Chapter 6: Industry Profile: Oil and Gas Extraction Industry

Chapter Contents

INTRODUCTION

The oil and gas industry uses non-contact, once-through water to cool crude oil, produced water, power generators, and various other pieces of machinery at oil and gas extraction facilities.[1] EPA did not consider oil and gas extraction facilities in the Phase I 316(b) rulemaking.

The Phase I proposal and its record included no analysis of issues associated with offshore and coastal oil and gas extraction facilities (such as significant space limitations on mobile drilling platforms and ships) that could significantly increase the costs and economic impacts and affect the technical feasibility of complying with the proposed requirements for land-based industrial operations. Additionally, EPA believes it is not appropriate to include these facilities in the Phase II regulations scheduled for proposal in February 2002; the Phase II regulations are intended to address the largest existing facilities in the steam-electric generating industry. During Phase III, EPA will address cooling water intake structures at existing facilities in a variety of industry sectors. Therefore, EPA believes it is most appropriate to defer rulemaking for offshore and coastal oil and gas extraction facilities to Phase III.

This chapter provides a starting point for future discussions with industry and other stakeholders on future Phase III regulatory decisions.

6.1 HISTORIC AND PROJECTED DRILLING ACTIVITIES

The oil and gas extraction industry drills wells both onshore, coastal, and offshore regions for the exploration and development of oil and natural gas. Various engines and brakes are employed which require some type of cooling system. The U.S. oil and gas extraction industry currently produces over 60 billion cubic feet of natural gas and over 9 million barrels of oil per day.[2] There were roughly 1,096 onshore drilling rigs in operation in August 2001.[3] This section focuses on the OCS oil and gas extraction activities as onshore facilities have less demand for cooling water and have more available options for using dry cooling systems. Moreover, OCS facilities are limited in physical space, payload capacity, and operating environments. EPA will further investigate onshore oil and gas extraction facilities for the Phase III rulemaking.

A large majority of the OCS oil and gas extraction occurs in the Gulf of Mexico (GOM). The Federal OCS generally starts three miles from shore and extends out to the outer territorial boundary (about 200 miles).[†] The U.S. Department of Interior's Mineral Management Service (MMS) is the Federal agency responsible for managing OCS mineral resources. The following summary statistics are from the 1999 MMS factbook.[2]

- The OCS accounts for about 27% of the Nation's domestic natural gas production and about 20% of its domestic oil production. On an energy basis (BTU), about 67 percent of the energy currently produced offshore is natural gas.

- The OCS contains about 19% of the Nation's proven natural gas reserves and 15% of its proven oil reserves. The OCS is estimated to contain more than 50% of the Nation's remaining undiscovered natural gas and oil resources.

- To date, the OCS has produced about 131 trillion cubic feet of natural gas and about 12 billion barrels of oil. The Federal OCS provides the bulk—about 89%—of all U.S. offshore production. Five coastal States—Alaska, Alabama, California, Louisiana and Texas—make up the remaining 11%.

Table 1 presents the number of wells drilled in three areas (GOM, Offshore California, and Coastal Cook Inlet, Alaska) for 1995 through 1997. The table also separates the wells into four categories: shallow water development, shallow water exploratory, deep water development, and deep water exploratory. Exploratory drilling includes those operations drilling wells to determine potential hydrocarbon reserves. Development drilling includes those operations drilling production wells once a hydrocarbon reserve has been discovered and delineated. Although the rigs used in exploratory and development drilling sometimes differ, the drilling process is generally the same for both types of drilling operations.

The water depth in which either exploratory or development drilling occurs may determine the operator's choice of drill rigs and drilling systems. MMS and the drilling industry classify wells as located in either deep water or shallow water, depending on whether drilling is in water depths greater than 1,000 feet or less than 1,000 feet, respectively.

[†]The Federal OCS starts approximately 10 miles from the Florida and Texas shores.

