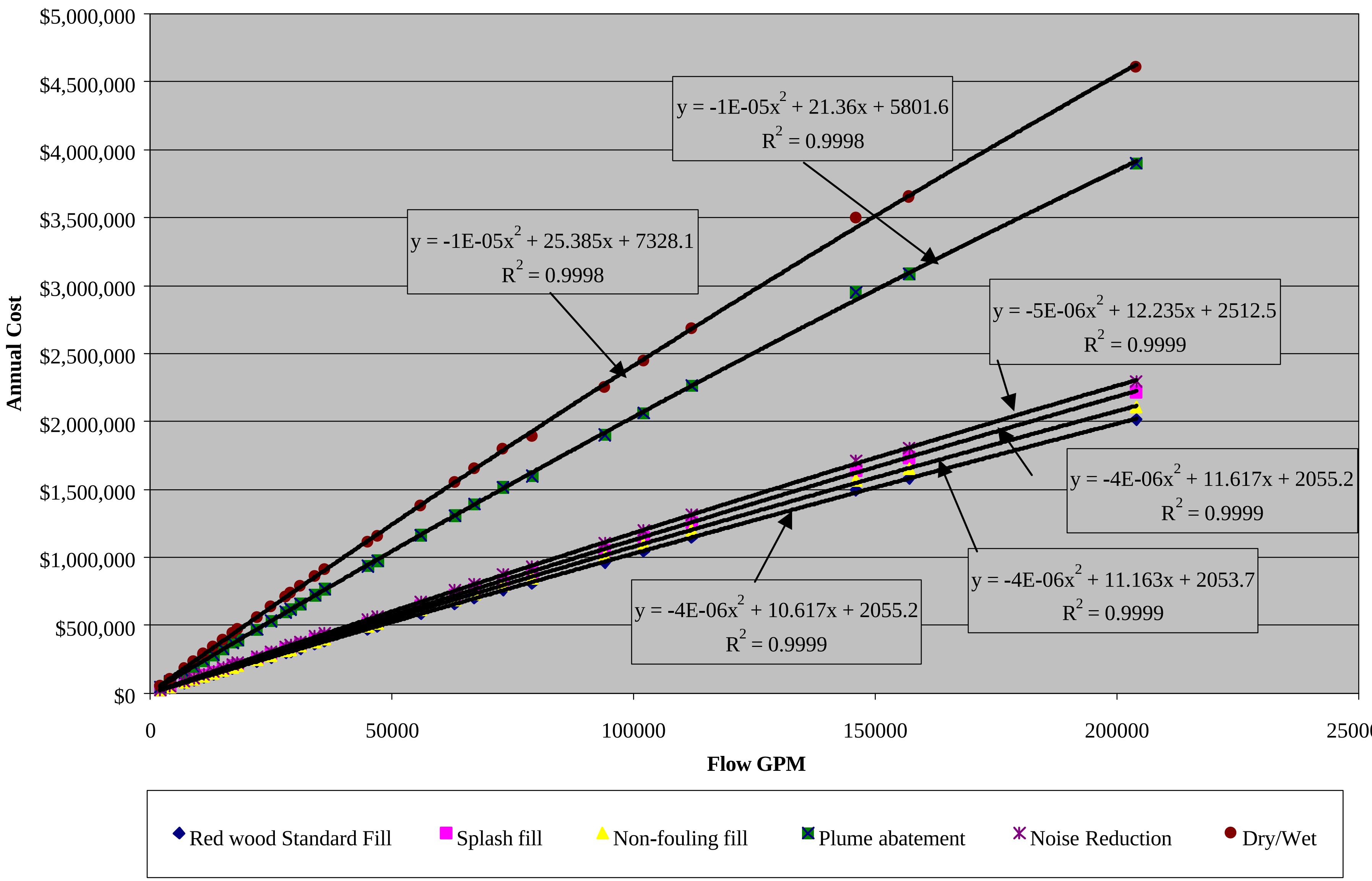


Chart 2-9. O&M Concrete Tower Annual Costs - 1st Scenario

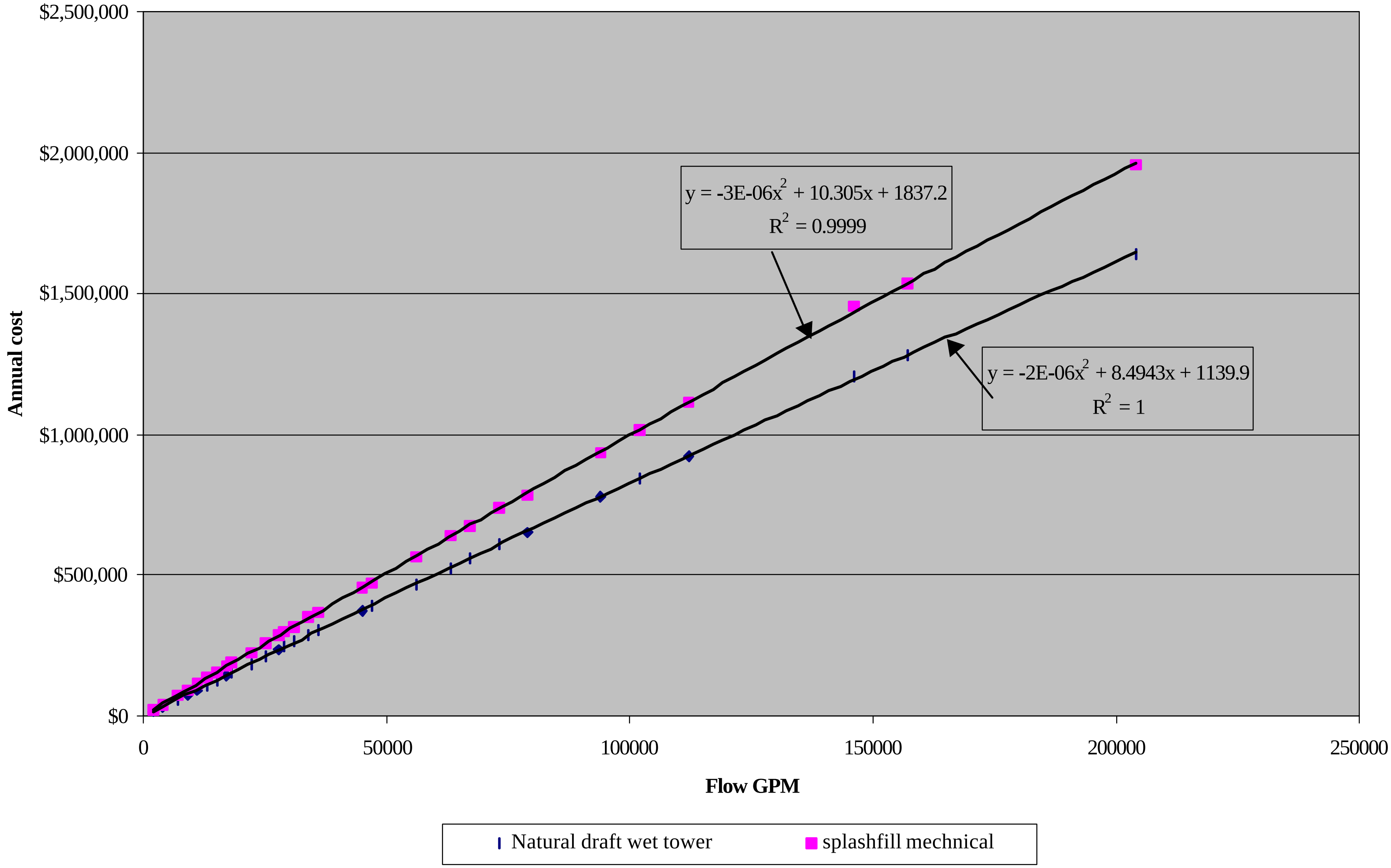


Chart 2-10. Variable Speed Pump Capital Cost

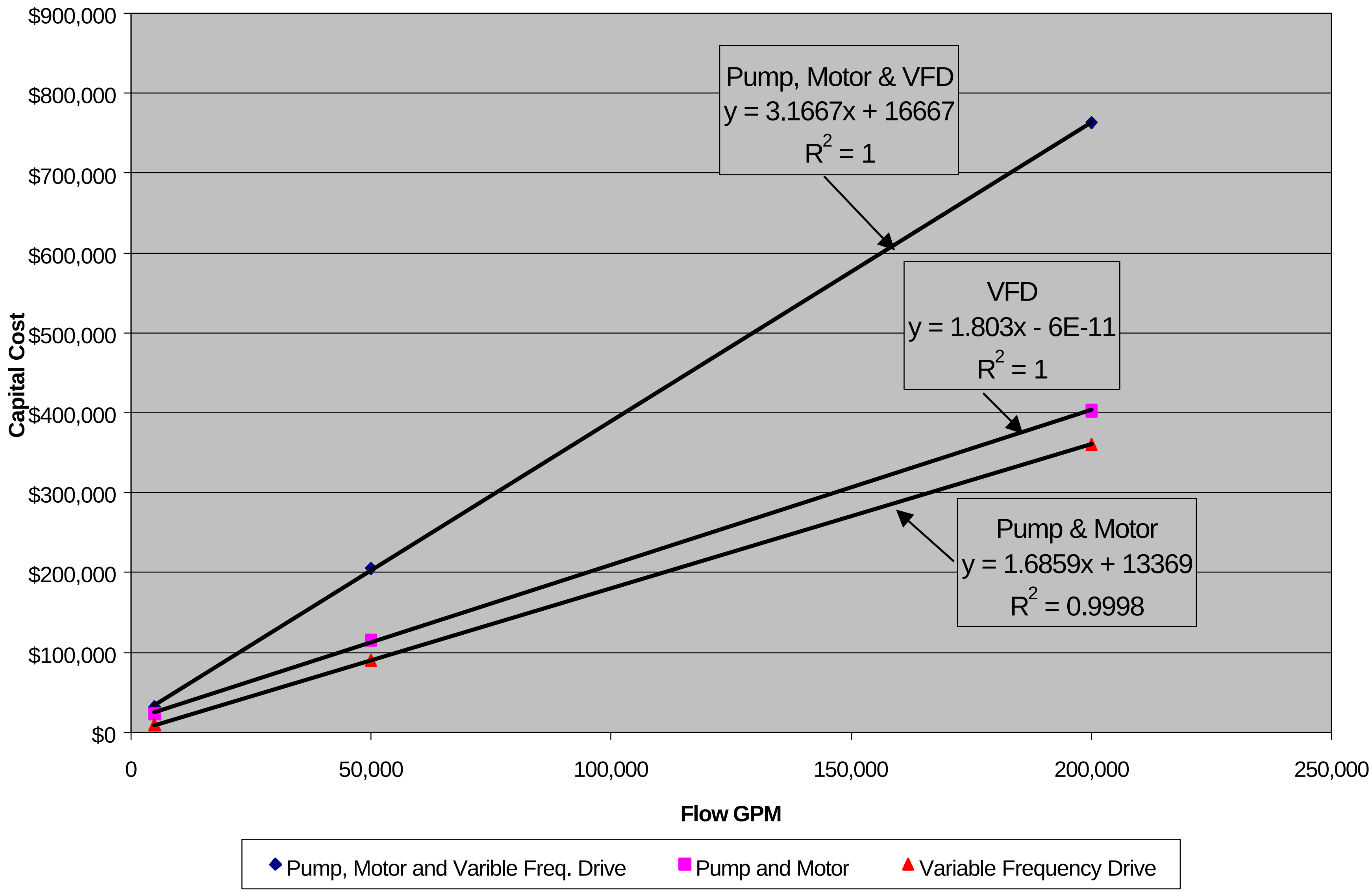


Chart 2-11. Municipal Water Use Costs

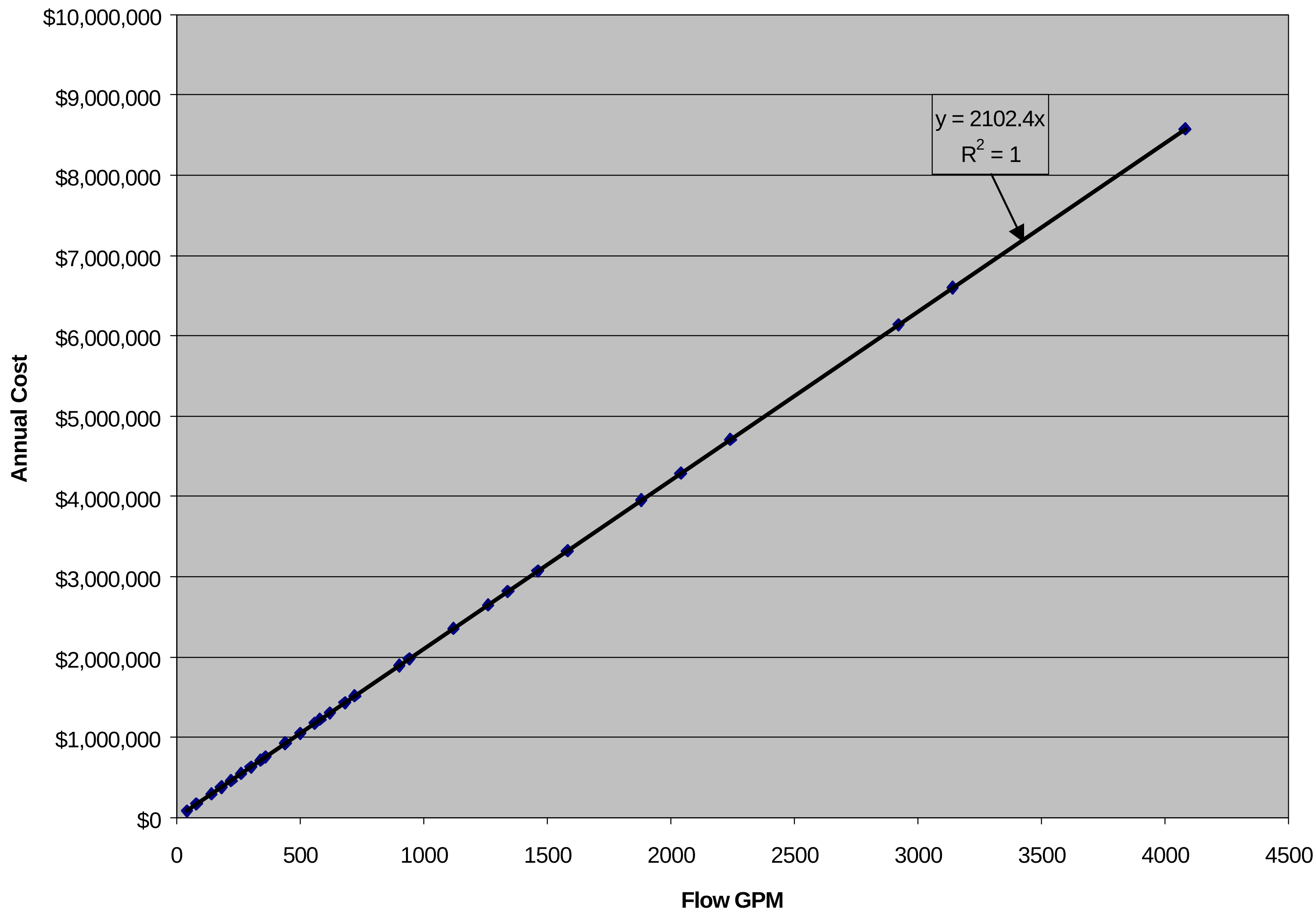


Chart 2-12. Gray Water Use Costs

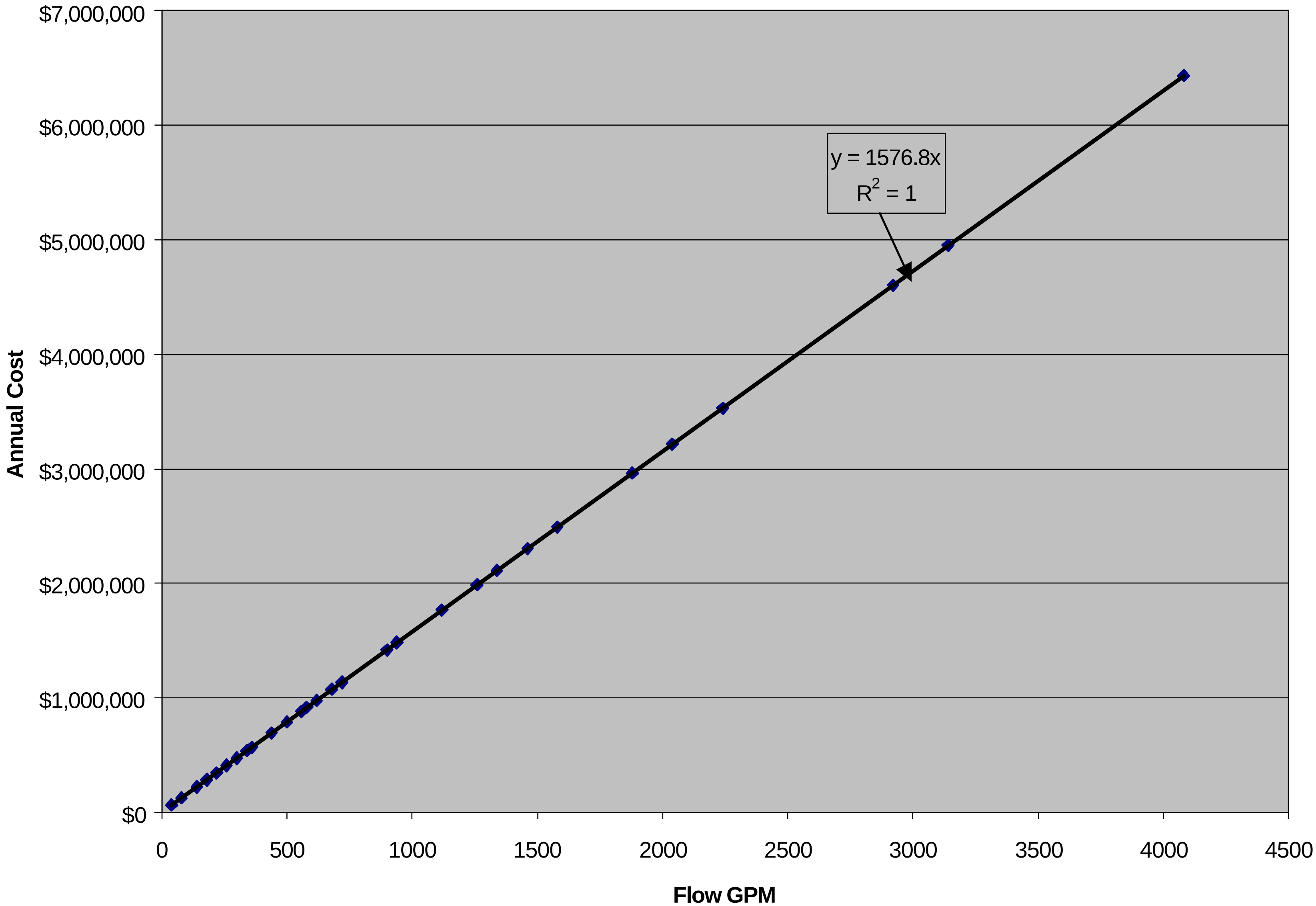


Chart 2-13. Capital Costs of Passive Screens Based on Well Depth

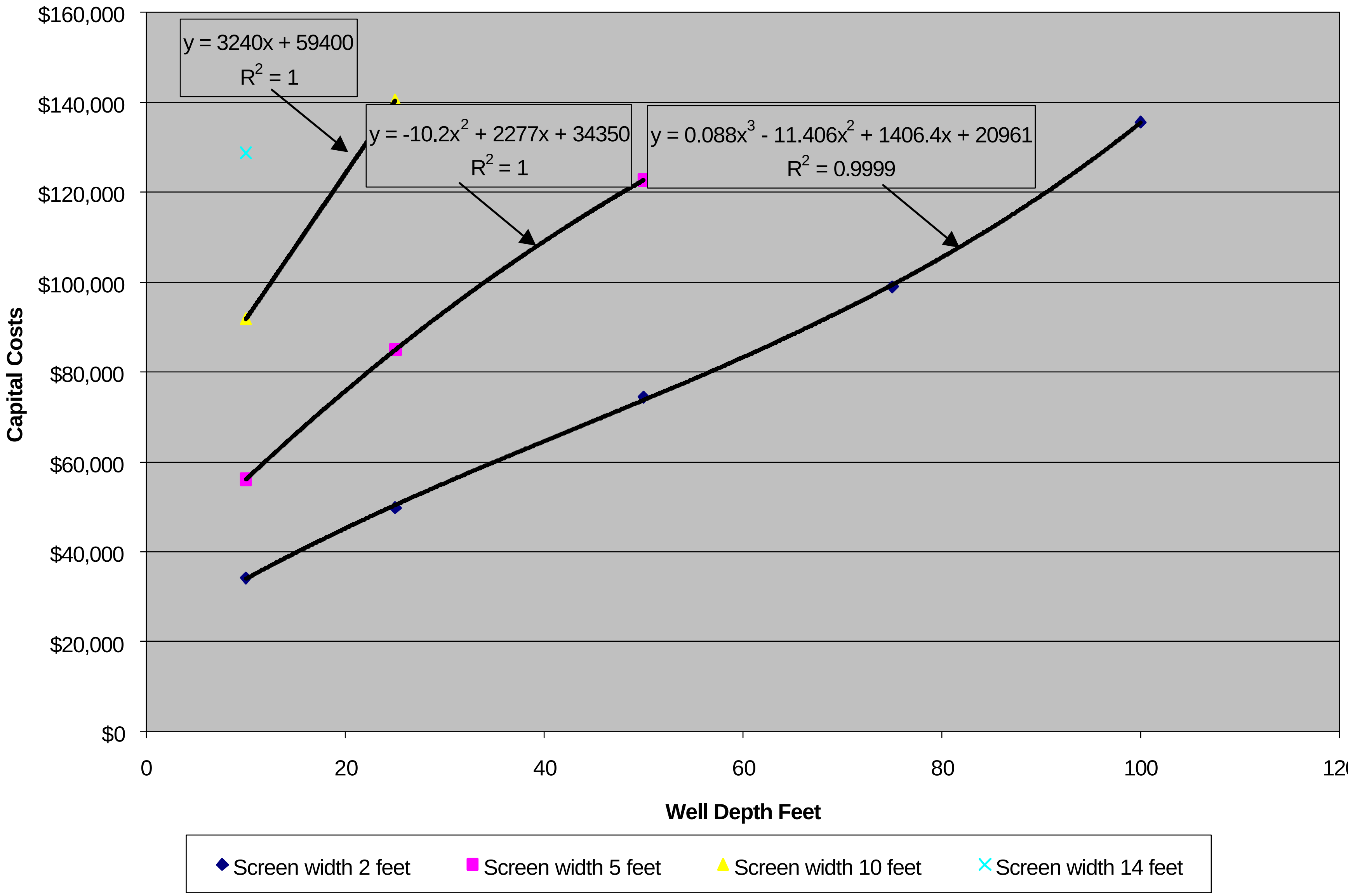


Chart 2-14. Capital Costs of Passive Screens - Flow Velocity 0.5 ft/sec

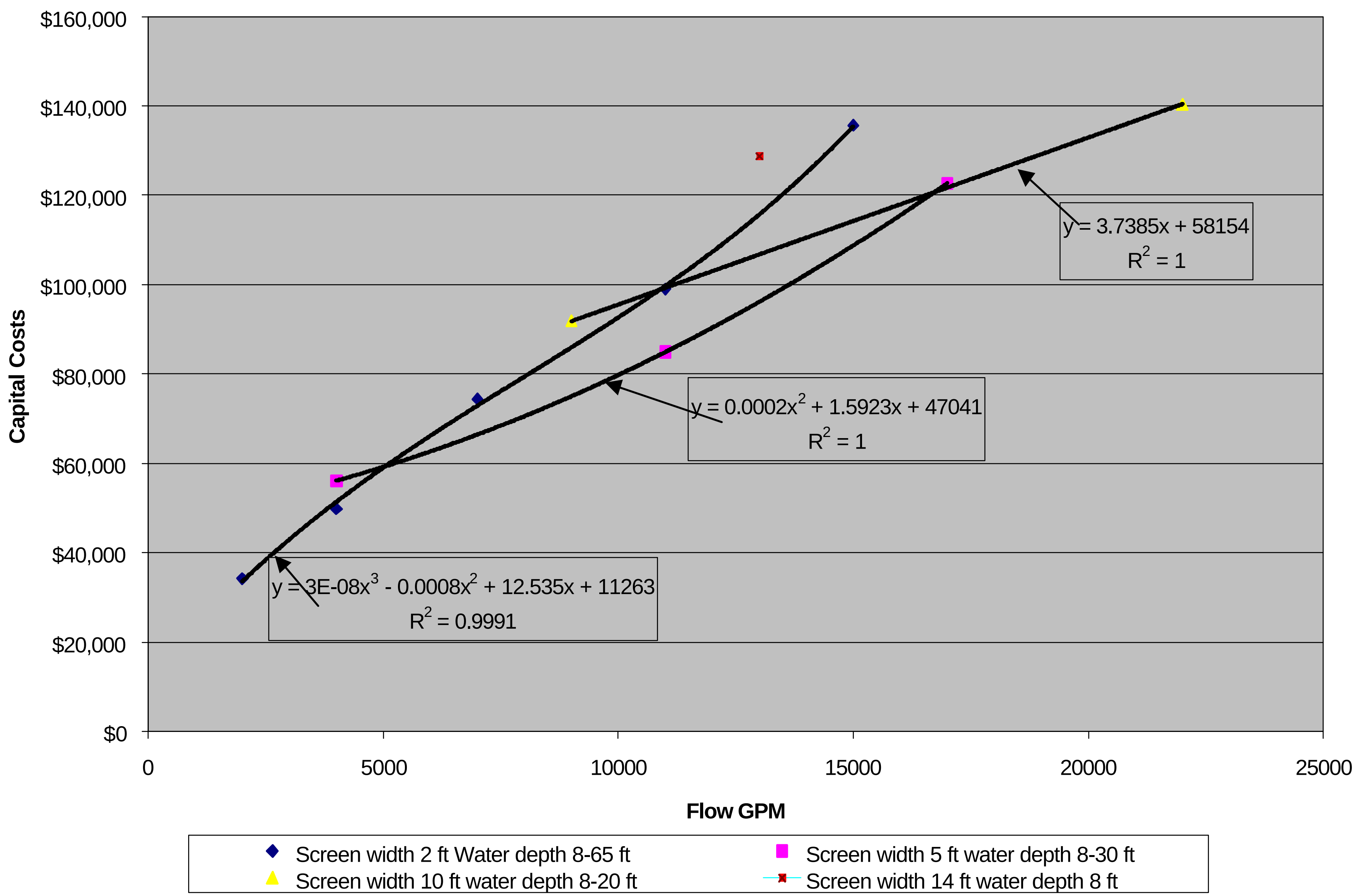


Chart 2-15. Capital Costs of Passive Screens - Flow Velocity 1 ft/sec

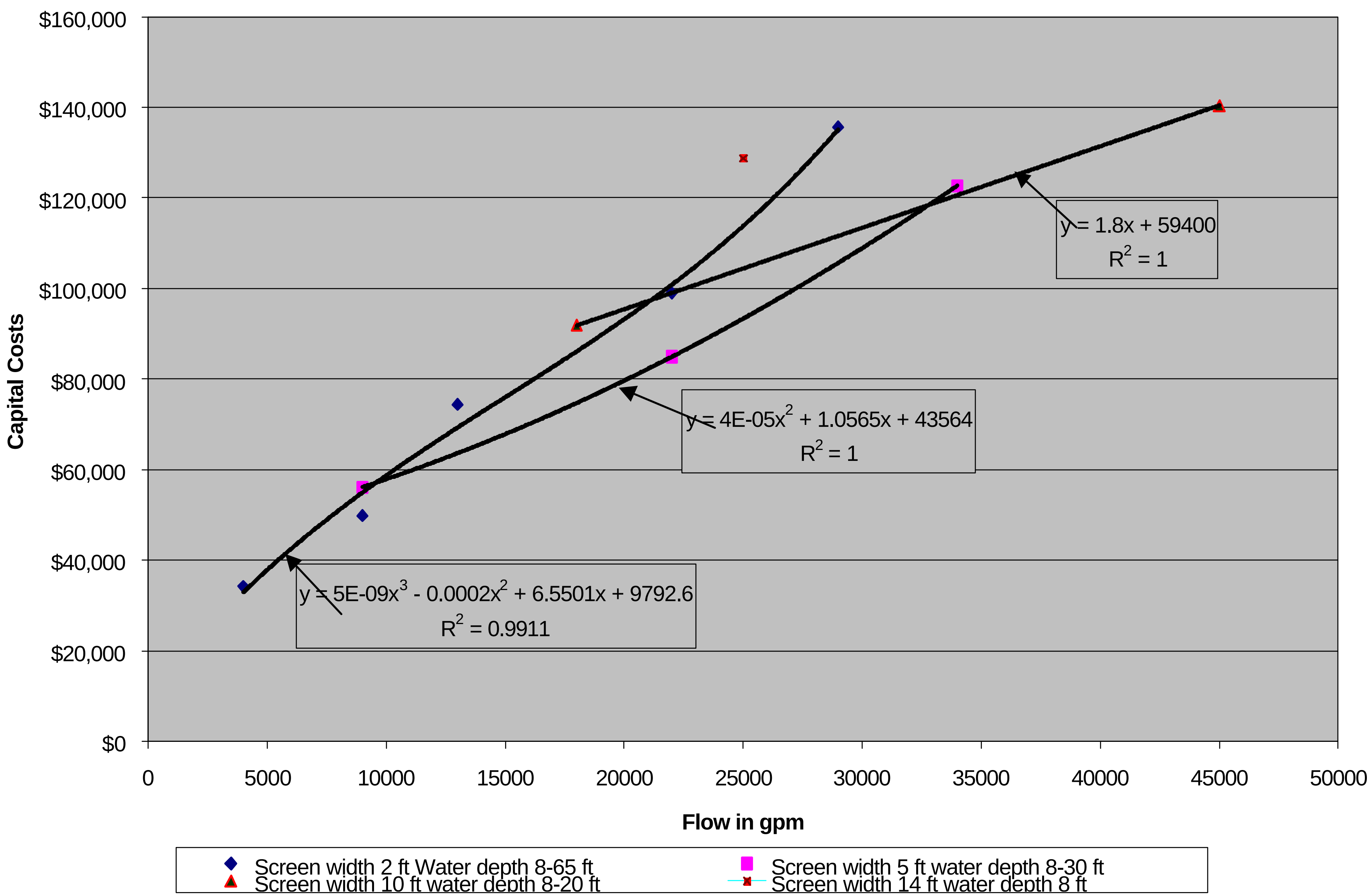


Chart 2-16. Velocity Caps Total Capital Costs

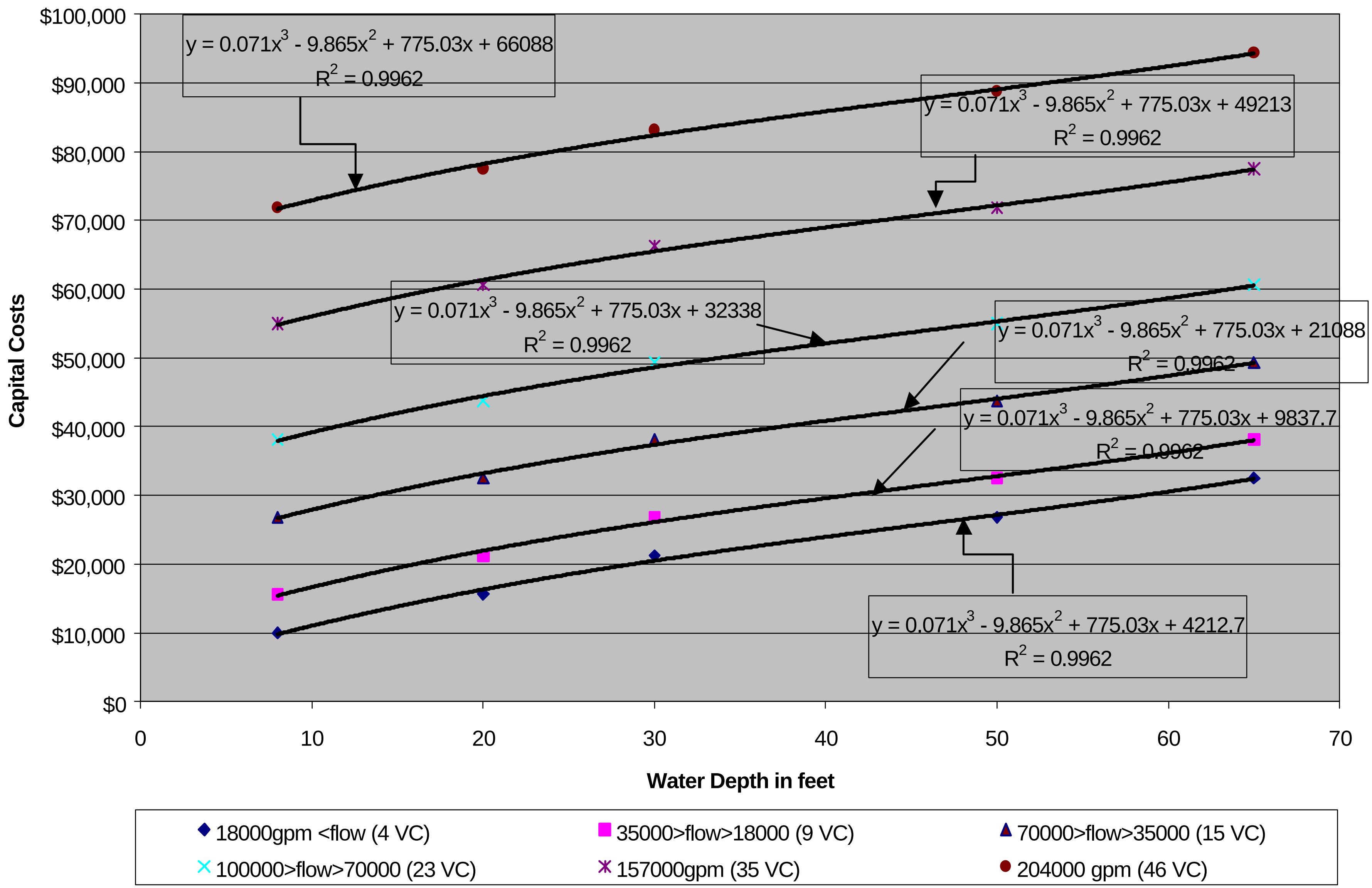


Chart 2-17. Concrete Fittings for Intake Flow Velocity Reduction

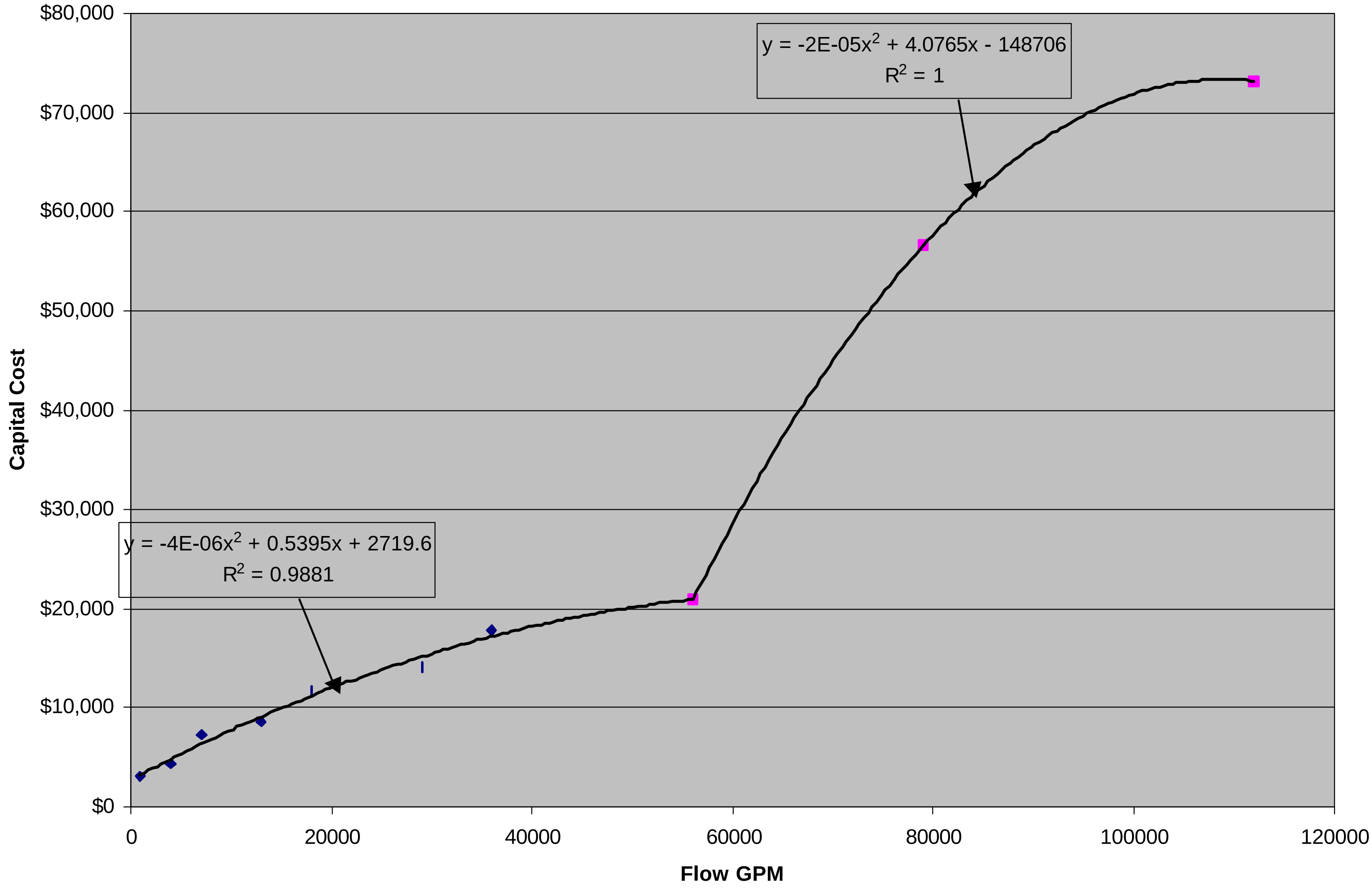


Chart 2-18. Steel Fittings for Intake Flow Velocity Reduction

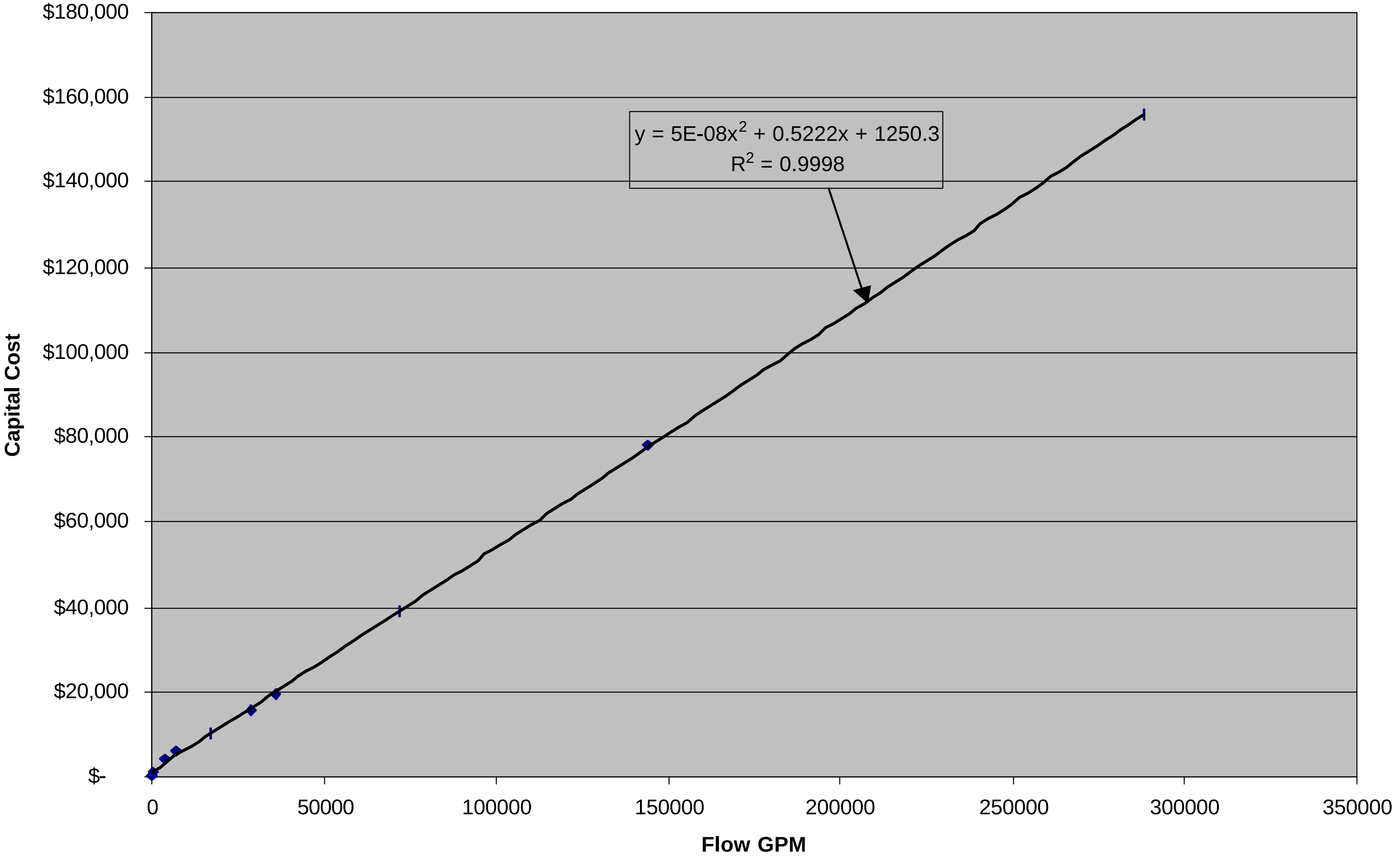


Chart 2-19. Travel Screens Capital Cost Without Fish Handling Features
Flow Velocity 0.5ft/sec

