ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9, 122, 123, 124, and 125

[OW–2004–0002, FRL–8181–5]

RIN 2040–AD70

National Pollutant Discharge Elimination System—Final Regulations To Establish Requirements for Cooling Water Intake Structures at Phase III Facilities

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On November 1, 2004, EPA published a proposal that contained several options for the control of cooling water intake structures at existing Phase III facilities and at new offshore oil and gas extraction facilities. This rule establishes categorical section 316(b) requirements for intake structures at new offshore oil and gas extraction facilities that have a design intake flow threshold of greater than 2 million gallons per day and that withdraw at least 25 percent of the water exclusively for cooling purposes. For existing Phase III facilities, EPA determined that uniform national standards are not the most effective way at this time to address cooling water intake structures at these facilities. Instead, EPA believes that it is better to continue to rely upon the existing National Pollutant Discharge Elimination System (NPDES) program, which implements section 316(b) for existing facilities not covered under the Phase II rule on a case-by-case, best professional judgment basis. This final action constitutes Phase III of EPA's section 316(b) regulation development. This rule does not alter the regulatory requirements for facilities subject to the Phase I or Phase II regulations.

DATES: This regulation is effective July 17, 2006. For judicial review purposes, this final rule is promulgated as of 1 p.m. Eastern Daylight Time (EDT) on June 30, 2006 as provided in 40 CFR 23.2.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–OW–2004–0002. All documents in the docket are listed on the *www.regulations.gov web site.* Although listed in the index, some information is not publicly available, *e.g.*, confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through www.regulations.gov or in hard copy at the Water Docket in the EPA Docket Center, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Water Docket is (202) 566–2426.

FOR FURTHER INFORMATION CONTACT: For additional technical information contact Paul Shriner, OW/OST at (202) 566–1076. For additional biological information contact Ashley Allen, OW/OST at (202) 566–1012. The address for the above contacts is: Office of Science and Technology, Engineering Analysis Division (Mailcode 4303T), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; fax number: (202) 566–1053; e-mail address: *rule.316b@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. What Entities Are Regulated By This Action?

This final rule applies to new offshore and coastal oil and gas extraction facilities, which were specifically excluded from the Phase I new facility rule. New offshore and coastal oil and gas extraction facilities with a design intake flow threshold of greater than 2 million gallons per day (MGD) are subject to requirements similar to those under the Phase I rule. A new offshore or coastal oil and gas extraction facility is defined as any building, structure, facility, or installation that (1) meets the definition of a ''new facility'' in 40 CFR 125.83; (2) is regulated by either the Offshore or Coastal subcategories of the Oil and Gas Extraction Point Source Category Effluent Guidelines in 40 CFR part 435, Subpart A or Subpart D; and (3) commences construction after July 17, 2006. Any offshore or coastal oil and gas extraction facility that does not meet these three criteria is subject to section 316(b) requirements established by the permit writer on a case-by-case basis. Exhibit I–1 provides examples of other industrial facility types potentially interested in this final action.

EXHIBIT I–1.—INDUSTRIAL FACILITY TYPES POTENTIALLY INTERESTED IN THIS FINAL ACTION

Category	Examples of potentially interested entities	Standard industrial classification codes	North American industry codes (NAIC)
Federal, State and local government.	Operators of steam electric generating point source dischargers that employ cooling water intake structures.	4911 and 493	221111, 221112, 221113, 221119, 221121, 221122
Industry	Operators of industrial point source dischargers that employ cooling water intake structures.	See below	See below
	Agricultural production	0133	111991, 11193
	Metal mining	1011	21221
	Oil and gas extraction	1311, 1321	211111, 211112
	Mining and quarrying of nonmetallic minerals	1474	212391
	Food and kindred products	2046, 2061, 2062, 2063, 2075, 2085.	311221, 311311, 311312, 311313, 311222, 311225, 31214
	Tobacco products	2141	312229, 31221
	Textile mill products	2211	31321
	Lumber and wood products, except furniture	2415, 2421, 2436, 2493	321912, 321113, 321918, 321999, 321212, 321219
	Paper and allied products	2611, 2621, 2631, 2676	3221, 322121, 32213, 322121, 322122, 32213, 322291
	Chemical and allied products	28 (except 2895, 2893, 2851, and 2879).	325 (except 325182, 32591, 32551, 32532)

EXHIBIT I–1.—INDUSTRIAL FACILITY TYPES POTENTIALLY INTERESTED IN THIS FINAL ACTION—Continued

Category	Examples of potentially interested entities	Standard industrial classification codes	North American industry codes (NAIC)
	Petroleum refining and related industries	2911, 2999	32411, 324199
	Rubber and miscellaneous plastics	3011, 3069	326211, 31332, 326192, 326299
	Stone, clay, glass, and concrete products	3241	32731
	Primary metal industries	3312, 3313, 3315, 3316, 3317, 3334, 3339, 3353, 3363, 3365, 3366.	324199, 331111, 331112, 331492, 331222, 332618, 331221, 22121, 331312, 331419, 331315, 331521, 331524, 331525
	Fabricated metal products, except machinery and transportation equipment.	3421, 3499	332211, 337215, 332117, 332439, 33251, 332919, 339914, 332999
	Industrial and commercial machinery and computer equipment.	3523, 3531	333111, 332323, 332212, 333922, 22651, 333923, 33312
	Transportation equipment	3724, 3743, 3764	336412, 333911, 33651, 336416
	Measuring, analyzing, and controlling instruments, photographic, medical, and optical goods, watches and clocks.	3861	333315, 325992
	Electric, gas, and sanitary services	4911, 4931, 4939, 4961	221111, 221112, 221113, 221119, 221121, 221122, 22121, 22133
	Educational services	8221	61131
	Engineering, accounting, research, management and related services.	8731	54171

This exhibit is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be interested in this action. This exhibit also lists the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the exhibit could also be regulated. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria in § 125.131 of this rule. If you have questions regarding the applicability of this action to a particular entity, consult the persons listed for technical information in the **FOR FURTHER INFORMATION CONTACT** section.

B. Supporting Documentation

The final regulation is supported by three major documents:

1. Economic and Benefits Analysis for the Final Section 316(b) Phase III Existing Facilities Rule (EPA–821–R–06–001), hereafter referred to as the Economic and Benefits Analysis or EA. This document presents the methodology employed to assess economic impacts of the options we considered for this action and the results of the analysis.

2. Regional Analysis for the Final Section 316(b) Phase III Existing Facilities Rule (EPA–821–R–06–002), hereafter referred to as the Regional Analysis Document. This document examines cooling water intake structure impacts and the environmental benefits of the national categorical regulatory options we considered for this action at the regional level.

3. Technical Development Document for the Final Section 316(b) Phase III Existing Facilities Rule (EPA–821–R–06–003), hereafter referred to as the Technical Development Document. This document presents the technical information that formed the basis for our decisions in this action, including information on the costs and performance of the impingement and entrainment reduction technologies we considered.

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II. Scope and Applicability of the Final Rule

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 this section.

New offshore oil and gas facilities that meet all of the following criteria are subject to this 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 million gallons per day (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 as a monthly average, during at least one month over the course of 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. Section II.A of the preamble discusses what constitutes a ''new'' offshore oil and gas extraction facility for purposes of the section 316(b) Phase III rule. Requirements for new offshore oil and gas extraction facilities are specified in 40 CFR Subpart N.

Existing Phase III facilities, including manufacturing facilities, electric power producers with a design intake flow (DIF) less than 50 MGD, and existing offshore oil and gas extraction facilities, are not subject to the national categorical requirements of this final rule. These facilities will continue to be regulated on a case-by-case basis using a permit director's best professional judgment.

Finally, this rule does not establish national categorical requirements for seafood processing vessels or offshore liquefied natural gas import terminals. Those facilities would be subject to permit conditions implementing CWA section 316(b) set by the permit director on a case-by-case, best professional judgment basis where the facility is a point source and uses a cooling water intake structure.

A. 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 part 435 Subpart D (Coastal Subcategory)); (2) commence construction after July 17, 2006; 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 convert 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 on the point source itself.

B. 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 United 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.

C. Would My Facility Be Covered if It Is a Point Source Discharger?

This rule applies only to facilities that have an NPDES permit or are required to obtain one. This is the same requirement EPA included in the Phase I and Phase II final rules (see 40 CFR 125.81(a)(1) and 40 CFR 125.91(a)(1), respectively). Requirements for complying with section 316(b) will continue to be applied through NPDES permits.

The Agency recognizes that some facilities that have or are required to have an NPDES permit might not own and operate the intake structure that supplies their facility with cooling water. For example, facilities operated by separate entities might be located on the same, adjacent, or nearby property(ies); one of these facilities might take in cooling water and then transfer it to other facilities prior to discharge of the cooling water to a water of the United States. Section 125.92(c) of this rule addresses such a situation. It provides that use of a cooling water intake structure includes obtaining cooling water by any sort of contract or arrangement with one or more independent suppliers of cooling water if the supplier withdraws water from waters of the United States. This provision is intended to prevent new Phase III facilities from circumventing the requirements of this rule by creating arrangements to receive cooling water from an entity that is not itself subject to the requirements of Phase III. EPA expects that a facility that is otherwise subject to the requirements of Phase I and that is an independent supplier to a Phase III facility would still be subject to the requirements of Phase I.

D. When Would a New Offshore Oil and Gas Extraction Facility Be Required To Comply With Any New 316(b) Requirements?

This final rule will become effective July 17, 2006. After that date, new offshore oil and gas extraction Phase III facilities will need to comply 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 may obtain permit coverage under these general permits until they expire. When EPA reissues these general permits, EPA will incorporate requirements based on today's rule. Facilities that are new offshore oil and gas extraction facilities, as defined in today's rule, will be subject to those Phase III section 316(b) new facility requirements should they seek permit coverage under those reissued general permits.

III. Legal Authority, Purpose, and Background of This Final Regulation

A. Legal Authority

This action is issued under the authority of sections 101, 301, 308, 316, 401, 402, 501, and 510 of the Clean Water Act (CWA), 33 U.S.C. 1251, 1311, 1318, 1326, 1341, 1342, 1361, and 1370. Publication of this action fulfills the final obligation of the U.S. Environmental Protection Agency (EPA) under a consent decree in *Riverkeeper, Inc.* v. *Johnson,* No. 93 Civ. 0314, (S.D.N.Y).

B. Purpose of This Regulation

Section 316(b) of the CWA provides that any standard established pursuant to section 301 or 306 of the CWA and applicable to a point source must require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. This rule establishes requirements that apply to new offshore oil and gas extraction facilities that have a design intake flow threshold of greater than 2 MGD. This is the same design intake flow threshold as for new facilities in the Phase I rule. To be covered, a facility would need to use at least 25 percent of the water withdrawn exclusively for cooling purposes and meet other specified criteria in order to be within the scope of the rule (see section II—Scope and Applicability of Final Rule). In this action, EPA is not promulgating any new section 316(b) requirements for existing facilities. Therefore, existing facilities that are not covered by the Phase II rule (Phase II is described in section III.C.5 of this preamble) must continue to meet requirements under Section 316(b) of the CWA determined by the permitting authority on a case-by-case, best professional judgment (BPJ) basis. *See* 40 CFR 125.90(b).

C. Background

1. The Clean Water Act

The Federal Water Pollution Control Act, also known as the Clean Water Act (CWA), 33 U.S.C. 1251 et seq., seeks to ''restore and maintain the chemical, physical, and biological integrity of the nation's waters.'' 33 U.S.C. 1251(a). The CWA establishes a comprehensive regulatory program, key elements of which are (1) a prohibition on the discharge of pollutants from point sources to waters of the United States, except as authorized by the statute; (2) authority for EPA or authorized States or Tribes to issue National Pollutant Discharge Elimination System (NPDES) permits that regulate the discharge of pollutants; and (3) requirements for limitations in NPDES permits based on effluent limitations guidelines and standards and water quality standards.

Section 316(b) addresses the adverse environmental impact caused by the intake of cooling water, not discharges into water. Despite this special focus, the requirements of section 316(b) are closely linked to several of the core elements of the NPDES permit program established under section 402 of the CWA to control discharges of pollutants into navigable waters. For example, while effluent limitations apply to the discharge of pollutants by NPDES-permitted point sources to waters of the United States, section 316(b) applies to facilities subject to NPDES requirements that withdraw water from waters of the United States for cooling and that use a cooling water intake structure to do so.

Section 301 of the CWA prohibits the discharge of any pollutant by any person, except in compliance with specified statutory requirements, including section 402. Section 402 of the CWA provides authority for EPA or an authorized State or Tribe to issue an NPDES permit to any person discharging any pollutant or combination of pollutants from a point source into waters of the United States. Forty-five States and one U.S. territory are currently authorized under section 402(b) to administer the NPDES permitting program. NPDES permits restrict the types and amounts of pollutants, including heat, that may be discharged from various industrial, commercial, and other sources of wastewater. These permits control the discharge of pollutants primarily by requiring dischargers to meet effluent limitations established pursuant to section 301 or section 306. Effluent limitations are based on Federal effluent limitations guidelines and new source performance standards, or in cases where there are no applicable effluent guidelines or standards, on the best professional judgment of the permit writer. Limitations based on these guidelines, standards, or best professional judgment are known as technology-based effluent limits. Where technology-based effluent limits are inadequate to ensure attainment of water quality standards applicable to the receiving water, section 301(b)(1)(C) of the CWA requires permits to include more stringent limits based on applicable water quality standards. NPDES permits also routinely include monitoring and reporting requirements, and other conditions, including conditions to implement the requirements of section 316(b).

Section 510 of the CWA provides that, except as provided in the CWA, nothing in the Act shall preclude or deny the right of any State or political subdivision thereof to adopt or enforce any requirement respecting control or abatement of pollution; except that if a limitation, prohibition or standard of performance is in effect under the CWA, such State or political subdivision may not adopt or enforce any other limitation, prohibition or standard of performance which is less stringent than the limitation, prohibition or standard of performance under the Act. EPA interprets this to reserve for the States authority to implement requirements that are more stringent than the Federal requirements under State law. *PUD No. 1 of Jefferson County* v. *Washington Dep't of Ecology,* 511 U.S. 700, 705 (1994).

Under sections 301, 304, and 306 of the CWA, EPA issues effluent limitations guidelines and new source performance standards for categories of industrial dischargers based on the pollutants of concern discharged by the industry, the degree of control that can be attained using various levels of pollution control technology, consideration of economics, as appropriate to each level of control, and other factors identified in sections 304 and 306 of the CWA. EPA has promulgated regulations setting effluent limitations guidelines and standards under sections 301, 304, and 306 of the CWA for more than 50 industries. See 40 CFR parts 405 through 471. EPA has established effluent limitations guidelines and standards that apply to most of the industry categories that use cooling water intake structures (e.g., steam electric power generation, iron and steel manufacturing, pulp and paper manufacturing, petroleum refining, and chemical manufacturing).

Section 316(b) states that any standard established pursuant to section 301 or section 306 of [the Clean Water] Act and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

The phrase ''best technology available'' in CWA section 316(b) is not defined in the statute, but its meaning can be understood in light of similar phrases used elsewhere in the CWA. *See Riverkeeper, Inc.* v. *EPA,* 358 F.3d 174, 186 (2nd Cir. 2004) (noting that the cross-reference in CWA section 316(b) to CWA section 306 ''is an invitation to look to section 306 for guidance in discerning what factors Congress intended the EPA to consider in determining ''best technology available'' for new sources).

In sections 301 and 306, Congress directed EPA to set effluent discharge standards for new sources based on the ''best available demonstrated control technology'' and for existing sources based on the ''best available technology economically achievable.'' For new sources, section 306(b)(1)(B) directs EPA to establish ''standards of performance.'' The phrase ''standards of performance'' under section 306(a)(1) is defined as being the effluent reduction that is ''achievable through application of the best available demonstrated control technology, processes, operating methods or other alternatives * * * .'' This is commonly referred to as ''best available demonstrated technology'' or ''BADT.'' For existing dischargers, section 301(b)(1)(A) requires the establishment of effluent limitations based on ''the application of best practicable control technology currently available.'' This is commonly referred to as ''best practicable technology'' or ''BPT.'' Further, section 301(b)(2)(A) directs EPA to establish effluent limitations for certain classes of pollutants ''which shall require the application of the best available technology economically achievable.'' This is commonly referred to as ''best available technology'' or ''BAT.'' Section 301 specifies that both BPT and BAT limitations must reflect determinations made by EPA under CWA section 304. Under these provisions, the limitations on the discharge of pollutants from point sources are based upon the capabilities of the equipment or ''control technologies'' available to control those discharges.

The phrases ''best available demonstrated technology'' and ''best available technology''—like ''best technology available'' in CWA section 316(b)—are not defined in the statute. However, section 304 of the CWA specifies factors to be considered in establishing the best practicable control technology currently available and best available technology.

For best practicable control technology currently available, the CWA directs EPA to consider the total cost of application of technology in relation to the effluent reduction benefits to be achieved from such application, and shall also take into account the age of the equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, non-water quality environmental impact (including energy requirements), and such other factors as [EPA] deems appropriate. (33 U.S.C. 1314(b)(1)(B)).

For ''best available technology,'' the CWA directs EPA to consider the age of equipment and facilities involved, the process employed, the engineering aspects * * * of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impacts (including energy requirements), and such other factors as [EPA] deems appropriate. (33 U.S.C. 1314(b)(2)(B)).

Section 316(b) expressly refers to section 301, and the phrase ''best technology available'' is very similar to ''best available technology'' in that section. These facts, coupled with the brevity of section 316(b) itself, prompted EPA to look to section 301 and, ultimately, section 304 for guidance in determining the ''best technology available to minimize adverse environmental impact'' of cooling water intake structures for Phase III existing facilities.

By the same token, however, there are significant differences between section 316(b) and sections 301 and 304. *See Riverkeeper,* 358 F.3d at 186 (''not every statutory directive contained [in sections 301 and 306] is applicable'' to a section 316(b) rulemaking). Section 316(b) requires that cooling water intake structures reflect ''the best technology available for minimizing adverse environmental impact.'' In contrast to the effluent limitations provisions, the object of the ''best technology available'' is explicitly articulated by reference to the receiving water: To minimize adverse environmental impact in the waters from which cooling water is withdrawn. In other words, EPA must consider the receiving water effects of the candidate technologies.

Because section 316(b) is silent as to the factors EPA should consider in deciding whether a candidate technology minimizes adverse environmental impact, EPA has broad discretion to identify the appropriate criteria. *See Riverkeeper,* 358 F.3d at 187, n.12 (brevity of section 316(b) reflects an intention to delegate significant rulemaking authority to EPA); *see id.* at 195 (appellate courts give EPA ''considerable discretion to weigh and balance the various factors'' where the statute does not state what weight should be accorded) (citation omitted).

For this Phase III rulemaking, EPA therefore interprets the phrase ''best available technology for minimizing adverse environmental impacts'' as authorizing EPA to consider the relationship of the costs of the technologies to the benefits associated with them. EPA has previously considered the costs of technologies in relation to the benefits of minimizing adverse environmental impact in establishing section 316(b) limits, which historically have been done on a case-by-case basis. *In Re Public Service Co. of New Hampshire,* 10 ERC 1257 (June 17, 1977); *In Re Public Service Co. of New Hampshire,* 1 EAD 455 (Aug. 4, 1978); *Seacoast Anti-Pollution League* v. *Costle,* 597 F.2d 306 (1st Cir. 1979).

In addition to helping EPA determine the effects of candidate technologies on the receiving water, considering the relationship of costs and benefits also helps EPA determine whether the technologies are economically practicable. EPA has long recognized, with the support of legislative history, that section 316(b) does not require adverse environmental impact to be minimized beyond that which can be achieved at an economically practicable cost. *See* 118 Cong. Rec. 33762 (1972) *reprinted in* 1 Legislative History of the Water Pollution Control Act Amendments of 1972, at 264 (1973) (Statement of Representative Don H. Clausen). EPA therefore may consider costs and benefits in deciding whether any of the technology options for Phase III existing facilities actually do minimize adverse environmental impact—or whether the choice of technologies should be left to BPJ decision-making. When the costs of establishing a national categorical rule substantially outweigh the benefits of such a rule, a national categorical section 316(b) rule may not be economically practicable, and therefore not the ''best technology available for minimizing adverse environmental impact.''

Nothing in section 316(b) requires EPA to promulgate a regulation to implement the requirements for cooling water intake structures. Section 316(b) of the CWA grants EPA broad authority to establish performance standards for cooling water intake structures based on the ''best technology available to minimize adverse environmental impact.'' Although EPA has chosen under section 316(b) to promulgate national categorical performance standards applicable to certain classes of point sources using cooling water intake structures, see 40 CFR part 125, Subpart I (new facilities), Subpart J (existing power generating facilities), and Subpart N (new offshore oil and gas facilities), the statute does not preclude EPA from determining BTA on a site-specific basis. Indeed, the U.S. Court of

Appeals for the Second Circuit, in upholding virtually the entire 316(b) Phase I rule for new facilities, specifically noted that section 316(b) does not compel EPA to regulate cooling water intake structures using any particular format, e.g. overarching regulation, different regulations for different categories of sources, or individually on a case-by-case basis. *Riverkeeper,* 358 F.3d at 203. In fact, EPA and state permitting authorities have been implementing Section 316(b) on a case-by-case basis for over 25 years (see Section III.C.3 below), and courts have recognized this practice as consistent with the statute. *See Hudson Riverkeeper Fund* v. *Orange & Rockland Utils., Inc.,* 835 F. Supp. 160, 165 (S.D.N.Y. 1993) (''This leaves to the Permit Writer an opportunity to impose conditions on a case-by-case basis, consistent with the statute * * *''). Moreover, in both the Phase I and II rules, EPA uses a case-by-case, BPJ permitting regime for facilities that do not meet the applicability criteria for EPA's national categorical rules. *See* 40 CFR 125.81(a), 125.90(b). In *Riverkeeper,* this provision of the Phase I rule was upheld by the Second Circuit. 358 F.3d at 203 (''[w]e see no textual bar in sections 306 or 316(b) to regulating below-threshold structures on a case-by-case basis.'').

2. Consent Decree

This final action fulfills EPA's obligation to comply with the Second Amended Consent Decree, which was filed on November 25, 2002, in the United States District Court, Southern District of New York, in *Riverkeeper, Inc.* v. *Johnson,* No. 93 Civ 0314 (AGS). That case was brought against EPA by a coalition of individuals and environmental groups. The original Consent Decree, filed on October 10, 1995, provided that EPA was to propose regulations implementing section 316(b) by July 2, 1999, and take final action with respect to those regulations by August 13, 2001. Under subsequent interim orders, the Amended Consent Decree filed on November 22, 2000, and the Second Amended Consent Decree, EPA divided the rulemaking into three phases. EPA took final action promulgating a rule governing cooling water intake structures used by new facilities (Phase I) on November 9, 2001 (66 FR 65255, December 18, 2001). EPA took final action promulgating a rule governing cooling water intake structures used by large existing power producers (Phase II) on February 16, 2004 (69 FR 41576, July 9, 2004). The consent decree further requires that EPA propose by November 1, 2004, and take final action on by June 1, 2006 regulations applicable to the following categories: Utility and non-utility power producers not covered by the Phase II regulations, pulp and paper manufacturing, petroleum and coal products manufacturing, chemical and allied products manufacturing, and primary metals manufacturing (Phase III). EPA proposed Phase III regulations on November 1, 2004 (69 FR 68444) and this final action fulfills EPA's obligations for Phase III.

