United States Environmental Protection Agency

# Technical Development Document for the Final Section 316(b) Phase III Rule

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# Acronyms

| | |
|---|---|
| a.k.a | also known as |
| AACE | American Association of Cost Engineers International |
| ADECA | Alabama Department of Economics and Community |
| AFB | aquatic filter barrier |
| AIF | actual intake flow |
| AKDFG | Alaska Department of Fish and Game |
| AKDNR | Alaska Department of Natural Resources |
| AOS | apparent opening size |
| ASCE | American Society of Civil Engineers |
| ASTM | American Society for Testing and Materials |
| BAFF | Bio-Acoustic Fish Fence |
| Bcf | billion cubic feet |
| BLS | Bureau of Labor Statistics |
| BPJ | best professional judgement |
| BPXA | BP Exploration, Inc. |
| BTA | best technology available |
| BTU | British thermal unit |
| C | Celsius |
| CalCOFI | California Cooperative Oceanic Fisheries Investigations |
| CEQ | Council of Environmental Quality |
| CFD | Computational Fluid Dynamics |
| CFR | Code of Federal Regulations |
| cfs | cubic feet per second |
| CGI | Conversion Gas Imports |
| cm | centimeter |
| CTR | cost to revenue |
| cu yd | cubic yard |
| CuNi | copper-nickel |
| CUR | capacity utilization rate |
| CWA | Clean Water Act |
| CWIS | cooling water intake structure |
| CWS | cooling water system |
| d | day |
| dB | decibel |
| dia | diameter |
| DIF | design intake flow |
| DOI | Department of the Interior |
| DTQ | Detailed Technical Questionnaire |
| DWPA | Deepwater Port Act of 1974 |
| E | entrainment |
| EA | Economic Analysis |
| EA | Environmental Assessment |
| EBA | Economic Benefits Analysis |
| EIS | Environmental Impact Statement |
| ENR | Engineering News Record |
| EPA | Environmental Protection Agency |
| EPRI | Electric Power Research Institute |
| Eqn | equation |

| | |
|---|---|
| ETSU | Energy Technology Support Unit |
| F | Fahrenheit |
| FERC | Federal Energy Regulatory Commission |
| FGS | fish guidance system |
| FPL | Florida Power & Light |
| fps | feet per second |
| FR | Federal Register |
| ft | foot |
| GBS | gravity based structure |
| GCOM | gross compliance operations and maintenance |
| GIS | geographical information system |
| GOM | Gulf of Mexico |
| gpm | gallons per minute |
| HP | horsepower |
| hr | hour |
| Hz | hertz |
| I | impingement |
| I&E | impingement and entrainment |
| IADC | International Association of Drilling Contractors |
| ICR | information collection request |
| IFV | intermediate fluid vaporizers |
| IM | impingement mortality |
| IM&E | impingement mortality and entrainment |
| in. | inch |
| IPM | Integrated Planning Model |
| kW | kilowatt |
| kWh | kilowatt hour |
| l | liter |
| lb | pound |
| LMOGA | Louisiana Mid-Continent Oil and Gas Association |
| LNG | liquefied natural gas |
| m | meter |
| mg | milligram |
| MGD | million gallons per day |
| MIS | modular inclined screen |
| MLES | Marine/Aquatic Life Exclusion System |
| mm | millimeter |
| MM Btu/hr | million British thermal units |
| MMS | Mineral Management Service |
| MMTPA | million tons per year |
| MODU | mobile offshore drilling units |
| MPEH | Main Pass Energy Hub |
| MRIF | maximum reported intake flow |
| MSL | mean sea level |
| MTSA | Maritime Transportation Security Act of 2002 |
| MW | megawatt |
| N/A | not applicable |
| NEPA | National Environmental Policy Act |
| NEST | Northeast Science and Technology |
| NOAA | National Oceanic and Atmospheric Administration |
| NODA | Notice of Data Availability |
| NOIA | National Oceans Industries Association |

| | |
|---|---|
| NOx | oxides of nitrogen |
| NPDES | National Pollutant Discharge Elimination System |
| NPP | nuclear power plant |
| NYDEC | New York Department of Environmental Conservation |
| O&G | oil and gas |
| O&M | operations and maintenance |
| OCS | outer continental shelf |
| OOC | Offshore Operators Committee |
| ORV | open rack vaporizer |
| OWR | Office of Water Resources |
| PCCP | prestressed concrete cylinder pipe |
| POA | percent open area |
| ppm | parts per million |
| psf | pounds per square foot |
| psi | pounds per square inch |
| psig | pounds per square inch gauge |
| PVC | polyvinyl chloride |
| re 1 mPa | at underwater reference pressure of 1 micro Pascal |
| s | second |
| SAV | submerged aquatic vegetation |
| SCV | submerged combustion vaporizers |
| SEAMAP | Southeast Area Monitoring and Assessment Program |
| SIC | Standard Industrial Classification |
| SPA | sound projector array |
| sq | square |
| SS | stainless steel |
| STL | submerged turret loading |
| STQ | short technical questionnaire |
| STV | shell and tube vaporizer |
| TBD | to be determined |
| TDD | Technical Development Document |
| TECC | total estimated capital costs |
| TVA | Tennessee Valley Authority |
| U.S. | United States |
| USC | United States Code |
| USCG | United States Coast Guard |
| USD | United States dollars |
| vs. | versus |
| WSPA | Western States Petroleum Association |
| yd | yard |

# Chapter 5: Costing Methodology for Phase III Existing Model Facilities

## INTRODUCTION

This chapter describes the methodology used to estimate engineering compliance costs associated with implementing the proposed regulatory options considered for section 316(b) Phase III facilities. Since Phase III existing facilities are not subject to national categorical requirements, this chapter is provided for information purposes only.

Section 1.0 of this chapter describes the regulatory control options considered by the Agency. To assess the economic impact of these control options, EPA estimates the costs associated with regulatory compliance. The methodology for technology and control costs for electric power generators and manufacturers is in section 2.0 of this chapter. The full economic burden is a function of these costs of compliance, which may include initial fixed and capital costs, annual O&M costs, downtime costs, recordkeeping, monitoring, studies, and reporting costs. The results of the economic impact analysis for the final regulation are found in the Economic Analysis (DCN 7-0002). A detailed description of the technologies and practices used as a basis for the proposed regulatory options is found in Chapter 3 of this document.

For the purpose of estimating incremental compliance costs attributable to regulatory requirements, EPA traditionally develops either facility-specific or model facility costs. Facility-specific compliance costs require detailed process information about many, if not all, facilities in the industry. These data typically include production, capacity, water use, wastewater generation, overall management, monitoring data, geographic location, financial conditions, and other industry-specific data that may be required for the analyses. EPA used a detailed technical survey of electric power and manufacturing facilities[1] to determine how each regulatory option would affect the surveyed facilities, and to estimate the cost of installing new or additional controls. The cost and basis for each control is described in section 1 of this chapter.

When facility-specific data are not available, EPA develops model facilities to provide a reasonable representation of the industry. EPA then determines the number of facilities that are represented by each model. Industry level costs are then calculated by multiplying the model-specific costs by the number of facilities that are represented by each particular model.

In developing costs for the section 316(b) Phase III proposed rule, EPA used the model facility approach. EPA primarily used facility-specific survey data, supplemented where necessary by industry supplied data and follow-up interviews to clarify a facility's responses. EPA did not survey all manufacturers, and therefore did not have sufficient data to conduct facility-specific costs for all facilities potentially subject to the proposed Phase III rule. EPA did send questionnaires to a statistically representative set of approximately 1400 manufacturers and power generators with a design intake flow of at least 2 MGD. EPA calculated facility-specific costs for 346 facilities potentially in-scope of the Phase III rulemaking, and applied the model facility approach to each facility-specific cost to calculate the industry level costs for 650 manufacturing and electric power producing facilities. EPA used the Cost Test Tool described in section 2.0 to calculate the model-facility costs. Section 3.0 provides some examples. Section 4.0 provides an analysis of the confidence in accuracy of the 316(b) compliance cost modules. Section 5.0 provides an estimate of facility downtime.

## 1.0 REGULATORY OPTIONS

EPA proposed requirements for the location, design, construction, and capacity of cooling water intakes based on the volume of water withdrawn by a Phase III facility. EPA proposed three regulatory options based on the design intake flow value and the type of waterbody from which a facility withdraws water for cooling. These included: 1) 50 MGD and above for all waterbodies; 2) 100 MGD and above on certain waterbodies (estuaries, oceans, tidal rivers, or Great Lakes); and 3) 200 MGD and above on all waterbodies.

[1] EPA focused its survey and data collection efforts on six industrial categories that, as a whole, were estimated to account for over 99 percent of all cooling water withdrawals: Utility Steam Electric, Nonutility Steam Electric, Chemicals & Allied Products, Primary Metals Industries, Petroleum & Coal Products, and Paper & Allied Products.

Data analyzed from EPA's detailed technical survey shows cooling water intake structures at Phase II electric power generating facilities are, in general, no different than those intake structures employed by Phase III facilities, particularly manufacturing facilities and lower flow electric power generating facilities. See Chapter 4 of this document for more detail. These factors, plus EPA's additional experiences in section 316(b) Phase I and Phase II rulemakings (see EPA's Final Response to Comments Document DCN 6-5049A and the Phase II Final Preamble 69 FR 41575), as well as Phase III stakeholders (such as small business concerns) led EPA to consider the regulatory options described above. Facilities that would have been subject to requirements on a case-by-case, BPJ basis (i.e., they had a design intake flow less than the threshold considered in the regulatory option) were assigned no costs.

### 1.1 Analysis of Capacity Utilization Rate

The final Phase II rule includes a provision that allows facilities that have either a historic capacity utilization rate of less than 15 percent or those agreeing to limit their future utilization rate to less than 15 percent to comply with impingement reduction requirements only. For Phase II facilities expected to upgrade technologies as a result of the rule (determined from information reported in the Detailed Questionnaire), the Agency determined that 1.0 percent of the total actual annual intake of these facilities shall be associated with those facilities falling below the 15 percent capacity utilization threshold. Furthermore, 0.7 percent of the total actual annual intake of the Phase II facilities expected to upgrade technologies could be attributed to those receiving relief from entrainment requirements due to the threshold. For this small number of facilities and negligible percentage of affected intake flow, the Agency concludes that the capacity utilization threshold will have no measurable national impact on the entrainment reduction of the final rule.

There is a potential for facilities to choose to operate at a lower capacity utilization rate to avoid entrainment requirements, forego electricity production as a result, and thereby have an impact on local or regional energy markets. EPA examined the electricity generation implications of the capacity utilization rate threshold at those facilities that are within close range of the capacity utilization rate (i.e., those between 15 and 20% historic capacity utilization) to determine if the facilities would economically benefit from reduced entrainment requirements. EPA conducted a break-even analysis of the net revenue from electricity production foregone compared against the savings of removing entrainment requirements for those facilities between 15 and 20% historic capacity utilization rates. Exhibit 5-1 presents the results of the break-even analysis. The median and average break-even capacity utilization rates are less than 15.1%. The Agency found one facility in its database of Phase II facilities that might fall between 15 and 15.1% capacity utilization. The amount of electricity production foregone as a result of this facility's change to avoid entrainment controls would be on the order of 3,000 megawatt hour (MWh) per year. This is a negligible amount of electricity generation in any local or regional market.

This same capacity utilization concept was applied to Phase III facilities. The Agency analyzed all power generating facilities projected under the 2 to 50 MGD threshold range and examined the likely operating periods for these facilities. Of the 42 facilities projected to fall within the threshold, 17 of these facilities are subject to impingement- only requirements, regardless of the existence of the utilization threshold. Furthermore, of the 25 facilities (5 percent of Phase II facilities) that receive reduced entrainment requirements under the capacity threshold, the total median operation period per year is 28 days. Considering that this operational period is broken about in two likely periods in winter and summer, the approximate 2-week period in each season will likely overlap only a small portion of potential spawning periods. The operational flow of the facilities receiving reduced entrainment requirements over the typical 28 days per year will be 1% of the total annual intake of facilities potentially within scope of the Phase III rulemaking (i.e. power generators with a DIF of 2 MGD to 50 MGD) that are subject to entrainment reduction requirements. Therefore, the capacity utilization rate threshold will not appreciably decrease the entrainment efficacy of the proposed performance standards.

EPA analyzed the cost to revenue ratios of facilities above and below the capacity utilization threshold. In addition, the Agency analyzed cost to revenue ratios for facilities in absence of the capacity utilization threshold relief. The Agency determined that facilities falling below the capacity utilization rate threshold of 15 percent experience average cost to revenue ratios of 4.4 % (median of 1.2%) with the threshold relief from entrainment and approximately 6% (median of 2.4%) without the presence of the utilization threshold. The Agency determined that facilities above the threshold experience far lower average cost to revenue ratios of 1.2% (median of 0.4%).

As can be seen from the results of the cost to revenue, operating period, and flow analysis in Exhibit 5-2, the Agency's capacity utilization rate of 15 percent balances the competing factors of providing needed compliance relief while providing environmental protection. The Agency notes that the possible environmental improvement in the average operating periods in the 10 percent compared to the 15 percent capacity utilization rate is very small (one week per year). Furthermore, the difference in the amount of flow subject to entrainment requirements between the 10 and 15 percent rates is also very small. Therefore, the Agency concludes that the improvement in average cost to revenue relief between the lower thresholds is sufficient to warrant the 15 percent rate. On the higher side, the Agency notes that both the operating periods and the percentage of flow receiving entrainment relief under the 20 and 30% rates are considerably higher than for 15 percent. In addition, the improvement in cost to revenue relief is not as great between 15 and 30 percent (and 20 percent, for that matter) as the difference improvement between 10 and 15 percent. The Agency concludes that its selection of the 15% rate is the most reasonable balance for all four threshold factors analyzed in Exhibit 5-2.

**Exhibit 5-1. Break-Even Analysis for Facilities that *Might* Reduce Capacity Utilization Rates To Avoid Entrainment Controls**

| Average Capacity Utilization Rate (1995-1999) | Average Annual Generation (MWh) | Annual Costs of Entrainment Reduction | Annual Costs of Impingement Only Reduction | Annual Cost Diff. Between Entrainment and Impingement Reduction | Annual Generation Loss (MWh / year) to Meet 15% Capacity Utilization | Cost of Annual Generation Foregone ($ / year) to meet 15% | Capacity Utilization Break-even Solver Value |
|---|---|---|---|---|---|---|---|
| 15.8% | 2,478,619 | $ 2,434,420 | $ 78,065 | $ 2,356,355 | 829,440 | $ 25,712,628 | 15.0693% |
| 16.4% | 128,032 | $ 510,945 | $ 62,589 | $ 448,356 | 72,620 | $ 2,251,210 | 15.2586% |
| 16.6% | 1,202,511 | $ 358,071 | $ 100,591 | $ 257,480 | 770,455 | $ 23,884,099 | 15.0061% |
| 16.7% | 200,024 | $ 704,805 | $ 59,781 | $ 645,025 | 134,919 | $ 4,182,475 | 15.2378% |
| 17.1% | 620,453 | $ 684,882 | $ 33,398 | $ 651,484 | 502,939 | $ 15,591,113 | 15.0766% |
| 18.4% | 574,367 | $ 1,073,438 | $ 149,075 | $ 924,364 | 708,362 | $ 21,959,212 | 15.1177% |
| 19.2% | 2,319,433 | $ 1,636,977 | $ 69,723 | $ 1,567,254 | 3,413,875 | $ 105,830,123 | 15.0492% |
| 19.4% | 6,406,991 | $ 94,825 | $ 81,322 | $ 13,503 | 9,712,022 | $ 301,072,695 | 15.0002% |
| 19.7% | 708,553 | $ 610,068 | $ 47,283 | $ 562,785 | 1,129,631 | $ 35,018,568 | 15.0579% |

**Exhibit 5-2. Threshold Comparison Analysis**

| Average Capacity Utilization Rate Threshold | Average cost to revenue (CTR) below threshold w/ entrainment relief | Average CTR below threshold if no entrainment relief | Average CTR of all facilities | Average operating days per year of facilities w/ entrainment relief | Percent of total flow subject to entrainment requirements receiving relief |
|---|---|---|---|---|---|
| 10 percent | 5.7% | 7.3% | 1.5% | 21 | 0.3% |
| 15 percent | 4.4% | 6.0% | 1.5% | 28 | 1.0% |
| 20 percent | 3.8% | 4.7% | 1.5% | 40 | 2.6% |
| 30 percent | 3.4% | 3.3% | 1.5% | 62 | 7.8% |

CTR = Cost-to-revenue ratio.

## 1.2 Analysis of Cooling System Type For Electric Power Generating Facilities

Combination Cooling Systems

The final Phase III rule does not affect electric power generating facilities. Therefore, this section is provided for information purposes only. Fifty facilities reported combination-cooling systems in the 316(b) survey (in the short-technical or detailed questionnaire). EPA analyzed the intake-level and cooling system-level information reported in the survey for each of these facilities. The Agency found that the median percentage of overall facility flow associated with the recirculating intake feed was 5.3 percent. Therefore, 95 percent of the facility's flow is associated with the once-through intakes.

EPA attempted to gauge the degree to which national costs may be overstated by examining these facilities with combination cooling systems and adjusting their technology upgrade costs to reflect the fact that a recirculating intake at the facility may have lesser requirements than as assumed. Because the Agency determined that 5 percent of the total facility intake would be typically associated with the recirculating intake, to which the Agency assigned costs for reducing entrainment and/or impingement mortality through technology upgrades, the Agency adjusted those annual cost items that are primarily a function of flow by multiplying by – 5%. The cost items that are primarily a function of flow include capital cost, O&M cost, and pilot study costs. For adjustments to downtime costs the Agency necessarily examined the portion of the plant's intakes associated with the recirculating system. Typically, the recirculating portion of the cooling system corresponded to one of several intakes at the facility. The most common occurrence was for one of two intakes to be dedicated to a recirculating system and the other to a once-through configuration. The average number of intakes at each of the facilities with combination cooling systems was close to three intakes. A frequent occurrence also was for one of three intakes to be dedicated to the recirculating system. Rarely was more than three intakes reported, and in these cases multiple intakes were generally associated with a recirculating system. Based on these facts, the Agency believes that a reasonable characterization for the "typical" combination cooling system in the database was for one of three intakes to correspond to a recirculating system and the others to be dedicated as once-through. Hence, for the case of downtime costs, the Agency considered a reasonable adjustment to be one-third of the cost of the downtime at the facility-level. The logic is that, should a generating unit with a unique intake not require a downtime and yet the Agency did assign one, then the cost of the downtime for the facility would be overestimated. Because the typical configuration for the combination cooling system has one of three intakes per facility dedicated to the recirculating system, then a facility-wide downtime assumption would potentially overstate downtimes by one-third, provided all units roughly generate equivalent amounts of electricity. This is a relatively conservative assumption due to the fact that, in the cases the Agency is familiar with, the recirculating systems are typically associated with the newest generating units at the plant. Therefore, significantly more than one-third of the plant-wide generation may come from the recirculating portion of the plant.

For the purposes of determining the extent to which costs may be overstated for these facilities, the Agency calculated for each of the 50 combination cooling system facilities an annualized adjustment cost. These costs totaled approximately $3.7 million annually (in 2002 $).

Facilities Utilizing Strategic Flow Reductions

Eleven facilities reported in the detailed questionnaire that they utilize strategic flow reduction. The Agency examined the assumed entrainment and/or impingement mortality requirements it utilized for the technology cost development and found that five of the strategic flow reduction facilities utilize significant strategic flow reductions and were assigned entrainment technology upgrades. This could overstate costs for these five facilities given that the median flow reduction percentage was 40 percent. Strategically implemented, an annual flow reduction of 40 percent (targeted to periods of spawning and the presence of large numbers or high density of organisms) could assist a facility in achieving entrainment reductions comparable to the entrainment reduction targets of the proposed regulatory options. It is possible that technology upgrades for entrainment would not be necessary at these five facilities. Overall, the fact that the Agency identified only five such facilities suggests EPA's national level cost estimates are relatively unaffected by their inclusion, since they represent only 4 percent of facilities potentially covered by the 50 MGD option. Nonetheless, the Agency analyzed the difference in costs attributable to the entrainment technology upgrades assigned for these facilities to the cost of impingement controls.

For the purposes of determining the extent to which costs may be overstated for these facilities, the Agency calculated an annualized adjustment cost for each of the 5 entrainment-upgrade facilities already utilizing strategic flow reduction. These costs totaled approximately $4.7 million annually (in 2002 $).

Overall Change to National Cost Estimates

EPA estimated that it assigned approximately $8.4 million (in 2002 average $) annually to the identified facilities. These costs may be costs potentially avoided by facilities in compliance with the rule requirements. See DCN 6-3585 in the Phase II docket for more information.

### 1.3 Regulatory Options for Seafood Processing Vessels

The final Phase III rule does not establish national categorical requirements for seafood processing vessels. Therefore, this section is provided for information purposes only. Based on site visits to shipyards and interviews with technical personnel, it was concluded that most of the seafood processing vessels employing cooling water intake structures have minimal to zero technologies in place to reduce impingement mortality and/or entrainment. Using the cost modules developed as described in Chapter 3, two compliance alternatives, impingement reduction and impingement and entrainment reduction were costed. Exhibit 5-3 below presents the different technology options for the two compliance alternatives costed for seafood processing vessels using sea chest intakes.

**Exhibit 5-3. Finalized Technology Options for Seafood Processing Vessels**

| Type of CWIS | Compliance Alternatives | Technology | Comments |
|---|---|---|---|
| Sea chest intake | Impingement | Replace Grill with fine mesh screen | Two options, stainless steel and CuNi fine mesh screens were costed |
| | | Horizontal Flow Diverter | Similar mechanism as a velocity cap. Two configurations for sea chests were costed; (1) located at the bottom of the vessel and (2) on the sides of the vessel. |
| | Impingement & Entrainment | Enlarged Intake Structure (Internal) | Two options, stainless steel and CuNi fine mesh screens were costed |
| | | Enlarged Intake Structure (External) | Two options, stainless steel and CuNi fine mesh screens were costed |

Facilities with simple pipe intakes are limited in their ability to retrofit control technologies without compromising seaworthiness and hydrodynamics. EPA identified that some impingement controls may entail installation of equipment projecting beyond the hull of the vessel. Such controls may not be practical or feasible for some Seafood Processing Vessels since the configuration may alter fluid dynamics and impede safe seaworthy travel, even for new facilities that could avoid the challenges of retrofitting control technologies.

### 1.4 Regulatory Options for Offshore Oil and Gas Extraction Facilities

EPA considered a number of regulatory options for offshore oil and gas extraction facilities. See Chapter 7.

## 2.0 COST TEST TOOL APPLIED TO MODEL FACILITIES

In Phase II, EPA developed a cost methodology that evaluated each individual intake. The intake type, location, size, design flow rate, existing control technologies, expected performance standards, and other parameters were used to determine an appropriate compliance technology. The performance standards proposed in Phase III are identical to the performance standards of the final Phase II rule. After comparing intakes at Phase II facilities to intakes at Phase III facilities, EPA concluded the same compliance technologies used in Phase II were appropriate for Phase III. Therefore the cost equations for each compliance technology used in Phase II could be applied to Phase III facility intakes.

The cost-test tool (version 4.1) was a spreadsheet program that created facility-specific or model-specific compliance costs. The cost-test tool was initially developed to predict facility-specific costs needed to implement the cost-cost compliance alternative of the final Phase II rule. The tool accepts site-specific intake data for an electric power generating facility, executes the methodology and analyses that EPA used to derive the costs of the Phase II final rule, and then outputs a set of costs for use in a cost-to-cost comparison. The use of this program makes multiple cost calculations rapid and reproducible. Potentially regulated facilities could apply the cost-test tool to predict EPA's compliance response and cost estimates. The intake-specific data and cost information is generally handled as confidential business information; use of the cost-test tool makes EPA's cost methodology transparent.

EPA adapted the cost-test tool to incorporate the intake data specific to Phase III facilities. EPA further modified the cost-test tool to incorporate corrections or methodology changes, and used the cost-test tool to calculate costs for the Phase III proposal. Additional methodology changes were identified in the Phase III NODA, and the specific variables are described in section 2.2 of this chapter. EPA used this last version (version 5.1) to determine the final costs for potential Phase III manufacturers and power generators.

Exhibit 5-4 lists the technology modules EPA used to cost potential Phase III existing facilities to comply with the regulatory options described in section 1.0. Section 2.1 describes how technology modules were assigned to each facility. See Chapter 3 for detailed descriptions of each technology.

**Exhibit 5-4. Technology Codes and Descriptions**

| Technology Codes | Technology Description |
|---|---|
| 1 | Addition of fish handling and return system to an existing traveling screen system |
| 2 | Addition of fine-mesh screens to an existing traveling screen system |
| 3 | Addition of a new, larger intake with fine-mesh and fish handling and return system in front of an existing intake system |
| 4 | Addition of passive fine-mesh screen system (cylindrical wedgewire) near shoreline with mesh width of 1.75 mm |
| 5 | Addition of a fish net barrier system |
| 6 | Addition of an aquatic filter barrier system |
| 7 | Relocation of an existing intake to a submerged offshore location with passive fine-mesh screen inlet with mesh width of 1.75 mm |
| 8 | Addition of a velocity cap inlet to an existing offshore intake |
| 9 | Addition of passive fine-mesh screen to an existing offshore intake with mesh width of 1.75 mm |
| 10 | [Module 10 not used] |
| 11 | Addition of dual-entry, single-exit traveling screens (with fine- mesh) to a shoreline intake system |
| 12 | Addition of passive fine-mesh screen system (cylindrical wedgewire) near shoreline with mesh width of 0.76 mm |
| 13 | Addition of passive fine-mesh screen to an existing offshore intake with mesh width of 0.76 mm |
| 14 | Relocation of an existing intake to a submerged offshore location with passive fine-mesh screen inlet with mesh width of 0.76 mm |

## 2.1 The Cost-Test Tool Structure

The cost test tool program makes use of basic database retrieval functions and logical statements to mirror the costing methodology hierarchy used by EPA for development of the final Phase II rule costs. (This costing methodology was published in the Phase II NODA for public comment.)

The cost model described here modifies the cost-test tool to version 5.1 to calculate the costs the Agency developed and considered for the proposed Phase III rule. The cost-tool combines the varied analyses and data presented in Chapter 3 into an automated decision tree that ultimately assigns a technology cost to each facility. In the "User Inputs" sheet of the cost-test tool, the user supplies data on the facility level, or the user may choose to input information at the intake level where multiple intakes at a single facility have different features that might affect which technology modules are feasible for that intake. Once the "user inputs" have been entered, the cost-test tool determines one of two possible sets of performance requirements: impingement requirements only or both impingement and entrainment requirements. The cost-tool then determines a compliance response for the facility/intake by accounting for existing technologies (such as wedgewire screens) and conditions (such as a shoreline intake location or the through-screen velocity). Next the cost-test tool applies EPA's decision tree for assigning site-specific cost modules; see Figure 5-1 for a schematic of this decision tree. Finally, the costing methodology is performed through a combination of calculations and functions (that is, an algorithm). This work is mostly carried out in the sheet titled "Calc. and Data" and is supplemented by a few logical functions and data retrieval in the "Output" sheet. The cost outputs include capital costs, incremental O&M costs, and downtime (in weeks).

The data fields requested in the "User Inputs" sheet (see Figure 5-2) come from questions in the surveys plus a few basic observations about the intake, such as a judgment about the degree of debris loading at the intake: "high" or "low," or whether there are navigational considerations for the location of the intake based on geographical information systems (GIS) maps. The program reproduces the methodology the Agency utilized to develop final costing decisions to determine what technology would best suit a particular intake.

## 2.2 Cost-Test Tool Inputs

This section describes the inputs to the Cost Test Tool (see Figure 5-2), and defines the default values used for Phase III facility costing. The default value was used when facility level information was not available from EPA's survey.

A detailed engineering review of the cost-test tool input data used at proposal was performed for Phase III facilities with DIF equal to or greater than 50 MGD. The 316(b) survey responses and written comments submitted with the surveys were reviewed to ensure that the correct parameters were identified and incorporated in the cost-test tool.

As a result of this review, the following additional input variables were added to the revised cost-test tool: *Facility Type; Maximum Reported Intake Flow (MRIF); Actual Intake Flow (AIF);* and *Through Screen Velocity Flow Basis*. In addition, the input variables *Distance Offshore for Submerged Intake* and *Canal Length* were modified to be separate input variables in the cost-test tool. The input variables in the final cost-test tool are described below:

**Facility Type.** This input value was added to allow for proper selection of input default values to the cost-test tool for different types of facilities.

Manufacturer: Code 3
Power generation: Code 2

*Facility type* is a required input variable in the cost-test tool.

**Cooling System Type.** A value of 1 (one) indicates the facility was identified in EPA's survey as using a fully recirculating system. A fully recirculating system uses minimum makeup and blowdown flows to withdraw cooling water, where the heat is dissipated by a cooling canal or channel, lake, pond, or tower. A facility identified as having a fully recirculating system does not receive any further technology costs, but still receives permit costs associated with record-keeping and reporting requirements. A value of 0 (zero) indicates the facility was identified in EPA's survey as using one of the following systems: once-through, combination, other, or unknown.

For the development of compliance technology costs, the Agency considered facilities with recirculating systems in-place to need no technology upgrades. Facilities with redundant intakes typically were treated as a facility with a single, large intake. For the purposes of the cost analysis, the Agency defined facilities with recirculating systems as only those facilities with recirculating cooling systems for the facility's entire intake system. If a facility had a combination of intakes that utilized once-through and recirculating systems, the Agency treated the facility as a full once-through facility. In addition, if a facility had a once-through or combination system and exercised strategic flow reductions (as reported in question 26 of the detailed questionnaire), the Agency still treated the facility as a full once-through facility.

Six facilities were sufficiently complex to require additional assumptions on EPA's part to complete the analysis. These facilities generally had more than one intake type, intake location, or cooling water system type that were substantially distinct and independent from the other intakes or cooling water systems to warrant individual attention. For example, one facility has multiple intakes, some of which withdraw from a freshwater river and some of which withdraw from a tidal river. These two intakes (or groups of intakes) are quite different (e.g., could be subject to different performance standards) and were costed individually. EPA "split" the intakes for a total of six facilities in the Phase III costing. Each intake (or group of intakes) was treated as an individual facility for the purposes of facility-level costs. As such, the design intake flows, technologies in place, and other technical data were applied to only the "split" intakes.

During the review process for the NODA, data for two facilities were changed from "full re-circulation" to "other" because the facility-specific schematic diagram showed the use of intake water for non-contact cooling purposes.

**State Abbreviation.** The two letter state abbreviation is used to identify the state where the intakes are located. The state is used to assign state-specific capital cost factors from the "location cost factor database" in RS Means Cost Works 2001. The state also is used to identify whether zebra mussels are a potential problem at a facility. Where zebra mussels are a potential problem, the costs include using CuNi alloys for intake upgrades located in freshwater.

**Waterbody Type.** The numeric values 1 through 5 represent the waterbody type for each intake's location. These values are 1=Ocean, 2=Estuary, 3=Great Lake, 4=Fresh River, 5=Lake/Reservoir. A facility located on a waterbody with unobstructed access to a Great Lake and located within 30 miles of a Great Lake shoreline is classified as Great Lake.

<u>Criteria for delineating/defining tidal rivers and estuaries.</u> EPA uses salinity as the principal criterion (EPA, 2001). From the final Phase I and final Phase II regulatory language (§125.83 and §125.93, respectively):

"Estuary means a semi-enclosed body of water that has a free connection with open seas and within which the seawater is measurably diluted with fresh water derived from land drainage. The salinity of an estuary exceeds 0.5 parts per thousand (by mass) but is typically less than 30 parts per thousand (by mass)."

EPA reviewed all of the waterbody types supplied by facilities in their survey using data from the National Oceanic and Atmospheric Association (NOAA) and other sources to plot the facilities in GIS and confirm the waterbody type. EPA also used NOAA data on tidal movements to cross-check the designations.

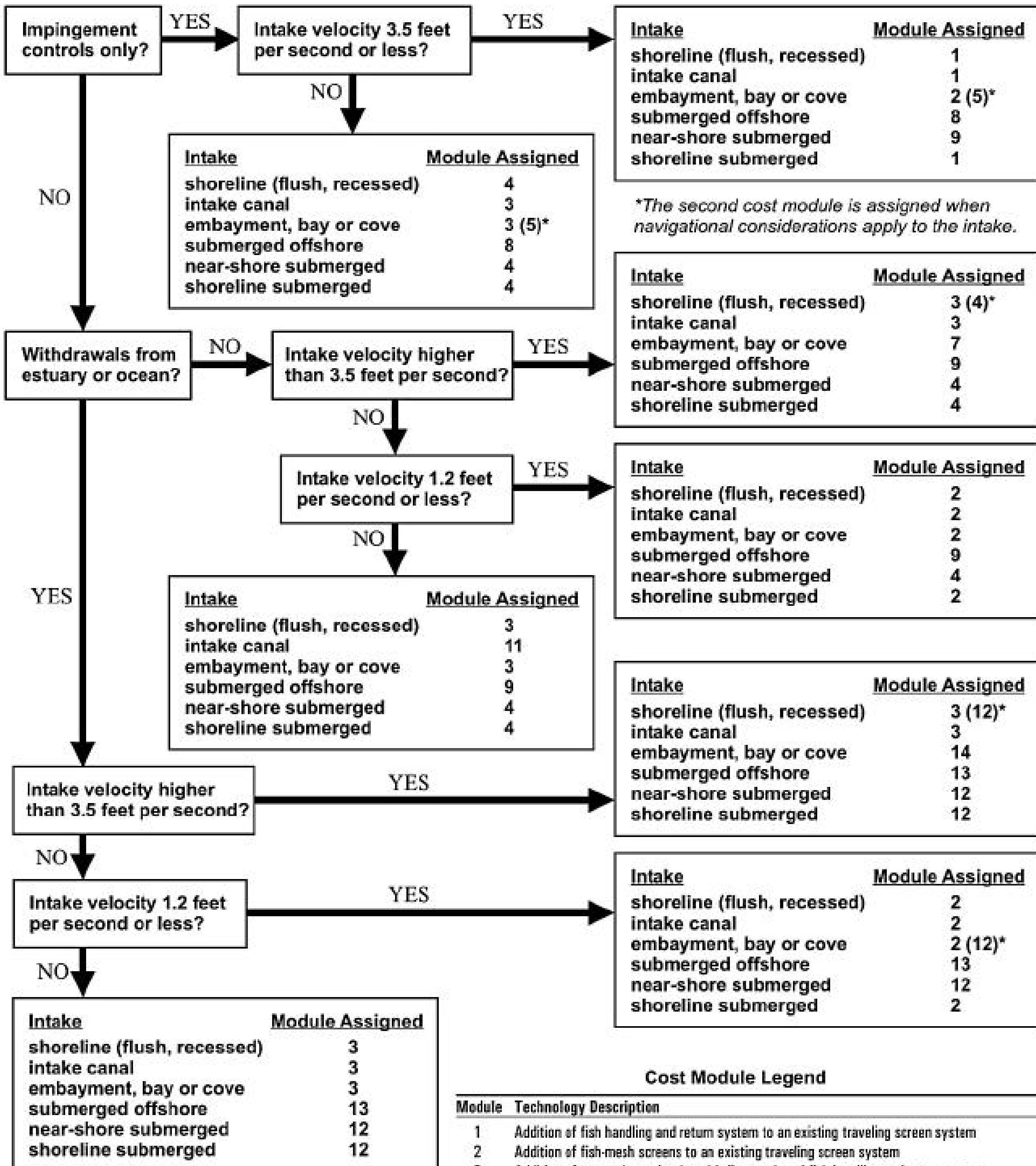
During the review process for the NODA, the intake data for one facility was divided because multiple intakes were withdrawing water from different waterbodies and two different waterbody types.

*Waterbody type* is a required input variable in the cost-test tool.

**Fuel Type.** A value of 1 (one) indicates the intake is part of a nuclear facility and results in additional cost factors. A value of 0 (zero) indicates the intake is non-nuclear. Construction and material costs tend to be substantially greater for nuclear facilities due to burden of increased security and to the requirements for more robust system design. Therefore, nuclear facilities in freshwater are assigned a cost factor of 1.33 and those in saltwater 1.45. See the Phase II TDD for further discussion.

Three facilities reported using nuclear fuel, but none of those facilities are regulated under the options considered at proposal for the Phase III rulemaking.

**Figure 5-1. Flow Chart for Assigning Cost Modules**




**Cost Module Legend**

| Module | Technology Description |
|---|---|
| 1 | Addition of fish handling and return system to an existing traveling screen system |
| 2 | Addition of fish-mesh screens to an existing traveling screen system |
| 3 | Addition of a new, larger intake with fine-mesh and fish handling and return system |
| 4 | Addition of passive fine-mesh screen system (cylindrical wedgewire) |
| 5 | Addition of a fish net barrier system |
| 7 | Relocation of an existing intake to a submerged offshore location with passive fine-mesh screen |
| 8 | Addition of a velocity cap inlet to an existing offshore intake |
| 9 | Addition of passive fine-mesh screen to an existing offshore intake |
| 11 | Addition of dual-entry, single-exit traveling screens to a shoreline intake system |
| 12 | Addition of passive fine-mesh screen system (cylindrical wedgewire) near shoreline |
| 13 | Addition of passive fine-mesh screen to an existing offshore intake |
| 14 | Relocation of an existing intake to a submerged offshore location with passive fine-mesh screen |

**Figure 5-2. Screen Capture of Cost-Test Tool User Inputs**

**User Inputs -- At The Intake Level** **Basis for Technology Capital $** 1 (0 = DIF, 1 = MRIF, 2 = AIF)

**Facility Information -- Input Intake-Specific Data In Blue Boxes**
**Items in Bold Must Be Entered**

| Field | Value | Notes |
|---|---|---|
| **Facility Type =** | | ( 3 = Manufacturer, 2 =Power Generation) (Required Field) |
| Cooling System Type = | | ( 1 = Full Recirculation, 0 = All Others) |
| State Abbreviation = | | (Required Field) |
| **Waterbody Type =** | | (1=Ocean, 2=Estuary, 3=Great Lake, 4=Fresh River, 5=Lake/Res.) |
| Fuel Type = | | (1 = Nuclear, 0 = Non-Nuclear) |
| Capacity Utilization (1996-99) = | | % |
| **Intake Location / Description** | | (choose from Description table at right) (Required Field) |
| Distance Offshore for Submerged Inlet | | ft |
| Canal Length = | | ft (if canal is present between mouth and screens) |
| Navigation / Waterbody Use | | (1 = boat/barge navigation near intake, 0 = clear intake area) |
| Mean Intake Water Depth = | | ft |
| Intake Well Depth = | | ft |
| River Proportional Flow = | | (If intake > 5% of mean annual river flow = 1, others = 0) |
| **Intake Flow (DIF)** | | gpm (Required Field) |
| Intake Flow (MRIF) | | gpm |
| **Intake Flow (AIF)=** | | gpm (Required Field) |
| Through Screen Velocity = | | fps |
| Through Screen Velocity Flow Basis = | | ( Choose from Through Screen Velocity Flow Basis list at right) |
| Water Type = | | (1 = marine, 0 = fresh) |
| Debris Loading = | | (1 = high, 0 = normal) |
| **Impingement Tech In-Place =** | | (choose from Impingment Tech list at right) |
| **Qualified Impingement? =** | | (1 = Qualified, 0 = none; see impingement reduction table to right) |
| **Entrainment Tech In-Place =** | | (choose from Entrainment Tech list at right) |
| **Qualified Entrainment? =** | | (1 = Qualified, 0 = none; see entrainment reduction table to right) |
| avg annual generation '96 - '99 = | | (MWh, reported data, excluding outliers, EG only) |

**Facility Information Tables/Keys**

Intake Location / **Description**
1 = Shoreline Intake (flush, recessed)
2 = Intake Canal
3 = Embayment, Bay, or Cove
4 = Submerged Offshore Intake
5 = Near-shore submerged intake
6 = Shoreline Submerged Intake

**Impingment Tech**nologies In-place
0 = None of those listed
1 = Traveling Screens
2 = Passive Intake (Velocity Cap, Coarse Wedgewire Dam, Leaky Dike,
3 = Barrier Net
4 = Fish Diversion or Avoidance (Louvers, Acoustics, etc.)

**Through Screen Velocity** Flow Basis
1 = Existing Equipment Design Intake Flow
2 = New Design Intake Flow
3 = Average Intake Flow

In-place Tech EPA "Qualified" for **Impingment** Reductions
Fish Handling and Return Systems for Traveling Screens
Passive Intakes (velocity cap, t-screens, porous dams, etc.)
Barrier Nets
Through screen velocity of .5 fps or less

**Entrainment Tech**nologies In-place
0 = None of those listed
1 = Traveling Screens w/ Fine Mesh
2 = Far Offshore Intake
3 = Passive Screens w/ Fine Mesh

In-place Tech EPA "Qualified" for **Entrainment** Reductions
Fine Mesh Screens (passive or traveling screens)
Far Offshore Intake w/ Passive Intake at Inlet

**Capacity Utilization Rate (CUR).** This percentage value reflects the ratio between the average annual net generation of power by the facility (in MWh) and the total net capability of the facility to generate power (in MW) multiplied by the number of hours during a year. EPA used the year 2008 CUR as projected by the IPM model as the base case. See the Preamble to Phase II (69 FR 41650) for a discussion of the sensitivity of costs to this assumption. Facilities with a CUR of 15 percent or higher and making cooling water withdrawals from tidal rivers, estuaries, oceans, or one of the Great Lakes (see waterbody type) are subject to entrainment requirements under the Phase II rule. The default CUR is 20 percent. Manufacturing facilities do not have a CUR and are assigned the default value. This default value insures facilities subject to entrainment receive a cost module for entrainment.

**Intake Location.** The numeric values 1 through 6 represent the location and description for each intake. These values are 1=shoreline intake description (flushed, recessed), 2= intake canal, 3=embayment, bank, or cove, 4=submerged offshore intake, 5=near-shore submerged intake, 6=shoreline submerged intake. Several facilities did not provide their intake location information in their industry questionnaire, so EPA used data from other parts of the facility's survey to determine the intake location. For example, a facility that gave no intake location but stated that it has a vertical traveling screen likely has a shoreline intake. Other facilities might have given information on the length of an intake canal or the presence of a wedgewire screen, indicating an intake canal and a submerged intake, respectively.

Some facilities included more than one description for their type of intakes. The description that best described the situation or was most crucial in development of the costs was selected. For example, where intake canals are present, this attribute took precedence over others because of the limitation in technology selection and added costs for extra fish return length.

Where multiple intakes had different descriptions, the intake with the largest DIF was selected. Numerous changes were made for this data because of the reassessment of values previously selected for multiple intakes and where multiple items were identified in the survey. When multiple intakes had substantially different descriptions, the intake data were separated and assigned to the respective intakes. As a result, intakes for three facilities were separated because one intake from each of these three facilities withdrew cooling water from a shoreline location and the other intake withdrew water from a submerged offshore location. As noted above, EPA "split" the intakes for six facilities in the Phase III costing.

*Intake Location/Description* is a required input variable in the cost-test tool.

**Distance Offshore for Submerged Intakes.** Submerged offshore intake distance affects construction and civil costs as well as O&M costs, and is a critical parameter for relocating intakes. The default distance of submerged offshore intakes is the median of all reported values from Phase II facilities by waterbody type as follows: (Note: The Agency has not obtained updated or contrary data and reasonably expects these values to be valid for Phase III.)

| | |
|---|---|
| Ocean | 500 meters |
| Estuary/Tidal River | 125 meters |
| Great Lake | 500 meters |
| Freshwater Stream/River | 125 meters |
| Lake/Reservoir | 125 meters |

In the Proposal cost-test tool, the offshore distances were selected based on Phase II Facility median values for each waterbody type. This new input variable data field was populated with reported survey data wherever the intake description was identified as submerged offshore. Where there were multiple intakes, DIF flow-weighted average value was used.

**Canal Length.** This variable is used to determine the length of the fish return system. The default value for the constructed canal length is the median of all reported values from Phase II facilities as follows: (Note: The Agency has not obtained updated or contrary data and reasonably expects these values to be valid for Phase III.)

| | |
|---|---|
| Ocean | 3,370 feet |
| Estuary/Tidal River | 1,650 feet |
| Great Lake | 1,460 feet |
| Freshwater Stream/River | 690 feet |
| Lake/Reservoir | 800 feet |

At Phase III proposal, the cost-test tool did not use this data. As part of the cost-test tool review and revision for the NODA, a cost component was added to account for the additional length of fish returns for cost modules requiring a fish return. This new input variable data field was populated with reported survey data wherever the intake description was identified as "intake canal." Where there were multiple intakes, the DIF flow-weighted average value was used.

**Navigation/Waterbody Use.** A value of 1 (one) indicates the intake is located where boat/barge navigation near the intake is a consideration when making any modifications to the intake. A value of 0 (zero) indicates navigation does not occur in the vicinity of the intake. Navigational considerations affect which technology modules may be used by intakes located in embayments, banks, or coves (see <u>intake location</u>). EPA used maps and satellite imagery obtained from *Mapquest* to identify which intakes were located in areas of boat/barge traffic. The default value is 1.

**Mean Intake Water Depth.** This value is used for the estimation of total existing screen width. Many of the corrections resulted in reducing the water depths, which in turn results in increased estimated compliance costs, as wider screens are required when the screen can not extend as far down. Where there were multiple intakes, the DIF flow-weighted average value was used. Where mean intake water depth was not reported, the mean intake water depth of 19 ft as reported by Phase III manufacturers with intake flow >50 MGD was used as a default value.

Exhibit 5-5 shows the default value used in Phase III for *Mean Intake Water Depth*.

**Intake Well Depth.** The intake well depth is the distance from the intake deck to the bottom of the screen well, and includes both water depth and distance from the water surface to the deck. The intake well depth is used to select the depth of the required screen. For a given screen width, deeper screens result in higher capital costs. Where facilities reported the distance above and below the mean water depth, the sum of these two values was used. Where mean intake water depth was reported but intake well depth was not reported, the intake well depth was assumed to be 1.2 times the mean intake water depth. Where mean intake water depth was not reported, the mean intake depth of 22 ft as reported by Phase III manufacturers with intake flow >50 MGD was used as a default value. This information was derived from existing facility data.

Exhibit 5-5 shows the default value used in Phase III for *Intake Well Depth*.

**Exhibit 5-5. Mean Intake Water Depth and Well Depth at Phase III Facilities**

| Industry | Design Capacity = or > 50 MGD | | Design Capacity < 50 MGD | |
|---|---|---|---|---|
| | Mean Intake Water Depth (ft) | Mean Intake Well Depth (ft) | Mean Intake Water Depth (ft) | Mean Intake Well Depth (ft) |
| manufacturing (n>22) | 19 | 22 | 16 | 17 |
| electric generating (n>46) | 15 | 18 | 12 | 14 |

**River Proportional Flow.** A value of 1 (one) indicates the design intake flow is greater than 5 percent of the mean annual flow of a freshwater river or stream. A value of 0 (zero) indicates the design intake flow is equal or less than 5 percent of the mean annual flow of a freshwater river or stream.

**Intake Flow (Design Intake Flow).** The DIF is the numerical value assigned during the facility's design to the total volume of water withdrawn. For facilities reporting one intake, the reported total DIF was used. If a facility reports multiple intakes, typically all intakes were used for purposes of calculating the facility's total DIF. (Fire suppression and emergency intakes, where clearly identified, were not included.) For the six facilities that were "split," EPA used the DIF associated with each separate intake(s). For costing purposes, only those intakes with a screen velocity greater than 0.5 feet per second received impingement controls (i.e., the DIF for the total facility is greater than the DIF used for costing; this occurs in 12 cases). If an intake is for a hydroelectric station, the flows are not used for exchange of waste heat and therefore do not meet the definition of cooling water. Furthermore, intakes at Phase III facilities with hydro plants do not meet the 25% of water use criterion, and these flows are not included for purposes of calculating costs; this occurs in 2 cases.

*Design Intake Flow* (DIF) is a required input variable in the cost-test tool.

**Intake Flow (Maximum Reported Intake Flow).** This value is intended to represent on-the-ground intake flow capacities, as opposed to the DIF, which is based on maximum design flow capacities. This input value was added to conduct a sensitivity analysis by using an alternative intake flow to the DIF for certain technology modules. EPA derived estimates for the MRIF based on the average reported daily maximum intake flow data. In most cases, the MRIF was lower than the DIF, reflecting an apparent trend of manufacturers implementing flow reduction measures. Since the MRIF is lower than the DIF, the size of compliance technology is reduced. As a result, the overall effect of using the MRIF for developing costs for certain technologies resulted in a reduction in compliance cost estimates. MRIF was used for sensitivity analyses only, and was not used to calculate final costs.

**Intake Flow (Average Intake Flow).** This input variable was added to allow for adjustment of the variable portion of the O&M costs to reflect actual equipment operating costs. In addition, this input value was used to conduct a sensitivity analysis by using an alternative intake flow to the DIF for certain technology modules.

The AIF was calculated based on the average flow over a three-year period as reported in the surveys. These data were presented at proposal, but were not used in developing compliance cost estimates.

*Average Intake Flow* (AIF) is a required input variable in the cost-test tool.

**Through-Screen Velocity.** This input variable is used to estimate the existing screen width as well as for selecting the appropriate compliance technology. A through-screen velocity of 0.5 feet per second or less would have met the performance standards for impingement mortality and would not incur any capital costs to meet impingement requirements. The Phase II default value is the mean reported value for all electric generators with greater than 50 MGD design intake flow, shown in gray in the table below. For Phase III facilities not reporting a through-screen velocity, EPA used mean reported values of Phase III facilities as shown in the following table:

**Exhibit 5-6. Through-Screen Velocity at Phase III Facilities**

| Industry | Design Capacity = or > 50 MGD | Design Capacity < 50 MGD |
|---|---|---|
| | Screen Velocity (feet per second) | Screen Velocity (feet per second) |
| manufacturing (n>22) | 1.2 | 0.8 |
| electric generating (n>46) | 1.5 | 0.6 |

Fourteen Phase III facilities had multiple intakes. EPA used the weighted average through-screen velocity for all intakes reported provided the screen velocity was greater than 0.5 feet per second. If the through-screen velocity for a particular intake was 0.5 feet per second or less, the intake meets impingement requirements and EPA did not assign technology controls to that particular intake. EPA assigned weights according to the design intake flow of each reported intake.