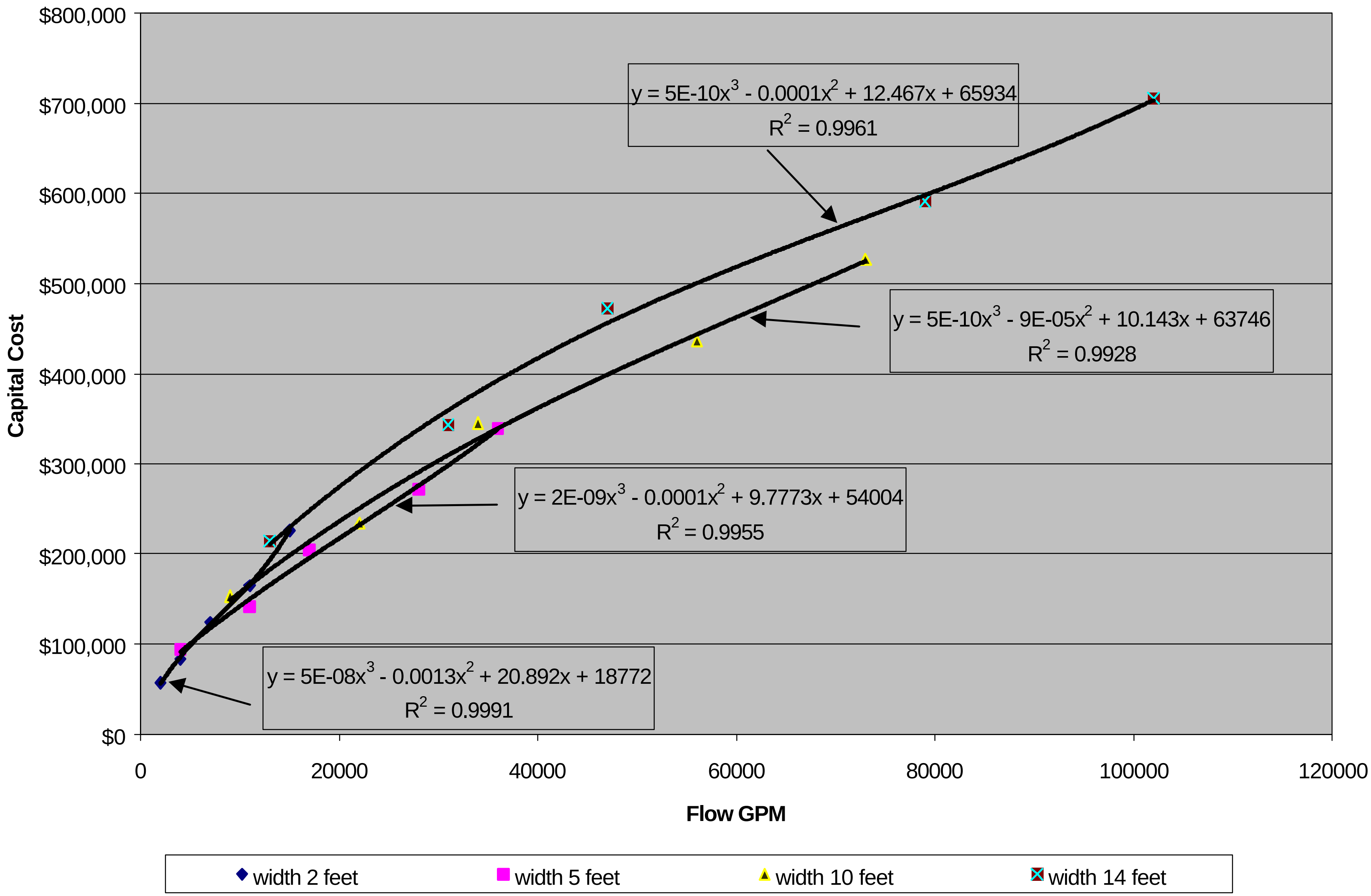
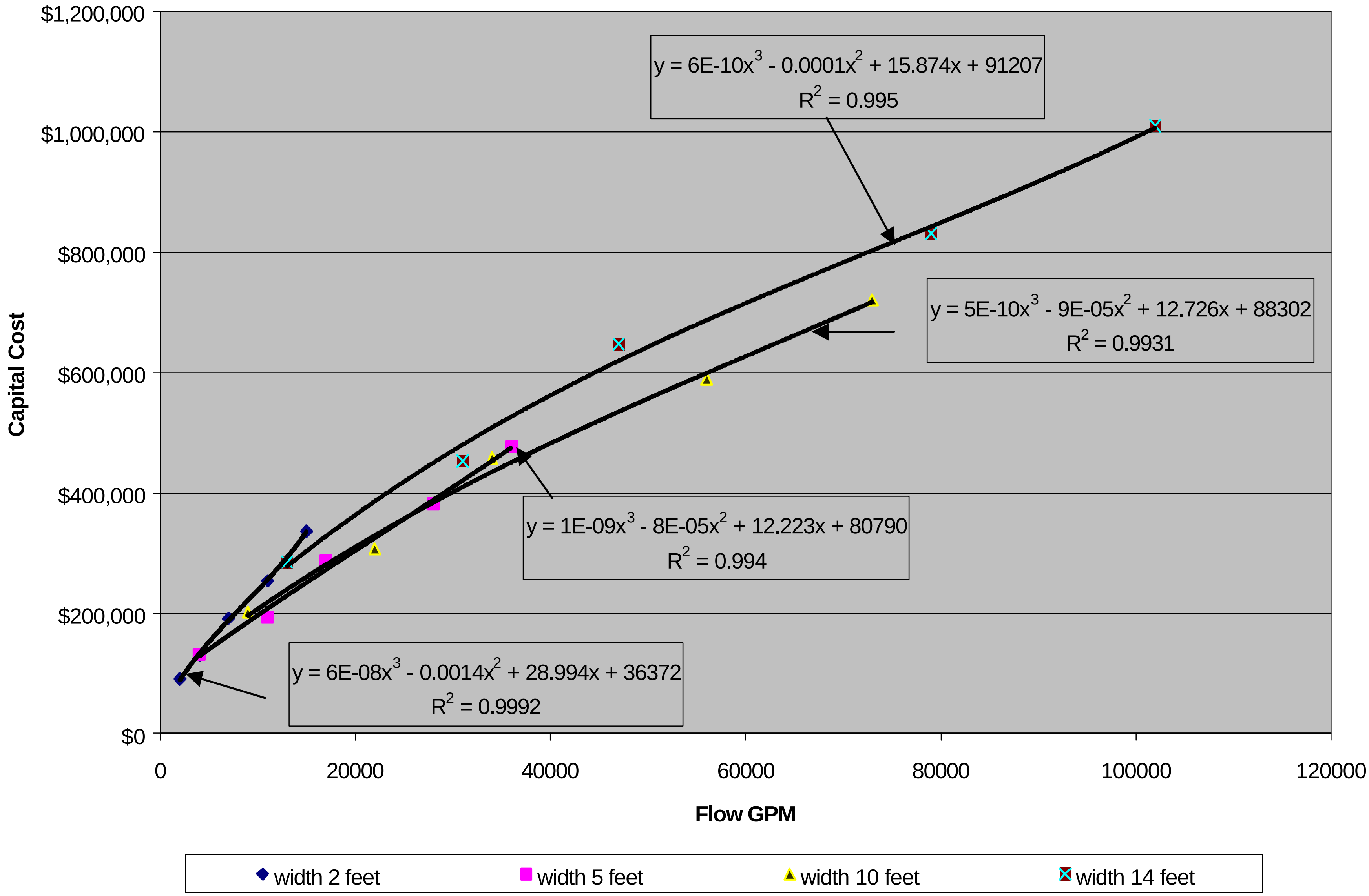


Chart 2-20. Travel Screens Capital Cost With Fish Handling Features
Flow Velocity 0.5ft/sec



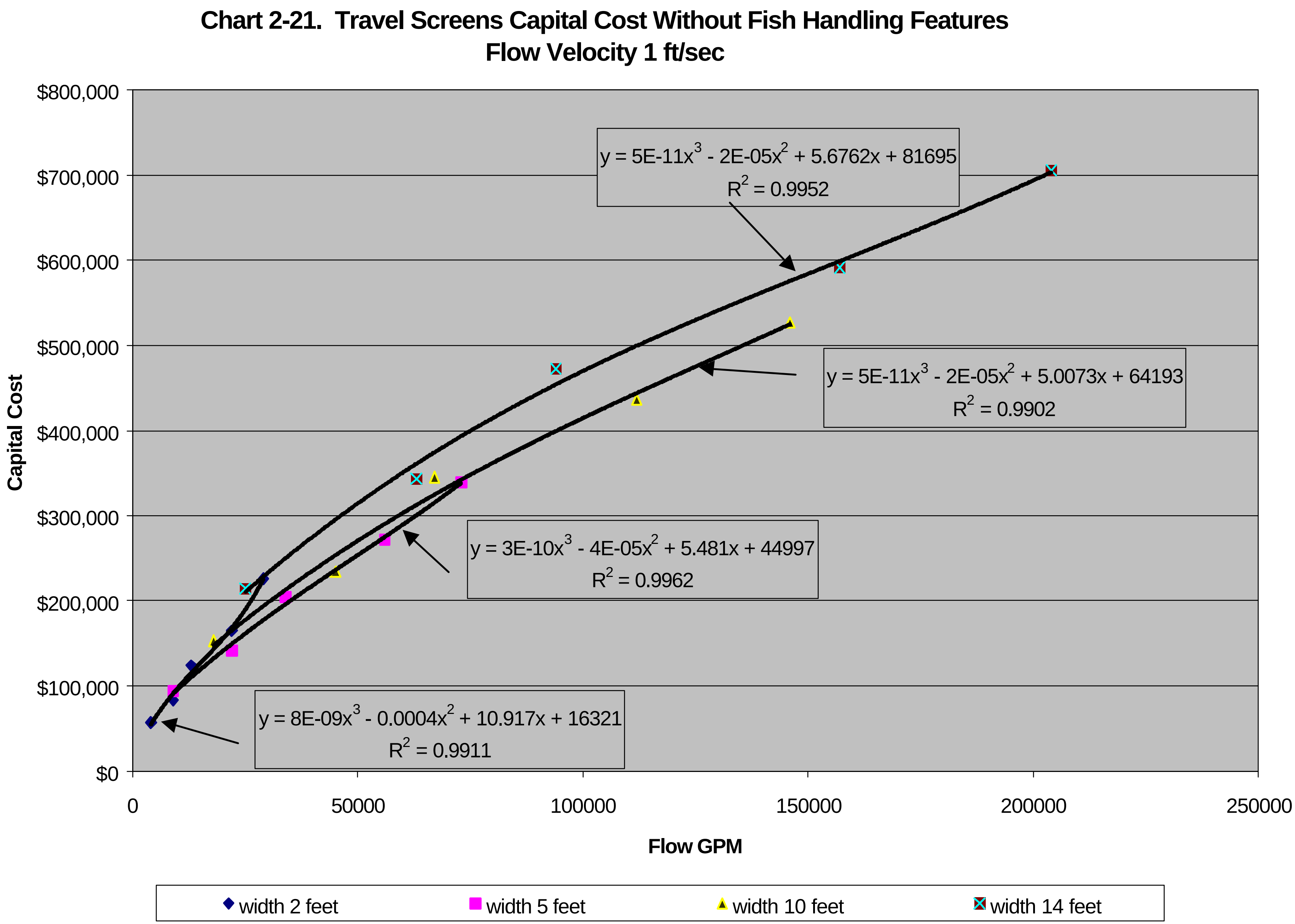


Chart 2-21. Travel Screens Capital Cost Without Fish Handling Features
Flow Velocity 1 ft/sec
$800,000
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$0
Capital Cost
y = 5E-11x3 - 2E-05x2 + 5.6762x + 81695
R2 = 0.9952
y = 5E-11x3 - 2E-05x2 + 5.0073x + 64193
R2 = 0.9902
y = 3E-10x3 - 4E-05x2 + 5.481x + 44997
R2 = 0.9962
y = 8E-09x3 - 0.0004x2 + 10.917x + 16321
R2 = 0.9911
0
50000
100000
150000
200000
250000
Flow GPM
width 2 feet
width 5 feet
width 10 feet
width 14 feet

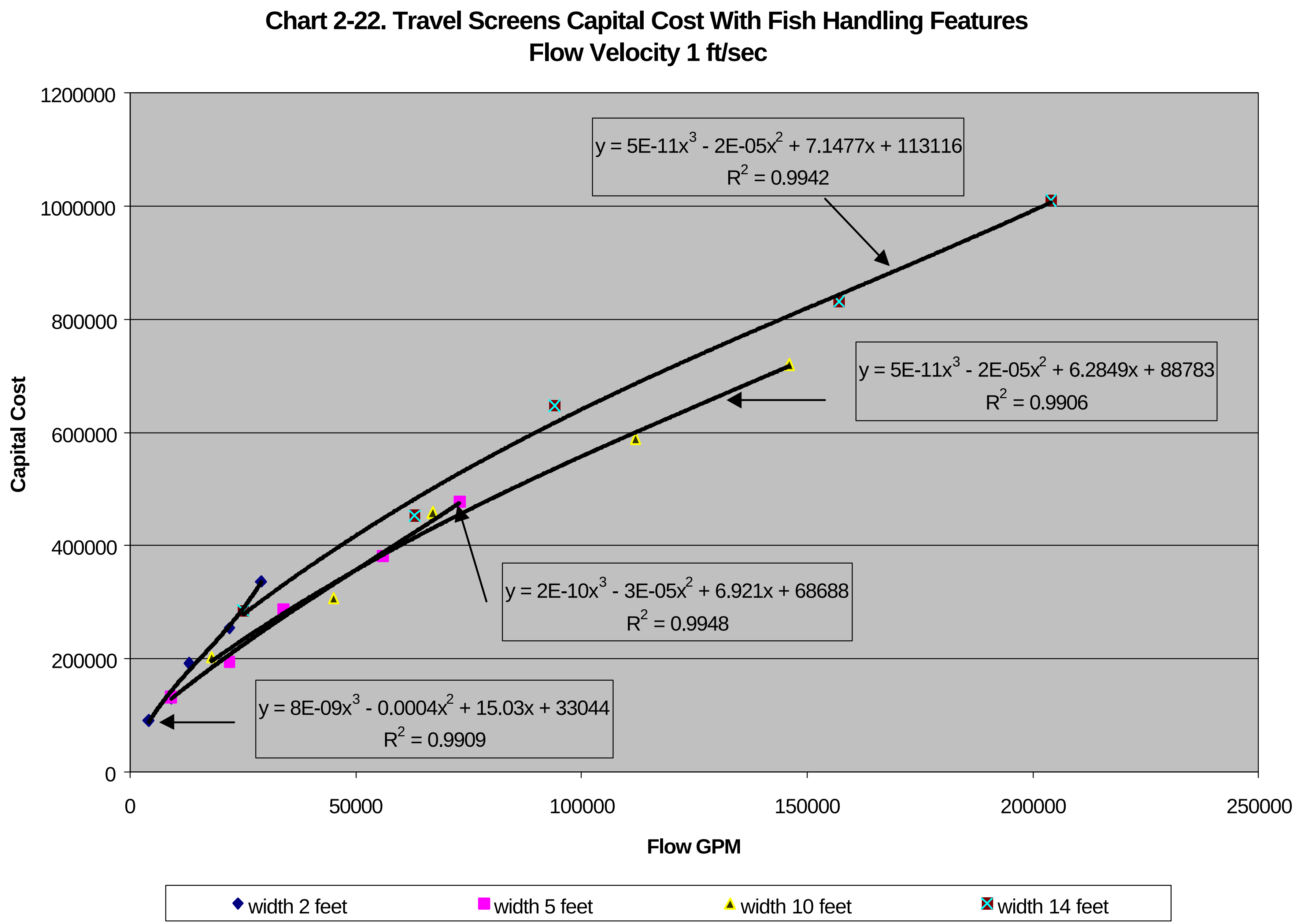


Chart 2-22. Travel Screens Capital Cost With Fish Handling Features
Flow Velocity 1 ft/sec
y = 5E-11x3 - 2E-05x2 + 7.1477x + 113116
R2 = 0.9942
y = 5E-11x3 - 2E-05x2 + 6.2849x + 88783
R2 = 0.9906
y = 2E-10x3 - 3E-05x2 + 6.921x + 68688
R2 = 0.9948
y = 8E-09x3 - 0.0004x2 + 15.03x + 33044
R2 = 0.9909
Capital Cost
1200000
1000000
800000
600000
400000
200000
0
0
50000
100000
150000
200000
250000
Flow GPM
width 2 feet
width 5 feet
width 10 feet
width 14 feet

Chart 2-23. Fish Spray Pumps Capital Costs

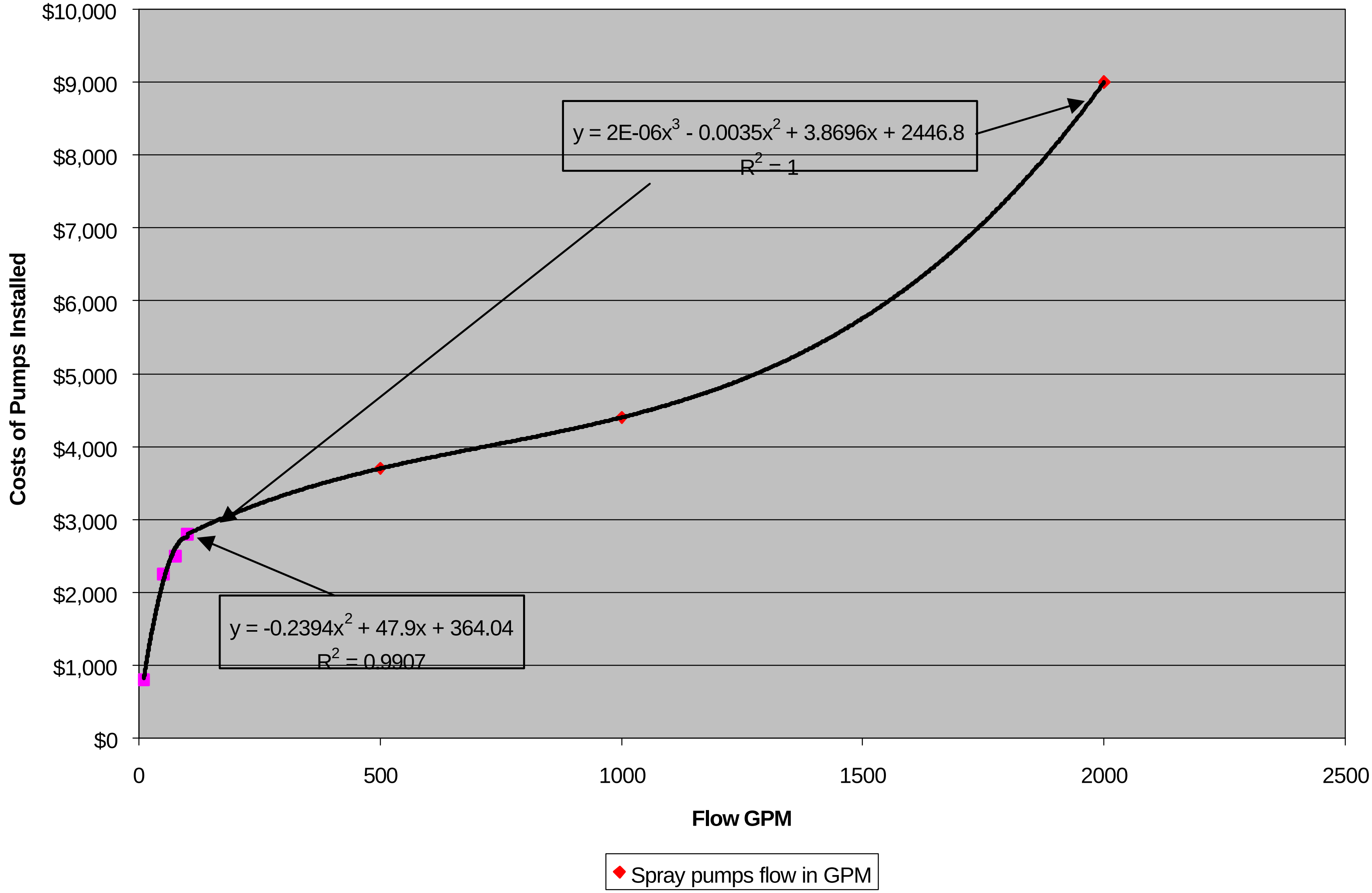
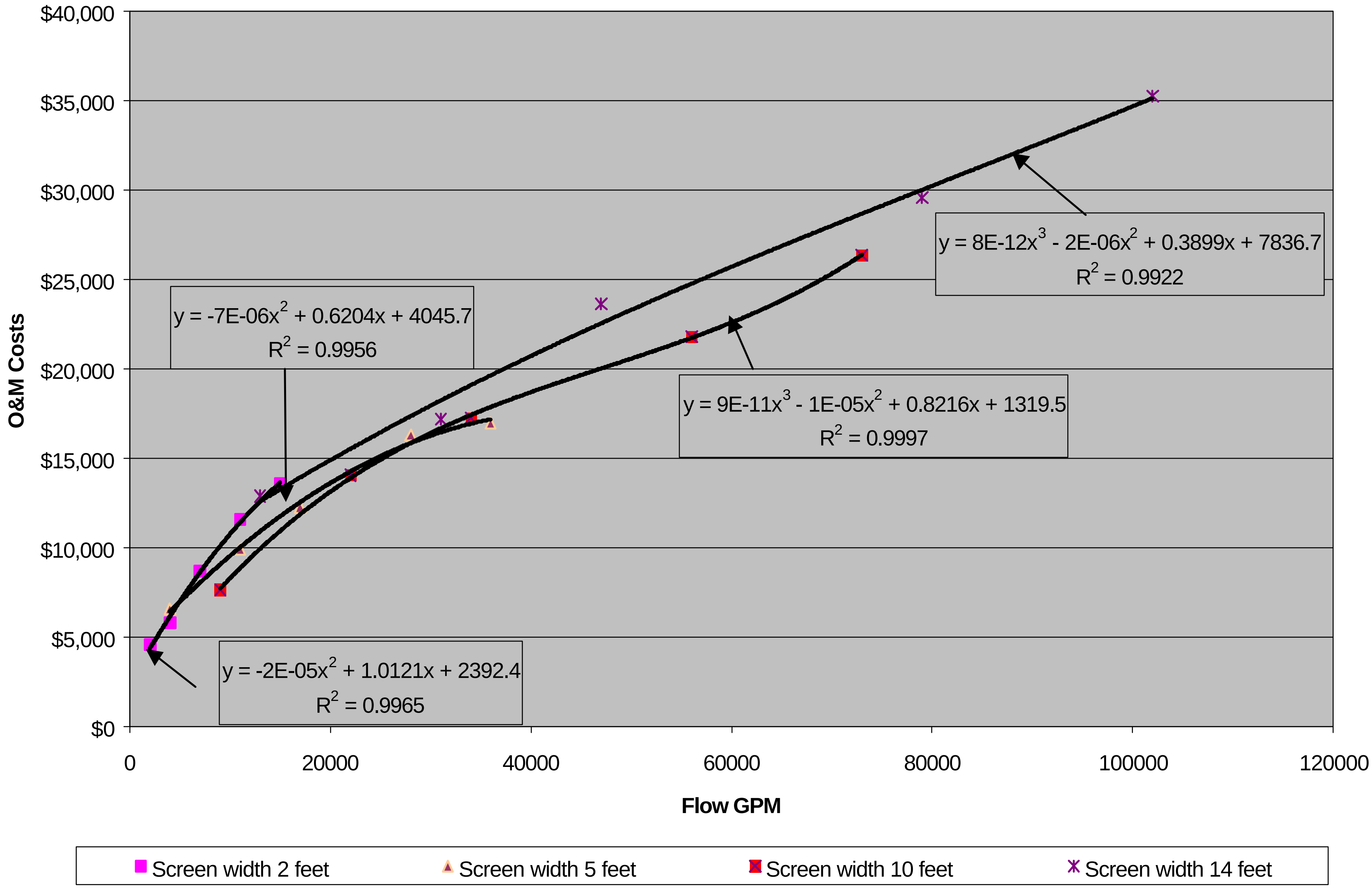


Chart 2-24. O&M Cost for Traveling Screens Without Fish Handling Features Flow Velocity 0.5ft/sec



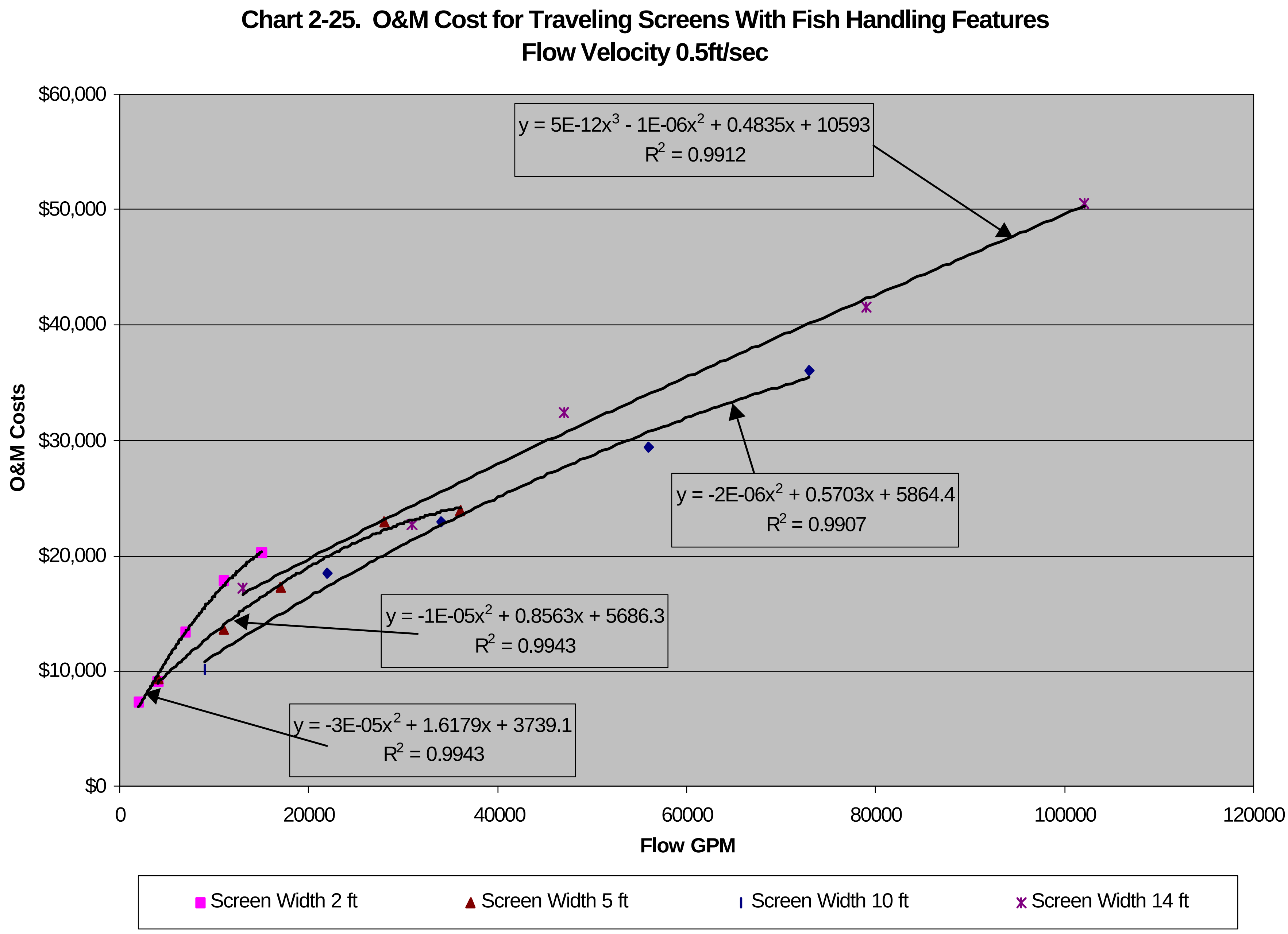
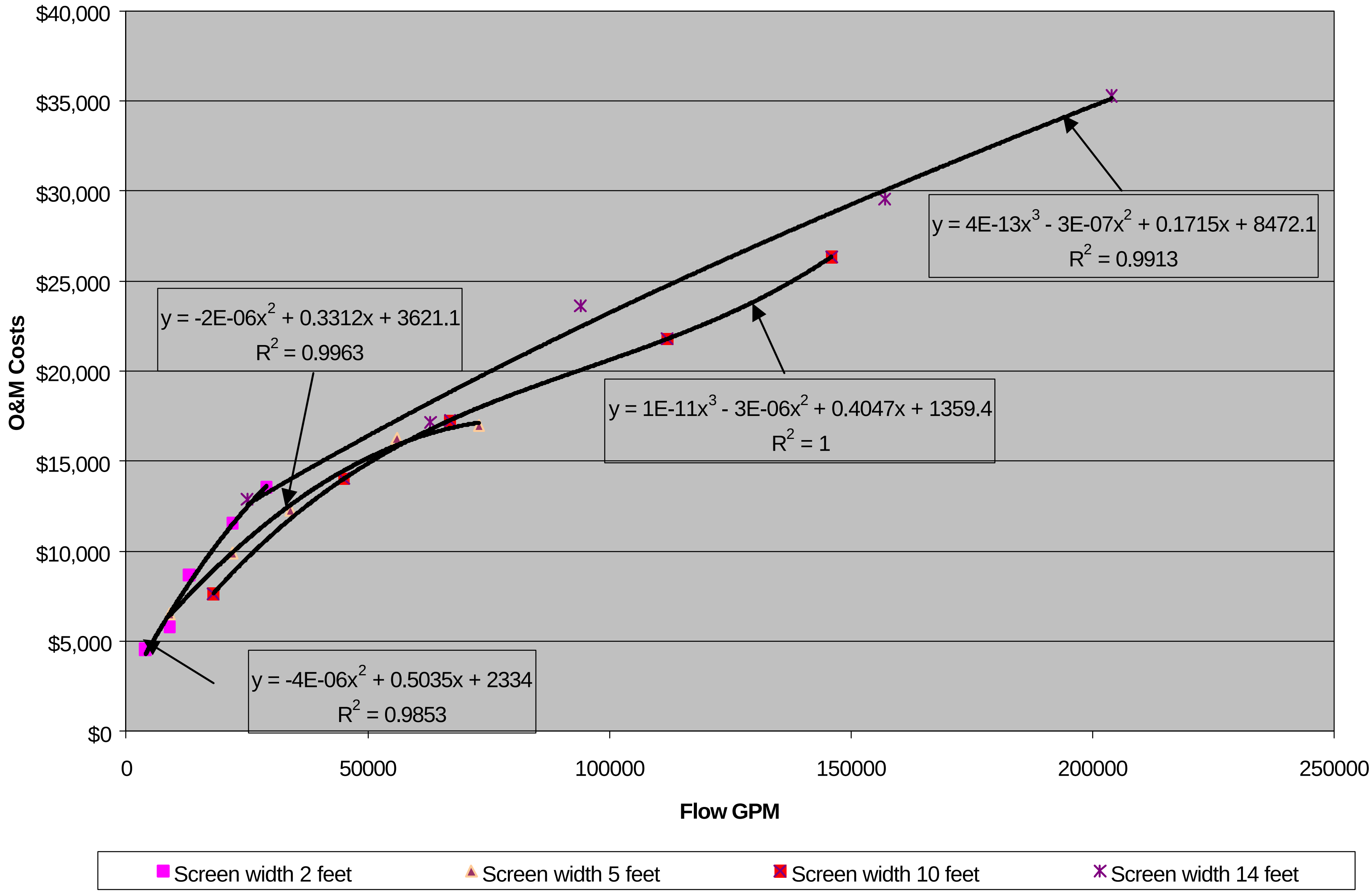


Chart 2-25. O&M Cost for Traveling Screens With Fish Handling Features
Flow Velocity 0.5ft/sec
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
O&M Costs
0
20000
40000
60000
80000
100000
120000
Flow GPM
y = 5E-12x3 - 1E-06x2 + 0.4835x + 10593
R2 = 0.9912
y = -2E-06x2 + 0.5703x + 5864.4
R2 = 0.9907
y = -1E-05x2 + 0.8563x + 5686.3
R2 = 0.9943
y = -3E-05x2 + 1.6179x + 3739.1
R2 = 0.9943
Screen Width 2 ft
Screen Width 5 ft
Screen Width 10 ft
Screen Width 14 ft

Chart 2-26. O&M Cost for Traveling Screens Without Fish Handling Features Flow Velocity 1 ft/sec



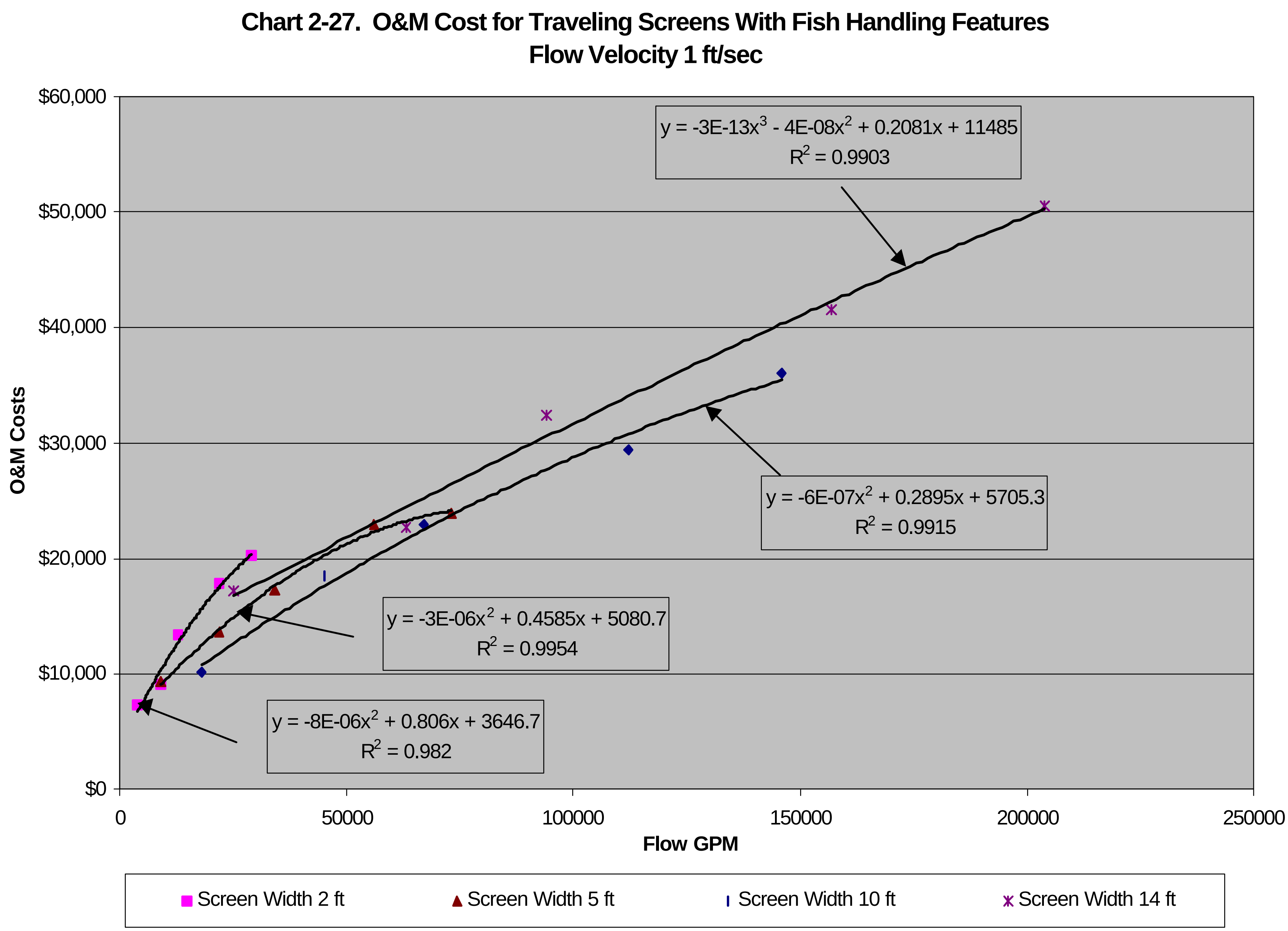
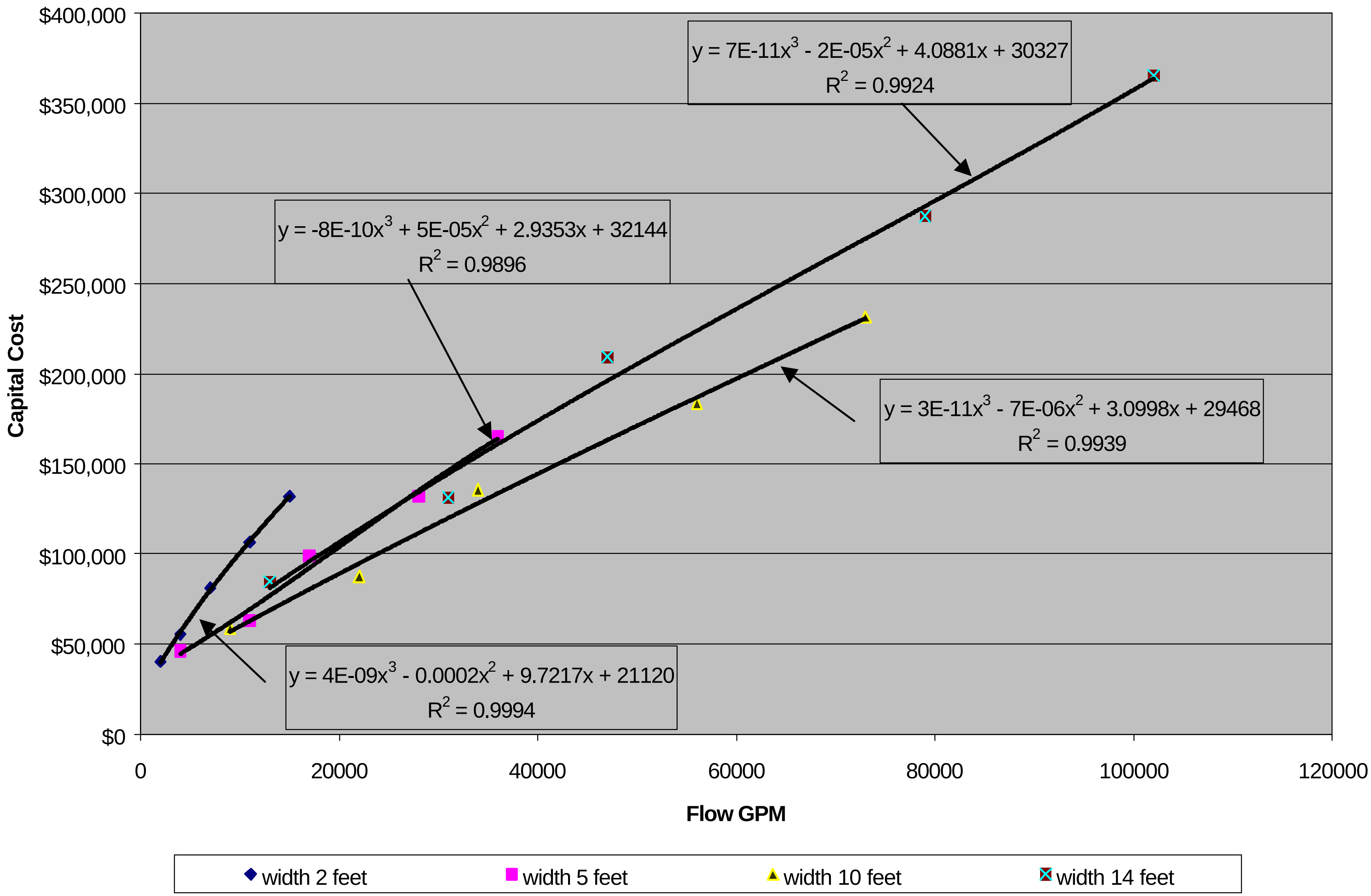


Chart 2-27. O&M Cost for Traveling Screens With Fish Handling Features
Flow Velocity 1 ft/sec
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
O&M Costs
0
50000
100000
150000
200000
250000
Flow GPM
y = -3E-13x3 - 4E-08x2 + 0.2081x + 11485
R2 = 0.9903
y = -6E-07x2 + 0.2895x + 5705.3
R2 = 0.9915
y = -3E-06x2 + 0.4585x + 5080.7
R2 = 0.9954
y = -8E-06x2 + 0.806x + 3646.7
R2 = 0.982
Screen Width 2 ft
Screen Width 5 ft
Screen Width 10 ft
Screen Width 14 ft

Chart 2-28. Capital Cost of Fish Handling Equipment Screen Flow Velocity 0.5 ft/sec



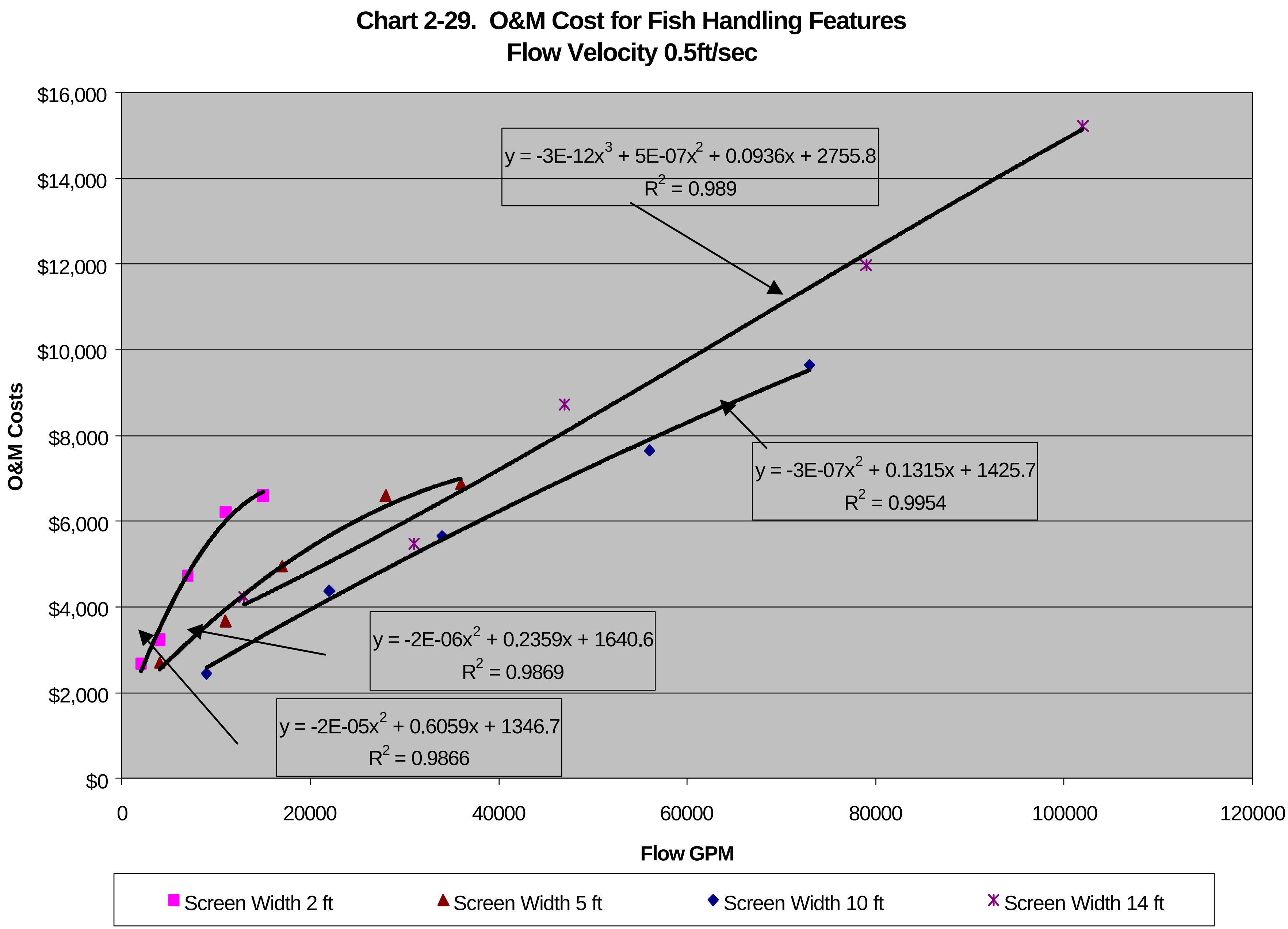
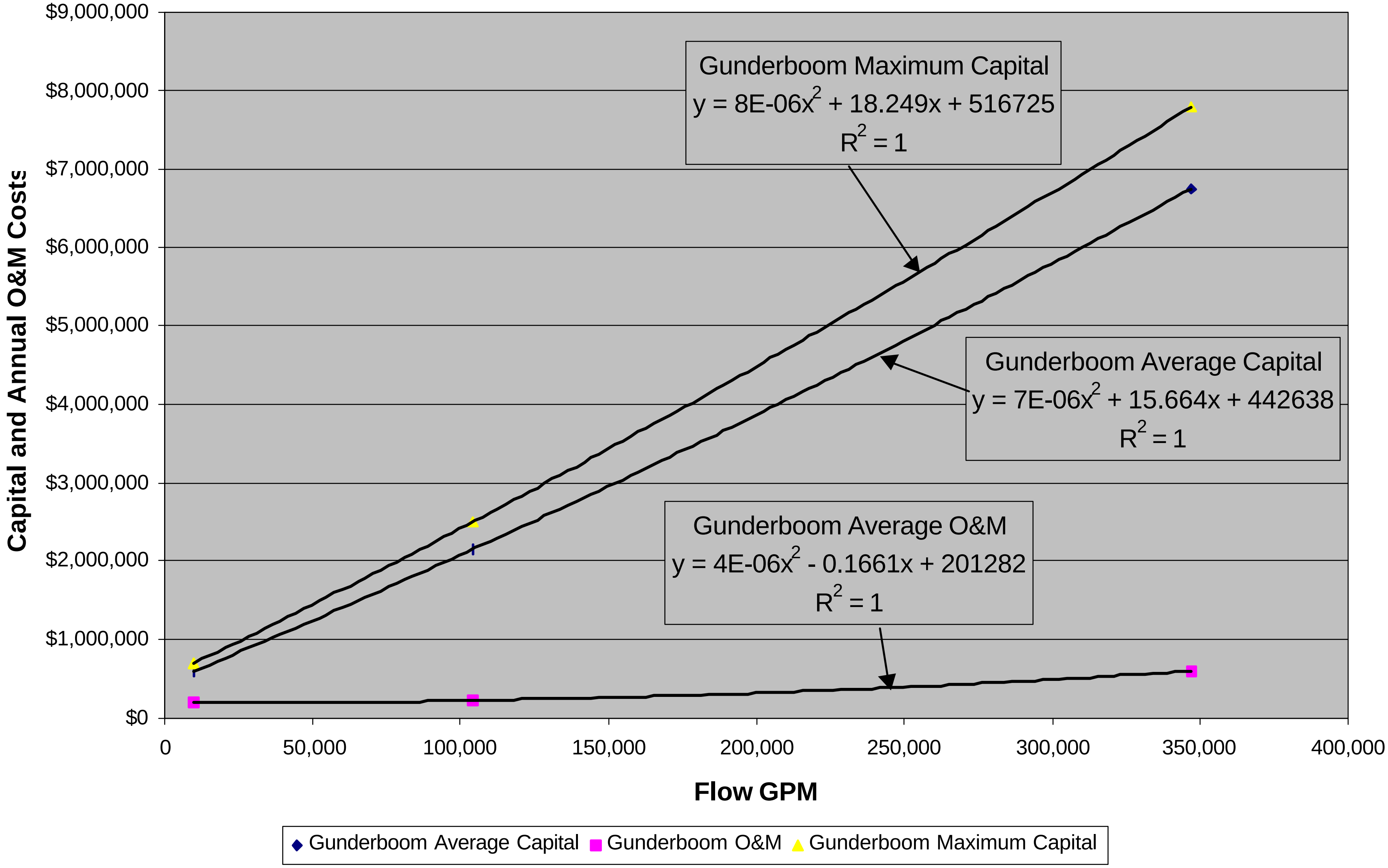


Chart 2-29. O&M Cost for Fish Handling Features
Flow Velocity 0.5ft/sec
y = -3E-12x3 + 5E-07x2 + 0.0936x + 2755.8
R2 = 0.989
y = -3E-07x2 + 0.1315x + 1425.7
R2 = 0.9954
y = -2E-06x2 + 0.2359x + 1640.6
R2 = 0.9869
y = -2E-05x2 + 0.6059x + 1346.7
R2 = 0.9866
O&M Costs
$16,000
$14,000
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$0
0
20000
40000
60000
80000
100000
120000
Flow GPM
Screen Width 2 ft
Screen Width 5 ft
Screen Width 10 ft
Screen Width 14 ft

Chart 2-30. Gunderboom Capital and O&M Costs For Simple Floating Structure



Chapter 3: Energy Penalties, Air Emissions, and Cooling Tower Side-Effects

Introduction

This chapter discusses the topics of energy penalties, air emissions, and other environmental impacts of cooling tower systems. The final rule projects that nine new facility power plants will install recirculating closed-cycle wet cooling systems as a result of this rule. These systems, mainly represented by natural-draft wet cooling towers, may present trade-offs in energy efficiency, associated air emissions increases, and some other environmental issues.

