Final National Pollutant Discharge Elimination System (NPDES)
General Permit No. GEG460000
For Offshore Oil and Gas Activities in the Eastern Gulf of Mexico

TABLE OF CONTENTS

ENVIRONMENTAL PROTECTION AGENCY

NOTICE OF FINAL NPDES GENERAL PERMIT

Final NPDES General Permit for New and Existing Sources in the Offshore Subcategory of the Oil and Gas Extraction Category for the Eastern Portion of the Outer Continental Shelf of the Gulf of Mexico (GEG460000)

SUMMARY: Today, the EPA Region 4 is finalizing the National Pollutant Discharge Elimination System (NPDES) general permit for the eastern portion of the Outer Continental Shelf (OCS) of the Gulf of Mexico (Permit No. GEG460000) for discharges from new sources, existing sources, and new dischargers, in the Offshore Subcategory of the Oil and Gas Extraction Point Source Category (40 Code of Federal Regulations (C.F.R.) Part 435, Subpart A). This permit replaces the previous permit issued on March 15, 2010, which became effective on April 1, 2010, and expired on March 31, 2015. The general permit authorizes discharges from oil and gas facilities and supporting pipeline facilities, engaged in exploration, development, and production operations located in, and discharging to, Federal waters of the Gulf of Mexico. The general permit coverage area is Federal Waters (Federal Waters are those water that are 3 Nautical Miles seaward of the baseline marking the seaward limit of inland waters or, if there is no baseline, the line of ordinary low water along the portion of the coast that is in direct contact with the open sea) of the Gulf of Mexico (1) seaward of the 200 meter depth contour offshore of Alabama in the Destin Dome lease block, (2) seaward of the 200 meter depth contour offshore of Florida, and (3) in the Viosca Knoll and Mobile lease blocks offshore of Mississippi and

Alabama. The term of the permit will be no longer than five years from the effective date of the permit.

FOR FURTHER INFORMATION CONTACT: Mrs. Bridget Staples, EPA Region 4, Water Protection Division, 61 Forsyth Street, Atlanta, Georgia 30303, Telephone: (404) 562- 9783, or via email to the following address: staples.bridget@epa.gov.

Authorization To Discharge Under the National Pollutant Discharge Elimination System

In compliance with the Federal Water Pollution Control Act, as amended (33 U.S.C. 1251 et. seq.), operators of new and existing sources and new discharges from offshore oil and gas development, production, and exploration facilities in lease blocks located in Outer Continental Shelf (OCS) Federal waters in the eastern portion of the Gulf of Mexico. The general permit coverage area is Federal waters of the Gulf of Mexico seaward of 200 meter depth contour offshore Alabama in the Destin Dome lease block and offshore Florida and seaward of the outer boundary of the territorial seas for offshore Mississippi and Alabama in Mobile and Viosca Knoll lease blocks. Operators in the coveage area are arauthorized to discharge to receiving waters in accordance with effluent limitations, monitoring requirements, and other conditions set forth in Parts I, II, III, IV and V, and appendices thereof.

Operators of facilities within the NPDES general permit coverage area must submit a Notice of Intent (NOI) to the Regional Administrator, prior to discharge, that they intend to be covered by the general permit (See Part I.A.3). The effective date of coverage will be the postmarked date of the NOI, or if the postmarked date is illegible, the effective date of coverage will be two days prior to the receipt date of the NOI.

This permit shall become effective at midnight, Eastern Standard Time, on January 20, 2018. Administratively continued coverage under the previous NPDES general permit will cease for operators 30 days after the effective date of this permit. Therefore, such operators must submit a new NOI to be covered under this general permit within 30 days after the effective date of this permit. If a permit application for an individual permit is filed, the coverage under the previous general permit terminates when a final action is taken on the application for an individual permit.

This permit and the authorization to discharge shall expire at midnight, Eastern Standard Time on January 19, 2023.

Signed this day of December 21, 2017.

Mary S. Walker
Director
Water Protection Division
U.S. EPA Region 4

Part I. Requirements for NPDES Permits

A. Permit Applicability and Coverage Conditions

1. Operations Covered

This permit establishes effluent limitations, prohibitions, reporting requirements and other conditions for discharges from oil and gas facilities, and supporting pipeline facilities, engaged in production, field exploration, drilling, well completion, and well treatment operations from potential new sources, existing sources, and new discharges.

The permit coverage area includes Federal waters in the Gulf of Mexico seaward of the 200 meter water depth for offshore Alabama and Florida and seaward of the outer boundary of the territorial seas for offshore Mississippi and Alabama in the Mobile and Viosca Knoll lease blocks. This permit is available to facilities located in, and discharging to, the Federal waters listed above and does not authorize discharges from facilities in or discharging to the territorial sea (within three miles of shore) of the Gulf coastal states or from facilities defined as "coastal" or "onshore" (see 40 Code of Federal Regulation (C.F.R.) Part 435, subparts C and D at internet address: www.epa.gov/epacfr40/chapt-I.info).

2. Types of Operators and Operations Excluded

Any operator seeking to discharge drill fluids, drill cuttings, well completion, well treatment or well workover fluids or produced water within 1000 meters of an Area of Biological Concern (ABC) or within 1000 meters of a Federally Designated Dredged Material Disposal Site is ineligible for coverage under this general permit and must apply for an individual permit. Any leases which are currently under moratorium are excluded from inclusion under this general permit.

For the purpose of this permit, "Operator" means any party that meets either of the following criteria and pertains only in the context of discharges associated with oil and gas exploration, development, and production activities covered under this permit:

1. Primary Operator – The party possesses the lease of the block where the exploration, development, or production activity will take place and has operational control over exploration, development, or production activities, including the ability to hire or fire contractors who conduct the actual work that results in discharges regulated by the permit (i.e., the lease holder) or designated operator who registers with the Bureau of Ocean Energy Management (BOEM); or
2. Day-to-day Operator - The party has a day-to-day operational control of those activities at an exploration, development, or production project which are necessary to ensure compliance with the permit (i.e., designated operator or contractor); or
3. Vessel Operator – The party has operational control over all vessel or other mobile facility with cooling water intake structures subject to Clean Water Act (CWA) Section 316(b). [Note: A vessel or mobile facility which engages in an exploration, development, or production activity is subject to this permit even if it is not subject to CWA Section 316(b).]

The primary operator must file an NOI for discharges to be covered by this permit. Other operators or vessel operators must file an NOI to cover discharges directly under their control but beyond primary operator's control, if such discharges are not covered by the NOI filed by the primary operator.

Permit coverage will not be extended to non-operational facilities, planned facilities or planned wells, i.e., those on which no production and no discharges have taken place in the two years prior to the effective date of this general permit, until such time that documentation is submitted to EPA that an Exploration Plan (EP), Development Operational Coordination Document (DOCD) or Development Production Plan (DPP) has been submitted to BOEM or approved by BOEM.

3. General Permit Applicability

In accordance with 40 C.F.R. §§ 122.28(b)(3) and 122.28(c), the Regional Administrator may require any person authorized by this permit to apply for and obtain an individual NPDES permit when:

a. The discharge(s) is a significant contributor of pollution;

b. The discharger is not in compliance with the conditions of this permit;

c. A change has occurred in the availability of the demonstrated technology or practices for the control or abatement of pollutants applicable to the point sources;

d. Effluent limitation guidelines are promulgated for point sources covered by this permit, which were not already subject to an effluent guideline;

e. A Water Quality Management Plan containing requirements applicable to such point source is approved;

f. It is determined that the facility is located in an ABC;

g. Circumstances have changed since the time of the request to be covered so that the discharge is no longer appropriately controlled under the general permit, or either a temporary or permanent reductions or elimination of the authorized discharge is necessary;

h. Other relevant factors (i.e., permittee was in non-compliance status with an individual NPDES permit for offshore oil and gas operations).

The Regional Administrator may require any operator authorized by this permit to apply for an individual NPDES permit only if the operator has been notified in writing that an individual permit is required.

Any operator authorized by this permit may request to be excluded from the coverage of this general permit at any time by applying for an individual permit. Such operator shall submit the appropriate application forms to the Regional Administrator. When an individual NPDES permit is issued to an operator otherwise subject to this permit, the applicability of this permit to the owner or operator is automatically terminated on the effective date of the individual permit.

A source excluded from coverage under this general permit solely because it already has an individual permit may request that its individual permit be revoked, and that it be considered for coverage by this general permit. Revocation of the individual permit will occur upon approval of coverage (see Part I.A.4, below) under this permit.

4. Notification Requirements (Existing Sources and New Sources)

A Notice of Intent (NOI) requesting coverage in accordance with the general permit requirements shall state whether the permittee is requesting coverage under the requirements for an existing source or requirements for new source, as well as all the following information. Please indicate "N/A" for those items that are not applicable to the coverage:

a. the legal name and address of the owner or operator;

b. Type of operator – primary operator, day-to-day operator, or vessel operator (see Part I.A.2)

c. the facility name, OCS number location, including the lease block assigned by BOEM, or if none, the name commonly assigned to the lease area;

d. the number and type of facilities and activities proposed within the lease block;

e. a map with longitude and latitude of the facility location and of the expected discharges identified by the nomenclature used in Part I.B.1 - 11. Additional information may be requested by the Director regarding miscellaneous discharges;

f. the date on which the owner/operator commenced/will commence on-site construction, including:

  i). any placement assembly or installation of facilities or equipment; or

  ii). the clearing or removal of existing structures or facilities.

g. the date on which the facility plans to commence exploration activities at the site, if applicable;

h. the date on which the owner/operator entered into a binding contract for the purchase of facilities or equipment intended to be used in its operation within a reasonable time (if applicable);

i. the date on which the owner/operator plans to commence development;

j. the date on which the owner/operator plans to commence production;

k. technical information on the characteristics of the sea bottom in accordance with BOEM Notice to Lessees (NTL) no. 2008-G05, Shallow Hazards Program, or the most current BOEM guidelines for shallow hazard investigation and analysis within 300 meters (965 feet) of the discharge point. For those facilities that submitted this information to EPA Region 4 as part of the previous NPDES general permit (GEG460000), only indicate the previous submittal date of the information to meet the requirement of this NOI element.

l. for facilities in less than 100-meter water depth for offshore Mississippi and Alabama in the Mobile and Viosca Knoll lease blocks, permittee's must submit a Live-Bottom Survey using either digital high-resolution acoustic data (sidescan sonar) or photo documentation. The acoustic data may be either new data acquired for this purpose or data obtained by the permittee for lease or site-specific surveys in compliance with BOEM requirements, as per NTL No. 2008-G04 *Information Requirements for Exploration Plans and Development Operations Coordination Documents*, or most current BOEM guidelines. Digital (or digitized analog data) sidescan sonar data obtained by survey methods described in NTL No. 2008-G05 *Shallow Hazard Program*, or most current BOEM guidelines, if sufficient, may be used as the source of acoustic data for preparation of a Live-Bottom Survey report. EPA will consider all natural or artificial hard structure detected by acoustic data to be live-bottom unless other data (i.e., video, still photographs, diver visual, etc.) determines otherwise. Permittees choosing to continue providing photo documentation will continue to conduct such surveys, as per NTL No. 2004-G05, attachment 7, or most current BOEM guidelines. Final siting of proposed outfalls must be no further than 500 meters from the proposed surface location. See Part I.D.5 for specific permit requirements pertaining to preparation of reports using high resolution acoustical data. For those facilities that submitted this information to EPA Region 4 as part of the previous NPDES general permit, only indicate the previous submittal date of the information to meet the requirement of this NOI element;

m. the type of drilling fluids to be used (e.g., water-based and/or synthetic-based);

n. documentation that an Application for Permit to Drill (APD) has been submitted to BSEE and the, EP, DOCD or DPP has been submitted to BOEM or approved by BOEM;

o. for facilities installed after March 4, 1993, the NOI must also identify that the facility is a new source and state the date on which the facility's protection from more stringent new source performance standards or technology-based limitations ends. That date is the soonest of ten years from the date that construction is completed, ten years from the date the source begins to discharge process or non-construction related wastewater, or the end of the period of depreciation or amortization of the facility for the purposes of Section 167 or 169 (or both) of the Internal Revenue Code of 1954;

p. the general permit coverage number for the previous general permit and/or the individual NPDES permit number of any individual permit issued by EPA Region 4 for this activity;

q. for production platforms, indicate the estimated distance (in meters) from the platform to the nearest Federally Designated Dredged Material Ocean Disposal Site;

r. any permit violations or under the previous Region 4 General Permit for the facility;

s. indicate if Phase III of EPA's Cooling Water Intake Structure Rule (CWIS) applies to the facility for which you are applying for coverage under this permit. Also indicate if the facility plans to comply under Track I or Track II of the CWIS. See Part I.D.3. Note that the Phase III CWIS rule applies to new offshore oil and gas extraction facilities for which construction commenced after July 17, 2006, that meet 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% of the water it withdraws for cooling purposes; 3) it has a design intake flow greater than two million gallons per day (MGD). 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. The threshold requirement that at least 25% 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% 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% of the total water withdrawn.

t. If known, indicate the name and NPDES permit coverage number under GEG460000 for vessel operators/contractors that are, or will be, performing work at your facility that are new oil and gas facilities subject to Phase III of the CWIS Rule.

u. Information on the specific chemical composition of any additives currently being used or proposed for use in well treatment, completion or workover operations or as biocides for sump/drain systems. If the information on the additive is not known at the time of the submittal of this NOI, operators shall include the information in a report that shall be submitted on to EPA Region 4 on September 30th of each year. Aside from submitting this information with the NOI, this information is also required to be recorded and retained on site for no less than five years from the issuance date of the permit. These record retention requirements in this section supersede the general record keeping requirments for all NPDES permits in Part II.C.5. of this permit.

v. Certification statement per 40 C.F.R. §§ 122.22(d) and signature of the responsible party per 40 C. F.R §§ 122.22(a).

w. Statement indicating intent, or not, to participate in the alternative Industry-wide Study regarding Whole Effluent Toxicity Testing of Well Treatment, Completion and Workover Fluids (Part I.B.6.b, page 50).

Operators with coverage under the previous general permit that was administratively continued (i.e., a request for continued coverage received prior to) must submit a new NOI to be covered under this permit no later than 30 days from the effective date of this permit. All facility owners for newly acquired leases must submit a written NOI prior to the date of discharge and no later than 14 days prior to the expiration date of this permit. All NOIs shall be signed in accordance with 40 C.F.R. § 122.22.

Beginning on the effect date and through the expiration date of this permit, all NOIs must be submitted electronically. However, if the electronic NOI system is not operational by September 1, 2017, or at any time through the expiration date of this permit, EPA will accept a written NOI. Once the system becomes operational, an electronic NOI will need to be submitted. For an NOI submitted in writing, the effective date of coverage will be the postmarked date of the NOI, or if the postmarked date is illegible, the effective date of coverage will be two days prior to the receipt date of the NOI. The effective date of coverage submitted electronically will be the date of the request. EPA will notify the applicant within 21 days of the receipt date regarding the new permit coverage number(s) and effective date of permit coverage. If an NOI is determined to be incomplete, EPA will notify the applicant within 21 days of receipt of the NOI regarding any discrepancies, and/or possible termination of coverage. Information regarding electronic submittals of NOIs is contained in Part III of this permit.

5. Operational Facilities

a. Change in designation from existing source to new source

Operators obtaining coverage under the existing source general permit for exploration activities (existing source) must send a new NOI for coverage of development and production activities as new source 14 days prior to commencing such operations. All NOIs requesting coverage should be sent by certified mail to: Director, Water Protection Division, U.S. EPA Region 4, Sam Nunn Federal Center, 61 Forsyth Street, S.W., Atlanta, GA 30303-8960.

b. "No Activity" Notification

For any activity for which no discharge is occurring, the operator shall submit a "No Activity" list each calendar quarter along with the quarterly submittal of the Discharge Monitoring Report (DMR). The No Activity list shall include:

(i) the NPDES general permit coverage number assigned to the facility,

(ii) the lease block designation and,

(iii) a certification statement signed in accordance with Part II.D.12. of this permit.

All NOIs, No Activity lists, and any subsequent reports required under this permit shall contain a signed certification statement (see Part II.D.12) and shall be sent by certified mail to the address given above.

6. Non-Operational Facilities

Non-operational facilities, planned facilities or planned wells are only eligible for coverage under this general permit after documentation has been submitted to EPA indicating that an EP, DOCD or DPP, has been submitted to, or approved by, BOEM.

7. Termination of Operations

Lease block operators shall notify the Director (at the address above) within 60 days after the permanent termination of discharges from their facility. Information regarding electronic submittals of Notices of Termination (NOTs) is contained in Part III of this permit.

8. Intent to be Covered by a Subsequently Issued Permit

This permit shall expire on December 31, 2023. A letter requesting coverage under a subsequent general permit must be submitted no later than the expiration date of this permit. (NOTE: Due to this being a general permit, this stipulation supersedes the 180-day time frame in Part II.D.11). The request letter must list the facilities to be covered under the subsequent permit, their current permit coverage numbers, and be certified in accordance with Part II.D.12. If reissuance of this general permit does not occur before its expiration date and the permittee has submitted the request letter, continued coverage under this permit will be allowed until the effective date of the reissued general permit. If the permittee is notified by EPA of the need to submit application forms for an individual permit and a letter requesting coverage under the subsequent permit was submitted, continued coverage under this general permit will be allowed until the effective date of the individual permit issued to the applicable facility.

Permittees that fail to notify the Director, during the term of this permit, of their intent to be covered by a subsequently issued permit cannot obtain continued authorization to discharge after the expiration date of this permit and will be operating without NPDES permit coverage until they apply for and obtain coverage under the subsequently issued general permit or apply for, and receive, an effective individual NPDES permit. All letters requesting coverage under a subsequently issued general permit should be sent by certified mail to: Director, Water Protection Division, U.S. EPA Region 4, Sam Nunn Federal Center, 61 Forsyth Street, S.W., Atlanta, GA 30303-8960.

9. Transfer of General Permit Coverage

This permit is not transferable to any entity except after written notice to the Director and subsequent written approval by the Director. The request for transfer shall include the permit coverage number, the OCS number, the facility name, and lease block name, the name of the existing permittee, name of the operator the coverage is being transferred to, and the projected date the transfer is to become effective. Submittal of a new NOI is not required for the transfer of permit coverage. The request must contain a certification statement (see Part II.D.12.d.) and be signed and dated by officials from each operating company. The Director may require modification or revocation and reissuance of the permit coverage to change the name of the permittee and incorporate such other requirements as may be necessary under the Clean Water Act (CWA). (The transfer of permit coverage requirements in this section supersede the "Transfer of Ownership of Control" requirements set forth in Part II.D.3 of this permit.)

B. Effluent Limitations and Monitoring Requirements for New and Existing Sources

Note: EPA published the final rule "Guidelines Establishing Test Procedures for the Analysis of Pollutants Under the Clean Water Act: Analysis and Sampling Procedures" in Federal Register, Vol. 77, No. 97, May 18, 2012. Any recent or future changes or incorporation of new testing protocol or methods in the Effluent Limitation Guideline at 40 C.F.R. Part 435 supersede the applicable requirements in this permit.

The following limitations and monitoring requirements are summarized in Part V, Table 1 of this permit. Note all samples must be representative of the effluent. Permittees are not allowed to filter samples.

1. Drilling Fluids

a. Prohibitions

i. Non-Aqueous Based Drilling Fluids (NAFs) [including Synthetic-Based Drilling Fluids (SBFs)]. There shall be no discharge of NAFs, except that which adheres to cuttings, or which are considered de minimus discharges (see Part I.D.1) or as small volume discharges (see Part I.D.2).

Exception - NAFs may be used as a carrier fluid (e.g., transporter fluid), lubricity additive or pill in water-based drilling fluids, and may be discharged with those drilling fluids provided the discharge continues to meet the no Free Oil limit, the 96-hour LC_{50} toxicity limits, and the pill is removed prior to discharge.

ii. Oil-Based Drilling Fluids. There shall be no discharge of oil-based drilling fluids and inverse emulsion drilling fluids.

iii. Oil-Contaminated Drilling Fluids. There shall be no discharge of drilling fluids to which waste engine oil, cooling oil, gear oil or any lubricants which have been previously used for purposes other than borehole lubrication have been added.

iv. Diesel Oil. There shall be no discharge of drilling fluids to which contain diesel oil.

v. No Discharge Near Areas of Biological Concern. Unless otherwise authorized by the Director, there shall be no discharge of drilling fluids and drill cuttings from those facilities within 1000 meters (or as determined by the Director) of an ABC.

vi. <u>No Discharge Near Federally Designated Dredged Material Ocean Disposal Sites</u>. Unless otherwise authorized by the Director, there shall be no discharge of any drilling fluids and drill cuttings from those facilities within 1000 meters (or as determined by the Director) of a Federally Designated Dredged Material Ocean Disposal Site. See 40 C.F.R. § 228.15(f) for a list of sites located within the area covered by this general permit.

b. Limitations

i. <u>Mineral Oil</u>. Mineral oil may be used only as a carrier fluid (e.g., transporter fluid), lubricity additive, or pill. If mineral oil is added to a water-based drilling fluid, the drilling fluid may not be discharged, unless the 96-hr LC_{50} of the drilling fluid is greater than 30,000 ppm (3% by volume) using the Suspended Particulate Phase (SPP) Toxicity Test and the sample passes the Static Sheen Test for free oil. The analytical methods for the SPP Toxicity Test and free oil are contained in Part I.B.1(b)(3) and (4) below. Samples must be taken at the nearest accessible location prior to discharge, or prior to combining with any other wastewaters.

ii. <u>Cadmium and Mercury in Barite</u>. There shall be no discharge of drilling fluids to which barite has been added if such barite contains mercury in excess of 1.0

mg/kg (dry weight) or cadmium in excess of 3.0 mg/kg (dry weight). The permittee shall analyze a representative sample of each supply of stock barite prior to drilling each well and submit the results for total mercury and cadmium on the DMR. If more than one well is being drilled at a site, new analyses are not required for subsequent wells, provided that no new supplies of barite have been received since the previous analysis. In this case, the results of the previous analysis should be used for completion of the DMR. Alternatively, the permittee may provide certification, as documented by the supplier(s), that the barite being used on the well will meet the above limits. The concentration of the mercury and cadmium in the barite shall be reported on the DMR as documented by the supplier. Analyses for cadmium shall be conducted by EPA Methods 200.7, 200.8 or EPA Method 3050 B followed by 6010 B or 6020A (EPA SW 846), or more recently approved EPA methods, and results shall be expressed in mg/kg (dry weight) of stock barite. Analysis for mercury shall be conducted using EPA Method 245.7 or EPA method 7471 A (EPA SW 846), or most recently approved EPA methods, and expressed as mg/kg (dry weight) of stock barite.

iii. Toxicity. Discharged water-based drilling fluids shall meet both a daily minimum and a monthly average minimum effluent toxicity limitation of 30,000 ppm (3.0% by volume), using a volumetric mud-to-water ratio of 1 to 9. The analytical method is cited in 40 C.F.R. Part 435, Appendix 2 of subpart A, entitled, "Drilling Fluid Toxicity Test." Monitoring shall be performed at least once per month by a grab sample taken from beneath the shale shaker for both the daily minimum and the monthly average minimum. If there are no returns across the shaker, the sample must be taken from a location that is characteristic of the overall mud system to be discharged. An end-of-well sample (See definition in Part V.B) is also required. The end-of-well test sample can also be used for the last monthly grab sample. The lowest daily minimum and lowest monthly average for the quarterly reporting period must be reported on the DMR. Copies of the summary sheets for laboratory reports must also be submitted with the DMR. If a failure occurs, the facility must submit the entire laboratory report with the DMR. Samples for this parameter must be taken at the nearest accessible location prior to discharge, or prior to combining with any other wastewaters.

iv. Free Oil. No free oil shall be discharged. Monitoring shall be performed once per week using the Static Sheen Test method in accordance with the method provided in Part V.A.3, as published in 40 C.F.R. Part 435, Appendix 1 of subpart A. The results of each sheen test must be recorded for the fluids that are discharged and the number of days a sheen is observed must be reported on the DMR.

v. Maximum Hourly Discharge Rate. The maximum discharge rate (water-based drilling fluids) shall not exceed 1,000 barrels (bbls) per hour. The maximum hourly discharge rate for each month must be recorded. The highest hourly discharge rate for the quarterly reporting period must be reported on the DMR in barrels/hour.

Exception - The Maximum Hourly Discharge Rate Limitation shall not apply to Water-Based Drilling Fluids discharged prior to the installation of the marine riser.

c. Monitoring Only Requirements

In addition to the above limitations, the following monitoring and reporting requirements also apply to drilling fluids discharges.

i. Drilling Fluids Inventory. The permittee shall maintain a precise chemical usage record of all constituents and their total volume, concentrations, and mass added for each well. Information shall be recorded and retained for the term of the permit.

ii. Volume. The total monthly volume (bbl/month) of bulk discharged drilling fluids must be estimated and recorded. The highest monthly volume (in bbl/month) and the average volume during the monitoring period shall be reported on the DMR.

2. Drill Cuttings

Except for the maximum hourly discharge rate, the permit prohibitions and limitations that apply to drilling fluids also apply to fluids that adhere to drill cuttings. Any permit condition that applies to the drilling fluid system, also applies to cuttings discharges. Monitoring requirements, however, may not be the same.

a. Prohibitions

i. <u>Cuttings from Oil-Based Drilling Fluids</u>. The discharge of cuttings is prohibited when they are generated while using an oil-based or invert emulsion mud.

ii. <u>Cuttings from Oil Contaminated Drilling Fluids</u>. There shall be no discharge of cuttings that are generated using drilling fluids that contain waste engine oil, cooling oil, gear oil or any lubricants which have been previously used for purposes other than borehole lubrication.

iii. <u>Cuttings Generated Using Drilling Fluids Which Contain Diesel Oil</u>. There shall be no discharge of drill cuttings generated using drilling fluids which contain diesel oil.

iv. <u>Cuttings Generated Using Mineral Oil</u>. The discharge of cuttings generated using drilling fluids which contain mineral oil is prohibited except when the mineral oil is used as a carrier fluid (e.g., transporter fluid), lubricity additive, or pill.

v. <u>No Discharge Near Areas of Biological Concern</u>. There shall be no discharge of drill cuttings from those facilities within 1000 meters (or as determined by the Director) of an ABC.

vi. <u>No Discharge Near Federally Designated Dredged Material Ocean Disposal Sites</u>. There shall be no discharge of any drilling fluids, drill cuttings or produced waters from those facilities within 1000 meters (or as determined by the Director) of a Federally Designated Dredged Material Ocean Disposal Site. See 40 C.F.R. § 228.15(f) for a list of sites in the general permitting area.

vii. Cuttings Generated Using Non-Aqueous Based Drilling Fluid. There shall be no discharge of non-aqueous based drilling fluid, except that which adheres to cuttings, de minimus discharges (see Part I.D.1) and small volume discharges (see Part I.D.2).

Exception - NAFs may be used as a carrier fluid (e.g., transporter fluid), lubricity additive or pill in water-based drilling fluids and discharged with those drilling fluids provided the discharge continues to meet the no free oil and 96-hour LC_{50} toxicity limits, and a pill is removed prior to discharge.

b. Limitations which apply to all drill cuttings

i. Mineral Oil. There shall be no discharge of mineral oil.

Exception - Cuttings from a water-based mud system may be discharged when mineral oil pills or mineral oil lubricity additives have been introduced if they meet the limitations below for aquatic toxicity and free oil.

ii. Free Oil. No free oil shall be discharged. Monitoring shall be performed on cuttings discharges once per week using the Static Sheen Test method in accordance with the method provided in Part V.A.3. Samples must be taken at the nearest accessible location prior to discharge, or prior to combining with any other wastewaters. There shall be no discharge of cuttings that fail the static sheen test. The results of each sheen test for fluids that are discharged must be recorded and the number of observations of a static sheen must be reported on the DMR.

iii. Suspended Particulate Phase Toxicity. Discharged cuttings shall meet both a daily minimum and a monthly average minimum effluent toxicity limitation of at least 30,000 ppm (3.0% by volume), using a volumetric mud-to-water ratio of 1 to 9. The analytical method is cited in 40 C.F.R. Part 435, Appendix 2 of subpart A, entitled, "Drilling Fluid Toxicity Test." Monitoring shall be performed at least once per month by taking a grab sample from beneath the shale shaker for both the daily minimum and the monthly average minimum limits. The toxicity test may be satisfied by the same sample used for the drilling fluid. An end-of-well sample is also required. The end-of-well test sample may also be used as the last monthly grab sample. The lowest daily minimum value for the 12-month reporting period as well as the lowest monthly average test result must be reported on the DMR. Copies of the summary sheets for laboratory reports also must be submitted with the DMR. If a failure occurs, the facility must submit the entire laboratory report with the DMR.

iv. Mercury and Cadmium in Stock Barite. There shall be no discharge of drill cuttings that are generated using drilling fluids to which barite has been added, if such barite contains mercury in excess of 1.0 mg/kg (dry weight) or cadmium in excess of 3.0 mg/kg (dry weight). The permittee shall analyze a representative sample of each supply of stock barite prior to drilling each well and submit the results for total mercury and total cadmium on the DMR. If more than one well is being drilled at a site, new analyses are not required for subsequent wells, provided that no new supplies of barite have been received since the previous analysis. In this case, the results of the previous analysis should be used for completion of the DMR. Alternatively, the permittee may provide certification, as documented by the supplier(s), that the barite being used on the well will meet the above limits. The concentration of the mercury and cadmium in the barite shall be reported on the DMR as documented by the supplier. Analyses for cadmium shall be conducted by EPA Methods 200.7, 200.8 or EPA Method 3050 B followed by 6010 B (EPA SW 846) and results expressed in mg/kg (dry weight) of stock barite. Analysis for mercury shall be conducted using method 245.7 or EPA Method 7471 A (EPA SW 846), and expressed as mg/kg (dry weight) of stock barite.

c. Discharge Limitations and Monitoring Requirements Applicable to Drill Cuttings Generated using Non-Aqueous Based Drilling Fluids

Except for the toxicity testing requirements for drilling fluids in Part I.B.1.b.(iii), all the limits for drill cuttings in Part I.B.2.(b) above, apply to drill cuttings that are generated using synthetic-based drilling fluids.

i. <u>Formation Oil</u>. There shall be no discharge of formation oil. Monitoring of the drilling fluids shall be performed as follows:

(1). Once prior to drilling using the gas chromatography/mass spectrometry test (GC/MS) method specified in Appendix 5 of 40 C.F.R. Part 435, subpart A. Alternatively, the permittee may provide certification, as documented by the supplier(s) that the drilling fluid being used on the well contains no formation oil as determined using the GC/MS method in Appendix 5 of 40 C.F.R. Part 435, subpart A.

(2). Once per week during drilling using the Reverse Phase Extraction (RPE) test method specified in Appendix 6 of 40 C.F.R. Part 435, subpart A. If an operator wishes to confirm the results of the RPE method, the GC/MS method may be used, and results of this method shall supersede the results of the RPE method. Alternatively, the operator may use the GC/MS method instead of the RPE method.

As an alternative to using the crude oil standard in Appendix 5 and 6 of 40 C.F.R. Part 435 A, the permittee may use National Institute of Standards and Technology method no. 2779, Gulf of Mexico Crude Oil Standard.

All test results shall be reported with the DMR.

ii. <u>Drilling Fluid Sediment Toxicity Ratio</u>. The sediment toxicity test ratio shall not exceed 1.0 and shall be calculated based on the following:

$$\text{Drilling Fluid Sediment Toxicity Ratio} = \frac{\text{4-day } LC_{50} \text{ of } C_{16}\text{-}C_{18} \text{ internal olefin reference drilling fluid}}{\text{4-day } LC_{50} \text{ of drilling fluid removed from the drill cuttings at the solids control equipment}}$$

The approved test method is ASTM method no. E1367-92 (or the most current EPA approved method) and monitoring for this parameter shall be once per month per well. Samples shall be collected and analyzed in accordance with the sampling protocol in Part V.12.

iii. <u>Base Fluid Retained on Cuttings</u>. For NAFs that meet the stock limitation of C_{16}-C_{18} internal olefin, the maximum weighted mass ratio averaged over all non-aqueous-based drilling fluid well sections shall not exceed 6.9 g NAF per 100 g of wet drill cuttings. For NAFs that meet the stock limitation of C_{12}-C_{14} esters or C_8 ester, the maximum weighted mass ratio averaged over all NAF well sections shall not exceed 9.4 g non-aqueous-based drilling fluid per 100 g of wet drill cuttings. A default value of 14% of base fluid retained on drill cuttings may be used for determining compliance with the base fluids retained on cutting limit where seafloor discharges are made from dual gradient drilling. In those cases, 15% will be used as a default value for the mass fraction of cuttings discharged at the sea floor. The default values will be averaged with results obtained from daily monitoring to determine compliance with the retention limitations. Monitoring for this parameter shall be once per day by grab sample except when meeting the conditions of the Best Management Practices described in Part I.V.3.g., or one sample for every 500 feet drilled, up to three samplings per day, using the American Petroleum Institute (API) Retort method specified in 40 C.F.R. Part 435, subpart A of Appendix 7. The weighted mass ratio averaged over all non-aqueous-based drilling fluid well sections shall be reported on the DMR. The sample for the drilling fluid retained on cuttings shall be taken at the solids control equipment.

d. Base Drilling Fluid Stock Limitations Applicable to Drill Cuttings Generated using Non-Aqueous Based Drill Fluids

i. Polynuclear Aromatic Hydrocarbon (PAH) Content. The PAH mass ratio shall not exceed 1×10^{-5}. Monitoring shall be by grab sample taken once per year on each fluid blend using EPA Method 1654A (or the most current version), in conjunction with the following equation:

$$\text{PAH mass ratio} = \frac{\text{mass (g) of PAH (as phenanthrene)}}{\text{mass (g) of stock base fluid}}$$

The PAH ratio shall be reported on the DMR.

ii. Stock Drilling Fluid Sediment Toxicity Ratio. The sediment toxicity ratio shall not exceed 1.0, and shall be calculated as follows:

For NAF base fluid of C_{16}-C_{18} internal olefin,

$$\text{Sediment Toxicity Ratio} = \frac{\text{10-day } LC_{50} \text{ of } C_{16}\text{-}C_{18} \text{ internal olefin reference fluid}}{\text{10-day } LC_{50} \text{ of stock base fluid}}$$

For NAF base fluids of 100% C_{12}-C_{14} ester or C_8 ester content,

$$\text{Base Fluid Sediment Toxicity Ratio} = \frac{\text{10-day } LC_{50} \text{ of } C_{12}\text{-}C_{14} \text{ ester or } C_8 \text{ ester reference base fluid*}}{\text{10-day } LC_{50} \text{ of stock base fluid}}$$

* Chemical Abstract No. 135800-37-2

Monitoring for the parameter shall be performed at least once per year on each fluid blend using the 10-day LC_{50} sediment toxicity test specified in ASTM E1367-92 (or the most current EPA approved method), and reported on the DMR. Samples shall be collected and analyzed using the sampling protocol in Part V.12.

iii. <u>Biodegradation Rate Ratio</u>. The biodegradation rate ratio of the stock base fluid shall not exceed 1.0, and shall be calculated using the following equation:

For NAF base fluid of C_{16}-C_{18} internal olefin,

$$\text{Biodegradation Rate Ratio} = \frac{\text{Cumulative gas production (ml) of } C_{16}\text{-}C_{18} \text{ internal olefin reference base fluid at 275 days}}{\text{Cumulative gas production (ml) of stock base fluid at 275 days}}$$

For NAF base fluid of 100% C_{12}-C_{14} ester or C_8 ester content,

$$\text{Biodegradation Rate Ratio} = \frac{\text{Cumulative gas production (ml) of } C_{12}\text{-}C_{14} \text{ ester or } C_8 \text{ ester reference base fluid* at 275 days}}{\text{Cumulative gas production of (ml) of stock base fluid at 275 days}}$$

* Chemical Abstract No. 135800-37-2

Monitoring for the parameter shall be performed at least once per year on each fluid blend using International Standards Organization (ISO) Method 11734:1995 (or the most current EPA approved method) and results reported on the DMR. See Parts V.13 and 14 for additional requirements. Samples shall be collected and analyzed using the sampling protocol in Part V.12.

Exception - Stock limitations are designed to ensure that only base fluids meeting Best Available Technology (BAT) criteria are added to existing drilling fluids. As long as fluids or blends of fluids that are added to a built whole mud meet stock limitations criteria, it is acceptable to mix a base fluid to a built whole mud that differs from that originally used to make that mud. It is also acceptable to mix together two built whole mud systems that contain different base fluids so long as they are themselves built with base fluids that are compliant with the stock limitations. Operators choosing to mix previously compliant fluids, or blends of fluids, must analyze the mixture to show compliance with the limitations for:

Formation Oil (see Part I.B.2.c.i (1)),

SPP toxicity (see Part I.B.1.b.iii), and

Drilling Fluid Sediment Toxicity (see Part I.B.2.c.ii).

All test results shall be submitted with the DMR.

e. Monitoring Only Requirements

Volume. The monthly total discharge of drill cuttings must be estimated. The estimated highest monthly volume (in bbl/month) and the average volume for the monitoring period for cuttings discharged shall be reported on the DMR.

3. Produced Water

Produced water is defined in Part V.B. and includes process water generated from the monoethylene glycol (MEG) reclamation processes including salt slurry generated from the salt centrifuge unit. This wastewater may be discharged separately from produced waters via outfall 014 (i.e., is not mixed and discharged with produced water via outfall 004). Permit requirements and limitations are the same as those for produced waters as stated in Part 3.a., b., and c., below.

a. Prohibitions

i. No Discharge Near Areas of Biological Concern. There shall be no discharge of produced water from those facilities within 1000 meters (or as determined by the Director) of an ABC.

ii. No Discharge Near Federally Designated Dredged Material Ocean Disposal Sites. There shall be no discharge of produced water from those facilities within 1000 meters (or as determined by the Director) of a Federally Designated Dredged Material Ocean Disposal Site. See 40 C.F.R. § 228.15(f) for a list of sites in the general permit area.

b. Limitations

i. Oil and Grease. Produced water discharges shall not exceed both a daily maximum limitation of 42.0 mg/l and a monthly average limitation of 29.0 mg/l for oil and grease.

ii. Toxicity. The No Observed Effect Concentration (NOEC) must be equal to, or greater than, the predicted effluent concentration at the edge of a 100-meter mixing zone. Predicted effluent concentrations, referred to as critical dilutions, are presented in Tables 4 and 5 of Appendix A for a range of discharge rates and pipe diameters. The critical dilution shall be determined using Tables 4 and 5 of Appendix A of this permit based on the highest monthly average discharge rate for the three months prior to the month in which the test sample is collected, discharge pipe diameter, and depth difference between the discharge pipe and the sea bottom (For reference, background information used to construct tables 4 and 5 are contained in Tables 1, 2 and 3). Facilities which have not previously reported produced water flow on the DMR shall use the estimated monthly average flow that was discharged during the first three months of produced water discharge for determining the critical dilution from Tables 4 and 5 of Appendix A of this permit.

The NOEC shall be calculated by conducting 7-day chronic toxicity tests in accordance with methods published in *Short Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Water to Marine and Estuarine Organisms* (EPA/821-R-02-014), or most current edition.

For facilities that had not previously reported produced water toxicity, testing to determine the NOEC shall begin after the third month of produced water discharge and shall be done every two months until the permittee demonstrates compliance with three consecutive produced water toxicity tests and reports those results. Permittees that comply with the toxicity limit for three consecutive produced water toxicity tests will be allowed to reduce sampling to a frequency of once every six months.

Permittees that were covered under the previous general permit, and that are currently performing routine toxicity tests every six months, shall continue testing with a frequency of once every six months. If at any time, a test result indicates a failed test, the permittee must resume testing at a greater frequency, as set forth in Part V.A.15, until such time that the facility demonstrates compliance through three consecutive tests. If a new well is drilled into a formation currently not producing, which contains produced water, the permittee shall perform a new toxicity test on the discharge beginning after the end of the first three months of flow.

The results for both species shall be reported on the DMR. See Part V.A.15 of this permit for Whole Effluent Toxicity Testing Requirements.

Samples must be taken at the nearest accessible location prior to discharge. A grab sample must be taken once during each discharge during the maximum effluent flow rate. In the case where seawater is added in accordance with the exception below, samples may be taken downstream of the point where seawater is added.

Exception - Permittees wishing to increase mixing may use a horizontal diffuser, add seawater, or may install multiple discharge ports (e.g., vertical diffuser). Permittees using a horizontal diffuser or multiple discharge ports shall install the system such that the NOEC is greater than or equal to the critical dilution. The projected percent effluent (critical dilution) at the edge of the mixing zone will be calculated using CORMIX2 (for horizontal diffusers) and CORMIX1 (for vertical diffusers), with the following input conditions:

Density Gradient = 0.163 kg/m^3/m

Ambient seawater density at diffuser depth (or at surface for vertical diffuser) = 1023.0 kg/m^3

Produced water density = 1070.2 kg/m^3

Current speed = 5 cm/sec (<200 m water depth); 15 cm/sec (>200 m water depth)

Permittees shall submit a certification that the diffuser, seawater addition, or multiple discharge ports has been installed and state the critical dilution and corresponding NOEC in the certification. The certification shall be submitted along with the first DMR for produced water discharges to: Director, Water Protection Division, U.S. EPA Region 4, Sam Nunn Atlanta Federal Center, 61 Forsyth Street, SW, Atlanta, GA 30303-8960. All modeling runs shall be retained by the permittee as part of its NPDES records.

Permittees using vertically aligned multiple discharge ports/vertical diffuser shall provide vertical separation between ports which is consistent with Table 6 of Appendix A of this permit. When multiple discharge ports are installed, the depth difference between the discharge port closest to the seafloor and the seafloor shall be the depth difference used to determine the critical dilution from Tables 4 and 5 of Appendix A of this permit.

Permittees discharging produced water at conditions other than those covered in Tables 4 and 5 of Appendix A (e.g., at a rate greater flows and pipe diameters) shall determine the critical dilution using the appropriate CORMIX model with the above input parameters. Permittees shall retain the model runs as part of the NPDES records.

The critical dilution value shall be based on the port flow rate (total flow rate divided by the number of discharge ports) and based on the diameter of the discharge port (or largest discharge port if they are of different styles).

When seawater is added to produced water prior to discharge, the total produced water flow, including the added seawater, shall be used in determining the critical dilution from Tables 4 and 5 of Appendix A. When freshwater is added to produced water prior to discharge, the total produced water flow, including the added freshwater, shall be used in determining the critical dilution from Table 7 of Appendix A.

Permittees wishing to reduce a produced water flow rate and thereby the critical dilution through operational changes must provide to EPA a description of the specific changes that were made and the resultant low rate. The permittee must certify that this flow rate will not be exceeded for the remainder of the DMR period, unless the permittee re-certifies.

c. Monitoring Requirements

i. Flow. Once per month, an estimate of the flow must be recorded in units of barrels per day (bbl/day). The highest monthly discharge flow rate (in bbl/day) shall be estimated and reported on the DMR.

ii. Oil and Grease. A grab sample must be taken at least once per month. The daily maximum sample may be based on the average concentration of four grab samples spaced evenly and weighted by the flow rate and taken within a 24-hour period. (Reference Parts II.E.4 and E.7.c). If only one sample is taken for any one month, it must meet both the daily and monthly limits. If more samples are taken, they may exceed the monthly average for any one day, provided that the average of all samples taken meets the monthly limitation. The gravimetric method is specified in 40 C.F.R. Part 136. Samples must be taken at the nearest accessible location after final treatment and prior to combining with any other wastewaters. The highest daily maximum concentration and the highest monthly average concentration shall be reported on the DMR.

In addition, a produced water sample shall be collected within two (2) hours of when a sheen is observed in the vicinity of the discharge or within two hours after startup of the system if it is shut down following a sheen discovery, and analyzed for oil and grease.

iii. Visual Sheen. The permittee shall monitor for free oil using the visual sheen test method on the surface of the receiving water. Monitoring shall be performed once per day when discharging, during conditions when observation of a sheen on the surface of the receiving water is possible in the vicinity of the discharge, and when the facility is manned.

4. Deck Drainage

Limitations

Free Oil. No free oil shall be discharged. Monitoring shall be performed on each day of discharge during daylight hours using the visual sheen test method in accordance with the method provided at Part V.A.4. Discharge of deck drainage that fails the visual sheen test shall be a violation of this permit. The results of each visual must be recorded and the number of observations of a sheen must be recorded for the monitoring period and reported on the DMR. Note: An observation of deck drainage sheen is not required when the facility is not being manned.

Biocides: A use of biocide for sump/drain systems to comply proper operation and maintenance requirements is permitted for those compounds that meet the requirement at 40 C.F.R. § 122.42(a)(2)(i-iii) (Also see Part II.D.11 of the permit).

5. Produced Sand

There shall be no discharge of produced sand. Wastes must be hauled to shore for treatment and disposal.

6. Well Treatment Fluids, Completion Fluids, and Workover Fluids

a. Limitations

i. Free Oil. No free oil shall be discharged. Monitoring shall be performed prior to discharge and on each day of discharge using the static sheen test method in accordance with the method provided at Part V.A.3. There shall be no discharge of well treatment, completion, or workover fluids that fail the static sheen test. Samples must be taken at the nearest accessible location after final treatment and prior to discharge, or prior to combining with any other wastewaters. The results of each sheen test for discharged fluids must be recorded and the number of observations of a sheen must be reported for the monitoring period on the DMR.

ii. Oil and Grease. Well treatment fluids, completion fluids, and workover fluids discharges must meet both a daily maximum of 42.0 mg/l and a monthly average of 29.0 mg/l limitation for oil and grease. A grab sample must be taken at least once per month when discharging. Samples must be taken at the nearest accessible location after final treatment and prior to discharge, or prior to combining with any other wastewaters. The daily maximum concentration may be based on the average of four grab samples spaced evenly and weighted by the flow rate and taken within a 24-hour period. (Reference Parts II.E.4 and E.7.c). taken within the 24-hour period. If only one sample is taken for any one month, it must meet both the daily and monthly limits. If more samples are taken, they may exceed the monthly average for any one day, provided that the average of all samples taken meets the monthly limitation. The analytical method is the gravimetric method, as specified in 40 C.F.R. Part 136. The highest daily maximum and the highest monthly average for the monitoring period shall be reported on the DMR.

iii. Priority Pollutants. For well treatment fluids, completion fluids, and workover fluids, the discharge of priority pollutants is prohibited except in trace amounts. If multiple fluids are mixed, each fluid must be checked for priority pollutants. "Trace amounts" shall mean the amount equal to or less than the most sensitive method detection limit listed in 40 C.F.R. Part 136 for the applicable parameter. Vendor certification indicating the fluids contain no priority pollutants is acceptable for meeting this requirement. Information on the specific chemical composition of any additives containing priority pollutants shall be recorded and submitted as part of the NOI (see part I.4.u). Any updated information regarding chemical composition of new formulations that contain priority pollutants and will be used shall be submitted to EPA Region 4 annually no later than September 30th. Copies of these records should also be kept on the rig while the rig is on the permitted location and thereafter at the permittee's shore base or office. These record retention requirements supersede those found in Part II.C.5. of this permit.

Note: If materials added downhole as well treatment, completion, or workover fluids contain no priority pollutants as determined by using analytical methods in 40 C.F.R. Part 136, the discharge is assumed not to contain priority pollutants.

b. Monitoring Requirements

Volume. The highest daily total discharge and the 3-month average discharge must be estimated and reported on the DMR in barrels per month.

Chronic Whole Effluent Toxicity for Well Treatment, Completion or Workover fluids. Permittes with discharges of well treatment fluids, completion, or workover lasting four or more consecutive days (i.e., a discharge to that occurs for any amount of time during a 24-hour timeframe over four or more consecutive days) must monitor and report the No Observable Effect Concentration (NOEC) relative to the predicted effluent concentration at the edge of a 100-meter mixing zone. A grab sample must be taken at least once per month when the maximum flow rate of WTCW fluids will be discharged. Permittes may request reduced monitoring requency after the first year of the permit.

Predicted effluent concentrations, referred to as critical dilutions, are presented in Tables 4 and 5 of Appendix B for a range of discharge rates and pipe diameters.

Permittees discharging well treatment wastewater at conditions other than those covered in Tables 4 and 5 of Appendix A (e.g., at a rate greater flows, pipe diameters, or discharge densities) shall determine the critical dilution using the appropriate CORMIX model with the input parameters shown below. Permittees shall retain the model runs as part of the NPDES records. The critical dilution shall be determined using the CORMIX model using the highest daily average discharge rate for the three days prior to the day in which the test sample is collected, the discharge pipe diameter, the measured discharge density, and the depth difference between the discharge pipe and the sea bottom.

Input Parameters:

Density Gradient = 0.163 kg/m^3/m

Ambient seawater density = 1023.0 kg/m^3

Well Treatment wastewater density = 1030.0 – 1680.0 kg/m^3

Completion and workover fluids = 1030.0 – 1680.0 kg/m^3

Current speed = 5 cm/sec (<200 m water depth); 15 cm/sec (>200 m water depth)

The NOEC shall be calculated by conducting 7-day chronic toxicity tests in accordance with methods published in *Short Term Methods for Estimating the Chronic Toxicity of*

Effluents and Receiving Water to Marine and Estuarine Organisms (EPA/821-R-02-014), or most current edition.

The results for both species shall be reported on the DMR. See Part V.A.15.a of this permit for Whole Effluent Toxicity Testing Requirements.
Samples must be taken at the nearest accessible location prior to discharge. All modeling runs shall be retained by the permittee as part of its NPDES records.

Acute Whole Effluent Toxicity Testing for Well Treatment, Completion or Workover Fluids. The following Acute Whole Effluent Testing requirements apply to discharges of well treatment fluids that last less than four days. Permittees must monitor and report the acute critical dilution (ACD) at the edge of a 100-meter mixing zone. The ACD is defined as 1.0 times the $LC_{50.}$ The ACD and the predicted effluent concentration at the edge of a 100-meter mixing zone must be reported on the DMR. Predicted effluent concentrations, referred to as "critical dilutions," are presented in Tables 4 and 5 of Appendix A for a range of discharge rates and pipe diameters. Critical dilution shall be determined using Tables 4 and 5 of this permit based on the most recent discharge rate, discharge pipe diameter, and water depth between the discharge pipe and the ocean bottom. LC_{50} shall be calculated by conducting 48-hour, non-static renewal, toxicity tests once per discharge using *Mysidopsis bahia* and *Menidia beryllina* (Inland silverside minnow). Additional acute toxicity testing requirements are contained in Part V.15.b of this permit.
Permittees discharging well treatment wastewater at conditions other than those covered in Tables 4 and 5 of Appendix A (e.g., at a rate greater flows, pipe diameters, or discharge

densities) shall determine the critical dilution using the appropriate CORMIX model with the input parameters shown below. Permittees shall retain the model runs as part of the NPDES records. The critical dilution shall be determined using the CORMIX model using the highest daily average discharge rate for the three days prior to the day in which the test sample is collected, the discharge pipe diameter, the measured discharge density, and the depth difference between the discharge pipe and the sea bottom.

Input Parameters:

Density Gradient = 0.163 kg/m3/m

Ambient seawater density = 1023.0 kg/m3

Well Treatment wastewater density = 1030.0 – 1680.0 kg/m3

Completion and workover fluids = 1030.0 – 1680.0 kg/m3

Current speed = 5 cm/sec (<200 m water depth); 15 cm/sec (>200 m water depth)

Permittees shall retain the model runs as part of the NPDES records.

Samples for the acute WET tests shall be obtained at the nearest accessible point after final treatment and prior to discharge to surface waters. A grab sample must be taken at least monthly when the maximum flow rate of WTCW fluids will be discharged. Permittes may request reduced monitoring requency after the first year of the permit.

Well Treatment Completion and Workover Reporting Requirements.

Operators of leases where well treatment, completion, or workover fluids are discharged shall collect and report the information listed below. This information shall be reported with the discharged monitoring report for the quarter in which the discharge is made. If discharges commence in one quarter and cease in the following quarter, reporting should be done in the later quarter.

For each well in which operations are conducted that result in the discharge of well treatment, completion, or workover fluids the following shall be reported with the discharge monitoring report for the quarter in which the activity is done:

- Lease and block number
- API well number
- Type of well treatment or workover operation conducted
- Date of discharge
- Time discharge commenced
- Duration of discharge
- Volume of well treatment
- Volume of completion or workover fluids used
- The common names and chemical parameters for all additives to the fluids
- The volume of each additive
- Concentration of all additives in the well treatment
- Concentration of all additives in the completion, or workover fluid
- Results of Whole Effluent Toxicity (WET) tests for well treatment fluids discharged separately from the produced water discharge. Additional toxicity testing requirements are contained in Part V.15.b of this permit.

Information collected for this reporting requirement shall be submitted as an attachment to the DMR or in an alternative format requested by the operator and approved by EPA Region 4.

Industry-Wide Study Alternative

Alternatively, operators who discharge well treatment completion and/or workover fluids may participate in an EPA-approved industry-wide study as an alternative to conducting monitoring of the fluids characteristic and reporting information on the associated operations. That study would, at a minimum, provide a characterization of well treatment, completion, and workover fluids used in a representative number of wells discharging well treatment, completion, and/or workover fluids from various well depths (shallow, medium depth and deep depths). In addition, an approved industry-wide study would be expected to provide greater detail on the characteristics of the resulting discharges, including their chemical composition and the variability of the chemical composition, and toxicity. The study area should include a statistical valid number of samples of wells located in the Eastern Gulf of Mexico (GOM) and may include the Western and Central Areas of the GOM under

the permitting jurisdiction of EPA Region 6, and operators may join the study after the start date. The study plan should also include interim dates/milestones.

A plan for an industry–wide study plan would be required to be submitted to EPA Region 4 for approval within six -eighteen months after the effective date of this permit. If the Region approves an equivalent industry-wide well treatment fluids discharge monitoring study, the monitoring conducted under that study shall constitute compliance with these monitoring requirements for permittees who participate in such the industry-wide study. Once approved, the study plan will become an enforceable part of this permit. The study must commence within six months of EPA's approval. If the Region does not approve the study plan, or if a permittee does not participate in the study, compliance with all the monitoring requirements for well, completion, and workover fluids is required (see above). The final study report must be submitted no later than four years from the effective date of this permit.

c. This discharge shall be considered "produced water" when commingled with produced water.

7. Sanitary Waste (Facilities Continuously Manned for 30 or more consecutive days by 10 or More Persons)

a. Prohibitions

Solids. There shall be no discharge of floating solids. Observations must be made once per day, during daylight in the vicinity of sanitary waste outfalls, and at the time during maximum estimated discharge. The number of days solids are observed during the quarter shall be reported on the DMR.

b. Limitations

Total Residual Chlorine. Discharges of sanitary waste must contain a minimum of 1.0 mg residual chlorine per liter and shall be maintained as close to this concentration as possible at all times. A grab sample must be taken once per month and the minimum and average concentrations for the monitoring period shall be reported on the DMR. The approved analytical methods are Hach CN-66-DPD or the EPA method specified in 40 C.F.R. Part 136 for Total Residual Chlorine. Samples must be taken at the nearest accessible location prior to discharge and after final treatment.

Exception - Any facility which properly maintains a marine sanitation device (MSD) that complies with pollution control standards and regulations under Section 312 of the Act shall be deemed in compliance with permit prohibitions and limitations for sanitary waste. The MSD shall be tested annually for proper operation and the test results maintained at the facility or at an alternative site if not practicable. The operator shall indicate use of an MSD on the DMR.

8. Sanitary Waste (Facilities Continuously Manned for 30 or more consecutive days by 9 or Fewer Persons or Intermittently by Any Number)

Prohibition. There shall be no discharge of floating solids. An observation must be made once per day when the facility is manned, during daylight in the vicinity of sanitary waste outfalls, and at a time during maximum estimated discharge. The number of days solids are observed shall be reported on the DMR.

Exception - Any facility which properly maintains an MSD that complies with pollution control standards and regulations under Section 312 of the Act shall be deemed in compliance with permit prohibitions and limitations for sanitary waste. The MSD shall be tested annually for proper operation and the test results maintained at the facility or at an alternative site if not practicable. The operator shall indicate use of an MSD on the DMR.

9. Domestic Waste

a. Prohibitions

Solids. There shall be no discharge of floating solids.

b. Limitations

Solids. See Part I.C.4 - Rubbish, Trash and Other Refuse.

c. Monitoring Only Requirements

Solids. An observation must be made during daylight in the vicinity of domestic waste outfalls and at a time during maximum estimated discharge. The number of days solids are observed must be recorded and reported on the DMR.

10. Miscellaneous Discharges

The following miscellaneous discharges are authorized for discharge: Desalination Unit Discharge; Blowout Preventer Control Fluid; Uncontaminated Ballast Water; Uncontaminated Bilge Water; Mud, Cuttings, and Cement (including tracers) at the Seafloor; Uncontaminated Seawater; Uncontaminated Freshwater; Boiler Blowdown; Source Water and Sand; Diatomaceous Earth Filter Media; Subsea Wellhead Preservation Fluids; Subsea Production Control Fluids; Umbilical Steel Tube Storage Fluid; Leak Tracer Fluid, Riser Tensioner Fluid, Well Test Fluids, Bulk Transfer Operations Powder (Note: Authorized discharge is limited to dust emitted from vents that falls into water directly. No discharge of collected dust powder is authorized); Excess Cement Slurry, (Note: Discharges of cement slurry used for testing cement handling equipment are not authorized), Cement Equipment Washdown, Hydrate Control Fluid or Brine used as piping equipment preservation fluid (i.e., pipeline brines), and Aqueous Film Forming Foam (AFFF).

Additional miscellaneous discharges associated with subsea operations may be discharged based on the requirements set forth in Parts I.C.6 and V.A.15 of this permit.

a. Prohibitions. Discharges of waste streams not mentioned above, including contaminated freshwater, contaminated seawater, contaminated bilge water and contaminated ballast water, are prohibited. ("Contaminated" refers to wastewater that has failed a Visual Sheen Test.)

b. Limitations

Free Oil. There shall be no discharge of free oil. Monitoring shall be performed using the visual sheen test method on the surface of the receiving water once per week when discharging, or by use of the Static Sheen Test method. Tests shall be conducted in accordance with the methods contained in Part V.A.3 and V.A.4. Discharges are limited to those times that a visual sheen observation is possible, unless monitoring is performed using the static sheen test. If the Static Sheen Test is used, samples must be taken at the nearest accessible location after final treatment and prior to discharge. The number of days a sheen is observed must be recorded and reported on the DMR.

Exception - Miscellaneous discharges may be discharged from platforms that are on automatic purge systems without monitoring for free oil when the facility is not manned. Discharges are not restricted to periods when observation is possible; however, the static sheen test method must be used during periods when the facility is manned and observation of a sheen is not possible, such as at night or during inclement conditions. The static sheen testing is not required for miscellaneous discharges occurring at the sea floor.

The discharge of AFFF during a fire emergency is not subject to permit limitations established in this permit. Any discharge of AFFF associated with regulatory certification and inspection must be minimized and a substitute foaming agent (i.e., non-fluorinated) must be used, if possible. If vessel maintenance and training discharges are required, AFFF must be collected and stored for onshore disposal unless the vessel uses a non-fluorinated or alternative foaming agent.

Toxicity. Fluids which are used as Subsea Wellhead Preservation Fluids, Subsea Production Control Fluids, Umbilical Steel Tube Storage Fluids, Leak Tracer Fluids, and Riser Tensioning Fluids shall have a 7-day No Observable Effect Concentration (NOEC) of no less than 50 mg/l. The 7-day NOEC shall be measured using *Mysidopsis bahia* (Mysid shrimp) chronic static renewal 7-day survival and growth test and *Menidia beryllina* (Inland Silverside minnow) chronic static renewal 7-day larval survival and growth test (Method 1006.0) as described in Part V.A.15 of this permit. A grab sample must be taken once during each discharge event when the maximum effluent flow rate is discharged. Compliance with this limit shall be measured at least annually (beginning from the effective date of this permit) using the survival and sub-lethal endpoints on each fluid added to an operation after the effective date of this permit. If the effluent fails the survival or sub-lethal test endpoint in any test, any discharge associated with the use of the product will be considered to be in violation of this permit. [For leak tracer fluid made from powder dye, the maximum concentration that can be discharged from the leak is the 7-day NOEC for that specific powder dye.]

Pipeline Brines. Operators must demonstrate that brines used for pipeline/equipment preservation must meet the following three criteria prior to applying as preservation fluids:

(1) there shall be no free oil as measured using the static sheen test.

(2) The maximum daily concentration on oil and grease shall not exceed 29.0 mg/l.

(3) There shall be no priority pollutants, except in trace amounts.

11. Miscellaneous Discharges of Freshwater and Seawater In Which Treatment Chemicals Have Been Added, including, but not limited to: 1) excess seawater which permits the continuous operation of fire control and utility lift pumps, 2) excess seawater from pressure maintenance and secondary recovery projects, 3) water released during training of personnel in fire protection, 4) seawater used to pressure test, or flush, new and existing piping and pipelines, 5) ballast water, 6) water flooding discharges, 7) once through non-contact cooling water, 8) seawater used as piping or equipment preservation fluids, and 9) seawater used during dual gradient drilling.

a. Limitations

Free Oil. There shall be no discharge of free oil. Monitoring shall be performed using the Visual Sheen Test method on the surface of the receiving water once per day when discharging or by use of the static sheen method at the operator's option. Both tests shall be conducted in accordance with the methods contained in Part V.A.3 and V.A.4. Samples must be taken at the nearest accessible location prior to discharge. Discharges are limited to those times that a visual sheen observation is possible, unless monitoring is done using the static sheen test. The number of days a sheen is observed must be recorded and reported on the DMR.

Exception - Miscellaneous discharges may be discharged from platforms that are on automatic purge systems without monitoring for free oil when the facility is not manned. Discharges are not restricted to periods when observation is possible; however, the static sheen test method must be used when the facility is manned during periods when observation of a sheen is not possible, such as at night or during inclement conditions. The static sheen testing is not required for miscellaneous discharges occurring at the sea floor.

b. Treatment Chemicals (see definition in Part V.B). The concentration of treatment chemicals in discharged chemically treated freshwater and seawater shall not exceed the most stringent of the following three constraints:

i. the maximum concentrations and any other conditions specified in the EPA product registration labeling if the chemical is an EPA registered product,

ii. the maximum manufacturer's recommended concentration, or

iii. the levels specified at 40 C.F.R. 122.42(a) for toxic pollutants not limited in the permit. (Also see Part II.D.11 of this permit.).

c. Toxicity. The toxicity of discharged freshwater or seawater in which chemicals have been added shall be limited as follows:

The 7-day minimum and monthly average minimum NOEC, must be equal to or greater than the critical dilution concentration specified in this permit in Table 7 for seawater discharges and Table 8 for freshwater discharges. Critical dilution shall be determined using either Table 7 or 8 of this permit in conjunction with (1) the discharge rate, (2) discharge pipe diameter, and (3) the water depth between the discharge pipe and bottom. The monthly average minimum NOEC value is defined as the arithmetic average of all 7-day minimum NOEC values determined during the month. Compliance with the toxicity limitation shall be demonstrated by conducting 7-day chronic toxicity tests, using *Mysidopsis bahia (Americamysis bahia* (Mysid shrimp)) and *Menidia beryllina* (Inland silverside minnow). The 7-day chronic toxicity test method is published in *Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms* (EPA/821-R-02-014), or the most current edition. The results for both species and the critical dilution shall be reported on the DMR. The operator shall also submit a copy of the summary sheets for all laboratory reports with the DMR. See Part V.A.15 of this permit for Whole Effluent Toxicity testing requirements.

Testing to determine the 7-day minimum and monthly average minimum NOEC shall begin after the third month of chemically treated water discharge and shall be done every two months until the permittee passes and reports three consecutive chemically treated water toxicity tests.

Toxicity testing for intermittent or batch discharges shall be performed at least once per discharge but is required to be monitored no more frequently than the corresponding frequencies specified above for continuous discharges, unless otherwise specified by the Director.

Samples shall be collected after addition of any substances, including seawater that is added prior to discharge and before the flow is split from multiple discharge ports. Samples also shall be representative of the discharge. A grab sample must be taken once during each discharge event when the maximum effluent flow rate is discharged. Methods to increase dilution also apply to seawater and freshwater discharges which have been chemically treated previously described for produced water in Part I.B.3.

Permittees that pass three consecutive chemically treated water toxicity tests will be allowed to reduce to a sampling frequency of every six months after notification from the EPA Region 4 Water Protection Division. Permittees that were covered under the previous general permit and that are currently performing routine toxicity tests, shall continue testing with a frequency of at least every six months. If at any time any toxicity test (i.e., for continuous or intermittent discharges) results indicates a failure, the permittee must resume more frequent toxicity testing intervals, in accordance with Part V.A.15, or as specified by the Director. Miscellaneous discharges of seawater and freshwater to which only chlorine or hypochlorite and bromide have been added, or which contain only electrically generated form of chlorine, hypochlorite, copper, iron, and aluminum, are excluded from the monitoring requirement.

In cases where the discharge point for hydrostatic test water is subsea, such as the subsea end of a pipeline, and it is impractical to collect a sample at the discharge point, operators may collect a sample of the effluent, including additives, for this monitoring requirement prior to use of the fluid.

d. Monitoring Only Requirements for discharges of chemically treated freshwater and seawater.

Flow. The average flow (in barrels per day) must be estimated each month and the highest average monthly flow for the monitoring period shall be recorded and reported on the DMR.

C. Other Discharge Limitations

1. Floating Solids or Visible Foam

There shall be no discharge of floating solids or visible foam from any source other than in trace amounts.

2. Halogenated Phenol Compounds

There shall be no discharge of halogenated phenol compounds as a part of any waste streams authorized in this permit.

3. Dispersants, Surfactants, and Detergents

The facility operator shall minimize the discharge of dispersants, surfactants, and detergents, except as necessary, to comply with the safety requirements of the Occupational Safety and Health Administration and BOEM. This restriction applies to tank cleaning and other operations which do not directly involve the safety of workers. (The restriction is imposed because detergents disperse and emulsify oil, potentially increasing toxic impacts and making the detection of a discharge of free oil more difficult.)

Waste water associated with tank and pit cleaning operations shall be classified as the same as the former contents of the tank or pit. (For example, wash water generated from cleaning drilling fluid pits would be subject to the same discharge limitations as the drilling fluid formerly contained in those pits.) The waste water is deemed to have the same compliance status as the whole fluid that was originally in the tank or pit. No additional sampling/monitoring of the waste water is required.

4. Rubbish, Trash, and Other Refuse

There shall be no discharge of any solid material not authorized in the permit.

This permit includes limitations set forth by the U.S. Coast Guard in regulations implementing Annex V of MARPOL 73/78 for domestic waste disposal from all fixed or floating offshore platforms and associated vessels engaged in exploration of seabed mineral resources (33 C.F.R. 151). These limitations, as specified by Congress (33 U.S.C. 1901, the Act to Prevent Pollution from Ships), apply to all navigable waters of the United States.

This permit prohibits the discharge of "garbage." Comminuted food waste (able to pass through a screen with a mesh size no larger than 25 mm, approximately one inch) may be discharged when 12 nautical miles or more from land. Greywater, drainage from dishwater, shower, laundry, bath, and washbasins are not considered garbage within the meaning of Annex V. Incineration ash and non-plastic clinkers that can pass through a 25-mm mesh screen may be discharged beyond three miles from nearest land. Otherwise, ash and non-plastic clinkers may be discharged beyond 12 nautical miles from nearest land.

5. Dual Gradient Drilling Discharges

Operators performing dual gradient drilling operations may require seafloor discharges of large cuttings (greater than 1/4") to ensure the proper operation of subsea pumps (e.g., electrical submersible pumps). Operators performing dual gradient drilling operations which lead to seafloor discharges of large cuttings for the proper operation of subsea pumps shall either:

a. measure the mass percent NAFs retained on cuttings value [% Base Fluid (BF)] and mass NAF-cuttings discharge fraction (X) for seafloor discharges each time a set of retorts is performed,

b. use the following set of default values, (%BF=14%; X=0.15) or,

c. use a combination for %BF and measure (X).

Additionally, operators performing dual gradient drilling operations which lead to seafloor discharges of large cuttings for the proper operation of subsea pumps shall also perform the following tasks:

a. use side scan sonar of shallow seismic to determine the presence of high density chemosynthetic communities. Chemosynthetic communities are assemblages of tube worms, clams, mussels, and bacterial mats that occur at natural hydrocarbon seeps or vents, generally in water depths of 500 meters or deeper. Seafloor discharges of large cuttings for the proper operation of subsea pumps shall not be permitted within 1000 feet of a high density chemosynthetic community;

b. seafloor discharges of large cuttings for the proper operation of subsea pumps shall be visually monitored and documented by a Remotely Operated Vehicle (ROV) within the tether limit (approximately 300 feet). The visual monitoring shall be conducted prior to each time the discharge point is relocated (cuttings discharge hose) and conducted along the same direction as the discharge hose position. Near-seabed currents shall be obtained at the time of the visual monitoring and;

c. seafloor discharges of large cuttings for the proper operation of subsea pumps shall be directed within a 150-foot radius of the wellbore.

6. Un-mixed Chemicals or Products

There shall be no discharge of any chemical or product not already mixed for use in any wastestream. Such unused chemicals or products shall be shipped onshore for final disposal or reuse. [Exception – This does not apply to the discharge of Bulk Transfer Operations Powder.]

7. Pipeline Brines

The operator must demonstrate that brines used for pipeline/equipment preservation meet the following three criteria prior to applying as preservation fluids:

a. No free oil shall be discharged. Discharge is limited to those times that a visible sheen observation is possible unless the operator uses the static sheen method. Grab samples must be taken at the nearest accessible location prior to discharge, or prior to combining with any other wastewaters. There shall be no discharge of pipeline brines that fail the static sheen test. The results of each sheen test must be recorded, and the number of observations of a static sheen test must be reported on the DMR.

b. The daily maximum concentration of oil and grease concentration shall be less than 29 mg/l. The sample type shall be grab, and the monitoring frequency shall be daily during discharge. The analytical test method is specified in 40 C.F.R. Part 136.

c. There shall be no discharge of priority pollutants, except in trace amounts.

D. Special Conditions

1. De minimus Discharges

De minimus discharges of non-aqueous based drilling fluids not associated with cuttings shall be contained to the extent practicable to prevent discharge. Allowable de minimus discharges can include wind-blown drilling fluids from the pipe rack, residual drilling fluids that are adhered to marine risers, diverter systems testing after drilling fluids displacement, blow-out preventers (BOP) after drilling fluids displacement, and minor drips and splatters around mud handling and solids control equipment. Such de minimus discharges are not likely to be measurable and are not considered in the base fluids retained on cuttings limit.

2. Small Volume Discharges

Small volume drilling fluid discharges which are associated with cuttings, and for which discharge is authorized include; displaced interfaces, accumulated solids in sand traps, pit clean-out solids, and centrifuge discharges made while changing mud weight. To determine the percent drilling fluids retained on cuttings for those discharges, the permittee may either monitor the discharge using the retort test method, or use a default value of 25% to determine compliance with the limitation. Required discharge monitoring for small volume discharges consists only of static sheen tests and retention on cuttings (or use of the default retention on cuttings value).

3. Cooling Water Intake Structure Requirements

Applicability: These requirements apply to new facilities for which construction was commenced after July 17, 2006, with a cooling water intake structure having a design intake capacity of greater than 2 million gallons of water per day, of which at least 25% is used for cooling purposes. New facilities with a design intake capacity of less than or equal to 2 million gallons per day and all existing facilities will be required to reduced entrainment and impingement to the greatest extent practicable using Best Professional Judgment. For the purposes of this permit, "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 semisubmersibles, jack-ups, submersibles, tender-assisted rigs, and drill barges). See 40 C.F.R. §§ 125.83 and 125.133. for other special definitions applicable to this section.

a. **Baseline Study Requirements**

These baseline study requirements are effective one year after the effective date of this permit. Operators of new facilities must submit sufficient information to characterize the biological community of commercial, recreational, and forage base fish and shellfish in the vicinity of the intake structure and to characterize the effects of the cooling water intake structure's operation on aquatic life. This biological characterization must include any available existing information along with field studies to obtain localized data. At a minimum, the information must include:

i. A list of the data required by this section that are not available and efforts made to identify sources of the data;

ii. A list of species (or relevant taxa) for all life stages and their relative abundance in the vicinity of the cooling water intake structure;

iii. Identification of the species and life stages that would be most susceptible to impingement and entrainment. Species evaluated should include the forage base as well as those most important in terms of significance to commercial and recreational fisheries;

iv. Identification and evaluation of the primary period of reproduction, larval recruitment, and period of peak abundance for relevant taxa;

v. Data representative of the seasonal and daily activities (e.g., feeding and water column migration) of biological organisms in the vicinity of the cooling water intake structure;

vi. Identification of all threatened, endangered, and other protected species that might be susceptible to impingement and entrainment at the cooling water intake structures;

vii. If the information above is supplemented with data from field studies, the supplemental data must include a description of all methods and quality assurance procedures for sampling and data analysis including a description of the study area; taxonomic identification of sampled and evaluated biological assemblages (including all life stages of fish and shellfish); and sampling and data analysis methods. The sampling and/or data analysis methods you use must be appropriate for a quantitative survey and based on consideration of methods used in other biological studies performed within the same source water body. The study area should include, at a minimum, the area of influence of the cooling water intake structure.

b. Supplemental Notification Requirements

Design information must be submitted at least 30 days in advance of a facility commencing operations in the geographical area covered by this permit. Design information required to be submitted for cooling water intake structures is only required to be submitted once for any facility that these requirements are applicable. Design information is not required to be resubmitted for additional leases where the facility subsequently operates or for a subsequent permit. EPA will notify the operator if additional information is required. Owners/operators of Mobile Offshore Drilling Units (MODUs) must also submit an NOI, in accordance with Part I.A.4 of this permit. The NOI shall be submitted and postmarked prior to operating.

New Non-Fixed Facilities Must Submit:

A narrative description and/or maps providing sufficient information on predicted locations during the permit term in sufficient detail for the Director to determine the appropriateness of additional impingement requirements. This information is only required to be submitted once for any facility.

<u>Velocity Information</u>, including:

i. A narrative description of the design, structure, equipment, and operation used to meet the requirements of a maximum through screen intake velocity of 0.5 ft/s at each cooling water intake structure; and

ii. For surface cooling water intake screens only, design calculations showing that the velocity requirement will be met at the minimum ambient source water surface elevation and maximum head loss across the screens or other device.

Cooling Water Intake Structure Data, including:

i. Design and construction technology plans and a description of operational measures which will be implemented to minimize impingement, including:

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

2) Design calculations, drawings, and estimates to support the descriptions above.

ii. A narrative description of the configuration of each of your cooling water intake structures and where it is located in the water body and in the water column;

iii. A narrative description of the operation of each of your cooling water intake structures, including design intake flows, daily hours of operation, number of days of the year in operation, and seasonal changes, if applicable;

iv. A flow distribution and water balance diagram that includes all sources of water to the facility, recirculating flows, and discharges; and

v. Engineering drawings of the cooling water intake structure.

New Fixed Facilities Must Submit:

Source Water Physical Data, including:

i. A narrative description and scaled drawings showing the physical configuration of all source water bodies used by your facility, including aerial dimensions, depths, salinity and temperature regimes, and other documentation that supports your determination of the water body type where each cooling water intake structure is located;

ii. Identification and characterization of the source water body's hydrological and geomorphological features, as well as the methods you used to conduct any studies to determine your intake's area of influence within the water body and the results of such studies; and

iii. Locational maps.

Cooling Water Intake Structure Data, including:

i. Design and construction technology plans and a description of operational measures which will be implemented to minimize impingement, including:

1) A narrative description of the design and operation of the design and construction technologies including fish handling and return systems that the facility will utilize to maximize the survival of species expected to be most susceptible to impingement;

2) For those new fixed facilities that do not employ sea chests as cooling water intake structures, a narrative description of the design, operation, and construction technologies that the facility will utilize to minimize entrainment of those species most susceptible to entrainment.

3) Design calculations, drawings, and estimates to support the design technologies.

ii. A narrative description of the configuration of each of your cooling water intake structures and where it is located in the water body and in the water column;

iii. Latitude and longitude in degrees, minutes, and seconds for each of your cooling water intake structures;

iv. A narrative description of the operation of each of your cooling water intake structures, including design intake flows, daily hours of operation, number of days of the year in operation and seasonal changes, if applicable;

v. A flow distribution and water balance diagram that includes all sources of water to the facility, re-circulating flows, and discharges; and

vi. Engineering drawings of the cooling water intake structure.

Velocity Information, including:

i. A narrative description of the design, structure, equipment, and operation used to meet the requirement of a maximum through-screen intake velocity of 0.5 ft/s at each cooling water intake structure; and

ii. For surface cooling water intake screens only, design calculations showing that the velocity requirement will be met at the minimum ambient source water surface elevation and maximum head loss across the screens or other device.

c. Cooling Water Intake Structure Requirements

New non-Fixed Facilities

i. The cooling water intake structure(s) must be designed and constructed so that the maximum through-screen design intake velocity is 0.5 ft/s or less;

ii. The operator must minimize impingement mortality of fish and shellfish through the use of cooling water intake design and construction technologies or operational measures.

New Fixed Facilities that do not employ sea chests as intake structures

i. The cooling water intake structure must be designed and constructed so that the maximum through-screen design intake velocity is 0.5 ft/s; and

ii. The operator must minimize impingement mortality of fish and shellfish and minimize entrainment of entrainable life stages of fish and shellfish through the use of cooling water intake design and construction technologies or operational measures.

New Fixed Facilities that Employ Sea Chests as Intake Structures

i. The cooling water intake structure(s) must be designed and constructed so that the maximum through-screen design intake velocity is 0.5 ft/s or less; and

ii. The operator must minimize impingement mortality of fish and shellfish through cooling water intake design and construction technologies or operational measures.

d) **Monitoring Requirements**

New non-Fixed Facilities

i. The operator must conduct either visual inspections or use remote monitoring devices (e.g., remotely operated vehicles (ROV), subsea cameras, or other monitoring device) during the period the cooling water intake structure is in operation. The operator must conduct visual inspections at least monthly,(For instance, operators must monitor at least once per month even if they are on location less than one month) or at a lesser frequency as approved by the Director, to ensure that the required design and construction technologies are maintained and operated so they continue to function as designed. Alternatively, the operator must inspect using remote monitoring devices to ensure that the impingement and entrainment technologies are functioning as designed.

However, visual or remote monitoring is not required when conditions such as storms, high seas, evacuation, or other factors make it unduly hazardous to personnel, the facility, or the equipment utilized. The operator must provide an explanation for any such failure to visually or remotely monitor with the subsequent DMR submittal.

ii. For facilities that employ surface intake screens systems, the operator must monitor intake velocity by measuring the head loss across the intake screens and correlating the measured value with the design intake velocity. The operator must measure the head loss at the minimum ambient source water surface elevation using best professional judgment based on available hydrological data. The operator must use the maximum head loss across the screen for each cooling water intake structure to determine compliance with the velocity requirement. For facilities utilizing devices other than surface intake screens, the facility shall monitor intake velocity at the point of entry through the intake device or through a comparable method such as pump curve calculations. The operator shall monitor either head loss or velocity during initial facility startup, and thereafter, at a frequency of no less than once per quarter.

New Fixed Facilities that do not employ sea chests as intake structures

i. The operator must conduct either visual inspections or use remote monitoring devices (e.g., remotely operated vehicles (ROV), subsea cameras, or other monitoring device) during the period the cooling water intake structure is in operation. The operator must conduct visual inspections at least monthly, (i.e.,operators must monitor at least once per month even if they are on location less than one month) or at a lesser frequency as approved by the Director, to ensure that the required design and construction technologies are maintained and operated so they continue to function as designed. Alternatively, the operator must inspect using remote monitoring devices to ensure that the impingement and entrainment technologies are functioning as designed.

However, visual or remote monitoring is not required when conditions such as storms, high seas, evacuation, or other factors make it unduly hazardous to personnel, the facility, or the equipment utilized. The operator must provide an explanation for any such failure to visually or remotely monitor with the subsequent DMR submittal.

ii. The operator must monitor for entrainment. The operator must collect samples to monitor entrainment rates (simple enumeration) for each species over a 24-hour period and no less than biweekly during the primary period of reproduction, larval recruitment, and peak abundance identified during the Source Water Baseline Biological Characterization Study. Representative species may be utilized for this monitoring consistent with their use in the Source Water Baseline Characterization Study. The operator must collect samples only when the cooling water intake structure is in operation. After 24 months of monitoring, the permittee may submit Southeast Area Monitoring and Assessment Program (SEAMAP) data annually to meet the requirements of 40 CFR § 125.137. This report may be done in conjunction with other Region 4 operators subject to these requirements.

iii. For facilities that employ surface intake screens systems, the operator shall monitor intake velocity by measuring the head loss across the intake screens and correlating the measured value with the design intake velocity. The operator must measure head loss at the minimum ambient source water surface elevation using best professional judgment based on available hydrological data. The operator must use the maximum head loss across the screen for each cooling water intake structure to determine compliance with the velocity requirement. For facilities utilizing devices other than surface intake screens, intake velocity shall be monitored at the point of entry through the intake device or through a comparable method such as pump curve calculations. The operator shall monitor either head loss or velocity during initial facility startup, and thereafter, at a frequency of no less than once per quarter.

New Fixed Facilities that Employ Sea Chests as Intake Structures

i. The operator must conduct either visual inspections or utilize remote monitoring devices (e.g., remotely operated vehicles (ROV), subsea cameras, or other monitoring device) during the period the cooling water intake structure is in operation. The operator must conduct visual inspections at least monthly, (i.e., operators must monitor at least once per month even if they are on location less than one month) or at a lesser frequency as approved by the Director, to ensure that the required design and construction technologies are maintained and operated so they continue to function as designed. Alternatively, the operator must inspect using remote monitoring devices to ensure that the impingement and entrainment technologies are functioning as designed.

However, visual or remote monitoring is not required when conditions such as storms, high seas, evacuation, or other factors make it unduly hazardous to personnel, the facility, or the equipment utilized. The operator must provide an explanation for any such failure to visually or remotely monitor with the subsequent DMR submittal.

ii. For facilities that employ surface intake screens systems, the operator shall monitor the intake velocity by monitoring the head loss across the intake screens and correlating the measured value with the design intake velocity. The operator must measure head loss at the minimum ambient source water surface elevation using best professional judgment based on available hydrological data. The operator must use the maximum head loss across the screen for each cooling water intake structure to determine compliance with the velocity requirement. For facilities utilizing devices other than surface intake screens, intake velocity shall be monitored at the point of entry through the intake device or through a comparable method such as pump curve calculations. The operator must monitor either head loss or velocity during initial facility startup, and thereafter, at a frequency of no less than once per quarter.

iii. No monitoring for entrainment is required.

The permit may be reopened and modified or revoked and reissued to require additional monitoring or to change the cooling water intake structure requirements if found warranted by the Director as a result of either baseline study or entrainment monitoring.

4. Reference Drilling Fluid Formulation

The reference C_{16}-C_{18} internal olefin drilling fluids used to determine the drilling fluid sediment toxicity ratio and compliance with the BAT sediment toxicity discharge limitation shall be formulated to meet the specifications in Table 1 of Appendix 8 of 40 C.F.R. Part 435, subpart A.

5. Preparation of Live-Bottom Survey and Live-Bottom Reports Using High Resolution Acoustical Data

Side-scan sonar data in the 100 kHz frequency or 500 kHz frequency if available (use data set providing best image quality) will be used to interpret for the presence of hard structure that could provide potential habitat for marine plant and animal communities. The area included in this interpretation should consist of a rectangular portion of the seabed with the proposed wells in the center. The sides of the rectangle should be at a distance of 1000 meters from the proposed wells. If several wells are proposed throughout the lease block, a separate live-bottom report shall be provided for each.

The live-bottom report shall consist of text and appropriate figures including a brief description of the lease block, proposed project, location of wells and water depth. The report shall contain a section describing the methods used to acquire sonar data including sonar and positioning equipment, frequencies, range setting, lane spacing and overlap, cable layback and vessel speed.

The report will include a narrative interpretation of the seabed within the survey area and any discrete features based on acoustical reflection of the seabed. The interpretation shall include a description of features, their relative position within the survey area, the dimensions of discrete features and surface area of scattered targets. The report will include a figure consisting of a sonar mosaic of the sonar lane segments comprising the survey area fitted to a standard page. The mosaic figure shall be a color print (no photocopies). The location of seabed features referred to in the text, including any small or large acoustical targets, scattered or individual, should be shown in a separate figure, consisting of a diagram of the survey area and proposed well locations.

The EPA will not accept previously prepared geophysical survey reports for lease blocks in substitution for the live-bottom survey report described. Remote sensing data from other instruments such as echo sounders, magnetometers, sub-bottom profilers and seismic data should not be included in the live-bottom survey report. Reports containing photocopies of acoustical imagery will not be accepted.

Part II. Standard Conditions for NPDES Permits

A. General Conditions

1. Duty to Comply

The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the CWA and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. The permittee shall comply with effluent standards or prohibitions established under section 307(a) of the CWA for toxic pollutants and with standards for sewage sludge use or disposal established under section 405(d) of the CWA within the time provided in the regulations that establish these standards or prohibitions or standards for sewage sludge use or disposal, even if the permit has not yet been modified to incorporate the requirement.

[40 C.F.R. §§ 122.41(a) and 122.41(a)(1)]

2. Penalties for Violations of Permit Conditions

The CWA provides that any person who violates section 301, 302, 306, 307, 308, 318 or 405 of the Act, or any permit condition or limitation implementing any such sections in a permit issued under section 402, or any requirement imposed in a pretreatment program approved under sections 402(a)(3) or 402(b)(8) of the Act, is subject to a civil penalty not to exceed $51,570 per day for each violation. The CWA provides that any person who negligently violates sections 301, 302, 306, 307, 308, 318, or 405 of the Act, or any condition or limitation implementing any of such sections in a permit issued under section 402 of the Act, or any requirement imposed in a pretreatment program approved under section 402(a)(3) or 402(b)(8) of the Act, is subject to criminal penalties of $2,500 to $25,000 per day of violation, or imprisonment of not more than one year, or both. In the case of a second or subsequent conviction for a negligent violation, a person shall be subject to criminal penalties of not more than $50,000 per day of violation, or by imprisonment of not more than two years, or both. Any person who knowingly violates such sections, or such conditions or limitations is subject to criminal penalties of $5,000 to $50,000 per day of violation, or imprisonment for not more than three years, or both. In the case of a second or subsequent conviction for a knowing violation, a person shall be subject to criminal penalties of not more than $100,000 per day of violation, or imprisonment of not more than six years, or both. Any person who knowingly violates section 301, 302, 303, 306, 307, 308, 318 or 405 of the Act, or any permit condition or limitation implementing any of such sections in a permit issued under section 402 of the Act, and who knows at that time that he thereby places another person in imminent danger of death or serious bodily injury, shall, upon conviction, be subject to a fine of not more than $250,000 or imprisonment of not more than 15 years, or both. In the case of a second or subsequent conviction for a knowing endangerment violation, a person shall be subject to a fine of not more than $500,000 or by imprisonment of not more than 30 years, or both. An organization, as defined in section 309(c)(3)(B)(iii) of the CWA, shall, upon conviction of violating the imminent danger provision, be subject to a fine of not more than $1,000,000 and can be fined up to $2,000,000 for second or subsequent convictions.

[40 C.F.R. § 122.41(a)(2)]

Any person may be assessed an administrative penalty by the Administrator for violating section 301, 302, 306, 307, 308, 318 or 405 of this Act, or any permit condition or limitation implementing any of such sections in a permit issued under section 402 of this Act. Administrative penalties for Class I violations are not to exceed $20,628 per violation, with the maximum amount of any Class I penalty assessed not to exceed $51,570. Penalties for Class II violations are not to exceed $20,628 per day for each day during which the violation continues, with the maximum amount of any Class II penalty not to exceed $257,848.

[40 C.F.R. § 122.41(a)(3)]

3. Civil and Criminal Liability

Except as provided in permit conditions on "Bypassing" Section B, Paragraph 3, and "Upset" Section B, Paragraph 4, nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance.

4. Duty to Mitigate

The permittee shall take all reasonable steps to minimize or prevent any discharge or sludge use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment.