Table 6-1: Number of Wells Drilled Annually, 1995 - 1997, by Geographic Area

Data Source		Shallow Water (<1,000 ft)		Deep Water (≥ 1,000 ft)		Total Wells
		Development	Exploration	Development	Exploration	
Gulf of Mexico†						
MMS:	1995	557	314	32	52	975
	1996	617	348	42	73	1,080
	1997	726	403	69	104	1,302
	Average Annual	640	355	48	76	1,119
RRC		5	3	NA	NA	8
Total Gulf of Mexico		**645**	**358**	**48**	**76**	**1,127**
Offshore California						
MMS:	1995	4	0	15	0	19
	1996	15	0	16	0	31
	1997	14	0	14	0	28
	Average Annual	**11**	**0**	**15**	**0**	**26**
Coastal Cook Inlet						
AOGC:	1995	12	0	0	0	12
	1996	5	1	0	0	6
	1997	5	2	0	0	7
	Average Annual	**7**	**1**	**0**	**0**	**8**

Source: Ref. 4

† Note: GOM figures do not include wells within State bay and inlet waters (considered "coastal" under 40 CFR 435) and State offshore waters (0-3 miles from shore). In August 2001, there were 1 and 23 drilling rigs in State bay and inlet waters of Texas and Louisiana, respectively. There were also 19 and 112 drilling rigs in State offshore waters (0-3 miles from shore), respectively.[3]

Offshore production in the Gulf of Mexico began in 1949 with a shallow well drilled in shallow water. It took another 25 years until the first deepwater well ($1,000 ft. of water) was drilled in 1974. Barriers to deepwater activity include technological difficulties of stabilizing a drilling rig in the open ocean, high financial costs, and natural and manmade barriers to oil and gas activities in the deep waters.

These barriers have been offset in recent years by technological developments (e.g., 3-D seismic data covering large areas of the deepwater Gulf and innovative structure designs) and economic incentives. As a result, deepwater oil and gas activity in the Gulf of Mexico has dramatically increased from 1992 to 1999. In fact, in late 1999, oil production from deepwater wells surpassed that produced from shallow water wells for the first time in the history of oil production in the Gulf of Mexico.[5]

As shown in Table 1, 1,127 wells were drilled in the Gulf of Mexico, on average, from 1995 to 1997, compared to 26 wells in California and 8 wells in Cook Inlet. In the Gulf of Mexico, over the last few years, there has been high growth in the number of wells drilled in deep water, defined as water greater than 1,000 feet deep. For example, in 1995, 84 wells were drilled in deep water, or 8.6 percent of all Gulf of Mexico wells drilled that year. By 1997, that number increased to 173 wells drilled, or over 13 percent of all Gulf of Mexico wells drilled. Nearly all exploration and development activities in the Gulf are taking place in the Western Gulf of Mexico, that is, the regions off the Texas and Louisiana shores.

6.2 OFFSHORE AND COASTAL OIL AND GAS EXTRACTION FACILITIES

There are numerous different types of offshore and coastal oil extraction facilities. Some facilities are fixed for development drilling while other facilities are mobile for both exploration and development drilling. Previous EPA estimates of non-contact cooling water for offshore and coastal oil and gas extraction facilities (OCOGEF) showed a wide range of cooling water demands (294 - 5,208,000 gal/day).[1]

6.2.1 Fixed Oil and Gas Extraction Facilities

Most of these structures use a pipe with passive screens (strainers) to convey cooling water. Non-contact, once-through water is used to cool crude oil, produced water, power generators and various other pieces of machinery (e.g., drawworks brakes). Due to the number of oil and gas extraction facilities in the GOM in relation to other OCS regions, EPA estimated the number of fixed active platforms in the Federal OCS region of the Gulf of Mexico using the MMS Platform Inspection System, Complex/Structure database. These fixed structures are generally used for development drilling. Out of a total of 5,026 structures, EPA identified 2,381 active platforms where drilling is likely to occur (Table 2).