The energy penalty is an important and controversial topic for the electricity generation industry. The topic is widely discussed and debated, yet precise theoretical or empirical measures of energy penalties were not readily available to met the Agency's needs. Therefore, the Agency researched and derived energy penalty estimates, based on empirical data and proven theoretical concepts, for a variety of conditions. This chapter presents the research, methodology, public comments, results, and conclusions for the Agency's thorough effort to estimate energy penalties due to the operational performance of power plant cooling systems.

As a consequence of energy penalties for some cooling systems, increased air pollutant emissions may occur for some power plants as compared to a baseline system. This chapter presents estimates of the increased air emissions for the four key pollutants that are currently well researched and monitored for at power plants in the United States: carbon dioxide (CO2), sulfur dioxide (SO2), nitrogen oxides (NOx), and mercury (Hg).

The remainder of this chapter is organized as follows:

Chapter Contents

< Section 3.1 presents the energy penalty estimates developed for the final rule and the dry cooling regulatory alternative.

< Section 3.2 presents the air emissions estimates developed for the final rule and the dry cooling regulatory alternative.

< Section 3.3 presents the background, research, and methodology of the energy penalty evaluation. The section focuses on power plants that use steam turbines and the changes in efficiency associated with using alternative cooling systems.

< Section 3.4 presents the methodology for estimation of air emissions increases.

< Section 3.5 discusses side effects of recirculating wet cooling towers, such as vapor plumes, displacement of habitat or wetlands, noise, salt or mineral drift, water consumption through evaporation, and solid waste generation due to wastewater treatment of tower blowdown.

3.1 Energy Penalty Estimates for Cooling

Tables 3-1 through 3-6 present the energy penalty estimates developed for the final rule and the dry cooling regulatory alternative. The Agency presents the methodology for estimation of energy penalties in Section 3.3 of this chapter.

Table 3-1: National Average Annual Energy Penalty, Summary Table

Cooling Type	Percent Maximum Load[a]	Nuclear Percent of Plant Output	Combined-Cycle Percent of Plant Output	Fossil-Fuel Percent of Plant Output
Wet Tower vs. Once-Through	67	1.7	0.4	1.7
Dry Tower vs. Once-Through	67	8.5	2.1	8.6
Dry Tower vs. Wet Tower	67	6.8	1.7	6.9

[a] Average annual penalties occur at non-peak loads..

Table 3-2: National Peak Summer Energy Penalty, Summary Table

Cooling Type	Percent Maximum Load[a]	Nuclear Percent of Plant Output	Combined-Cycle Percent of Plant Output	Fossil-Fuel Percent of Plant Output
Wet Tower vs. Once-Through	100	1.9	0.4	1.7
Dry Tower vs. Once-Through	100	11.4	2.8	10.0
Dry Tower vs. Wet Tower	100	9.6	2.4	8.4

[a] Peak-summer shortfalls occur when plants are at or near maximum capacity.

Table 3-3: Total Energy Penalties at 67 Percent Maximum Load[a]

Location	Cooling Type	Nuclear Annual Average	Combined-Cycle Annual Average	Fossil-Fuel Annual Average
Boston	Wet Tower vs. Once-Through	1.6	0.4	1.6
	Dry Tower vs. Once-Through	7.4	1.8	7.1
	Dry Tower vs. Wet Tower	5.8	1.4	5.5
Jacksonville	Wet Tower vs. Once-Through	1.9	0.4	1.7
	Dry Tower vs. Once-Through	12.0	3.0	12.5
	Dry Tower vs. Wet Tower	10.1	2.5	10.8
Chicago	Wet Tower vs. Once-Through	1.8	0.4	1.8
	Dry Tower vs. Once-Through	7.8	1.9	7.7
	Dry Tower vs. Wet Tower	5.9	1.5	5.9
Seattle	Wet Tower vs. Once-Through	1.5	0.4	1.5
	Dry Tower vs. Once-Through	7.0	1.7	6.9
	Dry Tower vs. Wet Tower	5.5	1.3	5.4

[a] Average annual penalties occur at non-peak loads.

Table 3-4: Total Energy Penalties at 100 Percent Maximum Load[a]

Location	Cooling Type	Nuclear Percent of Plant Output	Combined-Cycle Percent of Plant Output	Fossil-Fuel Percent of Plant Output
Boston	Wet Tower vs. Once-Through	2.1	0.5	1.9
	Dry Tower vs. Once-Through	11.6	2.9	10.2
	Dry Tower vs. Wet Tower	9.5	2.4	8.3
Jacksonville	Wet Tower vs. Once-Through	1.6	0.4	1.4
	Dry Tower vs. Once-Through	12.3	3.1	10.7
	Dry Tower vs. Wet Tower	10.7	2.7	9.3
Chicago	Wet Tower vs. Once-Through	2.2	0.5	2.0
	Dry Tower vs. Once-Through	11.9	2.9	10.4
	Dry Tower vs. Wet Tower	9.6	2.4	8.4
Seattle	Wet Tower vs. Once-Through	1.6	0.4	1.5
	Dry Tower vs. Once-Through	10.0	2.4	8.9
	Dry Tower vs. Wet Tower	8.4	2.0	7.4

[a] Peak-summer shortfalls occur when plants are at or near maximum capacity.

Table 3-5: Annual Penalties (in MW) for the Final Rule by Online Year[a]

Year	Coal-Fired Once-Through Cooling at Baseline	Combined-Cycle, Once-Through Cooling at Baseline
2001		
2002		
2003		
2004		4
2005	70	
2006		
2007	9	4
2008	1	
2009		
2010		4
2011		
2012		
2013		4
2014		
2015		
2016		
2017		4
2018		
2019		
2020		
Total	79	21

[a] The total energy penalty for the final rule is 100 MW, or 0.027 percent of all new generating capacity in the US over the next twenty years.

Table 3-6: Annual Penalties (in MW) for the Dry Cooling-Based Alternative by Online Year[a]

	Coal-Fired			Combined-Cycle		
Year	Recirculating Wet Cooling Baseline		Once-Through Baseline	Recirculating Wet Cooling Baseline		Once-Through Baseline
	Freshwater	Estuary	Freshwater	Freshwater	Estuary	Estuary
2001						
2002						
2003						
2004						22
2005			362	71	8	
2006	164			54	17	
2007	164	56	44	40		22
2008			5	77	8	
2009	108			46		
2010				61		22
2011				102	8	
2012				38		
2013				33		22
2014				54	8	
2015				35		
2016				34		
2017				30		22
2018				37	8	
2019	43			37		
2020	12			31		
Total	491	56	412	779	58	108

[a] The total energy penalty for the dry cooling option (at a total of 83 potentially impacted plants) would be 1900 MW, or 0.5 percent of all new capacity in the US over the next twenty years.

3.2 Air Emissions Estimates for Cooling Systems Upgrades

Tables 3-7 and 3-8 present the incremental air emissions estimates developed for the final rule and the dry cooling regulatory alternative. The Agency presents the methodology for estimation of air emissions increases in section 3.4 of this Chapter.

Table 3-7: Air Emissions Increases for the Final Rule[a]

Fuel Type	Total Effected Capacity (MW)	Annual CO_2 (tons)	Annual SO_2 (tons)	Annual NO_X (tons)	Annual Hg (lbs)
All	9,957	485,860	2,561	1,214	16

[a] These emissions increases represent an increase for the entire US electricity generation industry of approximately 0.02 percent per pollutant.

Table 3-8: Air Emissions Increases for the a Dry Cooling-Based Alternative[a]

Fuel Type	Total Effected Capacity (MW)	Annual CO_2 (tons)	Annual SO_2 (tons)	Annual NO_X (tons)	Annual Hg (lbs)
All	64,070	8,931,056	47,074	22,313	300

[a] These emissions increases represent an increase for the US electricity generation industry of approximately 0.35 percent. For the mercury emissions alone, these emissions are equivalent to the addition of three 800-MW coal-fired power plants operating at near full capacity.

3.3 Background, Research, and Methodology of Energy Penalty Estimates

This energy penalty discussion references the differences in steam power plant efficiency or output associated with the effect of using alternative cooling systems. In particular, this evaluation focuses on power plants that use steam turbines and the changes in efficiency associated with using alternative cooling systems. The cooling systems evaluated include: once-through cooling systems; wet tower closed-cycle systems; and dry cooling systems using air cooled condensers. However, the methodology is flexible as to be extended to other alternative types of cooling systems so long as the steam condenser performance or the steam turbine exhaust pressure can be estimated. A summary and discussion of public comments on EPA's energy penalty analysis is presented in Attachment F to this chapter.

3.3.1 Power Plant Efficiencies

Most power plants that use a heat-generating fuel as the power source use a steam cycle referred to as a "Rankine Engine," in which water is heated into steam in a boiler and the steam is then passed through a turbine (Woodruff 1998). After exiting the turbine, the spent steam is condensed back into water and pumped back into the boiler to repeat the cycle. The turbine, in turn, drives a generator that produces electricity. As with any system that converts energy from one form to another, not all of the energy available from the fuel source can be converted into useful energy in a power plant.

Steam turbines extract power from steam as the steam passes from high pressure and high temperature conditions at the turbine inlet to low pressure and lower temperature conditions at the turbine outlet. Steam exiting the turbine goes to the condenser, where it is condensed to water. The condensation process is what creates the low pressure conditions at the turbine outlet. The steam turbine outlet or exhaust pressure (which is often a partial vacuum) is a function of the temperature maintained at the condensing surface (among other factors) and the value of the exhaust pressure can have a direct effect on the energy available to drive the turbine. The lower the exhaust pressure, the greater the amount of energy that is available to drive the turbine, which in turn increases the overall efficiency of the system since no additional fuel energy is involved.

The temperature of the condensing surface is dependent on the design and operating conditions within the condensing system (e.g., surface area, materials, cooling fluid flow rate, etc.) and especially the temperature of the cooling water or air used to absorb heat and reject it from the condenser. Thus, the use of a different cooling system can affect the temperature maintained at the steam condensing surface (true in many circumstances). This difference can result in a change in the efficiency of the power plant. These efficiency differences vary throughout the year and may be more pronounced during the warmer months. Equally important is the fact that most alternative cooling systems will require a different amount of power to operate equipment such as fans and pumps, which also can have an effect on the overall plant energy efficiency. The reductions in energy output resulting from the energy required to operate the cooling system equipment are often referred to as parasitic losses.

In general, the penalty described here is only associated with power plants that utilize a steam cycle for power production. Therefore, this analysis will focus only on steam turbine power plants and combined-cycle gas plants. The most common steam turbine power plants are those powered by steam generated in boilers heated by the combustion of fossil fuels or by nuclear reactors.

Combined-cycle plants use a two-step process in which the first step consists of turbines powered directly by high pressure hot gases from the combustion of natural gas, oil, or gasified coal. The second step consists of a steam cycle in which a turbine is powered by steam generated in a boiler heated by the low pressure hot gases exiting the gas turbines. Consequently, the combined-cycle plants have much greater overall system efficiencies. However, the energy penalty associated with using alternative cooling systems is only associated with the steam cycle portion of the system. Because steam plants cannot be quickly started or stopped, they tend to be operated as base load plants which are continuously run to serve the minimum load required by the system. Since combined-cycle plants obtain only a portion of their energy from the slow-to-start/stop steam power step, the inefficiency of the start-up/stop time period is more economically acceptable and therefore they are generally used for intermediate loads. In other words, they are started and stopped at a greater frequency than base load steam plant facilities.

One measure of the plant thermal efficiency used by the power industry is the Net Plant Heat Rate (NPHR), which is the ratio of the total fuel heat input (BTU/hr) divided by the net electric generation (kW). The net electric generation includes only electricity that leaves the plant. The total energy plant efficiency can be calculated from the NPHR using the following formula:

$$\text{Plant Energy Efficiency} = 3473 / \text{NPHR} \times 100 \qquad (1)$$

Table 3-9 presents the NPHR and plant efficiency numbers for different types of power plants. Note that while there may be some differences in efficiencies for steam turbine systems using different fossil fuels, these differences are not significant enough for consideration here. The data presented to represent fossil fuel plants is for coal-fired plants, which comprise the majority in that category.

Table 3-9: Heat Rates and Plant Efficiencies for Different Types of Steam Powered Plants

Type of Plant	Net Plant Heat Rate (BTU/kWh)	Efficiency (%)
Steam Turbine - Fossil Fuel	9,355	37 to 40
Steam Turbine – Nuclear	10,200	34
Combined Cycle – Gas	6,762	51
Combustion Turbine	11,488	30

Source: Analyzing Electric Power Generation under the CAAA. Office of Air and Radiation U.S. Environmental Protection Agency. April 1996 (Projections for year 2000-2004).

Overall, fossil fuel steam electric power plants have net efficiencies with regard to the available fuel heat energy ranging from 37 to 40 percent. Attachment A at the end of this chapter (Ishigai, S. 1999.) shows a steam power plant heat diagram in which approximately 40 percent of the energy is converted to the power output and 44 percent exits the system through the condensation of the turbine exhaust steam, which exits the system primarily through the cooling system with the remainder exiting the system through various other means including exhaust gases. Note that the exergy diagram in Attachment A shows that this heat passing through the condenser is not a significant source of plant inefficiency, but as would be expected it shows a similar percent of available energy being converted to power as shown in Table 3-9 and Attachment A.

Nuclear plants have a lower overall efficiency of approximately 34 percent, due to the fact that they generally operate at lower boiler temperatures and pressures and the fact that they use an additional heat transfer loop. In nuclear plants, heat is extracted from the core using a primary loop of pressurized liquid such as water. The steam is then formed in a secondary boiler system. This indirect steam generation arrangement results in lower boiler temperatures and pressures, but is deemed necessary to provide for safer operation of the reactor and to help prevent the release of radioactive substances. Nuclear reactors generate a near constant heat output when operating and therefore tend to produce a near constant electric output.

Combustion turbines are shown here for comparative purposes only. Combustion turbine plants use only the force of hot gases produced by combustion of the fuel to drive the turbines. Therefore, they do not require much cooling water since they do not use steam in the process, but they are also not as efficient as steam plants. They are, however, more readily able to start and stop quickly and therefore are generally used for peaking loads.

Combined cycle plants have the highest efficiency because they combine the energy extraction methods of both combustion turbine and steam cycle systems. Efficiencies as high as 58 percent have been reported (Woodruff 1998). Only the efficiency of the second stage (which is a steam cycle) is affected by cooling water temperatures. Therefore, for the purposes of this analysis, the energy penalty for combined cycle plants is applicable only to the energy output of the steam plant component, which is generally reported to be approximately one-third of the overall combined-cycle plant energy output.

3.3.2 Turbine Efficiency Energy Penalty

a. Effect of Turbine Exhaust Pressure

The temperature of the cooling water (or air in air-cooled systems) entering the steam cycle condensers affects the exhaust pressure at the outlet of the turbine. In general, a lower cooling water or air temperature at the condenser inlet will result in a lower turbine exhaust pressure. Note that for a simple steam turbine, the available energy is equal to the difference in the enthalpy of the inlet steam and the combined enthalpy of the steam and condensed moisture at the turbine outlet. A reduction in the outlet steam pressure results in a lower outlet steam enthalpy. A reduction in the enthalpy of the turbine exhaust steam, in combination with an increase in the partial condensation of the steam, results in an increase in the efficiency of the turbine system. Of course, not all of this energy is converted to the torque energy (work) that is available to turn the generator, since steam and heat flow through the turbine systems is complex with various losses and returns throughout the system.

The turbine efficiency energy penalty as described below rises and drops in direct response to the temperature of the cooling water (or air in air-cooled systems) delivered to the steam plant condenser. As a result, it tends to peak during the summer and may be substantially diminished or not exist at all during other parts of the year.

The design and operation of the steam condensing system can also affect the system efficiency. In general, design and operational changes that improve system efficiency such as greater condenser surface areas and coolant flow rates will tend to result in an increase in the economic costs and potentially the environmental detriments of the system. Thus, the design and operation of individual systems can differ depending on financial decisions and other site-specific conditions. Consideration of such site-specific design variations is beyond the scope of this evaluation. Therefore, conditions that represent a typical, or average, system derived from available information for each technology will be used. However, regional and annual differences in cooling fluid temperatures are considered. Where uncertainty exists, a conservative estimate is used. In this context, conservative means the penalty estimate is biased toward a higher value.

Literature sources indicate that condenser inlet temperatures of 55 °F and 95 °F will produce turbine exhaust pressures of 1.5 and 3.5 inches Hg, respectively, in a typical surface condenser (Woodruff 1998). If the turbine steam inlet conditions remain constant, lower turbine exhaust pressures will result in greater changes in steam enthalpy between the turbine inlet and outlet. This in turn will result in higher available energy and higher turbine efficiencies.

The lower outlet pressures can also result in the formation of condensed liquid water within the low pressure end of the turbine. Note that liquid water has a significantly lower enthalpy value which, based on enthalpy alone, should result in even greater turbine efficiencies. However, the physical effects of moisture in the turbines can cause damage to the turbine blades and can result in lower efficiencies than would be expected based on enthalpy data alone. This damage and lower efficiency is due to the fact that the moisture does not follow the steam path and impinges upon the turbine blades. More importantly, as the pressure in the turbine drops, the steam volume increases. While the turbines are designed to accommodate this increase in volume through a progressive increase in the cross-sectional area, economic considerations tend to limit the size increase such that the turbine cannot fully accommodate the expansion that occurs at very low exhaust pressures.

Thus, for typical turbines, as the exhaust pressure drops below a certain level, the increase in the volume of the steam is not fully accommodated by the turbine geometry, resulting in an increase in steam velocity near the turbine exit. This increase in steam velocity results in the conversion of a portion of the available steam energy to kinetic energy, thus reducing the energy that could otherwise be available to drive the turbine. Note that kinetic energy is proportional to the square of the velocity. Consequently, as the steam velocity increases, the resultant progressive reduction in available energy tends to offset the gains in available energy that would result from the greater enthalpy changes due to the reduced pressure. Thus, the expansion of the steam within the turbine and the formation of condensed moisture establishes a practical lower limit for turbine exhaust pressures, reducing the efficiency advantage of even lower condenser surface temperatures particularly at higher turbine steam loading rates. As can be seen in the turbine performance curves presented below, this reduction in efficiency at lower exhaust pressures is most pronounced at higher turbine steam loading rates. This is due to the fact that higher steam loading rates will produce proportionately higher turbine exit velocities.

Attachment B presents several graphs showing the change in heat rate resulting from differences in the turbine exhaust pressure at a nuclear power plant, a fossil fueled power plant, and a combined-cycle power plant (steam portion). The first graph (Attachment B-1) is for a GE turbine and was submitted by the industry in support of an analysis for a nuclear power plant. The second graph (Attachment B-2) is from a steam turbine technical manual and is for a turbine operating at steam temperatures and pressures consistent with a sub-critical fossil fuel plant (2,400 psig, 1,000 °F). The third graph (Attachment B-3) is from an engineering report analyzing operational considerations and design of modifications to a cooling system for a combined-cycle power plant.

The changes in heat rate shown in the graphs can be converted to changes in turbine efficiency using Equation 1. Several curves on each graph show that the degree of the change (slope of the curve) decreases with increasing loads. Note that the amount of electricity being generated will also vary with the steam loading rates such that the more pronounced reduction in efficiency at lower steam loading rates applies to a reduced power output. The curves also indicate that, at higher steam loads, the plant efficiency optimizes at an exhaust pressure of approximately 1.5 inches Hg. At lower exhaust pressures the effect of increased steam velocities actually results in a reduction in overall efficiency. The graphs in Attachment B will serve as the basis for estimating the energy penalty for each type of facility.

Since the turbine efficiency varies with the steam loading rate, it is important to relate the steam loading rates to typical operating conditions. It is apparent from the heat rate curves in Attachment B that peak loading, particularly if the exhaust pressure is close to 1.5 inches Hg, presents the most efficient and desirable operating condition. Obviously, during peak loading periods, all turbines will be operating near the maximum steam loading rates and the energy penalty derived from the maximum loading curve would apply. It is also reasonable to assume that power plants that operate as base load facilities will operate near maximum load for a majority of the time they are operating. However, there will be times when the power plant is not operating at peak capacity. One measure of this is the capacity factor, which is the ratio of the average load on the plant over a given period to its total capacity. For example, if a 200 MW plant operates, on average, at 50 percent of capacity (producing an average of 100 MW when operating) over a year, then its capacity factor would be 50 percent.

The average capacity factor for nuclear power plants in the U.S. has been improving steadily and recently has been reported to be approximately 89 percent. This suggests that for nuclear power plants, the majority appear to be operating near capacity most of the time. Therefore, use of the energy penalty factors derived from the maximum load curves for nuclear power plants is reasonably valid. In 1998, utility coal plants operated at an average capacity of 69 percent (DOE 2000). Therefore, use of the energy penalty values derived from the 67 percent load curves would appear to be more appropriate for fossil-fuel plants. Capacity factors for combined-cycle plants tend to be lower than coal-fired plants and use of the energy penalty values derived from the 67 percent load curves rather than the 100 percent load curves would be appropriate.

b. Estimated Changes in Turbine Efficiency

Table 3-10 below presents a summary of steam plant turbine inlet operating conditions for various types of steam plants described in literature. EPA performed a rudimentary estimation of the theoretical energy penalty based on steam enthalpy data using turbine inlet conditions similar to those shown in Table 3-10. EPA found that the theoretical values were similar to the changes in plant efficiency derived from the changes in heat rate shown in Attachment B. The theoretical calculations indicated that the energy penalties for the two different types of fossil fuel plants (sub-critical and super-critical) were similar in value, with the sub-critical plant having the larger penalty. Since the two types of fossil fuel plants had similar penalty values, only one was selected for use in the analysis in order to simplify the analysis. The type of plant with the greater penalty value (i.e., sub-critical fossil fuel) was selected as representative of both types.

Table 3-10: Summary of Steam Plant Operating Conditions from Various Sources

System Type	Inlet Temp. / Pressure	Outlet Pressure	Comments	Source
Fossil Fuel - Sub-critical Recirculating Boiler	Not Given / 2,415 psia	1.5 In. Hg	Large Plants (>500MW) have three (high, med, low) pressure turbines. Reheated boiler feed water is 540 °F.	Kirk-Othmer 1997
Fossil Fuel - Super-critical Once-through Boiler	1,000 °F / 3,515 psia	Not Given		Kirk-Othmer 1997
Nuclear	595 °F / 900 psia	2.5 In. Hg	Plants have two (high, low) pressure turbines with low pressure turbine data at left. Reheated boiler feed water is 464 °F.	Kirk-Othmer 1997
Combined Cycle	Gas - 2,400 °F Steam - 900 °F	Not Given	Operating efficiency ranges from 45-53%	www.greentie.org
Fossil Fuel Ranges	900-1,000 °F / 1,800-3,600 psia	1.0-4.5 In Hg	Outlet pressures can be even higher with high cooling water temperatures or air cooled condensers.	Woodruff 1998.

The three turbine performance curve graphs in Attachment B present the change in heat rate from which changes in plant efficiency were calculated. The change in heat rate value for several points along each curve was determined and then converted to changes in efficiency using Equation 1. The calculated efficiency values derived from the Attachment B graphs representing the 100 percent or maximum steam load and the 67 percent steam load conditions have been plotted in Figure 1. Curves were then fitted to these data to obtain equations that can be used to estimate energy penalties. Figure 1 establishes the energy efficiency and turbine exhaust pressure relationship. The next step is to relate the turbine exhaust pressure to ambient conditions and to determine ambient conditions for selected locations.

Note that for fossil fuel plants the energy penalty affects mostly the amount of fuel used, since operating conditions can be modified, within limits, to offset the penalty. However, the same is not true for nuclear plants, which are constrained by the limitations of the reactor system.

Figure 1
Plot of Various Turbine Exhaust Pressure Correction Curves for 100% and 67% Steam Loads

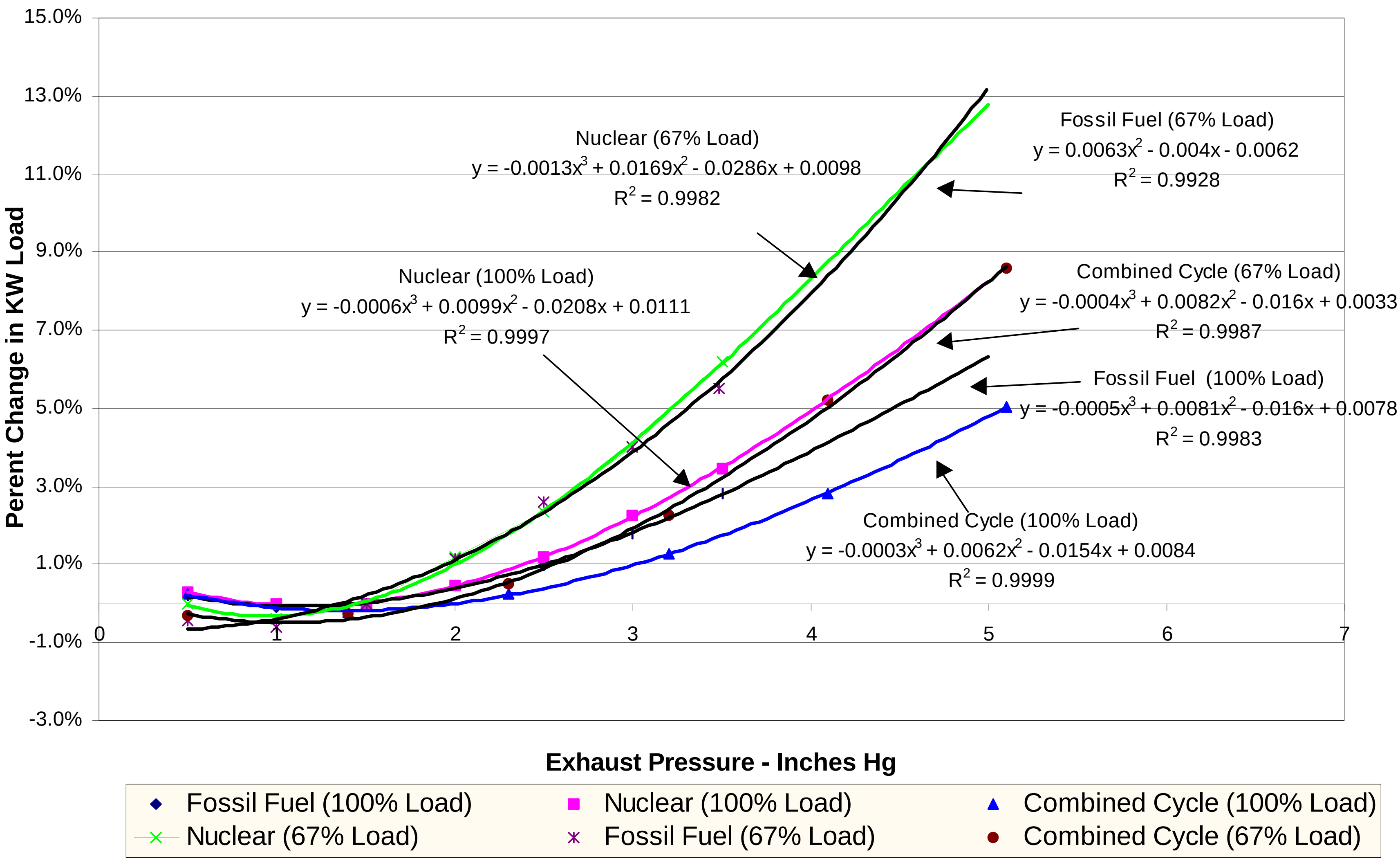
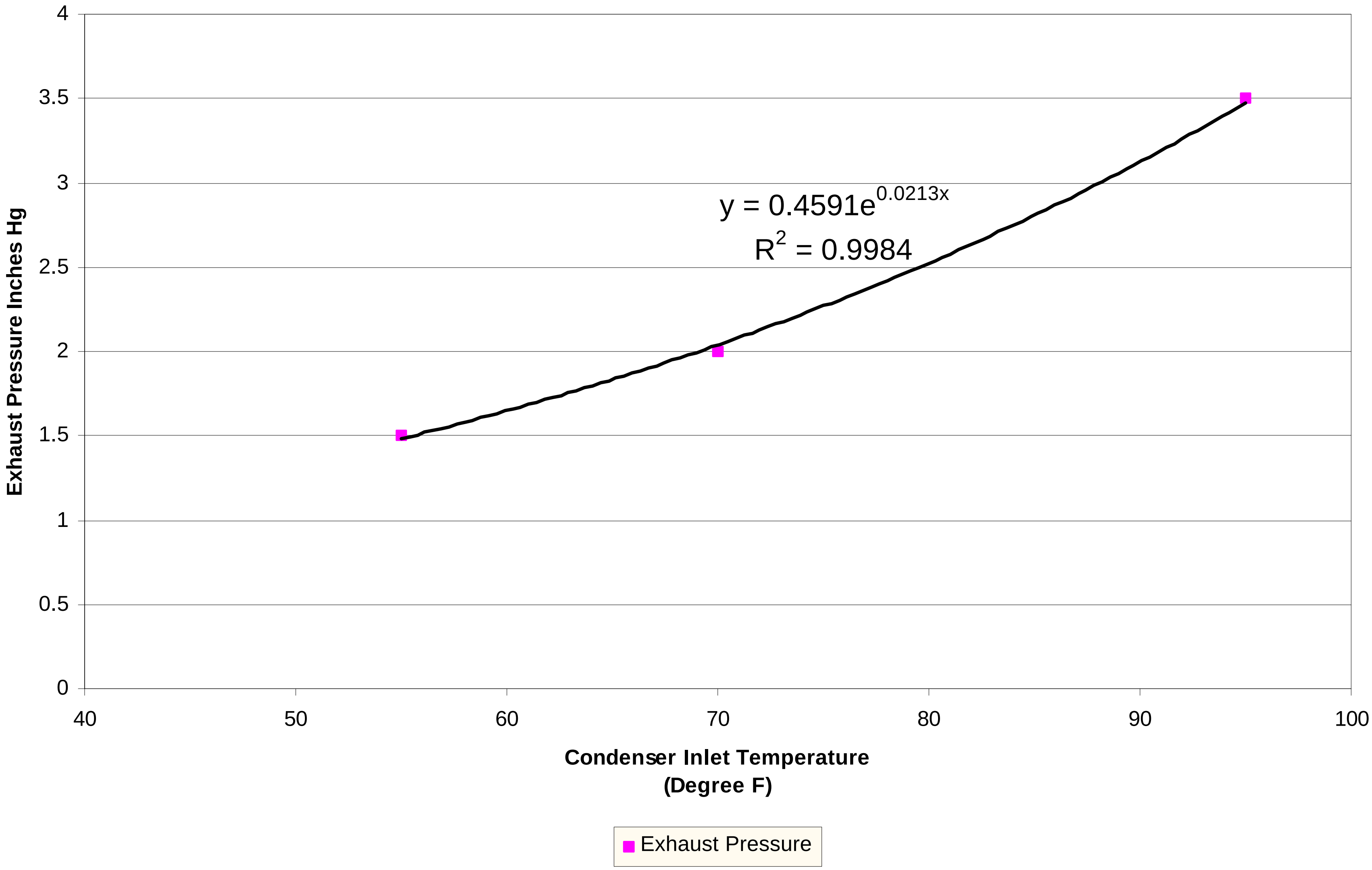


Figure 2
Surface Condenser Cooling Water Inlet Temperature and Steam Pressure Relationship



c. Relationship of Condenser Cooling Water (or Air) Temperature to Steam Side Pressure for Different Cooling System Types and Operating Conditions

˜ *Surface Condensers*

Both once-through and wet cooling towers use surface condensers. As noted previously, condenser inlet temperatures of 55 °F and 95 °F will produce turbine exhaust pressures of 1.5 and 3.5 inches Hg, respectively. Additionally, data from the Calvert Cliffs nuclear power plant showed an exhaust pressure of 2.0 inches Hg at a cooling water temperature of 70 °F. Figure 2 provides a plot of these data which, even though they are from two sources, appear to be consistent. A curve was fitted to these data and was used as the basis for estimating the turbine exhaust pressure for different surface condenser cooling water inlet temperatures. Note that this methodology is based on empirical data that simplifies the relationship between turbine exhaust pressure and condenser inlet temperature, which would otherwise require more complex heat exchange calculations. Those calculations, however, would require numerous assumptions, the selection of which may produce a different curve but with a similar general relationship.

˜ *Once-through Systems*

For once-through cooling systems, the steam cycle condenser cooling water inlet temperature is also the temperature of the source water. Note that the outlet temperature of the cooling water is typically 15 - 20 °F higher than the inlet temperature. This difference is referred to as the "range." The practical limit of the outlet temperature is approximately 100 °F, since many NPDES permits have limitations in the vicinity of 102 - 105 °F . This does not appear to present a problem, since the maximum monthly average surface water temperature at Jacksonville, Florida (selected by EPA as representing warmer U.S. surface waters) was 83.5 °F which would, using the range values above, result in an effluent temperature of 98.5 - 103.5 °F. To gauge the turbine efficiency energy penalty for once-through cooling systems, the temperature of the source water must be known. These temperatures will vary with location and time of year and estimates for several selected locations are presented in Table 3 below.

˜ *Wet Cooling Towers*

For wet cooling towers, the temperature of the cooling tower outlet is the same as the condenser cooling water inlet temperature. The performance of the cooling tower in terms of the temperature of the cooling tower outlet is a function of the wet bulb temperature of the ambient air and the tower type, size, design, and operation. The wet bulb temperature is a function of the ambient air temperature and the humidity. Wet bulb thermometers were historically used to estimate relative humidity and consist of a standard thermometer with the bulb encircled with a wet piece of cloth. Thus, the temperature read from a wet bulb thermometer includes the cooling effect of water evaporation.

Of all of the tower design parameters, the temperature difference between the wet bulb temperature and the cooling tower outlet (referred to as the "approach") is the most useful in estimating tower performance. The wet cooling tower cooling water outlet temperature of the systems that were used in the economic analysis for the final §316(b) New Facility Rule had a design approach of 10 °F. Note that the design approach value is equal to the difference between the tower cooling water outlet temperature and the ambient wet bulb temperature only at the design wet bulb temperature. The actual approach value at wet bulb temperatures other than the design value will vary as described below.

The selection of a 10 °F design approach is based on the data in Attachment C for recently constructed towers. Moreover, a 10 °F approach is considered conservative. As can be seen in Attachment D, a plot of the tower size factor versus the approach shows that a 10 °F approach has a tower size factor of 1.5. The approach is a key factor in sizing towers and has significant cost implications. The trade-off between selecting a small approach versus a higher value is a trade-off between greater capital cost investment versus lower potential energy production. In states where the rates of return on energy investments are fixed (say between 12% and 15%), the higher the capital investment, the higher the return.

For the wet cooling towers used in this analysis, the steam cycle condenser inlet temperature is set equal to the ambient air wet bulb temperature for the location plus the estimated approach value. A design approach value of 10 °F was selected as the common design value for all locations. However, this value is only applicable to instances when the ambient wet bulb temperature is equal to the design wet bulb temperature. In this analysis, the design wet bulb temperature was selected as the 1 percent exceedence value for the specific selected locations.

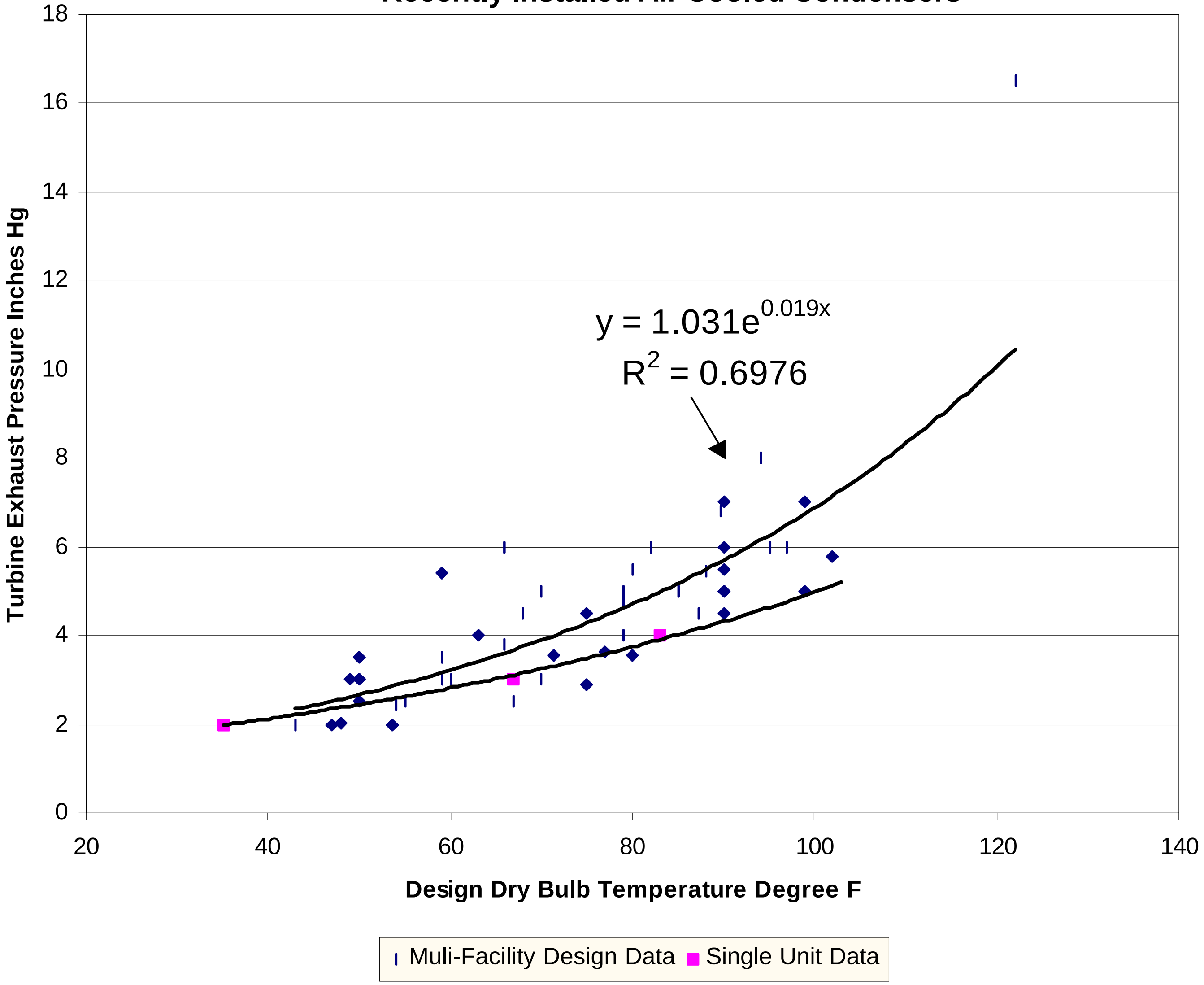
Attachment E provides a graph showing the relationship between different ambient wet bulb temperatures and the corresponding approach for a "typical" wet tower. The graph shows that as the ambient wet bulb temperature decreases, the approach value increases. The graph in Attachment E was used as the basis for estimating the change in the approach value as the ambient wet bulb temperature changes from the design value for each location. Differences in the location-specific design wet bulb temperature were incorporated by fitting a second order polynomial equation to the data in this graph. The equation was then modified by adjusting the intercept value such that the approach was equal to 10 °F when the wet bulb temperature was equal to the design 1 percent wet bulb temperature for the selected location. The location-specific equations were then used to estimate the condenser inlet temperatures that correspond to the estimated monthly values for wet bulb temperatures at the selected locations.

˜ *Air Cooled Condensers*

Air cooled condensers reject heat by conducting it directly from the condensing steam to the ambient air by forcing the air over the heat conducting surface. No evaporation of water is involved. Thus, for air cooled condensers, the condenser performance with regard to turbine exhaust pressure is directly related to the ambient (dry bulb) air temperature, as well as to the condenser design and operating conditions. Note that dry bulb temperature is the same as the standard ambient air temperature with which most people are familiar. Figure 3 presents a plot of the design ambient air temperature and corresponding turbine exhaust pressure for air cooled condensers recently installed by a major cooling system manufacturer (GEA Power Cooling Systems, Inc.). An analysis of the multiple facility data in Figure 3 did not find any trends with respect to plant capacity, location, or age that could justify the separation of these data into subgroups. Three facilities that had very large differences (i.e., >80 °F) in the design dry bulb temperature compared to the temperature of saturated steam at the exhaust pressure were deleted from the data set used in Figure 3.

A review of the design temperatures indicated that the design temperatures did not always correspond to annual temperature extremes of the location of the plant as might be expected. Thus, it appears that the selection of design values for each application included economic considerations. EPA concluded that these design data represent the range of condenser performance at different temperatures and design conditions. A curve was fitted to the entire set of data to serve as a reasonable means of estimating the relationship of turbine exhaust pressure to different ambient air (dry bulb) temperatures. To validate this approach, condenser performance data for a power plant from an engineering contractor report (Litton, no date) was also plotted. This single plant data produced a flatter curve than the multi-facility plot. In other words, the multi-facility curve predicts a greater increase in turbine exhaust pressure as the dry bulb temperature increases. Therefore, the multi-facility curve was selected as a conservative estimation of the relationship between ambient air temperatures and the turbine exhaust pressure. Note that in the case of air cooled condensers, the turbine exhaust steam pressure includes values above 3.5 inches Hg.

Figure 3
Design Dry Bulb and Design Exhaust Pressure for Recently Installed Air Cooled Condensers



˜ *Regional and Seasonal Data*

As noted above, both the source water temperature for once-through cooling systems and the ambient wet bulb and dry bulb temperatures for cooling towers will vary with location and time of year. To estimate average annual energy penalties, EPA sought data to estimate representative monthly values for selected locations. Since plant-specific temperature data may not be available or practical, the conditions for selected locations in different regions are used as examples of the range of possibilities. These four regions include Northeast (Boston, MA), Southeast (Jacksonville, FL), Midwest (Chicago, IL) and Northwest (Seattle, WA). The Southwest Region of the US was not included, since there generally are few once-through systems using surface water in this region.

Table 3-11 presents monthly average coastal water temperatures at the four selected locations. Since the water temperatures remain fairly constant over short periods of time, these data are considered as representative for each month.

Table 3-11: Monthly Average Coastal Water Temperatures (°F)

Location	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Boston, MA[a]	40	36	41	47	56	62	64.5	68	64.5	57	51	42
Jacksonville, FL[a]	57	56	61	69.5	75.5	80.5	83.5	83	82.5	75	67	60
Chicago, IL[b]	39	36	34	36	37	48	61	68	70	63	50	45
Seattle, WA[a]	47	46	46	48.5	50.5	53.5	55.5	56	55.5	53.5	51	49

[a] Source: NOAA Coastal Water Temperature Guides, (www.nodc.noaa.gov/dsdt/cwtg).

[b] Source: Estimate from multi-year plot "Great Lakes Average GLSEA Surface Water Temperature" (http://coastwatch.glerl.noaa.gov/statistics/).

˜ *Wet and Dry Bulb Temperatures*

Table 3-12 presents design wet bulb temperatures (provided by a cooling system vendor) for the selected locations as the wet bulb temperature that ambient conditions will equal or exceed at selected percent of time (June through September) values. Note that 1 percent represents a period of 29.3 hours. These data, however, represent relatively short periods of time and do not provide any insight as to how the temperatures vary throughout the year. The Agency obtained the *Engineering Weather Data Published by the National Climatic Data Center* to provide monthly wet and dry bulb temperatures. In this data set, wet bulb temperatures were not summarized on a monthly basis, but rather were presented as the average values for different dry bulb temperature ranges along with the average number of hours reported for each range during each month. These hours were further divided into 8-hour periods (midnight to 8AM, 8AM to 4PM, and 4PM to midnight).

Unlike surface water temperature, which tends to change more slowly, the wet bulb and dry bulb temperatures can vary significantly throughout each day and especially from day-to-day. Thus, selecting the temperature to represent the entire month requires some consideration of this variation. The use of daily maximum values would tend to overestimate the overall energy penalty and conversely, the use of 24-hour averages may underestimate the penalty, since the peak power production period is generally during the day.