**Through-Screen Velocity Flow Basis.** This input variable was added to allow for greater flexibility in the cost-test tool by allowing a user to report through-screen velocities in the input field described above, based on flow values other than the DIF. Only one facility reported screen velocity using a flow basis other than the DIF, and the proper input value was assigned.

**Water Type.** A value of 1 (one) indicates the water is marine. A value of 0 (zero) indicates the water is freshwater. The default is 0 (zero).

For one Phase III facility with separate intakes on freshwater and saltwater, the input data were separated in order to account for potential differences in costs and compliance technology modules required for the different waterbodies.

**Debris Loading.** A value of 1 (one) indicates high levels of debris and trash near the intake. A value of 0 (zero) indicates debris is low or negligible. The default is 1 (one). A facility reporting use of a trash rack in the survey is assumed to have high debris loading.

**Impingement Technology In-Place.** A numerical value of 0 through 4 is used to indicate the intake has impingement technologies reported as in-place by the facility. A value of 1= Traveling Screens, 2= Passive Intake (Velocity Cap, Coarse Wedgewire Screens, Porous Dam, Leaky Dike, etc.), 3= Barrier net, and 4 = Fish Diversion or Avoidance (Louvers, Acoustics, etc.). A facility is treated as having a traveling screen if the facility reported having both an intake screen and shoreline intake location. A value of zero means no controls or none of the above identified controls. The default is 0 (no controls).

As part of the review process during NODA, changes were made to the facility data for this input parameter. The engineering review focused on the responses to several survey questions along with the review of schematic diagrams in determining the technology in-place. Where multiple impingement technologies existed, traveling screens took precedence for this input variable. The majority of the changes involved changing the input value to "traveling screens" from "none" or "other technologies" as the technology in place. One overall effect of changing the input value to traveling screens was the addition of baseline O&M costs for traveling screens to the compliance cost calculation.

*Impingement Technology In-Place* is a required input variable in the cost-test tool.

**Qualified Impingement.** Facilities with Impingement Tech In-Place = 2 (Passive Intake) receive a numerical value of 1 (one). All other facilities receive a value of 0 (zero). The default is 0 (zero).

For facilities with traveling screens, this input value indicates whether a fish return mechanism is in-place. This in turn affects the cost module selected, as well as baseline O&M costs. Corrections resulted in many facilities being coded from "qualified" to "not qualified" and vice versa.

*Qualified Impingement* is a required input variable in the cost-test tool

**Entrainment Tech in-Place.** A numerical value of 0 through 3 is used to indicate the intake has entrainment technologies reported as in-place by the facility. A value of 1= Traveling Screens w/ Fine Mesh, 2= Far Offshore Intake, and 3 = Passive Screens w/ Fine Mesh. A value of zero means no controls or none of the above identified controls. The default is 0 (no controls).

Changes were made to the facility data for this input parameter. The engineering review focused on the responses to several survey questions together with the review of schematic diagram to determine the technology in-place. Where fine mesh screens coexisted with intakes submerged far offshore, fine mesh screens took precedence for this input value. Again, corrections resulted in many facilities going from "none" to "passive technology in-place" and vice versa.

*Entrainment Technology In-Place* is a required input variable in the cost-test tool.

**Qualified Entrainment.** Facilities with qualified entrainment controls receive a numerical value of 1 (one) and receive no further capital costs for entrainment controls. Entrainment Tech in-Place = 1 or 3 are qualified as meeting the entrainment controls. Facilities with Entrainment Tech in-Place=2 (far offshore) AND also with Impingement Tech In-Place = 2 (Passive Intake) are qualified, and receive a value of 1 (one). All other facilities receive a value of 0 (zero). The default is 0 (zero).

In the input data for the Phase III Proposal, numerous facilities were incorrectly identified as having "qualified" entrainment technology when the entrainment technology-in place should have been coded as "not qualified," when the entrainment technology was reported as "none," in the survey. In most cases, this input data was corrected from "qualified" to "not qualified."

*Qualified Entrainment* is a required input variable in the cost-test tool.

**Exhibit 5-7. Data Sources for Baseline Impingement and Entrainment Technologies In-place**

| TYPE OF TECHNOLOGY | SOURCE OF INFORMATION | |
|---|---|---|
| | **Detailed Questionnaire** | **Short Technical Questionnaire** |
| Impingement & Entrainment Technology | | |

| | | | |
|---|---|---|---|
| Passive Intake Systems | | | 14(b) |
| | *Wedgewire Screen ** | 21(b)G | |
| | *Perforated Pipe* | 21(b)H | |
| | *Porous Dike* | 21(b)I | |
| | *Leaky Dams* | 21(b)J | |
| | *Artificial Filter Bed* | 21(b)K | |
| **Impingement Technology** | | | |
| Fish Diversion or Avoidance Systems | | | 14(a) |
| | *Velocity Cap* | 22(b)M | |
| | *Louver Barrier* | 22(b)N | |
| | *Fish Net Barrier* | 22(b)P | |
| Fish Handling and Bypass Systems with any Traveling Screen | | | 14(c) and 14(d) |
| | *Fish Pump* | 19(b)A, B, E1-E6 & 23(b)W | |
| | *Fish Conveyance System(troughs of pipes)* | 19(b)A, B, E1-E6 & 23(b)X | |
| | *Fish Elevator/Lift baskets* | 19(b)A, B, E1-E6 & 23(b)Y | |
| | *Fish Bypass System* | 19(b)A, B, E1-E6 & 23(b)Z | |
| *Aquatic Filter Barrier Systems or "Gunderboom"* | | *** | *** |
| *Traveling fine mesh screens*** | | 19(b)E1-E6&19(c)(3)-(2) | |

* Only a Wedgewire with a Fine Mesh Screen meets requirement for entrainment.
** Fine Mesh is 5mm or less
*** Not implemented at Phase III cooling water intake structures.

## 2.3 Limitations of the Cost Test Tool

In Phase II, EPA allocated less than a dozen intakes to install more than one intake technology. The cost-test tool does not account for this fact, but rather assumes that a single best technology available can be prescribed for each intake. The end effect of this might be such that a few intakes that actually require multiple technologies to meet the rule would compare the costs of these to the individual technology cost derived in this tool. In addition, technology Module 6 (Gunderboom) and Module 10 (for submerged offshore intakes) are used sparingly in practice. To simplify the decision tree for assigning a compliance technology, these two technology modules are not included in the cost-test tool.

In Phase II, facilities have 5 compliance alternatives for meeting the final requirements. Under each regulatory option evaluated for Phase III facilities, the facility would have the same compliance alternatives described in the final Phase II rule. These compliance alternatives are not addressed by the cost-test tool. All facilities are costed for one or more of the technology modules, as shown below.

**Exhibit 5-8. Number of Phase III Facilities Assigned DIF-Based Compliance Costs By Cost Module**

| Module Code | Module Description | 50 MGD Option | | | |
|---|---|---|---|---|---|
| | | Unweighted | Weighted | Unweighted (%) | Weighted (%) |

| | | | | | |
|---|---|---|---|---|---|
| 0 | None | 20 | 32.0 | 22.2 | 19.9 |
| 1 | Add Fish Handling and Return System | 27 | 58.2 | 30 | 36.1 |
| 2 | Add Fine Mesh Travelling Screens with Fish Handling and Return | 1 | 1.1 | 1.1 | 0.7 |
| 2a | Add Fine Mesh Screen Overlays | 15 | 25.1 | 16.7 | 15.6 |
| 3 | Add New Larger Intake Structure with Fine Mesh, Handling and Return | 7 | 11.4 | 7.8 | 7.1 |
| 4 | Add Passive Fine Mesh Screens (1.75 mm mesh) at Shoreline | 4 | 7.7 | 4.4 | 4.8 |
| 5 | Add Fish Barrier Net | 0 | 0 | 0 | 0 |
| 6 | Gunderboom | 0 | 0 | 0 | 0 |
| 7 | Relocate Intake to Submerged Offshore with passive screen (1.75 mm mesh) | 0 | 0 | 0 | 0 |
| 8 | Add Velocity Cap at Inlet | 5 | 9.3 | 5.6 | 5.8 |
| 9 | Add Passive Fine Mesh Screen (1.75 mm mesh) at Inlet of Offshore Submerged | 6 | 9.9 | 6.7 | 6.2 |
| 11 | Add Double-Entry, Single-Exit with Fine Mesh, Handling and Return | 3 | 4.4 | 3.3 | 2.7 |
| | *For Estuary & Ocean only:* | | | | |
| 12 | 0.75 mm Passive Fine Mesh Screen at Shoreline | 2 | 2.1 | 2.2 | 1.3 |
| 13 | 0.75 mm Passive Fine Mesh Screen at Inlet of Offshore Submerged | 0 | 0 | 0 | 0 |
| 14 | Relocate Intake to Submerged Offshore with 0.75 mm passive screen | 0 | 0 | 0 | 0 |
| Total | | 90 | 161.1 | | |

Counts are for primary cost module assigned.
Note that some facilities were assigned different compliance technologies for two different intakes and may be counted twice.
Facilities with one of two intakes assigned "module 0" (None) were not included in the "Module 0" count.

For comparison purposes, the module assignments for Phase II are provided in Exhibit 5-9.

**Exhibit 5-9. Number of Phase II Facilities Assigned Compliance Costs By Cost Module**

| Module Code | Module Description | Final Option | | | |
|---|---|---|---|---|---|
| | | Unweighted | Weighted | Unweighted (%) | Weighted (%) |
| 0 | None | 197 | 198.9 | 35.4 | 35.2 |
| 1 | Add Fish Handling and Return System | 98 | 98.7 | 17.6 | 17.5 |
| 2 | Add Fine Mesh Travelling Screens with Fish Handling and Return | 44 | 45.3 | 7.9 | 8.0 |
| 2a | Add Fine Mesh Screen Overlays | 22 | 22.6 | 4.0 | 4.0 |
| 3 | Add New Larger Intake Structure with Fine Mesh, Handling and Return | 27 | 27.7 | 4.9 | 4.9 |
| 4 | Add Passive Fine Mesh Screens (1.75 mm mesh) at Shoreline | 60 | 61.3 | 10.8 | 10.8 |
| 5 | Add Fish Barrier Net | 42 | 42.3 | 7.5 | 7.5 |
| 6 | Gunderboom | 2 | 2.0 | 0.4 | 0.4 |
| 7 | Relocate Intake to Submerged Offshore with passive screen (1.75 mm mesh) | 14 | 14.1 | 2.5 | 2.5 |
| 8 | Add Velocity Cap at Inlet | 9 | 9.4 | 1.6 | 1.7 |
| 9 | Add Passive Fine Mesh Screen (1.75 mm mesh) at Inlet of Offshore Submerged | 15 | 16 | 2.7 | 2.8 |

| | | | | | |
|---|---|---|---|---|---|
| 11 | Add Double-Entry, Single-Exit with Fine Mesh, Handling and Return | 27 | 27.9 | 4.9 | 4.9 |
| | *For Estuary & Ocean only:* | | | | |
| 12 | 0.75 mm Passive Fine Mesh Screen at Shoreline | 0 | 0 | 0 | 0 |
| 13 | 0.75 mm Passive Fine Mesh Screen at Inlet of Offshore Submerged | 0 | 0 | 0 | 0 |
| 14 | Relocate Intake to Submerged Offshore with 0.75 mm passive screen | 0 | 0 | 0 | 0 |
| Total | | 557 | 565.7 | | |

Counts are for primary cost module assigned.
Note that some facilities were assigned different compliance technologies for two or more different intakes and may be counted multiple times.
Facilities with one of two or more intakes assigned "module 0" (None) were not included in the "Module 0" count.

Costs for permitting, monitoring, and recordkeeping are not included in the cost-test tool. Costs for these activities were developed separately, and may be found in the Information Collection Request for the Phase III proposed rule (ICR 2169.01, DCN 7-0001).

## 2.4 Fixed and Variable Costs

When developing the annual O&M cost estimates, the underlying assumption was that facilities were operating nearly continuously at design intake flow with the only downtime being periodic routine maintenance. This routine maintenance was assumed to be approximately four weeks per year. The economic model however, considers variations in capacity utilization. Lower capacity utilization factors reflect reductions in generation rates and additional generating unit shutdown that may result in reduced O&M costs. However, it is not valid to assume that intake technology O&M costs drop to zero during these additional shutdown periods. Even when the generating unit is shut down, there are some O&M costs incurred. To account for this, total annual O&M costs were divided into fixed and variable components. Fixed O&M costs include items that occur even when the unit is periodically shut down or operating at lower flow rates, and thus are assumed to occur year round. Variable O&M costs apply to items that are fully allocable when the intake is operating at the design capacity. The general assumption behind the fixed and variable determination is that shutdown periods are relatively short (on the order of several hours to several weeks), based on reported shutdown periods by power generators.

The annual O&M cost estimates used in the cost modules is the net O&M cost, which is the difference between the estimated baseline O&M and the incremental compliance O&M costs. Therefore, the fixed or variable proportions for each facility may vary depending on the mix of baseline and compliance technologies. When a facility has baseline O&M costs, and incurs no additional O&M costs as a result of new technology, the incremental O&M cost is 0 (zero). To calculate fixed and variable costs, EPA used the following equations (Eqn.) and baseline cost factors:

Eqn 2.41 Fixed baseline O&M = (baseline O&M) * (baseline cost factor)
Eqn 2.42 Fixed compliance O&M = (compliance O&M) * (technology cost factor)
Eqn 2.43 Net Total O&M = (Compliance O&M) - (Baseline O&M)
Eqn 2.44 Net Fixed O&M = (Fixed baseline O&M) + (Fixed compliance O&M)
Eqn 2.45 Net Variable O&M = (Net Total O&M) - (Net Fixed O&M)

**Exhibit 5-10. Baseline Cost Factors for Control Technologies**

| Technology | COST FACTOR |
|---|---|
| Baseline Technology Fixed O&M Cost Factors | 0.41 |
| Add Fish Handling and Return System | 0.40 |
| Add Fine Mesh Traveling Screens with Fish Handling and Return | 0.40 |
| Add New Larger Intake Structure with Fine Mesh, Handling and Return | 0.24 |
| Add Passive Fine Mesh Screens (1.75 mm mesh) at Shoreline | 0.24 |

| | |
|---|---|
| Add Velocity Cap at Inlet | 1.0 |
| Add Passive Fine Mesh Screen (1.75 mm mesh) at Inlet of Offshore Submerged | 0.24 |
| Add Double-Entry, Single-Exit with Fine Mesh, Handling and Return | 0.385 |
| Add 0.76 mm Passive Fine Mesh Screen at Shoreline for Estuary & Ocean only | 0.24 |
| Add 0.76 mm Passive Fine Mesh Screen at Inlet of Offshore Submerged for Estuary & Ocean only | 0.24 |

Basis of Calculating Variable O&M Costs

During an engineering review of the O&M cost estimates for NODA, it was noted that the O&M costs are based on the assumption that the intake technologies were operating at the DIF. The data reported by the facilities, however, indicate that most facilities operate at an average flow level that is often well below the DIF. Hence, the cost-test tool was revised such that for each O&M estimate, both baseline and compliance O&M costs are adjusted so that the variable component is reduced to reflect actual use. The method used was to apply a factor (i.e., AIF/DIF) to the variable portion to arrive at the revised O&M cost. The cost-test tool was revised to add AIF as an additional input value. O&M costs were adjusted using the following factor:

((1 - fixed factor)*AIF/DIF + fixed factor)

Baseline technology fixed O&M cost factors and compliance technology fixed O&M cost factors are presented in Exhibits 3-75 and 3-76, respectively.

## 3.0 EXAMPLES OF APPLICATION OF TECHNOLOGY COST MODULES TO MODEL FACILITIES

**Exhibit 5-11. Initial Capital-Cost Equations for Phase III Technology Upgrades**

| Technology Upgrade | Well Depth Range (ft) | Capital Cost Equation | Equation |
|---|---|---|---|
| Module 1 (freshwater): Add Fish Handling and/or Return System | 10 | $Y = 1.5111W^2 + 12863W + 56372$ | 1-1 |
| | 25 | $Y = 13.296W^2 + 18517W + 48889$ | 1-2 |
| | 50 | $Y = 8.5055W^2 + 27952W + 76555$ | 1-3 |
| | 75 | $Y = 12.91W^2 + 35525W + 97459$ | 1-4 |
| | 100 | $Y = 16.308W^2 + 42746W + 129320$ | 1-5 |
| Module 1 (saltwater): Add Fish Handling and/or Return System | 10 | $Y = 7.4491W^2 + 22493W + 79504$ | 1-6 |
| | 25 | $Y = 31.476W^2 + 32889W + 60070$ | 1-7 |
| | 50 | $Y = 22.351W^2 + 50846W + 110933$ | 1-8 |
| | 75 | $Y = 31.616W^2 + 65080W + 148273$ | 1-9 |
| | 100 | $Y = 38.869W^2 + 78611W + 207527$ | 1-10 |
| **Technology Upgrade** | **Distance Offshore (m)** | **Capital Cost Equation** | **Equation** |
| Module 12 (freshwater w/o zebra mussels): Add 0.76 mm Passive Fine Mesh Screen at Shoreline | 20 | $Y = -0.000002X^2 + 8.6127X + 99538$ | 12-1 |
| | 125 | $Y = -0.000001X^2 + 15.183X+ 111563$ | 12-2 |
| | 250 | $Y = -0.000003X^2 + 23.006X+125879$ | 12-3 |
| | 500 | $Y = 0.000003X^2 + 38.65X+ 154511$ | 12-4 |
| Module 12 (freshwater w/ zebra mussels): Add 0.76 mm Passive Fine Mesh Screen at Shoreline | 20 | $Y = -0.000003X^2 + 12.322X+ 97733$ | 12-5 |
| | 125 | $Y = -0.000001X^2 + 18.893X+ 109758$ | 12-6 |
| | 250 | $Y = -0.0000001X^2 + 26.715X+ 124074$ | 12-7 |
| | 500 | $Y = 0.000003X^2 + 42.359X + 152706$ | 12-8 |
| Module 12 (saltwater): Add 0.76 mm Passive Fine Mesh Screen at Shoreline | 20 | $Y = -0.000002X^2 +9.7123X + 99830$ | 12-9 |
| | 125 | $Y = -0.000001X^2 + 17.696X+ 113409$ | 12-10 |
| | 250 | $Y = -0.0000005X^2 + 27.201X+ 129575$ | 12-11 |
| | 500 | $Y = 0.000004X^2 + 46.211X+ 161906$ | 12-12 |

Note: The costing equations presented in this table do not include the cost factors to correct for different plant type and regional location.
Note: W is the screen width per costing unit in feet. X is the total design intake flow per costing unit in gallons per minute.

**Exhibit 5-12. Plant Type Cost Factors**

| Plant Type | Capital Cost Factor | O&M Cost Factor |
|---|---|---|
| Non-nuclear | 1 | 1 |
| Nuclear in freshwater | 1.8 | 1.33 |
| Nuclear in saltwater | 1.8 | 1.45 |

**Exhibit 5-13. Regional Cost Factors and List of States with Freshwater Zebra Mussels as of 2001**

| STATE | STATE MEDIAN | Zebra Mussels? | STATE | STATE MEDIAN | Zebra Mussels? |
|---|---|---|---|---|---|
| AK | 1.264 | No | NC | 0.766 | No |
| AL | 0.823 | Yes | ND | 0.864 | No |
| AR | 0.811 | No | NE | 0.853 | No |
| AZ | 0.905 | No | NH | 0.94 | No |
| CA | 1.108 | No | NJ | 1.11 | No |
| CO | 0.926 | No | NM | 0.927 | No |
| CT | 1.0695 | Yes | NV | 1.018 | No |
| DE | 1 | No | NY | 1.039 | Yes |
| FL | 0.84 | No | OH | 0.9885 | Yes |
| GA | 0.828 | No | OK | 0.8305 | Yes |
| HI | 1.257 | No | OR | 1 | No |
| IA | 0.942 | Yes | PA | 1.008 | Yes |
| IL | 1.028 | Yes | RI | 1.063 | No |
| IN | 0.955 | Yes | SC | 0.763 | No |
| KS | 0.96 | No | SD | 0.796 | No |
| KY | 0.908 | Yes | TN | 0.828 | Yes |
| LA | 0.832 | Yes | TX | 0.807 | No |
| MA | 1.1075 | No | VA | 0.861 | No |
| MD | 0.931 | No | VI | 1 | |
| ME | 0.952 | No | VT | 0.749 | Yes |
| MI | 1.0125 | Yes | WA | 1 | No |
| MN | 1.093 | Yes | WI | 0.989 | Yes |
| MO | 0.9765 | Yes | WV | 0.963 | Yes |
| MS | 0.783 | Yes | WY | 0.841 | No |
| MT | 0.932 | No | | | |

**Exhibit 5-14. Baseline O&M Cost Equations for Phase III Technology Upgrades**

| Existing Technology | Well Depth Range (ft) | Baseline O&M Cost Equation | Equation |
|---|---|---|---|
| (Freshwater): | 10 | $B = -0.4155W^2 + 921.84W + 3239.8$ | B-1 |

| | | | |
|---|---|---|---|
| Traveling Screens w/o Fish Handling and/or Return System | 25 | $B = -0.2419W^2 + 1082.2W + 3489.7$ | B-2 |
| | 50 | $B = -0.6885W^2 + 1329.4W + 4633.2$ | B-3 |
| | 75 | $B = -0.8842W^2 + 1508.1W + 5702.5$ | B-4 |
| | 100 | $B = -1.0776W^2 + 1679.2W + 7012.9$ | B-5 |
| (Freshwater): Traveling Screens with Fish Handling and/or Return System | 10 | $B = -0.6031W^2 + 3303.7W + 7189.7$ | B-6 |
| | 25 | $B = -0.0221W^2 + 3826W + 7582$ | B-7 |
| | 50 | $B = -0.6059W^2 + 4682.6W + 10003$ | B-8 |
| | 75 | $B = -0.79W^2 + 5370.4W + 12541$ | B-9 |
| | 100 | $B = -0.8662W^2 + 6050.4W + 15301$ | B-10 |
| (Saltwater): Traveling Screens w/o Fish Handling and/or Return System | 10 | $B = -0.329W^2 + 1060.4W+ 3562.6$ | B-11 |
| | 25 | $B = 0.1181W^2 + 1283.4W + 3457.4$ | B-12 |
| | 50 | $B = -0.6261W^2 + 1655.4W + 5238.8$ | B-13 |
| | 75 | $B = -0.8367W^2 + 1902.3W +6763.2$ | B-14 |
| | 100 | $B = -1.0778W^2 + 2131.2W + 8860.3$ | B-15 |
| (Saltwater): Traveling Screens with Fish Handling and/or Return System | 10 | $B = -0.2468W^2 + 3881.6W + 8577.6$ | B-16 |
| | 25 | $B = 1.0687W^2 + 4688.4W + 8252.8$ | B-17 |
| | 50 | $B = 0.2248W^2 + 6056.3W + 12066$ | B-18 |
| | 75 | $B = 0.3324W^2 + 7143.7W + 15590$ | B-19 |
| | 100 | $B = 0.4874W^2 + 8202.3W+ 19994$ | B-20 |
| (All Waterbodies) Passive intakes (excluding bar screens only) | All | $B = 0.0223\ DIF + 2977$ | B-21 |

Note: Only facility with existing traveling screens have baseline O&M cost.

**Exhibit 5-15. Initial Gross Compliance O&M Cost Equations for Phase III Technology Upgrades**

| Technology Upgrade | Well Depth Range (ft) | Gross Compliance O&M Cost Equation | Equation |
|---|---|---|---|
| Module 1 (freshwater): Add Fish Handling and/or Return System | 10 | $G = -0.6031W^2 + 3303.7W + 7189.7$ | G1-1 |
| | 25 | $G = -0.0221W^2 + 3826W + 7582$ | G1-2 |
| | 50 | $G = -0.6059W^2 + 4682.6W + 10003$ | G1-3 |
| | 75 | $G = -0.79W^2 + 5370.4W + 12541$ | G1-4 |
| | 100 | $G = -0.8662W^2 + 6050.4W + 15301$ | G1-5 |
| Module 12: Add 0.76 mm Passive Fine Mesh Screen at Shoreline | low debris | $G = -0.0000005X^2 + 0.1381X+ 17229$ | G12-1 |
| | high debris | $G = -0.0000008X^2 + 0.2952X+ 43574$ | G12-2 |

Note: W is screen width per costing unit in feet. X is total design intake flow per costing unit in gallons per minute.

**Exhibit 5-16. Information Collection Request Cost for Facility A and Facility B**

| Average per Facility Costs for each Information Collection Request Activities[a, b] | | | | | |
|---|---|---|---|---|---|
| | Labor Cost | Capital[c] | O&M | Facility A | Facility B |

| **NPDES Permit Application Activities** | **(2004$)** | **(2004$)** | **(2004$)** | **(Example 1 Electric Generation under 50 MGD)** | **(Example 2 Manufacturing)** |
|---|---|---|---|---|---|
| Start-up Activities | $448 | $0 | $10 | $458 | $458 |
| Permit Application Activities | $2,086 | $0 | $104 | $2,190 | $2,190 |
| Proposal for Collection of Information for Comprehensive Demonstration Study | $2,595 | $0 | $158 | $2,753 | $2,753 |
| Source Waterbody Flow Information | $733/$712 | $0 | $42 | $775 | $754 |
| Design and Construction Technology Plan | $1,039/$751 | $0 | $80/$78 | $1,119 | $829 |
| Freshwater Impingement Mortality and Entrainment Characterization Study | $84,635 | $0 | $16,641/ $16,870 | NA | NA |
| Marine Impingement Mortality and Entrainment Characterization Study | $153,936 | $0 | $33,020/ $32,729 | NA | $186,665 |
| Freshwater Pilot Study for Impingement Only Technology | $10,462 | $0/$21789 | $210 | $10,672 | NA |
| Freshwater Pilot Study for Impingement & Entrainment Technology | $16,176 | $25,628/ $103,927 | $1,410 | NA | NA |
| Marine Pilot Study for Impingement Only Technology | $11965 | $37,687/NF | $210 | NA | NA |
| Marine Pilot Study for Impingement & Entrainment Technology | $18,863 | $72,765/$19,599 | $1,770 | NA | $40,232 |
| Technology Installation and Operation Plan[d] | NA/$499 | NA/$0 | NA/$16 | NA | $515 |
| Verification Monitoring Plan | $1,247 | $0 | $84 | $1,331 | $1,331 |
| **Annual Monitoring and Reporting Activities** | | | | | |
| Biological Monitoring (Impingement, Freshwater) | $18,400 | $0 | $520 | $18,920 | NA |
| Biological Monitoring (Impingement, Marine) | $23,401 | $0 | $680 | NA | $24,081 |
| Biological Monitoring (Entrainment, Freshwater) | $30,206 | $0 | $8,320 | NA | NA |
| Biological Monitoring (Entrainment, Marine) | $37,775 | $0 | $10,820 | NA | $48,595 |
| Status Report Activities[e] | $17,497/$8,749 | $0 | $790/$395 | $18,287 | $9,144 |
| Verification Study[f] | $1,423 | $0 | $104 | $1,527 | $1,527 |
| TOTAL | | | | $62,838 | $319,912 |

NF: There are no facilities required to perform the activity.
NA: Not applicable
a: Costs are presented for Electrical Generation Facilities/Manufacturing Facilities (50 MGD option).
b: Costs for Electrical Generation Facilities were updated to 2004 dollars using Employment Cost Index from the Bureau of Labor Statistics and ENR Construction Cost Index.
c: Capital costs were annualized using 7% discount rate and 10-year amortization period.
d: Technology Installation and Operation Plan is applicable for Manufacturing Facilities only.
e: Status reporting is yearly for Electrical Generation Facilities and biannual for Manufacturing Facilities.
f: Average per facility labor and O & M costs for each NPDES Permit Application activity and Verification Study were distributed over a five-year period to reflect the permit term using Phase III 316(b) Information Collection Request costs.

### Example 1. Facility Requires Upgrade to Add Fish Handling and/or Return System to Existing Traveling Screen System

Facility A is an imaginary coal-fired steam electric facility located on a freshwater river in Tennessee. The facility has a design intake flow of 25 MGD, a shoreline intake, and an existing traveling screen system with 3/8-inch mesh (coarse mesh). In addition, Facility A produces electricity at near-full capacity and its intake flow is less than 5% of the river annual flow. It has been determined that to comply with the example Phase III regulatory requirements (“Example A”), Facility A would be required to meet impingement performance standards.

**Assumptions**

- Facility A’s existing through-screen velocity is 0.9 feet per second.
- Facility A’s mean intake water depth is 12 feet.
- Facility A’s intake well depth is 14 feet.
- There is no significant navigation or waterbody use near the intake entrance.
- There is normal debris loading.

**Step 1: Select the appropriate costing module from Figure 5-1.**

Using the through-screen velocity, the intake location, and regulatory requirements, you can determine which technology best suits the application. Since Facility A would be required to reduce impingement only, has low-range through-screen velocity, and has a shoreline intake, the appropriate costing module is module number 1.

Module 1 = Add fish handling and return system.

**Step 2: Select the appropriate equation from Exhibit 5-11.**

Using the intake well depth and the costing module identified in Step 1, you can select the appropriate equation from Exhibit 5-11 to use in determining the “Initial Capital Costs.” Since Facility A has an intake well depth of 14 feet, the appropriate equation to use from Exhibit 5-11 is Equation 1-2 because it is for costing module one and corresponds to intake well depth that range between 11 and 25 feet.

$$Y = 13.296W^2 + 18517W + 48889 \qquad \text{[See Eqn 1-2, Exhibit 5-11]}$$

Where W is the screen width per costing unit (in feet) which is calculated by dividing the total design intake flow by the through-screen velocity; mean intake water depth; and open area factor, and Y is the Initial Capital Costs (in 2002 U.S. dollars)

**Step 3: Determine the total design intake flow for the facility.**

The records indicate that the design intake flow for Facility A is 25 MGD. Design intake flow is defined as "the value assigned during the facility's design to the total volume withdrawn from the source waterbody over a specific time period." Facility A may have the design intake flow value available in their records or it can be estimated based on the size of the intake pumps. The design intake flow must be in the units "cubic feet per second (cfs)" for use with the equation in Step 4. Therefore, to convert the design intake flow from MGD to cfs you can perform a dimensional analysis using the following equation.

$$X(cfs) = X(mgd) \times \frac{1{,}000{,}000\,gallons}{1\ million\ gallons} \times \frac{1\,cubic\ feet}{7.48\,gallons} \times \frac{1\,day}{24\,hours} \times \frac{1\,hour}{60\,minutes} \times \frac{1\,minute}{60\,seconds}$$

Convert the 25 MGD to cfs as follows:

$$X(cfs) = 25\,mgd \times \frac{1{,}000{,}000\,gallons}{1\,million\,gallons} \times \frac{1\,cubic\ feet}{7.48\,gallons} \times \frac{1\,day}{24\,hours} \times \frac{1\,hour}{60\,minutes} \times \frac{1\,minute}{60\,seconds}$$

$$X = 38.68\ \text{cfs}$$

**Step 4: Determine the screen width per costing unit (feet), W.**

The screen width per costing unit is calculated from the following equation:

W(ft) = [X(cfs)] ÷ [Through -screen Velocity (fps)] ÷ [Mean Intake Water Depth (ft)] ÷ [open area factor]

$$W(ft) = \frac{38.68\,cubic\ feet}{second} \times \frac{second}{0.9\ feet} \times \frac{1}{12\ feet} \times \frac{1}{0.68}$$

$$W = 5.267\ \text{feet}$$

Note: Flat per traveling screen unit width should not exceed 140 feet.

**Step 5: Calculate the "Initial Capital Costs."**

Using the screen width per costing unit in Step 4 and the equation identified in Step 2, the Initial Capital Cost is calculated as follows:

$$Y = 13.296(5.267)^2 + 18517(5.267) + 48889$$

$$Y = \$146{,}787$$

**Step 6: Identify the appropriate cost factors from Exhibits 5-12 and 5-13.**

Plant type cost factors are listed in Exhibit 5-12. Since Facility A is a non-nuclear facility, the plant type cost factor is one (1). Regional cost factors are listed in Exhibit 5-13. Since Facility A is located in Tennessee, the regional cost factor is 0.828.

**Step 7: Calculate the Total Estimated Capital Costs (TECC)**

To calculate the TECC use the following equation:

$$TECC = (\text{Initial Capital Cost}) \times (\text{Plant Type Cost Factor}) \times (\text{Regional Cost Factor})$$

Entering the initial capital cost calculated in Step 5 and cost factors identified in Step 6, the total cost can be calculated as follows:

$$TECC = (\$146{,}787) \times (1) \times (0.828)$$

$$TECC = \$121{,}540$$

**Step 8: Select the appropriate equations from Exhibits 5-14 and 5-15 to use in determining the "Baseline Operation and Maintenance Costs," if applicable, and the "Gross Compliance Operation and Maintenance Costs."**

To calculate the annual O&M costs, you need to determine the gross compliance O&M (GCOM) costs and the baseline O&M costs, if applicable. Only facilities with existing traveling screens have baseline O&M costs.

**<u>BASELINE O&M COSTS (B)</u>**

Using the intake well depth (ft) you can select the appropriate equation from Exhibit 5-14 to use in determining the "Baseline Operation and Maintenance Costs." Since Facility A has an existing traveling screen without fish handling system and an intake well depth of 14 feet, the appropriate equation to use from Exhibit 5-14 is Equation B-2 because it corresponds to well depth range between 11 and 25 feet.

$$B = -0.2419W^2 + 1082.2W + 3489.7 \qquad \text{[See Eqn B-2, Exhibit 5-14]}$$

Where: W is the screen width per costing unit (in feet), and B is the Baseline Operation and Maintenance Costs (in 2002 U.S. dollars)

Entering the screen width per costing unit calculated in Step 4, W=5.267, the baseline operation and maintenance costs can be calculated as follows:

$$B = -0.2419W^2 + 1082.2W + 3489.7$$

$$B = \$\ 9{,}183$$

**<u>INITIAL GROSS COMPLIANCE O&M COSTS (G)</u>**

Using the intake well depth (ft) and the cost module identified in Step 1, you can select the appropriate equation from Exhibit 5-15 to use in determining the "Initial Gross Compliance Operation and Maintenance Costs." Since Facility A has an intake well depth of 14 feet, the appropriate equation to use from Exhibit 5-15 is Equation G1-2 because it is for costing module one and corresponds to well depth range between 11 and 25 feet.

$$G = -0.0221W^2 + 3826W + 7582 \qquad \text{[See Eqn G1-2, Exhibit 5-15]}$$

Where: W is the screen width per costing unit (in feet), and G is the Initial Gross Compliance Operation and Maintenance Costs (in 2002 U.S. dollars).

Entering the screen width per costing unit calculated in Step 4, W=5.267, the initial gross compliance operation and maintenance cost can be calculated as follows:

$$G = -0.0221(5.267)^2 + 3826(5.267) + 7582$$
$$G = \$\ 27{,}733$$

**GROSS COMPLIANCE O&M COSTS (GCOM)**

To determine the GCOM, you need the plant type cost factor from Exhibit 5-12 and the following equation:

GCOM = (Initial Gross Compliance O&M) x (Plant Type Cost Factor)

**Step 9: Calculate the Yearly Operation and Maintenance Costs.**

To calculate the yearly operation and maintenance costs, use the following equation:

Net Annual O&M Cost = (GCOM) - (Baseline O&M)

Entering the plant type cost factor from Exhibit 5-12, the plant type cost factor is 1, and the gross compliance operation and maintenance cost can be calculated as follows:

GCOM = (G) x (Plant Type Cost Factor)

GCOM = ($27,733) x (1)

GCOM = $27,733

**NET ANNUAL O&M COSTS**

Entering the calculated gross compliance operation and maintenance cost and the baseline operation and maintenance cost from above, the yearly operational and maintenance cost can be determined as follows:

Net Annual O&M Cost = (GCOM) - (Baseline O&M)

Net Annual O&M Cost = ($27,733) - ($9,183)

Net Annual O&M Cost = $18,550

**Exhibit 5-17 Costs for Facility A at Different DIFs**

| Summary of Costs for Facility A at Different DIFs | | | | | |
|---|---|---|---|---|---|
| | DIF= 2 MGD | DIF= 10 MGD | DIF= 25 MGD | DIF= 30 MGD | DIF= 40 MGD |
| Total Estimated Capital Costs | $46,943 | $72,833 | $121,540 | $137,831 | $170,477 |
| Annualized TECC | $6,684 | $10,370 | $17,305 | $19,624 | $24,272 |
| Net Annual O&M Costs | $5,249 | $9,874 | $18,551 | $21,444 | $27,232 |
| Information Collection Request (ICR) Costs | $58,198 | $58,198 | $58,198 | $58,198 | $58,198 |
| TOTAL | $70,131 | $78,442 | $94,054 | $99,266 | $109,702 |

Note: Annualized TECC is calculated using 7% discount rate and 10 years amortization period.

Note: See Exhibit 5-14 for additional information on the ICR costs.

**Example 2. Facility Requires Upgrade to Add Passive Fine Mesh Screen**

Facility B is an imaginary manufacturer located on an estuary in Massachusetts. The facility has a design intake flow of 100 MGD and a near-shore submerged intake with bar racks. It has been determined that to comply with the example Phase III regulatory requirements ("Example A"), Facility B would be required to meet impingement and entrainment performance standards.

**Assumptions**

- Facility B's existing intake velocity is 1.5 feet per second.
- Facility B's mean intake water depth is 19 feet.
- Facility B's intake well depth is 22 feet.
- Facility B's existing intake entrance is approximately 50 feet (15.3 meter) offshore.
- There is no significant navigation or waterbody use near the intake entrance.
- There is normal debris loading.

**Step 1: Select the appropriate costing module from Figure 5-1.**

Using the through-screen velocity, the intake location, and regulatory requirements, you can determine which technology best suits the application. Since Facility B would be required to reduce impingement and entrainment, has mid-range through-screen velocity, and has a near-shore submerged intake with bar rack, the appropriate costing module is module number 12.

Module 12 = Add Passive Fine Mesh Screen (0.76 mm).

**Step 2: Select the appropriate equation from Exhibit 5-11.**

Using the existing intake distance offshore and the costing module identified in Step 1, you can select the appropriate equation from Exhibit 5-11 to use in determining the "Initial Capital Costs." Since the Facility B intake is 50 feet offshore, the appropriate equation to use from Exhibit 5-11 is Equation 12-9 because it is for costing module 12 and corresponds to distance offshore that is less than 20 meters.

$$Y = -0.000002X^2 + 9.7123X + 99830 \qquad \text{[See Eqn 12-9, Exhibit 5-11]}$$

Where: X is the total design intake flow per costing unit in gpm, and Y is the Initial Capital Costs (in 2002 U.S. dollars)

**Step 3: Determine the total design intake flow for the facility.**

The records indicate that the design intake flow for Facility B is 100 MGD. Design intake flow is defined as "the value assigned during the facility's design to the total volume withdrawn from the source waterbody over a specific time period." Facility may have the design intake flow value available in their records or it can be estimated based on the size of the intake pumps. The design intake flow must be in the units gpm for use with the equation in Step 4. Therefore, to convert the design intake flow from MGD to gpm you can perform a dimensional analysis using the following equation.

$$X(gpm) = X(mgd) \times \frac{1{,}000{,}000\, gallons}{1\, million\, gallons} \times \frac{1\, day}{24\, hours} \times \frac{1\, hour}{60\, \min utes}$$

Convert the 100 MGD to gpm as follows:

$$X(gpm) = 100\, mgd \times \frac{1{,}000{,}000\, gallons}{1\, million\ gallons} \times \frac{1\, day}{24\, hours} \times \frac{1\, hour}{60\, \min utes}$$

$$X = 69{,}444 \text{ gpm}$$

Note: Flow per screen unit must stay below 165,000 gpm for passive intake technology.

**Step 4: Calculate the "Initial Capital Costs."**

Using the total design intake flow in Step 3 and the equation identified in Step 2, the Initial Capital Cost is calculated as follows:

$$Y = -0.000002(69444)^2 + 9.7123(69444) + 99830$$

$$Y = \$764,646$$

**Step 5: Identify the appropriate cost factors from Exhibit 5-12 and Exhibit 5-13.**

Plant type cost factors are listed in Exhibit 5-12. Since Facility B is a non-nuclear facility, the plant type cost factor is one (1). Regional cost factors are listed in Exhibit 5-13. Since Facility B is located in Massachusetts, the regional cost factor is 1.1075.

**Step 6: Calculate the TECCs**

To calculate the TECCs use the following equation:

$$\text{TECC} = (\text{Initial Capital Cost}) \times (\text{Plant Type Cost Factor}) \times (\text{Regional Cost Factor})$$

Entering the initial capital cost calculated in Step 4 and cost factors identified in Step 5, the total cost can be calculated as follows:

$$\text{TECC} = (\$764,646) \times (1) \times (1.1075)$$

$$\text{TECC} = \$\ 846,845$$

**Step 7: Select the appropriate equations from Exhibits 5-14 and 5-15 to use in determining the "Baseline Operation and Maintenance Costs," if applicable, and the "Gross Compliance Operation and Maintenance Costs."**

To calculate the annual O&M costs, you need to determine the GCOM and the baseline O&M costs, if applicable. Only facilities with existing traveling screens have baseline O&M costs.

<u>**BASELINE O&M COSTS (B)**</u>
There is no baseline O&M cost for Facility B because it does not have existing traveling screens.

<u>**INITIAL GROSS COMPLIANCE O&M COSTS (G)**</u>
Using the debris loading information and the cost module identified in Step 1, you can select the appropriate equation from Exhibit 5-15 to use in determining the "Initial Gross Compliance Operation and Maintenance Costs." Since Facility B has low debris loading, the appropriate equation to use from Exhibit 5-15 is Equation G12-1.

$$G = -0.0000005X^2 + 0.1381X + 17229 \qquad \text{[See Eqn G12-1, Exhibit 5-15]}$$

Where: X is the total design intake flow per costing unit (in gpm), and G is the Initial Gross Compliance Operation and Maintenance Costs (in 2002 U.S. dollars)

Entering the total design intake flow from Step 3, X=69444 gpm, the initial gross compliance operation and maintenance cost can be calculated as follows:

$$G = -0.0000005(69444)^2 + 0.1381(69444) + 17229$$

G = $ 24,408

**GROSS COMPLIANCE O&M COSTS (GCOM)**
To determine the GCOM, you need the plant type cost factor from Exhibit 5-12 and the following equation:

GCOM = (Initial Gross Compliance O&M) x (Plant Type Cost Factor)

Entering the plant type cost factor from Exhibit 5-12, for Facility B it is 1, the gross compliance operation and maintenance cost can be calculated as follows:

GCOM + (G) x (Plant Type Cost Factor)

GCOM = ($24, 408) x (1)

GCOM = $24, 408

**Step 8: Calculate the Yearly Operation and Maintenance Costs.**

To calculate the yearly operation and maintenance costs, use the following equation:

Net Annual O&M Cost = (GCOM) - (Baseline O&M)

**NET ANNUAL O&M COSTS**
Entering the calculated gross compliance operation and maintenance cost and the baseline operation and maintenance cost from above, the yearly operational and maintenance cost can be determined as follows:

Net Annual O&M Cost = (GCOM) - (Baseline O&M)

Net Annual O&M Cost = ($24,408) - ($0)

Net Annual O&M Cost = $24,408

**Exhibit 5-18. Costs for Facility B at Different DIFs**

| **Summary of Costs for Facility B at Different Design Intake Flow (DIF)** | | | | | |
|---|---|---|---|---|---|
| | DIF= 2 MGD | DIF= 10 MGD | DIF= 30 MGD | DIF= 40 MGD | DIF= 100 MGD |
| Total Estimated Capital Costs | $125,497 | $185,152 | $333,691 | $407,641 | $846,845 |
| Annualized TECC | $17,868 | $26,361 | $47,510 | $58,039 | $120,571 |
| Net Annual O&M Costs | $17,420 | $18,164 | $19,889 | $20,679 | $24,408 |
| ICR Costs | $382,620 | $382,620 | $382,620 | $382,620 | $382,620 |
| TOTAL | $417,908 | $427,145 | $450,019 | $461,338 | $527,599 |

Note: Annualized TECC is calculated using 7% discount rate and 10 years amortization period.
Note: See Exhibit 5-14 for additional information on the ICR costs.

## 4.0 ANALYSIS OF THE CONFIDENCE IN ACCURACY OF THE COMPLIANCE COST MODULES

This section provides an overview of the confidence in the accuracy of the compliance capital and O&M costs developed using the 316(b) Phase II Compliance Technology Cost Modules. A key element in cost estimation is the available data and information about site conditions. Some site conditions are favorable to design and construction works while others may involve higher degrees of uncertainty. In sites with favorable conditions, design and construction costs are expected to be lower than the cost of the same project designed and constructed under “typical” or “normal” site conditions. On the other end of the spectrum, the costs are expected to be significantly higher than that for the “typical” job site. The cost estimates developed for the compliance technologies assume a “typical” rather than the exceptional job site, except where noted below.

In every design and construction endeavor, a level of confidence is developed based on many factors. These factors include factual or data attributes and non-factual or information attributes. The data attributes have to do with level of detail that is available to the designer, the estimator, and the contractor. Also important is the information about the end product function and architectural features of the job site where construction or installation of equipment needs to take place. The confidence also has to do with the confidence in the source data and how the data was used to generate the information and confidence in the experience that is often used by engineers and cost estimators to bridge gaps in the available data. As such, many professional organizations and authorities in the engineering and construction arena have developed scales to identify necessary confidence levels at every stage of a project to keep a project within the realm and context of reasonableness within budget and execution potential limits.

For example, the American Association of Cost Engineers International (AACE) recommends the following three construction cost estimating categories with the corresponding different levels of accuracy shown in Exhibit 5-19. EPA generally develops budgetary level cost estimates to forecast compliance cost estimates for a regulation. However, for the compliance technology cost estimates, EPA took an additional step in developing costs that were closer to definitive or preliminary design costs estimates.

As described below, some of the cost components such as equipment costs and technologies available from a limited number of providers have an accuracy level that is much higher than a budgetary cost estimate. In general, given the context of the 316(b) developed cost estimates, the accuracy of any module is not expected to be less than that of a “budget estimate.”

The discussion below assesses in more detail the accuracy of elements of the cost modules. For clarification purposes, examples concerning the selection of assumed values used in the technology design or input variables are presented below. High-side design values were assumed where noted.

In some modules, median values of the data provided by the detailed questionnaire facilities are assumed for facilities where specific data input are not available (e.g., short technical questionnaire facilities). In some cases, the overall median is used and in others, waterbody-specific medians are used. The use of medians is intended to produce the best estimate of costs at the national level by equally over- and under-estimating individual facility costs as a result of the assumed median value being higher or lower than the actual value. A select set of module costs were designed to err on the high side because of the known unpredictability of job sites and technology performance.

Inaccuracies due to regional differences in labor and materials costs are accounted for where necessary through the use of regional cost factors. Where unit costs are based on RS Means data, the unit costs should be considered as having an accuracy of a definitive estimate, as these costs are derived and routinely updated using numerous national construction project data sources.

**Exhibit 5-19. Construction Cost Estimating Categories**

| Category | Purpose | Timing | Expected Accuracy |
|---|---|---|---|
| 1) Conceptual Estimate | -Preliminary estimates for proposed projects<br>-Generally used for screening of alternatives | -Major equipment is sized and specified<br>-Process flow is approved<br>-Utility requirements are specified<br>-Preliminary plot layout | +50% to -30% |
| 2) Budget Estimate | -To commit engineering budget<br>-To commit purchase of critical delivery of equipment<br>-Appropriation request<br>-Check contractor's bids | Same as above except:<br>-process design basis is approved<br>-selection of alternatives has been made | +30% to -15% |
| 3) Definitive Estimate | -Detailed control budget<br>-Cost control and reporting<br>-Finalize contract structure<br>-Fee: adjust or convert | -Plot plan finalized or approved<br>-Equipment size and specs firm<br>-Flow diagrams complete<br>-Complete set of specifications<br>-Production engineering may be completed up to 40% | +15% to -5% |

Source: (AACE 1996)

The Agency also considered the elevated costs for capital and operation and maintenance costs at nuclear stations. These costs were applied as numerical multipliers to the costs discussed below. As such, the analysis of confidence levels discussed below for fossil-fuel facilities will apply to nuclear facilities as well.

**PASSIVE SCREENS**

Cost Modules Covered:

- Module #4: Add Passive Fine Mesh Screens (1.75 mm mesh) at Shoreline
- Module #7: Relocate Intake to Submerged Offshore with Fine Mesh Passive Screen (1.75 mm mesh)
- Module #9: Add Passive Fine Mesh Screen (1.75 mm) at Inlet of Offshore Submerged
- Module #12: Add Very Fine Mesh (0.76 mm) Passive Screen at Shoreline
- Module #13: Add Very Fine Mesh (0.76 mm) Passive Screen at Inlet of Offshore Submerged
- Module #14: Relocate Intake to Submerged Offshore with Very Fine Mesh (0.76 mm) Passive Screen.

The differences between the fine mesh (1.75 mm) and very fine mesh (0.76 mm) screens were that the "per screen" flow rate was set lower for finer mesh similar sized screens based on vendor recommendations. The per screen cost was slightly higher for similar sized screens, and O&M cost were adjusted upward for finer mesh due to higher retention of debris with finer mesh. The analysis below focuses on fine mesh screens but should also apply to the very fine mesh screen modules.