Table 6-2: Identification of Structures in the Gulf of Mexico OCS

Category	Count	Remaining Count
All Structures	5,026	5,026
Abandoned Structures	1,403	3,623
Structures classified as production structures, i.e., with no well slots and production equipment	245	3,378
Structures known not to be in production	688	2,690
Structures with missing information on product type (oil or gas or both)	309	2,381
Structures whose drilled well slots are used solely for injection, disposal, or as a water source	0	2,381

Source: Ref. 5

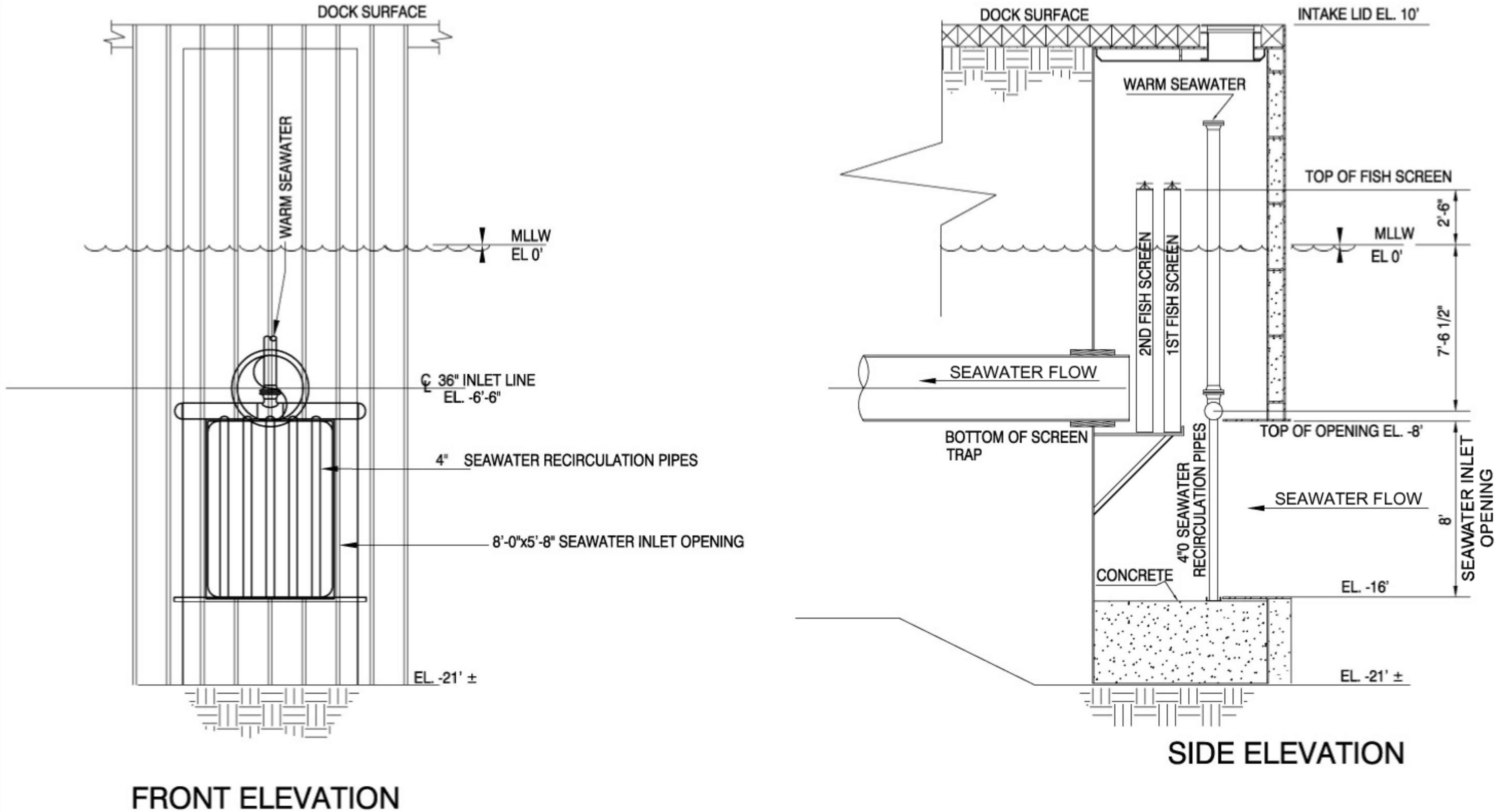
The Offshore Operators Committee (OOC) and the National Oceans Industries Association (NOIA) also noted in their comments to the May 25, 2001 316(b) Federal Register Notice that a typical platform rig for a Tension Leg Platform[††] will require 10 - 15 MM Btu/hr heat removal for its engines and 3 - 6 MM Btu/hr heat removal for the drawworks brake. The total heat removal (cooling capacity) is 13 - 21 MM Btu/hr. OOC/NOIA also estimated that approximately 200 production facilities have seawater intake requirements that exceed 2 MGD. OOC/NOIA estimate that these facilities have seawater intake requirements ranging from 2 - 10 MGD with one-third or more of the volume needed for cooling water. Other seawater intake requirements include firewater and ballasting. The firewater system on offshore platforms must maintain a positive pressure at all times and therefore requires the