Since the power demand and ambient wet bulb temperatures tend to peak during the daytime, a time- weighted average of the hourly wet bulb and dry bulb temperatures during the daytime period between 8AM and 4PM was selected as the best method of estimating the ambient wet bulb and dry bulb temperature values to be used in the analysis. The 8AM - 4PM time-weighted average values for wet bulb and dry bulb temperatures were selected as a reasonable compromise between using daily maximum values and 24-hour averages. Table 3-13 presents a summary of the time-weighted wet bulb and dry bulb temperatures for each month for the selected locations. Note that the highest monthly 8AM - 4PM time-weighted average tends to correspond well with the 15 percent exceedence design values. The 15 percent values represent a time period of approximately 18 days which are not necessarily consecutive.

Table 3-12: Design Wet Bulb Temperature Data for Selected Locations

Location	Wet Bulb Temp (°F)			Corresponding Cooling Tower Outlet Temperature (°F)		
	% Time Exceeding			% Time Exceeding		
	1%	5%	15%	1%	5%	15%
Boston, MA	76	73	70	86	83	80
Jacksonville, FL	80	79	77	90	89	87
Chicago, IL	78	75	72	88	85	82
Seattle, WA	66	63	60	76	73	70

Source: www.deltacooling.com

Table 3-13: Time-Weighted Averages for Eight-Hour Period from 8am to 4pm (°F)

Location		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Design 1%
Boston	Wet Bulb	27.5	29.3	36.3	44.6	53.9	62.7	67.9	67.4	61.5	52.0	42.6	32.6	74.0
	Dry Bulb	33.0	35.3	43.2	53.5	63.8	73.9	80.0	78.2	70.4	59.9	49.5	38.4	88.0
Jacksonville	Wet Bulb	52.9	55.3	59.6	64.5	70.3	75.1	77.1	77.1	75.1	69.1	63.1	55.9	79.0
	Dry Bulb	59.8	63.6	70.3	76.6	83.0	87.2	89.3	88.1	85.1	77.8	70.6	62.6	93.0
Chicago	Wet Bulb	23.3	27.0	37.2	46.6	56.6	64.9	69.8	69.3	62.2	51.2	39.1	27.9	76.0
	Dry Bulb	27.6	31.8	43.9	55.7	67.9	77.4	82.5	80.6	72.4	59.9	45.0	32.2	89.0
Seattle	Wet Bulb	39.4	41.8	44.2	47.2	52.0	56.0	59.2	59.6	57.2	51.0	44.0	39.7	65.0
	Dry Bulb	44.3	47.8	51.5	55.6	61.8	67.2	71.6	71.6	67.3	58.1	49.0	44.3	82.0

c. Calculation of Energy Penalty

Since the energy penalty will vary over time as ambient climatic and source water temperatures vary, the calculation of the total annual energy penalty for a chosen location would best be performed by combining (integrating) the results of individual calculations performed on a periodic basis. For this analysis, a monthly basis was chosen.

The estimated monthly turbine exhaust pressure values for alternative cooling system scenarios were derived using the curves in Figures 2 and 3 in conjunction with the monthly temperature values in Tables 3-11 and 3-13. These turbine exhaust pressure values were then used to estimate the associated change in turbine efficiency using the equations from Figure 1. EPA then calculated the energy penalty for each month. Annual values were calculated by averaging the 12 monthly values.

Tables 3-14 and 3-15 present a summary of the calculated annual average energy penalty values for steam rates of 100 percent and 67 percent of maximum load. These values can be applied directly to the power plant output to determine economic and other impacts. In other words, an energy penalty of 2 percent indicates that the plant output power would be reduced by 2 percent. In addition, Tables 3-14 and 3-15 include the maximum turbine energy penalty associated with maximum design conditions such as once-through systems drawing water at the highest monthly average, and wet towers and air cooled condensers operating in air with a wet bulb and dry bulb temperature at the 1 percent exceedence level. EPA notes that the maximum design values result from using the maximum monthly water temperatures from Table 3-11 and the 1% percent exceedence wet bulb and dry bulb temperatures from Table 3-12.

EPA notes that the penalties presented in Tables 3-14 and 3-15 **do not** comprise the total energy penalties (which incorporate all three components of energy penalties: turbine efficiency penalty, fan energy requirements, and pumping energy usage) as a percent of power output. The total energy penalties are presented in section 3.1 above. The tables below only present the turbine efficiency penalty. Section 3.3.3 presents the fan and pumping components of the energy penalty.

Table 3-14: Calculated Energy Penalties for the Turbine Efficiency Component at 100 Pecent of Maximum Steam Load

Location	Cooling Type	Percent Maximum Load	Nuclear Maximum Design	Nuclear Annual Average	Combined Cycle Maximum Design	Combined Cycle Annual Average	Fossil Fuel Maximum Design	Fossil Fuel Annual Average
Boston	Wet Tower vs. Once-through	100%	1.25%	0.37%	0.23%	0.05%	1.09%	0.35%
	Dry Tower vs. Once-through	100%	9.22%	2.85%	2.04%	0.55%	7.76%	2.48%
	Dry Tower vs. Wet Tower	100%	7.96%	2.48%	1.81%	0.50%	6.66%	2.13%
Jacksonville	Wet Tower vs. Once-through	100%	0.71%	0.54%	0.14%	0.10%	0.61%	0.38%
	Dry Tower vs. Once-through	100%	9.86%	6.21%	2.30%	1.35%	8.22%	5.16%
	Dry Tower vs. Wet Tower	100%	9.14%	5.68%	2.16%	1.25%	7.61%	4.78%
Chicago	Wet Tower vs. Once-through	100%	1.39%	0.42%	0.26%	0.05%	1.21%	0.40%
	Dry Tower vs. Once-through	100%	9.47%	3.09%	2.12%	0.60%	7.96%	2.68%
	Dry Tower vs. Wet Tower	100%	8.08%	2.67%	1.85%	0.55%	6.75%	2.28%
Seattle	Wet Tower vs. Once-through	100%	0.77%	0.29%	0.12%	0.03%	0.70%	0.28%
	Dry Tower vs. Once-through	100%	7.60%	2.63%	1.61%	0.49%	6.46%	2.30%
	Dry Tower vs. Wet Tower	100%	6.83%	2.34%	1.48%	0.45%	5.76%	2.02%
Average	Wet Tower vs. Once-through	100%	1.03%	0.40%	0.19%	0.06%	0.90%	0.35%
	Dry Tower vs. Once-through	100%	9.04%	3.70%	2.02%	0.75%	7.60%	3.15%
	Dry Tower vs. Wet Tower	100%	8.00%	3.29%	1.83%	0.69%	6.70%	2.80%

Note: See Section 3-1 for the total energy penalties. This table presents only the turbine component of the total energy penalty.

Table 3-15: Calculated Energy Penalties for the Turbine Efficiency Component at 67% Pecent of Maximum Steam Load

Location	Cooling Type	Percent Maximum Load	Nuclear Maximum Design	Nuclear Annual Average	Combined Cycle Maximum Design	Combined Cycle Annual Average	Fossil Fuel Maximum Design	Fossil Fuel Annual Average
Boston	Wet Tower vs. Once-through	67%	2.32%	0.73%	0.42%	0.14%	2.04%	0.88%
	Dry Tower vs. Once-through	67%	13.82%	4.96%	3.20%	0.98%	15.15%	4.69%
	Dry Tower vs. Wet Tower	67%	11.50%	4.23%	2.78%	0.84%	13.11%	3.81%
Jacksonville	Wet Tower vs. Once-through	67%	1.22%	1.03%	0.24%	0.18%	1.08%	0.93%
	Dry Tower vs. Once-through	67%	13.61%	9.63%	3.50%	2.14%	16.96%	10.06%
	Dry Tower vs. Wet Tower	67%	12.39%	8.60%	3.27%	1.96%	15.88%	9.14%
Chicago	Wet Tower vs. Once-through	67%	2.53%	0.98%	0.47%	0.16%	2.23%	1.02%
	Dry Tower vs. Once-through	67%	14.03%	5.39%	3.30%	1.07%	15.67%	5.30%
	Dry Tower vs. Wet Tower	67%	11.50%	4.41%	2.83%	0.91%	13.44%	4.27%
Seattle	Wet Tower vs. Once-through	67%	1.60%	0.67%	0.27%	0.11%	1.50%	0.74%
	Dry Tower vs. Once-through	67%	12.16%	4.60%	2.60%	0.90%	12.31%	4.50%
	Dry Tower vs. Wet Tower	67%	10.56%	3.93%	2.33%	0.79%	10.81%	3.75%
Average	Wet Tower vs. Once-through	67%	1.92%	0.85%	0.35%	0.15%	1.71%	0.89%
	Dry Tower vs. Once-through	67%	13.41%	6.14%	3.15%	1.27%	15.02%	6.14%
	Dry Tower vs. Wet Tower	67%	11.49%	5.29%	2.80%	1.12%	13.31%	5.24%

Note: See Section 3-1 for the total energy penalties. This table presents only the turbine component of the total energy penalty.

3.3.3 Energy Penalty Associated with Cooling System Energy Requirements

This analysis is presented to evaluate the energy requirements associated with the operation of the alternative types of cooling systems. As noted previously, the reductions in energy output resulting from the energy required to operate the cooling system equipment are often referred to as parasitic losses. In evaluating this component of the energy penalty, it is the differences between the parasitic losses of the alternative systems that are important. In general, the costs associated with the cooling system energy requirements have been included within the annual O&M cost values developed in Chapter 2 of this document. Thus, the costs of the cooling system operating energy requirements do not need to be factored into the overall energy penalty cost analysis as a separate value, but may have been in some instances as part of a conservative approach.

Alternative cooling systems can create additional energy demands primarily through the use of fans and pumps. There are other energy demands such as treatment of tower blowdown, but these are insignificant compared to the pump and fan requirements and will not be included here. Some seasonal variation may be expected due to reduced requirements for cooling media flow volume during colder periods. These reduced requirements can include reduced cooling water pumping for once-through systems and reduced fan energy requirements for both wet and dry towers. However, no adjustments were made concerning the potential seasonal variations in cooling water pumping. The seasonal variation in fan power requirements is accounted for in this evaluation by applying an annual fan usage rate. The pumping energy estimates are calculated using a selected cooling water flow rate of 100,000 gpm (223 cfs).

a. Fan Power Requirements

˜ ***Wet Towers***

In the reference *Cooling Tower Technology* (Burger 1995), several examples are provided for cooling towers with flow rates of 20,000 gpm using 4 cells with either 75 (example #1) or 100 Hp (example #2) fans each. The primary difference between these two examples is that the tower with the higher fan power requirement has an approach of 5 °F compared to 11 °F for the tower with the lower fan power requirement. Using an electric motor efficiency of 92 percent and a fan usage factor of 93 percent (Fleming 2001), the resulting fan electric power requirements are equal to 0.236 MW and 0.314 MW for the four cells with 75 and 100 Hp fan motors, respectively. These example towers both had a heat load of 150 million BTU/hr. Table 3-16 provides the percent of power output penalty based on equivalent plant capacities derived using the heat rejection factors described below. Note that fan gear efficiency values are not applicable because they do not affect the fan motor power rating or the amount of electricity required to operate the fan motors.

A third example was provided in vendor-supplied data (Fleming 2001), in which a cooling tower with a cooling water flow rate of 243,000 gpm had a total fan motor capacity brake-Hp of 250 for each of 12 cells. This wet tower had a design temperature range of 15 °F and an approach of 10 °F. The percent of power output penalty shown in Table 7 is also based on equivalent plant capacities derived using the heat rejection factors described below.

A fourth example is a cross-flow cooling tower for a 35 MW coal-fired plant in Iowa (Litton, no date). In this example, the wet tower consists of two cells with one 150 Hp fan each, with a cooling water flow rate of 30,000 gpm. This wet tower had a design temperature range of 16 °F, an approach of 12 °F, and wet bulb temperature of 78 °F. The calculated energy penalty in this example is 0.67 percent.

Example #2, which has the smallest approach value, represents the high end of the range of calculated wet tower fan energy penalties presented in Table 3-16. Note that smaller approach values correspond to larger, more expensive (both in capital and O&M costs) towers. Since the fossil fuel plant penalty value for example #4, which is based mostly on empirical data, is just below the fossil fuel penalty calculated for example #2, EPA has chosen the calculated values for example #2 as representing a conservative estimate for the wet tower fan energy penalty.

EPA notes that the penalties presented in Tables 3-16 **do not** comprise the total energy penalty (which incorporates all three components of energy penalties: turbine efficiency penalty, fan energy requirements, and pumping energy usage) as a percent of power output. The total energy penalties are presented in section 3.1 above. The table below only presents the fan component of the penalty.

Table 3-16: Wet Tower Fan Power Energy Penalty

Example Plant	Range/ Approach (Degree F)	Flow (gpm)	Fan Power Rating (Hp)	Fan Power Required (MW)	Plant Type	Plant Capacity (MW)	Percent of Output (%)
#1	15/11	20,000	300	0.236	Nuclear	35	0.68%
					Fossil Fuel	43	0.55%
					Comb. Cycle	130	0.18%
#2	15/5	20,000	400	0.314	Nuclear	35	0.91%
					Fossil Fuel	43	0.73%
					Comb. Cycle	130	0.24%
#3	15/10	243,000	3,000	2.357	Nuclear	420	0.56%
					Fossil Fuel	525	0.45%
					Comb. Cycle	1574	0.15%
#4	16/12	30,000	300.0	0.236	Fossil Fuel	35	0.67%

Note: See Section 3-1 for the total energy penalties. This table presents only the fan component of the total energy penalty.

˜ *Air Cooled Condensers*

Air cooled condensers require greater air flow than recirculating wet towers because they cannot rely on evaporative heat transfer. The fan power requirements are generally greater than those needed by wet towers by a factor of 3 to 4 (Tallon 2001). While the fan power requirements can be substantial, at least a portion of this increase over wet cooling systems is offset by the elimination of the pumping energy requirements associated with wet cooling systems described below.

The El Dorado power plant in Boulder, Nevada which was visited by EPA is a combined-cycle plant that uses air cooled condensers due to the lack of sufficient water resources. This facility is located in a relatively hot section of the U.S. Because the plant has a relatively low design temperature (67 ^{o}F) in a hot environment, it should be considered as representative of a conservative situation with respect to the energy requirements for operating fans in air cooled condensers. The steam portion of the plant has a capacity of 150 MW (1.1 million lb/hr steam flow).

The air cooled condensers consist of 30 cells with a 200 Hp fan each. A fan motor efficiency of 92 percent is assumed. Each fan has two operating speeds, with the low speed consuming 20 percent of the fan motor power rating.

The facility manager provided estimates of the proportion of time that the fans were operated at low or full speed during different portions of the year (Tatar 2001). Factoring in the time proportions and the corresponding power requirements results in an overall annual fan power factor of 72 percent for this facility. In other words, over a one year period, the fan power requirement will average 75 percent of the fan motor power rating. A comparison of the climatic data for Las Vegas (located nearby) and Jacksonville, Florida shows that the Jacksonville mean maximum temperature values were slightly warmer in the winter and slightly cooler in the summer. Adjustments in the annual fan power factor calculations to address Jacksonville's slightly warmer winter months resulted in a projected annual fan power factor of 77 percent. EPA chose a factor of 75 percent as representative of warmer regions of the U.S. Due to lack of available operational data for other locations, this value is used for facilities throughout the U.S. and represents an conservative value for the much cooler regions.

Prior to applying this factor, the resulting maximum energy penalty during warmer months is 3.2 percent for the steam portion only. This value is the maximum instantaneous penalty that would be experienced during high temperature conditions. When the annual fan power factor of 75 percent is applied, the annual fan energy penalty becomes 2.4 percent of the plant power output. An engineer from an air cooled condenser manufacturer indicated that the majority of air cooled condensers being installed today also include two-speed fans and that the 20 percent power ratio for the low speed was the factor that they used also. In fact, some dry cooling systems, particularly those in very cold regions, use fans with variable speed drives to provide even better operational control. Similar calculations for a waste-to-energy plant in Spokane, Washington resulted in a maximum fan operating penalty of 2.8 percent and an annual average of 2.1 percent using the 75 percent fan power factor. Thus, the factor of 2.4 percent selected by EPA as a conservative annual penalty value appears valid.

b. Cooling Water Pumping Requirements

The energy requirements for cooling water pumping can be estimated by combining the flow rates and the total head (usually given in feet of water) that must be pumped. Estimating the power requirements for the alternative cooling systems that use water is somewhat complex in that there are several components to the total pumping head involved. For example, a once-through system must pump water from the water source to the steam condensers, which will include both a static head from the elevation of the source to the condenser (use of groundwater would represent an extreme case) and friction head losses through the piping and the condenser. The pipe friction head is dependent on the distance between the power plant and the source plus the size and number of pipes, pipe fittings, and the flow rate. The condenser friction head loss is a function of the condenser design and flow rate.

Wet cooling towers must also pump water against both a static and friction head. A power plant engineering consultant estimated that the total pumping head at a typical once-through facility would be approximately 50 ft (Taylor 2001). EPA performed a detailed analysis of the cooling water pumping head that would result from different combinations of piping velocities and distances. The results of this analysis showed that the pumping head was in many scenarios similar in value for both once-through and wet towers, and that the estimated pumping head ranged from approximately 40 to 60 feet depending on the assumed values. Since EPA's analysis produced similar values as the 50 ft pumping head provided by the engineering consultant, this value was used in the estimation of the pumping requirements for cooling water intakes for both once-through and wet tower systems. The following sections describe the method for deriving these pumping head values.

˜ *Friction Losses*

In order to provide a point of comparison, a cooling water flow rate of 100,000 gpm (223 cfs) was used. A recently reported general pipe sizing rule indicating that a pipe flow velocity of 5.7 fps is the optimum flow rate with regards to the competing cost values was used as the starting point for flow velocity (Durand et al. 1999). Such a minimum velocity is needed to prevent sediment deposition and pipe fouling. Using this criterion as a starting point, four 42-inch steel pipes carrying 25,000 gpm each at a velocity of 5.8 fps were selected. Each pipe would have a friction head loss of 0.358 ft/100 ft of pipe (Permutit 1961), resulting in a friction loss of 3.6 ft for every 1,000 ft of length. Since capital costs may dictate using fewer pipes with greater pipe flow rates, two other scenarios using either three or two parallel 42-inch pipes were also evaluated. Three pipes would result in a flow rate and velocity of 33,000 gpm and 7.7 fps, which results in a friction head loss of 6.1 ft/1000ft. Two pipes would result in a flow rate and velocity of 50,000 gpm and 11.6 fps, which results in a friction head loss of 12.8 ft/1000ft. The estimated 50 ft total pumping head was most consistent with a pipe velocity of 7.7 fps (three 42-inch pipes).

The relative distances of the power plant condensers to the once-through cooling water intakes as compared to the distance from the plant to the alternative cooling tower can be an important factor. In general, the distances that the large volumes of cooling water must be pumped will be greater for once-through cooling systems. For this analysis, a fixed distance of 300 ft was selected for the cooling tower. Various distances ranging from 300 ft to 3,000 ft are used for the once-through system. The friction head was also assumed to include miscellaneous losses due to inlets, outlets, bends, valves, etc., which can be calculated using equivalent lengths of pipe. For 42-in. steel pipe, each entrance and long sweep elbow is equal to about 60 ft in added pipe length. For the purposes of this analysis, both systems were assumed to have five such fittings for an added length of 300 ft. The engineering estimate of 50 ft for pumping head was most consistent with a once-through pumping distance of approximately 1,000 ft.

˜ *Static Head*

Static head refers to the distance in height that the water must be pumped from the source elevation to the destination. In the case of once-through cooling systems, this is the distance in elevation between the source water and the condenser inlet. However, many power plants eliminate a significant portion of the static head loss by operating the condenser piping as a siphon. This is done by installing vacuum pumps at the high point of the water loop. In EPA's analysis, a static head of 20 ft produced a total pumping head value that was most consistent with the engineering consultant's estimate of 50 feet.

In the case of cooling towers, static head is related to the height of the tower, and vendor data for the overall pumping head through the tower is available. This pumping head includes both the static and dynamic heads within the tower, but was included as the static head component for the analysis. Vendor data reported a total pumping head of 25 ft for a large cooling tower sized to handle 335,000 gpm (Fleming 2001). The tower is a counter-flow packed tower design. Adding the condenser losses and pipe losses resulted in a total pumping head of approximately 50 feet.

˜ *Condenser Losses*

Condenser design data provided by a condenser manufacturer, Graham Corporation, showed condenser head losses ranging from 21 ft of water for small condensers (cooling flow <50,000 gpm) to 41 ft for larger condensers (Hess

2001). Another source showed head losses through the tubes of a large condenser (311,000 gpm) to be approximately 9 ft of water (HES. 2001). For the purposes of this analysis, EPA estimated condenser head losses to be 20 ft of water. For comparable systems with similar cooling water flow rates, the condenser head loss component should be the same for both once-through systems and recirculating wet towers.

˜ ***Flow Rates***

In general, the cooling water flow rate is a function of the heat rejection rate through the condensers and the range of temperature between the condenser inlet and outlet. The flow rate for cooling towers is approximately 95 percent that of once-through cooling water systems, depending on the cooling temperature range. However, cooling tower systems also still require some pumping of make-up water. For the purposes of this analysis, the flow rates for each system will be assumed to be essentially the same. All values used in the calculations are for a cooling water flow rate of 100,000 gpm. Values for larger and smaller systems can be factored against these values. The total pump and motor efficiency is assumed to be equal to 70 percent.

c. Analysis of Cooling System Energy Requirements

This analysis evaluates the energy penalty associated with the operation of cooling system equipment for conversion from once-through systems to wet towers and for conversion to air cooled systems by estimating the net difference in required pumping and fan energy between the systems. This penalty can then be compared to the power output associated with a cooling flow rate of 100,000 gpm to derive a percent of plant output figure that is a similar measure to the turbine efficiency penalty described earlier. The power output was determined by comparing condenser heat rejection rates for different types of systems. As noted earlier, the cost of this energy penalty component has already been included in the alternative cooling system O&M costs discussed in Chapter 2 of this document, but was derived independently for this analysis.

Table 3-17 shows the pumping head and energy requirements for pumping 100,000 gpm of cooling water for both once-through and recirculating wet towers using the various piping scenario assumptions. In general, the comparison of two types of cooling systems shows offsetting energy requirements that essentially show zero pumping penalty between once-through and wet towers as the pumping distance for the once-through system increases to approximately 1,000 ft. In fact, it is apparent that for once-through systems with higher pipe velocities and pumping distances, more cooling water pumping energy may be required for the once-through system than for a wet cooling tower. Thus, when converting from once-through to recirculating wet towers, the differences in pumping energy requirements may be relatively small.

As described above, wet towers will require additional energy to operate the fans, which results in a net increase in the energy needed to operate the wet tower cooling system compared to once-through. Note that the average calculated pumping head across the various scenarios for once-through systems was 54 ft. This data suggests that an average pumping head of 50 feet for once-through systems appears to be a reasonable assumption where specific data are not available.

EPA notes that the penalties presented in Tables 3-17 and 3-18 **do not** comprise the total energy penalties (which incorporate all three components of energy penalties: turbine efficiency penalty, fan energy requirements, and pumping energy usage) as a percent of power output. The total energy penalties are presented in section 3.1 above. The tables below only present the pumping components.

Table 3-17: Cooling Water Pumping Head and Energy for 100,000 gpm System Wet Towers Versus Once-through At 20' Static Head

Cooling System Type	Distance Pumped	Static Head	Condenser Head	Equiv. Length Misc. Losses	Pipe Velocity	Friction Loss Rate	Friction Head	Total Head	Net Difference	Flow Rate	Hydraulic-Hp	Brake-Hp	Power Required	Energy Penalty
	ft.	ft.	ft	ft.	fps	ft/1,000ft	ft.	ft.	ft	gpm	Hp	Hp	kW	kW
Once-through at 20' Static Head Using 4: 42" Pipes at 300' Length														
Once-through	300	20	21	300	5.8	3.6	2	43		100,000	1089	1556	1161	
Wet Tower	300	25	21	300	5.8	3.6	2	48	5	100,000	1216	1737	1296	135
Once-through at 20' Static Head Using 3: 42" Pipes at 300' Length														
Once-through	300	20	21	300	7.7	6.1	4	45		100,000	1127	1610	1201	
Wet Tower	300	25	21	300	7.7	6.1	4	50	5	100,000	1254	1791	1336	135
Once-through at 20' Static Head Using 2: 42" Pipes at 300' Length														
Once-through	300	20	21	300	11.6	12.8	8	49		100,000	1229	1755	1310	
Wet Tower	300	25	21	300	11.6	12.8	8	54	5	100,000	1355	1936	1444	135
Once-through at 20' Static Head Using 4: 42" Pipes at 1000' Length														
Once-through	1000	20	21	300	5.8	3.6	5	46		100,000	1153	1647	1229	
Wet Tower	300	25	21	300	5.8	3.6	2	48	2	100,000	1216	1737	1296	67
Once-through at 20' Static Head Using 3: 42" Pipes at 1000' Length														
Once-through	1000	20	21	300	7.7	6.1	8	49		100,000	1235	1764	1316	
Wet Tower	300	25	21	300	7.7	6.1	4	50	1	100,000	1254	1791	1336	20
Once-through at 20' Static Head Using 2: 42" Pipes at 1000' Length														
Once-through	1000	20	21	300	11.6	12.8	17	58		100,000	1455	2079	1551	
Wet Tower	300	25	21	300	11.6	12.8	8	54	-4	100,000	1355	1936	1444	-107
Once-through at 20' Static Head Using 4: 42" Pipes at 3000' Length														
Once-through	3000	20	21	300	5.8	3.6	12	53		100,000	1335	1907	1423	
Wet Tower	300	25	21	300	5.8	3.6	2	48	-5	100,000	1216	1737	1296	-127
Once-through at 20' Static Head Using 3: 42" Pipes at 3000' Length														
Once-through	3000	20	21	300	7.7	6.1	20	61		100,000	1543	2204	1644	
Wet Tower	300	25	21	300	7.7	6.1	4	50	-11	100,000	1254	1791	1336	-309
Once-through at 20' Static Head Using 2: 42" Pipes at 3000' Length														
Once-through	3000	20	21	300	11.6	12.8	42	83		100,000	2101	3002	2239	
Wet Tower	300	25	21	300	11.6	12.8	8	54	-30	100,000	1355	1936	1444	-795

Note: Wet Towers are assumed to always be at 300' distance and have the same tower pumping head of 25' in all scenarios shown.
The same flow rate of 100,000gpm (223 cfs) is used for all scenarios.
See Section 3-1 for the total energy penalties. This table presents only the pumping component of the total energy penalty.

˜ Cooling System Energy Requirements Penalty as Percent of Power Output

One method of estimating the capacity of a power plant associated with a given cooling flow rate is to compute the heat rejected by the cooling system and determine the capacity that would match this rejection rate for a "typical" power plant in each category. In order to determine the cooling system heat rejection rate, both the cooling flow (100,000 gpm) and the condenser temperature range between inlet and outlet must be estimated. In addition, the capacity that corresponds to the power plant heat rejection rate must be determined. The heat rejection rate is directly related to the type, design, and capacity of a power plant. The method used here was to determine the ratio of the plant capacity divided by the heat rejection rate as measured in equivalent electric power.

An analysis of condenser cooling water flow rates, temperature ranges and power outputs for several existing nuclear plants provided ratios of the plant output to the power equivalent of heat rejection ranging from 0.75 to 0.92. A similar analysis for coal-fired power plants provided ratios ranging from 1.0 to 1.45. Use of a lower factor results in a lower power plant capacity estimate and, consequently, a higher value for the energy requirement as a percent of capacity. Therefore, EPA chose to use values near the lower end of the range observed. EPA selected ratios of 0.8 and 1.0 for nuclear and fossil-fueled plants, respectively. The steam portion of a combined cycle plant is assumed to have a factor similar to fossil fuel plants of 1.0. Considering that this applies to only one-third of the total plant output, the overall factor for combined-cycle plants is estimated to be 3.0.

In order to correlate the cooling flow energy requirement data to the power output, a condenser temperature range must also be estimated. A review of data from newly constructed plants in Attachment C showed no immediately discernable pattern on a regional basis for approach or range values. Therefore, these values will not be differentiated on a regional basis in this analysis. The data did, however, indicate a median approach of 10 °F (average 10.4 °F) and a median range of 20 °F (average 21.1 °F). This range value is consistent with the value assumed in other EPA analyses and therefore a range of 20 °F will be used. Table 3-18 presents the energy penalties corresponding to the pumping energy requirements from Table 3-17 using the above factors.

Table 3-18: Comparison of Pumping Power Requirement and Energy Penalty to Power Plant Output

Cooling system Type	Distance Pumped	Static Head	Power Required	Flow Rate	Range	Nuclear Power/ Heat	Nuclear Equiv. Output	Nuclear Pumping	Fossil Fuel Power/ Heat	Fossil Fuel Equiv. Output	Fossil Fuel Pumping	Comb.-Cycle Power/ Heat	Comb.-Cycle Equiv.	Comb.-Cycle Pumping
	ft.	ft.	kW	gpm	ºF	Ratio	(MW)	% of Output	Ratio	(MW)	% of Output	Ratio	Output (MW)	% of Output
Once-through at 20' Static Head Using 4: 42" Pipes at 300' Length														
Once-through	300	20	1161.1	100,000	20	0.8	235	0.49%	1	294	0.39%	3	882	0.13%
Wet Tower	300	25	1295.6	100,000	20	0.8	235	0.55%	1	294	0.44%	3	882	0.15%
Once-through at 20' Static Head Using 3: 42" Pipes at 300' Length														
Once-through	300	20	1201.4	100,000	20	0.8	235	0.51%	1	294	0.41%	3	882	0.14%
Wet Tower	300	25	1335.9	100,000	20	0.8	235	0.57%	1	294	0.45%	3	882	0.15%
Once-through at 20' Static Head Using 2: 42" Pipes at 300' Length														
Once-through	300	20	1309.6	100,000	20	0.8	235	0.56%	1	294	0.45%	3	882	0.15%
Wet Tower	300	25	1444.1	100,000	20	0.8	235	0.61%	1	294	0.49%	3	882	0.16%
Once-through at 20' Static Head Using 4: 42" Pipes at 1000' Length														
Once-through	1000	20	1228.8	100,000	20	0.8	235	0.52%	1	294	0.42%	3	882	0.14%
Wet Tower	300	25	1295.6	100,000	20	0.8	235	0.55%	1	294	0.44%	3	882	0.15%
Once-through at 20' Static Head Using 3: 42" Pipes at 1000' Length														
Once-through	1000	20	1316.3	100,000	20	0.8	235	0.56%	1	294	0.45%	3	882	0.15%
Wet Tower	300	25	1335.9	100,000	20	0.8	235	0.57%	1	294	0.45%	3	882	0.15%
Once-through at 20' Static Head Using 2: 42" Pipes at 1000' Length														
Once-through	1000	20	1550.6	100,000	20	0.8	235	0.66%	1	294	0.53%	3	882	0.18%
Wet Tower	300	25	1444.1	100,000	20	0.8	235	0.61%	1	294	0.49%	3	882	0.16%
Once-through at 20' Static Head Using 4: 42" Pipes at 3000' Length														
Once-through	3000	20	1422.5	100,000	20	0.8	235	0.60%	1	294	0.48%	3	882	0.16%
Wet Tower	300	25	1295.6	100,000	20	0.8	235	0.55%	1	294	0.44%	3	882	0.15%
Once-through at 20' Static Head Using 3: 42" Pipes at 3000' Length														
Once-through	3000	20	1644.5	100,000	20	0.8	235	0.70%	1	294	0.56%	3	882	0.19%
Wet Tower	300	25	1335.9	100,000	20	0.8	235	0.57%	1	294	0.45%	3	882	0.15%
Once-through at 20' Static Head Using 2: 42" Pipes at 3000' Length														
Once-through	3000	20	2239.3	100,000	20	0.8	235	0.95%	1	294	0.76%	3	882	0.25%
Wet Tower	300	25	1444.1	100,000	20	0.8	235	0.61%	1	294	0.49%	3	882	0.16%

Note: Wet Towers are assumed to always be at 300' distance and have the same tower pumping head of 25' in all scenarios shown. The same flow rate of 100,000gpm (223 cfs) is used for all scenarios. Power/Heat Ratio refers to the ratio of Power Plant Output (MW) to the heat (in equivalent MW) transferred through the condenser. See Section 3-1 for the total energy penalties. This table presents only the pumping component of the total energy penalty

d. Summary of Cooling System Energy Requirements

EPA chose the piping scenario in Table 3-17 where pumping head is close to 50 ft for both (i.e., once-through at 1,000 ft and 3-42 in. pipes in Table 3-17). Thus, the cooling water pumping requirements for once-through and recirculating wet towers are nearly equal using the chosen site-specific conditions. Table 3-19 summarizes the fan and pumping equipment energy requirements as a percent of power output for each type of power plant. Table 3-20 presents the net difference in energy requirements shown in Table 3-19 for the alternative cooling systems. The net differences in Table 3-20 are the equipment operating energy penalties associated with conversion from one cooling technology to another.

EPA notes that the penalties presented in Tables 3-19 and 3-20 **do not** comprise the total energy penalties (which incorporate all three components of energy penalties: turbine efficiency penalty, fan energy requirements, and pumping energy usage) as a percent of power output. The total energy penalties are presented in section 3.1 above. The tables below only present the pumping and fan components. Section 3.3.2 presents the turbine efficiency components of the energy penalty.

Table 3-19: Summary of Fan and Pumping Energy Requirements as a Percent of Power Output

	Wet Tower Pumping	Wet Tower Fan	Wet Tower Total	Once-through Total (Pumping)	Dry Tower Total (Fan)
Nuclear	0.57%	0.91%	1.48%	0.56%	3.04%
Fossil Fuel	0.45%	0.73%	1.18%	0.45%	2.43%
Combined-Cycle	0.15%	0.24%	0.39%	0.15%	0.81%

Note: See Section 3.1 for the total energy penalties.

Table 3-20: Fan and Pumping Energy Penalty Associated with Alternative Cooling System as a Percent of Power Output

	Wet Tower Vs Once-through	Dry Tower Vs Wet Tower	Dry Tower Vs Once-through
Nuclear	0.92%	1.56%	2.48%
Fossil Fuel	0.73%	1.25%	1.98%
Combined-Cycle	0.24%	0.42%	0.66%

Note: See Section 3.1 for the total energy penalties.

3.4 AIR EMISSIONS INCREASES

Due to the cooling system energy penalties, as described in section 3.3 and presented in section 3.1 above, EPA estimates that air emissions will marginally increase from power plants which upgrade cooling systems. The energy penalties reduce the efficiency of the electricity generation process and thereby increase the quantity of fuel consumed per unit of electricity generated. In estimating annual increases in air emissions, the Agency based its calculations on the mean annual energy penalties provided in Table 3-1 above. EPA presents the annual air emissions increases for the final rule and the dry cooling regulatory alternative in Tables 3-7 and 3-8 in section 3.2 above.

EPA developed estimates of incremental air emissions estimates for the two types of power plants projected to upgrade cooling systems as a result of this rule (or a regulatory alternative): combined-cycle and coal-fired power plants. Generally, combined-cycle plants produce significantly less air emissions per kilowatt-hour of electricity generated than coal-fired plants. Because the combined-cycle plant requires cooling for approximately one-third of its process (on a megawatt capacity basis) and because of the differences in combustion products from natural gas versus coal, the combined-cycle plant produces less air emissions, even after coal-fired plants are equipped with state-of-the-art emissions controls. However, for the case of the air emissions estimates for the final rule and regulatory alternatives considered, EPA estimates that plants incurring an energy penalty will not increase their fuel consumption on-site to overcome incurred energy penalties. Instead, the Agency estimates that energy penalties at facilities affected by the requirements of this rule (or the regulatory alternatives) would purchase replacement power from the grid and the air emissions increases associated with a particular energy penalty at an effected plant would be released by the rest of the grid as a whole (thereby comprising negligible increases at a large number and variety of power plants). EPA received comments asserting that not all facilities, especially during times of peak demand, would be able to increase their fuel consumption to overcome energy penalties. Therefore, the air emissions increases presented in section 3.2 of this chapter represent uniform national air emissions increases per unit of energy penalty, regardless of the plant at which the energy penalty is occurring. For the final rule and regulatory alternatives considered, the key difference between air emissions increases estimated at facilities projected to upgrade cooling systems is directly related to the size of the energy penalty that the plant will incur. For the sake of comparison, EPA also calculated the air emissions increases for the final rule and regulatory alternatives in the case where the effected plants would increase fuel consumption to overcome the penalties. The comparative results are presented in Tables 3-21 and 3-22. EPA found small national differences between increased air emissions as calculated on the plant versus grid basis. For more information on the supporting calculations see DCN 3-3085.

The data source for the Agency's air emissions estimates of CO_2, SO_2, NO_X, and Hg is the EPA developed database titled E-GRID 2000. This database is a compendium of reported air emissions, plant characteristics, and industry profiles for the entire US electricity generation industry in the years 1996 through 1998. The database relies on information from power plant emissions reporting data from the Energy Information Administration of the Department of Energy. The database compiles information on every power plant in the United States and includes statistics such as plant operating capacity, air emissions, electricity generated, fuel consumed, etc. This database provided ample data for the Agency to conduct air emissions increases analyses for this rule. The emissions reported in the database are for the power plants' actual emissions to the atmosphere and represent emissions after the influence of air pollution control devices. To test the veracity of the database for the purposes of this rule, the Agency compared the information to other sources of data available on power plant capacities, fuel-types, locations, owners, and ages. Without exception, the E-GRID 2000 database provided accurate estimates of each of these characteristics versus information that EPA was able to obtain from other sources.

As noted above, the E-GRID 2000 database contains data on existing power plants. For the national analysis presented in section 3.2 above, EPA estimated that the annual generation of electricity would not increase over the life of the rule. Therefore, the emissions increases as a percent of national capacity presented in Tables 3-7 and 3-8 above are conservatively estimated and ignore projected growth rates of power plant capacity. For the comparative analysis of plant versus grid based emissions the Agency purposefully chose, when analyzing specific power plants (and not just the grid as a whole), to focus on the most recently constructed plants with multiple years of operating data (where possible). In addition, the Agency selected a variety of plants from different regions of the country with different urban versus rural locations. The capacity of the model plants was chosen as closely as possible to the average size plant within scope of the rule. Therefore, the Agency's comparative estimates of the air emissions increases from the scenario where individual plants are able to consume more fuel to overcome the energy penalties present nationally applicable results for the variety of plants and locations expected for the new facility rule. The model facility plant information along with the supporting calculations for this analysis can be found in DCN 3-3085.

Because the Agency estimates that the air emissions increases for the final rule (and regulatory alternatives) will come from the mix of plant types across the nation, the issue of baseline cooling systems is moot. However, for the scenario where EPA estimated (for the sake of comparison) that plants would increase fuel consumption to overcome energy penalties, and the air emissions would occur at the site, the issue of cooling system is more relevant. EPA attempted to consider baseline cooling systems when selecting the model facilities upon which to base the air emissions profiles for combined-cycle and coal-fired plants. However, because the emissions would be used to estimate changes in cooling systems from once-through to wet towers and, for the case of regulatory alternatives, from once-through to dry towers and wet towers to dry towers, the Agency ultimately determined that age, size, and location of the plant were more important factors to consider than the baseline cooling system. The effect is such, for the comparative example of plants increasing fuel consumption to overcome energy penalties as a result of the final rule, the Agency may have marginally overestimated the air emissions increases due to cooling system changes. EPA reiterates that this has no bearing on the estimated air emissions for the final rule and is relevant only for the comparative analysis presented in Tables 3-21 and 3-22. The basis for the Agency stating that it may have overestimated emissions in this comparative case for the final rule is due to the fact that several of the plants used as model facilities in the air emissions analysis actually utilize wet-cooling towers at baseline. Therefore, the baseline energy efficiency would be lower than a once-through system and the related baseline air emissions rates per unit of fuel consumed would be higher. Thus, for the case of the upgrades from once-through to wet cooling towers, EPA likely is overestimating the compliance air emissions rates per unit of fuel consumed in this comparative case. For the case of the dry cooling alternative, the effect is less pronounced and the Agency may be underestimating, in the end, the comparative air emissions increases. This is due to the fact that the majority of power plants have wet cooling towers at baseline. For the case of 90 percent of the plants to be upgraded to dry cooling in this regulatory alternative, the proper baseline cooling system is wet cooling towers. Therefore, the baseline air emissions rates per unit of electricity generated are lower than would represent a majority of plants employing wet cooling at baseline.

Table3-21. Comparison of Calculation Techniques for Net Air Emissions Increases of the Final Rule

Compensation Technique	Total Energy Penalty MW	Annual CO_2 (tons)	Annual SO_2 (tons)	Annual NO_x (tons)	Annual Hg (lbs)
Increased Fuel Consumption	100	712,886	1,543	1,518	23
Market Power Replacement	100	485,860	2,561	1,214	16

Table3-22. Comparison of Calculation Techniques for Net Air Emissions Increases of Dry Cooling

Compensation Technique	Total Energy Penalty MW	Annual CO_2 (tons)	Annual SO_2 (tons)	Annual NO_x (tons)	Annual Hg (lbs)
Increased Fuel Consumption	1,900	11,427,552	18,649	23,432	272
Market Power Replacement	1,900	8,931,036	47,074	22,313	300

3.5 Other Environmental Impacts

Recirculating wet cooling towers can produce side effects such as vapor plumes, displacement of habitat or wetlands, noise, salt or mineral drift, water consumption through evaporation, and increased solid waste generation due to wastewater treatment of tower blowdown. The *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (NUREG-1437 Vol. 1, Nuclear Regulatory Commission) addresses the majority of these issues in depth, and the Agency refers to the detailed research contained therein several times in this discussion.

The Agency considered non-aquatic impacts of recirculating cooling towers for the proposal. While the Agency did not present quantified information regarding these side effects in the proposal, the Agency discussed the effects of both wet and dry cooling towers in the proposal. Specifically, the Agency discussed discharge water quality, salt drift, water conditioning chemicals and biocides, vapor plumes, energy efficiency, land use, and air emissions increases (65 FR 49080-49081). The Agency invited comments to the proposal on the subject of adverse environmental impact and whether or not it should consider non-aquatic impacts such as salt/mineral drift and reductions in the efficiency of electricity generation leading to increased air emissions as examples of adverse environmental impact (65 FR 49075). In turn, the Agency received no usable data (only anecdotal information) from commenters supporting assertions that these "side effects" pose significant environmental problems. The Agency researched the subjects further after proposal and provided some of the information in the notice of data availability and has cited other information from NUREG-1437.

The vast majority (90 percent) of power plants projected within the scope of this rule would install recirculating wet cooling towers in absence of this rule. Of these 74 power plants, the Agency projects that the cooling towers to be constructed will be of the mechanical draft type. (Stone & Webster 1992). For the other nine power plants for which EPA has projected the compliance costs associated with wet cooling towers, the Agency projects that the towers to be installed would be of the mechanical draft type, also.

3.5.1 Vapor Plumes

Natural draft or mechanical draft cooling towers can produce vapor plumes. Plumes can create problems for fogging and icing, which have been recorded to create dangerous conditions for local roads and for air and water navigation. Plumes are in some cases disfavored for reasons of aesthetics. Generally, mechanical draft cooling towers have significantly shorter plumes than those for natural draft towers (by approximately 30 percent). A "treatment" technique for these plumes in very rare cases is the installation of plume abatement (wet/dry hybrid cooling towers) on the tower. This is currently practiced at a small portion of recently constructed facilities (See DCN #2-037). As such, EPA's capital costs are not adjusted to reflect this type of plume abatement for this nationally applicable rule in which only 9 facilities are projected to install wet cooling towers.

Regarding aesthetics of cooling tower plumes, the Agency points to the Track II compliance option as an alternative for new facility power plants, in addition to the plume abatement controls, which are an option for new plants that choose to site where plume aesthetics are a public nuisance. The Agency notes that land area buffers may also be a simple means for reducing the effects of visible plumes, though this would be highly site-specific. As such, EPA has considered the subject of visible plumes to be a small issue when weighed against the serious aquatic environmental impacts of once-through cooling.

In the development of the final rule, the Agency considered the land area required for installation of cooling towers at new power plants. The Agency examined the sensitivity of costs to new power plants of purchasing additional land for (1) installing mechanical draft cooling towers in lieu of once-through cooling (for those power plants expected to incur the costs of cooling towers only) and (2) providing land area buffers for plumes at a portion of facilities. The Agency determined the final annualized costs were not sensitive to the described changes in land costs. The Agency also understands that the costs of these land acquisitions as a portion of total project costs for new power plants are negligible. In addition, because this rule applies to new facilities which have the ability, in the majority of cases, to alter the design and location of their facilities without encountering most of the hurdles associated with retrofitting existing facilities, the issue of additional land acquisition is not as significant.

The Agency considers the issue of plume "re-entrainment" to be an issue that has been well addressed by designers and operators of wet cooling towers. The technology is mature and well designed after many decades of use throughout the world in a variety of climates. The Agency considers plume re-entrainment at the nine power plants projected to upgrade their cooling system to be a small effect. For wet cooling towers, the plume re-entrainment value occasionally referenced is 2 percent (Burns & Micheletti 2000). This value, in the Agency's estimates would not appreciably impact cooling tower performance, nor have a discernable environmental impact.