**Passive Screen Capital Costs**

Input Variables

The primary input variable was the intake design flow. Other variables included saltwater versus freshwater, and distance offshore. To reduce inaccuracy due to differences in distance offshore, costs are developed for 4 distances offshore; 20 meters (which corresponds to the "near shoreline" modules #4 and #12), 125 meters, 250 meters, and 500 meters. As can be seen in Exhibit 5-20 the distance offshore has a significant effect on the costs. Inevitably some inaccuracy will exist due to the potential mismatch of the module distance and the actual distance. For adding passive screens to existing offshore intakes at facilities where the distance was known, the next highest module distance was selected with a maximum of 500 meters. In general, this tended to bias the capital costs upward but increased the confidence that the costs would not be underestimated. However, for those with existing distances greater than 500 meters the costs were biased downward. For the short technical questionnaire facilities, the distance offshore for existing submerged intakes was assumed to be equal to the median value for the data provided in the detailed questionnaires for each waterbody category. This value was then rounded up to the next of the four module distances to increase the confidence that the costs would not be underestimated. The assumption that there would be sufficient depth for larger size screens, provides a potential bias of costs towards the low side where high design flows require large screens to be installed near shore in shallow water. For larger flows, shallow water requires multiple smaller screens which would tend to increase screen and piping costs. To limit this potential bias, facilities requiring multiple large screens were rarely considered as candidates for near shore applications.

Capital Cost Components:

The total estimated capital costs for adding passive wedgewire T-screens consists of the following cost components:

- Screens
- Backwash Equipment
- Backwash Air Piping
- Steel Pipe
- Connecting Wall

The proportion and significance of each to the total capital cost depends on the specific application. The proportion of the total for each component varies most with distance offshore. Exhibit 5-20 presents the proportion of each component calculated as an average of those for each of the 10 input flow values ranging from 2,500 to 163,000 gpm for the shortest (20 meters) and longest (500 meters) submerged intake pipes in freshwater applications. Each component cost includes installation costs and is discussed separately below.

**Exhibit 5-20. Relative Proportion of Each Capital Cost Component for Freshwater Applications for Adding Screens to Existing Submerged Intakes and Relocating Submerged Offshore for 20 Meters and 500 Meters Offshore**

| Relocate Passive Screens Offshore Components | Add to Existing Submerged Intake | | Relocate Offshore | |
|---|---|---|---|---|
| | 20 Meters Offshore | 500 Meters Offshore | 20 Meters Offshore | 500 Meters Offshore |
| Screens | 64% | 20% | 29% | 6% |
| Backwash Equipment | 17% | 6% | 7% | 2% |
| Backwash Air Piping | 20% | 74% | 9% | 24% |
| Steel Pipe | 0% | 0% | 28% | 62% |
| Connecting Wall | 0% | 0% | 27% | 6% |

Screen Costs

The screen cost component includes the sum of the cost of the screens, installation, mobilization, and steel fittings. Installation and mobilization can comprise from 80% of the screen costs for low flow operations to about 20% for high flow operations. The screen costs were obtained from a vendor who reported that the accuracy of the screen costs as that of a detailed estimate (+15% to -5%) (Whitaker 2004). The installation and mobilization costs are based on the BPJ application of vendor-provided cost estimates for velocity caps. While the equipment costs were reported to be relatively accurate, vendors of nearly all of the technologies have noted that installation costs are much more variable and dependent on site-specific conditions making a “typical” estimate potentially less accurate. As such, the installation and mobilization component costs (20% to 80% of total screen costs) should be viewed as having the accuracy of a budget estimate.

Actual project screen costs were obtained for six 48-in. screens installed at the Zimmer Power Plant on the Ohio River. The reported screen equipment cost when adjusted to 2002 dollars for inflation was $204,680. Comparable total screen costs using the cost module component data was $190,000 for CuNi screens. In this example the actual screen costs were 8% higher than the Module Cost and are well within the estimated accuracy range.

Backwash Equipment

The backwash equipment costs were also obtained from a vendor. This backwash equipment cost data came with the caveats that "the Air Burst system is very custom, based upon distance from screen, multiple compressors, receiver size, controls, etc." Thus, the accuracy of this cost component is difficult to quantify and the costs provided by the vendor should be viewed as having the accuracy of a budget estimate since it included variation due to differences in equipment sizes.

Backwash Air Piping

The costs for backwash air piping is based on unit costs reported in RS Means Costworks 2001 for installed stainless steel pipe (in an above ground application) multiplied by an underwater installation factor of 2 which was derived from looking at similar data for the steel pipe installation costs. While the cost of materials for the stainless steel pipe should have the accuracy of a definitive estimate, the installation factor was developed using BPJ and should be viewed as having the accuracy of a budget estimate.

Steel Pipe

The steel pipe costs were derived from the submerged steel pipe cost estimating methodology as described in Economic and Engineering Analyses of the Proposed Section 316(b) New Facility Rule, Appendix A, but modified based on a design pipe velocity of 5 feet per second. The 5 feet per second pipe velocity reflects a best engineering estimate based on typical design specifications and an efficient use of cross-sectional area within the pip to prevent sudden pressure drops. The pipe cost estimate is the result of a detailed engineering estimate and should have the accuracy of a budget estimate. The actual methodology used in the installation of the manifold piping may differ from the method used in developing the module costs.

The use of different pipe installation methods, however, does not necessarily indicate costs will vary widely. For example, a comparison of the bid costs provided for installation (using a coffer dam in this instance) of a 220-meter, 10-ft diameter steel pipe on a submerged drinking water intake on the Potomac River for the Fairfax County Water Authority was $2,856,000 for the wining low bid. The comparable Module component for a 250-meter pipe was $2,818,000. Note that the module pipe length was 14% greater than the example, but the cost of the accepted bid was within nearly one percent of the cost predicted by the module. While the installation method was different the costs were very similar.

Connecting Wall

The connecting wall design is based on the use of a sheet pile using sheet pile cost from RS Means. The primary independent variable used to develop costs for different flow values was the cross-sectional area of the front of the intakes to be covered. Several general assumptions were made that tended to bias the costs of this component upward, including assuming an existing through-screen velocity of 1.0 foot per second (whereas the median was around 1.5 feet per second) and a percent open area of 50% (rather than 68% for "typical" coarse mesh screens cited by traveling screen vendors). The cost was developed using a detailed engineering estimate and should have an accuracy of a budget estimate but biased somewhat on the high side.

Relocate to Submerged at Shoreline or Offshore

As described above, the screen equipment costs have the greatest accuracy (approximately +15% to -10%), but this only comprises 20% to 80% of the installed screen cost which itself is 29% to 6% of the total capital cost, depending on distance offshore. Combined, the screen equipment costs component (accuracy of +15% to -10%) constitutes roughly 25% to 1.2% of the total capital cost. The remaining components are considered as having an accuracy of a budget estimate (+30% to -15%).

Add to Existing Submerged Offshore

In this option the installed screen cost represents a greater portion of the total costs (64% to 20%) and therefore the total capital cost will have a greater overall accuracy. Combined together, the screen equipment costs component (accuracy of +15% to -10%) constitutes roughly 51% to 4% of the total capital cost. The remaining components are considered as having an accuracy of a budget estimate (+30% to -15%). As with the relocate offshore option, the non-screen costs increase as the distance offshore increases.

**Passive Screen O&M Costs**

O&M Input Variables

The primary independent variable was the intake design flow. High and low debris was selected as a secondary variable to increase confidence that the costs would be accurate for different environments. Distance offshore and saltwater versus freshwater were not considered as additional sources of variation in O&M costs. However, freshwater and saltwater determinations did play a role in designation of the debris level. Typically, saltwater intakes are subject to heavier debris loads, which increase the O&M costs due to increased frequencies of screen washes and diver cleaning.

O&M Cost Components

O&M costs consist of labor, power requirements and periodic underwater inspection and cleaning. A high debris and low debris option was developed for each scenario to increase the confidence of the estimates by accounting for the differences in backwash frequency and underwater inspection and cleaning frequency that would be expected for waterbodies with higher and lower amounts of debris. Costs for existing submerged intakes do not include any additional dive team costs above that which is already being performed prior to the installation of the screens. Exhibit 5-21 presents the average proportion of each component over the range of flow values costed for fine mesh screens. As can be seen, the power cost component represents a very minor proportion and therefore will not be discussed further.

**Exhibit 5-21. Relative Proportion of Each O&M Cost Component for Freshwater Applications for Adding Screens to Existing Submerged Intakes and Relocating Submerged Offshore**

| Relocate Passive Screens Offshore O&M Component | Add to Existing Submerged Intake | | Relocate Offshore | |
|---|---|---|---|---|
| | Low Debris | High Debris | Low Debris | High Debris |
| Power | 1.6% | 4.5% | 2% | 5% |
| Labor | 64% | 62% | 98% | 75% |
| Dive Team Inspection & Cleaning | 35% | 33% | 0% | 20% |

Labor

The O&M labor rate per hour is $41.10/hr. The rate is based on Bureau of Labor Statistics (BLS) data using the median labor rates for electrical equipment maintenance technical labor (SOC 49-2095) and managerial labor (SOC 11-1021); benefits and other compensation are added using factors based on SIC 29 data for blue collar and white-collar labor. The two values were combined into a single rate, assuming 90% technical labor and 10% managerial. This ratio for the labor rates was assumed in the Information Collection Request (ICR) for the Phase III rule and reflects a typical division of labor for industrial operations. This labor rate is fairly accurate, being based on national average BLS data, and is used in other module O&M cost development as well. The number of hours applied is based on vendor quotes of several hours per week, with a notation that during certain periods some systems must be manned 24 hours/day for a week or more during seasonal high debris. The selected rates of 2-4 hours per week plus one week at 24 hours per day for low debris or 3 weeks 24 hours per day for high debris are based on BPJ interpretation of the vendor-supplied information for "typical" operations. It is expected that the actual labor annual total will be quite variable. Therefore, while the labor dollar per hour rate is very accurate, the labor hours are considered to have a moderate accuracy, with a wide range resulting in the derived costs being that of a budget estimate.

Dive Team Inspection and Cleaning

The dive team costs are based on a vendor quote for a supervisor, tender and diver, including equipment, boat, and mobilization/demobilizations. Costs are calculated in single day increments. These costs should be considered as fairly accurate for typical diver costs. However, as with the labor hourly requirements, the frequency and duration of the dive team requirements are based on general vendor quotes, with caveats that actual frequencies and durations may vary greatly from site to site. As such, the dive team costs are considered as having an accuracy of a budget estimate.

Several facilities with submerged intakes were surveyed and annual underwater inspection and cleaning costs were reported by three facilities; the total annual costs were $3,800, $10,000, and $30,000. The first value is below the minimum one day module dive team cost of $5,260 (-28%) and the $30,000 value is greater than the high debris annual cost of $18,480 (+62%) for a comparable flow. This reported range confirms that such costs do vary considerably on a site-specific basis. However, it does show that EPA's estimates do represent a middle or "typical" value. Note that the higher value was for a facility experiencing zebra mussel problems that may have not been designed to prevent this problem. The EPA module technology applied to such situations include higher up front costs for screen materials (CuNi) that tend to inhibit mussel colonization.

Overall O&M

Considering the above discussion, the O&M costs for passive screens should be considered as having the accuracy of a budget estimate without any bias.

**TRAVELING SCREENS**

Cost Modules Covered:

- Module #1: Add Fish Handling and Return System
- Module #2: Add Fine Mesh Traveling Screens with Fish Handling and Return
- Module #11: Add Double-Entry, Single-Exit with Fine Mesh, Handling and Return

Based on the advice of traveling screen vendors, facilities receiving technology Module #1 received costs for replacement of the traveling screen units as well as the addition of a fish return sluice. The alternative was to replace only the baskets and screens and add fish spray equipment. This was based on vendor advice that a partial retrofit that would retain a portion of the original equipment would cost approximately 75% of the cost of replacement units, saving only about 25%, but possibly compromising system effectiveness and longevity. Thus, this was an assumption that could offset future costs that would be difficult to quantify. This increases the confidence in the O&M cost estimates for Module #1 by eliminating any uncertainty with regard to future performance and the need for corrective measures.

Facilities where Module #2 was specified received different costs, depending on whether the data available indicated they have a fish handling and return system already in place. If they did not, then the compliance costs included replacing the traveling screens as well as adding a fish return sluice. If they did, then only the costs for adding fine mesh overlays applied. With the exception of Module #3 (add new larger intake), the screen equipment size for traveling screens is limited to the size of the existing intake. In general, the above approach increased confidence in the accuracy of the capital and O&M costs by tailoring the cost estimates to the known technology in-place.

**Traveling Screen Capital Costs**

Input Variables

The cost of traveling screens is dependent on both the height (well depth) and width of screen unit. Screen cost data indicates that two screens with the same effective screen area but with different size height and width will have different costs. To increase the confidence in the cost estimates for considering application of the proposed rule to existing facilities, the design flow was combined with other data such as intake water depth and through-screen velocity to determine the calculated total effective screen width of the existing intake screens. Since the size of replacement screens is limited to the size of the existing intake structure, the estimated total screen width was considered a much better variable for estimating screen equipment costs compared to design flow alone. For all facilities, the percent open area (POA) of screens already in-place was assumed to be 68%, which was identified by screen vendors as the prevalent POA for coarse mesh screens. One vendor said that approximately 97% of existing intake screens use coarse mesh with 3/8-inch mesh, upon which this value is based. Flow data and through-screen velocity data were available for most facilities, while intake water depth was only available for detailed questionnaire facilities. Median values from the detailed questionnaire facility data were assumed for those without data. Well depth was another important screen sizing variable. To simplify the effort but still retain confidence in the costs over a range of sizes, costing scenarios for five different well depths were developed (10 feet, 25 feet, 50 feet, 75 feet, 100 feet). One of these five costing well depths was then applied to each facility based upon the actual or calculated well depth. Calculated or actual intake well depths that exceeded approximately 20% greater than any category was assigned to the next highest category. In general, this tended to bias this portion of costs slightly upward as the majority of those falling in-between the well depth categories were costed for deeper wells. In many cases, well depth data was available, but if not, the well depth was assumed to be 1.5 times intake water depth, which was the median value for those facilities that had provided both water and well depth data. Other variables include saltwater versus freshwater, which primarily affected screen costs due to differences in material costs, and the presence of a canal or intake channel. Where a canal or intake channel was present, cost for the added fish return flume length was added.

<u>Capital Cost Components:</u>

The total estimated capital costs for modifying and/or adding traveling screens consist of the following cost components:

- Traveling Screens
- Screen Installation
- Fine Mesh Overlays
- Spray Water Pumps
- Fish Flume
- Added Fish Flume Length for Those with Canals

Exhibit 5-22 presents the cost components and the percent of total cost of each component for a single 10 feet wide by 25 feet deep through-flow traveling screen. A 10 feet wide screen was selected as an example because it represents a commonly used standard screen size and the 25 feet depth was selected based on the median values from the detailed data. Dual-flow screens would present a similar cost mix as shown in Exhibit 5-22, but with slightly higher costs for the screen equipment component. Note that the proportions given are for facilities without canals. For those with canals, the fish flume component would be a higher proportion depending on the canal length.

**Exhibit 5-22. Compliance Module Scenarios and Corresponding Cost Component Relative Proportions for 10 ft Wide and 25 ft Deep Screen Well**

| Compliance Action | Cost Component Included in EPA Cost Estimates | Existing Technology | |
|---|---|---|---|
| | | Traveling Screens Without Fish Return | Traveling Screens With Fish Return |
| **Module 2 - Add Fine Mesh Only (Scenario A)** | New Screen Unit | NA | 0% |
| | Screen Installation | NA | 0% |
| | Add Fine Mesh Screen Overlay | NA | 100% |
| | Add Spray Water Pumps | NA | 0% |
| | Add Fish Flume | NA | 0% |
| **Module 1 - Add Fish Handling Only (Scenario B)** | New Screen Unit[1] | Freshwater 67%<br>Saltwater 80% | NA |
| | Screen Installation | Freshwater 14%<br>Saltwater 9% | NA |
| | Add Fine Mesh Screen Overlay[2] | 0% | NA |

| | | | |
|---|---|---|---|
| | Add Spray Water Pumps | Freshwater 2%<br>Saltwater 1% | NA |
| | Add Fish Flume | Freshwater 17%<br>Saltwater 10% | NA |
| **Module 2 - Add Fine Mesh With Fish Handling (Scenario C and Dual-Flow Traveling Screens)** | New Screen Unit | Freshwater 63%<br>Saltwater 74% | NA |
| | Add Fine Mesh Screen Overlay[3] | Freshwater 6%<br>Saltwater 7% | NA |
| | Add Spray Water Pumps | Freshwater 2%<br>Saltwater 1% | NA |
| | Add Fish Flume | Freshwater 16%<br>Saltwater 9% | NA |

[1] Replace entire screen unit, includes one set of smooth top or fine mesh screen.
[2] Add fine mesh includes costs for a separate set of overlay fine mesh screen panels that can be placed in front of coarser mesh screens on a seasonal basis.
[3] Does not include initial installation labor for fine mesh overlays. Seasonal deployment and removal of fine mesh overlays is included in O&M costs.

Screen Equipment

As can be seen in Exhibit 5-22 the majority of the screen costs are for the screen units. Screen equipment costs were obtained from vendors, one set for freshwater only in 1999 and one set for freshwater and saltwater in 2002. EPA found that the 2002 costs for freshwater screens were about 10% to 30% less than the 1999 cost even after adjusting for inflation. The screen cost data were reported by the vendors as "budget" level estimates (i.e.,+30% to -15%). EPA chose the higher 1999 costs (adjusted to 2001) because they were most suited for application to the selected screen size scenarios. The ratio of saltwater to freshwater screens from the 2002 data was used to derive corresponding saltwater screen costs. Thus, the screen equipment costs for both freshwater and saltwater have an accuracy equivalent to budget level estimates plus 10% to 30%.

Screen Installation Costs

Screen installation costs are much more variable than the equipment costs and can increase by 30% if screens must be installed in sections due to overhead obstructions. Two vendors provided values that differed by about 50%, but both noted that site-specific situations made estimating "typical" installation costs difficult. The installation costs were adjusted for screen size and selected to span the range of costs cited. Thus, the installation costs should be considered as having the accuracy of a budget estimate.

Fine Mesh Overlays

Fine mesh overlays are calculated as a percent of screen costs. A vendor quoted that the cost would be 8 to 10% of the screen equipment costs and EPA chose to use a 10% factor resulting in a slight bias on the high side. Otherwise these costs should have the same accuracy as the cost of the screen equipment alone. The assumption of using fine mesh overlays rather than permanent fine mesh screens for scenario C would be a conservative assumption for locations that do not have seasonal debris problems. This assumption increases the confidence that the module would not underestimate costs where seasonal debris problems exist.

Spray Water Pump Costs

As shown in Exhibit 5-22, the spray pump costs only contribute around 1% to 2% of the total costs and thus will not contribute significantly to variations in the data accuracy. However, as noted in the O&M discussion below, the estimated volume of spray water has a significant effect on the O&M costs. Spray water pump costs are derived based on a vendor supplied water use factor per ft of total screen width. Only the additional volume needed for the low pressure fish spray component is costed for additional pumps. A range of 26.6 to 74.5 gpm/ft total flow was cited by vendors. Only one vendor gave a breakdown between the two requirements as 17.4 gpm for debris and 20.2 for the fish spray. EPA chose a 30 gpm rate for the fish spray. The pump equipment and installation costs are based on flow and engineering unit costs for similar equipment and thus should be viewed as having the accuracy of a budget estimate.

Fish Flume

The cost of fish return flumes will vary with flow volume and length and other site-specific factors. All facilities that did not already have a fish return in-place received costs for a fish flume. The flumes are sized to return the entire flow generated (60 gpm/ ft screen width). A screen vendor cited flume lengths of 75 feet to 150 feet and survey data for facilities without canals reported a length of 30 feet to 300 feet. EPA chose the high end of this range of 300 feet as a "typical" installation. EPA notes that in some tidal applications, two return flumes are used to ensure that the debris is deposited downstream and this assumption ensures that such situations are accounted for.

For those facilities that reported the intake was at the end of a canal, an additional cost was added to account for the added distance needed to reach the main waterbody. This additional length was set equal to the canal length and was an additional cost above the 300 feet length. Note that the 300 feet length provides for placement of the debris discharge away from the intake. Flume costs include costs for polyvinyl chloride (PVC) pipe and support pilings spaced at 10 feet. Costs for a 12-inch diameter PVC pipe were developed from RS Means data and then converted to a rate of $10.15/ inch dia.-ft length, including site work and indirect costs. Flume diameter was calculated based on an assumed velocity when full of 1.5 feet per second. As such, the flume costs are based on engineering design assumptions that are conservative (high side) for the "typical" site to increase confidence that this component will not be underestimated. Therefore, the cost estimates should be viewed as having the accuracy of a budget estimate.

Module 2 Scenario A

The relative accuracy of these cost estimates should be equal to that of the screen equipment (+30% to -15%) and the cost factor (10%), which could be biased toward the high side by an additional 10%.

Module 1 Scenario B

The screen equipment costs which have an estimated accuracy of +30% to -15% accounts for 67% to 80% and may be biased toward the high side by 10% to 30% for the example screen. The remaining components are considered as also having an accuracy of a budget estimate for spray water pumps and flume length.

Module 2 Scenario C

The screen equipment costs which have an estimated accuracy of +30% to -15% accounts for 63% to 74% of the costs and may be biased toward the high side by 10% to 30% for the example screen. The remaining components are also considered as having an accuracy of a budget estimate for spray water pumps and flume length.

Module 11 Scenario C (Dual-flow)

The capital costs for dual-flow screens were developed by multiplying the through-flow screen total costs by factors recommended by a vendor. Thus, the component proportions and relative accuracy should be similar to that for through-flow screens.

**Traveling Screen O&M Costs**

Baseline O&M Costs

O&M costs for facilities that have traveling screens in-place are calculated on a net basis. In other words, a cost estimate is calculated for the existing intake screens and then subtracted from the compliance technology O&M cost estimate. As such, there is an additional O&M cost option for traveling screens without fish returns. In general, this option involves less operating time and no extra fish spray pumping and as a result, labor, power, and parts replacement costs (less wear and tear) are lower. All assumptions for this baseline option are based on vendor estimates of "typical" operations. In addition, the costs derived under Module 2 scenario B also served as the basis for baseline O&M costs for facilities with existing traveling screens with fish returns.

Net cost calculations were limited to facilities where the compliance technology was an upgraded version of the traveling screen technology or where the existing traveling screen technology was being replaced in function and would no longer be required. An example is where fine mesh passive screens replaced traveling screens. An example where baseline costs were not deducted is the addition of fish barrier nets. The accuracy of the net O&M costs are therefore, a combination of the accuracies of the positive and negative components. When deviations of the module results from the actual costs of both components (baseline and compliance) have the same sign (+ or -), the differences will tend to cancel each other out somewhat. But when they have different signs, the accuracy of the net value will be reduced.

For facilities with fixed screens or other non-traveling type screen technologies, no baseline costs were deducted because there was no reliable way to estimate baseline O&M costs. This results in a bias towards the high side of net O&M costs for these facilities, since even for fixed screens, there would be certain amount of labor associated with periodically inspecting and cleaning the screens.

<u>O&M Input Variables</u>

The O&M costs use the same input variables, total screen width, well depth and saltwater versus freshwater as the capital costs (see discussion above).

<u>O&M Cost Components</u>

O&M costs consist of labor, power requirements, and parts replacement. Exhibit 5-23 presents the corresponding O&M cost component relative proportions for 10 feet wide and 25 feet deep screen well.

**Exhibit 5-23. Compliance Module Scenarios and Corresponding O&M Cost Component Relative Proportions for 10 ft Wide and 25 ft Deep Screen Well**

| **Compliance Action** | **Cost Component Included in EPA Cost Estimates** | **Existing Technology** | |
|---|---|---|---|
| | | **Traveling Screens Without Fish Return** | **Traveling Screens With Fish Return** |
| **Module 2 - Add Fine Mesh Only(First Column) and Add Fine Mesh With Fish Handling(Second Column) (Scenarios A and C)*** | Basic Labor | Freshwater 35%<br>Saltwater 29% | Freshwater 35%<br>Saltwater 29% |
| | Overlay Labor | Freshwater 15%<br>Saltwater 12% | Freshwater 15%<br>Saltwater 12% |
| | Motor Power | Freshwater 2%<br>Saltwater 2% | Freshwater 2%<br>Saltwater 2% |
| | Pump Power | Freshwater 30%<br>Saltwater 26% | Freshwater 30%<br>Saltwater 26% |
| | Parts | Freshwater 18%<br>Saltwater 31% | Freshwater 18%<br>Saltwater 31% |
| **Module 1 - Add Fish Handling Only (Scenario B)** | Basic Labor | Freshwater 41%<br>Saltwater 33% | NA |
| | Overlay Labor | 0% | NA |
| | Motor Power | Freshwater 2%<br>Saltwater 2% | NA |
| | Pump Power | Freshwater 36%<br>Saltwater 29% | NA |

| | | | |
|---|---|---|---|
| | Parts | Freshwater 21%<br>Saltwater 35% | NA |

*The O&M costs are assumed to be he same for compliance scenarios A and C but the net costs will be different for each since the baseline technologies are different.

Basic Labor

A vendor provided general guidelines for estimating basic labor requirements for traveling screens averaging 200 hours and ranging from 100 to 300 hours per year per screen for coarse mesh screens without fish handling and double that for fine mesh screens with fish handling (Sunda 2002a, 2002b). If the range shown represented a single screen size then the accuracy would be roughly +50% to -50%, however a good portion of this variation in hours is related to intake size. Estimates for various screen sizes were scaled to span these ranges. Thus, the accuracy of the basic labor cost estimates should be considered as having the accuracy of a budget estimate because it included estimated hours. The hourly wage rate is fairly accurate as discussed under passive screens above.

Overlay labor

Overlay labor is based on recommended screen change-out times per screen panel. The number of screen panels is very accurate for each screen and so the accuracy of the labor estimate is associated with the accuracy of the estimated time for placing each screen overlay and whether the annual frequency estimate of once per year was correct. As such, it is reasonable to consider the overlay labor estimate as having an accuracy of a definitive estimate.

Motor and Pump Power

Power requirements for the motors comprises only 2% of the total and therefore will not be discussed. The spray water pump requirements, however, could be significant. Several aspects of the pump power requirements tend to bias these costs upward. The first as described in the pump capital costs above is that the flow rate chosen is on the high side. Secondly, the pump power requirements are based on the entire flow being pumped to the high pressure needed for debris removal. If the low pressure stream results from passing through a regulator from a high pressure pump, then this is a valid assumption. However, if a separate set of low and high pressure pumps are used, then this assumption will result in an overestimation of the pump energy and therefore power requirements. For a given site, it is difficult to determine which scenario is most likely. As the flow requirements are based on engineering estimates, it is reasonable to consider the pump power estimate as having the accuracy of a budget estimate.

Parts replacement

These costs are based entirely on proportions of the screen equipment costs using rough estimates provided by a vendor. (For equipment cost estimations, percentages of equipment costs are frequently used to estimate replacement part costs.) As such, it is reasonable to consider the pump power estimate as having the accuracy of a budget estimate, based on a factor multiplied by the screen equipment costs.

Overall O&M Costs for Through-flow Screens

In general, the Agency views the best way to quantify the accuracy of the components as being on the order of a conceptual estimate. There may be a bias towards the high side for some of the components because it provides greater certainty that costs are not underestimated and it provides a small contingency for site-specific variables that are not otherwise known.

Dual-flow Screens

The O&M costs for dual flow screens (scenario C only) were calculated as a fixed proportion of through-flow screen costs reported by a vendor as the typical values they have observed. As this factor itself is a rough estimate, the dual-flow screen O&M estimates will reflect similar accuracies as the through-flow screens.

**LARGER INTAKES**

Cost Module Covered:

- Module #3: Add New Larger Intake Structure with Fine Mesh, Handling and Return

**Larger Intake Capital Costs**

Input Variables

In this case, the independent variable was the estimated "compliance total screen width," which was calculated in a similar manner as the baseline total screen width used in the traveling screen cost estimates. As with the traveling screens, use of screen sizes, rather than flow alone, increases the confidence in the accuracy of the estimates. Differences in calculating the compliance screen width include using a through-screen velocity of 1.0 feet per second (instead of the actual velocity or data median of 1.5 feet per second that was used for the baseline) and a POA of 50%, instead of 68% that was used for baseline total screen width. The 50% POA is consistent with use of fine mesh screens. In this case the independent variable may be biased towards the low side if facilities select a lower through-screen velocity than 1.0 foot per second. This same independent variable was used for estimating the capital and O&M costs for dual-flow traveling screens installed in the new larger intake.

Overall Accuracy

The new larger intake costs are based on a detailed engineering estimate of costs for a larger intake located just in front of the existing intake. A review of the construction components, component quantities and indirect costs does not indicate any items that may have been estimated in a way that would tend to bias the cost estimates either high or lower. Unit costs are based on costs reported in RS Means Costworks 2001. Considering the detailed nature of the estimation method, the cost estimate should be viewed as having the accuracy of a budget estimate.

**Larger Intake O&M Costs**

No separate O&M costs were derived for the structure itself, since the majority of the O&M activities are covered in the O&M costs for the traveling screens to be installed in the new structure.

**FISH BARRIER NETS**

Cost Module Covered:

- Module #5: Add Fish Barrier Net

**Barrier Net Capital Costs**

Input Variables

In this case the independent variable was the design intake flow. A secondary variable was freshwater versus saltwater. Water depth was considered in the development of saltwater barrier nets, but a single depth close to the median value reported by facilities was used in the application. Different support and anchor strategies were used in freshwater and saltwater. These different approaches to freshwater and saltwater applications increases the confidence in the cost estimates by accounting for differences in design due to the presence of tidal currents in saltwater environments. Research indicated that nets are designed on a site-specific basis and that limited engineering guidelines to follow exist. Therefore, the barrier net costs are based on design and cost data from two facilities with barrier nets that had similar net velocities. The estimates were not just simple scaled costs, but rather an evaluation of each cost component was performed and then scaled for different sizes. Barrier net costs are primarily based on the required net size and support structures/equipment. Two facilities, one on a lake and another on an estuary, reported essentially the same velocity of 0.06 feet per second. Lacking more detailed engineering guidelines, use of actual reported net velocities was determined to be the best method to develop relatively accurate net costs.

Freshwater Barrier Nets (Scenario A)

Net costs are based on the unit costs in dollars/sq ft for both the installed net and a back-up replacement for the example facility. The freshwater unit costs include costs for shipping, floats and anchors. The freshwater facility cost data indicated that the unit costs used may be biased slightly toward the high side if shallower nets are used (e.g., 10 feet or less). The example facility had a net depth of 20 feet. The total reported installation cost was split into a fixed component of 20% (based on BPJ) and a variable dollar/sq ft component. While this module will provide a definitive quality estimate of the net costs at facilities similar to the example facilities, the fact that there are limited guidelines indicates that actual designs may vary considerably, tending to temper the accuracy of this module to an accuracy of a conceptual design estimate.

Saltwater Barrier Nets (Scenario B)

In this scenario, net costs are based on using two concentric nets, supported on pilings, as is the case with the example facility. The costs for the nets are based on the costs cited by both the facility and its supplier. Costs for the pilings are based on engineering designs using the 20 feet spacing at the example facility and RS Means unit costs for barge driven piles. Costs were derived for depths of 10 feet, 20 feet, and 30 feet. However, in developing the compliance cost estimates, EPA used only the 20 feet depth because it best reflected the median water depth for intake structures. In the case of this saltwater net design, shallower depths will tend to drive costs upward due to the requirement for more pilings. While this module will provide definitive quality estimates of the net costs at facilities similar to the example facilities, the fact that there are no guidelines indicates that actual designs may vary considerably, tending to temper the accuracy of this module to an accuracy of a conceptual design estimate.

**Barrier Net O&M Costs**

Input Variables

O&M costs use the same independent variables as capital costs. Duration of deployment was also considered.

Freshwater Barrier Nets

The O&M costs are based on reported labor requirements and net replacement rates. The period of deployment is also important. The example facility reported a deployment period of 120, but others reported longer periods. EPA chose to base the costs on a deployment period of 240 days as a conservative (high side) estimate. EPA scaled up the labor hours cited by the facility and added an additional net section replacement step. Costs for the example facility were developed and then converted to a straight line cost curve by assuming 20% of costs were fixed. While this module will provide a definitive quality estimate of the net O&M costs at facilities similar to the example facilities, as with the O&M costs, the fact that there are no guidelines indicates that actual operations may vary considerably, tending to temper the accuracy of this module to an accuracy of a budget estimate with a potentially biased towards the high side.

EPA notes that other O&M costs reported in literature are often less than what results from the cost module. However, EPA believes the literature O&M costs may not be all-inclusive or comprehensive in including all costs. For example, 1985 O&M cost estimates for the JP Pulliam plant ($7,500/year, adjusted to 2002 dollars) calculate to $11,800 (compared to $57,000 for the example facility) for a design flow roughly half that of example facility. This suggests the scenario A estimates represent the high end of the range of freshwater barrier net O&M costs (biased upward as noted above). Other O&M estimates that also were lower, however, do not describe the cost components that are included and cannot be used for comparison since they may not represent all cost components.

Saltwater Barrier Nets

The saltwater barrier net O&M costs are based on the net maintenance contractor costs plus replacement net costs. Nearly all of the O&M labor for Chalk Point facility is performed by a marine contractor who charges $1,400 per job to simultaneously remove the existing net and replace it with a cleaned net. The reported annual job frequency was used along with the reported net replacement rate. As with the capital costs, while this module will provide a accuracy of a definitive estimate at the example facility, the fact that actual designs may vary considerably indicates that the accuracy of this module can be considered as having the accuracy of a budget estimate

**VELOCITY CAPS**

Cost Module Covered:

- Module #8: Add Velocity Cap at Submerged Inlet

EPA identified only one vendor that supplied preconstructed velocity caps. This appears to be primarily due the fact that, for many installations, velocity caps are custom designed and constructed.

**Velocity Cap Capital Costs**

Input Variables

The primary input variable was design intake flow. Freshwater versus saltwater was an additional variable that affected equipment costs.

Capital Cost Components:

Capital costs consist of equipment, installation, and mobilization/demobilization. For higher flows, multiple heads are used with the costs including inlet piping modifications. The saltwater/freshwater differences are due to use of different materials. The vendor was very confident about the equipment, installation, and mobilization/demobilization costs as they had performed numerous recent jobs. The mobilization/demobilization costs were reported as a range of $15,000 to $30,000. This was applied such that the range spanned the range of flow rates costed.

The proportion of the total for equipment costs ranged from 39% for a 5,000 gpm freshwater intake to 71% for a 350,000 gpm freshwater intake and were roughly 7% less for saltwater. Due to the apparent limited number of prefabricated cap suppliers and the confidence expressed by the vendor, the equipment portion should be considered as having an accuracy of a definitive estimate and the remainder having an accuracy of a budget estimate. This estimate of accuracy should be limited to the use of prefabricated velocity caps. As noted above, many are custom-designed, built onsite, and in those instances, costs may vary considerably. This will tend to temper the accuracy of this module to an accuracy somewhere between a budget and a conceptual estimate when multiple methods of construction are considered.

**Velocity Cap O&M Costs**

Input Variables

The primary input variable was design intake flow. Freshwater versus saltwater was not considered as significant source of variance in the O&M costs.

O&M Cost Components

Since this was a passive technology, O&M costs were limited to periodic inspection and cleaning by a dive team. The same per day dive team costs that were applied to the passive screen O&M costs are applied to the velocity cap O&M costs. As such, the dive team costs are considered as fairly accurate but the duration and frequency estimates are considered as less accurate, resulting in an overall accuracy of a budget estimate.

**AQUATIC FILTER BARRIERS**

Cost Module Covered:

- Module #6: Add Aquatic Filter Barrier Net (Gunderboom)

Currently only one vendor (Gunderboom Inc.) is available to design and install this technology. The technology has been demonstrated, but is still somewhat in the developmental stage.

**Aquatic Filter Barrier Capital Costs**

<u>Input Variables</u>

Design intake flow was the primary variable.

<u>Capital Costs</u>

The cost data was provided for three flow values by the vendor in 1999 prior to any full-scale installations. Three different capital costs representing low, average and high costs were provided. These costs have been adjusted for inflation. The average costs were selected to serve as the basis for compliance costs for this module. No updated costs based on recent experience were made available. Given the lack of recent experience input, the cost estimates should be considered as having an accuracy somewhere between a budget and a conceptual estimate. Also note that additional filter fabric grades with different (mostly larger) pore sizes are now available. An increase in pore size can reduce the lateral forces acting on the barrier, resulting in the ability to reduce the required barrier total effective area. This in turn can result in reduced costs.

The vendor recently provided a total capital cost estimate of 8 to 10 million dollars for a full scale MLES™ system at the Arthur Kill Power Station in Staten Island, NY. The vendor is in the process of conducting a pilot study with an estimated cost of $750,000. The NYDEC reported the permitted cooling water flow rate for the Arthur Kill facility as 713 MGD or 495,000 gpm. Applying the cost equations results in a total capital cost of $8.7, $10.1 and $12.4 million dollars for low, average and high costs, respectively. These data indicate that the inflation-adjusted cost for an average cost estimate in this application are within the accuracy range of a budget estimate. However, the cost estimates provided by Gunderboom are themselves estimates and may or may not accurately reflect project costs after completion. The vendor estimates for this project do, however, indicate the vendor’s confidence in the module estimates at least in this flow range. The vendor had expressed a concern that for low flow applications the module costs may be too high. The range of module results (low and high) shown for the above example is consistent with budget estimate accuracy when compared to the average.

**O&M Costs**

<u>Input Variables</u>

Design intake flow was the primary variable.

<u>O&M Costs</u>

O&M costs are for the operation of the airburst system and fabric curtain maintenance. The cost estimates were obtained in a similar manner as the capital costs but in this case there was no recent corroboration of the original estimates. The range between the low, average, and high cost estimates indicate that the average O&M cost estimates should be considered as having an accuracy of a conceptual estimate and the cost estimates may be somewhat more accurate for higher flows.

## 5.0 FACILITY DOWNTIME ESTIMATES

Downtime costs generally reflect decreased revenues due to lost production or costs of supplemental power purchases incurred during the retrofit of existing cooling water intake structures. The length of downtime, when incurred, is a function of which technology is being retrofitted and the size of the intakes. In addition to the capital and annual operating and maintenance costs of the selected technology module, approximately 15 percent of existing Phase III facilities will incur downtime costs. The basic approach to estimating downtime costs uses the same data and methodology used in the Phase II rulemaking (see the final Phase II Development Document).

The methodology used in the Phase II economic analysis for incorporating the costs associated with downtime for the intakes during construction assumed that only a few facilities had an alternative to shutting down. For electric generators that utilize a once-through cooling system, the use of cooling water is an integral part of the entire electricity generation process and therefore any reduction in water use will result in a reduction in power generation. Because power plants essentially rely on a single process, a shutdown of the entire process is the most logical solution when the need arises to perform major construction or maintenance operations on any key component of the facility. EPA found that most power plants shut down for about four weeks each year to perform routine maintenance. This provides a window of opportunity for performing modifications on the intakes simultaneously during the shut down period for routine maintenance. Because routine plant shutdown for several weeks was common for power plants, the cost module technology scenarios derived for Phase II electric generators focused on retaining the use of the existing pumping equipment.

Unlike electric generators, manufacturing facilities typically involve numerous sequential processes with varying water requirements for the processes and in many cases, additional water requirements for plant electric power and steam generation. Many large manufacturing facilities not only have multiple types of processes, but also have multiple parallel process trains. Maintenance operations for the more complex operations may involve the shutdown of individual process trains or series of trains, but this leaves the remainder of the plant in operation. The sequential processes often have storage capacity for the intermediate products. The ability to store intermediate product facilitates this practice. As such, the need for electricity and process steam tends to be continuous. Because of the wide variety of process arrangements at different manufacturing facilities, there is the potential for wide variations in the frequency and duration of whole facility shutdowns between the various manufacturing sectors. It appears that the larger, more complex manufacturing operations, unlike electric generators, are less likely to schedule simultaneous annual shutdown of *all* processing units.

In order to determine what response a Phase III manufacturing facility would have if faced with the potential interruption of intake operations to implement major construction or retrofit of their intakes, six manufacturing facilities were contacted in August 2005. The objective was to inquire about the practices-in-place at these facilities and the measures they would implement to minimize interruption of the manufacturing processes associated with major construction or retrofitting of their intakes.

The inquiry included questions about the occurrence of scheduled plant shut downs in the past, modifications of plant operations to reduce water use, use of alternate intakes or other sources of cooling water, availability of alternate power sources if most cooling water is used for power generation, and details of implementing major construction or rehabilitation on intakes.

In general, the reported plant shutdown periods ranged from zero downtime for many chemical manufacturers to 30 to 50 days for refineries. However, the refinery downtime occurred less frequently than shutdown for other manufacturing sectors with shutdowns occurring once every four or six years compared to an annual shutdown for other manufacturing sectors. One refinery operator indicated that no downtime has been scheduled in the past. However, the refineries contacted had flexible intake arrangements that would allow major construction to be carried out without incurring any additional unscheduled downtime.

The chemical manufacturers reported that a complete shut down of the entire plant was rare because these facilities provided water to a variety of operations and hence shutting down the intakes completely would be highly problematic. None of the operators would speculate on a potential solution but suggested that an engineering solution, such as installation of an entirely new intake adjacent to the existing intake, may be sought to minimize the duration of the downtime.

The fact that some facilities would consider an engineering solution instead of a complete shutdown implies that an engineering solution would probably cost less than shutting down the plant for an extended period. An industrial gas manufacturing plant reported an annual shut down for one week but because the intake pumps withdrew water from a common channel, the facility did not have the flexibility reported by the refineries. This facility also has a contract to supply intake water to adjacent industrial facilities. As such, chemical manufacturers with similar limited flexibility for plant shutdown *may* opt for an engineering solution, if faced with potential interruption of intake operations, instead of a complete shut down of their plant operations.

Finally, to the extent an intake provides cooling water for a generating plant at a manufacturing facility, the facility may be able to avoid downtime by purchasing electricity. In such cases, the cost of downtime reflects the purchase of power as opposed to complete plant shutdown and loss of revenue due to the loss of produced goods. EPA's record suggests that some manufacturers have the flexibility to alter processes or use other intakes to avoid downtime, and other manufacturers may be able to purchase power and would experience a cost lower than the cost of lost production. For example, 14 percent of manufacturing facilities operate less than 75 percent of the year and would likely avoid downtime by scheduling installation of design and construction technologies during this downtime. Some facilities indicated they would select engineering solutions that avoid the need for downtime. However, downtime may be unavoidable at some facilities.

For all of these reasons, the downtime estimates (in weeks) calculated for power generators were replaced by the values shown in Table 5-24. For Phase III model facilities with multiple intakes, final downtime estimates remain at zero for those facilities with shoreline intakes that are not dedicated intakes. This approach was presented in the NODA, with national downtime estimates reduced by 49 weeks (47 percent), 14 weeks (87 percent), and 11 weeks (39 percent), respectively, for the three regulatory options (50 MGD All Waterbodies, 100 MGD Coastal/Great Lakes, and 200 MGD All Waterbodies, respectively).

OPTIONS AND ALTERNATIVES

A solution for a larger intake using technology module 3 (*Addition of a new, larger intake with fine-mesh and fish handling and return system in front of an existing intake system*) considered under Phase II for electric generators, was to add additional intake capacity adjacent to the existing intake. This would have required the addition of new pumps and the necessity to devise a way to reduce the flow in the old pumps, such as retrofitting the old pumps with variable frequency drives so that flow in each intake could be reduced. This scenario would substantially reduce the downtime requirements because each pump could be retrofitted independently and the new *adjacent* intake could be constructed while the existing intakes continue to operate. Only the construction step of tying the new intake piping into the existing piping would potentially involve brief downtime duration. However, many electric generators are located in close proximity to urban areas with limited available space in the vicinity of the existing intakes. Hence the construction scenarios for the technology to enlarge the total screen area involved constructing and connecting the new intake technology directly *in front* of the existing screens rather than adding additional intake capacity *adjacent to* the existing intake as described above for electric generators. This configuration inevitably results in the need to shut down the entire intake for a period of several weeks or more to make the final connection.

In contrast to electric generators, large manufacturing plants tend to be expansive and such facilities may have available space for alternative technology installation practices. For a Phase III manufacturing facility, depending on the site-specific conditions, an approach to retrofit independently with a new *adjacent* intake being constructed while the existing intakes continue to operate could potentially result in similar or even lower downtime costs compared to the total costs incurred for Phase II electric generating facilities. For certain sectors of manufacturing facilities which do not have scheduled shutdowns for routine maintenance and consequently may incur higher shutdown costs, alternative technology scenarios that include additions and or modifications to the existing pumps may prove to be less costly.

In the case of a refinery, EPA has found that one facility was able to install the equivalent of technology module 4 *(Addition of passive fine-mesh screen system (cylindrical wedgewire) near shoreline with mesh width of 1.75 mm)* with no downtime by connecting the new passive screens to each pump one at a time.

Exhibit 5-24 provides downtime estimates by facility size (DIF) in weeks. Facilities assigned technology modules 3, 4, 7, 12, or 14 were assessed downtime.

**Exhibit 5-24. Weeks of Downtime Included in Costs of Technology Modules**

| Technology Module Description | Downtime in Weeks | | |
|---|---|---|---|
| | DIF < 576 MGD | DIF between 576 MGD and 1152 MGD | DIF > 1152 MGD |
| New, larger intake with fine-mesh and fish handling and return system (module 3) | --- | 1 week | 2 weeks |
| Addition of passive fine-mesh screen (modules 4 and 12) | 7 weeks | 8 weeks | 9 weeks |
| Relocation to a submerged offshore location with passive fine-mesh screen (module 7) | 7 weeks | 8 weeks | 9 weeks |
| Relocation of coastal to a submerged offshore location with passive fine-mesh screen (module 14) | 7 weeks | 8 weeks | 9 weeks |

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# Chapter 6: Impingement Mortality and Entrainment Reduction Estimates

## INTRODUCTION

In order to quantify the benefits derived from compliance with the regulatory options considered for Phase III existing facilities, estimates of the reduction in impingement mortality and entrainment for each facility were calculated. This process is described in this chapter. A detailed example is included in Appendix 6A. As these regulatory options were considered for Phase III existing facilities which are not subject to national categorical requirements under the final Phase III rule, this section is provided for information purposes only. As discussed in the preamble, benefits can not be determined for new facilities and therefore benefits were not calculated for new offshore oil and gas extraction facilities.

## 1.0 REQUIRED INFORMATION

To determine the estimated reduction in impingement mortality and entrainment as a result of the proposed rule (sometimes referred to as "benefits reduction") requires the results of the facility-level costing, which determines the technology module assigned for each facility to comply with the rule. This process is further described in Chapter 5 of this TDD. In general, the costing exercise will determine what performance standards are required (impingement mortality only or impingement mortality and entrainment) and determine if the facility already meets either the impingement mortality or entrainment standards (e.g., has existing intake technologies that qualify). This assures only facilities that incur costs are assigned any benefits.

As a result of this exercise, one of 13 technology modules is assigned to each Phase III existing facility to meet the applicable performance standards. Performance standards are either "impingement mortality only" or "impingement mortality and entrainment," depending on what is required of the facility. If a facility already meets the performance standards, then no technology module is assigned.

## 2.0 ASSIGNING A REDUCTION

Once a compliance response has been determined for each facility, the benefit derived by installing a new technology is assigned. As discussed in Chapter 4, impingement mortality and entrainment rates can be substantially reduced by installing new control technology(ies). In general, EPA assigned an 80% reduction in impingement mortality and a 60% reduction in entrainment for facilities that installed control technologies.[1] Once the impingement mortality and entrainment reduction has been determined, this information was used to calculate the benefits associated with a facility's compliance with the regulation. For details on the process of calculating the benefits associated with these reductions, see the Regional Benefit Assessment.

For example, if a facility is required to meet impingement mortality standards and has no qualified technology in place to meet the requirements, a technology module will be assigned. The "new" technology will reduce the impingement mortality at the facility by the standard reduction of 80%. In some cases, the new technology may reduce entrainment as well.[2]

1 For the purposes of calculating the benefits of the rule, EPA assumed that any technologies installed to comply with the rule would meet the minimum end of the performance range of each performance standard (80 to 95% for impingement mortality and 60 to 80% for entrainment). EPA did so because the site-specific conditions at a facility affect the performance of the technologies, and assuming performance at the minimum end of the performance range provides the highest level of certainty in the benefit calculations. EPA does not know specifically how each intake would respond to the applied technology. Selecting a higher performance would increase uncertainty in the calculated benefits. Therefore the reductions assigned to a facility are a fixed value–80% for impingement mortality and/or 60% for entrainment.

2 It is possible for the technology module assigned to a facility to be more protective than required by the facility's performance standards. If a facility has only impingement mortality compliance requirements but is assigned a cost module that corresponds to a technology that reduces both impingement mortality ***and*** entrainment, the incidental (or "extra") benefits are also assigned to the facility. Even though the reduction in entrainment

The assignment of reductions in impingement mortality and entrainment generally follows these steps:

- Assignment of no reduction (0% reduction for both impingement mortality and entrainment) for facilities that have no cost module assigned
- Assignment of an 80% reduction in impingement mortality to facilities that are required to install a technology to reduce impingement mortality
- Assignment of an 80% reduction in impingement mortality and a 60% reduction in entrainment to facilities that are required to install a technology to reduce both impingement mortality and entrainment
- Assignment of a 60% reduction in entrainment to facilities that are required to install a technology to reduce both impingement mortality and entrainment, but that already have a qualifying impingement technology in place

is not explicitly required by the requirements for the given facility, site characteristics may dictate that a technology designed to reduce only impingement mortality may be impractical or less cost-efficient. In these cases, a technology designed to reduce both impingement mortality and entrainment may be assigned. Both the facility-level costs and benefits reflect this change.