[††] A Tension Leg Platform (TLP) is a fixed production facilities in deepwater environments (> 1,000 ft).

firewater pumps in the deep well casings to run continuously. Ballasting water for floating facilities may not be a continuous flow but is an essential intake to maintain the stability of the facility.

EPA and MMS could only identify one case where the environmental impacts of a fixed OCOGEF CWIS were considered.[6] BP Exploration (Alaska) Inc. (BPXA) plans to locate a vertical intake pipe for a seawater-treatment plant on the south side of Liberty Island, Beaufort Sea, Alaska. The pipe would have an opening 8 feet by 5.67 feet and would be located approximately 7.5 feet below the mean low-water level (Fig. 6-1). The discharge from the continuous flush system consists of the seawater that would be continuously pumped through the process-water system to prevent ice formation and blockage. Recirculation pipes located just inside the opening would help keep large fish, other animals, and debris out of the intake. Two vertically parallel screens (6 inches apart) would be located in the intake pipe above the intake opening. They would have a mesh size of 1 inch by 1/4 inch. Maximum water velocity would be 0.29 feet per second at the first screen and 0.33 feet per second at the second screen. These velocities typically would occur only for a few hours each week while testing the fire-control water system. At other times, the velocities would be considerably lower. Periodically, the screens would be removed, cleaned, and replaced.

MMS states in the Liberty Draft Environmental Impact Statement that the proposed seawater-intake structure will likely harm or kill some young-of-the-year arctic cisco during the summer migration period and some eggs and fry of other species in the immediate vicinity of the intake. However, MMS estimates that less than 1% of the arctic cisco in the Liberty area are likely to be harmed or killed by the intake structure. Further, MMS concludes that: (1) the intake structure is not expected to have a measurable effect on young-of-the-year arctic cisco in the migration corridor; and (2) the intake structure is not expected to have a measurable effect on other fishes populations because of the wide distribution/low density of their eggs and fry.



MLLW = Mean Lower Low Water

Source: BPXA, 1998b

ALL DIMENSIONS ARE APPROXIMATE

Figure 6-1 Liberty Development Project: Seawater Intake Detail

6.2.2 Mobile Oil and Gas Extraction Facilities

EPA also estimated the number of mobile offshore drilling units (MODUs) currently in operation. These numbers change in response to market demands. Over the past five years the total number of mobile offshore drilling units (MODUs) operating at one time in areas under U.S. jurisdiction has ranged from less than 100 to more than 200. There are five main types of MODUs operating in areas under U.S. jurisdiction: drillships, semi-submersibles, jack-ups, submersibles and drilling barges. Table 3 gives a brief summary of each MODU. EPA and MMS could not identify any cases where the environmental impacts of a MODU CWIS were considered.

Table 6-3: Description of Mobile Offshore Drilling Units and their CWIS

MODU Type	Water Intake† and Design	Water Depth	No. Currently in GOM	No. Currently Under Construction Over Next Three Years
Drill Ships	16 - 20 MGD Seachest	Greater than 400 ft	5	0
Semi-submersibles	2 - 15+ MGD Seachest	Greater than 400 ft	37	5
Jack-ups	2 - 10+ MGD Intake Pipe	Less than 400 ft	140	9
Submersibles	< 2 MGD Intake Pipe	Shallow Water (Bays and Inlet Waters)	6	0
Drill Barges	< 2 MGD Intake Pipe	Shallow Water (Bays and Inlet Waters)	20	0

Sources: Ref. 7, Ref. 8, Ref. 9, Ref. 10

† Approximately 80% of the water intake is used for cooling water with the remainder being used for hotel loads, fire water testing, cleaning, and ballast water.[7]