3. What Other EPA Rulemakings and Guidance Address Cooling Water Intake Structures?

In April 1976, EPA published a final rule under section 316(b) that addressed cooling water intake structures. 41 FR 17387 (April 26, 1976), see also the proposed rule at 38 FR 34410 (December 13, 1973). The rule added a new § 401.14 to 40 CFR Chapter I that reiterated the requirements of CWA section 316(b). It also added a new part 402, which included three sections: (1) § 402.10 (Applicability), (2) § 402.11 (Specialized definitions), and (3) § 402.12 (Best technology available for cooling water intake structures). Section 402.10 stated that the provisions of part 402 applied to ''cooling water intake structures for point sources for which effluent limitations are established pursuant to section 301 or standards of performance are established pursuant to section 306 of the Act.'' Section 402.11 defined the terms ''cooling water intake structure,'' ''location,'' ''design,'' ''construction,'' ''capacity,'' and ''Development Document.'' Section 402.12 included the following language:

> The information contained in the Development Document shall be considered in determining whether the location, design, construction, and capacity of a cooling water intake structure of a point source subject to standards established under section 301 or 306 reflect the best technology available for minimizing adverse environmental impact.

In 1977, fifty-eight electric utility companies challenged those regulations, arguing that EPA had failed to comply with the requirements of the Administrative Procedure Act (APA) in promulgating the rule. Specifically, the utilities argued that EPA had neither published the Development Document in the **Federal Register** nor properly incorporated the document into the rule by reference. The United States Court of Appeals for the Fourth Circuit agreed and, without reaching the merits of the regulations themselves, remanded the rule. *Appalachian Power Co.* v. *Train,* 566 F.2d 451 (4th Cir. 1977). EPA later withdrew part 402.44 FR 32956 (June 7, 1979). The regulation at 40 CFR 401.14, which reiterates the statutory requirement, remains in effect.

Since the Fourth Circuit remanded EPA's section 316(b) regulations in 1977, NPDES permit authorities have made decisions implementing section 316(b) on a case-by-case, site-specific basis. EPA published draft guidance addressing section 316(b) implementation in 1977. See *Draft Guidance for Evaluating the Adverse Impact of Cooling Water Intake Structures on the Aquatic Environment: Section 316(b) P.L. 92–500* (U.S. EPA, 1977). This draft guidance described the studies recommended for evaluating the impact of cooling water intake structures on the aquatic environment and recommended a basis for determining the best technology available for minimizing adverse environmental impact. The 1977 section 316(b) draft guidance states, ''The environmental-intake interactions in question are highly site-specific and the decision as to best technology available for intake design, location, construction, and capacity must be made on a case-by-case basis.'' (Section 316(b) Draft Guidance, U.S. EPA, 1977, p. 4). This case-by-case approach was also consistent with the approach described in the 1976 Development Document referenced in the remanded regulation.

The 1977 section 316(b) draft guidance suggested a general process for developing information needed to support section 316(b) decisions and presenting that information to the permitting authority. The process involved the development of a site-specific study of the environmental effects associated with each facility that uses one or more cooling water intake structures, as well as consideration of that study by the permitting authority in determining whether the facility must make any changes for minimizing adverse environmental impact. Where adverse environmental impact is present, the 1977 draft guidance suggested a stepwise approach that considers size, location, capacity, available technology, and other factors.

The draft guidance left the decisions on the appropriate location, design, capacity, and construction of cooling water intake structures to the permitting authority. Under this framework, the Director determined whether appropriate studies have been performed, whether a given facility has minimized adverse environmental impact, and what, if any, technologies may be required.

4. Phase I New Facility Rule

On November 9, 2001, EPA took final action on Phase I regulations governing cooling water intake structures at new facilities. 66 FR 65255 (December 18, 2001). On December 26, 2002, EPA made minor changes to the Phase I regulations. 67 FR 78947. 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 solely for cooling purposes.

With the new facility rule, EPA promulgated national minimum requirements for the location, design, capacity, and construction of cooling water intake structures at new facilities. The final new facility rule establishes a reasonable framework that creates certainty for permitting of new facilities, while providing significant flexibility to take site-specific factors into account.

EPA specifically excluded new offshore oil and gas extraction facilities from the Phase I new facility rule, but committed to consider establishing requirements for such facilities in the Phase III rulemaking. 66 FR 65338 (December 18, 2001).

5. Phase II Existing Facility Rule

On February 16, 2004, EPA took final action on regulations governing cooling water intake structures at certain existing power producing facilities. 69 FR 41576 (July 9, 2004). The final Phase II rule applies to existing facilities that are point sources; that, as their primary activity, both generate and transmit electric power or generate electric power for sale to another entity for transmission; that use or propose to use cooling water intake structures with a total design intake flow of 50 MGD or more to withdraw cooling water from waters of the United States; and that use at least 25 percent of the withdrawn water exclusively for cooling purposes.

Under the Phase II rule, EPA established performance standards for the reduction of impingement mortality and entrainment (see 40 CFR 125.94). The performance standards consist of ranges of reductions in impingement mortality and/or entrainment. These performance standards reflect the best technology available for minimizing adverse environmental impacts at facilities covered by the Phase II rule. The type of performance standard applicable to a particular facility (i.e., reductions in impingement mortality only or impingement mortality and entrainment) is based on several factors, including the facility's location (i.e., source waterbody), rate of use (capacity utilization rate), and the proportion of the waterbody withdrawn. The Phase II regulations address more than 90 percent of total cooling water intake flows in the United States.

6. Public Participation

EPA worked extensively with stakeholders from industry, public interest groups, State agencies, and other Federal agencies in the development of this rule. EPA included industry groups, environmental groups, and other government entities in the development, testing, refinement, and completion of the section 316(b) survey, which was used as a primary source of data for Phase III. As discussed in section III of this preamble, the survey, ''Information Collection Request, Detailed Industry Questionnaires: Phase II Cooling Water Intake Structures & Watershed Case Study Short Questionnaire,'' was initiated in 1997, and was used to collect data during 2000.

EPA sponsored a Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms, on May 6–7, 2003. This symposium brought together professionals from Federal, State, and Tribal regulatory agencies; industry; environmental organizations; engineering consulting firms; science and research organizations; academia; and others concerned with mitigating harm to the aquatic environment by cooling water intake structures. Efficacy and costs of various technologies to mitigate impacts to aquatic organisms from cooling water intake structures, as well as research and other future needs, were discussed.

During the development of this regulation, EPA met several times with trade associations whose members would be subject to Phase III requirements. EPA also conducted Phase III-specific data collection activities, including a study of entrainment at Phase III facilities, contacting Phase III facilities to request biological studies and conducting an industry survey of offshore oil and gas extraction facilities and seafood processing vessels.

In developing requirements for new offshore oil and gas extraction facilities, EPA drew on its experience from the offshore oil and gas, the coastal oil and gas, and the synthetic drilling fluids effluent limitations guidelines, which included extensive public outreach, meetings, public comment periods, industry surveys, and economic analysis and modeling of representative oil and gas operations as detailed in 61 FR 66086–66130 and 66 FR 6849–6919.

Finally, EPA convened a Small Business Advocacy Review (SBAR) panel (in accordance with the Regulatory Flexibility Act section 609(b) as amended by the Small Business Regulatory and Enforcement Fairness Act) to provide information to small entities and receive feedback during the Phase III rulemaking process. EPA hosted a pre-panel outreach meeting for small entities potentially subject to Phase III on January 22, 2004. The SBAR panel held an outreach meeting with small entity representatives (SERs) on March 16, 2004. Based on the information gathered from the participating small entities during these outreach meetings and subsequent correspondence, the SBAR panel produced a final report to the EPA Administrator on April 27, 2004. Results of the final report were considered in the development of the Phase III rule.

These coordination efforts and all of the meetings described in this section, as well as the comments submitted on the Phase I and II section 316(b) rules and EPA's response to these comments, are documented or summarized in the dockets for these three rules. The Administrative Record for this rule includes all materials from the Phase I, Phase II, and Phase III section 316(b) rule dockets.

IV. Environmental Impacts Associated With Cooling Water Intake Structures

EPA has identified a variety of environmental impacts that may be associated with cooling water intake structures at Phase III facilities, depending on conditions at an individual facility's site. These impacts include organism entrainment and impingement, which can contribute to impacts to threatened and endangered species; reductions in ecologically critical aquatic organisms, including important elements of an ecosystem's food chain; diminishment of population compensatory reserves; losses to populations, including reductions of commercial and recreational fisheries; and stresses to overall communities and ecosystems as evidenced by reductions in diversity, changes in species composition, or other changes in ecosystem structure or function. (See discussion at 69 FR 68461–66.)

The withdrawal of water affects a variety of aquatic organisms including phytoplankton (tiny, free-floating photosynthetic organisms suspended in the water column), zooplankton (small aquatic animals, including fish eggs and larvae, which may consume phytoplankton and other zooplankton), macroinvertebrates, shellfish, and fish. Other organisms, including reptiles, birds, and mammals can also be impinged or entrained.

Impingement takes place when organisms are trapped against a cooling water intake structure, particularly screening materials, by the force of water being drawn through the intake structure. The velocity of the water intake by the structure can remove fish scales or other organism structures, prevent proper gill function, or otherwise physically harm or cause the death of impinged organisms through exhaustion, starvation, asphyxiation, and descaling or other injury. Death from impingement (''impingement mortality'') can take place while organisms are impinged on an intake structure or it can take place after organisms have escaped impingement and have returned to a waterbody. An organism can die despite escaping impingement because of injuries it receives during the impingement process.

Entrainment occurs when organisms are drawn through a cooling water intake structure into a facility's cooling system. Organisms that become entrained are typically relatively small aquatic organisms, including many early life stages of fish and shellfish. As entrained organisms pass through a facility's cooling system they can be subject to mechanical, thermal, and/or, chemical stress. Sources of stress include physical impacts in the pumps and condenser tubing, pressure changes caused by diversion of the cooling water into the plant or by the hydraulic effects of the condensers, shear stress, thermal shock in the condenser and discharge tunnel, and chemical toxic effects from cooling system antifouling agents such as chlorine. Similar to impingement mortality, death from entrainment can occur during entrainment or at some time after the entrainment and return of entrained organisms to a waterbody.

Environmental Impacts from New Offshore Oil and Gas Extraction Facility Cooling Water Intake Structures

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 Phase III TDD; DCN [9–0004], Chapter 3.)

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 Notice of Data Availability (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).[1 2] 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/100m [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.[4] 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.[5] 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

[1] Adam Rettig and Blaine Snyder, Tetra Tech, Inc. Memorandum to Ashley Allen, EPA. A summary of ichthyoplankton presence and abundance in the Gulf of Mexico, as part of an assessment of the potential for entrainment by offshore oil and gas facilities. 2005. DCN 8–5220. Document ID OW–2004–0002–951.

[2] Adam Rettig and Blaine Snyder, Tetra Tech, Inc. Memorandum to Ashley Allen, EPA. A Summary of Fish Egg Presence and Abundance in the Gulf of Mexico, as Part of an Assessment of the Potential for Entrainment by Offshore Oil and Gas Facilities. DCN 9–5200.

[3] Average larval fish densities are greater than 450 organisms/100 m3 at sampling stations in waters less than 50 meters deep. Average larval fish densities gradually decrease to 100 organisms/100 m3 as sampling station depth-at-location increases to 150 meters. At stations in waters greater than 150 meters deep, larval fish densities are relatively uniform and fall between 25 organisms/100 m3 and 100 organisms/100 m3. See Document ID OW–2004–0002–951.

[4] A. L. Allen (EPA). Memorandum to EPA Docket OW–2004–0002. Summary of Information on Ichthyoplankton Densities in Various Aquatic Ecosystems in the United States. DCN 8–5240.

[5] A.L. Allen (EPA). Memorandum to EPA Docket OW–2004–0002. Summary of Information on Fish Species that Live and Spawn off the Coasts of Alaska and California in the Vicinity of Offshore Oil and Gas Production Areas. DCN 8–5260.

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 DCN 7–0013.)

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.

V. Description of the Rule

In this rule, EPA is promulgating requirements for new offshore and coastal oil and gas extraction facilities that are designed to withdraw at least 2 MGD. New offshore oil and gas extraction facilities were specifically excluded from the scope of the Phase I new facility rule so that EPA could gather additional data on these facilities (see 66 FR 65311). This final action also announces EPA's decision not to promulgate a national rule for existing Phase III facilities.

A. Final Rule for New Offshore Oil and Gas Extraction Facilities

This rule establishes national requirements for new offshore and coastal oil and gas extraction facilities that have a design intake flow of 2 MGD or greater and that withdraw at least 25 percent of the water exclusively for cooling purposes and meet other applicability criteria (see § 125.131). This rule imposes requirements for the reduction of impingement mortality on all facilities subject to the rule; a subset of these facilities must comply with requirements for the reduction of entrainment. Specifically, fixed[6] facilities without sea chests are required to comply with entrainment standards. EPA has established a two-track approach to offer maximum flexibility. Fixed facilities may choose to comply under Track I or Track II, but non-fixed facilities must comply under Track I. Track I establishes uniform requirements based on facility type (i.e., fixed or non-fixed) and, for fixed facilities the types of intake structures used (i.e., sea chest or non-sea chest). Under Track I, facilities are required to design their cooling water intake structures to meet a through-screen velocity of 0.5 feet per second or less. If they are a fixed facility and are located in estuaries or tidal rivers, they would also be required to meet proportional flow requirements. All facilities would need to implement technologies and/or operational measures for minimizing impingement if the permitting authority determines that there are protected species or critical habitat for those species, or species of impingement concern within the hydrologic zone of influence of the cooling water intake structure, or (based on available information, including information from fishery management agencies) that the proposed facility, after meeting the technology-based performance requirements, would still contribute unacceptable stress to protected species or critical habitat of those species, or species of concern. Fixed facilities that do not employ sea chests (openings in the hull of a vessel for withdrawing cooling water) are required to use fish protection technologies and/or operational measures to minimize entrainment.

As with other new facilities covered by the Phase I rule, fixed facilities could comply under Track II, which allows the facility to employ alternative technologies that the facility demonstrates provide comparable performance to meeting the 0.5 ft/s velocity standard, and for fixed facilities without sea chests, the requirement to minimize entrainment. EPA did not extend this provision to mobile facilities, as EPA does not believe that there were alternatives to the low-velocity standard for mobile facilities. Further, a Track II demonstration generally requires consideration of site-specific factors. Since mobile facilities are designed to operate at multiple locations over their use life, it is generally not possible for them to provide in advance the information that would be necessary for a Track II demonstration.

As described in § 125.135, facilities have the opportunity to conduct a cost-cost test and provide data to show that compliance with the requirements of § 125.134 would result in compliance costs wholly out of proportion to those EPA considered in establishing the requirements, or would result in significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on energy markets. In this case, alternative requirements may be imposed in the permit. See the Phase I final preamble for a more detailed explanation of this cost-cost test at 66 FR 65322, which is different than the cost-cost test for Phase II facilities.

These final requirements for new offshore oil and gas extraction facilities are essentially unchanged from the Phase III proposal. In response to comments, however, EPA is not promulgating national entrainment controls for fixed facilities with sea chests or mobile facilities in this final rule. EPA's data suggest that the only physical technology controls for entrainment at facilities with sea chests and non-fixed (i.e., mobile) facilities would entail installation of equipment projecting beyond the hull of the vessel or facility. Such controls may not be practical or feasible 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 also proposed national categorical requirements for Phase III existing facilities that use or propose to use a cooling water intake structure to withdraw cooling water from waters of the United States and that are point sources and use at least 25 percent of the water withdrawn exclusively for cooling purposes. As proposed, Phase III would have included either existing facilities on all waterbody types that had a design intake flow of 50 MGD or greater, existing facilities on all waterbody types that has a design intake flow of 200 MGD or greater, or those existing facilities with a design intake flow of 100 MGD or greater which were located on sensitive waterbodies (i.e., estuaries, tidal rivers, coastal waters, or the Great Lakes). Facilities not meeting these applicability criteria would have continued to be subject to 316(b) requirements set by the Director on a case-by-case basis. EPA also proposed the option of not promulgating national categorical requirements for existing

[6] A fixed facility is defined 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.

facilities potentially covered by Phase III in which case all Phase III existing facilities would have continued to be subject to 316(b) requirements set by the Director on a case-by-case basis.

For existing Phase III facilities meeting the selected threshold, the proposed rule would have established national performance standards for the reduction of impingement mortality and in some cases entrainment at land-based Phase III existing facilities (i.e., non-offshore facilities). The performance standards applicable to a particular facility (i.e., reductions in impingement only or impingement and entrainment) were based on several factors, including the facility's location (i.e., source waterbody) and the proportion of the waterbody withdrawn. Under the proposed rule, the performance standards could have been met, in whole or in part, by using design and construction technologies, operational measures, or restoration measures.

EPA rejected the proposed requirements for existing Phase III facilities for the reasons set forth in Section VI.B below. This section discusses EPA's reasoning in detail as applied to the lead option (the 50 MGD option). EPA's reasons for rejecting the 100 MGD and 200 MGD option were similar. In particular, the cost-benefit ratios were still unacceptable and there would have been even fewer facilities that would ultimately have been regulated by the rule and even smaller incremental environmental improvements that the regulation would have realized when compared to the significant environmental gains attributed to the Phase II rule.

B. Existing Facilities With Cooling Water Intake Structures

For existing Phase III facilities, EPA determined that uniform national technology-based standards are not the most effective way to address their cooling water intake structures because the monetized costs of such standards would have been wholly disproportionate to their monetized use benefits. Accordingly, EPA believes that it is better at this time to utilize the existing National Pollutant Discharge Elimination System (NPDES) program for existing Phase III facilities, which provides that any NPDES permitted facility not subject to the national categorical requirements in Phase I, Phase II, or Phase III of EPA's 316(b) regulation development is subject to section 316(b) requirements set by the Director on a case-by-case best professional judgment basis. Examples of such facilities include existing power generators with a design intake flow of less than 50 MGD, and new seafood processing vessels, and existing manufacturers.

These requirements must ensure that the location, design, construction and capacity of any cooling water intake structure reflect the best technology available for minimizing adverse environmental impact. Because the factors that EPA considered in evaluating candidate options for a national categorical determination of BTA vary considerably from site to site, including technology costs and feasibility, potential for adverse environmental impacts, and relationship of costs to benefits, EPA believes that for Phase III facilities a BPJ-based site specific approach is the best way to ensure that each Phase III existing facility adopts BTA appropriate to its site. The basis for this determination is further discussed in Section VI.B. below.

This rule does not alter the regulatory requirements for facilities subject to the Phase I or Phase II regulations.

VI. Basis for the Final Rule Decision

This section discusses EPA's basis for final requirements applicable to new offshore oil and gas extraction facilities and EPA's decision to continue to rely on case-by-case, best professional judgment permit conditions implementing CWA section 316(b) at existing Phase III facilities.

A. 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 for new facilities. On May 25, 2001, EPA published a Notice of Data Availability (NODA) for Phase I that, in part, sought additional data and information about mobile offshore and coastal drilling facilities (see 66 FR 28857). EPA was not able to fully consider this additional information in time to address new offshore oil and gas facilities in the final Phase I rule. Accordingly, 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.'' See 66 FR 65256. This regulation fulfills that commitment and establishes national requirements for new offshore oil and gas extraction facilities that meet the applicability requirements in § 125.131.

Requirements for new offshore oil and gas extraction facilities are specified in a new Subpart N of Part 125. New onshore oil and gas extraction facilities are currently regulated by section 316(b) Phase I requirements if these facilities meet the applicability criteria of the 316(b) Phase I regulations. As described in more detail below, the requirements for the offshore facilities are similar to some, but not all, of the requirements contained in the Phase I rule applicable to other new facilities. For example, the Phase I requirement to reduce intake flow commensurate with a closed-cycle, recirculating cooling system does not apply to these offshore facilities.

This rule distinguishes between new offshore oil and gas 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. Under this rule, new offshore oil and gas extraction facilities that meet the applicability criteria in § 125.131 and that employ sea chests as cooling water intake structures and are fixed facilities would have to comply with the requirements in § 125.134(b)(1)(ii). These requirements address intake flow velocity, percentage of the source waterbody withdrawn (if applicable), specific impact concerns (e.g., threatened or endangered species, critical habitat, migratory or sport or commercial species), required information submission, monitoring, and recordkeeping. Under this rule, new offshore oil and gas extraction facilities that meet the applicability criteria in § 125.131, that do not employ sea chests as cooling water intake structures, and that are fixed facilities would have to comply with the requirements in § 125.134(b)(1)(i). 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. Fixed facilities, whether they employ sea chests or not, can also choose to comply through Track II, which allows a site-specific demonstration that alternative requirements would produce comparable levels of impingement mortality and entrainment reduction.

New offshore oil and gas facilities that are not fixed facilities would have to comply with the regulations at § 125.134(b)(1)(iii), which address intake flow velocity, specific impact concerns (e.g., threatened or endangered species, critical habitat, migratory or sport or commercial species), required information submission, monitoring, and recordkeeping. Track II is not available to non-fixed (mobile) facilities because non-fixed facilities, which are expected to operate at multiple locations, would not be able to perform a site-specific demonstration. For this same reason, EPA has dropped some of the other site-dependent requirements for non-fixed facilities (e.g., provision of source waterbody flow information).

EPA has limited information on specific environmental impacts associated with the use of cooling water intake structures at new offshore oil and gas extraction facilities but believes the potential for such impacts is sufficient to warrant including requirements for new offshore oil and gas extraction facilities in this rule (see section IV for more detailed discussion). SEAMAP data for the Gulf of Mexico identified over 600 different fish taxa and indicate that ichthyoplankton occurs throughout the Gulf of Mexico, with densities highest (e.g., average densities greater than 450 organisms/100 m^3) at sampling stations in the shallower regions (less than 50 meters deep) of the Gulf, and lower in deeper waters. (70 FR 71,059–71,060). Most offshore oil and gas facilities, if they employ cooling water intake structures, operate them in near-surface (e.g., 20–100 feet deep) waters, rather than in deeper waters. (TDD, Chap. 3, Sec. III). As stated earlier in this preamble, 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. Data also indicate the presence of aquatic organisms identified off the California and Alaska coasts, both additional areas of offshore oil and gas production. In addition, although such technologies are not generally in use at all existing offshore oil and gas extraction facilities, technologies are in use and are available to new facilities in this subcategory to meet the requirements as described below.