# Appendix 6A: Detailed Description of Impingement Mortality and Entrainment Reduction Estimates

INTRODUCTION

This appendix supplements Chapter 6 by providing a detailed, step-by-step description of the process used to assign impingement mortality and entrainment reductions to Phase III existing facilities. This appendix uses a set of 10 fictional facilities with a variety of requirements, intake technologies, DIFs, and waterbody types. As discussed in the preamble, no impingement mortality or entrainment reductions were estimated for new offshore oil and gas extraction facilities.

## 1.0 REQUIRED INFORMATION

### 1.1 Technology Costing Information

The technology costing exercise produces the first of the necessary components by determining what requirements are to be applied to each facility and assigning a technology module to meet those requirements. These results are used to determine both the facility-level costs and the facility-level benefits associated with compliance. These results are shown in Exhibit 6A-1 below. The last two columns will be completed in the next steps.

**Exhibit 6A-1. Results of Technology Costing**

| Facility ID | Waterbody Type | DIF (MGD) | Perf. Standards Required | Tech. Cost Module | Impingement Upgrade Required? | Entrainment Upgrade Required? | Impingement Reduction | Entrainment Reduction |
|---|---|---|---|---|---|---|---|---|
| 1 | Freshwater River | 100 | I & E | 4 | YES | YES | | |
| 2 | Freshwater River | 82 | I only | 1 | YES | NO | | |
| 3 | Freshwater River | 112 | I only | 0 | NO | NO | | |
| 4 | Estuary/Tidal River | 320 | I & E | 0 | NO | NO | | |
| 5 | Freshwater River | 173 | I & E | 2a | NO | YES | | |
| 6 | Freshwater River | 510 | I & E | 0 | NO | NO | | |
| 7 | Great Lakes | 55 | I & E | 3 | YES | YES | | |
| 8 | Great Lakes | 88 | I only | 0 | NO | NO | | |
| 9 | Lake/Reservoir | 78 | I only | 0 | NO | NO | | |
| 10 | Great Lakes | 220 | I only | 9 | YES | NO | | |

<u>Description of the Data Fields</u>

**Facility ID:** Unique identifier.
**Waterbody Type:** Type of waterbody upon which the facility is located.
**Design Intake Flow:** Design intake flow for the facility.
**Performance Standards Required:** Under the requirements of a national categorical rule, what performance standards would the facility be required to meet? Note that this is irrespective of what technologies may already be in place at a facility.
**Technology Cost Module:** The technology module assigned by EPA to the facility in order to comply with the rule. (This does not necessarily reflect the technology the facility may ultimately install. See Chapter 5 in this Technical Development Document for more details.)
**Impingement Upgrade Required?:** If the facility is required to meet the impingement mortality performance standard, it may already have a qualifying technology in place. If not, it must upgrade its intake technology.
**Entrainment Upgrade Required?:** If the facility is required to meet the entrainment performance standard, it may already have a qualifying technology in place. If not, it must upgrade its intake technology.

**Impingement Reduction:** The reduction in impingement mortality assigned to a facility as a result of compliance with the rule.
**Entrainment Reduction:** The reduction in entrainment assigned to a facility as a result of compliance with the rule.

## 2.0 ASSIGNING A REDUCTION

As described in Chapter 6, assigning the reductions is an exercise in interpreting the results of the technology module assignments and categorizing facilities by the appropriate data field.

### 2.1 Facilities with No Requirements

Facilities that are not required to install any technologies are those that already have a qualifying technology in place. For example, if a facility is required to reduce impingement mortality under a national categorical rule and it has a qualifying impingement control technology, it would not be assigned a cost module. A 0% / 0% reduction is assigned to each facility with a "0" as the assigned technology cost module. In other words, a facility with no new technology assigned (a 0 module) is assigned no reduction for impingement mortality or entrainment.

**Exhibit 6A-2. Assigning Zero Reductions**

| Facility ID | Waterbody Type | DIF (MGD) | Perf. Standards Required | Tech. Cost Module | Impingement Upgrade Required? | Entrainment Upgrade Required? | Impingement Reduction | Entrainment Reduction |
|---|---|---|---|---|---|---|---|---|
| 1 | Freshwater River | 100 | I & E | 4 | YES | YES | | |
| 2 | Freshwater River | 82 | I only | 1 | YES | NO | | |
| 3 | Freshwater River | 112 | I only | 0 | NO | NO | 0% | 0% |
| 4 | Estuary/Tidal River | 320 | I & E | 0 | NO | NO | 0% | 0% |
| 5 | Freshwater River | 173 | I & E | 2a | NO | YES | | |
| 6 | Freshwater River | 510 | I & E | 0 | NO | NO | 0% | 0% |
| 7 | Great Lakes | 55 | I & E | 3 | YES | YES | | |
| 8 | Great Lakes | 88 | I only | 0 | NO | NO | 0% | 0% |
| 9 | Lake/Reservoir | 78 | I only | 0 | NO | NO | 0% | 0% |
| 10 | Great Lakes | 220 | I only | 9 | YES | NO | | |

### 2.2 Facilities with Requirements

Exhibit 6A-2 also identifies the facilities that are required to install technologies to comply with a national categorical rule. Facilities that must install an impingement control technology have a "YES" in the "Impingement Upgrade Required?" column and facilities required to install an entrainment control technology have a "YES" in the "Entrainment Upgrade Required?" column. Some facilities may be required to install a technology to address both performance standards. Some facilities may already have a qualifying technology for one of the performance standards, but may be required to install a second technology to meet the other performance standard. For example, a facility that is required to reduce both impingement mortality and entrainment but that has a qualifying impingement control technology would be required to install a technology for entrainment controls. The reductions assigned mirror the performance standards required at the facility. If both impingement mortality and entrainment controls are required, a reduction of 80% / 60% is assigned.

**Exhibit 6A-3. Assigning Reductions for Facilities with Rule Requirements**

| Facility ID | Waterbody Type | DIF (MGD) | Perf. Standards Required | Tech. Cost Module | Impingement Upgrade Required? | Entrainment Upgrade Required? | Impingement Reduction | Entrainment Reduction |
|---|---|---|---|---|---|---|---|---|
| 1 | Freshwater River | 100 | I & E | 4 | YES | YES | 80% | 60% |
| 2 | Freshwater River | 82 | I only | 1 | YES | NO | 80% | 0% |
| 3 | Freshwater River | 112 | I only | 0 | NO | NO | 0% | 0% |
| 4 | Estuary/Tidal River | 320 | I & E | 0 | NO | NO | 0% | 0% |
| 5 | Freshwater River | 173 | I & E | 2a | NO | YES | 0% | 60% |
| 6 | Freshwater River | 510 | I & E | 0 | NO | NO | 0% | 0% |
| 7 | Great Lakes | 55 | I & E | 3 | YES | YES | 80% | 60% |
| 8 | Great Lakes | 88 | I only | 0 | NO | NO | 0% | 0% |
| 9 | Lake/Reservoir | 78 | I only | 0 | NO | NO | 0% | 0% |
| 10 | Great Lakes | 220 | I only | 9 | YES | NO | 80% | 0% |

# Chapter 7: Technology Cost Modules for Offshore Oil and Gas Extraction Facilities

## INTRODUCTION

Under the final Phase III rule, no existing oil and gas (O&G) extraction facilities are subject to national performance standards. NPDES permit writers will continue to develop impingement and entrainment control standards for these existing facilities using BPJ on a case-by-case basis under authority of Section 316(b) of the Clean Water Act. New offshore oil and gas extraction facilities are subject to the final rule, as described in the preamble.

Since the Phase I 316(b) rulemaking, EPA collected technical, engineering, and economic information associated with this industry sector. EPA also received information from industry trade associations to assist its analyses. EPA used this information to assess costs, economic impact and unique technical issues associated with various technology-based options available to control impingement and entrainment of aquatic organisms, including technology-based options available for the sea chest type of cooling water intake structures for new and existing offshore oil and gas extraction facilities. EPA used Phase I public comments to evaluate a number of BTA options specific to the offshore oil and gas extraction cooling water intake structures in the Phase III rulemaking. In the Phase III proposal EPA solicited public comments on its data, methodology, and proposed regulatory options for controlling impingement and entrainment of aquatic organisms from new and existing offshore oil and gas extraction facilities. After reviewing and incorporating public comments on the Phase III proposal, EPA is promulgating national impingement and entrainment standards for cooling water intake structures at new offshore oil and gas extraction facilities.

This chapter provides an overview of the: (1) industrial sector; (2) information EPA collected and received from industry; (3) facilities in this industrial sector which EPA evaluated for the Phase III rulemaking; (4) technology options available to control impingement and entrainment of aquatic organisms; and, (5) technology options identified in the Phase III final rule.

## 1.0 INDUSTRIAL SECTOR PROFILE: OFFSHORE OIL AND GAS EXTRACTION FACILITIES

The oil and gas extraction industry drills wells at onshore, coastal, and offshore regions for the exploration and development of oil and natural gas. As part of this exploration and development operators employ various types of engines and brakes that require cooling systems. The U.S. oil and gas extraction industry currently produces over 64 billion cubic feet of natural gas and approximately 5.1 million barrels of crude oil per day.[1] The United States Outer Continental Shelf (OCS) contributes to this energy production and the largest 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).[2] The U.S. Department of Interior's Mineral Management Service (MMS) is the Federal agency responsible for managing Federal OCS mineral resources. The following are MMS summary statistics on OCS oil and gas production:[3]

- Annually, OCS leases produce over 600 million barrels of oil and 4.7 trillion cubic feet of natural gas. Since the passage of the OCS Lands Act in 1953, OCS lease sales have produced approximately 15 billion barrels of oil and more than 155 trillion cubic feet of natural gas.[4] 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%.

[1] U.S. DOE, Energy Information Administration Website, http://www.eia.doe.gov. Accessed on May 23, 2006.
[2] The Federal OCS starts approximately 10 miles from the Florida and Texas shores. See also Presidential Proclamation 5030 (March 10, 1983) (Exclusive Economic Zone of the United States of America).
[3] E-mail from James Cimato, MMS, to Carey Johnston, EPA, DCN 9-3585 March 6, 2006.
[4] U.S. DOI, MMS Budget Justifications and Performance Information, Fiscal Year 2007, Feb. 6, 2006, http://www.mms.gov/PDFs/2007Budget/FY2007BudgetJustification.pdf, Accessed on May 23, 2006.

- It is estimated that the OCS contains more than 60 percent of the Nation's remaining undiscovered oil and as much as half of the Nation's undiscovered recoverable natural gas. MMS estimates of oil and gas resources in undiscovered fields on the OCS (2003, mean estimates) total 76 billion barrels of oil and 406.1 trillion cubic feet of gas.[5]

Exhibit 7-1 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, deepwater development, and deepwater 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.

**Exhibit 7-1. 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: U.S. EPA, 2000, EPA-821-B-00-013.

† Note: GOM figures do not include wells within State bay and inlet waters (considered "coastal" under 40 Code of Federal Regulations (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.

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.

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. As shown in Exhibit 7-1, 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 rapid growth in the number of wells drilled in deepwater, defined as water greater than 1,000 feet deep. For example, in 1995, 84 wells were drilled in deepwater, 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.

[5] U.S. DOI, MMS Outer Continental Shelf Oil and Gas Leasing Program 2007-2012, http://www.mms.gov/ooc/press/2006/FY2007MMSBudget/MMSOCSOilAndGasLeasingProgram5year.pdf. Accessed on 23 May 2006.

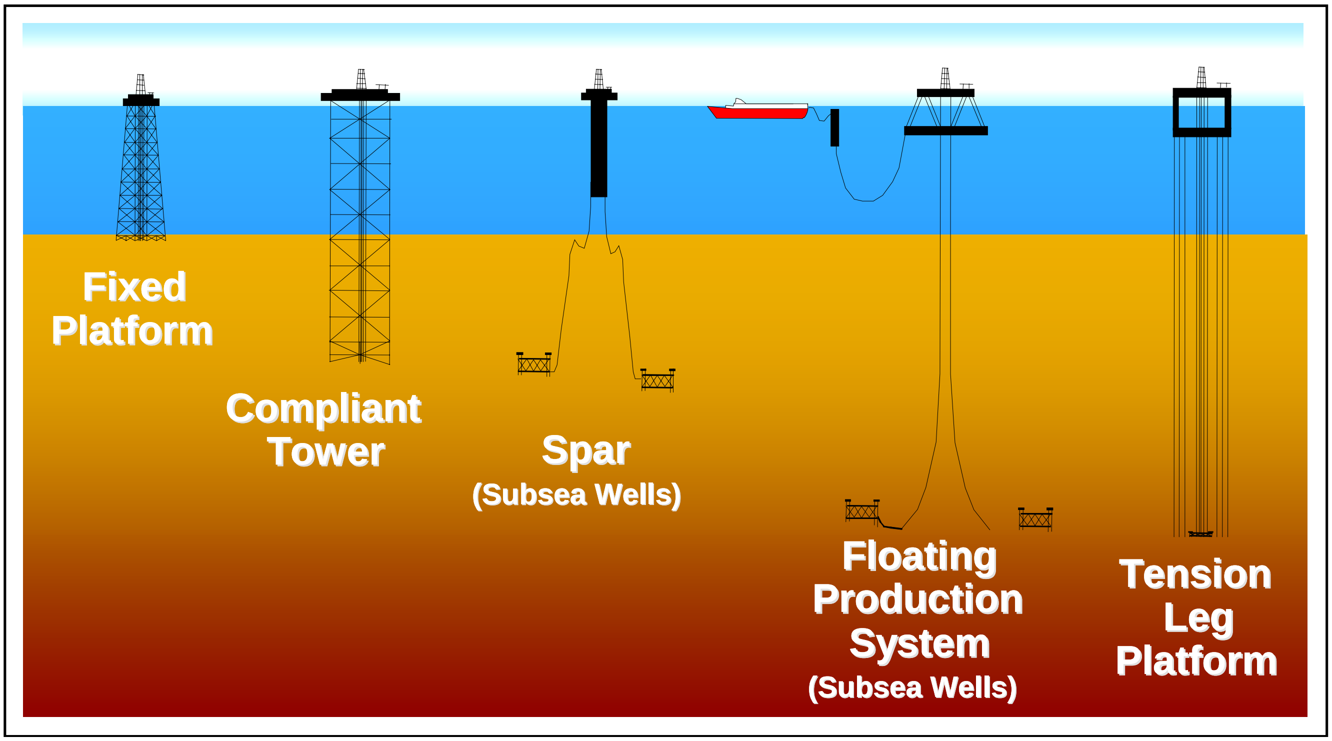
There are numerous different types of offshore oil extraction facilities. Some facilities are fixed in place for development drilling while other facilities are mobile for both exploration and development drilling. Previous EPA estimates of non contact cooling water for offshore oil and gas extraction facilities showed a wide range of cooling water demands (294 - 5,208,000 gal/day).[6]

## 1.1 Fixed Oil and Gas Extraction Facilities

Most of these structures (Figure 7-1) use a pipe with passive screens (strainers) to convey cooling water. There are a number of cooling water intake structure (CWIS) configurations for fixed facilities including sea chests (Figure 7-2), simple pipes (Figures 7-3 and 7-4), and caissons (Figures 7-5, 7-6, and 7-7). Perforated caissons or simple pipes have been used on some fixed platforms. For example, the Marathon platform at South Ewing Bank (OCS Block 873) has a design intake flow of 4 MGD and uses a 24-inch outer diameter simple pipe with square grid 0.5-inch perforations at the intake, which translates to an intake velocity of 1 foot per second. The Aera Energy Ellen (Beta) platform in offshore California withdraws 3.5 MGD and has two cooling water intakes structures, each with a through-screen velocity of 0.5 feet per second. This platform uses a simple 20-inch pipe with a 2-inch cone screen with approximately 0.5-inch openings. This intake uses a 90/10 CuNi alloy pipe for controlling biofouling.

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 2003 Deepwater Production Summary by Year. Abandoned platforms and platforms without production equipment were eliminated from the platform count. The platforms were then categorized by deepwater and shallow water, and 20+ wells and < 20 wells. The counts are presented in Exhibit 7-2. As the table shows, about 90 percent of platforms in the GOM are small platforms operating in shallow water. Only a limited number of structures (generally not the typical fixed platforms) are found in the deepwater regions of the GOM. Currently (2003 data) only 26 are considered completed and operational in the MMS database.

**Figure 7-1. Fixed Oil and Gas Extraction Facilities**




[6] U.S. EPA, Development Document for Effluent Limitations and Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, Table X-23, EPA-821-R-93-003, January 1993.

**Figure 7-2. Offshore Sea Chest Cooling Water Intake Structure Design**

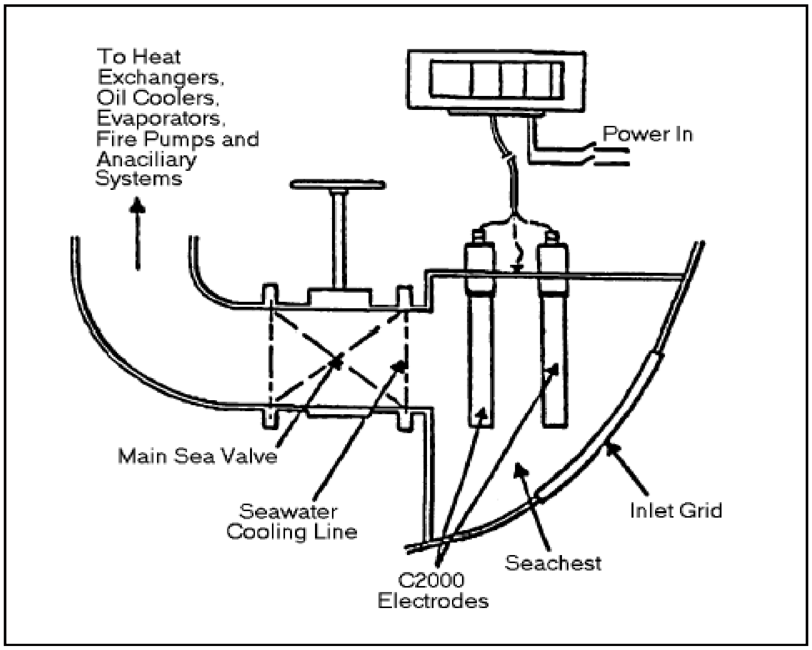



**Figure 7-3. Offshore Simple Pipe Cooling Water Intake Structure Design (Schematic)**

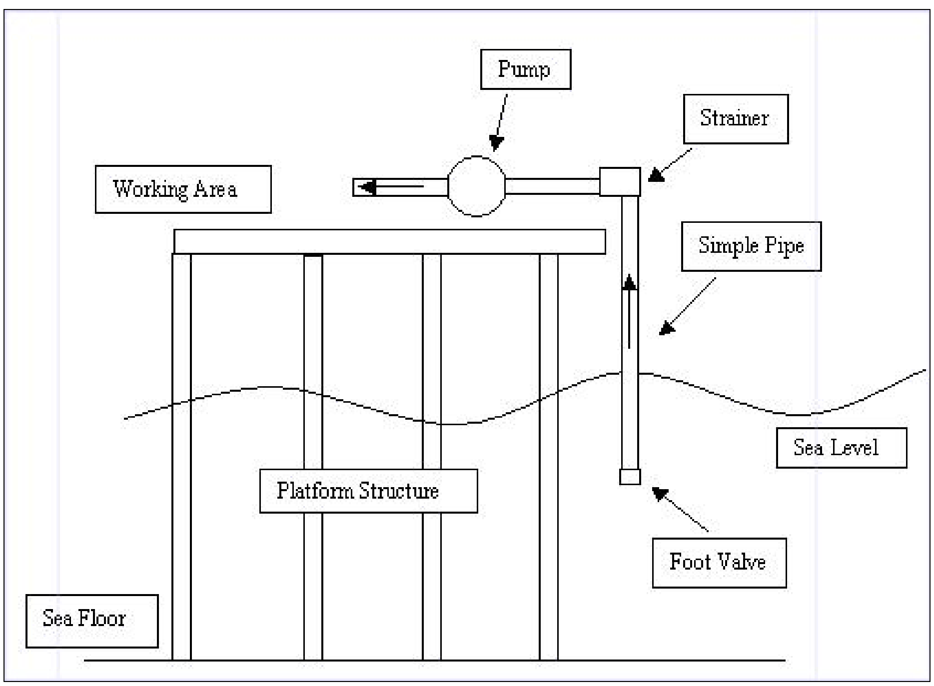
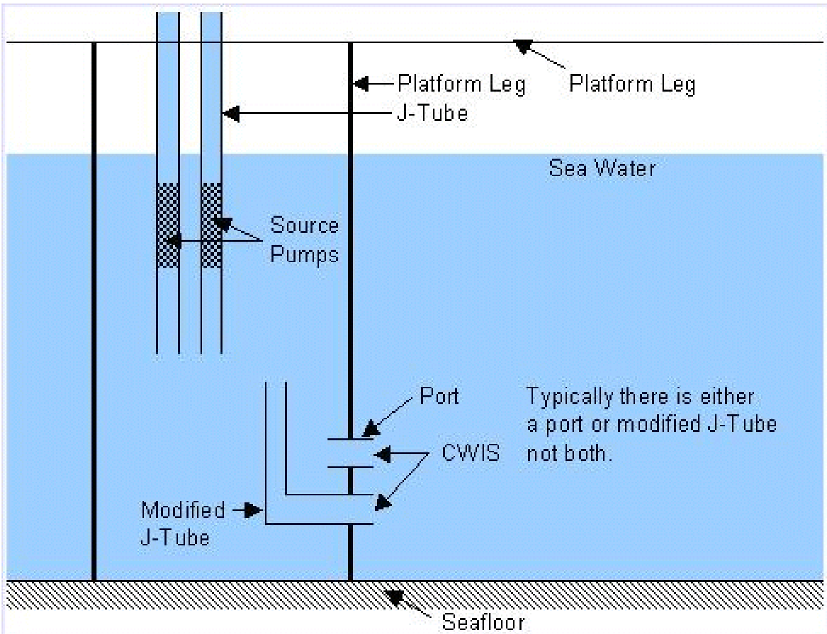


**Figure 7-4. Offshore Simple Pipe Cooling Water Intake Structure Design - Wet Leg**




Note: Another configuration, the "J" Tube configuration, also uses simple pipes as a cooling water intake structure but with no seawater in the platform leg.

**Figure 7-5. Offshore Caisson Cooling Water Intake Structure Design (Thompson Culvert Company)**

**Figure 7-6. Offshore Caisson Cooling Water Intake Structure Design - Leg Mounted Well Tower**

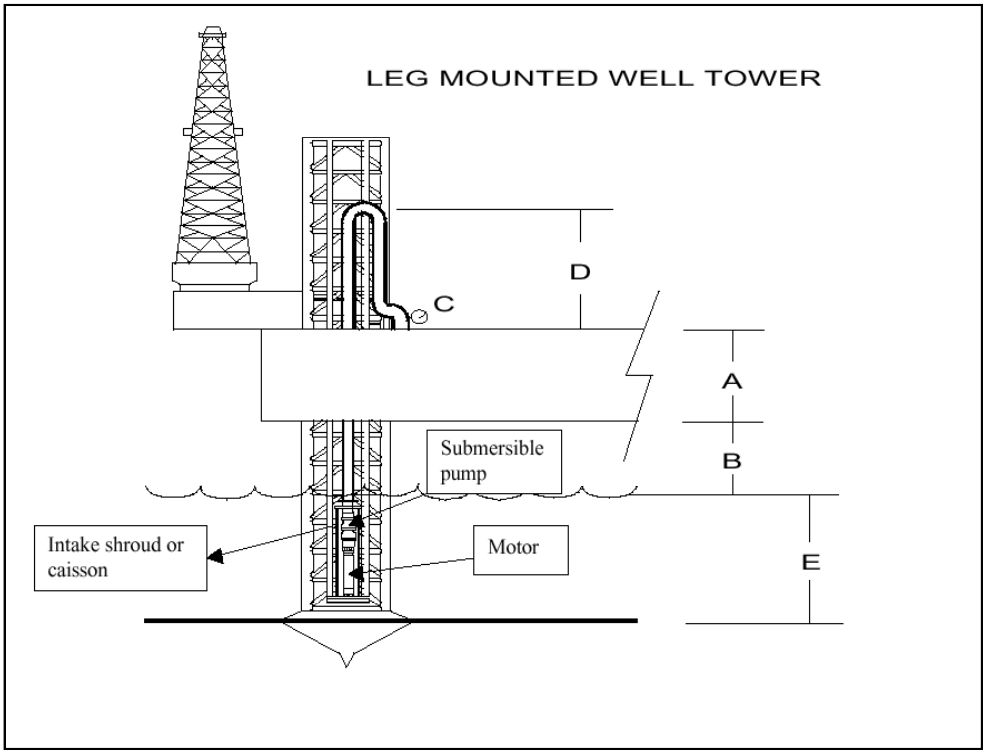
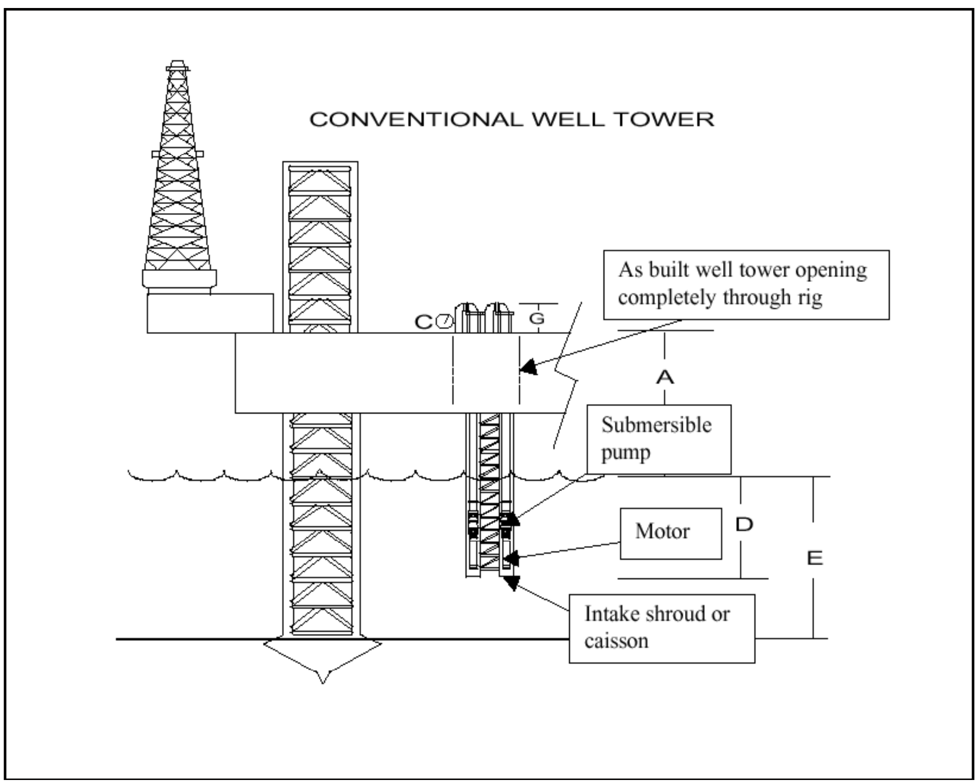



**Figure 7-7. Offshore Caisson Cooling Water Intake Structure Design - Conventional Well Tower**



The Offshore Operators Committee (OOC) and the National Oceans Industries Association (NOIA) also noted in their comments to the 316(b) Phase I Notice of Data Availability (NODA) (see May 25, 2001; 66 FR 28853) that a typical platform rig for a Tension Leg Platform, a fixed production facilities in deepwater environments (> 1,000 ft), will require 10 - 15 million British thermal units (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 required) is 13 - 21 MM Btu/hr. Assuming continuous once-through cooling and a seawater temperature increase of 10 $^{o}$ Celsius (C) between intake and discharge, the volume of seawater required for cooling these engines at a Tension Leg Platform can roughly be estimated between 2.0 to 3.3 MGD (see DCN 7-3645).

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 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.

## 1.2 Mobile Oil and Gas Extraction Facilities

EPA also estimated the number of mobile offshore drilling units (MODUs) currently in operation (see Figure 7-8 for examples). These numbers change in response to market demands. Over the past five years the total number of mobile offshore drilling units 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, jackups, submersibles and drilling barges. Exhibit 7-3 gives a brief summary of each MODU. EPA and MMS could not identify any cases where the environmental impacts of a MODU cooling water intake structure were considered as part of the permitting process.

**Figure 7-8. Mobile Oil and Gas Extraction Facilities**

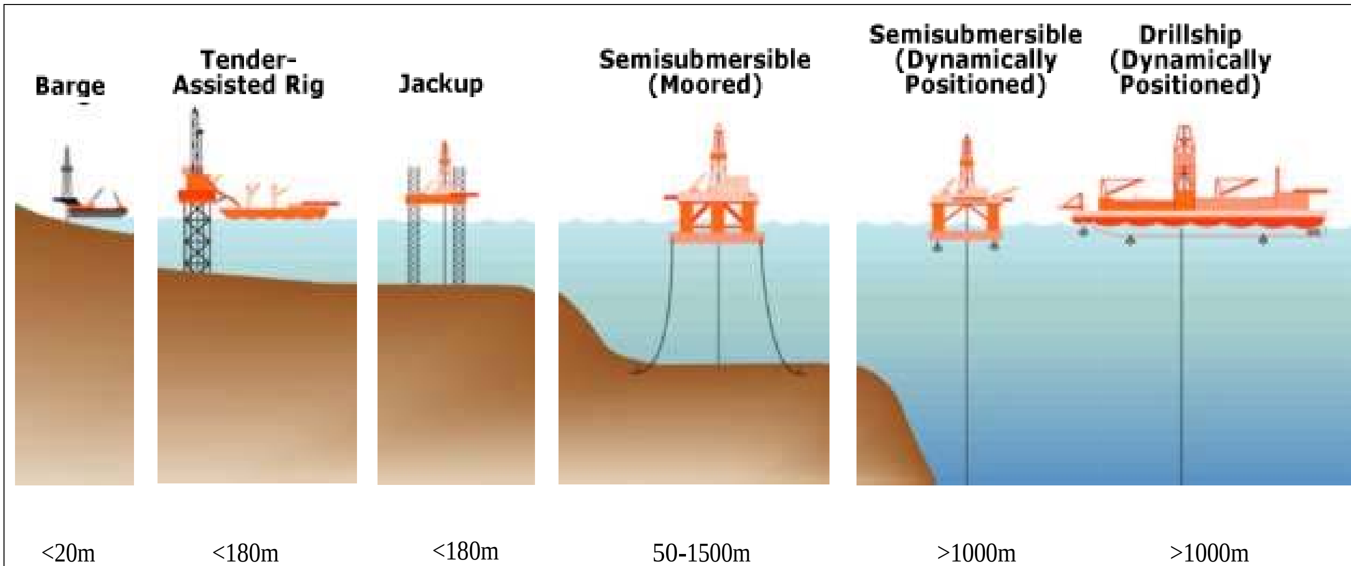


**Exhibit 7-2. Identification of Structures in the Gulf of Mexico OCS**

| Category | Count |
|---|---|
| Total Number of Platforms | 6,266 |
| Removed Platforms | 2,229 |
| Abandoned Platforms | 21 |
| Platforms without Production Equipment | 1,587 |
| Producing Platforms – Deepwater | 26 |
| Producing Platforms - Shallow water + 20 slots | 209 |
| Producing Platforms - Shallow water < 20 slots | 2,194 |
| Total Producing Platforms | 2,429 |

Source: MMS. 2003. Deepwater production summary by year. U.S. Department of the Interior, Mineral Management Service. http://www.gomr.mms.gov

**Exhibit 7-3. Description of Mobile Offshore Drilling Units and Their Cooling Water Intake Structures**

| MODU Type | Water Intake* and Design | Water Depth | Estimate of the Number of Existing MODUs** |
|---|---|---|---|
| Drill Ships | 16 - 20 MGD Sea chest | Greater than 400 ft | 11 |
| Semi-submersibles | 2 - 15+ MGD Sea chest | Greater than 400 ft | 63 |
| Jackups | 2 - 10+ MGD Intake Pipe | Less than 400 ft | 192 |
| Submersibles | < 2 MGD Intake Pipe | Shallow Water (Bays and Inlet Waters) | 47 |
| Drill Barges | < 2 MGD Intake Pipe | Shallow Water (Bays and Inlet Waters) | 70 |

Sources: 1) Johnston, Carey A. U.S. EPA, Memo to File, Notes from April 4, 2001 Meeting with US Coast Guard. April 23, 2001, DCN 2–012A. 2) ODS-Petrodata Group, Offshore Rig Locator, Houston, Texas, Vol. 28, No. 4, April 4, 2001. 3) Spackman, Alan, International Association of Drilling Contractors, Comments on Phase I 316(b) Proposed Rule, Comment Number 316bNFR.004.001. 4) Spackman, Alan, International Association of Drilling Contractors, Memo to Carey Johnston, U.S. EPA, 316(b), May 8, 2001.
* Approximately 80% of the water intake is used for cooling water with the remainder being used for hotel loads, firewater testing, cleaning, and ballast water.[7]
** MODU count from DCN 7-3657, Record Section 1.1.3.

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.[8]

a. Drillships and Semi-Submersibles MODUs

Drill ships and semi-submersibles use a "sea chest" as a cooling water intake structure.[9] In general there are three pipes for each sea chest (these include cooling water intake structures 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 (Comment Number 316bNFR.004.001). There are generally two sea chests for each drill ship or semi-submersible (port

[7] Johnston, Carey A. U.S. EPA, Memo to File, Notes from April 4, 2001 Meeting with US Coast Guard. April 23, 2001, DCN 2–012A.
[8] Spackman, Alan, International Association of Drilling Contractors, Memo to Carey Johnston, U.S. EPA, 316(b), May 8, 2001.
[9] A sea chest is an underwater compartment within the vessel's hull through which seawater is drawn in or discharged. A passive screen (strainer) is set along the flush line of the sea chest. Pumps draw seawater from open pipes in the sea chest cavity.

and starboard) for redundancy and ship stability considerations. In general, only one sea chest is required at any given time for drilling operations (DCN 2–012A).

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 they require the assistance of towing vessels to move from location to location. For example, the Transocean Deepwater Horizon semi-submersible MODU withdraws 16.0 MGD and has eight cooling water intakes structures each with a through-screen velocity of 0.5 feet per second. This MODU uses sea chests openings of 24.4 inches by 28.7 inches with single simplex strainers in the sea chest. The sea chest screens are simple passive strainers with a one-inch grid opening. The Transocean Cajun Express semi-submersible MODU withdraws 6.1 MGD and has six cooling water intakes structures each with a through-screen of velocity 0.23 feet per second. This MODU uses sea chests openings of 32 inches in diameter with 14-inch by 8-inch corrugated basket strainers in the sea chest. The sea chest screens are simple passive strainers with a one-inch grid opening.

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 (DCN 2–012A). Drill ships have their sea chests on the bottom of their hulls and are typically 20 to 40 feet below water at all times.

The International Association of Drilling Contractors (IADC) notes that one of the earlier semi-submersible designs still in use is the "victory" class unit (Spackman, May 8, 2001). This unit is provided with two seawater-cooling pumps, each with a design capacity of 2.3 MGD with a 300 head. An operating draft in 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 per second.

The more recent semi-submersible designs typically have higher installed power to meet the challenges of operating in deeper water, harsher environmental conditions, or for propulsion or positioning. IADC notes that a newly-built unit, of a new design, has a seawater intake capacity of 34.8 MGD, which includes salt water service pumps and ballast pumps, and averages 10.7 MGD of seawater intake, of which 7.4 MGD is for cooling water.

b. Jackup MODUs

Jackups, submersibles, and drill barges use intake pipes for cooling water intake structures. These facilities basically 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 on these facilities (e.g., drawworks brakes).

The jackup 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 contact 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 (Comment Number 316bNFR.004.001). 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. Jackups 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 jackup unit designs is the Marathon Letourneau 116-C (Spackman, May 8, 2001). For these types of jackups, 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 feet per second (Spackman, May 8, 2001). In addition, pre-loading involves the use of two or three pumps in sequence. Pre-loading is not a cooling water procedure, but a ballast water (which is later discharged) procedure.[10] 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 jackup MODUs were typically outfitted with either five diesel generator units, each rated at about 1,200 horsepower, or three diesel generator units, each rated at about 2,200 horsepower (Spackman, May 8, 2001). 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. IADC reports that a newly built jackup, 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 (Spackman, May 8, 2001). In this case one pump is typically used during rig operations with a 10-inch diameter suction at 20 to 50 feet below water level, delivering the cooling water at 3.2 MGD.

#### c. 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.

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.

## 2.0 PHASE III INFORMATION COLLECTION FOR OFFSHORE OIL AND GAS EXTRACTION FACILITIES

For decades, numerous researchers and State and Federal regulatory agencies have studied and controlled the effluent discharges from oil and gas extraction facilities (e.g., produced water, drill cuttings). The Federal technology-based standards for the effluent discharges from these facilities are located in 40 CFR 435 (Oil and Gas Extraction Point Source Category). Conversely, there has been little work done to investigate the environmental impacts or evaluation of the location, design, construction, and capacity characteristics of cooling water intake structures for offshore oil and gas extraction facilities.

During the Phase III rulemaking, EPA used a variety of sources to identify data on the current status of the oil and gas extraction industry and the cooling water intake structures associated with these facilities. Sources of data included: consultations with the two main regulatory entities of this industrial sector (i.e., U.S. Coast Guard, MMS), an EPA survey of the industry which collected both economic and technical data, technical data submittals from industry which were provided either directly or through various trade associations, and information available from the internet. Each of these sources of information is described in more detail below.

### 2.1 Consultations with USCG and MMS

EPA consulted with the U.S. Coast Guard (USCG) and the MMS to identify specific regulatory requirements for this industrial sector with respect to potential environmental impacts associated with cooling water intake structures. While the USCG does not investigate potential environmental impacts of MODU cooling water intake structures, it does require operators to inspect sea chests twice in every five-year period and conduct at least one cleaning to prevent blockages of firewater lines. This requirement to keep intakes free and clear of blockages helps keep the intake screens clean and has the added environmental benefit of keeping the through-screen velocity relatively constant and as low as possible. EPA met with Mr. James Magill of USCG, Vessel and Facility Operating Standards Division, to collect information on MODU operations and cooling water intake systems.[11]

[10] Vlahos, G., Martin, C.M., Cassidy, M.J., 2001. Experimental Investigation of a Model Jack-Up Unit on Clay, Proceedings of the Eleventh (2001) International Offshore and Polar Engineering Conference, Stavanger; Norway, June 17-22, 2001.
[11] Memorandum: Notes from April 4, 2001 Meeting with U.S. Coast Guard. From: Carey A. Johnston, USEPA/OW/OST, To: File, May 7, 2001.

At the time of 316(b) Phase III proposal, MMS was in the process of finalizing a rule requiring operators of oil and gas extraction facilities to compile and submit cooling water intake structure data to facilitate MMS decision-making on industry exploration and production plans. See the MMS proposed rule published on May 17, 2002 (67 FR 35372). After notice and comment, MMS finalized new requirements for industry and production plans, which briefly summarize information on cooling water intake structures, and mitigation measures for reducing adverse environmental impacts and biofouling of intake structures. See the MMS final rule published on August 30, 2005 (70 FR 51478). MMS included cooling water intake structures information collection requirements for operators of oil and gas extraction facilities in their final rule:

> "*…to more fully comply with the NEPA, its implementing regulations issued by the [Council of Environmental Quality] CEQ at 40 CFR Parts 1500 through 1508, and policies of [Department of the Interior] DOI and MMS. According to [National Environmental Policy Act] NEPA requirements, MMS must prepare an [Environmental Assessment] EA in connection with its review of plans for activities on the OCS. The contents of plans must be sufficient to support a sound analysis of potential environmental impacts that may result from the proposed activity. As required by NEPA, if the EA concludes that significant impacts will result from the proposed activity, MMS will prepare an [Environmental Impact Statement] EIS…MMS is required by NEPA to assess potential environmental impacts that may result from the proposed activity.*" See 70 FR 51485.

This MMS regulation requires operators to submit the following information to MMS:

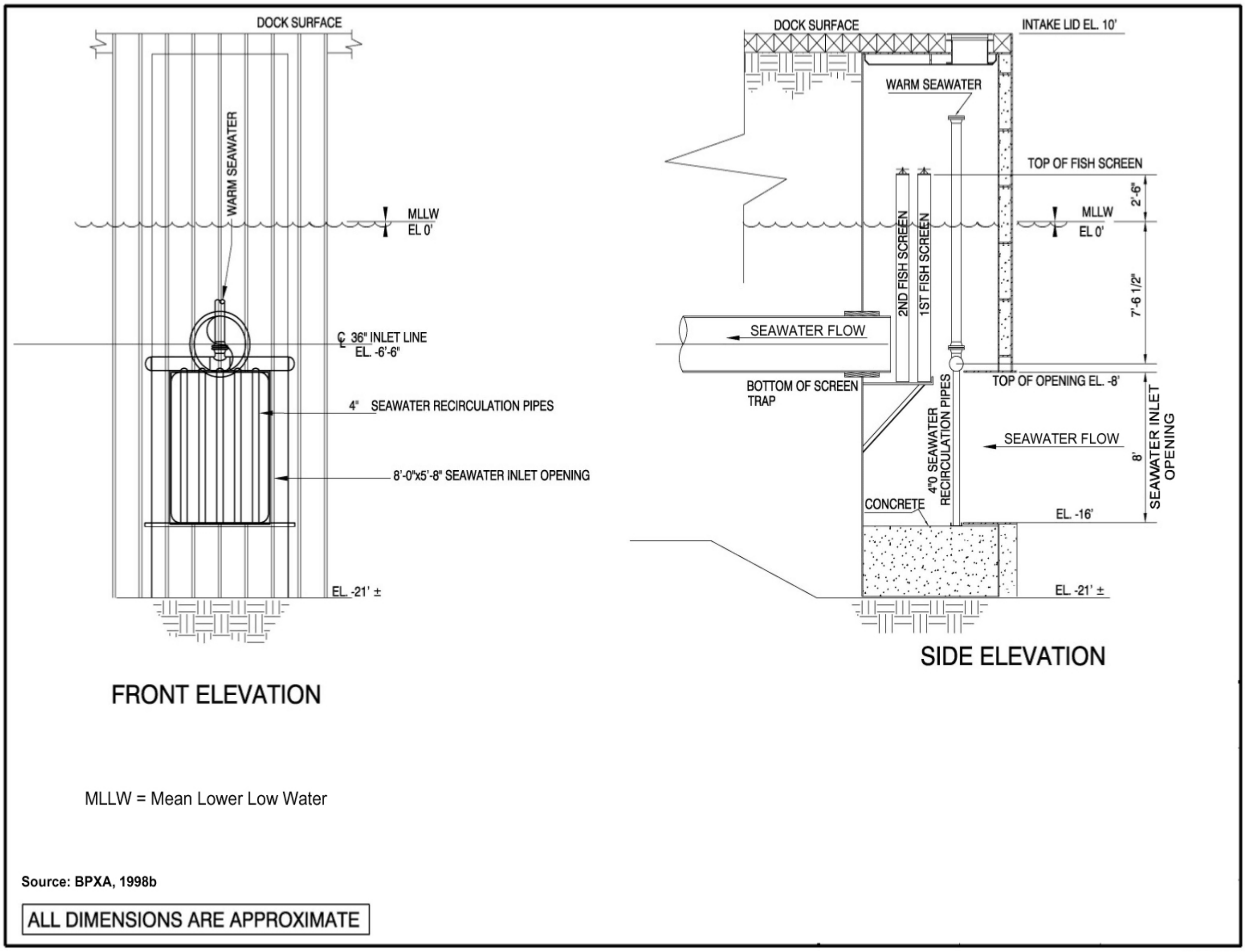
> *Projected cooling water intake. A table for each cooling water intake structure likely to be used by your proposed exploration activities that includes a brief description of the cooling water intake structure, daily water intake rate, water intake through screen velocity, percentage of water intake used for cooling water, mitigation measures for reducing impingement and entrainment of aquatic organisms, and biofouling prevention measures.*

EPA also consulted MMS, as they are the lead Federal agency responsible for managing OCS mineral resources. MMS has authority for leasing in OCS and therefore has current lists of owner-operators and lessees. EPA used the MMS Web site, MMS Platform Inspection System, Complex/Structure database, Lessees/Operators financial information, MMS's environmental impact statements, environmental assessments, and other MMS sponsored studies to collect information to support the Phase III rulemaking.

Specifically, EPA used the MMS databases to estimate the number of fixed OCS platforms in the Gulf of Mexico. EPA also used facility information from the Alaska OCS Region office to determine the number of facilities in the OCS. The Pacific OCS Region Web site provided general information on oil and gas production facilities in the Pacific OCS Region. No information on the number of facilities in State waters and Coastal waters were found. EPA used the MMS environmental impact statements, environmental assessments, and other MMS sponsored studies to evaluate impact on marine organism assemblages from offshore oil and gas exploration and production. In general, MMS did not have information on cooling water intake structures for oil and gas extraction facilities.

EPA identified one case in the MMS files where they evaluated potential environmental impacts from an oil and gas extraction facility cooling water intake structure as part of their NEPA analyses. This analysis was conducted as part of BP Exploration Inc. (BPXA) plans to locate a vertical intake pipe for a seawater-treatment plant on the south side of Liberty Island, Beaufort Sea, Alaska. Figure 7-9 depicts the cooling water intake structure planned for the BPXA seawater treatment plant. The pipe would have an opening 8 feet by 5.67 feet and would be located approximately 7.5 feet below

**Figure 7-9. Liberty Island Cooling Water Intake Structure**




the mean low-water level. 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 Island 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 Island area are likely to be harmed or killed by the intake structure. Furthermore, 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. However, essential fish habitat for salmon will be adversely affected according to MMS because it is expected that prey species of zooplankton and fish in their early life stages (juveniles, eggs, and larvae) could be killed in the intake.

MMS assisted EPA by providing an initial annotated bibliography on all available research reported in marine and coastal waters concerning the impingement and entrainment of estuarine and marine organisms by cooling water intake systems.[12] Most of the results obtained through this search were references about studies on fish impingement or entrainment by cooling water intakes of nuclear or thermoelectric power plants located on estuarine or marine environments. MMS did not identify any references specific to fish impingement or entrainment by cooling water intakes of oil and gas extraction facilities. MMS concluded that studies of impingement or entrainment by cooling water intakes of oil and gas extraction facilities are generally unavailable through the searched databases.

## 2.2 EPA 316(b) Phase III Survey

In September 2003, EPA sent out a 316(b) Phase III survey to oil and gas extraction facilities and seafood processing vessels (SPVs) to collect technical and economic data related to these types of facilities and their cooling water intake structures. EPA surveyed 90 facilities as part of this effort and received responses from 78 facilities. Exhibit 7-4 presents a breakout of the number of surveys mailed and responses by type of survey.

**Exhibit 7-4. 316(b) Phase III Survey Statistics**

| Industry/Type of Survey | No. of Surveys Mailed | No. of Survey Responses |
|---|---|---|
| Oil & Gas Platforms (Technical and Economic Survey) | 55 | 52 |
| Oil & Gas Platforms (Economic Survey only) | 5 | 3 |
| MODUs (Economic Survey only) | 30 | 23 |
| Total | 90 | 78 |

Source: Phase III Technical Questionnaire Tracking Report, From: Kelly Meadows, Tetra Tech, Date: 3/12/2004 (revised 3/23/2004).

EPA identified companies to survey based on a sampling frame of facilities expected to be in-scope. When a facility's eligibility was unknown, it was retained in the sampling frame. The sampling design selected by EPA included stratification of facilities based on the type of structure and its location. The stratification categories used in the survey included:

1. Gulf of Mexico Platforms - Deep Water
2. Gulf of Mexico Platforms - More than 20 Slots
3. Gulf of Mexico Platforms - Shallow Waters
4. California Platforms
5. Alaska Platforms
6. MODUs

These strata were chosen because they were expected to correspond to major differences in economic variables and also in the technology costs of implementing controls on impingement and entrainment. The survey samples were selected from lists for each of the subpopulations. A systematic sample with a random start was taken.

Exhibit 7-5 presents the number of facilities estimated to be in-scope in each of these strata and the number that were sampled in the survey.

**Exhibit 7-5. Number of In-Scope Facilities and Number Sampled by Frame**

| Sampling Stratification Frame | Number of Facilities Estimated to be In-Scope | Number of Facilities Sampled |
|---|---|---|
| Gulf of Mexico Platforms - Deep Water | 24 | 4 |
| Gulf of Mexico Platforms - More than 20 Slots | 206 | 33 |
| Gulf of Mexico Platforms - Shallow Waters | 2,194 | 18 |
| California Platforms | 20 | 3 |

12 MMS, 2003. "Marine and Coastal Fishes Subject to Impingement by Cooling water Intake Systems in the Northern Gulf of Mexico: An Annotated Bibliography," MMS 2003-040, August 2003.

| | | |
|---|---|---|
| Alaska Platforms | 19 | 2 |
| MODUs | 404 | 30 |
| All Frames | 2,867 | 90 |

Source: Memorandum: Sampling Selection for Offshore Oil & Gas - TD#W040917a dated September 17, 2003, From: G. Hussain Choudhry and Inho Park, Westat, To: John Fox, EPA, Date: October 7, 2003.

EPA used economic and technical data submitted as part of the responses in the economic and costing analyses conducted as part of the Phase III rulemaking.

## 2.3 Technical Data Submittals from Industry

EPA received the majority of its technical cooling water intake structure data from industry either directly or through industry trade associations. The trade associations supporting and providing data submittals included the:

- International Association of Drilling Contractors (IADC)
- Offshore Operators Committee (OOC)
- Western States Petroleum Association (WSPA)
- Louisiana Mid-Continent Oil and Gas Association (LMOGA)

IADC provided cooling water intake structures information, solicited from its members, for over 140 mobile offshore drilling units operating in or marketed for operations in areas under the jurisdiction of the U.S. In addition, the 2002 IADC membership directory listed companies that represent a significant portion of the world's exploration and production activity. The directory information included, names of key personnel, addresses of both headquarter and branch locations, telephone and fax numbers, and Internet addresses. The contractor directory also provided an alphabetical listing of drilling contractors who own and operate the vast majority of the world's land and offshore drilling units. That listing included the names of key personnel, addresses of both headquarter and branch locations, telephone and fax numbers, internet addresses, the size of each firm's rig fleet and operating theaters, and for offshore units, the rig type. The IADC submittals and directories did not include any economic information.