The particular type of MODU selected for operation at a specific location is governed primarily by water depth (which may be controlling), anticipated environmental conditions, and the design (depth, wellbore diameter, and pressure) of the well in relation to the units equipment. In general, deeper water depths or deeper wells demand units with a higher peak power-generation and drawworks brake cooling capacities, and this directly impacts the demand for cooling water.[10]

Drillships and Semi-Submersibles MODUs

Drill ships and semi-submersibles use a "seachest" as a CWIS. In general there are three pipes for each sea chest (these include CWIs and fire pumps). One of the three intake pipes is always set aside for use solely for emergency fire fighting operations. These pipes are usually back on the flush line of the sea chest. The sea chest is a cavity in the hull or pontoon of the MODU and is exposed to the ocean with a passive screen (strainer) often set along the flush line of the sea chest. These passive screens or weirs generally have a maximum opening of 1 inch.[9] There are generally two sea chests for each drill ship or semi-submersible (port and starboard) for redundancy and ship stability considerations. In general, only one seachest is required at any given time for drilling operations.[7]

While engaged in drilling operations most drillships and one-third of semi-submersibles maintain their position over the well by means of "dynamic positioning" thrusters which counter the effects of wind and current. Additional power is required to operate the drilling and associated industrial machinery, which is most often powered electrically from the same diesel generators that supply propulsion power. While the equipment powered by the ship's electrical generating system changes, the total power requirements for drillships are similar to those while in transit. Thus, during drilling operations the total seawater intake on a drillship is approximately the same as while underway. The majority of semi-submersibles are not self- propelled, and thus require the assistance of towing vessels to move from location to location.

Information from the U.S. Coast Guard indicates that when semi-submersibles are drilling their sea chests are 80 to 100 feet below the water surface and are less than 20 feet below water when the pontoons are raised for transit or screen cleaning operations.[7] Drill ships have their sea chests on the bottom of their hulls and are typically 20 to 40 feet below water at all times.

IADC notes that one of the earlier semi-submersible designs still in use is the “victory” class unit.[10] This unit is provided with two seawater-cooling pumps, each with a design capacity of 2.3 MGD with a 300 head. At operating draft the center of the inlet, measuring approximately 4 feet by 6 feet, is located 80 feet below the sea surface and is covered by an inlet screen. In the original design this screen had 3024 holes of 15mm diameter. The approximate inlet velocity is therefore 0.9 feet/sec.

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

Jack-up MODUs

Jack-up, submersibles, and drill barges use intake pipes for CWIS. These OCOGEF basically use a pipe with a passive screens (strainers) to convey cooling water. Non-contact, once-through water is used to cool crude oil, produced water, power generators and various other pieces of machinery on OCOGEF (e.g., drawworks brakes).

The jack-up is the most numerous type of MODU. These vessels are rarely self- propelled and must be towed from location to location. Once on location, their legs are lowered to the seabed, and the hull is raised (jacked-up) above the sea surface to an elevation that prevents wave impingement with the hull. Although all of these ships do use seawater cooling for some purposes (e.g., desalinators), as with the semi-submersibles a few use air-cooled diesel-electric generators because of the height of the machinery above the sea surface.[9] Seawater is drawn from deep-well or submersible pumps that are lowered far enough below the sea surface to assure that suction is not lost through wave action. Total seawater intake of these ships varies considerably and ranges from less than 2 MGD to more than 10 MGD. Jack-ups are limited to operating in water depths of less than 500 feet, and may rarely operate in water depths of less than 20 feet.

The most widely used of the jack-up unit designs is the Marathon Letourneau 116-C.[10] For these types of jack-ups typically one pump is used during rig operations with a 6” diameter suction at 20 to 50 feet below water level which delivers cooling water intake rates of 1.73 MGD at an inlet velocity of 13.33 ft/sec.[10] Additionally, pre-loading involves the use of two or three pumps in sequence. Pre-loading is not a cooling water procedure, but a ballasting procedure (ballast water is later discharged). Each pump is fitted with its own passive screen (strainer) at the suction point which provides for primary protection against foreign materials entering the system.