[40 C.F.R. § 122.41(d)]

5. Permit Actions

This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

[40 C.F.R. § 122.41(f)]

6. Toxic Pollutants

If any applicable toxic effluent standard or prohibition (including any schedule of compliance specified in such effluent standard or prohibition) is promulgated under Section 307(a) of the CWA for a toxic pollutant and that standard or prohibition is more stringent than any limitation on the pollutant in the permit, the Director shall institute proceedings under these regulations to modify or revoke and reissue the permit to conform to the toxic effluent standard or prohibition.

[40 C.F.R. § 122.44(b)(1)]

7. Oil and Hazardous Substance Liability

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee is or may be subject under Section 311 of the Act.

8. State Laws

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation under authority preserved by Section 510 of the Act.

9. Effect of a Permit

Except for any toxic effluent standards and prohibitions imposed under section 307 of the CWA and "standards for sewage sludge use or disposal" under 405(d) of the CWA, compliance with a permit during its term constitutes compliance, for purposes of enforcement, with sections 301, 302, 306, 307, 318, 403, and 405 (a)-(b) of the CWA. However, a permit may be modified, revoked and reissued, or terminated during its term for cause as set forth in 40 C.F.R. Sections 122.62 and 122.64.

Compliance with a permit condition which implements a particular "standard for sewage sludge use or disposal" shall be an affirmative defense in any enforcement action brought for a violation of that "standard for sewage sludge use or disposal" pursuant to sections 405(e) and 309 of the CWA.

[40 C.F.R. § 122.5(a)]

10. Property Rights

This permit does not convey any property rights of any sort, or any exclusive privilege.

[40 C.F.R. § 122.5(b) & 40 C.F.R. § 122.41(g)]

The issuance of a permit does not authorize any injury to persons or property or invasion of other private rights, or any infringement of State or local law or regulation.

[40 C.F.R. § 122.5(c)]

11. Onshore or Offshore Construction

This permit does not authorize or approve the construction of any onshore or offshore physical structures or facilities or the undertaking of any work in any waters of the United States.

12. Severability

The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

[40 C.F.R. § 124.16 paraphrased]

13. Duty to Provide Information

The permittee shall furnish to the Director, within a reasonable time, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or to determine compliance with this permit. The permittee shall also furnish to the Director upon request, copies of records required to be kept by this permit.

[40 C.F.R. § 122.41(h)]

B. Operation and Maintenance of Pollution Controls

1. Proper Operation and Maintenance

The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance also includes adequate laboratory controls and appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems which are installed by a permittee only when the operation is necessary to achieve compliance with the conditions of the permit.

[40 C.F.R. § 122.41(e)]

2. Need to Halt or Reduce not a Defense

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

[40 C.F.R. § 122.41(c)]

3. Bypass of Treatment Facilities

a. Definitions

(i) "Bypass" means the intentional diversion of waste streams from any portion of a treatment facility.

(ii) "Severe property damage" means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

b. Bypass not exceeding limitations.

The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of paragraphs (c.) and (d.) of this section.

c. Notice

(i) Anticipated bypass. If the permittee knows in advance of the need for a bypass, it shall submit prior notice, if possible at least ten days before the date of the bypass.

    - (ii) Unanticipated bypass. The permittee shall submit notice of an unanticipated bypass as required in Section D, Paragraph 8 (24-hour notice).

- d. Prohibition of bypass
    - (i) Bypass is prohibited, and the Director may take enforcement action against a permittee for bypass, unless:
        - (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;
        - (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
        - (3) The permittee submitted notices as required under paragraph (c) of this section.
    - (ii) The Director may approve an anticipated bypass, after considering its adverse effects, if the Director determines that it will meet the three conditions listed above in paragraph (m)(4)(i) of 40 CFR § 122.41.

[40 C.F.R. § 122.41(m)(1)-(4)]

4. Upsets

- a. Definition

"Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

b. Effect of an upset

An upset constitutes an affirmative defense to an action brought for noncompliance with such technology based permit effluent limitations if the requirements of paragraph (c) of this section are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

c. Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

(i) An upset occurred and that the permittee can identify the cause(s) of the upset;

(ii) The permitted facility was at the time being properly operated;

(iii) The permittee submitted notice of the upset as required in Section D, Paragraph 8 (24 hour notice); and

(iv) The permittee complied with any remedial measures required under paragraph (d) of this section.

d. Burden of proof

In any enforcement proceeding the permittee seeking to establish the occurrence of an upset has the burden of proof.

[40 C.F.R. § 122.41(n)(1)-(4)]

5. Removed Substances

This permit does not authorize discharge of solids, sludge, filter backwash, or other pollutants removed in the course of treatment or control of wastewaters of the United States unless specifically limited in Part I.

C. Monitoring and Records

1. Representative Sampling

Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity (i.e., no pre-filtered samples).

[40 C.F.R. § 122.41(j)(1)]

All samples shall be taken at the monitoring points specified in this permit and, unless otherwise specified, before the effluent joins or is diluted by any other wastestream, body of water, or substance. Monitoring points shall not be changed without notification to and the approval of the Director.

2. Flow Measurements

Appropriate flow measurement devices and methods consistent with accepted scientific practices shall be selected and used to ensure the accuracy and reliability of measurements of the volume of monitored discharges. The devices shall be installed, calibrated and maintained to ensure that the accuracy of the measurements are consistent with the accepted capability of that type of device. Devices selected shall be capable of measuring flows with a maximum deviation of less than ± 10% from the true discharge rates throughout the range of expected discharge volumes. Once-through condenser cooling water flow which is monitored by pump logs, or pump hour meters, and based on the manufacturer's pump curves shall not be subject to this requirement. Guidance in selection, installation, calibration, and operation of acceptable flow measurement devices can be obtained from the following references. These references are available from the National Technical Information Service (NTIS), 5285 Port Royal Road, Springfield, VA 22161. (800) 553-6847 or (703) 487-4650.

"A Guide to Methods and Standards for the Measurement of Water Flow," U.S. Department of Commerce, National Bureau of Standards, NBS Special Publication 421, May 1975, 100 pp. (Order by NTIS No. COM-7510683.)

"Water Measurement Manual," U.S. Department of Interior, Bureau of Reclamation, Revised Edition, 1984, 343 pp. (Order by NTIS No. PB-85221109.)

"Flow Measurement in Open Channels and Closed Conduits," U.S. Department of Commerce, National Bureau of Standards, NBS Special Publication 484, October 1977, 982 pp. (Order by NTIS No. PB-273535.)

"NPDES Compliance Flow Measurement Manual," U.S. Environmental Protection Agency, Office of Water Enforcement, Publication MCD-77, September 1981, 149 pp. (Order by NTIS No. PB-82131178.)

3. Monitoring Procedures

Monitoring results must be conducted according to test procedures approved under 40 C.F.R. Part 136 or, in the case of sludge use or disposal, approved under 40 C.F.R. Part

136 unless otherwise specified in 40 C.F.R. Part 503, unless other test procedures have been specified in the permit.

[40 C.F.R. § 122.41(j)(4)]

4. Penalties for Tampering

The CWA provides that any person who falsifies, tampers with, or knowingly renders inaccurate, any monitoring device or method required to be maintained under this permit shall, upon conviction, be punished by a fine of not more than $10,000, or by imprisonment for not more than two years, or both. If a conviction of a person is for a violation committed after a first conviction of such person under this paragraph, punishment is a fine of not more than $20,000 per day of violation, or by imprisonment of not more than four years, or both.

[40 C.F.R. § 122.41(j)(5)]

5. Retention of Records

Except for records of monitoring information required by this permit related to the permittee's sewage sludge use and disposal activities, which shall be retained for a period of at least five years (or longer as required by 40 C.F.R. Part 503), the permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least three years from the date of the sample, measurement, report or application. This period may be extended by request of the Director at any time. For the purposes of this permit, all records can be scanned and saved electronically, and electronic records are acceptable for inspector's review.

[40 C.F.R. § 122.41(j)(2)]

6. Record Contents

Records of monitoring information shall include:

a. The date, exact place, and time of sampling or measurements;

b. The individual(s) who performed the sampling or measurements;

c. The date(s) analyses were performed;

d. The individual(s) who performed the analyses;

e. The analytical techniques or methods used; and

f. The results of such analyses.

[40 C.F.R. § 122.41(j)(3)(i)-(vi)]

7. Inspection and Entry

The permittee shall allow the Director, or an authorized representative (including an authorized contractor acting as a representative of the Administrator), upon presentation of credentials and other documents as may be required by law, to:

a. Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

d. Sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the CWA, any substances or parameters at any location.

[40 C.F.R. § 122.41(i)(1)-(4)]

D. Reporting Requirements

1. Change in Discharge

Planned changes. The permittee shall give notice to the Director as soon as possible of any planned physical alterations or additions to the permitted facility. Notice is required only when:

a. The alteration or addition to a permitted facility may meet one of the criteria for determining whether a facility is a new source in § 122.29(b); or

b. The alteration or addition could significantly change the nature or increase the quantity of pollutants discharged. This notification applies to pollutants which are subject neither to effluent limitations in the permit, nor to notification requirements under Section D, Paragraph 10.

c. The alteration or addition results in a significant change in the permittee's sludge use or disposal practices, and such alteration, addition, or change may justify the application of permit conditions that are different from or absent in the existing permit, including notification of additional use or disposal sites not reported during the permit application process or not reported pursuant to an approved land application plan.

[40 C.F.R. § 122.41(l)(1)(i)-(iii)]

2. Anticipated Noncompliance

The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

[40 C.F.R. § 122.41(l)(2)]

Any maintenance of facilities, which might necessitate unavoidable interruption of operation and degradation of effluent quality, shall be scheduled during noncritical water quality periods and carried out in a manner approved by the Director.

3. Transfer of Ownership of Control

a. This permit is not transferable to any person except after notice to the Director. The Director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the CWA.

[40 C.F.R. § 122.41(l)(3)]

b. Automatic transfers. As an alternative to transfers under paragraph (a) of this section, any NPDES permit may be automatically transferred to a new permittee if:

(i) The current permittee notifies the Director at least 30 days in advance of the proposed transfer date in paragraph (b)(2) of this section;

(ii) The notice includes a written agreement between the existing and new permittees containing a specific date for transfer of permit responsibility, coverage, and liability between them; and

(iii) The Director does not notify the existing permittee and the proposed new permittee of his or her intent to modify or revoke and reissue the permit. A modification under this subparagraph may also be a minor modification under 40 C.F.R. § 122.63. If this notice is not received, the transfer is effective on the date specified in the agreement mentioned in paragraph (b)(2) of this section.

[40 C.F.R. § 122.61(b)]

4. Monitoring Reports

Monitoring results shall be reported at the intervals specified elsewhere in this permit. See Part III of the permit.

[40 C.F.R. § 122.41(l)(4)]

Monitoring results must be reported on a Discharge Monitoring Report (DMR) or forms provided or specified by the Director.

[40 C.F.R. § 122.41(l)(4)(i)]

5. Additional Monitoring by the Permittee

If the permittee monitors any pollutant more frequently than required by the permit using test procedures approved under 40 C.F.R. Part 136 or, in the case of sludge use or disposal, approved under 40 C.F.R. Part 136 unless otherwise specified in 40 C.F.R. Part 503, or as specified in the permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR or sludge reporting form specified by the Director.

[40 C.F.R. § 122.41(l)(4)(ii)]

6. Averaging of Measurements

Calculations for all limitations which require averaging of measurements shall utilize an arithmetic mean unless otherwise specified by the Director in the permit.

[40 C.F.R. § 122.41(l)(4)(iii)]

7. Compliance Schedules

Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 14 days following each schedule date.

[40 C.F.R. § 122.41(l)(5)]

Any reports of noncompliance shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

8. Twenty-Four Hour Reporting

The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances; contact the National Response Center at (800) 424-8802. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

The following shall be included as information which must be reported within 24 hours under this paragraph.

a. Any unanticipated bypass which exceeds any effluent limitation in the permit. (See 40 C.F.R. § 122.41(g)).

b. Any upset which exceeds any effluent limitation in the permit.

c. Violation of a maximum daily discharge limitation for any of the pollutants listed by the Director in the permit to be reported within 24 hours. (See 40 C.F.R. § 122.44(g).)

The Director may waive the written report on a case-by-case basis for reports under this section's paragraph if the oral report has been received within 24 hours.

[40 C.F.R. § 122.41(l)(6)]

9. Other Noncompliance

The permittee shall report all instances of noncompliance not reported under Section D at the time monitoring reports are submitted. The reports shall contain the information listed in paragraph D-8.

[40 C.F.R. § 122.41(l)(7)]

10. Other Information

Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Director, it shall promptly submit such facts or information to the Director.

[40 C.F.R. § 122.41(l)(8)]

11. Changes in Discharge of Toxic Substances

The following conditions apply to all NPDES permits within the categories specified below:

a. *Existing manufacturing, commercial, mining, and silvicultural dischargers.* All existing manufacturing, commercial, mining, and silvicultural dischargers must notify the Director as soon as they know or have reason to believe:

(i) That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

(1) One hundred micrograms per liter (100 ug/l);

(2) Two hundred micrograms per liter (200 ug/l) for acrolein and acrylonitrile; five hundred micrograms per liter (500 ug/l) for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter (1 mg/l) for antimony;

(3) Five (5) times the maximum concentration value reported for that pollutant in the permit application in accordance with 40 C.F.R. § 122.21(g)(7); or

[40 C.F.R. § 122.42(a)(1)(i-iii)]

(ii) That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

(1) Five hundred micrograms per liter (500 μg/l);

(2) One milligram per liter (1 mg/l) for antimony;

(3) Ten (10) times the maximum concentration value reported for that pollutant in the permit application in accordance with 40 C.F.R. § 122.21(g)(7).

[40 C.F.R. § 122.42(a)(2)(i-iii)]

b. *Publicly owned treatment works.* All POTWs must provide adequate notice to the Director of the following:

(i) Any new introduction of pollutants into the POTW from an indirect discharger which would be subject to section 301 or 306 of the CWA if it were directly discharging those pollutants;

(ii) Any substantial change in the volume or character of pollutants being introduced into that POTW by a source introducing pollutants into the POTW at the time of issuance of the permit; and

(iii) For purposes of this paragraph, adequate notice shall include information on:

(1) the quality and quantity of effluent introduced into the POTW, and

(2) any anticipated impact of the change on the quantity or quality of effluent to be discharged from the POTW.

[40 C.F.R. § 122.42(b)]

12. Duty to Reapply

If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must apply for and obtain a new permit.

[40 C.F.R. § 122.41(b)]

The application should be submitted at least 180 days before the expiration date of this permit. The Regional Administrator may grant permission to submit an application later than the 180 days in advance, but no later than the permit expiration date.

[40 C.F.R. § 122.21(d) paraphrased]

When EPA is the permit-issuing authority, the conditions of an expired permit continue in force until the effective date of a new permit if the permittee has submitted a timely application which is a complete application for a new permit; and the Regional Administrator, through no fault of the permittee does not issue a new permit with an effective date on or before the expiration date of the previous permit.

[40 C.F.R. § 122.6(a) paraphrased]

Permits continued under this section remain fully effective and enforceable.

[40 C.F.R. § 122.6(b)]

13. Signatory Requirements

All applications, reports, or information submitted to the Director shall be signed and certified.

[40 C.F.R. § 122.41(k)(1)]

a. *Applications.* All permit applications shall be signed as follows:

(i) *For a corporation.* By a responsible corporate officer. For the purpose of this section, a responsible corporate officer means:

(1) A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision-making functions for the corporation, or

(2) The manager of one or more manufacturing, production, or operating facilities, provided, the manager is authorized to make management decisions which govern the operation of the regulated facility including having the explicit or implicit duty of making major capital investment recommendations, and initiating and directing other comprehensive measures to assure long term environmental compliance with environmental laws and regulations; the manager can ensure that the necessary systems are established or actions taken to gather complete and accurate information for permit application requirements; and where authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

NOTE: EPA does not require specific assignments or delegations of authority to responsible corporate officers identified in 40 C.F.R. § 122.22(a)(1)(i). The Agency will presume that these responsible corporate officers have the requisite authority to sign permit applications unless the corporation has notified the Director to the contrary. Corporate procedures governing authority to sign permit applications may provide for assignment or delegation to applicable corporate positions under 40 C.F.R. § 122.22(a)(1)(ii) rather than to specific individuals.

(ii) *For a partnership or sole proprietorship.* By a general partner or the proprietor, respectively; or

(iii) *For a municipality, State, Federal, or other public agency.* By either a principal executive officer or ranking elected official. For purposes of this section, a principal executive officer of a Federal agency includes:

(1) The chief executive officer of the agency, or

(2) A senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., Regional Administrators of EPA).

b. All reports required by permits, and other information requested by the Director shall be signed by a person described in paragraph (a) of this section, or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(i) The authorization is made in writing by a person described in paragraph a. of this section;

(ii)The authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity such as the position of plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company, (A duly authorized representative may thus be either a named individual or any individual occupying a named position.) and (iii)The written authorization is submitted to the Director.

c. *Changes to authorization.* If an authorization under paragraph (b) of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph b. of this section must be submitted to the Director prior to or together with any reports, information, or applications to be signed by an authorized representative.

d. *Certification.* Any person signing a document under paragraph (a) or (b) of this section shall make the following certification:

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I have no personal knowledge that the information submitted is other than true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

[40 C.F.R. § 122.22]

14. Availability of Reports

Except for data determined to be confidential under 40 C.F.R. Part 2, all reports prepared in accordance with the terms of this permit shall be available for public inspection at the offices of the Permit Issuing Authority. As required by the Act, permit applications, permits and effluent data shall not be considered confidential.

[40 C.F.R. §§ 124.18 & 122.7 paraphrased]

15. Penalties for Falsification of Reports

The CWA provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or non-compliance shall, upon conviction, be punished by a fine of not more than $16,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

[40 C.F.R. § 122.41(k)(2)]

E. Definitions

1. Permit Issuing Authority

The Regional Administrator of the EPA Region 4 or his/her designee, unless at some time in the future the State or Indian Tribe receives authority to administer the NPDES program and assumes jurisdiction over the permit; at which time, the Director of the State program receiving the authorization becomes the issuing authority. The use of the term "Director" in this permit shall apply to the Water Protection Division Director for EPA Region 4.

2. Act

"Act" means the CWA (formerly referred to as the Federal Water Pollution Control Act) Public Law 92-500, as amended by Public Law 95-217 and Public Law 95-576, 33 U.S.C. 1251 et seq.

[40 C.F.R. § 124.2]

3. Mass/Day Measurements

a. The "average monthly discharge" is defined as the total mass of all daily discharges sampled and/or measured during a calendar month on which daily discharges are sampled and measured, divided by the number of daily discharges sampled and/or measured during such month. It is therefore, an arithmetic mean determined by adding the weights of the pollutant found each day of the month and then dividing this sum by the number of days the tests were reported. This limitation is identified as "Daily Average" or "Monthly Average" in Part I of the permit and the average monthly discharge value is reported in the "Average" column under "Quantity or Loading" on the Discharge Monitoring Report (DMR).

b. The "average weekly discharge" is defined as the total mass of all daily discharges sampled and/or measured during the calendar week on which daily discharges are sampled and measured, divided by the number of daily discharges sampled and/or measured during such week. It is, therefore, an arithmetic mean determined by adding the weights of pollutants found each day of the week and then dividing this sum by the number of days the tests were reported. This limitation is identified as "Weekly Average" in Part I of the permit and the average weekly discharge value is reported in the "Maximum" column under "Quantity or Loading" on the DMR.

c. The "maximum daily discharge" is the total mass (weight) of a pollutant discharged during a calendar day. If only one sample is taken during any calendar day, the weight of pollutant calculated from it is the "maximum daily discharge." This limitation is identified as "Daily Maximum," in Part I of the permit and the highest such value recorded during the reporting period is reported in the "Maximum" column under "Quantity or Loading" on the DMR.

d. The "average annual discharge" is a rolling average equal to the arithmetic mean of the mass measured in all discharges sampled and/or measured during consecutive reporting periods which comprise one year. For parameters that are measured at least once per month, the annual average shall be computed at the end of each month and is equal to the arithmetic mean of the monthly average of the month being reported and each of the previous eleven months. This limitation is defined as "Annual Average" in Part I of the permit and the average annual discharge value is reported in the "Average" column under "Quantity or Loading" on the DMR.

4. Concentration Measurements

a. The "average monthly concentration," other than for bacterial indicators, is the sum of the concentrations of all daily discharges sampled and/or measured during a calendar month on which daily discharges are sampled and measured, divided by the number of daily discharges sampled and/or measured during such month (arithmetic mean of the daily concentration values). The daily concentration value is equal to the concentration of a composite sample or in the case of grab samples is the arithmetic mean (weighted by flow value) of all the samples collected during that calendar day. This limitation is identified as "Monthly Average" or "Daily Average" under "Other Limits" in Part I of the permit and the average monthly concentration value is reported under the "Average" column under "Quality or Concentration" on the DMR.

b. The "average weekly concentration," other than for bacterial indicators, is the sum of the concentrations of all daily discharges sampled and/or measured during a calendar week on which daily discharges are sampled and measured divided by the number of daily discharges sampled and/or measured during such week (arithmetic mean of the daily concentration values). The daily concentration value is equal to the concentration of a composite sample or in the case of grab samples is the arithmetic mean (weighted by flow value) of all the samples collected during that calendar day. This limitation is identified as "Weekly Average" under "Other Limits" in Part I of the permit and the average weekly concentration value is reported under the "Maximum" column under "Quality or Concentration" on the DMR.

c. The "maximum daily concentration" is the concentration of a pollutant discharged during a calendar day. It is identified as "Daily Maximum" under "Other Units" in Part I of the permit and the highest such value recorded during the reporting period is reported in the "Maximum" column under "Quality or Concentration" on the DMR.

d. The "average annual concentration," other than for bacterial indicators, is a rolling average equal to the arithmetic mean of the effluent or influent samples collected during consecutive reporting periods which comprise one year. For parameters that are measured at least once per month, the annual average shall be computed at the end of each month and is equal to the arithmetic mean of the monthly average of the month being reported and the monthly average of each of the previous eleven months. This limitation is identified as "Annual Average" under "Other Limits" in Part I of the permit and the average annual concentration value is reported in the "Average" column under "Quality or Concentration" on the DMR.

5. Other Measurements

a. The effluent flow expressed as million gallons per day (MGD) is the 24-hour average flow averaged over a monthly period. It is the arithmetic mean of the total daily flows recorded during the calendar month. Where monitoring requirements for flow are specified in Part I of the permit, the flow rate values are reported in the "Average" column under "Quantity or Loading" on the DMR.

b. An "instantaneous flow measurement" is a measure of flow taken at the time of sampling, when both the sample and flow are representative of the total discharge.

c. Where monitoring requirements for pH, dissolved oxygen, or bacterial indicators are specified in Part I of the permit, the values are generally reported in the "Quality or Concentration" column on the DMR.

d. The "average annual discharge" for bacterial indicators shall be calculated in the same manner as that for mass limitations (see Paragraph II.E.3.d.).

6. Types of Samples

a. Composite Sample: A "composite sample" is a combination of not less than 8 influent or effluent portions, of at least 100 ml, collected over the full time period specified in Part I.A. The composite sample must be flow proportioned by either a time interval between each aliquot or by volume as it relates to effluent flow at the time of sampling or total flow since collection of the previous aliquot. Aliquots may be collected manually or automatically.

b. Grab Sample: A "grab sample" is a single influent or effluent portion which is not a composite sample. The sample(s) shall be collected at the period(s) most representative of the total discharge.

7. Calculation of Means

a. Arithmetic Mean: The "arithmetic mean" of any set of values is the sum of the individual values divided by the number of individual values.

b. Geometric Mean: The "geometric mean" of any set of values is the N^{th} root of the product of the individual values where N is equal to the number of individual values. The geometric mean is equivalent to the antilog of the arithmetic mean of the logarithms of the individual values. For purposes of calculating the geometric mean, values of zero (0) shall be considered to be one (1).

c. Weighted by Flow Value: "Weighted by flow value" means the sum of each concentration times its respective flow divided by the sum of the respective flows.

8. Calendar Day

A "calendar day" is defined as the period from midnight of one day until midnight of the next day. However, for purposes of this permit, any consecutive 24-hour period that reasonably represents the calendar day may be used for sampling.

9. Hazardous Substance

A "hazardous substance" means any substance designated under 40 C.F.R. Part 116 pursuant to Section 311 of the CWA.

[40 C.F.R. § 122.2]

10. Toxic Pollutants

A "toxic pollutant" is any pollutant listed as toxic under Section 307(a)(1) of the CWA or, in the case of "sludge use or disposal practices," any pollutant identified in regulations implementing section 405(d) of the CWA.

[40 C.F.R. § 122.2]

Part III. Monitoring Reports and Permit Modification

A. Monitoring Reports

The operator shall be responsible for submitting monitoring results for each permitted facility (e.g., well) within the lease block. If there is more than one type of wastewater for each well, the discharge outfalls shall be designated in the following manner:

001 for Water-based Drilling Fluids

002 for Water-based Drill Cuttings

003 for Synthetic-based Drill Cuttings

004 for Produced Water

005 for Deck Drainage

006 for Well Treatment Fluids

007 for Completion Fluids

008 for Workover Fluids

009 for Sanitary Discharges

010 for Domestic Waste Discharges

011 for Miscellaneous Discharges

012 for Miscellaneous Discharges in Which Chemicals Have Been Added

013 for Status Updates for Required Studies and Plans

014 Process water generated from the Monoethylene glycol reclamation process and discharged separately from produced water via outfall 004

Monitoring results obtained for each 3-month period (i.e., quarter), starting with the first month of coverage under this permit, shall be summarized for that timeframe and reported on either a DMR form (EPA No. 3320-1) or optional EPA Region 4 approved form, and shall be postmarked no later than the 58th day of the month following the completed quarterly period. For example, for coverage beginning on January 1, data for January 1 to March 31 shall be submitted by May 28th. If a failure of any permit limitation occurs, the permittee must report the incidents to the EPA Director, or their designated representative, orally within 24 hours and file a written report with the Director in accordance with the requirements in 40 C.F.R. Part 122.

All incidents shall be reported on the quarterly DMR along with the entire laboratory results for all non-compliant parameters, until such time as the facility returns to compliance. All laboratory reports submitted with DMRs should clearly indicate the permit number, outfall number(s), and any other identification information necessary to associate the report with the correct facility, waste stream, and outfall(s).

The Non-Compliance Report for Permit Exceedances shall include:

1. A description of the non-compliance and its cause,
2. The period of non-compliance, including dates and times,
3. The anticipated time the non-compliance is expected to continue (if it has not been corrected), and
4. Steps taken or planned to reduce, eliminate and prevent re-occurrence of the non-compliance.

Electronic Reporting. Due to the e-reporting regulations which require electronic submittal of NPDES reports and forms, EPA will not process any written NOIs after the effective date of the permit. Upon availability, permittees will be able to electronically submit NOIs via the eNOI system and NOTs via email. Additionally, DMRs must be submitted via the Network Discharge Monitoring Report (NetDMR) tool. Once finalized, instructions for all electronic submittals will be posted on EPA website at: https://www.epa.gov/aboutepa/about-epa-region-4-southeast#r4-public-notices

Until such time, signed copies of these and all other reports required by Part II.D. shall be submitted to the following address:

Director
Water Protection Division
U.S. EPA Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, S.W.
Atlanta, GA 30303-8960

If no discharge occurs during the reporting period, sampling requirements of this permit do not apply. The operator must check the "No Discharge" block on the DMR or enter "NODI=C" for quantity and concentration in cases where there is no discharge from a particular outfall. In cases where there is no discharge from any outfalls, the operator may include the facility on a "No Activity" list each monitoring period. If, during the term of this permit, the facility ceases discharge to surface waters, the Regional Director shall be notified within 60 days upon permanent cessation of discharge. This notification shall be in writing.

Additional Monitoring Requirements

1. For effluent monitoring of parameters in Part I of this permit, the permittee shall utilize an EPA-approved test procedure with a minimum level (ML) which is lower than the effluent limitations. The permittee must utilize a standard calibration where the lowest standard point is equal to, or less than, the concentration of the ML. In accordance with 40 C.F.R. § 122.45.45(c), effluent analyses for metals shall measure "total recoverable metal."

2. The permittee shall report the analytical results on the DMR, as follows:

a. Report for maximum daily, monthly or quarterly effluent limitation (or if no limitation applies but samples are collected during the reporting period):

   i. The maximum value of all analytical results, if the maximum value is greater than the ML; or

   ii. For no data (e.g., not quantifiable), report "NODI (Q)" on the DMR form, if the maximum value of all analytical results is greater than or equal to the laboratory's minimum detection limit (MDL), but less than the ML; or

   iii. Report "NODI (B)" (e.g., below detection level), if the maximum value of all analytical results is less than the laboratory's MDL.

b. Report for average monthly or quarterly effluent limitation (or if no limitation applies but samples are collected during the reporting period):

   i. As directed for maximum effluent limitation, if only one sample is collected during the monthly reporting period; or

   ii. The average value of all analytical results where 0 (zero) is substituted for NODI (B) and the laboratory's MDL is substituted for NODI (Q), if more than one sample is collected during the reporting period.

c. Report an attachment to the DMR form for each value reported under paragraphs 2.a and 2.b:

   i. The number or title of the approved analytical method, preparation procedure utilized by the laboratory, and MDL or ML of the analytical method for the pollutant available under 40 C.F.R. 136:

   ii. The laboratory's MDL for the analytical method computed in accordance with Appendix B of 40 C.F.R. 136, the standard deviation (S) from the laboratory's MDL study, and the number of replicate analyses (*n*) used to compute the laboratory's MDL; and

   iii. The lowest calibration standard (i.e., the ML, or lower value).

B. Permit Modification

1. This permit shall be modified, or alternatively, revoked and reissued, to comply with any applicable effluent standard or limitation issued or approved under sections 301(b)(2) (C) and (D), 304(b)(2), 307(b)(2) and 316(b) of the CWA, as amended, if the effluent standard or limitation requirement so issued or approved:
   a. Contains different conditions or is otherwise more stringent than any conditions in the permit; or
   b. Controls any pollutant or disposal method not addressed in the permit.

   The permit as modified or reissued under this paragraph shall also contain any other requirements of the CWA then applicable.
2. In accordance with Section 306(d) of the CWA, effluent limitations based on standards of performance for new sources in this permit shall not be made more stringent during a ten-

year period beginning on the date of completion of such construction or during the period of depreciation or amortization of such facility for the purposes of Section 167 and/or 169 of the Internal Revenue Code of 1954, whichever period ends first. The provisions of Section 306(d) do not limit the authority of the EPA to modify, or alternatively revoke and reissue, the permit to require compliance with a toxic effluent limitation promulgated under Best Available Technology (BAT) or toxic pollutant standard established under 307(a) of the Act, or to modify, as necessary to assure compliance with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2), and 307(a)(2) of the CWA, if the effluent standard or limitation so issued or approved:

a. Contains different conditions or is otherwise more stringent than any conditions in the permit; or

b. Controls any pollutant or disposal method not addressed in the permit.

The permit as modified or reissued under this paragraph shall also contain any other requirements of the CWA then applicable.

3. Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA), EPA is required to consult with the U.S. Fish and Wildlife Service (FWS), and the National Marine Fisheries Service (NMFS) and ensure that "agency action" such as the issuance of this Clean Water Act NDPES permit does not jeopardize the continued existence of any endangered or threatened species or result in destruction or adverse modification of the critical habitat of such species. Section 7(d) of the ESA requires that, after initiation of consultation under Section 7(a)(2), the Federal agency "shall not make any irreversible or irretrievable commitment of resources with respect to the agency action which has the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures which

would not violate subsection (a)(2) of this section." The EPA has not completed consultation with the NMFS in connection with issuance of this permit. Accordingly, in order to ensure compliance with Section 7(a)(2) and 7(d) of the ESA, this permit may be revoked or reopened and modified at any time during the life of the permit if further consultation with NMFS results in the identification of reasonable and prudent alternative measures that are necessary to avoid jeopardy to an ESA threatened or endangered species or adverse effects to its critical habitat. Any such reasonable and prudent alternative measures may be added as conditions to this permit through the reopening and modification process.

4. In addition to any other ground specified herein, this permit shall be modified or revoked at any time if, on the basis of any new data, the director determines that continued discharges may cause unreasonable degradation of the marine environment.

Note: Conditions of the permit section do not apply if the EPA proposes/promulgates a different and applicable New Source Performance Standard (NSPS) prior to "start of construction" for any new sources, as defined in 40 C.F.R. Section 122.29(b)(4) or 125.83. In such case, this permit shall be modified to comply with the requirements of such new NSPS.

Part IV. Best Management Practices/Pollution Prevention (BMP3) Plan

A. Objective

This part is directed towards developing and implementing best management practices plan that incorporates pollution prevention measures for the entire facility. The plan shall address measures towards reducing pollutants of concern and wastes from maintenance operations which discharge (or could discharge) to surface waters. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants, as defined below under Part IV.C.4, known to the discharger. If applicable, the plan shall address each component or system capable of generating or causing a release of non-aqueous drilling fluids (NAF) and identify specific preventative or remedial measures to be implemented.

B. General Requirements

In accordance with Section 304(e) and 402(a)(2) of the CWA as amended, 33 U.S.C. §§ 1251 et seq., and consistent with the policy of the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement a Best Management Practices (BMP) plan incorporating pollution prevention measures for the entire offshore facility. Note that this part does not require the permittee to incorporate pollution prevention measures that would jeopardize efficient operation or result in an unreasonable economic burden. If applicable, the plan shall also include measures to prevent, or minimize, the discharge of NAFs from the facility to waters of the United States through normal operations and ancillary activities. Ways to reduce impingement and entrainment of organisms in the cooling water intake structure shall also be evaluated.

A BMP plan developed as a requirement of a previous NPDES permit will satisfy the requirements of this part if it addresses both facility-wide and specific BMPs for NAFs per Appendix 7 of 40 C.F.R. Part 435, subpart A, to reduce the likelihood of spills or other releases of oil or oil contaminated water, chemicals, cleaning chemicals, and biocides that may enter waters of the United States. References which may be used in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act," found at 40 C.F.R.122.44(k), the Waste Minimization Opportunity Assessment Manual, EPA/625/7-88/003, and other EPA documents relating to BMP guidance.

Pollution prevention requirements per BSEE (see 30 C.F.R. Part 250.300), or other federal requirements relating to BMP guidance, may be incorporated by reference.

The BMP plan is to be retained on-site. Within one year of coverage, operators must submit a certification statement that the BMP plan has been developed and is being implemented. Unless otherwise required by the Director, submittal of the BMP plan to EPA is not required.

C. Part IV Special Definitions

1. The term "pollutants" refers to conventional, non-conventional and toxic pollutants, as appropriate for the NPDES storm water program and toxic pollutants.

2. Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.

3. Non-conventional pollutants are those which are not defined as conventional or toxic, such as phosphorus, nitrogen or ammonia. (Ref: 40 C.F.R. Part 122, Appendix D, Table IV)

4. For purposes of this part, Toxic Pollutants include, but are not limited to: a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, and b) any substance (that is not also a conventional or non-conventional pollutant) for which EPA has published an acute or chronic toxicity criterion, or that is a pesticide regulated by the Federal Insecticide, Fungicide, and Rodentcide Act (FIFRA).

5. "Pollution prevention" and "waste minimization" refer to the first two categories of EPA's preferred hazardous waste management strategy: first, source reduction and then, recycling.

6. "Recycle/Reuse" is defined as the minimization of waste generation by recovering and reprocessing usable products that might otherwise become waste; or the reuse or reprocessing of usable waste products in place of the original stock, or for other purposes such as material recovery, material regeneration or energy production.

7. "Source reduction" means any practice which: i) reduces the amount of any pollutant entering a waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment or disposal; and ii) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or procedure modifications, reformulation or substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.

8. "BMP3" means a Best Management Plan incorporating the requirements of 40 C.F.R. 122.44(k) and Addendum B of Appendix 7 of 40 C.F.R. Part 435, subpart A, plus pollution

prevention techniques, except where other existing programs are deemed equivalent by the permittee. The permittee shall certify the equivalency of the other referenced programs.

9. "Waste Minimization Assessment" means a systematic planned procedure with the objective of identifying ways to reduce or eliminate waste.

10. The term "material" refers to chemicals or chemical products used in any plant operation (i.e., caustic soda, hydrazine, degreasing agents, paint solvents, etc.). It does not include lumber, boxes, packing materials, etc.

D. Specific BMP3 Plan Requirements

1. Facility-Wide Operations

The following requirements may be incorporated by reference from existing facility procedures:

a. name and description of facility, a map illustrating the location of the facility and adjacent receiving waters, and other maps, plot plans or drawings, as necessary;

b. overall objectives (both short-term and long-term) and scope of the plan, towards reduction of pollutants, anticipated dates of achievement of reduction, and a description of means for achieving each reduction goal;

c. a description of procedures relative to spill prevention, control and countermeasures and a description of measures employed to prevent storm water contamination, where the storm water can reasonably be expected to reach waters of the U.S. prior to treatment;

d. a description of practices involving preventive maintenance, housekeeping, record keeping, inspections, and plant security;

e. a description of a waste minimization assessment (WMA) plan for this facility, to determine actions that could be taken to reduce waste loadings and chemical losses to all wastewater and/or storm water streams, without compromising production efficiency or jeopardizing operations. The plan shall address both short-term and long-term opportunities for minimizing waste generation at this facility, particularly for high volume and/or high toxicity components of wastewater and storm water streams. Initially, the WMA plan should focus primarily on actions that could be implemented quickly, thereby realizing tangible benefits to surface water quality. Long term goals and actions pertaining to waste reduction shall include investigation of the feasibility of eliminating toxic chemical use, instituting process changes, raw material replacements, etc. At minimum, the WMA plan should include the following items:

(i) <u>Material and Risk Assessment</u> - A materials and risk assessment shall be developed and shall include the following:

(1) identification of the types and quantities of materials used at the facility;

(2) identification of the location and types of materials management activities which occur at the facility;

(3) an evaluation of the following aspects of materials compatibility: containment and storage practices for chemicals, container compatibility, chemical mixing procedures; potential mixing or compatibility problems; and specific prohibitions regarding mixing of chemicals;

(4) technical information on human health and ecological effects of toxic or hazardous chemicals presently used or manufactured (including by-products produced) or planned for future use or production;

(5) analyses of chemical use and waste generation, including input parameters for all pollutants, overall facility material balances and as necessary, internal process balances, for all pollutants. (When actual measurements of the quantity of a chemical entering a wastewater or storm water stream are not readily available, reasonable estimates should be made based on best engineering judgment.) The analyses should address reasons for using particular chemicals, and/or measures or estimates of the actual and potential chemical discharges via wastewater, wastewater sludge, storm water, air, solid waste or hazardous waste media.

(ii) Pollutant Reduction Methods - The WMA plan shall include, at a minimum, the following means of reducing pollutant discharges in wastewater streams or of otherwise minimizing wastes:

(1) process related source reduction measures, including any or all of the following, as appropriate: improved process controls; reduction in use of toxic or hazardous materials; chemical modifications and/or material purification; chemical substitution employing non-toxic or less toxic alternatives; and equipment upgrades or modifications or changes in equipment use.

(2) housekeeping/operational changes, including waste stream segregation, inventory control, spill and leak prevention, equipment maintenance; <u>and</u> employee training in areas of pollution prevention, good housekeeping, and spill prevention and response;

(3) in-process recycling, on-site recycling and/or off-site recycling of materials (such as non-hazardous rags, pads and filters, antifreeze, lube oil, cooking oil, etc);

(4) following all source reduction and recycling practices, wastewater treatment process changes, including the use of new or improved treatment methods, such that treatment degradation products are less toxic to aquatic or human life; and

(5) other means as agreed upon by the permit issuing authority and the permittee.

(iii) <u>Storm Water Evaluation</u> - For storm water discharges and instances where storm water enters the wastewater treatment/disposal system or is otherwise commingled with wastewater, the BMP3 shall evaluate the following potential sources of storm water contamination, at a minimum:

(1) loading, unloading and transfer areas for dry bulk materials or liquids;

(2) outdoor storage of raw materials or products;

(3) outdoor processing activities;

(4) dust or particulate generating processes;

(5) on-site waste and/or sludge disposal practices.

The likelihood of storm water contact in these areas and the potential for spills from these areas shall be considered in the evaluation. The history of significant leaks or spills of toxic or hazardous pollutants shall also be considered. Recommendations for changes to current practices which would reduce the potential for storm water contamination from these areas shall be made, as necessary.

Practices which reduce pollutant loading in wastewater or storm water discharges with a consequent increase in solid hazardous waste generation, decrease in air quality, or adverse affect to groundwater shall not be considered waste reduction for the purposes of this assessment planning.

2. Wastes From Maintenance Operations

Maintenance waste, such as removed paint and materials associated with surface preparation and coating operations, must be contained to the maximum extent practicable to prevent discharge. This includes airborne material such as spent or over-sprayed abrasives, paint chips, and paint overspray. Measures such as vacuum abrasive blasting, covering grated areas with plywood, surrounding the area with canvas tarps and similar measures must be employed to capture as much material as practicable.

Prior to conducting sandblasting or similar maintenance activities, operators shall operate in accordance with company or site specific BMPs as needed. BMPs utilized must include specific containment measures which should be implemented to the maximum extent practicable. These measures should include, but not limited to:

a. enclose, cover, or contain blasting, sanding, painting, or mechanical cleaning activites, to prevent abrasives, dust, and paint chips from reaching the receiving water.

b. contain blasting, sanding, painting, or mechanical cleaning activities performed over open water.

c. prevent blasting, sanding, painting, or mechanical cleaning activities performed during windy and high precipitation conditions which render containment ineffective.

d. collect spent abrasives routinely and properly store pending shipment to shore for proper disposal.

e. mix paints and solvents in designated areas away from drains, ditches, piers, and surface waters, preferably indoors or under cover.

f. have absorbent and other cleanup items readily available for immediate cleanup of spills.

g. allow empty paint cans to dry before disposal.

h. use plywood and/or plastic sheeting to cover open areas between decks when water blasting, sandblasting and/or mechanical cleaning activities.

3. Non-Aqueous Drilling Fluids

Operators are not required to use specific BMPs for NAFs if all cuttings are monitored in accordance with Appendix 7 of 40 C.F.R. Part 435, subpart A. (This special exemption for NAFs cuttings does not excuse the facility from developing and implementing BMPs for other areas/operations at the site.)

The following specific best management practices and pollution prevention activities are required in the BMP3 Plan when operators elect to control NAF discharges associated with cuttings by a set of BMPs:

a. The operator shall identify and document each NAF well that uses BMPs before starting drilling operations and the anticipated total feet to be drilled with NAF for that particular well.

b. Each facility component or system controlled through use of BMPs shall be examined for its NAF-waste minimization opportunities and its potential for causing a discharge of NAF to waters of the United States due to natural phenomena (e.g., rain, snowfall).

c. For each NAF wastestream controlled through BMPs where experience indicates a reasonable potential for equipment failure (e.g., tank overflow or leakage), natural conditions (e.g., precipitation), or other circumstances to result in NAF reaching surface waters, the BMP3 plan shall include a prediction of the total quantity of NAF which could be discharged from the facility as a result of each condition or circumstance. Specifically, the BMP3 plan should address how NAF cuttings will be handled during routine preventative maintenance or repairs periods for non-crucial equipment such as mud cleaner and high-speed centrifuge and crucial equipment such as the cuttings dryer and cuttings transport system. See Part II.B.c. for NPDES permit requirements regarding "anticipated bypass."

d. The operator must establish programs for identifying, documenting, and repairing malfunctioning NAF equipment, tracking NAF equipment repairs, and training personnel to report and evaluate malfunctioning NAF equipment.

e. The operator must establish operating and maintenance procedures for each component in the solids control system in a manner consistent with the manufacturer's design criteria.

f. The operator must use the most applicable spacers, flushers, pills and displacement techniques in order to minimize contamination of drilling fluids when changing from water-based drilling fluids to NAF, and vice versa.

g. A daily retort analysis shall be performed (in accordance with Appendix 7 to 40 C.F.R. Part 435, subpart A) during the first 0.33 X feet drilled with NAF, where X is the anticipated total feet to be drilled with NAF for that particular well. The retort analyses shall be documented in the well retort log. The operators shall use the calculation procedures detailed in Appendix 7 to subpart A of 40 C.F.R. Part 435 (see equations 1 through 8) to determine the arithmetic average ($\%BF_{well}$) of the retort analyses taken during the first 0.33 X feet drilled with NAF.

h. When the arithmetic average (% BF_{well}) of the retort analyses taken during the first 0.33 X feet drilled with NAF is less than or equal to the base fluid retained on cuttings limitation or standard (see 40 C.F.R. §§ 435.13 and 435.15), retort monitoring of cuttings may cease for that particular well. The same BMPs and drilling fluid used during the first 0.33 X feet shall be used for all remaining NAF sections for that particular well.

i. When the arithmetic average (% BF_{well}) of the retort analyses taken during the first 0.33 X feet drilled with NAF is greater than the base fluid retained on cuttings limitation or standard (see 40 C.F.R. §§ 435.13 and 435.15), retort monitoring shall continue for the next 0.33 X feet drilled with NAF, where X is the anticipated total feet to be drilled with NAF for that particular well. The retort analyses for the first and second 0.33 X feet shall be documented in the well retort log.

j. When the arithmetic average (% BF_{well}) of the retort analyses taken during the first 0.66 X feet (i.e., retort analyses taken from the first and second X feet) drilled with NAF is less than or equal to the base fluid retained on cuttings limitation or standard (see 40 C.F.R. §§ 435.13 and 435.15), retort monitoring of cuttings may cease for that particular well. The same BMPs and drilling fluid used during the first 0.66 X feet shall be used for all remaining NAF sections for that particular well.

k. When the arithmetic average (%BF_{well}) of the retort analyses taken during the first 0.66 X feet shall (i.e., retort analyses taken from first and second 0.33 X feet) drilled with NAF is greater than the base fluid retained on cuttings limitation or standard (see 40 C.F.R. §§ 435.13 and 435.15), retort monitoring shall continue for all remaining sections for that particular well. The retort analyses for all NAF sections shall be documented in the well retort log.

l. When the arithmetic average (%BF_{well}) of the retort analyses taken over all NAF sections for the entire well is greater that the base fluid retained on cuttings limitation or standard (see §§ 435.13 and 435.15), the operator is in violation of the base fluid retained on cuttings limitation or standard and shall submit notification of these monitoring values in accordance with NPDES permit requirements. Additionally, the operator shall, as part of the BMP3 Plan, initiate a re-evaluation and modification to the BMP3 Plan in conjunction with equipment vendors and/or industry specialists.

m. The operator shall include retort monitoring data and dates of retort-monitored and non-retort-monitored NAF-cuttings discharges managed by BMPs in their NPDES permit reports.

n. The operator shall establish mud pit and equipment cleaning methods in such a way as to minimize the potential for building-up drill cuttings (including accumulated solids) in the active mud system and solids control equipment system. These cleaning methods shall include, but are not limited to, the following procedures:

    (1) Ensuring proper operation and efficiency of mud pit agitation equipment,

    (2) Using mud gun lines during mixing operations to provide agitation in dead spaces, and

    (3) Pumping drilling fluids off of drill cuttings (including accumulated solids) for use, recycle, or disposal before using wash water to dislodge solids.

E. Signatory Authority and Management Responsibilities

The BMP3 plan shall contain a written and dated statement (with signatures) from the individual responsible for development and implementation of the BMP3 plan stating that the review has been completed and that the BMP3 plan fulfills the objective and specific requirements set forth in Parts IV. A. and D., above. The statement shall be publicized or made known to all facility employees.

F. Plan Certification

The operator shall certify that its BMP3 plan is complete, on-site, and being implemented. This certification shall identify the NPDES permit number and be signed by an authorized representative of the operator. This certification shall be kept with the BMP3 plan. The certification shall be made no later than one year from the effective date of coverage under this general permit, and must be submitted to EPA Region 4.

G. Plan Documentation

The BMP3 plan shall be documented in narrative form, and shall include any necessary plot plans, drawings or maps, and shall be developed in accordance with good engineering practices. At a minimum, the BMP3 plan shall contain the planning, development and implementation, and evaluation/re-evaluation components. Examples of these components are contained in "Guidance Document for Developing Best Management Practices," EPA document no. 833-B-93-004 (1993).

The permittee shall maintain a copy of the BMP3 plan and related documentation (e.g., training certifications, summary of the monitoring results, records of NAF-equipment spills, repairs, and maintenance) at the facility and shall make the BMP3 plan and related documentation available to EPA upon request.

H. Best Management Practices and Pollution Prevention Committee:

A Best Management Practices Committee (Committee) should be established to direct or assist in the implementation of the BMP3 plan. The Committee should be comprised of individuals within the plant organization who are responsible for developing, implementing, monitoring of success, and revision of the BMP3 plan. The activities and responsibilities of the Committee should address all aspects of the facility's BMP3 plan. The scope of responsibilities of the Committee should be described in the plan.

I. Employee Training

Employee training programs shall inform appropriate personnel of the components and goals of the BMP3 plan and shall describe employee responsibilities for implementing the plan. Training shall address topics such as good housekeeping, materials management, record keeping and reporting, spill prevention and response, as well as specific waste reduction practices to be employed. The plan shall identify periodic dates for such training.

J. Plan Development and Implementation

The BMP3 plan shall be developed and implemented within one year after the effective date of this coverage under this general permit.

K. Plan Review

The plan shall be reviewed by the permittee's designated responsible party (such as the facility drilling engineer) to ensure compliance with the BMP3 plan purpose and objectives set forth above.

If following review by EPA, the BMP3 plan is determined insufficient, EPA may notify the permittee that the BMP3 plan does not meet one or more of the minimum requirements of this Part. Upon such notification from the Director, or authorized representative, the permittee shall amend the plan and shall submit to the Director a written certification that the requested changes have been made. Unless otherwise provided by the Director of the Water Protection Division, EPA Region 4, the permittee shall have 30 days after such notification to make the changes necessary.

L. Plan Modification

The permittee shall modify the BMP3 plan whenever there is a change in design, construction, operation, or maintenance, pertaining to the facility which has a significant effect on the potential for the discharge of pollutants to waters of the United States or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or wet weather discharges.

At a minimum, the BMP3 plan shall be reviewed once every five years, and amended within three months if warranted. Any such changes to the BMP3 plan shall be consistent with the objectives and specific requirements listed in this permit. All changes in the BMP3 plan shall be reviewed by the operator's drilling engineer and authorized on-site representative.

At any time, if the BMP3 plan proves to be ineffective in achieving the general objective of preventing and minimizing the discharge of toxic pollutants and/or NAF-wastes, the BMP3 plan be subject to modification. If the BMP3 requirements in the permit are modified, the BMP3 plan must be modified to incorporate the revised BMP3 requirements within three months.

In particular, for those NAF-waste streams controlled through BMPs, the operator shall amend the BMP3 plan within 30 days whenever there is a change in the facility or in the operation of the facility which materially increases the generation of those NAF wastes or their release, or potential release to the receiving waters.

Modifications to the plan may be reviewed by EPA in the same manner as described above.

Part V. Test Procedures and Definitions

A. Test Procedures

1. Samples of Wastes

If requested, the permittee shall provide EPA with a sample of any waste in a manner specified by the Agency.

2. Drilling Fluids Toxicity Test (Suspended Particulate Phase Toxicity Test)

The approved sampling and test methods for permit compliance are provided in the final effluent guidelines published at 58 FR 12507 on March 4, 1993, as Appendix 2 to subpart A of 40 C.F.R. Part 435.

3. Static Sheen Test

The approved sampling and test methods for permit compliance are provided in the final effluent guidelines published at 58 FR 12506 on March 4, 1993, as Appendix 1 to subpart A of 40 C.F.R. Part 435.

4. Visual Sheen Test

The visual sheen test is used to detect free oil by observing the surface of the receiving water for the presence of a sheen while discharging. A sheen is defined as a "silvery" or "metallic" sheen, gloss, or increased reflectivity; visual color; iridescence; or oil slick on the surface (see 58 FR 12507). The operator must conduct a visual sheen test only at times when a sheen could be observed. This restriction eliminates observations at night or when atmospheric or surface conditions prohibit the observer from detecting a sheen (e.g., during rain or rough seas, etc.). Certain discharges can only occur if a visual sheen test can be conducted.

The observer must be positioned on the rig or platform, relative to both the discharge point and current flow at the time of discharge, such that the observer can detect a sheen should it surface down current from the discharge. For discharges that have been occurring for at least 15 minutes, observations may be made any time thereafter. For discharges of less than 15 minutes duration, observations must be made both during discharge and 5 minutes after discharge has ceased.

5. Produced Water Toxicity Tests

Operators may choose to demonstrate compliance with the toxicity testing requirements for produced water by performing a 7-day chronic toxicity test in accordance with methods for determining the 7-day NOEC is *Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms* (EPA/821-R-02-014). The species to be used for compliance testing for this permit are *Mysidopsis bahia (Americamysis bahia* (Mysid shrimp*))* and *Menida beryllina* (Inland silverside minnow).

6. Base Fluid Sediment Toxicity Test

The approved test method for permit compliance is identified as ASTM E1367-92 (or most current EPA approved method) entitled, *Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods* (or the most current EPA approved method), with *Leptocheirus plumulosus* as the test organism and sediment preparation procedures specified in Appendix 3 of 40 C.F.R. Part 435, subpart A.

$$\text{The base fluid sediment toxicity ratio} = \frac{\text{10-day } LC_{50} \text{ of reference fluid*}}{\text{10-day } LC_{50} \text{ of stock base fluid}}$$

*C_{16}-C_{18} internal olefin, C_{12}-C_{14} ester or C_8 ester

7. Base Fluids Biodegradation Rate

The approved method for permit compliance is identified as International Standards Organization (ISO) 11734:1995 (or the most current EPA approved method) entitled, *Water quality - Evaluation of the ultimate anaerobic biodegradability of organic compounds in digested sludge - Method by measurement of the biogas production* (1995 edition), supplemented with modifications in Appendix 4 of 40 C.F.R. Part 435, subpart A. Compliance with the biodegradation limit will be determined using the following ratio. As described in Section 5.1 of this permit ("Total Gas monitoring procedures") the term "Cumulative gas production" in the following ratio refers to head space gas. This is consistent with the Western Gulf of Mexico Outer Continental Shelf General Permit (GMG290000).

$$\text{Biodegradation rate ratio} = \frac{\text{Cumulative gas production (ml) of reference fluid *}}{\text{Cumulative gas production (ml) of stock base fluid,}}$$

both at 275 days

*C_{16}-C_{18} internal olefin, C_{12}-C_{14} ester or C_8 ester

8. Polynuclear Aromatic Hydrocarbons

The approved method for permit compliance is EPA Method 1654A entitled, *PAH Content of Oil by High Performance Liquid Chromatography with a UV Detector*.

$$\text{PAH mass ratio} = \frac{\text{Mass (g) of PAH (as phenanthrene)}}{\text{Mass (g) of stock base fluid}}$$

9. Formation Oil

a. Contamination of Non-Aqueous Based Drilling Fluids

The approved test method for permit compliance is Gas Chromatography/Mass Spectrometry (GC/MS) contained in Appendix 5 of 40 C.F.R. Part 435, subpart A (or most current EPA approved method). This test shall be performed prior to drilling.

The GC/MS method reports results for the GC/MS test as a percentage crude contamination when calibrated for a specific crude oil. In order to define an applicable pass/fail limit to cover a variety of crude oils, the same crude oil used in calibration of the Reverse Phase Extraction (RPE) test shall be used to calibrate the GC/MS test results to a standardized ratio of the target ION Scan 105 (or most current EPA approved method). Based on the performance of a range of crude oils against the standardized ratio, a value will be selected as a pass/fail standard which will represent detection of crude oil.

b. Contamination of Discharged Non-Aqueous Based Drilling Fluids Retained on Cuttings

The approved test method for permit compliance is the RPE method in Appendix 6 of 40 C.F.R. Part 435, subpart A, which is applied to drilling fluid removed from drill cuttings. If the operator wishes to confirm with results of the RPE method (Appendix 6 of 40 C.F.R. Part 435, subpart A), the operator may use the GC/MS compliance assurance method (Appendix 5 of 40

C.F.R. Part 435, subpart A). Results from the GC/MS compliance assurance method shall supercede the results of the RPE method.

10. Drilling Fluids Sediment Toxicity

The approved test method for permit compliance is identified as ASTM E1367-92 (or the most current EPA approved method) entitled, *Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods*, with *Leptocheirus plumulosus* as the test organism and sediment preparation procedures specified in Appendix 3 of 40 C.F.R. Part 435, subpart A.

$$\text{The drilling fluid sediment toxicity ratio} = \frac{\text{4-day } LC_{50} \text{ of } C_{16}\text{-}C_{18} \text{ internal olefin}}{\text{4-day } LC_{50} \text{ drilling fluid removed from drill cuttings at the solids control equipment}}$$

11. Retention of Non-Aqueous Based Drilling Fluid on Cuttings

The maximum permissible retention of NAF base on wet drill cuttings averaged over drilling intervals using NAFs shall be determined by the American Petroleum Institute Retort method contained in Appendix 7 of 40 C.F.R. Part 435, subpart A. The required sampling, handling, and documentation procedures are listed in Addendum A of Appendix 7 of 40 C.F.R. Part 435, subpart A.

12. Sampling Protocol for Stock Drilling Fluid Sediment Toxicity Test, Drilling Fluid Sediment Toxicity Test and Biodegradation Rate Test

Compliance with the sediment toxicity test ratio limit of1.0 shall be based on the ratio of the arithmetic average of up to three test results from two grab samples. The first grab sample must be split into two aliquots (e.g., grab1A and grab1B) and analyzed separately. The second grab sample (grab2) shall be a backup sample, which shall be retained following proper storage and handling procedures. The second grab sample will be collected within 15 minutes of the first grab sample, and in the case of base fluid testing, will be from the same production lot. Permittees shall show compliance based on results from grab1A, or from the ratio of the arithmetic average of grab1A, grab1B, and if necessary grab2. All test results obtained shall be submitted with the DMR and all ratios shall be rounded to the nearest tenths.

All test results shall be generated as follows:

a. The 10-day stock base fluid toxicity test results consist of individual stock base fluid LC_{50}s and individual reference fluid LC_{50}s (paired results). The arithmetic average of the LC_{50} for the test fluid sample(s) will be compared to determine compliance with the 1.0 ratio permit limit.

b. The stock base fluid biodegradation test results consist of individual stock base fluid cumulative gas production (ml) and individual reference fluid cumulative gas production (ml) tests (paired results). The arithmetic average of the cumulative gas production (ml) for the test fluid samples(s) will be compared against the arithmetic average of the cumulative gas production (ml) of the reference fluid sample(s) to determine compliance with the 1.0 ratio permit limit.

c. The 4-day drilling fluid mud toxicity test results consist of the individual field mud LC_{50}s and individual reference mud LC_{50}s (paired results). The arithmetic average of the LC_{50} for the field mud sample(s) will be compared against the arithmetic average of the LC_{50} of the reference mud sample(s) to determine compliance with the 1.0 ratio permit limit.

13. Rounding of Ratios (to be applied in measuring compliance with the sediment toxicity and biodegradation tests)

All ratios shall be rounded as follows:

The following rounding procedures shall only be applied to the sediment toxicity and biodegradation limitations and standards in this permit:

a. If the digit 6, 7, 8, or 9 is dropped, increase preceding digit by one unit.

   Example: a calculated sediment toxicity or biodegradation ratio of 1.06 should be rounded to 1.1 and reported as a violation of the permit limit.

b. If the digit 0, 1, 2, 3, or 4 is dropped, do not alter the preceding digit.

   Example: a calculated sediment toxicity ratio of 1.04 should be rounded to 1.0 and reported to EPA as compliant with the permit limit.

c. If the digit 5 is dropped, round off preceding digit to the nearest even number.

   Example: a calculated ratio of 1.05 should be rounded to 1.0 and reported to EPA as compliant with the permit limit.

14. Protocol for the Determination of Degradation of Non aqueous Base Fluids in a Marine Closed Bottle Biodegradation Test System: Modified ISO 11734

Section 1: Summary of Method

This method determines the anaerobic degradation potential of mineral oils, paraffin oils and non aqueous fluids (NAF) in sediments. These substrates are base fluids for formulating offshore drilling fluids. The test evaluates base fluid biodegradation rates by monitoring gas production due to microbial degradation of the test fluid in natural marine sediment.

The test procedure places a mixture of marine/estuarine sediment, test substrate (hydrocarbon or controls) and seawater into clean 120 ml (150 ml actual volume) Wheaton serum bottles. The test is run using four replicate serum bottles containing 2000 mg carbon/kg dry weight concentration of test substrate in sediment. The use of resazurin dye solution (1 ppm) evaluates the anaerobic (redox) condition of the bottles (dye is blue when oxygen is present, reddish in low oxygen conditions and colorless if oxygen free). After capping the bottles, a nitrogen sparge removes air in the headspace before incubation begins. During the incubation period, the sample should be kept at a constant temperature of 29 (+/-1)°C. Gas production and composition is measured approximately every two weeks. The samples need to be brought to ambient temperature before making the measurements. Measure gas production using a pressure gauge. Barometric pressure is measured at the time of testing to make necessary volume adjustments.

ISO 11734 specifies that total gas is the standard measure of biodegradation. While modifying this test for evaluating biodegradation of NAF's, methane was also monitored and found to be an acceptable method of evaluating biodegradation Appendix 1 contains the procedures used to follow biodegradation by methane production. Measurement of either total gas or methane production is permitted. If methane is followed, determine the composition of the gas by using gas chromatography (GC) analysis at each sampling. At the end of the test when gas production stops, or at around 275 days, an analysis of sediment for substrate content is possible. Common methods which have been successfully used for analyzing NAF's from sediments are listed in Appendix 2.

Section 2: System Requirements

This environmental test system has three phases, spiked sediment, overlying seawater, and a gas headspace. The sediment/test compound mixture is combined with synthetic sea water and transferred into 120 ml serum bottles. The total volume of sediment/sea water mixture in the bottles is 75 mL. The volume of the sediment layer will be approximately 50 ml, but the exact volume of the sediment will depend on sediment characteristics (wet:dry ratio and density). The amount of synthetic sea water will be calculated to bring the total volume in the bottles to 75 mL. The test systems are maintained at a temperature of 29 °C during incubation. The test systems are brought to ambient temperatures prior to measuring pressure or gas volume.

Section 2.1: Sample Requirements

The concentration of base fluids are at least 2000 mg carbon test material/kg dry sediment. Carbon concentration is determined by theoretical composition based on the chemical formula or by chemical analysis by ASTM D5291-96. Sediments with positive, intermediate and negative control substances as well as a C1618 Internal Olefin type base fluid will be run in conjunction with test materials under the same conditions. The positive control is ethyl oleate (CAS 111-62-6), the intermediate control is 1-hexadecene (CAS 629-73-2), and the negative control is squalane (CAS 111-01-3). Controls must be of analytical grade or the highest grade available. Each test control concentration should be prepared according to the mixing procedure described in Section 3.1.

Product names will be used for examples or clarification in the following text. Any use of trade or product names in this publication is for descriptive use only, and does not constitute endorsement by EPA or the authors.

Section 2.2: Seawater Requirements

Synthetic seawater at a salinity of 25 parts per thousand should be used for the test. The synthetic seawater should be prepared by mixing a commercially available artificial seawater mix, into high purity distilled or de-ionized water. The seawater should be aerated and allowed to age for approximately one month prior to use.

Section 2.3: Sediment Requirements

The dilution sediment must be from a natural estuarine or marine environment and be free of the compounds of interest. The collection location, date and time will be documented and reported. The sediment is prepared by press-sieving through a 2000-micron mesh sieve to remove large debris, then press-sieving through a 500-micron sieve to remove indigenous organisms that may confound test results. The water content of the sediment should be less than 60% (w/w) or a wet to dry ratio of 2.5. The sediment should have a minimum organic matter content of 3% (w/w) as determined by ASTM D2974-87 (95) (Method A and D and calculate organic matter as in section 12 of method ASTM D2974-87).

To reduce the osmotic shock to the microorganisms in the sediment, the salinity of the sediment's pore water should be between 20-30 ppt. Sediment should be used for testing as soon as possible after field collection. If required, sediment can be stored in the dark at 4°C with 3-6 inches of overlying water in a sealed container for a maximum period of 2 months prior to use.

Section 3: Test Set up

The test is set up by first mixing the test or control substrates into the sediment inoculum, then mixing in seawater to make a pourable slurry. The slurry is then poured into serum bottles, which are then flushed with nitrogen and sealed.

Section 3.1: Mixing Procedure

Because base fluids are strongly hydrophobic and do not readily mix with sediments, care must be taken to ensure base fluids are thoroughly homogenized within the sediment. All concentrations are weight-to-weight comparisons (mg of base fluid to kg of dry control sediment). Sediment and base fluid mixing will be accomplished by using the following method.

3.1.1. Determine the wet to dry weight ratio for the control sediment by weighing approximately 10 sub-samples of approximately 1.0 g each of the screened and homogenized wet sediment into tared aluminum weigh pans. Dry sediment at 105 C for 18-24 h. Remove the dried sediments and cool in a desiccator. Repeat the drying, cooling, and weighing cycle until a constant weight is achieved (within 4% of previous weight). Re-weigh the samples to determine the dry weight. Calculate the mean wet and dry weights of the 10 sub-samples and determine the wet/dry ratio by dividing the mean wet weight by the mean dry weight using Formula 1. This is required to determine the weight of wet sediment needed to prepare the test samples.

$$\frac{\text{Mean Wet Sediment Weight (g)}}{\text{Mean Dry Sediment Weight (g)}} = \text{Wet to Dry Ratio} \qquad [1]$$

3.1.2. Determine the density (g/ml) of the wet sediment. This will be used to determine total volume of wet sediment needed for the various test treatments. One method is to tare a 5 ml graduated cylinder and add about 5 ml of homogenized sediment. Carefully record the volume then weigh this volume of sediment. Repeat this a total of three times. To determine the wet sediment density, divide the weight by volume per the following formula:

$$\frac{\text{Mean Wet Sediment Weight (g)}}{\text{Mean Wet Sediment Volume (ml)}} = \text{Wet Sediment Density (g/ml)} \qquad [2]$$

3.1.3. Determine the amount of base fluid to be spiked into wet sediment in order to obtain the desired initial base fluid concentration of 2000 mg carbon/kg dry weight. An amount of wet sediment that is the equivalent of 30 g of dry sediment will be added to each bottle. A typical procedure is to prepare enough sediment for 8 serum bottles (3 bottles to be sacrificed at the start of the test, 4 bottles incubated for headspace analysis, and enough extra sediment for 2 extra bottles). Extra sediment is needed because some of the sediment will remain coated onto the mixing bowl and utensils. Experience with this test may indicate that preparing larger volumes of spiked sediment is a useful practice, then the following calculations should be adjusted accordingly.

3.1.3.1 Determine the total weight of dry sediment needed to add 30 g dry sediment to 8 bottles. If more bottles are used then the calculations should be modified accordingly. For example:

30 g dry sediment per bottle x 8 = 240 g dry sediment [3]

3.1.3.2 Determine the weight of base fluid, in terms of carbon, needed to obtain a final base fluid concentration of 2000 mg carbon/kg dry weight. For example:

$$\frac{2000 \text{ mg carbon}}{\text{per kg dry sediment}} \times \frac{240 \text{ g}}{1000} = 480 \text{ mg carbon} \qquad [4]$$

3.1.3.3 Convert from mg of carbon to mg of base fluid.

This calculation will depend on the % fraction of carbon present in the molecular structure of each base fluid. For the control fluids, ethyl oleate is composed of 77.3% carbon, hexadecene is composed of 85.7% carbon, and squalane is composed of 85.3% carbon. The carbon fraction of each base fluid should be supplied by the manufacturer or determined before use. ASTM D5291-96 or equivalent will be used to determine composition of fluid.

To calculate the amount of base fluid to add to the sediment, divide the amount of carbon (480 mg) by the percent fraction of carbon in the fluid.

For example, the amount of ethyl oleate added to 240 g dry weight sediment can be calculated from the following equation:

$$480 \text{ mg carbon} \div (77.3/100) = 621 \text{ mg ethyl oleate} \quad [5]$$

Therefore, add 621 mg of ethyl oleate to 240 g dry weight sediment for a final concentration of 2000 mg carbon/kg sediment dry weight.

3.1.4. Mix the calculated amount of base fluid with the appropriate weight of wet sediment.

3.1.4.1 Use the wet:dry ratio to convert from g sediment dry weight to g sediment wet weight, as follows:

240 g dry sediment x wet:dry ratio = g wet sediment needed [6]

3.1.4.2 Weigh the appropriate amount of base fluid (calculated in section 3.1.3.3) into stainless mixing bowls, tare the vessel weight, then add the wet sediment calculated in equation 5, and mix with a high shear dispersing impeller for 9 minutes.

The sediment is now mixed with synthetic sea water to form a slurry that will be transferred into the bottles.

Section 3.2: Creating Seawater/Sediment Slurry

Given that the total volume of sediment/sea water slurry in each bottle is to be 75 mL, determine the volume of sea water to add to the wet sediment.

3.3.1 If each bottle is to contain 30 g dry sediment, calculate the weight, and then the volume, of wet sediment to be added to each bottle

30 g dry sediment x wet:dry ratio = g wet sediment added to each bottle [7]

g wet sediment ÷ density (g/mL) of wet sediment = mL wet sediment [8]

3.3.2 Calculate volume of sea water to be added to each bottle

75 mL total volume - mL wet sediment (from eq. 8) = mL of sea water [9]

3.3.3 Determine the ratio of sea water to wet sediment (volume:volume) in each bottle

$$\frac{\text{volume sea water per bottle (eq. 9)}}{\text{volume sediment per bottle (eq. 8)}} = \text{ratio of sea water:wet sediment} \quad [10]$$

3.3.4 Convert the wet sediment weight from equation 6 into a volume using the sediment density.

g wet sediment (eq. 6) ÷ density = volume (mL) of sediment [11]

3.3.5 Determine the amount of sea water to mix with the wet sediment.

mL wet sediment (eq. 11) x sea water:sediment ratio (eq. 10)

= mL sea water to add to wet sediment [12]

Mix sea water thoroughly with wet sediment to form a sediment/sea water slurry.

Section 3.3: Bottling the Sediment Seawater Slurry

The total volume of sediment/sea water slurry in each bottle is to be 75 mL. Convert the volume (mL) of sediment/sea water slurry into a weight (g) using the density of the sediment and the sea water.

3.4.1 Determine the weight of sediment to be added to each bottle

mL sediment (eq. 8) x density of wet sediment (g/mL) = g wet sediment [14]

3.4.2 Determine the weight of sea water to be added to each bottle

mL sea water (eq. 9) x density of sea water (1.01 g/mL) = g sea water [15]

3.4.3 Determine weight of sediment/sea water slurry to be added to each bottle

g wet sediment (eq. 14) + g sea water (eq. 15) = g sediment/sea water slurry [16]

This should provide each bottle with 30 g dry sediment in a total volume of 75 mL.

3.4.4 Putting the sediment:seawater slurry in the serum bottles.

Note: The slurry will need to be constantly stirred to keep the sediment suspended.

Place a tared serum bottle on a balance and add the appropriate amount of slurry to the bottle using a funnel. Once the required slurry is in the bottle remove the funnel, add 2-3 drops (25 μl) of a 1gram/L resazurin dye stock solution. Cap the bottle with a butyl rubber stopper (Bellco Glass, Part #2048- 11800) and crimp with an aluminum seal (Bellco Glass Part #2048-11020).

Using a plastic tube with a (23 gauge, 1 inch long) needle attached to one side and a nitrogen source to the other, puncture the serum cap with the needle. Puncture the serum cap again with a second needle to sparge the bottle's headspace of residual air for two minutes. The nitrogen should be flowing at no more than 100 mL/min to encourage gentle displacement of oxygenated air with nitrogen. Faster nitrogen flow rates would cause mixing and complete oxygen removal would take much longer. Remove the nitrogen needle first to avoid any initial pressure problems. The second (vent) needle should be removed within 30 seconds of removing the nitrogen needle.

Triplicate blank test systems are prepared with similar quantities of sediment and seawater without any base fluid. Incubate in the dark at a constant temperature of 29 ° C.

Record the test temperature. The test duration is dependent on base fluid performance, but at a maximum should be no more than 275 days. Stop the test after all base fluids have achieved a plateau of gas production. At termination, base fluid concentrations can be verified in the terminated samples by extraction and GC analysis according to Appendix 2 of ISO 11734.

Section 4: Concentration Verification Chemical Analyses

Because of the difficulty of homogeneously mixing base fluid with sediment, it is important to demonstrate that the base fluid is evenly mixed within the sediment sea water slurry that was added to each bottle. Of the seven serum bottles set up for each test or control condition, three are randomly selected for concentration verification analyses. These should be immediately placed at 4 ° C and a sample of sediment from each bottle should be analyzed for base fluid content as soon as possible. The coefficient of variation (CV) for the replicate samples must be less than 20%. The results should show recovery of at least 70% of the spiked base fluid. Use an appropriate analytical procedure described in Appendix 2 to perform the extractions and analyses. If any set of sediments fail the criteria for concentration verification, then the corrective action for that set of sediments is also outlined in Appendix 2.

The nominal concentrations and the measured concentrations from the three bottles selected for concentration verification should be reported for the initial test concentrations. The CV for the replicate samples must be less than 20%. If base fluid content results are not within the 20% CV limit, the test must be stopped and restarted with adequately mixed sediment.

Section 5 Gas monitoring procedures

Biodegradation is measured by total gas as specified in ISO 11734. Methane production can also be tracked and is described in Appendix 1.

Section 5.1 Total Gas monitoring procedures

Bottles should be brought to room temperature before readings are taken. The bottles are observed to confirm that the resazurin has not oxidized to pink or blue. Total gas production in the culture bottles (head space gas) should be measured using a pressure transducer (one source is Biotech International). The pressure readings from test and control cultures are evaluated against a calibration curve created by analyzing the pressure created by known additions of gas to bottles established identically to the culture bottles. Bottles used for the standard curve contain 75 mL of water, and are sealed with the same rubber septa and crimp cap seals used for the bottles containing sediment. After the bottles used in the standard curve have been sealed, a syringe needle inserted through the septa is used to equilibrate the pressure inside the bottles to the outside atmosphere. The syringe needle is removed and known volumes of air are injected into the headspace of the bottles. Pressure readings provide a standard curve relating the volume of gas injected into the bottles and headspace pressure. No less than three points may be used to generate the standard curve. A typical standard curve may use 0, 1, 5, 10, 20 and 40 ml of gas added to the standard curve bottles.

The room temperature and barometric pressure (to two digits) should be recorded at the time of sampling. One option for the barometer is Fisher Part #02-400 or 02-401. Gas production by the sediment is expressed in terms of the volume (mL) of gas at standard temperature ($0^oC = 273^oK$) and pressure (1 atm = 30 inches of mercury (Hg)) using Eqn.17,

$$V_2 = \frac{P_1 * V_1 * T_2}{T_1 * P_2} \qquad [17]$$

Where: V_2 = volume of gas production at standard temperature and pressure

P_1 = barometric pressure on day of sampling (inches of Hg)

V_1 = volume of gas measured on day of sampling (mL)

T_2 = standard temperature = 273^oK

T_1 = temperature on day of sampling ($^oC + 273 = {}^oK$)

P_2 = standard pressure = 30 inches Hg

An estimation can be made of the total volume of anaerobic gas that will be produced in the bottles. The gas production measured for each base fluid can be expressed as a percent of predicted total anaerobic gas production.

5.1.1. Calculate the total amount of carbon in the form of the base fluid present in each bottle.

Each bottle is to contain 30 g dry weight sediment. The base fluid concentration is 2000 mg carbon/kg dry weight sediment. Therefore:

2000 mg carbon/kg sediment x (30 g/1000) = 60 mg carbon per bottle [18]

5.1.2. Theory states that anaerobic microorganisms will convert 1 mole of carbon substrate into 1 mole of total anaerobic gas production.

Calculate the number of moles of carbon in each bottle.

The molecular weight of carbon is 12 (i.e., 1 mole of carbon = 12 g). Therefore, the number of moles of carbon in each bottle can be calculated.

(60 mg carbon per bottle/1000) ÷ 12 g/mole = 0.005 moles carbon [19]

5.1.3. Calculate the predicted volume of anaerobic gas.

One mole of gas equals 22.4 L (at standard temperature and pressure), therefore, 0.005 moles x 22.4 L = 0.112 L (or 112 mL total gas production). [20]

Section 5.2 Gas Venting

If the pressure in the serum bottle is too great for the pressure transducer or syringe, some of the excess gas must be wasted. The best method to do this is to vent the excess gas right after measurement. To do this, remove the barrel from a 10-mL syringe and fill it 1/3 full with water. This is then inserted into the bottle through the stopper using a small diameter (high gauge) needle. The excess pressure is allowed to vent through the water until the bubbles stop. This allows equalization of the pressure inside the bottle to atmospheric without introducing oxygen. The amount of gas vented (which is equal to the volume determined that day) must be kept track of each time the bottles are vented. A simple way to do this in a spreadsheet format is to have a separate column in which cumulative vented gas is tabulated. Each time the volume of gas in the cultures is analyzed, the total gas produced is equal to the gas in the culture at that time plus the total of the vented gas.

To keep track of the methane lost in the venting procedure, multiply the amount of gas vented each time by the corrected % methane determined on that day. The answer gives the volume of methane wasted. This must be added into the cumulative totals similarly to the total gas additions.

Section 6: Test Acceptability and Interpretation

Section 6.1 Test Acceptability

At day 275 or when gas production has plateaued, whichever is first, the controls are evaluated to confirm that the test has been performed appropriately. In order for this modification of the closed bottle biodegradation test to be considered acceptable, all the controls must meet the biodegradation levels indicated in Table 1. The intermediate control hexadecene must produce at least 30% of the theoretical gas production. This level may be re-examined after two years and more data has been generated.

Table 1: Test Acceptability Criteria

Concentration	Percent Biodegradability as a Function of Gas Measurement		
	Positive control	Squalane negative control	Hexadecene intermediate control
2000 mg carbon/kg	≥ 60% theoretical	≤ 5% theoretical	≥ 30% theoretical

Section 6.2 Interpretation

In order for a fluid to pass the closed bottle test, the biodegradation of the base fluid as indicated by the total amount of total gas (or methane) generated once gas production has plateaued (or at the end of 275 days, which ever is first) must be greater than or equal to the volume of gas (or methane) produced by the reference standard (internal elefin or ester).

The method for evaluating the data to determine whether a fluid has passed the biodegradation test must use the equations:

$$\frac{\text{\% Theoretical gas production of reference fluid}}{\text{\% Theoretical gas production of NAF}} \quad \text{X } 1.0$$

Where: NAF = stock base fluid being tested for compliance

Reference Fluid = C_{16}-C_{18} internal olefin or C_{12}-C_{14} or C_8 ester reference fluid

15. Whole Effluent Toxicity Testing

(a) The following Chronic Whole Effluent Toxicity testing requirements apply to: 1) Produced Water Discharges; 2) Well Treatment, Well Completion or Well Workover Fluid Discharges lasting four or more days; 3) Miscellaneous Discharges of Seawater and Freshwater to which chemicals have been added; and 4) Chemicals used in subsea operations, including but not limited to, Subsea Wellhead Preservation Fluids, Subsea Production Control fluids, Umbilical Steel Tube Storage Fluid, Leak Tracer Fluids and Riser Tensioner Fluids.

The control and dilution water will be natural or synthetic seawater at 25 ppt salinity as described in EPA-821-R-02-014, Section 7, or the most current edition. A standard reference toxicant quality assurance chronic toxicity test shall be conducted concurrently with each species used in the toxicity tests and the results included in summary laboratory report, which is to be submitted with the DMR. Alternatively, if monthly QA/QC reference toxicant tests are conducted, these results must be included in the summary laboratory report. The permittee shall submit a full laboratory report in the event a failure occurs for any test, or upon specific request of EPA. Any deviation from the bioassay procedures outlined or cited herein shall be submitted in writing to the EPA for review and approval prior to use.

1. a. The permittee shall conduct a mysid, _Mysidopsis bahia_, Survival and Reproduction test and an Inland silverside minnow, _Menida beryllina_, Larval Survival and Growth test. All tests shall be conducted using a control (0% effluent) and the following dilution concentrations: 0.25 times the critical dilution (CD), 0.5 times the CD, the CD, two times the CD and, four times the CD. The measured endpoints will be the survival and growth No Observed Effect Concentration (NOEC) concentration for each species. The survival and growth responses will be determined based on the number of _Mysidopsis bahia_ or _Menida beryllina_ larvae used to initiate the test.

   b. For each set of tests conducted, a grab sample of final effluent shall be collected and used to initiate the test within 36 hours of collection.

   c. If control mortality exceeds 20% in any test, the test(s) with that species (including the control) shall be repeated. For either species, a test will be considered valid only if control mortality does not exceed 20%. Each test must meet the test acceptability criteria for each species as defined in EPA-821-R-02-014, Section 13.12 for _Menida beryllina_ and Section 14.12 for _Mysidopsis bahia_, or the most current edition. Additionally, all test results must be evaluated and reported for concentration-response relationship based on "Method Guidance and Recommendations for Whole Effluent Toxicity (WET) Testing (40 C.F.R. Part 136)," EPA/821/B-00/004 (http://water.epa.gov/scitech/methods/cwa/wet/upload/2007_07_10_methods_wet_disk2_atx.pdf), or the most current edition. If the required concentration-response review fails to yield a valid relationship per EPA/821/B-00/004 (or the most current edition), that test shall be repeated if an additional sample can be obtained. Any test initiated but terminated prior to completion must be reported with a complete explanation for the termination. If the conditions of test acceptability are met as described above and in Part V.15.4, and the percent survival of the test organism is equal to or greater than 80% in the critical dilution concentration and all lower dilution concentrations, the survival test shall be considered to be passing and the permittee shall report a survival NOEC of not less than the critical dilution in the DMR.

2. a. Except for WTCW fluids, the toxicity tests specified above shall be conducted once every two months for the first year of the permit until three consecutive valid bimonthly tests with passing results are completed. The permittee may reduce monitoring frequency to once per every six months thereafter for the duration of the permit. For WTCW fluids, the monitoring frequency shall be at least once per month for the first year of the permit until three consecutive valid monthly tests with passing results are completed. The permittee may reduce monitoring frequency to once per every six months thereafter for the duration of the permit. These tests are referred to as "routine" tests.

Exception - Toxicity testing for chemicals/fluids used in subsea operations shall be once prior to use during the term of this general permit and at least annually thereafter on each product added to an operation after the effective date of this permit. Additionally, permittees that were covered under the previous general permit and that are currently performing toxicity tests for Produced Water discharges and have passed the most recent three consecutive toxicity test results shall continue beginning with a frequency of at least every six months, unless a subsequent non-compliance occurs or if the fluid formulation changes.

For well treatment, well completion or well workover fluid discharges monitoring only requirements apply. Test results shall be reported as pass or fail. A failure will not be considered a violation of the permit.

b. Results from routine tests shall be reported according to EPA-821-R-02-014, Section 10, or the most current edition. All results shall also be recorded and submitted on the Discharge Monitoring Report (DMR) in the following manner: If the NOEC of a test species is less than CD% effluent, this constitutes a test failure and "1" shall be entered on the DMR for that species. If the NOEC of a test species is greater than or equal to the CD% effluent, this constitutes a pass, and "0" shall be entered on the DMR.

c. The summary laboratory reports shall include, as a minimum, the following information:

    (1) Permittee's Name
    (2) Name of test and test method number
    (3) Name of test species
    (4) Outfall identification designation and type of wastewater
    (5) Name of biomonitoring laboratory
    (6) Date sample was collected

(7) Date and time test initiated

(8) Critical Dilution

(9) Indicate if test is "valid." If not, state reasons why.

(10) For each species, the percent effluent corresponding to each NOEC for both the growth test and the survival test.

3. a. An NOEC of less than CD % effluent in any valid routine or additional definitive Survival or Growth test for either species will be a violation of this permit for all wastewaters, except for WTCW fluids not discharged with produced waters.

b. If an NOEC of less than CD % effluent is found in a routine test, the permittee shall conduct three valid additional tests on each species indicating the violation and report each NOEC obtained. A valid additional definitive test result cannot be used to negate a permit violation based on failure of a routine test.

c. The first valid additional test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 0.0625 times the CD, 0.125 times the CD, 0.25 times the CD, 0.5 times the CD and the CD. The dilution series may be modified in the second and third valid tests to more accurately identify the toxicity.

d. For each additional test, the sample collection requirements and the test acceptability criteria and concentration-response relationships specified in sections 1.b. and c. above, respectively, must be met for the additional test to be considered valid. The first additional test shall begin within two weeks of the end of the routine test failure, and shall be conducted every two weeks thereafter until three consecutive additional valid tests are completed.

e. Results from additional tests, required due to a chronic toxicity failure in a routine test, shall be submitted in a single report prepared according to EPA-821-R-02-014, Section 10, or the most current edition and submitted within 30 days of completion of the third valid additional test.

f. After compliance is demonstrated for the three consecutive additional tests, the permittee may return to the testing frequency prior to the non-compliance.

4. To assess within test variability, test results must be evaluated for, and reported with the DMR in terms of the percent minimum significant difference (PMSD), in accordance with Section 10.28 of EPA/821-R-02-014. If toxicity is not found at the critical dilution concentration based on the value of the effect concentration estimate and the PMSD measured for a given test exceeds the upper PMSD bound as provided in this section, then the test shall not be accepted, and a new test must be conducted promptly on a newly collected sample.

5. This permit may be reopened to require chemical specific effluent limits, additional testing and/or other appropriate actions to address toxicity. A Toxicity Reduction Evaluation and/or a Toxicity Identification Evaluation may be required based on EPA' Guidance, Clarifications

Regarding Toxicity Reduction and Identification Evaluations in the National Pollutant Discharge Elimination System Program dated March 27, 2001.

(b) The following Acute Whole Effluent Toxicity testing requirements apply to Well Treatment, Well Completion or Well Workover Fluid Discharges lasting less than four consecutive days.

For well treatment, well completion or well workover fluid discharges monitoring only requirements apply. Test results shall be reported as pass or fail. A failure will not be considered a violation of the permit. Acute toxicity shall be used to determine the concentration of effluent that results in mortality of the test organisms during a 48-hour exposure. The control and dilution water will be natural or synthetic seawater at 25 parts per thousand salinity as described in EPA's acute WET test methods (2002), "Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters to Freshwater and Marine Organisms, EPA-821-R-02-012 *(hereafter EPA's acute test methods)*, Section 7, (http://water.epa.gov/scitech/methods/cwa/wet/upload/2007_07_10_methods_wet_disk2_atx.pdf) or the most current edition. A standard reference toxicant quality assurance acute toxicity test shall be conducted concurrently with each species used in the toxicity tests and the results included in summary laboratory report, which is to be submitted with the discharge monitoring report (DMR). Alternatively, if monthly quality assurance/quality control (QA/QC) reference toxicant tests are conducted, these results must be included in the summary laboratory report. The permittee shall submit a full laboratory report in the event a failure occurs (WET test demonstrates toxicity that would result in an exceedance of a NPDES WET compliance level for any test, or upon specific request of EPA). Any deviation from the EPA promulgated WET test methods (40 CFR Part 136) outlined or cited herein shall be submitted in writing to the EPA for review and approval prior to use.

(i). The permittee shall conduct a mysid, *Mysidopsis bahia*, Lethality test and an Inland silverside minnow, *Menida beryllina*, Lethality test, for the duration of a discharge of well treatment, well completion, or well workover fluids, based on an effluent grab sample. All tests shall be conducted using a control (0% effluent) and the following dilution concentrations: 0.25 times the critical dilution (CD), 0.5 times the CD, the CD, two times the CD and, four times the CD. The measured endpoints will be the survival and growth Lethal Concentration for 50% of the test organisms (LC_{50}) for each species. The endpoints will be determined based on a comparison of *Mysidopsis bahia* or *Menida beryllina* responses in the control (0% effluent) and in each of the five dilutions.

For each set of tests conducted, a grab sample of final effluent shall be collected and used to initiate the test within 36 hours of collection.