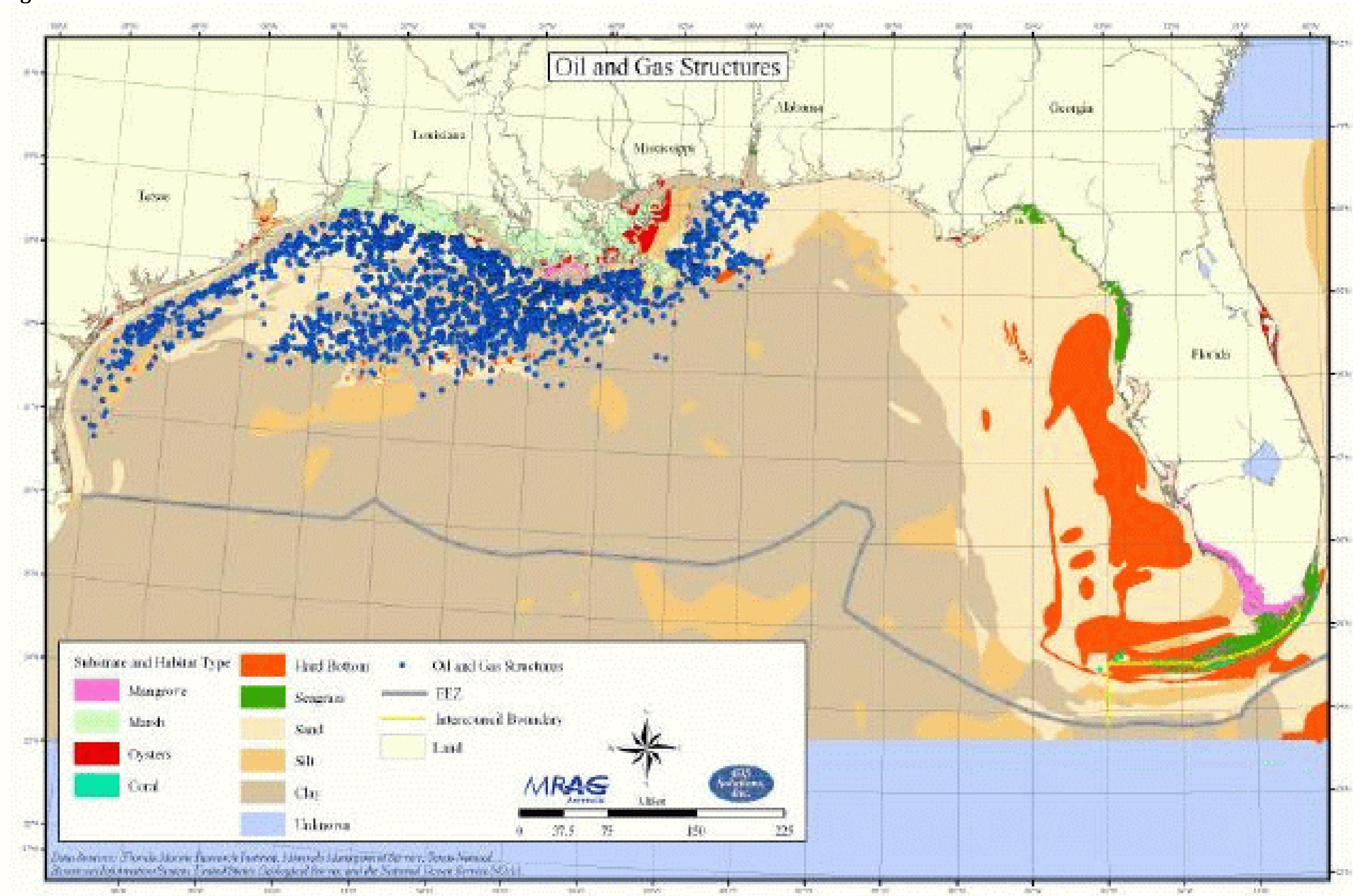
The OOC provided information, compiled on behalf of its members, on cooling water intake structures for offshore oil and gas extraction facilities in the Gulf of Mexico. Cooling water intake structure data were provided for 21 fixed platforms and no economic information were included. EPA was able to identify that 16 of the 2,429 fixed facilities and 87 of the

383 MODUs in the GOM withdrew more than 2 MGD of seawater, with more than 25% used for cooling (see Figures 7-10 and 7-11 for display of fixed facilities).

Operators in Cook Inlet, Alaska, also provided information to EPA on cooling water intake structures for Cook Inlet platforms. The oil and gas fields in Cook Inlet are considered mature and since 1995, production in the Trading Bay Field, Granite Point Field, Middle Ground Field, and Tyonek platform has declined from 17 to 92 percent. Consequently, fewer wells are being drilled in Cook Inlet and this means less equipment requires cooling. For example, the Spark and Spurr platforms have not operated their cooling water systems in over 7 years. These two cooling water system were decommissioned by their operator. Currently these two platforms are unmanned, remotely operated, gas production facilities without drilling, compression, or firewater suppression systems. Using industry data EPA was able to identify that five of the 16 fixed platforms in Cook Inlet withdrew more than 2 MGD of seawater, with more than 25% used for cooling (see Figure 7-11).

The WSPA provided information, compiled on behalf of its members, on cooling water intake structures for offshore oil and gas extraction facilities off the coast of California. Cooling water intake structure data were provided for 18 fixed platforms and no economic information were included. Using this data EPA was able to identify that six of the 32 fixed platforms withdrew more than 2 MGD of seawater with more than 25% used for cooling (see Figure 7-13).

**Figure 7-10. Gulf of Mexico Oil and Gas Extraction Facilities**




**Source:** Final Environmental Impact Statement for the Generic Essential Fish Habitat, Gulf of Mexico Fishery Management Council, March 2004.

**Figure 7-11. Gulf of Mexico Oil and Gas Extraction Facilities That Withdraw More than 2 MGD of Seawater with More than 25% of the Intake Is Used for Cooling**

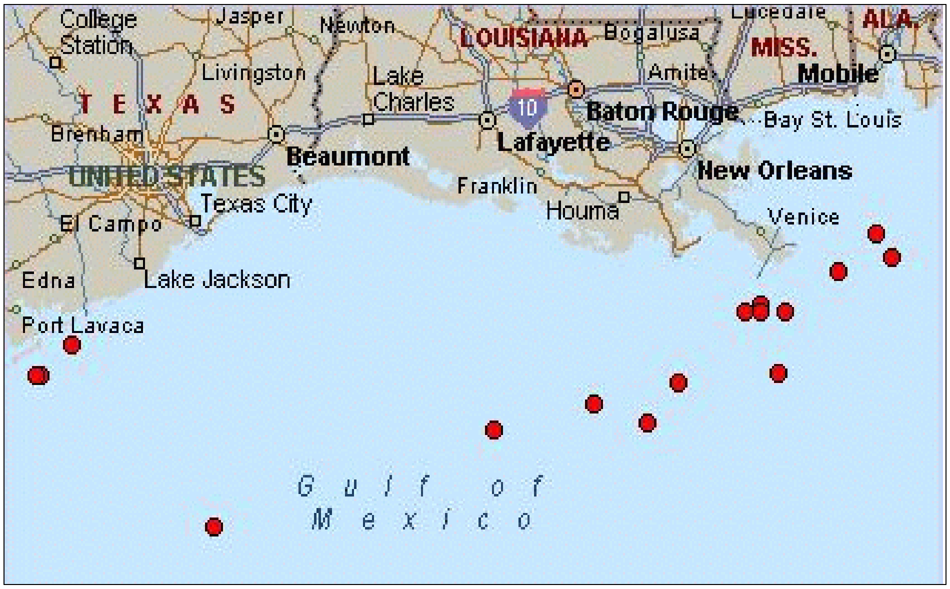
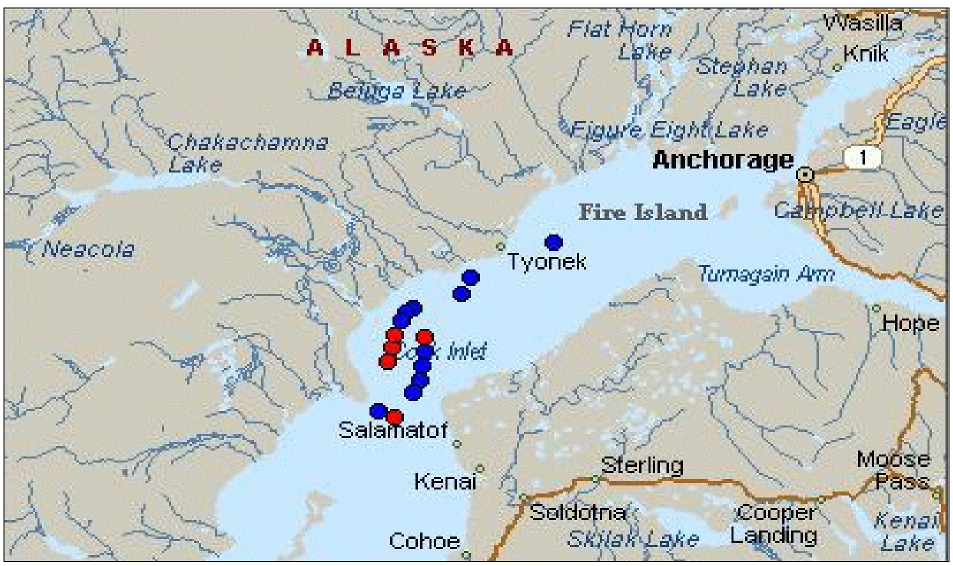



**Figure 7-12. Cook Inlet, Alaska, Oil and Gas Extraction Facilities**




Note: Platforms marked in red withdraw more than 2 MGD of seawater with more than 25% of the intake used for cooling.

**Figure 7-13. California Oil and Gas Extraction Facilities**


Note: Platforms marked in red withdraw more than 2 MGD of seawater with more than 25% of the intake used for cooling.

The LMOGA represents facilities located in the state and includes those facilities located in state waters of the Gulf of Mexico. LMOGA contacted its trade association members asking for information on water withdrawal rates. All respondents to the LMOGA data request indicated that they use less than 2 MGD of surface water. Again, no economic information was provided.

All technical information provided by industry and collected as part of the EPA Phase III survey for oil and gas exploration facilities was compiled into an Excel datasheet for use in costing existing in-scope facilities for cooling water intake structure control. That database is located in the rulemaking record (see DCN 7-3505, section 8.0).

## 2.4 Internet Sources

EPA collected pertinent information on the identity, number, and location of oil and gas extraction facilities from five Web sites:

The California Environmental Resources Evaluation System (http://www.ceres.ca.gov),
The Alabama State Oil and Gas Board (http://www.ogb.state.al.us ),
The Texas Railroad Commission (http://www.rrc.state.tx.us/ ),
World Oil (http://www.worldoil.com/ ),
Rig Zone (http://www.rigzone.com ), and
Drilling Contractor Web sites.

None of these Web sites provided technical information on cooling water intake structures or facility economic data. Exhibit 7-6 presents a description of the type of information that was collected from each site.

**Exhibit 7-6. Offshore Oil & Gas Extraction Facilities - Information Collected from Internet Sources**

| Source | Information Collected |
|---|---|
| California Environmental Resources Evaluation System Web site | This site contained an Oil, Gas, and Mineral Resources Background article. The article states there are twenty-six production platforms, one processing platform and six artificial oil and gas production islands located in the waters offshore of California. Of the twenty-seven platforms, four are located in State waters offshore Santa Barbara and Orange Counties, and twenty-three are located in Federal waters offshore Santa Barbara, Ventura and Los Angeles Counties. Four platforms in State waters off Santa Barbara County were abandoned and removed in 1966. The site did not include cooling water intake structure or economic information. |
| Alabama State Oil and Gas Board Web site | According to the Alabama State Oil and Gas Board Web site, there are 44 total structures in the state waters: 14 single well caissons; 11 well platforms; 4 well/production platforms; 4 bridge-connected well platforms; 1 bridge-connected well/production platform; 8 production platforms; 1 bridge-connected living quarters platform; and 1 gathering platform. The site does not contain any technical information on cooling water intake structure or economic information. The Alabama Offshore Fields database provides field name, county name, operator of the field, producing formation, date established, total wells, producing wells, monthly production, and cumulative production. The list of oil and gas operators in Alabama provides operator name, address, telephone and fax number. |
| Texas Railroad Commission Web site | The Texas Crude Oil Production - Offshore State Waters database contains Railroad Commission district number, field name, county, gas well, condensate, and cumulative gas production. The Texas Gas Well Production - Offshore State Waters contains Railroad Commission district number, field name, county, monthly production for December 2002, year-to-date production January to December 2002, and cumulative oil production. This site does not have information on the number of facilities in State waters or cooling water intake structures. |
| World Oil Web site | This site includes the World Oil's Marine Drilling Rigs 2002/2003 Directory, which lists performance data for 635 mobile offshore drilling units. Listings are separated into four categories, including jackups, semisubmersibles, drillships and barges, excluding inland barges, submersibles. Owners and rigs are listed alphabetically, with rigs grouped by class under a typical photograph. The directory provided EPA with a list of mobile offshore drilling units in US water. This site did not contain information on cooling water intake structures for mobile offshore drilling units. |
| Rig Zone Web site | This site includes a search engine, which provided the location of drill barges, drillships, inland barges, jackups, semisubmersibles, and submersibles worldwide. The site provided a list of mobile offshore drilling units currently in U.S. waters. |
| Drilling Contractor Web sites | These sites provide information on offshore oil and gas drilling contractors. These sites include:<br>- ENSCO Web site (http://www.enscous.com/RigStatus.asp?Content=All),<br>- Noble Web site (http://www.noblecorp.com/rig/foverviewfrX.html), and<br>- Rowan Web site (http://www.rowancompanies.com/)<br>- Transocean (http://www.deepwater.com/StatusandSpecs.cfm)<br>- Nabors (http://www.nabors.com/offshore/default.asp)<br><br>ENSCO has 53 offshore rigs servicing domestic and international markets and two rigs under construction. Its Web site includes a listing of ENSCO rigs with drilling equipment specifications (e.g., power plant and drawwork brake specifics) including information on available horsepower. Noble has 59 offshore rigs servicing domestic and international markets. Its Web site includes a listing of Noble rigs with drilling equipment specifications including information on available horsepower. Rowan has 25 offshore rigs servicing domestic and international markets. Its Web site identifies the companies rig utilization rate. Transocean has 95 offshore rigs and 70 shallow and inland water mobile drilling units servicing domestic and international markets. Its Web site includes a listing of Transocean rigs with drilling equipment specifications including information on available horsepower. Nabors markets 26 platform, nine jackup and three barge rigs in the Gulf of Mexico market. These rigs provide well-servicing, workover and drilling services. Its Web site identifies the companies rig utilization rate. |

## 2.5 Regulatory Agencies

EPA also contacted State regulatory agencies in Alaska, Florida, Alabama, Mississippi, Louisiana, and Texas to determine if they had any specific regulatory requirements for this industrial sector with respect to potential environmental impacts associated with cooling water intake structures. Only Alaska and Alabama provided information to EPA.

The State of Alaska has a standard clause in their oil and gas leasing agreements, which controls potential impingement and entrainment impacts from oil and gas extraction facilities. EPA contacted the Alaska Department of Natural Resources (AKDNR) to confirm that this clause (see below) is standard for all Alaska leasing statements and how the State ensures compliance with this mitigation measure throughout the duration of the lease:[13]

> Water intake pipes used to remove water from fish-bearing waterbodies must be surrounded by a screened enclosure to prevent fish entrainment and impingement. Screen mesh size shall not exceed 0.04 inches unless another size has been approved by Alaska Department of Fish and Game. The maximum water velocity at the surface of the screen enclosure may be no greater than 0.1 foot per second.

AKDNR confirmed that this clause is standard in all Alaska leasing statements to control impingement and entrainment impacts from oil and gas extraction facilities in Alaska state waters. This clause was developed by the Alaska Department of Fish and Game (AKDFG). Most water withdrawals occur on the North Slope for building ice roads and ice pads.

AKDNR also stated that the impingement and entrainment mitigation measures are first enforced when they review the oil and gas extraction plan of operations. A facility seeking approval from the State to begin operations must identify in their plans whether it is proposing any surface water withdrawals. They must also identify the source of the surface water, re-state compliance with the standard clause, or the need for a variance. The withdrawal will also require water withdrawal permits from AKDNR. As a matter of practice, unless there was some reason to believe the operator was not meeting the standard, the intake would not be inspected by AKDNR or AKDFG (Schmitz e-mail).

Alabama state law requires facilities to register water withdrawals (with capacities in excess of 100,000 gallons per day) with the Office of Water Resources (OWR) within the Alabama Department of Economic and Community Affairs (ADECA). However, OWR does not track water withdrawal facilities in Alabama by industry specific codes (i.e., SIC).[14] They register facilities under one of three categories: public, non-public and irrigation. Consequently, OWR does not have any useful records on whether oil and gas extraction facilities in Alabama state waters withdraw more than 100,000 gallons per day. In addition, the Alabama State Oil and Gas Board and the Alabama Petroleum Council were contacted by the Alabama Department of Environmental Management on behalf of EPA. Both Alabama State Oil and Gas Board and the Alabama Petroleum Council estimate that cooling water withdrawals for the oil and gas extraction industry in Alabama waters should be considered *de minimus*.[15] This estimate is also consistent with data provided by LMOGA.

EPA also contacted a few foreign regulatory agencies that control environmental impacts from oil and gas extraction facilities in their country's waters. Responses from these foreign regulatory agencies confirm that they have not: (1) investigated any potential impingement or entrainment impacts of surface water intakes at oil and gas extraction facilities; or (2) established any standards for controlling impingement or entrainment impacts for the oil and gas extraction industry.[16]

[13] E-mail communication between Steve Schmitz, AKDNR, and Carey A. Johnston, EPA, August 21, 2003.
[14] E-mail communication between Tom Littlepage, ADECA, and Carey A. Johnston, EPA, April 21, 2004.
[15] Letter from Glenda L. Dean, ADEM, to Mary T. Smith, EPA, March 30, 2004.
[16] Memo to record, C. Johnston, August 17, 2004.

## 3.0 FACILITIES IN THIS INDUSTRIAL SECTOR WHICH EPA EVALUATED FOR THE PHASE III RULEMAKING

EPA did not consider new offshore oil and gas extraction facilities in the 316(b) Phase I rulemaking. Consequently, EPA reviewed technology options available to control impingement and entrainment of aquatic organisms for both existing and new offshore oil and gas extraction facilities as part of the scope of the Phase III rulemaking.

## 4.0 TECHNOLOGY OPTIONS AVAILABLE TO CONTROL IMPINGEMENT AND ENTRAINMENT OF AQUATIC ORGANISMS AT OFFSHORE FACILITIES

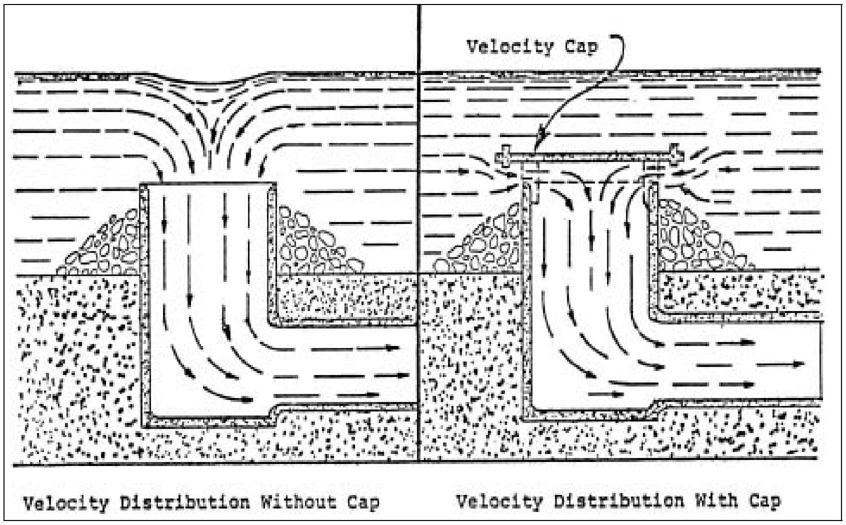
EPA notes that other impingement and entrainment control technologies (e.g., acoustic barriers and aquatic filter barrier systems) may also be available for use at certain site locations but may not control impacts to all aquatic organisms or be available across the industry sector. For example, one of the issues with acoustic barriers is that sounds used to repel some fish yet have no effect or attract fish. In addition, aquatic filter barrier systems may not be technically practical for very deepwater environments.

### 4.1 Summary of Technology Options to Control Impingement and Entrainment of Aquatic Organisms

There are three main technologies applicable to the control of impingement and entrainment of aquatic organisms for cooling water intakes at offshore facilities: passive intake screens, velocity caps, and modification of an intake location. Passive intake screens are static screens that act as a physical barrier to fish entrainment. These barriers include simple mesh over an open pipe end with a suitably low face velocity to prevent impingement, grille or mesh spanning an opening with a suitably low face velocity to impingement, and cylindrical and wedgewire T-screens designed for protecting fish stocks (Figure 7-14). A velocity cap is a device that is placed over vertical inlets at offshore intakes (Figure 7-15). This cover converts vertical flow into horizontal flow at the entrance of the intake.

**Figure 7-14. Cylindrical Wedgewire Screen (Johnson Screens)**

**Figure 7-15. Schematic of Seabed Mounted Velocity Cap**




The device works on the premise that fish will avoid rapid changes in horizontal flow. Beyond design alternatives, a facility may also be able to locate their cooling water intake structures in areas that minimize entrainment and impingement. Near shore coastal waters are generally the most biologically productive areas. The zone of photosynthetic available light typically does not extend beyond the first 328 feet of depth. Modification of an intake location may therefore be implemented by adding an extension to the bottom of an existing intake to relocate the opening to a low impact area. To identify low impact areas, an environmental study or assessment is required, as aquatic organisms may rise and fall in the water column.

EPA believes that the cost of modifying existing structures with deeper intakes will be significantly greater than the equipment costs associated with screens and velocity caps. In addition, the need for an environmental assessment to identify a lower impact zone for modified intakes would result in additional cost and time constraints. Therefore, EPA did not include modification of an intake location as part of their technology options in the final rule

EPA also considered but did not estimate costs associated with dry cooling options for oil and gas extraction facilities. The following items are typically direct air cooled at oil and gas extraction facilities: gas coolers on compressors, lubrication oil coolers on compressors and generators, and hydraulic oil coolers on pumps. However, seawater cooling is necessary in many cases because space and weight limitations render air cooling for all oil and gas extraction equipment infeasible. This is particularly true for floating production systems, which have strict payload limitations. 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 jackups and that it would be far more difficult to justify conversion of drillships or semi-submersibles. See Chapter 6 of the Phase I TDD for additional information.

The technologies EPA evaluated for cooling water intake structures at offshore oil and gas extraction facilities depend on the type of cooling water intake structure and the rig type (rig types are described in section 1.0). The cooling water intake structure types include simple pipes, caissons, and submerged pump intakes, and sea chests. The impingement and entrainment control technologies EPA identified for this sector (passive intake screens, velocity caps, and modification of an intake location) are being considered at other industries with marine intakes, such as LNG import terminals. Based on similarities in intake structures, EPA is transferring these impingement and entrainment control technologies to this industrial sector.

A simple intake pipe, as the name suggests, is a pipe that is open ended in the water. A pump draws water up through the pipe for distribution as required by the process. These systems generally include a strainer to protect the pump and, if the pump is above water level, a non-return valve to help keep the system primed. A caisson is a steel pipe attached to a fixed structure that extends from an operating area down some distance into the water. It is used to provide a protective shroud around another process pipe or pump that is lowered into the caisson from the operating area. A caisson to house seawater intake equipment is a very common arrangement for offshore oil and gas extraction facilities. Typical equipment installed in the caisson may be a simple suction pipe, submersible pump and discharge pipe or a shaft driven borehole/vertical turbine pump. All caisson arrangements have the similarity that seawater is drawn into a single opening at the bottom of the caisson. Submersible pumps are simply lowered off the deck of a unit into the water without caissons or shrouds and pump water up through an intake pipe.

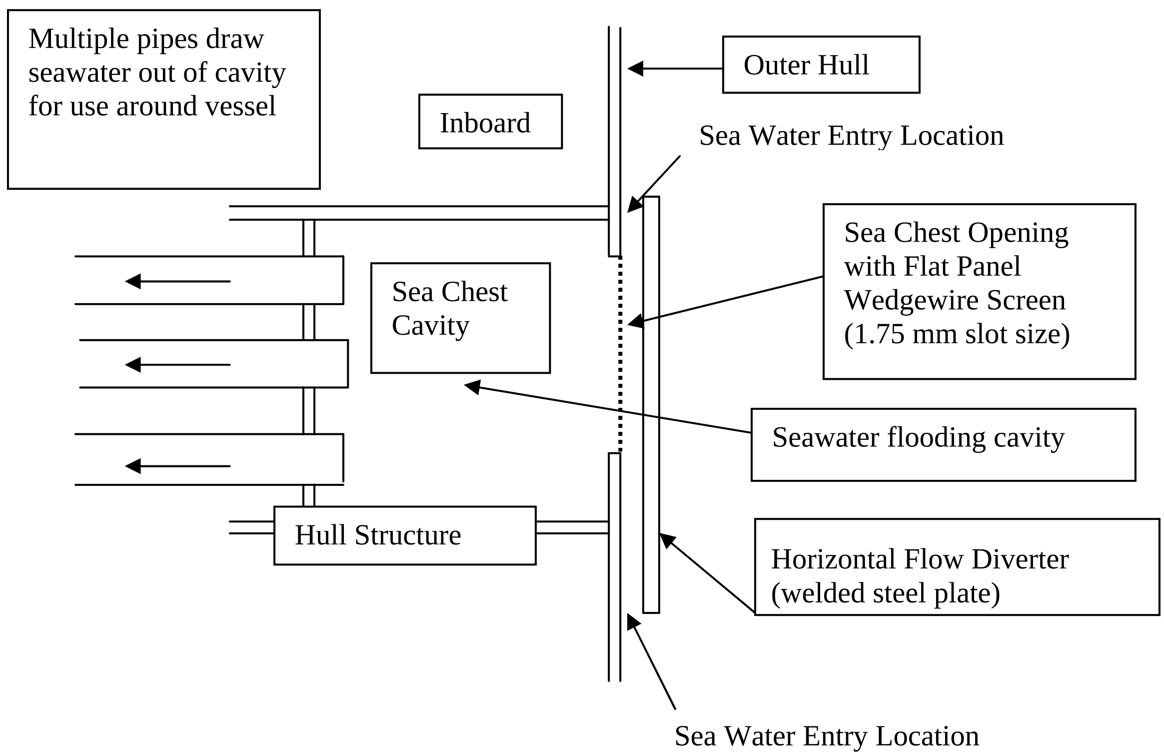
A sea chest is a cavity in the hull or pontoon of a MODU and is exposed to the ocean with a passive screen (strainer) often set along the flush line of the sea chest. In general there are three pipes for each sea chest (these include cooling water intakes and fire pumps). One of the three intake pipes is used for emergency fire fighting operations and the other pipes for cooling water. These pipes are usually back on the flush line of the sea chest.

For simple pipes, caissons and submerged pump intakes, cooling water intake structure control technologies include velocity caps or cylindrical wedgewire screens. Velocity caps result in impingement control and cylindrical wedgewire screens result in both impingement and entrainment control and are designed to create an intake velocity of equal to or less than 0.5 feet per second. Cylindrical wedgewire screens have a maximum slot size of 1.75 mm to prevent entrainment of aquatic organisms. In addition, cylindrical wedgewire screens can be fitted with air sparges to physically remove bio matter from a screen face. This is a suitable technology in most marine environments. In situations where there are prolific marine organisms that may grow on the screen surface (e.g., mussels, barnacles), alternative materials of construction may be needed to protect the screen. Alloys of copper and nickel (CuNi) have been found to limit marine growth on a submerged surface. These alloys are used in the manufacture of screen surfaces to prevent problems with invasive marine growth, and cylindrical wedgewire screens.

For sea chests, cooling water intake structure control technologies include horizontal flow diverters and/or flat panel wedgewire screens. Horizontal flow diverters provide impingement control as fish will avoid rapid changes in horizontal flow. Flat panel wedgewire screens (1.75 mm maximum slot size) covering the opening of the sea chest provide impingement control as aquatic organisms that come in contact with the intake screen will encounter a smooth surface and avoid an abrasive injury. These flat panel wedgewire screens also provide some entrainment control as the 1.75 mm maximum slot size will physically exclude non-motile aquatic organisms. Figure 7-16 is a cross sectional diagram of an example horizontal flow diverter and flat panel wedgewire screen placed over a side sea chest on the hull a vessel. EPA recognizes that MODUs using sea chests may require vessel specific designs to comply with the final 316(b) Phase III rule. EPA identified that some impingement controls for MODUs with sea chests may entail installation of equipment projecting beyond the hull of the vessel (e.g., horizontal flow diverters). Such controls may not be practical or feasible for some MODUs since the configuration may alter fluid dynamics and impede safe seaworthy travel, even for new facilities that could avoid the challenges of retrofitting control technologies. EPA assumed the use of horizontal flow diverters for all MODU sea chests to conservatively capture all the possible incremental compliance costs and economic impacts of the final 316(b) Phase III rule. These control technologies can also be constructed from CuNi alloys to limit marine growth on a submerged surface.

For fixed offshore oil and gas extraction facilities that use sea chests for cooling water intake (e.g., permanently moored semi-submersibles), horizontal flow diverters and flat-panel wedgewire screens (slot size less than 1.75 mm) similar to the example shown below could be considered. These vessels remain stationary and therefore equipment projecting beyond the hull to control impingement and entrainment would not have an impact on overall vessel stability. EPA assumed the use of horizontal flow diverters for all sea chests at fixed facilities to conservatively capture all the possible incremental compliance costs and economic impacts of the final 316(b) Phase III rule. These control technologies can also be constructed from CuNi alloys to limit marine growth on a submerged surface.

**Figure 7-16. Cross-Section of an Example Horizontal Flow Diverter On a Side Sea Chest**




Another option considered by EPA for reducing impingement and entrainment of aquatic organisms in cooling water intake structures on offshore oil and gas extraction facilities was closed-cycle, recirculating cooling systems (e.g., cooling towers and ponds). Available data suggest that closed-cycle, recirculating cooling systems (e.g., cooling towers or ponds) can reduce mortality from impingement by up to 98 percent and entrainment by up to 98 percent when compared with conventional once-through systems (see 69 FR 41601). EPA based the Phase I (new facility) final rule performance standards on closed-cycle, recirculating systems (see 66 FR 65274). In the final Phase II rule, EPA did not select a regulatory scheme based on closed-cycle, recirculating cooling systems at existing facilities based on (1) its generally high costs (due to conversions); (2) the fact that other technologies approach the performance of this option in impingement and entrainment reduction, (3) concerns for potential energy impacts due to retrofitting existing facilities, and (4) other considerations (see 69 FR 41605). Information included in the Phase II TDD (DCN 6-0004) shows that for individual high-flow facilities to convert to wet towers the capital costs range from $130 to $200 million, with annual operating costs in the range of $4 to $20 million. Based on this information EPA estimated that basing the Phase III rule on closed-cycle, recirculating cooling systems would cost more than $2 billion, a more than four-fold increase in total national pre-tax annualized costs as compared to the selected option, without proportionally greater benefits. Therefore, EPA did not further consider closed-cycle, recirculating cooling systems for oil and gas facilities.

Using the cost modules developed as described later in this chapter, two compliance alternatives, impingement mortality reduction and impingement mortality and entrainment reduction were costed. Exhibit 7-7 below presents the five different technology options considered for the two compliance alternatives costed for offshore oil and gas extraction facilities. The appropriate control technologies are a function of the cooling water intake structure and rig type.

**Exhibit 7-7. Regulatory Options and the Technologies Applicable to Each Option**

| | Option A | Option B | Option C | Option D | Option E |
|---|---|---|---|---|---|
| Option Requirements | I&E control for facilities with >2 MGD | I control for facilities with >2 MGD | I&E control for facilities with > 50 MGD and I control for facilities with 2-50 MGD | I&E control for facilities with > 50 MGD | I control for facilities with > 50 MGD |

| Type of Rig | | | | | |
|---|---|---|---|---|---|
| Platforms and Drill Barges which use simple pipes and caissons for cooling water intake | Cylindrical Wedgewire Screens for >2 MGD | Velocity Caps for > 2MGD | Cylindrical Wedgewire Screens for > 50 MGD and Velocity Caps for 2-50 MGD | Cylindrical Wedgewire Screens for >50 MGD | Velocity Caps for >50 MGD |
| Jackups which use sea chests while in transport and simple pipes/ caissons when stationary for cooling water intake | Cylindrical Wedgewire Screens plus Flat Panel Wedgewire Screens and Horizontal Flow Diverter for >2 MGD | Horizontal Flow Diverter and Velocity Caps for > 2 MGD | Cylindrical and Flat Panel Wedgewire Screens plus Horizontal Flow Diverter for pipes and sea chests for >50 MGD and Velocity Caps and Horizontal Flow Diverter for 2-50 MGD | Cylindrical Wedgewire Screens plus Flat Panel Wedgewire Screens and Horizontal Flow Diverter for > 50 MGD | Horizontal Flow Diverter and Velocity Caps for > 50 MGD |
| Submersibles, Semi-submersibles and Drill Ships which use sea chests for cooling water intake | Flat Panel Wedgewire Screens and Horizontal Flow Diverter for >2 MGD | Horizontal Flow Diverter for >2 MGD | Flat Panel Wedgewire Screens and Horizontal Flow Diverter for >50 MGD and Horizontal Flow Diverter for 2-50 MGD | Flat Panel Wedgewire Screens and Horizontal Flow Diverter for >50 MGD | Horizontal Flow Diverter for >50 MGD |

I = Impingement Control (includes velocity caps and horizontal flow diverters)
I&E = Impingement and Entrainment Control (includes cylindrical wedgewire screens and flat panel wedgewire screens with a horizontal flow diverter)

Based on interviews with technical personnel, it was concluded that most of the offshore oil and gas extraction facilities employing cooling water intake structures have minimal technologies in place to reduce impingement mortality and/or entrainment. Furthermore, as discussed in this document, entrainment controls were generally found to be infeasible for mobile offshore oil and gas extraction facilities.

## 4.2 Incremental Costs Associated with Technology Options to Control Impingement and Entrainment of Aquatic Organisms

EPA's general approach to estimate costs associated with the use of impingement and entrainment controls for offshore oil and gas facilities was to first identify the different types of cooling water intake structures (e.g., simple pipes, caissons, sea chests) being employed by the various types of offshore oil and gas extraction facilities (e.g., jackups, platforms, MODUs, drill ships). EPA then identified available impingement and entrainment control technologies (e.g., cylindrical wedgewire systems, flat panel wedgewire screens) for the different configurations of offshore oil and gas extraction facilities and cooling water intake structures. EPA estimated both capital and annual operating costs for each technology option for the different configurations of offshore oil and gas extraction facilities and cooling water intake structures. In determining potentially incremental compliance costs for the for the Phase III rulemaking, EPA did not include water withdrawal volumes related to fire protection or ballast water purposes.

In order to estimate the related economic impacts associated with the options considered for this rule, EPA used the available impingement and entrainment control technologies with superior reliability and performance and ease of operation. For example, EPA considered technologies such as airburst cleaning systems, which ensure that the through-screen intake velocities are relatively constant and as low as possible and cooling water intake structures constructed with copper-nickel alloy components for biofouling control where necessary. While EPA recognized that operators complying with this rule may choose less expensive impingement and entrainment control technologies than those upon which EPA based its economic analysis, EPA chose this method of estimating costs because EPA judged those compliance technologies to be the best technologies available. Moreover, EPA used these technologies as the basis for the requirements in this rule. EPA cannot reliably speculate on the variety of technology combinations a resourceful facility might employ in order to achieve compliance. Using the best technology available to estimate compliance costs avoids such speculation.

Indeed, this methodology is well-accepted in the context of effluent guidelines rulemaking. See Texas Oil and Gas Association vs. EPA, 161 F. 3d 923, 936 (5th Cir. 1998) ("[t]he cost of complying with a BAT-based regulation can be gauged by reference to the cost of the technology itself.").

Finally, EPA used the estimated incremental compliance costs for existing oil and gas extraction facilities to estimate the economic impacts associated the options considered for the Phase III final rule. This is a conservative approach to estimate potential economic impacts as the actual incremental compliance costs for new facilities will likely be lower than estimated incremental compliance costs for existing facilities presented in this chapter. This is primarily due to the fact that new facilities will not need to retrofit existing equipment. Economic impacts on new MODUs and platforms and their associated firms from these incremental compliance costs are expected to be minimal (see Section IX of the preamble to the final rule). Moreover, EPA estimates that the costs of the Phase III final rule are highly unlikely to have any production effects on new deepwater platforms, nor are these costs expected to pose a barrier to entry to new oil and gas development.

The remainder of this section documents the costs developed for cooling water intake structure control on "in-scope" offshore oil and gas extraction facilities evaluated for the Phase III rulemaking. This section includes a description of:

- In-Scope Facilities for Costing;
- Source of the Costing Equations and Assumptions; and
- Summary of the Capital and O&M Costs.

### *4.2.1 Existing In-Scope Facilities for Costing*

EPA developed incremental compliance costs for existing offshore oil and gas extraction facilities if they met two criteria. The first, is that the facility had design or actual water intake flows of greater than 2 MGD and the second is that there were data (or a documented assumption) to support a determination that 25 percent or greater of the intake water (on an intake flow weighted basis) is used for cooling purposes.

Using the Excel datasheet which included all technical information collected on existing oil and gas extraction facilities and their cooling water intake structures, EPA assessed which facilities had data supporting an "in-scope" determination and sufficient information to assess costs. In this datasheet, some MODUs did not have cooling water flow data for the 25 percent or greater cooling water criteria assessment. Based on EPA's data from the USCG, it was assumed that most MODUs use approximately 80% of their intake water for cooling purposes and therefore meet the second "in-scope" criteria. The facilities identified as "in-scope" for costing are presented in the rulemaking record (see DCN 7-3505, section 8.0).

### *4.2.2 Source of Costing Equations and Assumptions*

EPA developed costs for screens, velocity caps, and horizontal flow diverters using capital and O&M cost data from vendors. The costs include: (1) 10% engineering factor; (2) 10% contingency factor; and (3) an allowance of 6% of the capital cost for annual parts replacement. The capital and O&M equipment costs are summarized by pipe diameter (or by sea chest flow rate) in the Hatch Report[17], which is located in the rulemaking record (see DCN 7-0010). Using these costs per pipe diameter (or costs per sea chest flow rate), EPA developed linear costing equations, which were then used to develop facility specific costs.

Exhibits 7-8 through 7-11 present the costing equations and their source for each technology costed. Costs were prepared for both stainless steel flat panel and cylindrical wedgewire screens and also for CuNi flat panel and cylindrical wedgewire screens. All screens have a maximum slot size of 1.75 mm. Costs were also developed for cylindrical wedgewire systems with air sparging and without. Air sparging is used for cylindrical wedgewire screens installed in waters of shallow to medium depth (pipe depth less than 200 feet) to help prevent biofouling of the wedgewire screen. Copper-nickel screen

[17] Hatch Report "Off Shore and Coastal Oil and Gas Extraction Facilities Sea Water Intake Structure Modification Cost Estimate: Caisson and Simple Pipe", March 12, 2004.

material is more expensive than stainless steel but has also been shown to have a greater resistance to biofouling. In addition, costs were developed for both side and bottom horizontal flow diverters as well as velocity caps.

**Exhibit 7-8. Installed Capital Cost Equations and Variables for Stationary Platforms**

| Category | CWIS Type | Description* | Cost Equations | Variable | Ref. |
|---|---|---|---|---|---|
| Platform | Simple Pipe or Caisson | Stainless steel wedgewire screen - no air sparge cleaning | $ = 585.1 x dia +113,231 Single CWIS <60'<br>$ = (417.8 x dia + 15,993) x (No. CWIS - 1) Additional CWIS <60'<br>$ = 585.1 x dia + 161,981 Single CWIS 60-200'<br>$ = (417.8 x dia + 24,493) x (No. CWIS - 1) Additional CWIS 60-200'<br>$ = 585.1 x dia + 265,481 Single CWIS 200-350'<br>$ = (417.8 x dia + 27,993) x (No. CWIS - 1) Additional CWIS 200-350'<br>$ = 585.1 x dia + 326,981 Single CWIS >350'<br>$ = (417.8 x dia + 38,493) x (No. CWIS - 1) Additional CWIS >350' | CWIS Pipe Diameter (inches) and depth of CWIS opening | 1 |
| Platform | Simple Pipe or Caisson | Stainless steel wedgewire screen - with air sparge cleaning | $ = 1100.1 x dia +122,921 Single CWIS <60'<br>$ = (623.4 x dia + 12,841) x (No. CWIS - 1) Additional CWIS <60'<br>$ = 1100.1 x dia + 171,671 Single CWIS 60-200'<br>$ = (623.4 x dia + 21,341) x (No. CWIS - 1) Additional CWIS 60-200'<br>$ = 1100.1 x dia + 275,171 Single CWIS 200-350'<br>$ = (623.4 x dia + 24,841) x (No. CWIS - 1) Additional CWIS 200-350'<br>$ = 1100.1 x dia + 336,671 Single CWIS >350'<br>$ = (623.4 x dia + 35,341) x (No. CWIS - 1) Additional CWIS >350' | CWIS Pipe Diameter (inches) and depth of CWIS opening | 1 |
| Platform | Simple Pipe or Caisson | CuNi wedgewire screen - no air sparge cleaning | $ = 1036.8 x dia +108,837 Single CWIS <60'<br>$ = (1036.8 x dia + 8,587) x (No. CWIS - 1) Additional CWIS <60'<br>$ = 1036.8 x dia + 128,337 Single CWIS 60-200'<br>$ = (1036.8 x dia + 11,587) x (No. CWIS - 1) Additional CWIS 60-200'<br>$ = 1036.8 x dia + 261,087 Single CWIS 200-350'<br>$ = (1036.8 x dia + 17,087) x (No. CWIS - 1) Additional CWIS 200-350'<br>$ = 1036.8 x dia + 322,507 Single CWIS >350'<br>$ = (1036.8 x dia + 20,587) x (No. CWIS - 1) Additional CWIS >350 | CWIS Pipe Diameter (inches) and depth of CWIS opening | 1 |
| Platform | Simple Pipe or Caisson | CuNi wedgewire screen - with air sparge cleaning | $ = 1551.8 x dia +118,522 Single CWIS <60'<br>$ = (1075.1 x dia + 8,447) x (No. CWIS - 1) Additional CWIS <60'<br>$ = 1551.8 x dia + 167,277 Single CWIS 60-200'<br>$ = (1075.1 x dia + 11,447) x (No. CWIS - 1) Additional CWIS 60-200'<br>$ = 1551.8 x dia + 270,777 Single CWIS 200-350'<br>$ = (1075.1 x dia + 16,947) x (No. CWIS - 1) Additional CWIS 200-350'<br>$ = 1551.8 x dia + 332,277 Single CWIS >350'<br>$ = (1075.1 x dia + 20,447) x (No. CWIS - 1) Additional CWIS >350' | CWIS Pipe Diameter (inches) and depth of CWIS opening | 1 |
| Platform | Simple Pipe or Caisson | Stainless steel and CuNi velocity caps | $ = 482.8 x dia +135,863 Single CWIS <60'<br>$ = (482.8 x dia + 35,613) x (No. CWIS - 1) Additional CWIS <60'<br>$ = 482.8 x dia + 184,613 Single CWIS 60-200'<br>$ = (482.8 x dia + 44,113) x (No. CWIS - 1) Additional CWIS 60-200'<br>$ = 482.8 x dia + 288,113 Single CWIS 200-350'<br>$ = (482.8 x dia + 47,613) x (No. CWIS - 1) Additional CWIS 200-350'<br>$ = 482.8 x dia + 349,613 Single CWIS >350'<br>$ = (482.8 x dia + 58,113) x (No. CWIS - 1) Additional CWIS >350' | CWIS Pipe Diameter (inches) and depth of CWIS opening | 1 |

* All screens are designed with a maximum slot size of 1.75 mm.

References

1. Hatch Report “Off Shore and Coastal Oil and Gas Extraction Facilities Sea Water Intake Structure Modification Cost Estimate: Caisson and Simple Pipe”, March 12, 2004.

**Exhibit 7-9. O&M Cost Equations and Variables Used for Stationary Platforms**

| Category | CWIS Type | Description* | Cost Equations | Variable | Ref. |
|---|---|---|---|---|---|
| Platform | Simple Pipe or Caisson | Inspection and cleaning of stainless steel wedgewire screens using commercial divers - no air sparge system | $ = (45.77 x dia +16,180) x No. CWIS <60'<br>$ = (45.77 x dia + 19,180) x No. CWIS 60-200'<br>$ = (45.77 x dia + 24,680) x No. CWIS 200-350'<br>$ = (45.77 x dia + 28,180) x No. CWIS >350' | CWIS Pipe Diameter (inches) and depth of CWIS opening | 1 |
| Platform | Simple Pipe or Caisson | Inspection and cleaning of stainless steel wedgewire screens using commercial divers - with air sparge system | Add $ = (50.5 x dia + 9888.8) + ((21.9 x dia + 9229) x No. CWIS - 1) to each stainless steel screen inspection equation above | CWIS Pipe Diameter (inches) and depth of CWIS opening | 1 |
| Platform | Simple Pipe or Caisson | Inspection and cleaning of CuNi wedgewire screens using commercial divers - no air sparge system | $ = (18.63 x dia +16,444) x No. CWIS <60'<br>$ = (18.63 x dia + 19,444) x No. CWIS 60-200'<br>$ = (18.63 x dia + 24,944) x No. CWIS 200-350'<br>$ = (18.63 x dia + 28,444) x No. CWIS >350' | CWIS Pipe Diameter (inches) and depth of CWIS opening | 1 |
| Platform | Simple Pipe or Caisson | Inspection and cleaning of CuNi wedgewire screens using commercial divers - with air sparge system | Add $ = (50.5 x dia + 9888.8) + ((21.9 x dia + 9229) x No. CWIS - 1) to each CuNi screen inspection equation above | CWIS Pipe Diameter (inches) and depth of CWIS opening | 1 |
| Platform | Simple Pipe or Caisson | Inspection and cleaning of stainless steel or CuNi velocity caps using commercial divers | $ = (12.5 x dia +17,802) x No. CWIS <60'<br>$ = (12.5 x dia + 20,802) x No. CWIS 60-200'<br>$ = (12.5 x dia + 26,302) x No. CWIS 200-350'<br>$ = (12.5 x dia + 29,802) x No. CWIS >350' | CWIS Pipe Diameter (inches) and depth of CWIS opening | 1 |

* All screens are designed with a maximum slot size of 1.75 mm.

**Exhibit 7-10. Installed Capital Cost Equations and Variables for Jackup MODUs**

| Category | CWIS Type | Description* | Cost Equations | Variable | Ref. |
|---|---|---|---|---|---|
| Jackup | Simple Pipe or Caisson | Cylindrical wedgewire screen over tower inlet | \$ = (684.5 x dia +30,399) x No. CWIS (stainless no air sparge)<br>\$ = (1538.8 x dia + 50,540) x No. CWIS (stainless with air sparge)<br>\$ = (834.96 x dia + 30,389) x No. CWIS (CuNi no air sparge)<br>\$ = (1688.6 x dia + 50,541) x No. CWIS (CuNi with air sparge) | CWIS Tower Assembly Diameter (inches) | 2 |
| Jackup | Simple Pipe or Caisson | Horizontal Flow Modifier | \$ = (1106.1 x dia + 30,400 x No. CWIS) | CWIS Tower Assembly Diameter (inches) | 2 |
| Jackup | Sea Chest | Flat panel wedgewire screen over sea chest opening | \$ = (4.74 x flow (gpm) +29,700) x No. sea chests (stainless steel)<br>\$ = (5.05 x flow (gpm) + 29,700) x No. sea chests (CuNi) | Flow through sea chest (gpm) | 2 |
| Jackup | Sea Chest | Horizontal Flow Diverter for Side Sea Chests | \$ = (2.93 x flow (gpm) + 20,520) x No. sea chests | Flow through sea chest (gpm) | 2 |
| Jackup | Submersible Pumps | Cylindrical wedgewire screen over suction pipe inlet | \$ = (349.1 x dia - 1,030) x No. suction pumps (stainless steel)<br>\$ = (564.7 x dia - 1,389) x No. suction pumps (CuNi) | Pump suction diameter (inches) | 2 |

* All screens are designed with a maximum slot size of 1.75 mm.

**Exhibit 7-11. Installed Capital Cost Equations and Variables for Submersibles, Semi-Submersibles, Drill Ships, and Drill Barge MODUs**

| Category | CWIS Type | Description* | Cost Equations | Variable | Ref. |
|---|---|---|---|---|---|
| Submersibles, Semi-Submersibles and Drill Ships | Sea Chests | Flat panel wedgewire screen over sea chest | \$ = (6.4621 x flow (gpm) +0.287) x No. CWIS (stainless steel)<br>\$ = (6.773 x flow (gpm) - 0.273) x No. CWIS (CuNi) | Flow through sea chest (gpm) | 2 |
| Submersibles, Semi-submersibles and Drill Ships | Sea Chests | Horizontal flow diverter over side sea chest | \$ = (3.4995 x flow (gpm) + 0.014) x No. CWIS | Flow through sea chest (gpm) | 2 |
| Drill Barges | Simple Pipes | Cylindrical wedgewire screen over simple pipes | \$ = (393.67 x dia - 1208) x No. CWIS (stainless steel - no air sparge)<br>\$ = (908.67 x dia + 8481) x No. CWIS (stainless steel - air sparge)<br>\$ = (845.33 x dia - 5603) x No. CWIS (CuNi - no air sparge)<br>\$ = (1360.3 x dia + 4087) x No. CWIS (CuNi - air sparge) | Diameter of CWIS opening (inches) | 2 |
| Drill Barges | Simple Pipes | Velocity Cap on the CWIS | \$ = (291.33 x dia + 21423) x No. CWIS (stainless steel or CuNi) | Diameter of CWIS opening (inches) | 2 |

* All screens are designed with a maximum slot size of 1.75 mm.