In their early configurations, these jack-up MODUs were typically outfitted with either 5 diesel generator units (each rated at about 1,200 horsepower) or three diesel generator units (each rated at about 2,200 horsepower).[10] In subsequent configurations of this design or re-powering of these units, more installed power has generally been provided, as it has in more recent designs. With more installed power, there is a demand for more cooling water. The International Association of Drilling Contractors (IADC) reports that a newly-built jack-up, of a new design, typically requires 3.17 MGD of cooling water for its drawworks brakes and cooling of six diesel generator units, each rated at 1,845 horsepower.[10] In this case, one pump is typically used during rig operations with a 10" diameter suction at 20 to 50 feet below water level, delivering the cooling water at 3.2 MGD.

Submersibles and Drill Barge MODUs

The submersible MODU is used most often in very shallow waters of bays and inlet waters. These MODUs are not self-propelled. Most are powered by air-cooled diesel-electric
generators, but require seawater intake for cooling of other equipment, desalinators, and for other purposes. Total seawater intake varies considerably with most below 2 MGD.

The drilling barge MODU There are approximately 50 drilling barges available for operation in areas under U.S. jurisdiction, although the number currently in operation is less than 20. These ships operate in shallow bays and inlets along the Gulf Coast, and occasionally in shallow offshore areas. Many are powered by air-cooled diesel-electric generators. While they have some water intake for sanitary and some cooling purposes, water intake is generally below 2 MGD.

6.3 316(b) Issues Related to Offshore and Coastal Oil and Gas Extraction Facilities

There are several important 316(b) issues related to OCOGEF CWIS that EPA will be investigating in the Phase III 316(b) rulemaking: (1) Biofouling; (2) Definition of New Source; (3) Potential Costs and Scheduling Impacts. EPA will work with stakeholders to identify other issues for resolution during the Phase III 316(b) rulemaking process.

6.3.1 Biofouling

Industry comments to the 316(b) Phase I proposal assert that operators must maintain a minimum intake velocity of 2 to 5 ft/sec in order to prevent biofouling of the offshore oil and gas extraction facility CWIS. EPA requested documentation from industry regarding the relationship between marine growth (biofouling) and intake velocities.[11] Industry was unable to provide any authoritative information to support the assertion that a minimum intake velocity of 2 to 5 ft/sec is required in order to prevent biofouling of the OCOGEF CWIS. IADC asserts that it is common marine engineering practice to maintain high velocities in the seachest to inhibit attachment of marine biofouling organisms.[10]

The Offshore Operators Committee (OOC) and the National Oceans Industries Association (NOIA) also noted in their comments to the May 25, 2001 316(b) Federal Register Notice that the ASCE "Design of Water Intake Structures for Fish Protection" recommends an approach velocity in the range of 0.5 to 1 ft/s for fish protection and 1 ft/s for debris management but does not address biofouling specifically. OOC/NOIA were unable to find technical papers to support a higher intake velocity. The U.S. Coast Guard and MMS were also unable to provide EPA with any information on velocity requirements or preventative measures regarding marine growth inhibition or has a history of excessive marine growth at the sea chest.

EPA was able to identify some of the major factors affecting marine growth on offshore structures. These factors include temperature, oxygen content, pH, current, turbidity, and light.[12,13] Fouling is particularly troublesome in the more fertile coastal waters, and although it diminishes with distance from the shoreline, it does not disappear in midoceanic and in the abyssal depths.[13] Moreover, operators are required to perform regular inspection and cleaning of these CWIS in accordance with USCG regulations.

Operators are also required by the U.S. Coast Guard to inspect sea chests twice in five years with at least one cleaning to prevent blockages of firewater lines. The requirement to drydock MODUs twice in five years and inspect and clean their sea chests and sea valves are found in U.S. Coast Guard regulations (46 CFR 107.261 and 46 CFR 61.20-5). The U.S. Coast Guard may require the sea chests to be cleaned twice in 5 years at every drydocking if the unit is in an area of high marine growth or has had history of excessive marine growth at the sea chests.

EPA and industry also identified that there are a variety of specialty screens, coatings, or treatments to reduce biofouling. Industry and a technology vendor (Johnson Screens) also identified several technologies currently being used to control biofouling (e.g., air sparing, Ni-Cu alloy materials). Johnson Screens asserted in May 25, 2001 316(b) Federal Register Notice comments to EPA that their copper based material can reduce biofouling in many applications including coastal and offshore drilling facilities in marine environments.