Some offshore oil and gas extraction facilities employ an underwater compartment within the facility or vessel hull or pontoon through which sea water is drawn in or discharged, often called a ''sea chest.'' A passive screen (strainer) is often set along the flush line of the sea chest. Pumps draw seawater from open pipes in the sea chest cavity for a variety of purposes (e.g., cooling water, fire water, and ballast water). These intakes are normally the only source of cooling water for the facility; therefore, it is crucial to the operation of these facilities that the intake structures be kept clean and clear of fish, jellyfish, plastic bags, and other debris. To accomplish this, these intake structures can be, and have been, designed for low intake velocity (i.e., less than 0.5 feet per second) and/or include fish protection equipment. See the Technical Development Document for details.

As outlined in Alaska's oil and gas leasing requirements, oil and gas extraction facilities in Alaskan State waters are currently subject to an impingement control velocity limit of 0.1 feet per second (i.e., more stringent than EPA's design requirement of 0.5 feet per second in this rule). These State regulations suggest that impingement controls that would meet the velocity requirements of this rule are demonstrated as available for offshore oil and gas extraction facilities in Alaskan or similar waters.

However, facilities using sea chests may have few, if any, opportunities to meet the entrainment control requirements applicable to facilities subject to the Phase I rule. A 2003 literature survey by Mineral Management Services (DCN 7–0012) identified no evidence of entrainment controls successfully fitted to offshore oil and gas extraction vessels with sea chests such as drill ships, jack-ups, MODUs, and barges. EPA's data suggests that the only physical technology controls available for reducing entrainment at facilities with sea chests would entail installation of equipment projecting beyond the hull of the vessel. This outward projection has been shown to create problems with respect to fluid dynamics, vessel shapes and safe seaworthy profile. Therefore, EPA does not believe entrainment controls are feasible at such facilities, even for new facilities that could avoid the challenges of retrofitting control technologies.

EPA also considered whether all new offshore vessels could be constructed without employing sea chests. A technology must prove to be practicable to be a viable alternative to current technology. In this case, a viable alternative to a sea chest is any alternative configuration/technology successfully implemented at existing facilities, including those in other manufacturing industries, with similar seawater intake structures. EPA data suggest the only demonstrated design for drill ships and semi-submersible MODUs is to use sea chests because they allow the vessel to maintain appropriate fluid dynamics, overall optimal vessel shape, and a safe seaworthy profile. Therefore, EPA has concluded that building new offshore oil and gas facilities without sea chests has not been shown to be practicable for the category as a whole.

In contrast to facilities with sea chests, fixed offshore oil and gas extraction facilities with intake structures other than sea chests can feasibly install both impingement and entrainment controls. For example, technologies to reduce impingement mortality and entrainment of marine life at a caisson intake structure [7] include passive intake screens or velocity caps. Other technologies such as acoustic barriers, electro barriers, or intake relocation may also be used to reduce impingement and entrainment at intake structures. Air sparges and copper nickel alloys can also be used to control biofouling. EPA has concluded that these are all ''available'' technologies for these facilities and therefore justify impingement and entrainment requirements.

In summary, EPA is establishing requirements that are similar to some—but not all—of the Phase I provisions. The differences in requirements between this rule and the Phase I rule reflect the differences in technology availability between offshore oil and gas extraction facilities and those facilities covered in the Phase I rule.

Impingement and entrainment requirements for new offshore oil and gas facilities are not based on closed-cycle recirculating cooling because available information indicates that it is not feasible for all new offshore oil and gas extraction facilities to employ closed-cycle recirculating cooling systems. The rest of the requirements are similar to those in Phase I (e.g., velocity information and design and construction technology plan for Track I facilities, comprehensive demonstration study for Track II facilities).

B. Why Is EPA Implementing CWA Section 316(b) at Existing Phase III Facilities Through Case-By-Case, Best Professional Judgment Permit Conditions?

After considering available data, analyses and comments, EPA has decided not to promulgate a national categorical rule today for Phase III existing facilities. This means that section 316(b) requirements for Phase III existing facilities will continue to be

[7] A caisson intake (a steel pipe attached to a fixed structure that extends from an operating area down some distance into the water) is used to provide a protective shroud around another process pipe or pump that is lowered into the caisson from the operating area.

imposed on a case-by-case, best professional judgment basis.

EPA bases this decision on its judgment that the monetized costs associated with the primary option under consideration are wholly disproportionate to the monetized environmental benefits to be derived from that option. EPA has long considered the wholly disproportionate cost test to be appropriate for section 316(b) decision-making for existing facilities. Here, EPA is using the wholly disproportionate cost test to determine whether the national categorical rule options proposed by EPA are the best way to minimize adverse environmental impact. As the Administrator observed in In Re Public Service Company of New Hampshire when reviewing contested 316(b) requirements for an existing facility, costs may be considered ''in determining the degree of minimization to be required.'' 10 ERC 1257, 1261 (June 10, 1977). Otherwise, the Administrator noted, ''the effect would be to require cooling towers at every place that could afford to install them, regardless of whether or not any significant degree of entrainment or entrapment was anticipated. I do not believe that it is reasonable to interpret Section 316(b) as requiring use of technology whose cost is wholly disproportionate to the environmental benefit to be gained.'' *Id.*

The primary option EPA considered in today's final action was a rule that would have regulated Phase III existing facilities with a design intake flow of 50 MGD or greater. EPA also solicited comment on variations that would have narrowed the scope of the proposed rule. As discussed in more detail in section X of this preamble, EPA estimated that the total pre-tax costs of the 50 MGD option would be $38.3 to $39 million and the monetized benefits for commercial and recreational uses would be $1.8 to $2.3 million ($2004, 7 percent and 3 percent discount rates). This yields a cost to benefit ratio ranging from a low of 17 to 1 to a high of 22 to 1. EPA has concluded that the costs associated with the 50 MGD option are wholly disproportionate to the anticipated monetized benefits; therefore, EPA has concluded that this regulatory option does not constitute the ''best technology available for minimizing adverse environmental impacts.''

Making a decision on the grounds that the costs here are wholly disproportionate to the benefits is also consistent with Executive Order 12866, entitled ''Regulatory Planning and Review'' (Oct. 1993). That Executive Order directs agencies to ''assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs.'' E.O. 12866, Sec. 1(b)(6). This Executive Order has been in effect for over a decade under two Presidents, representing each major political party, and is now widely accepted as reflecting general principles of sound government regulation. It does not supersede any of the decision factors specified in the Clean Water Act and, in fact, says explicitly that it applies only ''to the extent permitted by law and where applicable,'' E.O. 12866, Sec. 1(b). EPA believes that in this case the directive of the Executive Order is fully consistent with the requirements of the Clean Water Act.

EPA considered non-use benefits as well as monetized use benefits in reaching its final decision. Non-use benefits may arise from reduced impacts to ecological resources that the public considers important. These include reduced impacts to species without direct commercial or recreational fishing value, such as forage fish, which play a role in the functioning of an aquatic ecosystem. In this rulemaking, EPA fully considered all benefits, but was able to assign a monetized value only to benefits associated with commercial and recreational uses. Non-use benefits can generally only be monetized when two steps have been completed: (1) Environmental impacts are quantified; and (2) a monetary value is available to be assigned to those impacts. EPA was unable to assign a monetary value that fully captured the value of avoiding the environmental impacts that EPA had identified because the necessary information was not available. EPA did attempt in the Phase III rule to monetize the loss of forage fish indirectly through its impact on reducing commercial and recreational harvests, and found these impacts to be generally small. However, this approach does not capture the value that society may place on these fish for their own sake. Therefore, EPA considered non-use benefits qualitatively. Doing so is consistent with accepted practices of benefits assessment and with EPA's past practice of fully evaluating benefits for purposes of section 316(b).

Ultimately, in reaching today's decision, EPA took into account the uncertainty inherent in qualitative benefits assessment, the size of the ratio of monetized costs to monetized benefits, qualitative information about the likely ecosystem impacts of cooling water withdrawals from Phase III existing facilities, and other policy concerns outlined in this preamble. When fully considering these non-monetized benefits in light of all of these factors, EPA determined that they were not likely to be of sufficient magnitude to alter EPA's decision to continue to use a case-by-case, best professional judgment approach for Phase III existing facilities. In the context of this rulemaking, EPA believes that a case-by-case approach is a reasonable way of identifying, for a particular Phase III existing facility, the best technology available for minimizing adverse environmental impact. This approach allows the permit writer to assess site-specific information regarding the impacts of the facility's cooling water impact structure and to decide how best to minimize them.

In reaching today's decision, EPA has taken note that the vast majority of environmental benefits from regulating cooling water intake structures have already been realized by the Phase II rule. As a result of the Phase II rule, approximately 90 percent of the total volume of cooling water withdrawn nationally is already subject to national categorical requirements. The 543 facilities covered by the Phase II rule withdraw on average more than 214 billion gallons of cooling water every day from the nation's waters and, in the process, more than 3.4 billion fish and shellfish were killed annually by impingement and entrainment prior to rule implementation. Compliance with the rule will reduce this loss by 1.4 billion fish and shellfish. 69 FR at 41586 & 41656–57. The 146 existing facilities that would have been covered by the broadest of the Phase III proposed options (the 50 MGD proposal), in contrast, withdraw 31 billion gallons of cooling water every day and kill about 265 million fish and shellfish annually. The proposed rule would have reduced this loss by about 98 million fish and shellfish. Had EPA codified national categorical rules for those facilities, EPA thus would have saved only an additional 7 percent of the fish and shellfish from impingement and entrainment while expanding the universe subject to national categorical regulations by 27 percent. Also illuminating is the fact that, of the 146 Phase III existing facilities, only ten have intake structures designed to take in more than 500 MGD. In contrast, 257 Phase II facilities use cooling water intake structures designed to take in more than 500 MGD. This information indicates that the majority of large-flow facilities and cooling water intake flows are already regulated by the Phase II rule. Most of the reductions in fish impinged and entrained at existing facilities, and therefore most of the benefits, are also already obtained through implementation of the Phase II regulations. The other options EPA considered—involving 200 MGD and 100 MGD facilities—involved even less flow and fewer regulated facilities than the 50 MGD option.

A comparison of the cost-benefit ratio for Phase II to the cost-benefit ratio for the primary Phase III option supports EPA's decision here. The ratio of costs to monetized benefits for the Phase II 50MGD rule was approximately 5 to 1. In contrast, the ratio of monetized costs to monetized benefits for the proposed Phase III 50 MGD rule ranges from 17 to 1 to 22 to 1. Moreover, due to the ten-fold greater impingement and entrainment losses at Phase II facilities, EPA was not able to determine for Phase II, as it has for Phase III, that non-quantified benefits, including non-use benefits, would not be sufficient to justify the costs. In light of the much smaller aggregate quantity of water withdrawals associated with Phase III and likely correspondingly smaller non-use benefits, EPA has determined that, at this time, a national categorical rule is not a reasonable approach for minimizing adverse environmental impacts for Phase III existing facilities.

Instead, EPA will continue to rely on case-by-case decision-making to regulate cooling water intake structures at Phase III existing facilities. In some situations, as was the case when EPA's Region 1 established section 316(b) requirements for the Brayton Point power station, a site-specific inquiry can produce performance standards that are more stringent than the categorical rules would have established. In other situations, the permit writer may determine that fewer controls need to be imposed. In both cases, however, the permitting authority is in a good position to perform the careful balancing contemplated by section 316(b) in order to select the best technology available for minimizing adverse environmental impact.

In reaching today's decision, EPA has given special consideration to the fact that existing manufacturers were the rule's primary focus. According to the study published by the U.S. Department of Commerce entitled ''Manufacturing in America: A Comprehensive Strategy to Address the Challenges to U.S. Manufacturers'' (Jan. 2004), manufacturers have ''focused on reducing costs to improve productivity and ensure their competitiveness.'' Id. at 33. At the same time, some manufacturers have found these efforts ''eroded by costs they cannot control—costs that result in part from government policy.'' Id. at 33. A study by the U.S. Office of Management and Budget (OMB) found that regulatory costs in 1997 comprised 3.7 percent of gross domestic product (GDP) (''Report to Congress on the Costs and Benefits of Federal Regulations,'' September 1997). These costs have risen significantly over time and U.S. manufacturers face considerably higher compliance costs than do many of the U.S.'s trading partners. Since U.S. manufacturers compete with other firms from both developed and developing countries in a global economy, any additional regulatory costs should be carefully evaluated in order to ensure U.S. firms' continued competitiveness in the global marketplace. In a second report entitled ''Regulatory Reform of the U.S. Manufacturing Sector'' (2005), OMB stated that ''[s]treamlining regulation is a key plank in the President's economic program.'' Id. at 1. This report suggests that any unnecessary regulatory burdens, especially on small and medium-sized manufacturers, should be removed. To address these concerns for U.S. manufacturers, benefits justifying costs is of paramount importance.

Today's decision, while based on statutory factors in the Clean Water Act, does also address the concerns in these reports. As proposed, the Phase III rule would have required most facilities to submit a number of highly detailed studies and reports to the permit writer, with additional studies required for facilities seeking alternative standards based on site-specific considerations. Today's final action for Phase III adopts a more flexible approach under which the permit writer can tailor the data and information request more specifically to the location, technology constraints, and potential adverse environmental impacts of a particular facility. Today's decision provides manufacturing facilities the opportunity to provide information to the permit writer relating to the site specific environmental impacts attributable to their cooling water intake structures and the technological feasibility and economic burdens associated with various levels of control. This tailored regulatory approach not only meets the Clean Water Act requirement to adopt the best technology available to minimize adverse environmental impacts, but it also advances EPA's policy of avoiding imposing unnecessary burdens on manufacturers.

Continuing a regime of BPJ decision-making for Phase III existing facilities does not mean that EPA is merely preserving the status quo. To the contrary, EPA believes that the rulemaking record contains important factual data that can help permit writers when reissuing NPDES permits for the Phase III existing facilities. The numeric performance standards that EPA had proposed, for example, reflect EPA's judgment regarding the level of reduction in impingement mortality and entrainment that available technologies can achieve. Similarly, the regulatory support documents describe a variety of control devices, analyze their effectiveness and present their costs. The record also contains information regarding environmental impacts associated with cooling water intake structures. EPA expects permit writers and permittees to fully consider this information and other useful guidance contained in the record as they develop site-specific section 316(b) requirements.

For the foregoing reasons, EPA has decided, based on its assessment of costs and benefits in this rulemaking, to continue to rely on permit writers' use of their best professional judgment to establish the statutorily mandated section 316(b) requirements on a case-by-case basis for existing Phase III facilities.

VII. Response to Major Comments on the Proposed Rule and Notice of Data Availability (NODA)

Fifty-one organizations and individuals submitted comments on a range of issues in the proposed rule. An additional six comments were received on the NODA. Detailed responses to all comments, including those summarized here, can be found in the Response to Comments document in the official public docket.

A. Offshore Oil and Gas Extraction Facilities

Commenters raised many issues concerning the regulation of offshore oil and gas extraction facilities. One commenter requested that EPA exclude mobile offshore drilling units (MODUs) from the rule. A few commenters also claimed that EPA did not demonstrate a need to regulate offshore oil and gas extraction facilities. Another commenter asserted that new offshore oil and gas extraction facilities should be included under the new facility definition promulgated under Phase I.

One commenter suggested that EPA exempt offshore oil and gas extraction facilities employing sea chests in order to facilitate international movement of MODUs. This commenter and others also requested that EPA establish a higher minimum flow threshold (of at least 25 MGD) for offshore oil and gas units in shallow waters, and exempt units in unproductive deep waters (over 100 meters deep).

One commenter added that the ichthyoplankton density data (SEAMAP data) provided in the NODA supports the assertion that location alone should be used to regulate requirements for offshore oil and gas extraction facilities and supports the exemption of units in unproductive waters offshore. The commenter stated that the SEAMAP data shows that these waters have significantly reduced levels of biological life. Several commenters expressed concern that intake technologies from other industries may not be appropriate for offshore oil and gas extraction facilities.

As presented in the NODA, EPA collected biological data from the Gulf of Mexico and other locations demonstrating that there is a potential for adverse environmental impacts due to the operation of cooling water intake structures at new offshore oil and gas extraction facilities. 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. As discussed in section IX, 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.

EPA recognizes the inherent differences in the design and operation of land-based and offshore facilities (as well as the differences between the several types of offshore facilities) and has adopted a regulatory approach that allows new offshore oil and gas extraction facilities ample flexibility in complying with the rule. EPA's record shows the technologies evaluated for use by new facilities are already in use at some existing offshore facilities. Furthermore, EPA does not have any (and commenters did not provide) data to suggest that MODUs with sea chests would be inhibited from international movement by the proposed requirements. Commenters did not submit any information that would lead EPA to believe that the intake technologies already used and demonstrated at existing facilities are inadequate or inappropriate for use at new offshore facilities. However, EPA recognizes that differences in types of offshore facilities may limit the technologies available, and is therefore requiring different performance standards for these classes of facilities. For this reason, new offshore oil and gas extraction facilities are subject to a new Subpart N rather than being included under the new facility definition promulgated under Phase I. As discussed in section II.A of this preamble, new offshore oil and gas extraction facilities are defined based on three criteria, one of which is that the facility meets the definition of a ''new facility'' in 40 CFR 125.83.

B. Applicability to Phase III Existing Facilities/Costs & Benefits

Numerous commenters argued that Phase III facilities should be regulated on a case-by-case basis, citing the proposed rule's high cost, low benefits, and a lack of Phase III data indicating environmental harm. Commenters questioned the need for and benefit of promulgating national standards covering existing manufacturing facilities and small electric utility plants that comprise smaller cooling water flows.

Many commenters expressed concern over the high costs relative to the monetized benefits of all three regulatory approaches presented in the proposed rule and indicated that EPA should thus withdraw the proposed rule.

As discussed in section VI of this preamble, EPA has decided not to promulgate national categorical requirements for Phase III existing facilities based in part on a consideration of relative costs and benefits. Section 316(b) requirements for these facilities will continue to be developed by permit writers using their best professional judgment.

C. Environmental Impacts Associated With Cooling Water Intake Structures

Many commenters asserted that there is no demonstrated need for national requirements at Phase III facilities since Phase III facilities have much smaller flows than Phase II facilities. These commenters also stated that most of the environmental impact data cited in the Phase III proposed rule is from Phase II power generator facilities and is not relevant to Phase III facilities. One commenter stated that EPA did not define adverse environmental impact. Another commenter argued that any measure of impingement or entrainment constitutes adverse environmental impact.

Another commenter stated that the low number of 316(b) studies conducted at Phase III facilities indicates that these facilities are not causing a problem. Other commenters maintained that actual national impacts due to cooling water intake structures are vastly underestimated due to poor data collection methodologies utilized when the majority of the studies were performed and because studies conducted on impinged and entrained organisms overlooked the vast majority of affected species.

As discussed in section IV of this preamble, EPA collected impingement mortality and entrainment data from multiple existing facilities including many Phase III facilities, and believes that the data is sufficient to demonstrate the potential for adverse environmental impacts by Phase III facilities (see also Regional Analysis Document). Consistent with discussions presented in the Phase I and Phase II rules, EPA believes that it is reasonable to interpret adverse environmental impact as the loss of aquatic organisms due to impingement mortality and entrainment. Commenters did not suggest alternative interpretations of adverse environmental impact. For additional discussion, see section IV of this preamble.

EPA believes that the studies collected from existing facilities and utilized in its analysis of impingement and entrainment impacts are sufficient to estimate and generally characterize the potential for national level impacts for the purposes of this action. The Regional Analysis document discusses a number of issues associated with the quality of the data in these studies. It is difficult to predict the effects of these study limitations on the impacts estimates, specifically whether they have led to an overestimate or underestimate of impacts. EPA acknowledges that the studies often measure impacts to only some of the fish and shellfish species impacted by cooling water intake structures and typically do not measure impacts to other marine organisms such as phytoplankton or invertebrates. However, EPA fully considered these impacts in its assessment of potential non-monetized benefits. For the reasons discussed above, including the much smaller withdraws associated with Phase III facilities relative to Phase II, EPA has determined that for these facilities impacts were not likely to be of sufficient magnitude to change its decision to rely on the existing site-specific regulatory framework for Phase III facilities. EPA believes the site-specific approach is particularly suited to addressing these non-quantified impacts because the nature and magnitude of such impacts is itself highly site-specific.

VIII. Implementation

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 Phase I requirements. This regulation establishes application requirements under 40 CFR 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).

A. When Does the Final Rule Become Effective?

This rule becomes effective July 17, 2006. 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.

B. What Information Will I Be Required To Submit to the Director When I Apply for My NPDES Permit?

General Information

This final rule modifies regulations at § 122.21 to require new offshore oil and gas extraction facilities to prepare and submit some of the same information required for new Phase I and existing Phase II facilities. New offshore oil and gas extraction facilities may be required to submit the Source Water Baseline Biological Characterization Data depending on whether they are fixed or non-fixed facilities. Non-fixed facilities are exempt from the requirement. Specific data requirements for the Source Water Baseline Biological Characterization Data are described later in this section. Studies to be submitted by new offshore oil and gas extraction facilities are described below. Under EPA's NPDES regulations new facilities must apply for their NPDES permit at least 180 days prior to commencement of operation. Under this final rule, new offshore oil and gas extraction facilities must submit the specified information with their application for permit issuance.

1. Source Water Physical Data (§ 122.21(r)(2))

Under the requirements at § 122.21(r)(2), new offshore oil and gas extraction facilities are required to provide the source water physical data specified at § 122.21(r)(2) in their application for a permit. EPA believes these data are necessary to characterize the facility and evaluate the type of waterbody and species potentially affected by the cooling water intake structure. EPA intends for the Director to use this information to evaluate the appropriateness of the design and construction technologies and/or operational measures proposed by the applicant.

The applicant is required to submit the following specific data: (1) A narrative description and scale drawings showing the physical configuration of all source waterbodies used by the facility, including areal dimensions, depths, salinity and temperature regimes, and other documentation; (2) an identification and characterization of the source waterbody's hydrological and geomorphological features, as well as the methods used to conduct any physical studies to determine the intake's zone of influence and the results of such studies; and (3) locational maps. For new non-fixed (mobile) offshore oil and gas extraction facilities, this provision requires only some of the location information and not the source water physical data required for new fixed offshore oil and gas extraction facilities.

EPA recognizes that mobile facilities may not always know where they will be operating during the permit term, and the requirement in (r)(2)(iv) is not meant to restrict them only to locations identified in the permit application. However, EPA expects that permit applicants will provide, based on available information, their best estimate as to where they will be operating during the permit term, at whatever level of detail they can.