References

1. Hatch Report "Off Shore and Coastal Oil and Gas Extraction Facilities Sea Water Intake Structure Modification Cost Estimate: Caisson and Simple Pipe", March 12, 2004.
2. Hatch Report "Off Shore and Coastal Oil and Gas Extraction Facilities Sea Water Intake Structure Modification Cost Estimate: Mobile Off Shore Drilling Units (MODUs)", March 12, 2004.

Operating and maintenance costs are associated with fixed platforms only. Operators are 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 or perform special examination in lieu of drydocking 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 107.265 and 107.267 and 46 CFR 61.20-5). It was therefore assumed that MODUs would undergo cooling water intake structure control maintenance as part of their regularly scheduled dry dock service. Operating and maintenance costs for fixed platform facilities do not include any costs associated with downtime because EPA assumed that, under current requirements, MODUs would undergo cooling water intake structure control maintenance as part of their regularly scheduled dry dock service and that this service would be sufficient to maintain the incremental impingement controls required by Phase III rule. Therefore, costs associated with downtime are not considered in estimating O&M costs for fixed platform facilities.

For fixed platform facilities using simple pipe and/or caisson intakes, the depth of the water intake is needed to determine maintenance costs for cooling water intake structure control inspection and cleaning. Since intake depth was not available for many of the fixed platform facilities costed, an estimate of the intake pipe depth was developed using available data. Based on the assessment of intake depth, a linear equation was developed to represent intake pipe depth versus total design intake flow. In general, the greater the design intake flow the deeper the intake depth.

The facility-level option costs (summarized below) include air sparging equipment for biofouling control at intake depths less than 200 feet for both stainless steel and CuNi cylindrical wedgewire screens with a slot size of 1.75 mm. According to a representative at Johnson Screens (e-mail correspondence dated May 20, 2004), the water is typically clean at depths below 40 to 50 feet and biofouling is typically not a concern; however it depends on the water quality at the actual location. As a conservative estimate, EPA assumed air sparging systems may be needed at depths up to 200 feet. In addition, for sea chests, costs were developed for both bottom and side horizontal flow diverters. Since it was unknown in most cases whether specific facilities had bottom or side sea chests, the costs included in the facility-level option costs used the more expensive option (i.e., assumed side sea chests).

### *4.2.3 Summary of Technology Option Costs for Existing Oil and Gas Extraction Facilities*

Exhibit 7-12 presents a summary of the cooling water intake control costs developed for existing "in-scope" O&G extraction facilities for cooling water intake structure control options A through E. These costs are broken out by platforms versus MODUs and by location. These costs do <u>not</u> represent scaled-up costs to the national level.

**Exhibit 7-12. Summary of Technology Option Costs for Existing Oil and Gas Extraction Facilities**

| | No. of Facilities Included in Costs | Option A | Option B | Option C | Option D | Option E |
|---|---|---|---|---|---|---|
| Capital Costs Platforms, GOM | 16 | $4,047,201 | $4,187,716 | $4,187,716 | | |
| Capital Costs Platforms, California | 6 | $2,546,486 | $2,598,198 | $2,598,198 | | |
| Capital Costs Platforms, Alaska | 5 | $1,543,426 | | | | |
| Capital Costs MODUs | 87 | $21,653,766 | $11,440,066 | $14,408,685 | $4,502,389 | $1,533,770 |
| Total Capital Costs ($) | 114 | $29,790,879 | $18,225,980 | $21,194,599 | $4,502,389 | $1,533,770 |
| O&M Costs Platforms, GOM | 16 | $905,315 | $675,924 | $675,924 | | |
| O&M Costs Platforms, California | 6 | $576,504 | $539,340 | $539,340 | | |
| O&M Costs Platforms, Alaska | 5 | $573,804 | | | | |
| O&M Costs MODUs | 87 | | | | | |
| Total O&M Costs ($) | 114 | $2,055,623 | $1,215,264 | $1,215,264 | | |

Option A = I & E control for facilities with > 2 MGD
Option B = I control for facilities with > 2 MGD
Option C = I & E control for facilities with > 50 MGD and I control for facilities with 2-50 MGD
Option D = I & E control for facilities with > 50 MGD
Option E = I control for facilities with >50 MGD

When these costs are scaled-up to include additional facilities believed to be "in-scope" and not costed, the total capital and O&M costs become:

| | Option A | Option B | Option C | Option D | Option E |
|---|---|---|---|---|---|
| Total Capital Costs ($) | 48,354,142 | 27,766,279 | 30,734,897 | 4,502,389 | 1,533,770 |
| Total O&M Costs ($) | 3,054,978 | 1,257,368 | 1,257,368 | 0 | 0 |

EPA used these costs for existing facilities to estimate the incremental compliance costs for new facilities. This is a conservative approach to estimate potential economic impacts as incremental compliance costs for new facilities will be lower than incremental compliance costs for existing facilities since new facilities will not need to retrofit existing equipment. Economic impacts on new MODUs and platforms and their associated firms from these incremental compliance costs are expected to be minimal (see DCN 7-0002). EPA estimates that the costs of the Phase III final rule are highly unlikely to have any production effects on new deepwater platforms, nor are these costs expected to pose a barrier to entry to new oil and gas development. The economic modeling does not indicate that production is very sensitive to costs estimated at the current order of magnitude.

As described in section IX of the preamble and in the EA, EPA projected a total social cost of $3.2 to 3.8 million for new offshore oil and gas extraction facilities. This estimate was based on EPA's projection that 124 new facilities would be constructed over the next 20 years (21 new fixed platforms and 103 new MODUs). Using the costing methodology and cost modules described in this chapter, EPA projected facility-level compliance costs. Costs for administrative and permitting activities, as well as O&M costs, were then added and the total costs were annualized over a period of 49 years. For more information, refer to the preamble and the EA

## 5.0 FINAL TECHNOLOGY OPTIONS IDENTIFIED IN THE PHASE III RULEMAKING

EPA proposed to require impingement and entrainment control requirements for new offshore oil and gas extraction facilities in the Phase III 316(b) rulemaking. EPA finds the technology available as discussed earlier in this chapter and affordable (see the Economic Benefits Analysis (EBA)). As stated in the Phase III Notice of Data Availability, EPA analyzed additional data on the regions in which offshore oil and gas extraction facilities operate in order to better characterize the potential for entrainment of ichthyoplankton (planktonic egg and larval life stages of fish) by offshore oil and gas extraction facilities. EPA believes these data indicate the potential for entrainment and impingement from cooling water intake structures at oil and gas facilities operating in offshore regions. While the data did show spatial and temporal variations, as well as variability at different depths, the range of ichthyoplankton densities found were within the same range seen in coastal and inland waterbodies addressed by the Phase I final rule. See 70 FR 71059 (November 25, 2005). Moreover, the importance of controlling impingement and entrainment at offshore oil and gas extraction facilities is highlighted by the fact that these structures may provide important fish habitat. There are some site specific analyses on the potential environmental benefits of these "artificial reef" effects; however, EPA was not able to locate a comprehensive summary analysis on this topic for the final rulemaking record.[18] Using site specific analyses EPA was able to identify that a variety of fish species are known to be attracted to and to aggregate around and directly under offshore oil and gas extraction facilities, often resulting in densities of fish of that are higher than the densities found in adjacent open waters. Both adult fish and young fish gather around these structures. Young fish may be more susceptible to impingement and entrainment than adult fish. For example, oil and gas platforms and artificial reefs may serve as red snapper habitat.[19] In general, five to 100 times more fish can be concentrated near offshore platforms than in the soft mud and clay habitats

[18] Carey Johnston, USEPA/OW/OST Memorandum "Documents Related to the Issue of Offshore Platforms as Benefits to the Ecosystem, May 23, 2006, EPA Docket Number OW-2004-0002.

[19] Reef Fish Stock Assessment Panel, Gulf of Mexico Fishery Management Council, 1996. "Review of 1996 Analysis by Gallaway and Gazey, http://www.gulfcouncil.org/downloads/RFSAP-GG-1996.pdf, August 1996.

elsewhere in the Gulf of Mexico.[20] As a result, 70 percent of all fishing trips in the Gulf of Mexico head for oil and natural gas platforms. Likewise, 30 percent of the 15 million fish caught by recreational fishermen every year off the coasts of Texas and Louisiana come from the waters around platforms. The offshore marine areas in which oil and gas extraction facilities are located contain large numbers of fish and shellfish eggs and larvae that drift with ambient currents and have minimal swimming ability. These organisms are vulnerable to entrainment by oil and gas facility cooling water intake structures. Densities of these organisms are variable across offshore marine areas, but they can be as great as the densities found in estuarine environments (see preamble section IV for further discussion).

EPA will address potential impingement and entrainment impacts at existing facilities through NPDES permits on a case-by-case basis, using best professional judgment (see 40 CFR 125.90(c)). For example, EPA Region 4 has included requirements for existing oil and gas extraction facilities to conduct a study to determine technologies or operating procedures to reduce the adverse environmental impact of these structures on aquatic life.[21]

EPA applied different regulatory requirements for new oil and gas extraction facilities depending on whether they are projecting to use sea chests as their cooling water intake structure. New oil and gas extraction facilities without sea chests as cooling water intake structures are required to meet impingement and entrainment requirements, while those with sea chests are only required to meet impingement requirements. EPA made this distinction based on the potential lack of technologies to control entrainment impacts at the 316(b) Phase I performance standard for cooling water intake structures using sea chests. Simple pipes, caissons and submersible pumps used for cooling water extraction can be fitted with pre-manufactured cylindrical wedgewire screens (<1.75 mm slot size) to prevent entrainment and impingement of marine life. Consequently, control technologies are available for these cooling water intake structures, and EPA is promulgating impingement and entrainment control requirements for new offshore oil and gas extraction facilities that do not use sea chests.

EPA had limited information on the effectiveness of flat-paneled wedgewire screens in controlling entrainment impacts. However, to estimate compliance costs associated with this technology, EPA costed flat paneled wedgewire screens for sea chest cooling water intake structures as potential impingement controls. EPA's costing methodology for sea chests is shown in Exhibits 7-10 and 7-11.

EPA identified in its record that only jackup-type oil and gas extraction facilities use both sea chests and non-sea chest cooling water intake structures. EPA estimates that the design of the cooling water intake structures for jackup oil and gas extraction facilities will primarily depend on the operation needs of the facility and will not be influence by reduced regulatory requirements.

## 6.0 316(B) ISSUES RELATED TO OFFSHORE OIL AND GAS EXTRACTION FACILITIES

EPA investigated and solicited comment on several issues related to 316(b) impingement and entrainment control technology options for this industrial sector. These issues included: biofouling; the definition of new source; potential lost production and downtime associated with technology options identified in the final rule; and drilling equipment at production platforms.

### 6.1 Biofouling

Industry comments to the 316(b) Phase I proposal assert that operators must maintain a minimum intake velocity of 2 to 5 feet per second to prevent biofouling of the offshore oil and gas extraction facility cooling water intake structure. EPA requested documentation from industry regarding the relationship between marine growth (biofouling) and intake velocities (DCN #7-3649). Industry was unable to provide any authoritative information to support the assertion that a minimum intake velocity of 2 to 5 feet per second is required to prevent biofouling of the facility's cooling water intake structure. IADC asserts that it is common marine engineering practice to maintain high velocities in the sea chest to inhibit attachment of marine biofouling organisms (DCN # 7-3652).

[20] Sandra Fury, Chevron Texaco, statements before U.S. Commission on Ocean Policy,http://oceancommission.gov/meetings/mar7_8_02/fury_statement.pdf, March 8, 2002.
[21] Final National Pollutant Discharge Elimination System (NPDES) General Permit No. GMG460000 for Offshore Oil and Gas Activities in the Eastern Gulf of Mexico, December 9, 2004, http://www.epa.gov/region4/water/permits/documents/R4finalOCSGP120904.pdf.

The OOC and the NOIA also noted in their comments to the May 25, 2001 316(b) Federal Register Notice that the American Society of Civil Engineers (ASCE) "Design of Water Intake Structures for Fish Protection" recommends an approach velocity in the range of 0.5 to 1 feet per second for fish protection and 1 foot per second 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 a case 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 (DCN #7-3649 and 7-3637). 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 (DCN #7-3637). Moreover, as detailed above, operators are required to perform regular inspection and cleaning of these cooling water intake structures in accordance with USCG regulations.

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 sparging, CuNi alloy materials). See Figure 7-17 for a schematic of air sparging at a cylindrical wedgewire screen. 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.

**Figure 7-17. Cylindrical Wedgewire Screen with Air Sparging (Johnson Screens)**

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 planned to use chlorine, in the form of calcium hypochlorite, to reduce biofouling. The operator (BPXA) planned to reduce the total residual chlorine concentration in the discharged cooling water by adding sodium metabisulfate to comply with limits of the National Pollution Discharge Elimination System Permit. MMS estimated that the effluent pH would have varied slightly from the intake seawater because of the chlorination/dechlorination processes, but this variation was not expected to be more than 0.1 pH units.

In another offshore industrial sector, LNG import terminals, industry is proposing intake velocities of 0.5 feet per second. In their Deepwater Port Act license applications, some operators have identified the use of chlorination/dechlorination processes to control biofouling and did not identify any concerns over the proposed intake velocity (0.5 feet per second) and biofouling. Moreover, some of these proposed facilities include in their designs cylindrical wedgewire screens with air sparging to remove biofouling and clear water intake structures.

In summary, EPA did not identify any relationship between the intake velocity and biofouling of an offshore oil and gas extraction facility cooling water intake structure. EPA finds that operators can reasonably control biofouling associated with cooling water intake structures in these marine environments. As previously mentioned, EPA included the costs of controlling biofouling for intakes at depths less than 200 feet as part of the incremental compliance costs.

## 6.2 Definition of New Source

Industry comments on the Phase I rulemaking stated that MODUs "could be considered 'new sources' when they drill new development wells under 40 CFR Part 435.11." See Comment Number 316bNFR.503.004. The commenter correctly notes that EPA's Oil and Gas Extraction point source category effluent guidelines includes a definition of a new source for the purpose of implementing these effluent guidelines. See 40 CFR Part 435.11(w). EPA developed this effluent guidelines new source definition after careful consideration of the types of facilities in this industrial sector. For example, this effluent guidelines new source definition clarifies that "exploratory activities are limited in nature and do not necessarily evidence an intent to establish permanent operations." See Response to Comment Number G.201 for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category effluent guidelines rulemaking (March 4, 1993; 58 FR 12454). Consequently, oil and gas extraction facilities drilling exploratory wells are excluded from this effluent guidelines new source definition. EPA developed this "approach to the definition of new sources in this [effluent guidelines] rule that the Agency believes effectuates the intent of the CWA and the regulations defining new source generally." See Response to Comment Number G.201.

Likewise, after careful consideration of the BTA impingement and entrainment controls for this industrial sector, EPA developed a 316(b) Phase III new source definition that is different from the effluent guidelines new source definition. Under 316(b) Phase III new offshore oil and gas extraction facilities are defined as those facilities that: (1) are subject to the Offshore or Coastal subcategories of the Oil and Gas Extraction Point Source Category Effluent Guidelines (i.e., 40 CFR Part 435 Subpart A (Offshore Subcategory) or 40 CFR 435 Subpart D (Coastal Subcategory)); (2) commence construction after [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]; and (3) meet the definition of a "new facility" in 40 CFR 125.83. For the purposes of the Phase III rule, construction commences if an entity either undertakes or begins certain work as part of a continuous on-site construction program, or enters into contractual obligations to purchase facilities or equipment.[22] In part, EPA did not use the new source definition from the oil and gas extraction point source category (Part 435) in the final Phase III rulemaking to eliminate the concern raised by commenters about the possibility of mobile facilities switching in and out of 316(b) Phase III new source status depending on whether they drill exploratory or development oil and gas wells. In addition, EPA did not find that the impingement and entrainment of aquatic organisms depended on whether these facilities drilled development or exploratory wells. Consequently, EPA did not exclude 316(b) Phase III new source facilities that drill exploratory wells from the 316(b) BTA impingement and entrainment performance standards. NPDES permit writers will need to make a effluent guidelines new source determination in accordance 40 CFR Part 435 as well as a 316(b) Phase III new source determination in accordance with 40 CFR 125, Subpart N.

## 6.3 Potential Lost Production and Downtime Associated with Technology Options Identified in the Final Rule

### *6.3.1 Potential Lost Production*

[22] There are some notable exceptions to this contract formation provision. The following types of contractual obligations do not cause the commencement of construction for 316(b) Phase III new source determinations: options to purchase; contracts which can be terminated or modified without substantial loss; and contracts for feasibility, engineering, and design studies. Commence construction in the context of new mobile facilities means construction of a new mobile facility has commenced subsequent to [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] and its launch is also subsequent to this date. Existing mobile facilities in operation or under a continuous construction program at a shipyard prior to [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] are not considered new sources.

EPA estimates that there will be no lost production for new offshore oil and gas extraction fixed platform facilities due to incremental 316(b) Phase III compliance costs.

Lost production for an offshore oil and gas extraction facility could occur if the operator made a decision to shut in a facility early due to the incremental costs associated with cooling water intake structure O&M. The decision to shut in a facility is generally made on an annual, semi-annual, or, at most, on a quarterly basis. At the end of a fixed facility production life, the costs of production would be approximately $3.7 million/year and the incremental cooling water intake structure O&M costs are estimated to be approximately $37,000/year. Therefore, the incremental cooling water intake structure O&M costs are approximately 0.1% of the production costs and would not impact a quarterly, semi-annual or annual shut in decision. Well shut in decisions will be much more sensitive to the price of oil and gas.

Economic analysis shows that the costs of the Phase III rule are highly unlikely to have any production effects on new deepwater platforms, nor are these costs expected to pose a barrier to new oil and gas development. The economic modeling does not indicate that production is very sensitive to costs estimated at the current order of magnitude.

### *6.3.2 Potential Downtime*

EPA evaluated the potential for downtime at existing offshore oil and gas extraction facilities to allow for cooling water intake structure control maintenance. This issue was evaluated for both mobile and fixed oil and gas extraction facilities. EPA gathered information from the following experts on the topic of maintenance practices for mobile and fixed oil and gas extraction facilities:

- April 4, 2001 Meeting with Mr. James M. Magill, U.S. Coast Guard, Vessel and Facility Operating Standards Division.
- June 8, 2004 E-mail Correspondence with Mr. Elmer Danenberger, MMS.
- June 9, 2004 E-mail Correspondence with Mr. Kent Satterlee, Shell Oil Company.

**Mobile Oil and Gas Extraction Facilities**

Mr. Magill of the U.S. Coast Guard provided information related to cooling water intake structures for MODUs. MODUs typically draw in intake water through a sea chest. Regarding maintenance downtime, Mr. Magill stated that current Coast Guard requirements are that operators must inspect sea chests twice in five years, with at least one scheduled cleaning. These requirements are particularly important to ensure that the separate intake for the fire pump is clear. The requirement to drydock MODUs or perform special examination in lieu of drydocking 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, 107.265, and 107.267 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 or special examination in lieu of drydocking if the unit is in an area of high marine growth or has had history of excessive marine growth at the sea chests. Mr. Magill estimated that the regular cleaning and inspection schedule should be enough to control marine biofouling in the Gulf of Mexico.

Based on this information, EPA assumed that the existing Coast Guard requirements for MODU sea chest maintenance are sufficient and no downtime or incremental compliance costs were developed for MODUs.

**Fixed Oil and Gas Extraction Facilities**

Fixed platforms were costed for cooling water intake structure control maintenance (i.e., annual screen inspection and cleaning using divers). EPA requested information from Mr. Danenberger and Mr. Satterlee to determine whether regular downtime is typical for fixed platforms during which cooling water intake structure control maintenance could occur, or whether maintenance costs would need to account for potential downtime lost production. Both Mr. Danenberger and Mr. Satterlee indicated that it is usual for fixed platforms to experience periodic shut ins for production maintenance purposes. Mr. Danenberger indicated that the frequency and duration of the production maintenance shut ins is dependent on platform age, complexity, condition of the facility, and company practices and policy. Newer facilities might only shut in once per year for two to three days; other facilities might average two shut ins per year, each for up to a week. Mr. Satterlee indicated that for Shell facilities, on average there are one to two scheduled shut ins per year of varying duration. He estimated that, on average, a typical shut in would be two to three days, depending on the scope of work to be performed. In addition, there can also be unplanned shut ins to address critical maintenance items.

Based on this information, EPA assumed that for fixed platform facilities, cooling water intake structure control maintenance can occur during a regularly scheduled downtime and costs beyond the maintenance costs for screen inspection and cleaning were not required. Consequently, EPA did not develop any downtime or incremental compliance costs for these fixed facilities.

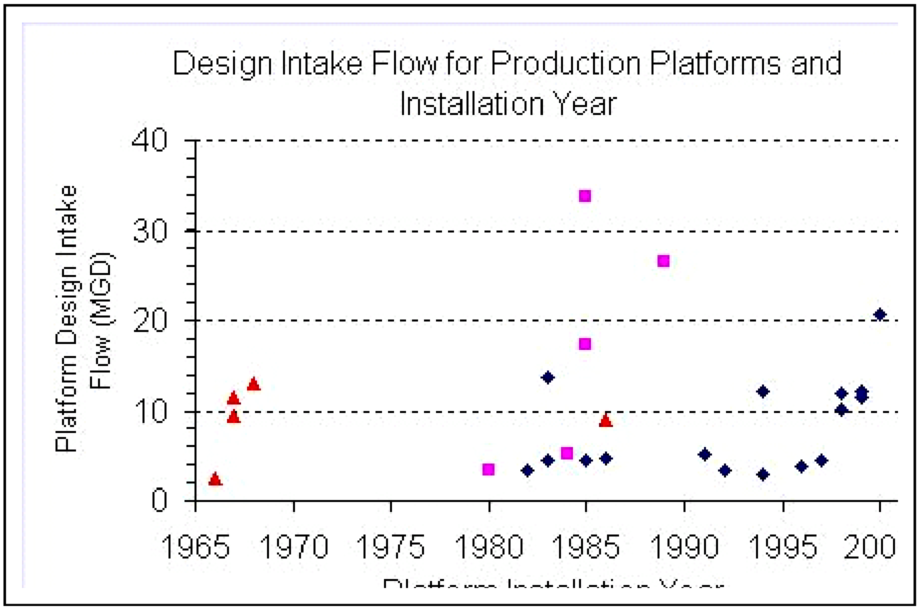
## 6.4 Drilling Equipment at Production Platforms

Drilling equipment is not generally permanently located on offshore fixed production platforms. However, some offshore fixed-production platforms do have permanent on-site drilling equipment and do drill development wells and sidetracks, as well as perform well workovers throughout the life of a project. EPA estimates that 115 fixed platforms have drilling equipment on the platform, out of roughly 2,500 platforms in the GOM. Some fixed production platforms that require more than 2 MGD of cooling water include platforms in deepwater, platforms with cooling needs for power equipment and machinery (e.g., winches), and platforms that require cooling for gas compression and other needs.

Based on data industry submitted to EPA, platforms with permanent drilling equipment are more often found in deepwater. Since passage of the Deep Water Royalty Relief Act (43 U.S.C. §1337) there has been an overall expansion in all phases of deepwater oil and gas extraction activity. This legislation provides economic incentives for operators to develop fields in areas with water depths greater than 200 m (656 ft). The number of producing deepwater projects has dramatically increased from 6 in 1992, to 17 in 1997, and to 86 in 2003. Deepwater production rates have risen by well over 100,000 barrels of oil per day and 400 million cubic ft of gas per day, respectively, each year since 1997.[23] Initial data suggests that while cooling water needs may decrease over the life of some fixed platforms with drilling equipment, the water intakes for some fixed platforms will stay above 2 MGD for their production needs (e.g., gas cooling and compression). High speed reciprocating gas and rotary screw natural gas compressors range up to 8,800 HP. Assuming continuous once-through cooling and a seawater temperature increase of 10 $^{o}$C between intake and discharge, the volume of seawater required for cooling these engines can be up to 3.5 MGD. As an example, there are some production platforms in shallow waters in mature fields that do very little drilling and withdraw more than 2 MGD of seawater (e.g., Offshore California, Cook Inlet, AK). Figure 7-18 demonstrates that design intake flows for some existing production platforms do not always fall below the 2 MGD flow threshold.

[23] U.S. Minerals Management Service, 2004. "Deepwater Gulf of Mexico 2004: America's Expanding Frontier," MMS 2004-021, http://www.gomr.mms.gov/homepg/whatsnew/techann/2004-021.pdf, May 2004.

**Figure 7-18. Design Intake Flow for Production Platforms with Surface Water Intakes Greater than 2 MGD and Installation Year**




Finally, MODUs also serve fixed production platforms to drill development wells and sidetracks, as well as perform workovers, throughout the life of a project when the offshore platform does not have a permanent drilling rig. MODUs also have the potential to impinge and entrain aquatic organisms at these fixed facilities. Consequently, EPA evaluated and selected technology options for these fixed and mobile oil and gas extraction facilities, including fixed production platforms without drilling equipment, to reduce potential adverse environmental impacts. Since most fixed production platforms without drilling equipment have seawater intakes less than 2 MGD, they are not subject to the final Phase III rule; however, they must meet §316(b) requirements as specified by the NPDES permitting authority on a case-by-case basis, using best professional judgment (see 40 CFR 125.90(c)).

# Chapter 8: Efficacy of Cooling Water Intake Structure Technologies

## INTRODUCTION

This chapter presents the data compiled by the Agency on the performance of the range of technologies currently used to minimize impingement mortality and entrainment (I&E) at existing manufacturing facilities and offshore oil and gas extraction facilities nationwide.

## I. EXISTING MANUFACTURING FACILITIES

### 1.0 DATA COLLECTION OVERVIEW

To support the section 316(b) proposed rule for existing facilities, the Agency compiled data on the performance of the range of technologies currently used to minimize I&E at power plants nationwide. The goal of this data collection and analysis effort was to determine whether specific technologies could be shown to provide a consistent level of proven performance. The information compiled was used to compare specific regulatory options and their associated costs and benefits, as well as provide stakeholders with a comprehensive summary of previous studies designed to assess the efficacy of the various technologies. It provided the supporting information for the rule and alternative regulatory options considered during the development process and final action by the Administrator.

Throughout this chapter, *baseline technology performance* refers to the performance of conventional, wide-mesh traveling screens that are not intended to prevent impingement and/or entrainment. The term *alternative technologies* generally refer to those technologies, other than closed-cycle recirculating cooling systems that can be used to minimize impingement and/or entrainment. Overall, the Agency has found that performance and applicability vary based on site-specific and seasonal conditions. The Agency has also determined, however, that alternative technologies can be used effectively on a widespread basis if properly designed, operated, and maintained.

#### 1.1 Scope of Data Collection Efforts

The Agency has compiled readily available information on the nationwide performance of I&E reduction technologies. This information has been obtained through the following:

- Literature searches and associated collection of relevant documents on facility-specific performance.
- Contacts with governmental (e.g., Tennessee Valley Authority (TVA)) and non-governmental entities (e.g., Electric Power Research Institute (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.

EPA could not obtain all the facility performance data available nor did it obtain the same amount and detail of information for every facility. The Agency is not aware of such an evaluation ever being performed nationally. The most recent national data compilation was conducted by EPRI in 2000; see *Fish Protection at Cooling Water Intakes, Status Report*. The findings of that report are cited extensively in the following subsections. EPRI's analysis, however, was primarily a literature collection and review effort and was not intended to be an exhaustive compilation and analysis of all available data. Through this evaluation, EPA worked to build on the EPRI review by reviewing primary study documents cited by EPRI as well as through the collection and reviewing of additional data.

## 1.2 Technology Database

In an effort to document and further assess the performance of various technologies and operational measures designed to minimize the impacts of cooling water withdrawals, EPA compiled a database of documents to allow analyses of the efficacy of a specific technology or suite of technologies. The data collected and entered into this database came from materials ranging from brief journal articles to the more intensive analyses found in historical section 316(b) demonstration reports and technology evaluations. In preparing this database, EPA assembled as much documentation as possible within the available timeframe to support future Agency decisions. It should be noted that the data may be of varying quality. EPA did not validate all database entries. However, EPA did evaluate the general quality and thoroughness of the study. Information entered into the database includes some notation of the limitations the individual studies might have for use in further analyses (e.g., no biological data or conclusions).

EPA's intent in assembling this information was fourfold. First, the Agency sought to develop a categorized database containing a comprehensive collection of available literature regarding technology performance. The database is intended to allow, to the extent possible, a rigorous compilation of data supporting the determination of the best technology available. Second, EPA used the data to demonstrate that the technologies chosen as compliance technologies for costing purposes are reasonable and can meet the performance standards. Third, the availability of a user-friendly database will allow EPA, state permit writers, and the public to more easily evaluate potential compliance options and facility compliance with performance standards. Fourth, EPA attempted to evaluate the technology efficacy data against objective criteria to assess the general quality and thoroughness of each study. This evaluation might assist in further analysis of conclusions made using the data.

Basic information from each document was recorded in the database (e.g., type of technology evaluated, facility at which it was tested). In addition to basic document information, the database contains two types of information: (1) general facility information and (2) detailed study information.

For those documents that refer to a specific facility (or facilities), basic technical information was included to enable EPA to classify facilities according to general categories. EPA collected locational data (e.g., waterbody type, name, state), as well as basic cooling water intake structure configuration information. Each technology evaluated in the study is also recorded, along with specific details regarding its design and operation. Major categories of technologies include modified traveling screens, wedgewire screens, fine-mesh screens, velocity caps, barrier nets, and behavioral barriers. (Data identifying the technologies present at a facility, as well as the configuration of the intake structure, refer to the configuration when the study was conducted and do not necessarily reflect the present facility configuration.)

Information on the type of study, along with any study results, is recorded in the second part of the database. EPA identifies whether the study evaluates the technology with respect to impingement mortality reduction (or avoidance), entrainment survival, or entrainment exclusion (or avoidance). Some studies address more than one area of concern, and that is noted. EPA records basic biological data used to evaluate the technology, if such data are provided. These data include target or commercially/recreationally valuable species, species type, life history stage, size, sample size, and raw numbers of impinged and/or entrained organisms. Finally, EPA records any overall conclusions reached by the study, usually presented as a percentage reduction or increase, depending on the area of focus. Including this information for each document allows EPA and others to readily locate and compare documents addressing similar technologies. Each document is reviewed according to five areas of data quality where possible: (1) applicability and utility, (2) soundness, (3) clarity and completeness, (4) uncertainty and variability, and (5) evaluation and review. Because the compiled literature comes from many different sources and was developed under widely varying standards, EPA reviewed all documents in the database against all five criteria.

To date, EPA has collected {154} documents for inclusion in the database. The Agency did not exclude from the database any document that addressed technology performance in relation to impingement mortality and entrainment, regardless of the overall quality of the data.

### 1.3 Data Limitations

Because EPA 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 variability leads to the following data limitations:

- Some facility data include all the major species and associated life stages present at an individual facility, whereas others include only data for selected species and/or life stages. The identification of important species can be a valid method for determining the overall effectiveness of a technology if the criteria used for selection are valid. In some studies, target species are identified but no reason for their selection is given.

- Many of the data were collected in the 1970s and early 1980s when existing facilities were required to complete their initial 316(b) demonstrations. In addition, the focus of these studies was not the effectiveness of a particular technology but rather the overall performance of a facility in terms of rates of impingement and entrainment.

- Some facility data includes only initial survival results, whereas other facilities have 48- to 96-hour survival data. These longer-term survival data are relevant because some technologies can exhibit significant latent mortality after initial survival.

- Analytical methods and collection procedures, including quality assurance/quality control protocols, are not always present or discussed in summary documentation. Where possible, EPA has reviewed study methods and parameters to determine qualifications, if any, that must be applied to the final results.

- Some data come from laboratory and pilot-scale testing rather than full-scale evaluations. Laboratory studies offer unique opportunities to control and alter the various inputs to the study but might not be able to mimic the real-world variables that could be present at an actual site. Although EPA recognizes the value of laboratory studies and does not discount their results, *in situ* evaluations remain the preferred method for gauging the effectiveness of a technology.

- Survival rates calculated in individual studies can vary as to their true meaning. In some instances, the survival rate for a given species (initial or latent) has been corrected to account for the mortality rate observed in a control group. Other studies explicitly note that no control groups have been used. These data are important because overall mortality, especially for younger and more fragile species, can be adversely affected by the collection and observation process, the factors by which mortality would not be affected under unobserved conditions.

EPA recognizes that the practicality or effectiveness of alternative technologies might not be uniform under all conditions. The chemical and physical nature of the waterbody, facility intake requirements, climatic conditions, and biology of the area all affect feasibility and performance. Despite the above limitations, however, EPA has concluded that significant general performance expectations can be inferred for the range of technologies and that one or more technologies (or groups of technologies) can provide significant impingement mortality and/or entrainment protection at most sites. In addition, in EPA's view many of the technologies have the potential for even greater applicability and higher performance when facilities optimize their use.

The remainder of this chapter is organized by groups of technologies. A brief description of conventional, once-through traveling screens is 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. (In general, ASCE 1982 provides such an all-inclusive discussion.) Instead, EPA has focused on those technologies that have shown significant promise at the laboratory, pilot-scale, or full-scale levels in consistently minimizing impingement mortality 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) can also be used to limit potential impingement mortality and/or entrainment effects. Habitat restoration projects were considered as an additional means to comply with the proposed rule. Such projects, however, have not had widespread application at existing facilities. Because the nature, feasibility, and likely effectiveness of such projects would be highly site-specific, EPA has not attempted to quantify their expected performance level in this document.

### 1.4 Conventional Traveling Screens

For impingement control technologies, performance is compared to conventional (unmodified) traveling screens, the baseline technology. These screens are the most commonly used intake technology 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 the system. The traveling screens 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 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. Approximately 89 percent of all existing facilities within the scope of the proposed rule used conventional traveling screens.

### 1.5 Closed-Cycle Wet Cooling System Performance

Although flow reduction serves the purpose of reducing both impingement and entrainment, flow reduction requirements function foremost as a reliable entrainment reduction technology. This is because entrainment is directly related to intake flow volume, while impingement mortality is related to a combination of factors such as species mix, water current speed and direction, species health, swimming ability, and species attractions. Throughout this chapter, EPA compares the performance of entrainment-reducing technologies to that of recirculating wet cooling towers. To evaluate the feasibility of regulatory options with flow reduction requirements and to allow comparison of costs and benefits of alternatives, EPA determined the likely range in flow reductions between wet, closed-cycle cooling systems and once-through systems. Closed-cycle systems intake some water because 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's performance. Therefore, some water (blowdown) must be discharged and makeup water added periodically to the system. An additional question that EPA has considered is the feasibility of constructing salt-water makeup cooling towers. For the development of the New Facility 316(b) Phase I rule, EPA 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 that use marine or otherwise high total dissolved solids/brackish makeup water. It is important to recognize the facilities listed represent only a selected group of facilities for which Marley has constructed cooling towers worldwide.

## 2.0 ALTERNATIVE TECHNOLOGIES

### 2.1 Modified Traveling Screens and Fish Handling and Return Systems

*Technology Overview*

Conventional traveling screens can be modified so that fish impinged on the screens can be removed with minimal stress and mortality. Ristroph screens have water-filled lifting buckets that 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 at which the fish are spilled onto a bypass, trough, or other protected area (Mussalli, Taft, and Hoffman 1978). Fish baskets are another modification of a conventional traveling screen and may be used in conjunction with fish buckets. Fish baskets are separate framed screen panels attached to vertical traveling screens. An essential feature of modified traveling screens is continuous operation during periods when fish are being impinged. Conventional traveling screens typically operate intermittently. (EPRI 2000, 1989; Fritz 1980). Removed fish are typically returned to the source waterbody by sluiceway or pipeline. ASCE (1982) provides guidance on the design and operation of fish return systems.

*Technology Performance*
Nationwide, a wide range of facilities has used modified screens and fish handling and return systems to minimize impingement mortality. Although many factors influence the overall performance of a given technology, modified screens with a fish return capability have been deployed with success under varying waterbody conditions. In recent years, some researchers, primarily Fletcher (1996), have evaluated the factors that affect 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 or baskets to minimize hydrodynamic turbulence within the bucket or basket.
- Using smooth-woven screen mesh to minimize fish descaling.
- Using fish rails to keep fish from escaping the buckets or baskets.
- Performing fish removal prior to high-pressure washing for debris removal.
- Optimizing the location of spray systems to provide a more gentle fish transfer to sloughs.
- Ensuring proper sizing and design of return troughs, sluiceways, and pipes to minimize harm.

### *2.1.1 Example Studies*

The example studies provide information about technology performance at large power plants. These studies are provided as information that may be appropriate for power plants with a design intake flow of less than 50 MGD. EPA's record documents the technologies described for Phase III facilities are the same as those used by Phase II electricity generation facilities to meet section 316(b) requirements. Specifically the types of intakes, intake locations, technologies currently installed, and the technologies available to address impingement and entrainment at Phase II facilities are the same as those found at Phase III existing facilities.

#### ***Salem Generating Station***

Salem Generating Station, on the Delaware Bay estuary in New Jersey, converted 6 of its 12 conventional traveling screen assemblies to a modified design that incorporated improved fish buckets constructed of a lighter composite material (which improved screen rotation efficiency), smooth-woven mesh material, an improved spray wash system (both low- and high-pressure), and flap seals to improve the delivery of impinged fish from the fish buckets to the fish return trough.

The initial study period consisted of 19 separate collection events during mid-summer 1996. The configuration of the facility at the time of the study (half of the screens had been modified) allowed for a direct comparison of the effectiveness of the modified and unmodified screens on impingement mortality rates. The limited sampling timeframe enabled the analysis of only the species present in numbers sufficient to support any statistical conclusions. 1,082 juvenile weakfish were collected from the unmodified screens while 1,559 were collected from the modified structure. Analysts held each sample group separately for 48 hours to assess overall mortality due to impingement on the screens. Results showed that use of the modified screens had increased overall survival by as much as 20 percent over the use of the unmodified screens. Approximately 58 percent of the weakfish impinged on the unmodified screens survived, whereas the new screens had a survival rate approaching 80 percent. Both rates were based on 48-hour survival and not adjusted for the mortality of control samples.

Water temperature and fish length are two independent factors cited in the study as affecting overall survival. Researchers noted that survival rates decreased somewhat as the water temperature increased, possibly as a result of lower levels of dissolved oxygen. Survival rates decreased to a low of 56 percent for the modified screens when the water temperature reached its maximum of 80°F. At the same temperature, the survival rate on the unmodified screens was 35 percent. Differences in survival rates were also attributable to the size of the fish impinged. In general, small fish (< 50 mm) fared better on both the modified and unmodified screens than large fish (> 50 mm). The survival rates of the two size categories did not differ significantly for the modified screens (85 percent survival for small, 82 percent for large), although a more pronounced difference was evident on the unmodified screens (74 percent survival for small, 58 percent for large).

Salem Generating Station conducted a second series of impingement sampling from 1997 to 1998. By that time, all screen assemblies had been modified to include fish buckets and a fish return system as described above. Additional modifications to the system sought to enhance the chances of survival of fish impinged against the screens. One modification altered the fish return slide to reduce the stress on fish being delivered to the collection pool. Flap seals were improved to better seal gaps between the fish return and debris trough, thus preventing debris from affecting returning fish. Researchers used a smaller mesh screen in the collection pools during the 1997-1998 sampling events than had been used during the 1995 studies. The study notes that the larger mesh used in 1995 might have enabled smaller fish to escape the collection pool. Since smaller fish typically have a higher mortality rate due to physical stress than larger fish, the actual mortality rates may have been greater than those found in the 1995 study.

The second impingement survival study analyzed samples collected from October through December 1997 and April through September 1998. Samples were collected twice per week and analyzed for survival at 24- and 48-hour intervals. Six principal species were identified as constituting the majority of the impinged fish during the sampling periods: weakfish, white perch, bay anchovy, Atlantic croaker, spot, and *Alosa* spp. Fish were sorted by species and size, classified by their condition, and placed in holding tanks.

For most species, survival rates varied noticeably depending on the season. For white perch, survival was above 90 percent throughout the sample period (as high as 98 percent in December). Survival rates for weakfish varied from a low of 18 percent in July to a high of 88 percent in September. Although the number of weakfish collected in September was approximately one-fifth of the number collected in July, a possible explanation for the variation in survival rates is the modifications to the collection system described above, which were implemented during the study period. Similarly, bay anchovy fared worst during the warmer months, dropping to a 20 percent survival rate in July while achieving a 72 percent rate during November. Rates for Atlantic croaker varied from 58 percent in April to 98 percent in November. Spot were collected in only one month (November) and had a survival rate of 93 percent. The survival rate for the *Alosa* spp. (alewife, blueback herring, and American shad) remained relatively consistent, ranging from 82 percent in April to 78 percent in November.

For all species in the study, with the exception of weakfish, survival rates improved markedly with the use of the modified screen system when compared to data from 1978-1982, when the unmodified system was still in use.

### *Mystic Station*

Mystic Station, on the Mystic River in Massachusetts, converted one of its two conventional traveling screen assemblies to a modified system incorporating fish collection buckets and a return system in 1981 to enable a side-by-side comparison of impingement survival. Fish buckets were attached to each of the screen panels. Low-pressure spray (10 psi) nozzles were installed to remove fish from the buckets and into the collection trough. The screen system was modified to include a two-speed motor with a four-speed transmission to enable various rotation speeds for the traveling screens.

The goal of the study was to determine the optimal screen rotation speed and rotation interval that could achieve the greatest survival rate without affecting the screen performance. The study analyzes 2-, 4- and 8-hour rotation intervals as well as continuous rotation. Samples were collected from October 7, 1980 to April 27, 1981. Fish collected from the screens were sorted several times per week, classified, and placed into holding tanks for 96 hours to observe latent mortality.

Results from the study indicated that impingement of the various species was highly seasonal in nature. Data from Unit 7 during the sample period indicate that in terms of both biomass and raw numbers, the majority of fish are present in the vicinity, and thus susceptible to impingement, during the fall and early winter. Almost 50 percent of the *Alosa* spp. were collected during one week in November, while 75 percent of the smelt were collected in a 5-week period in late fall. Likewise, nearly 60 percent of the winter flounder were collected in January. These data suggest that optimal rotation speeds and intervals, whatever they might be, might not be necessary throughout the year.

Continuous rotation of the screens, regardless of speed, resulted in a virtual elimination of impingement mortality for winter flounder. For all other species, survival generally increased with screen speed and rotation interval, with the best 96-hour survival rate (50 percent) occurring at a continuous rotation at 15 feet per second. The overall survival rate is affected by the high latent mortality of *Alosa* spp. in the sample. The study speculates that the overall survival rates would be markedly higher under actual (unobserved) operating conditions, given the high initial survival for large *Alosa* spp. Fragile species such as *Alosa* can be adversely affected by the stresses of collection and monitoring and might exhibit an abnormally higher mortality rate as a result.

### *Indian Point Unit 2*

Indian Point is located on the eastern shore of the Hudson River in New York. In 1985, the facility modified the intake for Unit 2 to include a fish-lifting trough fitted to the face of the screen panels. Two low-pressure (10 psi) spray nozzles removed collected fish into a separate fish return sluiceway. A high-pressure spray flushed other debris into a debris trough. The new screen also incorporated a variable speed transmission, enabling the rotation of the screen panels at speeds of up to 20 feet per minute. For the study period, screens were continuously rotated at a speed of 10 feet per minute.

The sampling period lasted from August 15, 1985 to December 7, 1985. Fish were collected from both the fish trough and the debris trough, though survival rates are presented for the fish collected from the fish trough only. The number of fish collected from the debris trough was approximately 45 percent of the total collected from the fish trough; the survival rate of these fish is unknown. Control groups were not used to monitor the mortality associated with natural environmental factors such as salinity, temperature, and dissolved oxygen. Collected fish were held in observation tanks for 96 hours to determine a latent survival rate.

White perch composed the majority (71 percent) of the overall sample population. Survival rates ranged from 63 percent in November to 90 percent in August. It should be noted that during the month with the greatest abundance (December), the survival rate was 67 percent. This generally represents the overall survival rate for this species because 75 percent of white perch collected during the sample period were collected during December. Weakfish were the next most abundant species, with an overall survival rate of 94 percent. A statistically significant number of weakfish were collected only during the month of August. Atlantic tomcod and blueback herring were reported to have survival rates of 73 percent and 65 percent, respectively. Additional species present in small numbers had widely varying survival rates, from a low of 27 percent for alewife to a high of over 95 percent for bluegill and hogchoker.

A facility-wide performance level is not presented for Indian Point, but a general inference can be obtained from the survival rates of the predominant species. A concern is raised, however, by the exclusion of fish collected from the debris trough. Their significant number might affect the overall mortality of each species. Because the fish in the debris trough have been subjected to high-pressure spray washes as well as any large debris removed from the screens, mortality rates for these fish are likely to be higher, thereby reducing the overall effectiveness of the technology as deployed. The experiences of other facilities suggest that modifications to the system might be able to increase the efficiency of moving impinged fish to the fish trough. In general, species survival appeared greater during late summer than in early winter. Samples were collected during one 5-month period. It is not known from the study how the technology would perform in other seasons.

***Roseton Generating Station***

Roseton Generating Station is located on the eastern shore of the Hudson River in New York. In 1990, the facility replaced two of eight conventional traveling screens with dual-flow screens that included water-retaining fish buckets, a low-pressure (10 psi) spray system, smooth-woven mesh screen panels, and a separate fish return trough. The dual-flow screens were also equipped with variable speed motors to achieve faster rotational speeds. For the study period, screens were continuously rotated at a speed of 10.2 feet per minute.

Impingement samples were collected during two periods in 1990: May 9 to August 30 and September 30 to November 29. A total of 529 paired samples were collected for the first period and 246 paired samples for the second period. Initial mortality was recorded at the Roseton facility. Collected samples were not held on site but rather transported to the fish laboratory at Danskammer Point, where they were observed for latent mortality. Latent mortality observations were made at 48- and 96-hour intervals. A control study using a mark-recapture method was conducted simultaneously to measure the influence, if any, that water quality factors and collection and handling procedures might have had on overall mortality rates. Based on the results of this study, the post-impingement survival rates did not need to be adjusted for a deviation from the control mortality.

Blueback herring, bay anchovy, American shad, and alewife composed the majority of the sample population in both sampling periods. Latent survival rates ranged from 0 percent to 6 percent during the summer and were somewhat worse during the fall. The other two predominant species, white perch and striped bass, fared better, having survival rates as high as 53 percent. Other species that composed less than 2 percent of the sample population survived at considerably higher rates (98 percent for hogchoker).

It is unclear why the more fragile species (alewife, blueback herring, American shad, and bay anchovy) had such high mortality rates. The study notes that debris had been collecting in the fish return trough and was disrupting the flow of water and fish to the collection tanks. Water flow was increased through the trough to prevent accumulation of debris. No information is presented to indicate the effect of this modification. Also noted is the effect of temperature on initial survival. An overall initial survival rate of 90 percent was achieved when the ambient water temperature was 54°F. Survival rates decreased markedly as water temperature increased, and the lowest initial survival rate (6 percent) was recorded at the highest temperature.

***Surry Power Station***

Surry Power Station is located on the James River in Virginia. Each of the two units has 3/8-inch mesh Ristroph screens with a fish return trough. A combined spray system removes impinged organisms and debris from the screens. Spray nozzle pressures range from 15 to 20 psi. During the first several months of testing, the system was modified to improve fish transfer to the sluiceway and increase the likelihood of post-impingement survival. A flap seal was added to prevent fish from falling between the screen and return trough during screen washing. Water volume in the return trough was increased to facilitate the transfer of fish to the river, and a velocity-reduction system was added to the trough to reduce the speed of water and fish entering the sample collecting pools.

Samples were collected daily during a 6-month period from May to November 1975. Initial mortality was observed and recorded after a 15-minute period during which the water and fish in the collection pools were allowed to settle. The average survival rate for the 58 different species collected was 93 percent, although how this average was calculated was not noted. Bay anchovy and the *Alosa* spp. constituted the majority of the sample population and generally had the lowest initial survival rates at 83 percent. The study does not indicate whether control samples were used and whether mortality rates were adjusted accordingly. A noticeable deficiency of the study is the lack of latent mortality analysis. Consideration of latent mortality, which could be high for the fragile species typically impinged at Surry Power Station, might significantly reduce the overall impingement survival rate.

***Arthur Kill Station***

The Arthur Kill Station is located on the Arthur Kill estuary in New York. To fulfill the terms of a consent order, Consolidated Edison modified two of the station's dual-flow intake screens to include smooth mesh panels, fish-retention buckets, flap seals to prevent fish from falling between screen panels, a low-pressure spray wash system (10 psi), and a separate fish return sluiceway. One of the modified screens had a1/8-inch by 1/2-inch mesh; the other had a 1/4-inch by 1/2-inch mesh, while the six unmodified screens all had a 1/8-inch by 1/8-inch mesh. Screens were continuously rotated at 20 feet per minute during the sampling events.

The sampling period lasted from September 1991 to September 1992. Weekly samples were collected simultaneously from all screens, with the exception of 2 weeks when the facility was shut down. Each screen sample was held separately in a collection tank where initial mortality was observed. A 24-hour survival rate was calculated based on the percentage of fish alive after 24 hours versus the total number collected. Because a control study was not performed, final survival rates have not been adjusted for any water quality or collection factors. The study did not evaluate latent survival beyond the 24-hour period.