3.5.2 Displacement of Wetlands or Other Land Habitats

Mechanical draft cooling towers can require land areas (footprints) approaching 1.5 acres for the average sized new cooling tower projected for this rule. When determining the area needed for wet cooling towers, plants generally consider the possible plume effects, and plan for the amount of space needed to minimize the effects of local fogging and icing and to minimize re-entrainment of the plume by the tower. The land requirements of mechanical draft wet cooling towers at new combined-cycle power plants generally do not approach the size of the campus. Dry cooling towers generally require approximately 3 to 4 times the area of a wet tower for a comparable cooling capacity. In consideration of displacement of wetlands or other land and habitat due to the moderate plant size increases due to cooling tower installations at nine facilities, the Agency determined that existing 404 programs would more than adequately protect wetlands and habitats for these modest land uses.

3.5.3 Salt or Mineral Drift

The operation of cooling towers using either brackish water or salt water can release water droplets containing soluble salts, including sodium, calcium, chloride, and sulfate ions. Additionally, salt drift may occur at fresh water systems that operate recirculating cooling water systems at very high cycles of concentration. Salt drift from such towers may be carried by prevailing winds and settle onto soil, vegetation, and waterbodies. Commenters expressed the concern that salt drift may cause damage to crops through deposition directly on the plants or accumulation of salts in the soil. The cooling tower system design and the salt content of the source water are the primary factors affecting the amount of salt emitted as drift. In addition, modern cooling towers utilize advanced fill materials that have been developed to minimize salt or mineral drift effects. The Agency estimates that the typical plant installing a cooling tower as a result of the requirements of this rule will equip the tower with modern splash fill materials. As such, the Agency has applied capital costs for the abatement of drift in the compliance costs of this rule.

In the cases where it is necessary, salt drift effects (if any) may also be mitigated by additional means that are similar to those used to minimize migrating vapor plumes (that is, through acquisition of buffer land area surrounding the tower). Additionally, modern cooling towers are designed as to minimize drift through the use of drift elimination technologies such as those costed by the Agency. NUREG-1437 states the following concerning salt/mineral drift from cooling towers: "generally, drift from cooling towers using fresh water has low salt concentrations and, in the case of mechanical draft towers, falls mostly within the immediate vicinity of the towers, representing little hazard to vegetation off-site. Typical amounts of salt or total dissolved solids in freshwater environments are around 1000 ppm (ANL/ES-53)." The Agency projects that four of the nine power plants which will upgrade their cooling system from once-through to recirculating closed-cycle will utilize freshwater sources, where salt drift will not be an issue. The Agency anticipates that the other five plants (each a combined-cycle design) will utilize estuarine/tidal water sources for cooling and that the issue of salt drift at these plants is of small significance and can be mitigated. This conclusion is supported by those reached in NUREG about salt-drift upon extensive study at existing nuclear plants: "monitoring results from the sample of [eighteen] nuclear plants and from the coal-fired Chalk Point plant, in conjunction with the literature review and information provided by the natural resource agencies and agricultural agencies in all states with nuclear power plants, have revealed no instances where cooling tower operation has resulted in measurable productivity losses in agricultural crops or measurable damage to ornamental vegetation. Because ongoing operational conditions of cooling towers would remain unchanged, it is expected that there would continue to be no measurable impacts on crops or ornamental vegetation as a result of license renewal. The impact of cooling towers on agricultural crops and ornamental vegetation will therefore be of small significance. Because there is no measurable impact, there is no need to consider mitigation. Cumulative impacts on crops and ornamental vegetation are not a consideration because deposition from cooling tower drift is a localized phenomenon and because of the distance between nuclear power plant sites and other facilities that may have large cooling towers."

3.5.4 Noise

Noise from mechanical draft cooling towers is generated by falling water inside the towers plus fan or motor noise or both. However, power plant sites generally do not result in off-site levels more than 10 dB(A) above background (NUREG-1437 Vol. 1). Noise abatement features are an integral component of modern cooling tower designs, and as such are reflected in the capital costs of this rule, which were empirically verified against real-life, turn-key costs of recently installed cooling towers. A very small fraction of recently constructed cooling towers also further install noise abatement features associated with low noise fans. The Agency collected data on recently constructed cooling tower projects from cooling tower vendors. The Agency obtained detailed project descriptions for these 20 projects and none utilize low noise fans. In addition, the cost contribution of low noise fans, in the rare case in which they may be installed at a new facility, would comprise a very small portion of the total installed capital cost of the cooling system. As such, the Agency is confident that the issue of noise abatement is not critical to the evaluation of the environmental side-effects of cooling towers. In addition, this issue is primarily in terms of adverse public reactions to the noise and not environmental or human health (i.e., hearing) impacts. The NRC adds further, "Natural-draft and mechanical-draft cooling towers emit noise of a broadband nature...Because of the broadband character of the cooling towers, the noise associated with them is largely indistinguishable and less obtrusive than transformer noise or loudspeaker noise."

3.5.5 Solid Waste Generation

For cooling towers, recirculation of cooling water increases solid wastes generated because some facilities treat the cooling tower blowdown in a wastewater treatment system, and the concentrated pollutants removed from the blowdown add to the amount of wastewater sludge generated by the facility.

EPA has accounted for solid waste disposal from cooling tower blow-down wastewater treatment in the operation and maintenance costs of this rule. EPA reiterates that only nine power plants would incur the costs to install wet cooling towers as a result of this rule. The associated solid waste disposal increases for these plants would be extremely small compared to the scope of facilities covered by the rule and negligible for the industry as a whole.

3.5.6 Evaporative Consumption of Water

Cooling tower operation is designed to result in a measurable evaporation of water drawn from the source water. Depending on the size and flow conditions of the affected waterbody, evaporative water loss can affect the quality of aquatic habitat and recreational fishing. Once-through cooling consumes water, in and of itself. According to NUREG-1437, "water lost by evaporation from the heated discharge of once-through cooling is about 60 percent of that which is lost through cooling towers." NUREG-1437 goes on to further state, "with once-through cooling systems, evaporative losses...occur externally in the adjacent body of water instead of in the closed-cycle system." Therefore, evaporation does occur due to heating of water in once-through cooling systems, even though the majority of this loss happens down-stream of the plant in the receiving water body.

The Agency has considered evaporation of water and finds these issues not to be significant for this rule. The Agency notes, again, that 90 percent of the in-scope power plants will install cooling towers regardless of the requirements of this rule. The nine other facilities, which may comply with the rule either through installation of flow reduction technologies similar to cooling towers (such as recirculating cooling lakes, cooling canals, or hybrid wet-dry cooling towers) or compliance with track II, are expected to consume approximately 127,000 gallons per minute (evaporative loss) when all new plants are operating. This represents less than three (3) percent of the baseline intake flow of the power plants within the scope of the rule. As a percentage of the total flow of water used for electricity generation in the US, this represents 0.1 percent. See DCN 3-3085.

3.5.7 Manufacturers

The Agency notes that the discussion thus far concerning side effects has focused exclusively on power plants. The Agency expects that 29 manufacturers will incur costs equivalent to installations of closed-cycle wet cooling towers as a result of this rule. However, even though these costs reflect cooling tower installations, the Agency projects that manufacturing facilities will comply, in the majority of cases, with this rule through the adoption of recycling and reuse design changes and operational practices at their plants. Therefore, the majority of issues discussed in this section are not of concern to manufacturing facilities for the final rule nor is the issue of energy penalties.

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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)

See Hard Copy

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)

See Hard Copy

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

(Source: Hensley 1985)

See Hard Copy

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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Chapter 4: Dry Cooling

Chapter Contents

INTRODUCTION

This chapter addresses the use and performance of dry cooling systems at power plants. Dry cooling systems transfer heat to the atmosphere without the evaporative loss of water. There are two types of dry cooling systems for power plant applications: direct dry cooling and indirect dry cooling. Direct dry cooling systems utilize air to directly condense steam, while indirect dry cooling systems utilize a closed cycle water cooling system to condense steam, and the heated water is then air cooled. Indirect dry cooling generally applies to retrofit situations at existing power plants because a water-cooled condenser would already be in place for a once-through or recirculated cooling system. Therefore, indirect dry cooling systems are not further considered in the Chapter for new sources subject to this regulation.

The most common type of direct dry cooling systems (towers) for new power plants are recirculated cooling systems with mechanical draft towers. Natural draft towers are infrequently used for installations in the United States and were not considered for evaluation in this Chapter.

For dry cooling towers the turbine exhaust steam exits directly to an air-cooled, finned-tube condenser. The arrangement of the finned tubes are most generally of an A-frame pattern to reduce the land area required. However, due to the fact that dry cooling towers do not evaporate water for heat transfer, the towers are quite large in comparison to similarly sized wet cooling towers. Because dry cooling towers rely on sensible heat transfer, a large quantity of air must be forced across the finned tubes by fans to improve heat rejection. The number of fans is therefore larger than would be used in a mechanical draft wet cooling tower.

Hybrid wet-dry cooling towers employ both a wet section and dry section and are used primarily to reduce or eliminate the vapor plumes associated with wet cooling towers. For the most common type of hybrid system, exhaust steam flows through smooth tubes, where it is condensed by a mixture of cascading water and air. The water and air move in a downward direction across the tube bundles and the air is forced upward for discharge to the atmosphere. The falling water is collected and recirculated, similarly to a wet cooling tower. The water usage of a hybrid system is generally one-third to one-half of that for a wet cooling system and the required pumping head is reduced somewhat. In the Agency's opinion, the common hybrid systems do not dramatically reduce water use as compared to wet cooling towers. The comparative cost increases of the hybrid systems to the wet cooling systems do not outweigh water use savings of approximately one-half to two-thirds. Therefore, the discussion of dry cooling towers for the remainder of the chapter focuses on direct dry cooling systems exclusively.

The key feature of dry cooling systems is that no evaporative cooling or release of heat to surface water occurs. As a result, water consumption rates are very low compared to wet cooling systems. Since the unit does not rely in principle on evaporative cooling as does a wet cooling tower, larger volumes of air must be passed through the system compared to the volume of air used in wet cooling towers. As a result, dry cooling towers need larger heat transfer surfaces and, therefore, tend to be larger in size than comparable wet cooling towers. The design and performance of the dry cooling system is based on the ambient dry bulb temperature. The dry bulb temperature is higher than the wet bulb temperature under most circumstances, being equal to the wet bulb temperature only when the relative humidity is at 100%.

The remainder of this chapter is organized as follows:

- Section 4.1 provides a brief overview of the status of dry cooling projects in the United States including discussion of the types of generating facilities, their locations, and factors affecting plant performance.
- Section 4.2 presents an evaluation of the dry cooling technology as a candidate for best technology available to minimize adverse environmental impact.

4.1 DEMONSTRATED DRY COOLING PROJECTS

This section provides a brief overview of the status of dry cooling projects in the United States. The section includes a brief discussion of the types of generating facilities, their locations, and factors affecting plant performance.

Dry cooling has been installed at a variety of power plants utilizing many fuel types. In the United States, dry cooling is most frequently applied at plants in northern climates. Additionally, arid areas with significant water scarcity concerns have also experiencing growth in dry cooling system projects. As demonstrated in Chapter 3, the comparative energy penalty of a dry cooling plant in a hot environment at peak summer conditions can exceed 12 percent, and the benefit of the water use savings must be analyzed with regard to the reduced cooling efficiency.

Table 4-1 presents a compilation of data pertaining to dry cooling systems installed at power plants within the United States and in foreign countries by a U.S. dry cooling system manufacturer from 1968 through the year 2000. The majority of these systems have been installed at combined cycle plants and at alternative fuel plants such as municipal solid waste and waste wood burning facilities. In many cases, systems with similar design dry bulb temperatures have different design exhaust pressure values, reflecting the selection of different dry tower sizes by the facility owners. Use of different relative dry tower sizes for similar facilities reflects the selection of different economic criteria with respect to size, costs, and efficiency.

Table 4-1: Air Cooled Condenser Data for Systems installed by GEA Power Cooling Systems, Inc.

Facility Name	City	State	Country	Size MW	Steam Flow lbs/hr	Turbine Exhaust Pressure In. Hg	Design Temp. °F	Year	Description	Sat. Steam Temp. °F	Temp. Difference °F
Neil Simpson I Sta.	Gillette	WY	USA	20	167,550	4.5	75	1968	Coal	130	55
NP Potter	Braintree	MA	USA	20	190,000	3.5	50	1975	Combine Cycle	120	70
Wyodak Sta.	Gillette	WY	USA	330	1,884,800	6	66	1977	Coal	141	75
Gerber Cogen	Gerber	CA	USA	3.7	52,030	2.03	48	1981	Combined Cycle Cogen	102	54
NAS North Is. Cogen	Coronado	CA	USA	4	65,000	5	70	1984	Combined Cycle Cogen	134	64
NTC Cogen	San Diego	CA	USA	2.6	40,000	5	70	1984	Combined Cycle Cogen	134	64
Chinese Sta.	China Camp	CA	USA	22.4	181,880	6	97	1984	Waste wood	141	44
Duchess Cnty. RRF	Poughkeepsie	NY	USA	7.5	50,340	4	79	1985	WTE	126	47
Sherman Sta.	Sherman Station	ME	USA	20	125,450	2	43	1985	Waste Wood	102	59
Olmstead Cnty. WTE	Rochester	MN	USA	1	42,000	5.5	80	1985	WTE	138	58
Chicago Northwest WTE	Chicago	IL	USA	1	42,000		90	1986	WTE		
SEMASS WTE	Rochester	MA	USA	54	407,500	3.5	59	1986	WTE	120	61
Haverhill RRF	Haverhill	MA	USA	46.9	351,830	5	85	1987	WTE	134	49
Cochrane Sta.	Cochrane	Ont.	CAN	10.5	90,000	3	60	1988	Combined Cycle Cogen	115	55
Grumman	Bethpage	NY	USA	13	105,700	5.4	59	1988	Combined Cycle Cogen	137	78
North Branch Power Sta.	North Branch	WV	USA	80	662,000	7	90	1989	Coal	147	57
Sayreville Cogen Pro.	Sayreville	NJ	USA	100	714,900	3	59	1989	Combined Cycle Cogen	115	56
Bellingham Cogen Pro.	Bellingham	MA	USA	100	714,900	3	59	1989	Combined Cycle Cogen	115	56
Spokane RRF	Spokane	WA	USA	26	153,950	2	47	1989	WTE	102	55
Exeter Energy L.P. Pro.	Sterling	CT	USA	30	196,000	2.9	75	1989	PAC System	114	39
Peel Energy from Waste	Brampton	Ont.	CAN	10	88,750	4.5	68	1990	WTE	130	62
Nipogen Power Plant	Nipogen	Ont.	CAN	15	169,000	3	59	1990	Combined Cycle Cogen	115	56
Linden Cogen Pro.	Linden	NJ	USA	285	1,911,000	2.44	54	1990	Combined Cycle Cogen	108	54
Maalaea Unit 15	Maui	HI	USA	20	158,250	6	95	1990	Combined Cycle	141	46
Norcon Welsh Plant	North East	PA	USA	20	150,000	2.5	55	1990	Combined Cycle Cogen	109	54
Univ of Alaska	Fairbanks	AK	USA	10	46,000	6	82	1991	Combined Cycle Cogen	141	59
Union County RRF	Union	NJ	USA	50	357,000	8	94	1991	WTE	152	58
Saranac Energy	Saranac	NY	USA	80	736,800	5	90	1992	Combined Cycle Cogen	134	44
Onondaga County RRF	Onondaga	NY	USA	50	258,000	3	70	1992	WTE	115	45
Neil Simpson II Sta.	Gillette	WY	USA	80	548,200	6	66	1992	Coal	141	75
Gordonsville Plant	Gordonsville	VA	USA	50	349,150	6	90	1993	C-Cycle (x2 Units)	141	51
Dutchess County RRF Exp.	Poughkeeksie	NY	USA	15	49,660	5	79	1993	WTE	134	55
Samalayuca II Power Sta.	Samalayuca		MEX	210	1,296,900	7	99	1993	Combined Cycle	147	48
Potter Station	Potter	Ont.	CAN	20	181,880	3.8	66	1993	Combined Cycle	124	58

Table 4-1: Air Cooled Condenser Data for Systems installed by GEA Power Cooling Systems, Inc.

Facility Name	City	State	Country	Size MW	Steam Flow lbs/hr	Turbine Exhaust Pressure In. Hg	Design Temp. °F	Year	Description	Sat. Steam Temp. °F	Temp. Difference °F
Streeter Generating Sta.	Cedar Falls	IA	USA	40	246,000	3.5	50	1993	Coal - PAC System	120	70
MacArthur RRF	Ronkonkoma	NY	USA	11	40,000	4.8	79	1993	WTE	132	53
North Bay Plant	North Bay	Ont.	CAN	30	245,000	2	53.6	1994	Combined Cycle	102	48.4
Kapuskasing Plant	Kapuskasing	Ont.	CAN	30	245,000	2	53.6	1994	Combined Cycle	102	48.4
Haverhill RRF Exp.	Haverhill	MA	USA	46.9	44,500	5	85	1994	WTE	134	49
Arbor Hills Landfill Gas Fac.	Northville	MI	USA	9	87,309	3	50	1994	Combined Cycle	115	65
Pine Bend Landfill Gas Fac	Eden Prairie	MN	USA	6	58,260	3	50	1994	Combined Cycle	115	65
Pine Creek Power Sta.	Pine Creek	N. Ter.	AUSTRAILIA	10	95,300	3.63	77	1994	Combined Cycle	122	45
Cabo Negro Plant	Punta Arenas		CHILE	6	74,540	4	63	1995	Methanol Plant	126	63
Emeraldas Refinery	Emeraldas		EQUADOR	15	123,215	4.5	87.3	1995	Combined Cycle	130	42.7
Mallard Lake Landfill Gas	Hanover Park	IL	USA	9	101,400	3	49	1996	Combined Cycle	115	66
Riyadh Power Plant 9	Riyadh		SAUDI ARABIA	107	966,750	16.5	122	1996	C-Cycle (x4 Units)	184	62
Barry CHP Project	Barry	S. Wales	UK	100	596,900	3	50	1996	Combined Cycle	115	65
Zorlu Enerji Project	Bursa		TURKEY	10	83,775	3.5	59	1997	Combined Cycle	120	61
Tucuman Power Sta.	El Bracho	Tucuman	ARGENTINA	150	1,150,000	5	99	1997	PAC System	134	35
Dighton Power Project	Dighton	MA	USA	60	442,141	5.5	90	1997	Combined Cycle	139	49
El Dorado Energy	Boulder	NV	USA	150	1,065,429	2.5	67	1998	Combined Cycle	109	42
Tiverton Power Project	Tiverton	RI	USA	80	549,999	5	90	1998	Combined Cycle	134	44
Coryton Energy Project	Corringham		ENGLAND	250	1,637,312	2.5	50	1998	Combined Cycle	109	59
Rumford Power Project	Rumford	ME	USA	80	545,800	5	90	1998	Combined Cycle	134	44
Millmerran Power Project	Toowoomba	Queensland	AUSTRAILIA	420	2,050,000	5.43	88	1999	Coal (x 2 Units)	137	49
Bajio Power Project	Quertetaro	Guananjuaro	MEX	450	1,307,000	3.54	71.4	1999	Combined Cycle	121	49.6
Monterrey Cogen Project	Monterrey		MEX	80	671,970	5.8	102	1999	Combined Cycle Cogen.	140	38
Gelugor Power Station	Penang		MALAYSIA	120	946,600	6.8	89.6	2000	Combined Cycle Cogen.	146	56.4
Front Range Power Project	Fountain	CO	USA	150	1,266,477	3.57	80	2000	Combined Cycle	121	41
Goldendale Energy Project	Goldendale	WA	USA	110	678,000	5	90	2000	C-Cycle PAC System	134	44
Athens Power Station	Athens	NY	USA	120	749,183	5	90	2000	Combined Cycle	134	44
					Average	4				Average	54
					Min	2				Min	35
					Max	16.5				Max	78
HIGH EXHAUST PRESSURE (Temperature Difference >80 °F)											
Beneccia Refinery	Beneccia	CA	USA	NA	48,950	9.5	100	1975		191	91
Beluga Unit 8	Beluga	AK	USA	65	478,400	5.6	35	1979	Combined Cycle	138	103
Univ. of Alberta	Edmonton	Alberta	CAN	25	277,780	9.15	59	1999	Gas Cogen.	158	99

As with wet cooling towers, the ambient air temperature and system design can have an effect on the steam turbine exhaust pressure, which in turn affects the turbine efficiency. Thus, the turbine efficiency can change over time as the air temperature changes. The fans used to mechanically force air through the condenser represent the greatest operational energy requirement for dry cooling systems.

A design measure comparable to the approach value used in wet towers is the difference between the design dry bulb temperature and the temperature of saturated steam at the design turbine exhaust pressure. In general, a larger, more costly dry cooling system will produce a smaller temperature difference across the condenser and, therefore, a lower turbine exhaust pressure. Three facilities in Table 4-1 had high temperature differences (>80 °F), which represent less efficient systems. Two of these facilities are from very cold climates where high temperature differences across the condenser are acceptable and one was for an industrial process (petroleum refining). The range in the temperature difference values for the remaining facilities was 35 to 78 °F. The average was 54 °F.

Steam turbines are designed to operate within certain exhaust pressure ranges. In general, steam turbines that are designed to operate at the exhaust steam pressure ranges typical of wet cooling systems, which generally operate at lower exhaust pressures (e.g., <5 in Hg), may be damaged if the exhaust pressure exceeds a certain value. New steam turbine facilities that are designed to condense steam with dry cooling systems can be equipped with steam turbines that are designed to be safely operated at higher exhaust pressures. EPA has assumed that the difference in costs for turbines that operate over different exhaust pressure ranges are insignificant compared to the total compliance cost and, therefore, no net compliance costs are estimated for the steam turbines.

The data in Table 4-1 shows that turbine exhaust pressures at the highest design dry bulb temperatures in the U.S. (which were around 100 °F) ranged from 5.0 to 9.5 inches Hg. The highest value of 9.5 inches Hg was for a refinery power system in California which, based on the steam rate, was comparable to other relatively small systems generating several megawatts and apparently did not warrant the use of an efficient cooling system. The other data show turbine exhaust pressures of around 6 to 7 inches Hg at dry bulb temperatures of around 100 °F. Maximum exhaust pressures in the range of 8 to12 inches Hg may be expected in hotter regions of the U.S.(Hensley 1985). An air cooled condenser analysis (Weeks 2000) reports that for a combined cycle plant built in Boulder City, Nevada, the maximum ambient temperature used for the maximum off-design specification was 108 °F with a corresponding turbine exhaust pressure of 7.8 inches Hg. Note that the equation used by EPA to generate the turbine exhaust pressure values in the energy penalty analysis produced an estimated exhaust pressure of 8.02 inches Hg at a dry bulb temperature of 108 °F. For wet towers, the typical turbine exhaust pressure operating range is1.5 to 3.5 inches Hg(Woodruff 1998).

For coal-fired plants, the largest operating plant in the United States with dry cooling is the Wyodak Station in Gillette, WY with a total cooling capacity of 330 MW (1.88 million lb/hr of steam). EPA notes that this is significantly smaller than 10 of the projected coal-fired power plants within the scope of the rule and slightly smaller than 25 of the combined cycle plants. The design temperature of the dry system at this plant (which directly affects the size of the dry cooling system) is below average for summer conditions throughout the United States (the Wyodak Station has a design temperature of 66 deg F, whereas recent combined-cycle systems in Rhode Island, Massachusetts, and New York have design targets above 90 deg F). EPA notes that the reported driving force behind the Wyodak Station's decision to utilize dry cooling was the fact that the plant designers wished to locate the plant immediately adjacent to a remote coal-mine mouth.

A demonstrated dry cooling system frequently recognized as the largest in the U.S. is the Linden Cogeneration Plant, in NJ. This cogeneration unit has a comparable cooling capacity to that of a small-sized coal-fired facility (such as the Wyodak Station described above). The cogeneration plant has a total steam flow which requires condensing of

1.91 million lb/hr, which just slightly exceeds the steam flow of the Wyodak station (1.88 million lb/hr). Despite the fact that the Linden plant is designed for a total generating capacity of 640 MW, only 285 MW requires steam condensing. This is because cogeneration units are designed to deliver steam to adjacent manufacturing plants for their use in processes. Therefore, the cogeneration plant has been designed such that only a portion of its steam generation requires cooling, and, for the purposes of evaluating the feasibility of dry cooling, EPA considers this a 285 MW dry cooling facility. EPA notes that the decision for this plant to adopt dry cooling over wet cooling related primarily to a highway safety issue and the visible plume of steam.

Several new combined-cycle projects with dry cooling are either planned or under-construction in the Northeastern US. EPA is aware of eight new dry cooling projects at combined cycle plants in this region that have 350 MW or greater of total plant capacity. The largest of these projects is the permitted Sithe Mystic Station in Massachusetts, which will be a 1500 MW combined-cycle plant. Because the project will utilize a combined-cycle, approximately 500 MW of steam power would require cooling. This will be the largest dry cooling system in the US when complete. However, the system size does not approach the projected cooling requirements for a majority of the coal-fired plants within the scope of this rule.

4.2 IMPACTS OF DRY COOLING

In establishing best technology available for minimizing adverse environmental impact for the final rule, EPA considered an alternative based on a zero-intake flow (or nearly zero, extremely low flow) requirement commensurate with levels achievable through the use of dry cooling systems. In evaluating dry cooling-based regulatory alternatives, EPA analyzed a zero or nearly zero intake flow requirement based on the use of dry cooling systems as the primary regulatory requirement in all waters of the U.S. The Agency also considered subcategorization strategies for the new facility regulation based on size and types of new facilities and location within regions of the country, since these factors may affect the viability of dry cooling technologies. In its evaluation, the Agency considered factors including the demonstration of existing or planned dry cooling systems, the reductions in cooling water intake flow, the environmental and energy impacts, and the associated costs of dry cooling systems.

4.2.1 Cooling Water Reduction

A dry cooling system will achieve an average reduction in cooling water intake flow greater than 99 percent over a once-through system. In comparison, the average flow reduction of a closed-cycle wet cooling system for an estuarine/tidal source is approximately 92 percent, and is 95 percent for a freshwater source. Dry cooling systems therefore achieve an incremental flow reduction from closed-cycle wet cooling to dry cooling of 4 to 7 percent.

4.2.2 Environmental and Energy Impacts

Dry cooling has the benefit of eliminating visual plumes, fog, mineral drift, and water treatment and disposal issues associated with wet cooling towers. The disadvantages of dry cooling include an increase in noise generation and decrease in efficiency of electricity generation which lead to an increase in air emissions as compared to wet cooling systems.

EPA notes that dry cooling systems in all climates are less efficient at removing heat than comparable wet-cooling systems. The practical limitations of the dry cooling system, as limited by the dry bulb temperature, which is always equal to or greater than the wet bulb temperature met by wet cooling systems, prevent its performance from exceeding that of wet cooling. Moreover, increased parasitic fan loads for dry cooling systems will ensure that the technology will not operate as efficiently as a comparable wet cooling system.

Therefore, EPA assessed the negative environmental impacts caused by this loss of efficiency. For combined-cycle plants the mean annual energy penalty (averaged across climates) is 2.1 percent for dry cooling compared to once-through systems, and 1.7 percent for wet cooling compared to once-through systems. For coal-fired plants, the mean annual energy penalty (averaged across climates) is 8.6 percent for dry cooling compared to once-through systems, and 6.9 percent for wet cooling compared to once-through systems. However, for many specific cases, the energy penalty may be dramatically higher for dry cooling due to climatic conditions of the cooling towers. For example, the peak summer shortfalls during hot periods can be debilitating in certain climates due to the energy penalty reaching up to 12.3 percent. See Chapter 3 of this document for further discussion of energy penalties.

EPA projects that a dry cooling based regulatory alternative would result in 1900 MW of lost energy. This is the equivalent electricity generation of two very large (or three large) power plants that would need to be constructed to overcome the energy losses of the dry cooling alternative. The air emissions increases as a result of this replacement capacity, if they were to come from increased generation across the US market, would be equivalent to those of three new 800MW coal-fired power plants. Alternatively, if the replacement capacity comes from new capacity exclusively, it would be from dry cooling equipped plants with the associated elevated capital and annual costs and land area requirements. Therefore, EPA considers the issue of inefficiency of dry cooling, and EPA's subsequent rejection of the dry cooling alternative, to be principal to the concept of energy conservation. Considering that the State of California recently experienced shortages of demand less than the energy penalty of the dry cooling option, the imposition of 1900 MW of mean annual energy penalty capacity loss on planned new power plants does not support the Administration's Energy Plan and associated Executive Orders.

The efficiency of the electricity generation process is directly affected by the cooling system to be installed. The vast majority of projected new plants (i.e., 90 percent) would install closed-cycle recirculating cooling towers regardless of the requirements of this rule. Therefore, EPA's technology-based performance requirements for the final rule based on recirculating closed-cycle cooling would have little impact on the majority of new plants. The flow reduction requirements of the rule are projected to impose changes in cooling system designs on only nine new plants. The comparable effect on the efficiency of these plants will be small on a facility level and national basis.

In contrast, a regulatory alternative based on dry cooling is projected to impose cooling system design changes on each of the 83 power plants within the scope of the final rule. Therefore, each of the 14 projected coal-fired plants would experience mean annual energy penalties ranging from 6.9 to 8.6 percent. The typical steam electric generator (such as modern coal-fired plants) would, at peak operation, operate at less than 40 percent efficiency. The energy penalty of nearly 9 percent is very significant when compared to the system-wide energy efficiency of this type of power plant. Additionally, each of the 69 projected new combined-cycle plants would experience mean annual energy penalties ranging from 1.7 to 2.1 percent. With new design efficiencies of 60 percent, at peak operating efficiency, a 2.1 percent energy penalty is less striking than in the coal-fired cases. However, the cumulative effect for all 69 power plants is substantial.

4.2.3 Costs of Dry Cooling

The final rule analysis, which includes the contribution of the energy penalty to the recurring annual costs, projects that the total annualized cost for the dry cooling alternative is $490 million (in 2000 dollars). EPA notes that the vast majority of costs associated with this option are incurred at the 83 power plants, and not at the 38 manufacturers subject to this rule. Because dry cooling is not a feasible option for all manufacturing facilities, EPA only applied costs of recirculating wet cooling towers to these types of facilities. The present value of total compliance costs for drying cooling are projected to be $6 billion.

A comparison of capital costs between equally sized combined-cycle plants for wet and dry cooling tower systems reveals that the dry cooling plant's capital costs would exceed those of the wet cooling tower plant by 3.3 fold. The installed wet cooling tower capital cost is approximately $10 million, while the dry cooling installation would cost approximately $33 million. For a typical, modern 700-MW combined-cycle power plant, the erected capital costs for a wet cooling tower represent approximately 2 percent of the total capital costs of the power plant construction project compared to 6.5 percent for dry cooling towers.

EPA also evaluated a comparison of the operation and maintenance costs associated with these two types of cooling systems for an equally sized combined-cycle model plant. The operation and maintenance costs of the wet cooling tower (without including the effects of energy penalties) would be $1.8 million per year, while the dry cooling system would cost $7.4 million per year. Without incorporating energy penalties, the ratio of operation and maintenance costs of dry cooling to wet cooling for a typical 700-MW combined-cycle power plant would be greater than 4 to 1. After factoring in the recurring costs of energy penalties for the two systems, the recurring annual costs increase to $2.3 million for the wet tower plant and $10.4 million for the dry cooling plant. This corresponds to a dry to wet ratio also greater than 4 to 1. The total annualized costs for this model facility are estimated at $3.1 for the wet cooling tower system and $13.1 for the dry cooling system (a ratio of 4.2 to 1). Note that these are comparative cost estimates for a hypothetical facility and do not represent actual compliance costs of the rule.

4.2.4 Methodology for Dry Cooling Cost Estimates

EPA estimated the capital and O&M costs using relative cost factors for various types of wet towers and air cooled condensers, using the cost of a comparable wet tower constructed of Douglas Fir as the basis. Chapter 2 provides the capital and operating cost factors that were used by EPA. These cost factors were developed by industry experts who are in the business of manufacturing, selling and installing cooling towers, including air cooled systems, for power plants and other applications. For air cooled condensers (constructed of steel), a range of cost factors is given in Table 4-3. EPA based the capital and O&M costs on these factors with some modifications. To be conservative, EPA chose the highest value within each range as the basis. The factors chosen are 325 percent and 225 percent (of the cost of a mechanical wet tower) for capital cost (for a tower with a delta of 10 ºF) and O&M cost, respectively. EPA applied a multiplier of roughly 1.7 to the dry tower capital cost estimates for a delta of 10 ºF to yield capital cost estimates for a dry tower with a delta of 5 ºF. EPA applied these factors to the capital costs derived for the basic steel mechanical draft wet cooling towers to yield the capital cost estimates for dry towers presented in Table 4- 2.

Note that the source document for these factors states that the factors represent comparable cooling systems for plants with the same generated electric power and the same turbine exhaust pressure. Since the cost factors generate equivalent dry cooling systems, the tower costs can still be referenced to the corresponding equivalent cooling water flow rate of the mechanical wet tower used as the cost basis. Since the final §316(b) New Facility Rule focuses primarily on water use, the use of the cooling flow or the "equivalent" was considered as the best way to compare costs. The costing methodology uses an equivalent cooling water flow rate as the independent input variable for costing dry towers.

Table 4-2: Estimated Capital Costs of Dry Cooling Towers with Delta of 5 °F and 10 °F (1999 Dollars)

Flow (gpm)	Delta 5 ºF	Delta 10 ºF
2000	$790,000	$450,000
4000	$1,580,000	$949,000
7000	$2,766,000	$1,658,000
9000	$3,556,000	$2,132,000
11,000	$4,345,000	$2,607,000
13,000	$5,135,000	$3,081,000
15,000	$5,925,000	$3,556,000
17,000	$6,715,000	$4,027,000
18,000	$7,108,000	$4,264,000
22,000	$8,515,000	$5,038,000
25,000	$9,675,000	$5,727,000
28,000	$10,836,000	$6,412,000
29,000	$11,222,000	$6,643,000
31,000	$11,996,000	$7,101,000
34,000	$13,156,000	$7,787,000
36,000	$13,933,000	$8,245,000
45,000	$17,059,000	$9,952,000
47,000	$17,817,000	$10,394,000
56,000	$21,229,000	$12,383,000
63,000	$23,881,000	$13,933,000
67,000	$25,399,000	$14,817,000
73,000	$27,674,000	$16,143,000
79,000	$29,325,000	$16,845,000
94,000	$34,892,000	$20,043,000
102,000	$37,859,000	$21,749,000
112,000	$41,574,000	$23,881,000
146,000	$54,194,000	$31,132,000
157,000	$57,034,000	$32,237,000
204,000	$72,498,000	$40,277,000
250,000	$100,800,000	$58,800,000
300,000	$120,000,000	$70,000,000
350,000	$140,400,000	$81,900,000
400,000	$160,800,000	$93,800,000

Using the estimated costs, EPA developed cost equations using a polynomial curve fitting function. Table 3 presents capital cost equations for dry towers with deltas of 5 and 10 degrees.

Table 4-3. Capital Cost Equations of Dry Cooling Towers with Delta of 5 °F and 10 °F

Delta	Capital Cost Equation[1]	Correlation Coefficient
5 °F	$y = -2E\text{-}10x^3 + 0.0002x^2 + 337.56x + 973608$	$R^2 = 0.9989$
10 °F	$y = -8E\text{-}11x^3 + 0.0001x^2 + 189.77x + 800490$	$R^2 = 0.9979$

1) x is for flow in gpm and y is cost in dollars.

For purposes of estimating costs for the dry cooling option (Option 2B) for the final §316(b) New Facility Rule, EPA used the O&M cost curve for air condensers contained in Appendix A of the *Economic and Engineering Analyses of the Proposed §316(b) New Facility Rule* without modification. Thus, EPA overcosted the O&M costs for dry towers for Option 2B for the final §316(b) New Facility Rule. See Section 2.9.1 of this document and the response to comment document (#316bNFR.068.330) for discussion of EPA's revised O&M costs for the final rule.

Validation of Dry Cooling Capital Cost Curves

To validate the dry tower capital cost curves and equations, EPA compared the costs predicted by the equation for dry towers with delta of 10 ºF to actual costs for five dry tower construction projects provided by industry representatives. To make this comparison, EPA first needed to estimate equivalent flows for the dry tower construction project costs. Obviously, as noted above, dry towers do not use cooling water. However, for every power plant of a given capacity there will, dependent on the selected design parameters, be a corresponding equivalent recirculating cooling water flow that would apply if wet cooling towers were installed to condense the same steam load.

EPA used the steam load rate and cooling system efficiency to determine the equivalent flow. Note that the heat rejection rate will be proportional to the plant capacity. EPA estimated the flow required for a wet cooling tower that is functionally equivalent to the dry tower by converting each plant's steam tons/hour into cooling flow in gpm using the following equations:

Steam tons/hr x 2000 lbs/ton x 1000 BTUs/lb steam = BTUs/hr
One ton/hr = 12,000 BTU/hr
BTUs/hr / 12000 = Tons of ice
Tons of Ice x 3 = Flow (gpm) for wet systems

Chart 4-2 presents a comparison of the EPA capital cost estimates for dry towers with delta of 10 ºF (with 25% error bars) to actual dry tower installations. This chart shows that EPA's cost curves produce conservative cost estimates, since the EPA estimates are greater than all of the dry tower project costs based on the calculated equivalent cooling flow rate for the actual projects.

Chart 4-1. Capital Costs of Dry Cooling Towers Versus Flows Of Replaced Wet Cooling Towers (5 &10 Degrees Delta)

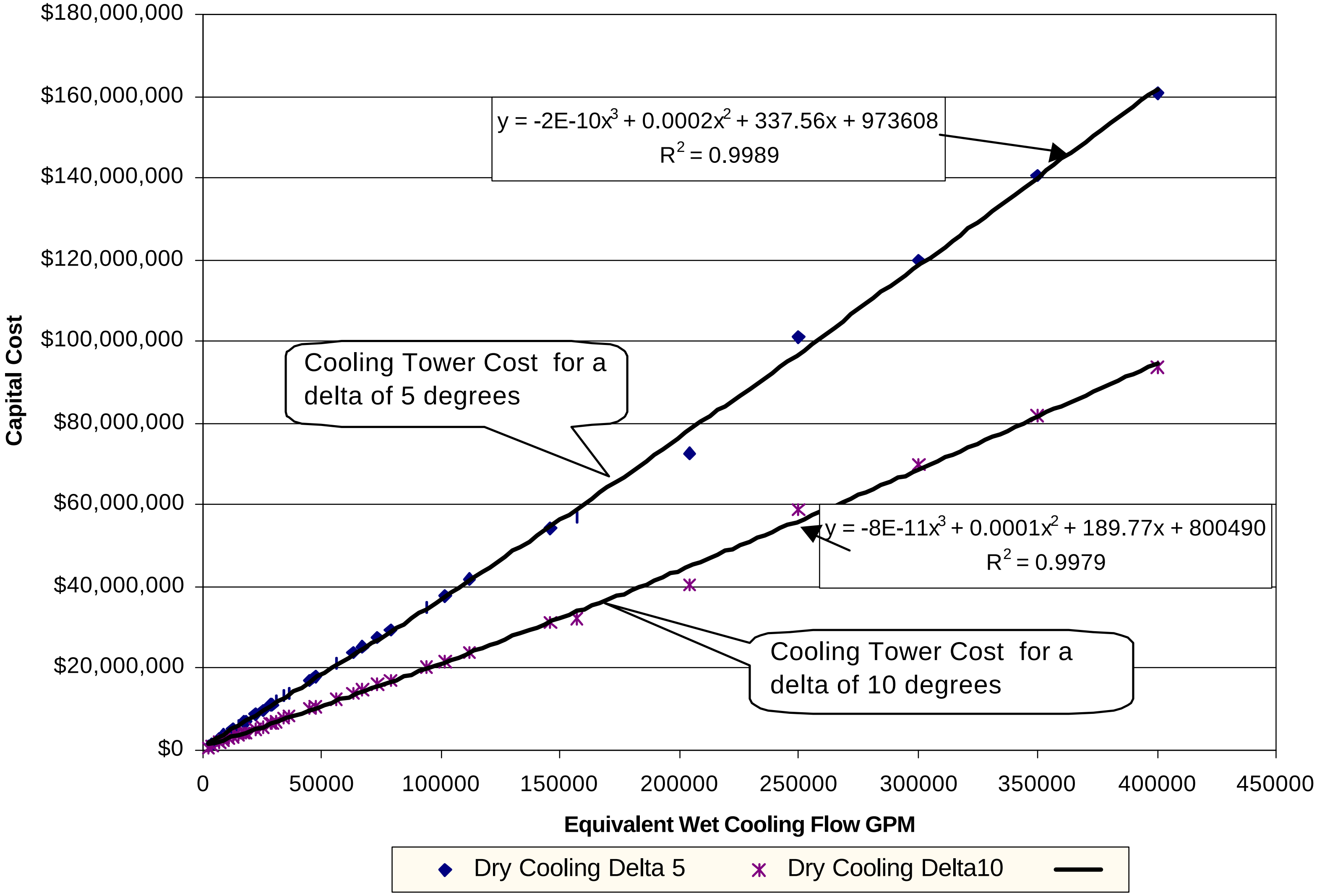
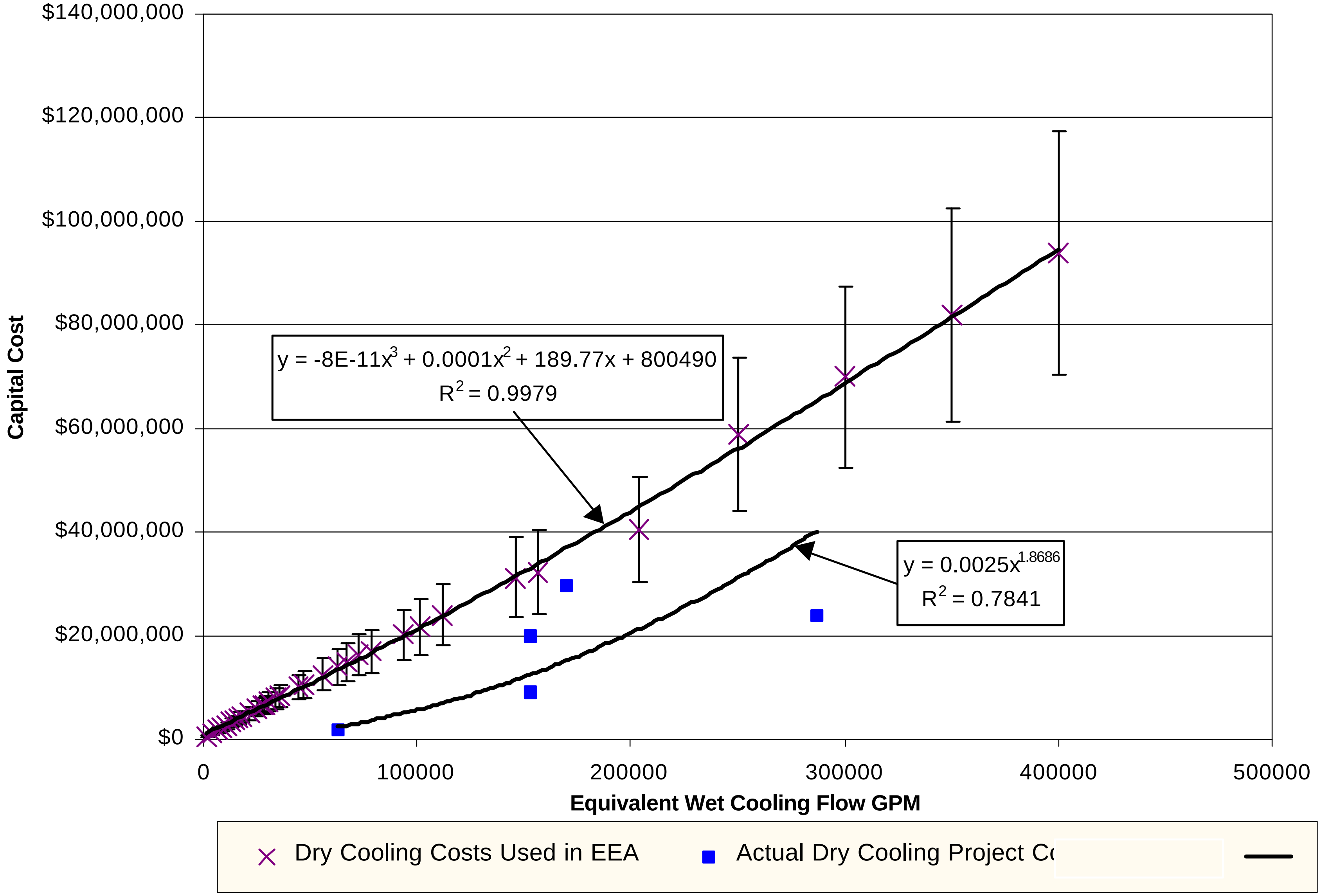


Chart 4-2. Actual Capital Costs of Dry Cooling Tower Projects and Comparable Costs from EPA Cost Curves



4.1.6 Economic Impacts of Dry Cooling

EPA concluded that the costs of dry cooling systems may be significantly prohibitive so as to pose barriers to entry for some new plants. EPA projected that the cost to revenue impacts exceed 10 percent for 12 new power plants and exceed 4 percent for all new plants under a dry cooling-based regulatory alternative. EPA considers this level of cost to revenue impacts to be significant. In comparison, the cost to revenue impacts of the final rule, which is based in part on flow reduction commensurate with that achieved using recirculating closed-cycle wet cooling, do not exceed 3 percent for a single facility, and the vast majority of the impacts are below 1 percent. A complete discussion of the cost to revenue impacts and discussion of barrier to entry analysis can be found in the Economic Analysis for the final rule. As such, regional subcategorization options would pose similar barriers to entry for new plants in the Northeastern United States, combined with imposing competitive disadvantages for the subset of facilities complying with more stringent and costly standards than the other regions of the country.