2. Cooling Water Intake Structure Data (§ 122.21(r)(3))

New offshore oil and gas extraction facilities are required to submit the cooling water intake structure data specified at § 122.21(r)(3) to characterize the cooling water intake structure and evaluate the potential for impingement and entrainment of aquatic organisms. Note that § 122.21(r)(3)(ii)—latitude and longitude of each intake structure—is not applicable to non-fixed (mobile) offshore oil and gas extraction facilities. Information on the design of the intake structure and its location in the water column allows the permit writer to evaluate which species or life stages are potentially subject to impingement mortality and entrainment. A diagram of the facility's water balance is used to identify the proportion of intake water used for cooling, make-up, and process water. The water balance diagram also provides a picture of the total flow in and out of the facility, allowing the permit writer to evaluate the suitability of proposed design and construction technologies and/or operational measures.

The applicant is required to submit the following specific data: (1) A narrative description of the configuration of each of its cooling water intake structures and where they are located in the waterbody and in the water column; (2) latitude and longitude in degrees, minutes, and seconds for each of its cooling water intake structures (not applicable to new non-fixed (mobile) offshore oil and gas extraction facilities); (3) a narrative description of the operation of each of the cooling water intake structures, including design intake flows, daily hours of operation, number of days of the year in operation, and seasonal operation schedules, if applicable; (4) a flow distribution and water balance diagram that includes all sources of water to the facility, recirculating flows, and discharges; and (5) engineering drawings of the cooling water intake structure.

The applicability criterion in § 125.131(a)(3) is based on total design intake flow. Total design intake flow must be specified by the applicant with the information required above. A facility may permanently decrease its total design intake flow (e.g., by removing an intake structure or installing intake pumps with a lower maximum capacity) and request that the permitting authority consider the facility's new total design intake flow to determine the applicability of the 316(b) Phase III Rule at the time of permitting. Note that for a facility that has a variable speed pump, the total design flow is the maximum intake capacity for the cooling water intake structure.

Specific Requirements

Under this final rule, new offshore oil and gas extraction facilities are required to submit the application requirements consistent with § 122.21(r)(2) (except (r)(2)(iv)), (3), and (4) and § 125.136 of Subpart N if they are fixed facilities and choose to comply with the Track I or II requirements in § 125.134(b) or (c). A fixed facility is defined 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. This definition does not include MODUs (e.g., drill ships, temporarily moored semi-submersibles, jack-ups, submersibles, tender-assisted rigs, and drill barges). The Track I and Track II application requirements are generally consistent with the Phase I requirements for new facilities (66 FR 65256). Under Track I, this includes velocity information, source waterbody flow information, and a design and construction technology plan. Track II requirements include source waterbody flow information and Track II comprehensive demonstration study (including source water biological study, evaluation of potential cooling water intake structure effects, and verification monitoring plan). These requirements are detailed later in this section.

As described in § 125.135, new offshore oil and gas extraction facilities have the opportunity to conduct a cost-cost test and provide data to assist the permit writer in determining if compliance with the Subpart N requirements would result in compliance costs wholly out of proportion to those EPA considered in establishing the requirement, or would result in significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on energy markets. In this case, alternative requirements may be imposed in the permit. See the Phase I final preamble for a more detailed explanation of this cost-cost test which is different than the cost-cost test for Phase II facilities (66 FR 65256).

In this final rule, fixed facilities with sea chests and all non-fixed (or ''mobile'') facilities are not required to comply with standards for entrainment. Fixed facilities with sea chests may choose either Track I or Track II to comply with impingement mortality performance standards. Non-fixed facilities must comply with the Track I 0.5 feet per second through-screen design intake flow velocity performance standard for impingement mortality. In addition, the Director must consider whether more stringent conditions are reasonably necessary to comply with any provision of federal or state law, including compliance with applicable water quality standards. Thus, the Director may determine that additional design and construction technologies to minimize impingement mortality are necessary where there are either protected species or critical habitat for these species or other species of impingement concern within the hydrologic zone of influence of the cooling water intake structure, or based on other information from fishery management services or agencies. The new mobile facility, when applying to operate under a general permit, must identify where it expects to be operating. EPA expects the Director to consult with the fishery management agencies, consider their data as well as any other relevant data, and decide whether to propose additional requirements based on any concerns the Director identifies (see § 125.134(b)(4)). For example, Region 10 has established a general permit for Cook Inlet that established a 0.1 feet per second through-screen design intake flow velocity performance standard. However, non-fixed facilities are not required to submit the source water baseline biological characterization data and some aspects of the source water physical data. Requirements for non-fixed facilities are described later in this section.

1. For New Offshore Oil and Gas Extraction Fixed Facilities, What Information Is Required To Be Collected for the NPDES Application?

Source Water Baseline Biological Characterization Data (§ 122.21(r)(4))

Under this final rule, Track I and Track II new offshore oil and gas extraction fixed facilities are required to submit source water baseline biological characterization data, just as other new facilities were required to do under Phase I. The data will be used to characterize the biological community in the vicinity of the cooling water intake structure and to characterize the operation of the cooling water intake structure. The data must include existing data (if available) supplemented with new field studies as necessary. Detailed data requirements are at § 122.21(r)(4). EPA recognizes that many offshore oil and gas extraction facilities are regulated under NPDES general permits and that regional studies are typically conducted as part of the general permit requirements. EPA expects that some new offshore oil and gas extraction fixed facilities may choose to jointly conduct a regional study to collect the source water baseline biological characterization data. The biological conditions characterized by a regional study should reflect the conditions found at each individual cooling water intake structure. EPA anticipates the regional studies would be conducted once each permit cycle. Under this final rule, the regional study would also include annual monitoring requirements.

Velocity Information (Track I)

The final rule requires that new offshore oil and gas extraction fixed facilities submit velocity information consistent with § 125.136(b)(2). The information will be used to demonstrate to the Director that the facility is complying with the requirement to meet a maximum through-screen design intake velocity of no more than 0.5 feet per second at the cooling water intake structure. The following information must be submitted: (1) a narrative description of the design, structure, equipment, and operation used to meet the velocity requirement; and (2) design calculations showing that the velocity requirement would 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 or, if the facility uses devices other than a surface intake screen, at the point of entry to the device.

Source Waterbody Flow Information (Track I and II)

The final rule also requires that new offshore oil and gas extraction fixed facilities located in an estuary or tidal river to submit source waterbody flow information in accordance with § 125.136(b)(2) or (c)(1). The information will be used to demonstrate to the Director that a new coastal facility's cooling water intake structure meets the proportional flow requirements at § 125.134(b)(3) or (c)(2). These requirements include specific provisions for fixed facilities located on estuaries or tidal rivers to provide greater protection for these sensitive waters. Specifically, the final rule requires that 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. See the final Phase I rule for the basis for this design intake flow limitation. Calculations and guidance on determining the tidal excursion is found in the preamble to the final Phase I rule at section VII.B.1.d.

Design and Construction Technology Plan (Track I)

The final regulation requires that new offshore oil and gas extraction fixed facilities submit a design and construction technology plan consistent with Subpart N requirements at § 125.136(b)(3). The design and construction technology plan must demonstrate that the facility has selected and will implement the design and construction technologies necessary to minimize impingement mortality and/or entrainment in accordance with § 125.134(b)(4) and/or (5). The design and construction technology plan requires delineation of the hydrologic zone of influence for the cooling water intake structure; a description of the technologies implemented (or to be implemented) at the facility; the basis for the selection of that technology; the expected performance of the technology, and design calculations, drawings and estimates to support the technology description and performance. The Agency recognizes that the selection of a specific technology or a group of technologies depends on the individual facility and waterbody conditions.

Track II Comprehensive Demonstration Study (Track II)

If a fixed facility chooses to comply under the Track II approach, the facility must perform and submit the results of a Comprehensive Demonstration Study (Study). This information will be used to characterize the source water baseline in the vicinity of the cooling water intake structure(s); characterize operation of the cooling water intake(s); and to confirm that the technology(ies) proposed and/or implemented at the cooling water intake structure reduce the impacts to fish and shellfish to levels comparable to those the facility would achieve were it to implement the applicable requirements in § 125.134(b)(2) and, for facilities without sea chests, in § 125.134(b)(5). To meet the ''comparable level'' requirement, the facility must demonstrate that it has reduced both impingement mortality and entrainment of all life stages of fish and shellfish to 90 percent or greater of the reduction that would be achieved through the applicable requirements in § 125.134(b)(2) and, for facilities without sea chests, in § 125.134(b)(5).

Similar to the Proposal for Information Collection required in Phase II, the facility must develop and submit a plan to the Director containing a proposal for how information will be collected to support the study. The plan must include:

- A description of the proposed and/or implemented technology(ies) to be evaluated in the Study;
- A list and description of any historical studies characterizing the physical and biological conditions in the vicinity of the proposed or actual intakes and their relevancy to the proposed Study. If the facility proposes to rely on existing source waterbody data, the data must be no more than 5 years old, and the facility must demonstrate that the existing data are sufficient to develop a scientifically valid estimate of potential impingement mortality and entrainment impacts, and provide documentation showing that the data were collected using appropriate quality assurance/quality control procedures;
- Any public participation or consultation with Federal or State agencies undertaken in developing the plan; and
- A sampling plan for data that will be collected using actual field studies in the source waterbody. The sampling plan must document all methods and quality assurance procedures for sampling and data analysis. The sampling and data analysis methods proposed must be appropriate for a quantitative survey and based on consideration of methods used in other studies performed in the source waterbody. The sampling plan must include a description of the study area (including the area of influence of the cooling water intake structure and at least 100 meters beyond); taxonomic identification of the sampled or evaluated biological assemblages (including all life stages of fish and shellfish); and sampling and data analysis methods.

The facility must submit documentation of the results of the Study to the Director. Documentation of the results of the Study includes: Source Water Biological Study, an evaluation of potential cooling water intake structure effects, and a verification monitoring plan as described below.

Source Water Biological Study

The Source Water Biological Study is similar to, but will generally be more comprehensive than, the Source Water Baseline Biological Characterization Study which is required for both Tracks I and II. The Source Water Biological Study must include:

(1) A taxonomic identification and characterization of aquatic biological resources including: a summary of historical and contemporary aquatic biological resources; determination and description of the target populations of concern (those species of fish and shellfish and all life stages that are most susceptible to impingement and entrainment); and a description of the abundance and temporal/spatial characterization of the target populations based on the collection of multiple years of data to capture the seasonal and daily activities (e.g., spawning, feeding and water column migration) of all life stages of fish and shellfish found in the vicinity of the cooling water intake structure;

(2) An identification of all threatened or endangered species that might be susceptible to impingement and entrainment by the proposed cooling water intake structure(s); and

(3) A description of additional chemical, water quality, and other anthropogenic stresses on the source waterbody.

Evaluation of Potential Cooling Water Intake Structure Effects

This evaluation must include:

(1) Calculations of the reduction in impingement mortality and, if applicable, entrainment of all life stages of fish and shellfish that would need to be achieved by the technologies selected to meet requirements under Track II. To do this, the facility must determine the reduction in impingement mortality and entrainment that would be achieved by implementing the requirements of § 125.134(b)(2) and, for facilities without sea chests, § 125.134(b)(5).

(2) An engineering estimate of efficacy for the proposed and/or implemented technologies used to minimize impingement mortality and, if applicable, entrainment of all life stages of fish and shellfish and maximize survival of impinged life stages of fish and shellfish. The facility must demonstrate that the technologies reduce impingement mortality and, if applicable, entrainment of all life stages of fish and shellfish to a comparable level to that which would be achieved if the facility were to implement the requirements in § 125.134(b)(2) and, for facilities without sea chests, § 125.134(b)(5). The efficacy projection must include a site-specific evaluation of technology suitability for reducing impingement mortality and entrainment based on the results of the Source Water Biological Study. Efficacy estimates may be determined based on case studies that have been conducted in the vicinity of the cooling water intake structure and/or site-specific technology prototype studies.

Verification Monitoring Plan

Under Track II, a fixed facility must include a plan to conduct, at a minimum, two years of monitoring to verify the full-scale performance of the proposed or implemented technologies, and/or operational measures. The verification study must begin at the start of operations of the cooling water intake structure and continue for a sufficient period of time to demonstrate that the facility is reducing the level of impingement mortality and entrainment to the level required for Track II compliance. The plan must describe the frequency of monitoring and the parameters to be monitored. The Director will use the verification monitoring to confirm that the facility is meeting the level of impingement mortality and entrainment reduction required in § 125.134(c), and that the operation of the technology has been optimized.

2. As an Owner or Operator of a New Offshore Oil and Gas Extraction Fixed Facility, What Monitoring Is Required?

Monitoring requirements for new offshore oil and gas extraction fixed facilities vary based on whether the facility selects Track I or Track II and whether it has a sea chest. For fixed facilities pursuing Track I that have sea chests, no monitoring is required. For fixed facilities pursuing Track I that do not have sea chests, only entrainment monitoring is required. Under Track II, fixed facilities with sea chests are required to conduct impingement mortality monitoring; fixed facilities without sea chests must conduct monitoring for both impingement mortality and entrainment.

Under this final rule, monitoring must characterize the impingement and, if applicable, entrainment rates of commercial, recreational, and forage base fish and shellfish species identified in either the Source Water Baseline Biological Characterization data required by 40 CFR 122.21(r)(4) (for Track I) or the Comprehensive Demonstration Study required by § 125.136(c)(2 (for Track II). The monitoring methods used must be consistent with those used for the Source Water Baseline Biological Characterization data required in 40 CFR 122.21(r)(4) or the Comprehensive Demonstration Study required by § 125.136(c)(2). For Track II, monitoring must be conducted in accordance with the Verification Monitoring Plan.

The fixed facility must follow the monitoring frequencies identified below for at least two (2) years after the initial permit issuance. After that time, the Director 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 variations in the species and numbers of individuals that are impinged or entrained.

Impingement sampling. The facility 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 cooling water intake structure is in operation.

Entrainment sampling. If the fixed facility does not use a sea chest, it 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 required by 40 CFR 122.21(r)(4) or the Comprehensive Demonstration Study required in § 125.136(c)(2). Samples must be collected only when the cooling water intake structure is in operation.

Velocity monitoring. All new offshore oil and gas extraction facilities must conduct velocity monitoring. Velocity monitoring consists of a demonstration requirement based on the new facilities' proposed design, and a compliance monitoring requirement that verifies the velocity limitation is being met.

Facilities must submit design specifications for the impingement control system to the Director. Impingement control systems must be designed to prevent flow velocities from exceeding 0.5 feet per second. The facility must demonstrate the 0.5 feet per second velocity limit will be met by submitting (1) a narrative description of the technology used to meet the velocity requirement, and (2) a design calculation that uses head loss to show the design flow through the screen will meet the velocity requirement.

After start-up, if the facility uses a surface intake screen system, it must monitor head loss across the screens and correlate the measured value with the design intake velocity. The head loss across the intake screen must be measured at the minimum ambient source water surface elevation (using best professional judgment based on available hydrological data). The maximum head loss across the screen for each cooling water intake structure will be used to determine compliance with the velocity requirement in § 125.134(b)(2). If the facility uses devices other than surface intake screens, it must monitor velocity at the point of entry through the device. Head loss or velocity must be monitored during initial facility startup, and thereafter, at the frequency specified in the NPDES permit, but no less than once per quarter.

Facilities must monitor and record flow data through the cooling water intake structure continuously in order to verify that 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 Director on an annual basis in order to verify that flow rates through cooling water intake structure did not exceed design capacity. Flow data can be collected and submitted to the Director either electronically or by hard copy.

Visual or remote inspections. The facility must conduct visual inspections or employ remote monitoring devices during the period the cooling water intake structure is in operation. Visual inspections must 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, the facility must inspect via remote monitoring devices to ensure that the impingement and entrainment technologies are functioning as designed.

3. What Recordkeeping and Reporting Is Required for New Offshore Oil and Gas Extraction Fixed Facilities?

Owners and operators of new offshore oil and gas extraction fixed 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. The Director may require that these records be kept for a longer period.

Additionally, this final rule requires that new offshore oil and gas extraction fixed facilities 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).

4. For New Non-fixed (Mobile) Offshore Oil and Gas Extraction Facilities, What Information Is Required To Be Collected for the NPDES Application?

Velocity Information (Track I)

This final rule at § 125.136(b)(1) requires that new nonfixed (mobile) offshore oil and gas extraction facilities submit velocity information. The information will be used to demonstrate to the Director that the facility is complying with the requirement to meet a maximum through-screen design intake velocity of no more than 0.5 feet per second at the cooling water intake structure. The following information must be submitted: (1) a narrative description of the design, structure, equipment, and operation used to meet the velocity requirement; and (2) design calculations showing that the velocity requirement would 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.

Design and Construction Technology Plan (Track I)

When the Director determines that additional design and construction technologies to minimize impingement mortality of fish and shellfish are necessary, pursuant to § 125.134(b)(4), new nonfixed (mobile) offshore oil and gas extraction facilities must submit a design and construction technology plan. As set forth in § 125.136(b)(3), the design and construction technology plan must demonstrate that the facility has selected and will implement the design and construction technologies necessary to minimize impingement mortality in accordance with § 125.134(b)(4). The design and construction technology plan requires delineation of the hydrologic zone of influence for the cooling water intake structure; a description of the technologies implemented (or to be implemented) at the facility; the basis for the selection of that technology; the expected performance of the technology, and design calculations, drawings and estimates to support the technology description and performance. The Agency recognizes that the selection of a specific technology or a group of technologies depends on the individual facility and waterbody conditions.

5. As an Owner or Operator of a New Non-fixed (Mobile) Offshore Oil and Gas Extraction Facility, What Monitoring Is Required?

Biological monitoring. Under this final rule, new non-fixed (mobile) offshore oil and gas extraction facilities are not required to conduct biological monitoring unless specified by the Director.

Velocity monitoring. If the mobile facility uses a surface intake screen system, it must monitor head loss across the screens and correlate the measured value with the design intake velocity. The head loss across the intake screen must be measured at the minimum ambient source water surface elevation (using best professional judgment based on available hydrological data). The maximum head loss across the screen for each cooling water intake structure will be used to determine compliance with the velocity requirement in § 25.134(b)(2). If the facility uses devices other than surface intake screens, it must monitor velocity at the point of entry through the device. Head loss or velocity must be monitored during initial facility startup, and thereafter, at the frequency specified in the NPDES permit, but no less than once per quarter.

Visual or remote inspections. The facility must conduct visual inspections or employ remote monitoring devices during the period the cooling water intake structure is in operation. Visual inspections must 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, the facility must inspect via remote monitoring devices to ensure that the impingement technologies are functioning as designed.

6. What Recordkeeping and Reporting Is Required for New Non-Fixed (Mobile) Offshore Oil and Gas Extraction Facilities?

Owners and operators of new mobile 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. The Director may require that these records be kept for a longer period.

Additionally, 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).

C. Are Permits for New Offshore Oil and Gas Extraction Facilities Subject to Requirements Under Other Federal Statutes?

EPA's NPDES permitting regulations at 40 CFR 122.49 contain a list of federal laws that might apply to NPDES permits issued by EPA. These include the Wild and Scenic Rivers Act, 16 U.S.C. 1273 et seq.; the National Historic Preservation Act of 1966, 16 U.S.C. 470 et seq.; the Endangered Species Act, 16 U.S.C. 1531 et seq.; the Coastal Zone Management Act, 16 U.S.C. 1451 et seq.; and the National Environmental Policy Act, 42 U.S.C. 4321 et seq. See 40 CFR 122.49 for a brief description of each of these laws. In addition, the provisions of the Magnuson-Stevens Fishery Conservation and Management Act, 16 U.S.C. 1801 et seq., relating to essential fish habitat might be relevant. Nothing in this final rulemaking authorizes activities that are not in compliance with these or other applicable Federal laws.

IX. Economic Impact Analysis

This section summarizes EPA's analysis of total social cost and economic impacts for the 316(b) Phase III final regulation for new offshore oil and gas extraction facilities and the regulatory options that were considered for promulgation of a final regulation for existing facilities. EPA's assessment of costs and economic impacts can be found in the Economics and Benefits Analysis.

A. New Offshore Oil and Gas Extraction Facilities

This rule establishes requirements for new offshore oil and gas extraction facilities that are point sources, employ a cooling water intake structure, are designed to withdraw 2 MGD or more from waters of the United States, and use at least 25 percent of the water withdrawn exclusively for cooling purposes. Oil and gas extraction facilities (''Oil and Gas Facilities'') are facilities primarily engaged in oil and gas production and drilling activities. This analysis includes oil and gas production platforms/structures and MODUs. EPA estimates that 21 new oil and gas extraction platforms and 103 new MODUs would be subject to the national requirements of the rule, assuming a 20-year period of construction from 2007 (the assumed effective date of the rule) to 2026. Each newly-constructed facility is assumed to operate for 30 years, extending the entire analysis period to 49 years (2007 to 2055).

Two types of cost analysis are presented. The social cost analysis includes before tax compliance costs to facilities and implementation costs to EPA. In this analysis, costs are discounted to 2007, assuming it would take a facility about 6 months to begin incurring costs. If the start date is actually later than 2007, social costs will be slightly reduced from those estimated here in present value terms. For the second type of cost analysis, industry after-tax compliance costs, costs are discounted for each individual facility to the year of compliance (the year the vessel is launched or the platform/structure come on line, which ranges from 2007 to 2026). The present value calculated for each facility is used in the economic impact analysis. These costs are subsequently discounted to 2004 and are then totaled to produce an aggregate present value of compliance costs. For both approaches annualized costs are then calculated by annualizing at a 3 percent (social costs) or 7 percent discount rate (social costs and industry compliance costs) over 30 years. All dollar values presented in this preamble are in $2004 (average or mid-year).

1. General Approach for Costing Impingement and Entrainment Equipment for Offshore Oil and Gas Extraction Facilities

EPA's general approach to estimate compliance 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 order to estimate the related economic impacts associated with 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 alternate 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, and accordingly used these technologies as the basis for the requirements in this rule

Using this methodology, EPA estimated compliance costs for the various configurations of offshore oil and gas extraction facilities and cooling water intake structures using the following:

- Stainless steel wedge wire screens with and without air sparging;
- Copper-nickel wedge wire screens with and without air sparging;
- Stainless steel velocity caps;
- Copper-nickel alloy velocity caps;
- Flat panel wedge wire screens over sea chests; and
- Horizontal flow diverters associated with sea chests.

EPA's detailed methodology for estimating these compliance costs is outlined in the Technical Development Document and the record supporting the final rule.