If control mortality exceeds 10% in any test, the test(s) with that species (including the control) shall be repeated if an additional sample can be obtained. For either species, a test will be considered valid only if control mortality does not exceed 10%. Each WET test must meet the required EPA WET test method's Test Acceptability Criteria (TAC) for each species as defined in the EPA's acute WET test method, (2002) EPA-821-R-02-012, Section 9, or the most current edition. Additionally, all WET test results must be evaluated and reported for concentration-response relationship based on EPA's (2000)

"Method Guidance and Recommendations for Whole Effluent Toxicity (WET) Testing (40 C.F.R. Part 136)," EPA/821/B-00/004, (http://water.epa.gov/scitech/methods/cwa/wet/upload/2007_07_10_methods_wet_wetguide.pdf) or the most current edition. If the recommended concentration-response review produces an inconsistent dose-response curve per EPA/821/B-00/004 (or the most current edition), the test is not considered an invalid test but should be repeated if an additional sample can be obtained. Any WET test initiated but terminated prior to completion must be reported with a complete explanation for the termination. If the requirements of EPA's WET test method's TAC are met as described above, and the percent survival of the test organism is equal to or greater than 90% in the critical dilution concentration and all lower dilution concentrations, the survival test shall be considered to be passing and the permittee shall report a LC_{50} greater than the critical dilution in the DMR.

(ii) The permittee may reduce monitoring frequency to once per discharge for the duration of the permit for Well Treatment, Completion or Workover fluid discharges after two consecutive valid tests, if an additional sample can be obtained. These tests are referred to as "routine" tests.

Results from routine WET tests shall be reported according to EPA's acute WET test methods (2002), EPA-821-R-02-012, Section 12, or the most current edition. All results shall also be recorded and submitted on the DMR in the following manner: If the LC_{50} of a test species is less than or equal to the CD% effluent, and enter"1" shall be entered on the DMR for that species. If the LC_{50} of a test species is greater than the CD% effluent, and "0" shall be entered on the DMR.

. The summary laboratory reports shall include, as a minimum, the following information:

(1) Permittee's Name

(2) Name of WET test and EPA WET test method number

(3) Name of WET test species

(4) Outfall identification designation and type of wastewater

(5) Name of biomonitoring laboratory

(6) Date sample was collected

(7) Date and time test initiated

(8) Critical Dilution

(9) Indicate if test is "valid." If not, state reasons why (i.e., what EPA WET test methods TAC not met).

(10) For each species, the percent effluent corresponding to each LC_{50} for both the growth test and the survival test.

(iii) An LC_{50} of less than or equal to the CD % effluent in any valid routine or additional definitive Survival or Growth WET test for either species will <u>not</u> be a violation of this permit.

. If an LC_{50} of less than CD % effluent is found in a routine WET test, the permittee shall conduct two valid additional WET tests on each species indicating the violation and report each LC_{50} obtained. A valid additional definitive WET test result cannot be used to negate a permit violation based on failure of a routine WET test.

- The first valid additional WET test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 0.0625 times the CD, 0.125 times the CD, 0.25 times the CD, 0.5 times the CD and the CD. The dilution series may be modified in the second valid WET test to more accurately identify the toxicity endpoints.

- For each additional WET test, the sample collection requirements and the required EPA WET test method's TAC must be met and the recommended concentration-response relationships (i.e., dose response curve) specified in sections 1.b. and c. above, respectively, must be met for the additional WET test to be considered valid. The first additional WET test shall begin within one day of the end of the routine WET test failure, and shall be conducted every other day thereafter until two consecutive additional passing WET tests are completed.

- Results from additional WET tests, required due to an acute toxicity violation in a routine WET test, shall be submitted in a single report prepared according to EPA's acute WET test methods (2002), EPA-821-R-02-012, Section 12, or the most current edition and submitted within 30 days of completion of the second valid additional test.

- After two consecutive additional WET tests are passed, the permittee may return to the testing frequency prior to the non-compliance.

(iv) This permit may be reopened to require chemical specific effluent limits, additional WET testing and/or other appropriate actions to address toxicity. A Toxicity Reduction Evaluation and/or a Toxicity Identification Evaluation may be required based on EPA' Guidance, Clarifications Regarding Toxicity Reduction and Identification Evaluations in the National Pollutant Discharge Elimination System Program dated March 27, 2001.

B. Other Definitions

1. Administrator means the Administrator of the U.S. Environmental Protection Agency.
2. Annual monitoring period means the 12-month period after the effective date of this permit.
3. Applicable effluent standards and limitations means all state and Federal effluent standards and limitations to which a discharge is subject under the Act, including, but not limited to, effluent limitations, standards or performance, toxic effluent standards and prohibitions, and pretreatment standards.
4. Areas of Biological Concern for water within the territorial seas (shoreline to 3-mile offshore) are those defined as "no activity zones" for biological reasons by the states of Alabama, Florida and Mississippi. For offshore waters seaward of three miles, areas of biological concern include "no activity zones" defined by the Department of Interior (DOI) for biological reasons, or identified by EPA in consultation with the DOI, the states, or other interested federal agencies, as containing biological communities, features or functions that are potentially sensitive to discharges associated with the oil and gas industry.
5. Base fluid means the continuous phase or suspending medium of a drilling fluid formation.

6. Base fluid retained on cuttings refers to the American Petroleum Institute Recommended Practice 13B-2 supplemented with the specifications, sampling methods, and averaging method for retention values provided in 40 C.F.R. Part 435, subpart A, Appendix 7.

7. Batch or Bulk Discharge is any discharge of a discrete volume or mass of effluent from a pit, tank, or similar container that occurs on a one-time, infrequent, or irregular basis.

8. Biodegradation rate refers to the ISO 11734:1995 (or most current EPA approved method). "Water quality - Evaluation of the ultimate anaerobic biodegradation of organic compounds in digested sludge-Method by measurement of the biogas production (1995 edition)," supplemented with modifications in Appendix 4 of 40 C.F.R. Part 435, subpart A.

9. Blow-Out Preventer Control Fluid means fluid used to actuate the hydraulic equipment on the blow-out preventer or subsea production wellhead assembly.

10. Boiler Blowdown means discharges from boilers necessary to minimize solids build-up in the boilers, including vents from boilers and other heating systems.

11. Bypass means the intentional diversion of waste streams from any portion of a treatment facility. (See Part II.B.3 of this permit.)

12. C_{12}-C_{14} Ester and C_8 Ester means the fatty-acid/2-ethylhexyl esters with carbon chain lengths ranging from 8 to 16 and represented by the Chemical Abstracts Service (CAS) No. 135800-37-2.

13. C_{16}-C_{18} Internal Olefin means a 65/35 blend, proportioned by mass, of hexadecene and octadecene, respectively. Hexadecene is an unsaturated hydrocarbon with a carbon chain length of 16, an internal double carbon bond, and is represented by the CAS No. 26952-14-7. Octadecene is an unsaturated hydrocarbon with a carbon chain length of 18, an internal double carbon bond, and is represented by CAS No. 27070-58-2.

14. C_{16}-C_{18} Internal Olefin Drilling Fluid means a C_{16}-C_{18} internal olefin drilling fluid formulated as specified in Appendix 8 of C.F.R. Part 435, subpart A.

15. Clinkers are small lumps of residual material left after incineration.

16. Cooling Water means water used for contact or noncontact cooling, including water used for equipment cooling, evaporative cooling tower make-up, and dilution of effluent heat content.

17. Cooling Water Intake Structure means the physical equipment with a design intake flow greater than or equal to 2 MGD, used to intake seawater, of which 25%, or more, is used for cooling water purposes.

18. Completion Fluids are salt solutions, weighted brines, polymers and various additives used to prevent damage to the well bore during operations which prepare the drilled well for hydrocarbon production. These fluids move into the formation and return to the surface as a slug with the produced water. Drilling muds remaining in the wellbore during logging, casing, and cementing operations or during temporary abandonment of the well are not considered completion fluids and are regulated by drilling fluids requirements.

19. Daily Discharge means the discharge of a pollutant measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in terms of mass, the daily discharge is calculated as the total mass of the pollutant or waste stream discharged over the sampling day. For pollutants with limitations expressed in other units of measurement, the daily discharge is calculated as the average measurement of the pollutant over the sampling day. Daily discharge determination of concentration made using a composite sample shall be the concentration of the composite sample. When grab samples are used, the daily discharge determination of

concentration shall be the average (weighted by flow value) of all samples collected during that sampling day.

20. <u>Daily Average</u> (also known as monthly average) discharge limitations means the highest allowable average of daily discharge(s) over a calendar month, calculated as the sum of all daily discharge(s) measured during a calendar month divided by the number of daily discharge(s) measured during that month. When the permit establishes daily average concentration effluent limitations or conditions, the daily average concentration means the arithmetic average (weighted by flow) of all daily discharge(s) of concentration determined during the calendar month where C = daily concentration, F = daily flow, and n = number of daily samples; daily average discharge =

$$\frac{C_1F_1 + C_2F_2 + \ldots + C_nF_n}{F_1 + F_2 + \ldots + F_n.}$$

21. <u>Daily Maximum</u> is the total mass (weight) of a pollutant discharged during a calendar day. If only one sample is taken during any calendar day, the weight of pollutant calculated from it is the "maximum daily discharge." This limitation is identified as "Daily Maximum" in Part I of the permit and the highest such value recorded during the reporting period is reported in the "Maximum" column under "Quantity or Loading" on the DMR.

22. <u>Deck</u> <u>Drainage</u> is all waste resulting from platform washings, deck washings, deck area spills, equipment washings, rainwater, and runoff from curbs, gutters, and drains, including drip pans and wash areas, pans and work areas within facilities subject to this permit.

23. <u>Desalination Unit</u> <u>Discharge</u> means waste water associated with the process of creating freshwater from seawater.

24. Development Drilling means the drilling of wells required to efficiently produce a hydrocarbon formation or formations.

25. Development Facility means any fixed or mobile structure that is engaged in the drilling of productive wells.

26. Diatomaceous Earth Filter Media is the filter media used to filter seawater or other authorized completion fluids and subsequently washed from the filter.

27. Diesel oil refers to the grade if distillate fuel oil, as specified in the American Society of Testing and Materials Standard Specifications for Diesel Fuel Oils D975-91, that is typically used as the continuous phase in conventional oil-based drilling fluids.

28. Director means the Director, EPA Region 4, Water Protection Division.

29. Domestic waste means materials discharged from sinks, showers, laundries, safety showers, eye-wash stations, hand-wash stations, fish cleaning stations, and galleys located within facilities subject to 40 C.F.R. Part 435, subpart A.

30. Drill cuttings means the particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling fluid. Examples of drill cuttings include small pieces of rock varying in size and texture from fine silt to gravel and particles of cured cement. Drill cuttings are generally generated from solids control equipment and settle out and accumulate in quiescent areas in the solids control equipment or the equipment processing drilling fluid (i.e., accumulated solids).

   a. Wet drill cuttings means the unaltered drill cuttings and adhering drilling fluid and formation oil carried out from the wellbore with the drilling fluid.

   b. Dry drill cuttings means the residue remaining in the retort vessel after completing the retort procedure specified in Appendix 7 of 40 C.F.R. Part 435, subpart A.

31. Drilling fluid means the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation.
    a. Water-based drilling fluid means the continuous phase and suspending medium for solids is a water-miscible fluid, regardless of the presence of oil.
    b. Non-aqueous drilling fluid means the continuous phase and suspending medium for solids is a water-immiscible fluid, such as oleaginous materials (e.g., mineral oil, paraffinic oil, C_{16}-C_{18} internal olefins, and C_8-C_{16} fatty acid/2-ethylhexyl esters).
        i. Oil-based means the continuous phase of the drilling fluid consists of diesel oil, mineral oil, or some other oil, but contains no synthetic material or enhanced mineral oil.
        ii. Enhanced mineral oil-based means the continuous phase of the drilling fluid is enhanced mineral oil.
        iii. Synthetic-based means the continuous phase of the drilling fluid is a synthetic material or a combination of synthetic materials.

32. Dual Gradient Drilling means well drilling where a pump is used at the seafloor to lift drilling fluids and cuttings to the surface. This allows for a dual pressure gradient - one from the hydrostatic weight of water in the riser and one from the mud weight in the well. Dual gradient drilling can include a discharge of the larger size cuttings at the seafloor.

33. End of Well Sample means the sample taken after the final log run is completed and prior to bulk discharge.

34. Enhanced mineral oil as applied to enhanced mineral-oil based drilling fluid means a petroleum distillate which has been highly purified and is distinguished from diesel oil in having a lower polynuclear aromatic hydrocarbon (PAH) content. Typically, conventional

mineral oils have a PAH content on the order of 0.35 weight percent expressed as phenanthrene, whereas enhanced mineral oils typically have a PAH content of 0.001 or lower weight percent PAH expressed as phenanthrene.

35. Excess Cement Slurry means the excess mixed cement, including additives and wastes from equipment washdown after a cementing operation.

36. Existing Sources are facilities conducting exploration activities and those that have commenced development or production activities that were permitted as of the effective date of the Offshore Guidelines (March 4, 1993).

37. Exploratory facility means any fixed or mobile structure subject to 40 C.F.R. Part 435, subpart A that is engaged in the drilling of wells to determine the nature of potential hydrocarbon reservoirs.

38. Formation oil means the oil from a producing formation which is detected in the drilling fluid, as determined by Gas Chromatography/Mass Spectrometer (GC/MS) compliance assurance method specified in Appendix 5 of 40 C.F.R. Part 435, subpart A, when the drilling fluid is analyzed prior to drilling and as determined by the Reverse Phase Extraction (RPE) method specified in Appendix 6 of 40 C.F.R. Part 435, subpart A, or the GC/MS method when the drilling fluid is analyzed at the offshore point of discharge. Detection of formation oil by the RPE method may be confirmed by the GC/MS method, and the results of the GC/MS compliance assurance method shall supersede those of the RPE method.

39. Four (4)-day LC_{50} as applied to the sediment toxicity BAT effluent limitations and NSPS means the concentration (milliliters/kilogram dry sediment) of the drilling fluid in sediment that is lethal to 50 percent of the *Leptocheirus plumulosus* test organisms exposed to that concentration of the drilling fluids after four days of constant exposure.

40. Free Oil is oil that causes a sheen, streak, or slick on the surface of the test container or receiving water.

41. Garbage means all kinds of food waste, waste generated in living areas on the facility, and operational waste, excluding fresh fish and parts thereof, generated during the normal operation of the facility and liable to be disposed of continuously or periodically except dishwater, graywater, and those substances that are defined or listed in other Annexes to MARPOL 73/78 regulations.

42. Graywater is drainage from dishwater, shower, laundry, bath, and wash basin drains and does not include drainage from toilets, urinals, hospitals, and drainage from cargo areas (see MARPOL 73/78 regulations).

43. Inverse Emulsion Drilling Fluids are oil-based drilling fluids which also contain large amounts of water.

44. Live Bottom Areas are those areas that contain biological assemblages consisting of such sessile invertebrates as sea fans, sea whips, hydroids, anemones, ascideians sponges, bryozoans, sea grasses, or corals living upon and attached to naturally occurring hard or rocky formations with fishes and other fauna.

45. Maximum as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings means the maximum concentration allowed as measured in any single sample of the barite for determination of cadmium and mercury content.

46. Maximum for any one day as applied to BCT and BAT effluent limitations and NSPS for oil and grease in produced water means the maximum concentration allowed as measured by the average of four grab samples collected over a 24-hour period that are analyzed separately.

Alternatively, for BAT and NSPS the maximum concentration allowed may be determined on the basis of physical composition of the four grab samples prior to a single analysis.

47. Maximum Hourly Rate is the greatest number of barrels of drilling fluids discharged within one hour, expressed as barrels per hour.

48. Maximum weighted mass ratio averaged over all NAF well sections for BAT effluent limitations and NSPS for base fluid retained on cuttings means the weighted average base fluid retention for all NAF well sections as determined by the API Recommended Practice 13B-2, using the methods and averaging calculations presented in Appendix 7 of 40 C.F.R. Part 435, subpart A.

49. Method 1654A refers to the method "PAH Content of Oil by High Performance Liquid Chromatography with a UV Detector," which was published in Methods for the Determination of Diesel, Mineral and Crude Oils in Offshore Oil and Gas Industry Discharges, EPA-821-R-92-008 (incorporated by reference and available from the National Technical Information Service).

50. Minimum as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings means the minimum 96-hour LC_{50} value allowed as measured in any single sample of the discharged waste stream. Minimum as applied to BPT and BCT effluent limitations and NSPS for sanitary wastes means the minimum concentration value allowed as measured in any single sample of the discharged waste stream.

51. Muds, Cuttings, and Cement at the Seafloor means discharges that occur at the seafloor prior to installation of the marine riser and during marine riser disconnect, well abandonment, and plugging operations.

52. National Pollutant Discharge Elimination System (NPDES) means the national program for issuing, modifying, revoking and reissuing, terminating, monitoring, and enforcing permits, and imposing and enforcing pretreatment requirements under sections 307, 316, 318, 402, 403, and 405 of the Act.

53. New Source means any facility or activity of this subcategory that meets the definition of "new source" under 40 C.F.R. § 122.2 and meets the criteria for determination of new sources under 40 C.F.R. § 122.29(b) applied consistently with all of the following definitions: (i) the term "water area" as used in the term "site" in 40 C.F.R. § 122.29 and § 122.2 shall mean the water area and ocean floor beneath any exploratory, development, or production facility where such facility is conducting its exploratory, development or production activities and, (ii) the term "significant site preparation work" as used in 40 C.F.R. § 122.29 shall mean the process of surveying, clearing, or preparing an area of the ocean floor for the purpose of constructing or placing a development or production facility on or over the site. New Source does not include facilities covered by an existing NPDES permit immediately prior to the effective date of 40 C.F.R. Part 435 pending EPA issuance of a new source NPDES permit.

54. Ninety-Six (96)-hour LC_{50} means the concentration (parts per million) or percent of the suspended particulate phase (SPP) from a sample that is lethal to 50 percent of the test organisms exposed to that concentration of the SPP after 96 hours of constant exposure.

55. No Activity Zones means those areas identified by the US Minerals Management Service where no structures, drilling rigs, or pipeline will be allowed. Those zones are identified in lease stipulations that are applied to BOEM oil and gas lease sites. Additional no activity zones may be identified by BOEM during the term of this permit.

56. No Discharge Areas are areas specified by EPA where discharge of pollutants may not occur.

57. No discharge of free oil means that waste streams may not be discharged that contain free oil as evidenced by monitoring method specified for that particular stream, e.g., deck drainage or miscellaneous discharges cannot be discharged when they would cause a film or sheen upon or discoloration of the surface of the receiving water; drilling fluids or cuttings may not be discharged when they fail the static sheen test defined in Appendix 1 of subpart A of 40 C.F.R. Part 435.

58. No Observed Effect Concentration (NOEC) means the greatest effluent dilution which does not result in lethality or sublethal endpoints that are statistically different from the control (0% effluent) at the 95% confidence level.

59. Non-Operational Leases are those facilities from which no discharge has taken place within two years prior to the effective date of the reissued general permit, until such time that documentation is submitted to EPA that MMS had previously granted approval of an EP, DOCO, or DPD or submitted a new MMS-approved EP, DPP, or DOCD.

60. Operating Facilities are facilities from which a discharge has taken place within two years of the effective date of the reissued general permit.

61. Operational Waste means all cargo associated waste, maintenance waste, cargo residues, and ashes and clinkers from incinerators and coal burning boilers.

62. Packer Fluids are low solids fluids between the packer, production string, and well casing. They are considered to be workover fluids.

63. PAH (as phenanthrene) means polynuclear aromatic hydrocarbons reported as phenanthrene.

64. Pipeline Brines shall means salt solutions and weighted brines used during pipeline commissioning for hydrotesting or flowline preservation. Brine is not a treatment chemical.

65. Priority Pollutants are the 126 chemicals or elements identified by EPA, pursuant to section 307 of the CWA and 40 C.F.R. § 401.15.

66. Produced Sand means the slurried particles used in hydraulic fracturing, the accumulated formation sands and scales particles generated during production. Produced sand also includes desander discharge from the produced water waste stream, and blowdown of the water phase from the produced water treating system.

67. Produced Water means the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process. Produced water also includes any wastewater generated during separation and processing operations or any chemicals added downhole, subsea or during separation and processing operations.

68. Production facility means any fixed or mobile structure subject to this subpart that is either engaged in well completion or used for active recovery of hydrocarbons from producing formations. It includes facilities that are engaged in hydrocarbon fluids separation even if located separately from wellheads.

69. Quarterly means a calendar quarter.

70. Sanitary Waste means human body waste discharged from toilets and urinals.

71. Sediment Toxicity as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings refers to the ASTM E1367-92 (or most current EPA approved method): Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods with *Leptocheirus plumulosus* as the test organism and sediment preparation procedures specified in Appendix 3 of 40 C.F.R. Part 435, subpart A.

72. Severe Property Damage means substantial physical damage to property, damage to the treatment facilities which cause them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

73. Sheen means a silvery or metallic sheen, gloss, or increased reflectivity; visual color; iridescence; or oil slick on the water surface.

74. Solids Control Equipment means shale shakers, centrifuges, mud cleaners, and other equipment used to separate drill cuttings and/or stock barite solids drilling fluid recovered from the wellbore.

75. Source Water and Sand are the water and entrained solids brought to the surface from non-hydrocarbon bearing formations for the purpose of pressure maintenance or secondary recovery.

76. Spotting means the process of adding a lubricant (spot) downhole to free stuck pipe.

77. SPP toxicity as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings refers to bioassay test procedure presented in Appendix 2 of subpart A of 40 C.F.R. Part 435.

78. Static sheen test means the standard test procedure that has been developed for this industrial subcategory for the purpose of demonstrating compliance with the requirement of no discharge of free oil. The methodology for performing the static sheen test is presented in Appendix 1 of subpart A of 40 C.F.R. Part 435.

79. Stock barite means the barite that was used to formulate a drilling fluid.

80. Stock base fluid means the base fluid that was used to formulate a drilling fluid.

81. Support pipeline facility is a facility that is designed to allow surface access to pipelines; there is no oil and gas production associated with the facility. They include but are not limited to, compressor stations, pumping stations, valve stations, pig launcher/receiving stations, gas/product metering stations, and other appurtenances thereto.

82. Synthetic material as applied to synthetic-based drilling fluid means material produced by the reaction of specific purified chemical feedstock, as opposed to the traditional base fluids such as diesel and mineral oil which are derived from crude oil solely through physical separation processes include fractionation and distillation and/or minor chemical reactions such as cracking and hydro processing. Since they are synthesized by the reaction of purified compounds, synthetic materials suitable for use in drilling fluids are typically free of polynuclear aromatic hydrocarbons (PAHs) but are sometimes found to contain levels of PAH up to 0.001 weight percent PAH expressed as phenanthrene. Internal olefins and vegetable esters are two examples of synthetic materials suitable for use by the oil and gas extraction industry in formulating drilling fluids. Internal olefins are synthesized from the isomerization of purified straight-chain (linear) alpha olefins. C_{16-18} linear alpha olefins are unsaturated hydrocarbons with the carbon to carbon double bond in the terminal position. Internal olefins are typically formed from heating linear alpha olefins with a catalyst. The feed material for synthetic linear alpha olefins is typically purified ethylene. Vegetable esters are synthesized from the acid-catalyzed esterfication of vegetable fatty acids with various alcohols. EPA listed these two branches of synthetic fluid base materials to provide examples, and EPA does not mean to exclude other synthetic materials that are either in current use or may be used in the future. A synthetic-based drilling fluid may include a combination of synthetic materials.

83. Territorial Seas means the belt of the seas measured from the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters, and extending seaward a distance of three miles.

84. Toxic pollutant means any pollutant listed as toxic under section 307(a)(1).

85. Toxicity Reduction Evaluation is a methodical, stepwise investigation of the causes(s) of, and appropriate control(s) for, an effluent that has demonstrated acute or chronic whole effluent toxicity, and a Toxicity Identification Evaluation is defined as a set of procedures that uses physical and chemical treatments to identify or classify the specific chemical compounds causing toxicity in an effluent sample. See EPA's Guidance entitled, "Clarifications Regarding Toxicity Reduction and Identification Evaluations in the National Pollutant Discharge Elimination System Program" dated March 27, 2001 (see https://www3.epa.gov/npdes/pubs/owmfinaltretie.pdf)

86. Trace Amounts means priority pollutants are present in a quantity greater than the minimum detection method for that pollutant in accordance with 40 C.F.R. Part 136. Discharges that have priority pollutants in less than trace amounts are assumed not to contain priority pollutants.

87. Tracer means a very small quantity of tracer (~1 mCi) of Sc-46 embedded in inert beads suspended in a gel (~1 cup by total volume), placed in the first 50 bbls of cement pumped.

88. Track I means new offshore oil and gas facilities that will comply with the CWIS rule based on the requirements at 40 C.F.R. § 125.84(b) or (c).

89. Track II means new offshore oil and gas facilities that will comply with the CWIS rule based on requirements at 40 C.F.R. § 125.84(d).

90. Treatment Chemicals means biocides, corrosion inhibitors, or other chemicals which are used to treat seawater or freshwater to prevent corrosion or fouling of piping or equipment. Non-toxic scale inhibitors and dyes are not considered treatment chemicals.

91. Uncontaminated Ballast/Bilge water means seawater added or removed to maintain proper draft that does not come in contact with surfaces that may cause contamination or a non-compliance of a limit in this permit.

92. Uncontaminated freshwater means freshwater which is discharged without the addition of chemicals, such as: (1) discharges of excess freshwater that permit the continuous operation of fire control and utility lift pumps, (2) excess freshwater from pressure maintenance and secondary recovery projects, (3) water released during training and testing of personnel in fire protection, and (4) water used to pressure test of flush new piping.

93. Uncontaminated seawater means seawater which is returned to the sea without the addition of chemicals, such as: (1) discharges of excess seawater which permit the continuous operation of fire control and utility lift pumps, (2) excess seawater from pressure maintenance and secondary recovery projects, (3) water released during training and testing of personnel in fire protection, (4) water used to pressure test, or flush, new piping, and (5) non-contact cooling water which has not been treated with biocides.

94. "Wastes from Maintenance Operations" includes, but is not limited to, removed paint and materials associated with surface preparation and coating applications, airborne material such as spent or oversprayed abrasives, paint chips, and paint overspray.

95. Water-based Drilling Fluids is the conventional drilling mud in which water is the continuous phase and the suspending medium for solids, whether or not oil is present.

96. Well treatment fluids means any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled. Stimulation fluids include substances such as acids, solvents, and propping agents. Types of well treatment include:

Hydraulic Fracture Treatment:

Data Frac: A fracture test pumped prior to the actual treatment to determine rates and breakdown pressures. These and other parameters are then used to customize the treatment.

Mini-Frac: Industry slang for a small fracture treatment designed to break through the near-wellbore damage caused by drilling and/or completion. Often times the fracture is "propped" open with sand or similar proppant. Mini-fracs are often the same as "Data Fracs".

Frac-Pac: Also a very small fracture treatment done in conjunction with a gravel pack job. Gravel is placed in the annulus between a wire wrapped screen and the formation. By injecting over the fracture pressure the sand is also placed a short distance into the fracture. Primary purposes are formation sand control and damage removal.

Acid Frac: Used primarily in carbonate reservoirs, acid is used as the fracture fluid. The acid etches the rock face inside the fracture and establishes a high conductivity flow path to the well.

Well Simulation Treatment (non-frac):

Matrix Acid/ Acid Squeeze: Acid is injected into the formation pore system to dissolve/remove damaging material. This treatment is always done below the fracture pressure.

Well Cleanup Treatment:

Acid wash: Acid (typically HCL) is placed across the perforations at a very low pressure to soak and dissolve damaged intervals.

Solvent wash: Hydrocarbon (typically Xylene) solvent is placed across perforated intervals to remove hydrocarbon based damage (sludge, heavy oils or paraffin).

Casing scrape/surge: Casing is mechanically scraped with a tool then the well is surged with water or mud to clean contaminants from the well.

Pressure/jet wash: High pressure (low volume) water is used to mechanically scour the casing and perforations to remove surface damage and corrosion.

97. Workover fluids means salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair or abandonment procedures. High solids drilling fluids used during workover operations are not considered workover fluids by definition and therefore must meet drilling fluid effluent limitations before discharge may occur. Packer fluids, low solids fluids between the packer, production string, and well casing are considered to be workover fluids and must meet only the effluent requirements imposed on workover fluids.

98. 96-hour LC_{50} means the concentration (parts per million) or percent of the suspended particulate phase (SPP) from a sample that is lethal to 50 percent of the test organisms exposed to that concentration of the SPP after 96 hours of constant exposure.

99. The term mg/l means milligrams per liter or parts per million (ppm).

100. The term μg/l shall means micrograms per liter or part per billion (ppb).

Table 1. Summary of Effluent Limitations, Prohibitions, and Monitoring Requirements for the Eastern Gulf of Mexico NPDES General Permit for Existing Sources and New Sources (Refer to permit for specific, enforceable requirements)

			Monitoring Requirement		
Discharge	Regulated & Monitored Discharge Parameter	Discharge Limitation/ Prohibition	Measurement Frequency	Sample Type/ Method	Recorded/ Reported Value
Water-Based Drilling Fluids	Oil-based Drilling Fluids	No discharge			
	Oil-contaminated Drilling Fluids	No discharge			
	Drilling Fluids to Which Diesel Oil has been Added	No discharge			
	Mercury (Hg) and Cadmium (Cd) in Barite	No discharge of drilling fluids if added barite contains Hg in excess of 1.0 mg/kg (dry wt) or Cd in excess of 3.0 mg/kg (dry wt)	Once per new source of barite used	EPA SW846 method 6010B, or EPA 200.7 or 200.8 for cadmium & EPA SW846 method 7471A or EPA 245.7 for mercury	mg Hg/kg and mg Cd/kg in stock barite
	Toxicity[a]	30,000 ppm daily minimum 30,000 ppm monthly average of minimum values	Once/month Once/end of well[b] Once/month	Grab/96-hr LC_{50} using *Mysidopsis bahia;* Method at 58 FR 12507	Minimum LC_{50} of tests performed and monthly average LC_{50}
	Free Oil	No free oil	Once/week during discharge	Static sheen; Method at 58 FR 12506	Number of days sheen observed

			Monitoring Requirement		
Discharge	Regulated & Monitored Discharge Parameter	Discharge Limitation/ Prohibition	Measurement Frequency	Sample Type/ Method	Recorded/ Reported Value
	Maximum Discharge Rate	1,000 barrels/hr	Once/day	Estimate	Max. hourly rate in bbl/hr
	Mineral Oil	Mineral oil may be used only as a carrier fluid, lubricity additive, or pill			
	Drilling Fluids Inventory	Record	Once/well	Inventory	Chemical constituents
	Volume	Report	Once/month	Estimate	Monthly total in bbl/month
Water-Based Drill Fluids (Continued)	Within 1000 Meters of an Area of Biological Concern (ABC) or a Federally Designated Dredged Material Disposal Site	No discharge			
Water-Based Drill Cuttings	Note: Drill cuttings are subject to the same limitations/prohibitions as drilling fluids except Maximum Discharge Rate				
	Free Oil	No Free Oil	Once/week	Static sheen; Method at 58 FR 12506	Number of days sheen observed
	Volume	Report	Once/month	Estimate	Monthly total in bbl/month

			Monitoring Requirement		
Discharge	Regulated & Monitored Discharge Parameter	Discharge Limitation/ Prohibition	Measurement Frequency	Sample Type/ Method	Recorded/ Reported Value
Produced Water	Oil and Grease	≤42.0 mg/l daily maximum and ≤29.0 mg/l monthly average	Once/month^{c}	Grab/ Gravimetric	Daily max. and monthly avg.
	Toxicity	Chronic toxicity (NOEC); critical dilution as specified by the requirements at Part I.B.3(b).	Once/2 month (or semiannually after passing three consecutive bimonthly test)	Grab/7-day NOEC using *Mysidopsis bahia* and Inland Silverside minnows	"Pass" or "Fail" for both species and summary laboratory report
	Flow (bbl/month)		Once/month	Estimate	Monthly rate
	Within 1000 meters of an ABC or a Federally Designated Dredged Material Disposal Site	No discharge			
Deck Drainage	Free Oil	No Free Oil	Once/day when discharging^{d}	Visual sheen	Number of days sheen observed
Produced Sand	No Discharge				
Well Treatment, Completion, and Workover Fluids (includes packer fluids)^{e}	Free Oil	No Free Oil	Once/day when discharging	Static sheen	Number of days sheen observed
	Oil and Grease	≤42.0 mg/l daily maximum and ≤29.0 mg/l monthly average	See permit	Grab/ Gravimetric	Monthly max. and monthly avg.

			Monitoring Requirement		
Discharge	Regulated & Monitored Discharge Parameter	Discharge Limitation/ Prohibition	Measurement Frequency	Sample Type/ Method	Recorded/ Reported Value
	Toxicity	Monitoring only.	For chronic toxicity: Once/2 month (or semiannually after passing three consecutive bimonthly test) For acute toxicity: Once/discharge (or semiannually after passing three consecutive tests)	For Chronic toxicity: Grab sample/7-day NOEC using *Mysidopsis bahia* and Inland Silverside minnows For acute toxicity: Grab/48-hr LC_{50} using *Mysidopsis bahia* and Inland Silverside minnows	NOEC" for both species and summary laboratory report
	Priority Pollutants	Non-detect for priority pollutants		Monitor added materials using methods in 40 C.F.R. Part 136	
	Volume (bbl/month)		Once/month	Estimate	See permit
Sanitary Waste (Continuously	Solids	No floating solids	Once/day, during daylight	Observation	Number of days solids observed

			Monitoring Requirement		
Discharge	Regulated & Monitored Discharge Parameter	Discharge Limitation/ Prohibition	Measurement Frequency	Sample Type/ Method	Recorded/ Reported Value
manned by 10 or more persons)[f]	Residual Chlorine	At least (but as close to) 1.0 mg/l	Once/month	Grab/Hach CN-66-DPD or TRC method in 40 C.F.R. Part 136	Concentration
Sanitary Waste (Continuously manned by 9 or fewer persons or intermittently by any)[f]	Solids	No floating solids	Once/day, during daylight	Observation	Number of days solids observed
Domestic Waste	Solids	No floating solids; no food waste within 12 miles of land; comminuted food waste smaller than 25-mm beyond 12 miles	Once/day following morning or midday meal at time of maximum expected discharge	Observation	Number of days solids observed

			Monitoring Requirement		
Discharge	Regulated & Monitored Discharge Parameter	Discharge Limitation/ Prohibition	Measurement Frequency	Sample Type/ Method	Recorded/ Reported Value
Miscellaneous Discharges[g] – 1. Desalination Unit 2. Blowout Preventer Fluid 3. Uncontaminated Ballast/Bilge Water 4. Mud, Cuttings, and Cement at the Seafloor 5. Uncontaminated Seawater 6. Boiler Blowdown 7. Source Water and Sand 8. Diatomaceous Earth Filter Media 9. Excess Cement Slurry 10. Uncontaminated Freshwater 11. Cement Equipment Washdown 12. Hydrate Control Fluid	Free Oil	No Free Oil	Once/week during discharge	Visual sheen	Number of days sheen observed

			Monitoring Requirement		
Discharge	Regulated & Monitored Discharge Parameter	Discharge Limitation/ Prohibition	Measurement Frequency	Sample Type/ Method	Recorded/ Reported Value
Miscellaneous Discharges to Which Treatment Chemicals Have Been Added	Free Oil	No Free Oil	Once/day when discharging	Visual Sheen	Number of days sheen observed
	Toxicity	7-day minimum and monthly average minimum NOEC	Rate Dependent	Grab	Lowest NOEC observed for either of the two species

[a] Toxicity test to be conducted using suspended particulate phase (SPP) of a 9:1 seawater:mud dilution. The sample shall be taken beneath the shale shaker, or if there are no returns across the shaker, the sample must be taken from a location that is characteristic of the overall mud system to be discharged.

[b] Sample shall be taken after the final log run is completed and prior to bulk discharge.

[c] The daily maximum concentration may be based on the average of up to four grab sample results in the 24-hour period.

[d] When discharging and facility is manned. Monitoring shall be accomplished during times when observation of a visual sheen on the surface of the receiving water is possible in the vicinity of the discharge.

[e] No discharge of priority pollutants except in non-detectable amounts using EPA methods in 40 C.F.R. Part 136. Information on the specific chemical composition shall be recorded but not reported unless requested by EPA.

[f] Any facility that properly operates and maintains a marine sanitation device (MSD) that complies with pollution control standards and regulations under Section 312 of the Act shall be deemed to be in compliance with prohibitions and permit limitations for sanitary waste. The MSD shall be tested yearly for proper operation and test results maintained at the facility.

[g] Based on LC_{50} results, the following compounds may also be included as miscellaneous discharges:subsea wellhead preservation fluids, subsea production control fluids, umbilical steel tune storage fluid, leak tracer fluid, riser tensioner fluid.

Table 2. Effluent Limitations, Prohibitions, and Monitoring Requirements for the Eastern Gulf of Mexico NPDES General Permit Existing and New Sources using Synthetic Based Drilling Fluids

			Monitoring Requirement		
Discharge	Regulated & Monitored Discharge Parameter	Discharge Limitation/ Prohibition	Measurement Frequency	Sample Type/ Method	Recorded/ Reported Value
Non-Aqueous Based Drilling Fluids	No discharge, except that which adheres to cuttings, de minimis discharges and small volume discharges				
Drill Cuttings Generated Using Non-Aqueous-Based Drilling	Cuttings from Oil-Based Drilling Fluids	No Discharge			
	Cuttings from Oil Contaminated Drilling Fluids	No Discharge			
	Cuttings Generated Using Mineral Oil	No Discharge			
	Cuttings Generated Using Drilling Fluids Which Contain Diesel Oil	No Discharge			
	Areas of Biological Concern or a Federally Designated Dredged Material Disposal Site	No discharge within 1000 meters			
	Free Oil	No Discharge	Once/week	Static sheen; method at 58 FR 12506	Number of days observed

			Monitoring Requirement		
Discharge	Regulated & Monitored Discharge Parameter	Discharge Limitation/ Prohibition	Measurement Frequency	Sample Type/ Method	Recorded/ Reported Value
	Volume	Report	Once/month	Estimate	Monthly total in bbl/month
	Formation Oil	No Discharge	RPE test once prior to drilling & RPE or GC/MS once/week	GC/MS method at 40 C.F.R. Part 435, Appendix 5 of Subpart A	Number of Days
	Suspended Particulate Phase Toxicity	30,000 ppm daily minimum 30,000 ppm monthly avg of minimum values	Once/month and Once/end of well[b]	Grab/96-hr LC_{50} using *Mysidopsis bahia* (same as *Americamysis bahia*); Method 58 FR 12507	Minimum LC_{50} of tests performed and monthly avg LC_{50}
	Drilling Fluid Sediment Toxicity Ratio	≤ 1.0	Once/month by grab sample(s)	Grab(s)/ASTM E1367-92	Ratio
	Polynuclear Aromatic Hydrocarbons (PAH)	$\leq 1 \times 10^{-5}$	Once per year on each fluid blend	Grab/EPA Method 1654A	Ratio
	Sediment Toxicity Ratio	≤ 1.0	Once per year on each fluids blend	Grab(s)/ASTM E1367-92	Ratio

			Monitoring Requirement		
Discharge	Regulated & Monitored Discharge Parameter	Discharge Limitation/ Prohibition	Measurement Frequency	Sample Type/ Method	Recorded/ Reported Value
	Base Fluid Retained on Cuttings ($C_{16\text{-}18}$ internal olefin)	≤6.9 g/100 g wet drill cuttings	Once per day by grab sample, up to three sampling episodes per day	API Retort Method; 40 C.F.R. Part 423, Subpart A, Appendix 7	g/ 100 g wet drill cuttings
	Base Fluid Retained on Cuttings ($C_{12\text{-}14}$ ester)	≤9.4 g/100 g wet drill cuttings	Once per day by grab sample, up to three sampling episodes per day	API Retort Method; 40 C.F.R. Part 423, Subpart A, Appendix 7	g/ 100 g wet drill cuttings
	Biodegradation Rate	≤1.0	Once per year on each fluid blend	Grab(s)/ISO 11734:1995	Ratio
	Mercury in Stock barite	≤1.0 mg/kg (dry wt.)	Representative sample of each stock barite prior to drilling	EPA SWA 846 method 7471A	mg/kg
	Cadmium in Stock barite	≤3.0 mg/kg (dry wt.)	Representative sample of each stock barite prior to drilling	EPA SWA 846 method 6010B	mg/kg

[a] Toxicity test to be conducted using suspended particulate phase (SPP) of a 9:1 seawater:mud dilution. The sample shall be taken beneath the shale shaker, or if there are no returns across the shaker, the sample must be taken from a location that is characteristic of the overall mud system to be discharged.

[b] Sample shall be taken after the final log run is completed and prior to bulk discharge.

Appendix A Table 1: CORMIX Ambient Input Parameters and Constant Discharge Input Parameters

Parameter	Units	Value
Surface Density (ρ_s)	kg/m^3	1023.00
Density Gradient ($\Delta\rho$)	$kg/m^3/m$	0.163 (Linear)
Current Speed for < 200 m	cm/sec	5
Current Speed for > 200 m	cm/sec	15
Wind Speed	m/sec	4
Darcy-Wiesbach Friction Factor (f)		0.02
Legal Mixing Zone	m	100
Discharge Density	kg/m^3	1070.2
Horizontal Discharge Angle (σ)	degrees	0
Vertical Discharge Angle (θ)	degrees	- 90

Table 2: Produced Water Discharge Pipe Diameters

Range on Table (inches)	Model Input (inches)	Model Input (meters)
0 - 5	4	0.1016
>5 - 7	6	0.1524
>7 - 9	8	0.2032
>9 - 11	10	0.3048
>11 - 15	13	0.3302

Table 3: Produced Water Discharge Rates

Range on Table	Model Input	
Barrels per Day (bbl/day)	(bbl/day)	(m^3/sec)
0 - 500	500	0.0009
501 - 1000	1000	0.0018
1001 - 2000	2000	0.0037
2001 - 3000	3000	0.0055
3001 - 4000	4000	0.0070
4001 - 5000	5000	0.0090
5001 - 6000	6000	0.0110
6001 - 7000	7000	0.0122
7001 - 8000	8000	0.0147

Table 4: Eastern Gulf of Mexico OCS Critical Dilutions (Percent Effluent) for Discharges with a Depth Difference Between the Discharge Pipe Outlet and the Sea Floor of Greater than 12 meters and in Waters Less than 200 meters – For Toxicity Limitations for Seawater to Which Treatment Chemicals Have Been Added

Discharge Rate	Pipe Diameter (inches)				
(bbl/day)	>0" to 5"	>5" to 7"	>7" to 9"	>9" to 11"	>11" to 15"
>0 to 500	0.10	0.10	0.10	0.10	0.10
501 to 1000	0.19	0.19	0.19	0.19	0.19
1001 to 2000	0.31	0.31	0.31	0.31	0.31
2001 to 3000	0.38	0.38	0.38	0.38	0.38
3001 to 4000	0.45	0.45	0.45	0.45	0.45
4001 to 5000	0.51	0.51	0.51	0.51	0.51
5001 to 6000	0.62	0.61	0.61	0.59	0.59
6001 to 7000	0.70	0.69	0.69	0.68	0.67
7001 to 8000	0.78	0.77	0.76	0.75	0.74

Shaded cells represent undesirable operating conditions

Table 5: Eastern Gulf of Mexico OCS Critical Dilutions (Percent Effluent) for Discharges with a Depth Difference Between the Discharge Pipe Outlet and the Sea Floor of Greater than 12 meters and in Waters Greater than 200 meters For Toxicity Limitations for Freshwater to Which Treatment Chemicals Have Been Added

Discharge Rate	Pipe Diameter (inches)				
(bbl/day)	>0" to 5"	>5" to 7"	>7" to 9"	>9" to 11"	>11" to 15"
>0 to 500	0.10	0.10	0.10	0.10	0.10
501 to 1000	0.13	0.13	0.13	0.13	0.13
1001 to 2000	0.19	0.19	0.19	0.19	0.19
2001 to 3000	0.22	0.22	0.22	0.22	0.22
3001 to 4000	0.26	0.26	0.26	0.26	0.26
4001 to 5000	0.28	0.28	0.28	0.28	0.28
5001 to 6000	0.30	0.30	0.30	0.30	0.30
6001 to 7000	0.32	0.33	0.33	0.33	0.33
7001 to 8000	0.34	0.35	0.35	0.35	0.35

Shaded cells represent undesirable operating conditions

Table 6: Minimum Vertical Port Separation to Avoid Interference

Port Discharge Rate	Waters Less than 200 meters	Waters Greater than 200 meters
(bbl/day)	(meters)	(meters)
>0 to 500	3.0	3.0
501 to 1000	3.0	6.0
1001 to 2000	4.0	6.0
2001 to 5000	5.0	6.0
5001 to 7000	5.5	6.0
7001 to 10,000	6.0	6.0

Table 7: Critical Dilutions (Percent Effluent) for Toxicity Limitations for Seawater to which treatment chemicals have been added

Water Depth	Discharge Rate (bbl/day)	Pipe Diameter Range (actual diameter modeled)		
		>0 to 2" (1)	>2 to 4" (3)	>4 to 6" (5)
Less than 200 meters (shelf)	500 (0 to 1000)	0.29	0.81	1.23
	1000 (1000 - 2000)	0.31	0.86	1.34
	2000 (2000-4000)	0.34	0.88	1.43
	4000 (4000-8000)	0.33	0.98	1.48
	8000 (>8000)	0.29	1.02	1.68

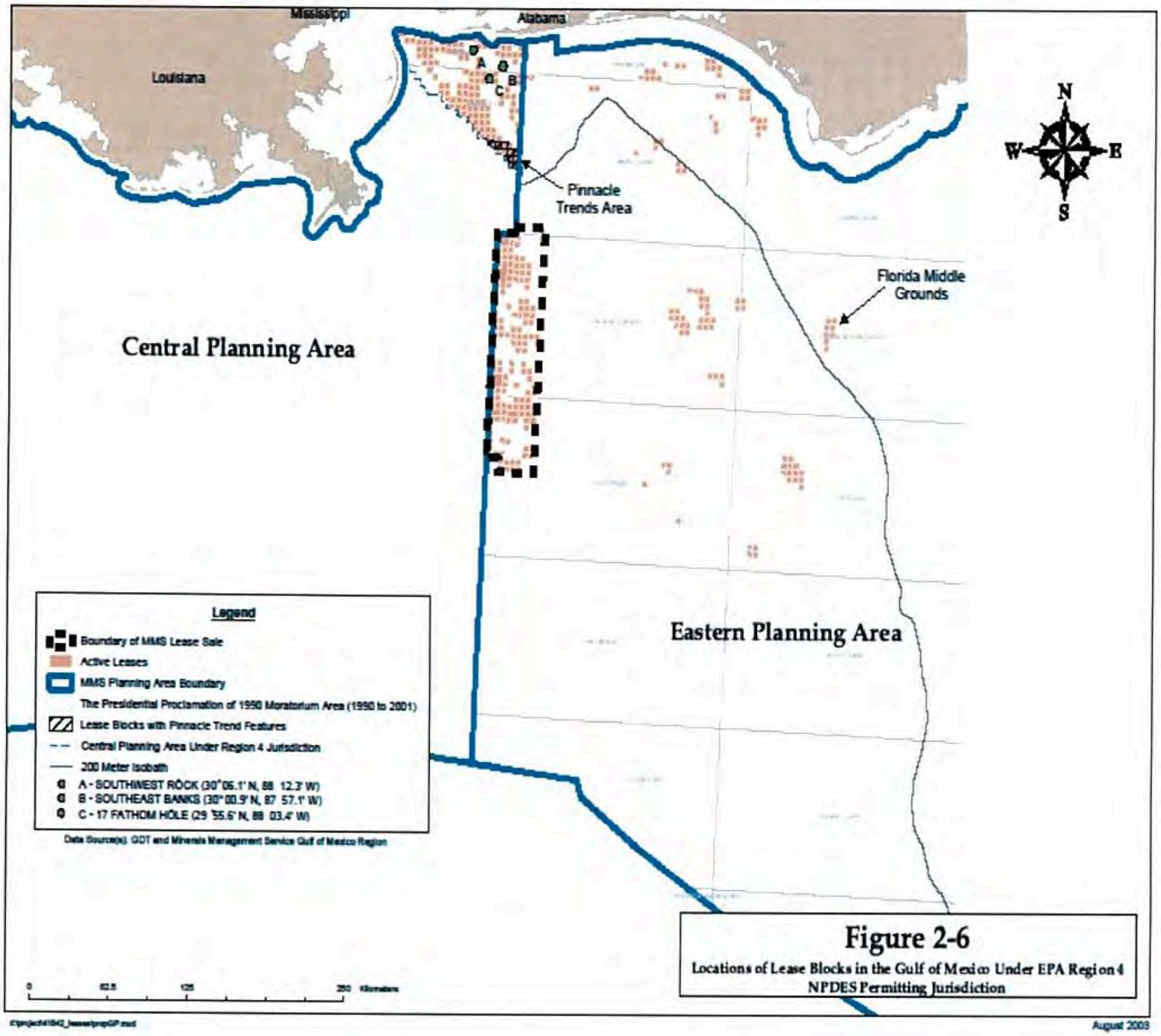
Deeper than 200 meters (slope)	**500 (0 to 1000)**	0.32	1.03	1.65
	1000 (1000-2000)	0.28	0.99	1.65
	2000 (2000-4000)	0.24	0.89	1.57
	4000 (4000-8000)	0.20	0.78	1.42
	8000 (>8000)	0.17	0.66	1.24

Table 8: Critical Dilutions (Percent Effluent) for Toxicity Limitations for Freshwater to which treatment chemicals have been added

Water Depth	Discharge Rate (bbl/day)	Pipe Diameter (actual diameter modeled)		
		>0 to 2" (1)	>2 to 4" (3)	>4 to 6" (5)
Less than 200 meters (shelf)	500 (0 to 1000)	0.57	3.85	16.9
	1000 (1000 - 2000)	0.44	3.20	16.7
	2000 (2000-4000)	0.34	2.50	5.76
	4000 (4000-8000)	0.35	1.86	4.66
	8000 (>8000)	0.30	1.36	3.52

Deeper than 200 meters (slope)	**500 (0 to 1000)**	0.67	11.6	29.9
	1000 (1000 - 2000)	0.40	6.69	29.1
	2000 (2000-4000)	0.26	3.57	15.9
	4000 (4000-8000)	0.22	1.96	9.14
	8000 (>8000)	0.19	1.06	4.67

Appendix B – Map Showing Areas of Biological Concern



Data Source(s): GDT and Minerals Management Service Gulf of Mexico Region

Figure 2-6

Locations of Lease Blocks in the Gulf of Mexico Under EPA Region 4 NPDES Permitting Jurisdiction

Date:

EPA Amendment to the Permit Fact Sheet at the Time of Issuance -
National Pollutant Discharge Elimination System (NPDES)
General Permit Number GEG460000

A. Substantive Changes from Draft Permit to Final Permit:

1. **Table of Contents:** The table, Produced Water (PW) Discharge Rates, was included in Appendix A of the permit as Table 3. This table was inadvertently omitted from the draft permit. The other tables in Appendix A were renumbered, accordingly.

2. **Part I.A.1**: The description of coverage area was revised, as follows, to more accurately denote the general permit coverage area.

"The general permit coverage area is Federal Waters (Federal Waters are those water that are 3 Nautical Miles seaward of the baseline marking the seaward limit of inland waters or, if there is no baseline, the line of ordinary low water along the portion of the coast that is in direct contact with the open sea) of the Gulf of Mexico (1) seaward of the 200 meter depth contour offshore of Alabama in the Destin Dome lease block, (2) seaward of the 200 meter depth contour offshore of Florida, and (3) in the Viosca Knoll and Mobile lease blocks offshore of Mississippi and Alabama.

3. **Part I.A.4 – Notification Requirements, pages 15-16**: Item w. was added, which requires operators to state their intention to participate in the alternative Industry-wide Study regarding Whole Effluent Toxicity (WET) Testing of Well Treatment, Completion and Workover (WTCW) Fluids (Part I.B.6.b, page 50). Language was also added to clarify operator options for submitting written, rather than electronic, Notices of Intent (NOI) in the event the EPA's system receiving electronic submittals is not operational.

4. **Part I.B.1.c.i – Drill Cuttings, page 24:** The word "concentrations" was added to the sentence in order to clarify that operators must keep an inventory of the total volume, total mass as well as concentrations of constituents added for each well.

5. **Part I.B.2.b.iv - Drill Cuttings, page 27:** The first sentence was corrected to state that the limits for mercury and cadmium in the section apply to drill cuttings and not to drilling fluids.

6. **Part I.B.2.c - Drill Cuttings, page 28:** The title for this section was corrected to clarify that this part of the permit includes limits as well as monitoring conditions for drill cuttings generated from non-aqueous based drilling fluids.

7. **Part I.B.3.b.ii - Produced Water, pages 34-36**: This section was simplified by deleting the superfluous reference to the limiting permissible concentration (LPC), which is the same as the "No Observed Effect Concentration." Also, in order to ensure representative samples were obtained, new language was added to clarify that grab samples must be obtained once each discharge during a time of the maximum effluent flow rate.

8. **Part I.B.6.a. - Well Treatment, Completions and Workover Fluids, page 42**: The sentence pertaining to submittal of some information as "Confidential Business Information" (CBI) was deleted. Permittees cannot claim information on the specific chemical composition of any additives used as CBI. Also, the language pertaining to the toxicity testing for well treatment completion and workovers fluids was moved to subsection b. (i.e., section for monitoring requirements), since the permit requirement does not require operators meet a permit limit.

9. **Part I.B.6.b -Well Treatment, Completions and Workover Fluids, page 50:** Language pertaining to the Industry-wide Alternative WET Testing was revised to clarify that the study would gather effluent data from wells discharging well treatment, completion, and/or workover fluids from various well depths. The timeframe to submit the study plan was extended to up to 18 months in order to agree with the language in the EPA Region 6 offshore oil and gas general permit (GP).

10. **Part I.B.10.b - Miscellaneous Discharges pages 54-55:** The language was revised to clarify that operators must monitor for free oil during times when observation of a visible sheen is possible, unless monitoring is performed using the static sheen test. Also, to ensure representative samples are obtained, language was added to specify that grab samples shall be taken for toxicity testing of miscellaneous discharges when the maximum flow is being discharged.

11. **Part I.B.11.a and c - Miscellaneous Discharges of Freshwater and Seawater to Which Chemicals Have Been Added, pages 56-57**: The language was revised to clarify that operators must monitor for free oil during times when observation of a visible sheen is possible, unless monitoring is performed using the static sheen test. Also to ensure representative samples are obtained, language was added to specify that grab samples shall be taken for toxicity testing of miscellaneous discharges when the maximum flow is being discharged.

12. **Part I.D.3.d. - Monitoring Requirements for facilities with Cooling Water Intake Structures, pages 72-75:** Language was revised to change the monitoring frequency from weekly to monthly and to clarify that "monthly" means at least once per month, even if the facility is at the location for less than one full month. Also, language was added to allow operators, after 24 months of monitoring at one location, the option to meet the requirements of annual reporting per 40 Code of Federal Regulations (CFR) § 125.137, using data from the Southeast Area Monitoring and Assessment Program (SEAMAP).

13. **Part II.13 - Signatory Requirement on page 100:** The final permit contains a requirement that any person signing the NOI, Notice of Termination (NOT), and any reports (including any monitoring data) submitted to the EPA, in accordance with the proposed permit must include the certification statement in Part II. This certification statement includes an additional sentence than has not previously been included in this NPDES general permit. The sentence reads: "I have no personal knowledge that the information submitted is other than true, accurate, and complete." The EPA believes this addition to the certification language is necessitated by the recent decision in U.S. v. Robison, 505 F.3d 1208 (11th Cir. 2007). In Robison, the Court of Appeals struck down the defendant's conviction for a false statement on the grounds that the certification language did not require him to have personal knowledge regarding the truth or falsity of the information submitted to the EPA. Rather, the court reasoned that the EPA's certification required the defendant to certify, in part, that he made an inquiry of the persons who prepared and submitted the information and based on that inquiry, the information was accurate to the best of his knowledge. The court further reasoned that there is no requirement in the certification that the person attest to his personal knowledge regarding the information submitted. The government had argued at trial that the defendant had personal knowledge that the facility had committed violations. As a result, the EPA feels it is necessary to include language which clarifies that the signatory is certifying that he or she has no personal knowledge that the information submitted is other than true, accurate, and complete.

14. **Part III.A - Monitoring Reports page 107:** The language was changed to allow operators more time to prepare and submit monitoring reports. Operators now have up to the 58th day following the quarterly reporting period to submit a Discharge Monitoring Report (DMR).

15. **Part V.A.15 - Whole Effluent Toxicity Testing, pages 151- 160:** Language was added to clarify the frequency of toxicity testing for WTCW fluids. The new language also clarifies that a failure of a WET test for these discharges is not a violation of the permit and states that

based on test results, a toxicity reduction evaluation and/or toxicity identification evaluation may be required.

16. **Part V.B – Definitions, page 174:** The definitions for “Toxicity Reduction Evaluation” and Toxicity Identification Evaluation” were added.

17. **Part III.B – Section 7(a) Endangered Species Reopener -** The following language was added to notify permittees that the permit may be reopened if the National Marine Fisheries Services (NMFS) Final Biological Opinion for the Gulf of Mexico (GOM) dictates additional permit conditions to protect endangered or threatened species under the Endangered Species Act:

> “Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA), EPA is required to consult with the U.S. Fish and Wildlife Service (FWS), and the National Marine Fisheries Service (NMFS) and ensure that “agency action” such as the issuance of this Clean Water Act (CWA) National Pollutant Discharge Elimination System (NDPES) permit does not jeopardize the continued existence of any endangered or threatened species or result in destruction or adverse modification of the critical habitat of such species. Section 7(d) of the ESA requires that, after initiation of consultation under Section 7(a)(2), the Federal agency “shall not make any irreversible or irretrievable commitment of resources with respect to the agency action which has the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures which would not violate subsection (a)(2) of this section.” The EPA has not completed consultation with the NMFS in connection with issuance of this permit. Accordingly, in order to ensure compliance with Section 7(a)(2) and 7(d) of the ESA, this permit may be revoked or reopened and modified at any time during the life of the permit if further consultation with NMFS results in the identification of reasonable and prudent alternative measures that are necessary to avoid jeopardy to an ESA threatened or endangered species or adverse effects to its critical habitat. Any such reasonable and prudent alternative measures may be added as conditions to this permit through the reopening and modification process.”

18. **Part III.B. - Ocean Discharge Criteria Reopener –** The following reopener was added, as required by 40 CFR §125.123(d)(4), to address any additional permit conditions, if necessary, to comply with Section 403 of the CWA:

    > “In addition to any other ground specified herein, this permit shall be modified or revoked at any time if, on the basis of any new data, the director determines that continued discharges may cause unreasonable degradation of the marine environment.”

19. **Fact Sheet**: Language pertaining to the Paperwork Reduction Act and the Impact on Small Businesses was updated, as follows:

> **Paperwork Reduction Act.** The information collection required by this permit will reduce paperwork significantly through implementation of electronic reporting requirements. The EPA is working on an electronic notice of intent (eNOI) system which will allow

applicants to file their NOIs online. The EPA estimates that it takes 10 to 15 minutes to fill in all information required by the eNOI for each lease block. It also takes much less time to add, delete, or modify eNOIs. In addition to the eNOI system, the EPA will incorporate an electronic discharge monitoring report (NetDMR) requirement into the permit. The time necessary for NetDMR preparation will be much less than that for paper DMR preparation. Both electronic filing systems will significantly reduce the mailing costs. The information collection activities in this permit is authorized by OMB, see ''ICR Supporting Statement Information Collection Request for National Pollutant Discharge Elimination System (NPDES) Program (Renewal) (EPA ICR No. 0229.22, OMB Control No. 2040-000)" with the exception if cooling water intake structures for new facilities which are addressed under a separate ICR, "Cooling Water Intake Structures at Phase III Facilities" (OMB Control No. 2040–0268, EPA ICR No. 2169.05). The ICR for Cooling Water Intake Structures at Phase III facilities expired on July 31, 2017. EPA is in the process of submitting information to OMB to have this ICR approved.

Impact on Small Businesses. EPA analyzed the potential impact of today's permit on small entities and concludes that this permit reissuance will not have a significant impact on a substantial number of small entities. All changes from the 2015 permit results in either no or negligible incremental cost and no or negligible operational and/or economical burdens. In addition, there are not a substantial number of small entities affected by this permit as EPA understands that there are few, if any, small businesses that are owners or operators of facilities subject to this permit. EPA did not conduct a quantitative analysis of impacts for this permit, as that would only be appropriate if the permit may affect a substantial number of small entities. Additionally, EPA previously found tha the promulgation of the Offshore Subcategory guidelines on which many of the permit's effluent limitations are based, did not have significant impact on a substantial number of small entities; see 48 FR 12454 dated March 4, 1993, page 12492. The permit also contains limits based on CWA Section 403 (c), Ocean Discharge Criteria Evaluation, but these limits did not change from those in the 2015 permit based on that analysis.

B. Public Comments Received during the Public Comment Period:

The public notice announcing the proposed reissuance of EPA Region 4's General NPDES GP for Offshore Oil and Gas in the eastern GOM, No. GEG460000, as well as the Draft Environmental Assessment (DEA) and other support documents, was published at 81 Federal Register 55198 on August 18, 2016. The announcement was also published in six local newspapers in and along the Gulf coast. EPA Region 4 received six comment letters and three email messages. Written comments received during the comment period were considered in the formulation of a final determination regarding Region 4's final action on the reissuance of the general permit. Written comment on the draft GP, Fact Sheet, DEA, and CWA Section 403 documents are paraphrased below, along with EPA's response to each comment.

Comments from the Offshore Operators Committee (OOC):

Comment 1: The OOC requests additional language be added pertaining to notification requirements for e-reporting.

Response to Comment 1: Requested change made. The change clarifies that written NOIs will continue to be submitted beyond the stated date for transition to e-Reporting if the e-NOI system is not operational.

Comment 2: The OOC requests acceptance of certification letter, the opportunity to have input during the Network DMRs (NetDMR) development process, the ability to BETA test the system, electronic Notices of Intent, a copy of instructions be provided for NetDMR and No Data Indicator (NODI) codes and date alignment for accepting written NOI submittal.

Response to Comment 2: Partial change made. Permit language was changed to clarify when written NOIs are accepted. The EPA developers of NetDMR have been in contact with Region 6 in order to share lessons learned. The EPA will not be able to accept a Certification Letter in lieu of required electronic submittals. A link is provided in the permit for NetDMR instruction and NODI codes.

Comment 3: The OOC requests that the EPA provide a 60-day submittal for Quarterly DMRs.

Response to Comment 3: Change was made. The permit now allows operators up to the 58th day following the quarter reporting period to submit a DMR.

Comment 4a: The OOC request a text revision to provide clarity, alignment and consistency with GMG290000 (Part I.B.12) permit requirements.

Response to Comment 4a: No change made. The current language is clear and aligns with permit language developed by the EPA Headquarters and Region 9 for the Region 9 Offshore Oil and Gas GP.

Comment 4b: The OOC requests changes to include language that an operator is not required to submit annual information if the operator is participating in the Part I.B.6.b alternative study; which would include this information and for alignment with Part I.B.6 of the permit for discharges.

Response to Comment 4b: No change made. Operators will submit annual information even when enrolled in the study. The study has not been designed at this time.

Comment 4c: The OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the Safety Data Sheet (SDS) for relevant additives.

Response to Comment 4c: All operators under the Region 4 Offshore Oil and GP will have to comply with the permit requirements for submitting information on additives and chemical used in WTCW operations until the EPA and the industry develops and implements the alternative industry-wide study to investigate the composition and toxicity of these discharged fluids. This process could take months to complete.

EPA R4 disagrees with the use of information on an SDS as a substitute for keeping detailed information on chemicals being used because this information would not be sufficient in the event of enforcement investigations by the EPA inspectors or in order to fully inform future permitting decisions. Also see the EPA's response 4d and 5a, below.

Comment 4d: The OOC requests that the disclosure requirement allow for the use of a "systems-style" disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications), consistent with the approach that has been adopted for use in certain jurisdictions and by FracFocus. System-style disclosure would satisfy the objectives of the permit revision while potentially reducing the necessity for companies to make CBI claims on such disclosures. The process known as system-style disclosure lists all known chemical constituents in a fluid (or fluids, in the case of multiple disclosed applications), but decouples those constituents from their parent additives, thus improving protection of the proprietary chemistry used in hydraulic fracturing while promoting greater disclosure. At the same time, reverse engineering of product formulas may still be possible with the use of a systems-style disclosure.

Response to Comment 4d: Although the use of a systems-style disclosure of the chemical composition would provide some helpful information, it would not be sufficiently detailed to examine potential environmental impacts of discharges with a high degree of certainty. Any such evaluation would be subject to interpretation and easily challenged. As the OOC pointed out in their above comment, SDS sheets could still be used to reverse engineer product formulas and would not provide a higher degree of protection.

Comment 4e: The OOC requests that service providers be permitted to disclose the trade secret/CBI information directly to the EPA rather than requiring disclosure through the operators.

Response to Comment 4e: Regarding submittal of CBI, such claims are not allowed regarding permit application information (see CWA § 402((j). As provided in 40 CFR § 122.28(b)(2), an NOI "fulfills the requirements for permit applications for purposes" of §§ 122.6, 122.21, and 122.26. See also, 40 CFR § 122.7, which provides that claims of confidentiality will be denied for permit applications, permit and effluent data and information required by NPDES application forms, including information submitted on the forms and any attachments. The information at issue is also ineligible for confidential treatment because it meets the definition of "effluent data" in 40 CFR § 2.302(a)(2). Effluent data is not eligible for confidential treatment pursuant to 40 CFR §§ 2.302(e) and (f). Facilities seeking to discharge pollutants into waters of the United States must be prepared to disclose information regarding the composition of their proposed discharge and such information must be made available to the public.

Comment 4f: The OOC requests deletion of the information requirement for biocide.

Response to Comment 4f: Region 4 needs information on biocides to determine the extent to which these substances may be toxic to the aquatic environment near the vicinity of the discharge and to determine whether any changes to the permit's current limits are needed to ensure that the permit is sufficiently protective of the environment.

Comment 5a: The OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives.

Response to Comment 5a: Some changes were made. The current language is clear and aligns with permit language developed by Region 9 for the Region 9 Offshore Oil and Gas GP. The EPA R4 disagrees with the use of information on a SDS as a substitute for keeping detailed information on chemicals being used because this information would not be in a form that would be useful for environmental analysis or in the event of enforcement investigations by the EPA inspectors. For instance, in the event of a toxicity test failure, the EPA would have immediate access to the specific chemical concentrations of probable toxicants in the effluent.

The SDSs are designed to provide information on materials in the event of worker exposure. The SDS includes information such as the properties of each chemical; the physical, health, and environmental health hazards; protective measures; and safety precautions for handling, storing, and transporting the chemical. Sections 1 through 8 contain general information about the chemical, identification, hazards, composition, safe handling practices, and emergency control measures. Sections 9 through 11 and 16 contain other technical and scientific information, such as physical and chemical properties, stability and reactivity information, toxicological information, exposure control information. Although Section 3 of an SDS requires information on a chemical's composition, if a trade secret is claimed, a company can omit the specific chemical identity and/or exact percentage (concentration) of composition.

The EPA R4 does agree with the OOC's suggestion to report the concentration because this information would be useful and it has been added to the permit.

5b: The OOC requests that the disclosure requirement be for composite chemical composition of all additives in the drilling fluids so as to conform to the system-style disclosure that has been adopted for use in many jurisdictions, including by the U.S. Department of Interior, and by "FracFocus."

Response to Comment 5b: No change made. See Responses to comments 4c, 4d and 5a.

Comment 6a: The OOC is requesting that WTCW Fluids Outfalls be combined into a single outfall as it is under the current permit. There is no reason to separate these outfalls. WTCW reporting requirements will provide detailed information on each discharge.

Response to Comment 6a: No change made. Requiring operators to report well treatment, well completions, and well workover fluids under separate outfalls does not pose a burden and is necessary for the EPA to more easily identify any possible toxic effluents from any of these three types of operations.

Comment 6b: The OOC is requesting an extension of the DMR reporting due date from the 28th day of the first month after the Quarter ends to the second month. Allowing OOC members more time to Quality Assurance/Quality Control the documents will ensure accurate information is reported to the EPA.

Response to Comment 6b: Change made.

Comment 6c: The OOC also requests that language be added to the permit addressing longer term issues (e.g. a Government Shutdown) where there is the possibility of a longer period of system unavailability (longer than a system refresh or update) and requests a grace period of 60 days from the date the system is back up and functioning.

Response to Comment 6c: Government shutdowns have historically been very infrequent and not an issue the EPA expects to be a burden for reporting.

Comment 7: The OOC is requesting insertion of the phrase “or more recently approved methods” to Section I.B.1.b for consistency and alignment with GMG290000 where new methods are approved during the permit term.

Response to Comment 7: Change made. This revision will allow use of new analytical methods that are approved by the EPA during the permit term.

Comment 8a: The OOC requests text changes for consistency and alignment regarding record keeping requirements in Part I.A.4.u and Part II.C.5 of the permit.

Response to 8a: The language in Part I.A.4.u. was changed to clarify that the length of time operators must keep records is 5 years, which supersedes the general requirements for all NPDES permits in Part II.C.5 for operators to retain records for only three years.

Comment 8b: The OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives.

Response to Comment 8b: See Comments 4c, 4d and 5a.

Comment 8c: The OOC requests that the disclosure requirement allows for the use of a systems-style disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications) consistent with the approach that has been adopted for use in some jurisdictions and by “FracFocus.”

Response to Comment 8c: See responses to comments 4c, 4d and 5a, above**.** The priority pollutant reporting requirements are part of the permits (no priority pollutants except in trace amount limits), and while some of the OOC's requests are appropriate for the chemical additive monitoring and study requirements, they do not appear to be adequate for this limit and reporting requirement**.**

Comment 9a: The OOC requests that the Chronic WET testing requirements for WTCW fluids be moved to Part I.B.6.b to provide additional clarity that these are not limitations The requirements shown under existing Part I.B.6.a.iv are monitoring only requirements.

Response to Comment 9a: Changes made. The permit language was moved from page 42 to page 45.

Comment 9b: The OOC requests the EPA verify the meaning of the language "lasting four or more consecutive days". A plain reading indicates this means a discharge to the ocean that is continuous over 24 hours per day and over four or more days.

Response to Comment 9b: Language was included to clarify that the meaning of a discharge "lasting four or more consecutive days" is a discharge that occurs for any amount of time during a 24- hour timeframe over four or more consecutive days

Comment 9c: For Chronic WET requirements for WTCW fluids, clarify sample frequency. The OOC requests the EPA adopt a frequency of monthly.

Response to Comment 9c: The permit was changed to clarify that operators must take a grab sample at least once per month when the maximum flow rate of WTCW fluids will be discharged.

Comment 9d: The OOC requests that certain table reference corrections be incorporated into the permit.

Response to Comment 9d: Changes made.

Comment 9e: The OOC requests adding "or calculated" to allow operators the flexibility to calculate discharge densities based on the average of all the fluids planned to be discharged. Discharge densities can vary throughout the discharge. Being able to calculate a discharge density will allow operators to run CORMIX prior to the discharge to calculate the critical dilution factor. This will allow operators to identify the size of sample containers needed to obtain the appropriate volume of sample needed to run the toxicity test.

Response to 9e: No change made. The EPA does not see a need for calculated densities. For our purposes, a direct measurement is preferred and ensures consistency and accuracy.

Comment 9f: The OOC requests removing the density ranges for well treatment, completion, and workover fluids as the proposed ranges may not cover the full range of densities of these types of fluids used.

Response to Comment 9f: No change made. Any changes outside the density range should be noted on the electronic DMR submittal.

Comment 9g: The OOC requests the EPA consider requiring acute toxicity testing in lieu of chronic toxicity testing

Response to Comment 9g: The EPA disagrees with the use of acute testing requirements in lieu of chronic toxicity requirements. Chronic testing is more sensitive and is appropriate for longer term discharges.

Comment 10a: The OOC requests that these Acute WET requirements for WTCW fluids be moved to Part I.B.6.b to provide additional clarity that these are not limitations. The requirements under Part I.B.6.a.v are monitoring only requirements.

Response to Comment 10a: Change made.

Comment 10b: The OOC requests the EPA add clarifying text as shown for the less than four-day acute WET test trigger.

Response to Comment 10b: Partial change made. The EPA clarified that operators must take a grab sample at least monthly when the maximum flow rate of WTCW fluids is being discharged.

Comment 10c: The OOC requests that referenced corrections be incorporated into the permit regarding the CORMX Modeling parameters.

Response to Comment 10c: Changes made.

Comment 10d: The OOC requests adding “or calculated” to allow operators the flexibility to calculate discharge densities based on the average of all the fluids planned to be discharged. Discharge densities can vary throughout the discharge.

Response to Comment 10d: No change made. See response to comment 9e.

Comment 10e: The OOC requests removing the density ranges for well treatment, completion, and workover fluids as the proposed ranges may not cover the full range of densities of these types of fluids used. As the EPA stipulates that the operator must use the discharge density, the range is not necessary and could unduly limit the operator.

Response to Comment 10e: No change made. See response to comment 9f.

Comment 11a: The OOC requests updating the references for “additional toxicity testing requirements” to be consistent with the request to change language regarding acute and chronic WET testing of WTCW fluids.

Response to Comment 11a: No change made. See response to comments 11b-11d.

Comment 11b: Consistent with comments to Part I.A.4.u, the OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives.

Response to Comment 11b: No change made. See responses to comments 4c, 4d, and 5a.

Comment 11c: The OOC requests that the disclosure requirement allow for the use of a systems-style disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications) consistent with the approach that has been adopted for use in some jurisdictions and by "FracFocus."

Response to Comment 11c: No change made. See **r**esponses to comments 4c, 4d and 5a.

Comment 11d: The OOC requests that service providers be permitted to disclose the trade secret/CBI information directly to the EPA rather than requiring disclosure through the operators. Such independent disclosure is necessary in order to protect the substantial investment of time and resources that service providers make in developing proprietary products.

Response to 11d: No change made. See responses to comments 4c, 4d, and 5a.

Comment 11e: The OOC is requesting that the EPA Region 4 incorporate the OSHA Hazard Communication trade secret criteria by reference in the proposed GEG460000 GP.

Response to Comment 11e: No change made. The EPA disagrees with allowing submittal of information on an SDS as a substitute for keeping detailed information on chemicals being used because this information would not be sufficiently detailed to be useful for environmental analysis of the discharges or in the event of enforcement investigations conducted by the EPA inspectors; see response to comment 4d and 5a. With respect to CBI concerns, see response to Comment 4e.

Comment 12a: The OOC is requesting that "active" be struck. It is unclear what is intended by "active", and could, for instance, unintentionally exclude well jobs associated with initial completion and with abandonment. It is enough to simply reference well jobs where WTCW fluids will be discharged.

Response to Comment 12a: The word "active" has been deleted.

Comment 12b: The OOC requests striking "of varying depths (shallow, medium depth and deep depths)" and replacing simply with "discharging well treatment, completion, and/or workover fluids". It's unclear what the EPA means by this term (is it water depth, well depth to reservoir, discharge depth?)

Response to Comment 12b: No change made. The EPA wants to ensure that samples are representative of the various well depths. “Well depth” has been added for clarification to the permit.

Comment 12c: The OOC is requesting changes to the permit language to clarify that a financial commitment to participate in the Industry-Wide Study Alternative satisfies the chronic and acute monitoring requirements and the WTCW Reporting Requirements of the permit, and ensure consistency with prior approved industry studies. Further, the change allows the option for new permittees to benefit from the industry-wide study after initiation and completion of the study.

Response to Comment 12c: The EPA has worked with the industry on a number of similar industry-wide studies as alternatives to individual monitoring. The Agency prefers to allow the industry flexibility to determine how individual companies participate. Thus, the final permit does not address how operators participate in any industry-wide study that is conducted., which will be developed jointly between Region 4, EPA Headquarters and the OOC.

Comment 13: The OOC recommends removing WTCW fluid discharges lasting four or more days from this section of the permit and adding a section specific to this type of discharge to ensure clarity, as presented in comment 14.

Response to Comment 13: A partial change was made. Chronic toxicity testing requirements apply to WTCW fluid discharges lasting four or more days. However, this is a monitoring only requirement and not an effluent limit. Clarifying language was added to Part V.A.15(a) to differentiate the monitoring chronic testing requirements for WTCW fluids from the chronic toxicity testing limits that apply for other waste streams.

Comment 14a: There are some requirements in Part V.A.15.a that are not applicable to the “monitoring only” requirements for WTCW fluid discharges lasting four or more days. The OOC is proposing the addition of this new section to only capture the requirements from Part V.A.15.a applicable to “monitoring only”. The OOC has removed all language regarding permit violations. The OOC is proposing to strike the DMR language requiring reporting pass/fail due to this being a monitoring only requirement.

Response to Comment 14a: A clarification of violation language for these discharges was added. Test results will still be reported as pass or fail.

Comment 14b: The OOC has also requested clarifying language to indicate that repeat samples for invalid test results are only required if the discharge is still occurring and the additional sample can be obtained.

Response to Comment 14b: The permit now clarifies that retesting can only be done if an additional sample can be obtained.

Comment 14c: The OOC requests not including a frequency for testing in this section.

Response to Comment 14c: No change made. Testing frequency is needed to ensure a representative sample is obtained.

Comment 15a: The OOC is requesting to renumber this section and make changes to only capture the requirements applicable to "monitoring only."

Response to 15a: The permit is clear regarding where to find the appropriate acute and chronic WET testing requirements for WTCW fluids.

Comment 15b: The OOC requests removing the language at V.A.15.b.ii as applied to WTCW fluids. The frequency for testing has been addressed above under our comments for I.B.6 for well fluids. Additionally, the OOC states that Part V.A.15.b.ii "standard" frequency requirements, if left in the permit, would conflict with Part I.B.6 - to apply a recurring test frequency, and associated reduction criteria to "monitor only", short term, well specific fluid discharges is extremely confusing. The frequencies for this testing are adequately specified at I.B.6.

Response to Comment 15b: Partial changes made. Part V.15 was changed to clarify that for WTCW fluid discharges, monitoring only requirements apply. Test results shall be reported as pass or fail. A failure will not be considered a violation of the permit. The frequency was changed to agree with the frequency in Part I.B.6, which allows permittees to request reduced monitoring after the first year of the permit.

Comment 16: The OOC requests that the baseline study requirements be removed from the permit for operators that participate(d) in the 2012 Industry-Wide Source Water Biological Baseline Characterization Study (SWBBCS). This study was approved by US EPA Region 4 on 2/27/12.

Response to Comment 16: No change made. The EPA disagrees that new offshore operators should automatically be deemed to be in compliance with the baseline study requirements of the Cooling Water Intake Structure rule for New Sources based on previously submitted and now dated results of the Industry-Wide Study completed in 2012.

Comment 17: The OOC requests that visual inspections be required monthly for New non-Fixed Facilities. This request is backed by visual inspection data obtained in EPA Region 4. The observed rate of growth of biological material does not result in significant change over a one-week period. Changes are hard to discern over a monthly period. For a deep-water facility (does not employ a sea chest) that performed entrainment monitoring under the EPA Region 4 NPDES permit, the 2015 average monthly rate of growth expressed as % screen coverage was 2.5% with a monthly range of 0-6% growth.

Response to Comment 17: A change was made to requiring monitoring at least once per month (instead of weekly, as provided in draft permit) during the monitoring periods. For instance, operators must monitor at least once per month even if they are on location less than one month.

Comment 18: The OOC requests that visual inspections be required monthly for new fixed facility that do not employ sea chests as intake structures. This request is backed by visual inspection data obtained in EPA Region 4. The observed rate of growth of biological material does not result in significant change over a one-week period. Changes are hard to discern over a monthly period. For a deep-water facility (does not employ a sea chest) that performed entrainment monitoring under the EPA Region 4 NPDES permit, the 2015 average monthly rate of growth expressed as % screen coverage was 2.5% with a monthly range of 0-6% growth.

Response to Comment 18: See response to comment 17, above.

Comment 19a: The OOC strongly objects to the continued requirement to conduct ongoing entrainment monitoring (after initial two-year biweekly sampling). The OOC requests that the requirements for entrainment monitoring be removed from the permit for operators that participate(d) in the 2014 entrainment monitoring study. This request is further supported by EPA's own finding in the permit's Environmental Assessment, specifically, per section 6.2 of the DEA: *"EPA Region 4 has determined the study fulfills the requirements of the 2010 General Permit and demonstrated that cooling water intake structures on offshore oil and gas facilities have no significant impact on the selected species investigated."* As the species studied were reliable indicators for overall entrainment, and given no species of concern were caught within the 60,376 individuals identified from 1,515 tows spread throughout the 24-month sampling period, the Agency has no basis to continue to require costly on platform monitoring at affected facilities. The OOC is therefore petitioning the EPA per their proposed language to reduce monitoring frequency to "none required". Summarizing and amplifying information previously submitted, the OOC suggests that Region 4 accept the results of the 24-month entrainment monitoring study completed for Region 4 as meeting, for the participating companies, the corresponding Region 4 requirement.

Response to Comment 19a: The EPA agrees with and has incorporated the OOC's proposed language, pursuant to which, after 24 months of entrainment monitoring, new fixed facilities that do not employ sea chests as intake structures may submit SEAMAP data annually to fulfill the requirements of 40 CFR § 125.137.

Comment 19b: As alternative to ongoing monitoring (after the initial 2 years of sampling) at affected facilities, the OOC suggests using the SEAMAP database to establish the seasonality of entrainment potential, as required by 40 CFR § 125.137. Using the SEAMAP database for entrainment risk assessment is actually preferable to platform specific monitoring because:

- Data are collected and maintained over the long term, using consistent methodology for all sites, ensuring comparability of data over time
- The existing SEAMAP database already provides an assessment of seasonality of entrainment risk (as required by 40 CFR § 125.137) which can be periodically updated as new data are added to detect changes in risk over time.
- SEAMAP larval data could be selected for most common species in each region
- Approach is cost effective and appropriate to the low level of risk demonstrated in the 24-month Entrainment Monitoring Study and in a peer-reviewed study of entrainment risk

from much larger water volumes in depths of 20-60 m where egg and larval densities are much higher.

Response to Comment 19b: The EPA agrees with and has incorporated the OOC's proposed alternative language, pursuant to which, after 24 months of entrainment monitoring, new fixed facilities that do not employ sea chests as intake structures may submit SEAMAP data annually to fulfill the requirements of 40 CFR § 125.137.

Comment 20: The OOC requests that visual inspections be required monthly for new fixed facilities that employ sea chests as intake structures. This request is backed by visual inspection data obtained in EPA Region 4. The observed rate of growth of biological material does not result in significant change over a one-week period. Changes are hard to discern over a monthly period. For a deep-water facility (does not employ a sea chest) monitored under the EPA Region 4 NPDES permit, the 2015 average rate of growth expressed as % screen coverage was 2.5% with a monthly range of 0-6% growth.

Response to Comment 20: See response to comment 17, above.

Comment 21: The OOC requests changes to provide alignment and consistency between the text of the permit and the Tables in Appendix A. In addition, the OOC requests that all references to these tables be updated within the permit text. Table 3.A is listed in the Table of Contents, but not provided in the Appendix nor referenced in the text. Appendix A now includes four additional tables. With the addition of Table 3 into the Appendix, all other tables have been shifted in position. The OOC presents no opposition to the addition of Table 3; however, the OOC claims that the addition of Tables 6, 7 and 8 are unwarranted and/or has replaced tables that appear to be omitted as an oversight (see comments below).

Response to Comment 21: The text was revised so that it now accurately refers to tables in Appendix A.

Comment 22: The OOC requests correction of the misspelling of the word "Produced."

Response to Comment 22: The typographical error was corrected.

Comment 23: The OOC requests correction of the misspelling of the word "Produced." The OOC also states that the Results portion of Table 3, along with Figures 1 and 2 subsequently provided in the Appendix, might be better served in a supplemental document or fact sheet to the permit, as further comment may be necessary. This paragraph describes conditions that, based on uncertainty factors (Table 6), prompted the "adjusted" critical dilution tables provided as Tables 7 and 8. However, further information is needed regarding the uncertainty factors and how they are applied. In addition, references to Table 3 within the permit text should be revised or deleted.

Response to Comment 23: The typographical error was corrected. However, the tables were not moved.

Comment 24: The current permit references use of Table 5 by permittees with vertically aligned multiple discharge ports (vertical diffusers) and requirements for minimum port separation; however, this table has been omitted from the draft permit

Response to Comment 24: Change made. Corrections were made in the permit regarding references to Tables 4 and 5.

Comment 25: The OOC requests the deletion of Table 6 in the draft permit, which replaces critical dilution tables for chemically treated seawater and provides uncertainty factors for model simulations presented in Tables 4 and 5. The OOC states it is unclear how these uncertainty factors were calculated and how they are applied. Therefore, the addition of this table is confusing and unwarranted. In addition, the OOC requests the addition of the minimum vertical port separation table, which appears to have been deleted as an oversight from the draft permit. References to Table 6 within the permit text should be revised or deleted accordingly.

Response to Comment 25: The text was revised so that it now accurately refers to tables in Appendix A. The table "Vertical Port Separation to Avoid Interference", was inadvertently omitted in the draft GP, and was added to Appendix A.

Comment 26: The OOC requests the deletion of Tables 7 and 8 in the draft permit, which replace critical dilution tables for chemically treated waters and provide the "adjusted" critical dilution tables using uncertainty factors from Table 6. The OOC states it is unclear if the adjusted tables are to be used by the permittee in lieu of Tables 4 and 5 or what purpose these tables serve, as Tables 6, 7 and 8 are not discussed within the main text of the permit or the Appendix in this regard. In addition, the OOC requests the addition of the chemically treated seawater and freshwater critical dilution tables, which appear to have been deleted as an oversight from the draft permit. Reference to Table 7 within the permit text is made with regard to chemically treated freshwater. No mention of Table 8 is made within the text. References to these tables within the permit text should be revised or deleted accordingly.

Response to Comment 26: All tables referenced in Appendix A are mentioned in the text. Revisions were made so now all tables are included and labeled correctly.

Comment 27: The OOC requests that discharges of cement used for testing and unused cement slurry be authorized by adding a new discharge under Miscellaneous Discharges: "Unused Cement Slurry". As an alternative, the OOC recommends a joint industry study be performed to assess the overall environmental and safety impacts of this discharge.

Response to Comment 27: The comment requests that the permit authorize the discharge of unused cement slurry. No change will be made at this time in order for the EPA to gather more information about fate and transport of chemical constituents in the cement that will be ultimately disposed of at the seafloor. This would allow us time to better determine appropriate permit parameters and conditions for this effluent. The permit's prohibition on the discharge of excess cement slurry does not prevent testing of equipment. This prohibition has been included in the general permit for a number of years and presumably operators have tested and properly maintained cement systems and drilling equipment during that time. Excess cement can be hauled to shore for disposal.

Comment 28: The OOC requests that the Best Management Pollution Prevention Practice (BMP3) requirements be removed from the permit.

Response to Comment 28: No change made. BMP3s are central to many industrial permits. EPA understands that some provisions in a BMP3 plan for the NPDES permit may also be in BMPs for other regulatory agencies. For purposes of complying with the BMP3 provisions of Region 4's NPDES permit, operators can incorporate and rely on any duplicative compliance measures developed to comply with other regulatory authorities.

Comment 29: The OOC is requesting the addition of brine and/or water based mud discharge at the seafloor to the list of Miscellaneous Discharges**.**

Response to Comment 29: No change made at this time in order for the EPA to gather more information about fate and transport of chemical constituents in brine and water-based mud proposed to be disposed of at the seafloor. This would allow us time to better determine appropriate permit parameters and conditions for this effluent.

Comment 30*:* The OOC requests that a change be made to the title and list for "Miscellaneous Discharges of Seawater and Freshwater which have been chemically Treated". This will be a word change from "Seawater" and "Freshwater" to "Water". This change will ensure that both "Seawater" and "Freshwater" are included in the chemically treated discharge list.

Response to Comment 30: No change made. The terminology used in the permit is clear.

Comment 31: The OOC requests a change to Table 1 regarding the references to the acute and chronic WET requirements.

Response to Comment 31: Change made. For simplification, Table 1 refers back to the permit for details.

Comments from the Center of Biological Diversity

Comment 1: While the Center of Biological Diversity (the 'Center') appreciates the EPA's new permit condition requiring oil companies to maintain an inventory of the chemicals used in offshore fracking and other well stimulation treatments, such condition does not go nearly far enough to protect Gulf ecosystems or marine species from these environmentally destructive practices.