Biocide treatment can also be used to minimize biofouling. IADC reports that one of their members uses Chloropac systems to reduce biofouling (www.elcat.co.uk/chloro_anti_mar.htm). The Liberty Project plans to use chlorine, in the form of calcium hypochlorite, to reduce biofouling. The operator (BPXA) will reduce the total residual chlorine concentration in the discharged cooling water by adding sodium metabisulfate in order to comply with limits of the National Pollution Discharge Elimination System Permit. MMS estimates that the effluent pH will vary slightly from the intake seawater because of the chlorination/dechlorination processes, but this variation is not expected to be more than 0.1 pH units.

In summary, EPA has not yet identified any relationship between the intake velocity and biofouling of a offshore oil and gas extraction facility CWIS. However, EPA will be pursuing this and other matters related to biofouling in the offshore oil and gas industry in the Phase III 316(b) regulation.

6.3.2 Definition of New Source

Industry claimed in comments to the Phase I 316(b) proposal and the May 25, 2001 316(b) Federal Register Notice that existing MODUs could be considered "new sources" when they drill new development wells under 40 CFR 435.11 (exploration facilities are excluded from the definition of new sources). EPA will work with stakeholders to clarify the regulatory status of existing MODUs in the Phase III 316(b) proposal and final rule.

6.3.3 Potential Costs and Scheduling Impacts

Costs to Retrofit for Velocity Standard

EPA did not identify any additional costs to incorporate the 0.5 fps maximum velocity standard into new designs for future (not yet built) OCOGEF CWIS. Retrofit cost for production facilities will vary depending on the type of cooling water intake structure the facility has in place. The U.S. Coast Guard did not have a good estimate of seachest CWIS retrofit costs but did have a general idea of the work requirements for these potential retrofits.[7] The Coast Guard stated that retrofits for drill ships and semi-submersibles that use seachests as the CWI structure could probably be in the millions of dollars (approximately 8-10 million dollars) and require several weeks to months for drydocking operations. Complicating matters is that there are only a few deepwater drydock harbors capable of handling semi-submersibles. MMS did not have any information on costs and issues relating to retrofitting sea chests or other offshore CWIS.

OOC/NOIA estimated costs for retrofitting a larger intake for a floating production system tension leg platform (TLP).[14] Under their costing scenario, it was assumed that the TLP had a seachest intake structure with a pre-existing flange on the exterior of the intake structure which could be used to bolt on a larger diameter intake in order to reduce the intake velocity to below 0.5 ft/s. The estimated cost to retrofit this new intake is $75,000. OOC/NOIA estimates that this same cost can be assumed for retrofiting a deep well pump casing with a larger diameter intake provided the bottom of the casing is not obstructed and the intake structure can be clamped over the casing.

OOC/NOIA further estimates that for TLP's with seachests without a pre-existing flange for an intake structure and for deep well pump casings that are obstructed and prevent the installation of an intake structure, the retrofit costs are estimated to be much higher.[14] OOC/NOIA estimates that if underwater welding or the installation of new pump casing are required, the costs can be as high as $500,000. In these cases, the platform would need to be shut-in for some period of time (1-3 days) to allow for this installation. Included in this estimate is the need to provide for additional stiffening of underwater legs and supports to resist the wave loading forces of the new intake structures. OOC/NOIA estimates that many facilities have multiple deepwell casings or seachests that would require retrofitting.

IADC notes that the feasibility of redesigning seachests to reduce intake velocity would need to be examined on a case-by-case basis.[10] As interior space is typically optimized for the particular machinery installation, IADC further notes that a prerequisite for enlarging any seachest would be repositioning of machinery, piping and electrical systems and that such operations could only be undertaken in a drydock. Seachests on semi-submersible units are not likely located in stress-critical areas, so effective compensation of hull strength is unlikely to be a major concern, unlike a drillship where, depending on the design, it might be difficult to provide effective compensation to hull girder strength for an enlarged seachest

Costs for retro-fitting jack-ups would likely be much less complicated and expensive than semi-submersible and drillship sea chest retro-fits.[7] The U.S. Coast Guard estimates that operators could install a bell or cone intake device on the existing CWIS to reduce CWI velocities. IADC notes that installing passive screens (strainers) with a larger surface area on jack-up CWIS in order to reduce the intake velocity at the face of the screen would add weight and pose handling problems (e.g., require more frequent cleaning).