Atlantic herring, blueback herring and bay anchovy typically composed the majority (> 90 percent) of impinged species during the course of the study period. Bay anchovy alone accounted for more than 72 percent of the sample population. Overall performance numbers for the modified screens are greatly influenced by the survival rates for these three species. In general, the unmodified screens demonstrated a substantially lower impingement survival rate when compared to the modified screens. The average 24-hour survival for fish impinged on the unmodified screens was 15 percent. Fish impinged on the larger mesh (1/4") and smaller mesh (1/8") modified screens had average 24-hour survival rates of 92 percent and 79 percent, respectively. Most species with low survival rates on the unmodified screens showed a marked improvement on the modified screens. Bay anchovy showed a 24-hour survival rate increase from 1 percent on the unmodified screens to 50 percent on the modified screens.

The study period at the Arthur Kill station offered a unique opportunity to conduct a side-by-side evaluation of modified and unmodified intake structures. The results for 24-hour post-impingement survival clearly show a marked improvement for all species that had fared poorly on the conventional screens. The study notes that the collection tanks and protocols might have adversely affected lower survival rates for fragile species, such as Atlantic herring. Larger holding tanks appeared to improve the survival of these species, suggesting that the reported survival rates may underrepresent the rate that would be achieved under normal (unobserved) conditions, though by how much is unclear.

***Dunkirk Steam Station***

Dunkirk Steam Station is located on the southern shore of Lake Erie in New York. In 1998 a modified dual-flow traveling screen system was installed on Unit 1 for an impingement mortality reduction study. The new system incorporated an improved fish bucket design to minimize turbulence caused by flow through the screen face, as well as a nose cone on the upstream wall of the screen assembly. The nose cone was installed to reduce the flow and velocity variations that had been observed across the screen face.

Samples were collected during the winter months of 1998/1999 and evaluated for 24-hour survival. Four species (emerald shiner, juvenile gizzard shad, rainbow smelt, and spottail shiner) compose nearly 95 percent of the sample population during this period. All species exhibited high 24-hour survival rates; rainbow smelt fared worst at 83 percent. The other three species had survival rates of better than 94 percent. Other species were collected during the sampling period but were not present in numbers significant enough to warrant a statistical analysis.

The results presented above represent one season of impingement sampling. Species not in abundance during cooler months might be affected differently by the intake structure. Sampling continued beyond the winter months, but EPA has not reviewed these data.

***Kintigh Station***

Kintigh Station is located on the southern shore of Lake Ontario in New York. The facility operates an offshore intake in the lake with traveling screens and a fiberglass fish return trough. Fish are removed from the screens and deposited in the return trough by a low-pressure spray wash (10 psi). It is noted that the facility also operates with an offshore velocity cap. This does not directly affect the survival rate of fish impinged against the screen but might alter the distribution of species subject to impingement on the screen.

Samples were collected seasonally and held for observation at multiple intervals up to 96 hours. Most species exhibited a high variability in their rate of survival depending on the season. Rainbow smelt had a 96-hour survival rate of 95 percent in the spring and a 22 percent rate in the fall. (The rate was 1.5 percent in summer but the number of samples was small.) Alewife composed the largest number among the species in the sample population. Survival rates were generally poor (0 percent to 19 percent) for spring and summer sampling before the system was modified 1989. After the screen assembly had been modified to minimize stress associated with removal from the screen and return to the waterbody, alewife survival rates increased to 45 percent. Survival rates were not adjusted for possible influence from handling and observation stresses because no control study was performed.

***Calvert Cliffs Nuclear Power Plant***

Calvert Cliffs Nuclear Power Plant (NPP) is located on the eastern shore of the Chesapeake Bay in Maryland. The facility used to have conventional traveling screens on its intake screen assemblies. Screens were rotated for 10 minutes every hour or when triggered by a set pressure differential across the screen surface. A spray wash system removed impinged fish and debris into a discharge trough. The original screens have since been converted to a dual-flow design. The data discussed in the 1975-1981 study period are related to the older conventional screen systems.

Sampling periods were determined to account for the varying conditions that might exist due to tides and time of day. Impingement and survival rates were estimated monthly based on the number and weights of the individual species in the sample collection. No control studies accompanied the impingement survival evaluation although total impingement data and estimated mortalities were provided for comparative purposes. Latent survival rates were not evaluated for this study; only initial survival was included.

Five species typically constituted over 90 percent of the sample population in the study years. Spot, Atlantic menhaden, Atlantic silverside, bay anchovy, and hogchoker had composite initial survival rates of 84, 52, 54, 68, and 99 percent, respectively. Other species generally had survival rates greater than 75 percent, but these data are less significant to the facility-wide survival rate given their low percentage of the overall sample population (< 8 percent). Overall, the facility showed an initial survival rate of 73 percent for all species.

It is notable that the volume of impingement data collected by Calvert Cliffs NPP (over 21 years) has enabled the facility to anticipate possible large impingement events by monitoring fluctuations in the thermal and salinity stratification of the surrounding portion of the Chesapeake Bay. When possible, operational changes during these periods (typically mid to late summer) might allow the facility to reduce cooling water intake volume, thereby reducing the potential for impingement losses.

The facility has also studied ways to maintain adequate dissolved oxygen levels in the intake canal to assist fish viability and better enable post-impingement survival and escape.

***Huntley Steam Station***

Huntley Steam Station is located on the Niagara River in New York. The facility recently replaced four older conventional traveling screens with modified Ristroph screens on Units 67 and 68. The modified screens are fitted with smoothly woven coarse mesh panels on a rotating belt. A fish collection basket is attached to the screen face of each screen panel. Bucket contents are removed by low-pressure spray nozzles into a fish return trough. High-pressure sprays remove remaining fish and debris into a separate debris trough. The study does not contain the rotation interval of the screen or the screen speed at the time of the study.

Samples were collected over five nights in January 1999 from the modified-screen fish return troughs. All collected fish were sorted according to initial mortality. Four targeted species (rainbow smelt, emerald shiner, gizzard shad, and alewife) were sorted according to species and size and held to evaluate 24-hour survival rates. Together, the target species accounted for less than 50 percent of all fish impinged on the screens. (An additional 6,364 fish were not held for latent survival evaluation.) Of the target species, rainbow smelt and emerald shiners composed the greatest percentage with 57 and 37 percent, respectively.

Overall, the 24-hour survival rate for rainbow smelt was 84 percent; some variation was evident for juveniles (74 percent) and adults (94 percent). Emerald shiner were present in the same general life stage and had a 24-hour survival rate of 98 percent. Gizzard shad, both juvenile and adult, fared poorly, with an overall survival of 5 percent for juveniles and 0 percent for adults. Alewife were not present in large numbers ($n$ = 30) and had an overall survival rate of 0 percent.

The study notes the low survival rates for alewife and gizzard shad and posits the low water temperature as the principal factor. At the Huntley facility, both species are near the northern extreme of their natural ranges and are more susceptible to stresses associated with extremes in water conditions. The water temperatures at the time of collection were among the coldest of the year. Laboratory evaluations conducted on these species at the same temperatures showed high degrees of impairment that would likely adversely affect post-impingement survival. A control evaluation was performed to determine whether mortality rates from the screens would need to be adjusted for waterbody or collection and handling factors. No discrepancies were observed, and therefore no corrections were made to the final results. Also of note in the study is the inclusion of a spray wash collection efficiency evaluation. The spray wash and fish return system were evaluated to determine the proportion of impinged fish that were removed from the buckets and deposited in the fish trough instead of the debris trough. All species had suitable removal efficiencies.

### *2.1.2 Summary*

Studies conducted at steam electric power generating facilities over the past three decades have built a sizable record demonstrating the performance potential for modified traveling screens that include some form of fish return. Comprehensive studies, such as those cited above, have shown that modified screens can achieve an increase in the post-impingement survival of aquatic organisms that come under the influence of cooling water intake structures. Hardier species, as might be expected, have exhibited survival rates as high as 100 percent. More fragile species, which are typically smaller and more numerous in the source waterbody, understandably have lower survival rates. Data indicates, however, that with fine tuning, modified screen systems can increase survival rates for even the most susceptible species.

## 2.2 Cylindrical Wedgewire Screens

*Technology Overview*

Wedgewire screens are designed to reduce entrainment and impingement by physical exclusion and by exploitation of hydrodynamics and the natural flushing action of currents present in the source waterbody. Physical exclusion occurs when the mesh size of the screen is smaller than the organisms susceptible to entrainment. Screen mesh sizes range from 0.5 to 10 mm, with the most common slot sizes in the 1.0 to 2.0 mm range. Hydrodynamic exclusion results from maintenance of a low through-slot velocity, which, because of the screen's cylindrical configuration, is quickly dissipated. This allows organisms to escape the flow field (Weisberd et al. 1984). The name of these screens arises from the triangular or wedge-shaped 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). Wedgewire screens are also referred to as profile screens, Johnson screens, or "vee wire".

General understanding of the efficacy of cylindrical wedgewire screens holds that to achieve the optimal reduction in impingement mortality and entrainment, certain conditions must be met. First, the slot size must be small enough to physically prevent the entrainment of the organisms identified as warranting protection. Larger slot sizes might be feasible in areas where eggs, larvae, and some classes of juveniles are not present in significant numbers. Second, a low through-slot velocity must be maintained to minimize the hydraulic zone of influence surrounding the screen assembly. A general rule of thumb holds that a lower through-slot velocity, when combined with other optimal factors, will achieve significant reductions in entrainment and impingement mortality. Third, a sufficient ambient current must be present in the source waterbody to aid organisms in bypassing the structure and to remove other debris from the screen face. A constant current also aids the automated cleaning systems that are now common to cylindrical wedgewire screen assemblies.

### *2.2.1 Example Studies*

The example studies provide information about technology performance at large power plants. These studies are provided as information that may be appropriate for power plants with a design intake flow of less than 50 MGD. EPA's record documents the technologies described for Phase III facilities are the same as those used by Phase II electricity generation facilities to meet section 316(b) requirements. Specifically the types of intakes, intake locations, technologies currently installed, and the technologies available to address impingement and entrainment at Phase II facilities are the same as those found at Phase III existing facilities.

#### ***Laboratory Evaluation (EPRI 2003)***

EPRI recently published (May 2003) the results of a laboratory evaluation of wedgewire screens under controlled conditions in the Alden Research Laboratory Fish Testing Facility. A principal aim of the study was to identify the important factors that influence the relative rates of impingement and entrainment associated with wedgewire screens. The study evaluated characteristics such as slot size, through-slot velocity, and the velocity of ambient currents that could best carry organisms and debris past the screen. When each of the characteristics was optimized, wedgewire screen use became increasingly effective as an impingement reduction technology; in certain circumstances it could be used to reduce the entrainment of eggs and larvae. EPRI notes that large reductions in impingement and entrainment might occur even when all characteristics are not optimized. Localized conditions unique to a particular facility, which were not represented in laboratory testing, might also enable successful deployment. The study cautions that the available data are not sufficient to determine the biological and engineering factors that would need to be optimized, and in what manner, for future applications of wedgewire screens.

Slot sizes of 0.5, 1.0, and 2.0 mm were each evaluated at two different through-slot velocities (0.15 and 0.30 m/s) and three different channel velocities (0.08, 0.15, and 0.30 m/s) to determine the impingement and entrainment rates of fish eggs and larvae. Screen porosities increase from 24.7 percent for the 0.5 mm screens to 56.8 percent for 2.0 mm screens. The study evaluated eight species (striped bass, winter flounder, yellow perch, rainbow smelt, common carp, white sucker, alewife, and bluegill) because of their presence in a variety of waterbody types and their history of entrainment and impingement at many facilities. Larvae were studied for all species except alewife, while eggs were studied for striped bass, white sucker, and alewife. (Surrogate, or artificial, eggs of a similar size and buoyancy substituted for live striped bass eggs.)

Individual tests followed a rigorous protocol to count and label all fish eggs and larvae prior to their introduction into the testing facility. Approach and through-screen velocities in the flume were verified, and the collection nets used to recapture organisms that bypassed the structure or were entrained were cleaned and secured. Fish and eggs were released at a point upstream of the wedgewire screen selected to deliver the organisms at the centerline of the screens, which maximized the exposure of the eggs and larvae to the influence of the screen. The number of entrained organisms was estimated by counting all eggs and larvae captured on the entrainment collection net. Impinged organisms were counted by way of a plexiglass window and video camera setup.

In addition to the evaluations conducted with biological samples, Alden Laboratories developed a Computational Fluid Dynamics (CFD) model to evaluate the hydrodynamic characteristics associated with wedgewire screens. The CFD model analyzed the effects of approach velocity and through-screen velocities on the velocity distributions around the screen assemblies. Using the data gathered from the CFD evaluation, engineers were able to approximate the “zone of influence” around the wedgewire screen assembly under different flow conditions and estimate any influence on flow patterns exerted by multiple screen assemblies located in close proximity to each other.

The results of both the biological evaluation and the CFD model evaluation support many of the conclusions reached by other wedgewire screen studies, as well as in situ anecdotal evidence. In general, the lower impingement rates were achieved with larger slot sizes (1.0 to 2.0 mm), lower through-screen velocities, and higher channel velocities. Similarly, the lowest entrainment rates were seen with low through-screen velocities and higher channel velocities, although the lowest entrainment rates were achieved with smaller slot sizes (0.5 mm). Overall impingement reductions reached as high as 100 percent under optimal conditions, and entrainment reductions approached 90 percent. It should be noted that the highest reductions for impingement and entrainment were not achieved under the same conditions. Results from the biological evaluation generally agree with the predictions from the CFD model: the higher channel velocities, when coupled with lower through-screen velocities, would result in the highest rate of protection for the target organisms.

***JH Campbell***

JH Campbell is located on Lake Michigan in Michigan, with the intake for Unit 3 located approximately 1,000 meters from shore at a depth of 10.7 meters. The cylindrical intake structure has 9.5-mm mesh wedgewire screens and withdraws approximately 400 MGD. Raw impingement data are not available, and EPA is not aware of a comprehensive study evaluating the impingement reduction associated with the wedgewire screen system. Comparative analyses using the impingement rates at the two other intake structures (on shore intakes with conventional traveling screens) have shown that impingement of emerald shiner, gizzard shad, smelt, yellow perch, and alewife associated with the wedgewire screen intake has been effectively reduced to insignificant levels. Maintenance issues have not been shown to be problematic at JH Campbell because of the far offshore location in deep water and the periodic manual cleaning using water jets to reduce biofouling. Entrainment has not been shown to be of concern at the intake structure because of the low abundance of entrainable organisms in the immediate vicinity of the wedgewire screens.

***Eddystone Generating Station***

Eddystone Generating Station is located on the tidal portion of the Delaware River in Pennsylvania. Units 1 and 2 were retrofitted to include wide-mesh wedgewire screens and currently withdraw approximately 500 MGD from the Delaware River. Pre-deployment data showed that over 3 million fish were impinged on the unmodified intake structures during a single 20-month period. An automatic airburst system has been installed to prevent biofouling and debris clogging from affecting the performance of the screens. EPA has not been able to obtain biological data for the Eddystone wedgewire screens but EPRI indicates that fish impingement has been eliminated.

### *2.2.2 Other Facilities*

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 than 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 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) facilities, 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 or 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. In 1982 and 1983 the State of Maryland conducted testing 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 were observed during the tests. In the late 1970s, Delmarva Power and Light conducted laboratory testing of fine-mesh wedgewire screens for the proposed 1,540 MW Summit Power Plant. This testing showed that entrainment of fish eggs (including striped bass eggs) could effectively be prevented with slot widths of 1 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 3 weeks.

*Applicability to Large-Capacity Facilities*

EPA believes that cylindrical wedgewire screens can be successfully employed by large intake facilities under certain circumstances. Although many of the current installations of this technology have been at smaller-capacity facilities, EPA does not believe that the increased capacity demand of a large intake facility, in and of itself, is a barrier to deployment of this technology. Large water withdrawals can be accommodated by multiple screen assemblies in the source waterbody. The limiting factor for a larger facility may be the availability of sufficient accessible space near the facility itself because additional screen assemblies obviously consume more space on the waterbody floor and might interfere with navigation or other uses of the waterbody. Consideration of the impacts in terms of space and placement must be evaluated before selecting wedgewire screens for deployment.

*Applicability in High-Debris Waterbodies*

As with any intake structure, the presence of large debris poses a risk of damage to the structure if not properly managed. Cylindrical wedgewire screens, because of their need to be submerged in the water current away from shore, might be more susceptible to debris interaction than other onshore technologies. Vendor engineers indicated that large debris has been a concern at several of their existing installations; however, selecting the optimal site and constructing debris diversion structures have effectively minimized the risk associated with large debris. Significant damage to a wedgewire screen is most likely to occur from fast-moving submerged debris. Because wedgewire screens do not need to be sited in the area with the fastest current, a less damage-prone area closer to shore or in a cove or constructed embayment can be selected, provided it maintains a minimum ambient current around the screen assembly. If placement in the main channel is unavoidable, deflecting structures can be employed to prevent free-floating debris from contacting the screen assembly. Typical installations of cylindrical wedgewire place them roughly parallel to the direction of the current, exposing only the upstream nose to direct impacts with debris traveling downstream. EPA has noted several installations where debris-deflecting nose cones have been installed to effectively eliminate the damage risk associated with large debris.

Apart from the damage that large debris can cause, smaller debris, such as household trash or organic matter, can build up on the screen surface, altering the through-slot velocity of the screen face and increasing the risk of entrainment and/or impingement of target organisms. Again, selection of the optimal location in the waterbody might be able to reduce the collection of debris on the structure. Ideally, cylindrical wedgewire is located away from areas with high submerged aquatic vegetation (SAV) and out of known debris channels. Proper placement alone may achieve the desired effect, although technological solutions also exist to physically remove small debris and silt. Automated airburst systems can be built into the screen assembly and set to deliver a short burst of air from inside and below the structure. Debris is removed from the screen face by the airburst and carried downstream and away from the influence of the intake structure. Improvements to the airburst system have eliminated the timed cleaning cycle and replaced it with one tied to a pressure differential monitoring system.

*Applicability in High Navigation Waterbodies*

Wedgewire screens are more likely to be placed closer to navigation channels than other onshore technologies, thereby increasing the possibility of damage to the structure itself or to a passing commercial ship or recreational boat. Because cylindrical wedgewire screens need to be submerged at all times during operation, they are typically installed closer to the waterbody floor than the surface. In a waterbody of sufficient depth, direct contact with recreational watercraft or small commercial vessels is unlikely. EPA notes that other submerged structures (e.g., pipes, transmission lines) operate in many different waterbodies and are properly delineated with acceptable navigational markers to prevent accidents associated with trawling, dropping anchor, and similar activities. Such precautions would likely be taken for a submerged wedgewire screen as well.

### *2.2.3 Summary*

Cylindrical wedgewire screens have been effectively used to mitigate impingement and, under certain conditions, entrainment impacts at many different types of facilities over the past three decades. Although not yet widely used at steam electric power plants, 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 at 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 (closed-cycle systems). Nevertheless, 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. For example, there are no full-scale data available specifically for marine environments where biofouling and clogging are significant concerns. Technological advances have been made to address such concerns. Automated cleaning systems can now be built into screen assemblies to reduce the disruptions debris buildup can cause. Likewise, vendors have been experimenting with different screen materials and coatings to reduce the on-screen growth of vegetation and other organisms (zebra mussels).

Fine-mesh wedgewire screens (0.5 - 1 mm) also have the *potential* for use to control both impingement and entrainment. EPA is not aware of the installation of any fine-mesh wedgewire screens at any power plants with high intake flows (> 100 MGD). However, such screens have been used at some power plants with lower intake flow requirements (25 to 50 MGD), which would be comparable to a very large power plant with a closed-cycle cooling system. With the exception of Logan, EPA has not identified any full-scale performance data for these systems. They could be even more susceptible to clogging than wide-mesh wedgewire screens (especially in marine environments). It is unclear whether clogging would simply necessitate more intensive maintenance or preclude their day-to-day use at many sites. Their successful application at Logan and Cope and the historical test data from Florida, Maryland, and Delaware at least suggest 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 (readily accessible). Manual cleaning needs might be reduced or eliminated through use of an automated flushing (e.g., microburst) system.

## 2.3 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 control of both impingement and entrainment. However, they have not been installed, maintained, and optimized at many facilities.

### *2.3.1 Example Facilities*

The example studies provide information about technology performance at large power plants. These studies are provided as information that may be appropriate for power plants with a design intake flow of less than 50 MGD. EPA's record documents the technologies described for Phase III facilities are the same as those used by Phase II electricity generation facilities to meet section 316(b) requirements. Specifically the types of intakes, intake locations, technologies currently installed, and the technologies available to address impingement and entrainment at Phase II facilities are the same as those found at Phase III existing facilities.

***Big Bend***

The most significant example of long-term use of fine-mesh screens 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 drums 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.

### *2.3.2 Other Facilities*

Although egg and larvae entrainment performance data 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 an overall 86 percent initial survival rate 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 or 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. At the Kintigh Generating Station in New Jersey, pilot testing indicated that 1-mm screens provided 2 to 35 times the reduction in entrainment over conventional 9.5-mm screens. Finally, TVA pilot-scale studies performed in the 1970s showed reductions in striped bass larvae entrainment of up to 99 percent for 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 with 1- and 2-mm screens combined.

### *2.3.3 Summary*

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 reduction is contingent on optimized operation and intensive maintenance to avoid biofouling and clogging, especially in marine environments. It might also be appropriate to use removable fine mesh that is installed only during periods of egg and larval abundance, thereby reducing the potential for clogging and wear and tear on the systems.

## 2.4 Fish Net Barriers

*Technology Overview*

Fish net barriers are wide-mesh nets that are placed in front of the entrance to intake structures. The size of the mesh needed is a function of the species present at a particular site and varies from 4 mm to 32 mm (EPRI 2000). The mesh must be sized to prevent fish from passing through the net, which could cause them to be 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 requires fish diversion facilities at only specific times of the year.

*Technology Performance*

Barrier nets can provide a high degree of impingement reduction by preventing large fish from entering the vicinity of the intake structure. Because of typically wide openings, they do not reduce entrainment of eggs and larvae. A number of barrier net systems have been used or studied at large power plants.

### *2.4.1 Example Studies*

The example studies provide information about technology performance at large power plants. These studies are provided as information that may be appropriate for power plants with a design intake flow of less than 50 MGD. EPA's record documents the technologies described for Phase III facilities are the same as those used by Phase II electricity generation facilities to meet section 316(b) requirements. Specifically the types of intakes, intake locations, technologies currently installed, and the technologies available to address impingement and entrainment at Phase II facilities are the same as those found at Phase III existing facilities.

***JP Pulliam Station***

The JP Pulliam Station is located on the Fox River in Wisconsin. Two separate nets with 6-mm mesh are deployed on opposite sides of a steel grid supporting structure. The operation of a dual net system facilitates the cleaning and maintenance of the nets without affecting the overall performance of the system. Under normal operations, nets are rotated at least two times per week to facilitate cleaning and repair. The nets are typically deployed when the ambient temperature of the intake canal exceeds 37°F. This usually occurs between April 1 and December 1.

Studies undertaken during the first 2 years after deployment showed an overall net deterrence rate of 36 percent for targeted species (noted as commercially or recreationally important, or forage species). Improvements to the system in subsequent years consisted of a new bulkhead to ensure a better seal along the vertical edge of the net and additional riprap along the base of the net to maintain the integrity of the seal along the bottom of the net. The improvements resulted in a deterrence rate of 98 percent for some species; no species performed at less than 85 percent. The overall effectiveness for game species was better than 90 percent while forage species were deterred at a rate of 97 percent or better.

***JR Whiting Plant***

The JR Whiting Plant is located on Maumee Bay of Lake Erie in Michigan. The Michigan Water Resources Commission deployed a 3/8-inch mesh barrier net in 1980 as part of a best technology available determination. Estimates of impingement reductions were based on counts of fish impinged on the traveling screens inside the barrier net. Counts in years after the deployment were compared to data from the year immediately prior to the installation of the net when over 17 million fish were impinged. Four years after deployment, annual impingement totals had fallen by 98 percent.

***Bowline Point***

Bowline Point is located on the Hudson River in New York. A 150-foot long, 0.95-cm mesh net has been deployed in a V-shaped configuration around the intake pump house. The area of the river in which the intake is located has currents that are relatively stagnant, thus limiting the stresses to which the net might be subjected. Relatively low through-net velocities (0.5 feet per second) have been maintained across a large portion of the net because of low debris loadings. Debris loads directly affecting the net were reduced by including a debris boom outside the main net. An air bubbler was also added to the system to reduce the buildup of ice during cold months.

The facility has attempted to evaluate the reduction in the rate of impingement by conducting various studies of the fish populations inside and outside the barrier net. Initial data were used to compare impingement rates from before and after deployment of the net and showed a deterrence of 91 percent for targeted species (white perch, striped bass, rainbow smelt, alewife, blueback herring, and American shad). In 1982 a population estimate determined that approximately 230,000 striped bass were present in the embayment outside the net area. A temporary mesh net was deployed across the embayment to prevent fish from leaving the area. A 9-day study found that only 1.6 percent of the estimated 230,000 fish was ultimately impinged on the traveling screens. A mark-recapture study that released individual fish inside and outside the barrier net showed similar results; more than 99 percent of fish inside the net were impinged and less than 3 percent of fish outside the net were impinged. Gill net capture studies sought to estimate the relative population densities of fish species inside and outside the net. The results agreed with those of previous studies, showing that the net was maintaining a relatively low density of fish inside the net as compared to the outside.

### *2.4.2 Summary*

Barrier nets have clearly proven effective for controlling *impingement* (i.e., more than 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 can also be a concern but it can be addressed through frequent maintenance. In addition, barrier nets are also often used only 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 might be further limited by the physical constraints and other uses of the waterbody.

## 2.5 Aquatic Microfiltration Barriers

*Technology Overview*

Aquatic microfiltration barrier systems are barriers that employ a filter fabric designed to allow water to pass 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 the cooling water system. These systems can be floating, flexible, or fixed. Because these systems usually have such a large surface area, the velocities maintained at the face of the permeable curtain are very low. One company, Gunderboom, Inc., has a patented full-water-depth filter curtain composed 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 off of sediment buildup and release any other material back into the water column.

*Technology Performance*

EPA has determined that microfiltration barriers, including the Gunderboom, show significant *promise* for minimizing entrainment. EPA acknowledges, however, that the 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 that facility showed significant potential for reducing entrainment. Entrainment reductions of up to 82 percent were observed for eggs and larvae, and these levels were maintained for extended month-to-month periods during 1999 through 2001. At Lovett, some operational difficulties 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 of 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 5 feet. The Gunderboom system is 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 gpm intakes would require filter systems 500 and 1,000 feet long (assuming a 20-foot depth). In some locations, this may preclude the successful deployment of the system because of space limitations or conflicts with other waterbody uses.

## 2.6 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 both 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 that 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. Because eggs and early stages of larvae cannot swim away, they are not affected by the diversions and there is no associated reduction in entrainment.

Although 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; 306,200 were 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, was 50 percent or less. The facility has also 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 to 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. These findings are generally consistent with the ASCE’s findings from the late 1970s, which showed that 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). The overall guidance efficiency was found to be 75 to 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 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 percent (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 (more than 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.

## 2.7 Angled and Modular Inclined Screens

*Technology Overview*

Angled traveling screens use standard through-flow traveling screens in which the screens are set at an angle to the incoming flow. Angling the screens improves the fish protection effectiveness because 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, in which 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 provide only potential reductions in impingement mortality because eggs and larvae will not generally detect the factors that influence diversion. Like 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 to 70 percent) for northern anchovies and moderate to good guidance (60 to 90 percent) for other species. Latent survival varied by species: fragile species had only 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 at 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 that evaluated the angled screens from 1984 through 1986 showed a diversion efficiency of 76 percent with a 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 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 smelt. Follow-up tests for Niagara Mohawk confirmed 100 percent diversion efficiency for alewife with mortalities only 4 percent higher than those in 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 1-week mean mortality was only 3 percent. Alden performed further tests during 1978 to 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 velocities. 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-mm screens can provide post larvae diversion efficiencies of greater than 80 percent. The tests found, however, that latent mortality for diverted species was also high. Finally, EPRI tested 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 the mortalities were comparable to control mortalities. Based on the laboratory data, an 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 were also observed for largemouth and smallmouth bass, yellow perch, and bluegill. Lower diversion efficiency and survival were found for herring.

In October 2002, EPRI published the results of a combined louver/angled screen assembly study that evaluated the diversion efficiencies of various configurations of the system. In 1999, fish guidance efficiency was evaluated with two bar rack configurations (25- and 50-mm spacings) and one louver configuration (50-mm clearance), with each angled at 45 degrees to the approach flow. In 2000, the same species were evaluated with the 50-mm bar racks and louvers angled at 15 degrees to the approach flow. Diversion efficiencies were evaluated at various approach velocities ranging from 0.3 to 0.9 meters per second (m/s).

Guidance efficiency was lowest, generally lower than 50 percent, for the 45-degree louver/bar rack array, with efficiencies distributed along a bell shaped curve according to approach velocity. For the 45-degree array, diversion efficiency was best at 0.6 m/s, with most species approaching 50 percent. All species except one (lake sturgeon) experienced higher diversion efficiencies with the louver/bar rack array set at 15 degrees to the approach flow. With the exception of lake sturgeon, species were diverted at 70 percent or better at most approach velocities.

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.

## 2.8 Velocity Caps

*Technology Description*

A velocity cap is a device that is placed over a vertical inlet at an offshore intake. This cover converts vertical flow into horizontal flow at the entrance to the intake. The device works on the premise that fish will avoid rapid changes in horizontal flow but are less able to detect and avoid vertical velocity vectors. Velocity caps have been installed at many offshore intakes and have usually been successful in minimizing impingement.

*Technology Performance*

Velocity caps can reduce the number of fish drawn into intakes based on the concept that they tend to avoid rapid changes in 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, such as screens with fish returns. Therefore, there are somewhat limited data on their performance when used alone. Facilities that have velocity caps include the following:

- 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
- Palisades Nuclear Plant in Michigan

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 each have velocity caps on one of 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 by about 62 percent as compared to intake A.

## 2.9 Porous Dikes and Leaky Dams

*Technology Overview*

Porous dikes, also known as leaky dams or dikes, are filters that resemble 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 as both a physical and a 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 buildup, and colonization by 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. They will not, however, prevent entrainment by nonmotile 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, and the Agency is not aware of any full-scale porous dike or leaky dam systems currently used at power plants in the United States. Examples of early study results include:

- Studies of porous dike and leaky dam systems by Wisconsin Electric Power at Lake Michigan plants showed, in general, lower I&E rates than those for 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 Station 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 the 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.

## 2.10 Behavioral Systems

*Technology Overview*

Behavioral devices are designed to enhance fish avoidance of intake structures or to 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 species avoid light; however, it is also known that some species are attracted by light.

- Sound Barriers: Sound barriers are noncontact 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 sectional area. The general purpose of air bubble barriers is to repel fish that might 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, for example, EPRI 2000. For the most part, these studies have been inconclusive or have shown no significant 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 might 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 impingement reductions were observed for rainbow smelt and gizzard shad. Testing of sound systems in 1993 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 those for Fitzpatrick and Pickering. Impingement of gizzard shad was also three times lower than that 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 toward an individual species (e.g., alewife).

## 2.11 Other Technology Alternatives

Use of variable speed pumps can provide for greater system efficiency and have reduced flow requirements (and associated entrainment) by 10 to 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 could be used in conjunction with other technologies.

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 the pipes were specifically designed to screen out detritus, not to protect fish (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 makeup 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, but I&E performance data for these facilities are unavailable. In general, EPA projects that perforated pipe system performance should be comparable to that of 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; there was, however, a substantial increase in impingement survival for surfperch and rockfish.

Facilities might be able to use recycled cooling water to reduce their intake flow needs. The Brayton Point Station has a "piggyback" system in which 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 it reduces the makeup water needs (and thereby entrainment) by 29 percent.

## 2.12 Intake Location

Beyond design alternatives for CWISs, an operator might be able to relocate CWISs offshore or in others areas that minimize I&E (compared to conventional onshore locations). In conjunction with offshore inlet technologies such as cylindrical wedgewire T-screens or velocity caps, the relocated offshore intake could be quite effective at reducing impingement and/or entrainment effects. However, the action of relocating at existing facilities is costly due to significant civil engineering works. 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 (the shore zone areas where light penetrates to the bottom) 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, 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 and 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 and rivers). Use of the deepest open water region of a lake or 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 and 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 and reservoirs. Planktonic movement of eggs, larvae, post larvae, and early juvenile organisms along the shore zone is generally limited to relatively short distances. As a result, the shore zone placement of CWISs in rivers might potentially impact local spawning populations of fish. The impact potential associated with entrainment might 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 shore zone eggs and larvae, as well as the near-surface drift community of ichthyoplankton, is minimized. Impacts could also be minimized by controlling the timing and frequency of withdrawals from rivers. In temperate regions, the number of entrainable or 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 can 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. With local knowledge of these characteristics, however, the entrainment effects of a CWIS could be minimized by adjusting the intake design to areas (e.g., depths) least likely to affect concentrated numbers and species of organisms.

In oceans, near-shore coastal waters are typically the most biologically productive areas. The euphotic zone (zone of light available for photosynthesis) 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 only limited published data quantifying the locational differences in I&E rates at individual power plants. Some information, however, 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 feet offshore (with a velocity cap) in the Atlantic Ocean. This approach 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 the area from 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 finding 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.

# II. OFFSHORE OIL AND GAS EXTRACTION FACILITIES AND SEAFOOD PROCESSING VESSELS

## INTRODUCTION

To identify suitable technologies to minimize impingement mortality and entrainment of fish in typical seawater intake structures, the Agency evaluated currently used technologies as well as other newly developed technologies. Technologies known to be used at existing seawater intakes include standard screens, velocity caps and barrier nets. Other technologies identified as possible candidates include acoustic barriers, air curtains and electric barriers. Data on technologies such as acoustic or electric barriers were collected and evaluated as they have the potential to limit impingement on what are otherwise difficult to modify systems, such as sea chests. Chapter 7 provides a detailed discussion on the impingement and entrainment control technologies for oil and gas extraction facilities that EPA used for estimating incremental compliance costs of the final 316(b) Phase III final rule. This chapter also provides information on biofouling control for these offshore facilities.

An alternative technology must prove to be practical before progressing as a viable and technically feasible candidate technology. The primary criterion for a practical/acceptable alternative configuration/technology is that it is successfully implemented at one or more facilities, including but not limited to other manufacturing industries with a similar seawater intake structure located anywhere around the world.

In addition to identifying appropriate 316(b) control technologies, the following section characterizes typical seawater intake structures used by offshore oil and gas extraction facilities and/or seafood processing vessels.

## 1.0 AVAILABLE TECHNOLOGIES

### 1.1 Known Technologies

There are three main technologies applicable to the control of impingement and entrainment of aquatic organisms for cooling water intakes at offshore industry sectors evaluated for this rulemaking: passive intake screens, velocity caps, and modification of an intake location. Each technology is discussed below with respect to its potential use with intakes at offshore oil and gas extraction facilities and seafood processing vessels.

#### *1.1.1 Passive Intake Screens*

Passive intake screens cover the whole range of static screens that act as a physical barrier to fish entrainment. These barriers include:

- Simple mesh over an open pipe end (caisson or simple intake pipe),
- Grill or fine mesh wedgewire screen (1.75 mm slot size) spanning an opening (as used on sea chest), and
- Cylindrical and wedgewire T-screens (suitable for caissons or simple intake pipes but not sea chests).

Passive intake screens as a class of technology are commonly used throughout industry and are readily available. Simple mesh over a caisson or simple intake pipe are designed to function with a suitably low face velocity to prevent impingement. The smooth surface of a fine mesh wedgewire screen (1.75 mm slot size) will also mitigate impingement impacts as aquatic organisms that come in contact with the intake screen will encounter a smooth surface and avoid an abrasive injury.

Similarly, grill or mesh over a seachest can be operated with a suitably low face velocity to prevent impingement. The sea chest is a shipping industry term that refers to the sea water intake structure of a vessel. A sea chest arrangement typically includes a screen on the outside of the vessel, an open pipe from grill to an isolation valve on the inside of the vessel, a screen box containing a fine screen and removable lid and another isolation valve to the on board pump header. In addition to this, engine room sea chests are normally installed in pairs (more than a single pair of intakes for larger vessels) on each side of the vessel centre line. A passive intake screen over the opening in the hull is the only demonstrated and practical physical barrier for this type of intake. However, the use of a passive intake screen on a sea chest may be prone to impingement issues. Consequently, biofouling controls should be considered and included in the design of these types of intakes for proper screen operation. With respect to seafood processing vessels, interviews with the designers of fishing and commercial vessels revealed that plastic bags are the primary concern for sea chests. A single plastic bag has the potential to completely clog an intake and result in some serious mechanical damage to the engines. The intakes and grilles are consequently sized to limit the impingement of plastic bags. Vessels that operate in a stationary manner (such as pearl processors) use sea chests that are twice the diameter of an equivalent vessel that is normally in motion (refer to Appendix A). This design consideration has the double benefit that it also limits fish entrainment and impingement.

With respect to seafood processing vessels, interviews with the operators/maintainers of sea chests on commercial vessels revealed that it is not common for fish to be drawn into the intake structures. The Big Lift vessel Happy Buccaneer operates stationary for long periods and utilises plate type heat exchangers. Any fish remnants passing through the cooling water system would clog up the heat exchangers. The only incidents that EPA found of problems with fish in the water intakes involved jellyfish swarms.

EPA's Phase II TDD data shows impingement and entrainment control performances for this technology. For example, one case study of this technology identified virtually no impingement and 99 and 62 percent reductions in larvae entrainment for the 1-mm and 2-mm wedgewire screens, respectively, over conventional screen (9.5 mm) systems (U.S. EPA, Technical Development Document for the Final Section 316(b) Phase II Existing Facilities Rule, Attachment A, Fact Sheet No. 5, EPA 821-R-04-007, February 12, 2004). Biofouling controls should be considered and included in the design of these types of intakes for proper screen operation.

The use of a passive intake screen on a sea chest for an existing facility (as used by some MODUs and many seafood processing vessels) may be limited. This is because the size of the opening of a sea chest into the ocean is essentially fixed. To increase the size of a sea chest would be very costly due to significant works at a dry dock. A passive screen that has a suitably low face velocity may therefore have to protrude outside the hull of the vessel. This would have a negative impact on the hydrodynamics of the vessel and create a catch point under the waterline. Alternatively, the passive screen may be used in conjunction with another technology such as an acoustic or electro barrier to reduce impingement, but EPA has no data demonstrating the effectiveness of such a combination of technologies for non-fixed facilities. The use of a passive intake screen on a sea chest for a new facility may be possible depending on the ship design requirements and biofouling controls. Due to the success of passive intake screens at many installations around the world, this type of technology is a suitable fish barrier for retrofit applications on offshore oil and gas extraction facilities and seafood processing vessels that do not employ sea chests.

### *1.1.2 Velocity Caps*

A velocity cap is a device that is placed over vertical inlets at offshore intakes (see Figure 7-15). This cover converts vertical flow into horizontal flow at the entrance of the intake. In general, velocity caps have been installed at many offshore intakes and have been successful in minimizing impingement. 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 by the ASCE (1982), velocity caps are often used in conjunction with other fish protection devices. Therefore, there is somewhat limited data on their performance when used alone. In the case of offshore oil and gas extraction facilities, velocity caps may be used in conjunction with a passive intake screen. However, the biofouling drawback of a passive intake screen may also be present and existing biofouling control technologies should control these operational concerns. Other possible barriers to use in conjunction with a velocity cap may include the "other" technologies noted below.

Facilities using sea chests may have limited opportunities to control entrainment as required by the Phase I rule. EPA recognizes that MODUs using sea chests may require vessel specific designs to comply with the final 316(b) Phase III rule.

EPA identified that some impingement controls for MODUs with sea chests may entail installation of equipment projecting beyond the hull of the vessel (e.g., horizontal flow diverters). Such controls may not be practical or feasible for some MODUs since the configuration may alter fluid dynamics and impede safe seaworthy travel, even for new facilities that could avoid the challenges of retrofitting control technologies.

### 1.1.3 Modification of an Intake Location

An offshore facility may also be able to locate their cooling water intake structures in areas that minimize entrainment and impingement. It is well known that there are certain areas within every waterbody with increased biological productivity, and therefore where the potential for entrainment and impingement of organisms is higher (Phase I TDD (EPA-821-R-01-036, DCN 3-0002)). In oceans, nearshore coastal waters are generally the most biologically productive areas. The euphotic zone (zone of photosynthetically available light) typically does not extend beyond the first 100 meters (328 feet) of depth. Therefore, near-shore waters are generally more productive due to photosynthetic activity and due to the input from estuaries and runoff of nutrients from land (Phase I TDD (EPA-821-R-01-036, DCN 3-0002)). Modification of an intake location may therefore be implemented by adding an extension to the bottom of an existing intake to relocate the opening to a low impact area. To identify low impact areas, an environmental study or assessment is required, as aquatic organisms may rise and fall in the water column.

Woodside Energy Limited in Western Australia indicated that the depth of the intake structure may be used as a method of controlling fish entrainment in offshore oil and gas extraction facility seawater intake structures. Unfortunately, EPA was not able to gather additional details on the systems that are employed by Woodside.

EPA believes that the cost of modifying existing structures with deeper intakes will be significantly greater than the equipment costs associated with screens and velocity caps. In addition, the need for an environmental assessment to identify a lower impact zone for modified intakes would result in additional cost and time constraints. Therefore, EPA did not include modification of an intake location as part of their proposed technology options in the final rule. Additionally, this type of technology is not suitable for MODUs since they would operate in various locations, depths and environments.

## 2.0 OTHER TECHNOLOGIES

Other technologies reviewed include acoustic barriers, air curtains, electro fish barriers, keel cooling, strobe lights and illumination, barrier nets, perforated intake pipe, traveling screens, and porous dikes and leaky dams. Each technology is discussed below with respect to its potential use in minimizing impingement and entrainment at offshore oil and gas extraction facilities and/or seafood processing vessels. EPA notes that other impingement and entrainment control technologies (e.g., aquatic filter barrier systems) may also be available for use at certain site locations but may not control impacts to all aquatic organisms or be available across offshore industry sectors. For example, aquatic filter barrier systems may not be technically practical for very deepwater environments.

### 2.1 Acoustic Barriers

Although there is simplicity in the concept of an acoustic fish deterrent, it is apparent that the use of sound for fish repulsion is not a simple task. The use of sound has been established as an effective means of repelling many species of fish. The major problems with acoustic barriers are that some sounds repel some fish yet have no effect or attract others, and fish may, over time, become desensitized to a sound that would otherwise scare them away. There have been a number of studies undertaken on specific fish entrainment issues at specific locations. However, from a commercial perspective, supply of acoustic barrier equipment is not commonly available.

For fish to be repelled by a sound, a number of criteria must be met (derived from www.fish-guide.com):

- The fish must be able to detect the frequencies used to compose the deterrent signal.
- The sound signal composition must be of a type that is repellent to fish (some sounds attract, others have no effect).

- The level of the sound must be high enough to elicit a reaction, taking account of background noise.

The issue of background noise is important, especially where acoustic systems are deployed near underwater machinery such as pumps and turbines. In such cases, it may be necessary to measure the underwater noise spectra under typical operating conditions.

Underwater noise may be repellent to fish if:

- Noise of any type having frequencies that lie within the fish hearing range is emitted at very high audio levels (but this is very expensive and may impact other biota);
- The characteristics of the noise have any special biological meaning to the fish (e.g., mimicking the approach of a predator);
- The noise is designed by experimentation to cause particularly strong avoidance.

The biological theory may offer good possibilities for individual species, but the empirical results have yielded a number of signal types that are effective against a wide range of species. The signal types that have proved most effective in all applications are based on artificially generated waveforms that rapidly cycle in amplitude and frequency content, thus reducing habituation. A human equivalent would be being made to stand near to a wailing police or ambulance siren. It simply gets uncomfortable, so you move away. In practice, considerable attention needs to be given to the design and specification of a system to ensure it achieves high fish deflection efficiencies. Key variables include the type of fish, background noise, hydraulic conditions (e.g., intake velocities, attraction flow to the fish pass) and acoustic design. Acoustic systems may be designed primarily either to block or to deflect fish movement.

Deflection is usually the best course of action, as the fish are moved swiftly from the source of danger (e.g., water intake) into a safe flow. Blocking can be more difficult if the fish are not moved away from the area, as the risk of habituation to the sound signals becomes increased. This can be overcome to some extent by changing the signal pattern at intervals, but acoustic deterrents are essentially a mild form of stimulus less effective than electric barriers purely for blocking. For this reason it is advised that a well-designed and suitably placed bypass facility be provided.

Sound projectors are electro-mechanical devices and regular maintenance of them is required to ensure optimum performance. This involves removing the underwater units to replace perished seals and to check moving components. Also, it is desirable to raise and clean the units occasionally to remove any buildup of silt or fouling. It is necessary to provide a deployment system to bring sound projectors to the surface for maintenance, without the need to use divers.

As it is difficult to check the performance of submerged equipment, diagnostic units can be attached to the control electronics to monitor performance of the sound projectors.

### *2.1.1 Example Installations*

It must be noted that the examples of acoustic barriers did not include any facilities that fall into the category of offshore oil and gas extraction facilities. However, the following installations share similarities with fixed offshore structures. The use of this equipment on sea chests or mobile equipment may be possible, but has not been proven by example installations.

*Doel Power Station - SPA System*

Doel nuclear power station operated by Electrabel responded to concerns expressed by environmental regulators and fishermen to reduce the numbers of fish that were being drawn into their cooling water intake each year. The main species being affected were herring and sprat (clupeid family).

In 1997, a SPA fish deterrent system was designed and installed on the offshore intake. In total, 20 large Fish Guidance System (FGS) Mk II 30-600 sound projectors were installed to create a repellent sound field close to the water intake openings, causing passing fish to veer away. A multiple signal generator was used to avoid resident species habituating to any one sound signal. To allow servicing of the fish deterrent system while the station is still operating, a deployment frame has been installed to lower sound projectors into their optimum position and to allow them to be raised for routine inspections and maintenance.

The acoustic installation has subsequently undergone a number of evaluation trials by researchers from Belgium's Leuven University. Independent trials have shown a reduction in the target species by 98%. In addition, the catch of other non-target species has been reduced, with the overall reduction being 81%.

*Foss Flood Relief Pumping Station SPA System*

The Environment Agency responded to a fish kill at the River Foss Flood Alleviation Pumping Scheme in York (UK). The scheme consists of a barrier gate to prevent floodwater from the River Ouse flowing up the River Foss. Water flowing down the Foss is pumped from the upstream side of the floodgate by eight vertical, axial flow propeller pumps, and discharged below the gate. Fish damage was attributable to contact with moving machinery and rapid pressure changes during passage through the pumps.

In 1994, an acoustic fish deflection system was installed to deflect fish away from pumps prior to and during operation. As the pump inlets formed a popular shelter for resident fish, the acoustic system was designed to start operating 15 minutes prior to the pumps operating. The SPA installation also provided important protection to resident fish while the pumps were operating by creating a gradient of deterrent sound, increasing towards the intake openings. The installation comprised six FGS Mk I Model 30-600 sound projectors.

A series of independent trials were performed to test the effectiveness of an acoustic fish deterrent system in 1994. Coarse fish representing 12 species were captured during the trial. The most abundant species were bleak, dace, chub, perch and common bream. Prior to the trial, it was previously considered that the sudden commencement of pumping accounted for a larger proportion of the fish entrained through the pumps, as the enclosed environment of the pump channels provided a potential refuge for fish. It was found that the majority of fish were drawn into the Foss Basin during pumping. The acoustic system was found to reduce overall fish entrainment by 80%, with the system deflecting fish in the pumpwells and outside the Foss Basin during operation.

*Other Installations*

- Central Hidroelectrica de Allones, Spain: Four 15-100 Sound Projector Array system supplied to deflect fish away from a head race channel entrance. (August 2000)

- Blackdyke Water Transfer Pumping Station, UK: Eight 15-100 Sound Projector Array system supplied to deflect fish out of pumping station chambers, prior to and during water transfers. (July 2000)

- Great Yarmouth CCGT, UK: Eight 30-600 Sound Projector Array system supplied for cooling water system to new CCGT power station. (July 2000)

- Shoreham CCGT, UK: Six 30-600 Sound Projector Array system supplied for cooling water intake to new CCGT power station. (June 2000)

- Drinking Water Abstraction, River Stour, UK: Six 15-100 Sound Projector Array system supplied for drinking water abstraction. (April 2000)

### *2.1.2 Acoustic Barrier Conclusions*

Acoustic barriers have proven to be effective as fish impingement and entrainment barriers. Since there is no fine mesh covering the intake, this type of barrier is not prone to issues with biofouling. This type of equipment is commercially available and has been proven effective at a number of locations. The typical application of this technology has been onshore-based intake structures rather than offshore oil and gas extraction facilities. The transfer of this technology to offshore oil and gas extraction facility intake structures may be possible with further development. It is particularly suitable for fitting to sea chest intake structures.

### 2.2 Air Curtains

Air curtains are screens of bubbles used to guide fish away from an intake structure. Air bubbles have proven to have some effect for herding and guiding fish or as a barrier to their normal activity (Bibko *et al.* 1973). However, the effectiveness of air bubble curtains at water intakes varies greatly (NEST 1996). Northeast Science and Technology (NEST) undertook a detailed study into the effectiveness of many different types of technology for preventing lake Sturgeon impingement and entrainment for the Little Long Generating Station Facilities (NEST 1996). This facility is located in Northeastern Ontario on the Mattagami River and represents one of the last refuges for lake sturgeon.

Overall, air curtains on their own do not effectively deter fish or substantially reduce impingement (Zweiacker *et al.* 1977; Lieberman and Muessig 1978; Patrick *et al.* 1988: NEST 1996). Factors that reduce the effectiveness of an air curtain include:

- water temperature (Bibko *et al.* 1973),
- fish crowding (Smith 1961),
- the presence of predators (Smith 1961), and
- levels of light (Alevras 1973).