Response to comment 1: The proposed GP is based upon current available data and federal standards. The EPA finds that the discharges covered under this permit will not result in an unreasonable degradation of the marine environment in the vicinity of the discharges. The GP contains prohibitions, technology-based effluent limits (TBELS), water-quality based requirements (i.e., WET limits on discharges of produced water, water-based drilling fluids, drill cuttings, and non-aqueous-based drill cuttings)]), to minimize water-quality impacts from the discharges. In addition, the GP includes whole effluent toxicity monitoring only requirements for WTCW fluid discharges. The WET monitoring for WTCW fluids will provide additional information regarding potential impacts from the discharge and inform future permit decision-making. The permit also prohibits bulk discharges of non-aqueous based drilling fluids (NAFs) including synthetic based drilling fluids (i.e., only de minimus discharges of NAFs are allowed), produced sand, oil based drilling fluids, oil contaminated drilling fluids, diesel oil, and priority pollutants contained in well treatment, completion, and workover fluids, which are prohibited except in trace amounts. The permit prohibits discharge of PW water, and drill cuttings within a 1000 meters of an Area of Biological Concern (ABC) or a federally designated dredged material ocean disposal site.

As noted, TBELs, WQBELS, and WET monitoring are included. The general permit authorizes discharges from oil and gas facilities and supporting pipeline facilities, engaged in exploration, development, and production operations located in and discharging to Federal Waters of the Gulf of Mexico (1) seaward of the 200-meter depth contour offshore Alabama in the Destin Dome lease block, (2) seaward of the 200-meter depth contour offshore of Florida, and (3) in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama.

There are no applicable federal water quality criteria. However, the permit must comply with Ocean Discharge Criteria at 40 CFR Part 125. The permit's effluent limits ensure these discharges will cause no unreasonable degradations per CWA § 403(c) and Ocean Discharge Criteria (see 40 CFR Part 125, Subpart M). The 100-meter diameter mixing zone for toxicity is based on Ocean Discharge Criteria found at 40 CFR § 125.121(c). Based on WET data reported by permittees under the current R4 offshore NPDES GP, there have been no toxicity limit violations.

The EPA has not found that available toxicity test results or other available information would justify use of a more restrictive mixing zone as described in 40 CFR §125.121(c).

The permit includes a new requirement for permittees to monitor for toxicity for WTCW fluids not commingled with produced water. This information will allow the EPA to obtain additional/targeted data on possible impacts/toxicity of WTCW discharges and the information will inform future permitting decisions.

Lastly, all permittees are required to submit as part of NOIs for coverage under the GP technical information on the characteristics of the sea bottom. Specifically, in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. Operators must submit images for the Live Bottom Report using either digital high-resolution acoustic data (sidescan sonar) or photo documentation.

Prior to publicly noticing the GP, the EPA Region 4 prepared a DEA pursuant to the National Environmental Policy Act (NEPA) and also engaged in consultation with the US Fish and Wildlife Service (USFWS) and NMFS in accordance with the ESA. Since publication of the DEA, USFWS provided concurrence with the EPA Region 4's determination that issuance of the Offshore Oil and Gas GP is not likely to adversely (NLAA) affect species or critical habitat under the ESA. The USFWS provided concurrence in a letter to the EPA Region 4 dated January 19, 2017, and the NMFS concurred with the EPA Region 4's Essential Fish Habitat (ESH) assessment in a letter dated December 16, 2016. In addition, the EPA Region 4 has determined that its proposed action will NLAA listed species under the purview of the NMFS and will not likely jeopardize species and/or adversely modify critical habitat. The NMFS has not yet completed consultation or provided its concurrence on EPA's NLAA determination, but based on information in the record EPA anticipates that NMFS will concur with this determination. EPA has determined that it can issue the GP prior to completion of consultation with NMFS in accordance with Section 7(a)(2) and Section 7(d) of the ESA because the issuance of the permit will not result in any irreversible or irretrievable commitment of resources which would have the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures that might be identified by NMFS pursuant to the consultation process. In the event that NMFS does identify necessary reasonable and prudent alternative measures that are necessary to prevent jeopardy to protected species or adverse impacts to critical habitat, EPA has authority to modify the permit to include whatever conditions are necessary to implement such reasonable and prudent alternative measures.

In a letter dated August 7, 2017, the EPA Region 4 notified NMFS of its intent to reissue the GP in accordance with Section 7(a)(2) and Section 7(d) of the ESA. To avoid an irreversible or irretrievable commitment of resources, the reissued GP includes a specific re-opener clause that will enable the EPA Region 4 to modify the GP should further consultation reveal a need to formulate or implement reasonable and prudent alternative measures. This updated information regarding ESA consultation is reflected in our preliminary Finding of No Significant Impact (FONSI).

Comment 2: The Center urges the EPA to prohibit the dumping of chemicals used in offshore fracking and other well stimulation into the Gulf, and implement a zero discharge requirement for wastewater generated by offshore oil and gas drilling activities. According to the Center, such action is necessary to ensure the Proposed GP does not result in an unreasonable degradation of the marine environment as required by the CWA.

Response to comment 2: All permitted discharges meet the no unreasonable degradation requirement. The term 'unreasonable degradation' is defined in 40 CFR § 125.121(e)(1-3). The record, including information regarding impacts from discharges during prior permit cycles, does not contain evidence indicating that the discharges will cause "significant adverse changes" in ecosystem diversity, productivity or stability of the biological community as a result of the discharges and there has been no threat to human health through direct exposure to pollutants or consumption of exposed aquatic organisms. Furthermore, the EPA has found that there has been no loss of esthetic, recreational, scientific or economic values which is unreasonable in relation to the benefit derived from the discharge.

Comment 3: Prior to issuing the permit, the EPA must prepare an environmental impact statement under the NEPA and must engage in formal consultation under the ESA. Such actions are necessary to protect imperiled marine species from the myriad dangerous pollutants discharged by offshore oil and gas activities. Failure to do so would violate NEPA and the ESA.

Response to comment 3:

The EPA Region 4 conducted multiple previous NEPA reviews on the issuances during prior permit cycles (NPDES permits may be issued for a maximum duration of five years) of the Region 4 NPDES GP for Offshore Oil and Gas Activities. These reviews have included an environmental impact statement (EIS) in 1998, Supplemental EIS in 2004, and an environmental assessment (EA) in 2009. For this proposed action, the EPA Region 4 tiered off of these previous NEPA documents as allowed under 40 CFR § 1502.20. Relevant information from these documents were updated and we determined that the analyses from these documents are still valid and therefore, are incorporated by reference, as appropriate, in the most recent DEA. Based on the analysis of the potential environmental impacts associated with the issuance of the GP, the EPA Region 4 determined that no significant environmental impacts are anticipated from the proposed action. Therefore, the EPA Region 4 does not believe it is appropriate to prepare an EIS for this proposed action. In addition, the EPA Region 4 has determined the proposed action is consistent with 40 CFR § 6.204 (a)(1)(iv).

In regards to consultation under ESA, the EPA Region 4 has had on-going coordination with NMFS and the USFWS for the proposed action. A biological evaluation (BE) was prepared and included in the DEA in Appendix E and has been shared with the NMFS and USFWS. Prior to publicly noticing the GP, the EPA Region 4 prepared a DEA pursuant to the NEPA and also engaged in consultation with the USFWS the NMFS in accordance with the ESA. Since publication of the DEA, USFWS provided concurrence with the EPA Region 4's determination that issuance of the Offshore Oil and Gas GP is not likely to adversely (NLAA) affect species or critical habitat under the ESA. The USFWS provided concurrence in a letter to the EPA Region 4 dated January 19, 2017. In addition, the NMFS concurred with the EPA Region 4's E S H assessment in a letter dated December 16, 2016. The EPA Region 4 has determined that its proposed action will NLAA listed species under the purview of the NMFS and will not likely jeopardize species and/or adversely modify critical habitat. The NMFS has not yet completed consultation or provided its concurrence on EPA's NLAA determination, but based on information in the record EPA anticipates that NMFS will concur with this determination. The EPA has determined that it can issue the GP prior to completion of consultation with NMFS in accordance with Section 7(a)(2) and Section 7(d) of the ESA because the issuance of the permit will not result in any irreversible or irretrievable commitment of resources which would have the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures that might be identified by NMFS pursuant to the consultation process. In the event that NMFS does identify necessary reasonable and prudent alternative measures that are necessary to prevent jeopardy to protected species or adverse impacts to critical habitat, the EPA has authority to modify the permit to include whatever conditions are necessary to implement such reasonable and prudent alternative measures. To avoid an irreversible or irretrievable commitment of resources, the reissued GP includes a specific re-opener clause that will enable the EPA Region 4 to modify the GP should further consultation reveal a need to formulate or implement reasonable and prudent alternative measures. This updated information regarding ESA consultation is reflected in our preliminary FONSI. The EPA Region 4 determined that formal consultation is not required (50 CFR § 402.14(b)(1)). This updated information regarding ESA consultation is reflected in our preliminary FONSI.

Comment 4: The Proposed GP does not comply with the Ocean Discharge Criteria or adequately protect water quality because it allows the unlimited discharge of Produced Waters. It allows the discharge of toxic fracking and other well treatment fluids and is less protective of water quality than other offshore oil and gas permits. It is wholly shocking that the EPA allows the oil and gas industry to dump its wastewater into the GOM. The EPA must implement substantial changes to the terms and conditions of the Proposed Permit prior to its issuance, including zero-discharge requirements for all produced wastewaters and well treatment fluids. Also, the EPA cannot make a valid finding that the permit does not cause an unreasonable degradation of the marine environment. The permit allows the unlimited discharge of produced wastewater, including the unlimited discharge of chemicals used in offshore fracking and other well stimulation treatments. There are significant data gaps on the impacts of these discharges on the marine environment, and what is known indicates that the discharges of such wastewater is inherently dangerous and causes undue degradation of the ocean environment.

Response to comment 4: The EPA is aware that there is a significant body of information regarding chemicals used in hydraulic fracturing demonstrating potential harm to aquatic communities in upland environments. The EPA understands that chemicals used in offshore well stimulation fluids could be equally harmful to marine life if exposed to sufficiently high concentrations for sufficient periods of time or with repeated exposure to high concentrations. However, the EPA finds that the conditions and limits in the proposed permit are sufficient to prevent long-term exposures to high concentrations of such chemicals. The permit is protective of sensitive aquatic communities. In the Mobile and Viosca Knoll lease block areas offshore of Mississippi and Alabama , a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. Facilities offshore FL and offshore of Alabama in the Destin Dome lease block, will be in a minimum of 200 m water depths. All facilities must operate a minimum of 1000 m from sensitive marine habitat. Due to high rates of dilution in the open ocean, exposure to high concentrations of added chemicals are likely to occur only for short durations in the discharge plume in the immediate vicinity of the outfall. EPA finds that exposures to concentrations high enough to cause biological effects will be brief and that no significant adverse impacts to marine life will result.

All permitted discharges meet the no unreasonable degradation requirement as unreasonable degradation is defined in 40 CFR § 125.121(e)(1-3). The record, including information regarding impacts from discharges during prior permit cycles, does not contain evidence indicating that the discharges will cause “significant adverse changes” in ecosystem diversity, productivity or stability of the biological community. The record does not indicate that the discharges pose a threat to human health through direct exposure to pollutants or consumption of exposed aquatic organisms, and there has been no loss of esthetic, recreational, scientific or economic values which is unreasonable in relation to the benefit derived from the discharges. Existing information, including information relating to the impacts of discharges during the previous permit term, is sufficient to support EPA’s determination that the discharges authorized in the GP will not result in unreasonable degradation of the marine environment.

Produced water discharges have technology-based and water quality-based limits. WTCW fluids are covered under the NPDES permit with technology-based effluent limits per the Effluent Guidelines. WTCW fluids commingled with produced waters have technology-based and water quality-based limits. WTCW fluids not commingled with produced waters discharged have technology-based effluent limits. The available data show no violations of WET limits. Both these waste streams, when discharged as permitted, do not cause any significant adverse impact to the marine environment in the GOM. The proposed final GP includes additional water quality based monitoring only condition for WTCW fluids that will provide information for future permitting decisions and enable EPA to identify environmental harm from the discharges that can be addressed through permit modification and in future permit cycles.

Comment 5: Studies show that exposure to produced wasters can cause a wide range of negative effects in fish and invertebrates. Several of the responses to produced water exposure suggest substantial impacts, such as loss of cell membrane integrity, gene expression changes, cytotoxicity, DNA damage, hepatic lipid composition, and reproductive disruption. Based on these studies, chronic exposure to even low concentrations of produced waters has negative consequences for the physiology of fish and invertebrates, Population and community effects are mostly unknown, as are the cumulative effects of chronic and acute produced water exposure.

Response to comment 5: The EPA is aware that produced water may contain a variety of substances that could be harmful to marine life if exposed to sufficiently high concentrations for sufficient periods of time or with repeated exposure to high concentrations. The EPA is aware that a number of biological responses have been documented in laboratory studies of controlled exposures to produced water. The EPA is confident that, due to high rates of dilution in the open ocean, such conditions as produced in controlled laboratory studies are likely to occur only for short durations in the discharge plume in the immediate vicinity of the outfall. The EPA finds that any exposures to concentrations high enough to cause biological effects will be brief and that no significant adverse impacts to marine life will result.

Comment 6: Habitat degradation due to produced waters is high near outfalls. Most PWs contain relatively high concentrations of several metals compared with clean sea water, with barium, iron, and manganese being the most abundant. These metals tend to rapidly precipitate from the plume, forming barium sulfate and oxides of iron and manganese on sediment surfaces over large areas around the produced water discharges. Evidence suggests that effects of discharges of PW in the water column and on the seabed in general have higher impacts within 1 or 2 kilometers from the outfall sources. However, the published literature has not yet been able to demonstrate with high confidence that the effects of PW are only local. Studies have shown that benthic communities require at least 5-10 years to recover from wastes accumulated on the seabed from produced waters.

Response to comment 6: The EPA agrees that some benthic impact may occur as a result of PW discharges that are made near the seafloor in relatively non-energy environments. Impacts may occur from direct contact of the concentrated discharge plume with the benthos and the accumulation of particulates that settle to the seafloor. Published studies show that PW impacts are highly variable with most being limited to within a few hundred meters from the outfall. It should be noted that the majority of studies that have shown an impact in the GOM concerned production wells in shallow (less than 30 meters) depths. The GP is protective of sensitive aquatic communities because, for facilities in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. Additionally, the GP covers only facilities operating in depths of 200 m or more offshore of Florida and offshore of Alabama in the Destin Dome lease block. All facilities must operate a minimum of 1000 m from sensitive marine habitats in pre-designated Areas of Biological Concern. Discharge models show that maximum plume concentrations occur from 8-12 m from the discharge point and plumes have been measured to dilute 100 times within 10 m of the discharge and 1,000 times within 103 m of the discharge.

Rapid dilution of the produced waters decreases the possible toxicity with distance from the outfall. Also, the proposed permit places restrictions on the discharge of produced water, which require the effluent concentration 100 m from the outfall to be less than the 7-day no observable effect concentration based on laboratory exposures. This will limit the impacts on nearby benthic resources.

Comment 7: Studies demonstrate that there are many unknowns regarding the impacts of the discharge of produced water on the marine environment, including on marine species, but what is known indicates that produced waters substantially degrade the marine environment. The EPA therefore cannot make the non-degradation finding for produced water. Available technologies exist that allow for zero discharge of such waters.

Response to comment 7: Available and cost-effective technologies exist for nearshore facilities. However, the EPA has determined that feasible technologies for offshore facilities that are at substantial distances from the shore are not available to the industry. See Responses CBD-4, CBD-5 and CBD-6.

Comment 8: The EPA's evaluation acknowledges that offshore fracking and other well stimulation occurs in the GOM. There are significant data gaps regarding the impacts of offshore fracking and acidization on the marine environment, and the best available scientific information indicates that the discharge of well treatment chemicals does not meet the ocean discharge criteria. Therefore, the EPA cannot permit the discharge of fracking and other well stimulation chemicals. The EPA cannot make a valid finding that the permit does not cause an unreasonable degradation of the marine environment because "insufficient information exists" regarding the impacts of well stimulation chemicals "to make a reasonable judgment" that the discharge satisfies all of the ocean discharge criteria. For example, an independent scientific review of offshore well stimulation by the California Council on Science and Technology found significant data gaps on basic questions regarding offshore fracking and acidizing.

Response to comment 8: The EPA Region 4 is aware that there is a significant body of information regarding chemicals used in hydraulic fracturing, demonstrating potential harm to aquatic communities in upland environments. The EPA Region 4 believes that chemicals used in offshore well stimulation fluids could be equally harmful to marine life if exposed to sufficiently high concentrations for sufficient periods of time or with repeated exposure to high concentrations. However, the EPA Region 4 is confident that the conditions and limits in the proposed GP are sufficient to prevent long-term exposures to high concentrations of such chemicals. The GP is protective of sensitive aquatic communities. In the Mobile and Viosca Knoll lease block areas offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. Additionally, the GP covers only facilities operating in depths of 200 m or more offshore of Florida and offshore of Alabama in the Destin Dome lease block. All facilities must operate a minimum of 1000 m from sensitive marine habitats in pre-designated Areas of Biological Concern. Due to high rates of dilution in the open ocean, exposure to high concentrations of added chemicals are likely to occur only for short durations in the discharge plume in the immediate vicinity of the outfall. The EPA Region 4 believes that exposures to concentrations high enough to cause biological effects will be brief and that no significant adverse impacts to marine life will result. Existing information, including information relating to the impacts of discharges during the previous GP term, is sufficient to support the EPA Region 4's determination that the discharges authorized in the GP will not result in unreasonable degradation of the marine environment.

The EPA Region 4 also notes that comparisons of the large-scale, induced hydraulic fracturing procedures used in onshore and off-shore California oil and gas operations for low-permeability reservoirs with well treatment operations carried out on the OCS in the GOM are misleading. Typical use of pressurized fluids for well treatment and well stimulation in the GOM are small-scale by comparison and use significantly smaller volumes of fracking fluids and the associated chemicals. In addition, the number of added chemicals is typically much smaller.

Comment 9: EPA claims that the conditions in the Proposed GP are sufficiently protective of the marine environment. But this conclusion is arbitrary—the existing permit conditions do not prevent undue degradation of the marine environment. In determining no undue degradation, EPA relies on the treatment of produced water and the toxicity testing required under the permit. But treatment of produced water is only oil-water separation, which does not remove any of the chemicals that flow back. Moreover, whole effluent testing is insufficient to ensure that discharges are not toxic because the testing is not required for discharge events, including the discharge of flowback from well treatment such as fracking. Most facilities are only required to test semi-annually, even those required to test bimonthly are not at the same time as a fracking event.

Response to comment 9: The EPA finds that past studies and NEPA documents support the conclusion that the proposed GP will be sufficient to protect the marine environment. See Responses CBD-4, CBD-5 and CBD-6.

Comment 10: The toxicity requirement that no observable effect concentrations should occur at the edge of the 100-m mixing zone is arbitrary. Rather, the no observable effect standard should be met at the outfall. Discharges must meet water quality and ocean discharge standards at the point of discharge. The WET testing of PW is good, but should be required to be conducted concomitant with discharges from well treatments, such as acidization, fracking, water flooding, gravel packing, etc.

Response to comment 10: The EPA does have some discretion with regard to the size of mixing zones used in NPDES permits, however, the EPA does not agree that the use of a 100-meter mixing zone to determine toxicity is arbitrary. Nor does EPA agree that a more restrictive mixing zone is necessary at this time. The concept for the 100 m mixing zone comes from 40 CFR § 125 Ocean Discharge Criteria: *"§125.121 (c)* Mixing zone *means the zone extending from the sea's surface to seabed and extending laterally to a distance of 100* *meters in all directions from the discharge point(s) or to the boundary of the zone of initial dilution as calculated by a plume model approved by the director, whichever is greater, unless the director determines that the more restrictive mixing zone or another definition of the mixing zone is more appropriate for a specific discharge."* At present, the EPA does not have information that would justify a change in the size of the mixing zone prescribed in the proposed NPDES GP. The EPA will use the data acquired through the WET testing requirement for well treatment fluid discharges to determine whether a more restrictive mixing zone may be required.

Comment 11: While the inventory requirement that requires reporting of well treatment fluids to EPA with discharge monitoring reports is a step in the right direction, it does not prevent such chemicals from being discharged, and is thus inadequate to protect water quality. It is unclear whether the inventory requirement applies to well treatment fluids that are comingled with Produced Water. The Proposed GP states that discharge of WTCW fluids "shall be considered 'produced water when commingled with produced water." This appears to undermine the requirements to inventory and disclose the discharges thus failing to protect water quality when well treatments, such as fracking, result in flow back or otherwise dilute the discharges with produced water. Similarly, it is generally good to incentivize the industry-wide study and characterization of discharge of well treatment chemicals; but this does not assuage concerns that the discharges should be prohibited until proven safe.

Response to comment 11: The inventory requirement for WTCW fluids are targeted for discharges that occur prior to the production phase of the well. EPA is aware that there may be numerous discharges of WTCW fluids during well development, and the permit contains new WET testing monitoring only requirements applicable to WTCW fluids not commingled with PW in an effort to provide the EPA with new information in order to evaluate the extent to which these discharges ~~are~~ may be toxic. Based on current information, including information developed during previous permit terms, the EPA finds that the terms of the GP will ensure that the discharges do not cause unreasonable degradation of the marine environment. The chemical inventory and toxicity testing monitoring results will provide information to support future permitting decisions, including whether to add more stringent conditions, if warranted.

Comment 12: The discharge of pollution from offshore oil and gas drilling into this important habitat is unnecessary because a zero discharge permit is feasible. There are already oil and gas operations that meet zero discharge requirements. For example, coastal offshore drilling operations in the GOM already require zero discharge of produced water and treatment, workover, and completion fluids as well as drilling fluids, drill cuttings, and dewatering effluent. If the EPA does not implement the restriction as a technology-based effluent limitation, the BMPs should require the zero discharge requirement. BMPs are used to address the developments for which the effluent limitation guidelines have not kept pace.

Response to comment 12:

EPA is aware that some coastal states require zero discharge for oil and gas operations in near-shore coastal waters. Because EPA recognizes that shallower nearshore environments are most biologically productive and, therefore, more sensitive to direct exposure to pollutants from oil and gas operations, the proposed GP only covers operations seaward of the 200-meter isobaths offshore of Florida and in the Destin Dome lease block offshore of Alabama. These facilities will be considerably further from shallow nearshore environments. As a result, the greater distances make hauling operational discharges to onshore disposal site less feasible. The GP also requires facilities in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama to submit a live bottom survey to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. This will likely also steer facilities away from shallow and nearshore environments. In addition, the permit prohibits discharge of produced water, and drill cuttings within a 1000 m of an ABC or a federally designated dredged material ocean disposal site.

Regarding inclusion of BMPs to prohibit discharges, BMPs may be implemented in lieu of or in addition to numeric limits in some circumstances, for example if it is infeasible to calculate numeric limits BMPs limits may be appropriate. Alternatively, BMP-based limits may be appropriate when reasonably necessary to carry out the purposes of the CWA. See 40 CFR § 122.44(k). In this case, numeric technology-based limits for produced water and WCTW fluids have been established by the offshore oil and gas effluent guideline, which establishes the appropriate technology-based effluent limit for this category of discharges. A limit of zero discharge is not what is intended by a BMP, as it is a numeric effluent limit of zero, or a prohibition of discharge, which is inconsistent with the required federal effluent guideline-based numeric effluent limits in the GP. Additional limits based on water quality may be considered, but EPA has determined that the limits and conditions in the GP ensure that unreasonable degradation of the marine environment will not be caused by the authorized discharges.

Comment 13: The EPA must place a numeric volume limit for produced water allowed to be discharged. As explained above, produced water degrades water quality and introduces toxins into the marine environment. Well treatment activities may increase produced water discharges and extend the life of oil and gas operations; without a limit on produced water volume it is impossible for EPA to guarantee against the degradation of the marine environment and water quality. Already the amount of produced water that is discharged into the GOM is harmful, and the quantity could increase with new leases and changes in drilling and well stimulation practices. The proposed permit is more relaxed than other OCS GPs, and it is therefore arbitrary and inconsistent with other EPA GPs. For example, the Pacific OCS GP, the EPA set a limit of volume of produced water allowed for each platform.

Response to comment 13: The proposed GP covers produced water discharges only within the Region 4 jurisdictional area of the GOM. Within the Region 4 jurisdictional area EPA expects, during the approximate term of the permit from the year 2017 to 2022, an estimated 120 - 470 total wells, including about 60 - 235 production wells. Produced water is addressed in the proposed permit with both technology-based and water quality based limits. The ocean discharge criteria require that a waste stream cannot be permitted if EPA determines that the discharge of wastes will cause unreasonable degradation of the marine environment. The available evidence, including whole effluent toxicity data reported by permittees under the current R4 offshore permit, indicates that produced water discharges made consistent with the permit's terms and conditions will not result in unreasonable degradation to the portion of the GOM affected by the proposed permit. The EPA does not have information to justify imposing additional or more stringent limits.

It should be noted that, concerning the southern California offshore oil and gas facilities covered under the EPA Region 9 GP, most of the platforms are operating fairly close to shore in areas containing sensitive habitat in less than 100 meter depths. The proposed R4 GP will cover facilities in greater that 200 m depths offshore of Florida or in the Destin Dome lease block offshore of Alabama, most of which are expected to be located much further from shore in areas containing less biologically sensitive habitats. Further, facilities in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama must submit a live bottom survey to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas It should also be noted that the Region 9 GP Produced Water volume limits range from 4,666 barrels per day (bbl/d) to 114,346 bbl/d. A 2005 report[1] of the produced water volumes from 50 operators in the GOM reported annual averages ranging from 3 bbl/d to 63,828 bbl/d.

Comment 14: EPA should require zero discharge of WTCW comingled with PW. Well treatment fluids contain toxic chemicals that are harmful for aquatic animals and water quality. Well treatment uses chemicals for a variety of functions, such as: dissolving acids, biocides, breakers, clay stabilizers, corrosion inhibitors, crosslinkers, foamers and defoamers, friction reducers, gellants, pH controllers, proppants, scale controllers, and surfactants. And, as explained above, modern hydraulic fracturing uses hundreds of chemicals that cause cancer or damage to the nervous, cardiovascular, and endocrine systems; and can be incredibly toxic to fish and other marine life. But the proposed permit authorizes the discharge of unlimited volumes of PW, including those mixed with fracking chemicals.

Response to comment 14: The EPA has found from past studies that a zero discharge is not feasible or necessary to protect the marine environment. See Responses to CBD-5, CBD-8 and CBD-12.

Comment 15: EPA should also require monitoring and reporting for additional chemicals in all types of discharges. For example, the Pacific OCS GP requires monitoring for specific chemicals, such as benzene, in produced water for each platform, for certain chemicals it also prescribes discharge limits. Here, given the new information about produced water and its potential toxicity, the EPA should require more robust monitoring for chemicals that could degrade the marine environment.

Response to comment 15: The EPA understands that the various discharges contain a variety of chemical compounds that have the potential to adversely impact the marine environment that will not be individually limited or monitored. The EPA has determined, however, that the limits and conditions in the GP will mitigate the potential toxicity of the discharge, and such limits and conditions (e.g., WET limits and WET monitoring) in the proposed GP are preferable to chemical-specific limits and monitoring, given the variability of composition. WET testing for well treatment fluids will commence with the authorization of the proposed permit as will reporting of chemicals used. Additionally, the permit will require the permittees to submit information on specific chemical constituents used during well treatment operations. This information may be used by the EPA in the future to determine if additional limits are warranted.

Comment 16: While discharges of well treatment fluids should be completely prohibited, if EPA nonetheless decides to allow such discharges, it must place numeric limits on the toxic chemicals that occur in well treatment fluids and require robust monitoring to ensure compliance. In addition to limits, the EPA should identify biologically sensitive areas or seasons to require zero discharge to protect sensitive species. For example, the EPA should restrict discharges in sea turtle critical habitat and Desoto Canyon. This would be more consistent with other EPA permits. For example, the Beaufort OCS GP prohibits discharge of drilling fluids during bowhead whaling activities and no discharge near the Boulder Patch.

Response to comment 16: The EPA limits discharges under the GP to water depths greater than 200 m offshore of Florida and offshore of Alabama in the Destin Dome lease block, to avoid the most sensitive benthic habitats on the continental shelf. In addition, in the Mobile and Viosca Dome lease block areas offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth. EPA can review the survey and deny permit coverage to protect sensitive areas. Lastly, all facilities must operate a minimum of 1000 m from sensitive marine habitats in pre-designated Areas of Biological Concern.

Comment 17: Several significance factors are raised, clearly necessitating the preparation of an EIS. In particular, the Proposed GP—which allows the unlimited discharge of PW and well stimulation fluids into the GOM—impacts a geographically, ecologically, culturally important area; may have adverse environmental impacts, including impacts to ESA-listed species and their critical habitat; represents a substantial public controversy; and has unique or unknown risks.

Response to comment 17: The EPA has found that the potential impacts to the environment resulting from the proposed action do not require the preparation of an EIS. See CBD-3 Response above. For the 10 factors of significance, see preliminary FONSI.

Comment 18: EPA's Proposed GP allows oil companies to discharge unlimited quantities of produced water, and allows the chemicals used in fracking and other well stimulation treatments to be discharged into the GOM. EPA must prepare an EIS because the discharge of produced water, including the discharge of chemicals used in offshore fracking and acidizing, have adverse impacts, and may impact ESA-listed species and their critical habitat. While substantial data gaps exist regarding the impacts of these practices, what is known is cause for great alarm.

Response to comment 18: PW is addressed in the proposed GP with both technology-based and water quality based limits. The EPA Region 4 is confident that the conditions and limits in the proposed GP are sufficient to prevent long-term exposures to high concentrations of such chemicals. The ocean discharge criteria require that a waste stream cannot be permitted if the EPA Region 4 determines that the discharge of wastes will cause unreasonable degradation of the marine environment. The available evidence, including WET data reported by permittees under the current Region 4 offshore GP, indicates that PW water discharges made consistent with the GP's terms and conditions will not result in unreasonable degradation to the portion of the GOM affected by the proposed GP.

EPA Region 4 has determined that issuance of the Offshore Oil and Gas GP is not likely to adversely affect species or critical habitat under the ESA. With respect to the status of EPA Region 4's ESA consultation, see Responses CBD-1 and 4, above.

In addition, based on the EPA Region 4's analysis of the potential environmental impacts associated with the issuance of the GP, the EPA Region 4 has determined that no significant environmental impacts are anticipated from the proposed action. Therefore, the EPA Region 4 has determined that it is not necessary to prepare an EIS for this proposed action. Please refer to the preliminary FONSI and Response CBD-3, above.

Comment 19: Several spills of fracking fluid from pipelines in Pennsylvania over the last few years also resulted in significant fish kills. Such contamination incidents are a real risk in the GOM given the EPA's Proposed GP that would allow oil companies to dump fracking chemicals into the Gulf. EPA must therefore prepare an EIS.

Response to comment 19: The EPA Region 4 is aware inland discharges of large volumes of fracking fluids into small volume enclosed waterways such as streams and rivers can result in significant impacts to resident aquatic life. However, the EPA Region 4 finds that discharges of relatively small volumes of WTCW fluids into the GOM do not present similar risks of significant adverse impact.

With regard to the request to prepare an EIS, the EPA Region 4 conducted multiple previous NEPA reviews in connection with prior issuances of the EPA Region 4 GP for Offshore Oil and Gas Activities in our jurisdictional area, including the development of EIS's. For this proposed action, the EPA Region 4 tiered off of previous NEPA documents as allowed under 40 CFR § 1502.20. Relevant information from these documents was updated. The EPA Region 4 determined that the analyses from these documents are still valid and are incorporated by reference, as appropriate, in the most recent DEA. In addition, based on the analysis of the potential environmental impacts associated with the issuance of the GP, the EPA Region 4 has determined that no significant environmental impacts are anticipated from the proposed action. Therefore, the EPA Region 4 has determined that it is not necessary to prepare an EIS for this proposed action. Also see Responses to CBD-3 and 18, above.

Comment 20: The oil industry claims offshore fracking has no adverse environmental impacts, while numerous scientists and reports have linked fracking to water contamination, air contamination, spills, and earthquakes. EPA's proposal to allow oil and gas companies to dump fracking wastewater into the GOM clearly constitutes a substantial public controversy. Indeed, it is hard to imagine an issue more fitting of this description than offshore fracking activities. An EIS is therefore required.

Response to comment 20: See Responses to CBD-3, 18 and 19, above. Based on the analysis of the potential environmental impacts of the issuance of the GP the EPA Region 4 has determined that no significant environmental impacts are anticipated from the proposed action. This determination considered both context and intensity, including "the degree to which the effects on the quality of the human environment are likely to be highly controversial." As supported by the DEA for the proposed action, the EPA Region 4 has neither observed nor discovered scientific evidence of:

(1) "significant adverse changes" in ecosystem diversity, productivity or stability of the biological community as a result of the discharges,
(2) a threat to human health through direct exposure to pollutants or consumption of exposed aquatic organisms, or
(3) a loss of esthetic, recreational, scientific, economic values which is unreasonable in relation to the benefit derived from the discharge.

Comment 21: The EPA appears to rely on the lack of information to find that there will not be significant impacts from allowing oil companies to dump fracking and other well stimulation fluids into the GOM. But as the 9th Circuit has made perfectly clear, "lack of knowledge does not excuse the preparation of an EIS; rather it requires the [agency] to do the necessary work to obtain it." In other words, the substantial data gaps that exist regarding the impacts of offshore fracking and acidizing on the marine environment necessitate the preparation of an EIS.

Response to comment 21: The EPA Region 4 has taken a 'hard look' at the potential impacts to the GOM based upon the analyses provided in the DEA. The EPA Region 4 in the DEA has determined that no significant environmental impacts are anticipated from the proposed action based on the analysis of the potential environmental impacts associated with the issuance of the GP. As mentioned above, the record, including information regarding impacts from discharges during prior permit cycles, does not contain evidence indicating that the discharges will cause "significant adverse changes" in ecosystem diversity, productivity or stability of the biological community as a result of the discharges and the record does not indicate that the discharges pose a threat to human health through direct exposure to pollutants or consumption of exposed aquatic organisms. Furthermore, the EPA has determined that there has been no loss of esthetic, recreational, scientific or economic values which is unreasonable in relation to the benefit derived from the discharges. Additionally, existing information, including information relating to the impacts of discharges during the previous GP term, is sufficient to support the EPA Region 4's determination that the discharges authorized in the GP will not result in unreasonable degradation of the marine environment. In addition, as described under response CBD-3, the EPA Region 4 has fully evaluated the OCS oil and gas NPDES GP and impacts on water quality through multiple previous EISs and EAs. These NEPA documents, including the most recent DEA on the proposed action, have all analyzed the impacts of oil and gas activities in the OCS covered under the NPDES GP in the EPA Region 4 jurisdictional area.

Comment 22: EPA's purpose and need statement fails to comply with NEPA. NEPA's implementing regulations provide that an environmental document should specify the underlying purpose and need to which the agency is responding in proposing the alternative including the proposed action. This purpose and need inquiry is crucial for a sufficient environmental analysis because "[t]he stated goal of a project necessarily dictates the range of 'reasonable' alternatives." Thus, an agency cannot define its objectives in unreasonably narrow terms" without violating NEPA.

Response to comment 22: The stated purpose and need in the DEA is consistent with both 40 CFR § 1502.13 and previous EAs and EISs supporting issuance of prior NPDES GPs for offshore oil and gas in the EPA Region 4 coverage areas. Additionally, the purpose and need of the reissuance "of an existing NPDES GP authorizing discharges from existing and new source oil and gas facilities operating in the federal waters of the GOM where the EPA Region 4 is the permitting authority" is consistent with the mandate outlined in 40 CFR § 128.28(C)(1).

Comment 23: EPA's DEA fails to analyze a reasonable range of alternatives. NEPA requires a "detailed statement" of alternatives to the proposed action." The purpose of this section is "to insist that no major federal project should be undertaken without intense consideration of other more ecologically sound courses of action, including shelving the entire project, or of accomplishing the same result by entirely different means."

Response to comment 23: The range of alternatives considered in the DEA is consistent with both 40 CFR § 1502.14 and past NEPA evaluations regarding issuance of an NPDES GP in the Region 4 jurisdictional area of the GOM. During the development of the DEA, the EPA Region 4 considered the alternative of "zero discharge" of WTCW to not be a feasible alternative and therefore, it was not considered in the range of alternatives analyzed in the DEA.

Comment 24: EPA's analysis of the no-action alternative is inadequate. The EPA states that if the EPA did not issue the Proposed GP, offshore oil and gas facilities would need to apply for an individual permit. Thus, according to the EPA the only difference between the no-action alternative with the action alternatives is the increased administrative burden on EPA. In other words, the no-action alternative encompasses the same potential impacts as a decision to issue the GP. But this approach "avoid[s] the task actually facing [EPA]. In assuming that, no matter what, the proposed activities would surely occur, [EPA is] neglecting to consider what would be a true 'no action' alternative." However, a true no-action alternative would examine and compare the impacts resulting from the cessation of the discharge of produced wastewater and other oil and gas drilling wastes. EPA should consider and disclose such impacts.

Response to comment 24: The "no action" alternative is not a feasible alternative in this case because there is no basis in the record for determining that issuance of the proposed general permit fails to meet applicable legal requirements (e.g., CWA NPDES or ESA). The EPA recognizes that, for offshore discharges such as those that would be authorized by the GP, no permit may be issued when the EPA determines that the discharges will not satisfy the ocean discharge criteria as set out in 40 CFR § 125.120-124 (Ocean Discharge Criteria). The Ocean Discharge Criteria prohibit the issuance of permits for discharges that will cause unreasonable degradation of the marine environment (*See* 40 CFR § 125.123(b)). As explained in EPA's Response to CBD Comment 1, however, the EPA has conducted an analysis of the proposed General Permit under the Ocean Discharge Criteria and determined that the GP may be issued consistent with the Ocean Discharge Criteria. This determination follows previous permit cycles where the required Ocean Discharge Criteria analysis was undertaken and the EPA has similarly found that the discharges will not cause significant degradation of the marine environment. Similarly, the EPA has determined that the general permit may be issued consistent with other regulatory requirements, such as the ESA.

In the absence of a record basis for determining that a general permit does not meet applicable CWA NPDES or other regulatory requirements, the "no action" alternative was structured in the DEA to satisfy the requirements of 40 CFR § 128.28 (c)(1), which states that "The Regional Administrator shall, except as provided below, issue GPs covering discharges from offshore oil and gas exploration and production facilities within the Region's jurisdiction." Those exceptions listed in 40 CFR § 128(c)(1) include circumstances where offshore areas of biological concern require separate permit conditions warranting the use of Individual Permits instead of coverage under a GP. However, 40 CFR § 128.28 makes clear that, absent such circumstances, the use of the EPA's general permit authority is an appropriate mechanism for permitting offshore oil and gas exploration and production facilities.

For these reasons, the EPA believes including an alternative that contemplates no NPDES permit (GP or Individual Permit) is not a feasible alternative and not consistent with the intent of the "no action" alternative definition under NEPA. In addition, where a choice of the "no action" would result in predictable actions by others, the consequence of the "no action" alternative should be included in the analysis (Reference: CEQ's 40 Most Asked NEPA Questions). This supports our determination that the "no action", no issuance of any NPDES GP, would result in the issuance of individual permits for existing and new dischargers for the same level of activity. Therefore, the DEA analyzed impacts from the proposed action and alternatives given that there is not a record basis for issuing no permit, and there is no distinction among any remaining alternatives (GP or individual permit) with respect to environmental consequences.

Comment 25: EPA's analysis fails to consider the direct, indirect, and cumulative impact of produced waters discharges and the impacts of discharging chemicals used in offshore fracking and other well stimulation treatments. Such failures violate NEPA.

Response to comment 25: The EPA Region 4 has considered the direct, indirect, and cumulative impacts of produce waters discharges and the impacts of discharging chemicals used in offshore fracking and other well stimulations treatments in the DEA for the proposed action. The EPA Region 4 has fully evaluated the OCS oil and gas NPDES GP and impacts on water quality through multiple EISs and EAs; including the current DEA for the proposed action. Previous NEPA documents and NPDES permits have contemplated the use of well stimulation and fracking activities and have evaluated the direct, indirect, and cumulative impact of these activities. Based on best available information, the EPA Region 4 has no reason to believe that conclusions in these NEPA documents are invalid or that the impacts associated with offshore well stimulation and fracking will cause significant impacts to the environment. The EPA Region 4 has determined that no significant environmental impacts are anticipated from the proposed action based on the analysis of the potential environmental impacts of the issuance of the GP in the preliminary FONSI.

Comment 26: Relying on data that is nearly three decades old is improper. NEPA requires EPA to "describe the environment of the areas to be affected or created by the alternatives under consideration." Thus, the establishment of the baseline conditions of the affected environment is a fundamental requirement of the NEPA process.

Response to comment 26: Based on WET data reported by permittees under the current EPA Region 4 offshore GP permit, there have been no toxicity limit violations. This data reflects the current operations with respect to toxicity of discharges.

The EPA Region 4 agrees that additional data should be collected to ensure that other discharge data also reflects current operations. As stated on Page 2-6 of the DEA*: "The number of WTCW jobs is not reliably known, especially with respect to current operations."* And: the *"EPA Region 4 recognizes this information is limited and dated (i.e., from 1988), and operational practices may have changed. Therefore, EPA Region 4 is requiring testing and reporting requirements for this waste stream beyond those of the 2010 GP."*

Therefore, the current DEA acknowledged the potential data gaps regarding WTCW fluids and analyzes the potential impacts of the proposed action which includes additional permit requirements under the new GP to address these gaps. Baseline conditions, including water quality and aquatic life, are described in Sections 3.1 to 3.3.6 in the DEA. One of the prime purposes of the EPA preparing the DEA was to identify any significant changes to the baseline conditions following the *Deepwater Horizon* incident.

Comment 27: EPA's study of the volume of PW is from 1983, which is also incredibly outdated. Fracking and other new information indicate that produced waters may have increased in volume. EPA records reveal that offshore oil and gas platforms in Region 6 discharged *more than 75 billion gallons* of produced waters in 2014. Failure to base its analysis on more recent information that adequately reflects the volume of discharges of produced water would also violate NEPA.

Response to comment 27: Comparisons of PW volumes between Regions 6 and 4 are not valid because there are significantly fewer production wells in Region 4. A 2005 report[1] of the produced water volumes from 50 operators in the GOM reported annual averages ranging from 3 bbl/d to 63,828 bbl/d. This is within the 134 bbl/d to 150,000 bbl/d range reported in the 1983 study referenced in the Ocean Criteria Discharge Evaluation.

[1] Veil, J.A., Kimmell, T.A., Rechner, A.C. 2005. Characteristics of Produced Water Discharged to the Gulf of Mexico Hypoxic Zone. U.S. Dept. of Energy. Contract W-31-109-Eng-38. 74pp.

Comment 28: The Proposed GP has no limits on the amount of well stimulation chemicals that can be discharged when combined with PW.

Response to comment 28: See Response to CBD-1 for a detailed description of the current GP protections and an explanation of the EPA Region 4's determination that the discharges covered under this GP will not result in an unreasonable degradation of the marine environment in the vicinity of the discharges. In addition, the direct, indirect and cumulative environmental impacts from issuance of the GP are appropriately analyzed in the DEA. As part of the broader analysis of the GP, the EPA Region 4 determined that there is currently no scientific basis for numerical limits on specific chemicals used in WTCW fluids discharged into the GOM.

Comment 29: The EPA ignores the impacts to water quality and marine life that will result from the discharge of chemicals used in fracking and other well stimulation treatments because the wastewater discharges will be subject to permit conditions, including toxicity testing. But NEPA clearly obligates EPA to look at *all* environmental impacts, and it cannot excuse itself from its NEPA hard look duty because a "facility operates pursuant to a…permit..." or because the impacts have been discussed in a non-NEPA document.

Response to comment 29: The NPDES permit requires quarterly samples for discharges of WTCW fluids not comingled with produced waters. The EPA Region 4 has determined that this monitoring frequency is adequate. The NPDES permit also requires that all samples be representative of the monitored activity. Also, see Responses to comments CBD-1 and CBD-10.

The EPA Region 4 has taken a "hard look" at the potential impacts to water quality and marine life. The EPA Region 4 evaluated impacts to water quality and marine life in multiple previous NEPA documents (EISs and EAs) and the current DEA for the proposed action. We do, however, acknowledge that more information regarding WTCW fluids would be useful to inform future permitting decisions and are proposing additional permit requirements under the new GP to address these gaps. Baseline conditions including water quality and aquatic life are described in Sections 3.1 to 3.3.6 of the DEA.

Comment 30: Testing of WCTW fluids does not prevent the chemicals from being dumped into the ocean in the first place; and because the monitoring requirement is at most quarterly or once every six months, testing is unlikely to coincide with discharge of well stimulation chemicals (nor is there a requirement that it do so). In addition, much of the testing is based on the concentrations at the edge of the mixing zone, not at the discharge location. The EPA arbitrarily ignores all impacts inside the mixing zone. Relatedly, the EPA fails to analyze whether any mixing zones will overlap, and what the impact of such overlap could be. Moreover, by focusing on impacts based on the mixing zone radius, the EPA largely ignores the effect of wastewater plumes on water quality. Yet, as explained above, the discharge of fracking chemicals can have myriad negative impacts on water quality, including impacts on marine species. The EPA's failure to take a hard look at the water quality impacts on this basis violates NEPA.

Response to comment 30: Any well stimulation fluids remaining in the formation after the well completion and stimulation phase of well construction naturally mix (comingle) with formation (produced) water. The comingled water is brought to the surface and discharged after treatment. The discharge of stimulation fluids mixed with produced water is continuous until the volume of stimulation fluids remaining in the formation is exhausted. Therefore, the prescribed monitoring frequency will be adequate to include stimulation fluids until it is completely removed from the producing formation.

See Response to CBD-10 regarding mixing zones. With respect to monitoring frequency, the NPDES permit requires quarterly samples for discharges of WTCW fluids not comingled with PW. The EPA has determined that this monitoring frequency is adequate.

See Response to CBD-29 regarding the "hard look" comment.

Comment 31: The Proposed GP authorizes the discharge of unlimited volumes of Produced Waters, including those mixed with fracking chemicals. But EPA has not meaningfully analyzed the massive volume of produced water that flows into the GOM from oil and gas operations. For example, the EPA's DEA states that "[d]ischarges are subject to dilution and dispersion that reduce the potential extent of acute water column impacts to within a few hundred meters of the discharge." Yet the EPA wholly fails to discuss what the impacts within a few hundred meters of the discharge will be. In addition, the EPA admits that the discharges authorized by the Proposed GP could potentially affect fish species through impacts to water and sediment quality, but EPA wholly fails to state what those impacts might be. The EPA makes similar statements for each species found in the Eastern Gulf, including marine mammals, sea turtles, birds, deepwater benthic communities, live bottom communities, and seagrasses. But, again, the EPA does not state, or analyze, what those impacts might be.

Response to comment 31: See Response to CBD-6 for response related to impacts of PW.

The EPA Region 4 has taken a "hard look" at the impact of produced water. The EPA Region 4 has evaluated the impact of PW in both multiple previous NEPA documents (EISs and EAs) and the current DEA for the proposed action. Specifically, Chapter 4 of the DEA analyzes impacts from produced water on the environment, including impacts to marine species, from the proposed action and reasonable alternatives.

Comment 32: The Proposed GP establishes a mixing zone of 100 m for each discharge location. But EPA fails to analyze any impacts within that mixing zone, or the impacts on migratory species that live in the GOM, including fish, sea turtles, whales, and dolphin, that may travel through multiple mixing zones in a single migration.

Response to comment 32: The volumes of PW discharged are not limited; however, the permit minimizes impacts to marine life by including several prohibitions regarding discharges near ABC and federally designated disposal sites, TBELs and WQBELs. Based on whole effluent toxicity data reported by permittees under the current R4 offshore permit, there have been no toxicity testing violations, hence no need at this time to impose further restrictions on produced waters. See Responses to CBD-10 and CBD-3 regarding mixing zones and ESA and EFH.

Comment 33: In addition, EPA's DEA fails to adequately consider the cumulative impacts of its proposal to adopt the preferred alternative and allow oil companies to dump toxic wastewater into the GOM. In particular, the EPA did not consider impacts to benthic communities based on its conclusory statements that impacts to benthic communities are unlikely because the Proposed GP would only cover activities seaward of the 200-m isobath; and that operations in water depths shallower than 200 meters will require coverage under

NPDES individual permits. But the issuance of individual permits in this area is a reasonable foreseeable action that the EPA must consider as part of its cumulative impacts analysis.

Response to comment 33: The EPA Region 4 will be responsible for reviewing NPDES permit applications for individual permit coverage in waters beyond state authority in the Gulf, and maintains the right to issue individual permit in lieu of coverage under the GP. The general permit coverage area is Federal Waters of the Gulf of Mexico (1) seaward of 200- meter depth contour offshore of Alabama in the Destin Dome lease block, (2) seaward of the 200-meter depth contour offshore of Florida, and (3) in the Mobile and Viosca Knoll lease block areas offshore of Mississippi and Alabama. In areas of the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. All facilities must operate a minimum of 1000 m from sensitive marine habitats in pre-designated Areas of Biological Concern. In development of the DEA, the EPA Region 4 contemplated the cumulative impacts of individual permits within the areas inside the 200-m isobaths offshore Florida and in the Destin Dome lease block offshore of Alabama; however, the majority of these areas are currently under congressional moratoria for the anticipated GP period and any issued individual permits would have more protective permit conditions which would address and minimize any direct, indirect, and cumulative impacts to these areas, as necessary to meet relevant regulatory requirements. The cumulative impacts have been adequately considered in the proposed action. Chapter 4 of the DEA includes detailed discussion of environmental consequences for the proposed action for each resource area along with a detailed discussion on cumulative impacts for each resource area. In addition, anticipated cumulative impacts to benthic communities from the proposed action are discussed in Section 4.3.5.3.

Comment 34: The EPA also dismisses the cumulative impacts of the discharge of wastewater into the GOM on marine water quality because the impacts are low compared to the oil and gas industry as a whole. This misses the entire point of a cumulative impacts analysis. Cumulative impacts, by definition, may be relatively minor when viewed in isolation yet significant in combination. It is the combined effect that the EPA is required to analyze, not the comparative effect. The EPA's dismissal of such impacts on this basis is improper.

Response to comment 34: The EPA has determined that the permit conditions in previous GPs for offshore oil and gas development and the newly proposed GP is protective of water quality and marine life. Based on available data and research the EPA found that there are no "significant" cumulative impacts to water quality and marine life in the GOM due to authorization of the EPA Region 4 GP. In addition, see preliminary FONSI.

Comment 35: EPA cannot issue a FONSI. EPA must therefore prepare an EIS.

Response to comment 35: See Responses to CBD Comments-3, 22, 23, and 25. The EPA has determined that the requirements under 40 CFR Section 6.206(a) can be met regarding the issuance of a FONSI.

Comment 36: EPA cannot issue the permit unless and until formal Section 7 consultation is complete and any measures required to mitigate the harm to listed species or their critical habitat from the discharge of offshore oil and drilling wastes are including as binding conditions of the permit.

Response to comment 36: Prior to publicly noticing the GP, the EPA Region 4 prepared a DEA pursuant to the NEPA and also initiated consultation with the USFWS and the NMFS in accordance with the ESA. Since publication of the DEA, USFWS provided concurrence with the EPA Region 4's determination that issuance of the Offshore Oil and Gas GP is not likely to adversely affect species or critical habitat under the ESA. The USFWS provided concurrence in a letter to the EPA Region 4 dated January 19, 2017, and the NMFS concurred with the EPA Region 4's EFH assessment in a letter dated December 16, 2016. The EPA Region 4 has determined that its proposed action will NLAA listed species under the purview of the NMFS and will not likely jeopardize species and/or adversely modify critical habitat. The NMFS has not yet completed consultation or provided its concurrence on EPA's NLAA determination, but based on information in the record EPA anticipates that NMFS will concur with this determination. The EPA has determined that it can issue the GP prior to completion of consultation with NMFS in accordance with Section 7(a)(2) and Section 7(d) of the ESA because the issuance of the permit will not result in any irreversible or irretrievable commitment of resources which would have the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures that might be identified by NMFS pursuant to the consultation process. In the event that NMFS does identify necessary reasonable and prudent alternative measures that are necessary to prevent jeopardy to protected species or adverse impacts to critical habitat, the EPA has authority to modify the permit to include whatever conditions are necessary to implement such reasonable and prudent alternative measures. To avoid an irreversible or irretrievable commitment of resources, the reissued GP includes a specific re-opener clause that will enable the EPA Region 4 to modify the GP should further consultation reveal a need to formulate or implement reasonable and prudent alternative measures. This updated information regarding ESA consultation is reflected in our preliminary FONSI. The EPA Region 4 determined that formal consultation is not required (50 CFR § 402.14(b)(1)). This updated information regarding ESA consultation is reflected in our preliminary FONSI.

Comments for Cubic Image Environmental, LLC

Comment 1 (paraphrased): The Permit has no provision for characterization or treatment of naturally-occurring chemicals and dissolved contaminants in formation water prior to discharge. Parts I(B)3) and V(B)(67) of the GP fail to acknowledge that dissolved contaminants are washed out of crude oil and become dissolved in formation water, which is a component of PW. Pollutants such as benzene, toluene, ethylbenzene and xylenes (BTEX) and benzo(a)pyrene and naturally-occurring radioactive material (NORM) (i.e., radium 226 and 228) are considered to be human carcinogens and are also carcinogenic to marine fauna.

Response to Comment 1: The EPA acknowledges that pollutants present in formation water and produced water can include BTEX, polyromantic hydrocarbons, and NORM, and permit conditions have been developed to minimize the impacts of the discharge on human health and aquatic life. Impacts from chemical species, such as BTEX and PAH, are addressed using TBELs, water-quality based effluent limits (WQBELs), and BMPs. TBELs are established in EPA’s effluent guidelines for the offshore industry (reference 40 CFR Part 435). In particular, the permit’s oil and grease limit serves as an indicator for toxic pollutants in Produced Water and WTCW fluids waste streams based on the EPA’s determination that toxic pollutants are largely controlled by removal of oil and grease. The permit also prohibits the discharge of free oil. Effluent limits and monitoring for WET are included in the permit for Produced Water discharges in order to protect aquatic life near the vicinity of the discharges. Lastly, the permit also includes BMPs to help address pollutants not controlled by effluent limits. The regulation of NORM under the NPDES program is complex. There are no TBELs or WQBELs which directly address this category of pollutants, which create potential radiation exposure risks to humans and the environment. Studies also have been done to determine whether produced water discharges have the potential to cause bioaccumulation of pollutants such as BETX and PAHs. Based on the results of those studies we have not found that additional permit limits are needed to prevent bioaccumulation and the associated impacts to human health from fish tissue consumption.

The EPA acknowledges that releases of NORM due to mining, drilling and other human activities are an environmental and human health concern. The Agency uses the term Technologically Enhanced Naturally Occurring Radioactive Material (TENORM), which is defined as, " naturally occurring radioactive materials that have been concentrated or exposed to the accessible environment as a result of human activities such as manufacturing, mineral extraction, or water processing." Not all oil and gas fields have TENORM accumulations, and EPA understands that if it is present, it may form a mineral scale on production piping, and other equipment, thereby increasing exposure to workers most likely via inhalation of dusts and direct radiation. Human protection from impacts of radiation is addressed in company occupational health and safety documents. The EPA has previously required monitoring of produced water discharges for Radium 226 and 288; however, data from that monitoring did not show that they were in sufficient concentrations to pose a potential environmental impact.

Comment 2 (paraphrased): The GP contains inadequate sampling requirements and analysis of oil and grease content and the toxicity of PW discharges, and it does not require permittees to quantify the mass of contaminants being discharged. Additionally, the GP requires testing of oil and grease using the gravimetric method instead of a more accurate gravimetric/mass spectrometry method. Toxicity is analyzed using a grab sample which has been diluted to a predicted critical dilution. The toxicity test does not analyze for target chemicals nor is the dilution of the sample protective enough.

Response to Comment 2: PW discharges are relatively long term and occur once the facility begins the production phase of operations. Based on the Best Professional Judgment (BPJ) of the permit writer, the permit requires grab samples to be analyzed monthly using an EPA-approved method in 40 CFR Part 136. The commenter did not provide specifics regarding he inadequacy of the current permit requirements; however, the EPA welcomes and will consider any data suggesting that the current sampling frequency and analytical method are inadequate.

The WET test is a gauge that the effluent will be protective of aquatic life, and it is designed to detect the synergistic impacts of chemicals. Only if the WET testing results show more than three failures in a row are operators required to perform additional testing to investigate the causative toxicant (i.e., individual chemical species). Since the receiving waterbody is large, it is reasonable to allow a mixing zone for certain waste streams.

Comment 3 (paraphrased): There is no provision in the GP for testing the corrosivity (i.e., pH) of PW prior to discharge, and the GP's contains an inadequate provision allowing operators to self-certify that there are no priority pollutants in chemicals used in these fluids. WTCW fluids are allowed to be commingled in PW prior to discharge. These fluids contain acids, biocides, friction reducers and viscosity enhancers, which are corrosive.

Response to Comment 3: Some WTCW fluids may be corrosive and commingled with PW prior to discharge. However, based on the EPA data, the pH of PW commingled with WTCW fluids is within a range of 6-9 standard units, which is protective of aquatic life. Therefore, there is no need to test pH of PW prior to discharge. Also, although the permit does not include a pH limit, permittees must sample and perform WET testing to demonstrate PW effluents are not toxic to aquatic life. By design, the NPDES permitting program requires permittees to self-monitor and self-certify. Permittees must sign certification statements that the information/data being submitting is accurate, including proper quality control of samples, and the regulations impose penalties for submitting false information. The permit requires permittees to self-certify that WTCW fluids contain priority pollutants in less than detectable amounts, which the EPA believes is a sufficient demonstration that the effluent will be protective of aquatic life.

Comment 4 (paraphrased): The GP fails to include provisions for verifying actual chemical concentrations at the edge of the 100-m mixing zone using documented laboratory analysis with proper quality control.

Response to Comment 4: NPDES permit regulations require sampling only where the sample point is accessible and safe and, ultimately, it is the permittee's responsibility to provide a safe and accessible sampling point that is representative of the discharge. For practical reasons, in lieu of verifying actual chemical concentrations via sampling at the edge of the mixing zone in the GOM, the permit allows the use of a CORMIX model to predict concentrations.

Comment 5 (paraphrased): The EPA has a duty to uphold the CWA, specifically the regulations at 40 CFR § 125.122, which prevent the unreasonable degradation of the marine environment. The practice of ocean disposal of PW exists only because EPA excludes oil and gas industry wastes from Resource Conservation and Recovery Act regulations.

Response to comment 5: The permit address both Sections 402 and 403 of the CWA, and the EPA works with the federal and state agencies to insure that the permit will not adversely impact endangered species and coastal communities. A CWA Section 403 determination was prepared and publicly notice with the draft GP. The Section 403 determination addresses the potential for permitted discharges to cause an unreasonable degradation of the marine environment in the vicinity of the discharges. This document was transmitted separately to the US FWS and the NMFS for their review of potential impacts to Endangered Species and commercial fisheries. Additionally, the states of Mississippi, Alabama and Florida were contacted in order for coastal programs to provide input regarding potential impacts to coastal waterbodies. The permit allows the discharge of PW in accordance with the prescribed permit conditions for this waste stream, which the EPA has determined are protective of aquatic life.

Comments from the International Association of Drilling Contractors

Comment 1: The IADC shares the concerns and recommendations expressed by the Offshore Operator's Committee.

Response to Comment 1: Please refer to EPA Region 4's above responses to comments submitted by the OOC in its letter to EPA dated October 17, 2016.

Comments from the Petroleum Equipment and Service Association

Comment 1 (paraphrased): The permit notification language at Part I.A.4.u. should be revised to allow operators to disclose information on well treatment, completion and workover fluids based on information on SDSs. Operators should be allowed to claim some information pertaining to formulation of chemicals used as "Confidential Business Information" in accordance with 40 CFR Part 2.

Response to comment 1: A revision to this language was not made. EPA disagrees that the information on the SDS should be used to report information on the chemical composition of additives. Also, information submitted cannot be designated as "Confidential Business Information". (See EPA responses to the OOC comments 4,5, and 11, above.). Details of the industry-wide study have not been developed yet, but the EPA envisions different levels of participation. Participants may still have to report annual information regarding additives used in well treatment, completion and workover operations.

Comment 2 (paraphrased): The Drilling Fluids limitations language in Part I.B.1.b. should be revised to reflect the correct analytical method for mercury. Specifically, EPA method 245.7 should be changed to method 245.5.

Response to Comment 2: The requested correction was made regarding the EPA approved method for mercury analysis.

Comment 3 (paraphrased): The Drilling Fluids Inventory Documentation language in Part I.B.1.c.1 should be revised to require permittees to maintain a chemical usage of all products used rather than all constituents used. Drilling Fluid Chemical inventory for drilling operations is currently maintained using product names and quantities or products added to the drilling fluid. Use of the term products will maintain clarity and conformity of the records maintained by Drilling Fluid Specialist and Service company records provided to the operators for commercial, technical and permit compliance purposes.

Response to comment 3: No change made. The permit requires operators to maintain a record of chemicals added to each well drilled in order to determine which specific components may be toxic to the marine environment.

Comment 4 (paraphrased): The language in Part I.B.6.a.iii & b. for WTCW fluids and priority pollutants should be changed to delete specific requirements pertaining to reporting of information on priority pollutants.

Response to Comment 4: No change made. The EPA's proposed language is very similar to the language in the current permit. During the term of the current permit, EPA received no complaints regarding restrictions to discharge fluids with priority pollutants in less than "trace" amounts.

Comment 5 (paraphrased): Off-the-shelf toxicity testing requirements for well treatment, completion, and workover fluids not discharged with produced water may not be appropriate. Therefore, the EPA should work with industry to develop an objective-based approach to toxicity evaluation.

Response to Comment 5: The EPA requires offshore oil and gas operators to use current EPA-approved toxicity tests being used by many industries nationwide. Results of new toxicity testing information to be obtained in this permit will help determine if any changes to toxicity test methods for oil and gas operators is warranted.

Comment 6 (paraphrased): The current permit language pertaining to Test Procedures and Definitions for Formation Oil is redundant. The permit language should be more standardized.

Response to comment 6: No changes were made. The test for Formation Oil is contained in Pat V.9 and the EPA definition for Formation Oil is in Part B.38. Although both parts refer to where the operator can find the EPA approved test method, EPA does not believe the permit is redundant. The commenter did not present any information that suggests ambiguities or problems with operators understanding the required test method to be used based on the current language in the permit. Also, standardization of the language is not necessary. The EPA is unaware of any compliance difficulties or problems with operators using the current procedures in the permit pertaining to contamination of non-aqueous based drilling fluids. Lastly, the commenter did not present suggested revised language for consideration.

Commenter: Kathryn Dombey of Pensacola, FL; email dated August 18, 2016

Comment (paraphrased): I do not support a permit that continues to allow additional pollution of the GOM off the Florida and Alabama coast. It is to protect the precious resort areas for our grandchildren and great-grandchildren.

Response: The NPDES permit includes conditions to ensure that it does not result in unreasonable degradation of the marine environment and complies with federal regulations for point source discharges to waters of the U.S. and is protective of human health and aquatic life.

Commenter: Susan Patton of Tennessee; email dated October 4, 2016

Question 1: Is it true that the EPA plans to dump unlimited amounts of fracking chemicals into the GOM and if true why?

Response: The proposed NPDES GP authorizes discharges of PW and WTCW fluids from oil and gas exploration, development and production activities, including field exploration, drilling, and well treatment and completion activities (known as hydraulic fracturing). The GP is protective of sensitive aquatic communities. In the Mobile and Viosca Knoll lease block areas offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. Additionally, the GP covers only facilities operating in depths of 200 m or more offshore Florida and offshore Alabama in the Destin Dome lease block. All facilities must operate a minimum of 1000 m from sensitive marine habitats in pre-designated Areas of Biological Concern.

When issued, the permit term is 5 years. The NPDES permit includes conditions to ensure that it does not result in unreasonable degradation of the marine environment, complies with federal regulations for point source discharges to waters of the U.S. and is protective of human health and aquatic life.

Question 2: Does the EPA allow dumping of offshore fracking byproduct into the Gulf?

Response: Discharges of fluids used in fracking operations may occur during WTCW operations prior to oil and gas production. Such discharges are allowed but must meet conditions in the permit that ensure that the permit does not cause unreasonable degradation of the marine environment. The permit applies effluent guideline-based limitations and toxicity testing requirements limits on the discharge of WTCW fluids not commingled with PW.

Question 3: Is there any water quality monitoring associated with the dumping?

Response: The draft GP includes new WET monitoring requirements specifically for discharges resulting from well treatment fluid operations, including hydraulic fracturing. It also includes reporting requirements to better understand potential impacts of discharges, including location, volume of fluids used, chemical parameters and duration of discharge.

Commenter: Paul D. Steury; email dated October 5, 2016

Comment (paraphrased): Is the EPA thinking about allowing frack water to be disposed of in the GOM?

Response: Yes. The draft NPDES GP authorizes discharges of PW and WCTW fluids from oil and gas exploration, development and production activities, including field exploration, drilling, and well treatment and completion activities (known as hydraulic fracturing). The permit covers all discharges in the Eastern GOM (1) offshore of Florida in water depths seaward of 200 meters, (2) in the Destin Dome lease block offshore of Alabama in water depths seaward of 200 meters, and (3) in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama. When issued, the permit term is 5 years. Discharges are allowed provided certain conditions are met. The permit applies effluent guideline-based limitations and toxicity limits on the discharge of well treatment, completion and workover fluids when discharged with produced water, and effluent guideline-based limitations and monitoring requirements apply to well completion and treatment fluid discharged separately.

The proposed GP includes new WET monitoring requirements specifically for discharges resulting from well treatment fluid operations, including hydraulic fracturing. It also includes reporting requirements to better understand potential impacts of discharges, including location, volume of fluids used, chemical parameters and duration of discharge.

The NPDES GP includes conditions to ensure that it does not result in unreasonable degradation of the marine environment, complies with federal regulations for point source discharges to waters of the U.S. and is protective of human health and aquatic life. The issuance of the GP is consistent with the requirements of the CWA and NEPA. The EPA will continue to engage in the required consultation with the appropriate agencies as required by various statutes, such as the ESA, in connection with issuance of the final GP.

Comments from the American Petroleum Institute, letter dated October 18, 2016.

Comment 1 (paraphrased): The API support's the OOC's detailed comments on the permit and adopt and incorporate those comments by reference.

Response to Comment 1: See the EPA's response to comments from the OOC on the draft permit.

Comment 2: The API supports the proposed findings of no significant impact within the draft Environmental Assessment; however, sections 1.3.4.2 and 3.6.3.3 should be made consistent.

Response to Comment 2: EPA reviewed section 1.3.4.2 (Scope of this NEPA Document) and 3.6.3.3 (Deepwater Horizon Impacts on Socioeconomic Resources-Human Health Impacts) of the DEA and did not note any inconsistences in the text.

Comment 3: EPA should modify the deadline for electronic reporting to ensure accuracy and operational functionality of the system, and we support the OOC's request to provide input during the NetDMR development process and beta testing prior to implementation.

Response to Comment 3: The deadline in the permit of December 21, 2016, is mandated by the regulation and cannot be extended. Beta testing has already begun by the EPA at the Headquarters level.

Comment 4: The API supports the OOC's request for the permit to clarify that toxicity monitoring only requirements be in the permit. We furthermore support the concerns the OOC has raised in regards to the CBI contained in the proposed reporting requirements.

Response to Comment 4: See the Responses to the OOC comment numbers 4 and 9.

Comment 5: The API supports the OOC's objection to continued ongoing entrainment monitoring and supports a two-year study for newly affected facilities and the use of SEAMAP data to show compliance with the CWA Section 316(b) requirements in lieu actual sampling.

Response to Comment 5: See the Response to the OOC comment number 19.

ENVIORNMENTAL PROTECTION AGENCY-REGION 4
NPDES ENFORCEMENT AND PERMITS BRANCH
WATER PROTECTION DIVISION

Appeal of NPDES Permits from
Title 40, Code of Federal Regulations (40 CFR) Section 124.19

§ 124.19 Appeal of RCRA, UIC, NPDES, and PSD Permits.

(a) Within 30 days after a RCRA, UIC, NPDES, or PSD final permit decision (or a decision under 270.29 of this chapter to deny a permit for the active life of a RCRA hazardous waste management facility or unit) has been issued under § 124.15 of this part, any person who filed comments on that draft permit or participated in the public hearing may petition the Environmental Appeals Board to review any condition of the permit decision. Persons affected by an NPDES general permit may not file a petition under this section or otherwise challenge the conditions of the general permit in further Agency proceedings. They may, instead, either challenge the general permit in court, or apply for an individual NPDES permit under § 122.21 as authorized in § 122.28 and then petition the Board for review as provided by this section. As provided in § 122.28(b)(3), any interested person may also petition the Director to require an individual NPDES permit for any discharger eligible for authorization to discharge under an NPDES general permit. Any person who failed to file comments or failed to participate in the public hearing on the draft permit may petition for administrative review only to the extent of the changes from the draft to the final permit decision. The 30-day period within which a person may request review under this section begins with the service of notice of the Regional Administrator's action unless a later date is specified in that notice. The petition shall include a statement of the reasons supporting that review, including a demonstration that any issues being raised were raised during the public comment period (including any public hearing) to the extent required by these regulations and when appropriate, a showing that the condition in question is based on:
(1) A finding of fact or conclusion of law which is clearly erroneous, or
(2) An exercise of discretion or an important policy consideration which the Environmental Appeals Board should, in its discretion, review.
(b) The Environmental Appeals Board may also decide on its own initiative to review any condition of any RCRA, UIC, NPDES, or PSD permit decision issued under this part for which review is available under paragraph (a) of this section. The Environmental Appeals Board must act under this paragraph within 30 days of the service date of notice of the Regional Administrator's action.
(c) Within a reasonable time following the filing of the petition for review, the Environmental Appeals Board shall issue an order granting or denying the petition for review. To the extent review is denied, the conditions of the final permit decision become final agency action. Public notice of any grant of review by the Environmental Appeals Board under paragraph (a) or (b) of this section shall be given as provided in § 124.10. Public notice shall set forth a briefing schedule for the appeal and shall state that any interested person may file an amicus brief. Notice of denial of review shall be sent only to the person(s) requesting review.
(d) The Regional Administrator, at any time prior to the rendering of a decision under paragraph (c) of this section to grant or deny review of a permit decision, may, upon notification to the Board and any interested parties, withdraw the permit and prepare a new draft permit under § 124.6 addressing the portions so withdrawn. The new draft permit shall proceed through the same process of public comment and opportunity for a public hearing as would apply to any other draft permit subject to this part. Any portions of the permit which are not withdrawn and which are not stayed under § 124.16(a) continue to apply.
(e) A petition to the Environmental Appeals Board under paragraph (a) of this section is, under 5 U.S.C. 704, a prerequisite to the seeking of judicial review of the final agency action.
(f)

(1) For purposes of judicial review under the appropriate Act, final agency action occurs when a final RCRA, UIC, NPDES, or PSD permit decision is issued by EPA and agency review procedures under this section are exhausted. A final permit decision shall be issued by the Regional Administrator:
(i) When the Environmental Appeals Board issues notice to the parties that review has been denied;
(ii) When the Environmental Appeals Board issues a decision on the merits of the appeal and the decision does not include a remand of the proceedings; or
(iii) Upon the completion of remand proceedings if the proceedings are remanded, unless the Environmental Appeals Board's remand order specifically provides that appeal of the remand decision will be required to exhaust administrative remedies.
(2) Notice of any final agency action regarding a PSD permit shall promptly be published in the *Federal Register.*
(g) Motions to reconsider a final order shall be filed within ten (10) days after service of the final order. Every such motion must set forth the matters claimed to have been erroneously decided and the nature of the alleged errors. Motions for reconsideration under this provision shall be directed to, and decided by, the Environmental Appeals Board. Motions for reconsideration directed to the administrator, rather than to the Environmental Appeals Board, will not be considered, except in cases that the Environmental Appeals Board has referred to the Administrator pursuant to § 124.2 and in which the Administrator has issued the final order. A motion for reconsideration shall not stay the effective date of the final order unless specifically so ordered by the Environmental Appeals Board.

[48 FR 14264, Apr. 1, 1983, as amended at 54 FR 9607, Mar. 7, 1989; 57 FR 5335, Feb. 13, 1992; 65 FR 30911, May 15, 2000]

OCEAN DISCHARGE CRITERIA EVALUATION FOR THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM GENERAL PERMIT FOR THE EASTERN GULF OF MEXICO OUTER CONTINENTAL SHELF

May, 2017

U.S. Environmental Protection Agency, Region 4
Water Management Division
Atlanta Federal Center
61 Forsyth Street, S.W.
Atlanta, GA 30303

CONTENTS

TABLES

FIGURES

1. INTRODUCTION

The U.S. Environmental Protection Agency (EPA), Region 4, issuing a new National Pollutant Discharge Elimination System (NPDES) general permit for discharges from new and existing sources and new discharges of oil and gas extraction activities in its jurisdictional area of the Outer Continental Shelf (OCS) of the Gulf of Mexico. The permit will apply to exploration, development and production phases for both existing and new sources within the Eastern Planning Area and portions of the Central Planning Area of the U.S. Department of the Interior (DOI), Bureau of Ocean Energy Management (BOEM).

This Ocean Discharge Criteria Evaluation (ODCE) addresses the U.S. Environmental Protection Agency's (EPA) regulations for preventing unreasonable degradation of the receiving waters in portions of the Gulf of Mexico covered under this General Permit.

1.1 Background

Section 402 of the Clean Water Act (CWA) authorizes EPA to issue National Pollutant Discharge Elimination System (NPDES) permits to regulate discharges to waters of the United States. Sections 402 and 403 of the CWA require that an NPDES permit for a discharge into the territorial seas (baseline to 3 miles), or farther offshore in the contiguous zone or the ocean, be issued in compliance with EPA's regulations for preventing unreasonable degradation of the receiving waters in Title 40 of the Code of Federal Regulations [CFR] Part 125, Subpart M.

Prior to permit issuance, discharges must be evaluated against EPA's published criteria for determination of unreasonable degradation. Unreasonable degradation is defined in the NPDES regulations (40 CFR 125.121[e]) as the following.

1. Significant adverse changes in ecosystem diversity, productivity, and stability of the biological community within the area of discharge and surrounding biological communities

2. Threat to human health through direct exposure to pollutants or through consumption of exposed aquatic organisms

3. Loss of aesthetic, recreational, scientific or economic values, which is unreasonable in relation to the benefit derived from the discharge.

Ten factors are specified at 40 CFR 125.122 for determining unreasonable degradation. They are the following.

1. The quantities, composition, and potential for bioaccumulation or persistence of the pollutants to be discharged

2. The potential transport of such pollutants by biological, physical or chemical processes

3. The composition and vulnerability of the biological communities which may be exposed to such pollutants, including the presence of unique species or communities of species, the presence of species identified as endangered or threatened pursuant to the Endangered Species Act, or the

presence of those species critical to the structure or function of the ecosystem, such as those important for the food chain

4. The importance of the receiving water area to the surrounding biological community, including the presence of spawning sites, nursery/forage areas, migratory pathways, or areas necessary for other functions or critical stages in the life cycle of an organism
5. The existence of special aquatic sites including, but not limited to, marine sanctuaries and refuges, parks, national and historic monuments, national seashores, wilderness areas, and coral reefs
6. The potential impacts on human health through direct and indirect pathways
7. Existing or potential recreational and commercial fishing, including finfishing and shellfishing
8. Any applicable requirements of an approved Coastal Zone Management plan
9. Such other factors relating to the effects of the discharge as may be appropriate
10. Marine water quality criteria developed pursuant to Section 304(a)(1).

On the basis of the analysis in this ODCE, the Regional Administrator will determine whether the general permit may be issued. The Regional Administrator can make one of three findings:

1. The discharges will not cause unreasonable degradation of the marine environment and issue the permit.
2. The discharges will cause unreasonable degradation of the marine environment, and may deny the permit or impose more stringent permit conditions and/or monitoring.
3. There is insufficient information to determine, before permit issuance, that there will be no unreasonable degradation of the marine environment, and issue the permit if, on the basis of available information, that:
    - Such discharge will not cause irreparable harm1 to the marine environment during the period in which monitoring will take place.
    - There are no reasonable alternatives to the on-site disposal of these materials.
    - The discharge will be in compliance with additional permit conditions set out under (40 CFR 125.123(d)).

1.2 Scope

The new general permit covers discharges from offshore oil and gas activities that fall into three operational categories:

1) Exploratory drilling operations, which identify the location of producing formations.
2) Development operations conducted on platforms from which multiple wells are drilled.
3) Production operations that occur during and after developmental drilling.

This Ocean Discharge Criteria Evaluation (ODCE) evaluates the impacts from the waste discharges regulated under the permit including drilling fluids; drill cuttings; deck drainage; produced water; produced sand; well treatment, completion, and workover fluids; sanitary waste; domestic waste; and miscellaneous wastes.

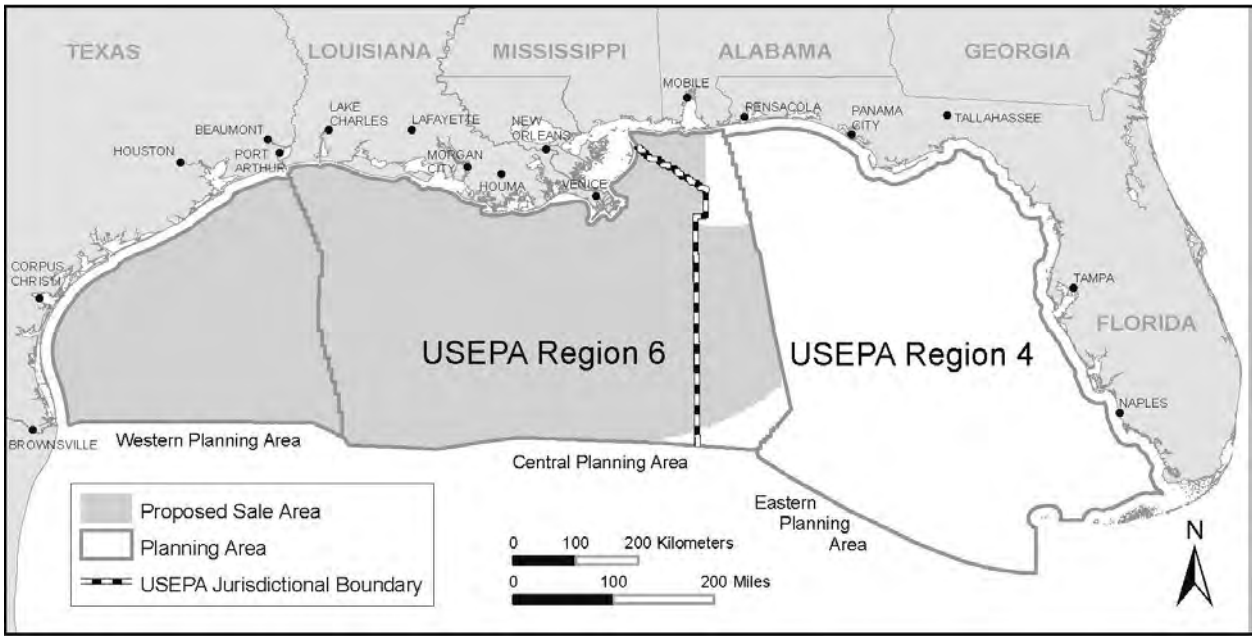
In this evaluation the ODCE addresses the 10 factors for determining unreasonable degradation as outlined above and at 40 CFR 125.122. It also assesses whether the information exists to make a "no unreasonable degradation" determination, including any recommended permit conditions that may be necessary to reach that conclusion.

1.3 Area of Coverage

Figure 1-1 shows the EPA Region 4 and 6 CWA jurisdictional boundary and its relationship with BOEM Eastern, Central and Western Planning Areas for leasing activities in the GOM. The Clean Water Act provides EPA with federal jurisdiction for NPDES permitting beginning three statute miles from the landward boundary of the territorial seas, or "baseline," for all states bordering the Gulf of Mexico.

The general permit will authorize new and existing source discharges from oil and gas activities within the Region 4 jurisdictional area seaward from the 200 meter depth contour. Activities landward of the 200 meter depth contour will require individual NPDES permits.

Figure 1-1. USEPA Region 4 and 6 water quality jurisdictional boundaries.



Source BOEM 2012

1.4 Document Overview

Section 2 of this document provides a description of the physical environment relevant to the portions of the Eastern and Central Planning areas covered by the General permit (ODCE Factor 2). Section 3 describes the characteristics, composition, and quantities of materials that potentially will be discharged from the facility (ODCE Factor 1). Section 4 describes the transport and persistence of pollutants in the marine environment (ODCE Factor 2). Section 5 describes the toxicity and potential for bioaccumulation of contaminants in the waste streams covered by the proposed permit (ODCE Factors 1 and 6). Section 6 provides a biological overview of the affected environment (ODCE Factors 3 and 4). Section 7 provides information on commercial and recreational fisheries in the receiving water environment (ODCE Factor 7). Section 8 describes the Florida Coastal Zone Management Plan (CZMP) and Special Aquatic Sites (ODCE Factors 5 and 8). Section 9 provides a Federal Water Quality Criteria and State Water Quality Standards Analysis (ODCE Factor 10). Section 10 describes potential impacts on human health (ODCE Factor 6). Section 11 lists cited references. Factor 9, the consideration of additional factors, was not considered necessary in this evaluation.

2.0 The Physical Environment

2.1 Physical Oceanography

The Gulf of Mexico GOM is bounded by Cuba on the southeast; Mexico on the south and southwest; and the U.S. Gulf Coast on the west, north, and east. The GOM has a total area of 564,000 square kilometers (km2) (217,762 square miles [mi2]). Shallow and intertidal areas (water depths of less than 20 m) compose 38 percent of the total area, with continental shelf (22 percent), continental slope (20 percent), and abyssal (20 percent) composing the remainder of the basin.

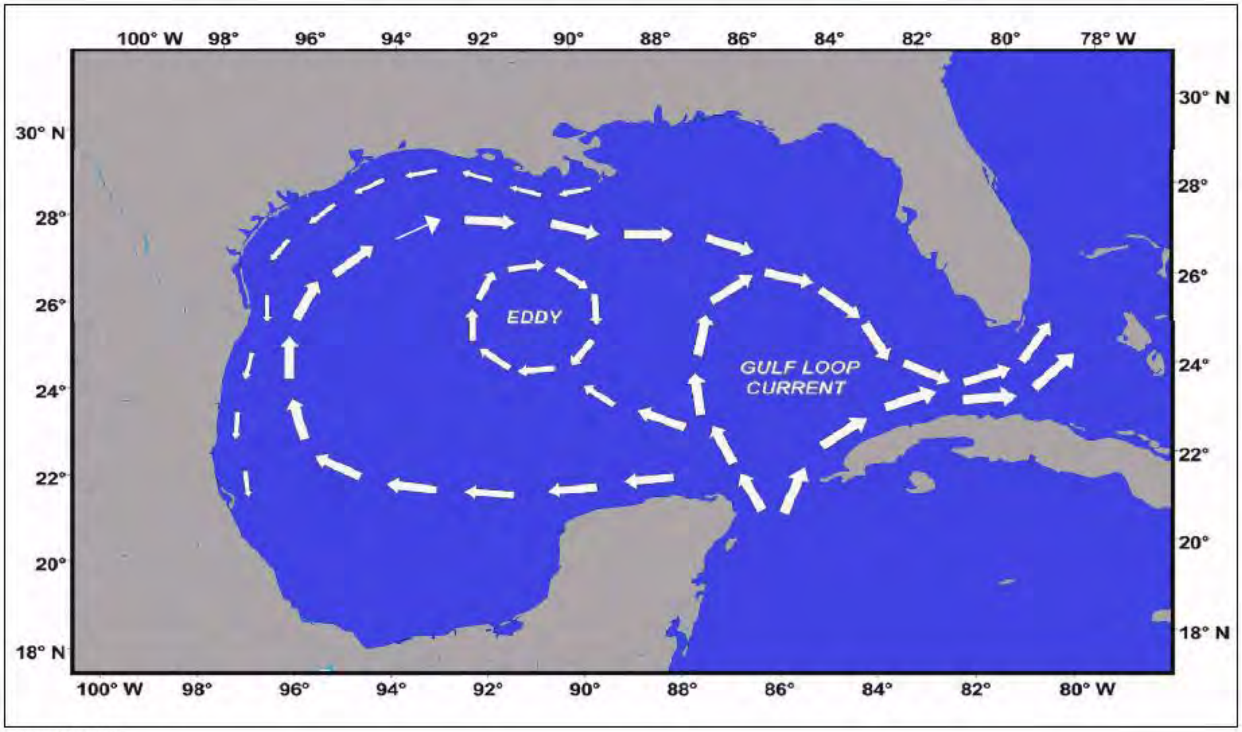
The Gulf is separated from the Caribbean Sea and Atlantic Ocean by Cuba and other islands, and has relatively narrow connections to the Caribbean and Atlantic through the Florida and Yucatan Straits. The Gulf is composed of three distinct water masses, including the North and South Atlantic Surface Water (less than 100 m deep), Atlantic and Caribbean Subtropical Water (up to 500 m deep), and Subantarctic Intermediate Water.

2.1.1 Circulation

Circulation patterns in the Gulf of Mexico are characterized by two interrelated systems, the offshore or open Gulf, and the shelf or inshore Gulf. Both systems involve the dynamic interaction of a variety of factors. Open Gulf circulation is influenced by eddies, gyres, winds, waves, freshwater input, density of the water column, and currents. Offshore water masses in the eastern Gulf may be partitioned into a Loop Current, a Florida Estuarine Gyre in the northeastern Gulf, and a Florida Bay Gyre in the southeastern Gulf (Austin, 1970).

The strongest influence on circulation in the eastern Gulf of Mexico is the Loop Current (Figure 2-1). The location of the Loop Current is variable, with fluctuations that range over the outer shelf, the slopes, and the abyssal areas off Mississippi, Alabama, and Florida. Within this zone, short-term strong currents exist, but no permanent currents have been identified (MMS, 1990). The Loop Current forms as the Yucatan Current enters the Gulf through the Yucatan Straits and travels through the eastern and central Gulf before exiting via the Straits of Florida and merging with other water masses to become the Gulf Stream (Leipper, 1970; Maul, 1977). The Loop Current extends to about 1000 m depth with surface speeds as high as 150-200 cm/s, decreasing with depth (MMS 2000a).

Figure 2-1 Major current regime in the Gulf of Mexico.



Source: NOAA 2007

In the shelf or inshore Gulf region, circulation within the Mississippi, Alabama, and west Florida shelf areas is controlled by the Loop Current, winds, topography, and tides. Freshwater input also acts as a major influence in the Mississippi/Alabama shelf and eddy-like perturbations play a significant role in the west Florida shelf circulation. Current velocities along the shelf are variable. Brooks (1991) found that average current velocities in the Mississippi/Alabama shelf area were are about 1.5 centimeters per second and east-west and northeast-southwest directions dominate. MMS (1990) data showed that winter surface circulation is directed along shore and westward with flow averaging 4 cm/s to 7 cm/s. During the spring and summer, the current shifts to the east with flow averaging 2 cm/s to 7 cm/s. The mean circulation on the west Florida shelf is directed southward with mean flow ranging from 0.2 cm/s to 7 cm/s (MMS, 1990).

Wind patterns in the Gulf are primarily anticyclonic (clockwise around high pressure areas), and tend to follow an annual cycle; winter winds from the north and southeast and summer winds from the northeast and south (Figure 5). During the winter, mean wind speeds range from 8 knots to 18 knots. Several examples of mean annual wind speeds in the eastern Gulf are 8.0 millibars (mb) in Gulf Port, Mississippi; 8.3 mb in Pensacola, Florida; and 11.2 mb in Key West, Florida (NOAA, 1961-1986).