Costs to Retrofit to Dry Cooling

OOC/NOIA stated in their May 25, 2001 316(b) Federal Register Notice comments that offshore production platforms will typically use direct air cooling or cooling with a closed loop system for cooling requirements where technically feasible. The following items are typically direct air cooled: gas coolers on compressors, lubrication oil coolers on compressors and generators, and hydraulic oil coolers on pumps. These coolers will range from 1 to 35 MM Btu/hr heat removal capacity. Seawater cooling is necessary in many cases because space and weight limitations render air cooling infeasible. This is particularly true for floating production systems which have strict payload limitations.

IADC reports that some jack-up MODUs were converted from sea water cooling systems to closed-loop air cooling systems for engine and drawworks brake cooling.[10] IADC reported the cost of the conversion, completed during a regular shipyard period, was approximately $1.2 million and required a six-month lead-time to obtain the required equipment. The conversion resulted in the loss of deck space associated with the installation of the air-cooling units, and a small loss in variable deck load equal to the additional weight of the air-cooling units and associated piping.

OOC/NOIA provided initial costs to convert from seawater cooling to air cooling with a radiator on a platform rig. In this case, a cantilevered deck was installed onto the side of the pipe rack. The radiator was rated at about 15 MM Btu/hr, and the cost for the installation was about $150,000. The weight of the addition was about 15,000 pounds. The cost of space and payload on an offshore platform is about $5/pound; therefore, the added weight cost about $75,000 bringing the total cost to about $225,000.

EPA agrees with industry that dry cooling systems are most easily installed during planning and construction, but some can be retrofitted with additional costs. IADC believes that it is already difficult to justify such conversions of jack-ups and that it would be far more difficult to justify conversion of drillships or semi-submersibles. EPA will also look at the net gain or loss in the energy efficiency of conversions from wet to dry cooling.

6.3.4 Description of Benefits for Potential 316(b) Controls on Offshore and Coastal Oil and Gas Extraction Facilities

EPA was only able to identify one case where potential impacts to aquatic communities from OCOGEF CWIS were described (MMS Liberty Draft Environmental Impact Statement).[6] MMS estimated that less than 1% of the arctic cisco in the Liberty area are likely to be harmed or killed by the intake structure but that the intake structure is not expected to have a measurable effect on young-of-the-year arctic cisco in the migration corridor or on other fishes populations.

OOC submitted a video tape of three different OCOGEF CWIS as part of their public comments. These CWIS have an intake of 5.9 to 6.3 MGD with a intake velocity of 2.6 to 2.9 ft/s. The intake has a passive screen (strainer) with 1 inch diameter slots. EPA will use this documentation in determining potential impacts on aquatic communities from OCOGEF CWIS.

6.4 Phase III Activities Related to Offshore and Coastal Oil and Gas Extraction Facilities

Numerous researchers and State and Federal regulatory agencies have studied and controlled the discharges from these facilities for decades. The technology-based standards for the discharges from these facilities are located in 40 CFR 435. Conversely, there has been extremely little work done to investigate the environmental impacts or evaluation of the location, design, construction, and capacity characteristics of OCOGEF CWIS that reduce impingement and entrainment of aquatic organisms.

EPA discussions with two main regulatory entities of OCOGEF (i.e., MMS, USCG) identified no regulatory requirements on these OCOGEF CWIS with respect to environmental impacts. MMS generally does not regulate or consider the potential environmental impacts of these OCOGEF CWIS. MMS could only identify one case where the environmental impacts of a OCOGEF CWIS were considered.[6] Moreover, MMS does not collect information on CWI rates, velocities and durations for any OCOGEF CWIS. The U.S. Coast Guard does not investigate potential environmental impacts of MODU CWIS but does require operators to inspect sea chests twice in five years with at least one cleaning to prevent blockages of firewater lines.

EPA will work with industry and other stakeholders to identify all major issues associated with OCOGEF CWIS and potential Phase III 316(b) requirements. EPA will also collect additional data to identify the costs and benefits associated with any regulatory alternative.

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