2. Social Cost for New Oil and Gas Extraction Facilities

The total annualized social cost of this rule for new Oil and Gas facilities is estimated at $3.8 million using a 3 percent discount rate, and $3.2 million using a 7 percent discount rate. The largest component of social cost is the pre-tax cost of regulatory compliance incurred by complying facilities; these costs include one-time technology costs of complying with the rule, annual O&M costs, and permitting costs (initial permit costs, annual monitoring costs, and permit reissuance costs). Social cost also includes implementation costs incurred by the Federal government. EPA expects that the final regulation will be implemented under general permits.[8]

EPA estimates that direct compliance costs will be $3.4 million and $2.8 million, using a 3 percent and 7 percent discount rate, respectively. The estimated Federal government cost for administering the rule for new facilities is comparatively minor in relation to the estimated direct cost of regulatory compliance. Federal administrative costs are estimated to be $0.4 million and $0.3 million per year under the 3 percent and 7 percent discount rates, respectively. EPA did not estimate costs to States for administering the new rule because the waters in which the regulated facilities would be located generally lie outside the States' jurisdiction. Specifically, facilities more than 3 miles off the coast are in federal waters. In the case of Alaska which does not have NPDES program authority, EPA Region 10 is expected to write NPDES permits for facilities in Alaskan waters. EPA does not expect any new facilities to locate in California because no new platforms have been constructed there since 1994, and a moratorium on lease sales extends to the year 2012.

3. Economic Impacts for New Oil and Gas Extraction Facilities

The following two subsections present economic impacts for MODUs and production platforms/structures, respectively. Certain aspects of the methodology differ between the two segments. Oil and gas production operations involve production of a finite resource, which limits the potential life of a production platform. Thus, the analysis for production platforms/structures must account for the production and resulting exhaustion of the finite oil and gas resource. Key considerations in the platforms analysis are: (1) When does production terminate? and (2) would the year of termination change due to regulation? The economic life of a MODU is not limited by such considerations and the analysis for MODUs is accordingly simpler. The Economic and Benefits Analysis and the rulemaking record contain additional data and details on the methodology and assumptions used in these analyses.

a. Mobile Offshore Drilling Units (MODUs)

EPA projects that 80 new jackups, 20 new semi-submersibles, and three new drill ships will be constructed over the 20 years for which new facility additions are analyzed. The economic impact analysis for these new MODUs is conducted at two levels: the vessel level and the firm level. EPA conducted two vessel-level analyses and one firm-level analysis:

- The first vessel-level analysis is a closure analysis, which assesses

[8] Because individual permits are typically not issued to offshore oil and gas extraction facilities, costs for pre-permitting and re-permitting studies are assumed to be shared among groups of new facilities expected to be covered by the general permits (see DCN 7–4036 for detailed information on how permitting costs are assumed to be shared under the general permits).

changes in vessel cash flow and net income. Because the financial condition of new vessels is unknown, EPA used financial information from representative existing vessels, collected in EPA's 316(b) survey of MODUs ([DCN 7–0008 and DCN 7–0018), to represent the financial characteristics of new facilities. The financial information from these representative vessels is used for a general assessment of how well these vessels would perform financially under the requirements of the final regulation. This analysis is used as an alternative assessment of the potential for a barrier to entry.

- The second vessel-level analysis is a barrier-to-entry analysis for new facilities. This analysis computes the present value of estimated initial permitting costs, which are assumed to be incurred over five years prior to the incorporation of section 316(b) permit requirements in the applicable general permits (see DCN 7–4036) and are discounted to the year of compliance (the year the vessel is assumed to be launched). The one-time capital costs of compliance (assumed to be incurred in the year of compliance) are then added to this figure. These summed compliance costs are then compared to the baseline construction costs for each type of MODU. Neither recurring costs of compliance (e.g., repermitting costs or recurring capital costs of intake controls) nor recurring baseline costs (e.g., O&M, refitting costs) are considered in this analysis. The analysis compares baseline start-up costs and incremental start-up costs associated with the final rule.
- The firm-level analysis is a cost-to-revenue test which compares the annualized compliance costs for representative new vessels to the revenue of firms likely to construct MODUs, assuming each of these firms builds a share of the 103 new MODUs expected to be constructed over the 20-year construction time frame. This analysis was conducted on a pre-tax and after-tax basis.

i. Vessel-Level Closure Analysis

To estimate potential closures (or more precisely, decisions not to proceed with constructing and placing a vessel into service) as a result of this rule for new MODUs, EPA used two models. The first model is a net income model, which computes the estimated present value of baseline after-tax net income (i.e., without compliance costs) for representative MODUs (based on survey data from existing MODUs) over a 30-year operating period for each new facility. Consistent with generally accepted methods of business value analysis, EPA would have preferred to use the present value of after-tax cash flow instead of net income as the basis for this analysis. However, because it could not reliably estimate all of the elements of cash flow, EPA instead used the present value of net income for its closure test. In particular, EPA was unable to estimate the ongoing capital outlays (apart from those resulting from regulatory compliance) that MODUs would need to make as part of their ordinary business operations. In performing the analysis in this way, EPA essentially used the facility's reported depreciation and amortization—which, being non-cash items, are normally excluded from cash flow accounting—as an approximation of ongoing capital outlays. How use of reported depreciation and amortization, instead of a reliable estimate of capital outlays, affects the findings from this analysis cannot be precisely known. For some businesses—in particular those with relatively strong financial performance—depreciation and amortization may be less than ongoing capital outlays; for these businesses, the analysis will tend to overstate business value and understate the potential effect of compliance outlays on financial performance and business value. On the other hand, for some businesses—in particular those with relatively weak financial performance—depreciation and amortization may exceed ongoing capital outlays; for these businesses, the analysis will tend to understate business value and overstate the potential effect of compliance outlays on financial performance and business value. The second model used by EPA is an after-tax cost calculation model, which estimates the present value of after-tax compliance costs using engineering and permitting cost inputs. Comparing the results of these two models shows the potential effect of costs on vessel net income.

EPA estimated after-tax net income using data provided by surveyed operators of existing MODUs (EPA received economic surveys for three semi-submersibles, three jackups, and two drill ships). EPA was only able to undertake financial analysis for those MODUs with a positive net income for the three years of financial information provided in the survey (2000 to 2002). EPA assumed that any MODU whose net income is negative over the three years is unlikely to be a viable operation in the baseline and cannot be analyzed with respect to compliance costs.

EPA used the net income over the three years of survey data to create a moving cycle of net income over the period of analysis. Among the years of data collected (2000 to 2002), 2002 was generally a poor year of financial condition for the industry as a whole. EPA was thus able to represent industry financials in both good and bad years. The three-year cycle simulates the effect of volatility in oil and gas prices and other business conditions (e.g., rig utilization rates) over each facility's 30-year operating period. Future operating periods are likely to include major swings in the prices of oil and gas, the driving force behind the level of operations, rig pricing, and, thus, financial performance of the newly constructed vessels. EPA assumed that net income will be flat, on a three-year average basis, over the 30 years of analysis and thus did not apply any factors to increase or decrease net income over the years of analysis. The net income figures from the survey, therefore, repeat every three years for 30 years. EPA then computed the present value of that stream of net income and compared it to the present value of after-tax compliance costs for the final regulation.

EPA used the estimated compliance cost elements—capital, O&M, and permitting costs—for each new MODU to calculate the present value of the after-tax cost of compliance with this final requirements. Each compliance-related cost was accounted for in the year it is assumed to be incurred. Tax effects of compliance outlays were based on the owner company's marginal tax rate as determined from the firm's average taxable earnings over the three years of survey data (converted to a mid-year 2003 basis). EPA calculated depreciation for the compliance capital outlay using the modified accelerated cost recovery system (MACRS) and included it in the pre-tax compliance cost stream. The compliance cost stream was then reduced by the amount of avoided tax liability, based on the estimated marginal tax rate, to yield the after-tax compliance cost stream (for more information on these calculations, see DCN 7–4016). The final result of these calculations is the present value of after-tax compliance costs.

The present value of after-tax compliance costs was then subtracted from the present value of baseline net income for the vessel. If the present value of net income remained positive after accounting for compliance costs, EPA assumed that the MODU would operate post-compliance. If the present value of net income became negative, EPA assumed that the new MODU would not be a financially viable project and was counted as a potential "regulatory closure."

The analysis is based on the assumption that costs cannot be passed through to customers. EPA bases this assumption on the fact that new MODUs will be competing with existing MODUs, which will not incur compliance costs. Based on EPA's assumption that finances for new MODUs will look like those for existing MODUs, this analysis found that no new MODUs would be a regulatory closure as a result of the incremental compliance costs associated with the final rule.

ii. Vessel-Level Barrier-to-Entry Analysis

The barrier-to-entry analysis compares the present value of compliance costs (including the present value of initial permitting costs discounted to the compliance year and first-time capital/installation costs, excluding recurring costs), to the costs of constructing a new MODU. If compliance costs comprised a small fraction of construction costs, EPA assumed that compliance costs would have no effect on the decision to build a new MODU.

EPA developed incremental compliance costs for new MODUs using estimated initial permitting costs and technology cost estimates. The initial permitting costs are based on each new MODU's share of regional permitting costs (EPA expects that facilities in a particular geographic region would collect data from representative facilities in that region) and individual administrative start-up and permit application costs. The technology costs are based on the weighted average cost of installing controls at existing MODUs, by type of MODU, for all existing MODUs with technical data. The estimated present value of the initial permitting cost stream, plus the first-time capital/installation costs of compliance costs, sum to approximately $130,000 for semi-submersibles, $269,000 for jackups, and $261,000 for drill ships. According to Rigzone (2006), the cost of new MODUs averages $285 million for semi-submersibles, $130 million for jackups, and $385 million for drill ships (DCN 9–4002). The present value of initial permitting costs plus one-time capital/installation compliance costs is therefore estimated to range from 0.03 percent to 0.21 percent of construction costs for the three types of MODU. Because total up-front costs represent a very small fraction of total costs of construction (and even of contingency costs, which typically range from 10 percent to 20 percent of capital costs), EPA believes that these costs would not have a material effect on decisions to build new MODUs.

iii. Firm-Level Cost-to-Revenue Analysis

EPA's research showed that firms likeliest to build MODUs with a design intake flow of 2 MGD or more are those that currently own such MODUs. EPA identified nine firms that either already own jackups, semi-submersibles, or drill ships that would be subject to the requirements for new facilities if newly constructed, or that are currently in the process of building such MODUs. Most of these firms are among the largest firms in the industry. EPA estimates that these nine firms would own the 103 new MODUs subject to the final national requirements for new facilities. To determine the potential impact of the final rule on the nine firms determined likely to build new MODUs subject to regulation, EPA used a cost-to-revenue test, which compares the annualized pre-tax and after-tax costs of compliance (calculated for representative new MODUs), with 2004 revenue reported by these firms. Because nearly all of the firms (other than foreign-owned) are publicly owned, EPA relied on revenue data compiled from corporate 10K reports (see Chapter C2 of the EA). EPA then assigned a number of MODUs potentially subject to regulation to each of the firms and used the average per-MODU compliance costs multiplied by the number of these MODUs to calculate the total compliance costs that might be faced by these firms.

Estimated total annual pre-tax compliance costs are approximately $15,300 for a semi-submersible, $33,800 for a jackup, and $39,100 for a drill ship. Estimated after-tax costs are approximately $10,000, $22,000, and $25,400, respectively, based on a 35 percent marginal corporate tax rate assumption, which is the highest marginal corporate tax rate applicable (all potentially affected entities are large or very large corporations whose earnings generally would put them in this tax bracket). These annualized costs are very small compared to the revenue a MODU might receive for drilling even one exploratory well in deepwater. Exploratory wells cost at least $30 million to drill, a large portion of which is paid to MODU operators (DCN 7–4017). Compliance costs are also small compared to the typical day rates (daily charges) paid to MODUs while drilling wells. These rates can range up to $180,000 per day (DCN 9–4001). Because EPA assumed that the majority of rigs to be constructed will be jackups, EPA used the compliance cost of a jackup rig to represent the cost of compliance with this rule in order to judge impacts on firms. Seven firms are each assumed to build 9 jackups over the time frame of the analysis (approximately one MODU every other year). The two additional firms, GlobalSantaFe and Transocean, are the dominant firms in the industry. These two firms are each assumed to build 18 jackups, plus one drill ship and two drill ships, respectively, over the time frame of the analysis for a total of 19 or 21 MODUs in total. For the comparison of annualized costs of compliance with annual revenue, EPA assumed that all of a firm's new rigs would be constructed in one year. If this assumption has any effect, it would increase the likelihood of finding economic impacts. With no firm-level impacts found under this scenario, then there will also be no impacts under other more likely scenarios in which costs are incurred over several years.

Using these assumptions, EPA estimates that the annualized pre-tax costs per firm range from $0.3 to $0.7 million, and the after-tax costs range from $0.2 to $0.4 million. The pre-tax cost-to-revenue ratio ranges from 0.01 percent to 0.2 percent, while the after-tax ratios range from 0.01 percent to 0.1 percent. Given that the highest estimated ratio is 0.2 percent, EPA concludes that firm-level impacts would not pose a barrier to entry.

b. Oil and Gas Production Platforms

EPA projects that 20 deepwater platforms and one Alaska platform will be constructed over the 20 years over which new facility additions are analyzed. The economic impact analysis for these new platforms is conducted at two levels: the platform level and the firm level. EPA conducted two platform-level analyses and one firm-level analysis:

- The first platform-level analysis assesses the potential effects of compliance costs on platform operation. Two effects of the final rule are considered: (1) A reduction in the expected economic value of the platform, driven by all costs of compliance, which could prevent oil and gas resources from being brought into production, and (2) earlier production shut-in, driven by the increase in O&M costs. The baseline operating and financial profile for this analysis is based on data from existing platforms whose cooling water intake rates would cause them to be subject to the final rule if they were being newly constructed after rule promulgation. These existing platforms serve as a baseline model of the operating and financial conditions of new platforms that would be regulated under the rule.

Estimated compliance costs are added to the baseline cost profile in the analysis of the impact of compliance costs on platform operations.

- The second platform-level analysis is a barrier-to-entry analysis for new facilities. This analysis compares the present value of estimated initial permitting costs plus the one-time capital costs of compliance (excluding any recurring costs) to the construction costs for each type of platform.
- The firm-level analysis is a cost-to-revenue test, which compares the annualized compliance costs for representative new platforms to the revenue of firms likely to construct new platforms/structures. This analysis assumes that each firm likely to build a deepwater platform/structure subject to regulation would bring two platforms/structures on line over the time frame of the analysis; and that only one firm will build an Alaska platform during the analysis period. To reflect the possibility that two structures could be built in one year by one firm, those firms assumed to bring two deepwater structures on line are assigned the annualized costs of compliance for two platforms in one year for comparison against one year's revenue. This analysis was conducted on a pre-tax and after-tax basis. If the assumption of two platforms built in one year has any effect, it would increase the likelihood of finding economic impacts. With no firm-level impacts found under this scenario, then there will also be no impacts under other, possibly more likely, scenarios in which costs are incurred over several years.

i. Platform-Level Production/Shut-In Analysis

Compliance costs resulting from the final regulation may affect a platform's financial performance and related operating decisions in two ways. First, increased costs from regulatory compliance will reduce the expected economic value of an oil and gas production project, and may prevent an otherwise financially viable project from being undertaken. Second, even if a project overall remains financially viable, increased operating costs may lead to an earlier production shut-in than would occur in the baseline. Details of the analysis of these effects are provided below.

For the analysis of these effects, EPA constructed a general platform analysis model, which simulates the operations and economics of oil and gas development and production. The platform model analyzes production over a period extending as long as 30 years. Pre-tax costs (including costs incurred in pre-production years, O&M, monitoring costs, and repermitting costs) are input into the model in the year in which they occur, until the model shows the platform is uneconomical to operate. To determine the shut-in year, projected net revenue is compared to operating costs in each production year. Net revenue is based on an assumed price of oil, current and projected production of oil and gas, well production decline rates, and severance and royalty rates. Operating costs are based on a calculated cost per barrel of oil equivalent (BOE) produced. The model simulates operations for the lesser of 30 years or to the year when operating costs exceed production revenue, at which point the operator is assumed to terminate production. The model calculates the lifetime of the project, total production, and the net present value of the operation (net income of the operation over the life of the project in terms of today's dollars). A comparison of the baseline model outputs to the post-compliance model outputs yields any losses of production and project duration and the net present value of the operation. If the net present value of the operation is positive in the baseline but negative post-compliance, the project is considered nonviable post-compliance. It is assumed the platform would not be built.

The model uses as baseline data, financial information from representative existing platforms, collected in EPA's 316(b) survey of production platforms to represent the financial characteristics of future platforms that would be subject to this final regulation. EPA received an economic survey from only one deepwater platform with cooling water intake rates meeting the final regulatory criteria. EPA used data from this survey and from other sources of publicly available information, such as the Minerals Management Service, to develop a model new deepwater oil and gas production platform. EPA also received a survey from a platform in Alaska but did not include it in the analysis because the surveyed platform is a very old structure and at the end of its productive life. EPA believed that it would not be representative of new platforms being built after the Phase III rule is finalized. The Alaska platform is therefore analyzed only in the barrier to entry analysis.

Analysis of Project Viability

As noted above, any increase in costs, whether operating, capital, or permitting, will reduce the expected economic value of an oil and gas project, as represented by the present value of project net income, and may cause an otherwise economic oil and gas production project to never be undertaken. In this case, the entire economic value of the project and its otherwise recoverable oil and gas production are assumed to be lost. (EPA notes that this loss need not be permanent but may only be delayed until higher product prices, or reduced development and production costs allow the project to become financially viable.) For this potential impact, EPA analyzed whether the reduction in value from all regulatory compliance outlays would be sufficient to cause the expected discounted net income of an otherwise economically viable oil and gas production project to be negative at the outset. In this case, the operator is assumed not to proceed with development and production. If the platform has a positive net present value under baseline conditions but a negative net present value in the post-compliance scenario, EPA notes an impact on the platform and estimates the lost production resulting from the costs of regulatory compliance.

Analysis of Production Shut-In Effects

Although a project overall remains financially viable, the increased operating costs from regulatory compliance may lead to an earlier production shut-in than would occur in the baseline. Apart from the financial impact, an earlier shut-in will also lead to reduced production of otherwise economically recoverable oil and gas. For this analysis, projected net revenue is compared to operating costs at each year for the model project.[9] Net revenue (after subtracting royalties and severance, which are payments to the lease owner and a State, if relevant) is based on an assumed price of oil, current and projected production of oil and gas, well production decline rates, and severance and royalty rates. Operating costs are based on a calculated cost per barrel of oil equivalent (BOE) produced. The model simulates operations for the lesser of 30 years or to the year when operating costs exceed production revenue, at which point the operator is assumed to terminate production. A comparison of total production and total project lifetime in the baseline vs. post-compliance shows any differences in

[9] Following engineering review of surveyed deepwater platforms/structures, only one was determined to have a total design cooling water intake structure intake flow rate meeting the proposed 316(b) thresholds for regulation of oil and gas facilities, had the structure been newly constructed, so only one model of deepwater structures was developed.

these variables following the imposition of compliance costs.

This analysis found no impacts on deepwater oil and gas development or production as a result of the incremental compliance costs associated with this rule, for the one platform that was analyzed. Impacts on net present value were very small.

ii. Platform-Level Barrier-to-Entry Analysis

The barrier-to-entry analysis compares the present value of the initial permitting cost stream (discounted to the year of compliance) plus one-time capital/installation costs to the costs of constructing a new platform. If compliance costs comprise a small fraction of construction costs, EPA assumes that compliance costs would not have an effect on the decision to build a new platform.

The estimated total present values of incremental compliance costs are $306,323 for deepwater projects and $708,058 for Alaska projects. Costs for constructing new deepwater platforms are estimated to range from $114 million to $2.3 billion (see EA for the Synthetic Drilling Fluid Effluent Limitations Guidelines in the rulemaking record, DCN 7–4017). For Alaska, EPA used a value of $120 million (DCN 7–4028). The ratio of incremental compliance costs to current total construction costs therefore ranges from 0.01 percent to 0.3 percent for deepwater projects and is estimated to be 0.6 percent for an Alaska project. Because this represents a small fraction of total construction costs (and even of contingency costs), EPA believes that these costs would not have a material effect on decisions to build new platforms.

iii. Firm-Level Cost-to-Revenue Analysis

• To determine the potential impact of the final rule on firms, EPA used a cost-to-revenue test, which compares the annualized pre-tax and after-tax costs of compliance (calculated for a representative new platform times the maximum number of platforms assumed built by each firm in any one year), with 2004 revenue reported by all firms determined likely to be affected by this regulation. The firms that are considered affected are (1) those identified as currently having existing deepwater platforms or structures that would be subject to regulation if they were newly constructed and (2) the likeliest type of firm to build a new Alaska platform during the time frame of the analysis. EPA assumed each of the 11 firms operating in the deepwater Gulf would bring on-line two platforms during the period of analysis. To reflect the possibility that two structures could be built in one year by one firm, EPA assumes the two platforms come on line in one year for comparison with one year's revenue at each firm. If this assumption has any effect, it would increase the likelihood of finding economic impacts. With no firm-level impacts found under this scenario, then there will also be no impacts under other, possibly more likely, scenarios in which costs are incurred over several years. In addition, one small firm is assumed to build the one Alaska platform over the period of analysis, and the annualized compliance cost is also compared to one year's revenue at that firm.

Using these assumptions, EPA estimates that the annualized pre-tax costs per firm are about $0.2 million, and the after-tax costs are about $0.1 million. The pre-tax cost-to-revenue ratio ranges from <0.001 percent to 0.032 percent, while the after-tax ratios range from <0.001 percent to 0.021 percent. Given that the highest estimated ratio is 0.032 percent, EPA concludes that firm-level impacts would not pose a barrier to entry.

c. Total Facility Compliance Costs and Impacts for All New Oil and Gas Facilities

Exhibit IX–1 summarizes the total facility compliance costs and impacts associated with the final regulation for Phase III new offshore oil and gas facilities. Annualized after-tax costs total $1.9 million per year for MODUs and $1.3 million per year for platforms, or a total of $3.2 million per year for all affected new oil and gas operations estimated to be constructed over the period of the analysis (using a 7 percent discount rate). Costs are incurred assuming 20 years of new facility construction, with each facility incurring costs over a 30-year operating period, discounted to the year the facility is launched or comes on-line. The present value of these costs is calculated, then annualized over the 30 operating years at 7 percent. The present value of private after-tax costs is less than the previously described present value of social costs, which are based on pre-tax costs, because of differences in the discounting for private costs and social costs. Private costs are discounted, for each analysis, only to the first year of compliance. In contrast, for the social cost calculation, all costs are discounted to the beginning of 2007, regardless of when new facilities come into operation. Because new facilities are scheduled to begin operation for a 20 year period following rule promulgation, the total effect of discounting is much greater for the present value of social cost calculation than for the private cost calculation. As a result, the present value of social cost, even though based on pre-tax costs, is less than the present value of private, after-tax cost.

EXHIBIT IX–1.—SUMMARY OF PRIVATE COSTS AND IMPACTS FOR NEW OIL AND GAS FACILITIES

Type of oil and gas facility	Number of new facilities	Annualized private after-tax compliance costs (in millions, $2004)	Facility impacts	Firm impacts
MODUs	103	$1.9	0	0
Platforms	21	1.3	0	0
Total	124	3.2	0	0

Note: Component values may not sum to the reported total due to independent rounding.