The tides in the Gulf of Mexico are less developed and have smaller ranges than those in other coastal areas of the United States. The range of tides is 0.3 meters to 1.2 meters, depending on the location and time of year. The Gulf has three types of tides, which vary throughout the area: diurnal, semidiurnal, and mixed (both diurnal and semidiurnal). Wind and barometric conditions will influence the daily fluctuations in sea level. Onshore winds and low barometric readings, or offshore winds and high barometric readings, cause the daily water levels either to be higher or lower than predicted. In shelf areas, meteorological conditions occasionally mask local tide-induced circulation. Tropical storms in summer and early fall may affect the area with high winds (18+ meters per second), high waves (7+ meters), and storm surge (3 to 7.5 meters). Winter storm systems also may cause moderately high winds, waves, and storm conditions that mask local tides.

2.1.2 Climate

The GOM is influenced by a maritime subtropical climate controlled mainly by the clockwise wind circulation around a semi-permanent, high barometric pressure area alternating between the Azores and Bermuda Islands. The circulation around the western edge of the high pressure cell results in the predominance of moist southeasterly wind flow in the region. However, winter weather is quite variable. During the winter months, December through March, cold fronts associated with outbreaks of cold, dry continental air masses influence mainly the northern coastal areas of the GOM. Tropical cyclones may develop or migrate into the GOM during the warmer season, especially in the months of August through October. In coastal areas, the land-sea breeze is frequently the primary circulation feature in the months of May through October. (BOEM, 2013)

2.1.2 Temperature

In the Gulf, sea-surface temperatures range from nearly isothermal (29-30^0C) in August to a sharp horizontal gradient in January, ranging from 25^0C in the Loop core to values of 14-15^0C along the shallow northern coastal estuaries. A 7^0C sea-surface temperature gradient occurs in winter from north to south across the Gulf. During summer, sea-surface temperatures span a much narrower range. The range of sea-surface temperatures in the eastern Gulf tends to be greater than the range in the western Gulf, illustrating the contribution of the Loop Current.

Eastern Gulf surface temperature variation is affected by season, latitude, water depth, and distance offshore. During the summer, surface temperatures are uniformly 26.6^0C or higher. The mean March isotherm varies from approximately 17.8^0C in the northern regions to 22.2^0C in the south (Smith, 1976). Surface temperatures range as low as 10^0C in the Louisiana-Mississippi shelf regions during times of significant snow melt in the upper Mississippi valley (MMS, 1990).

At a depth of 1,000 m, the temperature remains close to 5^0C year-round (MMS, 1990). In winter, nearshore bottom temperatures in the northern Gulf of Mexico are 3-10^0C cooler than those temperatures offshore. A permanent seasonal thermocline occurs in deeper offshelf water throughout the Gulf. In summer, warming surface waters help raise bottom temperatures in all shelf areas, producing a decreasing distribution of bottom temperatures from about 28EC at the coast to about 18-20^0C at the shelf break.

The depth of the thermocline, defined as the depth at which the temperature gradient is a maximum, is important because it demarcates the bottom of the mixed layer and acts as a barrier to the vertical transfer of materials and momentum. The thermocline depth is approximately 30-61 m in the eastern Gulf during January (MMS, 1990). In May, the thermocline depth is about 46 m throughout the entire Gulf (MMS, 1990).

2.1.3 Salinity

Characteristic salinity in the open Gulf is generally between 36.4 and 36.5 parts per thousand (ppt). Coastal salinity ranges are variable due to freshwater input, draught, etc. (MMS, 1990). During months of low freshwater input, deep Gulf water penetrates into the shelf and salinities near the coastline range from 29-32 ppt. High freshwater input conditions (spring-summer months) are characterized by strong horizontal gradients and inner shelf salinity values of less than 20l ppt (MMS, 1990).

2.2 Chemical Composition

Of the 92 naturally occurring elements, nearly 80 have been detected in seawater (Kennish, 1989). The dissolved material in seawater consists mainly of eleven elements. These are, in decreasing order, chlorine, sodium, magnesium, calcium, potassium, silicon, zinc, copper, iron, manganese, and cobalt (Smith, 1981). The major dissolved constituents in seawater are shown in Table (2.1). In addition to dissolved materials, trace metals, nutrient elements, and dissolved atmospheric gases comprise the chemical make-up of seawater.

Table 2.1. Major dissolved constituents in seawater with a chlorinity of 19 ‰ and a salinity of 34.32 ‰.

Dissolved substance Ion or compound	Concentration (grams per kilogram)	Percent by weight
Chloride Cl-	18.980	55.04
Sodium Na+	10.556	30.61
Sulfate SO42-	2.649	7.68
Magnesium Mg2+	1.272	3.69
Calcium Ca2+	0.400	1.16
Potassium K+	0.380	1.10
Bicarbonate HCO3-	0.14	0.41
Bromide Br-	0.065	0.19
Boric Acid H3BO3	0.026	0.07
Strontium Sr2+	0.013	0.04
Fluoride F-	0.001	0.0
Totals	34.482	99.99

2.2.1 Micronutrients

In Gulf of Mexico waters, generalizations can be drawn for three principal micronutrients; phosphate, nitrate, and silicate. Phytoplankton consume phosphorus and nitrogen in an approximate ratio of 1:16 for growth. The following nutrient levels and distribution values were obtained from MMS (1990): phosphates range from 0 ppm to 0.25 ppm, averaging 0.021 ppm in the mixed layer, and with shelf values similar to open Gulf values; nitrates range from 0.0031 ppm to 0.14 ppm, averaging 0.014 ppm; silicates range predominantly from 0.048 ppm to 1.9 ppm, with open Gulf values tending to be lower than shelf values.

In the eastern Gulf, inner shelf waters tend to remain nutrient deficient, except in the immediate vicinity of estuaries. On occasions when the loop current occurs over the Florida slope, nutrient-rich waters are upwelled from deeper zones (MMS, 1990).

2.2.2 Dissolved Gases

Dissolved gases found in seawater include oxygen, nitrogen, and carbon dioxide. Oxygen is often used as an indicator of water quality of the marine environment and serves as a tracer of the motion of deep water masses of the oceans. Dissolved oxygen values in the mixed layer of the Gulf average 4.6 mg/l, with some seasonal variation, particularly during the summer months when a slight lowering can be observed. Oxygen values generally decrease with depth to about 3.5 mg/l through the mixed layer (MMS, 1990). In some offshore areas in the northern Gulf of Mexico, hypoxic (<2.0 mg/l) and occasionally anoxic (<0.1 mg/l) bottom water conditions are widespread and seasonally regular (Rabalais, 1986). These conditions have been documented since 1972 and have been observed mostly from June to September on the inner continental shelf at a depth of 5 to 50 meters (Renauld, 1985; Rabalais et al., 1985).

3. DISCHARGED MATERIAL

3.1 Discharges Covered Under the Permit

In this chapter, the following discharges are characterized by their sources and uses during drilling and production operations and by their physical and chemical compositions.

Exploration and development activities for the extraction of oil and gas include work necessary to locate, drill, and complete wells. Exploration activities are those operations that involve drilling wells to determine potential hydrocarbon reserves. Exploratory activities are usually of short duration at a given site, involve a small number of wells, and are generally conducted from mobile drilling units. Development activities involve drilling production wells once a hydrocarbon reserve has been discovered and delineated. These operations, in contrast to exploration activities, may involve a large number of wells which may be drilled from either fixed or floating platforms or mobile drilling units. Production operations, which consist of the work necessary to bring hydrocarbon reserves from the producing formation, begin with the completion of each well at the end of the development phase. The primary wastewater sources from the exploration, development and production phases of the offshore oil and gas extraction industry produce the following wastewater sources:

Drilling Fluids
Drill Cuttings
Deck Drainage
Sanitary Waste
Domestic Waste
Completion Fluids
Cement
Workover Fluids
Blowout Preventer Control Fluids
Desalination Unit Discharge
Ballast and Storage Displacement Water
Bilge Water
Uncontaminated Seawater
Boiler Blowdown
Source Water and Sand

3.2 Drilling Fluids

Drilling fluids (muds), along with drill cuttings with adherent drilling fluid comprise the largest volume of waste discharges from drilling operations. Drilling fluids and drill cuttings are the most significant waste streams from exploratory and development operations in terms of volume and potentially toxic pollutants (EPA, 1993, 58 FR 12454, March 4, 1993, EPA 2009 citation from draft EA). The bulk of drilling muds consists of barite, clays, and a base fluid that can be any of a number of synthetic oils, mineral or diesel oil, or fresh/salt water that may or may not have an oil added for lubricity that are used in rotary drilling operations (EPA, 2009 citation from draft EA). The rotary drill bit is rotated by a hollow drill stem made of pipe, through which the drilling fluid is circulated. Drilling fluids are formulated for each well to meet specific physical and chemical requirements. Geographic location, well depth, rock type, geologic formation, and other conditions affect the mud composition required. The number and nature of mud components varies by well, and several to many products may be used at any time to create the necessary properties. The primary functions of a drilling fluid include the following.

- Transport drill cuttings to the surface
- Control subsurface pressures
- Lubricate the drillstring
- Clean the bottom of the hole
- Aid in formation evaluation
- Protect formation productivity
- Aid formation stability (Moore, 1986).

The functions of drilling fluid additives and typical additives are listed on Table 3-1. Five basic components account for approximately 90 percent by weight of the materials that compose drilling muds: barite, clay, lignosulfonate, lignite, and caustic soda (EPA, 1993).

Barite. Barite is a chemically inert mineral that is heavy and soft. In water-based muds, barite is composed of over 90 percent barium sulfate. Synthetic-based fluids contain about 33% barium sulfate. Barium sulfate is virtually insoluble in seawater. Barite is used to increase the density of the drilling fluid to control formation pressure. The concentration of barite in drilling fluid can be as high as 700 lb/bbl (Perricone, 1980). Quartz, chert, silicates, other minerals, and trace levels of metals can also be present in barite. Barium sulfate contains varying concentrations of metals depending on the characteristics of the deposit from where the barite is mined. One study indicates that there is a correlation between cadmium and mercury and other trace metals in the barite (SAIC, 1991). EPA currently regulates cadmium and mercury concentrations in barite and refers to the stock barite that meets EPA limitations as “clean” barite. Table 3-2 provides mean metals concentrations in “clean” barite compared to their concentration in the earth's crust.

Clay. The most common clay used is bentonite, which is composed mainly of sodium montmorillonite clay (60 to 80%). It can also contain silica, shale, calcite, mica, and feldspar. Bentonite is used to maintain the rheologic properties of the fluid and prevent loss of fluid by providing filtration control in permeable zones. The concentration of bentonite in mud systems is usually 5 to 25 lb/bbl. In the presence of concentrated brine, or formation waters, attapulgite or sepiolite clays (10 to 30 lb/bbl) are substituted for bentonite (Perricone, 1980).

Table 3-1. Functions of Common Drilling Fluid Chemical Additives [a]

Action	Typical Additives	Function
Alkalinity and pH Control	Caustic soda; sodium bicarbonate; sodium carbonate; lime	1. Control alkalinity 2. Control bacterial growth
Bactericides	Paraformaldehyde; alkylamines; caustic soda; lime; starch	Reduce bacteria count NOTE: Halogenated phenols are not permitted for OCS use
Calcium Removers	Caustic soda; soda ash; sodium bicarbonate; polyphosphate	Control calcium buildup in equipment
Corrosion Inhibitors	Hydrated lime; amine salts	Reduce corrosion potential
Defoamers	Aluminum stearate; sodium aryl sulfonate	Reduce foaming action in brackish water and saturated salt muds
Emulsifiers	Ethyl hexanol; silicone compounds; lignosulfonates; anionic and nonionic products	Create homogenous mixture of two liquids
Filtrate Loss Reducers	Bentonite; cellulose polymers; pregelated starch	Prevent invasion of liquid phase into formation
Flocculants	Brine; hydrated lime; gypsum; sodium tetraphosphate	Cause suspended colloids to group into "flocs" and settle out
Foaming Agents		Foam in the presence of water and allow air or gas drilling through formations producing water
Lost Circulation Additives	Wood chips or fibers; mica; sawdust; leather; nut shells; cellophane; shredded rubber; fibrous mineral wool; perlite	Used to plug in the well-bore wall to stop fluid loss into formation
Lubricants	Hydrocarbons; mineral oil; diesel oil; graphite powder; soaps	Reduce friction between the drill bit and the formation
Shale Control Inhibitors	Gypsum; sodium silicate; polymers; lime; salt	Reduce well collapse caused by swelling or hydrous disintegration of shales
Surface Active Agents (Surfactants)	Emulsifiers; de-emulsifiers; flocculants	1. Reduce relationship between viscosity and solids concentration 2. Vary the gel strength 3. Reduce the fluid plastic viscosity
Thinners	Lignosulfonates; lignite; tannis; polyphosphates	Deflocculate associated clay particles
Weighting Material	Barite; calcite; ferrophosphate ores; siderite; iron oxides (hematite)	Increase drilling fluid density
Petroleum Hydrocarbons	Diesel oil; mineral oil	Used for specialized purposes such as freeing stuck pipe

[a] Source: EPA, 1993.

Table 3-2. Trace Metal Concentrations in Barite[a]

Pollutant	Estimated Concentrations on Dry Weight Basis (mg/kg)	
	Barite	Earth's Crust
Aluminum	9,069.9	
Antimony	5.7	
Arsenic	7.1	2
Barium	359,747	
Beryllium	0.7	
Cadmium	1.1	0.2
Chromium	240	
Copper	18.7	45
Iron	15,344.3	50,000
Lead	35.1	15
Mercury	0.1	0.1
Nickel	13.5	80
Selenium	1.1	
Silver	0.7	
Thallium	1.2	
Tin	14.6	
Titanium	87.5	
Zinc	200.5	65

[a] Source: EPA, 1993.

Lignosulfonate. Lignosulfonate is used to control viscosity in drilling muds by acting as a thinning agent or deflocculant for clay particles. Concentrations in drilling fluid range from 1 to 15 lb/bbl. It is made from the sulfite pulping of wood chips used to produce paper and cellulose. Ferrochrome lignosulfonate, the most commonly used form of lignosulfonate, is made by treating lignosulfonate with sulfuric acid and sodium dichromate. The sodium dichromate oxidizes the lignosulfonate and cross linking occurs. Hexavalent chromium supplied by the chromate is reduced during reaction to the trivalent state and complexes with the lignosulfonate. At high down-hole temperatures, the chrome binds onto the edges of clay particles and reduces the formation of colloids. Ferrochrome lignosulfonate retains its properties in high soluble salt concentrations and over a wide range of alkaline pH. It also is resistant to common mud contaminants and is temperature stable to approximately 177°C (EPA, 1993).

Lignite. Lignite is a soft coal used in drilling muds as a deflocculant for clay, to control the filtration rate, and to control mud gelation at elevated temperatures. Concentrations vary from 1 to 25 lb/bbl (Perricone, 1980). Lignite products are more commonly used as thinners in freshwater muds.

Caustic Soda. Sodium hydroxide is used to maintain the pH of drilling muds between 9 and 12. A pH of 9.5 provides for maximum deflocculation and keeps the lignite in solution. A more basic pH lowers the corrosion rate and provides protection against hydrogen sulfide contamination by limiting microbial growth.

Drilling fluids can be water-based, oil-based, or synthetic-based. In water-based fluids (WBF), water is the suspending medium for solids and is the continuous phase, whether or not oil is present. Water-based drilling fluids are composed of approximately 50 to 90 percent water by volume, with additives comprising the rest. Historically, most drilling in the Gulf of Mexico has been performed with WBMs. WBMs are more cost effective in drilling many shallow wells, and WBM will continue to be used in those instances. However, for more complicated or deeper wells, SBM is often used.

WBFs have been classified into eight generic types based on their compositions (EPA, 1993).

1. Potassium/polymer fluids are inhibitive fluids, as they do not change the formation after it is cut by the drill bit. They are used in soft formations such as shale where sloughing may occur.

2. Seawater/lignosulfonate fluids are also inhibitive. This type of mud is used to maintain viscosity by binding lignosulfonate cations onto the broken edges of clay particles. It is also used to control fluid loss and to maintain the borehole stability. Under more complicated conditions, such as higher temperatures, this type of mud can be easily altered.

3. Lime (or calcium) fluids are inhibitive fluids. The viscosity of the mud is reduced as calcium binds the clay platelets together to release water. This type of mud system can maintain more solids. Lime fluids are used in hydratable, sloughing shale formations.

4. Nondispersed fluids are used to maintain viscosity, to prevent fluid loss, and to provide improved penetration, which may be impeded by clay particles in dispersed fluids.

5. Spud fluids are noninhibitive muds that are used in approximately the first 300 meters of drilling. This is the most simple mixture of mud and contains mostly seawater and a few additives.

6. Seawater/freshwater gel fluids are inhibitive muds used in early drilling to provide fluid control, shear thinning, and lifting properties for removing cuttings from the hole. Prehydrated bentonite is used in both seawater and freshwater fluids and attapulgite is used in seawater when fluid loss is not a concern.

7. Lightly treated lignosulfonate freshwater/seawater fluids resemble seawater/ lignosulfonate muds except their salt content is less. The viscosity and gel strength of this mud are controlled by lignosulfonate or caustic soda.

8. Lignosulfonate freshwater fluids are similar to the muds at #2 and #7 except the lignosulfonate content is higher. This mud is used for higher temperature drilling.

Oil-based drilling fluids (OBF) are those with oil, typically diesel, as the continuous phase and water as the dispersed phase. These fluids were found to be toxic to marine organisms and are no longer permitted for discharge. Due to the high cost of hauling the muds to shore and proper land disposal, the use of oil-based muds, particularly in offshore areas, has decreased significantly.

3.2.1 Synthetic-Based Drilling Fluids

Synthetic-based drilling fluids represent a new technology which developed in response to the widespread permit discharge bans of oil-based drilling fluids. SBMs have drilling and operational properties similar to OBM systems and are used where OBMs are commonly used, e.g., in difficult drilling situations or highly directionally deviated holes, or where the properties of WBMs have limited performance, e.g., hydratable shales or salt. SBMs reduce drilling times compared to WBMs, reducing drilling rig costs, are less toxic than OBM, and have higher penetration rates in rock (MMS, 2003 as cited in EPA, 2009 cited in EA). An SBF has a synthetic material as its continuous phase and water as the dispersed phase. The types of synthetic material which have been used include vegetable esters, polyalpha olefins (PAO), linear alphaolefins, internal olefins, and esters (USEPA, 1996). A model SBF formulation consists of 47% synthetic base fluid, 33% solids, and 20% water (by weight), a 70%/30% ratio of synthetic base to water, typical of commercially available SBFs (USEPA 1999).

SBFs are reported to perform as well as or better than OBFs in terms of rate of penetration, borehole stability, and shale inhibition. Due to decreased washout (erosion), drilling of narrower gage holes, and lack of dispersion of the cuttings in the SBF, compared to WBF the quantities of muds and cuttings waste generated is reduced, reportedly in some cases by as much as 70 per cent. (Burke and Veil, 1995; Candler, et al, 1993).

The pollutants of concern from water-based muds discharges are primarily metals, most of which are associated with the barite added to the mud system and organics, which are added for lubricity or to free stuck pipe. The pollutant concentrations in water-based drilling fluid discharges characteristic of most offshore operations are presented in Table 3-3. The naphthalene concentration in Table 3-3 is based on a pill volume of 100 bbl and is calculated for an average well depth and mud volume.

According to standard formulation data, all of the solids in synthetic-based fluids are barite, making SBF a source of heavy metals and total suspended solids. SBFs are also one source of the conventional pollutant oil and grease. Table 3-4 shows the waste characteristics of SBFs.

Table 3-3. Water Based Drilling Fluids Pollutant Concentrations

Pollutant	Concentration in Whole Mud (µg/l)
Aluminum	4,123,615
Antimony	2,592
Arsenic	3,228
Barium	163,558,125
Beryllium	318
Cadmium	500
Chromium	109,116
Copper	8,502
Iron	6,976,260
Lead	15,958
Mercury	45
Nickel	6,138
Selenium	500
Silver	318
Thallium	546
Tin	6,638
Titanium	39,800
Zinc	91,157
Naphthalene	330

[a] Source: EPA, 1993.

Table 3-4. Synthetic-based fluids drilling waste characteristics. (Modified from USEPA, 1999).

Waste Characteristics	Value
SBF formulation	47% synthetic base fluid, 33%barite, 20% water (by weight)
Synthetic base fluid density	280 pounds per barrel
Barite density	1,506 pounds per barrel
SBF drilling fluid density	9.6 pounds per gallon
Percent (vol.) formation oil	0.2%
Pollutant Concentrations in SBF	
Conventionals	**lbs/bbl of SBF**
Total oil as synthetic base fluid	190
Total oil as formation oil	0.59
Total suspended solids as barite	133
Priority Pollutant Organics	**lbs/bbl of SBF**
Naphthalene	0.0010052
Fluorene	0.0005483
Phenanthrene	0.0013004
Phenol	7.22E-08
Priority Pollutant Metals	**mg/kg/Barite**
Cadmium	1.1
Mercury	0.1
Antimony	5.7
Arsenic	7.1
Berylium	0.7
Chromium	240
Copper	18.7
Lead	35.1
Nickel	13.5
Selenium	1.1
Silver	0.7
Thallium	1.2
Zinc	200.5
Non-Conventional Metals	**mg/kg Barite**
Aluminum	9069.9
Barium	120000
Iron	15344.3
Tin	14.6
Titanium	87.5
Non-Conventional Organics	**lbs/bbl of SBF**
Alkylated benzenes	0.0056587
Alkylated naphthalenes	0.0531987
Alkylated fluorenes	0.0064038

Alkylated phenanthrenes	0.0080909
Alkylated phenols	0.0000006
Total biphennyls	0.0105160
Total dibenzothiophenes	0.0000092

The discharge of neat synthetic-based drilling fluids is prohibited under this permit; however, the permit will allow discharges of water-based fluids. Because of their cost, SBFs, used or unused, are considered a valuable commodity by the industry and not a waste. It is industry practice to continuously reuse the SBF while drilling a well interval, and at the end of the well, to ship the remaining SBF back to shore for refurbishment and reuse. Compared to water-based fluids, SBFs are relatively easy to separate from the drill cuttings because the drill cuttings do not disperse in the drilling fluid to the same extent. With WBF, due to dispersion of the drill cuttings, drilling fluid components often need to be added to maintain the required drilling fluid properties. These additions are often in excess of what the drilling system can accommodate. The excess "dilution volume" of WBF is discharged. This excess dilution volume does not occur with SBF. For these reasons, SBF is only discharged as a contaminant of the drill cuttings waste stream. It is not discharged as neat drilling fluid (drilling fluid not associated with cuttings).

3.3 Drill Cuttings

Drill cuttings are fragments of the geologic formation broken loose by the drill bit and carried to the surface by the drilling fluids that circulate through the borehole. They are composed of the naturally occurring solids found in subsurface geologic formations and bits of cement used during the drilling process. Cuttings are removed from the drilling fluids by a shale shaker and other solids control equipment before the fluid is recirculated down the hole. Removed cuttings are discharged (EPA 2009).

The volume of cuttings generated while drilling the SBF intervals of a well depends on the type of well (development or production) and the water depth. According to analyses of the model wells provided by industry representatives, wells drilled in less than 1,000 feet of water are estimated to generate 565 barrels of cuttings for a development well and 1,184 barrels of cuttings for an exploratory well. Wells drilled in water greater than 1,000 feet deep are estimated to generate 855 barrels of cuttings for a development well, and 1,901 cuttings for an exploratory well (USEPA, 2000). These values assume 7.5 percent washout, based on the rule of thumb reported by industry representatives of 5 to 10 percent washout when drilling with SBF. Washout is caving in or sluffing off of the well bore. Washout, therefore, increases hole volume and increases the amount of cuttings generated when drilling a well. Assuming no washout, the values above become, respectively, 526, 1,101, 795, and 1,768, barrels of dry cuttings.

As the drilling fluid returns from downhole laden with drill cuttings, it normally is first passed through primary shale shakers, vibrating screens, which remove the largest cuttings, ranging in size of approximately 1 to 5 millimeters. The composition of a shale-shaker discharge is presented in Table 3-4. The drilling fluid may then be passed over secondary shale shakers to remove smaller drill cuttings. Finally, a portion or all of the drilling fluid may be passed through a centrifuge or other shale shaker with a very fine mesh screen, for the purpose of removing the fines. It is important to remove fines from the drilling fluid in order to maintain the desired flow properties of the active drilling fluid system. Thus, the cuttings waste stream usually consists of larger cuttings from a primary shale shaker, smaller cuttings from a secondary shale shaker, and fines from a fine mesh shaker or centrifuge. As a final step, the wet cuttings are sent to a dryer which uses high temperatures to separate SBFs from cuttings. The dried residue from the dryer consists of fine cuttings and SBF material and is transported to an onshore waste handling facility. The cleaned cuttings are then discharged overboard.

The recovery of SBF from the cuttings serves two purposes. The first is to deliver drilling fluid for reintroduction to the active drilling fluid system and the second is to minimize the discharge of SBF. The recovery of drilling fluid from the cuttings is a conflicting concern, because as more aggressive methods are used to recover the drilling fluid from the cuttings, the cuttings tend to break down and become fines. The fines are more difficult to separate from the drilling fluid (an adverse effect for pollution control purposes), but in addition they deteriorate the properties of the drilling fluid. Increased recovery from cuttings is more of a problem for WBF than SBF because in WBFs the cuttings disperse more and spoil the drilling fluid properties. Therefore, compared to WBF, more aggressive methods of recovering SBF from the cuttings waste stream are practical. These more aggressive methods may be justified for cuttings associated with SBF so as to reduce the incidental discharge of SBF. This, consequently, will reduce the quantity of toxic organic and metallic components of the drilling fluid discharged.

Table 3-5. Mineral Composition of a Shale-Shaker Discharge from a Mid-Atlantic Well[a]

Pollutant	Percent by Weight (Dry Basis)
Barium Sulfate	3
Montmorillonite	21
Illit	11
Kaolinite	11
Chlorite	6
Moscovite	5
Quartz	23
Feldspar	8
Calcite	5
Pyrite	2
Siderite	4

[a] Source: Adapted by NRC (1983) from Ayers et al. (1980b); 65% solids, density 1.7 g/cm^3.

3.4 Produced Water

Produced water (also known as production water, process water, formation water, or produced brine) is the water brought up from the hydrocarbon-bearing strata with the produced oil and gas. Produced water includes small volumes of treating chemicals that return to the surface with the produced fluids and pass through the produced water system. It constitutes a major waste stream from offshore oil and gas production activities.

Produced water is composed of formation water that is brought to the surface combined with the oil and gas, injection water (if used for secondary oil recovery and has broken through into the oil formation), and various added chemicals (biocides, coagulants, corrosion inhibitors, etc.). The constituents include dissolved, emulsified, and particulate crude oil constituents, natural and added salts, organic and inorganic chemicals, solids, and trace metals. Chemicals used on production platforms such as biocides, coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers, and scale inhibitors also may be present.

Produced water constitutes the major waste stream from offshore oil and gas production activities. The pollutant concentrations in produced water used in this analysis were used for development of the final effluent guidelines for the offshore subcategory (EPA, 1993). The concentrations are based on treatment by gas flotation before discharge. The pollutants and their average concentrations are presented in Table 3-6.

Produced water can be classified into three groups--meteoric, connate, and mixed waters--depending on its origin. Meteoric water is water that originates as rain and fills porous or permeable shallow rocks or percolates through them along bedding planes, fractures, and permeable layers. Carbonates, bicarbonates, and sulfates in the produced water are indicative of meteoric water. Connate water is the water in which the marine sediments or the original formation was deposited. It comprises the interstitial water of the reservoir rock and is characterized by chlorides, mainly sodium chloride, and high concentrations of dissolved solids. Mixed waters have both high chloride and sulfate-carbonate-bicarbonate concentrations suggesting meteoric water mixed or partially displaced by connate water (MMS, 1982).

The salinity and chemical composition vary from different strata and different petroleum reserves. The chlorides content of produced water ranges from 3,400 mg/l to 172,500 mg/l based on a study of 30 platforms in the Gulf of Mexico (U.S. EPA, 1985). Produced water generally contains little or no dissolved oxygen and the water may contain high concentrations of total organic carbon and dissolved organic carbon (Boesch and Rabalais, 1989).

Produced waters have also been found to include radioactive materials such as radium. Normal surface waters in the open ocean contain 0.05 pCi/liter of radium. Radionuclide data from Gulf coast drilling areas show Ra-226 concentrations of 16 to 393 pCi/liter and Ra-228 concentrations of 170 to 570 pCi/liter (U.S. EPA, 1978). After treatment using gas flotation, produced water radium concentrations are reduced by 10% (EPA, 1993).

Produced water production rates depend on the method of recovery used and the formation being drilled. Discharge rates can vary from none at some platforms to large quantities from central processing facilities. The EPA 30 platform study reported estimated discharge rates at 134 bbl/day to 150,000 bbl/day for offshore platforms in the central and western Gulf of Mexico (Burns and Roe, 1983). A 2005 report of the produced water volumes from 50 operators in the GOM reported annual averages ranging from 3 bbl/day to 63, 828 bbl/day (Veil et.al., 2005).

After treatment in an oil-water separator, produced water is usually discharged into the sea, or in some cases is reinjected for disposal or pressure maintenance purposes.

Table 3-6. Produced Water Pollutant Concentrations[a]

Pollutant	Concentration (ug/l)
Oil and Grease	23.5 mg/l
TSS	30.0 mg/l
Priority and Non-Conventional Organic Pollutants:	
Anthracene	7.40
Benzene	1,225.91
Benzo(a)pyrene	4.65
2-Butanone	411.58
Chlorobenzene	7.79
Di-n-butylphthalate	6.43
2,4-Dimethylphenol	250.00
Ethylbenzene	62.18
n-Alkanes	656.60
Naphthalene	92.02
p-Chloro-m-cresol	10.10
Phenol	536.00
Steranes	31.00
Toluene	827.80
Triterpanes	31.20
Xylene (total)	378.01
Priority and Non-Conventional Metal Pollutants:	
Aluminum	49.93
Arsenic	73.08
Barium	35,560.83
Boron	16,473.76
Cadmium	14.47
Copper	284.58
Iron	3,146.15
Lead	124.86
Manganese	74.16
Nickel	1,091.49
Titanium	4.48
Zinc	133.85
Radionuclides:	
Radium-226	0.00020365
Radium-228	0.00024904

[a] Source: EPA, 1993.

Under the proposed permit produced water from the last stage of processing must meet a 29/42 mg/l (monthly average/daily maximum). The limitation is based on the use of gas flotation for oil-water separation.

3.5 Produced Sand

Produced sand is the material removed from the produced water. Produced sand also includes desander discharge from the produced water waste stream and blowdown of water phase from the produced water treating system. Sands that are finer and of low volume may be drained into drums on deck or carried through the oil-water treatment system and appear as suspended solids in the produced water effluent, or they may be settled out in treatment vessels. If sand volumes are larger and sand particles coarser, the solids are removed in cyclone separators, thereby producing a solid-phase waste. The sand that drops out in these separators is generally contaminated with crude oil (oil production) or condensate (gas production) and requires washing to recover the oil. The sand is washed with water combined with detergents, or solvents. The oily water is directed to the produced water treatment system or to a separate oil-water separator to become part of the produced water discharge following oil separation. The final effluent guidelines, and therefore, the proposed permit prohibit the discharge of this waste stream.

3.6 Deck Drainage

Deck drainage is waste resulting from platform washings, deck washings, deck area spills, rainwater, and runoff from curbs, gutters, and drains, including drip pans and wash areas. The runoff collected as deck drainage also may include detergents used in deck and equipment washing.

In deck drainage, oil and detergents are the pollutants of primary concern. During drilling operations, spilled drilling fluids also can end up as deck drainage. Acids (hydrochloric, hydrofluoric, and various organic acids) used during workover operations may also contribute to deck drainage, but generally these are neutralized by deck wastes and/or brines prior to disposal. Based on an analysis of 950 platforms in the Gulf of Mexico from 1982-1983, EPA (1993) determined that the oil and grease levels reported for deck drainage discharges were 28 mg/l monthly average and 75 mg/l daily maximum, greatly exceeding the current NPDES general permit limit of no free oil as determined by visual sheen.

A typical platform-supported rig is equipped with pans to collect deck and drilling floor drainage. The drainage is separated by gravity into waste material and liquid effluent. Waste materials are recovered in a sump tank, then treated and disposed, returned for use in the drilling mud system, or transported to shore. The liquid effluent, primarily washwater and rain water, is discharged. It is expected that, following treatment, deck drainage discharge will meet the no free oil prohibition in the general permit.

The 1993 EPA study determined that deck drainage quantities range from 1 to 4,304 bbl/day/platform with an average discharge of 50 bbl/day.

3.7 Sanitary Waste

The sanitary wastes discharged offshore are human body wastes from toilets and urinals. The volume and concentrations of these wastes vary widely with time, occupancy, platform characteristics, and operational situation. Usually the toilets are flushed with brackish water or seawater. Due to the compact nature of the facilities, the wastes have less dilution water than common municipal wastes. This creates greater waste concentrations. Some platforms combine sanitary and domestic waste waters for treatment; others maintain sanitary wastes separate for chemical or physical treatment by an approved marine sanitation device.

3.8 Domestic Waste

Domestic wastes (gray water) originate from sinks, showers, safety showers, eye wash stations, laundries, food preparation areas, and galleys on the larger facilities. Domestic wastes also include solid materials such as paper, boxes, etc. These wastes are governed by the Coast Guard under MARPOL 73/78 (the International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978 relating thereto). The Coast Guard regulations at 33 CFR Part 151 specify regulations for disposal of garbage. These are summarized in Table 3-7.

3.9 Cement

In order to protect the well from being penetrated by aquifers, it is necessary to install a casing in the bore hole. The casing is installed in stages of successively smaller diameters as the drilling progresses. The casings are cemented in place after each installation.

A cement slurry is mixed on site and is pumped through a special valve at the well head through the casing to the bottom and up the annular space between the bore hole wall and the outside of the casing to the surface. The cement is allowed to harden and drilling is resumed.

Most wells are cemented with an ordinary Portland cement slurry. Additives are used to compensate for site-specific temperature and salt water conditions. The amount of cement used for each well depends on the well depth and the volume of the annular space. Typically, excess cement discharges are less than 10 barrels/year/well.

Table 3-7. Garbage Discharge Restrictions[a]

Garbage Type	Fixed or Floating Platforms & Associated Vessels[b] (33 CFR 151.73)
Plastics - includes synthetic ropes and fishing nets and plastic bags.	Disposal prohibited (33 CFR 151.67)
Dunnage, lining and packing materials that float.	Disposal prohibited
Paper, rags, glass, metal bottles, crockery and similar refuse.	Disposal prohibited
Paper, rags, glass, etc. comminuted or ground.[c]	Disposal prohibited
Victual waste not comminuted or ground.	Disposal prohibited
Victual waste comminuted or ground.[c]	Disposal prohibited less than 12 miles from nearest land and in navigable waters of the U.S.
Mixed garbage types.	See footnote d.

[a] Source: EPA, 1993.

[b] Fixed or floating platforms and associated vessels include all fixed or floating platforms engaged in exploration, exploitation, or associated offshore processing of seabed mineral resources, and all ships within 500 m of such platforms.

[c] Comminuted or ground garbage must be able to pass through a screen with a mesh size no larger than 25 mm (1 inch) (33 CFR 151.75).

[d] When garbage is mixed with other harmful substances having different disposal requirements, the more stringent disposal restrictions shall apply.

3.10 Well Treatment, Workover, and Completion Fluids

The following definitions are from the Development Document for the final effluent guidelines (EPA, 1993).

> Well treatment fluids are any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.
>
> Workover fluids are salt solutions, weighted brines, polymers and other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures.
>
> Completion fluids are salt solutions, weighted brines, polymers, and various additives used to prevent damage to the wellbore during operations which prepare the drilled well for hydrocarbon production.

The volume of fluids needed for workover, treatment, and completion operations depends on the type of well and the specific operation being performed. Chevron has based estimates average volumes of fluids (accounting for reuse of the fluids) as 300 bbl of workover fluids per job and 250 bbl of treatment fluids per treatment operation. Based on an assumption of one treatment or one workover every four years, an average of 200 bbl of treatment or workover fluid can be expected to be used per well every four years.

Well treatment fluids are acid in water solutions (using hydrochloric acid, hydrofluoric acid, and acetic acid). Formation solubility, reaction time, and reaction products determine the type of acid used. A treatment operation consists of a preparation solution of ammonium chloride (3-5 percent) to force the hydrocarbons into the formation; an acid solution; and a post-flush of ammonium chloride the remains in the formation for 12 to 24 hours to force the acid farther into the formation before being pumped out.

Solvents also may be used for well treatment, including hydrofluoric acid, hydrochloric acid, ethylene diaminetetraacetic acid (EDTA), ammonium chloride, nitrogen, methanol, xylene, and toluene. Additives such as corrosion inhibitors, mutual solvents, acid neutralizers, diverters, sequestering agents, and antisluding agents are often added to treatment fluid solutions. The pollutant concentrations for a well treatment fluid used in two wells at a THUMS facility in California are presented in Table 3-8.

Workover fluids are put into a well to allow safe repair and maintenance, for abandonment procedures, or to reopen plugged wells. During repair operations, the fluids are used to create hydrostatic pressure at the bottom of the well to control the flow of oil or gas and to carry materials out of the well bore. To reopen wells, fluids are used to stimulate the flow of hydrocarbons. Both of these operations must be accomplished without damaging the geologic strata.

Fluids used for hydraulic fracturing are considered well treatment or stimulation fluids in the proposed general permit. To reopen or increase productivity in a well, hydraulic fracturing of the formation may be necessary. Hydraulic fracturing is achieved by pumping fluids into the bore hole at high pressure, frequently exceeding 10,000 psi. Proper fracturing accomplishes the following:

- Creates reservoir fractures thereby improving the flow of oil to the well
- Improves the ultimate oil recovery by extending the flow paths, and
- Aids in the enhanced oil recovery operation.

Hydraulic fracturing has also been used in the GOM since the early 1990’s in combination with gravel packing as a type of well stimulation and sand control technology commonly referred to as “Frac Pack” operations (API, 2015). Most of the petroleum bearing formations in the GOM consist of highly permeable unconsolidated sands. Produced sand occurs when the loose formation sands back up into the well piping and production equipment. To limit and prevent sand production the gravel pack places a courser sand filter in the immediate vicinity of the well at the depth of production to limit migration of fine sands into the well pipe. The fracturing component uses treated seawater under high pressure to fracture the formation and force additional sand into the producing formation a greater distance from the well to increase the size of the sand filter (gravel pack). The Frac Pack sand filter may be up to 10 times larger than that resulting from a conventional gravel pack completion. The unconsolidated producing formations in the GOM make them less brittle than shales and tight sands therefore the fracture network produced by a Frac Pack completion are less dense and remain close to the bore hole (Middle East and

Asia Reservoir Review, 2007; API, 2015).

Hydraulic fracturing used in repair of damaged formations or as well stimulation/sand control in the GOM differs from that used to recover hydrocarbons from low permeability shales, coal beds and other tight formations being produced in the continental U.S. mainly with regard to the magnitude of the intended fracturing in the surrounding formation. The permeability of these tight formations may be as low as 1/1000 of 1% of the permeability of the more conventional formations on the GOM shelf and, therefore, require much more extensive fracturing to stimulate flow (King, 2012). Typical Frac Pack completions in the GOM may inject 50,000lbs to over 200,000lbs of proppant into the producing formation within a radius of usually less than 30 meters of the well pipe, whereas a shale gas operation may inject up to 4 million lbs. of proppant suspended in 0.5-10 million gallons of water into a single well (USEPA, 2015). Fractures may extend for hundreds or several thousand feet from the well pipe (GWPC & IOGCC, 2016). Added chemicals in operations this large may range from 80-330 tons.

Deepwater (greater than 500 meters of water) oil and gas production is becoming more prevalent in the GOM following the discovery of significant reserves at water depths as great as 3000 meters. In these cases, the oil bearing formations may be an additional 8000 meters below the mudline. The technical challenges to production include much higher overburden pressures and temperatures and may require larger scale fracturing to maximize production (Mullen et. al, 2003; Dribus et. Al., 2008; Dutton and Loucks, 2014).

New information indicates that hydraulic fracturing of oil may have the potential to cause potential health and environmental effects. Some of the pollutants released by hydrofracking include benzene, toluene, xylene and ethyl benzene (BTEX); particulate matter and dust; ground-level ozone; nitrogen oxides; carbon monoxide; formaldehyde; and metals contained in diesel fuel combustion. These pollutants can travel in the atmosphere. The exposure to these chemicals could cause short-term effects to human health and the environment (Shonkoff, 2014; Elliott, et. at. 2016). This information indicates that potential risks of hydrofracking may be greater from onshore activities as compared to offshore OCS-related activities (BOEM, 2015b).

High solids drilling fluids used during workover operations are not considered workover fluids by definition and therefore must meet drilling fluid effluent limitations before discharge may occur. Packer fluids, low solids fluids between the packer, production string, and well casing, are considered to be workover fluids and must meet only the effluent requirements imposed on workover fluids.

Table 3-8. Analysis of Fluids from an Acidizing Well Treatment[a]

Analyte	Concentration (ug/l)	Analyte	Concentration (ug/l)
Aluminum	53.1	Tin	6.66
Antimony	< 3.9	Titanium	0.68
Arsenic	< 1.9	Vanadium	36.1
Barium	12.6	Yttrium	0.19
Beryllium	< 0.1	Zinc	28.5
Boron	31.9	Aniline	434
Cadmium	0.4	Naphthalene	ND
Calcium	35.3	o-Toluidine	1,852
Chromium	19	2-Methylnaphthalene	ND
Cobalt	< 1.9		
		2,4,5-Trimethylanine	2,048
Copper	3.0	Oil and Grease	619
Iron	572	pH	2.48
Lead	< 9.82		
Magnesium	162		
Molybdenum	< 0.96		
Nickel	52.9		
Selenium	< 2.9		
Silver	< 0.7		
Sodium	1,640		
Thallium	5.0		

[a]Source: EPA, 1993.

Well completion occurs if a commercial-level hydrocarbon reserve is discovered. Completion of a well involves setting and cementing the casing, perforating the casing and surrounding cement to provide a passage for oil and gas from the formation into the wellbore, installing production tubing, and packing the well. Completion fluids are used to plug the face of the producing formation while drilling or completion operation are conducted in hydrocarbon-bearing formations. They prevent fluids and solids from passing into the producing formation, thereby reducing its productivity or damaging the oil or gas.

The production zone is a porous rock formation containing the hydrocarbons, either oil or gas, and can be damaged by mud solids and water contained in drilling fluids. The completion fluids create a thin film of solids over the surface of the producing formation without forcing the solids into the formation. A successful completion fluid is one that does not cause permanent plugging of the formation pores. The composition of the completion fluid is site-specific depending on the nature of the producing formation. Drilling muds remaining in the wellbore during logging, casing, and cementing operations or during temporary abandonment of the well are not considered completion fluids and are regulated as drilling fluids discharges.

Treatment, workover, and completion fluids are either collected and disposed onshore if there are priority pollutants detected or otherwise treated for oil and grease, pH neutralized, and commingled with produced water for discharge (EPA, 2009). Region 4 is including the components of the fracking process as they occur in existing waste streams: slurried particles from hydraulic fracturing are covered under the produced sand waste stream; fluids and materials used in or derived from the fracking process are included in the well treatment, completion, and workover fluids waste stream.

3.11 Blowout Preventer Fluids

A vegetable or mineral oil solution or antifreeze (polyaliphatic glycol) is used as a hydraulic fluid in BOP stacks while drilling a well. The blowout preventer may be located on the seafloor and is designed to contain pressures in the well that cannot be maintained by the drilling mud. Small quantities of BOP fluid are discharged to the seafloor during weekly testing of the blowout preventer device. The volume of BOP fluid discharge ranges from 67 to 314 bbl/day when testing (EPA, 1993).

3.12 Desalination Unit Discharge

This is the residual high-concentration brine discharged from distillation or reverse-osmosis units used for producing potable water and high-quality process water offshore. It has a chemical composition and ratio of major ions similar to seawater, but with high concentrations. This waste is discharged directly to the sea as a separate waste stream. The typical volume discharged from offshore facilities is less than 240 barrels per day.

3.13 Ballast Water and Storage Displacement Water

Ballast and storage displacement water are used to stabilize the structures while drilling from the surface of the water. Two types of ballast water are found in offshore producing areas (tanker and platform ballast). Tanker ballast water would not be covered under an NPDES permit.

Platform stabilization (ballast) water is taken on from the waters adjacent to the platform and may be contaminated with stored crude oil and oily platform slop water. More recently designed and constructed floating storage platforms use permanent ballast tanks that become contaminated with oil only in emergency situations when excess ballast must be taken on. Oily water can be treated through an oil-water separation process prior to discharge.

Storage displacement water from floating or semi-submersible offshore crude oil structures is mainly composed of seawater. Much of its volume can usually be discharged directly without treatment. Water that is contaminated with oil may be passed through an oil-water separator for treatment.

3.14 Bilge Water

Bilge water, which seeps into all floating vessels, is a minor waste for floating platforms. This seawater becomes contaminated with oil and grease and with solids such as rust where it collects at low points in vessels. This bilge water is usually directed to the oil-water separator system used for the treatment of ballast water or produced water, or it is discharged intermittently. The total volume of ballast/bilge water discharged is from 70 to 620 bbl/day (EPA, 1993).

3.15 Uncontaminated Seawater

Seawater used on the rig for various reasons is considered uncontaminated if chemicals are not added before it is discharged. Included in this discharge are waters used for fire control equipment and utility lift pump operation, pressure maintenance and secondary recovery projects, fire protection training, pressure testing, and non-contact cooling.

3.16 Boiler Blowdown

Boiler blowdown discharges consist of water discharged from boilers as is necessary to minimize solids build-up in the boilers, including vents from boilers and other heating systems.

3.17 Diatomaceous Earth Filter Media

Diatomaceous earth filter media are used in the filtration unit for seawater or other authorized completion fluids. They are periodically washed from the filtration unit for discharge.

4. TRANSPORT AND PERSISTENCE

The discussion of transport processes affecting drilling wastes treats the two major waste streams, water-based drilling fluids (WBF) and synthetic-base drilling fluids (SBF) separately, due to differences in characteristics, mode of entry and behavior in the environment. The synthetic-based fluids associated with cuttings discharges are expected to behave differently from WBFs due to several important differences:

- Only SBF-cuttings are discharged, with retention of the SBF base fluid generally ranging between a low of 2 percent for the larger cuttings and a high of 20 percent for the smallest cuttings (fines). Effluent guidelines will limit the maximum retention to 6.9 percent. With WBFs, in addition to the WBF-cuttings, large volumes of WBF are discharged. Thus, for an equal volume of hole drilled, the volume of WBF-related discharge is expected to be much greater than the volume of SBF-related discharge.

- WBFs contain very high levels of suspended and settleable solids (and are, in fact, referred to as “muds” in the industry) that disperse in the water column and produce a plume with many fine particles that settle rather slowly. Hence, they may be transported large distances. SBF-cuttings, however, tend not to disperse in the water column nearly to the same extent as WBFs because the particles are “oil” wet with the synthetic material. Compared to WBF-cuttings, SBF-cuttings tend to be larger than WBF-cuttings. Again the reason is that SBFs do not disperse the cuttings particles to the same extent as WBFs. Because larger particles settle faster than smaller particles, SBF-cuttings tend to be deposited in a smaller impact area than WBF-cuttings.

- SBF-cuttings have a significant organic component that is not present in WBFs, namely the synthetic base fluid. The synthetic base fluid, in general, is insoluble in water and deposits in the sediment with the cuttings. The fluids separation technologies used on SBF cuttings remove the fine cuttings, causing what remains to settle rapidly upon discharge and accumulate nearer the point of discharge than WBF wastes.

These differences suggest that discharge plumes characteristic of WBF discharges will not be an important mechanism for the transport of SBF wastes.

4.1 Water-Based Drilling Fluids

Drilling fluids contain quantities of coarse material, fine material, dissolved solids, and free liquids. While all of these components are affected by the momentum of the discharge jet, density-driven turbulent mixing, and diffusive processes, the larger particulates of drilling fluids separate more rapidly from the fines and soluble portions of the discharge plume due to the additional effect of gravitational settling. Fall velocities are largely controlled by particulate size, with larger particulate separating out more rapidly from the plume. Upon discharge, this mixture appears to separate rapidly. An upper plume is formed from shear forces and local turbulent flow at the discharge pipe. This upper plume contains about five to seven percent, by weight, of the total drilling fluid discharge (Ayers et al., 1980b). This plume migrates to its level of neutral buoyancy while particulates slowly settle to the bottom and is advected with prevailing currents. The fine solids settle at a rate depending on aggregate particle size, which is very dependent on flocculation.

A lower plume contains the remainder of the discharged drilling fluids. Coarser materials fall rapidly out of the lower plume. Ayers et al. (1980b) found that the lower plume components deposited on the bottom within a few meters of the discharge point from an outfall located 3 meters below the surface in a water depth of 23 meters. In deeper waters, settleable solids will deposit over a larger area, depending upon the total fall depth, the settling velocity of the particles, and current speeds. If water depths are great enough to prevent bottom impact of the discharge plume, fine particulates in the lower plume will reach a level of neutral buoyancy and will be advected with ambient current flow, similar to their behavior in the upper plume.

Both upper and lower plumes are affected by three different transport processes or pathways: physical, chemical, and biological. Physical transport processes affect concentrations of discharge components in the water column through dilution[1], dispersion[1], and settling. Physical processes include currents, turbulent mixing, settling, and diffusion. These processes include current speed and direction, tidal regime, kinetic energy availability, and the characteristics of the receiving water such as water depth and density stratification. Physical processes are the most understood of the three transport pathways.

Chemical and biological processes more frequently produce changes in the structure and/or speciation of materials that affect their bioavailability and toxicity. Chemical processes include the dissolution of substances in seawater, particle flocculation, complexing of compounds that may remove them from the water column, redox/ionic changes, and absorption of dissolved pollutants on solids. Biological processes include bioaccumulation and biomagnification in soft or hard tissues, fecal agglomeration and settling of materials, and physical reworking to mix solids into the sediment (bioturbation).

4.1.1 *Physical Transport Processes*

Pollutant concentrations resulting from offshore platform discharges are influenced by several factors related to the discharge and the medium into which it is released. Discharge-related factors include the solids content of the effluent, distribution of particle sizes and their settling rates, effluent chemical composition, discharge rates and duration, and density.
Environmental factors that affect dispersion and transport of discharged materials include current speed, current direction, tidal influences, wave action, wind regime, density structure of the water column, topography of the ocean bottom, bottom currents, and turbulence caused by platform wake. These factors influence dispersion and dilution of effluents in the water column, and resuspension and transport of

---

[1] In analyzing the impacts of discharged drilling fluids, the behavior of either the mud solids or the aqueous portion of the effluent can be measured. In this document, the term “dispersion” refers to tracking the behavior of the plume with respect to its solids content; dilution refers to a volumetric tracking of plume behavior and is intended to apply to soluble components of drilling fluids. The term “dispersion” in the ODCE does not necessarily refer to settling and removal of solids from the water column as they settle on the seafloor, but may also only refer to the concentration of suspended solids in the water column.

solids settled on the seafloor. Areas of high hydrodynamic energy will disperse discharges more rapidly than less energetic areas. Current speed and boundary conditions also affect mixing because turbulence increases with current speed and proximity to the seafloor. Currents and turbulence can vary markedly with location and site characteristics and affect the movement of suspended matter and the entrainment, resuspension, and advection of sedimented matter.

Two studies by Houghton et al. (1980; 1981) suggest that turbulence induced by submerged portions of the drilling platform also may significantly contribute to the dispersion of the muds. Houghton et al. (1981) concluded that turbulence became a major source of dispersion when current speeds ranged from 5 to 10 cm/sec (0.16 to 0.32 ft/sec) or greater. However, this wake-effect has not been systematically studied at other locations. Ray and Meek (1980), for example, observed little change in plume dilution at Tanner Bank, offshore southern California, with current speed variations between 2 and 45 cm/sec (0.076 and 1.48 ft/sec).

Physical Transport Processes Affecting the Upper Plume

The upper plume contains only a small portion of the discharge effluent (some 5%), which is split off from the main, lower plume and is thought to be due to sheer forces in the immediate vicinity of the discharge pipe. Finer suspended materials are contained in the upper plume. Relative to the lower plume, the initial mixing of the upper plume (in which the momentum of the initial jet is dissipated) is less of a factor, and passive diffusion (in which the plume is transported at the speed and direction of prevailing currents) is a more important factor. Sinking rates of solids in the upper plume will largely depend on the following four factors:

- Discharged material properties
- Characteristics of receiving waters
- Currents and turbulence
- Flocculation and agglomeration.

The physical properties of the discharged materials affect mixing and sedimentation. For suspended clay particulates, particle size and both physical and biological flocculation will determine settling rates. While oil exhibits little tendency to sink, it has displayed the ability to flocculate clay particles and to adsorb to particulates and sink with them to the bottom (Middleditch, 1980).

One of the major receiving water characteristics influencing plume behavior is density structure and stratification. In a stratified water column, density drives the collapse of the plume, i.e., the spreading of the plume at its level of neutral buoyancy. After sufficient spreading, the spreading rate of the plume from dynamic forces declines to a rate comparable to that resulting from turbulence ("far-field" or "passive" dispersion). Density stratification may concentrate certain components along the pycnocline. If flocculation produces particles large enough to overcome the barrier, settling will continue. If density stratification is weak or the pycnocline is above the discharge point, it may not affect plume behavior.

Ecomar (1978), as reported in Houghton et al. (1981), noted that upper plumes in the Gulf of Mexico follow major pycnoclines in the receiving water. A similar finding has been observed by Trefry et al. (1981), who traced barium levels along pycnoclines. This type of transport is a potential concern because sensitive life stages of planktonic, nektonic, and benthic organisms may collect along the pycnocline. Ayers et al. (1980a) observed that the bottom of the upper plume followed a major pycnocline after drilling fluid discharges at rates of 275 bbl/hr and 1,000 bbl/hr in the Gulf of Mexico.

Flocculation and agglomeration affect plume behavior by increasing sedimentation rates as larger particles are formed. Flocculation is enhanced in salt or brackish waters due to increased cohesion of clay particles (Meade, 1972). Agglomeration also occurs when larger particles are formed from a number of smaller ones through the excretion of fecal pellets by filter-feeding organisms.

Most studies of upper plume behavior have measured particulate components and paid less attention to the liquid and dissolved materials present. Presumably, these latter components are subject to the same physical transport processes as particulate matter, with the exclusion of settling. Studies suggest that suspended solids in the upper plume may undergo a higher dispersion rate than dissolved components.

Houghton et al. (1980) measured upper plume transport in Lower Cook Inlet, using a soluble, fluorescent dye (fluorescein) in current speeds of 41 to 103 cm/sec. The water depth at the site is 63 m (207 ft) but the plume never sank below 23 m (75 ft). From transmissometry data collected in the Gulf of Mexico, Ayers et al. (1980b) estimated upper plume volume and found that a 275 bbl/hr drilling fluid discharge exhibited a dilution ratio of 32,000:1 after 60 minutes and a 1,000 bbl/hr discharge showed a dilution ratio of 14,500:1 after 62 minutes. Dispersion ratios for suspended solids at these distances would be approximately one to two orders of magnitude greater than for soluble components.

From radiotracer data collected for offshore Southern California and Cook Inlet, Petrazzuolo (1983) estimates dilution rates of "soluble" tracers (based on generalized estimates of distances to specified levels of dispersion; Table 4-1).

Physical Transport Processes Affecting the Lower Plume

The physical transport processes affecting the lower plume differ little in nature from those influencing the upper plume; differences are more related to the relative contribution of the various processes. The lower plume contains the main body of the discharged material. The initial momentum of the discharge jet is more dominant a factor in lower plume behavior, but is still followed by a dynamic collapse phase and then passive diffusion. The lower plume contains a component composed of coarser material that settles rapidly to the bottom regardless of current velocity. This rapid settling is most pronounced during high-rate bulk discharges in shallow waters. With the high downward momentum of these discharges, the plume reaches the bottom. At Tanner Bank, the lower plume was relatively unaffected by average currents of 21 cm/sec (0.69 ft/sec) and bottom surges of up to 36 cm/sec (1.18 ft/sec; Ecomar, 1978).

Table 4-1. Estimates of Distances Required to Achieve Specified Levels of Dilution of a Soluble Drilling Fluid Tracer in the Upper Plume at Fixed Current Speeds based on Field Study Data[a]

	Distance Required (m)[b] **Current Speed (cm/sec)**		
Dilution Criterion	5	10	15
10^4	10 - 17	19 - 34	29 - 51
10^5	80 -146	169 - 291	240 - 437
5×10^5	355 - 657	709 - 1,313	1,063 - 1,970
10^6	673 - 1,256	1,345 - 2,512	2,018 - 3,768

[a] Source: Petrazzuolo, 1983.
[b] Ranges in distances represent discharge rates of 21 to 1,200 bbl/hr.

The amount of fine solids settling to the bottom from the lower plume appears to depend to some degree on the aggregation of clay particles, which in turn depends on suspended material concentration, salinity, and the cohesive quality of the material. Fine particles tend to flocculate more readily than larger particles. Houghton et al. (1981) cites earlier work by Drake (1976), which concluded that physical-chemical flocculation can increase settling rates an order of magnitude over rates for individual fine particles.

4.1.2 *Seafloor Sedimentation*

Houghton et al. (1981) produced an idealized pattern for drilling fluids sedimentation around an offshore platform located in a tidal regime (Figure 4-1). Zero net current was assumed. The area of impact may have been overestimated from the true field case. Because no initial downward motion was assumed, longer settling times and greater plume dispersion were achieved. The result was an elliptical pattern, with the coarse fraction (10 mm-2 mm) deposited within 125 to 175 m of the discharge point, the intermediate fraction (250 µm-2 mm) deposited at 1,000 to 1,400 m, and the medium fraction (250 µm-74 µm) deposited beyond that distance. This is the greatest areal extent of bottom sedimentation for continuous discharges under the assumed conditions. Discontinuous discharges will be transported by currents at the time of release, and will form a starburst pattern over time (Zingula, 1975).

Studies have shown the extent of drilling fluid accumulation on the bottom to be inversely related to the energy dynamics of the receiving water. Vertical mixing also appears to be directly related to energy dynamics. Analysis of sediments at Tanner Bank showed no visible evidence of cuttings or mud accumulation 10 days after the last discharge, even though over 800,000 kg (882 short tons) of solids had been discharged over an 85-day period (Ray and Meek, 1980). Size analysis also indicated little change in the grain size distribution.

Low-energy environments, however, are not subject to (or only intermittently subject to) currents removing deposited material from the bottom or mixing it into sediments. In the low-energy Mid-Atlantic environment, for example, Menzie (1982) reported that cuttings piles were visibly distinct one

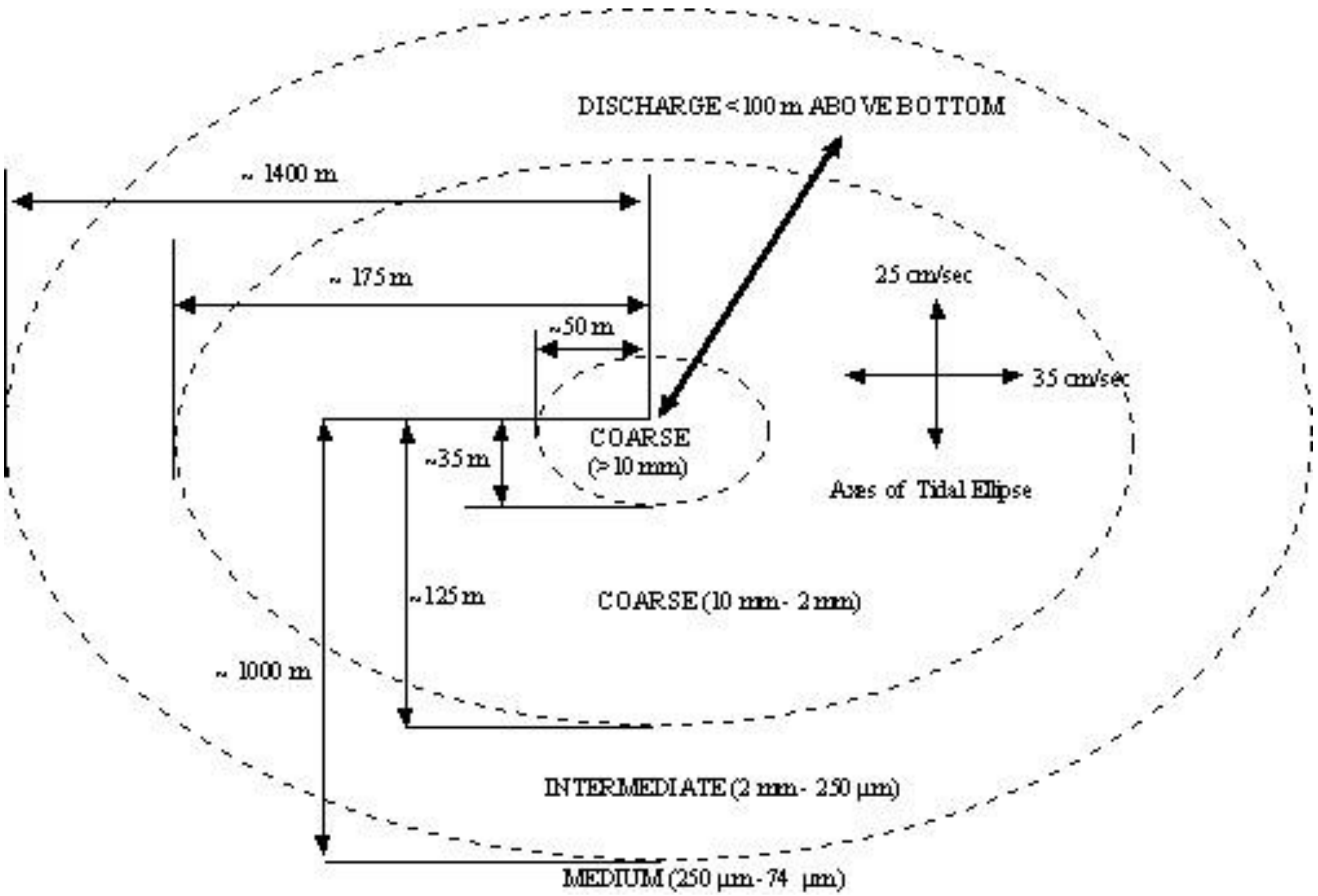


Figure 4-1. Approximate Pattern of Initial Particle Deposition (modified from Houghton et al., 1981)

year after drilling had ceased. Zingula (1975) also reported visible cuttings pile characteristics in the Gulf of Mexico shortly after drilling had terminated.

One study in the Gulf of Mexico (Ayers et al., 1980b) examined the short-term sedimentation of drilling fluids and cuttings in 23 m of water. Sediment traps were deployed only to a distance of 200 m. No distance-dependent quantitative estimates were possible from the data. More material, 10 to 100 fold, was collected in traps after a 1,000 bbl/hr discharge than after a 275 bbl/hr discharge. The relative barium, chromium, and aluminum contents of collected matter was more similar to that found in the initially discharged fluid for the 1,000 bbl/hr discharge than for the 275 bbl/hr discharge. This suggests a reduced influence of differential dispersion of drilling fluid components during the higher rate discharge.

Vertical incorporation of plume components into sediments is caused by physical and biological reworking of sediments. The relative contributions of these processes to vertical entrainment has not been well-described. Petrazzuolo (1983) cites a Gulf of Mexico operation where barium concentration was substantially enriched to a 4-cm (1.6 in) depth at both 100-m (330 ft) and 500-m (1,600 ft) distances. The upper 2 cm (0.8 in) of sediment was highly enriched with barium. This study was conducted along one transect (not aligned with major current flows) after four wells had been drilled at the platform. Boothe and Presley (1985) describe excess sediment barium concentrations that penetrate to depths of 5 to 20 cm (up to 30 cm at 30 m from one well site), with penetration depth generally decreasing with distance from the well site.

4.1.3 *Biological Transport*

Biological transport refers to the movement of pollutants through the environment via biological processes. Bioaccumulation, the accumulation of tissue burdens of pollutants contributes to transport of pollutants through the food web through predation. Bioaccumulation is discussed in Chapter 5. Another pathway of biological removal of pollutants involves a process known as bioturbation, benthic organisms reworking sediment and mixing surface material into deeper sediment layers.

Bioturbation generally mixes surface components into deeper sediment layers, although bioturbation can also expose previously buried materials. No work was found to quantify bioturbation effects, although a few studies have observed organisms living on a cuttings pile or in the vicinity of drilling discharges (Menzie et al., 1980; Ayers et al., 1980b). However, if the environment is one which rapidly removes cuttings piles, or where physical forces dominate resuspension and reworking processes, then biological mixing activities may not prove significant.

4.1.4 *Chemical Transport Processes*

Chemical transport of drilling fluids is poorly described. Much must be gleaned from general principles and studies of other related materials. Several broad findings are suggested, but the data for a quantitative assessment of their importance are lacking. Chemical transport will most likely arise from oxidation/reduction and reactions that occur in sediments. Changes in redox potentials will affect the speciation and physical distribution (i.e., sorption-desorption reactions) of drilling mud constituents.

Dissolved metals tend to form insoluble complexes through adsorption on fine-grained suspended solids and organic matter, both of which are efficient scavengers of trace metals and other contaminants. Trace metals, when adsorbed to clay particles and settled to the bottom, are subjected to different chemical conditions and processes than when suspended in the water column. If the sediments become anoxic, conversion of metals to insoluble sulfides is the most probable reaction, and the metals are then removed from the water column. Environments that experience episodic sediment resuspension favor metal release if reducing conditions existed previously in buried sediments; such current conditions also allow further exposure of organic matter complexes for further reduction and eventual release.

Alterations in Sediment Barium Levels

The long-term fate of discharge drilling fluids has been followed in several studies using sediment barium levels as a tracer. Four studies have been performed in the Gulf of Mexico from which data have been analyzed to estimate the dispersion of sediment barium. The subsequent fate of deposited material depends primarily on the physical processes that resuspend and transport particulates or entrain them into the sediments. Biological or chemical factors also could be important in stabilizing or mobilizing the material on the seafloor (e.g., through covalent binding of sediments or bioturbation). High concentrations of barium persistently found near a well site suggest a lower energy bottom environment, which favors deposition. If elevated levels cannot be found, even soon after drilling, resuspension and sediment transport have taken place and a higher energy bottom environment is suggested.

A series of power-law regression analyses were developed to relate average barium levels to distances from the discharge source (Petrazzuolo, 1983). These equations predicted the distance-dependent decreases in sediment barium levels that were obtained in four field studies. A multivariate analysis was used to estimate average sediment barium levels with respect to distance and number of wells. At locations of approximately 100 m to 30,000 m from a nine-well platform, this analysis suggested that sediment barium data collected early in the development phase of an operation may provide accurate predictions of sediment barium levels later in the operation.

Data from exploratory drilling operations have been used to examine deposition of metals resulting from drilling operations. These data indicate that any of several metals may be deposited, in a distance-dependent manner, around platforms, including cadmium, chromium, lead, mercury, nickel, vanadium, and zinc. These sediment metal studies, when considered as a group, suggested that the enrichment of certain metals in surficial sediments may occur as a result of drilling activities (Table 4-2). While confounding factors occur in most of these studies (i.e., seasonal variability and other natural and anthropogenic sources of metal enrichment), discharged drilling fluids and cuttings are probably not the only drilling-related source. The only two metals clearly associated with drilling fluids that appear to be elevated around rigs or platforms are barium and chromium.

Metals that appear to be elevated as a result of drilling activities, and are not solely related to drilling fluids, include cadmium, mercury, nickel, lead, vanadium, and zinc. Cadmium, lead, and zinc in drilling fluids are the result of the use of pipe dope or pipe thread compounds. Mercury, nickel, and zinc may originate from sacrificial anodes. Cadmium, lead, and vanadium may also originate from the release of oil in drilling operations. This release can result from burning, incidental discharges or spills from the rig or supply boat traffic, or use of oil as a lubricant in drilling fluids. Vanadium also may derive from wearing of drill bits. In a Gulf of Mexico platform study, brine (formation water) discharges were identified as an additional potential source of metal contamination.

Although a variety of trace metals were variously found to be enriched in the sediment, enrichment factors were generally low to moderate, seldom exceeding a factor of 10. The spatial extent of this sediment enrichment also was limited. Either of two cases occurred: enrichment was generally distributed but undetectable beyond 300-500 m, or enrichment was directionally based by bottom current flows and extended further (to about 1,800 m) within a smaller angular component. These considerations suggest that exploratory activities will not result in environmentally significant levels of trace metal contamination. A study in the Canadian Arctic found that mercury would be the best trace metal tracer of discharged fluids (Crippen et al., 1980). However, reanalysis of the data also has suggested that the alterations in sediment mercury levels may have resulted from construction of the gravel island.

Alterations in sediment trace metal levels resulting from development drilling operations have not been as well characterized as those from exploratory operations. Two efforts have been made to estimate spatial distribution and fate of discharged material from a two-well operation in the Gulf of Mexico. One industry-sponsored analysis indicates that 49 percent of discharged barium is dispersed beyond a radius of 1,250 m from the platform (Mobil Oil Corporation, 1978). Another analysis of these data indicates that 78 percent of the barium is located within a 1,000-m radius, and essentially all of the barium (calculated as 111 percent) is located within 1,250 m.

Table 4-2. Summary of Sediment Trace Metal Alterations from Drilling Activities[a]

Location	Trace Metal								
	As	**Cd**	**Cr**	**Cu**	**Hg**	**Ni**	**Pb**	**V**	**Zn**
Gulf of Mexico, Mustang Island Area									
suspended sediment	ND[b]	-	+(8-31X)	+(7-10X)	ND	-	-	+(6-25X)	-
surficial sediment	ND	+(3-9X)	-	-	ND	-	-	-	+(2.5-3.5X)
Gulf of Mexico, Mustang Island Area	ND	±	±	±	ND	±	-	-	ND
Central Gulf of Mexico	ND	+	+	+	ND	+	+	+	
Mid-Atlantic	-	-	-	-	BLD	+(2.5X)	+(4-4X)	+(2-9.5X)	+(4X)
Mackenzie River Delta	+(1.2-2.5X)	+(2-6X)	+(4-7X)	ND	+(1.2-15X)	ND	+(1.5-2.2X)	ND	+(11.7X)
Beaufort Sea	ND	+(2-6X)	+(1.4-2X)	±	-	ND	+(1.2-2.6X)	ND	+(1.2-1.4X)

[a] Adapted from Tillery and Thomas (1980); Mariani et al. (1980); Crippen et al. (1980) in Petrazzuolo (1983).

[b] Abbreviations:

ND	- not determined
+	- increased levels (magnitude change in parentheses) related to drilling
-	- decreased levels related to drilling
±	- isolated increases, not a clearly distance-related pattern
BLD	- below the level of detection

Boothe and Presley (1985) conducted a survey of sediment chemistries around six platforms in the Gulf of Mexico. They concluded that only a small fraction of the total barium discharged is present in sediments near the discharge site. They estimated only 1 - 1.5% of discharged barium within 500 m of the discharge at shallower sites (13 - 34 m) and only 9 - 12% at deeper sites (76 - 102 m). Similarly, within a 3 km radius, their estimates accounted for 5 - 7% at the shallower sites and 47 - 84% at the deeper sites. Statistically significant barium enrichment (≥ twice background) existed in surface sediments at 25 of the 30 control stations located at a distance of 3 km from the drill sites.

In the Santa Maria Basin, offshore Southern California, barium was found to be the only metal enriched in sediments near development drilling operations (Steinhauer et al., 1994). Sporadic elevations in sediment trace metals also were noted by Boothe and Presley. Mercury and lead were significantly correlated to barium at several sites; distance dependent decreases were noted at two sites for mercury and one site for lead. Significant increases were noted generally only out to 125 m from the site; however, the trend indicated increases perhaps to 300 - 500 m. The large statistical variability of the trace metal data set makes statistical inferences difficult.

The general conclusion of this study is that barium and probably other drilling fluid contaminants associated with the settleable fraction of drilling muds appear to be relatively mobile. Thus, drilling discharges are expected to be spread over a large area (i.e., > 3 km from their discharge source) on time scales of a year or so. These data are consistent with other data that indicate drilling discharges can be distributed widely (Continental Shelf Associates, 1983; Ng and Patterson, 1982; Bothner et al., 1983 as cited in Boothe and Presley, 1985).

4.2 Discharge Modeling - Drilling Fluids

Two approaches have been used to project plume behavior for the purposes of water quality assessments. One approach uses a range of generalized operational, effluent, and ambient data to broadly assess plume behavior and water quality impacts. The second approach uses project-specific operational and a range of effluent and ambient data to assess these same parameters. Both approaches are discussed below; results of the water quality impact assessments are presented in Chapter 9 of this document.

The first approach uses two sets of Offshore Operator's Committee (OOC) Mud Discharge Model runs previously conducted for EPA Region 10 using a broad set of environmental and operational conditions. One set of OOC model scenarios (U.S. EPA Region 10, 1984) are based on a varied set of operational and environmental conditions for operations in Alaskan waters. A second set of model runs, intended to confirm and extend the earlier model runs conducted for Region 10, was completed for Region 10 by Dr. Maynard Brandsma (Brandsma Engineering, 1991). This last set of model runs was completed using the OOC Mud and Produced Water Discharge Model, Version 1.2F, which is an updated version of the 1983 OOC Mud Discharge Model used previously. Although these model runs were conducted for Region 10, many of these discharge scenarios are also generally appropriate to the present Gulf of Mexico analysis and were used to evaluate drilling fluids plume behavior.

The characteristics and results of these modeling exercises have been compiled and reviewed. A subset of cases was identified that comprise cases conducted for minimum water depths of 10 meters and at the maximum discharge rate authorized in the Gulf of Mexico permit (1,000 bbl/hr). This subset is believed to represent a reasonable range of potential drilling fluid discharge scenarios and, therefore, presents a reasonable indication of the dilutions and dispersions that may be expected for high rate drilling fluid discharges. Mean drilling fluids dilution among these 1,000 bbl/hr discharge scenarios, for 15-meter, 40-meter, and 70-meter water depth scenarios, were used by the Region for the purpose of conducting water quality assessments.

4.2.1 *OOC Mud Discharge Model*

The OOC Mud Discharge Model is the most general of the available drilling fluid plume models and is the discharge model used for both approaches. It uses LaGrangian calculations to track material (clouds) settling out of a fixed pipe and a Gaussian formulation to sum the components from the clouds. The OOC model includes the initial jet phase, the dynamic collapse phase, and the passive diffusion phase of plume behavior.

The minimum waste stream data input requirements for the OOC Mud Discharge Model include effluent bulk density and particle size distribution. The dispersion of up to 12 drilling fluid particle size solid fractions (i.e., settling velocity fractions) can be followed. For each constituent particle fraction, its settling velocity and its fractional proportion of total solids must be input to the model. The OOC model requires the following operational data input: the depth of the discharge, diameter of the discharge pipe, discharge rate, and orientation of the discharge relative to ambient currents. Ambient environmental data input requirements of the OOC model include current, density stratification, and bathymetry.

Operational data are generally adequate to fulfill the data input needs for the OOC Mud Discharge Model. Waste stream input data requirements are adequately addressed by existing information, with the possible exception of settling velocities for drilling fluid solids fractions. Currently, these data are both extremely limited and a key model parameter. Existing settling velocity data are available for only a very few drilling muds. Thus, lacking data on more mud samples, it is difficult to know if the available data adequately represent drilling fluids. Also, settling velocity profiles are a key parameter in the model, forming the basis for calculating the effect of gravitational setting of drilling fluid solids. Thus, any shift in the particle size distribution (i.e., settling velocity distribution) will have significant effects on the calculated behavior of the plume. Particle size (settling velocity) data should be considered minimally adequate.

4.2.2 *Derivation of Generalized Dispersion/Dilution Estimates*

The first set of model scenarios run for Region 10 was conducted over a range of environmental and operational conditions. The mud weight used, with the exception of one 9.0 lb/gal case, was a 17.4 lb/gal mud with a total suspended solids concentration (TSS) of 1,441,000 mg/l. Surface current speeds ranged from 2 cm/sec to 32 cm/sec; density stratification ranged from 0.008 σ_t/m to 0.1 σ_t/m. Operationally, discharge rates ranged from 100 bbl/hr to 1,000 bbl/hr, the discharge was located 1 foot below the water line, and the discharge pipe was 12 inches in diameter. Water depths ranged from 5 meters to 120 meters.

The second data set on modeling of drilling fluids dispersion and dilution (Brandsma Engineering, 1991) was conducted to confirm and extend the first data set prepared for Region 10. Thus, the input data used were the same as for the first data set. The principle alteration for this set of modeling data was that a newer, revised version of the OOC model was used. Also, in comparing the results of the earlier versus the more recent model runs, Brandsma noted that a computational error occurred in the derivation of soluble tracer dilution in the earlier data set. This error has been corrected for the first Region 10 data set in the ODCE review of the data.

4.2.3 *Model Results from Generalized Input*

The results of these two drilling fluids modeling data sets are compiled and presented in Table 4-3. Results have been sorted first by discharge rate and second, by dilution at 100 meters. These data have been analyzed in several ways. Data that were considered special cases of the model scenarios were eliminated from these analyses. These included model runs that excluded the rig wake effect from the model algorithm

Table 4-3. Summary of OOC Mud Model Drilling Fluid Plume Behavior

Case #	Water Depth (m)	Rate (bbl/h)	Current (cm/s)	Density Gradient (sigma-t/m)	100 m Dispersion	100 m Dilution
TT 8	10	100	10	0.07	3,859	2,579
TT 4	40	100	10	0.10	5,246	4,728
MB 3	5	250	10	0.10	2,318	222
MB 4	5	250	30	0.10	1,582	468
TT 18	5	250	10	0.02	6,109	662
TT 19	15	250	2	0.07	8,873	1,426
TT 20	15	250	10	0.07	2,558	1,617
MB 5	5	500	10	0.10	1,136	124
MB 6	5	500	30	0.10	770	211
MB 7	20	500	10	0.10	1,640	1,035
MB 8	20	500	30	0.10	1,626	1,583
MB 10	20	750	30	0.10	1,024	676
MB 9	20	750	10	0.10	1,305	789
TT 9	10	1,000	10	0.07	299	107
TT 5	5	1,000	10	0.02	4,810	127
TT 11	15	1,000	10	0.07	1,748	335
TT 6	10	1,000	10	0.07	1,785	341
TT 12	15	1,000	30	0.07	752	575
MB 11	20	1,000	10	0.10	942	655
TT 13	20	1,000	10	0.05	1,092	689
TT 14	40	1,000	10	0.01	731	755
TT 10	15	1,000	2	0.07	11,407	776
TT 3	40	1,000	10	0.10	905	818
MB 12	20	1,000	30	0.10	1,130	973
TT 15	70	1,000	10	0.04	1,803	1,721

Source: MB - Brandsma, 1991; TT - TetraTech, 1984.

and model runs that were conducted for pre-diluted drilling fluid discharges. Table 4-4 presents a summary of dilution results for data sorted by discharge rate. Table 4-5 presents a summary of dilution results for 1,000 bbl/hr discharges, sorted by water depth. These results are generally consistent with what would be expected for these discharges. Dilutions decrease with increasing discharge rates when they are considered in terms of their mean behavior, although there is considerable overlap between the ranges of dilution observed among the various discharge rates.

Table 4-4. Summary of OOC Mud Discharge Model Results by Discharge Rate

Discharge Rate (bbl/hr)	100-m Dilution Mean (Range)	100-m Dispersion Mean (Range
100	3,654 (2,579 - 4,728)	4,552 (3,859 - 5,246)
250	879 (222 - 1,617)	4,288 (1,582 - 8,873)
500	738 (124 - 1,583)	1,293 (770 - 1,640
750	733 (676 - 789)	1,165 (1,024 - 1,305)
1,000	656 (107 - 1,721)	2,284 (299 - 11,407)

Table 4-5. Summary of OOC Mud Discharge Model Results by Water Depth for High Weight (17.4 lb/gal) Muds Discharged at 1,000 bbl/hr

Water Depth (bbl/hr)	100-m Dilution Mean (Range)	100-m Dispersion Mean (Range)
5	127 (127)	4,810 (4,810)
10	224 (107 - 341)	1,042 (299 - 1,785)
15	562 (335 - 776)	4,636 (752 - 11,407)[a]
20	772 (655 - 973)	1,055 (942 - 1,130)
40	787 (755 - 818)	818 (731 - 905)
70	1,721 (1,721)	1,803 (1,803)

[a] Includes the only model run for 17.4 lb/gal muds at 1,000 bbl/hr at 2 cm/sec current speed (all others run at 10-30 cm/sec); if deleted from data set, the mean dispersion at 15 m is 1,250-fold.

Likewise, the general trend for dilution is to increase water depth; the effect of water depth on dispersion appears less clear from this data set, with no well-defined trend. Others (U.S. EPA, Region 10, 1984) noted an apparent biphasic behavior in their more homogenous data set.

For the water quality assessment (see Chapter 9), the results of mean dilution at the maximum authorized discharge rate were used. For this assessment, mean dilution at 100 meters for a water depth of 15 meters was 562 dilutions; for water depths of 40 meters and 70 meters, the respective means were 787 dilutions and 1,721 dilutions.

4.3 Synthetic-Based Drilling Fluids

4.3.1 Dispersal and Accumulation of SBF Drill Cuttings

Laboratory dispersal experiments showed that the various types of SBF's displayed a relative dispersibility as follows: Ester > Di-Ether >> Linear alkyl benzene > PAO > Low-Toxicity Mineral Oil. It is expected that the IOs and LAOs, the most commonly used synthetics today, should fall between esters and PAOs in dispersibility.

Because most SBF cuttings do not disperse efficiently in the water column following discharge, the rapid settling results in accumulation on the bottom near the platform discharge site. The field studies reviewed (Neff et al., 2000) show a high degree of variability in the depth of the SBF cuttings piles and distribution of cuttings on the seafloor. The variety of methods used in the studies and variation in discharge depths, discharge rates, total volumes discharged and oceanic conditions prevent drawing clear relationships between cuttings pile depths and distributions and SBF type, water depths and cuttings mass.

Generally, the distance from the rig to the highest concentration of SBF cuttings on the bottom varies depending on distance from the discharge to the seafloor, the net water current speed, and cuttings density. Results of some field studies indicate that SBF cuttings are distributed very heterogeneously in surface and subsurface sediments around deep-water drilling sites. The uneven distribution of cuttings on the bottom appears to be caused by clumping of the hydrophobic SBF-coated cuttings falling to the seafloor in large clumps. The distributions of SBF cuttings accumulations on the bottom is controlled by the direction and velocity of water currents at different depths in the water column.

Because of the variability in the data reviewed, it is not possible to draw any firm conclusions about rates of biodegradation, dilution, or washout of different types of SBF cuttings from sediments. Generally, the rate of loss of SBFs, other than esters, from sediments appears to be low. Ester concentrations in sediments near rigs using ester SBFs were lower than concentrations of other SBFs near the platforms using other SBFs. This observation lends support to the hypothesis that esters biodegrade rapidly in sediments.

Based on the data reviewed, no clear relationship can be determined between concentrations of SBFs in sediments and water depth, mass of cuttings discharged, or mass of SBFs discharged. There was a trend for SBF cuttings concentrations in sediments near discharging platforms to decrease as water depth increased. In most cases, SBF cuttings do not penetrate and mix deeply into surface sediments near the platform. SBF concentrations usually are higher in the surface layer (0 - 2 cm) of sediments than in deeper layers (2 - 5 cm and 5 - 8 cm). Approximately a year after completion of drilling, concentrations of SBF in the surface layer of sediments often decrease; however, concentrations at greater depths in the sediment core may increase or decrease. Temporal changes in SBF concentrations below the sediment surface probably are controlled by the amount of sediment reworking (by bioturbation and current-induced bed transport) and biodegradation. After more than a year, SBF concentrations at all depths in sediment may decline to low values, particularly if ester SBF cuttings were discharged.

The distribution of SBF concentrations in sediments around platforms discharging SBF cuttings varied widely from one site to another. The distribution of SBF cuttings piles around drilling rigs in the UK Sector of the North Sea ranges from less than 2800 m^2 to 94,250 m^2. The cuttings are not evenly distributed in sediments around the rig with most cuttings settling in the direction of the net current flow.

The distance from the rig to the highest concentration of SBF cuttings on the bottom varied depending on distance from the discharge to the seafloor, the net water current speed, and cuttings density. In studies of SBF discharges to the UK Sector of the North Sea the highest concentrations of SBF in sediments were located 0 m to 224 m from the rig immediately after drilling. Approximately one year after completion of drilling, the highest SBF concentrations in sediments were located 5 m to 153 m from the former drilling sites. The distance from the rig sites to sediment SBF concentrations below about 1,000 mg/kg ranged from 40 m to about 500 m from the rigs.

4.3.2 Biodegradation of SBFs

Microbial metabolism is the main mechanism of degradation of SBF base materials into harmless byproducts. Natural populations of sediment-dwelling bacteria, fungi, and protists are able to biodegrade some hydrocarbons and related oxygen-containing organic chemicals (e.g., esters, ethers, acetals) and use the carbon fragments as a source of nutrition.

Hydrocarbons vary in their susceptibility to biodegradation. The biodegradation of paraffins and olefins decreases sharply with increasing carbon chain length and molecular weight. As a result, high molecular weight, insoluble SBF base chemicals, such as PAOs, are less bioavailable and biodegradable than lower molecular weight, slightly soluble base chemicals, such as IOs. As a general rule, linear hydrocarbons are more easily biodegraded than branched or aromatic hydrocarbons. Biodegradation rate of linear paraffins decreases as chain length increases. Branching of hydrocarbon chains tends to slow biodegradation. Carbon-carbon double bonds and internal oxygen atoms (e.g., esters) are more readily attacked by microbes than carbon-carbon single bonds. Hydrocarbons are biodegraded mainly by oxidation; therefore, biodegradation of SBF base materials and other hydrocarbons is much more rapid under aerobic conditions than in anaerobic environments.

A normal alkane (e.g., linear paraffin) or an alkene (e.g., LAO, IO, and PAO) is oxidized by microbes to an alcohol; the alcohol is oxidized further to a fatty acid. Two atoms of oxygen are consumed for each atom of fatty acid formed. Fatty acids are storage and structural nutrients for all plants and animals. The fatty acids derived from oxidation of SBF base chemicals are oxidized two carbons at a time through oxidation. The resulting acetate (CH_3COOH) molecules are incorporated into the energy and synthetic pathways of the microorganism. Thus, SBF base chemicals are biodegraded completely under aerobic conditions, with the reduction of a large amount of oxygen. Aerobic biodegradation of SBFs may deplete the oxygen in sediments, rendering the sediments anaerobic, if loading of the sediments with biodegradable organic matter from SBF cuttings is high and aeration of sediments is slow. In the absence of oxygen, SBF base chemicals are dehydrogenated to alcohols that are converted to fatty acids via chemical reactions are very inefficient under anaerobic conditions, and their rate probably limits the overall net rate of SBF biodegradation in marine sediments. Carbon-carbon double bonds and ester linkages are more easily oxidized than carbon-carbon single bonds by marine anaerobic bacteria. Thus, esters and unsaturated SBF base chemicals would be expected to biodegrade more rapidly than paraffins, linear alkyl benzenes, ethers, and acetals in anoxic sediments. Under anaerobic conditions, fatty acid oxidation also is inefficient. Alternatives to oxygen (e.g., NO_3^- , SO_4^{-2}, and CO_2) are used by the microbes to oxidize fatty acids, producing byproducts, such as hydrogen sulfide, ammonia, and methane, that are toxic to some sediment-dwelling marine organisms. Sulfate is abundant in seawater (~ 29 mM) and marine sediments; therefore, it is the dominant terminal electron acceptor for microbial oxidation of SBF base chemicals in anoxic marine sediments. Methanogenesis (reduction of CO_2 to CH_4) occurs only when most of the available sulfur has been reduced to sulfide. Sulfate reducing bacteria are more aggressive than methanogens, and olefins and esters should biodegrade more rapidly in marine sediments than indicated by anaerobic biodegradation tests, most of which are based on methanogenesis. The most important environmental factors affecting biodegradation rate of SBFs in sediments are temperature, oxygen concentration, and seafloor energy.

Results of laboratory biodegradation tests reviewed by Neff et al. (2000) indicate that aerobic and anaerobic biodegradation rates of synthetics occur in the following order: ester>LA>IO>PAO> acetal>ether. Mineral oils are less biodegradable than SBF base chemicals, particularly under anaerobic conditions.