The effectiveness of an air curtain may be improved when used in combination with acoustic deterrents. When a pneumatic popper is used in combination with an air curtain, there is an improved overall effectiveness. This same effect is not observed with use of strobe lights (Patrick *et al.* 1988). Supply of air curtain and acoustic barrier equipment is not commonly available. Fish Guidance Systems Limited from Southampton in the United Kingdom design and manufacture a device that utilizes both a bubble curtain and an acoustic deterrent for large industrial water intakes.

The Bio-Acoustic Fish Fence (BAFF) is used to divert fish from a major flow, e.g., entering a turbine, into the minor flow of a fish pass channel. It may be regarded as analogous to a conventional angled fish screen. It uses an air bubble curtain to contain a sound signal that is generated pneumatically. Effectively, this creates a "wall of sound" (an evanescent sound field) that can be used to guide fish around river structures by deflection into fish passes.

Physically, the BAFF comprises a pneumatic sound transducer coupled to a bubble-sheet generator, causing sound waves to propagate within the rising curtain of bubbles. The sound is contained within the bubble curtain as a result of refraction, since the velocity of sound in a bubble-water mixture differs from that in either water or air alone. The sound level inside the bubble curtain may be as high as 170 decibels (dB) at underwater reference pressure of 1 micro Pascal (re 1mPa), typically decaying to 5% of this value within 0.5-1 m from the bubble sheet. It can be deployed in much the same way as a standard bubble curtain, but its effectiveness as a fish barrier is greatly enhanced by the addition of a repellent sound signal. The characteristics of the sound signals are similar to those used in SPA systems, i.e., within the 20-500 hertz (Hz) frequency range and using frequency or amplitude sweeps.

FGS acoustic BAFF systems comprise the following components:

- BAFF Unit: The BAFF system comprises of modular sections, each 2.4 m long, which are linked together to form the required length. The acoustic signal is entrapped in the bubbles by a driver unit and the resulting 'wall of sound' produces an uninterrupted guidance system.

- Air Blower or Compressor: The BAFF uses an air blower or compressor to supply pressurized air to create a continuous bubble curtain.
- Air Blower/Compressor Pipe: A temperature / pressure-resistant pipe delivers air from the air blower or compressor to the BAFF control equipment.
- BAFF Control Equipment and Control Lines: The BAFF control equipment is used to operate the BAFF system. A main air supply and two control lines feed driver units fitted on each of the BAFF units. Solenoids located in the returning control line regulate the airflow to the driver units. Pressure feedback lines run from the BAFF units back to the control panel to allow pressure within the BAFF to be monitored. An alarm system indicates a sudden drop in pressure resulting from a failure in air supply.

### *2.2.1 Example Installations*

It must be noted that the examples found did not include any facilities that fall into the category of offshore oil and gas extraction facilities. However, the following installations share similarities with fixed offshore structures. The use of this equipment on sea chests or mobile equipment may be possible but is not specifically demonstrated.

*Beeston Hydro-electric Station*

- Beeston Weir Hydro Scheme, a 1.3MW station, was commissioned in May 2000. The £3 million ($ 5.5 million United States dollars (USD)) Beeston Hydro Scheme was installed at an existing weir on the River Trent near Nottingham in the UK. A prime objective of the new hydro was to make the scheme fit the environment, and not the other way around.

- The river supports a mixed population of resident coarse fish and migratory eels. Owing to a history of poor water quality, the river currently has a very small population of salmonoid fish. However, the Environment Agency has a program underway of continuous improvement of water quality, with the goal of restoring the salmonoid population.

- To divert downstream migrating fish away from the headrace channel, an 80m long BAFF system was installed. It is located diagonally upstream of the weir to guide juvenile salmon and other fish moving downstream to the fish ladder. A new vertical single slot fish pass was added to facilitate upstream and downstream passage of both salmonoid and coarse fish, prior to construction of the hydro facility.

- The BAFF system produces a "wall of underwater sound" by using compressed air to generate a continuous bubble curtain, into which low frequency sound (varying between 50 and 500 hertz) is injected and entrapped. Although well-defined lines of high level sound (at least 160 decibels) are generated within the bubble curtain, the noise levels are negligible a few meters away from it. By restricting the sound curtain to a small area, the system allows fish to act normally throughout the remainder of the reservoir or river.

- A Smith-Root graduated electric barrier is located just below the power plant to divert adult salmon migrating upstream away from the tailrace and into the fish ladder.

*Other Installations*

- Blantyre, Hydro Station, Scotland, UK: Combined Sound Projector Array and BAFF system installed on low-head hydro-electric power station for evaluation trials. Results published in ETSU report H/01/00046/REP www.dti.gov.uk/NewReview/nr32/html/fish.html (Spring 1996).

- Northampton, Inland Waterway Pumping Station, UK: Two bubble curtain systems installed on canal pumping station intake to reduce transfer of zander. (January 1999)

### *2.2.2 Air Curtain Conclusions*

Air curtains have proven to be ineffective barriers to impingement and entrainment of fish stocks when they are used on their own. When used in combination with other acoustic deterrent systems, their effectiveness is greatly increased. This type of equipment is commercially available and has been proven effective at a number of locations.

The typical application of this technology has been on hydroelectric power station intake structures rather than offshore oil and gas extraction facilities. The transfer of this technology to offshore oil and gas extraction facility intake structures may be possible with further development. As such, this technology has the potential to become suitable after further development.

## 2.3 Electro Fish Barriers

Electrical fields are frequently used to frighten, attract, stun, or kill fish. Upon approaching the field, many fish exhibit a fright reaction and may be repelled (NEST, 1996).

Smith-Root is a leading supplier of Electro Fish barriers. The following information was obtained from the Smith-Root Web page (www.smith-root.com):

> Electric current passing between the electrodes, via the water medium, produces an electric field. When fish are within the field, they become part of the electrical circuit with some of the current flowing through their body. The electric current passing through fish can evoke reactions ranging from a slight twitch to full paralysis, depending on the current level and shock duration they receive. (Smith-Root.com)

One of the most important advantages of the parallel field orientation is that when a fish is crosswise to the electric field it receives almost no electric shock. Fish learn very quickly that by turning side ways to the flow they can minimize the effects of the electric field.

### *2.3.1 Example Installations*

*Great Lakes Division - 80" Mill, Pump House #2 (1994)*

Ecorse, Michigan
Barrier Type: Smith-Root Concrete weir with bottom mounted electrodes.

Keeps gizzard shad and other river fish from entering the pumping systems used for steel mill cooling. Previously, dense fish runs caused several shutdowns each year. Since installation in 1994, they have not had single shutdown attributed to fish runs.

*Shields Lake*

Forest Lake, Minnesota 1996
Barrier Type: Smith-Root Plastic culvert with stainless steel electrodes. Prevents carp from entering Shields Lake.

*Heron Lake*

Worthington, Minnesota 1993
Barrier Type: Smith-Root Concrete weir with bottom mounted electrodes.
Prevents carp from entering Heron Lake. Barrier is very effective and currently in operation. This once-sterile lake is now restored to a bird and game fish habitat.

### *2.3.2 Electro Fish Barrier Conclusions*

Electro Fish Barriers have proven to be effective as fish impingement and entrainment barriers. The main limitation is that the high conductivity of seawater limits the size of a practical electro barrier. Discussions with a supplier of this type of equipment (Smith-Root) stated that a practical installation would be possible at a caisson or sea chest opening. Electro Fish Barriers are commercially available and have been shown to be effective at a number of locations. The most common location for this technology to be used is on river or lake intake locations for power stations where local fish stocks are to be protected.

The typical application of this technology has been onshore-based intake structures rather than offshore oil and gas extraction facilities. The transfer of this technology to offshore oil and gas extraction facility intake structures may be possible with further development. As such, this technology has the potential to become suitable after further development. It is particularly useful for fitting to sea chest intake structures.

## 2.4 Keel Cooling

Keel cooling is a process that bypasses the need to draw cooling water on board a vessel. This is achieved by installing a heat exchanger in the waterbody and pumping cooling water through a closed loop system. This technology was developed during the Second World War and is commonly used on many vessels today. The Shine Fisheries Factory Trawlers operating out of Fremantle in Western Australia use keel cooling for all cooling water on all of their vessels.

Fernstrum Company has confirmed that this system is suitable for retrofitting to an existing on-board cooling water system. Furthermore, it is not limited to mobile vessels. The coolers may be designed using natural convection (fixed structure) rather than forced convection (moving structure) to meet a heat transfer requirement. Therefore, this equipment could be used on the cooling water systems of stationary or mobile offshore oil and gas extraction facilities. It is believed that Brown and Root installed one of the Fernstrum systems on a new offshore oil and gas extraction facility approximately 20 years ago. EPA was unable to gather additional details of this system. Biofouling of keel coolers is limited with the use of CuNi alloys for fabrication. See anti-biofouling technologies discussion in Chapter 7.

### *2.4.1 Keel Cooling Conclusions*

Keel cooling is a suitable technology for MODUs. Stationary offshore oil and gas extraction facilities may also be able to benefit from this technology.

## 2.5 Strobe Lights and Illumination

The reaction of fish to light is not consistent. It changes with the type of light, intensity, angular distribution, polarization and duration (Hocutt 1980). Some fish may exhibit a positive response to a light source, while the same light may repel others. Also, the reaction of a fish to a light source may vary depending on the life stage of the particular species (Fore 1969). Studies have been undertaken into the use of strobe lights. The effectiveness of a strobe has been found to vary with species, time of day, and fish size (Taft *et al.* 1987).

Compared with other behavioral barriers, strobe lights and other illumination generally appear to be the least effective. A combination of strobe lights and air curtains are more effective for repelling fish than either on their own, but were less effective than the air curtain / acoustic deterrents (NEST 1996). Based on this research, strobe lights and illumination are not acceptable as a suitable technology on their own. However, their use in combination with other technologies may prove to be successful.

## 2.6 Barrier Nets

Barrier nets are typically utilized in locations where impingement is a problem. In these situations, a net is used to keep relatively large fish away from an intake screen. 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 varies from 4 mm to 32 mm. A number of barrier net systems have been used/studied at large onshore power plants. 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 can also be a concern but this can be addressed through frequent maintenance. Also, barrier nets are often only used seasonally where the source water body is subject to freezing, which can tear the net, or ice flows, which can tear the net. In most cases the net is removed during the freeze season for repair and maintenance. In some applications, the barrier net is lowered below the freeze line. 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. Barrier nets are not suitable for use on MODUs and vessels since the net would be a major hindrance to the operation of the vessel, and where the shear forces of the vessel in full motion would easily tear the net. Of particular concern is the safety issue where nets may get tangled in other equipment including the propulsion and/or propellers. Another feasibility concern is the bottom of a barrier net requires a fixed point of attachment, so for a non-fixed vessel the net would need to wrap around and beneath the vessel – a completely impractical application. Fixed platforms, in contrast, may potentially use barrier nets to reduce impingement. One possible application is to set the nets up in removable panels around the intake. For all of these reasons, nets were not selected as a compliance technology module for non-fixed vessels.

## 2.7 Perforated Intake Pipe

A perforated pipe arrangement draws water through perforations or elongated slots in a cylindrical section placed in the waterbody. Early designs of this technology were not efficient, velocity distribution was poor, and they were specifically designed to screen out debris and not for the protection of aquatic organisms. Perforated caissons or simple pipes have been used on some fixed platforms by installing the perforated platform inside of the simple pipe. For example, Marathon South Pass (Block 86) used a 20” inner diameter simple pipe with the bottom at 59’ below water level. The lower 8’ pipe section is slotted with bottom open, slots are 1”W x 4”L, and slots are spaced 3” apart along the circumference and 8” apart vertically.

Since impingement and entrainment performance data for perforated pipe arrangements are unavailable, the use of this technology is questionable. 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) because of the technologies’ similar physical characteristics. For non-fixed facilities (including MODUs and seafood processing vessels) the projection of a perforated intake poses the same hydrodynamic and safety issues posed by cylindrical and wedgewire screens. The hydrodynamic and seaworthiness considerations are not avoided by new vessel construction.

## 2.8 Traveling Screens (Includes Angular and Modular Screens)

Traveling screens are generally used on onshore facilities that incorporate large stilling and pump pits. The traveling screen installation requires a significant amount of specifically designed structure to be included in the intake design. Retrofitting a structure to accept a traveling screen on offshore oil and gas extraction facilities would be generally impractical and extremely costly. Furthermore, the maintenance of a sub-sea traveling screen retrofitted to an existing structure would also be impractical and very costly. The design of traveling intake screens is not suited to offshore oil and gas extraction facilities. Even for new vessel construction, the space requirements and equipment costs suggest this technology would not be selected. As such, this technology has been deemed to be unsuitable for these facilities, and was not costed as a compliance technology for vessels.

## 2.9 Porous Dikes and Leaky Dams

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. Clearly the construction of a fixed major civil installation such as a porous dam or leaky dike is not possible for MODUs. The use of this type of equipment on fixed platforms may also be rejected due to the fact that if one were constructed in the middle of the ocean it would be extremely impractical and costly and result in the death or dislocation of a large number of marine wildlife. As such, this technology has been deemed to be unsuitable for the facilities evaluated here.

## III. CONCLUSION

As suggested by the technology studies evaluated in this chapter, the technologies presented can substantially reduce impingement mortality and entrainment. With proper design, installation, and operation and maintenance, a facility can realize marked reductions. However, EPA recognizes that there is a high degree of variability in the performance of each technology, which is in part due to the site-specific environmental conditions at a given facility. EPA also recognizes that much of the data cited in this document was collected under a variety of performance standards and study protocols that have arisen over the years since EPA promulgated its last guidance in 1977.

EPA expects that this information on technologies may be useful in developing case-by-case, best professional judgment permit conditions implementing CWA section 316(b). While EPA acknowledges that site-specific factors may affect the efficacy of impingement and entrainment reduction technologies, EPA believes that there are a reasonable number of options from which most facilities may choose. EPA also believes that, in cases where one technology cannot meet the performance standards alone, a combination of additional intake technologies, operational measures, and/or restoration measures can be employed.

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# Chapter 9: 316(b) Phase III Implementation for New Offshore Oil and Gas Extraction Facilities

INTRODUCTION

This chapter provides guidance to permit writers and the regulated community for implementing the 316(b) Phase III requirements for new offshore and coastal oil and gas extraction facilities. The national categorical requirements in this rule apply to new offshore oil and gas extraction facilities, which were specifically excluded from the Phase I new facility rule. (40 CFR Part 125, Subpart I). This rule defines the term “new offshore oil and gas extraction facility” to encompass facilities in both the offshore and the coastal subcategories of EPA’s Oil and Gas Extraction Point Source Category for which effluent limitations are established at 40 CFR Part 435. Although the term "offshore" denotes only one of these two subcategories for purposes of the effluent guidelines, EPA is using the term "offshore" here to denote facilities in either subcategory because the requirements in this rule are the same for both offshore and coastal facilities and the term "offshore" is commonly understood to include any facilities not located on land. In order to be covered by this rule, these facilities would need to use cooling water intake structures to withdraw water from waters of the U.S. and meet all other applicability criteria, as described in the final 316(b) Phase III regulation.

## 1.0 WHY IS EPA PROMULGATING NATIONAL REQUIREMENTS FOR NEW OFFSHORE AND COASTAL OIL AND GAS EXTRACTION FACILITIES?

After EPA proposed the Phase I rule for new facilities (65 FR 49060, August 10, 2000), the Agency received adverse comment from operators of offshore and coastal (collectively “offshore”) drilling facilities concerning the limited information about their cooling water intakes, associated impingement mortality and entrainment, costs of technologies, or achievability of the controls proposed by EPA. On May 25, 2001, EPA published a NODA for Phase I that, in part, sought additional data and information about mobile offshore and coastal drilling facilities. In the Phase I final rule, EPA committed to “propose and take final action on regulations for new offshore oil and gas extraction facilities, as defined at 40 CFR 435.10 and 40 CFR 435.40, in the Phase III section 316(b) rule.” EPA established national technology-based impingement and entrainment control performance standards in the final 316(b) Phase III regulation. These requirements are finalized in 40 CFR 125, Subpart N.

Offshore oil and gas extraction facilities currently operate off the coasts of California and Alaska and throughout the Gulf of Mexico. Most activity currently takes place in the Gulf of Mexico. EPA expects that most new facility activity will also take place in this region. (See Chapter 7 of this TDD).

While EPA is not aware of any studies that directly examine or document impingement mortality and entrainment by offshore oil and gas extraction facilities, numerous studies show that offshore marine environments provide habitat for a number of species of fish, shellfish, and other aquatic organisms. Many of these species have life stages that are small and planktonic or have limited swimming ability. These life stages are potentially vulnerable to entrainment by cooling water intake structures. Larger life stages are potentially vulnerable to impingement. The introduction of cooling water intake structures into the offshore habitat in which these organisms live creates the potential for impingement and entrainment of these organisms.

The densities of organisms in the immediate vicinity of offshore oil and gas extraction facilities relative to densities in estuaries and other nearshore coastal waters is not well characterized. In the Phase III NODA (70 FR 71059), EPA presented an analysis of additional data from the general regions in which existing offshore oil and gas extraction facilities operate and where new facilities might operate in the future in order to better characterize the potential for impingement and entrainment by these facilities.

EPA obtained data on densities of ichthyoplankton (planktonic fish eggs and larvae) in the Gulf of Mexico from the Southeast Area Monitoring and Assessment Program (SEAMAP). This long-term sampling program collects information on the density of fish eggs and larvae throughout the Gulf of Mexico. EPA analyzed the SEAMAP data to determine average ichthyoplankton densities in the Gulf of Mexico for the period of time for which sampling data was available (1982-2003). Actual conditions at any one location and at any one point in time may vary from the calculated averages.

EPA's analysis of the SEAMAP data indicates that ichthyoplankton occur throughout the Gulf of Mexico. On average, densities are highest at sampling stations in the shallower regions of the Gulf of Mexico and lowest at sampling stations in the deepest regions. The overall range of average larval fish densities was calculated to be 25-450+ organisms/100$m^3$. The wide range of ichthyoplankton densities seen in the offshore Gulf of Mexico region falls within the range of larval fish densities documented in freshwater and coastal water bodies in various coastal and inland regions of the United States. Over 600 different fish taxa were identified in the SEAMAP samples, including species of commercial and recreational utility.

In the area surrounding existing offshore oil and gas extraction facilities off the California coast, the California Cooperative Oceanic Fisheries Investigations (CalCOFI) program has gathered data on densities of ichthyoplankton and other organisms. According to the CalCOFI and other research programs, a number of fish and shellfish species, including species of commercial and recreational value, are known to live and spawn in this region. EPA does not know of similarly extensive sampling programs for the Alaska offshore region. However, a number of fish and shellfish species, including species of commercial and recreational value, are known from various research programs to live and spawn in the offshore regions of Alaska where oil and gas extraction activities currently take place or may take place in the future. The eggs and larvae of many species found in the offshore regions of California and Alaska are planktonic and could therefore be vulnerable to entrainment by a facility's cooling water intake structure operating in these regions. Larger life stages (e.g., juveniles and adults) could be vulnerable to impingement.

The densities of organisms in the immediate vicinity of offshore oil and gas extraction facilities may differ from those suggested by analysis of SEAMAP and other collections of data that characterize typical organism densities in marine waters. Offshore oil and gas extraction facilities have been shown to attract and concentrate aquatic organisms in the immediate vicinity of the underwater portions of their structures. A variety of species of pelagic fish have been found to gather around the underwater portions of offshore oil and gas extraction facilities within short time periods after the facilities' appearance in the water column. If a facility remains in one place for a sufficient length of time, some aquatic organism species take up residence directly upon the underwater structure and form reef-like communities. The increased number of organisms living near the underwater portion of facilities where cooling water intake structures are located increases the potential for impingement mortality and entrainment of those organisms. The extent to which the increased numbers of aquatic organisms represents an overall increase in organism populations, rather than a concentration of organisms from surrounding areas, is not known. (For additional information, see DCNs 7-0013, 8-5220, and 8-5240.)

EPA believes the data it has gathered on organisms that inhabit offshore environments indicate the potential for their entrainment and impingement by cooling water intake structures associated with new offshore oil and gas extraction facilities. Given this potential for impingement and entrainment, EPA believes that these new facilities have the potential to create multiple types of undesirable and unacceptable impacts.

While the data in the Phase III rulemaking record did show spatial and temporal variations, as well as variability at different depths, the range of ichthyoplankton densities found were within the same range seen in coastal and inland waterbodies addressed by the 316(b) Phase I final rule. As discussed in section IX of the preamble to the final rule, there is no economic barrier for new offshore oil and gas facilities to meet the performance standards as proposed. Based in part on these results, EPA is addressing new offshore oil and gas extraction facilities in this final rule. EPA proposed to set a regulatory threshold of 2 MGD for new offshore oil and gas facilities. EPA has not identified nor have commenters provided a basis for selecting an alternative regulatory threshold. Therefore, consistent with the Phase I rule, new offshore oil and gas extraction facilities with a design intake flow greater than 2 MGD are subject to this rule.

## 2.0 WHAT IS THE APPLICABILITY OF THE 316(B) PHASE III FINAL RULE TO NEW OFFSHORE OIL AND GAS EXTRACTION FACILITIES?

Final section 316(b) requirements for new offshore oil and gas extraction facilities will be implemented through the NPDES permit program. This final rule establishes implementation requirements for new offshore oil and gas extraction facilities that are generally similar to the 316(b) Phase I requirements.[1] This regulation establishes application requirements under 40 CFR Part 122.21 and §125.136, monitoring requirements under §125.137, and record keeping and reporting requirements under §125.138. The regulations also require the Director to review application materials submitted by each regulated facility and include monitoring and record keeping requirements in the permit (§125.139).

## 2.1 When Does the 316(b) Phase III Final Rule Become Effective?

The 316(b) Phase III final rule becomes effective [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. Under this final rule, new offshore oil and gas extraction facilities will need to comply with the Subpart N requirements when an NPDES permit containing requirements consistent with Subpart N is issued to the facility.

## 2.2 When Do New Offshore Oil And Gas Extraction Facilities Need To Comply With the 316(B) Phase III Final Rule?

After the 316(b) Phase III final rule becomes effective, new offshore oil and gas extraction Phase III facilities will need to demonstrate compliance with these impingement and entrainment control performance standards when an NPDES permit containing requirements consistent with this rule is issued to the facility (see §125.132). Under current NPDES program regulations, this will occur when a new NPDES permit is issued or when an existing NPDES permit is issued, reissued, or modified or revoked and reissued.

Most offshore oil and gas extraction facilities are covered by general permits issued by EPA. New offshore oil and gas extraction facilities that meet the applicability criteria for the Phase III rule are not eligible for coverage under NPDES general permits that are already in effect because these general permits will not include today's section 316(b) requirements for new offshore oil and gas extraction facilities. EPA expects to modify or revise existing, and/or issue new, general permits to include today's section 316(b) requirements for new offshore oil and gas extraction facilities. Until that time, should a new offshore oil and gas extraction facilities apply for a permit the facility will most likely be issued an individual NPDES permit that contains requirements for cooling water intake structures consistent with today's rule. A discussion of the timing of the implementation of this rule is provided in Section VIII of the preamble to the final rule.

## 2.3 What is a "New" Offshore Oil and Gas Extraction Facility for Purposes of the Section 316(b) Phase III Rule?

For purposes of this rule, new offshore oil and gas extraction facilities are those facilities that: (1) are subject to the Offshore or Coastal subcategories of the Oil and Gas Extraction Point Source Category Effluent Guidelines (i.e., 40 CFR Part 435 Subpart A (Offshore Subcategory) or 40 CFR 435 Subpart D (Coastal Subcategory)); (2) commence construction after [INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]; and (3) meet the definition of a "new facility" in 40 CFR 125.83.

For a discussion of the definition of new facility, see 66 FR 65256, 65258-59, 65785-87 (December 18, 2001) and 69 FR 41576, 41578-80 (July 9, 2004). New offshore oil and gas extraction facilities were not subject to the Phase I new facility rule. The determination of whether a facility is "new" or "existing" is focused on the point source discharger – not on the cooling water intake structure. In other words, modifications or additions to the cooling water intake structure (or even the total replacement of an existing cooling water intake structure with a new one) does not reclassify an otherwise unchanged existing facility into a new facility, regardless of the purpose of such changes. Rather, the determination as to whether a facility is new or existing focuses first on the point source itself. In addition, Section II.A of the preamble to the final rule also

1 The final Phase I new facility rule (40 CFR Part 125, Subpart I) establishes requirements applicable to the location, design, construction, and capacity of cooling water intake structures at new facilities that withdraw greater than two (2) MGD and use at least twenty-five (25) percent of the water they withdraw for cooling purposes.

discusses what constitutes a "new" offshore oil and gas extraction facility for purposes of the section 316(b) Phase III final rule.

Any offshore or coastal oil and gas extraction facility that does not meet these three criteria will continue to be subject to section 316(b) requirements established by the permit writer on a case-by-case basis.

## 2.4 Which New Offshore Oil and Gas Extraction Facilities are Regulated by the Section 316(b) Phase III Final Rule?

New offshore oil and gas facilities that meet all of the following criteria are subject to the section 316(b) Phase III final rule:

- The facility is a point source;
- The facility uses or proposes to use cooling water intake structures, including a cooling water intake structure operated by one or more independent suppliers (other than a public water system), with a total design intake flow equal to or greater than 2 MGD to withdraw cooling water from waters of the United States;
- The facility is expected to use at least 25 percent of water withdrawn exclusively for cooling purposes, based on the new facility's design and measured on an average monthly basis over a year.

For the purposes of this rule, a new facility is a point source if it has, or is required to have, an NPDES permit. If a new facility is a point source that uses a cooling water intake structure, but does not meet the applicable design intake flow/source waterbody threshold or the 25 percent cooling water use threshold, it would continue to be subject to permit conditions implementing CWA section 316(b) set by the permit director on a case-by-case, best professional judgment basis.

## 2.5 What is "Cooling Water" and What is a "Cooling Water Intake Structure?"

This rule adopts the same definition of a "cooling water intake structure" that applies to new facilities under the final Phase I rule and existing facilities under the final Phase II rule. Under this final rule, a cooling water intake structure is defined as the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the Unites States. Under this definition, the cooling water intake structure extends from the point at which water is withdrawn from the surface water source up to and including the intake pumps. This rule also adopts the definition of "cooling water" used in the Phase I and Phase II rules: water used for contact or noncontact cooling, including water used for equipment cooling, evaporative cooling tower makeup, and dilution of effluent heat content. The definition specifies that the intended use of cooling water is to absorb waste heat rejected from the processes used or auxiliary operations on the facility's premises. As is the case with the Phase I and Phase II rules, only the water used exclusively for cooling purposes is to be counted when determining whether the 25 percent threshold in §125.131(a)(2) is met.

# 3.0 WHAT ARE THE REGULATORY REQUIREMENTS FOR AN OWNER OR OPERATOR OF A NEW NON-FIXED (MOBILE) OFFSHORE OIL AND GAS EXTRACTION FACILITY?

The 316(b) Phase III rule distinguishes between new offshore oil and gas extraction facilities that are "fixed," and those that are not fixed. Offshore oil and gas extraction facilities that are not fixed are considered mobile offshore drilling units (MODUs) and include facilities such as drill ships, temporarily moored semi-submersibles, jack-ups, submersibles, tender-assisted rigs, and drill barges. New MODUs that withdraw more than 2 MGD of cooling water must comply with the requirements set forth in §125.134(b)(2), (4), (6), (7), and (8) of final rule. These requirements include:

- Design and construct each cooling water intake structure to a maximum through-screen design intake velocity of 0.5 ft/s;

- Submit the information required in 40 CFR 122.21(r)(2)(iv), (r)(3) (except (r)(3)(ii)) and §125.136(b) as part of your permit application;

- Implement the monitoring requirements specified in §125.137; and

- Implement the recordkeeping requirements specified in §125.138.

In addition, the permitting authority can go beyond the requirements listed in the first bullet above if any of the following criteria are met:

1) There are threatened, endangered or protected species, or critical habitat for these species, within the hydraulic zone of influence of the cooling water intake structure;

2) There are migratory and/or sport or commercial species that pass through the hydraulic zone of influence of the cooling water intake structure; or

3) If the technology-based performance requirements in paragraph (b)(2) of Section §125.134 still contribute unacceptable stress to the protected species, critical habitat of those species, or species of concern.

Only the Track I uniform requirements found in §125.134 are available to non-fixed new offshore oil and gas extraction facilities (i.e., MODUs).

## 4.0 WHAT ARE THE REGULATORY REQUIREMENTS FOR AN OWNER OR OPERATOR OF A NEW FIXED (STATIONARY) OFFSHORE OIL AND GAS EXTRACTION FACILITY?

As previously stated, the 316(b) Phase III rule also distinguishes between new offshore oil and gas extraction facilities that are "fixed," and those that are not fixed. For "fixed" facilities, the rule further distinguishes between those with sea chests and those without. EPA has defined a fixed facility as a bottom founded offshore oil and gas extraction facility permanently attached to the seabed or subsoil of the outer continental shelf (e.g., platforms, guyed towers, articulated gravity platforms) or a buoyant facility securely and substantially moored so that it cannot be moved without a special effort (e.g., tension leg platforms, permanently moored semi-submersibles) and which is not intended to be moved during the production life of the well.

### 4.1 Fixed Facilities With Sea Chests

New offshore oil and gas extraction facilities that withdraw greater than 2 MGD, employ sea chests as cooling water intake structures, and are fixed facilities must comply with the requirements in paragraphs set forth in §125.134 (b)(2), (3), (4), (6), (7), and (8). These requirements include:

- Design and construct each cooling water intake structure to a maximum through-screen design intake velocity of 0.5 ft/s;

- For cooling water intake structures located in an estuary or tidal river, the total design intake flow over one tidal cycle of ebb and flow must be no greater than one (1) percent of the volume of the water column within the area centered about the opening of the intake with a diameter defined by the distance of one tidal excursion at the mean low water level;

- Submit the information required in 40 CFR 122.21(r)(2) (except (r)(2)(iv)), (3), and (4) and §125.136(b) as part of your permit application;

- Implement the monitoring requirements specified in §125.137; and

- Implement the recordkeeping requirements specified in §125.138.

In addition, the permitting authority can go beyond the requirements listed above if any of the following criteria are met:

1) There are threatened, endangered or protected species, or critical habitat for these species, within the hydraulic zone of influence of the cooling water intake structure;

2) There are migratory and/or sport or commercial species that pass through the hydraulic zone of influence of the cooling water intake structure; or

3) If the technology-based performance requirements in paragraphs (b)(2) of §125.134, still contribute unacceptable stress to the protected species, critical habitat of those species, or species of concern..

Only the Track I uniform requirements found in §125.134 are available to fixed facilities that use sea chests for cooling water withdraw.

4.2 Fixed Facilities Without Sea Chests

New fixed offshore oil and gas extraction facilities that withdraw greater than 2 MGD, and do not employ sea chests as cooling water intake structures, must comply with all of the requirements in paragraphs (b)(2) through (8) of §125.134. Owners or operators of fixed offshore fixed offshore oil and gas extraction facilities (e.g., platforms) have the opportunity to follow either the Track I or Track II uniform requirements found in §125.134. If the facility selects the Track I uniform requirements, they must do the following:

- Design and construct each cooling water intake structure to a maximum through-screen velocity of 0.5 ft/s to prevent impingement of aquatic organisms;

- Design and construct technologies or operational measures for minimizing entrainment of entrainable life stages of fish and shellfish. These include screening systems (e.g., cylindrical wedgewire screens) with a maximum slots size of 1.75 mm on all cooling water intake structures;

- For cooling water intake structures located in an estuary or tidal river, the total design intake flow over one tidal cycle of ebb and flow must be no greater than one (1) percent of the volume of the water column within the area centered about the opening of the intake with a diameter defined by the distance of one tidal excursion at the mean low water level;

- Submit the information required in 40 CFR 122.21(r)(2) (except (r)(2)(iv)), (3), and (4) and §125.136(b) as part of your permit application;

- Implement the monitoring requirements specified in §125.137; and

- Implement the recordkeeping requirements specified in §125.138.

In addition, the permitting authority can go beyond the requirements listed above if any of the following criteria are met:

1) There are threatened, endangered or protected species, or critical habitat for these species, within the hydraulic zone of influence of the cooling water intake structure;

2) There are migratory and/or sport or commercial species that pass through the hydraulic zone of influence of the cooling water intake structure; or

3) If the technology-based performance requirements in paragraphs (b)(2) of §125.134, still contribute unacceptable stress to the protected species, critical habitat of those species, or species of concern.

If the fixed facility without sea chests decides to comply with the rule under the Track II requirements in 125.134(c), then they must do the following:

- Demonstrate that the technologies employed will reduce the level of adverse environmental impact from the cooling water intake structures to a comparable level to that which would be achieve if the facility implemented the 0.5 ft/sec maximum through screen velocity for impingement control and the 1.75 mm screening requirement for entrainment control.

- For cooling water intake structures located in an estuary or tidal river, the total design intake flow over one tidal cycle of ebb and flow must be no greater than one (1) percent of the volume of the water column within the area centered about the opening of the intake with a diameter defined by the distance of one tidal excursion at the mean low water level;

- Submit the information required in 40 CFR 122.21(r)(2) (except (r)(2)(iv)), (3), and (4) and §125.136(b) as part of your permit application;

- Implement the monitoring requirements specified in §125.137; and

- Implement the recordkeeping requirements specified in §125.138.

The permit writer or permitting authority also has the option to require fixed and non-fixed new offshore oil and gas extraction facilities (MODUs) to comply with more stringent requirements relating to the location, design, construction, and capacity of a cooling water intake structure or monitoring requirements as described in §125.134(d). The permit writer or permit authority my exercise this option if its deemed reasonably necessary to comply with any provision of federal or state law, including compliance with applicable state water quality standards (including designated uses, criteria, and anti-degradation requirements).

## 5.0 REQUIRED INFORMATION FOR NEW OR REISSUED NPDES PERMIT APPLICATIONS FOR OFFSHORE OIL AND GAS EXTRACTION FACILITIES

To obtain either a new or reissued NPDES permit for CWIS associated with new offshore oil and gas extraction facilities, the owner or operator must first determine if the facility intends to comply with either Track I (§125.134(b)) or, for fixed facilities, possibly Track II requirements (§125.134(c)) (see Exhibit 9-1). If the owner or operator decides to comply with Track I, then information demonstrating compliance with the maximum 0.5 ft/s through-screen design intake velocity must be gathered. This information must include a narrative description of the design, structure, equipment, and operation used to meet the velocity requirement, and design calculations showing that the velocity requirement will be met at minimum ambient source water surface elevations (based on best professional judgment using available hydrological data) and maximum head loss across the screens or other device. If the fixed facility's CWIS is located in an estuary or tidal river, then the owner or operator must provide the mean low water tidal excursion distance and any supporting documentation and engineering calculations to show the CWIS facility meets the flow requirements found in Section §125.134(b)(3) of the rule.

Track I also requires the owner or operator to prepare and submit a Design and Construction Technology Plan that explains the technologies and measures selected for impingement and entrainment controls. Examples of appropriate technologies include, but are not limited to, increased opening to cooling water intake structure to decrease design intake velocity, wedgewire screens with slot sizes less than or equal to 1.75 mm, fixed screens with slot sizes less than or equal to 1.75 mm, velocity caps, location of cooling water intake opening in water body, etc. Examples of appropriate operational measures include, but are not limited to, seasonal shutdowns or reductions in flow, continuous operations of screens, etc. Detailed information on the specific requirements for the Design and Construction Technology Plan are found in Section §125.136(b)(3) of the final rule.

If the owner or operator of the new fixed facility decides to comply with Track II, then both source water body flow information and the results of a Track II Comprehensive Demonstration Study must be submitted with the permit application. Requirements for both the source water body and Comprehensive Demonstration Study are found in Section §125.136(c)(1) and (2).

## 6.0 WHAT ARE THE COMPLIANCE MONITORING AND RECORDKEEPING REQUIREMENTS FOR NEW OFFSHORE OIL AND GAS EXTRACTION FACILITIES?

### 6.1 Compliance Monitoring Requirements for New Offshore Oil and Gas Extraction Facilities

Compliance monitoring requirements for new offshore oil and gas extraction facilities are found in Section §125.137 of the final rule. For new fixed facilities that do not use sea chests for cooling water withdraw and decide to comply with the Track I requirements (see Exhibit 9-1), the permitting authority will require the owner or operator to perform entrainment monitoring of all intakes. New offshore oil and gas extraction facilities that are fixed and use sea chests for cooling water withdraw, or are non-fixed offshore oil and gas extraction facilities and choose to comply with Track I requirements, will not be required to perform biological monitoring unless the permitting authority determines that the information would be necessary to evaluate the need for or compliance with additional requirements in accordance with § 125.134(b)(4) or more stringent requirements in accordance with §125.134(d). New fixed facilities with sea chests that choose to comply with Track II requirements in accordance with §125.134(c), must monitor for impingement only. New fixed facilities without sea chests that choose to comply with Track II requirements must monitor for both impingement and entrainment.

Monitoring must characterize the impingement rates and (if applicable) entrainment rates of commercial, recreational, and forage base fish and shellfish species identified in the Source Water Baseline Biological Characterization data required by 40 CFR 122.21(r)(4), identified in the Comprehensive Demonstration Study required by §125.136(c)(2), or as specified by the permitting authority. The monitoring methods used must be consistent with those used for the Source Water Baseline Biological Characterization, those used by the Comprehensive Demonstration Study, or as specified by the permitting authority.

The owner or operator of the new offshore oil and gas extraction facility must follow the monitoring frequencies identified below for at least two (2) years after the initial permit issuance. After that time, the permitting authority may approve a request for less frequent sampling in the remaining years of the permit term and when the permit is reissued if supporting data show that less frequent monitoring would still allow for the detection of any seasonal and daily variations in the species and numbers of individuals that are impinged or entrained.

- Impingement sampling. Owners or operators must collect samples to monitor impingement rates (simple enumeration) for each species over a 24-hour period and no less than once per month when the CWIS is in operation.

- Entrainment sampling. If the new offshore oil and gas extraction facility is subject to the requirements of either Track I or Track II (§125.134(b)(1)(i) or (c)), the owner or operator must collect samples to monitor entrainment rates (simple enumeration) for each species over a 24-hour period and no less than biweekly during the primary period of reproduction, larval recruitment, and peak abundance identified during the Source Water Baseline Biological Characterization or the Comprehensive Demonstration Study.

All sampling must be conducted when the CWIS is in operation.

For new offshore oil and gas extraction facilities that use surface intake screen systems, head loss across the screens must be monitored and head loss measurements correlated with the design intake velocity. The head loss across the intake screen must be measured at the minimum ambient source water surface elevation (best professional judgment based on available hydrological data). The maximum head loss across the screen for each CWIS must be used to determine compliance with the 0.5 ft/s velocity requirement in found in §125.134(b)(2). For new offshore oil and gas extraction facilities that use devices other than surface intake screens, velocity monitoring must be conducted at the point of water entry through the device. Head loss or velocity monitoring must be conducted during the initial facility startup, and thereafter, at the frequency specified in NPDES permit, but no less than once per quarter.

One alternative to measuring head loss across the intake screen is to submit design specifications for screen system to the permit authority and then measure intake flow rate (e.g., gpm) through the CWIS. The impingement control systems must be designed to prevent flow velocities from exceeding 0.5 ft/second at the maximum design flow of the CWIS. Facilities must monitor and record flow data through the CWIS continuously to verify flows do not exceed the maximum design flow for the system, therefore causing flow velocities to exceed 0.5 ft/sec. As a minimum, facilities must summarize and provide flow data to the permit authority on an annual basis to verify flow rates through CWIS did not exceed 0.5 ft/sec through the intake screen. Selecting this alternative method to verify compliance, in addition to the frequency of data submittal will be subject to approval based on BPJ by the permit authority and will be specified in the NPDES permit.

New offshore oil and gas extraction facilities must either conduct visual inspections or employ remote monitoring devices during the period the CWIS is in operation. Visual inspections should be conducted at least weekly to ensure that any design and construction technologies required in §125.134(b)(4), (b)(5), (c), and/or (d) are maintained and operated to ensure that they will continue to function as designed. Alternatively, new offshore oil and gas extraction facilities can inspect via remote monitoring devices to ensure that the impingement and entrainment technologies are functioning as designed.

New fixed facilities that withdraw seawater through CWIS such as simple pipes or caissons can also choose to comply through Track II (see Exhibit 9-1), which allows a site-specific demonstration that alternative requirements would produce comparable levels of impingement mortality and entrainment reduction. Track II is not available to new non-fixed (MODUs) facilities because non-fixed facilities, which are expected to operate at multiple locations, would not be able to perform a site-specific demonstration. Track II is also not available to fixed facilities that use sea chests to withdraw seawater for cooling.

## 6.2 Recordkeeping Requirements for New Offshore Oil and Gas Extraction Facilities

Owners and operators of new offshore oil and gas extraction <u>fixed</u> facilities must keep records of all the data used to complete the permit application and show compliance with the requirements, any supplemental information developed under '125.136, and any compliance monitoring data submitted under '125.137, for a period of at least three years from the date of permit issuance.

In addition, new offshore oil and gas extraction fixed facilities must also submit the following in a yearly status report:

- Biological monitoring records for each cooling water intake structure as required by '125.137(a);
- Velocity and head loss monitoring records for each cooling water intake structure as required by '125.137(b); and
- Records of visual or remote inspections as required in '125.137(c).

Owners and operators of new <u>non-fixed</u> (e.g., MODUs) offshore oil and gas extraction facilities must keep records of all the data used to complete the permit application and show compliance with the requirements, any supplemental information developed under '125.136, and any compliance monitoring data submitted under '125.137, for a period of at least three years from the date of permit issuance. In addition, this final rule requires that new mobile offshore oil and gas extraction facilities submit the following in a yearly status report:

- Velocity and head loss monitoring records for each cooling water intake structure as required by '125.137(b); and

- Records of visual or remote inspections as required in '125.137(c).

## 7.0 SUMMARY OF REGULATORY REQUIREMENTS FOR NEW OIL AND GAS EXTRACTION FACILITIES

Exhibit 9-1 provides a road map to the permit writer and the regulated community to determine the 316(b) Phase III applicability for new offshore oil and gas extraction facilities. As indicated in Exhibit 9-1, new offshore oil and gas extraction facilities that meet the applicability criteria in §125.131, that do <u>not</u> employ sea chests as CWIS, and are fixed facilities would have to comply with the requirements in §125.134(b)(2) through (8) or §125.134(c)(1) through (8). The one additional requirement for these facilities is §125.134(b)(5), which requires the selection and implementation of design and construction technologies, or operational measures to minimize entrainment of entrainable life stages of fish or shellfish.

Exhibit 9-1 also shows that new offshore oil and gas extraction facilities that meet the applicability criteria in §125.131 and employ sea chests as CWIS and are fixed facilities would have to comply with the requirements in §125.134(b)(2)(3)(4)(6)(7) and (8). These requirements address intake flow velocity, percentage of the source water body withdrawn, specific impact concerns (e.g., threatened or endangered species, critical habitat, migratory or sport or commercial species), required information submission, monitoring, and record keeping.

Exhibit 9-2 outlines the technologies applicable to each general rig type for new offshore oil and gas extraction facilities and the control limits. The appropriate control technologies are a function of the CWIS and rig type. The intent of this table is to provide the permit writer with a methodology to identify potential control technologies for impingement and entrainment on offshore oil and gas extraction CWIS.

**Exhibit 9-1. 316(b) Phase III Regulatory Requirements for New Offshore Oil and Gas Extraction Facilities**

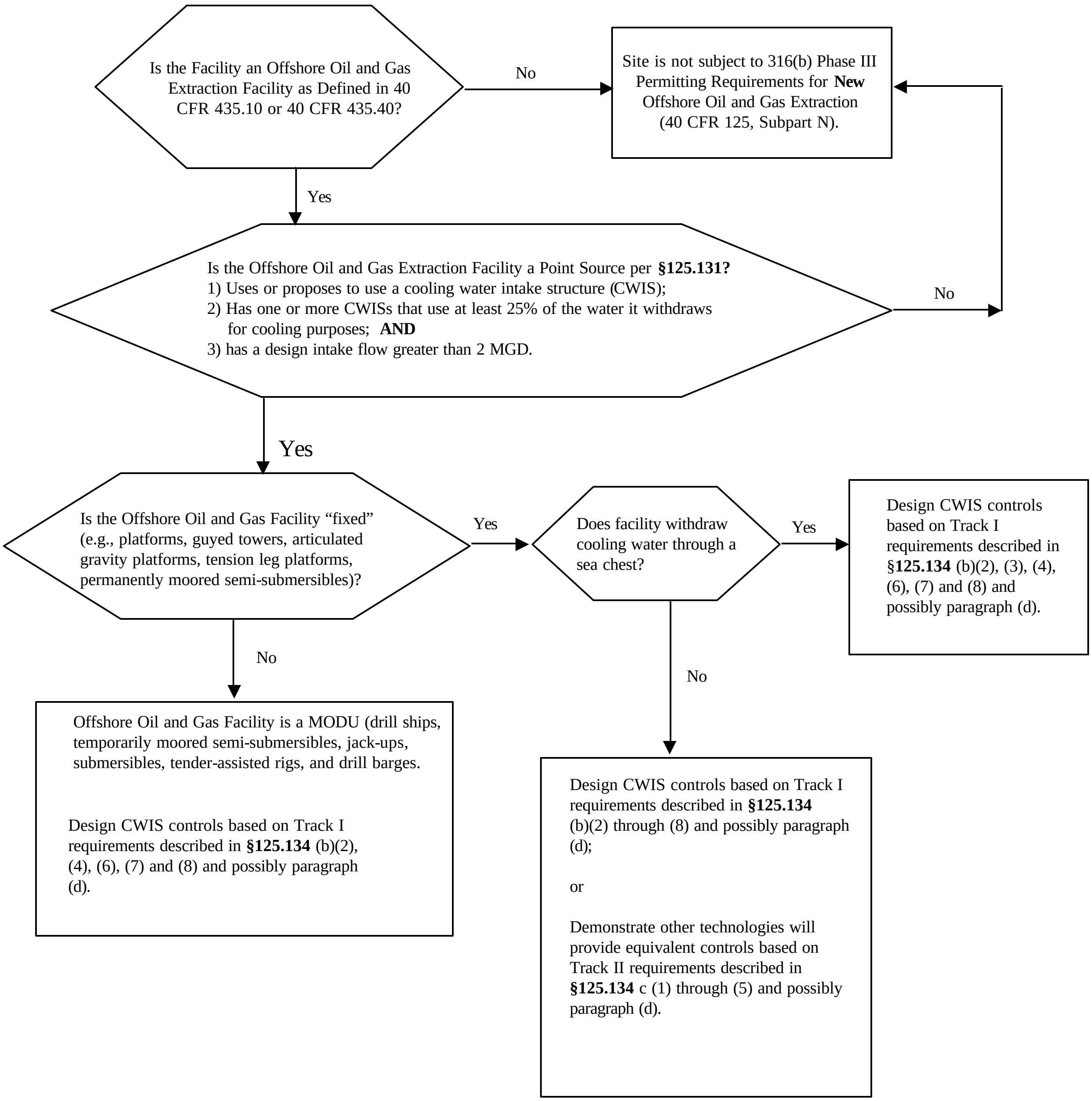

**Exhibit 9-2. Summary of Regulatory Requirements and Possible Technology Options for New Offshore Oil and Gas Extraction Facilities**

| Compliance Option | Facility Types | Regulatory Requirements | Possible Technology Options |
|---|---|---|---|
| Track I | Fixed facilities that do not employ sea chests (e.g. use simple pipes and caissons for cooling water intake) | 1) Design and construct each cooling water intake structure to a maximum through-screen design intake velocity of 0.5 ft/sec.<br>2) Design and construct technologies for intake flow limitations based on intake source water.<br>3) Implement design and construction technologies to minimize impingement & entrainment, as determined by the Regional Director.<br>4) Submit application information required in §122.21(r) and §125.136(b).<br>5) Implement monitoring & record-keeping requirements in §125.137 & §125.138, respectively. | Cylindrical, fine-mesh wedgewire screens (1.75 mm slot size) and velocity caps for simple pipes and caissons. |
| | Fixed facilities that employ sea chests for cooling water | 1) Design and construct each cooling water intake structure to a maximum through-screen design intake velocity of 0.5 ft/sec.<br>2) Design and construct technologies for intake flow limitations based on intake source water.<br>3) Implement design and construction technologies to minimize impingement, as determined by the Regional Director.<br>4) Submit application information required in §122.21(r) and §125.136(b).<br>5) Implement monitoring & record-keeping requirements in §125.137 & §125.138, respectively. | Flat panel wedgewire screens (1.75 mm slot size), and horizontal flow diverters |
| | Non-fixed facilities (e.g., MODUs) | 1) Design and construct each cooling water intake structure to a maximum through-screen design intake velocity of 0.5 ft/sec.<br>2) Implement design and construction technologies to minimize impingement, as determined by the Regional Director.<br>3) Submit application information required in §122.21(r) and §125.136(b).<br>4) Implement monitoring & record-keeping requirements in §125.137 & §125.138, respectively. | Flat panel wedgewire screens (1.75 mm slot size), and horizontal flow diverters for sea chests |
| Track II | Fixed facilities that do not employ sea chests (e.g. use simple pipes and caissons) for cooling water intake | 1) Facility to demonstrate and establish, through EPA Director approved protocol, that alternative technologies will achieve comparable performance to Track I.<br>2) Design and construct technologies for intake flow limitations based on intake source water.<br>3) Submit application information required in §122.21(r) and §125.136(c).<br>4) Implement monitoring & record-keeping requirements in §125.137 & §125.138, respectively. | Cylindrical fine-mesh wedgewire screens (1.75 mm slot size) and velocity caps for simple pipes and caissons. |