Exhibit IX–2, below, summarizes total social costs and impacts for the final regulation for new offshore oil and gas extraction facilities.

EXHIBIT IX–2.—SUMMARY OF ECONOMIC ANALYSIS FOR THE 316(b) PHASE III FINAL REGULATION APPLICABLE TO NEW OFFSHORE OIL AND GAS EXTRACTION FACILITIES

	Annualized social cost (in millions, $2004) [1 2]	Number of facilities subject to national requirements	Number of facilities with impacts
Direct Compliance Cost for New Oil and Gas Facilities	$3.4–$2.8	124	0
Total State and Federal Administrative Cost	$0.4–$0.3		
Total Social Cost	$3.8—$3.2		

[1] The left side of the each range is the cost discounted at 3% and the right side is cost discounted at 7%.
[2] Numbers may not sum to totals due to independent rounding.

B. Existing Phase III Facilities

As described earlier in this Preamble, EPA has decided that Phase III facilities should continue to be permitted on a case-by-case best professional judgment basis. Since EPA is not promulgating a national categorical section 316(b) rule for existing Phase III facilities, there are no additional compliance costs associated with this action for these facilities. However, EPA did estimate the costs for the national categorical regulatory options we considered. More information on the costing analysis can be found in the Development Document and in the public record for this action.

This part of the Preamble describes the cost and economic impact analyses undertaken for the three national categorical regulatory options that were considered for the Phase III final regulation for existing facilities. These three options were defined by a regulatory applicability threshold based on design intake flow (DIF) and by the type of waterbody from which cooling water is withdrawn. As described at Proposal, these regulatory options are as follows:

1. Facilities with a total design intake flow of 50 million gallons per day (MGD) or more and located on any source waterbody type (50 MGD All Waterbodies);

2. Facilities with a total design intake flow of 200 MGD or more and located on any source waterbody type (200 MGD All Waterbodies);

3. Facilities with a total design intake flow of 100 MGD or more and located on certain source waterbody types (*i.e.*, an ocean, estuary, tidal river/stream or one of the Great Lakes) (100 MGD Coastal/Great Lakes).

These facilities are primarily engaged in the manufacturing of paper, chemicals, petroleum, aluminum, and steel, but include other industries such as food production as well as a few non-manufacturing facilities. As described in the NODA, EPA evaluated Food and Kindred Products as a primary industry; see Chapter B2F of the final EA. Non-manufacturing industries comprise less than 1 percent of the total facilities potentially regulated under each of the co-proposed options. In addition to engaging in production activities, some facilities also generate electricity for their own use and occasionally for sale.

Summary of Facilities Potentially Subject to a Final National Categorical Phase III Regulation for Existing Facilities

Exhibit IX–3 presents, by DIF option, EPA's estimates of (1) the number of existing facilities potentially subject to this rulemaking, (2) the number of baseline closures, and (3) the number of existing facilities subject to national requirements under the proposed regulations, after removal of baseline closures.

EXHIBIT IX–3.—PHASE III EXISTING MANUFACTURERS FACILITY COUNTS, BY DIF OPTION

Industry	Facilities potentially subject to regulation, based on applicability criteria	Baseline closures	Subject to National requirements, excluding baseline closures
50 MGD All Waterbodies			
Primary Man. Industries	155	14	140
Other Industries	7	1	6
Total	161	15	146
Total DIF (MGD)	31,215	1,907	29,308
200 MGD All Waterbodies			
Primary Man. Industries	31	1	30
Other Industries	2	1	1
Total	33	2	31
Total DIF (MGD)	18,973	682	18,292
100 MGD Coastal/Great Lakes			
Primary Man. Industries	24	3	21
Other Industries	3	1	2

EXHIBIT IX–3.—PHASE III EXISTING MANUFACTURERS FACILITY COUNTS, BY DIF OPTION—Continued

Industry	Facilities potentially subject to regulation, based on applicability criteria	Baseline closures	Subject to National requirements, excluding baseline closures
Total	27	4	23
Total DIF (MGD)	8,654	747	7,907

Note: Totals may not sum due to independent rounding.

1. Method for Estimating Costs to Manufacturers

Detailed information was not available for the universe of potential Phase III facilities, and the precise cost and performance of each technology on a site-specific basis cannot be determined. Thus, EPA developed model facility costs using the methodology outlined at proposal (see 69 FR 68498) and discussed in Chapter 5 of the TDD. EPA collected facility-specific process information using a detailed technical survey of Electric Generators and Manufacturers (see 69 FR 68457). EPA first calculated facility-specific costs for 354 facilities for which detailed information was available, and applied the model facility approach used at proposal to the remaining facilities to calculate the industry-level costs. This universe included all potential Phase III facilities, including those with a design intake flow of 2 MGD to 50 MGD that were not included in any of the proposed regulatory options.

As was the case in its analysis of compliance costs for the oil and gas extraction rule promulgated today, EPA adopted the best-performing technology approach for estimating compliance costs at cooling water intakes for Phase III existing facilities. EPA recognizes that the actual technology and/or operational measures that each facility might select are based on site-specific considerations. In particular, it is difficult to determine the precise performance of each technology on a site-specific basis for several hundred facilities. The Agency thus selected, for the subset of sites where multiple technologies could be considered to meet the proposed national categorical requirements, a best performing technology rather than the least cost technology from among the choices. As articulated in the preamble to the Phase II final rule (69 FR 41650), the best performing technology concept relies on assigning technologies around a median cost, with some choices above and some choices below. EPA believes that the best-performing technology approach, unlike a least-cost approach, takes site-specific considerations that cannot be accurately predicted in advance into account. EPA believes that the best-performing technology approach is appropriate to use for existing facilities under Phase III, and it has continued to rely upon it here. EPA notes that the proposal and NODA identified refinements made to the methodology, and made it available for public comment.

In addition to the capital and annual operating costs of the selected technology module, some facilities were projected to incur net downtime costs. Downtime costs generally reflect decreased revenue due to lost production or costs of supplemental power purchases during the retrofit of existing cooling water intake structures. As described in the NODA (70 FR 71057), 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 Phase III model facilities with multiple intakes, final downtime estimates remain at zero for those facilities with shoreline intakes that are not dedicated intakes, as discussed in the proposal. Using the approach presented in the NODA, downtime estimates were 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). Costs also reflect the corrected design intake flow as described in the NODA. See chapter 5, section 5 of the TDD and DCN 8–6601A, Downtime Duration Input and Analysis of Manufacturing Facilities, for additional details on the final downtime analysis.

Permit costs, including costs for permitting, monitoring, permit reissuance, and recordkeeping were developed separately as part of the proposed Information Collection Request (ICR) for Cooling Water Intake Structures Phase III (''ICR''; DCN 7–0001). The per facility permit costs were added to the incremental compliance costs, along with installation downtime costs (where appropriate), in developing the total model facility cost. The per facility permit costs may be found in Chapter B1 of the EA (also see the ICR for this rule, DCN 9–0001, for more information).

2. Social Cost for Existing Manufacturing Facilities

EPA calculated the social cost of the principal regulatory options for existing manufacturing facilities using two discount rate values: 3 percent and 7 percent. All dollar values presented are in $2004 (average or mid-year). For the analysis of social costs, EPA discounted all costs to the beginning of 2007, assuming that it would take facilities about six months to begin incurring costs. EPA assumed that all facilities subject to the regulation would achieve compliance between 2010 and 2014. EPA estimated the time profile of compliance and related costs over 30 years from the year of compliance for each complying facility.[10] Costs incurred by governments for administering the regulation were analyzed over the same time frame. The last year for which costs were tallied is 2043. Exhibit IX–4 presents the total social cost.

[10] Benefits are tallied and discounted in the same way, although the total time profile for recognition of benefits is longer than the profile for recognition of costs to account for a 1–6 year lag reflecting population dynamics.

EXHIBIT IX–4.—ANNUALIZED SOCIAL COST [1]

(In millions, $2004)

	50 MGD all waterbodies	200 MGD all waterbodies	100 MGD CWB
Direct Compliance Cost:			
Primary Manufacturing Industries	$36.3–37.1	$18.8–$19.5	$13.7–$13.3
Other Industries	1.3–1.2	0.5–0.4	0.7–0.7
Total Direct Compliance Cost	37.6–38.3	19.3–20.0	14.4–13.9
State and Federal Administrative Cost	0.6–0.6	0.2–0.2	0.2–0.2
Total Social Cost	38.2–39.0	19.5–20.2	14.6–14.1

[1] The left side of each range is the cost discounted at 3%, and the right side of each range presents the cost with a 7% discount rate. The effect of the discount rate varies across regulatory options in the table because the time profile of costs varies across facilities and technology choices.

3. Economic Impacts for Manufacturers

The economic impact analyses assess how facilities, and the firms that own them, would potentially be affected financially by the national categorical options. The facility impact analysis uses compliance cost estimates (see section IX.A.2) to calculate how incurring these costs would affect the financial performance and condition of the regulated facilities.

This section presents EPA's estimated economic impacts on manufacturers for the national categorical regulatory options considered by EPA. Impact measures include (1) facility closures and associated losses in employment, (2) financial stress short of closure (''moderate impacts''), and (3) firm-level impacts. EPA eliminated from this analysis those facilities showing materially inadequate financial performance in the absence of additional regulation (''baseline closures'').

For the remaining facilities, EPA identified a facility as a regulatory closure if it would have operated under baseline conditions but would fall below an acceptable financial performance level under additional regulatory requirements. EPA's analysis of regulatory closures is based on the estimated change in facility after-tax cash flow and business value as a result of the national categorical regulatory options considered. (See EA, Chapter B3 for details of the cash flow calculation and assessment of the potential for facility closure as a result of additional regulatory requirements.)

EPA's analysis of moderate financial impact is based on change in facility financial performance and condition as indicated by Interest Coverage Ratio (ICR) and Pre-Tax Return on Assets (PTRA). (See EA Appendix B3–A6 for details of the moderate impacts analysis.) See the EA for a detailed description of EPA's baseline closure analysis and firm level analyses.

As shown in Exhibit IX–5, EPA estimated that none of the baseline-pass facilities would incur a severe impact (closure) or a moderate economic impact (financial impact short of closure) under the national categorical regulatory options considered.

EXHIBIT IX–5.—SUMMARY OF COST AND REGULATORY IMPACTS FOR EXISTING MANUFACTURING FACILITIES BY REGULATORY OPTION

	50 MGD All	200 MGD All	100 MGD CWB
Facilities Operating in Baseline	144	144	144
Facilities with Regulatory Requirements	144	30	24
Percentage of Facilities with Regulatory Requirements	100.0%	20.8%	16.7%
Facilities Assessed as Closures (Severe Impacts)	0	0	0
Percentage of Facilities with Regulatory Requirements Assessed as Closures	0.0%	0.0%	0.0%
Facilities Assessed as Moderate Impacts	0	0	0
Percentage of Facilities with Regulatory Requirements with Moderate Impacts	0.0%	0.0%	0.0%
Annualized Compliance Costs (after tax, million $2004)	$26.8	$11.8	$12.1

X. Benefits Analysis

A. Introduction

Since EPA is not promulgating national section 316(b) requirements for existing Phase III facilities, this action will achieve no benefits with respect to existing facilities. Any benefits associated with establishing section 316(b) requirements for existing Phase III facilities will be realized at the permitting level, as is currently the case, and therefore should not be attributed to today's decision. However, EPA did estimate the benefits for the national categorical regulatory options considered. These benefits estimates should be compared only to the cost estimates for these options for existing Phase III facilities.

The benefit estimates presented below reflect impingement mortality and entrainment reductions at Phase III existing facilities but not at new offshore oil and gas extraction facilities. EPA does not project benefits for facilities that have not yet been built because to do so would require projecting where these facilities would be built and/or operate. For a comparison of social use benefits and total social costs, refer to Section XI.

B. Study Design and Methods

The methodologies used here are built upon those used for estimating benefits of the final rule for Phase II facilities (see FR 69, 41576–693). The national benefit estimates are derived from a series of regional studies for a range of waterbody types throughout the U.S. EPA evaluated impingement and entrainment data from 76 Phase II facilities and 20 potentially regulated

Phase III facilities.[11] Using standard fishery modeling techniques, EPA combined facility-derived impingement and entrainment counts with relevant life history data to derive estimates of (1) age-one equivalent losses (the number of individuals of different ages impinged and entrained expressed as an equivalent number of age-one fish), and (2) foregone fishery yield (pounds of commercial harvest and numbers of recreational fish and shellfish not harvested due to impingement and entrainment). Of the organisms that were anticipated to be protected by the national categorical analysis option, approximately 2 to 3 percent would have been eventually harvested by commercial and recreational fishers and therefore can be valued with direct use valuation techniques.

To obtain a national estimate of losses at all potentially regulated facilities, EPA extrapolated impingement and entrainment rates from facilities with data (model facilities) to facilities without data, on the basis of operational intake flow in millions of gallons per day (MGD). Exhibit X–1 presents EPA's estimates of current annual impingement and entrainment (I&E) and EPA's estimates of annual I&E reductions under the national categorical regulatory options.

EXHIBIT X–1.—ANNUAL IMPINGEMENT AND ENTRAINMENT [a] BASELINE LOSSES AND ESTIMATED REDUCTIONS UNDER THE NATIONAL CATEGORICAL REGULATORY OPTIONS

	Age-1 equivalent fish	Foregone fishery yield (lbs)
Baseline	265,000,000	9,640,000
50 MGD All Option	98,200,000	4,770,000
200 MGD All Option	74,500,000	3,290,000
100 MGD CWB Option	71,100,000	4,510,000

[a] I&E data are rounded to three significant figures.

C. National Benefits

Economic benefits of the national categorical regulatory options for the section 316(b) regulation for Phase III existing facilities can be defined according to categories of goods and services provided by the species affected by impingement and entrainment by cooling water intake structures.

The first category includes benefits that pertain to the use (direct or indirect) of the affected fishery resources. Use value reflects the value of all current direct and indirect uses of a good or service such as commercial and recreational harvest of fish (Mitchell and Carson, 1989, DCN 5–1287). In this context, direct use values are associated with harvested fish, while indirect use values are associated with non-harvested fish that are prey for harvested fish. The second category includes benefits that are independent of any current or anticipated use of the resource; these are known as ''non-use'' or ''passive use'' values. Non-use values include ''nonmarketed'' goods and services, which reflect human values associated with existence, bequest, and altruistic motives.

EPA estimated the economic benefits from the national categorical regulatory options using a range of valuation methods, depending on the benefit category, data availability, and other suitable factors. EPA calculated benefits of the national categorical regulatory options for existing Phase III facilities using two discount rate values: 3 percent and 7 percent. All dollar values presented are in $2004 (average or mid-year). Because avoided fish deaths occur mainly in fish that are younger than harvestable age (eggs, larvae and juveniles), the benefits from avoided impingement and entrainment would be realized typically 3–4 years after their avoided death. A detailed description of the approaches used can be found in the Regional Analysis Document.

1. Use Benefits

To estimate recreational benefits of the national categorical regulatory options, EPA developed a benefits transfer approach based on a meta-analysis of recreational fishing valuation studies designed to measure the various factors that determine willingness-to-pay for catching an additional fish per trip. To estimate the benefits, EPA multiplied the per fish values by the number of additional fish that would be caught by anglers under the national categorical regulatory options due to reductions in impingement and entrainment, compared to current levels of recreational catch. To estimate commercial fishing benefits, EPA monetized the reduction in forgone fishery yield using market prices, effectively assuming that the change in forgone yield was small enough to have an insignificant impact on price.

2. Non-Use Benefits

To assess the public policy significance of the ecological gains from the national categorical regulatory options for Phase III facilities, EPA also attempted to quantify nonuse benefits associated with reduction in impingement and entrainment of fish, shellfish, and other aquatic organisms under the national categorical regulatory options, but was unable to do so in time to meet the consent decree deadline. EPA also conducted a break-even analysis of non-use benefits (see the Regional Analysis Document for details).

3. National Benefits

This section presents EPA's estimated benefits of the national categorical regulatory options considered by EPA's final regulation for Phase III existing facilities. Since the Agency was unable to monetize non-use benefits, the monetized estimates of total benefits reflect use values only. National use benefit estimates (see Exhibit X–2) are subject to uncertainties inherent in valuation approaches used for assessing the benefits categories. The combined effect of these uncertainties is of unknown magnitude or direction (*i.e.*, the estimates may over- or under-state the anticipated national-level benefits); however, EPA has no data to indicate that the results for each benefit category are atypical or unreasonable.

[11] ''Potentially regulated Phase III facilities'' refers to all existing facilities with design intake flows greater than 2 MGD and not regulated under the Phase II rule.

EXHIBIT X–2.—SUMMARY OF MONETIZED SOCIAL USE BENEFITS UNDER THE NATIONAL CATEGORICAL REGULATORY OPTIONS

[Thousands, $2004] [a]

Option	Annualized commercial fishing benefits	Annualized recreational fishing benefits	Total annualized value of monetizable impingement and entrainment reductions [b]
50 MGD All	$255–$321	$1,543–$1,931	$1,798–$2,251
200 MGD All	167–211	1,027–1,288	1,194–1,499
100 MGD CWB	244–308	1,244–1,564	1,489–1,872

[a] All benefits presented in this table are annualized. These annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a thirty year period. For a more detailed discussion of the discounting methodology, refer to section X.D.2 of this preamble. The low end of these ranges is based on the value of benefits discounted using a 7% discount rate while the high end is based on the value of benefits discounted using a 3% discount rate.

[b] The estimate of the total monetizable value of impingement and entrainment reductions includes use benefits only.

XI. Comparison of Benefits and Costs

Since EPA is not promulgating national section 316(b) requirements for existing Phase III facilities, there are no benefits or compliance costs for existing facilities from this action. However, EPA did estimate the benefits and costs for the regulatory options considered for existing facilities. You can find more information on these benefit and cost analyses in the Economic and Benefits Analysis, Regional Analysis Document, and in the public record for this action.

EPA does not project benefits for facilities that have not yet been built because such estimates would rely on speculating where these facilities would be built and/or operate. EPA has no basis to predict exactly where the new facilities might locate, when the facilities might commence operation, or when and where mobile facilities may relocate; therefore EPA did not develop benefits estimates for new offshore oil and gas extraction facilities. Hence it is not possible to compare quantified costs and benefits associated with this final rule.

This section presents comparisons of the national benefits and costs of the national categorical regulatory options. The benefit-cost analysis for the national categorical regulatory options compares total annualized use benefits to total annualized pre-tax costs (social costs) at existing facilities that remain open in the baseline. Benefits and costs were discounted using both a 3 percent and a 7 percent discount rate. The cost estimates include costs of compliance to facilities subject to the final rule as well as administrative costs incurred by state and local governments and by the federal government. The benefits estimates include monetized benefits to commercial and recreational fishing. The total monetizable benefits include only use benefits. The non-use benefits were evaluated qualitatively.

Exhibit XI–1 summarizes total annualized use benefits, total annualized costs, and net benefits for the national categorical options.

EXHIBIT XI.—SUMMARY OF SOCIAL BENEFITS AND COSTS FOR THE NATIONAL CATEGORICAL REGULATORY OPTIONS

[Millions; $2004]

Option	Number facilities subject to option	Number of facilities installing technology	Total annualized use value of I&E reductions [a]	Total annualized costs [b]	Cost/benefit ratio
50 MGD All Waterbodies	146	111	$1.80–$2.25	$38.27–$39.00	17/1–22/1
200 MGD All Waterbodies	31	27	1.19–1.5	19.48–20.14	13/1–17/1
100 MGD Coastal/Great Lakes	23	22	1.49–1.87	14.57–14.11	8/1–10/1

[a] The total monetizable value of I&E reductions includes use benefits only. EPA evaluated non-use benefits only qualitatively. The low and high use values reflect the range of benefits values presented in Section X of the preamble.

[b] Total costs are based on pre-tax facility costs and include State, local, and Federal administrative costs of $0.6 million. The low and high cost values reflect the range of cost values presented in Section IX of the preamble.

XII. Statutory and Executive Order Reviews

The discussion of the regulatory statutes and Executive Orders in this section addresses requirements relevant to new offshore oil and gas extraction facilities. As discussed in section VI of this preamble, EPA has decided not to promulgate national categorical standards for Phase III existing facilities.

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866, (58 FR 51735 (October 4, 1993)) the Agency must determine whether the regulatory action is ''significant'' and therefore subject to OMB review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

• Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

• Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.''

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a ''significant regulatory action.'' As such, this action was submitted to OMB for review. Substantive changes made in response to OMB suggestions or recommendations will be documented in the public record.

B. Paperwork Reduction Act

The Office of Management and Budget (OMB) has approved the information collection requirements contained in this rule under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control number 2040–0268.

The information collected under this final rule will assist EPA in regulating environmental impacts, namely impingement mortality and entrainment, at cooling water intake structures at new offshore oil and gas extraction facilities. This information will be used by these facilities as appropriate to prepare permit applications and comprehensive demonstration studies, monitor impingement mortality and entrainment, verify compliance, and prepare annual reports as required under this rule. The information collected will be reviewed by EPA to ensure that appropriate National Pollutant Discharge Elimination System (NPDES) permit conditions regulating cooling water intake structures are developed and complied with. Compliance with the applicable information collection requirements imposed under this final rule is mandatory (see §§ 122.21(r), 125.136, 125.137, 125, 138).

EPA does not consider the specific data that will be collected under this final rule to be confidential business information. However, if a respondent does consider this information to be confidential, the respondent may request that such information be treated as confidential. All confidential data submitted to EPA will be handled in accordance with 40 CFR 122.7, 40 CFR part 2, and EPA's Security Manual Part III, Chapter 9, dated August 9, 1976.

This final rule modifies regulations at § 122.21 to require new offshore oil and gas extraction facilities to prepare and submit information consistent with that required for Phase I facilities (the requirements vary based on whether the facility is a ''fixed'' facility and whether it uses a sea chest). A detailed list of required data items is provided below.

The total average annual burden of the information collection requirements for new offshore oil and gas facilities associated with this final rule is estimated at 11,238 hours for an average of 22 facilities during the first three years after promulgation of the rule. Hence, the annual average reporting and recordkeeping burden for the collection of information from facilities complying with the final rule is estimated to be 511 hours per respondent.

For new offshore oil and gas extraction facilities, the permitting process is handled directly by EPA Regions. Because this burden is incurred by the Federal Government rather than the States, it is not included as part of the burden statement for State Directors. Hence, there will be no increase in the Director reporting and recordkeeping burden for the review, oversight, and administration of the rule.

The corresponding estimates of costs other than labor (labor and non-labor costs are included in the total cost of the final rule discussed in section IX of this preamble) during the first three years after promulgation of the rule is $0.58 million. Non-labor costs include activities such as capital costs for remote monitoring devices, laboratory services, photocopying, and the purchase of supplies. The burden and costs are for the information collection, reporting, and recordkeeping requirements for the three-year period beginning with the assumed effective date of this rule. Additional information collection requirements will occur after this initial three-year period as new offshore oil and gas extraction facilities are issued permits and such requirements will be counted in a subsequent information collection request.