Considering the high concentrations of SBFs measured in surficial sediments within 100 m of some offshore platforms discharging SBF cuttings, it is probable that most SBF biodegradation will occur under anaerobic conditions after sediment oxygen concentration is reduced to low levels by the initial aerobic biodegradation of the SBF cuttings. In low energy environments where cuttings dispersion at the seafloor is a minor factor, anaerobic degradation of SBF cuttings probably is the rate-limiting step in recovery of benthic marine ecosystems contaminated with SBF cuttings. Anaerobic biodegradation rate is highest for esters, followed by LAOs. In general, SBF base chemicals, other than ester, do not biodegrade anaerobically at a substantially higher rate than mineral oils used in OBFs. Alkylbenzenes are not biodegraded under anaerobic conditions. Of the possible degradation products, alcohols are highly biodegradable, and ethers are resistant to anaerobic biodegradation.

4.4 Produced Water

The major processes affecting the fate of discharged produced water and associated chemicals include dilution and advection, volatilization, and adsorption/sedimentation. Hydrocarbons that become associated with sedimentary particles by adsorption can accumulate around production platforms, either settling to the seafloor through the water column or more directly through bottom impact of the discharge plume. Sediment contamination by produced water hydrocarbons was observed in shallow water studies at Trinity Bay, Texas (Armstrong et al., 1979) and at coastal Texas and Louisiana sites (Roach et al., 1992; Boesch and Rabalais, 1989; Rabalais et al., 1992). Roach et al. (1992) sampled sediments in the vicinity of produced water discharges at two coastal sites in Texas. Elevated levels of PAHs, aliphatics, and oil and grease were observed to a distance of 370 m from the discharge. Boesch and Rabalais (1989) noted that concentrations of naphthalenes in the sediment were enriched compared to effluent levels (21 mg/kg in the sediment versus 1.62 mg/liter in the effluent) and naphthalene levels were elevated in the immediate vicinity of the discharge with a subsurface concentration maximum in the sediment. Rabalais et al. (1992) compared sediment contamination and benthic community effects at 14 study sites in Louisiana (Table 4-6). Alkylated PAH were found to the maximum distance of the study transects at two sites (to 1,000 and 1,300 m) and from <100 to 500 m at the other sites. The two sites with no contaminants detected had outfalls that directed flow to a holding pond or marsh area. Benthic community effects were detected to a maximum distance of 800 m.

Table 4-6. Comparison of Extent of Sediment Contamination, and Benthic Community Impacts for Produced Water Discharges in the Gulf of Mexico

Site	Discharge (bbl/day)	Receiving Water Depth (m)	Environment	Zone of Sediment Contaminants (m)	Extent of Benthic Community Impacts (m)
Bayou Rigaud[1,2]	146,000	4-5	Dredged Bayou	1,300	700
Pass Fourchon[1,2]	48,000	3-4	Canal-Dredged Bayou	1,000	800
East Timbalier Island[1,2]	26,000	1.5-2	Canals Near Bay	360	100
Eugene Island Block 18[1,2]	21,000	2	Shallow Shelf	250	300
Romere Pass[1,2]	20,200	2	Miss. R. Distributary	450	None
Empire Waterway[1,2]	11,000	3	Marsh, Dredged Canal	None	None
Trinity Bay[3]	4,000-10,000	3	Open Bay	250-300	150
Emeline Pass[1,2]	3,700	3-6	Marsh, Miss. R. Distributary	None	None
Lake Pelto[4]	3,700	2	Open Bay (near pass)	100	20
Lafitte Field[5]	3,700	2	Dredged Canal	500	250
Eugene Island 120[4]	3,700	12	Shallow Shelf	100	20
Golden Meadow Field[5]	2,800	2-3	Dredged Canal, Bayou	100	100
Bayou Sale Field[5]	2,500	2-3	Dredged Canal	500	100
Buccaneer Field[6]	120-2,000	20	Shallow Shelf	200	NA

References:

1 Boesch and Rabalais (1989a)
2 Rabalais et al. (1991)
3 Armstrong et al. (1979)
4 Neff et al. (1989)
5 Boesch and Rabalais (1989b)
6 Middleditch (1981)

Source: Rabalais et al., 1992.

The sediment accumulation observed in these shallow water studies is provided for comparison and is not expected to directly compare to the open Gulf areas covered by the general permit for the eastern Gulf. Studies of sediment impacts for open waters are not available to the extent that coastal studies are. One study, Neff et al. (1988), reports little chemical contamination at their offshore study sites that exceeded a 300 m radius. Neff (1997) reviewed the available scientific literature on the fates and effects of produced water in the ocean. Saline produced waters dilute rapidly upon discharge to well-mixed marine waters.

Dispersion modeling studies of the fate of produced water differ in specific details but all predict a rapid initial dilution of discharges by 30- to 100-fold within the first few tens of meters of the outfall, followed by a slower rate of dilution at greater distances (Smith, 1993; Terrens and Tait, 1993; Smith et al., 1994; Stromgren et al., 1995; Brandsma and Smith 1996). Terrens and Tait (1993) modeled the fate of produced water discharged to the Bass Strait off southeastern Australia. Under typical oceanographic conditions for the area, the produced water is diluted nearly 30-fold within 10 m of the discharge and by 1,800-fold 1,000 m down-current of the produced water discharges. Brandsma and Smith (1996) modeled the fate of produced water discharged under typical Gulf of Mexico conditions. For a median produced water discharge rate of 115 m^3/d (772 bbl/d), a 500-fold dilution was predicted at 10 m from the outfall and a 1,000-fold dilutions was predicted at 100 m from the outfall. For a maximum discharge rate of 3,978 m^3/d (25,000 bbl/d), a 50-fold dilution was predicted at 100 m from the outfall. High volume discharges of warm high-salinity produced water to the North Sea are diluted by about 500-fold within about 60 m of the outfall under well-mixed water column conditions. Under conditions of stratified water column, a 300-fold dilution is reached 60 m from the discharge (Stephenson et al., 1994). Further dilution is slower; a 1,000-fold dilution is attained after about 1 hour when the produced water plume has drifted about 1,000 m.

Field measurements of produced water dilution are highly variable, but confirm the predictions of modeling studies that dilution is rapid. Continental Shelf Associates (1993) reported that radium from a 6,570 bbl/d produced water discharge in a water depth of 18 meters in the Gulf of Mexico was diluted by a factor of 426 at 5 m from the discharge, and by a factor of 1,065 at 50 m from the discharge. Smith et al. (1994) used a dye tracer to measure dilution of produced water being discharged at a rate of 2,900 bbl/d to 6,500 bbl/d in a water depth of 82 m and found a 100-fold dilution within 10 m of the discharge and a 1,000-fold dilution within 103 m of the discharge. Somerville et al. (1987) measured a 2,800-fold dilution of produced water 1,000 m downcurrent from a North Sea produced water discharge. Rabalais et al. (1992) were able to measure elevated (compared to background) concentrations of radium, but not volatile hydrocarbons, to about 1,000 m downcurrent of a high-volume produced water discharge to shallow coastal waters of Louisiana.

Chemical processes important to the fate of produced water constituents generally are those that affect metal and petroleum hydrocarbon behavior in marine systems. Factors affecting metals have been described above under drilling fluids. An important factor affecting the fate of hydrocarbons in produced water is volatilization. Produced water contains a high fraction of volatile compounds (e.g., benzene), which can be lost from the system over time. However, because produced water can be much more dense than seawater (salinities >150 ppt are not uncommon), discharge plumes sink rapidly. Thus, elevated levels of benzene in bottom water have been observed in shallow coastal waters (Boesch and Rabalais, 1989; Rabalais et al., 1992).

For compounds with higher molecular weights, a major chemical process involves biodegradation of compounds. Polynuclear aromatic hydrocarbons tend to be more resistant to such degradation and, thus, can persist in the environment (primarily in sediment) for extended periods. The subsequent fate of petroleum hydrocarbons associated with sediments will depend on resuspending and transporting processes, desorption processes, and biological processes. Because produced waters provide a continuous input of light aromatic hydrocarbons over the life of a field (generally 10 to 30+ years), there is the potential for these chemicals to accumulate in sediments. This differs from oil spill situations wherein the chemicals are rapidly lost and the sediments generally exhibit a decline of lighter aromatics with time.

The most abundant hydrocarbons of environmental concern in produced water are the light, one-ring aromatic hydrocarbons. Because they are volatile, they can be expected to evaporate rapidly from the water following produced water discharge. Brooks et al. (1980) reported that the maximum concentration of benzene measured in seawater immediately below the produced water discharge pipe at a production platform in the Buccaneer Field off Galveston, Texas was 0.065 ug/l, representing a nearly 150,000-fold dilution compared to the concentration of benzene in the produced water effluent (9,500 ug/l).

Concentrations of total gaseous and volatile hydrocarbons, including BTEX aromatics (75 percent of the total) decreased from 22,000 ug/l in the effluent, to 65 ug/l at the air/water interface below the outfall, to less than 2 ug/l in the surface water about 50 m away, indicating very rapid evaporation and dilution of the volatile components of the produced water. Concentrations of volatile liquid hydrocarbons discharged with produced water (600 bbl/d) at the Buccaneer Field were reduced on the order of 10^{-4} to 10^{-5} within 50 m from the platform (Middleditch, 1981).

BTEX concentrations in the upper water column near production platforms off Louisiana ranged from 0.008 to 0.332 ug/l (Sauer, 1980) compared to background concentrations of 0.009 to 0.10 ug/l of benzene in surface waters of the outer continental shelf off Texas and Louisiana (Sauer et al., 1978). These compounds are very volatile with half-lives in the water column of a few hours or days, depending on water temperature and mixing conditions.

Terrens and Tate (1996) measured concentrations of BTEX and several PAHs in ambient sea water 20 m from an 11 million liter/d (69,000 bbl) produced water discharge from a platform in the Bass Straits off Australia. There was an inverse relationship between molecular weight (and thus, volatility) and the dilution of individual aromatic hydrocarbons. Individual monoaromatic hydrocarbons were diluted by 53,000-fold (benzene) to 12,000-fold (xylenes). PAHs were diluted by 12,000-fold (naphthalene) to 2,000-fold (pyrene). Concentrations of higher molecular weight PAHs were below the detection limit (0.0002 ug/l) in the ambient sea water 20 m from the outfall. The inverse relationship between molecular weight of the aromatic hydrocarbons and their rates of dilution probably was attributed to the high temperature (95° C) of the discharged produced water.

Dilution of BTEX from produced water is less rapid where a large volume of highly saline produced water is discharged to poorly mixed, low-salinity estuarine waters. The concentration of total volatile hydrocarbons (including BTEX) approached 100 ug/l on one occasion in the bottom water in the vicinity of three produced water discharges (total volume ~ 43,000 bbl/d) to Pass Fourchon, a shallow marsh area in south Louisiana (Rabalais et al., 1991). BTEX compounds do not adsorb strongly to suspended or deposited marine sediments. Their concentrations in sediments near produced water discharges are usually low (Armstrong et al., 1979; Neff et al., 1989).

However, higher molecular weight aromatic and aliphatic hydrocarbons may accumulate in sediments near produced water discharges (Armstrong et al., 1979; Neff et al., 1989; Means et al., 1990; Rabalais et al., 1991). In well-mixed estuarine and offshore waters, elevated concentrations of saturated hydrocarbons and PAHs in surficial sediments may be observed out to a few hundred meters from a large-volume produced water discharge. In shallow, poorly mixed estuarine environments, elevated concentrations of PAHs in sediments may be detected to distances of at least 1,300 m from large-volume produced water discharges (Rabalais et al., 1991; 1992). Sediment contamination is greatest and extends the farthest from the discharge sites where large volumes of produced water (48,000 to 145,000 bbl/d) have been discharged to shallow (2 to 5 m) salt marsh canals.

4.4.1 Biological Transport Processes

Biological transport processes occur when an organism performs an activity with one or more of the following results.

- An element or compound is removed from the water column
- A soluble element or compound is relocated within the water column
- An insoluble form of an element or compound is made available to the water column
- An insoluble form of an element or compound is relocated.

Biological transport processes include bioaccumulation in soft and hard tissues, biomagnification, ingestion and excretion in fecal pellets, and reworking of sediment to move material to deeper layers (bioturbation).

Ingestion and Excretion

Organisms remove material from suspension through ingestion of suspended particular matter and excretion of this material in fecal pellets. These larger pellets exhibit different transport characteristics than the original smaller particles. Houghton et al. (1981) notes that filter-feeding plankton and other organisms ingest fine suspended solids (1 µm to 50 µm) and excrete large fecal pellets (30 µm to 3,000 µm) with a settling velocity typical of coarse silt or fine sand grains. The study also notes that copepods are important in forming aggregate particles.

Zooplankton have been found to play a major role in transporting metals and petroleum hydrocarbons from the upper water levels to the sea bottom (Hall et al., 1978). The largest fraction of ingested metals moves through the animal with the unassimilated food and passes out with the fecal pellets in a more concentrated state (Fowler, 1982). Zooplankton fecal pellets have also been found to contain high concentrations of petroleum oil, especially those of barnacle larvae and copepods. Hall et al. (1978) calculate that a population of calanoid copepods grazing on an oil slick could transport three tons of oil per square kilometer per day to the bottom.

Bioaccumulation and Biomagnification

Studies assessing biomagnification of certain petroleum hydrocarbons are more limited than for other pollutants. The data available suggest that these contaminants are not subject to biomagnification. One reason for this observation is that the primary source of these compounds for organisms may be absorption from the water column rather than ingestion. Additionally, biological half-times of some petroleum hydrocarbons may be short, with many species purging themselves within a few days.

There is some evidence that hydrocarbons discharged with produced water are bioaccumulated by various marine organisms. In a central Gulf of Mexico study (Nulton et al., 1981), analyses revealed the presence of low levels of alkylated benzenes, naphthalenes, alkylated naphthalenes, phenanthrene, alkylated three-ring aromatics, and pyrene in a variety of fish and epifauna. Isomer distributions of alkylated benzenes and naphthalenes were similar to those seen in crude oil.

Middleditch (1980) analyzed hydrocarbons in tissues of organisms in the Buccaneer Field. During the first two years of the study, tissue from barnacles from the platform fouling community at depths approximately 3 m below the surface contained up to 4 ppm petroleum alkanes. Middleditch (1980), in studying the fouling community and associated pelagic fish, found that many species were contaminated with hydrocarbons discharged in produced water. Middleditch claims that biodegradation of petroleum hydrocarbons in the barnacles was apparently efficient. Analyses of the fouling mat on the platform revealed that most samples contained petroleum hydrocarbons, and concentrations were particularly high in those collected just below the air/sea surface.

Middleditch (1980) found petroleum hydrocarbons in 15 of 31 fish species examined around the Buccaneer Field platform. Analyses were focused on four species--crested blenny, sheepshead, spadefish, and red snapper. Virtually every specimen of crested blenny examined contained petroleum alkanes. In this species, the n-octadecane/phytane ratio was similar to that of produced water but the n-octadecane/pristane ratio is distorted by the presence of endogenous pristane of biogenic origin. The mean alkane concentration in this species was 6.8 ppm. This species feeds on the platform fouling community, and it was suggested that this food was the source of petroleum hydrocarbons to the fish. Similar results were obtained with sheepshead, which also partially feed on the platform community. Petroleum alkanes were found in about half of the muscle samples and in about one quarter of the liver samples. The mean alkane concentration in these tissues were 4.6 and 6.1 ppm, respectively. Spadefish exhibited lower concentrations of alkanes in muscle and liver (0.6 and 2.0 ppm), and this species does not utilize the platform fouling community as a food source to the same extent as the two previously described species. Lower levels of alkanes were also observed in red snapper (1.3 ppm in muscle, and 1.1 ppm in livers).

With one exception, most shrimp analyzed by Middleditch did not contain alkanes. This probably reflects the highly migratory behavior of these animals. Similarly, the petroleum hydrocarbons were not found in white squid. Middleditch also examined nine benthic organisms for petroleum hydrocarbons. Yellow corals (*Alcyonarians*) contained alkanes, but Middleditch suggested these could be of biogenic origin. Various hydrocarbon profiles were observed in species. Few of the specimens of winged oyster (*Pteria colymbus*) contained petroleum alkanes while they did contain methylnaphthalenes and benzo(a)pyrene. The results presented above, however, are rendered ambiguous inasmuch as Middleditch may not have clearly differentiated between biogenic and petrogenic alkanes.

4.4.2 Discharge Modeling - Produced Water

The fate of produced water discharges was projected using the CORMIX expert system, which was developed as a regulatory assessment tool for the EPA Environmental Research Laboratory at Athens, Georgia (Doneker and Jirka, 1990). A review of the model by LimnoTech Inc. (1993) for application to the OCS Federal waters resulted in the modified version used for the projections in this assessment.

4.4.2.1 CORMIX Expert System Description

The Cornell Mixing Zone Expert System (CORMIX) is a series of software subsystems for the analysis, prediction, and design of aqueous conventional or toxic pollutant discharges into watercourses (Doneker and Jirka, 1993). CORMIX (Version 2.10) was developed to predict the dilution and trajectory of submerged, single port discharges of arbitrary buoyancy (positive, negative, neutral) into water body conditions representative of rivers, lakes, reservoirs, estuaries, or coastal waters (i.e., shallow or deep, stagnant or flowing, uniform density or stratified). CORMIX assumes steady state flow conditions both for the discharge and the ambient environment.

The CORMIX expert system emphasizes the geometry and initial mixing of the discharge, predicting concentrations and dilutions, and the shape of the regulatory mixing zone. CORMIX requests necessary data input, checks the input data for consistency, assembles and executes the appropriate hydrodynamic models, interprets results of the simulation with respect to the specified legal mixing zone requirements (including toxic discharge criteria), and suggests design alternatives to improve dilution characteristics.

CORMIX uses the expert system shell VP-Expert (Paperback Software, Inc.) and FORTRAN. CORMIX uses knowledge and inference rules, based on hydrodynamic expertise captured in the system, to classify and predict jet mixing. CORMIX was developed with the intent to provide an expert system that would work for a large majority of typical discharges (better than 95%), ranging from simple cases to fairly complex cases.

CORMIX requires input of water depth, selection of stratification profile (it provides four profiles from which to choose), surface/bottom water densities and stratification height if one exists, ambient current velocity (uniform), distance to the nearest bank, outfall port diameter, flow rate, depth of the outfall port (restricted to the lower third of the water column), vertical and horizontal discharge angles, effluent density, and the shape and dimension of regulatory mixing zones.

In response to industry comments on a proposed general NPDES permit issued by EPA Region 6, EPA requested a review of CORMIX to determine the system's applicability to discharges to open waters of the Gulf of Mexico. While it was determined that CORMIX was the best choice of the dispersion/ dilution models available, it was also determined that two adjustments were needed to make the far-field projections more accurate.

The first adjustment concerns the limitation imposed by the system requiring that the discharge pipe opening be located in the bottom one-third of the water column. For produced water outfalls located at or above the water surface and is a negatively buoyant effluent (such as produced water), this configuration does not provide an accurate prediction of scenarios where the full water column is available for mixing. To correct for this, the water column and discharge densities have been inverted for two of the three discharge modeling scenarios where surface discharges occur, in the following manner. (The remaining case, where the discharge is shunted into the lower third of the water column, no adjustments to CORMIX were necessary.)

Based on a linear stratification with a density gradient (σ_t/m) of 0.163 kg/m^3/m, the bottom density is calculated using a surface density of 1,023 kg/m^3. The water column is "inverted" by using the surface density as the bottom density and calculating a new surface density, keeping the density differential constant (e.g., for a 10 meter water depth, the new surface density would be 1,023 kg/m^3- (10 *0.163 kg/m^3) = 1,021.37 kg/m^3). The effluent density is inverted to create a positively buoyant plume keeping the produced water ambient density differential consistent with the original scenario. This is accomplished by reducing the effluent density at the outfall by the difference between it and the original ambient density (e.g., the initial density differential of 1,070 kg/m^3 - 1,023 kg/m^3 = +47 kg/m^3 is transformed into a density differential of -47 kg/m^3 by changing the effluent density to 1,023 kg/m^3 - 47 kg/m^3 = 976 kg/m^3). The inverted scenario is run through the CORMIX system with the discharge located at the seafloor creating a mirror image of a negatively buoyant discharge located just below the water surface. Trial runs of the CORMIX system verify that these scenarios produce identical results.

The second adjustment to the CORMIX system corrects for an underestimation of far-field dilutions as discussed in Wright (1993). For model projections that do not result in the plume impacting the seafloor (or the surface in the case of the inverted scenario), Brook's 4/3 power law is applied to the control volume outflow results of the model at the end of the impingement zone to predict the dilutions at the edge of the mixing zone. The derivation from the Brook's equation used to calculate farfield dilution is:

$$C_i = \mathrm{erf}[(1.5/((1 + 8\ A\ H^{4/3}\ (t/H^2))^3 - 1))^{1/2}]$$

where,

H = the width of the collapsed plume
A = 0.000453 m$^{2/3}$/s
t = travel time from the end of the plume collapse to 100 m (edge of the mixing zone)
(100/u-T); where T is the time to complete the collapse phase
erf = the error function
C_i = the maximum concentration in the far field after travel time t_i.

The input needed for this equation is provided by the CORMIX output.

4.4.2.2 Derivation of Dilution Estimates

Input data for stratification conditions in the CORMIX model predictions used for the general assessment of produced water dilution were primarily based on a study by Temple et al. (1977). A study transect off Mobile Bay was monitored for temperature and salinity over one year. The 7- and 14-meter stations were used to determine the average surface water density and density gradient in the water column. For the existing produced water outfalls located offshore Alabama, a surface density of 1,023 kg/m^3 and a gradient (σ_t/m) of 0.163 kg/m^3/m were used. The effluent density of 1070 kg/m^3, used as input for the model, was derived from data obtained from the Louisiana Department of Environmental Quality (*Avanti* Corporation, 1992). The density represents a produced water with a salinity of 100 ppt (approximately the lower 33rd percentile of coastal and offshore Louisiana produced water chlorinity) and an effluent temperature of 105°F (approximately the upper 90th percentile of coastal and offshore Louisiana produced water temperature).

The current speed used for this assessment of produced water dilution (5 cm/sec) is the median of current speeds recorded for offshore Alabama by Texas A&M (1991). The current meter was placed at a 10 meter depth in 30 meters of water.

Operational data for the three existing produced water outfalls were supplied by the operators at the request of Region 4. This data as well as other input parameters needed for the CORMIX model are listed in Table 4-7. Shell, operating in Mobile Block 821, is located in 49 feet (15.25 m) of water. The outfall is shunted to 40 feet (12.2 m) below the water surface and the average produced water discharge rate is 1500 bbl/day from a 35-inch pipe. Because the outfall is within the bottom one-third of the water column, inversion of the water column densities was not needed. Also, because CORMIX indicated plume interaction with the seafloor, the Brook's equation modification for the farfield dilution was not applied in this case. Chevron is operating in Mobile Block 990 located in 54 feet (17.5 m) of water with the outfall located above the surface of the receiving water. The discharge averages 450 bbl/day from a 4-inch pipe. Callon Petroleum is located in Mobile Block 908 in 66 feet (21.1 m) of water with the outfall located above the receiving water surface. The average discharge rate is 2 bbl/day from a 6-inch pipe.

4.4.3 Model Results

The results of the CORMIX model are presented in Table 4-7 for a 100-meter mixing zone. These results are used for the water quality analysis in Chapter 9 of this document. Both the Chevron and Callon Petroleum produced water outfalls are located above the water surface. In these cases, the ambient water densities and effluent/ambient density differential were inverted; because the discharge plume does not impact the surface, the Brook's equation was used to estimate far-field dilution. The CORMIX dilution at 100 m, without the Brook's modification was used for the Shell facility produced water modeling scenario.

Table 4-7. Summary of CORMIX Input Parameters and Model Results for Produced Water Discharges

Input Parameter[a]	Shell (MOB 821)	Chevron (MOB 990)	Callon Petroleum (MOB 908)
Water Depth	49 ft. (15.25 m)	54 ft. (17.46 m)	66 ft. (21.1 m)
Pipe Depth	40 ft. (12.2 m) or 3.05 m from bottom	Above surface or 0 m from bottom	Above surface or 0 m from bottom
Pipe Diameter	35 in. (0.889 m)	4 in. (0.1016 m)	6 in. (0.1524 m)
Discharge Rate (bbl/d)	1,500 bbl/day	450 bbl/day	2 bbl/day
Current Speed (m/s)	0.05 m/s	0.05 m/s	0.05 m/s
Ambient Surface Density (kg/m^3)	1,023	1,020.15	1,019.56
Ambient Bottom Density (kg/m^3)	1,025.49	1,023	1,023
Density Stratification (sigma-t/m)	0.163	0.163	0.163
Produced Water Density (kg/m^3)	1,070	976	976
Dilutions at 1,000 m	333	3,570	89,235

[a] Input data provided to Region 4 by operators; current speed and density stratification determined from data for the Gulf of Mexico offshore Alabama (Texas A&M, 1991; Temple et al., 1977).

5. TOXICITY AND BIOACCUMULATION

5.1 Overview

The release of drilling and production wastes from oil and gas platforms is of interest due to the potential toxicity and the potential for bioaccumulation. The following is a brief summary of the available data regarding water-based and synthetic-based drilling fluids. It is important to note that the permit limits the toxicity of drilling fluids (30,000 ppm of the suspended particulate phase), prohibits the discharge of any muds containing diesel, the discharge of neat synthetic-based fluids, and limits the cadmium and mercury content of muds so that only the less contaminated sources of barite may be use in mud formulations.

5.2 Toxicity of Drilling Fluids

Toxicity testing data are often used to assess the toxicological characteristics of an effluent. Toxicity tests have been conducted with a wide variety of drilling muds, drilling mud fractions, and test organisms. The presence of diesel oil in used drilling mud also has been shown to contribute to increased toxicity (Conklin et al., 1983; Duke and Parrish, 1984).

The "fractions" or “phases” of drilling fluids that have been used in toxicity testing include:

Suspended Particulate Phase (SPP). One part by volume of drilling fluid is added to nine parts seawater. The drilling fluid-seawater slurry is well mixed and the suspension is allowed to settle for one hour before the supernatant SPP is decanted off. The SPP is mixed for five minutes and then used immediately in bioassays. Testing protocol currently employed by EPA specifies testing of the SPP.

Layered Solid Phase (LSP). A known volume of drilling fluid is layered over the bottom of the test vessel or added to seawater in the vessel. Although little or no mixing of the slurry occurs during the test, the water column contains a residual of very fine particulates which do not settle out of solution.

Suspended Solids Phase (SSP). Known volumes of drilling fluids are added to seawater and the mixture is kept in suspension by aeration or mechanical means.

Mud Aqueous Fraction (MAF). One part by volume of drilling fluid is added to either four or nine parts seawater. The mixture is stirred thoroughly and then allowed to settle for 20-24 hours. The resulting supernatant MAF is siphoned off for immediate use in bioassays. The MAF is similar to the SPP but has a longer settling time, so the concentration of particulates in the supernatant is lower.

Filtered Mud Aqueous Fraction (FMAF). The mud aqueous fraction of whole drilling fluid is centrifuged and/or passed through a 0.45 μm filter and the resulting solution is the filtered mud aqueous fraction.

Because the synthetic-base fluids are water insoluble and the SBFs do not disperse in water as water-based drilling fluids (WBFs) do, but rather tend to sink to the bottom with little dispersion, most research has focused on determining toxicity in the sedimentary phase as opposed to the aqueous phase.

5.2.1 *Acute Toxicity*

Acute toxicity tests of whole drilling fluids have generally produced low toxicity. Petrazzuolo (1983) summarized the results of 415 such tests of 68 muds in 70 species and found 1 to 2 percent had LC50s ranging from 100 to 999 ppm, 6 percent had LC50s ranging from 1,000 to 9,999 ppm, 46 percent had LC50s ranging from 10,000 to 99,999 ppm, and 44 percent had LC50s of greater than 100,000 ppm (Table 5-1).

Test results also indicate that whole drilling fluid is more toxic than the aqueous or particulate fractions (Table 5-2). These data show whole fluid toxicity ranging from one to five times that of the aqueous fraction, and 1.3 times the toxicity of the particulate fraction. The reason for this increased toxicity is unclear, although a combination of chemical and physical interactions is possible. Also, in terms of using toxicity test results to project potential receiving water impacts, drilling fluids generally undergo a rapid physical separation of their solids components over once discharged.

Acute toxicity test results for used drilling fluids and drilling fluid components are presented in Appendix A. Criterion values for drilling fluid fractions in the table have been converted to whole fluid equivalents to provide greater comparability to whole fluid tests. For example, the MAF is prepared by mixing one-part drilling mud with 9 parts seawater, so an LC50 value derived from 100 percent MAF is the supernatant from a 10 percent drilling fluid mixture and is therefore expressed as 100,000 ppm (10 percent whole fluid equivalent).

Petrazzuolo (1981) used a semi-quantitative procedure to rank organisms in terms of sensitivity to drilling fluids, based on laboratory tests. The results ranked groups of organisms as follows, in order of decreasing sensitivity: copepods and other plankton; shrimp; lobster; mysids and finfish; bivalves; crab; amphipods; echinoderms; gastropods and annelids; and isopods. This ranking is admittedly biased because it is limited by the actual bioassay test results that have been published, and not based on theoretical considerations. For example, if more tests, more toxic drilling fluids, and more sensitive life stages have been tested on certain types of organisms, they would appear to be more sensitive in the rankings. These shortcomings notwithstanding, the ranking is a reasonable general indicator of the relative sensitivity of organisms to drilling fluids.

Table 5-1. Summary Table of the Acute Lethal Toxicity of Drilling Fluid[a]

	Number of species tested	Number of fluids tested	Number of tests	Not determinable	Number of 96-hr LC50 values (ppm)[b]				
					< 100	100-999	1,000-9,999	10,000-99,000	> 100,000
Phytoplankton	1	9	12	5	0	0	7	0	0
Invertebrates									
Copepods	1	9	11	1	0	3	5	2	0
Isopods	2	4	6	0	0	0	0	1	5
Amphipods	4	11	22	0	0	0	0	7	15
Gastropods	5	5	10	0	0	0	0	2	8
Decapods									
Shrimp	9	23	66	0	0	6(1)[c]	5	36	19
Crab	8	18	32	1	0	0	3	17	11
Lobster	1	2	7	0	0	0	1	3	3
Bivalves	11	22	59	19	0	0	1	19	20
Echinoderms	2	2	4	0	0	0	0	1	3
Mysids	4	17	64	2	0	0	1	29	32
Annelids	7	14	34	3	0	0	0	12	19
Finfish	15	24	80	0	0	0	2	50	36
TOTALS	70	40[d]	407	31	0	4-9	25	179	0.00

[a] Source: Adapted from Petrazzuolo, 1983.

[b] Placement in classes according to LC50 value. Lowest boundary of range if LC50 expressed as a range.

Cited values if given as ">" or "<." There were 199 such LC50 values; 95 were >100,000 ppm; 20 were <3,200 ppm.

[c] These include tests conducted on drilling fluids obtained from Mobile Bay, Alabama, and which may not be representative of drilling fluids used and discharged on the OCS. The value in parentheses is the result of not including those drilling fluids.

[d] The fluids used in Gerber et al., 1980, Neff et al., 1980, and Carr et al., 1980 were all supplied by API. Their characteristics were very similar and they may have been subsamples of the same fluids. If so, the total number of fluids tested would be 35.

Table 5-2. Comparison of Whole Fluid Toxicity and Aqueous and Particulate Fraction Toxicity for Some Organisms

Organism	Whole fluid vs. aqueous fraction	Whole fluid vs. particulate fraction
Gammarus (amphipod)	> 1.4 to 3.6:1	
Thais (gastropod)	> 1.2:1	
Crangon (shrimp)	> 1.1 to 1.4:1	
Carcinus (crab)	> 1.1 to 1.5:1	
Homarus (lobster)	> 3.5 to 5.3:1	
Strongylocentrotus (sea urchin)	> 2:1	
Coregonus (whitefish)	< 1.7:1	
Neomysis (shrimp)		1.3:1

Source: Petrazzuolo, 1981

Toxicity tests also highlight the toxicity variations that occur during a given organism's life cycle. Larval stage organisms are generally more sensitive than adult stages, and invertebrates are more sensitive while molting than during intermolt stages. These variations affect the potential for impact associated with offshore operations. Drilling fluids discharged into an area occupied by an adult community will presumably cause less impact than if the area were occupied by juvenile communities or if the area serves as a spawning ground.

Toxicity tests with larvae of the grass shrimp (*Palaemonetes intermedius*; Table 5-3) indicate that they are not as sensitive to whole muds as mysids. Average 96-hour LC50 values for whole muds ranged from 142 to 100,000 ppm. *Mercenaria mercenaria* one-hour-old larvae showed a lack of development (48-hour EC50) at relatively low concentrations of the liquid and suspended solids phases of the muds (Table 5-4). Concentrations as low as 87 and 64 ppm (respectively) halted larval development. Similarly, embryogenesis of *Fundulus* and echinoderms was affected by drilling fluid exposure. "Safe" levels (defined as a concentration of 10 percent of that having an adverse effect on the most sensitive assay system) ranged from one to 100 ppm. A study of sublethal effects of drilling mud on corals (*Acropora cervicornis*) indicated a decrease in the calcification rate and changes in amino acids at concentrations of 25 ppm.

All of the muds tested in an earlier drilling mud study (Duke and Parrish, 1984) were found to contain some No. 2 fuel (diesel) oil. Surrogate "diesel" oil content ranged from 0.10 to 9.43 mg/g in the whole mud. Spearman rank order correlation of the relationship between toxicity and fuel oil content showed a significant correlation between these factors in all tests.

Table 5-3. Drilling Fluid Toxicity to Grass Shrimp (*Palaemonetes intermedius*) Larvae

Mud	**Type**	**96-h LC50 (95% CI)**	
MIB	Seawater Lignosulfonate	28,750 ppm	(26,332-31,274)
AN31	Seawater Lignosulfonate	2,390 ppm	(1,896-2,862)
SV76	Seawater Lignosulfonate	1,706 ppm	(1,519-1,922)
P1	Lightly Treated Lignosulfonate	142 ppm	(133-153)
P2	Freshwater Lignosulfonate	4,276 ppm	(2,916-6,085)
P3	Lime	658 ppm	(588-742)
P4	Freshwater Lignosulfonate	4,509 ppm	(4,032-5,022)
P5	Freshwater/Seawater	3,570 ppm	(3,272-3,854)
P6	Lignosulfonate	100,000 ppm	---
P7	Low Solids Nondispersed	35,420 ppm	(32,564-38,877)
P8	Lightly Treated Lignosulfonate	2,577 ppm	(2,231-2,794)
NBS Reference	Seawater/Potassium/Polymer	17,917 ppm	(15,816-20,322)

Source: Adapted from Duke and Parrish (1984). All tests conducted at 20 ppt salinity and 20+2°C with day-1 larvae.

Table 5-4. Results of Continuous Exposure (48 hr) of 1-hr Old Fertilized Eggs of Hard Clams (*Mercenaria mercenaria*) to Liquid and Suspended Particulate Phases of Various Drilling Fluids

Drilling Fluid	Liquid Phase EC50 (µl/l)[a]		Control % "D" Stage	Suspended Particulate EC50 (µl/l)[b]		Control % "D" Stage
AN31	2,427	(2,390-2,463)	88	1,771	(1,710-1,831)	93
MIB	>3,000		95	>3,000		95
SV76	85	(81-88)	88	117	(115-119)	93
P1	712	(690-734)	97	122	(89-151)	99
P2	318	(308-328)	97	156	(149-162)	99
P3	683	(665-702)	98	64	(32-96)	99
P4	334	(324-345)	98	347	(330-364)	99
P5	385	(371-399)	98	382	(370-395)	99
P6	>3,000		97	>3,000		93
P7	>3,000		97	2,799	(2,667-2,899)	93
P8	269	(257-280)	93	212	(200-223)	93

aEC50 and 95% confidence interval. The percentage of each test control (n = 625+125 eggs) that developed into normal straight-hinge or "D" stage larvae and the EC50 are provided.

Source: NEA, 1984.

Other studies also implicated diesel and mineral oil in the toxicity of certain drilling fluids. In these studies, the toxicity of drilling fluids with and without added diesel or mineral oil were compared (Table 5-5). The drilling fluids tested included "used" fluids as well as a National Bureau of Standards (NBS) reference fluid which contained no measurable amount of diesel. In each case, the addition of diesel or mineral oil increased the toxicity of the drilling fluids.

Conklin et al. (1983) also found a significant relationship between the toxicity of drilling fluids and diesel oil content. Their study was designed to assess the roles of chromium and petroleum hydrocarbons in the total toxicity of whole mud samples from Mobile Bay to adult grass shrimp (*Palaemonetes pugio*). The range of 96-hour LC50 values was from 360 to 14,560 ppm. The correlation between chromium concentration of the mud and the LC50 value was not significant; however, the correlation between diesel oil concentration and the LC50 value was significant. As the concentration of diesel oil in the muds increased, there was a general increase in the toxicity values. Similar toxicity tests using juvenile sheepshead minnows (*Cyprinodon variegatus*) showed higher LC50 levels but no significant correlation between either chromium or diesel oil content and toxicity.

Diesel oil appeared to be a key factor in drilling fluid toxicity. It may explain some of the increased toxicity of used versus unused drilling fluids. As a result of these data, EPA has prohibited the discharge of drilling fluids to which diesel oil has been added.

Table 5-5. Toxicity of API #2 Fuel Oil, Mineral Oil, and Oil-Contaminated Drilling Fluids to Grass Shrimp (*Palaemonetes intermedius*) Larvae

Materials Tested	Oil Added (g/l)	Total Oil Content (g/l)	96-hr LC50 (95% CI)[a] (ppm; µl/l)
API #2 fuel oil[b]	---	---	1.4 (1.3-1.6)
Mineral Oil[c]	---	---	11.1 (9.8-12.5)
P7 mud	None	0.68	35,400 (32,564-8,877)
P7 mud + API #2 fuel	17.52	18.20	177 (165-190)
P7 mud + API #2 fuel oil (hot-rolled)	17.52	18.20	184 (108-218)
P7 mud + mineral oil	17.52	18.20	538 (446-638)
P7 mud + mineral oil (hot-rolled)	17.52	18.20	631 (580-674)
NBS reference drilling mud	None	0	17,900 (15,816-20,332)
NBS mud + API #2 fuel oil	18.20	18.20	114 (82-132)
NBS mud + API #2 fuel oil (hot-rolled)	18.20	18.20	116 (89-133)
NBS mud + mineral oil	18.20	18.20	778 (713-845)
NBS mud + mineral oil (hot-rolled)	18.20	18.20	715 (638-788)
P1 drilling mud	None	18.20	142 (133-153)

[a] 95% confidence intervals computed by using a "t" value of 1.96.

[b] Properties: Specific gravity at 20°C, 0.86; pour point -23°C; viscosity, saybolt, 38°C, 36; saturates, wt% 62; aromatics, wt% 38; sulfur, wt%, 0.32.

[c] Properties: Specific gravity at 15.5°C, 0.84-0.87; flash point, 120-125°C; pour point, -12 to -15°C; aniline point, 76-78°C; viscosity, cst 40°C, 4.1 to 4.3; color saybolt, +28; aromatics, wt%, 16-20; sulfur, 400-600 ppm.

Source: Adapted from Duke and Parrish, 1984.

SBFs have routinely been tested using the Suspended particulate phase (SPP) toxicity test and found to have low toxicity (Candler et al., 1997). Rabke et al. (1998), have recently presented data from an interlaboratory variability study indicating that the SPP toxicity results are highly variable when applied to SBFs, with a coefficient of variation of 65.1 percent. Variability reportedly depended on such things as mixing times and the shape and size of the SPP preparation containers. As part of the coastal effluent guidelines effort, published in December 1996, EPA identified the problems with applying the SPP toxicity test to SBFs due to the insolubility of the SBFs in water (USEPA, 1996).

North Sea testing protocols require monitoring the toxicity of fluids using a marine algae (*Skeletonema costatum*), a marine copepod (*Arcartia tonsa*), and a sediment worker (*Corophium volutator* or *Abra alba*). The algae and copepod tests are performed in the aqueous phase, whereas the sediment worker test uses a sedimentary phase. Again, because the SBFs are hydrophobic and do not disperse or dissolve in the aqueous phase, the algae and copepod tests are only considered appropriate for the water soluble fraction of the SBFs, while the sediment worker test is considered appropriate for the insoluble fraction of the

SBFs (Vik et al., 19960. As with the aqueous phase algae and copepod tests, the SPP toxicity test mentioned above is only relevant to the water soluble fraction of the SBFs (Candler et al., 1997).

Both industry and EPA identified the need for more appropriate toxicity test methods for assessing the relative toxicities of various SBFs. Data presented by industry and EPA have shown that the abbreviated acute toxicity test of 96 hours increases the discriminatory power between the toxicity of individual SBFs and between the toxicity of SBFs and diesel (USEPA 2000). Both EPA and industry data have indicated that esters are the least toxic followed by internal olefin (IO), linear alpha olefin (LAO) and paraffins. These data also indicate toxicity for all base fluids tested and variability within individual tests both increase with increased test duration. Industry data indicate that a suitable 100%-formulated sediment for dilution sediment has yet to be developed. The toxicity data on SBFs and SBF base fluids are summarized in Table 5-6 and Table 5-7.

Table 5-6. Reported Toxicities of Synthetic-Based Fluids (LC50s)	***Ampelisca abdita***	***Leptocheirus plumulosus***	***oxynius ronius***	***Corophium volutator***	***Abra alba***	***keletonema costatum***	***Acartia tonsa***	***Fundulus grandis***
BASE FLUID - Natural Sediment								
Candler, 1997 Rabke, 1998b Still, 1997	879 mg/kg 1.0 ml/kg 0.7 ml/kg	 850 mg/kg	 mg/kg	840 mg/kg				
Candler, 1997 Still, 1997	557 mg/kg	 251 mg/kg	 mg/kg	7146 mg/kg				
Candler, 1997 Rabke, 1998b Vik, 1996 Still, 1997	121 mg/kg 4.0 ml/kg 3.0 ml/kg	 3.7 ml/kg 2,944 mg/kg	 mg/kg	30,000mg/kg 7,100 mg/l	 300 mg/l	 2,050 mg/l	 10,000 mg/l	
Candler, 1997 Rabke, 1998b Vik, 1996 Still, 1997	0,690 mg/kg 13.4 ml/kg 12.5 ml/kg	 9,636 mg/kg	 mg/kg	30,000mg/kg 12.0 ml/kg 3.0 ml/kg	 7,900 mg/l	 3,900 mg/l	 50,000 mg/l	
Vik, 1996a					100,000 mg/l	60,000 mg/l	50,000 mg/l	
Vik, 1996a					549 mg/l	100,000 mg/l	100,000 mg/l	
Vik, 1996a					1,021 mg/l	10,000 mg/l	10,000 mg/l	
BASE FLUID - Formulated Sediment								

Rabke, 1998b		1.0 ml/kg 0.7 ml/kg						
WHOLE FLUID - Natural Sediment								
Rabke, 1998b	1.5 ml/kg	9.4 ml/kg						
Rabke, 1998b	1.5 ml/kg	2.3 ml/kg						
Friedheim et al., 1996				7,131 mg/kg	303 mg/kg			
Rabke, 1998	3.7 ml/kg	36.5 ml/kg						
Jones, 1991								8.4% TPH
Friedheim et al., 1996				10,000 mg/kg	572 mg/kg			
Vik, 1996a				>10,000 mg/l	7,000 mg/l	82,400 mg/l	50,000 mg/l	
Vik, 1996a							00-145,000 mg/l	50,000 mg/l
Friedheim et al., 1996				1,268 mg/kg	277 mg/kg			
WHOLE FLUID - Formulated Sediment								
Rabke, 1998b		2.9 ml/kg 1.7 ml/kg 0.7 ml/kg 1.3 ml/kg						
Rabke, 1998b	3.6 ml/kg	2.5 ml/kg 2.7 ml/kg 10.5 ml/kg						

Hood, 1997		2,279 mg/kg 4,498 mg/kg 2,245 mg/kg 1,200 mg/kg 943 mg/kg						
Rabke, 1998b		<2.5 ml/kg						
WHOLE FLUID -No Sediment								
	Mysidopsis bahia							
Rabke, 1998a Hood, 1997	221,436 - >1,000,000 ppm (SPP) 56,500 - >1,000,000 ppm (SSP)							

Table 5-7. Minimum and Maximum LC50 Values for New Sediment Toxicity Data Presented as Comment Response on Either the Proposed Rule (12/99) or the Notice of Data Availability (4/00) for Effluent Limitations Guidelines for the Oil and Gas Extraction Point Source Category.

	Minimum and Maximum LC 50 Values (mg/kg)				
	96-h LC 50			**10-day LC 50**	
Base Fluid	**Minimum**	**Maximum**		**Minimum**	**Maximum**
Diesel NS[a]	NA	NA		343[b,c]	NA
	776[b,d]			340[b,d]	
	892[e]	1133[e]		585[e]	951[e]
	703[b,f]			138[f]	635[f]
Diesel FS[g]	255[e]	374[e]		157[e]	312
	450[h]	703[h]		495[h]	495[h]
Ester NS	7686[d]	21824[d]		4275[d]	10,219[d]
	>12,800[b,e]			8743[b,e]	
Ester FS	27,986[b,e]			2816[b,e]	
IO NS	5874[c]	6306[c]		464[c]	2501[c]
	2675[d]	>8000[d]		2416[d]	2530[d]
	10,306[e]	19,522[e]		1988[e]	5270[e]
	27,269[f]	37,035[f]		2075[f]	16,131[f]
IO FS	<500[c]	2624[c]		<500[b,c]	

	3128[e]	17,501[e]		626[e]	1422[e]
	2289[h]	5913[h]		--	--
Paraffin NS	--	--		111[c]	1047[c]
	2263[b,d]			1151[b,d]	
	3241[b,f]			600[b,f]	1233[b,f]
LAO NS	--	--		205[c]	407[c]
	930[d]	2921[d]		1065[d]	1207[d]
PAO NS	2841[b,e]			707[b,e]	
PAO FS	2275[b,e]			333[b,e]	

[a] natural sediment

[b] one data point reported

[c] reported by Commenter III.B.b.9 Public Comments PR

[d] EPA unpublished data

[e] Commenter A.a.13 NODA

[f] Commenter A.a.30 NODA

[g] Formulated Sediment

[h] Commenter A.a.29 NODA

Summary

Since the original EA for the proposed SBF guidelines, both EPA and industry have conducted studies to evaluate the sediment toxicity of SBFs. Industry's initial attempt to examine different test organisms yielded a series of range-finder data that lead to the use of the amphipod *Leptocheirus plumulosus* as the primary test organism. Industry also examined the use of formulated sediments. Results of testing formulated sediments and estuarine organisms appeared to be more difficult than expected and industry, although continuing research on the issue, has suspended further testing with formulated sediments. Both EPA and industry's data have led to the following assumptions on the toxicity of SBF.

_ The ranking for the SBF toxicity from least toxic to most is esters-IOs-LAOs-PAOs-paraffins.

_ Although formulated sediments appear to indicate more discriminatory power between individual base fluids, control mortality continues to be a problem with 100% formulated sediments.

_ The abbreviated acute test of 96 hours increases discriminatory power between individual SBFs, however they are not to true measure of SBF toxicity.

_ The toxicity of SBFs appear to increase with time (in comparison of a 96-hour exposure to a 10-day exposure).

5.2.2 *Chronic Toxicity*

Stress Tests on Corals

There has been considerable investigation regarding the effects of whole drilling fluids on corals, due to their sensitivity, ecological interest, and presence in the Texas Flower Garden Banks area. Respiration, excretion, mucous production, degree of polyp expansion, and clearing rates for materials deposited on the surface are all useful parameters for indicating stress.

Laboratory experiments using the corals *Montastrea* and *Diplora* showed essentially unchanged clearing rates after applications of calcium carbonate, barite, and bentonite. However, exposure to a used drilling fluid significantly decreased clearing rates, although dose quantification was not possible (Thompson and Bright, 1977). When seven coral species were studied using *in situ* exposures to used drilling fluid, *Montastrea* and *Agaricia* displayed no mortality after a 96-hour exposure to 316 ppm concentration, but 100 percent mortality at the 1,000 ppm level (Thompson and Bright, 1980). Stress reaction were displayed by six species at the 316-ppm exposure level, including partial or complete polyp retraction and mucous secretion. A similar response was observed after a 96-hour exposure to 100 ppm.

Thompson, in an undated report to the USGS, exposed *Montastrea* and *Porites* to used drilling fluids from a well of 4,200 m (13,725 ft) drilling depth. The corals were buried for eight hours under the fluid and then removed to a sand flat to observe recovery. The exposure produced tissue atrophy and decay, formation of loose strands of tissue, and expulsion of zooxanthellae (zooxanthellae are algae living within coral cells in a symbiotic relationship), all indicative of severe stress. The *Montastrea* colonies were dead 15 hours after removal, and the *Porites* colonies were dead after 10 days.

The effects of thin layer application to these species were also observed. *In situ* exposures of drilling mud produced no apparent effects on clearing rates; however, laboratory application did demonstrate effects. Applications of 10-mm thick carbonate sand or drilling fluid from a depth of either 4,200 m (13,800 ft) or 1,650 m (5,413 ft) were applied to the corals, with the following results:

- Colonies in the sand experiment cleared themselves in 4 hours
- Colonies in the 1,650-m fluid experiment cleared themselves in 2 hours
- Colonies in the 4,200-m fluid experiment were 20% (*Montastrea*) and 40% (*Porites*) cleared after 4 hours, 20% (*Montastrea*) and 100% (*Porites*) cleared after 26 hours.

Additional testing with *Porites* indicated that the 4,200-m fluid was more toxic than the 1,650-m fluid, probably because the use of additives increases with well depth. No data are available on actual drilling fluid composition, however.

Krone and Biggs (1980) exposed coral (*Madracis decactis*) to suspensions of 100-ppm drilling mud from Mobile Bay, Alabama, which had been spiked with 0, 3, and 10 ppm ferrochrome lignosulfonate (FCLS). The drilling mud was presumably one with a low (<1 ppm) FCLS concentration. The corals were exposed for 17 days, at which time they were placed in uncontaminated seawater and allowed to recover for 48 hours. All of the corals exposed to the FCLS-spiked mud exhibited short-term increases in oxygen consumption and ammonia excretion. Photographic documentation of the corals revealed a progressive development of the following conditions: 1) a reduction in the number of polyps expanded indicating little or no active feeding; 2) extrusion of zooxanthellae; 3) bacterial infections with subsequent algal overgrowth; and 4) large-scale polyp mortality in two of the colonies. Coral behavior and condition improved dramatically during the recovery period. Polyps of surviving corals reexpanded and fed actively on day two of the recovery period.

Dodge (1982) evaluated the effects of drilling fluid exposure on the skeletal extension of reef-building corals (*Montastrea annularis*). Corals were exposed to 0, 1, 10, or 100 ppm drilling fluid ("Jay" fluid) for 48 days in a flow-through bioassay procedure. The drilling mud composition was changed approximately weekly as new mud taken from the well was added. One significant change in mud composition was in the diesel oil content, which was 0.4% by weight from the fourth week to the end of the experiment. Corals exposed to 100 ppm had significantly depressed linear growth rates and increased mortality. Calcification rates of corals exposed to 100 ppm decreased by 53% after four weeks and by 84% after six weeks. There was no indication of lowered growth rates for either the 1- or 10-ppm exposure.

Hudson and Robbin (1980) exposed corals (*Montastrea annularis*) to unused drilling fluid in heavy doses of 2- to 4-mm layers applied four times at 150-minute intervals. Drilling mud particles were generally removed by a combination of wave action, tentacle cleansing action, and mucous secretions. At the end of the exposure period, corals were placed in protected waters for six months. At the end of another six months, the corals were removed and examined for growth characteristics. Results of the growth analysis indicated that heavy concentrations of drilling mud applied directly to the coral surface over a period of only 7½ hours reduced growth rates and suppressed variability. Trace element analyses of the corals indicated that neither barium nor chromium incorporated into the skeletal materials.

Experiments with the coral *Acropora cervicornis* revealed reduced calcification rates after exposure to concentrations as low as 25 ppm of used Mobile Bay drilling mud (Kendall et al., 1983). Calcification rates in growing tips were reduced to 88%, 83%, and 62% of control values after 24-hour exposures to 25, 50, and 100 ppm (v/v) drilling mud, respectively. Effects on soluble tissue protein and ninhydrin positive substance were also noted at these or higher levels. Further experiments with kaolin, designed to reproduce the turbidity levels of the drilling mud without its chemical effects, revealed slight metabolic changes to the corals that were much less pronounced than those observed for the drilling mud treatments.

5.2.3 *Long Term Sublethal Effects*

Crawford and Gates (1981) examined the effect of a Mobile Bay drilling mud (mud XVI) on the fertilization and development of the sand dollar *Echinarachnius parma*. Fertilization studies showed that sperm were highly refractive to the toxic action of this drilling mud. Exposure even at 10,000 mg solids/ml (a 26-fold dispersion of the whole mud) reduced fertilization by only 7 percent. Eggs were more sensitive; exposure to 1,000 mg/ml (262-fold dilution of the whole fluid) reduced fertilization from 88-90 percent to 4-6 percent. No effect was noted at 100 mg/ml (2,620-fold whole mud dilution). At this same exposure level (100 mg solids/ml), no effects were observed in development. At 1,000 to 10,000 mg solids/ml, development was delayed.

No EC50/LC50 ratio could be determined from these data. However, the apparent lower limit of 1,000 ppm drilling mud as the lowest level that results in statistically significant sublethal reproductive changes is consistent with other data. For example, killifish (*Fundulus heteroclitus*) embryos were exposed to a seawater-lignosulfonate mud (Neff et al., 1980). Several parameters were examined, including percentage hatch, percentage increased time to hatch, percentage decreased heart rate, and anomalies at day 16. Although no EC50/LC50 ratios could be calculated, data were available to plot and obtain EC01 values. These ranged from 1,000 to 6,000 ppm. For the shrimp *Palaemonetes pugio*, exposure to 1,000 to 10,000 ppm of a high density lignosulfonate mud did not alter the duration of any larval instar (Neff et al., 1980).

The effects of 6-week exposures to the aqueous phases of both medium- and high-density lignosulfonate muds on the condition index (dry meat weight/shell weight) of oyster spat (*Crassostrea gigas*) have been reported (Neff et al., 1980). For the medium-density mud (12.6 lb/gal), no effect was noted at 5,000 ppm or 10,000 ppm whole mud equivalents. The index was reduced about 20 percent at 20,000 ppm. For the high-density mud (17.4 lb/gal), approximately a 30 percent reduction occurred in the index at all concentrations tested.

Mussels (*Mytilus* sp.) were exposed to 50 ppm TSS for 30 days by Gerber et al. (1980). Growth was 75 percent of that observed in control animals. It is not known, however, whether this represents a process of reversible growth retardation or irreversible growth inhibition.

Juvenile mysids were exposed to 15,000-75,000 ppm of the aqueous phase of a lignosulfonate mud for 7 days by Carr et al. (1980). On a dry-weight basis, no effect on respiration occurred. This contrasts with the increased respiration seen in shrimp exposed to 35,000 ppm of the same mud's aqueous phase and suggests that compensatory adaptation had occurred. Average dry weights were significantly lower in exposed shrimp.

When polychaetes (*Nereis* sp.) were exposed to 100,000 ppm of the aqueous phase of a lignosulfonate mud for 4 days, glucose-6-phosphate dehydrogenase activity was significantly decreased (Gerber et al., 1980). Activity recovered, however, during a 4-day depuration period.

Histologic alterations were noted following exposure of grass shrimp to 100 ppm or 500 ppm barite for 30 days (Conklin et al., 1980). Mortalities in two replicates of the experiment were 20 percent for control shrimp and 60 percent for exposed shrimp (no concentrations of barite given). In 40 percent of the surviving shrimp, there were no histologic changes. In the remainder of surviving shrimp, a variety of changes were noted, including: absence of posterior midgut epithelia (20 percent of the survivors); degenerative changes in microvilli; dilated and hypertrophied rough endoplasmic reticulum; and both nuclear and Golgi changes. Barite was also observed in statocysts. Although controls were provided with a sand substrate, exposed shrimp were not. Thus, it remains unclear whether such changes would occur in a sediment-barite mixture. Also, because of concerns over settling of barite particles, no dose-response relationship could be identified or constructed from the data.

Lobsters were exposed to a Jay field fluid (an onshore operation) for 36 days in a flow-through system by Atema et al. (1982). The exposure was nominal at 10 mg/l. However, settling of solids was noted and the actual exposure was undefined. The number of dead or damaged lobsters was not significantly different from controls. The number of dead plus damaged lobsters was significantly higher among treated animals. Although molts from larval stage IV to V were unaffected, molts from stage V to VI were delayed in exposed animals. Exposed lobsters also exhibited poor coordination and food alert suppression.

Three studies in a Gulf of Mexico laboratory examined the effects of drilling muds or drilling mud components on community recruitment and development of benthic macrofauna (Tagatz et al., 1980; Tagatz and Tobia, 1978) and meiofauna (Cantelmo et al., 1979). Test substances were mixed at various ratios with sediment, or were applied as a covering layer over sediment in a flow-through system.

The tests conducted with drilling mud indicated that annelids were the most sensitive group, exhibiting significant reductions in abundance at 1:10 and 1:5 mixtures of mud and sediment, as well as when exposed to a covering of drilling mud (Tagatz et al., 1980). This sensitivity of annelids was also observed for a similar experiment conducted with barite as the toxicant. Coelenterate abundance was also significantly reduced by exposure to the 1:5 mixture of mud and sediment and the drilling mud covering. Arthropods were affected only by a drilling mud covering. Mollusks were not significantly affected by exposure to drilling mud, but were reduced in abundance when exposed to barite covering (Tagatz and Tobia, 1978). Annelid abundance was also reduced by exposure to barite covering (Tagatz and Tobia, 1978), but no other groups were significantly affected. Exposure to barite as a mixture in sediment significantly increased the abundance of nematodes and increased total meiofaunal density, whereas barite layering slightly reduced total meiofauna density and densities of nematodes and copepods. The reduction was not statistically significant (Cantelmo et al., 1979).

Certain difficulties arise in the interpretation of these data. First, results for total abundance are apparently skewed by the greater sensitivity of a certain few predominant species. This does not affect the significance of the results within the constraints of this experiment, but may reduce the applicability of these results to areas *in situ* where community structure is not similar to those observed in this experiment. Second, any attempt to relate these studies to effects *in situ* is confounded by the absence of sediment barium levels given for these studies. Barium is the only useful tracer of drilling mud dispersion in the sediment.

5.2.4 *Metals*

The potential accumulation of metals in biota represents an issue of concern in the assessment of oil and gas impacts. Sublethal effects resulting from bioaccumulation of these highly persistent compounds are most often measured. Gross metal contamination from drilling fluids may also cause mortality, particularly in benthic species. Sources of metals include drilling fluids, produced waters, sacrificial anodes, and contamination from other minor sources. Drilling fluids and produced waters are the primary sources of the metals of concern: arsenic, barium, chromium, cadmium, copper, mercury, nickel, lead, vanadium, silver, and zinc.

Field studies of metal concentration in sediments around platforms suggest that enrichment of certain metals may occur in surface sediments around platforms (Tillery and Thomas, 1980; Mariani et al., 1980; Crippen et al., 1980; and others). In the review of these studies conducted by Petrazzuolo (1983), enrichment of metals around platforms is generally distance dependent with maximum enrichment factors seldom exceeding ten. In platforms studied, enrichment of metals that could be attributed to drilling activities was either generally distributed to 300-500 m around the platform, or distributed downcurrent in a plume to a larger distance from the structure.

The concentrations of metals required to produce physiological or behavioral changes in organisms vary widely and are determined by factors such as the physicochemical characteristics of the water and sediments, the bioavailability of the metal, the organism's size, physiological characteristics, and feeding adaptations. Metals are accumulated at different rates and to different concentrations depending on the tissue or organ involved. Laboratory studies on metal accumulation as a result of exposure to drilling muds have been conducted by Tornberg et al. (1980), Brannon and Rao (1979), Page et al. (1980), McCulloch et al. (1980), Liss et al. (1980), and others. Data from these laboratory studies are summarized in Appendix B. Maximum enrichment factors for the metals measured were generally low (<10) with the exception of barium and chromium, which had enrichment factors of up to 300 and 36, respectively.

Depuration studies conducted by Brannon and Rao (1979), McCulloch et al. (1980), and Liss et al. (1980) have shown that organisms tested have the ability to depurate some metals when removed from a zone of contamination. In various tests, animals were exposed to drilling fluids from 4-28 days, followed by a 1-14 day depuration period. Uptake and depuration of barium, chromium, lead, and strontium were monitored and showed a 40-90% decrease in excess metal in tissues following the depuration period. Longer exposure generally meant a slower rate of loss of the metal. In addition, if uptake was through food organisms rather than a solute, release of the excess metal was slowed.

The available laboratory data on metals accumulation are difficult to correlate with field exposure and accumulation. Petrazzuolo's review (1983) notes that in the field, bioaccumulation of metals in the benthos will result from exposure to the particulate components of drilling muds. However, laboratory studies have almost always used either whole fluids or mud aqueous fractions, and thus are either over- or underestimating potential accumulation.

Field studies of metal accumulation in marine food webs off southern California have been conducted by Schafer et al. (1982) and others. These data have indicated that most metals measured (including Cr, Cu, Cd, Ag, Zn) do not increase with trophic level either in open water or in contaminated regions such as coastal sewage outfalls.

5.3 Bioaccumulation Potential of Synthetic-Based Drilling Fluids

One factor considered in assessing the potential environmental impacts of discharged drilling fluids and drill cuttings is their potential for bioaccumulation. This section presents information concerning the bioaccumulation of oleaginous-base fluids, including the synthetic-base fluids and mineral oil.

Most of the available information has been developed by mud suppliers to provide information to government regulators to assess the acceptability of these materials for discharge into the marine environment. The available information on the bioaccumulation potential of synthetic base fluids is scant, comprising only a few studies on octanol:water partition coefficients (P_{ow}) and three on tissue uptake in experimental exposures. The P_{ow} represents the ratio of a material that dissolves or disperses in octanol (the oil phase) versus water. The P_{ow} generally increases as a molecule becomes less polar (more hydrocarbon-like). EPA reviewed the available information on the bioaccumulation potential of synthetic-base fluids (USEPA, 2000). The review covers four types of synthetics: an ester (two studies), internal olefins (IO; four studies), and poly alpha olefins (PAO; five studies). One study included a low toxicity mineral oil (LTMO) for comparative purposes. The types of synthetic-base fluids tested represent the more common of synthetic-base fluid types currently in use in drilling operations.

The data that EPA identified concerning the bioaccumulation potential of synthetic base fluids are summarized in Table 5-8. Nine reports provided original information. This information consisted of P_{ow} data (based on calculated or experimental data), dispersibility data, or subchronic exposure of test organisms to yield data for calculating BCFs or assessing uptake. log P_{ow} values less than three or greater than seven would indicate that a test material is not likely to bioaccumulate (Zevallos et al., 1996).

For PAOs, the log P_{ow}s reported were >10, 11.19, 11.9, 14.9, 15.4, and 15.7 in the five studies reviewed. The four studies of IOs that were reviewed reported log P_{ow}s of 8.57 (8.6) and >9. The ester was reported to have a log P_{ow} of 1.69 in the two reports in which it was presented. The LAO log P_{ow} was cited as 7.82 and a log P_{ow} of 15.4 was reported for an LTMO. The only BCF reported was calculated for

Table 5-8. Bioaccumulation Data for Synthetic Fluids and Mineral Oil Muds

Type of Synthetic Base Fluid or LTMO	Parameter Determined	Reference
PAO	log Pow: 15.4 (calculated)	Friedheim et al., 1991
PAO	log Pow: >10 (calculated)	Leutermann, 1991
PAO	log P_{ow}: 14.9 - 15.7 (measured)	Schaanning, 1995
PAO	log P_{ow}: 11.9 (measured)	Zevallos et al., 1996
PAO	log P_{ow}: 11.19	Moran, 2000
IO	log P_{ow}: > 9	Environment & Resource Technology, Ltd., 1994a
IO	log P_{ow}: 8.57	Zevallos et al., 1996; Moran, 2000
LAO	log P_{ow}: 7.82	Moran, 2000
Ester	log P_{ow}: 1.69	Growcock et al., 1994; Moran, 2000
LTMO	log P_{ow}: 15.4	Growcock et al., 1994
various	dispersibility: ranking = ester> di-ether >> detergent alkylate > PAO > LTMO	Growcock et al., 1994
IO	10-day uptake; 20-day depuration exposure gave log BCF: 5.37 (C16 forms); 5.38 (C18 forms)	Environment & Resource Technology, Ltd., 1994b; Moran, 2000
PAO	Uptake: no measured uptake in tissues after 30-day exposure; presence noted in 1 of 24 gut samples	Rushing et al., 1991; Moran, 2000
LTMO	Uptake: after 30-day exposure, detectable amounts in 50% of tissues analyzed (12 of 24) and 19 of 24 gut samples examined	Rushing et al., 1991
PAO	Subchronic effects: equal or better growth vs controls	Jones et al., 1991
LTMO	Subchronic effects: retarded growth vs controls	Jones et al., 1991

Type of Synthetic Base Fluid or LTMO	Parameter Determined	Reference
LAO	Mytilus edulis log BCF: 4.84	Moran, 2000

Abbreviations: PAO: poly alpha olefin; IO: internal olefin; LAO: linear alpha olefin; LTMO: low toxicity mineral oil

IOs; a value of 5.4 l/kg was determined. In 30-day exposures of mud minnows (*Fundulus grandis*) to water equilibrated with a PAO- or LTMO-coated cuttings, only the LTMO was reported to produce adverse effects and tissue uptake/occurrence. Growth retardation was observed for the LTMO and LTMO was observed at detectable levels in 50% of the muscle tissue samples examined (12 of 24) and most (19 of 24) of the gut samples examined. The PAO was not found at detectable levels in any of the muscle tissue samples and occurred in only one of twenty-four gut samples examined.

These limited data suggest that synthetic base fluids do not pose a serious bioaccumulation potential. Despite this general conclusion, existing data cannot be considered sufficiently extensive to be conclusive. This caution is specifically appropriate given the wide variety of chemical characteristics resulting from marketing different formulations of synthetic fluids (i.e., carbon chain length or degree of unsaturation within a fluid type, or mixtures of different fluid types).

6. BIOLOGICAL OVERVIEW

This chapter describes the biological communities and processes in the eastern Gulf of Mexico which may be exposed to pollutants, the presence of endangered species, any unique species or communities of species, and the importance of the receiving water to the surrounding biological communities. The species identified as threatened or endangered by the USFWS and NMFS are characterized in the last section of this chapter for compliance with Section 7 of the Endangered Species Act.

6.1 Primary Productivity

Primary productivity is "the rate at which radiant energy is stored by photosynthetic and chemosynthetic activity of producer organisms in the form of organic substances which can be used as food materials" (Odum, 1971). Primary productivity is affected by light, nutrients, and zooplankton grazing, as well as other interacting forces such as currents, diffusion, and upwelling.

The producer organisms in the marine environment consist primarily of phytoplankton and benthic macrophytes. Since benthic macrophytes are depth/light limited, primary productivity in the open ocean is attributable primarily to phytoplankton. The productivity of nearshore waters can be attributed to benthic macrophytes--including seagrasses, mangroves, salt marsh grasses, and seaweeds--and phytoplankton.

There are numerous methods for estimating primary productivity in marine waters. One method is to measure chlorophyll content per volume of seawater and compare results over time to establish a productivity rate. The chlorophyll measurement, typically of chlorophyll a, gives a direct reading of total plant biomass. Chlorophyll a is generally used because it is considered the "active" pigment in carbon fixation (Steidinger and Williams, 1970). Another method, the C^{14} (radiocarbon) method, measures photosynthesis (a controversy exists as to whether "net", "gross", or "intermediate" photosynthesis is measured by this method; Kennish, 1989). The C^{14} method introduces radiolabeled carbon into a sample and estimates the rate of carbon fixation by measuring the sample's radioactivity.

The units used to express primary productivity are grams of carbon produced in a column of water intersecting one square meter of sea surface per day ($g\ C/m^2/d$), or grams of carbon produced in a given cubic meter per day ($g\ C/m^3/d$).

C^{14} uptake throughout the Gulf is 0.25 $g\ C/m^3/hr$ or less, and chlorophyll measurements range from 0.05 to 0.30 mg/m^3 (ppb). Eastern regions of the Gulf of Mexico are generally less productive than western regions, and throughout the eastern Gulf, primary productivity is generally low. However, outbreaks of "red-tide" caused by pathogenic phytoplankton may occur in the mid- to inner-shelf. Also, depth-integrated productivity values in the area of the Loop Current (primarily the outer shelf and slope) are actually higher than western and central Gulf values. Enhanced productivity occurs in areas affected by upwelling. Near the bottom of the euphotic zone, chlorophyll and productivity values are about an order of magnitude greater, probably due to the often intruded, nutrient-rich Loop undercurrent waters (MMS, 1990).

Productivity measurements in the oceanic waters of the Gulf of Mexico include:

- 0.1 g C/m^2/d yielding 17 g C/m^2/yr or 86 million tons of phytoplankton biomass (MMS, 1983)
- 103-250 g C/m^2/yr (Flint and Kamykowski, 1984)
- 103 g C/m^2/yr (Flint and Rabalais, 1981).

Biomass (chlorophyll a) measurements in the predominantly oceanic waters of the Gulf of Mexico include:

- 0.05-0.30 mg Chl a/m^3 (MMS, 1983a)
- 0.05-0.1 mg Chl a/m^3 (Yentsch, 1982)
- 0.22 mg Chl a/m^3 (El-Sayed, 1972)
- 0.17 mg Chl a/m^3 (Trees and El-Sayed, 1986).

For comparisons, the following data on primary productivity are presented for coastal wetland systems as compiled by Thayer and Ustach (1981):

· Salt Marshes	200-2000 g C/m^2/yr
· Mangroves	400 g C/m^2/yr
· Seagrasses	100-900 g C/m^2/yr
· *Spartina alterniflora*	1300 g C/m^2/yr
· *Thalassia*	580-900 g C/m^2/yr
· Phytoplankton	350 g C/m^2/yr

For the eastern Gulf of Mexico, biomass (chlorophyll a) measurements include the following (Yoder and Mahood, 1983):

- Surface mixed layer values of 0.1 mg/m^3
- Subsurface measurements at 40-60 m ranged from 0.2 to 1.2 mg/m^3
- Average integrated values for the water column over the 100-200 m isobath was 10 mg/m^2
- Average integrated values for the water column greater than 200 m isobath was 9 mg/m^2.

6.2. Phytoplankton

6.2.1 *Distribution*

Phytoplankton distribution and abundance in the Gulf of Mexico is difficult to measure. Shipboard or station measurements cannot provide information about large areas at one moment in time, and satellite imagery cannot provide definitive information about local conditions that may be important. Due to fluctuations in light and nutrient availability and the immobility of phytoplankton, distribution is temporally and spatially variable. Seasonal fluctuations in location and abundance are often masked by patchy distributions which human sampling designs must attempt to interpret. In addition, methods for measurement of chlorophyll or uptake of carbon cannot always resolve all questions concerning variability among or within species under different conditions, or concerning the effects of grazing on abundance.

As mentioned in the previous section, phytoplankton occupy a niche at the base of food chain as primary producers of our oceans. Herbivorous zooplankton populations require phytoplankton for maintenance and growth -- generally 30-50% of their weight each day and surpassing 300% of their weight in exceptional cases (Kennish, 1989). In the Gulf of Mexico, phytoplankton are also often closely associated with bottom organisms, and may also contribute to benthic food sources for demersal feeding fish.

Phytoplankton seasonality has been explained in terms of salinity, depth of light penetration, and nutrient availability. Generally, diversity decreases with decreased salinity and biomass decreases with distance from shore (MMS, 1990).

6.2.2 *Principal Taxa*

The principal taxa of planktonic producers in the ocean are diatoms, dinoflagellates, coccolithophores, silicoflagellates and blue-green algae (Kennish, 1989).

Diatoms. Many specialists regard diatoms as the most important phytoplankton group, contributing substantially to oceanic productivity. Diatoms consist of single cells or cell chains, and secrete an external rigid silicate skeleton called a frustule.

In 1969, Saunders and Glenn reported the following for diatom samples collected 5.6 to 77.8 km from shore in the Gulf of Mexico between St. Petersburg and Ft. Myers, Florida. Diatoms averaged 1.4 x $10^7\mu^2/l$ surface area offshore, 13.6 x $10^7\mu^2/l$ at intermediate locations and 13.0 x $10^8\mu^2/l$ inshore. The ten most important species in terms of their cellular surface area were: *Rhizosolenia alata, R. setigera, R. stolterfothii, Skeletonema costatum, Leptocylindrus danicus, Rhizosolenia fragilissima, Hemidiscus hardmanianus, Guinardia flaccida, Bellerochea malleus,* and *Cerataulina pelagica*.

Dinoflagellates. Dinoflagellates are typically unicellular, biflagellated autotrophic forms that also supply a major portion of the primary production in many regions. Some species generate toxins and when blooms reach high densities, mass mortality of fish, shellfish, and other organisms can occur (Kennish, 1989). Notably, *Gymnodinium breve* is responsible for most of Florida's red tides and several of the *Gonyaulax* species are known to cause massive blooms (Steidinger and Williams, 1970). Table 6-1 lists species and varieties of dinoflagellates found to be abundant during the Hourglass Cruises (a systematic sampling program in the eastern Gulf of Mexico.)

Coccolithophores. Coccolithophores are unicellular, biflagellated algae named for their characteristic calcareous plate, the coccolith, which is embedded in a gelatinous sheath that surrounds the cell.

Phytoplankton of offshore Gulf of Mexico are reported to be dominated by coccolithophores (Iverson and Hopkins, 1981).

Silicoflagellates. Silicoflagellates are unicellular flagellated (single or biflagellated) organisms that secrete an internal skeleton composed of siliceous spicules (Kennish, 1989). Perhaps because of their small size (usually less than 30 µm in diameter) little specific information relative to Gulf of Mexico distribution and abundance, is available for this group.

Blue Green Algae. Blue green algae are prokaryotic organisms that have chitinous walls and often contain a pigment called phycocyanin that gives the algae their blue green appearance (Kennish, 1989). On the west Florida shelf, inshore blooms of the blue green algae *Oscillatoria erethraea* sometimes occur in spring or fall.

6.3 Zooplankton

Like phytoplankton, zooplankton are seasonal and patchy in their distribution and abundance. Zooplankton standing stocks have been associated with the depth of maximum primary productivity and the thermocline (Ortner et al., 1984). Zooplankton feed on phytoplankton and other zooplankton, and are important intermediaries in the food chain as prey for each other and larger fish.

As in many marine ecosystems, zooplankton fecal pellets contribute significantly to the detrital pool. The ease of mixing in Gulf coastal waters may make them extremely important to nutrient circulation and primary productivity, as well as benthic food stocks. Also contributing to the detrital pool is the concentration of zooplankton in bottom waters, coupled with phytoplankton in the nepheloid layer during times of greater water stratification.

Copepods are the dominant zooplankton group found in all Gulf waters. They can account for as much as 70% by number of all forms of zooplankton found (NOAA, 1975). In shallow waters, peaks occur in the summer and fall (NOAA, 1975), or in spring and summer, (MMS, 1983a). When salinities are low, estuarine species such as *Acartia tonsa* become abundant.

The following information on zooplankton distribution and abundance in the eastern Gulf of Mexico is summarized from Iverson and Hopkins (1981).

- During Bureau of Land Management-sponsored studies, small copepods predominated in net catches over the shelf regions of the eastern and western Gulf of Mexico.

- During Department of Energy-sponsored studies at sights located over the continental slope of Mobile and Tampa Bays, small calanoids such as *Parcalanus*, and *Clausocalanus* and cyclopoids such as *Farralanula, Oncaea*, and *Oithona* predominated at the 0-200 m depths; and larger copepods such as *Eucalanus, Rhincalnus,* and *Pleuromamma* dominated at 1,000 m depths. Euphausiids were also more conspicuous. Night-time samples taken near Tampa showed larger crustaceans such as Lucifer and Euphasia. Biomass data for the same site revealed a decrease in zooplankton with increasing depth. The mean cumulated biomass value for the upper 1,000 m was 21.9 ml/m^2.

Table 6-1. Significant Dinoflagellate Species of the Eastern Gulf of Mexico

Species	**Biomass Value (μ^3)**
Amphisolenia bidentata	67,039 - 95,406
Ceratium carriense	637,219 - 1,115,367
C. carriense var. *volans*	622,206 - 1,196,643
C. contortum var. *karstenii*	943,121 - 1,655,573
C. extensum	189,709 - 323,546
C. furca	23,157 - 43,369
C. fusus	34,463 - 154,722
C. hexacanthum	687,593 - 1,384,016
Ceratium hircus	211,709
C. inflatum	145,897 - 221,276
C. massiliense	543,762 - 1,002,222
C. trichoceros	104,110 - 357,437
C. tripos var. *atlanticum*	518,659 - 964,436
Dinophysis caudata var. *pedunculata*	92,153 - 231,405
Gonyaulax splendens	51,651
Prorocentrum crassipes	329,540
P. gracile	25,773
P. micans	65,412

Source: Steidinger and Williams, 1970.

- Studies funded by the National Science Foundation in the east-central Gulf found diurnal patterns of distribution in the upper 1,000 m--with increases in the 50-m range at night and in the 300-600-m zone during the day--most likely attributable to vertical migration. In the upper 200 m, in addition to copepods, group such as chaetognaths, tunicates, hydromedusae, and euphausiids were significant contributors to the biomass.

Icthyoplankton studies for the eastern Gulf conducted during 1971-1974 found fish eggs to be more abundant in the northern half and fish larvae to be more abundant in the southern half of the eastern Gulf. Mean abundances were 5,454 eggs/m^2 and 3,805 larvae/m^2 in the northern Gulf and 4,634 eggs/m^2 and 4,869 larvae/m^2 in the southern Gulf. Eggs were more abundant in waters less than 450 meters deep, whereas larvae were more abundant in depth zones greater than 50 meters (Houde and Chitty, 1976).

6.4 Habitats

6.4.1 *Seagrasses*

Seagrasses are vascular plants that serve a variety of ecologically important functions. As primary producers, seagrasses are a direct food source and also contribute nutrients to the water column. Seagrass communities serve as a nursery habitat for juvenile fish and invertebrates and seagrass blades provide substrate for epiphytes. Species such as *Thalassia testudinum* have an extensive root system that stabilize substrate, and broad ribbon-like blades that increase sedimentation. Seagrasses mainly occur in shallow, clear, highly saline waters. Seagrass beds do not occur in the proposed activity area (MMS, 2000).

Approximately 1.25 million acres of seagrass beds are estimated to exist in exposed, shallow, coastal/nearshore waters and embayments of the Gulf of Mexico**.** About 3% of these beds are in Mississippi. Florida with Florida Bay and coastal Florida accounting for more than 80%. True seagrasses that occur in the Gulf of Mexico are shoal grass, paddle grass, star grass, manatee grass, and turtle grass. Although not considered a true seagrass because it has hydroanemophilous pollination (floating pollen grains) and can tolerate freshwater, widgeon grass is common in the brackish waters of the Gulf. (BOEM 2013).

6.4.2 *Offshore Habitats*

Offshore habitats include the water column and the sea floor. The eastern Gulf benthos consist primarily of low relief live-bottom areas. Live-bottom areas contain biological assemblages consisting of such sessile invertebrates as sea fans, sea whips, hydroids, anemones, ascidians, sponges, bryozoans, seagrasses, or corals living upon and attached to naturally occurring hard or rocky formation with fishes and other fauna. Live-bottom types include pinnacle-trend, low-relief, offshore seagrasses, and coral reef communities. Coral reef communities are not found within the proposed permit coverage area and are therefore not discussed in this document. Within the eastern Gulf, live-bottom communities are scattered across the west Florida shelf and at the outer edge of the Mississippi/Alabama shelf.

Deepwater Benthic Resources

Deepwater benthic habitats, as discussed here, refer to those in water depths greater than 300 meters. These include a number of unique chemosynthetic habitat and community types occur in the deep waters of the Gulf of Mexico. Chemosynthetic communities consist of sessile invertebrates such as clams, mussels and tube worms and motile invertebrates similar to hydrothermal vent communities discovered in the eastern Pacific (Corliss et al., 1979). Detailed descriptions of deepwater benthic resources in the central and eastern Gulf of Mexico are presented in a number of recent studies and reports including CSA International, Inc. 2007, and Brooks et. al., 2014 as well as several recent BOEM EIS documents (BOEM 2012; 2013).

Chemosynthetic communities are those that use a carbon source, from fluids venting from the seafloor, other than sun driven photosynthesis to support life. Primary production of chemosynthetic bacteria can support assemblages of higher organisms via symbiosis. The existence of deep benthic chemosynthetic communities was initially discovered in the eastern Pacific (Corliss et al., 1979). Communities using both hydrocarbon seepage and hydrogen sulfide vents were discovered during investigations in the Gulf during the 1980's with most occurring within the western and central Gulf (MMS 2000b).

Chemosynthetic communities are not known to be abundant within the area of the Gulf of Mexico under Region 4 permit authority. At present the only known chemosynthetic community in the Eastern Planning Area, and the first to be discovered in the Gulf of Mexico in 1983, was found in an area termed the Florida Escarpment at Vernon Basin 926 block about 400 km south of Apalachicola, FL (MMS 2000b). These communities are similar to deep sea hydrothermal vent communities of the eastern Pacific. The presence of hydrogen sulfide seeps on the Escarpment indicate the potential for additional chemosynthetic communities in this area.

The deepwater GOM consists mainly of soft mud bottoms with occasional patches of hard substrate that support non-chemosynthetic reef communities. Wherever hard substrate exists, deepwater live bottom communities, comprised of all phyletic groups of organisms found on the continental shelf and other marine environments including coral communities, can establish. Deepwater coral communities are now known to occur in many locations in the deep GOM (>300 m; 984 ft).

Investigations of 3D seismic data revealed over 16,000 hard sonar returns, most shown to be hard bottom substrate supporting nonchemosynthetic communities and/or live bottom reef communities. This data suggests that nonchemosynthetic and coral communities are much more common in the deepwater GOM than previously known (BOEM, 2013).

6.5 Fish and Shellfish Resources

Table 2-6 on pages 2-26 to 2-31 in *Final Environmental Impact Statement, National Pollutant Discharge Elimination System permitting for Eastern Gulf of Mexico Offshore Oil and Gas Extraction* (USEPA,

1998) provide a detailed list and information on fish and shellfish resources that occupy the waters of Alabama, Florida, and Mississippi.

The distribution of fish resources in the central and eastern Gulf of Mexico are highly dependent on a variety of factors including habitat type, chemical and physical water quality variables, biological, and climatic factors. The Gulf contains both a temperate fish fauna and a tropical fauna arrayed into inshore and offshore habitats depending on latitude. To the south of the 20°C winter isotherm, approximately middle Florida, the more tropical fish fauna occupies inshore habitats replacing the temperate fauna. To the north the tropical fauna is pushed further offshore to avoid cold winter temperature and by increased competition by temperate species able to tolerate cooler waters. In the northern Gulf where temperate species dominate inshore, a well-developed tropical fauna occurs on offshore structures, particularly reefs (Hoese and Moore, 1977). During warm weather the early life stages of the tropical fauna move further inshore around piers and jetties.

The temperate fish and invertebrate fauna of the north-central Gulf tend to be dominated by estuary dependent species such as sciaenids (i.e., croaker, red and black drum, spotted seatrout), menhaden, shrimp, oysters and crabs. These species require the transportation of early life stages into estuaries for grow out into mature adults or juveniles and migration out to shelf environments. Shellfish resources in the Gulf tend to be more estuarine dependent than finfishes. Gulf of Mexico shellfish habitats range from brackish wetlands to nearshore shelf environments. Of the 15 penaeid shrimp species found in the Gulf the brown, white and pink shrimp are the most important. Adults of these species spawn in offshore marine waters and the free swimming postlarvae move into estuaries to remain through their juvenile stages. Juvenile shrimp move back offshore to molt into adults.

Reef fish assemblages may consist of mainly temperate species in the more northern Gulf with increasing dominance of more tropical fish species, typically associated with coral reefs, further offshore and in the more southern portions of the Gulf. Natural reef habitat in the eastern Gulf ranges from low relief (>1 m) livebottom, high relief ridge habitats along the Florida shelf break and pinnacle formations of the Florida Middle Grounds on the west Florida shelf. Man-made or artificial reef habitats also exist from oil and gas platforms, sunken vessels and a variety of other structures placed intentionally for fisheries enhancement. These structures comprise critical habitats for many important commercial and recreational fishes such as groupers and snappers.

Pelagic fish species are distributed by water column depth and relationship to the shore. Coastal pelagics are those that move mainly around the continental shelf year round, singly or in schools of various size (MMS 2000b). These include some commercially important groups of fishes including sharks, anchovies, herring, mackerel, tuna, mullet, bluefish and cobia. Oceanic pelagics occur at or seaward of the shelf edge throughout the Gulf. Oceanic pelagics include many larger species such as sharks, tuna, bill fishes, dolphin and wahoo.

Deepwater Fishes

Extensive discussions of deepwater fishes are available in: *Deepwater Gulf of Mexico Environmental and Socioeconomic Data Search and Literature Synthesis, Volume 1: Narrative Report* (MMS, 2000c) and in several recent BOEM EIS documents (BOEM 2012; 2013).

Deepwater Pelagic Fishes

Mesopelagic fishes are restricted mainly to the midwater (200 m - 1000 m) environment in the Gulf. These are dominated by lanternfishes (myctophids) and bristlemouths (gonostomatids). The Stomiidae (dragonfishes) with 73 species is the most diverse family of fishes known for the Gulf of Mexico (Sutton and Hopkins 1996; McEachran and Fechhelm 1998). The second most diverse group is the myctophids represented by 49 species in the Gulf of Mexico (Backus et al. 1977; Gartner et al. 1987). Mesopelagic fishes make extensive vertical migrations, from 400-800 m to near or at the surface, at night to feed in the upper portions of the water column and are important in the transfer of nutrients and energy between the mesopelagic and epipelagic (upper 200 m) zone (Hopkins and Baird, 1985).

Bathypelagic fishes live a depths greater than 1000 m and seldom move up into shallower waters. This group consists of little-know species such as slickheads, gulper eels, deep-sea anglers, whalefishes and bigscales and is not well studied in the Gulf.

Deepwater Demersal Fish

Deepwater demersal fishes are species that associate with benthic structure, living on or above it, from the shelf slope transition to the abyssal plain. In the Gulf this group consists of some 300 species (MMS 2000c). Studies by Pequegnat (1983) and Galloway et al. (1988) showed that the number of demersal species and the distribution of individuals among species declined with increasing depth. Several species of snapper, grouper and tilefish are caught commercially on demersal habitat in depths of up to 500 m.

6.8 Marine Mammals

Twenty-nine species of marine mammals (listed in EPA, 1998, Table 3-4) are known to occur in or migrate through the northern Gulf of Mexico based on sightings and/or strandings (Schmidly, 1981; Davis et al., 2000). Extensive discussions can be found in the 2016 EPA Environmental Assessment for the EPA Oil and Gas general NPDES permit (EPA 2016) and in several recent BOEM EIS documents (BOEM 2012; 2013). Cetaceans (whales, dolphins, and porpoises) are the most common. Five of the seven baleen whales in the Gulf are currently listed as threatened or endangered and of the 20 toothed whales present only the sperm whale is endangered. During 1978 to 1987, a total of 1,200 cetacean strandings/sightings was reported for Alabama, Florida and Mississippi to the Southeastern U.S. Marine Strandings Network. Ninety percent of these stranding/sighting occurred off Florida coasts (the Florida figure reflects strandings from both the Gulf and the Atlantic waters; NOAA, 1991). The cetaceans found in the Gulf include species that occur in most major oceans and, for the most part, are eurythermic, with a broad range of temperature tolerances (Schmidly 1981). An introduced species of pinniped, the California sea lion, occurred in small numbers only in the feral condition, however no sightings of this species has been reported in the Gulf since 1990. All marine mammals are protected under the Marine Mammal Protection Act of 1972.