EPA is concerned that the barrier to entry, high costs, and energy penalty of dry cooling systems may remove the incentive for replacing older coal-fired power plants with more efficient and environmentally favorable new combined-cycle facilities. By basing the requirements of the rule on dry cooling, regulated entities faced with the prospects of building new facility power plants that are required to utilize dry cooling would, instead of beginning or continuing with the new facility project, turn to existing power-plants (many of which are significantly aged) and attempt to extend their operating lives further or refurbish them such that the new facility rule would not apply.

EPA notes that there have been recent advances in the efficiency of power plants, specifically combined-cycle plants, that have many environmental advantages. Combined-cycle plants produce significantly less air emissions of NOx, SO_2, and Hg per MWh generated, use less water for condensing of steam than fossil-fueled or nuclear plants (greater than one-half water use reduction per MWh of generation), and are significantly more energy efficient in their generation of electricity than comparable coal-fired plants. The Agency does not wish to create disincentives for the construction of new efficient plants such as these.

4.3 Evaluation of Dry Cooling as BTA

This section presents a summary of EPA's evaluation of the dry cooling technology as a candidate for best technology available to minimize adverse environmental impacts. Based on the information presented in the previous sections, EPA concluded that dry cooling systems do not represent the best technology available for a national requirement and under the subcategorization strategies described above.

First, EPA concluded that dry cooling is not adequately demonstrated for all facilities within the scope of this regulation. As noted previously, the majority of operating or planned dry cooling systems are located either in colder or arid climates where the average dry bulb temperatures of ambient air is amenable to dry cooling. As demonstrated in Chapter 3, the comparative energy penalty of a dry cooling plant in a hot environment at peak summer conditions can exceed 12 percent at a facility, thereby making dry cooling extremely unfavorable in many areas of the U.S. for some types of power plant types.

EPA's record demonstrates that of the demonstrated, permitted, or planned power plants in the Northeastern United States with dry cooling, the size and capacity of these dry cooling systems is considerably smaller than that necessary to condense the steam load for even below average sized coal-fired power plants projected within the scope of this rule.

Dry cooling technology has a detrimental effect on electricity production by reducing energy efficiency of steam turbines, especially in warmer climates The reduced energy efficiency of the dry cooling system will have the effect of increasing air emissions from power plants.

Lastly, EPA concluded that the costs of dry cooling systems may be significantly prohibitive so as to pose barriers to entry for some new plants that may discourage the construction of new, more energy efficient plants.

In addition to the technical feasibility and cost impacts of dry cooling, EPA also evaluated the expected benefits that would be achieved by dry cooling. EPA notes that the two-track option based on reducing intake flow to a level commensurate with wet cooling towers reduces intake flows by 92 to 95 percent over a once-through system. Dry cooling would only reduce intake flow by an additional 4 to 7 percent. Additionally, the selected option requires velocity and design and construction technology-based performance requirements for the remaining intake flow. These performance requirements are expected to further decrease the negative environmental impacts of the cooling water intake flow, thereby reducing impingement and entrainment of organisms to dramatically low levels. See Chapter 5 for discussion of design and construction technologies to reduce impingement and entrainment.

In summary, EPA concluded that dry cooling is not technically or economically feasible for all facilities subject to this rule, would increase air emissions due to the energy penalty, has a cost more than three times that of the selected regulatory option, and would not significantly reduce impingement and entrainment beyond the regulatory approach selected by EPA to offset these drawbacks. For these reasons, EPA concluded that dry cooling does not represent the "best technology available" for minimizing adverse environmental impact.

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Chapter 5: Efficacy of Cooling Water Intake Structure Technologies

INTRODUCTION

To support the Section 316(b) new facility rulemaking, the Agency has compiled data on the performance of the range of technologies currently used to minimize impingement and entrainment (I&E) at power plants nationwide. The goal of this data collection and analysis effort has been to determine whether specific technologies can be demonstrated to provide a consistent level of proven performance. This information has been used throughout the rulemaking process including comparing specific regulatory options and their associated costs and benefits. It provides the supporting information for the selected alternatives, which require wet, closed-cycle cooling systems (under Track 1) with the option of demonstrating comparable performance (under Track II) using alternative technologies. Throughout this chapter, baseline technology performance refers to the performance of conventional, wide mesh traveling screens that are not intended to prevent I&E. Alternative technologies generally refer to those technologies, other than closed-cycle cooling systems that can be used to minimize I&E. Overall, the Agency has found that performance and applicability vary to some degree based on site-specific conditions. However, the Agency has also determined that alternative technologies can be used effectively on a widespread basis with proper design, operation, and maintenance.

Chapter Contents

5.1 SCOPE OF DATA COLLECTION EFFORTS

Since 1992, the Agency has been evaluating regulatory alternatives under Section 316(b) of the Clean Water Act. As part of these efforts, the Agency has compiled readily available information on the nationwide performance of I&E reduction technologies. This information has been obtained through:

- Literature searches and associated collection of relevant documents on facility-specific performance.
- Contacts with governmental (e.g., TVA) and non-governmental entities (e.g., EPRI) that have undertaken national or regional data collection efforts/performance studies
- Meetings with and visits to the offices of EPA Regional and State agency staff as well as site visits to operating power plants.

It is important to recognize that the Agency did not undertake a systematic approach to data collection, i.e., the Agency did not obtain all of the facility performance data that are available nor did it obtain the same level of information for each facility. The Agency is not aware of such an evaluation ever being performed nationally. The most recent national data compilation was undertaken by the Electric Power Research Institute (EPRI) in 2000, see *Fish Protection at Cooling Water Intakes, Status Report*. The findings of this report are cited extensively in the following subsections. However, EPRI's analysis was primarily a literature collection and review effort and was not intended to be an exhaustive compilation and analysis of all data.

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5.2 DATA LIMITATIONS

Because the Agency did not undertake a systematic data collection effort with consistent data collection procedures, there is significant variability in the information available from different data sources. This leads to the following data limitations:

- Some facility data include all of the major species and associated life stages present at an individual facility. Other facilities only include data for selected species and/or life stages.
- Much of the data were collected in the 1970s and early 1980s when existing facilities were required to complete their initial 316(b) demonstrations.
- Some facility data includes only initial survival results, while other facilities have 48 to 96-hour survival data. These data are relevant because some technologies can exhibit significant latent mortality after initial survival.
- The Agency did not review data collection procedures, including quality assurance/quality control protocols.
- Some data come from laboratory and pilot-scale testing rather than full-scale evaluations.

The Agency recognizes that other than closed-cycle cooling and velocity reduction technologies the practicality or effectiveness of alternative technologies not be uniform under all conditions. The chemical and physical nature of the waterbody, the facility intake requirements, climatic conditions, and biology of the area all effect feasibility and performance. However, despite the above limitations, the Agency has concluded that significant general performance expectations can be implied for the range of technologies and that one or more technologies (or groups of technologies) can provide significant I&E protection at most sites. In addition, in the Agency's view many of the technologies have the potential for even greater applicability and higher performance when facilities are required to optimize their use.

The remainder of this chapter is organized by groups of technologies. A discussion of wet, closed-cycle cooling tower performance is included to present the Agency's view of the likely minimum standard that Track II facilities will be required to achieve (although each facility will have to present it's own closed-cycle system scenario). A brief description of conventional, once-through traveling screens is also provided for comparison purposes. Fact sheets describing each technology, available performance data, and design requirements and limitations are provided in Attachment A. It is important to note that this chapter does not provide descriptions of all potential CWIS technologies. (ASCE 1982 generally provides such an all-inclusive discussion). Instead, the Agency has focused on those technologies that have shown significant promise at the laboratory, pilot-scale, and/or full-scale levels in consistently minimizing impingement and/or entrainment. In addition, this chapter does not identify every facility where alternative technologies have been used but rather only those where some measure of performance in comparison to conventional screens has been made. The chapter concludes with a brief discussion of how the location of intakes (as well as the timing of water withdrawals) could also be used to limit potential I&E effects at new facilities.

Finally, under Track II in the new facility rule, facilities may use habitat restoration projects as an additional means to demonstrate consistency with Track I performance. Such projects have not had widespread application at existing facilities. Because the nature, feasibility, and likely effectiveness of such projects would be highly site-specific, the Agency has not attempted to quantify their expected performance level herein.

5.3 CLOSED-CYCLE WET COOLING SYSTEM PERFORMANCE

Under Track I, facilities are required meet requirements based on the design and installation of wet, closed-cycle cooling systems. Although flow reduction serves the purpose of reducing both impingement and entrainment, these requirements function as the primary entrainment reduction portion of Track I. Under Track II, new facilities must demonstrate I&E performance comparable to 90 percent of the performance of a wet, closed-cycle system designed for their facility. In part, to evaluate the feasibility of meeting this requirement and to allow comparison of costs/benefits of alternatives, the Agency determined the likely range in flow reductions between wet, closed-cycle cooling systems compared to once-through systems. In closed-cycle systems, certain chemicals will concentrate as they continue to be recirculated through the tower. Excess buildup of such chemicals, especially total dissolved solids, affects the tower performance. Therefore, some water (blowdown) must be discharged and make-up water added periodically to the system.

See Section 2.3.5 of Chapter 2 of this document for further discussion of flow reduction using wet, closed-cycle cooling.

An additional question that the Agency has considered is the feasibility of constructing salt-water make-up cooling towers. The Agency contacted Marley Cooling Tower (Marley), which is one of the largest cooling tower manufacturers in the world. Marley provided a list of facilities (Marley, 2001) that have installed cooling towers with marine or otherwise high total dissolved solids/brackish make-up water. It is important to recognize that this represents only a selected group of facilities constructed by Marley worldwide; there are also facilities constructed by other cooling tower manufacturers. For example, Florida Power and Light's (FPL) Crystal River Units 4 and 5 (about 1500 MW) use estuarine water make-up.

5.4 CONVENTIONAL TRAVELING SCREENS

For impingement control technologies, performance is compared to conventional traveling screens as a baseline technology. These screens are the most commonly used intakes at older existing facilities and their operational performance is well established. In general, these technologies are designed to prevent debris from entering the cooling water system, not to minimize I&E. The most common intake designs include front-end trash racks (usually consisting of fixed bars) to prevent large debris from entering system. They are equipped with screen panels mounted on an endless belt that rotates through the water vertically. Most conventional screens have 3/8-inch mesh that prevents smaller debris from clogging the condenser tubes. The screen wash is typically high pressure (80 to 120 pounds per square inch (psi)). Screens are rotated and washed intermittently and fish that are impinged often die because they are trapped on the stationary screens for extended periods. The high-pressure wash also frequently kills fish or they are re-impinged on the screens. Conventional traveling screens are used by approximately 60 percent of all existing steam electric generating units in the U.S. (EEI, 1993).

5.5 ALTERNATIVE TECHNOLOGIES

5.5.1 Modified Traveling Screens and Fish Handling and Return Systems

Technology Overview
Conventional traveling screens can be modified so that fish, which are impinged on the screens, can be removed with minimal stress and mortality. "Ristroph Screens" have water-filled lifting buckets which collect the impinged organisms and transport them to a fish return system. The buckets are designed such that they will hold approximately 2 inches of water once they have cleared the surface of the water during the normal rotation of the traveling screens. The fish bucket holds the fish in water until the screen rises to a point where the fish are spilled onto a bypass, trough, or other protected area (Mussalli, Taft, and Hoffman, 1978). Fish baskets are also a modification of a conventional traveling screen and may be used in conjunction with fish buckets. Fish baskets are separate framed screen panels that are attached to vertical traveling screens. An essential feature of modified traveling screens is continuous operation during periods where fish are being impinged. Conventional traveling screens typically operate on an intermittent basis. (EPRI, 2000 and 1989; Fritz, 1980). Removed fish are typically returned to the source water body by sluiceway or pipeline. ASCE 1982 provides guidance on the design and operation of fish return systems.

Technology Performance
Modified screens and fish handling and return systems have been used to minimize impingement mortality at a wide range of facilities nationwide. In recent years, some researchers, primarily *Fletcher 1996,* have evaluated the factors that effect the success of these systems and described how they can be optimized for specific applications. Fletcher cited the following as key design factors:

- Shaping fish buckets/baskets to minimize hydrodynamic turbulence within the bucket/basket
- Using smooth woven screen mesh to minimize fish descaling
- Using fish rails to keep fish from escaping the buckets/baskets
- Performing fish removal prior to high pressure wash for debris removal
- Optimizing the location of spray systems to provide gentler fish transfer to sloughs
- Ensuring proper sizing and design of return troughs, sluiceways, and pipes to minimize harm.

In 1993 and 1994, the Salem Generating Station specifically considered Fletcher's work in the modification of their fish handling system. In 1996, the facility subsequently reported an increase in juvenile weakfish impingement survival from 58 percent to 79 percent with an overall weakfish reduction in impingement losses of 51 percent. 1997 and 1998 test data for Units 1 and 2 showed: white perch had 93 to 98 percent survival, bay anchovy had 20 to 72 percent survival, Atlantic croaker had 58 to 98 percent survival, spot had 93 percent survival, herring had 78 to 82 percent survival, and weakfish had 18 to 88 percent survival.

Additional performance results for modified screens and fish return systems include:

- 1988 studies at the Diablo Canyon and Moss Landing Power Plants in California found that overall impingement mortality could be reduced by as much as 75 percent with modified traveling screens and fish return sluiceways.

- Impingement data collected during the 1970s from Dominion Power's Surry Station (Virginia) indicated a 93.8 percent survival rate of all fish impinged. Bay anchovies had the lowest survival 83 percent. The facility has modified Ristroph screens with low pressure wash and fish return systems.

- In 1986, the operator of the Indian Point Station (New York) redesigned fish troughs on the Unit 2 intake to enhance survival. Impingement injuries and mortality were reduced from 53 to 9 percent for striped bass, 64 to14 percent for white perch, 80 to 17 percent for Atlantic tomcod, and 47 to 7 percent for pumpkinseed.

- 1996 data for Brayton Point Units 1-3 showed 62 percent impingement survival for continuously rotated conventional traveling screens with a fish return system.

- In the 1970s, a fish pump and return system was added to the traveling screens at the Monroe Power Plant in Michigan. Initial studies showed 70 to 80 percent survival for adult and young-of-year gizzard shad and yellow perch.

- At the Hanford Generating Plant on the Columbia River, late 1970s studies of modified screens with a fish return system showed 79 to 95 percent latent survival of impinged Chinook salmon fry.

- The Kintigh Generating Station in New Jersey has modified traveling screens with low pressure sprays and a fish return system. After enhancements to the system in 1989, survivals of generally greater than 80 percent have been observed for rainbow smelt, rock bass, spottail shiner, white bass, white perch, and yellow perch. Gizzard shad survivals have been 54 to 65 percent and alewife survivals have been 15 to 44 percent.

- The Calvert Cliffs Station in Maryland has 12 traveling screens that are rotated for 10 minutes every hour or when pressure sensors show pressure differences. The screens were originally conventional and are now dual flow. A high pressure wash and return system leads back to the Chesapeake Bay. Twenty-one years of impingement monitoring show total fish survival of 73 percent.

- At the Arthur Kill Station in New York, 2 of 8 screens are modified Ristroph type; the remaining six screens are conventional type. The modified screens have fish collection troughs, low pressure spray washes, fish flap seals, and separate fish collection sluices. 24-hour survival for the unmodified screens averages 15 percent, while the two modified screens have 79 and 92 percent average survival rates, respectively.

In summary, performance data for modified screens and fish returns are somewhat variable due to site conditions and variations in unit design and operation. However, the above results generally show that at least 70-80 percent reductions in impingement can be achieved over conventional traveling screens.

5.5.2 Cylindrical Wedgewire Screens

Technology Overview

Wedgewire screens are designed to reduce entrainment by physical exclusion and by exploiting hydrodynamics. Physical exclusion occurs when the mesh size of the screen is smaller than the organisms susceptible to entrainment. The screen mesh ranges from 0.5 to 10 mm. Hydrodynamic exclusion results from maintenance of a low through-slot velocity, which, because of the screen's cylindrical configuration, is quickly dissipated, thereby allowing organisms to escape the flow field (Weisberd et al, 1984). Adequate countercurrent flow is needed to transport organisms away from the screens. The name of these screens arises from the triangular or "wedge" cross section of the wire that makes up the screen. The screen is composed of wedge-wire loops welded at the apex of their triangular cross section to supporting axial rods presenting the base of the cross section to the incoming flow (Pagano et al, 1977).

Wedgewire screens may also be referred to as profile screens or Johnson screens.

Technology Performance

Wide mesh wedgewire screens have been used at 2 Ahigh flow@ power plants: J.H. Campbell Unit 3 (770 MW) and Eddystone Units 1 and 2 (approximately 700 MW combined). At Campbell, Unit 3 withdraws 400 million gallons per day (mgd) of water from Lake Michigan approximately 1,000 feet from shore. Unit 3 impingement of gizzard shad, smelt, yellow perch, alewife, and shiner species is significantly lower than Units 1 and 2 that do not have wedgewire screens. Entrainment is not a major concern at the site because of the deep water, offshore location of the Unit 3 intake. Eddystone Units 1 and 2 withdraw over 500 mgd of water from the Delaware River. The cooling water intakes for these units were retrofitted with wedgewire screens because over 3 million fish were reportedly impinged over a 20-month period. The wedgewire screens have generally eliminated impingement at Eddystone. Both the Campbell and Eddystone wedgewire screens require periodic cleaning but have operated with minimal operational difficulties.

Other plants with lower intake flows have installed wedgewire screens but there are limited biological performance data for these facilities. The Logan Generating Station in New Jersey withdraws 19 MGD from the Delaware River through a 1-mm wedgewire screen. Entrainment data show 90 percent less entrainment of larvae and eggs then conventional screens. No impingement data are available. Unit 1 at the Cope Generating Station in South Carolina is a closed cycle unit that withdraws about 6 MGD through a 2-mm wedgewire screen, however, no biological data are available. Performance data are also unavailable for the Jeffrey Energy Center, which withdraws about 56 MGD through a 10-mm screen from the Kansas River in Kansas. The system at the Jeffrey Plant has specifically operated since 1982 with no operational difficulties. Finally, the American Electric Power Corporation has installed wedgewire screens at the Big Sandy (2 MGD) and Mountaineer (22 MGD) Power Plants, which withdraw water from the Big Sandy and Ohio Rivers, respectively. Again, no biological test data are available for these facilities.

Wedgewire screens have been considered/tested for several other large facilities. In situ testing of 1 and 2-mm wedgewire screens was performed in the St. John River for the Seminole Generating Station Units 1 and 2 in Florida in the late 1970s. This testing showed virtually no impingement and 99 and 62 percent reductions in larvae entrainment for the 1-mm and 2-mm screens, respectively, over conventional screen (9.5 mm) systems. The State of Maryland conducted testing in 1982 and 1983 of 1, 2, and 3-mm wedgewire screens at the Chalk Point Generating Station, which withdraws water from the Patuxent River in Maryland. The 1-mm wedgewire screens were found to reduce entrainment by 80 percent. No impingement data were available. Some biofouling and clogging was observed during the tests. In the late 1970s, Delmarva Power and Light conducted laboratory testing of fine mesh wedgewire screens for the proposed 1540 MW Summit Power Plant. This testing showed that entrainment of fish eggs (including striped bass) could effectively be prevented with slot widths of l mm or less, while impingement mortality was expected to be less than 5 percent. Actual field testing in the brackish water of the proposed intake canal required the screens to be removed and cleaned as often as once every three weeks.

As shown by the above data, it is clear that wedgewire screen technology has not been widely applied in the steam electric industry to date. It has only been installed at a handful of power plant facilities nationwide. However, the limited data for Eddystone and Campbell indicate that wide mesh screens, in particular, can be used to minimize impingement. Successful use of the wedgewire screens at Eddystone as well as Logan in the Delaware River (high debris flows) suggests that the screens can have widespread applicability. This is especially true for facilities that have relatively low intake flow requirements (i.e., closed-cycle systems). Yet, the lack of more representative full-scale plant data makes it impossible to conclusively say that wedgewire screens can be used in all environmental conditions. There are no full-scale data specifically for marine environments where biofouling and clogging are significant concerns. In addition, it is important to recognize that there must sufficient crosscurrent in the waterbody to carry organisms away from the screens.

Fine mesh wedgewire screens (0.5 - 1 mm) also have the *potential* for use to control both I&E. The Agency is not aware of any fine-mesh wedgewire screens that have been installed at power plants with high intake flows (>100 MGD). However, they have been used at some power plants with lower intake flow requirements (25-50 MGD) that would be comparable to a large power plant with a closed-cycle cooling system. With the exception of Logan, the Agency has not identified any full-scale performance data for these systems. They would be even more susceptible to clogging than wide-mesh wedgewire screens (especially in marine environments). It is unclear whether this simply would necessitate more intensive maintenance or preclude their day-to-day use at many sites. Their successful application at Logan and Cope and the historic test data from Florida, Maryland, and Delaware at least suggests promise for addressing both fish impingement and entrainment of eggs and larvae. However, based on the fine-mesh screen experience at Big Bend Units 3 and 4, it is clear that frequent maintenance would be required. Therefore, relatively deep water sufficient to accommodate the large number of screen units, would preferably be close to shore (i.e., be readily accessible). Manual cleaning needs might be reduced or eliminated through use of an automated flushing (e.g., microburst) system.

5.5.3 Fine-Mesh Screens

Technology Overview
Fine-mesh screens are typically mounted on conventional traveling screens and are used to exclude eggs, larvae, and juvenile forms of fish from intakes. These screens rely on gentle impingement of organisms on the screen surface. Successful use of fine-mesh screens is contingent on the application of satisfactory handling and return systems to allow the safe return of impinged organisms to the aquatic environment (Pagano et al, 1977; Sharma, 1978). Fine mesh screens generally include those with mesh sizes of 5 mm or less.

Technology Performance
Similar to fine-mesh wedgewire screens, fine-mesh traveling screens with fish return systems show promise for both I&E control. However, they have not been installed, maintained, and optimized at many facilities. The most significant example of long-term fine-mesh screen use has been at the Big Bend Power Plant in the Tampa Bay area. The facility has an intake canal with 0.5-mm mesh Ristroph screens that are used seasonally on the intakes for Units 3 and 4. During the mid-1980s when the screens were initially installed, their efficiency in reducing I&E mortality was highly variable. The operator, Florida Power & Light (FPL) evaluated different approach velocities and screen rotational speeds. In addition, FPL recognized that frequent maintenance (manual cleaning) was necessary to avoid biofouling. By 1988, system performance had improved greatly. The system's efficiency in screening fish eggs (primarily drums and bay anchovy) exceeded 95 percent with 80 percent latent survival for drum and 93 percent for bay anchovy. For larvae (primarily drums, bay anchovies, blennies, and gobies), screening efficiency was 86 percent with 65 percent latent survival for drum and 66 percent for bay anchovy. (Note that latent survival in control samples was also approximately 60 percent). Although more recent data are generally not available, the screens continue to operate successfully at Big Bend in an estuarine environment with proper maintenance. While egg and larvae entrainment performance are not available, fine mesh (0.5 mm) Passavant screens (single entry/double exit) have been used successfully in a marine environment at the Barney Davis Station in Corpus Christi, Texas. Impingement data for this facility show overall 86 percent initial survivals for bay anchovy, menhaden, Atlantic croaker, killfish, spot, silverside, and shrimp.

Additional full-scale performance data for fine mesh screens at large power stations are generally not available. However, some data are available from limited use/study at several sites and from laboratory and pilot-scale tests. Seasonal use of fine mesh on two of four screens at the Brunswick Power Plant in North Carolina has shown 84 percent reduction in entrainment compared to the conventional screen systems. Similar results were obtained during pilot testing of 1-mm screens at the Chalk Point Generating Station in Maryland, and, at the Kintigh Generating Station in New Jersey, pilot testing indicated 1-mm screens provided 2 to 35 times reductions in entrainment over conventional 9.5-mm screens. Finally, Tennessee Valley Authority (TVA) pilot-scale studies performed in the 1970s showed reductions in striped bass larvae entrainment up to 99 percent using a 0.5-mm screen and 75 and 70 percent for 0.97-mm and 1.3-mm screens, respectively. A full-scale test by TVA at the John Sevier Plant showed less than half as many larvae entrained with a 0.5-mm screen than 1.0 and 2.0-mm screens combined.

Despite the lack of full-scale data, the experiences at Big Bend (as well as Brunswick) show that fine-mesh screens can reduce entrainment by 80 percent or more. This is contingent on optimized operation and intensive maintenance to avoid biofouling and clogging, especially in marine environments. It also may be appropriate to have removable fine mesh that is only used during periods of egg and larval abundance, thereby reduced the potential for clogging and wear and tear on the systems.

5.5.4 Fish Net Barriers

Technology Overview
Fish net barriers are wide-mesh nets, which are placed in front of the entrance to intake structures. The size of the mesh needed is a function of the species that are present at a particular site and vary from 4 mm to 32 mm (EPRI, 2000). The mesh must be sized to prevent fish from passing through the net causing them to become gilled. Relatively low velocities are maintained because the area through which the water can flow is usually large. Fish net barriers have been used at numerous facilities and lend themselves to intakes where the seasonal migration of fish and other organisms require fish diversion facilities for only specific times of the year.

Technology Performance
Barrier nets can provide a high degree of impingement reduction. Because of typically wide openings, they do not reduce entrainment of eggs and larvae. A number of barrier net systems have been used/studied at large power plants. Specific examples include:

- At the J.P. Pulliam Station (Wisconsin), the operator installed 100 and 260-foot barrier nets across the two intake canals, which withdraw water from the Fox River prior to flowing into Lake Michigan. The barrier nets have been shown to reduce impingement by 90 percent over conventional traveling screens without the barrier nets. The facility has the barrier nets in place when the water temperature is greater than 37ºF or April 1 through December 1.

- The Ludington Storage Plant (Michigan) provides water from Lake Michigan to a number of power plant facilities. The plant has a 2.5-mile long barrier net that has successfully reduced I&E. The overall net effectiveness for target species (five salmonids, yellow perch, rainbow smelt, alewife, and chub) has been over 80 percent since 1991 and 96 percent since 1995. The net is deployed from mid-April to mid-October, with storms and icing preventing use during the remainder of the year.

- At the Chalk Point Generating Station (Maryland), a barrier net system has been used since 1981, primarily to reduce crab impingement from the Patuxent River. Eventually, the system was redesigned to include two nets: a 1,200-foot wide outer net prevents debris flows and a 1,000-foot inner net prevents organism flow into the intake. Crab impingement has been reduced by 84 percent. The Agency did not obtain specific fish impingement performance data for other species, but the nets have reduced overall impingement liability for all species from over $2 million to less than $140,000. Net panels are changed twice per week to control biofouling and clogging.

- The Bowline Point Station (New York) has an approximately 150-foot barrier net in a v-shape around the intake structure. Testing during 1976 through 1985 showed that the net effectively reduces white perch and striped bass impingement by 91 percent. Based on tests of a "fine" mesh net (3.0 mm) in 1993 and 1994, researchers found that it could be used to generally prevent entrainment. Unfortunately, species' abundances were too low to determine the specific biological effectiveness.

- In 1980, a barrier net was installed at the J.R. Whiting Plant (Michigan) to protect Maumee Bay. Prior to net installation, 17,378,518 fish were impinged on conventional traveling screens. With the net, sampling in 1983 and 84 showed 421,978 fish impinged (97 percent effective), sampling in 1987 showed 82,872 fish impinged (99 percent effective), and sampling in 1991 showed 316,575 fish impinged (98 percent effective).

Barrier nets have clearly proven effective for controlling *impingement* (i.e., 80+ percent reductions over conventional screens without nets) in areas with limited debris flows. Experience has shown that high debris flows can cause significant damage to net systems. Biofouling concerns can also be a concern but this can be addressed through frequent maintenance. Barrier nets are also often only used seasonally, where the source waterbody is subject to freezing. Fine-mesh barrier nets show some promise for entrainment control but would likely require even more intensive maintenance. In some cases, the use of barrier nets may be further limited by the physical constraints and other uses of the waterbody.

5.5.5 Aquatic Microfiltration Barriers

Technology Overview
Aquatic microfiltration barrier systems are barriers that employ a filter fabric designed to allow for passage of water into a cooling water intake structure, but exclude aquatic organisms. These systems are designed to be placed some distance from the cooling water intake structure within the source waterbody and act as a filter for the water that enters into the cooling water system. These systems may be floating, flexible, or fixed. Since these systems generally have such a large surface area, the velocities that are maintained at the face of the permeable curtain are very low. One company, Gunderboom, Inc., has a patented full-water-depth filter curtain comprised of polyethylene or polypropylene fabric that is suspended by flotation billets at the surface of the water and anchored to the substrate below. The curtain fabric is manufactured as a matting of minute unwoven fibers with an apparent opening size of 20 microns. Gunderboom systems also employ an automated "air burst" system to periodically shake the material and pass air bubbles through the curtain system to clean it of sediment buildup and release any other material back into the water column.

Technology Performance
The Agency has determined that microfiltration barriers, including the Gunderboom, show significant *promise* for minimizing entrainment. However, the Agency acknowledges that Gunderboom technology is currently "experimental in nature." At this juncture, the only power plant where the Gunderboom has been used at a "full-scale" level is the Lovett Generating Station along the Hudson River in New York, where pilot testing began in the mid-1990s. Initial testing at this facility showed significant potential for reducing entrainment. Entrainment reductions up to 82 percent were observed for eggs and larvae and these levels have been maintained for extended month-to-month periods during 1999 through 2001. At Lovett, there have been some operational difficulties that have affected long-term performance. These difficulties, including tearing, overtopping, and plugging/clogging, have been addressed, to a large extent, through subsequent design modifications. Gunderboom, Inc. specifically has designed and installed a "microburst" cleaning system to remove particulates. Each of the challenges encountered

at Lovett could be significantly greater concern at marine sites with higher wave action and debris flows. Gunderboom systems have been otherwise deployed in marine conditions to prevent migration of particulates and bacteria. They have been used successfully in areas with waves up to five feet. The Gunderboom system is currently being tested for potential use at the Contra Costa Plant along the San Joaquin River in Northern California.

An additional question related to the utility of the Gunderboom and other microfiltration systems is sizing and the physical limitations and other uses of the source waterbody. With a 20-micron mesh, 100,000 and 200,000 gallon per minute intakes would require filter systems 500 and 1,000 feet long (assuming 20 foot depth). In some locations, this may preclude its successful deployment due space limitations and/or conflicts with other waterbody uses.

5.5.6 Louver Systems

Technology Overview
Louver systems consist of series of vertical panels placed at 90 degree angles to the direction of water flow (Hadderingh, 1979). The placement of the louver panels provides both changes in the flow direction and velocity, which fish tend to avoid. The angles and flow velocities of the louvers create a current parallel to the face of the louvers which carries fish away from the intake and into a fish bypass system for return to the source waterbody.

Technology Performance
Louver systems can reduce impingement losses based on fishes' abilities to recognize and swim away from the barriers. Their performance, i.e., guidance efficiency, is highly dependant on the length and swimming abilities of the resident species. Since eggs and early stages of larvae cannot "swim away," they are not affected by the diversions and there is no associated reduction in entrainment.

While louver systems have been tested at a number of laboratory and pilot-scale facilities, they have not been used at many full-scale facilities. The only large power plant facility where a louver system has been used is San Onofre Units 2 and 3 (2,200 MW combined) in Southern California. The operator initially tested both louver and wide mesh, angled traveling screens during the 1970s. Louvers were subsequently selected for full-scale use at the intakes for the two units. In 1984, a total of 196,978 fish entered the louver system with 188,583 returned to the waterbody and 8,395 impinged. In 1985, 407,755 entered the louver system with 306,200 returned and 101,555 impinged. Therefore, the guidance efficiencies in 1984 and 1985 were 96 and 75 percent, respectively. However, 96-hour survival rates for some species, i.e., anchovies and croakers, were 50 percent or less. The facility also has encountered some difficulties with predator species congregating in the vicinity of the outlet from the fish return system. Louvers were originally considered for use at San Onofre because of 1970s pilot testing at the Redondo Beach Station in California where maximum guidance efficiencies of 96-100 percent were observed.

EPRI 2000 indicated that louver systems could provide 80-95 percent diversion efficiency for a wide variety of species under a range of site conditions. This is generally consistent with the American Society of Civil Engineers' (ASCE) findings from the late 1970s which showed almost all systems had diversion efficiencies exceeding 60 percent with many more than 90 percent. As indicated above, much of the EPRI and ASCE data come from pilot/laboratory tests and hydroelectric facilities where louver use has been more widespread than at steam electric facilities. Louvers were specifically tested by the Northeast Utilities Service Company in the Holyoke Canal on the Connecticut River for juvenile clupeids (American shad and blueback herring). Overall guidance efficiency was found to be 75-90 percent. In the 1970s, Alden Research Laboratory observed similar results for Hudson River species (including alewife and smelt). At the Tracy Fish Collection Facility located along the San Joaquin River in California, testing was performed from 1993 and 1995 to determine the guidance efficiency of a system with primary and secondary louvers. The results for green and white sturgeon, American shad, splittail, white catfish, delta smelt, Chinook salmon, and striped bass showed mean diversion efficiencies ranging from 63 (splittail) to 89 percent (white catfish). Also in the 1990s, an experimental louver bypass system was tested at the USGS' Conte Anadromous Fish Research Center in Massachusetts. This testing showed guidance efficiencies for Connecticut River species of 97 percent for a "wide array" of louvers and 100 percent for a "narrow array." Finally, at the T.W. Sullivan Hydroelectric Plant along the Williamette River in Oregon, the louver system is estimated to be 92 percent effective in diverting spring Chinook, 82 percent for all Chinook, and 85 percent for steelhead. The system has been optimized to reduce fish injuries such that the average injury occurrence is only 0.44 percent.

Overall, the above data indicate that louvers can be highly effective (70+ percent) in diverting fish from potential impingement. Latent mortality is a concern, especially where fragile species are present. Similar to modified screens with fish return systems, operators must optimize louver system design to minimize fish injury and mortality

5.5.7 Angled and Modular Inclined Screens

Technology Overview

Angled traveling screens use standard through-flow traveling screens where the screens are set at an angle to the incoming flow. Angling the screens improves the fish protection effectiveness since the fish tend to avoid the screen face and move toward the end of the screen line, assisted by a component of the inflow velocity. A fish bypass facility with independently induced flow must be provided (Richards 1977). Modular inclined screens (MISs) are a specific variation on angled traveling screens, where each module in the intake consists of trash racks, dewatering stop logs, an inclined screen set at a 10 to 20 degree angle to the flow, and a fish bypass (EPRI 1999).

Technology Performance

Angled traveling screens with fish bypass and return systems work similarly to louver systems. They also only provide potential reductions in impingement mortality since eggs and larvae will not generally detect the factors that influence diversion. Similar to louver systems, they were tested extensively at the laboratory and pilot scales, especially during the 1970s and early 1980s. Testing of angled screens (45 degrees to the flow) in the 1970s at San Onofre showed poor to good guidance (0-70 percent) for northern anchovies with moderate to good guidance (60-90 percent) for other species. Latent survival varied by species with fragile species only having 25 percent survival, while hardy species showed greater than 65 percent survival. The intake for Unit 6 at the Oswego Steam plant along Lake Ontario in New York has traveling screens angled to 25 degrees. Testing during 1981 through 1984 showed a combined diversion efficiency of 78 percent for all species; ranging from 53 percent for mottled sculpin to 95 percent for gizzard shad. Latent survival testing results ranged from 22 percent for alewife to nearly 94 percent for mottled sculpin.

Additional testing of angled traveling screens was performed in the late 1970s and early 1980s for power plants on Lake Ontario and along the Hudson River. This testing showed that a screen angled at 25 degrees was 100 percent effective in diverting 1 to 6 inch long Lake Ontario fish. Similar results were observed for Hudson River species (striped bass, white perch, and Atlantic tomcod). One-week mortality tests for these species showed 96 percent survival. Angled traveling screens with a fish return system have been used on the intake from Brayton Point Unit 4. Studies from 1984 through 1986 that evaluated the angled screens showed a diversion efficiency of 76 percent with latent survival of 63 percent. Much higher results were observed excluding bay anchovy. Finally, 1981 full-scale studies of an angled screen system at the Danskammer Station along the Hudson River in New York showed diversion efficiencies of 95 to 100 percent with a mean of 99 percent. Diversion efficiency combined with latent survival yielded a total effectiveness of 84 percent. Species included bay anchovy, blueback herring, white perch, spottail shiner, alewife, Atlantic tomcod, pumpkinseed, and American shad.

During the late 1970s and early 1980s, Alden Research Laboratories (Alden) conducted a range of tests on a variety of angled screen designs. Alden specifically performed screen diversion tests for three northeastern utilities. In initial studies for Niagara Mohawk, diversion efficiencies were found to be nearly 100 percent for alewife and smolt. Follow-up tests for Niagara Mohawk confirmed 100 percent diversion efficiency for alewife with mortalities only four percent higher than control samples. Subsequent tests by Alden for Consolidated Edison, Inc. using striped bass, white perch, and tomcod also found nearly 100 percent diversion efficiency with a 25 degree angled screen. The one-week mean mortality was only 3 percent.

Alden further performed tests during 1978-1990 to determine the effectiveness of fine-mesh, angled screens. In 1978, tests were performed with striped bass larvae using both 1.5 and 2.5-mm mesh and different screen materials and approach velocity. Diversion efficiency was found to clearly be a function of larvae length. Synthetic materials were also found to be more effective than metal screens. Subsequent testing using only synthetic materials found that 1.0 mm screens can provide post larvae diversion efficiencies of greater than 80 percent. However, the tests found that latent mortality for diverted species was also high.

Finally, EPRI tested modular inclined screens (MIS) in a laboratory in the early 1990s. Most fish had diversion efficiencies of 47 to 88 percent. Diversion efficiencies of greater than 98 percent were observed for channel catfish, golden shiner, brown trout, Coho and Chinook salmon, trout fry and juveniles, and Atlantic salmon smolts. Lower diversion efficiency and higher mortality were found for American shad and blueback herring but comparable to control mortalities. Based on the laboratory data, a MIS system was pilot-tested at a Niagara Mohawk hydroelectric facility on the Hudson River. This testing showed diversion efficiencies and survival rates approaching 100 percent for golden shiners and rainbow trout. High diversion and survival was also observed for largemouth and smallmouth bass, yellow perch, and bluegill. Lower diversion efficiency and survival was found for herring.

Similar to louvers, angled screens show potential to minimize impingement by greater than 80 to 90 percent. More widespread full-scale use is necessary to determine optimal design specifications and verify that they can be used on a widespread basis.

5.5.8 Velocity Caps

Technology Description
A velocity cap is a device that is placed over vertical inlets at offshore intakes. This cover converts vertical flow into horizontal flow at the entrance into the intake. The device works on the premise that fish will avoid rapid changes in horizontal flow. In general, velocity caps have been installed at many offshore intakes and have been successful in minimizing impingement.

Technology Performance
Velocity caps can reduce fish drawn into intakes based on the concept that they tend to avoid horizontal flow. They do not provide reductions in entrainment of eggs and larvae, which cannot distinguish flow characteristics. As noted in *ASCE 1981*, velocity caps are often used in conjunction with other fish protection devices. Therefore, there are somewhat limited data on their performance when used alone. Facilities that have velocity caps include:

- Oswego Steam Units 5 and 6 in New York (combined with angled screens on Unit 6).
- San Onofre Units 2 and 3 in California (combined with louver system).
- El Segundo Station in California
- Huntington Beach Station in California
- Edgewater Power Plant Unit 5 in Wisconsin (combined with 9.5 mm wedgewire screen)

- Nanticoke Power Plant in Ontario, Canada
- Nine Mile Point in New York
- Redondo Beach Station in California
- Kintigh Generation Station in New York (combined with modified traveling screens)
- Seabrook Power Plant in New Hampshire
- St. Lucie Power Plant in Florida.

At the Huntington Beach and Segundo Stations in California, velocity caps have been found to provide 80 to 90 percent reductions in fish entrapment. At Seabrook, the velocity cap on the offshore intake has minimized the number of pelagic fish entrained except for pollock. Finally, two facilities in England have velocity caps on one of each's two intakes. At the Sizewell Power Station, intake B has a velocity cap, which reduces impingement about 50 percent compared to intake A. Similarly, at the Dungeness Power Station, intake B has a velocity cap, which reduces impingement about 62 percent compared to intake A.

5.5.9 Porous Dikes and Leaky Dams

Technology Overview
Porous dikes, also known as leaky dams or dikes, are filters resembling a breakwater surrounding a cooling water intake. The core of the dike consists of cobble or gravel that permits free passage of water. The dike acts both as a physical and behavioral barrier to aquatic organisms. Tests conducted to date have indicated that the technology is effective in excluding juvenile and adult fish. The major problems associated with porous dikes come from clogging by debris and silt, ice build-up, and by colonization of fish and plant life.

Technology Performance
Porous dike technologies work on the premise that aquatic organisms will not pass through physical barriers in front of an intake. They also operate with low approach velocity further increasing the potential for avoidance. However, they will not prevent entrainment by non-motile larvae and eggs. Much of the research on porous dikes and leaky dams was performed in the 1970s. This work was generally performed in a laboratory or on a pilot level, i.e., the Agency is not aware of any full-scale porous dike or leaky dam systems currently used at power plants in the U.S. Examples of early study results include:

- Studies of porous dike and leaky dam systems by Wisconsin Electric Power at Lake Michigan plants showed generally lower I&E rates than other nearby onshore intakes.

- Laboratory work by Ketschke showed that porous dikes could be a physical barrier to juvenile and adult fish and a physical or behavioral barrier to some larvae. All larvae except winter flounder showed some avoidance of the rock dike.

- Testing at the Brayton Point Power Plant showed that densities of bay anchovy larvae downstream of the dam were reduced by 94 to 99 percent. For winter flounder, downstream densities were lower by 23 to 87 percent. Entrainment avoidance for juvenile and adult finfish was observed to be nearly 100 percent.

As indicated in the above examples, porous dikes and leaky dams show *potential* for use in limiting passage of adult and juvenile fish, and, to some degree, motile larvae. However, the lack of more recent, full-scale performance data makes it difficult to predict their widespread applicability and specific levels of performance.

5.5.10 Behavioral Systems

Technology Overview

Behavioral devices are designed to enhance fish avoidance of intake structures and/or promote attraction to fish diversion or bypass systems. Specific technologies that have been considered include:

- Light Barriers: Light barriers consist of controlled application of strobe lights or mercury vapor lights to lure fish away from the cooling water intake structure or deflect natural migration patterns. This technology is based on research that shows that some fish avoid light, however it is also known that some species are attracted by light.

- Sound Barriers: Sound barriers are non-contact barriers that rely on mechanical or electronic equipment that generates various sound patterns to elicit avoidance responses in fish. Acoustic barriers are used to deter fish from entering cooling water intake structures. The most widely used acoustical barrier is a pneumatic air gun or "popper."

- Air bubble barriers: Air bubble barriers consist of an air header with jets arranged to provide a continuous curtain of air bubbles over a cross section area. The general purpose of air bubble barriers is to repel fish that may attempt to approach the face of a CWIS.

Technology Performance

Many studies have been conducted and reports prepared on the application of behavioral devices to control I&E, see EPRI 2000. For the most part, these studies have either been inconclusive or shown no tangible reduction in impingement or entrainment. As a result, the full-scale application of behavioral devices has been limited. Where data are available, performance appears to be highly dependent on the types and sizes of species and environmental conditions. One exception may be the use of sound systems to divert alewife. In tests at the Pickering Station in Ontario, poppers were found to be effective in reducing alewife I&E by 73 percent in 1985 and 76 percent in 1986. No benefits were observed for rainbow smelt and gizzard shad. 1993 testing of sound systems at the James A. Fitzpatrick Station in New York showed similar results, i.e., 85 percent reductions in alewife I&E through use of a high frequency sound system. At the Arthur Kill Station, pilot- and full-scale, high frequency sound tests showed comparable results for alewife to Fitzpatrick and Pickering. Impingement of gizzard shad was also three times less than without the system. No deterrence was observed for American shad or bay anchovy using the full-scale system. In contrast, sound provided little or no deterrence for any species at the Roseton Station in New York. Overall, the Agency expects that behavioral systems would be used in conjunction with other technologies to reduce I&E and perhaps targeted towards an individual species (e.g., alewife).

5.5.11 Other Technology Alternatives

The proposed new facility rule does not specify the individual technology (or group of technologies) to be used to minimize I&E to same levels as those achieved with the Track I requirements based, in part, on wet, closed-cycle cooling system. In addition to the above technologies, there are other approaches that may be used on a site-by-site basis. For example:

- Use of variable speed pumps can provide for greater system efficiency and reduced flow requirements (and associated entrainment) by 10-30 percent. EPA Region 4 estimated that use of variable speed pumps at the Canaveral and Indian River Stations in the Indian River estuary would reduce entrainment by 20 percent. Presumably, such pumps would have to be used in conjunction with other technologies. EPA conservatively estimated that facilities complying with the requirements final rule would install variable speed pumps regardless of the baseline cooling system projected for the facility. See Chapter 2 of this document for more information.