Studies to be submitted by new offshore oil and gas extraction facilities under this final rule are listed below. New offshore oil and gas fixed platforms would be required to provide the general information listed below.

• Source Water Physical Data (§ 122.21(r)(2)) (§ 122.21(r)(2)(iv) only for non-fixed new offshore oil and gas extraction facilities)

• Cooling Water Intake Structure Data (§ 122.21(r)(3)) (§ 122.21(r)(3)(ii) not applicable to non-fixed new offshore oil and gas extraction facilities)

New offshore oil and gas extraction facilities would be required to submit the following information under Track I:

• Source Water Baseline Biological Characterization Data (§ 122.21(r)(4)) (not required for non-fixed facilities)

• Velocity Information (§ 125.136(b)(1))

• Source Waterbody Flow Information (§ 125.136(b)(2)) (only applicable to fixed facilities located in estuaries or tidal waters)

• Design and Construction Technology Plan (§ 125.136(b)(3))

Under Track II, new offshore oil and gas extraction facilities would be required to submit the following information:

• Source Waterbody Flow Information (§ 125.136(c)(1)) (only applicable to fixed facilities located in estuaries or tidal waters)

• Comprehensive Demonstration Study (§ 125.136(c)(2))

○ Source Water Biological Study (§ 125.136(c)(2)(iii)(A))

○ Evaluation of Potential Cooling Water Intake Structure Effects (§ 125.136(c)(2)(iii)(B))

○ Verification Monitoring Plan (§ 125.136(c)(2)(iii)(C))

In addition to the information requirements of the permit application, NPDES permits normally specify monitoring and reporting requirements to be met by the permitted entity. New offshore oil and gas extraction fixed facilities would be required to perform monitoring as determined by the Track I or Track II requirements in § 125.136 and in accordance with § 125.137. Additional ambient water quality monitoring may also be required of facilities depending on the specifications of their permits (e.g., as part of velocity monitoring at § 125.137(b)). New offshore oil and gas extraction facilities would be expected to analyze the results from their monitoring efforts and are required to provide these results in an annual status report to the permitting authority. Finally, facilities would be required to maintain records of all submitted documents, supporting materials, and monitoring results for at least three years.

All impacted facilities would carry out the specific activities necessary to fulfill the general information collection requirements. The estimated burden includes developing a water balance diagram that can be used to identify the proportion of intake water used for cooling, make-up, and process water. Facilities would also gather data to calculate the reduction in impingement mortality and entrainment of all life stages of fish and shellfish that would be achieved by the technologies and operational measures they select. The burden estimates include sampling, assessing the source waterbody, estimating the magnitude of impingement mortality and entrainment, and reporting results in a comprehensive demonstration study. The burden may also include conducting a pilot study to evaluate the suitability of the technologies and operational measures based on the species that are found at the site.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. In addition, EPA is amending the table in 40 CFR part 9 of currently approved OMB control numbers for various regulations to list the regulatory citations for the information requirements contained in this final rule.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. This section summarizes EPA's analyses in compliance with the RFA.

1. Definition of Small Entity

Small entities include small businesses, small organizations, and small governmental jurisdictions. For assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

The SBA small business size standards changed from a SIC code-based system to a NAICS code-based system on October 1, 2000. The SBA revised the size standards upwards effective January 5, 2006. Since EPA conducted its data collection effort for existing facilities before these changes, EPA performed the small entity analysis for existing facilities based on SIC codes. EPA then conducted a subsequent analysis to determine if the size standards based on the revised NAICS codes would have any effect on the results of the small entity analysis. To be conservative, for those SIC codes that are associated with more than one NAICS code, the highest threshold of the associated NAICS codes was used as the threshold for the SIC code (e.g., if an SIC was associated with two NAICS codes, one with a small business threshold of 500 employees and one with a small business threshold of 750 employees, the SIC code was assigned a small business threshold of 750 employees, the higher of the associated NAICS). This process ensured that at least all small entities would be captured, but could potentially overstate the total number of small entities. This analysis showed there would be no changes to the small entity determination, and therefore to small entity impacts, as a result of switching from SIC-based size standards to NAICS-based size standards.

2. Certification Statement

After considering the economic impacts of this rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This regulation applies to new offshore oil and gas extraction facilities that withdraw 2 MGD or more from waters of the United States.

3. Statement of Basis

From its analysis, EPA estimates that the final rule will apply national standards to only one small entity, a new offshore oil and gas platform. EPA estimates this entity will incur annualized, after-tax compliance costs of less than 0.1 percent of annual revenue. EPA does not know precisely which firms will undertake construction of new offshore oil and gas extraction facilities. However, based on the firms that are currently active in building the types of facilities representative of those covered by the rulemaking, EPA believes that the small firm analyzed represents the smallest firm that will be involved in such activities over the period of the analysis.

4. Summary of Small Business Advocacy Review Panel

As described at Proposal, although not required by the RFA, EPA convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives (SERs) during development of the proposed regulation. A summary of EPA's small entity outreach and information on the composition, process, and findings of the SBAR panel can be found in the preamble of the Proposal. As noted above, only one small entity is estimated to be subject to national standards under this final regulation.

5. Small Entity Flexibility Analysis

Despite the determination that this rule will not have a significant economic impact on a substantial number of small entities, EPA prepared at Proposal, and updated its analysis for the final regulation, a Small Entity Flexibility Analysis that has all the components of a Final Regulatory Flexibility Analysis (FRFA). A FRFA examines the impact of a rule on small entities along with regulatory alternatives that could reduce that impact. The Small Entity Flexibility Analysis (which is described in detail in the Economic Analysis document) is available for review in the docket.

Under the final regulation, EPA estimates that only one small entity (a new offshore oil and gas facility) will be subject to the national categorical requirements. The one new offshore oil and gas facility potentially affected by the final rule is estimated to have a cost-to-revenue ratio of less than 0.1 percent.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of the UMRA, a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant intergovernmental mandates, and informing, educating, and advising small governments on compliance with regulatory requirements.

From its analysis for the final regulation, EPA estimates the total annualized after-tax costs of compliance to be $1.9 million ($2004). All of these direct facility costs are incurred by the private sector (124 oil and gas facilities). No facility owned by State or local governments is subject to the national requirements under the final rule. Additionally, permitting authorities will not incur costs to administer the rule for new offshore oil and gas extraction facilities because these facilities are not likely to be under State jurisdiction. As required by UMRA section 202, EPA estimates that the highest undiscounted after-tax cost incurred by the private sector in any one year is approximately $1.5 million in 2013.

From this analysis, EPA determined that this rule does not contain a Federal mandate that would result in expenditures of $100 million or more for State, local, and Tribal governments, in the aggregate, or the private sector in any one year. (See Economic Analysis, Chapter D2: UMRA Analysis, for more detailed information.) At proposal, when including the potential costs of the national categorical rule options, EPA determined that the proposal may have resulted in expenditures of $100 million or more for State, local, or Tribal governments, in the aggregate, or the private sector in any one year (69 FR 68539). Since EPA has chosen to continue to rely upon the permitting authority's best professional judgment to establish section 316(b) limits for existing facilities not covered by the Phase II rule, those potential costs were not included in the estimate for the final rule. EPA has determined that this final rule does not contain a federal mandate of $100 million or more. EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. Thus, this rule is not subject to the requirements of sections 202 and 205 of UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' are defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the Federal government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Rather, this rule would result in minimal administrative costs to States that have an authorized NPDES program.

States do not incur any burden hours and nonlabor costs to administer the rule for new offshore oil and gas extraction facilities since these facilities are outside of the jurisdiction of the States. EPA has identified zero Phase III existing facilities that are owned by federal, state or local government entities; therefore, the annual impacts on these facilities are zero.

The national cooling water intake structure requirements would be implemented through permits issued under the NPDES program. Forty-five States and the Virgin Islands are currently authorized pursuant to section 402(b) of the CWA to implement the NPDES program. In States not authorized to implement the NPDES program, EPA issues NPDES permits. Under the CWA, States are not required to become authorized to administer the NPDES program. Rather, such authorization is available to States if they operate their programs in a manner consistent with section 402(b) and applicable regulations. Generally, these provisions require that State NPDES programs include requirements that are as stringent as Federal program requirements. States retain the ability to implement requirements that are broader in scope or more stringent than Federal requirements. (See section 510 of the CWA.)

This rule would not have substantial direct effects on either authorized or nonauthorized States or on local governments because it would not change how EPA and the States and local governments interact or their respective authority or responsibilities for implementing the NPDES program. This rule would establish national requirements for new offshore oil and gas extraction facilities with cooling water intake structures. NPDES-authorized States that currently do not comply with the regulations based on this rule might need to amend their regulations or statutes to ensure that their NPDES programs are consistent with Federal section 316(b) requirements. For purposes of this rule, the relationship and distribution of power and responsibilities between the Federal government and the States and local governments are established under the CWA (e.g., sections 402(b) and 510); nothing in this rule would alter that. Thus, the requirements of section 6 of the Executive Order do not apply to this rule.

Although section 6 of Executive Order 13132 does not apply to this rule, EPA did consult with State governments and representatives of local governments in developing the rule. During the development of the proposed and final Phase I and Phase II section 316(b) rules and the proposed Phase III rule, EPA conducted several outreach activities through which State and local officials were informed about this rule and they provided information and comments to the Agency. The outreach activities were intended to provide EPA with feedback on issues such as adverse environmental impact, best technology available, and the potential cost associated with various regulatory alternatives. These outreach activities are discussed in section III of the preamble to the proposed rule at 69 FR 68457, as well as in the Response to Comment Document.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 6, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.''

This rule would not have tribal implications. It would not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian Tribes, or on the distribution of power and responsibilities between the Federal government and Indian Tribes, as specified in Executive Order 13175. At this time, there are no Tribes that own or operate facilities covered under this rule. Accordingly, the requirements of Executive Order 13175 do not apply to this rule.

Nevertheless, in the spirit of Executive Order 13175 and consistent with EPA policy to promote communications between EPA and Tribal governments, EPA solicited comment on the proposed rule from all stakeholders. EPA did not receive any comments from Tribal governments.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe might have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health and safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. This final rule is not an economically significant rule (using the $100 million threshold) as defined under Executive Order 12866. Further, it does not concern an environmental health or safety risk that would have a disproportionate effect on children.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This rule is not subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355 (May 22, 2001)) because it is not a significant regulatory action under Executive Order 12866. Based on comments received at Proposal, EPA examined the potential for the regulation to cause a ''significant adverse effect'' on the Nation's energy economy through its potential impact on petroleum refining operations. EPA performed this analysis, which is documented in the Economic Analysis Report for the final regulation, in accordance with guidance for implementing Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use''). Based on this analysis, EPA continues to find, as stated at Proposal, that the 316(b) Phase III regulation will not cause a Significant Adverse Effect and does not constitute a Significant Energy Action within the meaning of Executive Order 13211. As a result, EPA did not prepare a Statement of Energy Effects.

I. National Technology Transfer and Advancement Act

As noted in the proposed rule, section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995, Public Law 104–113, Sec. 12(d) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standard bodies. The NTTAA directs EPA to provide Congress, through the Office of Management and Budget (OMB), explanations when the Agency decides not to use available and applicable voluntary consensus standards. This rule does not involve any technical standards. Therefore, EPA did not considering the use of any voluntary consensus standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 requires that, to the greatest extent practicable and permitted by law, each Federal agency must make achieving environmental justice part of its mission. Executive Order 12898 provides that each Federal agency must conduct its programs, policies, and activities that substantially affect human health or the environment in a manner that ensures such programs, policies, and activities do not have the effect of excluding persons (including populations) from participation in, denying persons (including populations) the benefits of, or subjecting persons (including populations) to discrimination under such programs, policies, and activities because of their race, color, or national origin.

The Executive Order's main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and/or low-income populations.

This rule would require that the location, design, construction, and capacity of cooling water intake structures at new offshore oil and gas extraction facilities reflect the best technology available for minimizing adverse environmental impact. Due to the offshore location of these facilities, EPA does not expect that this rule would have an exclusionary effect, deny persons the benefits of the participating in a program, or subject persons to discrimination because of their race, color, or national origin.

In fact, because EPA expects that this rule would help to preserve the health of aquatic ecosystems located in reasonable proximity to new offshore oil and gas extraction facilities, it believes that all populations, including minority and low-income populations, would benefit from improved environmental conditions as a result of this rule. Thus EPA concludes that this action will not have the effect of excluding persons (including populations) from participating in, denying persons (including populations) the benefits of, or subjecting persons (including populations) to discrimination because of their race, color, or national origin.

K. Executive Order 13158: Marine Protected Areas

Executive Order 13158 (65 FR 34909, May 31, 2000) requires EPA to ''expeditiously propose new science based regulations, as necessary, to ensure appropriate levels of protection for the marine environment.'' EPA may take action to enhance or expand protection of existing marine protected areas and to establish or recommend, as appropriate, new marine protected areas. The purpose of the Executive Order is to protect the significant natural and cultural resources within the marine environment, which means ''those areas of coastal and ocean waters, the Great Lakes and their connecting waters, and submerged lands thereunder, over which the United States exercises jurisdiction, consistent with international law.''

This final rule recognizes the biological sensitivity of tidal rivers, estuaries, and oceans and their susceptibility to adverse environmental impact from cooling water intake structures. This rule provides requirements for reducing both impingement and entrainment using technologies to minimize adverse environmental impact for cooling water intake structures located on these types of waterbodies.

EPA expects that this rule would reduce impingement and entrainment at new offshore oil and gas extraction facilities. The rule would afford protection of aquatic organisms at individual, population, community, and/or ecosystem levels of ecological structures. Therefore, EPA expects this rule would advance the objective of the Executive Order to protect marine areas.

L. Congressional Review Act

The Congressional Review Act, 5. U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule can not take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This will be effective July 17, 2006.

List of Subjects

40 CFR Part 9

Environmental protection, Reporting and recordkeeping requirements.

40 CFR Part 122

Environmental protection, Administrative practice and procedure, Confidential business information, Hazardous substances, Reporting and recordkeeping requirements, Water pollution control.

40 CFR Part 23

Environmental protection, Administrative practice and procedure, Confidential business information, Hazardous substances, Indians-lands, Intergovernmental relations, Penalties, Reporting and recordkeeping requirements, Water pollution control.

40 CFR Part 124

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous waste, Indians-lands, Reporting and recordkeeping requirements, Water pollution control, Water supply.

40 CFR Part 125

Environmental protection, Cooling water intake structure, Reporting and recordkeeping requirements, Waste treatment and disposal, Water pollution control.

Dated: June 1, 2006.

Stephen L. Johnson,

Administrator.

■ For the reasons set forth in the preamble, chapter I of title 40 of the Code of Federal Regulations is amended as follows:

PART 9—OMB APPROVALS UNDER THE PAPERWORK REDUCTION ACT

■ 1. The authority citation for part 9 continues to read as follows:

Authority: 7 U.S.C. 135 *et seq.*, 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671, 21 U.S.C. 331j, 346a, 348; 31 U.S.C. 9701; 33 U.S.C. 1251 *et seq.*, 1311, 1313d, 1314, 1318, 1321, 1326, 1330, 1342, 1344, 1345 (d) and (e), 1361; E.O. 11735, 38 FR 21243, 3 CFR, 1971–1975 Comp. p. 973; 42 U.S.C. 241, 242b, 243, 246, 300f, 300g, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–1, 300j–2, 300j–3, 300j–4, 300j–9, 1857 *et seq.*, 6901–6992k, 7401–7671q, 7542, 9601–9657, 11023, 11048.

■ 2. In § 9.1 the table is amended by revising the entry for ''122.21(r)'' and by adding entries in numerical order under the indicated heading to read as follows:

§ 9.1 OMB approvals under the Paperwork Reduction Act.

* * * * *

40 CFR citation	OMB control No.
* * * * * *	*
EPA Administered Permit Programs: The National Pollutant Discharge Elimination System	
* * * * * *	*
122.21(r)	2040–0241, 2040–0257, 2040–0268
* * * * * *	*
Criteria and Standards for the National Pollutant Discharge Elimination System	
* * * * * *	*
125.134	2040–0268
125.135	2040–0268
125.136	2040–0268
125.137	2040–0268
125.138	2040–0268
125.139	2040–0268
* * * * * *	*

PART 122—EPA ADMINISTERED PERMIT PROGRAMS: THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

■ 3. The authority citation for part 122 continues to read as follows:

Authority: The Clean Water Act, 33 U.S.C. 1251 *et seq.*

■ 4. Section 122.21 is amended as follows:

■ a. Revising paragraph (r)(1)(i).

■ b. Removing ''and'' from the end of paragraph (r)(2)(ii).

■ c. Removing the period at the end of paragraph (r)(2)(iii) and adding ''; and'' in its place.

■ d. Adding a new paragraph (r)(2)(iv).

■ e. Revising paragraph (r)(4) introductory text.

§ 122.21 Application for a permit (applicable to State programs, see § 123.25)

* * * * *

(r) *Application requirements for facilities with cooling water intake structures*—(1)(i) *New facilities with new or modified cooling water intake structures.* New facilities (other than offshore oil and gas extraction facilities) with cooling water intake structures as defined in part 125, subpart I, of this chapter must submit to the Director for review the information required under paragraphs (r)(2) (except (r)(2)(iv)), (3), and (4) of this section and § 125.86 of this chapter as part of their application. New offshore oil and gas extraction facilities with cooling water intake structures as defined in part 125, subpart N, of this chapter that are fixed facilities must submit to the Director for review the information required under paragraphs (r)(2) (except (r)(2)(iv)), (3), and (4) of this section and § 125.136 of this chapter as part of their application. New offshore oil and gas extraction facilities that are *not* fixed facilities must submit to the Director for review only the information required under paragraphs (r)(2)(iv), (r)(3) (except (r)(3)(ii)), and § 125.136 of this chapter as part of their application. Requests for alternative requirements under § 125.85 or § 125.135 of this chapter must be submitted with your permit application.

* * * * *

(2) * * *

(iv) For new offshore oil and gas facilities that are not fixed facilities, a narrative description and/or locational maps providing information on predicted locations within the waterbody during the permit term in sufficient detail for the Director to determine the appropriateness of additional impingement requirements under § 125.134(b)(4).

* * * * *

(4) Source water baseline biological characterization data. This information is required to characterize the biological community in the vicinity of the cooling water intake structure and to characterize the operation of the cooling water intake structures. The Director may also use this information in subsequent permit renewal proceedings to determine if your Design and Construction Technology Plan as required in § 125.86(b)(4) or § 125.136(b)(3) of this chapter should be revised. This supporting information must include existing data (if they are available). However, you may supplement the data using newly conducted field studies if you choose to do so. The information you submit must include:

* * * * *

■ 5. Section 122.44 is amended by revising paragraph (b)(3) to read as follows:

§ 122.44 Establishing limitations, standards, and other permit conditions (applicable to State NPDES programs, see § 123.25).

* * * * *

(b) * * *

(3) Requirements applicable to cooling water intake structures under section 316(b) of the CWA, in accordance with part 125, subparts I, J, and N of this chapter.

* * * * *

PART 123—STATE PROGRAM REQUIREMENTS

■ 6. The authority citation for part 123 continues to read as follows:

Authority: The Clean Water Act, 33 U.S.C. 1251 *et seq.*

■ 7. Section 123.25 is amended by revising paragraph (a)(36) to read as follows:

§ 123.25 Requirements for permitting.

(a) * * *

(36) Subparts A, B, D, H, I, J, and N of part 125 of this chapter;

* * * * *

PART 124—PROCEDURES FOR DECISIONMAKING

■ 8. The authority citation for part 124 continues to read as follows:

Authority: Resource Conservation and Recovery Act, 42 U.S.C. 6901 *et seq.*; Safe Drinking Water Act, 42 U.S.C. 300f *et seq.*; Clean Water Act, 33 U.S.C. 1251 *et seq.*; Clean Air Act, 42 U.S.C. 7401 *et seq.*

■ 9. Section 124.10 is amended by revising paragraph (d)(1)(ix) to read as follows:

§ 124.10 Public notice of permit actions and public comment period.

* * * * *

(d) * * *

(1) * * *

(ix) Requirements applicable to cooling water intake structures under section 316(b) of the CWA, in accordance with part 125, subparts I , J, and N of this chapter.

* * * * *

PART 125—CRITERIA AND STANDARDS FOR THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

■ 10. The authority citation for part 125 continues to read as follows:

Authority: Clean Water Act, 33 U.S.C. 1251 *et seq.*; unless otherwise noted.

■ 11. In § 125.93 revise the definition of ''existing facility'' to read as follows:

§ 125.93 What special definitions apply to this subpart?

* * * * *

Existing facility means any facility that commenced construction as described in 40 CFR 122.29(b)(4) on or before January 17, 2002 or July 17, 2006 for an offshore oil and gas extraction facility); and any modification of, or any addition of a unit at such a facility that does not meet the definition of a new facility at § 125.83.

* * * * *

■ 12. Add subpart N to part 125 to read as follows:

Subpart N—Requirements Applicable to Cooling Water Intake Structures for New Offshore Oil and Gas Extraction Facilities Under Section 316(b) of the Act

Subpart N—Requirements Applicable to Cooling Water Intake Structures for New Offshore Oil and Gas Extraction Facilities Under Section 316(b) of the Act

§ 125.130 What are the purpose and scope of this subpart?

(a) This subpart establishes requirements that apply to the location, design, construction, and capacity of cooling water intake structures at new offshore oil and gas extraction facilities. The purpose of these requirements is to establish the best technology available for minimizing adverse environmental impact associated with the use of cooling water intake structures at these facilities. These requirements are implemented through National Pollutant Discharge Elimination System (NPDES) permits issued under section 402 of the Clean Water Act (CWA).

(b) This subpart implements section 316(b) of the CWA for new offshore oil and gas extraction facilities. Section 316(b) of the CWA provides that any standard established pursuant to sections 301 or 306 of the CWA and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

(c) New offshore oil and gas extraction facilities that do not meet the threshold requirements regarding amount of water withdrawn or percentage of water withdrawn for cooling water purposes in § 125.131(a) must meet requirements determined by the Director on a case-by-case, best professional judgement (BPJ) basis.

(d) Nothing in this subpart shall be construed to preclude or deny the right of any State or political subdivision of a State or any interstate agency under section 510 of the CWA to adopt or enforce any requirement with respect to control or abatement of pollution that is more stringent than those required by Federal law.

§ 125.131 Who is subject to this subpart?

(a) This subpart applies to a new offshore oil and gas extraction facility if it meets all of the following criteria:

(1) It is a point source that uses or proposes to use a cooling water intake structure;

(2) It has at least one cooling water intake structure that uses at least 25 percent of the water it withdraws for cooling purposes as specified in paragraph (c) of this section; and

(3) It has a design intake flow greater than two (2) million gallons per day (MGD).