6.10 Endangered Species

The USFWS and NMFS evaluate the conditions of species and their populations within the United States. Those species populations considered in danger of extinction are listed as endangered species per the Endangered Species Act of 1973. In addition, Section 7(a)(2) of the Endangered Species Act requires federal agencies to ensure that their action do not jeopardize the continued existence of listed species or destroy or adversely modify critical habitat. Threatened and endangered species that occur in the Gulf of Mexico are discussed extensively in the 2016 EPA Environmental Assessment for the EPA Oil and Gas general NPDES permit (EPA 2016) and in several recent BOEM EIS documents (BOEM 2012; 2013). Table 6-2 provides an updated list of species either listed as threatened or endangered that potentially could occur in impacted areas of the central or eastern Gulf.

Table 6.2. Federally Listed Species in the Eastern Gulf of Mexico.

Species	Scientific Name	Status
Birds		
Piping plover	*Charadrius melodus*	Threatened
Wood stork	*Mycteria americana*	Endangered
Roseate tern	*Sterna dougallii*	Threatened
Interior Least turn	*Sterna antillarum athalassos*	Endangered
Whooping crane	*Grus americana*	Endangered
Mississippi Sandhill crane	*Grus canadensis*	Endangered
Everglades snail kite	*Rostrhamus sociabilis*	Endangered
Red knot	*Calidris cantunus*	Threatened
Reptiles		
American crocodile	*Crocodylus acutus*	Threatened
Loggerhead sea turtle	*Caretta caretta*	Threatened
Kemp’s Ridley sea turtle	*Lepidochelys kempii*	Endangered
Green sea turtle	*Chelonia mydas*	Threatened
Hawks bill sea turtle	*Eretmochelys imbricata*	Threatened
Leatherback sea turtle	*Dermochelys coriacea*	Endangered
Marine Mammals		
West Indian manatee	*Trichechus manatus*	Endangered
Finback whale	*Balaenoptera physalus*	Endangered
Humpback whale	*Megaptera novaeangliae*	Endangered
Right whale	*Eubalaena glacialis*	Endangered
Blue whale	*Balaenoptera musculus*	Endangered
Sei whale	*Balaenoptera borealis*	Endangered
Sperm whale	*Physeter macrocephalus*	Endangered

Terrestrial Mammals		
Choctawhatchee beach mouse	*Peromyscus polionotus allophrys*	Endangered
Alabama beach mouse	*Peromyscus polionotus ammobates*	Endangered
Perdido Key beach mouse	*Peromyscus polionotus trissyllepsis*	Endangered
Key Largo cotton mouse	*Peromyscus gossypinus allapaticola*	Endangered
Florida panther	*Puma concolor coryi*	Endangered
Key Largo woodrat	*Neotoma floridana smalli*	Endangered
Lower Keys rabbit	*Sylvilagus palustris hefneri*	Endangered
Florida salt marsh vole	*Microtus pennsylvanicus dukecampbelli*	Endangered
St. Andrew beach mouse	*Peromyscus polionotus peninsularis*	Endangered
Rice rat	*Oryzomys palustris*	Endangered
Fishes		
Gulf sturgeon	*Acipenser oxyrhynchus desotoi*	Threatened
Smalltooth sawfish	*Pristis pectinata*	Endangered
Corals		
Staghorn coral	*Acropora cervicornis*	Threatened
Elkhorn coral	*Acropora palmata*	Threatened
Lobed star coral	*Orbicella faveolata*	Threatened
Boulder star coral	*Montastraea annularis*	Threatened
Mountainous star coral	*Orbicella faveolata*	Threatened
Pillar coral	*Dendrogyra cylindricus*	Threatened
Rough cactus coral	*Mycetophyllia ferox*	Threatened

Sources: USFWS 2010. Federally Listed Wildlife and Plants Threatened by Gulf Oil Spill
http://www.fws.gov/home/dhoilspill/pdfs/FedListedBirdsGulf.pdf

USFWS 2013. Gulf Restoration. **Threatened and Endangered Species on the Gulf Coast.**
http://www.fws.gov/gulfrestoration/TandEspecies.html

NOAA. 2016. Endangered and Threatened Marine Species under NMFS' Jurisdiction
http://www.nmfs.noaa.gov/pr/species/esa/listed.htm

7.0 COMMERCIAL AND RECREATIONAL FISHERIES

7.1 Overview

Though the Gulf of Mexico Region includes Alabama, Louisiana, Mississippi, Texas, and West Florida, much of the following discussion will focus on Gulf states in the eastern portion of the GOM. Federal fisheries in this region are managed by the Gulf of Mexico Fishery Management Council (GMFMC) and NOAA Fisheries (NMFS) under seven fishery management plans (FMPs): Red Drum, Shrimp, Reef Fish, Coastal Migratory Pelagic Resources (with SAFMC), Spiny Lobster (with SAFMC), Corals, and Aquaculture. The coastal migratory pelagic resources and spiny lobster fisheries are managed in conjunction with the South Atlantic Fishery Management Council (SAFMC).

The most recent change is the development of the Aquaculture FMP to establish a regional permitting process to manage the development of an environmentally sound and economically sustainable aquaculture industry in federal waters of the Gulf of Mexico (NMFS, 2014). The final rule was published in January, 2016. More information can be found at: http://sero.nmfs.noaa.gov/sustainable_fisheries/gulf_fisheries/aquaculture/.

Several of the stocks or stock complexes covered in these fishery management plans, are currently listed as overfished: gag, gray triggerfish, greater amberjack, and red snapper. Other impacts to commercial fisheries in the GOM in recent years include a number of hurricanes, especially with major storms making landfall in Louisiana and Texas in 2005 (Hurricanes Katrina and Rita) and 2008 (Hurricanes Gustav and Ike). Locally, these storms severely disrupted or destroyed the infrastructure necessary to support fishing, such as vessels, fuel and ice suppliers, and fish houses. Current information on the status of US fisheries can be found at: http://www.nmfs.noaa.gov/sfa/fisheries_eco/status_of_fisheries/.

The Deepwater Horizon MC252 oil spill in 2010 severely affected fisheries in the Gulf. Large parts of the GOM, including state and federal waters, were closed to fishing during May through October, 2010. Both Alabama and Mississippi reported less than half and Louisiana about three quarters of their annual shrimp landings compared to the average of the previous three years. The impacts of the spill remain under study and the long term consequences of the oil spill on fish stocks and the fishing industry have yet to be fully assessed.

7.2 Commercial Fisheries

National Marine Fishery Service (NMFS 2014; 2015) data show that in 2013, commercial fishermen in the Gulf of Mexico Region landed 1.4 billion pounds of finfish and shellfish, earning $937 million in landings revenue. In 2014 1.1 billion pounds were landed at a value of over $1.0 billion. From 2003 to 2013, most of the commercial fisheries revenue and catch (91% and 96% respectively) was dominated by ten key species or species groups (Table 7-1).

Table 7-1. Key Gulf of Mexico Region Commercial Species or species groups

Shellfish	Finfish
Crawfish	Groupers
Blue crab	Menhaden
Oysters	Mullets
Shrimp	Red snapper
Stone crab	Tunas

Commercially important species groups in the GOM include oceanic pelagic (epipelagic) fishes, reef (hard bottom) fishes, coastal pelagic species, and estuarine-dependent species. Landings revenue in 2012 was dominated by shrimp ($392 million) and menhaden ($87 million). These species comprised 63% of total landings revenue, and 90% of total landings in the Gulf of Mexico Region. Other invertebrates such as blue crab, spiny lobster, and stone crab also contributed significantly to the value of commercial landings. Other finfish species that contributed substantially to the overall commercial value of the GOM fisheries included red grouper, red snapper, and yellowfin tuna. In terms of landing weight, Atlantic menhaden far surpassed other commercial fish species in the GOM, accounting for approximately 73% of the total weight of landed commercial species in 2013 (Table 7-2). However, Atlantic menhaden accounted for only about 10% of the total value of the GOM commercial fishery. The portion of commercial fishery landings that occurred in nearshore and offshore waters of the GOM States is presented in Table 7-3.

TABLE 7.2. Total Weights and Values of Key Commercial Fishery Species in the GOM Region in 2013.

Species	Weight (thousands of pounds)	Value (Thousands of dollars)	% Weight	% Value
Menhaden	1,020,244	95,277	73.3	10.2
Shrimp	204,527	503,842	14.7	53.8
Blue crab	46,543	61,264	3.3	6.5
Oyster	19,230	76,729	1.4	8.2
Crayfish	19,823	16,593	1.4	1.8
Mullets	13,482	13,222	0.01	0.01
Stone crab	3,778	24,762	0.003	2.6
Groupers	7,280	23,396	0.005	2.5
Red snapper	5,286	20,493	0.004	2.2
Tuna	2,107	7352	0.002	0.008
Total	**1,392,364**	**936,660**		

Source: NMFS 2015.

TABLE 7-3 Value of Gulf Coast Fish Landings by Distance from Shore and State for 2012 ($1,000)

	Distance from shore	
State	0-3	3-200
Florida (GOM)	64,727	75,232
Alabama	15,870	27,195
Mississippi	29,767	19,509
Louisiana	232,710	95,242
Texas	63,135	130,813

https://www.st.nmfs.noaa.gov/commercial-fisheries/commercial-landings/other-specialized-programs/preliminary-annual-landings-by-distance-from-shore/index

In 2013, the eastern GOM Region's seafood industry generated $527 million in sales in Alabama, $268 million in sales in Mississippi, and $15 billion in sales in Florida Table 7-4). Florida generated the largest employment, income, and value added impacts, generating 78,000 jobs, $2.9 billion, and $5.1 billion, respectively. The smallest income impacts were generated in Mississippi ($200 million) and the smallest employment impacts were also generated in Mississippi (6,432 jobs) (NMFS 2015).

Table 7-4. 2013 Economic Impacts of the Eastern Gulf of Mexico Region Seafood Industry (thousands of dollars)

	Landings Revenue	**Jobs**	**Sales**	**Income**	**Value Added**
Alabama	55,434	12,090	526,767	200,494	265,580
Mississippi	46,618	6,432	268,367	107,340	138,779
Florida	148,058	78,378	15,319,435	2,878,309	5,136,623

Source: NMFS 2015

In 2013 1.4 billion pounds of finfish and shellfish were landed in the Gulf of Mexico Region. This was a 6.7% decrease from the 1.5 billion pounds landed in 2004 and a 7.0% increase from the 1.3 billion pounds landed in 2012. Finfish landings experienced a 9.6% decrease between 2012 and 2013 while shellfish landings experienced a 1.6% decrease over the same period (Table 7-5).

Table 7-5. Total Landings and Landings of Key Species/Species Groups From 2010 to 2013 (thousands of pounds).

	2010	**2011**	**2012**	**2013**
Total landings	1,072,068	1,792,550	1,293,195	1,392,364
Finfish & other	810,649	1,472,798	987,374	1,092,148
Shellfish	261,419	319,752	305,821	300,216

Source: NMFS 2015

From 2004 to 2013, species or species groups with large changes in landings include tunas (decreasing 46%), groupers (decreasing 39%), and oysters (decreasing 23%). Species or species groups with large changes in landings between 2012 and 2013 include crawfish (increasing 66%), and red snapper (increasing 24%) (NMFS, 2015).

The DWH event had immediate effects on the GOM fishing industry between April and November 2010, with up to 40% of Federal waters being closed to commercial fishing in June and July (CRS 2010). Portions of Louisiana, Alabama, Mississippi, and Florida State waters have also been closed. These areas are some of the richest fishing grounds in the GOM for major commercial species such as shrimp, blue crab, and oysters, and as prices for these items have increased, imports of these species have likely taken the place of lost GOM coast production. NOAA continued to reopen areas to fishing once chemical tests revealed levels of hydrocarbons or dispersants in commercial species were not of concern to human health.

It cannot be determined from these data whether the decreases in fin and shell fish landings were the result of reduced stock sizes, changes in stock geographic distribution or changes in fishing effort, however studies are currently ongoing and it is not known at this time whether there are long term affects to fisheries due to the spill.

7.3 Recreational Fishing

The NMFS (2015) estimates that in 2013, over 3.3 million recreational anglers took 25 million fishing trips in the Gulf of Mexico Region. The key fish species or species groups making up most of the recreational fishery in the GOM are listed in Table 7-6.

Table 7-6. Key Gulf of Mexico Region Recreational Species

- Atlantic croaker
- Sand and silver seatrout
- Sheepshead porgy
- Red snapper
- Spanish mackerel
- Gulf and southern kingfish
- Spotted seatrout
- Red drum
- Southern flounder
- Striped mullet

Source: NMFS, 2015

Of the three eastern GOM States, western Florida had the highest number of anglers and fishing trips in 2013 (15.9 million), followed by Alabama (2.8 million), and Mississippi (1.8 million) (Table 7.7). Almost 67% of the fishing trips in the GOM coast left out of west Florida, followed by Alabama (7%), and Mississippi (5%). 41.8% of the total recreational fish landings (by weight) in the GOM occurred in Florida, 12.8% 33 in Alabama, and 5.3% in Mississippi.

In Mississippi nearly all landings were made in inland waters (98.6%). While the inland catch was important in Alabama (50.0%) and Florida (44.0%), the offshore catch was larger in these States, with 34.1% of the total catch landed up to 5 km (3 mi) from shore, and 16% at more than 5 km (3 mi) in Alabama and 28.7% at less than 16 km (10 mi), and 27.3% at more than 16 km (10 mi) in Florida.

TABLE 7.7. Estimated Number of People Participating in Eastern GOM Marine Recreational Fishing in 2013 [a] (thousands).

	Coastal	Non-coastal	Out of state	Total
West Florida	1,813	NA	2,538	4,351
Alabama	279	224	549	1,050
Mississippi	171	67	101	339
GOM Total*	2,263	291	3,098	5,740

a Coastal, non-coastal, and out-of-State refer to place of residence of participants in marine
recreation in each State.
*Texas does not collect angler data.
Source: NMFS, 2015

Recreational fishing contributes to the Gulf state economies mainly through employment, expenditures (fishing trips and durable good), and sales. Table 7-8 shows the economic impacts of recreational fisheries by Gulf state. Recreational fishing activities generated over 87,000 full- and part-time jobs in Alabama, Mississippi and West Florida, and over $10.0 billion in sales.

Table 7-8. 2013 Economic Impacts of Recreational Fishing Expenditures in the Eastern GOM (thousands of dollars)

	Trips	**Jobs**	**Sales**	**Income**	**Value Added**
Alabama	2,862	10,163	927,409	358,769	569,144
Mississippi	1,761	1,583	146,333	53,602	87,684
West Florida	15,949	76,236	9,086,311	3,423,836	5,341,420

Source: NMFS, 2015

8.0 COASTAL ZONE MANAGEMENT CONSISTENCY AND SPECIAL AQUATIC SITES

This chapter addresses two of the 10 ocean discharge criteria: (5) The existence of special aquatic sites including, but not limited to marine sanctuaries and refuges, parks, national and historic monuments, national seashores, wilderness areas and coral reefs, and (8) Any applicable requirements of an approved Coastal Zone Management plan.

8.1 Coastal Zone Management Consistency

The Coastal Zone Management Act requires that any Federally-licensed or permitted activity affecting the coastal zone of a state that has an approved coastal zone management program (CZMP) be reviewed by that state for consistency with the state's program (16 USC 1456(c)(A) Subpart D). Under the Act, applicants for Federal licenses and permits must submit a certification that the proposed activity complies with the state's approved CZMP and will be conducted in a manner consistent with the CZMP. The state then has the responsibility to either concur with or object to the consistency determination under the procedures set forth by the Act and their approved plan. For NPDES program general permits, the EPA is considered the applicant and must submit the general permit and consistency determination to the affected states for concurrence.

Consistency certifications are required to include the following information (15 CFR 930.58):

A detailed description of the proposed activity and its associated facilities, including maps, diagrams, and other technical data;

A brief assessment relating the probable coastal zone effects of the proposal and its associated facilities to relevant elements of the CZMP;

A brief set of findings indicating that the proposed activity, its associated facilities, and their effects are consistent with relevant provisions of the CZMP; and

Any other information required by the state.

The States of Mississippi, Alabama, and Florida have federally approved coastal zone management programs (CZMP). Each Gulf state has specific requirements in their CZM plans that outline procedures for determining whether the permitted activity is consistent with the provision of the program.

Discharges covered by this OCS general permit will occur in Federal waters outside the boundaries of the coastal zones of the States of Alabama, Florida, and Mississippi. However, because these discharges could occur in close proximity to state waters, creating the potential for impacts on state waters, consistency determinations for the general permit will be prepared and submitted to the States of Alabama, Florida, and Mississippi. The following summaries describe the requirements of each state’s management plan for consistency determination. The permitting agency must provide the necessary data and information for the State to determine that the proposed activities comply with the enforceable policies of the States’ approved program, and that such activities will be conducted in a manner consistent with the program. (See 16 U.S.C. 1456(c)(3)(A) and 15 CFR 930.76.)

8.2 Alabama Coastal Area Management Program

Alabama's Coastal Management Plan (ADEM Admin. Code R. 335-8-x-.xx, as revised 2013) contains a Review Process for Federally Regulated Activities (335-8-1-.09):

Pursuant to 15 CFR Part 930, Subpart D, uses which are federally licensed or permitted activities affecting the coastal area are required to be conducted in a manner consistent with the management program. The Department shall review and respond to a federal license or permit applicant's consistency certification in accordance with the provisions of 15 CFR Part 930, Subpart D.

The [Environmental Protection Agency] federal license and permit activities which are subject to review, listed pursuant to 15 CFR Part 930, Subpart D, are: Permits and licenses required under Sections 401, 402, 403, 404 and 405 of the Federal Water Pollution Control Act of 1972, as amended.

The Alabama Coastal Area Management Program requires compliance with Federal and state statutes and regulations that relate to the development and preservation of resources within the coastal area. In order to be deemed consistent with the Program, activities must comply with the relevant substantive requirements of those Federal and state statutes and any regulations adopted pursuant to these statutes to the extent applicable under the terms of those statutes or regulations.

In addition to the data and information required to be furnished to the Department with the consistency certification pursuant to 15 C.F.R. §§ 930.58, the following data and information must be provided:

1. An informational copy of the application for the license or permit;
2. A copy of the federal agency's written determination that the license or permit application is complete;
3. A copy of the federal agency's draft or proposed license or permit if a draft or proposed license or permit is required to be prepared by federal law or regulations;
4. A copy of any transcript of any public hearing conducted by the federal agency concerning the federal license or permit application and all written comments received by the federal agency during any comment period; and,
5. A copy of any draft Environmental Assessment or draft Environmental Impact Statement required under the National Environmental Policy Act §§ 102, 42 U.S.C. §§ 4332 or implementing federal regulations.

ADEM will issue a public notice at least 15 days prior to a decision regarding an activity requiring a federal permit to solicit public comment and may hold a public hearing on the proposed activity if any person has satisfactorily demonstrated that a relevant and significant issue cannot be effectively or fully communicated to the Department in writing or a significant public interest would be served thereby.

8.3 Mississippi Coastal Program

The Mississippi Coastal Program was approved by the Associate Administrator, Office of Coastal Zone Management, under provisions of Coastal Zone Management Act on September 30, 1980 and became effective October 1, 1980. The document entitled *Mississippi Coastal Program*, prepared by the Bureau of Marine Resources of the Mississippi Department of Wildlife Conservation, was used to prepare the following understanding of the requirements of the Mississippi Coastal Zone Management Plan. The Mississippi Commission on Wildlife Conservation (MCWC) was created by legislation in 1978 to implement the Mississippi Coastal Program.

Currently, implementation of the Mississippi Coastal Program is the primary responsibility of the Office of Coastal Resources. The Mississippi Coastal Program was legislatively mandated in Section 57-15-6 of the Mississippi Code of 1972 (MS Code Section 57-15-6, 2013).

The primary authority guiding the coastal management program is the Coastal Wetlands Protection Act. The Mississippi coastal zone includes the three coastal counties, as well as all adjacent coastal waters and the barrier islands of the coast.

In addition to coastal management responsibilities, Coastal Resources Management also administers the Coastal Preserves Program, Wetlands Permitting, and other special projects.

Coastal management consistency determination requirements are determined for coastal uses and activities based on their effect on water quality, water quantity, bottom disturbances, water pollution, sedimentation (runoff), shoreline erosion, marine aquatic life, and historical and archaeological sites. Oil and gas activities regulated under NPDES (section 402) permits are subject to management by the Mississippi Coastal Program under two sets of guidelines: wetlands management and policy coordination.

The Wetlands Management Guidelines are mainly concerned with the placing of structures and pipelines. These concerns are addressed by BOEM in lease stipulations or Army Corp. of Engineers dredge permits and are not covered under the NPDES program. The one guideline that does affect the NPDES general permit is that no discharge of cuttings, drilling fluids, produced waters, sanitary wastes, and contaminated deck drainage shall be discharged into coastal waters. The general permit does not permit discharges to state waters, and therefore, is in compliance with this guideline.

The Policy Coordination Guidelines protect the wetlands, waterfront sites, seafood, natural scenic qualities, and natural interests of publicly owned lands within the state's jurisdiction. Although the general permit covers only Federal waters, the conclusions concerning potential effects demonstrate that the permit is consistent with the policy guidelines of Mississippi.

8.4 Florida Coastal Management Program

The Florida Coastal Management Program (FCMP) was approved by NOAA in 1981 and is codified at Chapter 380, Part II, F.S. The State of Florida's coastal zone includes the area encompassed by the state's 67 counties and its territorial seas. The FCMP consists of a network of 24 state statutes administered by eight state agencies and five water management districts.

Federal consistency reviews are integrated into other review processes conducted by the state depending on the type of federal action being proposed. The Florida State Clearinghouse administered by the DEP Office of Intergovernmental Programs, is the primary contact for receipt of consistency evaluations from federal agencies. The Clearinghouse coordinates the state’s review of applications for federal permits other than permits issued under Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act.

The review of federal activities is coordinated with the appropriate state agency. Each agency is given an opportunity to provide comments on the merits of the proposed action, address concerns, make recommendations, and state whether the project is consistent with its statutory authorities in the FCMP. Regional planning councils and local governments also may participate in the federal consistency review process by advising the Department of Economic Opportunity (DEO) on the local and regional impact of proposed federal actions. Comments provided by regional planning councils and local governments are considered by the DEO in determining whether the proposed federal activity is consistent with specific sections of Chapter 163, Part II, F.S., that are included in the FCMP. If a state agency determines that a proposed federal activity is inconsistent, the agency must explain the reason for the objection, identify the statutes the activity conflicts with and identify any alternatives that would make the project consistent.

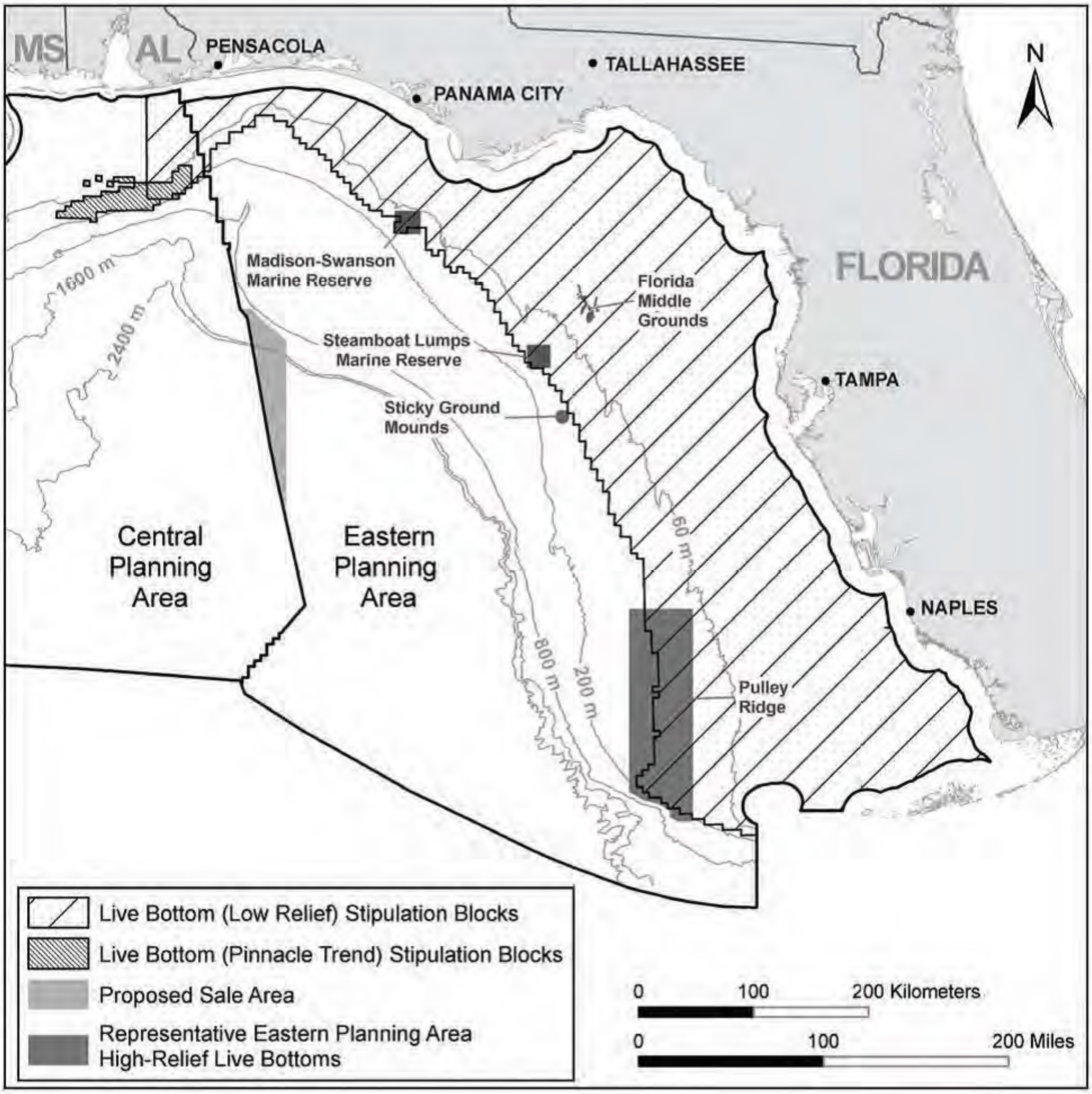
As the designated lead coastal agency for the state, the DEP communicates the agencies' comments and the state's final consistency decision to federal agencies and applicants for all actions other than permits issued under Clean Water Act Section 404 and Section 10 of the Rivers and Harbors Act.

8.5 Special Aquatic Sites

The Code of Federal Regulations, 40 CFR 230.3 q, Defines Special aquatic sites as "geographic areas, large or small, possessing special ecological characteristics of productivity, habitat, wildlife protection, or other important and easily disrupted ecological values. These areas are generally recognized as significantly influencing or positively contributing to the general overall environmental health or vitality of the entire ecosystem of a region."

Areas of high relief outcroppings (Pinnacle Trend) occur on the outer edge of the Mississippi-Alabama shelf between the Mississippi River and De Soto Canyon (Figure 8-1). The Pinnacle Trend covers some 2,680 km^2 area in water depths of 60-200 meters. High-relief features have complex shape and structure that provide varied zones of microhabitat for attached organisms and attract large numbers of fish.
Areas of high relief live bottom habitat also occur off the west Florida coast. These include the Madison-Swanson Marine Reserve, Florida Middle Grounds, Pulley Ridge, Steamboat Lumps Special Management Area, and Sticky Ground Mounds (BOEM, 2013).

Figure 8-1. High Relief Live Bottom Areas in the Central and Eastern Gulf of Mexico.



Source BOEM 2013

Various species of sessile attached reef fauna and flora grow on the exposed hard grounds. Some taller species (e.g., sea whips and other gorgonians) appear to survive this intermittent sand movement and accretion. Surveys on the southwest Florida Shelf revealed that the biotic cover on the live bottom patches is generally low and that the patches tend to be dominated by either algae or encrusting invertebrates (Woodward-Clyde Consultants and CSA, 1983).

BOEM has included a Live Bottom Stipulation in NTL No. 2009-G39 designed to protect both high and low relief live bottom areas. The Stipulation designated affected lease blocks near the Pinnacle Trends and on the West Florida Shelf out to a 100-meter depth as Live Bottom Stipulation Blocks. A lease stipulation to avoid and protect pinnacle trend features has been made a part of relevant Central Planning

Area OCS oil and gas leases since 1974. A lease stipulation to avoid and protect low relief features has been made a part of relevant OCS oil and gas leases since 1982. Both Pinnacle Trends and Low Relief Live Bottom Stipulations are intended to identify and protect these communities from bottom disturbances from activities such as platform and pipeline placement and well drilling. Requirements include preparing a live-bottom survey report containing a bathymetry map constructed from remote-sensing data and an interpretation of live-bottom area surveys that extend to at least 1,000 meters from the site of the proposed activity.

A portion of the Central Gulf of Mexico Planning Area and most of the Eastern Gulf of Mexico Planning Area is under moratoria until 2022 as part of the Gulf of Mexico Energy Security Act of 2006. The area restricted is that portion of EPA within 125 miles of Florida, all areas in the Gulf of Mexico east of the Military Mission Line (86º 41' west longitude), and the area within the CPA that is within 100 miles of Florida.

The portion of the Pinnacle Trend in the Central Planning Area under EPA Region 4 jurisdiction is shoreward of the 200 meter isobath proposed general permit coverage area. The portion of the Eastern Planning Area open to oil and gas activity are seaward of the 125 mile moratoria area that includes the high relief hardbottom features off the West Florida coast.

9. FEDERAL WATER QUALITY CRITERIA AND STATE WATER QUALITY STANDARDS

Factor 10 of the 10 ocean discharge criteria used to determine no unreasonable degradation requires the assessment of Federal marine water quality criteria and applicable state water quality standards. This chapter evaluates compliance with the Federal water quality criteria at the edge of a 100-meter mixing zone. In addition, compliance with Florida, Alabama and Mississippi water quality standards has been analyzed.

9.1 Federal Water Quality Criteria

Federal water quality criteria are established as guidelines for protection of water quality and human health. Table 9-1 presents a list of Federal water quality criteria for priority pollutants found in drilling or production discharges.

Table 9-1. Federal Water Quality Criteria

Pollutant	Marine Acute Criterion (µg/l)	Marine Chronic Criterion (µg/l)	Human Health Criterion (µg/l)
Anthracene			110,000
Antimony			640
Arsenic	69	36	0.14
Benzene			51
Benzo(a)pyrene			0.018
Cadmium	40	8.8	
Chlorobenzene			21,000
Chromium (VI)	1100	50	
Copper	4.8	3.1	
Di-n-butylphthalate			4,500
2,4-Dimethylphenol			850
Ethylbenzene			29,000
Fluorene			5,300
Lead			
Manganese			100
Mercury	210	8.1	
Nickel			
Phenol	1.8	0.94	
Selenium	74	8.2	
Silver			
Thallium	290	71	6.3
Toluene	1.9		200,000
Zinc			
	90	81	

[a] Human health criteria for consumption of organisms only; risk factor of 10^{-6} for carcinogens.
Source: EPA, 2015

9.2 Florida Water Quality Standards

Water quality standards for the surface waters of Florida are established by the Department of Environmental Regulation in the Official Compilation of Rules and Regulations of the State of Florida, Chapter 62-302 -530 Surface Water Quality Standards (effective 08/01/2013). These standards are presented in Table 9-2 for use classes applicable to the Desoto Canyon receiving water.

Table 9-2. Florida Water Quality Standards

Parameter	Shellfish Propagation of Harvesting (Class II) and Recreation, Fish and Wildlife (Class III-Marine) [a] (µg/l)
Aluminum	1,500
Antimony	4,300
Arsenic (total)	50
Benzene	71.28 annual average
Beryllium	0.13 annual average
Biological Integrity [b]	not reduced <75% of natural background
BOD	DO shall not drop below depressed limit for class
Cadmium	8.8
Chlorides	not more than 10% above natural background
Chlorine (total residual)	10
Chromium (VI)	50
Copper	3.7
Detergents	500
Dissolved Oxygen	5,000 daily average
Fluorides	5,000
Iron	300
Lead	8.5
Manganese	100 [c]
Mercury	0.025
Nickel	8.3
Oil and Grease	none visible
dissolved or emulsified--	5,000
pH	natural background ± .2 unit; 6.5 min. - 8.5 max.
Phenol	300
Phenolic Compounds	1.0
Radioactive Substances --radium	5 pCi/l
(226+228)--	15 pCi/l
gross alpha--	
Selenium	71
Silver	0.05
Thallium	6.3
Turbidity	≤29 NTU above natural background
Zinc	86

[a] Shall be applied to all state waters except within the zones of mixing.

[b] According to the Shannon-Weaver diversity index of benthic macroinvertebrates.

[c] Standard applies only to Class II water use

The antidegradation policy of the standards requires that new and existing sources be subject to the highest statutory and regulatory requirements under Sections 301(b) and 306 of the Clean Water Act. In addition, water quality and existing uses of the receiving water shall be maintained and violations of water quality standards shall not be allowed.

Minimum criteria apply to all surface waters of the state and require that all places shall at all times be free from discharges that, alone or in combination with other substances or in combination with other components of discharges, cause any of the following conditions.

- Settleable pollutants to form putrescent deposits or otherwise create a nuisance
- Floating debris, scum, oil, or other matter in such amounts as to form nuisances
- Color, odor, taste, turbidity, or other conditions in such degree as to create a nuisance
- Acute toxicity (defined as greater than 1/3 of the 96-hour LC50)
- Concentrations of pollutants that are carcinogenic, mutagenic, or teratogenic to human beings or to significant, locally occurring wildlife or aquatic species
- Serious danger to the public health, safety, or welfare.

These general criteria of surface water apply to all surface waters except within zones of mixing. A mixing zone is defined as the surface water surrounding the area of discharge "within which an opportunity for the mixture of wastes with receiving waters has been afforded." Effluent limitations can be set where the analytical detection limit for pollutants is higher than the limitation based on computation of concentration in the receiving water.

9.3 Alabama Water Quality Standards

The Alabama Water Quality Criteria Standards are set forth by the Alabama Environmental Management Commission at Title 22, Chapter 335-6-10.

Toxic pollutant standards applicable to state waters are presented in Table 9-3. Alabama water quality standards provide instruction for calculating human health criteria based on pollutant-specific reference doses, bioconcentration factors, and cancer potency factors. These values used for the calculations are presented in Table 9-4.

Table 9-3. Alabama Toxic Pollutant Standards

Pollutant	Marine Acute Criteria (µg/l)	Marine Chronic Criteria (µg/l)	Human Health Criteria (µg/l)
Antimony			933
Arsenic	69	36	
Benzene			155
Benzo(a)pyrene			0.0675
Cadmium	40	8.8	
Chromium (VI)	1,100	50	
Copper	4.8	3.1	
2,4-Dimethylphenol			498
Di-n-butylphthalate			2,622
Ethylbenzene			6,222
Lead	210	8.1	
Mercury	2.1	0.025	0.121
Nickel	74	8.2	933
Phenol			1,000,000
Selenium	290	71	
Silver	1.9		
Thallium			133
Toluene			43,614
Zinc	90	81	

[a] Non-carcinogenic pollutant criteria calculated as:
[Human body weight (70 kg) x RfD]/[Fish consumption rate (0.030 kg/day) x BCF] x 1,000 µg/mg
RfD = Reference dose (Values presented in Table 9-4).
BCF = Bioconcentration factor (Values presented in Table 9-4).

[b] Carcinogenic pollutant criteria calculated as: [Human body weight (70 kg) x Risk level (1 x 10^{-5})]/
[CPF x Fish consumption rate (0.030 kg/day) x BCF] x 1,000 µg/mg
CPF = Cancer potency factor (Values presented in Table 9-4).

Source: Alabama Department of Environmental Management, Water Division - Water Quality Program

Table 9-4. Reference Doses, BCFs, and Cancer Potency Factors Used to Calculate Alabama Toxic Pollutant Standards

Pollutant	Reference Dose (RfD) [mg/(kg-day)]	Bioconcentration Factor (BCF) (l/kg)	Cancer Potency Factor (CPF) [kg/day)/mg]
Antimony	0.0004	1.0	
Benzene		5.2	0.029
Benzo(a)pyrene		30	7.3
Beryllium		19	4.3
Chromium (VI)	0.005	16	
2,4-Dimethylphenol	0.02	93.8	
Di-n-butylphthalate	0.1	89	
Ethylbenzene	0.1	37.5	
Mercury	0.0001	5,500	
Nickel	0.02	47	
Phenol	0.3	1.4	
Thallium	0.000068	116	
Toluene	0.2	10.7	

Source: Alabama Department of Environmental Management Water Division, Water Quality Program, September 29, 2015.

9.4 Mississippi Water Quality Standards

The Mississippi Water Quality Criteria for Intrastate, Interstate, and Coastal Waters are set forth by the Mississippi Department of Environmental Quality as adopted June 28, 2012. The Mississippi water quality criteria general conditions require that the following be met in all waters of the state:

1. In open ocean waters there shall be no oxygen demanding substances added which will depress the dissolved oxygen content below 5.0 mg/1.
2. Although mixing zones are sometimes unavoidable they will not substitute waste treatment. Application of mixing zones shall be made on a case-by-case basis and shall only occur in cases involving large surface water bodies in which a long distance or large area is required for the wastewater to completely mix with the receiving water body.
3. The location of a mixing zone shall not significantly alter the designated uses of the receiving water outside its established boundary. Adequate zones of passage for the migration and free movement of fish and other aquatic biota shall be maintained. Toxicity and human health concerns within the mixing zone shall be addressed as specified in the *Environmental Protection Agency Technical Support Document* for Water Quality-Based Toxics Control (EPA-505/2-90-001, March 1991) and amendments thereof. Under no circumstances shall mixing zones overlap or cover tributaries, nursery locations, locations of threatened or endangered species, or other ecologically sensitive areas.

Minimal conditions that are applicable to all waters include the following:

Waters shall be free from substances attributable to municipal, industrial, agricultural, or other discharges that will settle to form putrescent or otherwise objectionable sludge deposits.

Waters shall be free from floating debris, oil, scum, and other floating materials attributable to municipal, industrial, agricultural, or other discharges in amounts sufficient to be unsightly or deleterious.

Waters shall be free from materials attributable to municipal, industrial, agricultural, or other discharges producing color, odor, taste, total suspended or dissolved solids, sediment, turbidity, or other conditions in such degree as to create a nuisance, render the waters injurious to public health, recreation, or to aquatic life and wildlife, or adversely affect the palatability of fish, aesthetic quality, or impair the waters for any designated use. Except as prohibited in Rule 2.1.H. above, the turbidity outside the limits of a 750-foot mixing zone shall not exceed the background turbidity at the time of discharge by more than 50 Nephelometric Turbidity Units (NTU). Exemptions to the turbidity standard may be granted under the following circumstances:

(a) in cases of emergency to protect the public health and welfare
(b) for environmental restoration projects which will result in reasonable and temporary deviations and which have been reviewed and approved by the Department of Environmental Quality.

Waters shall be free from substances attributable to municipal, industrial, agricultural, or other discharges in concentrations or combinations that are toxic or harmful to humans, animals, or aquatic life. Specific requirements for toxicity are found in Rule 2.2.F.

Municipal wastes, industrial wastes, or other wastes shall receive effective treatment or control in accordance with Section 301, 306, and 307 of the Federal Clean Water Act. A degree of treatment greater than defined in these sections may be required when necessary to protect legitimate water uses. Mississippi numerical standards are presented in Table 9-5.

Table 9-5. Mississippi Toxic Pollutant Standards

Pollutant	Marine Acute Criteria (µg/l)	Marine Chronic Criteria (µg/l)	Human Health Criteria (µg/l)
Arsenic	69	36	0.14
Cadmium	40	8.8	168
Chromium (III)			140,468
Chromium (VI)	1,100	50	1470
Copper	4.8	3.1	1,000
Lead	210	8.1	
Mercury			0.153
Nickel	75	8.3	4,600
Phenol	300	58	860,000
Selenium	290	71	4200
Silver	1.9		
Zinc	90	81	26,000

Source: State of Mississippi Water Quality Criteria for Intrastate, Interstate, and Coastal Waters, Adopted June 28, 2012. Mississippi Department of Environmental Quality.

9.5 Compliance with Federal Water Quality Criteria

9.5.1 *Water Based Drilling Fluids Discharges*

Federal water quality criteria are compared to effluent concentrations projected for the edge of a 100-m mixing zone to determine the ability of drilling fluid discharges to achieve sufficient mixing and occur at concentrations below criteria in the surrounding waters. Table 9-6 presents the results of calculating the minimum number of dilutions that will ensure that all criteria are met by drilling fluid discharges at 100 meters from the discharge point. The minimum number of dilutions to achieve sufficient mixing for drilling fluids is projected to be 118 (the number of dilutions required to meet the arsenic human health criterion). Compared to drilling fluids modeling results presented in Chapter 4, there appears to be significant probability that the criteria can be met by the edge of a 100-m mixing zone.

For comparison, the preferred option of the MMS EIS for this development and production project specifies a maximum 400 bbl/hr discharge rate; water depths for the proposed activity area range from approximately 30 m to 150 m. For the generalized drilling fluid modeling approach that had been performed for EPA Region 10, a 500 bbl/hr discharge in a water depth of 20 m resulted in a minimum projected dilution of 1,035; even at a 1,000 bbl/hr discharge rate the available dilution is 655 at a water depth of 20 m and 731 at a water depth of 40 m. For a 1,000 bbl/hr discharge in a 70-m water depth, the dilutions achieved at 100 meters is 1,721, 10-fold greater than the amount required to meet the most stringent Federal water quality criteria in the Desoto Canyon area.

Table 9-6. Comparison of Federal Water Quality Criteria to Projected Drilling Fluids Pollutant Concentrations at 100 Meters

Pollutant	Effluent Conc.[a] (mg/l)	Leach Factor[b]	Federal Criteria (µg/l)			Minimum Dilutions Required[c]
			Marine Acute	Marine Chronic	Human Health	
Antimony	2,592	11%			110,000	<1
Arsenic	3,228	0.51%	69	36	0.14	118
Cadmium	0.50	11%	42	9.3		6
Chromium	109	3.4%	1,100	50		74
Copper	8.50	0.63%	4.8	3.1		17
Lead	15.9	2.0%	210	8.1		39
Mercury	0.045	1.8%	1.8	0.94	0.051	16
Nickel	6.138	4.3%	74	8.2	4,600	32
Selenium	0.50	11%	290	71	11,000	<1
Silver	0.318	11%	1.9			18
Thallium	0.546	11%			6.3	10
Zinc	91.16	0.41%	90	81	69,000	5

[a] See Table 3-3.

[b] The leach factor for metals for which no value was available is assumed to be 11%, equal to the highest value reported (cadmium).

[c] Calculated for each pollutant as: [(Effluent conc. x 1000 µg/mg) x leach factor]/lowest criterion value.

For the project-specific modeling approach, the minimum available dilutions under the most conservative scenario modeled was 150, which although closer to the required minimum dilution still affords an excess dilution under the least probable set of operational and environmental conditions. The occurrence of non-compliance with Federal water quality criteria appears to be highly unlikely based on the results of either modeling approach. And although the project-specific modeling approach and results have yet to be reviewed and verified by EPA, the comparability of the results lends some re-assurance to the likelihood that the project-specific approach will be found to be technically sound.

9.5.2 *Synthetic Based Drilling Fluids Discharges*

Assessments of water quality impacts from the discharge of cuttings with adhered synthetic based fluids (SBF-cuttings) rely on modeling data presented in a study (Brandsma, 1996) of the post-discharge transport behavior of oil and solids from cuttings contaminated with oil-based fluids (OBF-cuttings). Due to the similar hydrophobic and physical properties between SBFs and OBFs, EPA assumes that above 5% retention, that dispersion behavior of SBF-cuttings is similar to that of OBF-cuttings when discharged following shale shaker only (i.e. baseline technology) treatment of cuttings. However, at controlled discharge levels reflecting best-available technology treatment the cuttings are expected to disperse similar to WBF-cuttings.

The analyses in this chapter are somewhat conservative due to the assumption that discharged pollutants immediately leach into the water column. In the water column, total organic pollutant discharge concentrations are assumed to represent the soluble concentration. Metals are assumed to leach immediately into the water column at pollutant-specific amounts determined for mean seawater pH (as derived in Avanti Corporation, 1993).

To evaluate the relative water quality impacts of the current industry practice and regulatory options, EPA estimates the water column concentration of pollutants present in SBF drilling discharges under regulatory discharge options and compares them to Federal water quality criteria/toxic values. This comparative analysis applies only to those pollutants found in SBF discharges, and for which EPA has published numeric criteria, as presented in Table 9-1. Note that there are no criteria for the synthetic-based fluid compounds themselves.

In order to determine the water column pollutant concentrations, EPA used data regarding the transport of discharged drill solids and corresponding oil concentration in the water column. The study was performed by Brandsma (1996) and the data are published in the E&P Forum Summary Report No. 2.61/202 (1996). Following is a description of the Brandsma (1996) study from that E&P report.

Brandsma modeled the discharge of nine treatments of cuttings obtained from a North Sea drilling platform to obtain: (1) a maximum deposition density (g/m^2) of cuttings and oil; (2) water column concentrations of suspended solids and oil; (3) the maximum thickness (cm) of cuttings deposited on the seabed; and (4) the seabed area (ha) that would achieve a 100 ppm oil content threshold in the upper 4 cm or 10 cm of the sediment.

The treatment technologies included: (1) no treatment (lab formulated control), (2) untreated cuttings from shale shakers, (3) centrifugation, (4) solvent extraction, (5) thermal treatment, and (6) water washing. The bulk densities of the cutting ranged from 1,830 g/l to 2,430 g/l; oil content for the six types of cuttings ranged from 0.02% (dry weight basis) to 19.6%.

The author simulated four sites in the North Sea: Southern (30 m water depth and depth-averaged, root mean-squared current speed of 0.37 m/s); Central (100 m water depth and current speed of 0.26 m/s); Northern (150 m water depth and current speed of 0.22 m/s); and Haltenbanken (250 m water depth and current speed of 0.10 m/s).

The Offshore Operators Committee (OOC) drilling and production discharge model was used to simulate the concentrations and deposition of discharged cuttings. The OOC model utilized a mixture of 12 profile size classes of mud and cuttings particles (with adsorbed oil) and water. All other discharge conditions were fixed. All discharges simulated a 68.5-hour discharge of 152 m^3 of cuttings from a 0.3 m diameter pipe shunted to a depth of 15.2 m below mean sea level. This cuttings volume is the volume expected from a single well section of OBF-cuttings. Results presented are based on these 152 m^3 model efforts, however, results are scaled up to a 300 m^3 volume which was later determined by the project steering committee to be more representative of actual OBF-cuttings volumes generated using OBFs (representing two well sections).

Hydrographic conditions were conservatively selected to maximize predicted cuttings deposition on the seabed by choosing the minimum water column stratification at each site. The result is no density gradient at all sites but the Haltenbanken site which exhibited only a weak (0.0016 kg/m^3/m) gradient.

Water column results were determined at a radial distance of 1000 m downstream. For untreated and centrifuged OBF-cuttings, projected water column oil concentrations at 1000 m were below maximum North Sea background levels at all four sites; all other treatments resulted in projected 1000 m oil concentrations that exceeded maximum background levels (except through treatment at the Haltenbanken site). The explanation for this phenomenon is that while treatments other than centrifugation also reduce oil content (from an untreated level of 15.8% [w/w] to a range of 0.3% to 5.1%), these treatments also generate cuttings with finer particle sizes. Thus, according to the model, the untreated and centrifuged

OBF-cuttings would not reach the 1000 m mark to the same extent that the treated OBF-cuttings would because the finer particles created by the treatment have lower settling velocities and are transported farther in the water column (Brandsma, 1996).

Although Brandsma (1996) does not present oil concentration data for a radial distance of 100 m (the edge of the mixing zone established for U.S. offshore discharges by Clean Water Act Section 403, Ocean Discharge Criteria, as codified at 40 CFR 125 Subpart M), the study does present data on suspended solids and oil concentration as a function of transport time. Using current speeds representative of each geographic area (Gulf of Mexico; Cook Inlet, Alaska; and offshore California) and the transport times reported by Brandsma, EPA derived the corresponding oil concentrations and dilutions at 100 m. For example, assuming a mean current speed of 15 cm/s as representative of the Gulf of Mexico, a transport time of approximately 11 minutes is derived as the time required for the plume to reach 100 m (100 m/0.15 m/sec). Using data obtained from Brandsma's 1996 study, EPA conducted a regression analysis to determine the oil concentration at selected transport times. Based on the mean initial oil concentration of the 9 cuttings cases presented in the study (5.5% in water-washed cuttings), the dilutions achieved can be estimated for a selected time (i.e., distance) in the following manner. The 5.5% (w/w) oil content converts to 55 g oil/kg wet cuttings. Based on a reported mean OBF-cuttings density of 2.050 kg wet cuttings/l, the initial oil concentration of 112,750 mg oil/l (55 g/kg x 2.050 kg/l) is used to determine the dilutions achieved. For the Gulf of Mexico example, the oil concentration at 11 minutes of 3.0 mg/l is used to calculate a 37,425-fold dilution (112,750 mg/3.0127 mg) at 11 minutes (Bowler, 1999). As described above, 11 minutes represents the estimated time at which the plume would reach the edge of the mixing zone at 100 meters.

Projected water column pollutant concentrations at the edge of a 100-m mixing zone are calculated by dividing the drilling waste pollutant concentration by the dilutions available. The effluent concentrations for metals are further adjusted by a leach factor to account for the portion of the total metal pollutant concentration that is dissolved and therefore available in the water column. In terms of metal concentrations, this analysis is conservative in that it assumes that all leachable metals are immediately leached into the water column.

When comparing the Federal water quality criteria to the SBF concentration in the water column at 100 meters from the discharge, no exceedances of any of the Federal water quality criteria occurred for any model wells in the Gulf of Mexico using the current technology, nor under either the discharge or zero discharge options.

9.6 Compliance with State Water Quality Standards

9.6.1 *Water Based Drilling Fluids Discharges*

Tables 9-7 and 9-8 respectively summarize the state water quality standards and the minimum dilutions required for drilling fluid discharges to achieve them for Florida and Alabama. State standards for Florida and Alabama are the same for 7 of 12 common pollutants (Cd, Cr, Cu, Hg, Ni, Se, and Zn). Alabama standards for antimony and arsenic (933 and 36 mg/l, respectively) are more stringent than Florida; Florida's standards for lead, silver, and thallium are more stringent than Alabama's standards. Florida also lists three pollutants that are not listed in Alabama - aluminum, beryllium, and iron. From the tables, it is readily apparent that, based on comparisons of dispersion/dilution projections and the required dispersions/dilutions listed in these tables, complying with all Alabama standards is highly likely.

In contrast, the minimum dispersions/dilutions required to meet Florida standards are greater than the minimum available dispersions/dilutions projected by either the generalized modeling approach or the project-specific approach in certain areas. Beryllium and aluminum, respectively, require 269 and 302 dispersions/dilutions; silver requires 700 and iron requires 2,558 dispersions/dilutions to meet state standards.

Table 9-7. Comparison of Florida State Water Quality Standards to Projected Drilling Fluids Pollutant Concentrations at 100 Meters

Pollutant	Effluent Conc. [a] (mg/l)	Florida Standard (µg/l)	Minimum Dilutions Required
Aluminum	4,124	1,500	302
Antimony	2,592	4,300	>1
Arsenic	3,228	50	>1
Beryllium	0.318	0.13	269
Cadmium	0.50	9.3	6
Chromium	109	50	74
Copper	8.50	2.9	18
Iron	6,976	300	2,558
Lead	15.9	5.6	57
Mercury	0.045	0.025	32
Nickel	6.138	8.3	32
Selenium	0.50	71	1
Silver	0.318	0.05	700
Thallium	0.546	6.3	10
Zinc	91.16	86	4

[a] See Table 3-3.

Table 9-8. Comparison of Alabama Water Quality Standards to Projected Drilling Fluids Pollutant Concentrations at 100 Meters

Pollutant	Effluent Conc. [a] (mg/l)	Alabama Standards (µg/l) Marine Acute	Marine Chronic	Human Health	Minimum Dilutions Required
Antimony	2,592			933	<1
Arsenic	3,228	69	36		<1
Cadmium	0.50	43	9.3		6
Chromium	109	1,100	50		74
Copper	8.50	2.9	2.9		18
Lead	15.9	220	8.5		37
Mercury	0.045	2.1	0.025		32
Nickel	6.138	75	8.3		32
Selenium	0.50	300	71		<1
Silver	0.318	2.3			15
Thallium	0.546			133	<1
Zinc	91.16	95	86		4

[a] See Table 3-3.

Using the generalized modeling approach, the projected minimum available dispersions/dilutions required for all pollutants but iron are sufficient to comply with Florida standards at the edge of the 100-m mixing zone. Only in the case of iron, which requires 2,552 dispersions/dilutions to achieve the state standard, is there an issue with respect to compliance with state standards. The results of the project-specific analysis indicate that for worst case analyses, the dilutions available are not sufficient to comply with Florida's standards for four pollutants (Be, Al, Ag, and Fe). For modeling scenarios other than those for which the minimum dispersion/dilution is projected, again, only iron remains a potential issue.

Several factors mitigate the potential water quality non-compliance projected above. First, these non-compliance issues occur for worst case conditions, which requires a set of assumptions that are not likely to be encountered except rarely. Second, for iron, which is the pollutant with the largest exceedances, a surrogate leach factor is used (11%) based on the most mobile trace metal (Cd) because no leach data are available for iron. Related to this factor, iron is expected to have a low leach factor; it has low solubility in seawater due to its ability to form precipitates from several anions that are in abundance in seawater. Third, compliance with state standards is being assessed at the edge of the 100-m mixing zone. While appropriate for discharges in state waters, this project is located some 16 miles from the state waters of Florida. It is expected that no state water quality standards will be violated within the territorial seas of the State of Florida.

In Mississippi, the projected maximum drilling fluid discharge rate would not cause any exceedances of the state water quality standards (Table 9- 8).

Table 9-9. Comparison of Mississippi Water Quality Standards to Projected Drilling Fluid Pollutant Concentrations at 100 meters (in µg/l)

Pollutant	Effluent Concentrations[a]	Extraction Factors[b]	Concentration at 100 meters			State Standard[e]		
			15 m water depth[c]	40m water depth[c]	70m water depth[c]	Marine Acute	Marine Chronic	Human Health
Arsenic	3,228	0.51%	0.029	0.021	0.010	69	36	0.14
Cadmium	500	11 %	0.098	0.070	0.032	43	9.3	168
Chromium VI	109,116	3.4%	6.60	4.714	2.156	1,100	50	3,365
Copper	8,502	0.63%	0.095	0.068	0.031	2.9	2.9	1,000
Lead	15,958	2.0%	0.568	0.406	0.185	140	5.6	
Mercury	45	1.8 %	0.001	0.001	0.0005			0.153
Nickel	6,138	4.3 %	0.470	0.335	0.153	75	8.3	4,584
Selenium	500	100 %	0.890	0.635	0.290	300	71	
Silver	318	100%	0.566	0.404	0.185	2.3		
Zinc	91,157	0.41 %	0.665	0.475	0.217	95	86	5,000

[a] See Table 3-3.

[b] The extraction factors represent the trace metal leach percentages from barite and drilling fluids.

[c] The average OOC Model run dilution results were used for each of the water depths (See Table 4-7). For 15m, dilution = 562, 40m = 787, and 70m = 1,721.

[d] See Table 9-5.

Source: Avanti, 1993.

10. EVALUATION OF THE OCEAN DISCHARGE CRITERIA

This chapter discusses the ten factors that the Regional Administrator must consider in the analysis of compliance of this permit with Section 403 of the Clean Water Act, how conditions and limitations included in the final general permit for the Eastern Portion of the Outer Continental Shelf (OCS) ensure compliance with these ocean discharge criteria, and the determination, under Section 403, that this NPDES permit will not cause unreasonable degradation of the marine environment with all permit limitations, conditions, and monitoring requirements in effect.

10.1 Introduction

The ten factors for determining unreasonable degradation were presented in Chapter 1. The chapters that followed discussed the available information concerning the issues to be evaluated. This chapter presents a summary of these issues, the conditions and limitations that are included by the Region in the final NPDES permit that ensure compliance with Section 403, and a discussion of the determination that no unreasonable degradation of the marine environment will result from discharges authorized by this permit.

10.2 Evaluation of the Ten Ocean Discharge Criteria

Factor 1 - Quantities, Composition, and Potential for Bioaccumulation or Persistence of Pollutants

The quantities and composition of the discharged material was presented in Chapter 3 and the potential for bioaccumulation or persistence was addressed in Chapter 5. For discharges other than drilling fluids, the volume and constituents of the discharged material are not considered sufficient to pose a potential problem through bioaccumulation or persistence. However, to confirm the Agency's decision and as a precaution against any changes in operational practices that could change the Agency's assumptions, the discharged volumes of deck drainage, well treatment, completion, and workover fluids, and sanitary waste must be recorded monthly and reported once each year on the compliance monitoring report.

EPA is limiting the potential for bioaccumulation or persistence of discharge-related pollutants by placing specific limitations on metals contained in the barite added to water-based drilling fluids. The limits on cadmium and mercury will ensure that not only these two metals but an entire suite of other trace metals found in barite will be reduced in concentration, and their potential for bioaccumulation and persistence thereby decreased. Discharge limitations in the proposed permit are as follows:

Water Based Drilling Fluids	Statutory Basis
Discharge limited to a rate of 1,000 bbl/hour	BPJ
Report volume discharged (bbl/month)	CWA §308

Water Based Drilling Fluids	**Statutory Basis**
Whole effluent toxicity (WET) must meet both a daily minimum and a monthly average minimum limitation of 30,000 ppm (3.0% by volume), using a volumetric mud-to-water ratio of 1 to 9 [2]	BAT
No discharge of free oil as determined by the static sheen test	BCT/BAT
No discharge of fluids to which barite has been added if the barite contains mercury in excess of 1.0 mg/kg (dry weight) or cadmium in excess of 3.0 mg/kg (dry weight) [3]	BAT
No discharge within 100 meters of designated dredged material ocean disposal sites	BPJ
Record chemical usage inventory for each well	CWA §308

Synthetic Based Drilling Fluids	**Statutory Basis**
No discharge of OBM or SBM	BCT/BAT

Water Based Drill Cuttings	**Statutory Basis**
No discharge when using OBM or oil contaminated fluids	BCT/BAT
Report volume discharged (bbl/month)	CWA §308
WET must meet both a daily minimum and a monthly average minimum limitation of 30,000 ppm (3.0% by volume), using a volumetric mud-to-water ratio of 1 to 9	BAT
No discharge of free oil as determined by the static sheen test	BCT/BAT
No discharge of oil based drilling fluids	BCT/BAT
No discharge of fluids to which barite has been added if the barite contains mercury in excess of 1.0 mg/kg (dry weight) or cadmium in excess of 3.0 mg/kg (dry weight)	BAT
No discharge within 100 meters of designated dredged material ocean disposal sites	BPJ

Synthetic Based Drill Cuttings	**Statutory Basis**
No discharge if formation oil is detected in the drilling fluid as determined by GC/MS	BAT
Sediment toxicity test ratio shall not exceed 1.0 [4, 5]	BAT
Amount of SBM retained on cuttings must not exceed 6.9g	BAT

---

[2] Methodology is specified at 40 CFR Part 435, Subpart A, Appendix 2, Drilling Fluid Toxicity Test (EPA Method 1619).

[3] Methodologies are EPA Methods 200.7, 200.8, or Method 3050B followed by 6010B for cadmium and EPA 245.7 or 7471 A for mercury.

[4] Methodology is ASTM method no. E1367-92.

[5] Methodology is ASTM E1367-92 and equation in permit.

SBM/100g wet cuttings for C_{16}-C_{18} IOs or 9.4g SBM/100g wet cuttings for C_{12}-C_{14} or C_8 esters;[6] a default value of 14% retained fluid is used for compliance with discharges at the seafloor	
Polynuclear Aromatic Hydrocarbons (PAH) mass ratio must not exceed 1×10^{-5} [7]	BAT
Biodegradation rate ratio of the stock base fluid shall not exceed 1.0 [8]	BAT

Well Treatment, Completion and Workover Fluids	**Statutory Basis**
Report frequency/flow (bbl/month)	CWA §308
No discharge of free oil as determined by the static sheen test	BCT/BAT
Oil and grease must meet maximum limitation of 42.0 mg/l and monthly average limitation of 29.0 mg/l	BAT
No discharge of priority pollutants except in trace amounts	BAT

Sanitary Wastes	**Statutory Basis**
No discharge of floating solids	BCT
Manned by 10 or more: Total residual chlorine must be maintained at 1.0 mg/l at all times	BCT/BAT

Domestic Wastes	**Statutory Basis**
No discharge of floating solids or foam	BCT/BAT
No discharge except comminuted food waste (<25mm) may be discharged 12 nautical miles or more from land	BCT/MARPOL

Deck Drainage	**Statutory Basis**
Report frequency/flow	CWA §308
No discharge of free oil as determined by the visual sheen test	BCT/BAT

Miscellaneous Discharges	**Statutory Basis**
No discharge of free oil as determined by the visual sheen test	BCT/BAT
Toxicity limitation for Subsea Wellhead Preservation Fluids; Subsea Production Control Fluids; Umbilical Steel Tube Storage Fluids; Leak Tracer Fluids; and Riser Tensioning Fluids is a NOEC of no less than 50 mg/l	BPJ

---

[6] Methodology is the API Retort method specified at 40 CFR §435, subpart A of Appendix 7.

[7] Methodology is EPA Method 1654A and equation in permit.

[8] Methodology is ISO Method 11734:1995 and equation in permit.

Miscellaneous Discharges of Freshwater and Seawater to Which Treatment Chemicals Have Been Added	Statutory Basis
Report average flow (bbl/day)	CWA §308
No discharge of free oil as determined by the visual sheen test	BCT/BAT
Concentration of chemicals must meet the most stringent of: maximum concentration of product labeling, manufacturer's recommended concentration, or 500 mg/l	BPJ
Toxicity limitation is that NOEC must be equal to or greater than the critical dilution concentration as specified in the permit based on discharge rate, pipe diameter, and water depth	BPJ

The EPA believes that the limits imposed on the operational discharges authorized under the proposed permit are sufficient that no significant adverse impacts are likely to occur.

Factor 2 - Potential for Biological, Physical, or Chemical Transport

Chapter 4 of this document is based on the literature available concerning the transport of water based and synthetic based drilling fluids in the marine environment. Under a general permit, it is not possible to determine the potential for physical transport at each facility due to varying currents, discharge rates and configurations, and fluctuating effluent characteristics. Therefore, for drilling fluids, generalizations and assumptions were made to project scenarios to describe the industry and the coverage area. A protective modeling approach, which was appropriate to the area of coverage of this permit, was used to determine potential physical transport processes and to regulate discharges of drilling fluids based on the predicted dilutions and dispersions.

Drilling fluids are regulated based on the modeling predictions about how the waste streams will behave when introduced into the marine environment. Discharge rate restrictions for drilling fluids are the result of the predicted transport of the constituents of the effluent.

Biological and chemical transport processes are not as well understood for drilling fluid discharges. The literature available is inconclusive about these processes and computer models do not account for them. Bioturbation should serve to mix sediments vertically, thereby enhancing the dispersion of muds and cuttings. The physical transport of these waste streams is considered to be the most significant source for dispersion of the wastes and monitoring and regulation is based on the results of those investigations.

Factor 3 - Composition and Vulnerability of Biological Communities

The third factor used to determine no unreasonable degradation of the marine environment is an assessment of the presence of unique species or communities of species, endangered species, or species critical to the structure or function of the ecosystem. Chapter 6 describes the biological community of the eastern Gulf including the presence of endangered species and factors that make these communities or species vulnerable to the permitted activities.

Drilling fluids (and the drilling fluids that adhere to cuttings) have been shown to cause smothering effects when discharged to shallow waters. The permit covers areas in deep waters of the Gulf of Mexico and the permit prohibits the discharge of neat synthetic based fluids and restricts the water based fluids discharge rate to 1,000 bbl/hr for all areas. The potential impacts due to toxic effects from drilling fluids have been reduced by placing restrictions on total toxicity. This toxicity limitation ensures that the whole effluent will not be toxic to pelagic or benthic species once mixed with the receiving water.

In Chapter 6, the biological community and its health are described according to available literature. The permit coverage area may include habitats that are sensitive to the discharges that may occur and special conditions have been implemented through the permit. MMS has special stipulations for chemosynthetic communities in the Gulf and when an operator proposes to commence drilling on a lease containing these communities, MMS may require mitigations to protect them from impact.

Factor 4 - Importance of the Receiving Water to the Surrounding Biological Community

The importance of the receiving waters to the species and communities of the eastern Gulf is discussed in Chapter 6 in conjunction with the discussion of the species and biological communities. The receiving water is considered when determining the discharge rate restrictions. The dispersion modeling considered concentrations of pollutants that may have impacts on aquatic life (through evaluation of marine water quality criteria - see Factor 10, below) and the toxicity limitations on both drilling fluids ensure that levels of the effluent is below levels that could have impacts on local biological communities. By protecting local biological communities, EPA believes that adverse impacts on species migrating to coastal or inland waters for spawning or breeding will also be protected.

In addition, free oil, toxicity, oil content, oil and grease levels, solids, and chlorine concentrations are monitored in selected waste streams in order to ensure adequate water quality. Other requirements that apply to all discharges are no discharge of visible foam and minimal use of dispersants, surfactants, and detergents.

Factor 5 - Existence of Special Aquatic Sites

No designated Special Aquatic Sites are known to be present within the lease blocks under consideration or adjacent lease blocks.

Factor 6 - Potential Impacts on Human Health

Chapter 9 details the Federal and state human health criteria and standards for pollutants in drilling fluids. These criteria and standards are for marine waters based on based on fish consumption. These analyses compare projected pollutant concentrations at 100 m with these criteria and standards.

The permit prohibits the discharge of free oil, oil-based muds, synthetic based muds and muds with diesel oil added. These prohibitions are based on the potential effects of the organic pollutants in these discharges to human and aquatic life. In addition, the limitations that require low levels of cadmium and mercury in the barite added to drilling fluids also effectively lower the concentrations of other heavy metals found in barite.

Factor 7 - Recreational or Commercial Fisheries

The commercial and recreational fisheries businesses in Alabama, Florida, and Mississippi are assessed in Chapter 7. The conditions and limitations in the permit were determined to protect water quality and preserve the health of these fisheries. These permit conditions and limitations include no discharge of free oil, no discharge of oil-based or synthetic based muds, no discharge of diesel oil, no discharge of produced sand, and no discharge of produced water, discharge rate limitations around live-bottom areas, and limitations on the whole effluent toxicity of water based and synthetic based drilling fluids.

Factor 8 - Coastal Zone Management Plans

Chapter 8 provides an evaluation of the coastal zone management plans of Alabama, Florida, and Mississippi. The states will have an opportunity to review the proposed permit to determine consistency with their plans. As detailed in Chapter 8, the permit meets the requirements of the plans implemented by the states and is considered by the Region to be in compliance with those plans.

Factor 9 - Other Factors Relating to Effects of the Discharge

The BAT (Best Available Technology Economically Achievable) and BCT (Best Conventional Pollutant Control Technology) effluent limitation guidelines for the Offshore Subcategory were promulgated in 1993. BAT conditions within the permit include: cadmium and mercury limitations in barite; toxicity limitations in drilling muds; no free oil discharge from drilling fluids, well treatment, completion, and workover (TWC) fluids, deck drainage, well test fluids or minor wastes; no oil-based drilling fluids discharge; produced water and TWC fluid oil and grease limitations; no discharge of produced sand; residual chlorine limitations in sanitary wastes; and no floating solids in either domestic or sanitary wastes. Final Effluent Limitation Guidelines and Standards for Synthetic-based Drilling Fluids (promulgated in 2001) prohibit the discharge of neat synthetic based drilling fluids and limit the amount retained on drill cuttings discharges.

Factor 10 - Marine Water Quality Criteria

The Federal and state marine water quality criteria and standards for pollutants found in drilling fluids are assessed in Chapter 9. The potential effects due to organic pollutants in drilling fluids have been eliminated with the prohibition of the use of oil-based muds and diesel oil and the discharge of neat synthetic based muds. The heavy metals that exist in drilling fluids have been reduced in concentration by requiring the use of clean barite measured by the concentration of cadmium and mercury.

10.3 Conclusions

After consideration of the ten factors discussed above and elsewhere in this document, it is determined that no unreasonable degradation of the marine environment will result from the discharges authorized under this permit, with all permit limitations, conditions, and monitoring requirements in effect. After reviewing the available data, the Region has included a variety of technology-based, water quality-based, and Section 403-based requirements in the final permit to ensure compliance with Section 403 of the Clean Water Act, under a no reasonable degradation determination as well as other relevant sections of the Act.

11. REFERENCES

Alabama Bureau of Marine Resources (BMR) and Dept. of Wildlife Conservation (DWC). 1988. Mississippi Coastal Program. Biloxi, MS. October, 1988.

Alabama Department of Economic and Community Affairs. 1999. Alabama Coastal Area Management Plan, ACAMP III. Coastal Programs Office, currently in the Department of Conservation and Natural Resources. January 1999. 103 pp.

Anderson, J.W. 1982. The transport of petroleum hydrocarbons from sediments to benthos and the potential effects. Pages 165-179 In: G.F. Mayer (ed.), Ecological Stress and the New York Bight: Science and Management. Estuarine Research Federation, Columbia, SC.

American Petroleum Institute. 2015. Offshore well control and well stimulation technology. Briefing Paper. DM2015-027. 2pp.

Andreasen, J.K. and R.W. Spears. 1983. Toxicity of Texan petroleum well brine to the sheepshead minnow (*Cyprinodon variegatus*) a common estuarine fish. *Bull. Environ. Contam. Toxicol.* 30:277-283.

Armstrong, H.W., K. Fucik, J.W. Anderson, and J.M. Neff. 1979. Effects of oil field brine effluent on sediments and benthic organisms in Trinity Bay, TX. *Mar. Environ. Res.* 2:55-69.

Armstrong, R.S. 1981. Transport and dispersion of potential contaminants. p. 403-419. In: B. Middleditch (ed.). Environmental Effects of Offshore Oil Production. The Buccaneer Gas and Oil Field Study. Plenum Press, NY.

Atema, J., E.B. Karnofsky, S. Olszko-Szuts, and B. Bryant. 1982. Sublethal effects of number 2 fuel oil on lobster behavior and chemoreception. Report to U.S. EPA, Environmental Research Lab, Gulf Breeze, FL. EPA-600/S3-82-013.

Atlantic Richfield Co. (ARCO). 1978. Drilling Fluid Dispersion and Biological Effects Study for the Lower Cook Inlet C.O.S.T. Well. Prepared by Dames and More. 309 pp. In: Petrazzuolo, G. 1983. Environmental Assessment of Drilling Fluids and Cuttings Discharge on the OCS. Draft Final Report. U.S. EPA, Office of Water Enforcement and Permits, Washington, DC.

Auble, G.T., A.K. Andrews, R.A. Ellison, D.B. Hamilton, R.A. Johnson, J.E. Roelle, and D.R. Marmorek. 1982. Results of an Adaptive Environmental Assessment Modeling Workshop Concerning Potential Impacts of Drilling Muds and Cuttings on the Marine Environment. Prepared for U.S. FWS, Fort Collins, CO. 64 pp.

Augenfield, J.M., J.W. Anderson, R.G. Riley, and B.L. Thomas. 1982. The fate of polyaromatic hydrocarbons in an intertidal sediment exposure system: bioavailability to *Macoma inquinata* (Molluska: Pelecypoda) and *Abarenicola pacifica* (Annelida: Polychaetea). *Mar. Environ. Res.* 7:31-50.

Austin, H. 1970. Florida Middle Ground. *Int. Poll. Bull.* 2(2):71-72.

Avanti Corporation. 1992. Characterization of Produced Water Discharges to Coastal Waters of Louisiana and Texas. Draft prepared for U.S. EPA Region 6, Water Management Division.

Avanti Corporation. 1993. Biological Assessment for the NPDES General Permit for Oil and Gas Exploration, Development, and Production Activities on the Eastern Gulf of Mexico OCS. Submitted to U.S. EPA Region 4, Water Management Division.

Avanti Corporation. 1993. Environmental Analysis of the Final Effluent Guidelines, Offshore Subcategory, Oil and Gas Industry, Volume I- Modeled Impacts. Prepared for U.S. EPA Office of Science and Technology, Standards and Applied Science Division, January 14, 1993.

Ayers, R.C., Jr. 1981. Fate and effects of drilling discharges in the marine environment. Proposed North Atlantic OCS oil and gas lease sale 52. Statement delivered at public hearing Boston, MA. Nov. 19, 1981. BLM, U.S. DOI.

Ayers, R.C., Jr., T.C. Sauer, Jr., D.O. Stuebner, and R.P. Meek. 1980a. An environmental study to assess the effect of drilling fluids on water quality parameters during high rate, high volume discharges to the ocean. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, September 1980. API, Washington, DC. pp. 351-381.

Ayers, R.C., Jr., T.C. Sauer, Jr., R.P. Meek, and G. Bowers. 1980b. An environmental study to assess the impact of drilling discharges in the Mid-Atlantic. I. Quantity and Fate of Discharges. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, September 1980. API, Washington, DC. pp. 382-418.

Backus, R.H., J.E. Craddock, R.L. Haedrick and B.H. Robinson. 1977. Atlantic mesopelagic zoogeography. In: Fishes of the western north Atlantic, Part 7. Mem. Sears Found. Mar. Res. 1:266-287.

Baggett, H.D. 1982. Schaus' Swallowtail. In: P. Pritchard, Ed., Rare and Endangered Biota of Florida, Volume Six, Invertebrates. University Presses of Florida. Gainesville, FL.

Bielsa, L.M., W.H. Murdich and R.F. Labisky. 1983. Species Profiles: Life Histories and Environmental Requirements of Coastal Fishes and Invertebrates (South Florida)--Pink Shrimp. Prepared for U.S. Army Corps of Engineers and U.S. FWS. FWS/OBS-82/11.17, TR EL-82-4.

BOEM. 2012. Outer Continental Shelf Oil and Gas Leasing Program: 2012-2017. Final Programmatic Environmental Impact Statement. U.S. Department of the Interior. Bureau of Ocean Energy Management. OCS EIS/EA BOEM 2012-030.

BOEM. 2013. Eastern Planning Area Lease Sales 225 and 226. Final Environmental Impact Statement. Volume I. Oil and Gas Lease Sales: 2014 and 2016. U.S. Department of the Interior. Bureau of Ocean Energy Management. Gulf of Mexico OCS Region. Gulf of Mexico OCS. OCS EIS/EA. BOEM 2013-200

Boesch, D.F. and N.N. Rabalais, eds. 1985. The long-term effects of offshore oil and gas development: an assessment and a research strategy. NOAA, National Marine Pollution Program Office. 738 pp.

Boesch, D.F. and N.N. Rabalais. 1989a. Produced waters in sensitive coastal habitats: an analysis of impacts, central coastal Gulf of Mexico. Prepared under MMS Contract 14-12-001-30325. New Orleans, LA: U.S. Dept. of the Interior, MMS, Gulf of Mexico OCS Region. OCS Study/MMS 89-0031. 157 pp.

Boesch, D.F. and N.N. Rabalais. 1989b. Environmental Impact of Produced Water Discharges in Coastal Louisiana. Final Rept. to Louisiana Div. of Mid-Continent Oil and Gas Assoc., Louisiana Universities Marine Consortium, Chauvin, Louisiana.

Bookhout, C.G., R. Monroe, R. Forward, and J.D. Costlow, Jr. 1984. Effects of soluble fractions of drilling fluids on development of crabs, *Rhithropanopeus harrisii* and *Callinectes sapidus*. *Water, Air, Soil Pollut.* 21:183-197.

Boothe, P.N. and B.J. Presley. 1985. Distribution and Behavoir of Drilling Fluids and Cuttings Around Gulf of Mexico Drilling Sites. Final Report to API. Texas A&M University.

Brandsma, M.G., L.R. Davis, R.C. Ayers Jr., T.C. Sauer Jr. 1980. A Computer Model to Predict the Short-term Fate of Drilling Discharges in the Marine Environment. In: Symposium on research on the environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Brandsma Engineering. 1991. Simulations of Discharge Scenarios on the Alaskan Outer Continental Shelf. Prepared for *Avanti* Corporation for submission to U.S. EPA, Region 10, Water Management Division. 43 pp.

Brandsma, M.G. and J.P. Smith. 1996. Dispersion modeling perspectives on the environmental fate of produced water discharges. In: M. Reed and S. Johses, Eds., Produced Water 2: Environmental Issues and Mitigation Technologies. Plenum Press, New York (in press).

Brannon, A.C. and K.R. Rao. 1979. Barium, Strontium, and Calcium Levels in the Exoskeleton, Hepatopancreas and Abdominal Muscle of the Grass Shrimp *Palaemontes pugio*: Relation to Molting and Exposure to Barite. Comp. Biochem. and Phys., Vol. 63A, pp. 261-274.

Brendenhaug, J., S. Johnson, K.H. Bryne, A.L Gjøse, T.H. Eide, and E. Aamot. 1992. Toxicity Testing and Chemical Characterization of Produced Water - A Preliminary Study. In: J.P. Ray and F.R. Engelhardt (Eds.) Produced Water Technological/Environmental Issues and Solutions. PennWell Books, New York, NY. pp. 245-256.

Breteler, R.J., P.D. Boehm, J.M. Neff, and A.G. Requejo. 1983. Acute toxicity of drilling muds containing hydrocarbon additives and their fate and partitioning between liquid, suspended and solid phases. Draft final report to API, Washington, DC. 93 pp.

Brooks, J.M., E.L. Estes, D.A. Wisenburg, C.R. Schwab, and H.A. Abdel-Reheim. 1980. Investigations of Surficial Sediments, Suspended Particulates and Volatile Hydrocarbons at Buccaneer Gas and Oil Field. In: Volume I - Environmental Assessment of Buccaneer Gas and

Oil Field in the Northwestern Gulf of Mexico, 1975-1980. Edited by W.B. Jackson and E.P. Wilkins. NOAA Technical Memorandum NMFS-SEFC-47, Washington, DC.

Brooks, J.M., C. Fisher, H. Roberts, B. Bernard, I. McDonald, R. Carney, S. Joye, E. Cordes, G. Wolff, E. Goehring. 2014. Investigations of chemosynthetic communities on the lower continental slope of the Gulf of Mexico: Volume I: Final report. U.S. Dept. of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study BOEM 2014-650. 560 pp.

Bryan, G.W. 1983. The biological availability and effects of heavy metals in marine deposits. In: Proc. Ocean Dumping Symposium. Wiley Interscience, New York.

Burk, C.J. and J.A. Veil. 1995. Potential Environmental Benefits from Regulatory Consideration of Synthetic Drilling Muds. Argonne National Laboratory Technical Memorandum ANL/EAD/TM-43, February 1995.

Burns and Roe Industrial Services Corporation. 1983. Data Report for EPA Priority Pollutant Sampling Program Offshore Oil and Gas Program. Prepared for U.S. EPA Effluent Guidelines Division. Evaluation of Analytical Data; Revision February 1983, Vols. I and II.

Candler, J.E., A.J.J. Leuterman, and J.H. Rushing. 1993. “Synthetic-Based Mud Systems Offer Environmental Benefits Over Traditional Mud Systems,” SPE 25993 presented at SPE/EPA Exploration & Production Environmental Conference held in San Antonio, TX, March 7-10, 1993.

Candler, J., R. Herbert and A.J.J. Leuterman. 1997. Effectiveness of a 10-day ASTM Amphipod Sediment Test to Screen Drilling Mud Base Fluids for Benthic Toxicity. SPE 37890 Society of Petroleum Engineers Inc. March 1997. 19 pp.

Cantelmo, F.R., M.E. Tagatz, and K.R. Rao. 1979. Effect of Barite on Meiofauna in a Flow-Through Experimental System. *Marine Environmental Research*, pp. 301-309.

Capuzzo, J.M. and J.G.S. Derby. 1982. Drilling fluid effects to developmental stages of the American lobster. Report to U.S. EPA, Environmental Research Lab., Gulf Breeze, FL, EPA-600/S4-82-039.

Carls, M.G. and S.D. Rice. 1980. Toxicity of oil well drilling fluids to Alaskan larval shrimp and crabs. Research Unit 72. Final Rept. Proj. No. R7120822, Outer Continental Shelf Environmental Assessment Program. U.S. Dept. of Interior, BLM, 29 pp.

Conklin, P.J., D.G. Doughtie and K.R. Rao. 1980. Effects of barite and used drilling fluids on crustaceans, with particular reference to the grass shrimp, *Palaemonetes pugio*. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC. pp. 723-738.

Conklin, P.J., D. Drysdale, D.G. Doughtie, K.R. Rao, J.P. Kakareka, T.R. Gilbert and R.F. Shokes. 1983. Comparative toxicity of drilling fluids: role of chromium and petroleum hydrocarbons. *Marine Environmental Research*. 10:105-125.

Continental Shelf Associates (CSA). 1983. Monitoring study of exploratory drilling activity at High Island Block A-384. Final Report to Conoco Oil Company.

Corliss, J.B., J. Dymond, L. Gordon, J.M. Edmund, R.P. von Herzen, R.D. Ballard, K. Green, D. Williams, A. Bainbridge, K. Crane, and T.H. Van Adel. 1979. Submarine thermal springs on the Galapagos Rift. Science. 203: 1073-1083.

CSA. 1986. Southwest Florida Shelf Regional Biological Communities Survey, Marine Habitat Atlas-Year 3, Vol. I Maps. OCS Study/MMS 86-0072.

CSA. 1993. Measurement of Naturally Occurring Radioactive Materials at Two Offshore Production Platforms in the Northern Gulf of Mexico. Final Report to the American Petroleum Institute, Washington, DC.

CSA. 2007. Characterization of northern Gulf of Mexico deepwater hard bottom communities with emphasis on *Lophelia* coral. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study MMS 2007-044. 169 pp. + app.

Crawford, R.B. and J.D. Gates. 1981. Effects of drilling fluids on the development of a teleost and an echinoderm. *Bull. Environ. Contam. Toxicol*. 26:207-212.

Crippen, R.W., S.L. Hood and G. Green. 1980. Metal levels in sediment and benthos resulting from a drilling fluid discharge into the Beaufort Sea. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC. pp. 636-669.

Ditton, R.B. and A.R. Graefe. 1978. Recreational fishing use of artificial reefs on the Texas coast. College Station, TX: Texas A & M University, Department of Recreation and Parks. 155 pp.

Dodge, R.E. 1982. Effects of Drilling Muds on the Reef-Building Coral *Montastrea annularis*. *Marine Biology*. 71:141-147.

DOE. 1997. Levels of Naturally Occurring Radioactive Materials, Metals, and Organic compounds in Produced Water, Produced Sand, Receiving Water, Ambient water, Sediment, and Biota on the Texas/Louisiana Shelf. Draft Report to US Dept. of Energy, Barlesville, OK.

Doneker, R.L. and G.H. Jirka. 1990. Expert System for Hydrodynamic Mixing Zone Analysis of Conventional and Toxic Submerged Single Port Discharges (CORMIX1). Prepared by Cornell University for U.S. EPA, Environmental Research Laboratory, Athens, GA. EPA/600/3-90/012.

Doneker, R.L. and G.H. Jirka. 1993. Cornell Mixing Zone Expert System (CORMIX v. 2.10). Prepared by Cornell University for U.S. EPA, Environmental Research Laboratory, Athens, GA. May 1993.

Drake, D.E. 1976. Suspended sediment transport and mud deposition on continental shelves. In: Stanley, D.J. and D.J.P. Swift (eds). Marine Sediment Transport and Environmental Management. John Wiley & Sons, New York, NY, p. 127-158. In: Houghton, J.P., K.R. Critchlow, D.C. Lees, R.D. Czlapinski. 1981. Fate and Effects of Drilling Fluids and Cuttings Discharges in Lower Cook Inlet, Alaska, and on Georges Bank - Final Report. NOAA, and BLM, Washington, DC.

Dribus, John R.; Jackson, Martin P.A.; Kapoor, Jerry and Smith, Martiris F. 2008. The prize beneath the salt. Oilfield Review. 14pp.

Dugas, R., V. Guillory and M. Fischer. 1979. Oil rigs and offshore fishing in Louisiana. *Fisheries* 4(6):2-10.

Duke, T.W. and P.R. Parrish. 1984. Results of the Drilling Fluids Program Sponsored by the Gulf Breeze Research Laboratory, 1976-1984, and their Application to Hazard Assessment. U.S. EPA, Environmental Research Laboratory, Gulf Breeze, FL. EPA/600/4-84-055.

Dutton, Shirley P. and. Loucks, Robert G. 2014. Reservoir quality and porosity-permeability trends in onshore Wilcox sandstones, Texas and Louisiana Gulf Coast: Application to deep Wilcox plays, offshore Gulf of Mexico. GCAGS Journal. Vol 3. 33pp.

Ecomar, Inc. 1978. Tanner Bank fluids and cuttings study. Conducted for Shell Oil Company, January through March, 1977. Ecomar, Inc. Goleta, CA. 95 pp. In: Houghton, J.P., K.R. Critchlow, D.C. Lees and R.D. Czlapinski. 1981. Fate and Effects of Drilling Fluids and Cuttings Discharges in Lower Cook Inlet, Alaska, and on Georges Bank - Final Report. NOAA and BLM, Washington, DC.

EG&G. 1982. A study of environmental effects of exploratory drilling on the Mid-Atlantic OCS - Final Report of the Block 684 Monitoring Program. EG&G, Environmental Consultants, Waltham, MA. Prepared for OOC, Environmental Subcommittee, New Orleans, LA.

Eleuterius, C.K., and S.L. Beaugez. 1979. Mississippi Sound, a hydrographic and climatic atlas. Mississippi-Alabama Sea Grant Consortium MASGP-79-009. Gulf Coast Research Lab, Ocean Springs, MS. 136pp.

El-Sayed, S.Z. 1972. Primary productivity and standing crop of phytoplankton in the Gulf of Mexico. In: El-Sayed, S.Z. et al., eds. Chemistry, primary productivity and benthic algae of the Gulf of Mexico. Serial atlas of the marine environ., Folio 22. New York, NY: American Geographic Society. pp. 8-13.

Elliott, E.G., Ettinger, A.S, Brian P. Leaderer, B.P., Michael B. Bracken, M.B., and Nicole C. Deziel, N.C. 2016. A systematic evaluation of chemicals in hydraulic-fracturing fluids and wastewater for reproductive and developmental toxicity. Journal of Exposure Science and Environmental Epidemiology (2016), 1–10.

ERT (Environment & Resource Technology Ltd). 1994a. Bioaccumulation potential of ISO-TEQ base fluid. ERT 94/209. Report to Baker Hughes INTEQ, Houston, TX.

ERT (Environmental & Resource Technology Ltd.). 1994b. Bioconcentration assessment report. Assessment of the bioconcentration factor (BCF) of ISO-TEQ base fluid in the blue mussel *Milts elude*s. ERT 94/061. Report to Baker Hughes INTEQ, Houston, TX.

Flint, R.W. and D. Kamykowski. 1984. Benthic nutrient regeneration in South Texas coastal water. *Estuar. Coast. Shelf. Sci.* 18(2):221-230.

Flint, R.W. and N.N. Rabalais. 1981. Environmental Studies of a Marine Ecosystem: South Texas Outer Continental Shelf. Univ. Texas Press, Austin. 272 pp.

Florida Department of Community Affairs (DCA). 1997. Florida Coastal Management Program, 1997 Revision, Florida Coastal Program Guide and Reference Book. Tallahassee, FL.

Fowler, S.W. 1982. Biological Transfer and Transport Processes. In: Pollutant Transfer and Transport in the Sea, G. Kullenberg, ed. CRC Press, Inc., Boca Raton, FL.

Friedheim, J.E., G.J. Hans, A. Park and C.R. Ray. 1991. An environmentally superior replacement for mineral-oil drilling fluids. SPE 23062. Pages 299-311 In: The Offshore Europe Conference. Aberdeen, 3-6 September 1991. Society of Petroleum Engineers, Inc. Richardson, TX.

Gallaway, B.J. 1980. Pelagic, reef and demersal fishes and macrocrustaceans/ biofouling communities. In: Jackson, W.B. and E.O. Wilkens (eds). Environmental assessment of Buccaneer gas and oil field in the northwestern Gulf of Mexico, 1975-1978. NOAA technical memorandum NMFS-SEFC-48. Galveston, TX: U.S. DOC, NMFS. 82 pp.