- Perforated pipes draw water through perforations or elongated slots in a cylindrical section placed in the waterway. Early designs of this technology were not efficient, velocity distribution was poor, and they were specifically designed to screen out detritus (i.e., not used for fish protection) (ASCE, 1982). Inner sleeves were subsequently added to perforated pipes to equalize the velocities entering the outer perforations. These systems have historically been used at locations requiring small amounts of make-up water. Experience at steam electric plants is very limited (Sharma, 1978). Perforated pipes are used on the intakes for the Amos and Mountaineer Stations along the Ohio River. However, I&E performance data for these facilities are unavailable. In general, EPA projects that perforated pipe system performance should be comparable to wide-mesh wedgewire screens (e.g., at Eddystone Units 1 and 2 and Campbell Unit 3).

- At the Pittsburg Plant in California, impingement survival was studied for continuously rotated screens versus intermittent rotation. Ninety-six-hour survival for young-of-year white perch was 19 to 32 percent for intermittent screen rotation versus 26 to 56 percent for continuous rotation. Striped bass latent survival increased from 26 to 62 percent when continuous rotation was used. Similar studies were also performed at Moss Landing Units 6 and 7, where no increased survival was observed for hardy and very fragile species, however, there was a substantial increase in impingement survival for surfperch and rockfish.

- Facilities may be able to use recycled cooling water to reduce intake flow needs. The Brayton Point Station has a “piggyback” system where the entire intake requirements for Unit 4 can be met by recycled cooling water from Units 1 through 3. The system has been used sporadically since 1993 and reduces the make-up water needs (and thereby entrainment) by 29 percent.

5.6 INTAKE LOCATION

Beyond design alternatives for CWISs, an operator may able to locate CWISs offshore or otherwise in areas that minimize I&E (compared to conventional onshore locations). It is well known that there are certain areas within every waterbody with increased biological productivity, and therefore where the potential for I&E of organisms is higher.

In large lakes and reservoirs, the littoral zone (i.e., shorezone areas where light penetrates to the bottom) of lakes/reservoirs serves as the principal spawning and nursery area for most species of freshwater fish and is considered one of the most productive areas of the waterbody. Fish of this zone typically follow a spawning strategy wherein eggs are deposited in prepared nests, on the bottom, and/or are attached to submerged substrates where they incubate and hatch. As the larvae mature, some species disperse to the open water regions, whereas many others complete their life cycle in the littoral zone. Clearly, the impact potential for intakes located in the littoral zone of lakes and reservoirs is high. The profundal zone of lakes/reservoirs is the deeper, colder area of the waterbody. Rooted plants are absent because of insufficient light, and for the same reason, primary productivity is minimal. A well-oxygenated profundal zone can support benthic macroinvertebrates and cold-water fish; however, most of the fish species seek shallower areas to spawn (either in littoral areas or in adjacent streams/rivers). Use of the deepest open water region of a lake and reservoir (e.g., within the profundal zone) as a source of cooling water typically offers lower I&E impact potential (than use of littoral zone waters).

As with lakes/reservoirs, rivers are managed for numerous benefits, which include sustainable and robust fisheries.

Unlike lakes and reservoirs, the hydrodynamics of rivers typically result in a mixed water column and (overall) unidirectional flow. There are many similarities in the reproductive strategies of shoreline fish populations in rivers and the reproductive strategies of fish within the littoral zone of lakes/reservoirs. Planktonic movement of eggs, larvae, post larvae, and early juvenile organisms along the shorezone are generally limited to relatively short distances. As a result, the shorezone placement of CWISs in rivers may potentially impact local spawning populations of fish. The impact potential associated with entrainment may be diminished if the main source of cooling water is recruited from near the bottom strata of the open water channel region of the river. With such an intake configuration, entrainment of shorezone eggs and larvae, as well as the near surface drift community of ichthyoplankton, is minimized. Impacts could also be minimized by the control of the timing and frequency of withdrawals from rivers. In temperate regions, the number of entrainable/impingeable organisms of rivers increases during spring and summer (when many riverine fishes reproduce). The number of eggs and larvae peak at that time, whereas entrainment potential during the remainder of the year may be minimal.

In estuaries, species distribution and abundance are determined by a number of physical and chemical attributes including: geographic location, estuary origin (or type), salinity, temperature, oxygen, circulation (currents), and substrate. These factors, in conjunction with the degree of vertical and horizontal stratification (mixing) in the estuary, help dictate the spatial distribution and movement of estuarine organisms. However, with local knowledge of these characteristics, the entrainment effects of a CWIS could be minimized by adjusting the intake design to areas (e.g., depths) least likely to impact upon concentrated numbers and species of organisms.

In oceans, nearshore coastal waters are generally the most biologically productive areas. The euphotic zone (zone of photosynthetic available light) typically does not extend beyond the first 100 meters (328 feet) of depth. Therefore, inshore waters are generally more productive due to photosynthetic activity, and due to the input from estuaries and runoff of nutrients from land.

There are limited published data *quantifying* the locational differences in I&E rates at individual power plants. However, some information is available for selected sites. For example,

- For the St. Lucie plant in Florida, EPA Region 4 permitted the use of a once through cooling system instead of closed-cycle cooling by locating the outfall 1,200 offshore (with a velocity cap) in the Atlantic Ocean. This avoided impacts on the biologically sensitive Indian River estuary.

- In *Entrainment of Fish Larvae and Eggs on the Great Lakes, with Special Reference to the D.C. Cook Nuclear Plant, Southeastern Lake Michigan* (1976), researchers noted that larval abundance is greatest within about the 12.2-m (40 ft) contour to shore in Lake Michigan and that the abundance of larvae tends to decrease as one proceeds deeper and farther offshore. This led to the suggestion of locating CWISs in deep waters.

- During biological studies near the Fort Calhoun Power Station along the Missouri River, results of transect studies indicated significantly higher fish larvae densities along the cutting bank of the river, adjacent to the Station’s intake structure. Densities were generally were lowest in the middle of the channel.

5.7 SUMMARY

Tables 5-1 and 5-2 summarize I&E performance data for selected, existing facilities. The Agency recognizes that these data are somewhat variable, in part depending on site-specific conditions. This is also because there generally have not been uniform performance standards for specific technologies. However, during the past 30 years, significant experience has been gained in optimizing the design and maintenance of CWIS technologies under various site and environmental conditions. Through this experience and the performance requirements under Track II of the proposed new facility rule, the Agency is confident that technology applicability and performance will continue to be improved

The Agency has concluded that the data indicate that several technologies, i.e., wide-mesh wedgewire screens and barrier systems, will generally minimize impingement to levels comparable to wet, closed cycle cooling systems. Other technologies, such as modified traveling screens with fish handling and return systems, and fish diversion systems, are likely to be viable at some sites (especially those with hardy species present). In addition, these technologies may be used in groups, e.g., barrier nets and modified screens, depending on site-specific conditions.

Demonstrating that alternative design technologies can achieve comparable entrainment performance to closed-cycle systems is more problematic largely because there are relatively few fully successful examples of full-scale systems being deployed and tested. However, the Agency has determined that fine-mesh traveling screens with fish return systems, fine-mesh wedgewire screens and microfiltration barriers (e.g., gunderbooms) are all promising technologies that could provide a level of protection reasonably consistent with the I&E protection afforded by wet, closed-cycle cooling. In addition, the Agency is also confident that on a site-by-site basis, many facilities will be able to further minimize entrainment (and impingement) by optimizing the location and timing of cooling water withdrawals. Similarly, habitat restoration could also be used, as appropriate as needed, in conjunction with CWIS technologies and/or locational requirements.

Table 5-1: Impingement Performance

Site	Location	Name/Type of Waterbody	Technology	Impingement	Entrainment	Notes
Diablo Canyon/Moss Landing	California	Pacific Ocean	Modified traveling/fish return	75	0	
Brayton Point	Massachusetts	Mt. Hope Bay (Estuary)	Angled screens/fish return	76	0	63% latent
Danskammer	New York	Tidal River (Hudson)	Angled screens/fish return	99	0	84% latent
Monroe	Michigan	River/Great Lake	Fish pump/return (screenwell)	70-80	0	Raisin River trib to L. Erie
Holyoke Canal	Connecticut	Connecticut River Basin	Louvers	85-90	0	Test results
Tracy Fish Collection	California	San Joaquin River	Louvers	63-89	0	
Salem	New Jersey	Tidal River (Delaware)	Ristroph screens	18-98	0	Species specific (no avg.)
Redondo Beach	California	Pacific Ocean	Louvers	96-100	0	Test for San Onofre
San Onofre	California	Pacific Ocean	Louvers	75-96	0	
Dominion Power Surry	Virginia	Estuary (James River)	Modified Fish/fish return	94	0	Includes survival
Barney Davis	Texas	Estuary (coastal lagoon)	Passavant screens (1.5 mm)	86	NA	Entrainment data Not Avail
Kintigh	New York	Great Lake	Modified with fish return	>80	50-97	Except shad 54-65, alewife 15-44
Calvert Cliffs	Maryland	Bay/estuary	Dual flow, cont. rot., return	73	0	Includes survival
Arthur Kill	New York	Estuary	Ristroph screens	79-92	0	
J.H. Campbell	Michigan	Great Lake	Wide mesh wedgewire	99+	0	
Eddystone	Pennsylvania	Estuary (Delaware)	Wide mesh wedgewire	99+	0	
Lovett	New York	Tidal River (Hudson)	Gunderboom	99	82	
J.P. Pulliam	Wisconsin	River/Great Lake	Barrier net	90	0	Only when above 37 degrees C
Ludington Storage	Michigan	Great Lake	Barrier net	96	0	
Chalk Point	Maryland	Bay/Estuary	Barrier net	90+	0	Based on liability reduced 93%
Bowline	New York	Tidal River (Hudson)	Barrier net	91	0	
J.R. Whiting	New York	Great Lake	Barrier net	97-99	0	
D.C. Cook	Michigan	Great Lake	Barrier net	80	0	Estimated by U. of Michigan
Oswego Steam	New York	Great Lake	Velocity cap	78	0	

Table 5-2: Entrainment Performance

Site	Location	Name/Type of Waterbody	Technology	Impingement	Entrainment	Notes
Big Bend	Florida	Tampa Bay	Fine mesh traveling	NA	86-95	66-93% survival
Seminole	Florida	River/Estuary	Fine mesh wedgewire	NA	99	Testing, not full-scale
Logan	New Jersey	River/Estuary	Fine mesh wedgewire	NA	90	19 mgd
TVA (studies)	Various	Fresh Water	Fine mesh traveling	NA	99	lab testing, striped bass larvae only
Lovett	New York	River/Tidal	Gunderboom	99	82	
Brunswick	North Carolina	River/Estuary	Fine mesh traveling	NA	84	used only when less than 84 deg F
Chalk Point	Maryland	Bay/Estuary	Fine mesh wedgewire	NA	80	Testing, not full-scale
Kintigh	New York	Great Lake	Fine mesh traveling	>80	50-97	
Summit	Delaware	Bay/Estuary	Fine mesh wedgewire	NA	90+	"impingement eliminated"

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ATTACHMENT A
CWIS Technology Fact Sheets

Intake Screening Systems	Fact Sheet No. 1: Single-Entry, Single-Exit Vertical Traveling Screens (Conventional Traveling Screens)

DESCRIPTION:

The single-entry, single-exit vertical traveling screens (conventional traveling screens) consist of screen panels mounted on an endless belt; the belt rotates through the water vertically. The screen mechanism consists of the screen, the drive mechanism, and the spray cleaning system. Most of the conventional traveling screens are fitted with 3/8-inch mesh and are designed to screen out and prevent debris from clogging the pump and the condenser tubes. The screen mesh is usually supplied in individual removable panels referred to as " baskets" or "trays".

The screen washing system consists of a line of spray nozzles operating at a relatively high pressure of 80 to 120 pounds per square inch (psi). The screens are usually designed to rotate at a single speed. The screens are rotated either at predetermined intervals or when a predetermined differential pressure is reached across the screens based on the amount of debris in the intake waters.

Because of this intermittent operation of the conventional traveling screens, fish can become impinged against the screens during the extended period of time while the screens are stationary and eventually die. When the screens are rotated the fish are removed from the water and then subjected to a high pressure spray; the fish may fall back into the water and become re-impinged or they may be damaged (EPA, 1976, Pagano et *al*, 1977).

Conventional Traveling Screen (EPA, 1976)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

- C The conventional traveling screens are the most common screening device presently used at steam electric power plants. Sixty percent of all the facilities use this technology at their intake structure (EEI, 1993).

RESEARCH/OPERATION FINDINGS:

- C The conventional single-entry single screen is the most common device resulting in impacts from entrainment and impingement (Fritz, 1980).

DESIGN CONSIDERATIONS:

- C The screens are usually designed structurally to withstand a differential pressure across their face of 4 to 8 feet of water.

- C The recommended normal maximum water velocity through the screen is about 2.5 feet per second (ft/sec). This recommended velocity is where fish protection is not a factor to consider.

- C The screens normally travel at one speed (10 to 12 feet per minute) or two speeds (2.5 to 3 feet per minute and 10 to 12 feet per minute). These speeds can be increased to handle heavy debris load.

ADVANTAGES:

- C Conventional traveling screens are a proven "off-the-shelf" technology that is readily available.

LIMITATIONS:

- C Impingement and entrainment are both major problems in this unmodified standard screen installation, which is designed for debris removal not fish protection.

REFERENCES:

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Intake Screening Systems	Fact Sheet No. 2: Modified Vertical Traveling Screens

DESCRIPTION:

Modified vertical traveling screens are conventional traveling screens fitted with a collection "bucket" beneath the screen panel. This intake screening system is also called a bucket screen, Ristroph screen, or a Surry Type screen. The screens are modified to achieve maximum recovery of impinged fish by maintaining them in water while they are lifted to a release point. The buckets run along the entire width of the screen panels and retain water while in upward motion. At the uppermost point of travel, water drains from the bucket but impinged organisms and debris are retained in the screen panel by a deflector plate. Two material removal systems are often provided instead of the usual single high pressure one. The first uses low-pressure spray that gently washes fish into a recovery trough. The second system uses the typical high-pressure spray that blasts debris into a second trough. Typically, an essential feature of this screening device is continuous operation which keeps impingement times relatively short (Richards, 1977; Mussalli, 1977; Pagano et al., 1977; EPA , 1976).

Modified Vertical Traveling Screens (White et al, 1976)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Facilities which have tested the screens include: the Surry Power Station in Virginia (White et al, 1976) (the screens have been in operation since 1974), the Madgett Generating Station in , Wisconsin, the Indian Point Nuclear Generating Station Unit 2 in New York, the Kintigh (formerly Somerset) Generating Station in New Jersey, the Bowline Point Generating Station (King et al, 1977), the Roseton Generating Station in New York, the Danskammer Generating Station in New York (King et al, 1977), the Hanford Generating Plant on the Columbia River in Washington (Page et al, 1975; Fritz, 1980), the Salem Genereating on the Delaware River in New Jersey, and the Monroe Power Plant on the Raisin River in Michigan.

RESEARCH/OPERATION FINDINGS:

Modified traveling screens have been shown to have good potential for alleviating impingement mortality. Some information is available on initial and long-term survival of impinged fish (EPRI, 1999; ASCE, 1982; Fritz, 1980). Specific research and operation findings are listed below:

- In 1986, the operator of the Indian Point Station redesigned fish troughs on the Unit 2 intake to enhance survival. Impingement injuries and mortality were reduced from 53 to 9 percent for striped bass, 64 to14 percent for white perch, 80 to 17 percent for Atlantic tomcod, and 47 to 7 percent for pumpkinseed (EPRI, 1999).

- The Kintigh Generating Station has modified traveling screens with low pressure sprays and a fish return system. After enhancements to the system in 1989, survivals of generally greater than 80 percent have been observed for rainbow smelt, rock bass, spottail shiner, white bass, white perch, and yellow perch. Gizzard shad survivals have been 54 to 65 percent and alewife survivals have been 15 to 44 percent (EPRI, 1999).

- Long-term survival testing was conducted at the Hanford Generating Plant on the Columbia River (Page et al, 1975; Fritz, 1980). In this study, 79 to 95 percent of the impinged and collected Chinook salmon fry survived for over 96 hours.

- Impingement data collected during the 1970s from Dominion Power's Surry Station indicated a 93.8 percent survival rate of all fish impinged. Bay anchovies had the lowest survival rate of 83 percent. The facility has modified Ristroph screens with low pressure wash and fish return systems (EPRI 1999).

- At the Arthur Kill Station, 2 of 8 screens are modified Ristroph type; the remaining six screens are conventional type. The modified screens have fish collection troughs, low pressure spray washes, fish flap seals, and separate fish collection sluices. 24-hour survival for the unmodified screens averages 15 percent, while the two modified screens have 79 and 92 percent average survival rates (EPRI 1999).

DESIGN CONSIDERATIONS:

- C The same design considerations as for Fact Sheet No. 1: Conventional Vertical Traveling Screens apply (ASCE, 1982).

ADVANTAGES:

- C Traveling screens are a proven "off-the-shelf" technology that is readily available. An essential feature of such screens is continuous operation during periods where fish are being impinged compared to conventional traveling screens which operate on an intermittent basis

LIMITATIONS:

- C The continuous operation can result in undesirable maintenance problems (Mussalli, 1977).
- C Velocity distribution across the face of the screen is generally very poor.
- C Latent mortality can be high, especially where fragile species are present.

REFERENCES:

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Intake Screening Systems	**Fact Sheet No. 3: Inclined Single-Entry, Single-Exit Traveling Screens (Angled Screens)**

DESCRIPTION:

Inclined traveling screens utilize standard through-flow traveling screens where the screens are set at an angle to the incoming flow as shown in the figure below. Angling the screens improves the fish protection effectiveness of the flush mounted vertical screens since the fish tend to avoid the screen face and move toward the end of the screen line, assisted by a component of the inflow velocity. A fish bypass facility with independently induced flow must be provided. The fish have to be lifted by fish pump, elevator, or conveyor and discharged to a point of safety away from the main water intake (Richards, 1977).

fig : Richards, 4^{th} page 419

Inclined Traveling Screens (Richards, 1977)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Angled screens have been tested/used at the following facilities: the Brayton Point Station Unit 4 in Massachusetts; the San Onofre Station in California; and at power plants on Lake Ontario and the Hudson River (ASCE, 1982; EPRI, 1999).

RESEARCH/OPERATION FINDINGS:

- Angled traveling screens with a fish return system have been used on the intake for Brayton Point Unit 4. Studies from 1984 through 1986 that evaluated the angled screens showed a diversion efficiency of 76 percent with latent survival of 63 percent. Much higher results were observed excluding bay anchovy. Survival efficiency for the major taxa exhibited an extremely wide range, from 0.1 percent for bay anchovy to 97 percent for tautog. Generally, the taxa fell into two groups: a hardy group with efficiency greater than 65 percent and a sensitive group with efficiency less than 25 percent (EPRI, 1999).

- Southern California Edison at its San Onofre steam power plant had more success with angled louvers than with angled screens. The angled screen was rejected for full-scale use because of the large bypass flow required to yield good guidance efficiencies in the test facility.

DESIGN CONSIDERATIONS:

Many variables influence the performance of angled screens. The following recommended preliminary design criteria were developed in the studies for the Lake Ontario and Hudson River intakes (ASCE, 1982):

- Angle of screen to the waterway: 25 degrees

- Average velocity of approach in the waterway upstream of the screens: 1 foot per second

- Ratio of screen velocity to bypass velocity: 1:1

- Minimum width of bypass opening: 6 inches

ADVANTAGES:

- The fish are guided instead of being impinged.

- The fish remain in water and are not subject to high pressure rinsing.

LIMITATIONS:

- Higher cost than the conventional traveling screen

- Angled screens need a stable water elevation.

- Angled screens require fish handling devices with independently induced flow (Richards, 1977).

REFERENCES:

ASCE. Design of Water Intake Structures for Fish Protection. Task Committee on Fish-Handling Capability of Intake Structures of the Committee on Hydraulic Structures of the Hydraulic Division of the American Society of Civil Engineers, New York, NY. 1982.

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Intake Screening Systems	Fact Sheet No.4: Fine Mesh Screens Mounted on Traveling Screens

DESCRIPTION:

Fine mesh screens are used for screening eggs, larvae, and juvenile fish from cooling water intake systems. The concept of using fine mesh screens for exclusion of larvae relies on gentle impingement on the screen surface or retention of larvae within the screening basket, washing of screen panels or baskets to transfer organisms into a sluiceway, and then sluicing the organisms back to the source waterbody (Sharma, 1978). Fine mesh with openings as small as 0.5 millimeters (mm) has been used depending on the size of the organisms to be protected. Fine mesh screens have been used on conventional traveling screens and single-entry, double-exit screens. The ultimate success of an installation using fine mesh screens is contingent on the application of satisfactory handling and recovery facilities to allow the safe return of impinged organisms to the aquatic environment (Pagano et al, 1977).

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

The Big Bend Power Plant along Tampa Bay area has an intake canal with 0.5-mm mesh Ristroph screens that are used seasonally on the intakes for Units 3 and 4. At the Brunswick Power Plant in North Carolina, fine mesh is used seasonally on two of four screens has shown 84 percent reduction in entrainment compared to the conventional screen systems.

RESEARCH/OPERATION FINDINGS:

- C During the mid-1980s when the screens were initially installed at Big Bend, their efficiency in reducing impingement and entrainment mortality was highly variable. The operator evaluated different approach velocities and screen rotational speeds. In addition, the operator recognized that frequent maintenance (manual cleaning) was necessary to avoid biofouling. By 1988, system performance had improved greatly. The system's efficiency in screening fish eggs (primarily drums and bay anchovy) exceeded 95 percent with 80 percent latent survival for drum and 93 percent for bay anchovy. For larvae (primarily drums, bay anchovies, blennies, and gobies), screening efficiency was 86 percent with 65 percent latent survival for drum and 66 percent for bay anchovy. Note that latent survival in control samples was also approximately 60 percent (EPRI, 1999).

- C At the Brunswick Power Plant in North Carolina, fine mesh screen has led to 84 percent reduction in entrainment compared to the conventional screen systems. Similar results were obtained during pilot testing of 1-mm screens at the Chalk Point Generating Station in Maryland. At the Kintigh Generating Station in New Jersey, pilot testing indicated 1-mm screens provided 2 to 35 times reductions in entrainment over conventional 9.5-mm screens (EPRI, 1999).

- C Tennessee Valley Authority (TVA) pilot-scale studies performed in the 1970s showed reductions in striped bass larvae entrainment up to 99 percent using a 0.5-mm screen and 75 and 70 percent for 0.97-mm and 1.3-mm screens. A full-scale test by TVA at the John Sevier Plant showed less than half as many larvae entrained with a 0.5-mm screen than 1.0 and 2.0-mm screens combined (TVA, 1976).

- C Preliminary results from a study initiated in 1987 by the Central Hudson and Gas Electric Corporation indicated that the fine mesh screens collect smaller fish compared to conventional screens; mortality for the smaller fish was relatively high, with similar survival between screens for fish in the same length category (EPRI, 1989).

DESIGN CONSIDERATIONS:

Biological effectiveness for the whole cycle, from impingement to survival in the source water body, should be investigated thoroughly prior to implementation of this option. This includes:

- C The intake velocity should be very low so that if there is any impingement of larvae on the screens, it is gentle enough not to result in damage or mortality.

- C The wash spray for the screen panels or the baskets should be low-pressure so as not to result in mortality.

- C The sluiceway should provide smooth flow so that there are no areas of high turbulence; enough flow should be maintained so that the sluiceway is not dry at any time.

- The species life stage, size and body shape and the ability of the organisms to withstand impingement should be considered with time and flow velocities.

- The type of screen mesh material used is important. For instance, synthetic meshes may be smooth and have a low coefficient of friction, features that might help to minimize abrasion of small organisms. However, they also may be more susceptible to puncture than metallic meshes (Mussalli, 1977).

ADVANTAGES:

- There are indications that fine mesh screens reduce entrainment.

LIMITATIONS:

- Fine mesh screens may increase the impingement of fish, i.e., they need to be used in conjunction with properly designed and operated fish collection and return systems.

- Due to the small screen openings, these screens will clog much faster than those with conventional 3/8-inch mesh. Frequent maintenance is required, especially in marine environments.

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Passive Intake Systems	Fact Sheet No. 5: Wedgewire Screens

DESCRIPTION:

Wedgewire screens are designed to reduce entrainment by physical exclusion and by exploiting hydrodynamics. Physical exclusion occurs when the mesh size of the screen is smaller than the organisms susceptible to entrainment. Hydrodynamic exclusion results from maintenance of a low through-slot velocity, which, because of the screen's cylindrical configuration, is quickly dissipated, thereby allowing organisms to escape the flow field (Weisberd et al, 1984). The screens can be fine or wide mesh. The name of these screens arise from the triangular or "wedge" cross section of the wire that makes up the screen. The screen is composed of wedgewire loops welded at the apex of their triangular cross section to supporting axial rods presenting the base of the cross section to the incoming flow (Pagano et al, 1977). A cylindrical wedgewire screen is shown in the figure below. Wedgewire screens are also called profile screens or Johnson screens.

mitre report

Schematic of Cylindrical Wedgewire Screen (Pagano et al, 1977)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Wide mesh wedgewire screens are used at two large power plants, Eddystone and Campbell. Smaller facilities with wedgewire screens include Logan and Cope with fine mesh and Jeffrey with wide mesh (EPRI 1999).

RESEARCH/OPERATION FINDINGS:

- In-situ observations have shown that impingement is virtually eliminated when wedgewire screens are used (Hanson, 1977; Weisberg et al, 1984).

- At Campbell Unit 3, impingement of gizzard shad, smelt, yellow perch, alewife, and shiner species is significantly lower than Units 1 and 2 that do not have wedgewire screens (EPRI, 1999).

- The cooling water intakes for Eddystone Units 1 and 2 were retrofitted with wedgewire screens because over 3 million fish were reportedly impinged over a 20-month period. The wedgewire screens have generally eliminated impingement at Eddystone (EPRI, 1999).

- Laboratory studies (Heuer and Tomljanovitch, 1978) and prototype field studies (Lifton, 1979; Delmarva Power and Light, 1982; Weisberg et al, 1983) have shown that fine mesh wedgewire screens reduce entrainment.

- One study (Hanson, 1977) found that entrainment of fish eggs (striped bass), ranging in diameter from 1.8 mm to 3.2 mm, could be eliminated with a cylindrical wedgewire screen incorporating 0.5 mm slot openings. However, striped bass larvae, measuring 5.2 mm to 9.2 mm were generally entrained through a 1 mm slot at a level exceeding 75 percent within one minute of release in the test flume.

- At the Logan Generating Station in New Jersey, monitoring shows shows 90 percent less entrainment of larvae and eggs through the 1 mm wedgewire screen then conventional screens. In situ testing of1 and 2-mm wedgewire screens was performed in the St. John River for the Seminole Generating Station Units 1 and 2 in Florida in the late 1970s. This testing showed virtually no impingement and 99 and 62 percent reductions in larvae entrainment for the 1-mm and 2-mm screens, respectively, over conventional screen (9.5 mm) systems (EPRI, 1999).

DESIGN CONSIDERATIONS:

- To minimize clogging, the screen should be located in an ambient current of at least 1 feet per second (ft/sec).

- A uniform velocity distribution along the screen face is required to minimize the entrapment of motile organisms and to minimize the need of debris backflushing.

- In northern latitudes, provisions for the prevention of frazil ice formation on the screens must be considered.

- Allowance should be provided below the screens for silt accumulation to avoid blockage of the water flow (Mussalli et al, 1980).

ADVANTAGES:

- Wedgewire screens have been demonstrated to reduce impingement and entrainment in laboratory and prototype field studies.

LIMITATIONS:

- The physical size of the screening device is limiting in most passive systems, thus, requiring the clustering of a number of screening units. Siltation, biofouling and frazil ice also limit areas where passive screens such as wedgewire can be utilized.

- Because of these limitations, wedgewire screens may be more suitable for closed-cycle make-up intakes than once-through systems. Closed-cycle systems require less flow and fewer screens than once-through intakes; back-up conventional screens can therefore be used during maintenance work on the wedge-wire screens (Mussalli et al, 1980).

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Passive Intake Systems	Fact Sheet No. 6: Perforated Pipes

DESCRIPTION:

Perforated pipes draw water through perforations or slots in a cylindrical section placed in the waterway. The term "perforated" is applied to round perforations and elongated slots as shown in the figure below. The early technology was not efficient: velocity distribution was poor, it served specifically to screen out detritus, and was not used for fish protection (ASCE, 1982). Inner sleeves have been added to perforated pipes to equalize the velocities entering the outer perforations. Water entering a single perforated pipe intake without an internal sleeve will have a wide range of entrance velocities and the highest will be concentrated at the supply pipe end. These systems have been used at locations requiring small amounts of water such as make-up water. However, experience at steam electric plants is very limited (Sharma, 1978).

(Figure ASCE page 79).

Perforations and Slots in Perforated Pipe (ASCE, 1982)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Nine steam electric units in the U.S. use perforated pipes. Each of these units uses closed-cycle cooling systems with relatively low make-up intake flow ranging from 7 to 36 MGD (EEI, 1993).

RESEARCH/OPERATION FINDINGS:

C Maintenance of perforated pipe systems requires control of biofouling and removal of debris from clogged screens.

- C For withdrawal of relatively small quantities of water, up to 50,000 gpm, the perforated pipe inlet with an internal perforated sleeve offers substantial protection for fish. This particular design serves the Washington Public Power Supply System on the Columbia River (Richards, 1977).

- C No information is available on the fate of the organisms impinged at the face of such screens.

DESIGN CONSIDERATIONS:

The design of these systems is fairly well established for various water intakes (ASCE, 1982).

ADVANTAGES:

The primary advantage is the absence of a confined channel in which fish might become trapped.

LIMITATIONS:

Clogging, frazil ice formation, biofouling and removal of debris limit this technology to small flow withdrawals.

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Passive intake Systems	**Fact Sheet No. 7: Porous Dikes/Leaky Dams**

DESCRIPTION:

Porous dikes, also known as leaky dams or leaky dikes, are filters resembling a breakwater surrounding a cooling water intake. The core of the dike consists of cobble or gravel, which permits free passage of water. The dike acts both as a physical and a behavioral barrier to aquatic organisms and is depicted in the figure below. The filtering mechanism includes a breakwater or some other type of barrier and the filtering core (Fritz, 1980). Tests conducted to date have indicated that the technology is effective in excluding juvenile and adult fish. However, its effectiveness in screening fish eggs and larvae is not established (ASCE, 1982).

Porous Dike (Schrader and Ketschke, 1978)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

- Two facilities which are both testing facilities and have used the technology are: the Point Beach Nuclear Plant in Wisconsin and the Baily Generating Station in Indiana (EPRI, 1985). The Brayton Point Generating Station in Massachusetts has also tested the technology.

RESEARCH/OPERATION FINDINGS:

- Schrader and Ketschke (1978) studied a porous dike system at the Lakeside Plant on Lake Michigan and found that numerous fish penetrated large void spaces, but for most fish accessibility was limited.
- The biological effectiveness of screening of fish larvae and the engineering practicability have not been established (ASCE, 1982).
- The size of the pores in the dike dictates the degree of maintenance due to biofouling and clogging by debris.
- Ice build-up and frazil ice may create problems as evidenced at the Point Beach Nuclear Plant (EPRI, 1985).

DESIGN CONSIDERATIONS:

- The presence of currents past the dike is an important factor which may probably increase biological effectiveness.
- The size of pores in the dike determines the extent of biofouling and clogging by debris (Sharma, 1978).
- Filtering material must be of a size that permits free passage of water but still prevents entrainment and impingement.

ADVANTAGES:

- Dikes can be used at marine, fresh water, and estuarine locations.

LIMITATIONS:

- The major problem with porous dikes comes from clogging by debris and silt, and from fouling by colonization of fish and plant life.
- Backflushing, which is often used by other systems for debris removal, is not feasible at a dike installation.
- Predation of organisms screened at these dikes may offset any biological effectiveness (Sharma, 1978).

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Fish Diversion or Avoidance Systems	Fact Sheet No. 8: Louver Systems

DESCRIPTION:

Louver systems are comprised of a series of vertical panels placed at an angle to the direction of the flow (typically 15 to 20 degrees). Each panel is placed at an angle of 90 degrees to the direction of the flow (Hadderingh, 1979). The louver panels provide an abrupt change in both the flow direction and velocity (see figure below). This creates a barrier, which fish can immediately sense and will avoid. Once the change in flow/velocity is sensed by fish, they typically align with the direction of the current and move away laterally from the turbulence. This behavior further guides fish into a current created by the system, which is parallel to the face of the louvers. This current pulls the fish along the line of the louvers until they enter a fish bypass or other fish handling device at the end of the louver line. The louvers may be either fixed or rotated similar to a traveling screen. Flow straighteners are frequently placed behind the louver systems.

These types of barriers have been very successful and have been installed at numerous irrigation intakes, water diversion projects, and steam electric and hydroelectric facilities. It appears that this technology has, in general, become accepted as a viable option to divert juvenile and adult fish.

Top view of a Louver Barrier with Fish By-Pass (Hadderingh, 1979)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Louver barrier devices have been tested and/or are in use at the following facilities: the California Department of Water Resource's Tracy Pumping Plant; the California Department of Fish and Game's Delta Fish Protective Facility in Bryon; the Conte Anadromous Fish Research Center in Massachusetts, and the San Onofre Nuclear Generating Station in

California (EPA, 1976; EPRI, 1985; EPRI, 1999). In addition, three other plants also have louvers at their facilities: the Ruth Falls Power Plant in Nova Scotia, the Nine Mile Point Nuclear Power Station on Lake Erie, and T.W. Sullivan Hydroelectric Plant in Oregon. Louvers have also been tested at the Ontario Hydro Laboratories in Ontario, Canada (Ray et al, 1976).

RESEARCH/OPERATION FINDINGS:

Research has shown the following generalizations to be true regarding louver barriers:
1) the fish separation performance of the louver barrier decreases with an increase in the velocity of the flow through the barrier; 2) efficiency increases with fish size (EPA, 1976; Hadderingh, 1979); 3) individual louver misalignment has a beneficial effect on the efficiency of the barrier; 4) the use of center walls provides the fish with a guide wall to swim along thereby improving efficiency (EPA, 1976); and 5) the most effective slat spacing and array angle to flow depends upon the size, species and ability of the fish to be diverted (Ray et al, 1976).

In addition, the following conclusions were drawn during specific studies:

- Testing of louvered intake structures offshore was performed at a New York facility. The louvers were spaced 10 inches apart to minimize clogging. The array was angled at 11.5 percent to the flow. Center walls were provided for fish guidance to the bypass. Test species included alewife and rainbow smelt. The mean efficiency predicted was between 22 and 48 percent (Mussalli 1980).

- During testing at the Delta Facility's intake in Byron California, the design flow was 6,000 cubic feet per second (cfs), the approach velocity was 1.5 to 3.5 feet per second (ft/sec), and the bypass velocities were 1.2 to 1.6 times the approach velocity. Efficiencies were found to drop with an increase in velocity through the louvers. For example, at 1.5 to 2 ft/sec the efficiency was 61 percent for 15 millimeter long fish and 95 percent for 40 millimeter fish. At 3.5 ft/sec, the efficiencies were 35 and 70 percent (Ray et al. 1976).

- The efficiency of a louver device is highly dependent upon the length and swimming performance of a fish. Efficiencies of lower than 80 percent have been seen at facilities where fish were less than 1 to 1.6 inches in length (Mussalli, 1980).

- In the 1990s, an experimental louver bypass system was tested at the USGS' Conte Anadromous Fish Research Center in Massachusetts. This testing showed guidance efficiencies for Connecticut River species of 97 percent for a "wide array" of louvers and 100 percent for a "narrow array" (EPRI, 1999).

- At the Tracy Fish Collection Facility located along the San Joaquin River in California, testing was performed from 1993 and 1995 to determine the guidance efficiency of a system with primary and secondary louvers. The results for green and white sturgeon, American shad, splittail, white catfish, delta smelt, Chinook salmon, and striped bass showed mean diversion efficiencies ranging from 63 (splittail) to 89 percent (white catfish) (EPRI, 1999).

- In 1984 at the San Onofre Station, a total of 196,978 fish entered the louver system with 188,583 returned to the waterbody and 8,395 impinged. In 1985, 407,755 entered the louver system with 306,200 returned and 101,555 impinged. Therefore, the guidance efficiencies in 1984 and 1985 were 96 and 75 percent, respectively. However, 96-hour survival rates for some species, i.e., anchovies and croakers, were 50 percent or less. Louvers were originally considered for use at San Onofre because of 1970s pilot testing at the Redondo Beach Station in California where maximum guidance efficiencies of 96-100 percent were observed. (EPRI, 1999)

- At the Maxwell Irrigation Canal in Oregon, louver spacing was 5.0 cm with a 98 percent efficiency of deflecting immature steelhead and above 90 percent efficiency for the same species with a louver spacing of 10.8 cm.

- At the Ruth Falls Power Plant in Nova Scotia, the results of a five-year evaluation for guiding salmon smelts showed that the optimum spacing was to have wide bar spacing at the widest part of the louver with a gradual reduction in the spacing approaching the bypass. The site used a bypass:approach velocity ratio of 1.0 : 1.5 (Ray et al, 1976).

- Coastal species in California were deflected optimally (Schuler and Larson, 1974 in Ray et al, 1976) with 2.5 cm spacing of the louvers, 20 degree louver array to the direction of flow and approach velocities of 0.6 cm per second.

- At the T.W. Sullivan Hydroelectric Plant along the Williamette River in Oregon, the louver system is estimated to be 92 percent effective in diverting spring Chinook, 82 percent for all Chinook, and 85 percent for steelhead. The system has been optimized to reduce fish injuries such that the average injury occurrence is only 0.44 percent (EPRI, 1999).

DESIGN CONSIDERATIONS:

The most important parameters of the design of louver barriers include the following:

- The angle of the louver vanes in relation to the channel velocity ,

- The spacing between the louvers which is related to the size of the fish,

- Ratio of bypass velocity to channel velocity,

- Shape of guide walls,
- Louver array angles, and
- Approach velocities.

Site-specific modeling may be needed to take into account species-specific considerations and optimize the design efficiency (EPA, 1976; O'Keefe, 1978).

ADVANTAGES:

- Louver designs have been shown to be very effective in diverting fish (EPA, 1976).

LIMITATIONS:

- The costs of installing intakes with louvers may be substantially higher than other technologies due to design costs and the precision required during construction.
- Extensive species-specific field testing may be required.
- The shallow angles required for the efficient design of a louver system require a long line of louvers increasing the cost as compared to other systems (Ray et al, 1976).
- Water level changes must be kept to a minimum to maintain the most efficient flow velocity.
- Fish handling devices are needed to take fish away from the louver barrier.
- Louver barriers may, or may not, require additional screening devices for removing solids from the intake waters. If such devices are required, they may add a substantial cost to the system (EPA, 1976).
- Louvers may not be appropriate for offshore intakes (Mussalli, 1980).

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Fish Diversion or Avoidance Systems	**Fact Sheet No. 9: Velocity Cap**

DESCRIPTION:

A velocity cap is a device that is placed over vertical inlets at offshore intakes (see figure below). This cover converts vertical flow into horizontal flow at the entrance into the intake. The device works on the premise that fish will avoid rapid changes in horizontal flow. Fish do not exhibit this same avoidance behavior to the vertical flow that occurs without the use of such a device. Velocity caps have been implemented at many offshore intakes and have been successful in decreasing the impingement of fish.

Typical Offshore Coling Water Intake Structure with Velocity Caps (Helrey, 1985; ASCE, 1982)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

The available literature (EPA, 1976; Hanson, 1979; and Pagano et al, 1977) states that velocity caps have been installed at offshore intakes in Southern California, the Great Lakes Region, the Pacific Coast, the Caribbean and overseas; however, exact locations are not specified.

Velocity caps are known to have been installed at the El Segundo, Redondo Beach, and Huntington Beach Steam Electric Stations and the San Onofre Nuclear Generation Station in Southern California (Mussalli, 1980; Pagano et al, 1977; EPRI, 1985).

Model tests have been conducted by a New York State Utility (ASCE, 1982) and several facilities have installed velocity caps in the New York State /Great Lakes Area including the Nine Mile Point Nuclear Station, the Oswego Steam Electric Station, and the Kintigh Generating Station (EPRI, 1985).

Additional known facilities with velocity caps include the Edgewater Generation Station in Wisconsin, the Seabrook Power Plant in New Hampshire, and the Nanticoke Thermal Generating Station in Ontario, Canada (EPRI, 1985).

RESEARCH/OPERATION FINDINGS:

- Horizontal velocities within a range of 0.5 to 1.5 feet per second (ft/sec) did not significantly affect the efficiency of a velocity cap tested at a New York facility; however, this design velocity may be specific to the species present at that site (ASCE, 1982).
- Preliminary decreases in fish entrapment averaging 80 to 90 percent were seen at the El Segundo and Huntington Beach Steam Electric Plants (Mussalli, 1980).
- Performance of the velocity cap may be associated with cap design and the total volumes of water flowing into the cap rather than to the critical velocity threshold of the cap (Mussalli, 1980).

DESIGN CONSIDERATIONS:

- Designs with rims around the cap edge prevent water from sweeping around the edge causing turbulence and high velocities, thereby providing more uniform horizontal flows (EPA, 1976; Mussalli, 1980).
- Site-specific testing should be conducted to determine appropriate velocities to minimize entrainment of particular species in the intake (ASCE, 1982).
- Most structures are sized to achieve a low intake velocity between 0.5 and 1.5 ft/sec to lessen the chances of entrainment (ASCE, 1982).
- Design criteria developed for a model test conducted by Southern California Edison Company used a velocity through the cap of 0.5 to 1.5 ft/sec; the ratio of the dimension of the rim to the height of the intake areas was 1.5 to 1 (ASCE, 1982; Schuler, 1975).

ADVANTAGES:

- Efficiencies of velocity caps on West Coast offshore intakes have exceeded 90 percent (ASCE, 1982).

LIMITATIONS:

- Velocity caps are difficult to inspect due to their location under water (EPA, 1976).

- In some studies, the velocity cap only minimized the entrainment of fish and did not eliminate it. Therefore, additional fish recovery devices are be needed in when using such systems (ASCE, 1982; Mussalli, 1980).

- Velocity caps are ineffective in preventing passage of non-motile organisms and early life stage fish (Mussalli, 1980).

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Fish Diversion or Avoidance Systems	**Fact Sheet No. 10: Fish Barrier Nets**

DESCRIPTION:

Fish barrier nets are wide mesh nets, which are placed in front of the entrance to an intake structure (see figure below). The size of the mesh needed is a function of the species that are present at a particular site. Fish barrier nets have been used at numerous facilities and lend themselves to intakes where the seasonal migration of fish and other organisms require fish diversion facilities for only specific times of the year.

V-Arrangement of Fish Barrier Net (ASCE, 1982)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

The Bowline Point Generating Station, the J.P. Pulliam Power Plant in Wisconsin, the Ludington Storage Plant in Michigan, and the Nanticoke Thermal Generating Station in Ontario use barrier nets (EPRI, 1999).

Barrier Nets have been tested at the Detroit Edison Monroe Plant on Lake Erie and the Chalk Point Station on the Patuxent River in Maryland (ASCE, 1982; EPRI, 1985). The Chalk Point Station now uses barrier nets seasonally to reduce fish and Blue Crab entry into the intake canal (EPRI, 1985). The Pickering Generation Station in Ontario evaluated rope nets in 1981 illuminated by strobe lights (EPRI, 1985).

RESEARCH/OPERATION FINDINGS:

- At the Bowline Point Generating Station in New York, good results (91 percent impingement reductions) have been realized with a net placed in a V arrangement around the intake structure (ASCE, 1982; EPRI, 1999).

- In 1980, a barrier net was installed at the J.R. Whiting Plant (Michigan) to protect Maumee Bay. Prior to net installation, 17,378,518 fish were impinged on conventional traveling screens. With the net, sampling in 1983 and 84 showed 421,978 fish impinged (97 percent effective), sampling in 1987 showed 82,872 fish impinged (99 percent effective), and sampling in 1991 showed 316,575 fish impinged (98 percent effective) (EPRI, 1999).

- Nets tested with high intake velocities (greater than 1.3 feet per second) at the Monroe Plant have clogged and subsequentially collapsed. This has not occurred at facilities where the velocities are 0.4 to 0.5 feet per second (ASCE, 1982).

- Barrier nets at the Nanticoke Thermal Generating Station in Ontario reduced intake of fish by 50 percent (EPRI, 1985).

- The J.P Pulliam Generating Station in Wisconsin uses dual barrier nets (0.64 centimeters stretch mesh) to permit net rotation for cleaning. Nets are used from April to December or when water temperatures go above 4 degrees Celsius. Impingement has been reduced by as much as 90 percent. Operating costs run about $5,000 per year, and nets are replaced every two years at $2,500 per net (EPRI, 1985).

- The Chalk Point Station in Maryland realized operational costs of $5,000-10,000 per year with the nets being replaced every two years (EPRI, 1985). However, crab impingement has been reduced by 84 percent and overall impingrment liability has been reduced from $2 million to $140,000 (EPRI, 1999).