(b) Use of a cooling water intake structure includes obtaining cooling water by any sort of contract or arrangement with an independent supplier (or multiple suppliers) of cooling water if the supplier or suppliers withdraw(s) water from waters of the United States. Use of cooling water does not include obtaining cooling water from a public water system or the use of treated effluent that otherwise would be discharged to a water of the U.S.

(c) The threshold requirement that at least 25 percent of water withdrawn be used for cooling purposes must be measured on an average monthly basis. A new offshore oil and gas extraction facility meets the 25 percent cooling water threshold if, based on the new facility's design, any monthly average over a year for the percentage of cooling water withdrawn is expected to equal or exceed 25 percent of the total water withdrawn.

(d) Neither this subpart nor Subpart I of this part applies to seafood processing vessels or offshore liquefied natural gas import terminals that are new facilities as defined in 40 CFR 125.83. Seafood processing vessels and offshore liquefied natural gas import terminals must meet requirements established by the Director on a case-by-case, best professional judgment (BPJ) basis.

§ 125.132 When must I comply with this subpart?

You must comply with this subpart when an NPDES permit containing requirements consistent with this subpart is issued to you.

§ 125.133 What special definitions apply to this subpart?

In addition to the definitions set forth at 40 CFR 125.83, the following special definitions apply to this subpart:

Cooling water means water used for contact or noncontact cooling, including water used for equipment cooling, evaporative cooling tower makeup, and dilution of effluent heat content. The intended use of the cooling water is to absorb waste heat rejected from the process or processes used, or from auxiliary operations on the facility's premises. Cooling water that is used in another industrial process either before or after it is used for cooling is considered process water rather than cooling water for the purposes of calculating the percentage of a new offshore oil and gas extraction facility's intake flow that is used for cooling purposes in § 125.131(c).

Fixed facility means 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. This definition does not include mobile offshore drilling units (MODUs) (e.g., drill ships, temporarily moored semi-submersibles, jack-ups, submersibles, tender-assisted rigs, and drill barges).

Minimum ambient source water surface elevation means the mean low tidal water level for estuaries or oceans. The mean low tidal water level is the average height of the low water over at least 19 years.

New offshore oil and gas extraction facility means any building, structure, facility, or installation that: meets the definition of a ''new facility'' at 40 CFR 125.83; and is regulated by the Offshore or Coastal Subcategories of the Oil and Gas Extraction Point Source Category Effluent Guidelines in 40 CFR 435.10 or 40 CFR 435.40; but only if it commences construction after July 17, 2006.

Offshore liquefied natural gas (LNG) import terminal means any facility located in waters defined in 40 CFR 435.10 or 40 CFR 435.40 that liquefies, re-gasifies, transfers, or stores liquefied natural gas.

Sea chest means the underwater compartment or cavity within the facility or vessel hull or pontoon through which sea water is drawn in (for cooling and other purposes) or discharged.

Seafood processing vessel means any offshore or nearshore, floating, mobile, facility engaged in the processing of fresh, frozen, canned, smoked, salted or pickled seafood, seafood paste, mince, or meal.

§ 125.134 As an owner or operator of a new offshore oil and gas extraction facility, what must I do to comply with this subpart?

(a)(1) The owner or operator of a new offshore oil and gas extraction facility must comply with:

(i) Track I in paragraph (b) or Track II in paragraph (c) of this section, if it is a fixed facility; or

(ii) Track I in paragraph (b) of this section, if it is *not* a fixed facility.

(2) In addition to meeting the requirements in paragraph (b) or (c) of this section, the owner or operator of a new offshore oil and gas extraction facility may be required to comply with paragraph (d) of this section.

(b) *Track I requirements for new offshore oil and gas extraction facilities.* (1)(i) New offshore oil and gas extraction facilities that *do not* employ sea chests as cooling water intake structures and are fixed facilities must comply with all of the requirements in paragraphs (b)(2) through (8) of this section.

(ii) New offshore oil and gas extraction facilities that employ sea chests as cooling water intake structures and are fixed facilities must comply with the requirements in paragraphs (b)(2), (3), (4), (6), (7), and (8) of this section.

(iii) New offshore oil and gas extraction facilities that are *not* fixed facilities must comply with the requirements in paragraphs (b)(2), (4), (6), (7), and (8) of this section.

(2) You must design and construct each cooling water intake structure at your facility to a maximum through-screen design intake velocity of 0.5 ft/s;

(3) 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;

(4) You must select and implement design and construction technologies or operational measures for minimizing impingement mortality of fish and shellfish if the Director determines that:

(i) There are threatened or endangered or otherwise protected federal, state, or tribal species, or critical habitat for these species, within the hydraulic zone of influence of the cooling water intake structure; or

(ii) Based on information submitted by any fishery management agency(ies) or other relevant information, there are migratory and/or sport or commercial species of impingement concern to the Director that pass through the hydraulic zone of influence of the cooling water intake structure; or

(iii) Based on information submitted by any fishery management agency(ies) or other relevant information, that the proposed facility, after meeting the technology-based performance requirements in paragraphs (b)(2) and (5) of this section, would still contribute unacceptable stress to the protected species, critical habitat of those species, or species of concern;

(5) You must select and implement design and construction technologies or operational measures for minimizing entrainment of entrainable life stages of fish and shellfish;

(6) You must submit the applicable application information required in 40 CFR 122.21(r) and § 125.136(b). If you are a fixed facility you must submit the information required in 40 CFR 122.21(r)(2) (except (r)(2)(iv)), (3), and (4) and § 125.136(b) of this subpart as part of your application. If you are a not a fixed facility, you must only 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 application.

(7) You must implement the monitoring requirements specified in § 125.137; and

(8) You must implement the recordkeeping requirements specified in § 125.138.

(c) *Track II requirements for new offshore oil and gas extraction facilities.* The owner or operator of a new offshore oil and gas extraction facility that is a fixed facility and chooses to comply under Track II must comply with the following requirements:

(1) You must demonstrate to the Director that the technologies employed will reduce the level of adverse environmental impact from your cooling water intake structures to a comparable level to that which you would achieve were you to implement the applicable requirements of paragraph (b)(2) and, if your facility is a fixed facility without a sea chest, also paragraph (b)(5) of this section. This demonstration must include a showing that the impacts to fish and shellfish, including important forage and predator species, will be comparable to those which would result if you were to implement the requirements of paragraph (b)(2) and, if your facility is a fixed facility without a sea chest, also paragraph (b)(5) of this section. In identifying such species, the Director may consider information provided by any fishery management agency(ies) along with data and information from other sources;

(2) 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;

(3) You must submit the applicable information required in 40 CFR 122.21(r)(2) (except (r)(2)(iv)), (3) and (4) and § 125.136(c);

(4) You must implement the monitoring requirements specified in § 125.137;

(5) You must implement the record-keeping requirements specified in § 125.138.

(d) You must comply with any more stringent requirements relating to the location, design, construction, and capacity of a cooling water intake structure or monitoring requirements at a new offshore oil and gas extraction facility that the Director deems are 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 antidegradation requirements).

§ 125.135 May alternative requirements be authorized?

(a) Any interested person may request that alternative requirements less stringent than those specified in § 125.134(a) through (d) be imposed in the permit. The Director may establish alternative requirements less stringent than the requirements of § 125.134(a) through (d) only if:

(1) There is an applicable requirement under § 125.134(a) through (d);

(2) The Director determines that data specific to the facility indicate that compliance with the requirement at issue would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirement at issue or would result in significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on energy markets;

(3) The alternative requirement requested is no less stringent than justified by the wholly out of proportion cost or the significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on energy markets; and

(4) The alternative requirement will ensure compliance with other applicable provisions of the Clean Water Act and any applicable requirement of federal or state law.

(b) The burden is on the person requesting the alternative requirement to demonstrate that alternative requirements should be authorized.

§ 125.136 As an owner or operator of a new offshore oil and gas extraction facility, what must I collect and submit when I apply for my new or reissued NPDES permit?

(a)(1) As an owner or operator of a new offshore oil and gas extraction facility, you must submit to the Director a statement that you intend to comply with either:

(i) The Track I requirements for new offshore oil and gas extraction facilities in § 125.134(b); or

(ii) If you are a fixed facility, you may choose to comply with the Track II requirements in § 125.134(c).

(2) You must also submit the application information required by 40 CFR 122.21(r) and the information required in either paragraph (b) of this section for Track I or, if you are a fixed facility that chooses to comply under Track II, paragraph (c) of this section when you apply for a new or reissued NPDES permit in accordance with 40 CFR 122.21.

(b) *Track I application requirements.* To demonstrate compliance with Track I requirements in § 125.134(b), you must collect and submit to the Director the information in paragraphs (b)(1) through (3) of this section.

(1) *Velocity information.* You must submit the following information to the Director to demonstrate that you are complying with the requirement to meet a maximum through-screen design intake velocity of no more than 0.5 ft/s at each cooling water intake structure as required in § 125.134(b)(2):

(i) A narrative description of the design, structure, equipment, and operation used to meet the velocity requirement; and

(ii) 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.

(2) *Source waterbody flow information.* If you are a fixed facility and your cooling water intake structure is located in an estuary or tidal river, you must provide the mean low water tidal excursion distance and any supporting documentation and engineering calculations to show that your cooling water intake structure facility meets the flow requirements in § 125.134(b)(3).

(3) *Design and Construction Technology Plan.* To comply with § 125.134(b)(4) and/or (5), if applicable, you must submit to the Director the following information in a Design and Construction Technology Plan:

(i) If the Director determines that additional impingement requirements should be included in your permit:

(A) Information to demonstrate whether or not you meet the criteria in § 125.134(b)(4);

(B) Delineation of the hydraulic zone of influence for your cooling water intake structure;

(ii) New offshore oil and gas extraction facilities required to install design and construction technologies and/or operational measures must develop a plan explaining the technologies and measures you have selected. (Examples of appropriate technologies include, but are not limited to, increased opening to cooling water intake structure to decrease design intake velocity, wedgewire screens, fixed screens, velocity caps, location of cooling water intake opening in waterbody, etc. Examples of appropriate operational measures include, but are not limited to, seasonal shutdowns or reductions in flow, continuous operations of screens, etc.) The plan must contain the following information, if applicable:

(A) A narrative description of the design and operation of the design and construction technologies, including fish-handling and return systems, that you will use to maximize the survival of those species expected to be most susceptible to impingement. Provide species-specific information that demonstrates the efficacy of the technology;

(B) To demonstrate compliance with § 125.134(b)(5), if applicable, a narrative description of the design and operation of the design and construction technologies that you will use to minimize entrainment of those species expected to be the most susceptible to entrainment. Provide species-specific information that demonstrates the efficacy of the technology; and

(C) Design calculations, drawings, and estimates to support the descriptions provided in paragraphs (b)(3)(ii)(A) and (B) of this section.

(c) *Application requirements for Track II.* If you are a fixed facility and have chosen to comply with the requirements of Track II in § 125.134(c) you must collect and submit the following information:

(1) *Source waterbody flow information.* If your cooling water intake structure is located in an estuary or tidal river, you must provide the mean low water tidal excursion distance and any supporting documentation and engineering calculations to show that your cooling water intake structure facility meets the flow requirements in § 125.134(c)(2);

(2) *Track II Comprehensive Demonstration Study.* You must perform and submit the results of a Comprehensive Demonstration Study (Study). This information is required to characterize the source water baseline in the vicinity of the cooling water intake structure(s), characterize operation of the cooling water intake(s), and to confirm that the technology(ies) proposed and/or implemented at your cooling water intake structure reduce the impacts to fish and shellfish to levels comparable to those you would achieve were you to implement the applicable requirements in § 125.134(b).

(i) To meet the ‘‘comparable level’’ requirement, you must demonstrate that:

(A) You have reduced impingement mortality of all life stages of fish and shellfish to 90 percent or greater of the reduction that would be achieved through the applicable requirements in § 125.134(b)(2); and

(B) If you are a facility without sea chests, you have minimized entrainment of entrainable life stages of fish and shellfish to 90 percent or greater of the reduction that would have been achieved through the applicable requirements in § 125.134(b)(5);

(ii) You must develop and submit a plan to the Director containing a proposal for how information will be collected to support the study. The plan must include:

(A) A description of the proposed and/or implemented technology(ies) to be evaluated in the Study;

(B) A list and description of any historical studies characterizing the physical and biological conditions in the vicinity of the proposed or actual intakes and their relevancy to the proposed Study. If you propose to rely on existing source water body data, it must be no more than 5 years old, you must demonstrate that the existing data are sufficient to develop a scientifically valid estimate of potential impingement mortality and (if applicable) entrainment impacts, and provide documentation showing that the data were collected using appropriate quality assurance/quality control procedures;

(C) Any public participation or consultation with Federal or State agencies undertaken in developing the plan; and

(D) A sampling plan for data that will be collected using actual field studies in the source water body. The sampling plan must document all methods and quality assurance procedures for sampling and data analysis. The sampling and data analysis methods you propose must be appropriate for a quantitative survey and based on consideration of methods used in other studies performed in the source water body. The sampling plan must include a description of the study area (including the area of influence of the cooling water intake structure and at least 100 meters beyond); taxonomic identification of the sampled or evaluated biological assemblages (including all life stages of fish and shellfish); and sampling and data analysis methods; and

(iii) You must submit documentation of the results of the Study to the Director. Documentation of the results of the Study must include:

(A) *Source Water Biological Study.* The Source Water Biological Study must include:

(*1*) A taxonomic identification and characterization of aquatic biological resources including: A summary of historical and contemporary aquatic biological resources; determination and description of the target populations of concern (those species of fish and shellfish and all life stages that are most susceptible to impingement and entrainment); and a description of the abundance and temporal/spatial characterization of the target populations based on the collection of multiple years of data to capture the seasonal and daily activities (e.g., spawning, feeding and water column migration) of all life stages of fish and shellfish found in the vicinity of the cooling water intake structure;

(*2*) An identification of all threatened or endangered species that might be susceptible to impingement and entrainment by the proposed cooling water intake structure(s); and

(*3*) A description of additional chemical, water quality, and other anthropogenic stresses on the source waterbody.

(B) *Evaluation of potential cooling water intake structure effects.* This evaluation must include:

(*1*) Calculations of the reduction in impingement mortality and, (if applicable), entrainment of all life stages of fish and shellfish that would need to be achieved by the technologies you have selected to implement to meet requirements under Track II. To do this, you must determine the reduction in impingement mortality and entrainment that would be achieved by implementing the requirements of § 125.134(b)(2) and, for facilities without sea chests, § 125.134(b)(5) of Track I at your site.

(*2*) An engineering estimate of efficacy for the proposed and/or implemented technologies used to minimize impingement mortality and (if applicable) entrainment of all life stages of fish and shellfish and maximize survival of impinged life stages of fish and shellfish. You must demonstrate that the technologies reduce impingement mortality and (if applicable) entrainment of all life stages of fish and shellfish to a comparable level to that which you would achieve were you to implement the requirements in § 125.134(b)(2) and, for facilities without sea chests, § 125.134(b)(5) of Track I. The efficacy projection must include a site-specific evaluation of technology(ies) suitability for reducing impingement mortality and (if applicable) entrainment based on the results of the Source Water Biological Study in paragraph (c)(2)(iii)(A) of this section. Efficacy estimates may be determined based on case studies that have been conducted in the vicinity of the cooling water intake structure and/or site-specific technology prototype studies.

(C) *Verification monitoring plan.* You must include in the Study a plan to conduct, at a minimum, two years of monitoring to verify the full-scale performance of the proposed or implemented technologies and/or operational measures. The verification study must begin at the start of operations of the cooling water intake structure and continue for a sufficient period of time to demonstrate that the facility is reducing the level of impingement mortality and (if applicable) entrainment to the level documented in paragraph (c)(2)(iii)(B) of this section. The plan must describe the frequency of monitoring and the parameters to be monitored. The Director will use the verification monitoring to confirm that you are meeting the level of impingement mortality and entrainment reduction required in § 125.134(c), and that the operation of the technology has been optimized.

§ 125.137 As an owner or operator of a new offshore oil and gas extraction facility, must I perform monitoring?

As an owner or operator of a new offshore oil and gas extraction facility, you will be required to perform monitoring to demonstrate your compliance with the requirements specified in § 125.134 or alternative requirements under § 125.135.

(a) *Biological monitoring.* (1)(i) Fixed facilities without sea chests that choose to comply with the Track I requirements in § 125.134(b)(1)(i) must monitor for entrainment. These facilities are not required to monitor for impingement, unless the Director 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).

(ii) Fixed facilities with sea chests that choose to comply with Track I requirements are not required to perform biological monitoring unless the Director 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).

(iii) Facilities that are not fixed facilities are not required to perform biological monitoring unless the Director 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).

(iv) Fixed facilities with sea chests that choose to comply with Track II requirements in accordance with § 125.134(c), must monitor for impingement only. Fixed facilities without sea chests that choose to comply with Track II requirements, must monitor for both impingement and entrainment.

(2) 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 Director.

(3) The monitoring methods used must be consistent with those used for the Source Water Baseline Biological Characterization data required in 40 CFR 122.21(r)(4), those used by the Comprehensive Demonstration Study required by § 125.136(c)(2), or as specified by the Director. You must follow the monitoring frequencies identified below for at least two (2) years after the initial permit issuance. After that time, the Director 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 variations in the species and numbers of individuals that are impinged or entrained.

(4) *Impingement sampling.* You 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 cooling water intake structure is in operation.

(5) *Entrainment sampling.* If your facility is subject to the requirements of § 125.134(b)(1)(i), or if your facility is subject to § 125.134(c) and is a fixed facility without a sea chest, you 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 required by 40 CFR 122.21(r)(4) or the Comprehensive Demonstration Study required in § 125.136(c)(2). You must collect samples only when the cooling water intake structure is in operation.

(b) *Velocity monitoring.* If your facility uses a surface intake screen systems, you must monitor head loss across the screens and correlate the measured value 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 cooling water intake structure must be used to determine compliance with the velocity requirement in § 125.134(b)(2). If your facility uses devices other than surface intake screens, you must monitor velocity at the point of entry through the device. You must monitor head loss or velocity during initial facility startup, and thereafter, at the frequency specified in your NPDES permit, but no less than once per quarter.

(c) *Visual or remote inspections.* You must either conduct visual inspections or employ remote monitoring devices during the period the cooling water intake structure is in operation. You must conduct visual inspections 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, you must inspect via remote monitoring devices to ensure that the impingement and entrainment technologies are functioning as designed.

§ 125.138 As an owner or operator of a new offshore oil and gas extraction facility, must I keep records and report?

As an owner or operator of a new offshore oil and gas extraction facility you are required to keep records and report information and data to the Director as follows:

(a) You 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 (3) years from the date of permit issuance. The Director may require that these records be kept for a longer period.

(b) You must provide the following to the Director in a yearly status report:

(1) For fixed facilities, biological monitoring records for each cooling water intake structure as required by § 125.137(a);

(2) Velocity and head loss monitoring records for each cooling water intake structure as required by § 125.137(b); and

(3) Records of visual or remote inspections as required in § 125.137(c).

§ 125.139 As the Director, what must I do to comply with the requirements of this subpart?

(a) *Permit application.* As the Director, you must review materials submitted by the applicant under 40 CFR 122.21(r), § 125.135, and § 125.136 at the time of the initial permit application and before each permit renewal or reissuance.

(1) After receiving the initial permit application from the owner or operator of a new offshore oil and gas extraction facility, the Director must determine applicable standards in § 125.134 or § 125.135 to apply to the new offshore oil and gas extraction facility. In addition, the Director must review materials to determine compliance with the applicable standards.

(2) For each subsequent permit renewal, the Director must review the application materials and monitoring data to determine whether requirements, or additional requirements, for design and construction technologies or operational measures should be included in the permit.

(3) For Track II facilities, the Director may review the information collection proposal plan required by § 125.136(c)(2)(ii). The facility may initiate sampling and data collection activities prior to receiving comment from the Director.

(b) *Permitting requirements.* Section 316(b) requirements are implemented for a facility through an NPDES permit. As the Director, you must determine, based on the information submitted by the new offshore oil and gas extraction facility in its permit application, the appropriate requirements and conditions to include in the permit based on the track (Track I or Track II), or alternative requirements in accordance with § 125.135, the new offshore oil and gas extraction facility has chosen to comply with. The following requirements must be included in each permit:

(1) *Cooling water intake structure requirements.* At a minimum, the permit conditions must include the performance standards that implement the applicable requirements of § 125.134(b)(2), (3), (4) and (5); § 125.134(c)(1) and (2); or § 125.135.

(i) For a facility that chooses Track I, you must review the Design and Construction Technology Plan required in § 125.136(b)(3) to evaluate the suitability and feasibility of the technology proposed to minimize impingement mortality and (if applicable) entrainment of all life stages of fish and shellfish. In the first permit issued, you must include a condition requiring the facility to reduce impingement mortality and/or entrainment commensurate with the implementation of the technologies in the permit. Under subsequent permits, the Director must review the performance of the technologies implemented and require additional or different design and construction technologies, if needed to minimize impingement mortality and/or entrainment of all life stages of fish and shellfish. In addition, you must consider whether more stringent conditions are reasonably necessary in accordance with § 125.134(d).

(ii) For a fixed facility that chooses Track II, you must review the information submitted with the Comprehensive Demonstration Study information required in § 125.136(c)(2), evaluate the suitability of the proposed design and construction technology and/or operational measures to determine whether they will reduce both impingement mortality and/or entrainment of all life stages of fish and shellfish to 90 percent or greater of the reduction that could be achieved through Track I. In addition, you must review the Verification Monitoring Plan in § 125.136(c)(2)(iii)(C) and require that the proposed monitoring begin at the start of operations of the cooling water intake structure and continue for a sufficient period of time to demonstrate that the technologies and operational measures meet the requirements in § 125.134(c)(1). Under subsequent permits, the Director must review the performance of the additional and /or different technologies or measures used and determine that they reduce the level of adverse environmental impact from the cooling water intake structures to a comparable level that the facility would achieve were it to implement the requirements of § 125.134(b)(2) and, if applicable, § 125.134(b)(5).

(iii) If a facility requests alternative requirements in accordance with § 125.135, you must determine if data specific to the facility meet the requirements in § 125.135(a) and include in the permit requirements that are no less stringent than justified by the wholly out of proportion cost or the significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on energy markets.

(2) *Monitoring conditions.* At a minimum, the permit must require the permittee to perform the monitoring required in § 125.137. You may modify the monitoring program when the permit is reissued and during the term of the permit based on changes in physical or biological conditions in the vicinity of the cooling water intake structure. The Director may require continued monitoring based on the results of monitoring done pursuant to

the Verification Monitoring Plan in § 125.136(c)(2)(iii)(C).

(3) *Record keeping and reporting.* At a minimum, the permit must require the permittee to report and keep records as required by § 125.138.

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