- The Ludington Storage Plant (Michigan) provides water from Lake Michigan to a number of power plant facilities. The plant has a 2.5-mile long barrier net that has successfully reduced impingement and entrainment. The overall net effectiveness for target species (five salmonids, yellow perch, rainbow smelt, alewife, and chub) has been over 80 percent since 1991 and 96 percent since 1995. The net is deployed from mid-April to mid-October, with storms and icing preventing use during the remainder of the year (EPRI, 1999).

DESIGN CONSIDERATIONS:

- The most important factors to consider in the design of a net barrier are the site-specific velocities and the potential for clogging with debris (ASCE, 1982).

- The size of the mesh must permit effective operations, without excessive clogging. Designs at the Bowline Point Station in New York have 0.15 and 0.2 inch openings in the mesh nets, while the J.P. Pulliam Plant in Wisconsin has 0.25 inch openings (ASCE, 1982).

ADVANTAGES:

- Net barriers, if operating properly, should require very little maintenance.

- Net barriers have relatively little cost associated with them.

LIMITATIONS:

- Net barriers are not effective for the protection of the early life stages of fish or zooplankton (ASCE, 1982).

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Fish Diversion or Avoidance Systems	Fact Sheet No. 11: Aquatic Filter Barrier Systems

DESCRIPTION:

Aquatic filter barrier systems are barriers that employ a filter fabric designed to allow for passage of water into a cooling water intake structure, but exclude aquatic organisms. These systems are designed to be placed some distance from the cooling water intake structure within the source waterbody and act as a filter for the water that enters into the cooling water system. These systems may be floating, flexible, or fixed. Since these systems generally have such a large surface area, the velocities that are maintained at the face of the permeable curtain are very low. One company, Gunderboom, Inc., has a patented full-water-depth filter curtain comprised of polyethylene or polypropylene fabric that is suspended by flotation billets at the surface of the water and anchored to the substrate below. The curtain fabric is manufactured as a matting of minute unwoven fibers with an apparent opening size of 20 microns. The Gunderboom Marine/Aquatic Life Exclusion System (MLES)™ also employs an automated "air burst"™ technology to periodically shake the material and pass air bubbles through the curtain system to clean it of sediment buildup and release any other material back in to the water column.

Gunderboom Marine/Aquatic Life Exclusion System (Gunderboom, Inc., 1999)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

C Gunderboom MLES ™ have been tested and are currently installed on a seasonal basis at Unit 3 of the Lovett Station in New York. Prototype testing of the Gunderboom system began in 1994 as a means of lowering ichthyoplankton entrainment at Unit 3. This was the first use of the technology at a cooling water intake structure. The Gunderboom tested was a single layer fabric. Material clogging resulted in loss of filtration capacity and boom submergence within 12 hours of deployment. Ichthyoplankton monitoring while the boom was intact indicated an 80 percent reduction in entrainable organisms (Lawler, Matusky, and Skelly Engineers, 1996).

- A Gunderboom MLES ™ was effectively deployed at the Lovett Station for 43 days in June and July of 1998 using an Air-Burst cleaning system and newly designed deadweight anchoring system. The cleaning system coupled with a perforated material proved effective at limiting sediment on the boom, however it required an intensive operational schedule (Lawler, Matusky, and Skelly Engineers, 1998).

- A 1999 study was performed on the Gunderboom MLES ™ at the Lovett Station in New York to qualitatively determine the characteristics of the fabric with respect to the impingement of ichthyoplankton at various flow regimes. Conclusions were that the viability of striped bass eggs and larvae were not affected (Lawler, Matusky, and Skelly Engineers, 1999).

- Ichthyoplankton sampling at Unit 3 (with Gunderboom MLES ™ deployed) and Unit 4 (without Gunderboom) in May through August 2000 showed an overall effectiveness of approximately 80 percent. For juvenile fish, the density at Unit 3 was 58 percent lower. For post yolk-sac larvae, densities were 76 percent lower. For yolk-sac larvae, densities were 87 percent lower (Lawler, Matusky & Skelly Engineers 2000).

RESEARCH/OPERATION FINDINGS:

Extensive testing of the Gunderboom MLES ™ has been performed at the Lovett Station in New York. Anchoring, material, cleaning, and monitoring systems have all been redesigned to meet the site-specific conditions in the waterbody and to optimize the operations of the Gunderboom. Although this technology has been implemented at only one cooling water intake structure, it appears to be a promising technology to reduce impingement and entrainment impacts. It is also being evaluated for use at the Contre Costa Power Plant in California.

DESIGN CONSIDERATIONS:

The most important parameters in the design of a Gunderboom ® Marine/Aquatic Life Exclusion System include the following (Gunderboom, Inc. 1999):

- Size of booms designed for 3-5 gpm per square foot of submerged fabric. Flows greater than 10-12 gallons per minute.

- Flow-through velocity is approximately 0.02 ft/s.

- Performance monitoring and regular maintenance.

ADVANTAGES:

- Can be used in all waterbody types.
- All larger and nearly all other organisms can swim away from the barrier because of low velocities.
- Little damage is caused to fish eggs and larvae if they are drawn up against the fabric.
- Modulized panels may easily be replaced.
- Easily deployed for seasonal use.
- Biofouling not significant.
- Impinged organisms released back into the waterbody.
- Benefits relative to cost appear to be very promising, but remain unproven to date.
- Installation can occur with no or minimal plant shutdown.

LIMITATIONS:

- Currently only a proven technology for this application at one facility.
- Extensive waterbody-specific field testing may be required.
- May not be appropriate for conditions with large fluctuations in ambient flow and heavy currents and wave action.
- High level of maintenance and monitoring required.
- Higher flow facilities may require very large surface areas; could interfere with other waterbody uses.

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Fish Diversion or Avoidance Systems	**Fact Sheet No. 12: Sound Barriers**

DESCRIPTION:

Sound barriers are non-contact barriers that rely on mechanical or electronic equipment that generates various sound patterns to elicit avoidance responses in fish. Acoustic barriers are used to deter fish from entering industrial water intakes and power plant turbines. Historically, the most widely-used acoustical barrier is a pneumatic air gun or "popper." The pneumatic air gun is a modified seismic device which produces high-amplitude, low-frequency sounds to exclude fish. Closely related devices include "fishdrones" and "fishpulsers" (also called "hammers"). The fishdrone produces a wider range of sound frequencies and amplitudes than the popper. The fishpulser produces a repetitive sharp hammering sound of low-frequency and high-amplitude. Both instruments have ahd limited effectiveness in the field (EPRI, 1995; EPRI, 1989; Hanson, et al., 1977; EPA, 1976; Taft, et al., 1988; ASCE, 1992).

Researchers have generally been unable to demonstrate or apply acoustic barriers as fish deterrents, even though fish studies showed that fish respond to sound, because the response varies as a function of fish species, age, and size as well as environmental factors at specific locations. Fish may also acclimate to the sound patterns used (EPA, 1976; Taft et al., 1988; EPRI, 1995; Ray at al., 1976; Hadderingh, 1979; Hanson et al., 1977; ASCE, 1982).

Since about 1989, the application of highly refined sound generation equipment originally developed for military use (e.g., sonar in submarines) has greatly advanced acoustic barrier technology. Ibis technology has the ability to generate a wide array of frequencies, patterns, and volumes, which are monitored and controlled by computer. Video and computer monitoring provide immediate feedback on the effectiveness of an experimental sound pattern at a given location. In a particular environment, background sounds can be accounted for, target fish species or fish populations can quickly be characterized, and the most effective sound pattern can be selected (Menezes, at al., 1991; Sonalysts, Inc.).

TESTING FACILITIES AND/OR FACILITIES WITH TECHNOLOGY IN USE:

No fishpulsers and pneumatic air guns are currently in use at power plant water intakes.

Research facilities that have completed studies or have on-going testing involving fishpulsers or pneumatic air guns include the Ludington Storage Plant on Lake Michigan; Nova Scotia Power; the Hells Gate Hydroelectric Station on the Black River; the Annapolis Generating Station on the Bay of Fundy; Ontario Hydro's Pickering Nuclear Generating station; the Roseton Generating Station in New York; the Seton Hydroelectric Station in British Columbia; the Surry Power Plant in Virginia; the Indian Point Nuclear Generating Station Unit 3 in New York; and the U.S. Army Corps of Engineers on the Savannah River (EPRI, 1985; EPRI, 1989; EPRI, 1988; and Taft, et al., 1998).

Updated acoustic technology developed by Sonalysts, Inc. has been applied at the James A. Fitzpatrick Nuclear Power Plant in New York on Lake Ontario; the Vernon Hydroelectric plant on the Connecticut River (New England Power Company, 1993; Menezes, et al., 1991; personal communication with Sonalysts, Inc., by SAIC, 1993); and in a quarry in Verplank, New York (Dunning, et al., 1993).

RESEARCH/OPERATION FINDINGS:

- Most pre-1976 research was related to fish response to sound rather than on field applications of sound barriers (EPA, 1976; Ray et al., 1976; Uziel, 1980; Hanson, et al., 1977).

- Before 1986, no acoustic barriers were deemed reliable for field use. Since 1986, several facilities have tried to use pneumatic poppers with limited successes. Even in combination with light barriers and air bubble barriers, poppers and fishpulsers, were ineffective for most intakes (Taft and Downing, 1988; EPRI, 1985; Patrick, et al., 1988; EPRI, 1989; EPRI, 1988; Taft, et al., 1988; McKinley and Patrick, 1998; Chow, 1981).

- A 1991 full-scale 4-month demonstration at the James A. FitzPatrick (JAF) Nuclear Power Plant in New York on Lake Ontario showed that the Sonalysts, Inc. FishStartle System reduced alewife impingement by 97 percent as compared to a control power plant located 1 mile away. (Ross, et al., 1993; Menezes, et al., 1991). JAF experienced a 96 percent reduction compared to fish impingement when the acoustic system was not in use. A 1993 3-month test of the system at JAF was reported to be successful, i.e., 85 percent reduction in alewife impingement. (Menezes, et al., 1991; EPRI, 1999).

- In tests at the Pickering Station in Ontario, poppers were found to be effective in reducing alewife impingement and entrainment by 73 percent in 1985 and 76 percent in 1986. No benefits were observed for rainbow smelt and gizzard shad. Sound provided little or no deterrence for any species at the Roseton Generating Station in New York.

- During marine construction of Boston's third Harbor Tunnel in 1992, the Sonalysts, Inc. FishStartle System was used to prevent shad, blueback herring, and alewives from entering underwater blasting areas during the fishes' annual spring migration. The portable system was used prior to each blast to temporarily deter fish and allow periods of blastmg as necessary for the construction of the tunnel (personal communication to SAIC from M. Curtin, Sonalysts, Inc., September 17, 1993).

- In fall 1992, the Sonalysts, Inc. FishStartle System was tested in a series of experiments conducted at the Vernon Hydroelectric plant on the Connecticut River. Caged juvenile shad were exposed to various acoustical signals to see which signals elicited the strongest reactions. Successful in situ tests involved applying the signals with a transducer system to divert juvenile shad from the forebay to a bypass pipe. Shad exhibited consistent avoidance reactions to the signals and did not show evidence of acclimation to the source (New England Power Company, 1993).

DESIGN CONSIDERATIONS:

- Sonalysts Inc.'s FishStartle system uses frequencies between 15 hertz to130 kilohertz at sound pressure levels ranging from 130 to 206+ decibels referenced to one micropascal (dB//uPa). To develop a site-specific FishStartle program, a test program using frequencies in the low frequency portion of the spectrum between 25 and 3300 herz were used. Fish species tested by Sonalysts, Inc. include white perch, striped bass, atlantic tomcod, spottail shiner, and golden shiner (Menezes et al., 1991).

- Sonalysts' FishStartle system used fixed programming contained on Erasable Programmable Read Only Memory (EPROM) micro circuitry. For field applications, a system was developed using IBM PC compatible software. Sonalysts' FishStartle system includes a power source, power amplifiers, computer controls and analyzer in a control room, all of which are connected to a noise hydrophone in the water. The system also uses a television monitor and camera controller that is linked to an underwater light and camera to count fish and evaluate their behavior.

- One Sonalysts, Inc. system has transducers placed 5 m from the bar rack of the intake.

- At the Seton Hydroelectric Station in British Columbia, the distance from the water intake to the fishpulser was 350 m (1150 ft); at Hells Gate, a fishpulser was installed at a distance of 500 feet from the intake.

- The pneumatic gun evaluated at the Roseton intake had a 16.4 cubic cm (1.0 cubic inch) chamber connected by a high pressure hose and pipe assembly to an Air Power Supply Model APS-F2-25 air compressor. The pressure used was a line pressure of 20.7 MPa (3000 psi) (EPRI, 1988).

ADVANTAGES:

- The pneumatic air gun, hammer, and fishpulser are easily implemented at low costs.

- Behavioral barriers do not require physical handling of the fish.

LIMITATIONS:

- The pneumatic air gun, hammer, and fishpulser are not considered reliable.
- Sophisticated acoustic sound generating system require relatively expensive systems, including cameras, sound generating systems, and control systems. No cost information is available since a permanent system has yet to be installed.
- Sound barrier systems require site-specific designs consisting of relatively high technology equipment that must be maintained at the site.

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Chapter 6: Industry Profile: Oil and Gas Extraction Industry

Chapter Contents

INTRODUCTION

The oil and gas industry uses non-contact, once-through water to cool crude oil, produced water, power generators, and various other pieces of machinery at oil and gas extraction facilities.[1] EPA did not consider oil and gas extraction facilities in the Phase I 316(b) rulemaking.

The Phase I proposal and its record included no analysis of issues associated with offshore and coastal oil and gas extraction facilities (such as significant space limitations on mobile drilling platforms and ships) that could significantly increase the costs and economic impacts and affect the technical feasibility of complying with the proposed requirements for land-based industrial operations. Additionally, EPA believes it is not appropriate to include these facilities in the Phase II regulations scheduled for proposal in February 2002; the Phase II regulations are intended to address the largest existing facilities in the steam-electric generating industry. During Phase III, EPA will address cooling water intake structures at existing facilities in a variety of industry sectors. Therefore, EPA believes it is most appropriate to defer rulemaking for offshore and coastal oil and gas extraction facilities to Phase III.

This chapter provides a starting point for future discussions with industry and other stakeholders on future Phase III regulatory decisions.

6.1 HISTORIC AND PROJECTED DRILLING ACTIVITIES

The oil and gas extraction industry drills wells both onshore, coastal, and offshore regions for the exploration and development of oil and natural gas. Various engines and brakes are employed which require some type of cooling system. The U.S. oil and gas extraction industry currently produces over 60 billion cubic feet of natural gas and over 9 million barrels of oil per day.[2] There were roughly 1,096 onshore drilling rigs in operation in August 2001.[3] This section focuses on the OCS oil and gas extraction activities as onshore facilities have less demand for cooling water and have more available options for using dry cooling systems. Moreover, OCS facilities are limited in physical space, payload capacity, and operating environments. EPA will further investigate onshore oil and gas extraction facilities for the Phase III rulemaking.

A large majority of the OCS oil and gas extraction occurs in the Gulf of Mexico (GOM). The Federal OCS generally starts three miles from shore and extends out to the outer territorial boundary (about 200 miles).[†] The U.S. Department of Interior's Mineral Management Service (MMS) is the Federal agency responsible for managing OCS mineral resources. The following summary statistics are from the 1999 MMS factbook.[2]

- The OCS accounts for about 27% of the Nation's domestic natural gas production and about 20% of its domestic oil production. On an energy basis (BTU), about 67 percent of the energy currently produced offshore is natural gas.

- The OCS contains about 19% of the Nation's proven natural gas reserves and 15% of its proven oil reserves. The OCS is estimated to contain more than 50% of the Nation's remaining undiscovered natural gas and oil resources.

- To date, the OCS has produced about 131 trillion cubic feet of natural gas and about 12 billion barrels of oil. The Federal OCS provides the bulk—about 89%—of all U.S. offshore production. Five coastal States—Alaska, Alabama, California, Louisiana and Texas—make up the remaining 11%.

Table 1 presents the number of wells drilled in three areas (GOM, Offshore California, and Coastal Cook Inlet, Alaska) for 1995 through 1997. The table also separates the wells into four categories: shallow water development, shallow water exploratory, deep water development, and deep water exploratory. Exploratory drilling includes those operations drilling wells to determine potential hydrocarbon reserves. Development drilling includes those operations drilling production wells once a hydrocarbon reserve has been discovered and delineated. Although the rigs used in exploratory and development drilling sometimes differ, the drilling process is generally the same for both types of drilling operations.

The water depth in which either exploratory or development drilling occurs may determine the operator's choice of drill rigs and drilling systems. MMS and the drilling industry classify wells as located in either deep water or shallow water, depending on whether drilling is in water depths greater than 1,000 feet or less than 1,000 feet, respectively.

[†] The Federal OCS starts approximately 10 miles from the Florida and Texas shores.

Table 6-1: Number of Wells Drilled Annually, 1995 - 1997, by Geographic Area

Data Source		**Shallow Water (<1,000 ft)**		**Deep Water (≥ 1,000 ft)**		**Total Wells**
		Development	**Exploration**	**Development**	**Exploration**	
Gulf of Mexico†						
MMS:	1995	557	314	32	52	975
	1996	617	348	42	73	1,080
	1997	726	403	69	104	1,302
	Average Annual	640	355	48	76	1,119
RRC		5	3	NA	NA	8
Total Gulf of Mexico		**645**	**358**	**48**	**76**	**1,127**
Offshore California						
MMS:	1995	4	0	15	0	19
	1996	15	0	16	0	31
	1997	14	0	14	0	28
	Average Annual	**11**	**0**	**15**	**0**	**26**
Coastal Cook Inlet						
AOGC:	1995	12	0	0	0	12
	1996	5	1	0	0	6
	1997	5	2	0	0	7
	Average Annual	**7**	**1**	**0**	**0**	**8**

Source: Ref. 4

† Note: GOM figures do not include wells within State bay and inlet waters (considered "coastal" under 40 CFR 435) and State offshore waters (0-3 miles from shore). In August 2001, there were 1 and 23 drilling rigs in State bay and inlet waters of Texas and Louisiana, respectively. There were also 19 and 112 drilling rigs in State offshore waters (0-3 miles from shore), respectively.[3]

Offshore production in the Gulf of Mexico began in 1949 with a shallow well drilled in shallow water. It took another 25 years until the first deepwater well ($1,000 ft. of water) was drilled in 1974. Barriers to deepwater activity include technological difficulties of stabilizing a drilling rig in the open ocean, high financial costs, and natural and manmade barriers to oil and gas activities in the deep waters.

These barriers have been offset in recent years by technological developments (e.g., 3-D seismic data covering large areas of the deepwater Gulf and innovative structure designs) and economic incentives. As a result, deepwater oil and gas activity in the Gulf of Mexico has dramatically increased from 1992 to 1999. In fact, in late 1999, oil production from deepwater wells surpassed that produced from shallow water wells for the first time in the history of oil production in the Gulf of Mexico.[5]

As shown in Table 1, 1,127 wells were drilled in the Gulf of Mexico, on average, from 1995 to 1997, compared to 26 wells in California and 8 wells in Cook Inlet. In the Gulf of Mexico, over the last few years, there has been high growth in the number of wells drilled in deep water, defined as water greater than 1,000 feet deep. For example, in 1995, 84 wells were drilled in deep water, or 8.6 percent of all Gulf of Mexico wells drilled that year. By 1997, that number increased to 173 wells drilled, or over 13 percent of all Gulf of Mexico wells drilled. Nearly all exploration and development activities in the Gulf are taking place in the Western Gulf of Mexico, that is, the regions off the Texas and Louisiana shores.

6.2 OFFSHORE AND COASTAL OIL AND GAS EXTRACTION FACILITIES

There are numerous different types of offshore and coastal oil extraction facilities. Some facilities are fixed for development drilling while other facilities are mobile for both exploration and development drilling. Previous EPA estimates of non-contact cooling water for offshore and coastal oil and gas extraction facilities (OCOGEF) showed a wide range of cooling water demands (294 - 5,208,000 gal/day).[1]

6.2.1 Fixed Oil and Gas Extraction Facilities

Most of these structures use a pipe with passive screens (strainers) to convey cooling water. Non-contact, once-through water is used to cool crude oil, produced water, power generators and various other pieces of machinery (e.g., drawworks brakes). Due to the number of oil and gas extraction facilities in the GOM in relation to other OCS regions, EPA estimated the number of fixed active platforms in the Federal OCS region of the Gulf of Mexico using the MMS Platform Inspection System, Complex/Structure database. These fixed structures are generally used for development drilling. Out of a total of 5,026 structures, EPA identified 2,381 active platforms where drilling is likely to occur (Table 2).

Table 6-2: Identification of Structures in the Gulf of Mexico OCS

Category	Count	Remaining Count
All Structures	5,026	5,026
Abandoned Structures	1,403	3,623
Structures classified as production structures, i.e., with no well slots and production equipment	245	3,378
Structures known not to be in production	688	2,690
Structures with missing information on product type (oil or gas or both)	309	2,381
Structures whose drilled well slots are used solely for injection, disposal, or as a water source	0	2,381

Source: Ref. 5

The Offshore Operators Committee (OOC) and the National Oceans Industries Association (NOIA) also noted in their comments to the May 25, 2001 316(b) Federal Register Notice that a typical platform rig for a Tension Leg Platform[††] will require 10 - 15 MM Btu/hr heat removal for its engines and 3 - 6 MM Btu/hr heat removal for the drawworks brake. The total heat removal (cooling capacity) is 13 - 21 MM Btu/hr. OOC/NOIA also estimated that approximately 200 production facilities have seawater intake requirements that exceed 2 MGD. OOC/NOIA estimate that these facilities have seawater intake requirements ranging from 2 - 10 MGD with one-third or more of the volume needed for cooling water. Other seawater intake requirements include firewater and ballasting. The firewater system on offshore platforms must maintain a positive pressure at all times and therefore requires the

[††] A Tension Leg Platform (TLP) is a fixed production facilities in deepwater environments (> 1,000 ft).

firewater pumps in the deep well casings to run continuously. Ballasting water for floating facilities may not be a continuous flow but is an essential intake to maintain the stability of the facility.

EPA and MMS could only identify one case where the environmental impacts of a fixed OCOGEF CWIS were considered.[6] BP Exploration (Alaska) Inc. (BPXA) plans to locate a vertical intake pipe for a seawater-treatment plant on the south side of Liberty Island, Beaufort Sea, Alaska. The pipe would have an opening 8 feet by 5.67 feet and would be located approximately 7.5 feet below the mean low-water level (Fig. 6-1). The discharge from the continuous flush system consists of the seawater that would be continuously pumped through the process-water system to prevent ice formation and blockage. Recirculation pipes located just inside the opening would help keep large fish, other animals, and debris out of the intake. Two vertically parallel screens (6 inches apart) would be located in the intake pipe above the intake opening. They would have a mesh size of 1 inch by 1/4 inch. Maximum water velocity would be 0.29 feet per second at the first screen and 0.33 feet per second at the second screen. These velocities typically would occur only for a few hours each week while testing the fire-control water system. At other times, the velocities would be considerably lower. Periodically, the screens would be removed, cleaned, and replaced.

MMS states in the Liberty Draft Environmental Impact Statement that the proposed seawater-intake structure will likely harm or kill some young-of-the-year arctic cisco during the summer migration period and some eggs and fry of other species in the immediate vicinity of the intake. However, MMS estimates that less than 1% of the arctic cisco in the Liberty area are likely to be harmed or killed by the intake structure. Further, MMS concludes that: (1) the intake structure is not expected to have a measurable effect on young-of-the-year arctic cisco in the migration corridor; and (2) the intake structure is not expected to have a measurable effect on other fishes populations because of the wide distribution/low density of their eggs and fry.

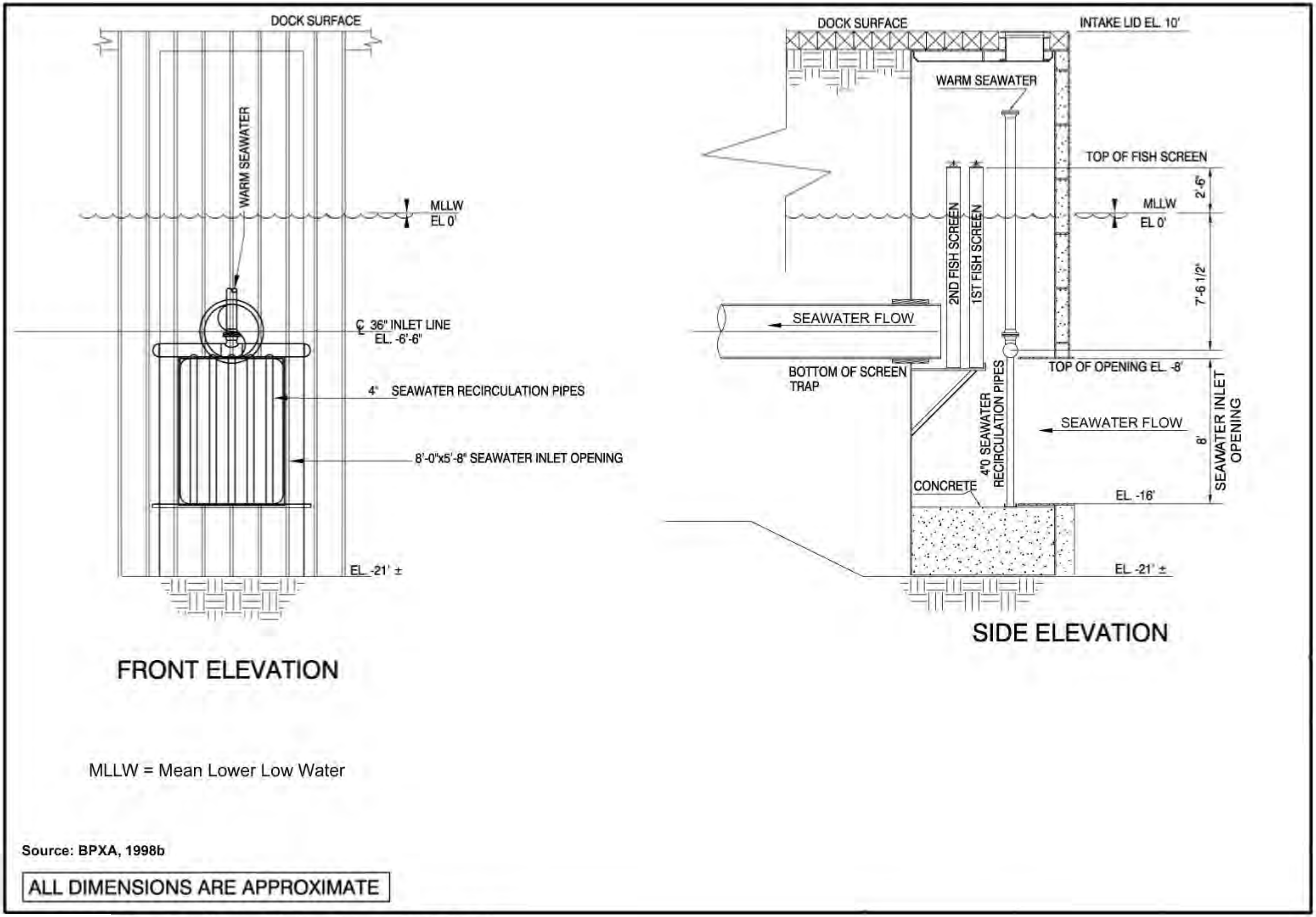

Figure 6-1 Liberty Development Project: Seawater Intake Detail

6.2.2 Mobile Oil and Gas Extraction Facilities

EPA also estimated the number of mobile offshore drilling units (MODUs) currently in operation. These numbers change in response to market demands. Over the past five years the total number of mobile offshore drilling units (MODUs) operating at one time in areas under U.S. jurisdiction has ranged from less than 100 to more than 200. There are five main types of MODUs operating in areas under U.S. jurisdiction: drillships, semi-submersibles, jack-ups, submersibles and drilling barges. Table 3 gives a brief summary of each MODU. EPA and MMS could not identify any cases where the environmental impacts of a MODU CWIS were considered.

Table 6-3: Description of Mobile Offshore Drilling Units and their CWIS

MODU Type	Water Intake† and Design	Water Depth	No. Currently in GOM	No. Currently Under Construction Over Next Three Years
Drill Ships	16 - 20 MGD Seachest	Greater than 400 ft	5	0
Semi-submersibles	2 - 15+ MGD Seachest	Greater than 400 ft	37	5
Jack-ups	2 - 10+ MGD Intake Pipe	Less than 400 ft	140	9
Submersibles	< 2 MGD Intake Pipe	Shallow Water (Bays and Inlet Waters)	6	0
Drill Barges	< 2 MGD Intake Pipe	Shallow Water (Bays and Inlet Waters)	20	0

Sources: Ref. 7, Ref. 8, Ref. 9, Ref. 10

† Approximately 80% of the water intake is used for cooling water with the remainder being used for hotel loads, fire water testing, cleaning, and ballast water.[7]

The particular type of MODU selected for operation at a specific location is governed primarily by water depth (which may be controlling), anticipated environmental conditions, and the design (depth, wellbore diameter, and pressure) of the well in relation to the units equipment. In general, deeper water depths or deeper wells demand units with a higher peak power-generation and drawworks brake cooling capacities, and this directly impacts the demand for cooling water.[10]

Drillships and Semi-Submersibles MODUs

Drill ships and semi-submersibles use a "seachest" as a CWIS. In general there are three pipes for each sea chest (these include CWIs and fire pumps). One of the three intake pipes is always set aside for use solely for emergency fire fighting operations. These pipes are usually back on the flush line of the sea chest. The sea chest is a cavity in the hull or pontoon of the MODU and is exposed to the ocean with a passive screen (strainer) often set along the flush line of the sea chest. These passive screens or weirs generally have a maximum opening of 1 inch.[9] There are generally two sea chests for each drill ship or semi-submersible (port and starboard) for redundancy and ship stability considerations. In general, only one seachest is required at any given time for drilling operations.[7]

While engaged in drilling operations most drillships and one-third of semi-submersibles maintain their position over the well by means of "dynamic positioning" thrusters which counter the effects of wind and current. Additional power is required to operate the drilling and associated industrial machinery, which is most often powered electrically from the same diesel generators that supply propulsion power. While the equipment powered by the ship's electrical generating system changes, the total power requirements for drillships are similar to those while in transit. Thus, during drilling operations the total seawater intake on a drillship is approximately the same as while underway. The majority of semi-submersibles are not self- propelled, and thus require the assistance of towing vessels to move from location to location.

Information from the U.S. Coast Guard indicates that when semi-submersibles are drilling their sea chests are 80 to 100 feet below the water surface and are less than 20 feet below water when the pontoons are raised for transit or screen cleaning operations.[7] Drill ships have their sea chests on the bottom of their hulls and are typically 20 to 40 feet below water at all times.

IADC notes that one of the earlier semi-submersible designs still in use is the “victory” class unit.[10] This unit is provided with two seawater-cooling pumps, each with a design capacity of 2.3 MGD with a 300 head. At operating draft the center of the inlet, measuring approximately 4 feet by 6 feet, is located 80 feet below the sea surface and is covered by an inlet screen. In the original design this screen had 3024 holes of 15mm diameter. The approximate inlet velocity is therefore 0.9 feet/sec.

The more recent semi-submersible designs typically have higher installed power to meet the challenges of operating in deeper water, harsher environmental condition, or for propulsion or positioning. IADC notes that a new design, newly-built unit has a seawater intake capacity of 34.8 MGD (including salt water service pumps and ballast pumps) and averages 10.7 MGD of seawater intake of which 7.4 MGD is used for cooling water.

Jack-up MODUs

Jack-up, submersibles, and drill barges use intake pipes for CWIS. These OCOGEF basically use a pipe with a passive screens (strainers) to convey cooling water. Non-contact, once-through water is used to cool crude oil, produced water, power generators and various other pieces of machinery on OCOGEF (e.g., drawworks brakes).

The jack-up is the most numerous type of MODU. These vessels are rarely self- propelled and must be towed from location to location. Once on location, their legs are lowered to the seabed, and the hull is raised (jacked-up) above the sea surface to an elevation that prevents wave impingement with the hull. Although all of these ships do use seawater cooling for some purposes (e.g., desalinators), as with the semi-submersibles a few use air-cooled diesel-electric generators because of the height of the machinery above the sea surface.[9] Seawater is drawn from deep-well or submersible pumps that are lowered far enough below the sea surface to assure that suction is not lost through wave action. Total seawater intake of these ships varies considerably and ranges from less than 2 MGD to more than 10 MGD. Jack-ups are limited to operating in water depths of less than 500 feet, and may rarely operate in water depths of less than 20 feet.

The most widely used of the jack-up unit designs is the Marathon Letourneau 116-C.[10] For these types of jack-ups typically one pump is used during rig operations with a 6” diameter suction at 20 to 50 feet below water level which delivers cooling water intake rates of 1.73 MGD at an inlet velocity of 13.33 ft/sec.[10] Additionally, pre-loading involves the use of two or three pumps in sequence. Pre-loading is not a cooling water procedure, but a ballasting procedure (ballast water is later discharged). Each pump is fitted with its own passive screen (strainer) at the suction point which provides for primary protection against foreign materials entering the system.

In their early configurations, these jack-up MODUs were typically outfitted with either 5 diesel generator units (each rated at about 1,200 horsepower) or three diesel generator units (each rated at about 2,200 horsepower).[10] In subsequent configurations of this design or re-powering of these units, more installed power has generally been provided, as it has in more recent designs. With more installed power, there is a demand for more cooling water. The International Association of Drilling Contractors (IADC) reports that a newly-built jack-up, of a new design, typically requires 3.17 MGD of cooling water for its drawworks brakes and cooling of six diesel generator units, each rated at 1,845 horsepower.[10] In this case, one pump is typically used during rig operations with a 10" diameter suction at 20 to 50 feet below water level, delivering the cooling water at 3.2 MGD.

Submersibles and Drill Barge MODUs

The submersible MODU is used most often in very shallow waters of bays and inlet waters. These MODUs are not self-propelled. Most are powered by air-cooled diesel-electric
generators, but require seawater intake for cooling of other equipment, desalinators, and for other purposes. Total seawater intake varies considerably with most below 2 MGD.

The drilling barge MODU There are approximately 50 drilling barges available for operation in areas under U.S. jurisdiction, although the number currently in operation is less than 20. These ships operate in shallow bays and inlets along the Gulf Coast, and occasionally in shallow offshore areas. Many are powered by air-cooled diesel-electric generators. While they have some water intake for sanitary and some cooling purposes, water intake is generally below 2 MGD.

6.3 316(b) Issues Related to Offshore and Coastal Oil and Gas Extraction Facilities

There are several important 316(b) issues related to OCOGEF CWIS that EPA will be investigating in the Phase III 316(b) rulemaking: (1) Biofouling; (2) Definition of New Source; (3) Potential Costs and Scheduling Impacts. EPA will work with stakeholders to identify other issues for resolution during the Phase III 316(b) rulemaking process.

6.3.1 Biofouling

Industry comments to the 316(b) Phase I proposal assert that operators must maintain a minimum intake velocity of 2 to 5 ft/sec in order to prevent biofouling of the offshore oil and gas extraction facility CWIS. EPA requested documentation from industry regarding the relationship between marine growth (biofouling) and intake velocities.[11] Industry was unable to provide any authoritative information to support the assertion that a minimum intake velocity of 2 to 5 ft/sec is required in order to prevent biofouling of the OCOGEF CWIS. IADC asserts that it is common marine engineering practice to maintain high velocities in the seachest to inhibit attachment of marine biofouling organisms.[10]

The Offshore Operators Committee (OOC) and the National Oceans Industries Association (NOIA) also noted in their comments to the May 25, 2001 316(b) Federal Register Notice that the ASCE "Design of Water Intake Structures for Fish Protection" recommends an approach velocity in the range of 0.5 to 1 ft/s for fish protection and 1 ft/s for debris management but does not address biofouling specifically. OOC/NOIA were unable to find technical papers to support a higher intake velocity. The U.S. Coast Guard and MMS were also unable to provide EPA with any information on velocity requirements or preventative measures regarding marine growth inhibition or has a history of excessive marine growth at the sea chest.

EPA was able to identify some of the major factors affecting marine growth on offshore structures. These factors include temperature, oxygen content, pH, current, turbidity, and light.[12,13] Fouling is particularly troublesome in the more fertile coastal waters, and although it diminishes with distance from the shoreline, it does not disappear in midoceanic and in the abyssal depths.[13] Moreover, operators are required to perform regular inspection and cleaning of these CWIS in accordance with USCG regulations.

Operators are also required by the U.S. Coast Guard to inspect sea chests twice in five years with at least one cleaning to prevent blockages of firewater lines. The requirement to drydock MODUs twice in five years and inspect and clean their sea chests and sea valves are found in U.S. Coast Guard regulations (46 CFR 107.261 and 46 CFR 61.20-5). The U.S. Coast Guard may require the sea chests to be cleaned twice in 5 years at every drydocking if the unit is in an area of high marine growth or has had history of excessive marine growth at the sea chests.

EPA and industry also identified that there are a variety of specialty screens, coatings, or treatments to reduce biofouling. Industry and a technology vendor (Johnson Screens) also identified several technologies currently being used to control biofouling (e.g., air sparing, Ni-Cu alloy materials). Johnson Screens asserted in May 25, 2001 316(b) Federal Register Notice comments to EPA that their copper based material can reduce biofouling in many applications including coastal and offshore drilling facilities in marine environments.

Biocide treatment can also be used to minimize biofouling. IADC reports that one of their members uses Chloropac systems to reduce biofouling (www.elcat.co.uk/chloro_anti_mar.htm). The Liberty Project plans to use chlorine, in the form of calcium hypochlorite, to reduce biofouling. The operator (BPXA) will reduce the total residual chlorine concentration in the discharged cooling water by adding sodium metabisulfate in order to comply with limits of the National Pollution Discharge Elimination System Permit. MMS estimates that the effluent pH will vary slightly from the intake seawater because of the chlorination/dechlorination processes, but this variation is not expected to be more than 0.1 pH units.

In summary, EPA has not yet identified any relationship between the intake velocity and biofouling of a offshore oil and gas extraction facility CWIS. However, EPA will be pursuing this and other matters related to biofouling in the offshore oil and gas industry in the Phase III 316(b) regulation.

6.3.2 Definition of New Source

Industry claimed in comments to the Phase I 316(b) proposal and the May 25, 2001 316(b) Federal Register Notice that existing MODUs could be considered "new sources" when they drill new development wells under 40 CFR 435.11 (exploration facilities are excluded from the definition of new sources). EPA will work with stakeholders to clarify the regulatory status of existing MODUs in the Phase III 316(b) proposal and final rule.

6.3.3 Potential Costs and Scheduling Impacts

Costs to Retrofit for Velocity Standard

EPA did not identify any additional costs to incorporate the 0.5 fps maximum velocity standard into new designs for future (not yet built) OCOGEF CWIS. Retrofit cost for production facilities will vary depending on the type of cooling water intake structure the facility has in place. The U.S. Coast Guard did not have a good estimate of seachest CWIS retrofit costs but did have a general idea of the work requirements for these potential retrofits.[7] The Coast Guard stated that retrofits for drill ships and semi-submersibles that use seachests as the CWI structure could probably be in the millions of dollars (approximately 8-10 million dollars) and require several weeks to months for drydocking operations. Complicating matters is that there are only a few deepwater drydock harbors capable of handling semi-submersibles. MMS did not have any information on costs and issues relating to retrofitting sea chests or other offshore CWIS.

OOC/NOIA estimated costs for retrofitting a larger intake for a floating production system tension leg platform (TLP).[14] Under their costing scenario, it was assumed that the TLP had a seachest intake structure with a pre-existing flange on the exterior of the intake structure which could be used to bolt on a larger diameter intake in order to reduce the intake velocity to below 0.5 ft/s. The estimated cost to retrofit this new intake is $75,000. OOC/NOIA estimates that this same cost can be assumed for retrofiting a deep well pump casing with a larger diameter intake provided the bottom of the casing is not obstructed and the intake structure can be clamped over the casing.

OOC/NOIA further estimates that for TLP's with seachests without a pre-existing flange for an intake structure and for deep well pump casings that are obstructed and prevent the installation of an intake structure, the retrofit costs are estimated to be much higher.[14] OOC/NOIA estimates that if underwater welding or the installation of new pump casing are required, the costs can be as high as $500,000. In these cases, the platform would need to be shut-in for some period of time (1-3 days) to allow for this installation. Included in this estimate is the need to provide for additional stiffening of underwater legs and supports to resist the wave loading forces of the new intake structures. OOC/NOIA estimates that many facilities have multiple deepwell casings or seachests that would require retrofitting.

IADC notes that the feasibility of redesigning seachests to reduce intake velocity would need to be examined on a case-by-case basis.[10] As interior space is typically optimized for the particular machinery installation, IADC further notes that a prerequisite for enlarging any seachest would be repositioning of machinery, piping and electrical systems and that such operations could only be undertaken in a drydock. Seachests on semi-submersible units are not likely located in stress-critical areas, so effective compensation of hull strength is unlikely to be a major concern, unlike a drillship where, depending on the design, it might be difficult to provide effective compensation to hull girder strength for an enlarged seachest

Costs for retro-fitting jack-ups would likely be much less complicated and expensive than semi-submersible and drillship sea chest retro-fits.[7] The U.S. Coast Guard estimates that operators could install a bell or cone intake device on the existing CWIS to reduce CWI velocities. IADC notes that installing passive screens (strainers) with a larger surface area on jack-up CWIS in order to reduce the intake velocity at the face of the screen would add weight and pose handling problems (e.g., require more frequent cleaning).

Costs to Retrofit to Dry Cooling

OOC/NOIA stated in their May 25, 2001 316(b) Federal Register Notice comments that offshore production platforms will typically use direct air cooling or cooling with a closed loop system for cooling requirements where technically feasible. The following items are typically direct air cooled: gas coolers on compressors, lubrication oil coolers on compressors and generators, and hydraulic oil coolers on pumps. These coolers will range from 1 to 35 MM Btu/hr heat removal capacity. Seawater cooling is necessary in many cases because space and weight limitations render air cooling infeasible. This is particularly true for floating production systems which have strict payload limitations.

IADC reports that some jack-up MODUs were converted from sea water cooling systems to closed-loop air cooling systems for engine and drawworks brake cooling.[10] IADC reported the cost of the conversion, completed during a regular shipyard period, was approximately $1.2 million and required a six-month lead-time to obtain the required equipment. The conversion resulted in the loss of deck space associated with the installation of the air-cooling units, and a small loss in variable deck load equal to the additional weight of the air-cooling units and associated piping.

OOC/NOIA provided initial costs to convert from seawater cooling to air cooling with a radiator on a platform rig. In this case, a cantilevered deck was installed onto the side of the pipe rack. The radiator was rated at about 15 MM Btu/hr, and the cost for the installation was about $150,000. The weight of the addition was about 15,000 pounds. The cost of space and payload on an offshore platform is about $5/pound; therefore, the added weight cost about $75,000 bringing the total cost to about $225,000.

EPA agrees with industry that dry cooling systems are most easily installed during planning and construction, but some can be retrofitted with additional costs. IADC believes that it is already difficult to justify such conversions of jack-ups and that it would be far more difficult to justify conversion of drillships or semi-submersibles. EPA will also look at the net gain or loss in the energy efficiency of conversions from wet to dry cooling.

6.3.4 Description of Benefits for Potential 316(b) Controls on Offshore and Coastal Oil and Gas Extraction Facilities

EPA was only able to identify one case where potential impacts to aquatic communities from OCOGEF CWIS were described (MMS Liberty Draft Environmental Impact Statement).[6] MMS estimated that less than 1% of the arctic cisco in the Liberty area are likely to be harmed or killed by the intake structure but that the intake structure is not expected to have a measurable effect on young-of-the-year arctic cisco in the migration corridor or on other fishes populations.

OOC submitted a video tape of three different OCOGEF CWIS as part of their public comments. These CWIS have an intake of 5.9 to 6.3 MGD with a intake velocity of 2.6 to 2.9 ft/s. The intake has a passive screen (strainer) with 1 inch diameter slots. EPA will use this documentation in determining potential impacts on aquatic communities from OCOGEF CWIS.

6.4 Phase III Activities Related to Offshore and Coastal Oil and Gas Extraction Facilities

Numerous researchers and State and Federal regulatory agencies have studied and controlled the discharges from these facilities for decades. The technology-based standards for the discharges from these facilities are located in 40 CFR 435. Conversely, there has been extremely little work done to investigate the environmental impacts or evaluation of the location, design, construction, and capacity characteristics of OCOGEF CWIS that reduce impingement and entrainment of aquatic organisms.

EPA discussions with two main regulatory entities of OCOGEF (i.e., MMS, USCG) identified no regulatory requirements on these OCOGEF CWIS with respect to environmental impacts. MMS generally does not regulate or consider the potential environmental impacts of these OCOGEF CWIS. MMS could only identify one case where the environmental impacts of a OCOGEF CWIS were considered.[6] Moreover, MMS does not collect information on CWI rates, velocities and durations for any OCOGEF CWIS. The U.S. Coast Guard does not investigate potential environmental impacts of MODU CWIS but does require operators to inspect sea chests twice in five years with at least one cleaning to prevent blockages of firewater lines.

EPA will work with industry and other stakeholders to identify all major issues associated with OCOGEF CWIS and potential Phase III 316(b) requirements. EPA will also collect additional data to identify the costs and benefits associated with any regulatory alternative.

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