Gallaway, B.J. 1988. Northern Gulf of Mexico continental slope study, Final report, Year 4. Volume II, Synthesis report. Prepared for the U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Regional Office, New Orleans, Louisiana. OCS Study MMS 88-053.

Gartner, J.V., T.L. Hopkins, R.C. Baird, and D.M. Milliken. 1987. The lanternfishes of the eastern Gulf of Mexico. Fish. Bull. 85: 81-98.

Gerber, R.P., E.S. Gilfillan, B.T. Page, D.S. Page, and J.B. Hotham. 1980. Short- and long-term effects of used drilling fluids on marine organisms. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC. pp. 882-911.

Gerber, R.P., E.S. Gilfillan, J.R. Hotham, L.J. Galletto, and S.A. Hanson. 1981. Further studies on the short- and long-term effect of used drilling fluids on marine organisms. Unpublished. Final Report, Year II to API, Washington, DC., 30 pp.

Gettleson, D.A. and C.B. Laird. 1980. Benthic barium in the vicinity of six drill sites in the Gulf of Mexico. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Gilbert, T.R. 1981. A study of the impact of discharged drilling fluids on the Georges Bank environment. New England Aquarium, H.E. Edgerton Research Laboratory. Progress Report No. 2 to U.S. EPA, Gulf Breeze, FL, 98 pp.

Gilbert, T.R. 1982. A survey of the toxicities and chemical compositions of used drilling muds. Annual Report to U.S. Environmental Research Laboratory, Gulf Breeze, FL from Edgerton Research Lab., New England Aquarium, Boston, MA, 31 pp.

Ground Water Protection Council & Interstate Oil and Gas Compact Commission. 2016. Hydraulic Fracturing: The Process. https://fracfocus.org/hydraulic-fracturing-how-it-works/hydraulic-fracturing-process.

Growcock, F.B., S.L. Andrews, and T.P. Frederick. 1994. Physicochemical properties of synthetic drilling fluids. IADC/SPE 27450. Pages 181-190 In: 1994 IADC/SPE Drilling Conference. Dallas, TX, 15-18 February 1994. International Association of Drilling Contractors/Society of Petroleum Engineers, Inc. (IADC/SPE). Richardson, TX.

Hall, C.A.S., R.G. Howarth, B, Moore, III, ad C.J. Vorosmarty. 1978. Environmental Impacts of Industrial Energy Systems in the Coastal Zone. Annual Review of Energy. 3:395-475.

Higashi, R.M., G.N. Cherr, C.A. Bergens, and T.W.M. Fan. 1992. An Approach to Toxicant Isolation from a Produced Water Source in the Santa Barbara Channel. In: J.P. Ray and F.R. Engelhardt (Eds.) Produced Water Technological/Environmental Issues and Solutions. PennWell Books, New York, NY. pp. 223-233.

Hoese, H.D. and R.H. Moore. 1977. Fishes of the Gulf of Mexico, Texas, Louisiana, and Adjacent Waters. Texas A7M University Press. 327 pp.

Holtzman, R.B. 1969. Concentrations of the naturally occurring radionuclides ^{226}Ra, ^{210}Po in aquatic fauna. In: Proc. 2nd Nat. Symp. Radioecology, U.S. Atomic Energy Commission, Conf. 670503. pp. 535-546.

Hopkins, T.S. and R.C. Baird. 1985. Feeding ecology of four hatchetfishes (Sternoptychidae) in the eastern Gulf of Mexico. Bull. Mar. Sci. 36: 260-277.

Houde, E.D. and N. Chitty. 1976. Seasonal Abundance and Distribution of Zooplankton, Fish Eggs, and Fish Larvae in the Eastern Gulf of Mexico, 1972-1974. Prepared for NMFS, Seattle, WA. NMFS SSRF-701. 18 pp.

Houghton, J.P., D.L. Beyer, and E.D. Thielk. 1980. Effects of oil well drilling fluids on several important Alaskan marine organisms. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC. pp. 1017-1043.

Houghton, J.P., K.R. Critchlow, D.C. Lees, R.D. Czlapinski. 1981. Fate and Effects of Drilling Fluids and Cuttings Discharges in Lower Cook Inlet, Alaska, and on Georges Bank - Final Report. U.S. DOC, NOAA, and the U.S. Department of Interior, BLM, Washington, DC.

Houghton, J.P., R.P. Britch, R.C. Miller, A.K. Runchal, and C.P. Falls. 1980. Drilling Fluid Dispersion Studies at the Lower Cook Inlet C.O.S.T. Well. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Hudson, J.H. and D.M. Robbin. 1980. Effect of Drilling Mud on the Growth Rate of the Reef-Building Coral, *Montastrea annularis*. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Hunt, C.D. and D.L. Smith. 1983. Remobilization of metals from polluted marine sediments. *Can. Journal Fish Aquat. Sci.* 40:132-142.

Iverson, R.L. and T.L. Hopkins. 1981. A summary of knowledge of plankton production in the Gulf of Mexico: Recent Phytoplankton and Zooplankton research. Proceedings of a Symposium on Environmental Research Needs in the Gulf of Mexico (GOMEX), Key Biscayne, FL, 30 September - 5 October, 1979.

Jenne, E.A. and S.N. Luoma. 1977. Forms of trace elements in soils, sediments, and associated waters: An overview of their determination and biological availability. Pages 110-143. In: H. Drucker and R.E. Wildung (eds.), Biological Implications of Metals in the Environment.

Jensen, A., Eimhjellen, K., Raasok, K., Saetersdal, G., Wedege, N.P., and Ostvedt, O.J. 1984. The fate of oil and its effect in the sea: summary of final report from the Norwegian marine pollution research and monitoring programme. Oslo, Norway: Harald Lyche & Co. A.S. 20 pp.

Jones, F.V., J.H. Rushing, and M.A. Churan. 1991. The chronic toxicity of mineral oil-wet and synthetic liquid-wet cuttings on an estuarine fish, *Fundulus grandi*s. SPE 23497. Pages 721-730 In: The First International Conference on Health, Safety and Environment. Hague, The Netherlands, 10-14 November 1991. Society of Petroleum Engineers, Inc. Richardson, TX.

Kendall, J.J., Jr., E.N. Powell, S.J. Connor and T.J. Bright. 1983. The Effects of Drilling Fluids (muds) and Turbidity on the Growth and Metabolic State of the Coral *Acropora cervicornis* with Comments on Methods of Normalization for Coral Data. *Bull. Mar. Sci.*, 33(2):336-352.

Kennish, M.J. (ed.). 1989. Practical Handbook of Marine Science. CRC Press Inc. Boca Raton, FL. 710 pp.

King, George E. 2012. Hydraulic Fracturing 101: What every representative, environmentalist, regulator, reporter, invertor, university researcher, neighbor and engineer should know about estimating frac risk and improving frac performance in unconventional oil and gas wells. Society of Petroleum Engineers. SPE Hydraulic Fracturing Technology Conference, TX. SPE 152596. 80pp.

Krause, P.R., C.W. Osenberg, and R.J. Schmitt. 1992. Effects of Produced Water on Early Life Stages of a Sea Urchin: Stage-Specific Responses and Delayed Expression. In: J.P. Ray and F.R. Engelhardt, Eds. Produced Water. Plenum Press, New York. pp. 431-444.

Krone, M.A. and D.C. Biggs. 1980. Sublethal Metabolic Responses of the Hermatypic Coral *Madracis decactis* Exposed to Drilling Mud Enriched with Ferrochrome Lignosulfonate. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Leipper, D.F., 1970. A sequence of current patterns in the Gulf of Mexico. Jour. Geo. Res. 75(3): 637-657.

Leuterman, A.J.J. 1991. Environmental considerations in M-I product development. Novasol/Novadril. M-I Drilling Fluids Co., Houston, TX.

LimnoTech, Inc. 1993. Recommendation of Specific Models to Evaluate Mixing Zone Impacts of Produced Water Discharges to the Western Gulf of Mexico Outer Continental Shelf. Prepared for U.S. EPA Office of Wastewater Enforcement and Compliance. 22 pp.

Lindberg, W.J. and M.J. Marshall. 1984. Species Profile: Life Histories and Environmental Requirements of Coastal Fishes and Invertebrates (Gulf of Mexico)--Stone Crab. Prepared for U.S. Army Corps. of Engineers and U.S. FWS. FWS/OBS-82/11.21, TR EL-82-4.

Liss, R.G., F. Knox, D. Wayne, and T.R. Gilbert. 1980. Availability of Trace Elements in Drilling Fluids to the Marine Environment. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Luoma, S.N. 1983. Bioavailability of trace metals to aquatic organisms: A review. *Sci. Tot. Environ.* 28:1-22.

Lyes, M.C. 1979. Bioavailability of hydrocarbon from water and sediments to the marine worm *Arenicola marina*. *Mar. Biol.* 55: 121-127.

Mariani, G.M., L.V. Sick, and C.C. Johnson. 1980. An Environmental Monitoring Study to Assess the Impact of Drilling Discharges in the Mid-Atlantic. Report 3, Chemical and Physical Alterations in the Benthic Environment. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Marine Mammal Commission. 1988. Annual Report of the Marine Mammal Commission, Calendar Year 1987, A Report to Congress. Washington, DC. 209 pp.

Marx, J.M. and W.F. Herrnkind. 1986. Species Profile: Life Histories and Environmental Requirements of Coastal Fishes and Invertebrates (Gulf of Mexico)--Spiny Lobster. Prepared for U.S. Army Corps of Engineers and USFWS. Biological Report 82(11.61), TR EL-82-4.

Maul, G.A., 1977. The annual cycle of the Gulf Loop Current, Part 1: Observations during a one-year time series. *Jour. Mar. Res*. 35(1):29-47.

McCain, B.B., H.O. Hodgins, W.D. Gronlund, J.W. Hawkes, D.W. Brown, M.S. Myers, and J.J. Vandermuelen. 1978. Bioavailability of crude oil from experimentally oiled sediments to English sole (*Parophrus vetulus*), and pathological consequences. *J. Fish. Res. Board Canada.* 35:657-664.

McCulloch, W.L., J.M. Neff, and R.S. Carr. 1980. Bioavailability of Selected Metals from Used Offshore Drilling Muds to the Clam *Rangia cuneata* and the Oyster *Crassostrea gigas*. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Meade, R.H. 1972. Transport and Deposition of Sediments in Estuaries. Environmental Framework of Coastal Plain Estuaries. Geol. Society Am. Mem., B. Nelson (ed) 33:91-120.

Means, J.C., C.S. Milan, and D.J. McMillin. 1990. Hydrocarbon and trace metal concentrations in produced water effluents and proximate sediments. pp. 94-199 In: K.M. St. Pe, Ed., An Assessment of Produced Water Impacts to Low-Energy, Brackish Water Systems in Southeast Louisiana. Report to Louisiana Dept. of Environmental Quality, Water Pollution Control Div., Lockport, LA.

Meek, R.P., and J.P. Ray. 1980. Induced sedimentation, accumulation, and transport resulting from exploratory drilling discharges of drilling fluids and cuttings. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC. pp. 259-284.

Menzie, C.A. 1982. The environmental implications of offshore oil and gas activities. Environ. Sci. Technol. 16:454A-472A.

Menzie, C.A., D. Maurer, and W.A. Leatham. 1980. An Environmental Monitoring Study to Assess the Impact of Drilling Discharge in the Mid-Atlantic. Report 4, The Effects of Drilling Fluids and

Cuttings. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Middle East and Asia Reservoir Review. 2007. Frac Packing: Fracturing for sand control. No. 8. 7pp.

Middleditch, B.S. 1980. Hydrocarbons, Biocides, and Sulfurs. In: Volume 5 - Environmental Assessment of Buccaneer Gas and Oil Field in the Northwestern Gulf of Mexico, 1975-1980, edited by W.B. Jackson and E.P. Wilkins. NOAA Technical Memorandum NMFS-SEFC-47, NOAA, Washington, DC.

Middleditch, B.S. 1981. Environmental Effects of Offshore Oil Production - The Buccaneer Gas and Oil Field Study. Plenum Press, NY. 446 pp.

Middleditch, B.S. 1984. Ecological effects of produced water discharges from offshore oil and gas production platforms. Final Report on API Project No. 248. API, Washington, DC. 160 pp.

Minerals Management Service (MMS). 1982. Draft regional environmental impact statement, Gulf of Mexico. U.S. DOI, MMS, Gulf of Mexico OCS Region, Metairie, LA. 735 pp.

MMS. 1983. Final regional environmental impact statement. Proposed OCS oil and gas lease sales 72, 74, and 79 (Central, Western, and Eastern Gulf of Mexico). Vol. 1, PB84-102805. U.S. Department of the Interior, Washington, DC. xxxv + 527 pp.

MMS. 1986. "Physical Oceanography of the Gulf of Mexico." Visual No. 7, Figures 5A; 6A-D; and 9A, B, and E.

MMS. 2000. Gulf of Mexico OCS Oil and Gas Lease Sale 181 Eastern Planning Area, Draft Environmental Impact Statement. Gulf of Mexico Regional Office. MMS 2000-077.

MMS. 2000. Environmental Assessment. Gulf of Mexico Deepwater Operations and Activities. Gulf of Mexico OCS Region Office. MMS 2000-001.

Mobil Oil Corporation. 1978. Monitoring Program for Wells #3 and #4 Lease OCG-G-2759, Block A-389 High Island Area, East Addition South Extension. Prepared by Continental Shelf Assoc. Volume I Technical Section. 162 pp.

Moffitt, C.M., M.R. Rhea, P.B. Dorn, J.F. Hall, J.M. Bruney, and S.H. Evans. 1992. Short-Term Chronic Toxicity of Produced Water and its Variability as a Function of Sample Time and Discharge Rate. In: J.P. Ray and F.R. Engelhardt (Eds.) Produced Water Technological/Environmental Issues and Solutions. PennWell Books, New York, NY. pp. 235-244.

Montgomery, R.M. 1987. Personal communication concerning research conducted at U.S. EPA/ERL Gulf Breeze. Seven drilling fluid samples submitted from coastal TX and LA.

Moore, P.L. 1986. Drilling Practices Manual. Second Edition. PennWell Books, Tulsa, OK. 586 pp.

Moore, W.S., S. Krishmaswami and S.G. Bhat. 1973. Radiometric determination of coral growth rates. *Bull. Mar. Sci.* 23:157-176.

Mullen, Mike; Svatek, Kevin; Sevadjian, Emile; Vitthal, Sanjay and Grigsby, Tommy. 2003. Deepwater Reservoirs Requiring High Rate/High-Volume Frac Packing Continue to Stretch Downhole Tool Capabilities – Latest Tool Design and Qualification Testing Results. American Association of Drilling Engineers. AADE-03-NTCE-18. 15pp.

NAS (National Academy of Sciences). 1975. Petroleum in the marine environment: Workshop on inputs, fates and the effects of petroleum in the marine environment. Airlie, VA; May 1973. NAS, Washington, DC. 107 pp.

National Oceanic and Atmospheric Administration (NOAA). 1961-1986. Data Service, National Climate Center. U.S. Department of Commerce, NOAA.

NOAA. 1975. Environmental Studies of the South Texas Outer Continental Shelf, 1975. Report to the BLM, I.A. #08550-IA5-19. Volume I.

NOAA. 2016. Endangered and Threatened Marine Species under NMFS' Jurisdiction http://www.nmfs.noaa.gov/pr/species/esa/listed.htm

NMFS. 2010. Fisheries of the United States, 2009. U.S. Department of Commerce, NOAA Current Fishery Statistics No.2009. Available at: https://www.st.nmfs.noaa.gov/commercial-fisheries/fus/fus09/index

NMFS. 2014. Fisheries Economics of the United States, 2012. U.S. Dept. Commerce, NOAA. Tech. Memo. NMFS-F/SPO-137, 175p. Available at: https://www.st.nmfs.noaa.gov/st5/publication/index.html.

NMFS. 2014. Fisheries of the United States, 2013. U.S. Department of Commerce, NOAA Current Fishery Statistics No.2013. Available at: https://www.st.nmfs.noaa.gov/commercial-fisheries/fus/fus13/index

NMFS. 2015. Fisheries of the United States, 2014. U.S. Department of Commerce, NOAA Current Fishery Statistics No.2014. Available at: https://www.st.nmfs.noaa.gov/commercial-fisheries/fus/fus14/index

NMFS. 2013. Fisheries Economics of the United States NOAA Technical Memorandum NMFS-F/SPO-159. October 2015.

National Research Council (NRC). 1983. Drilling Discharges into the Marine Environment. National Academy Press, Washington, DC. 180 pp.

Neff, J.M., R.S. Foster, and J.F. Slowey. 1978. Availability of sediment-adsorbed heavy metals to benthos with particular emphasis on deposit feeding infauna. Technical Report D-78-42 to U.S. Army Engineer Waterways Experiment Station, Dredge Material Program, Vicksburg, MS. 286 pp.

Neff, J.M. 1979. Polycyclic Aromatic Hydrocarbons in the Aquatic Environment: Sources, Fates, and Biological Effects. Applied Science Publ., Barking Essex, England. 262 pp.

Neff, J.M. 1980. Effects of Used Drilling Fluids on Benthic Marine Animals. Publ # 4330. API, Washington, DC.

Neff, J.M. 1982. Accumulation and release of polycyclic aromatic hydrocarbons from water, food, and sediment by marine animals. pp. 282-320. In: N.L. Richards and B.L. Jackson (eds.) Symposium: Carcinogenic Polynuclear Aromatic Hydrocarbons in the Marine Environment. USEPA, Gulf Breeze, FL. EPA-600/9-82-013.

Neff, J.M. 1985. Biological effects of drilling fluids, drill cuttings, and produced waters. in: D.F. Boesch and N.N. Rabalais (eds.). The Long-Term Effects of Offshore Oil and Gas Development: An Assessment and Research Strategy. Report to NOAA, National Marine Pollution Program Office for the Interagency Committee on Ocean Pollution Research, Development, and Monitoring. Prepared by LUMCON, Chauvin, LA.

Neff, J.M., R.E. Hillman, B. Leczynski, and T. Berner. 1986. Final Report on Bioavailability of Trace Metals from Barite to Benthic Marine Organisms. Prepared for the OOC. 41 pp.

Neff, J.M., T.C. Sauer, N. Maciolek. 1988. Fate and Effects of Produced Water Discharges in Nearshore Marine Waters. Final Report to API, Washington, DC. 300 pp.

Neff, J.M., W.E. Hillman, and J.J. Waugh. 1989. Bioaccumulation of trace metals from drilling mud barite by marine animals. In: F.R. Engelhardt, J.P. Ray, and A.H. Gillam, Eds. Drilling Wastes. Elsevier Applied Science Publishers, London. pp. 461-479.

Neff, J.M., T.C. Sauer, Jr., and N. Maciolek. 1992. Composition, ate and effects of produced water discharges to nearshore marine waters. pp. 371-386 In: J.P. Ray and F.R. Engelhardt, Eds., Produced Water: Technological/Environmental Issues. Plenum Press, New York.

Neff, J.M. 1997. Metals and Organic Chemicals Associated with Oil and Gas Well Produced Water: Bioaccumulation, Fates, and Effects in the Marine Environment. Draft Report to the OOC, New Orleans, LA. As cited in OOC comments on propose permit.

Neff, J.M., S. McKelvie and R.C. Ayers, Jr. 2000. Environmental Impacts of Synthetic Based Drilling Fluids. Report prepared by Robert Ayers & Associates, Inc. August 2000. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico Region, New Orleans, LA. OCS Study MMS 2000-64. 118 pp.

Nelson, D.A., et al. 1976. Biological effects of heavy metals on juvenile bay scallops, *Argopecten irradians*, in short term exposures. *Bull. Environ. Contam. Toxicol.* 16:275. In: U.S. EPA. 1985. Ambient Water Quality Criteria for Arsenic - 1984. U.S. EPA, Washington, D.C. EPA 440/5-84-033.

New England Aquarium (NEA). 1984. A Survey of Toxicity of Chemical Composition of Used Drilling Muds. Final Report to the U.S. EPA. Coop. Agreement No. CR806776. January 1984.

Ng, A. and C.C. Patterson. 1982. Changes of lead and barium with time in California offshore basin sediments. Geochem. Cosmochem. Acta. 46(11):2307-2321.

Northern Technical Services. 1983. Open-water drilling effluent disposal study. Tern Island, Beaufort Sea, Alaska. Report for Shell Oil Co. from Northern Technical Services, Anchorage, AK. 87 pp.

Nulton, C.P. and D.E. Johnson. 1981. Aromatic Hydrocarbons in Marine Tissues from the Central Gulf of Mexico. *Journal of Environmental Science and Health*, A16(37):271-288.

Odum, E.P. 1971. Fundamentals of Ecology, 3rd Edition. W.B. Saunders, Philadelphia, PA. In: Kennish, M.J. (ed.). 1989. Practical Handbook of Marine Science. CRC Press Inc. Boca Raton, FL. 710 pp.

Olla, B.L., W.W. Steiner, and J.J. Luczkovich. 1982. Effects of drilling fluids on the behavior of the juvenile red hake, *Urophycis chuss* (Walbaum). II. Effects on established behavioral baselines. Progress Report to U.S. EPA, Gulf Breeze, Florida. Report No. SHL 82-15 from NOAA/NMFS, Northeast Fisheries Center, Sandy Hook Laboratory, NJ.

Ortner, P.B., R.L. Ferguson, S.R. Piotrowicz, L. Chesal, G. Berberian, and A.V. Palumbo. 1984. Biological consequences of hydrographic and atmospheric advection within the Gulf Loop Intrusion. Deep-Sea Research. Vol. 31, no. 94:1101-1120.

Page, O.S., B.T. Page, J.R. Hotham, E.S. Gilfillan and R.P. Gerber. 1980. Bioavailability of Toxic Constituents of Used Drilling Muds. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Pequegnat, W.E. 1983. The ecological communities of the continental slope and adjacent regimes of the northern Gulf of Mexico. A final report by TerEco Corporation for the U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Regional Office, New Orleans, Louisiana. Contract No. AA851-CTI-12.

Perricone, C. 1980. Major Drilling Fluid Additives--1979. In: Symposium on Research on Environmental Fate and Effects of Drilling Fluids and Cuttings. Lake Buena Vista, FL. January, 1980. API, Washington, DC. pp. 15-29.

Petrazzuolo, G. 1981. An Environmental Assessment of Drilling Fluids and Cuttings Released onto the OCS for the Gulf of Mexico - Draft. U.S. EPA, Office of Water Enforcement and Permits, Washington, DC.

Petrazzuolo, G. 1983. Environmental Assessment of Drilling Fluids and Cuttings Discharge on the OCS. Draft Final Report. U.S. EPA, Office of Water Enforcement and Permits, Washington, DC.

Powell, E.N., M. Kasschau, E. Che, M. Loenig, and J. Peron. 1982. Changes in the free amino acid pool during environmental stress in the gill tissue of oyster, *Crassostrea virginica*. Comp. Biochem. Physiol. 71A:591-598.

Rabalais, N.N., 1986. Oxygen-depleted waters on the Louisiana continental shelf. Proceedings of the MMS, Information Transfer Meeting, November 4-6, 1986. 4 pp.

Rabalais, N.N., M.J. Dagg, and D.F. Boesch, 1985. Nationwide Review of Oxygen Depletion and Eutrophication in Estuarine and Coastal Waters: Gulf of Mexico (Alabama, Mississippi, Louisiana and Texas). Report to NOAA, Ocean Assessments Division. 60 pp.

Rabalais, N.N., B.A. McKee, D.J. Reed, and J.C. Means. 1991. Fate and effects of nearshore discharges of OCS produced waters. Vol. 1: Executive Summary. Vol. 2: Technical Report. Vol. 3: Appendices. OCS Studies MMS 91-004, MMS 91-005, and MMS 91-006. USDOI, MMS, Gulf of Mexico OCS Regional Office, New Orleans, LA.

Rabalais, N.N., B.A. McKee, D.J. Reed, and J.C. Means. 1992. Fate and Effects of Produced Water Discharges in Coastal Louisiana, Gulf of Mexico, USA. In: J.P. Ray and F.R. Engelhart (Eds.). Produced Water Technological/Environmental Issues and Solutions. Plenum Press, New York, NY. pp. 355-369.

Rabke S. et al. 1998a. Interlaboratory Comparison of a 96-hour *Mysidopsis bahia* Bioassay Using a Water Insoluble Synthetic-Based Drilling Fluid. Presented at 19th Annual Meeting of Society of Environmental Toxicology and Chemistry Charlotte NC 1998.

Ray, J.P. and R.P. Meek. 1980. Water Column Characterization of Drilling Fluids Dispersion from an Offshore Exploratory Well on Tanner Bank. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Renaud, M.L., 1985. Hypoxia in Louisiana coastal waters during 1983: Implications for fisheries. *Fishery Bulletin* 84(1):19-26.

Roach, R.W., R.S. Carr, and C.L. Howard. 1992. An Assessment of Produced Water Impacts at Two Sites in the Galveston Bay System. U.S. Fish and Wildlife Service, Division of Ecological Services, Houston, TX.

Robinson, M.K. 1973. Atlas of monthly mean sea surface and subsurface temperature and depth of the top of the thermocline Gulf of Mexico and Caribbean Sea. Scripps Inst. of Ocean., Reference 73-8, 12 pp + 93 figures. In: MMS. 1990. Draft environmental impact statement. Gulf of Mexico Sales 131, 135, and 137: Central Western and Eastern Planning Areas. Gulf of Mexico OCS Region Office. MMS 90-0003.

Roesijadi, G., J.W. Anderson, and J.W. Blaylock. 1978. Uptake of hydrocarbons from marine sediments contaminated with Prudoe Bay crude oil: Influence of feeding type of test species and availability of polycyclic aromatic hydrocarbons. J. Fish. Res. Bd. Canada. 35:608-614.

Roithmayr, C.M., and R.A. Waller. 1983. Seasonal occurrance of *Brevoortia patronus* in the northern Gulf of Mexico. *Trans. Am. Fish. Soc.* 92(3):301-302.

Rose, C.D., and T.J. Ward. 1981. Acute toxicity and aquatic hazard associated with discharge formation water. Pages 301-328 In: B.S. Middleditch (ed.), Environ. Effects of Offshore Oil Production. The Buccaneer Gas and Oil Field Study. Plenum Press, NY.

Rossi, S.S. 1977. Bioavailability of petroleum hydrocarbon from water, sediments, and detritus to the marine annelid *Neanthes arenaceodentata*. In: Proceedings 1977 Oil Spill Conference (Prevention, Behavior, Control, Cleanup). API, Washington, DC. pp. 621-626.

Rubenstein, N.I., R. Rigby, and C.N. D'Asaro. 1980. Acute and sublethal effects of whole used drilling fluids on representative estuarine organisms. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC. pp. 828-848.

Rushing, J.H., M.A. Churan, and F.V. Jones. 1991. Bioaccumulation from mineral oil-wet and synthetic liquid-wet cuttings in an estuarine fish, *Fundulus grandi*s. SPE 23350. Pages 311-320 In: The First International Conference on Health, Safety and Environment. The Hague, The Netherlands, 10-14 November 1991. Society of Petroleum Engineers, Inc. Richardson, TX.

Sauer, T.C., Jr., T.J. Ward, J.S. Brown, S. O'Neill, and M.J. Wade. 1978. Volatile liquid hydrocarbons in the surface coastal waters of the Gulf of Mexico. Mar. Chem. 7:1-16.

Sauer, T.C., Jr. 1980. Volatile liquid hydrocarbons in waters of the Gulf of Mexico and Caribbean Sea. Limnol. Oceanog. 25:338-351.

Sauer, T.C., Jr., T.J. Ward, J.S. Brown, S. O'Neill, and M.J. Wade. 1992. Identification of Toxicity in Low-TDS Produced Waters. In: J.P. Ray and F.R. Engelhardt (Eds.) Produced Water Technological/Environmental Issues and Solutions. PennWell Books, New York, NY. pp. 209-222.

Saunders, R.P., and D.A. Glenn. 1969. Diatoms. Mem. Hourglass Cruises. Florida Marine Research Publications Series. 119 pp.

Schaanning, M.T. 1996. Environmental Fate of Synthetic Drilling Fluids from Offshore Drilling Operations. NIVA rapport nr. 3429-96.

Schafer, H.A., G.P. Hershelman, D.R. Young, and A.J. Mearns. 1982. Contamination in ocean food webs. p. 17-28. In: W. Bascom (ed.) SCCWRP Biennial Rep. 1981-1982.

SAIC. 1991. Descriptive Statistics and distributional Analysis of Cadmium and Mercury Concentrations in Barite, Drilling Fluids, and Drill Cuttings from the API/USEPA Metals Database. Prepared for Industrial Technology Division, U.S. Environmental Protection Agency, February 1991.

SAIC. 1992. Discharge Characterization Spreadsheets. Submitted to Office of Science and Technology, U.S. EPA, Washington, DC.

Sharp, J.R., R.S. Carr, and J.M. Neff. 1984. Influence of used chrome lignosulfonate drilling and fluids on the early life history of the mummichog *Fundulus heteroclitus*. In: Proc. Ocean Dumping Symposium. John Wiley & Sons, New York. 14 pp.

Shonkoff S.B., Hays J, Finkel M.L. 2014. Environmental public health dimensions of shale and tight gas development. Environ Health Perspect 122:787–795; http://dx.doi.org/10.1289/ehp.1307866

Smith, G.G. (ed.) 1981. Cambridge Encyclopedia of Earth Sciences. Cambridge University Press, Cambridge. In: Kennish, M.J. (ed.). 1989. Practical Handbook of Marine Science. CRC Press Inc. Boca Raton, FL. 710 pp.

Smith, J.P. 1993. Field Observations of Dilution of Radium-226 from Produced Water Discharges - Comparison with Dispersion Model Predictions. Report to the Offshore Operators Committee.

Smith, J.P., H.L. Mairs, M.G. Brandsma, R.P. Meek, and R.C. Ayers. 1994. Field Validation of the Offshore Operators Committee (OOC) Produced Water Discharge Model. SPE Paper 28350. SPE 69th Annual Technical Conference and Exhibit, New Orleans, LA. Society of Petroleum Engineers, Richardson, TX.

Somerville, H.J., D. Bennett, J.N. Davenport, M.S. Holt, A. Lymes, A. Mahieu, B. McCourt, J.G. Parker, R.R. Stephenson, R.J. Watkinson, and T.G. Wilkinson. 1987. Environmental effects of produced water from North Sea oil operations. Mar. Pollut. Bull. 18:549-558.

Stephenson, M.T., R.C. Ayers, L.J Bickford, D.D. Caudle, J.T. Cline, G. Cranmer, A. Duff, E. Garland, T.A. Herenius, R.P.W.M. Jacobs, C. Inglesfield, G. Norris, J.D. Petersen, and A.D. Read. 1994. North Sea produced water: fate and effects in the marine environment. Report No. 2.62/204. E&P Forum, London, England. 48 pp.

Steidinger, K.A., and J. Williams. 1970. Dinoflagellates. Mem. Hourglass Cruises. Florida Marine Research Publications Series. 225 pp.

Steinhauer, M., E. Crecelius, and W. Steinhauer. 1994. Temporal and spatial changes in the concentrations of trace metals in the vicinity of an offshore oil-production platform. Mar. Environ. Res. 37:129-163.

Stevens, L. 1993. Letter to H.J. Mueller, U.S. EPA, Region 4 regarding endangered species in Mississippi, Alabama, and Florida from L. Stevens, NMFS. March 25, 1993.

Strømgren, T., S.E. Sørstrøm, L. Schou, I. Kaarstad, T. Aunaas, O.G. Brakstad, and Ø. Johansen. 1995. Acute toxic effects of produced water in relation to chemical composition and dispersion. Mar. Environ. Res. 40:147-169.

Sutter, F.C., R.S. Waller, and T.D. McIlwain. 1986. Species Profile: Life Histories and Environmental Requirements of Coastal Fishes and Invertebrates (Gulf of Mexico)--Black Drum. Prepared for U.S. Army Corps of Engineers and U.S. FWS. Biological report 82(11.51), TR EL-82-4.

Sutton, T.T. and T.L. Hopkins. 1996. Species composition, abundance and vertical distribution of the stomiid (Pices: Stomiiformes) fish assemblage of the eastern Gulf of Mexico. Bull. Mar. Sci. 59: 530-542.

Tagatz, M.E., J.M. Ivey, H.K. Lehman, M. Tobia, and J.L. Oglesby. 1980. Effects of Drilling Mud on Development of Experimental Estuarine Macrobenthic Communities. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Tagatz, M.E. and M. Tobia. 1978. Effect of Barite ($BaSO_4$) on Development of Estuarine Communities. Estuarine and Coastal Marine Science, 7:401-407.

Technical Resources, Inc. 1988. Analysis of Effluent Dispersion Models Potentially Applicable to Shallow Water Discharges from Oil and Gas Activities. Prepared for U.S. EPA, Region 6, Dallas, TX. 43 pp.

Temple, R.F., D.L. Harrington, and J.A. Martin. 1977. Monthly Temperature and Salinity Measurements of Continental Shelf Waters of the Northwestern Gulf of Mexico, 1963-1965. NOAA Tech. Rep. SSRF-707. 29 pp.

Terrens, G.W. and R.D. Tait. 1993. Effects on marine environment of produced formation water discharges from Esso/BHPP's Bass Strait Platforms. Esso Australia Ltd., Melbourne, Australia. 25 pp.

Terrens, G.W. and R.D. Tait. 1996. Monitoring ocean concentrations of aromatic hydrocarbons from produced formation water discharges to Bass Strait, Australia. SPE 36033. Proceedings of the International Conference on Health, Safety & Environment. Society of Petroleum Engineers, Richardson, TX.

Texas A&M University. 1991. Mississippi-Alabama Continental Shelf Ecosystem Study, Data Summary and Synthesis. Prepared for MMS Gulf of Mexico OCS Region. MMS 91-0064.

Thayer, G.W., and J.F. Ustach. 1981. Gulf of Mexico Wetlands: Value, state of knowledge and research needs. In: Proceedings of a Symp. on Environ. Res. Needs in the Gulf of Mexico (GOMEX), Key Biscayne, FL, September 1979. Atwood, D.K. (ed). Vol. IIB: 2-19.

Thomas, R.E. and S.D. Rice. 1979. The Effect of Exposure Temperatures on Oxygen Consumption and Operation Breathing Rates of Pink Salmon Fry Exposed to Toluene, Naphthalene, and Water-Soluble Fractions of Cook Inlet Crude Oil and No. 2 Fuel Oil. In: Marine Pollution: Functional Response. Academic Press, Inc.

Thompson, J.H., Jr. and T.J. Bright. 1977. Effect of drilling mud on clearing rates of certain hermatypic corals. Proceedings of the Oil Spill Conference (Prevention, Behavior, Control, Clean-up). March 8-10, 1977. New Orleans. pp. 495-498. In: Petrazzuolo, G. 1983. Environmental Assessment of Drilling Fluids and Cuttings Discharge on the OCS. Draft Final Report. U.S. EPA, Washington, DC.

Thompson, J.H., Jr. and T.J. Bright. 1980. Effects on an Offshore Drilling Fluid on Selected Corals. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Tillery, J.B. and R.E. Thomas. 1980. Heavy Metals Contamination from Petroleum Production Platforms in the Central Gulf of Mexico. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Tornberg, L.D., E.D. Thielk, R.E. Nakatani, R.C. Miller, and S.O. Hillman. 1980. Toxicity of Drilling Fluids to Marine Organisms in the Beaufort Sea, Alaska. In: Symposium on research on environmental fate and effects of drilling fluids and cuttings. Lake Buena Vista, FL, January 1980. API, Washington, DC.

Trees, C.C., and S.Z. El-Sayed. 1986. Remote sensing of chlorophyll concentrations in the northern Gulf of Mexico. Proceedings of SPIE, the International Society for Optical Engineering: Ocean Optics Viii. M. Blizzard (ed). Vol. 637, pp 328-334.

Trefry, J.H., R. Trocine, and D. Meyer. 1981. Tracing the Fate of Petroleum Drilling Fluids in the Northwest Gulf of Mexico. *Oceans*, September 1981. pp. 732-736.

Trefry, J.H., R.P. Trocine, S. Metz and M.A. Sisler. 1986. Forms, Reactivity and Availability of Trace Metals in Barite. Draft Final Report to OOC.

Trocine, R.P., J.H. Trefry and D.B. Meyer. 1981. Inorganic tracers of petroleum drilling fluid dispersion in the northwest Gulf of Mexico. Reprint Extended Abstract. Div. Environ. Chem., ACS Meeting, Atlanta, GA, March-April, 1981.

U.S. Environmental Protection Agency (U.S. EPA). 1978. Natural Radioactivity Contamination Problems. EPA 520/4-77-015.

U.S. EPA. 1985. Development Document for Effluent Limitations, Guidelines, and Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category. EPA 440/1-85-055.

U.S. EPA. 1993. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category. Office of Water. EPA 821-R-93-003.

U.S. EPA. 1996. Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. EPA-821-R-96-023.

U.S. EPA. 1998. Final Environmental Impact Statement, National Pollutant Discharge Elimination System permitting for Eastern Gulf of Mexico Offshore Oil and Gas Extraction. EPA-904/9-98-003.

U.S. EPA. 1997. Letter from Alexandra Tarnay, U.S. EPA to Nerija Orentas, *Avanti* Corporation, regarding Current Federal Water Quality Criteria, February 20, 1997.

U.S. EPA. 1999. Development Document for Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category. EPA-821-B-98-021.

U.S. EPA, Region 10. 1984. Final Ocean Discharge Criteria Evaluation, Diapir Field. OCS Lease Sales 87 and State Lease Sales 39, 43, and 43a. Prepared by Jones and Stokes Assoc., Inc. and Tetra Tech, Inc.

U.S. EPA. 2000. Environmental Assessment of Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category. Office of Water. EPA-821-B-00-014

U.S. EPA. 2002. National Recommended Water Quality Criteria: 2002. Office of Water. EPA-822-R-02-047.

U.S. EPA. 2015. Technical Development Document for Effluent Limitations Guidelines and Standards for Oil and Gas Extraction. EPA-821-R-15-003. 205pp.

U.S. EPA. 2016. Draft Environmental Assessment, National Pollutant Discharge Elimination System (NPDES) Permit for Eastern Gulf of Mexico Offshore Oil and Gas Exploration, Development, and Production. EPA-904-P-001.

USFWS 2010. Federally Listed Wildlife and Plants Threatened by Gulf Oil Spill http://www.fws.gov/home/dhoilspill/pdfs/FedListedBirdsGulf.pdf

USFWS 2013. Gulf Restoration. Threatened and Endangered Species on the Gulf Coast. http://www.fws.gov/gulfrestoration/TandEspecies.html

van der Borght, O. 1963. Accumulation of radium-226 by the freshwater gastropod *Lymnaea stagnolis* L. *Nature* 197:612-613.

Veil, J.A., Kimmell, T.A., Rechner, A.C. 2005. Characteristics of Produced Water Discharged to the Gulf of Mexico Hypoxic Zone. U.S. Dept. of Energy. Contract W-31-109-Eng-38. 74pp.

Versar. 1992. Aquatic and Human Health Toxicity Data for Produced Water Pollutants, Draft. Memorandum from L. Wilson, March 2, 1992.

Vik, E.A., S. Dempsey, B. Nesgard. 1996. Evaluation of Available Test Results from Environmental Studies of Synthetic Based Drilling Muds. OLF Project, Acceptance Criteria for Drilling Fluids. Aquateam Report No. 96-010.

Vukovich, F.M., B.W. Crissman, M. Bushnell, and W.J. King. 1978. Sea-surface temperature variability analysis of potential OTEC sites utilizing satellite data. Research Triangle Institute, Research Triangle Park, NC. 153 pp.

Wheeler, R.B., J.B. Anderson, R.R. Schwarzer, and C.L., Hokanson. 1980. Sedimentary processes and trace metal contaminants in the Buccaneer oil/gas field, northwest Gulf of Mexico. *Environ. Geol.* 3:163-175.

Woodward-Clyde Consultants and CSA, Inc. 1984. Southwest Florida Shelf Ecosystems Study-Year 2. Report to MMS. 14-12-0001-29144.

Wright, S.J. 1993. Analysis of CORMIX1 and UM/PLUMES Predictive Ability for Buoyant Jets in a Density-Stratified Flow. Prepared for U.S. EPA Office of Wastewater Enforcement and Compliance.

Yentsch, C.S. 1982. Satellite observation of phytoplankton distribution associated with large scale oceanic circulation. NAFO Sci. Counc. Stud. No. 4. pp. 53-59.

Yoder, J.A. and A. Mahood. 1983. Primary Production in Loop Current Upwelling. In: Univ. of Maryland Eastern Shore. 1985. Federal OCS Oil and Gas Activities: A Relative Comparison of Marine Productivity Among the OCS Planning Areas. Draft report prepared for MMS. Coop. Agree. No. 14-12-0001-30114. 1,450 pp.

Zein-Eldin, Z.P., and P.M. Keney. 1979. Bioassay of Buccaneer oil field effluents with penaeid shrimp. Pages 2.3.4-1 to 2.3.4-25. In: Environmental Assessment of an Active Oil Field in the Northwestern Gulf of Mexico, 1977-1978. Volume II: Data Management and Biological Invest. NOAA, NMFS, Galveston, TX.

Zevallos, M.A.L., J. Candler, J.H. Wood, and L.M. Reuter. 1996. Synthetic-based fluids enhance environmental and drilling performance in deepwater locations. SPE 35329. Pages 235-242 In: SPE International Petroleum Conference & Exhibition of Mexico. Villahermosa, Tabasco, Mexico, 5-7 March 1996. Society of Petroleum Engineers, Inc. Richardson, TX.

Zingula, R.P. 1975. Effects of Drilling Operations on the Marine Environment. In: Conference Proceedings on Environmental Aspects of Chemical Use in Well-Drilling Operations, Houston, TX, May 21-23, 1975. EPA-550/1-75-004, 443-450. U.S. EPA, Washington, DC.

Appendix A. Acute Lethal Toxicities of Used Drilling Fluids and Components to Marine Organisms

Test Organism	Fluid Description[a]	Criterion Value (ppm)	Toxicity Ratin
	USED DRILLING FLUIDS		
ALGA	Imco LDLS/SW	1,325-4,700 (96-h EC50)	4
Skeletonema costatum	Imco Lime/SW	1,375 (96-h EC50)	4
	Imco non-dispersed/SW	5,700 (96-h EC50)	4
	Lightly treated LS/SW-FW	3,700 (96-h EC50)	4
COPEPODS	Imco LDLS/SW	5,300-9,300	4
Acartia tonsa	Imco Lime/SW	5,600	4
	Imco non-dispersed/SW	66,500	5
	Lightly treated LS/SW-FW	10,000	5
	FCLS/FW	100-230	3
	Saltwater Gel	100	3
ISOPODS	FCLS/FW	70,000	5-6
Gnorimosphaeroma	XC-Polymer/Unical	314,000-500,000	6
oregonsis *Saduria*	CMC-Resinex Tannathin-Gel	530,000-600,000	6
entomon			
AMPHIPODS	FCLS/FW	10,000-50,000	5
Anisogammarus	FCLS/FW	10,000-200,000 (48-h	5-6
confervicolus	XC-Polymer/Unical	LC50)	6
	Spud mud	200,000-436,000	6
Onisimus sp./*Boekisima*	MDLS	100,000	5
sp. *Gammarus locusta*	MDLS (MAF)	74,000-90,000	6
	HDLS	100,000	5
	HDLS (MAF)	28,000-88,000	6
		100,000	
GASTROPODS	CMC-Resinex Tannathin-Gel	600,000-700,000	6
Nautica clausa, Neptuna	LDLS (MAF)	100,000	6
sp., & *Buccinum* sp.	LDLS	83,000	5
Littorina littorea	LDLS (MAF)	100,000	6
Thais lapillis	LDLS (suspended WM)	15,000	5
	MDLS	100,000	6
	MDLS (MAF)	100,000	6
	HDLS	100,000	6
	HDLS (MAF)	100,000	6
DECAPODS-SHRIMP	FCLS/FW	100,000 (48-h LC50)	6
Artemia salina	FCLS/FW	32,000-150,000	5-6
Pandalus hypsinotus		50,000-100,000 (48-h	5
	Spud mud (MAF)	LC50) 100,000	6
Crangon septemspinosa	Seawater LS (MAF)	100,000	6
	LDLS	71,000	5
	LDLS (suspended WM)	15,000	5
	LDLS (MAF)	98,000-100,000	5
	MDLS	82,000	5

Test Organism	**Fluid Description**[a]	**Criterion Value (ppm)**	**Toxicity Ratin**
	MDLS (suspended WM)	15,000	5
	MDLS (MAF)	17,000	5
	MDLS (FMAF)	19,000	5
	HDLS	92,000	5
	HDLS (suspended WM)	15,000	5
	HDLS (MAF)	100,000	6
	HDLS (FMAF)	100,000	6
	HDLS (MAF)	65,000	5
Pandalus borealis	HDLS (FMAF)	55,000	5
Stage I larvae	Spud Mud (MAF)	100,000	6
Palaemonetes pugio	Seawater-chrome LS (MAF)	27,500	5
Stage I zoeae	MDLS (MAF)	35,000	5
Adults	HDLS (MAF)	18,000	5
	HDLS (SPP)	11,800	5
	Spud Mud (MAF)	100,000	6
	Seawater-chrome LS (MAF)	92,400	5
	MDLS (MAF)	91,000	5
Stage III zoeae	HDLS (MAF)	100,000	6
Late premolt stage	Lightly treated LS	201	3
D_2 - D_4	HDLS (SPP)	11,700-13,200	5
Palaemonetes pugio	Mobile Bay fluid	318-863	3
larvae	Mobile Bay fluid	360-14,560	3-5
	Seawater LS	1,706-28,750	4-5
	Lightly treated LS	142	3
	Freshwater LS	4,276-4,509	4
	Lime	658	3
	FW/SW-LS	3,570	4
	Non-dispersed	100,000	6
	LTLS	35,420	5
Penaeus aztecus	Seawater-K-polymer	2,557	4
juvenile	Seawater-chrome LS (MAF)	41,500	5
Orchestia traskiana	MDLS (MAF)	16,000	5
	Seawater-polymer	230,000	6
	Pelly gel Chemical XC	80,000	5
	KCI-XC-Polymer	14,000	5
	Weighted shell polymer	34,000	5
	Gel-SX-polymer	420,000-500,000	6
	Imnak gel-XC-polymer	560,000	6
DECAPODS-CRABS	LDLS	89,100	5
Carcinus maenus	LDLS (suspended WM)	15,000	5
	LDLS (MAF)	100,000	6
	MDLS	68,000-100,000	5-6
	MDLS (suspended WM)	15,000	5
	MDLS (MAF)	100,000	6
	HDLS (MAF)	100,000	6
	Seawater-chrome LS (MAF)	28,700	5
Clibanarius vittatus	MDLS (MAF)	34,500	5
	HDLS (MAF)	65,600	5
	Seawater polymer	530,000	6
Hemigrapsus nudus	Shell Kipnik-KCL polymer	53,000	5

Test Organism	Fluid Description[a]	Criterion Value (ppm)	Toxicity Ratin
	Pelly gell chemical XC	560,000	6
	KCI-XC-polymer	78,000	5
	Weighted shell polymer	62,000	5
	Pelly weighted gel-XC-polymer	560,000	6
	Imnak gel-XC-polymer	560,000	6
DECAPODS-LOBSTER			
Homarus americanus	LDLS (MAF)	5,000	5
Stage V larvae	MDLS	100,000	6
	MDLS (MAF)	29,000	5
Adult	LDLS	19,000-25,000	5
	LDLS (MAF)	100,000	6
Larvae	Mobile Bay/Jay fluids	73.8-500 ppm	2-3
BIVALVES	FCLS/FW	30,000	5
Modiolus		30,000 (14 day LC50)	5
	Spud mud (MAF)	100,000	6
Mytilus edilus	Seawater LS (MAF)	100,000	6
	MDLS (MAF)	100,000	6
	MDLS (suspended WM)	15,000	5
	HDLS (MAF)	100,000	6
	HDLS (suspended WM)	15,000	5
Macama balthica	LDLS	100,000	6
	LDLS (MAF)	100,000	6
	LDLS (suspended WM)	15,000	5
	HDLS	100,000	6
	HDLS (MAF)	100,000	6
	HDLS (FMAF)	100,000	6
	LDLS	49,000	5
Placopecten magellanicus	MDLS	3,200	4
	Spud mud (SPP)	100,000	6
Crassostrea gigas	MDLS (SPP)	50,000-53,000	5
	HDLS (SPP)	73,000-74,000	5
	Spud mud (SPP)	100,000	6
Donax variabilis texasiana	Seawater-chrome LS (SPP)	53,700	5
	MDLS (SPP)	29,000	5
	HDLS (SPP)	56,000	5
	Seawater polymer	320,000	6
	Kipnik-KC1 polymer	42,000	5
Mya arenaria	Polly gel chemical XC	560,000	6
	KC1-XC-polymer	56,000	5
	Weighted shell polymer	10,000	5
	Weighted gel XC-polymer	560,000	6
	Weighted KC1-XC-polymer	560,000	6
	Imnak gel-XC-polymer	560,0008	6
Mercenaria Larvae	Seawater LS (LP)	7-3,000	2-4
	Seawater LS (SPP)	117-3,000	3-4
	LTLS (LP)	719-3,000	3-4
	LTLS (SPP)	122-2,889	3-4
	FWLS (LP)	319-330	3
	FWLS (SPP)	158-338	3

Test Organism	Fluid Description[a]	Criterion Value (ppm)	Toxicity Ratin
	FW/SW LS (LP)	380	3
	FW/SW LS (SPP)	82	2
	Lime (LP)	682	3
	Lime (SPP)	64	2
	Low solids non-dispersed (LP)	3,000	4
	Low-solids non-dispersed (SPP)	3,000	4
	Potassium polymer (LP)	269	3
	Potassium polymer (SPP)	220	3
ECHINODERMS	LDLS	55,000	5
Strongylocentrotus droebachiensis	LDLS (MAF)	100,000	6
	MDLS	100,000	6
	MDLS (MAF)	100,000	6
MYSIDS			
Neomysis integer	FCLS/FW	10,000-200,000 (48-h	5-6
		LC50)	5-6
Mysis sp.	CMC-Gel	10,000-125,000	6
	CMC-Gel-Resinex	142,000-349,000	5
	XC-polymer (supernatant)	58,000-93,000	6
Mysidopsis almyra	XC-polymer	250,000	5-6
	Spud mud (MAF)	50,000-170,000	6
	Seawater-chrome LS (MAF)	100,000	5
	MDLS (MAF)	27,000	5
	HDLS (MAF)	12,800-13,000	5
	MDLS (SPP)	16,000-32,500	5
	MDLS (MAF)	32,000	5
	MDLS (MAF) (static test)	26,800-66,300	5-6
	Reference mud (MAF) (static test)	72,100-113,000	6
		100,000	
Mysidopsis bahia	Seawater LS	429-1,557	3-4
	Seawater LS (LP)	150,000	6
	Seawater LS (SPP)	15,123-19,825	5
	Seawater LS (SP)	50,000	5
	LTLS	14-1,958	2-4
	LTLS (LP)	150,000	6
	LTLS (SPP)	1,641-50,000	3-5
	LTLS (SP)	1,246-2,437	3
	FWLS	301-1,500	3-4
	FWLS (LP)	97,238-121,476	5-6
	FWLS (SPP)	14,068-29,265	5
	Lime	87-98	2
	Lime (SPP)	650-791	3
	Lime (SP)	8,213-1,369,393	4-6
	FW/SW-LS	115-379	3
	FW/SW-LS (LP)	150,000	6
	FW/SW-LS (SPP)	11,380-38,362	5
	FW/SW-LS (SP)	50,000	5
	Low-solids non-dispersed	1,500	4
	Low-solids non-dispersed (LP)	150,000	6
	Low-solids non-dispersed (SPP)	50,000	5

Test Organism	**Fluid Description^a**	**Criterion Value (ppm)**	**Toxicity Ratin**
	Low-solids non-dispersed (SP)	50,000	5
	Potassium polymer	1,500	4
	Potassium polymer (LP)	150,000	6
	Potassium polymer (SPP)	26,025-28,070	5
POLYCHAETES	CMC-Resinex-Tannathin	600,000	6
Melaenis loveni	CMC-Resinex-Tannathin-Gel	700,000	6
	Spud mud (MAF)	100,000	6
Nereis virens	Seawater-LS (MAF)	100,000	6
	LDLS	100,000	6
	LDLS (MAF)	100,000	6
	MDLS	100,000	6
	MDLS (MAF)	100,000	6
	HDLS	100,000	6
	HDLS (MAF)	100,000	6
	Spud mud (MAF)	100,000	6
Ophryotrocha labronica	Seawater-chrome LS (MAF)	100,000	6
	MDLS (MAF)	60,000	5
	HDLS (MAF)	100,000	5
	Seawater polymer	220,000	6
Neveis vexillosa	Kipnik-KC1 polymer	37,000	5
	Gel chemical XC	560,000	6
	KC1-XC-polymer	41,000	5
	Weighted shell polymer	23,000	5
	Weighted gel XC-polymer	320,000-560,000	6
	Imnak gel-XC-polymer	200,000	6
TELEOST FISH	Imco LDLS/SW	56,500-175,000	5-6
Menidia	Imco Lime	43,000-53,000	5
	Imco non-dispersed	345,000-385,000	6
	Saltwater gel	100,000	6
	LDLS-SW/FW	48,500	5
	FCLS	100,000	6
	FCLS/FW	3,000-29,000	4-5
Oncorhynchus gorbuscha	FCLS/FW	100,000-200,000	6
Leptocuttus armatus	CMC-Gel	120,000	6
Myoxocephalus quadricornis	CMC-Gel-Resinex	50,000-70,000	5
	XC-Polymer	50,000-215,000	5-6
	XC-Polymer (supernatant)	250,000	6
	Lignosulfonate	350,000	6
	CMC-Gel	200,000	6
	XC-Polymer	57,000-370,000	5-6
Coregonus nasus	XC-Polymer (supernatant)	100,000-250,000	6
	Lignosulfonate	0-100,000	6
	CMC-Gel	170,000-300,000	6
	XC-Polymer	250,000	6
Elegonus naraga	Lignosulfonate	200,000-250,000	6
Boreogodus saida	Lignosulfonate	85,000-1,000,000	6
	Spud mud (MAF)	100,000	6
Coregonus autumnalis	Seawater-LS (MAF)	100,000	6
Fundulus heteroclitus	MDLS (suspended whole mud)	15,000	5

Test Organism	Fluid Description[a]	Criterion Value (ppm)	Toxicity Ratin
	MDLS (MAF)	100,000	6
	HDLS (suspended whole mud)	15,000	6
	HDLS (MAF)	100,000	6
	Kipnik-KC1 polymer	24,000-42,000	5
Salmo gairdneri (juvenile)	Seawater polymer	130,000	6
	KC1-XC polymer	34,000	5
	Weighted shell polymer	16,000	5
	Pelly gel chemical-XC	42,000	5
	Weighted gel XC-polymer	18,000-48,000	5
	Imnak-Gel XC-polymer	42,000	5
	Kipnik-KC1 polymer	29,000	5
	Seawater polymer	130,000	5
Oncorhynchus kisutch (juvenile)	KC1-XC polymer	20,000-23,000	5
	Weighted shell polymer	4,000-15,000	4-5
	Pelly Gel chemical-XC	28,000-130,000	5-6
	Weighted gel XC-polymer	24,000-190,000	5-6
	Imnak-Gel XC-polymer	23,000-30,000	5
	Kipnik-KC1 polymer	24,000	5
O. keta (juvenile)	Kipnik-KC1 polymer	41,000	5
O. gorbuscha (juvenile)			
DRILLING FLUID COMPONENTS			
Skeletonema costatum	Barite	385-1,650	3-4
	Aquagel	9,600	4
Arcartia tonsa	Barite	590	3
	Aquagel	22,000	5
Pandalus hypsinotus	Barite	100,000	6
	Aquagel	100,000	6
Molliensias latipinna	Barite	100,000	6
	Calcite	100,000	6
	Siderite	100,000	6
	Chrome lignosulfonate	7,800-12,200	4-5
	Quebracho	135-158	3
	Lignite	15,500-24,500	5
	Sodium acid pyrophosphate	1,200-7,100	4
Penaeus setiferus	Hemlock bark extract	265	3
	Polyacrylate	3,500	4
	$CaCO_3$ workover additive	1,925	4
	Chrome-treated lignosulfonate	465	3
	Lead-treated lignosulfonate	2,100	4

Table footnotes and references appear on following page.

Appendix A. Footnotes and References

[a] Drilling fluids abbreviations (test fractions in parenthesis):

WM = Whole mud
MAF = Mud aqueous fraction
FMAF = Filtered mud aqueous fraction

SW = Saltwater dispersed
FW = Freshwater dispersed
LS = Lignosulfonate

SPP = Suspended particulate phase
SP = Solid phase
LP = Liquid phase
LDLS = Low-density lignosulfonate
MDLS = Medium-density lignosulfonate
HDLS = High-density lignosulfonate
LTLS = Lightly-treated lignosulfonate
FCLS = Ferrochrome lignosulfonate

[b] Toxicity ratings as per Hocutt & Stauffer, 1980.

1. Very toxic (1 ppm)
2. Toxic (1-100 ppm)
3. Moderately toxic (100-1,000 ppm)
4. Slightly toxic (1,000-10,000 ppm)
5. Practically non-toxic (10,000-100,000 ppm)
6. Non-toxic (100,000 ppm)

[c] References:

1. IMCO Services, 1977.
2. Shell Oil Co., 1976.
3. Atlantic Richfield, 1978.
4. Tornberg et al., 1980.
5. Gerber et al., 1980.
6. Neff et al., 1980.
7. Conklin et al., 1980.
8. Environmental Protection Service, 1976.
9. Conklin et al., 1983.
10. Capuzzo and Derby, 1982.
11. Duke et al., 1984.
12. Carr et al., 1980.
13. Grantham and Sloan, 1975.
14. Hollingsworth and Lockhart, 1975.
15. Chesser and McKenzie, 1975.

Appendix B. Metal Enrichment Factors in Shrimp, Clams, Oysters, and Scallops Following Exposure to Drilling Fluids and Drilling Fluid Components

Test Organism	Test Substance Concentration (ppm)	Exposure Period (days)	Metals Enrichment Factor [a]				
			Ba	Cr	Pb	Sr	Zn
Palaemonetes pugio [b]	Barite						
Whole animal not	5	7, 48-hr replacement	150			1.3	
gutted	50	(after 14-d depuration)	350			1.9	
	5	(after 14-d depuration)	2.2			1.8	
	50		29			2.2	
	Barite	8 days post-ecdysis,					
Carapace	(500)	range = 8-21	7.7			1.2-2.5	
Hepatopancreas	(500)	(48-hour replacement)	13			1.9-2.8	
Abdominal muscle	(500)		12			1.5-2.8	
	Barite	106					
Carapace	(500)		60-100			1.6-7.4	
Hepatopancreas	(500)		70-300			0.03	
Abdominal muscle	(500)		50-120			0.71	
Rangia cuneata [c]	12.7 lb/gal						
(soft tissue)	lignosulfonate fluid	4, static		1.4	1.7		
	(50,000 MAF)	(after 4-dy depuration)		1.1	1.2		
	13.4 lb/gal	16, static		2.5			
	lignosulfonate fluid	(after 1-dy depuration)		1.7			
	(100,000 MAF)	(after 14-dy depuration)		1.6			
		4, daily replacement					
	Layered solid phase	(after 1-dy depuration)		4.3			
				2.0			
Crassostrea gigas [c]	9.2 lb/gal spud fluid						
(soft tissue)	(40,000 MAF)	10, static			2.1		1.1
	(10,000 SPP)	4, 24-hr replacement		2.5			
	(20,000 SPP)			3.0			
	(40,000 SPP)			3.0			
	(60,000 SPP)			5.5			
	(80,000 SPP)			7.4			

Source: Adapted from Petrazzuolo, 1983; footnotes at end of table.

Appendix B. Metal Enrichment Factors in Shrimp, Clams, Oysters, and Scallops Following Exposure to Drilling Fluids and Drilling Fluid Components (cont.)

Test Organism	Test Substance Concentration (ppm)	Exposure Period (days)	Metals Enrichment Factor [a]				
			Ba	Cr	Pb	Sr	Zn
Crassostrea gigas	12.7 lb/gal						

Test Organism	Test Substance Concentration (ppm)	Exposure Period (days)	Metals Enrichment Factor [a]				
			Ba	Cr	Pb	Sr	Zn
(soft tissue cont.)	lignosulfonate fluid						
	(40,000 MAF)	10, static			2.3		1.4
	(20,000 MAF)	14		2.9			
	(40,000 MAF)	14		3.9			
	(10,000 SPP)	4, 24-hr replacement		2.2			
	(20,000 SPP)			4.4			
	(40,000 SPP)			8.6			
	(60,000 SPP)			24			
	(80,000 SPP)			36			
	17.4 lb/gal lignosulfonate fluid						
	(40,000 MAF)	10, static			0.56		1.0
	(20,000 MAF)	14		2.1			
	(40,000 MAF)	14		2.2			
Placopecten magellanicus [d]	Uncirculated lignosulfonate fluid						
Kidney	(1,000)	28	8.8	2.6			
Adductor muscle	(1,000)	28	10	1.2			
	Low density lignosulfonate fluid						
Kidney	(1,000)	14		1.6			
		27		2.1			
		(after 15-dy depuration)		2.3			
Adductor muscle	(1,000)	14		2			
		27		2			
		(after 15-dy depuration)		2			
	FCLS (30)	14		5.7			
		(after 15-dy depuration)		3.2			
	(100)	14		6.0			
		(after 15-dy depuration)		5.2			
	(1,000)	14		7.2			
		(after 15-dy depuration)		6.0			

[a] Enrichment factor = concentration in exposed group/concentration in controls.
[b] Source: Brannon and Rao, 1979.
[c] Source: McCulloch et al., 1980.
[d] Source: Liss et al., 1980.

ESSENTIAL FISH HABITAT ASSESSMENT

National Pollutant Discharge Elimination System (NPDES) General Permit
for the Eastern Portion of the Outer Continental Shelf (OCS)
of the Gulf of Mexico (GEG460000)

Project Description

The Regional Administrator of EPA Region 4 is proposing to reissue a National Pollutant Discharge Elimination System (NPDES) general permit for its jurisdictional area in the Outer Continental Shelf (OCS) of the Gulf of Mexico (General Permit No. GEG460000) for discharges in the Offshore Subcategory of the Oil and Gas Extraction Point Source Category (40 Code of Federal Regulations (CFR) part 435, subpart A). The existing general permit which became effective on April 1, 2010, expired on March 31, 2015, and has been administratively continued, authorizes discharges from exploration, development, and production facilities located in and discharging to all Federal waters of the Gulf of Mexico seaward of the outer boundary of the territorial seas.

The proposed draft NPDES permit covers existing and new source facilities in the Eastern Planning Area with operations located on Federal leases occurring in water depths seaward of 200 meters, occurring offshore the coasts of Alabama and Florida. The western boundary of the coverage area is demarcated by Mobile and Visoca Knoll lease blocks located seaward of the outer boundary of the territorial seas from the coasts of Mississippi and Alabama in the Central Planning Area (CPA). The eastern boundary of the coverage area is demarcated by the Vernon Basin leases north of the 26° parallel and in water depths seaward of 200 meters. This permit does not cover areas included under Congressional or Presidential moratorium for oil and gas activities in Federal waters.

As proposed, these NPDES general permits include best practicable control technology currently available (BPT), best conventional pollutant control technology (BCT), and best available technology economically achievable (BAT) limitations for existing sources and new source performance standards (NSPS) limitations for new sources as promulgated in the effluent guidelines for the offshore subcategory at 58 FR 12454 and amended at 66 FR 6850 (March 4, 1993 and January 22, 2001 respectively).

Background Information Concerning General Permits

Section 301(a) of the Clean Water Act (CWA or the Act), U.S.C. 1311(a), provides that the discharge of pollutants is unlawful except in accordance with the terms of a National Pollutant Discharge Elimination System (NPDES) permit. CWA section 402, 33 U.S.C. 1342, authorizes EPA to issue NPDES permits allowing discharges on condition they will meet certain requirements, including CWA sections 301, 304, and 401, 33 U.S.C. 1311, 1314, and 1341.

EPA may issue NPDES permits to operators of individual facilities or general permits to a class of similar dischargers within a discreet geographical area. Issuance of general permits is not controlled by the procedural rules EPA uses for individual permits, but is instead subject to section 4 of the Administrative Procedure Act (APA), 5 U.S.C. 553, as supplemented by EPA regulations, e.g., 40 CFR 124.58. EPA must, however, comply with the substantive requirements of the CWA without regard to whether it is issuing an individual or general NPDES permit.

At the time of issuance for the previous NPDES general permit, a 2009 final Environmental Assessment (EA) was published. Prior to that EA, a 2004 Supplemental EIS was published in support of the NPDES general permit that included an authorization to discharge drill cuttings wetted with synthetic drilling fluids. A 1998 Final EIS in support of the 1998 general permit concluded that because of the abundance and sensitivity of the biological resources present from 200 meters of depth and shallower and potential secondary impacts, individual permits for these areas which incorporate permit stipulations on a case-by-case review would be more protective of the numerous biological communities present in the 200 meter water depths or shallower, and help ensure compliance with Section 403(c) of the CWA. This strategy required current, or proposed, oil and gas operations shoreward of the 200 meter water depth to seek individual existing source or new source permits, as appropriate.

In order to update information used for the 2016 EA, a draft Environmental Assessment has been prepared which reviews available data and studies on discharges from oil and gas facilities and the potential for these discharges resulting in impacts to physical and biological resources of short and long term duration. Though no new or additional waste streams are proposed in this permit, the draft EA evaluates impacts of the Deep Water Horizon spill to GOM resources with emphasis on whether those impacts may have affected sensitivity to authorized waste streams.

Description of Activities, Facilities and Discharges Subject to the Proposed Draft Permit

The Oil and Gas Extraction Point Source Category (40 CFR part 435 - subpart A) includes facilities engaged in field exploration, development and well production and well treatment. Exploration facilities are fixed or mobile structures engaged in the drilling of wells to determine the nature of potential hydrocarbon reservoirs. A development facility is any fixed or mobile structure engaged in the drilling and completion of productive wells, which may occur prior to, or simultaneously with production operations. Production facilities are fixed or mobile structures engaged in well completion or used for active recovery of hydrocarbons from producing formations.

The proposed general permit will authorize the following discharges to occur in water depths seaward of the 200 meter water depth: drilling muds; drill cuttings; produced water; well treatment fluids; workover fluids; completion fluids; deck drainage, sanitary wastes; domestic wastes, desalinization unit discharges, blowout preventer fluid; fire control system test water; non-contact cooling water; uncontaminated ballast water; uncontaminated bilge water; excess cement slurry; and mud, cuttings and cement at the seafloor. The proposed permits will authorize discharges from facilities engaged in field exploration, development and well production and well treatment, for offshore operations for both existing and new sources occurring seaward of the 200 meter water depth.

Fish Habitat Overview

According to the final 1998 Environmental Impact Statement, and NEPA documentation prepared in support of subsequent general permit renewals, which discuss the habitat in the eastern portion of the Gulf of Mexico OCS, the coverage area of the draft general Permit is known to support commercially important invertebrates and bottom fishes including penaeid shrimp, stone crab, spiny lobster, grouper, snapper, jack, mackerel and drum. The proposed draft General Permit coverage area consists of a wide variety of marine habitats including soft sands and both low and high-relief live bottom habitat, supporting virtually all of the commercially important fishes and invertebrates in the central, eastern and northern Gulf, including deep-water species.

Assessment and Ecological Notes on the EFH Fisheries and Species

The seasonal and year-round locations of designated EFH for the managed fisheries are depicted on figures available on the NMFS' Galveston web page (http://ccma.nos.noaa.gov/products/biogeography/gom-efh). NMFS selected 27 species from seven existing Fisheries Management Units (FMUs). Table 1 lists the 26 species (plus various coral reef fish assemblages) which are known to reside in Gulf waters and which are managed under the Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA). The listed species are considered ecologically significant to their respective FMU, and their collective habitat types occur throughout marine and estuarine waters in the Gulf.

Table 1. Essential Fish Habitat Species within the Central and Eastern Gulf of Mexico

Species	Life Stage Ecotype	EFH
Brown shrimp Greatest abundance From Apalachicola Bay to Mexico	eggs larvae adults	<110m, demersal <110m, planktonic <110m, silt sand, muddy sand
White shrimp Greatest abundance from Suwannee River to Mexico	eggs larvae adults	<40m, demersal <40m, planktonic <33m, silt, soft mud
Pink shrimp Greatest abundance in Florida	eggs larvae adults	<65m, demersal <65m, planktonic <65m, sand/shell substrate

Table 1. Essential Fish Habitat Species within the Central and Eastern Gulf of Mexico		
Species	**Life Stage Ecotype**	**EFH**
Royal red Shrimp Greatest abundance in terrigenous silt and silty sand & calcareous mud	adults	250 - 500m,
Red drum Greatest abundance from Florida through Texas	eggs larvae postlarvae/juvenile adults	planktonic planktonic SAV, estuarine mud bottoms, marsh/water interface Gulf of Mexico & estuarine mud bottoms, oyster reef
Red grouper Greatest abundance in eastern Gulf of Mexico (W. FL Shelf)	eggs juvenile adults	planktonic, 25-50 meters hard bottoms, SAV, reefs reefs, ledges, outcrops
Black grouper Greatest abundance in eastern Gulf of Mexico	juvenile adults	FL estuaries & Gulf of Mexico rocky coral reefs to 150 m
Gag grouper Greatest abundance in eastern Gulf of Mexico	eggs juvenile adults	planktonic SAV & oyster beds in coastal lagoons and estuaries hard bottoms, reefs, coral; 10 -100 m
Scamp Greatest abundance in eastern Gulf of Mexico	juvenile adults	hard bottoms, reefs; 12-33m hard bottoms; 12-189m
Red snapper Greatest abundance from Florida through Texas	larvae postlarvae/juvenile adults	structure, sand/mud; 17-183m structure, sand/mud; 17-183m reefs, rock outcrops, gravel; 7-146m
Vermilion snapper Greatest abundance from Florida through Texas	juvenile	reefs, hard bottom, 20-200m
Gray snapper Greatest abundance in eastern Gulf of Mexico	larvae adults	planktonic SAV, mangrove, sand, mud
Yellowtail snapper Greatest abundance in eastern Gulf of Mexico	juvenile adults	SAV, mangrove, sand, mud reefs
Lane snapper Greatest abundance in Florida & Texas	juvenile adults	SAV, mangrove, sand, mud reefs, sand, 4-132m
Greater amberjack Greatest abundance from Florida through Texas	juvenile adults	floating plans (Sargassum), debris oil rigs, irregular bottom features
Lesser amberjack Greatest abundance from Florida through Texas	juvenile adults	floating plans (Sargassum), debris oil rigs, irregular bottom features

Table 1. Essential Fish Habitat Species within the Central and Eastern Gulf of Mexico

Species	Life Stage Ecotype	EFH
Tilefish Greatest abundance from Florida through Texas	juvenile adults	burrows rough bottom, 250-350m
Gray triggerfish Greatest abundance in FL & LA/TX Shelves	eggs larvae postlarvae/juvenile adults	sand floating plans (Sargassum), debris floating plans (Sargassum), debris, mangrove reefs, >10m
King mackerel Greatest abundance in F & LA/TX Shelves	juvenile adults	pelagic pelagic
Spanish mackerel Greatest abundance from Florida through Texas	larvae juvenile adults	<50 meter isobath offshore, beach, estuarine pelagic
Cobia Greatest abundance from Florida through Texas	eggs larvae postlarvae/juveile adults	pelagic estuarine & shelf coastal & shelf coastal & shelf
Dolphin Greatest abundance from Florida through Texas	larvae postlarvae/juvenile adults	epipelagic epipelagic epipelagic
Bluefish Greatest abundance from Florida through Texas	postlarvae/juvenile adults	beaches, estuaries, inlets Gulf and estuaries, pelagic
Little tunny Greatest abundance from Florida through Texas	postlarvae/juvenile adults	coastal & shelf, pelagic coastal & shelf, pelagic
Stone crab Greatest abundance in estuaries from Florida to Texas	larvae juvenile adults	planktonic, moderate-high salinity shell, SAV shell, SAV, coral
Spiny lobster Greatest abundance in eastern Gulf of Mexico	larvae juvenile adults	algae, SAV sponge, coral hard bottoms, crevices
Coral FlowerGardens FL Middle Grounds	all stages	

Source: Essential Fish Habitat: A Marine Fish Habitat Conservation Mandate for Federal Agencies, NMFS, St. Petersburg, FL, October 2000.

The EFH assessment is based on species distribution maps and habitat association tables. In offshore areas, EFH consists of those areas depicted as “adult areas”, “spawning areas”, and “nursery areas”. A determination of potential impacts to the selected species according to the indicated abundance within the area of the permitted disposal site has been made.

Shrimp Fishery

The brown, white and pink shrimp yields in the Gulf are highly dependent upon the abundance and health of estuarine marshes and seagrass beds. The prey species (food source) for these shrimp also depend on similar vegetated coastal marshes and seagrass beds.

Brown Shrimp

Brown shrimp are generally more abundant in the central and western Gulf and found in the estuaries and offshore waters to depths of 360 feet. Postlarve and juveniles typically occur within estuaries while adults occur outside of bay areas. In estuaries, brown shrimp postlarve and juveniles are associated with shallow vegetated habitats, but also are found over silty sand and non-vegetated mud bottoms. In Florida, adult areas are primarily seaward of Tampa Bay, and associated with silt, muddy sand, and sandy substrates.

Spawning area: Florida waters to edge of continental shelf; *year round*

Nursery area: Tampa Bay

White Shrimp

White shrimp are offshore and estuarine dwellers, and are pelagic or demersal depending on their life stage. The eggs are demersal and larval stages are planktonic, and both occur in nearshore marine waters. Adult white shrimp are demersal and generally inhabit nearshore Gulf waters in depths less than 100 feet on soft mud or silty bottoms. In Florida, white shrimp are not common east or south of Apalachee Bay, and are not expected to be impacted by the discharges.

Spawning area: off Mississippi and Alabama; *March to October*

Nursery area: Mississippi Sound

Pink Shrimp

Juvenile pink shrimp inhabit most estuaries in the Gulf, but are most abundant in Florida. Juveniles are commonly found in estuarine areas with seagrass. Postlarve, juvenile, and subadults may prefer coarse sand/shell/mud mixtures. Adults inhabit offshore marine waters, with the highest concentration in depths of 30 to 144 feet. According to the NMFS species distribution map, pink shrimp use Tampa Bay from the larval stage until the species matures to the late juvenile stage.

Spawning area: Mississippi, Alabama, and Florida offshore; year round

Nursery area: major nursery areas in Tampa Bay and Florida west coast state waters; *summer and fall in the northern Gulf*

Royal Red Shrimp

Royal red shrimp are most abundant in the northeastern Gulf in water depths between 820 and 1,640 feet. Little is known about the larvae. Distribution maps were not available by the NMFS for the royal red shrimp due to the limited knowledge and information available for the species. The permitted discharges will take place at or near the surface, thus there should be no impact on the primary EFH.

Spawning area: unknown

Nursery area: unknown

Red Drum Fishery

Red Drum

In the Gulf, red drum occur in a variety of habitats, ranging from depths of about 130 feet offshore to very shallow estuarine waters. They commonly occur in all of the Gulf's estuaries where they are associated with a variety of substrate types including sand, mud, and oyster reefs. Estuaries are important to red drum for both habitat requirements and for dependence on prey species which include shrimp, blue crab, striped mullet and pinfish. The GMFMC considers all estuaries to be EFH for the red drum. Schools of large red drum are common in the deep Gulf waters with spawning occurring in deeper water near the mouths of bays and inlets, and on the Gulf side of the barrier islands. The Tampa Bay EFH estuarine map shows red drum juveniles to be abundant or highly abundant in the fall and winter and common in the spring and summer.

Spawning area: Gulfwide from nearshore to just outside state waters, *fall and winter*

Nursery area: major bays and estuaries including Mobile Bay and Tampa Bay, *year round*

Reef Fishery

Many species of snapper and grouper (mutton, dog, lane, gray and yellowtail snapper- and red, gag and yellowfin groupers) occupy inshore areas during juvenile stages where they feed on estuarine-dependent prey. As these species mature they generally move to offshore waters and change their feeding habits. However, reef fishery species still depend on estuarine species for prey.

Red Grouper

The red grouper is demersal and occurs throughout the Gulf at depths from 10 to about 650 feet, preferring 100 to 400 foot depths. Juveniles are associated with inshore hard bottom habitat, and grassbeds, rock formations, while shallow reefs are preferred for nursery areas. Species distribution maps show that spawning for the red grouper occurs throughout much of the Gulf waters off Florida, including the Florida Middle Grounds. Nursery areas occur within and around the selected disposal site.

> *Spawning area:* Florida continental shelf, well offshore, extending from south of Apalachicola Bay all the way to west of the Florida Keys; *April to May*
>
> *Nursery area:* extensively throughout the continental shelf off Florida and along the northern *Gulf, year round*

Black Grouper

The black grouper occurs in the eastern half of the Gulf. The species is demersal and is found from shore to depths of 500 feet. Adults occur over wrecks and rocky coral reefs. Juveniles travel into estuaries occasionally (NCAA 1985). Species distribution maps for the black grouper indicate that the range of the species occurs within the Gulf, outside of state waters.

> *Spawning area:* throughout eastern Gulf to 500 foot depth, *spring and summer*
>
> *Nursery area:* probably the same as the red grouper

Gag Grouper

The gag grouper is demersal and is most common in the eastern Gulf, especially the west Florida shelf. Post larvae and pelagic juveniles move through inlets, coastal lagoons and high salinity estuaries in April-May where they settle into grass flats and oyster beds. Late juveniles move offshore in the fall. Adults prefer hard bottom areas, offshore reefs and wrecks, coral and live bottom. The species EFH distribution maps indicate presence throughout the Gulf including estuarine areas.

> *Spawning area:* spawning areas are not specified on EFH maps
>
> *Nursery area:* pelagic waters until post larvae or juvenile

Scamp

Scamp are demersal and widely distributed in the shelf areas of the Gulf, especially off of Florida. Juveniles prefer inshore hard bottoms and reefs in depths of 40 to 108 feet. Adults prefer high relief hard bottom areas. The species EFH distribution maps indicate presence throughout the Gulf including estuarine areas. Presence in these areas is based only on records for adults.

Spawning area: spawning area not specified in the EFH maps

Nursery area: nurseries not specified in the EFH maps

Red Snapper

Red snapper are demersal and found over sandy and rocky bottoms, around reefs, and underwater objects in depths to 656 feet. Juveniles are associated with structures, objects or small burrows, or barren sand and mud bottoms in shelf waters ranging from 55 to 600 feet. Adults favor deeper water in the northern gulf preferring submarine gullies and depressions, and over coral reefs, rock outcroppings, and gravel bottoms. Spawning occurs in offshore waters over fine sand bottoms away from reefs. Gulf distribution map show red snapper nursery areas within the estuarine waters of the Mississippi Sound, and Tampa Bay offshore of state waters

Spawning area: spawning occurs throughout the Gulf, *June to October*

Nursery area: extensive throughout the Gulf, *year-round,* including Mississippi Sound and Tampa Bay

Vermillion Snapper

Vermillion snapper are found over reefs and rocky bottom from depths of 7 to 656 feet in the shelf areas of the Gulf spawning occurs in offshore areas, with juveniles occupying the same areas as the adults.

Spawning area: EHF maps not available, not specified in literature reviewed

Nursery area: EHF maps not available, not specified in literature reviewed

Gray Snapper

The gray snapper generally occurs in the shelf waters of the Gulf and is particularly abundant in south and southwest Florida. Gray snapper occur in almost all of the Gulf's estuaries but are most common in Florida. Adults are demersal and mid-water dwellers, occurring in marine, estuarine, and riverine habitats. They are found among mangroves, sandy grassbeds, and coral reefs, and over sandy muddy bottoms. Spawning occurs offshore, with post larvae moving into estuarine habitat over dense beads of *Halodule* and *Syringodium* grasses. Juveniles are marine, estuarine, and riverine found in most types of habitats. They appear to most prefer Thalassia grass flats, marl bottoms, seagrass meadows and mangrove roots. Species distribution maps indicate that nursery areas exist within estuarine areas including the Mississippi Sound and Tampa Bay.

Major adult areas are encountered from the Mississippi Sound across Gulf waters to west of Tampa Bay, where year round adult areas occur within Florida state waters and into the southern half of Tampa Bay.

Spawning area: spawning areas probably exist in the Gulf off many of the nursery areas, but have not been positively identified

Nursery area: found in coastal waters throughout the Gulf, including Mississippi Sound and Tampa Bay

Yellowtail Snapper

Juvenile yellowtail snapper are found in nearshore nursery areas over vegetated sandy substrate and in muddy shallow bays (NCAA 1985). *Thalassia* beds and mangrove roots are preferred habitat of the gray snapper. Late Juvenile and adults prefer shallow reef areas. According to the Gulf distribution map, this species has nursery areas within the 3 League Line and Tampa Bay. Spawning and adult areas occur in Gulf waters outside of the 3 League Line through the Florida Middle Ground and southern Apalachicola areas. EFH is not designated in the state waters of Mississippi or Alabama.

Spawning area: west and north of Tampa Bay; *spring and summer*

Nursery area: throughout the western and southern coast of Florida, including Tampa Bay

Lane Snappers

The snappers seem to prefer mangrove roots and grassy estuarine areas as well as sandy and muddy bottoms. Juveniles favor grass flats, reefs and soft bottom areas, to offshore depths of 66 feet (NCAA 1985). Adults occur offshore at sand bottoms, natural channels, banks, and manmade reef and structures. Gulf distribution maps indicate that the lane snapper use shallow coastal waters including the Mississippi Sound and Tampa Bay and areas outside of state waters as nursery areas.

Spawning area: throughout the adult areas, *summer*

Nursery areas: shallow coastal areas throughout the Gulf including Mississippi Sound and Tampa Bay.

Greater Amberjack

Greater amberjack seem to prefer habitats that are marine but not estuarine. Based on the Gulf distribution maps, greater amberjack occur outside the barrier islands across Gulf waters, and usually over reefs, wrecks and around buoys. Spawning and nursery areas are similar.

Spawning area: throughout the adult areas in most of the Gulf; *year round*

Nursery area: throughout the adult areas; *year round*

Lesser Amberjack

Juvenile lesser amberjack are found offshore in the late summer and fall in the northern Gulf, along with smaller juveniles, in areas associated with sargassum. Adults and spawning areas are found offshore year round in the northern gulf where they are associated with oil and gas rigs and irregular bottom. The Gulf distribution map shows the range of the species throughout the majority of the Gulf and into the Atlantic coastline.

Spawning area: in adult areas, offshore, in the northern Gulf; *year round*

Nursery area: probably similar to adult areas year round; EHF map not available

Tilefish

Tilefish occur throughout the deeper waters of the Gulf. The permitted discharges will take place at or near the surface, thus there should be no impact on the primary EFH.

Spawning area: throughout the adult area from *March to September*

Nursery area: throughout the adult area; *year round*

Triggerfish

Larval and juvenile gray triggerfish are associated with grassbeds (Sargassum) and mangrove estuaries. Adults seem to prefer offshore waters associated with reefs. A general species distribution map was not available, however a map showing catches per hour by trolling methods within the Gulf was available from the National Oceanic and Atmospheric Administration (NOAA) Southeast Atlantic (SEA), the EFH web page (http://christensenmac.nos.noaa.gov/gom-efli/gtrigger.gif). This map indicated that there is a record of occupancy for gray triggerfish in state waters of Mississippi/Alabama and Florida.

Spawning area: EHF map not available; assumed to be adult preferred areas offshore.

Nursery area: EHF map not available; assumed to be estuarine areas throughout the Gulf

Coastal Migratory Pelagic Fishery

Collectively, these species are commonly distributed from the estuaries throughout the marine waters of the entire Gulf. However, estuaries are very important, since they contain the major prey base for these species.

King Mackerel

King mackerel are found throughout the Gulf and seldom venture into brackish waters. Juveniles occasionally use estuaries but are not estuarine dependent, and nursery areas occur in marine environments. According to the species distribution map, adult areas are also used for nurseries and spawning (May to November). These areas occur outside of the Mississippi Sound, across state waters, throughout the Gulf and into Tampa Bay.

> *Spawning area:* throughout the Gulf, estuaries and coastal waters in adult areas; *May to November.*
>
> *Nursery area:* adult areas; *year round,* marine waters, estuaries used occasionally

Spanish Mackerel

Adult spanish mackerel tolerate brackish to oceanic waters and often inhabit estuaries. Estuarine and coastal waters also offer year round nursery habitat. Juveniles appear to prefer marine salinities and sandy bottoms. Adults and spawning areas typically occur in offshore areas. According to the species distribution map, EFH for adult and nursery areas occurs throughout the selected disposal site. Spawning areas occur in Gulf waters off the coast of Florida.

> *Spawning area:* waters off the coast on the western *(Summer and Fall)* and eastern Gulf *(Spring and Summer)*
>
> *Nursery area:* coastal waters throughout the Gulf

Cobia

Cobia only occasionally inhabit estuaries. Spawning occurs in nearshore areas and larvae are found in estuarine and offshore waters. Nursery areas are the same as the adult areas which include coastal areas, bays and river mouths (NCAA 1985). The range of cobia extends throughout the Gulf nearshore areas, with the summer adult areas and vear-round nursery areas from the Mississippi Sound into Gulf waters and to the adult area (spring, summer, and fall) and year round nursery area that extends from just inside Gulf water, halfway into Tampa Bay.

> *Spawning area:* occurs throughout the adult areas except in bays and estuaries in the northern Gulf, Spring and Summer

Nursery area: coastal areas, bays and river mouths

Dolphin (Mahi-Mahi)

Dolphin are primarily an oceanic species, but occasionally enter coastal waters with high enough salinity. They are common in coastal waters of the northern Gulf mainly during the summer months. It is an epipelagic species known for aggregating underneath or near floating objects, especially Sargassum. Spawning occurs throughout the adult areas of the open Gulf year-round, with peaks in early spring and fall. Larvae are usually found over depths of greater than 50 meters and are most abundant at depths over 180 meters. Adults occur over depths up to 1,800 meters, but are most common in waters at 40 to 200 meters in depth. Nursery areas are year round in oceanic and coastal waters where salinity is high.

Spawning: throughout the adult areas in open waters of the Gulf; *year round*

Nursery area: throughout the adult areas in open waters of the Gulf; *year round*

Bluefish

Bluefish can be found in Gulf estuaries but are more common in estuaries and waters of the Atlantic Ocean. Spawning grounds are located on the outer half of the continental shelf Nursery areas occur inshore along beaches and in estuaries, inlets and rivers (NCAA 1985). Gulf distribution maps were not available for this species and therefore EFH could not be identified, but may be assumed to include nursery areas within the Mississippi Sound and Tampa Bay.

Spawning area: not specified in literature reviewed, EHF map not available

Nursery area: not specified in literature reviewed; EHF map not available, but probably exists within the Mississippi Sound and Tampa Bay

Little Tunny

Little tunny are pelagic species most often occurring in coastal areas with swift currents and near shoals. Spawning and nursery areas occur in the same coastal pelagic waters. Gulf distribution maps for adult areas indicate a range throughout the Gulf coastal areas.

Spawning area: EHF map not available; literature reviewed suggests the potential existence of spawning areas within the disposal site.

Nursery area: EHF map not available; literature reviewed suggests the potential existence of spawning areas within the disposal site.

Stone Crab Fishery

Stone Crabs

Adult stone crabs burrow under rock ledges, coral heads, dead shell or grass clumps and occasionally inhabit oyster bars and rock jetties. Juveniles are abundant on shell bottoms, sponges, and Sargassum mats, as well as in channels and deep grass flats. Some juvenile and small adults inhabit oyster reefs. Adults and juveniles appear to be hardy: they tolerate most environmental extremes within their distributional range and are capable of surviving salinities considerably higher or lower than 33 parts per thousand. Stone crab populations are dependent on prey produced in estuaries and seagrass beds along the west Florida coast particularly in the Everglades-Florida Bay area. The selected disposal site is within the range of the stone crab and extends throughout the entire Gulf with nursery areas in the estuaries, and spawning and adult areas in state and Gulf waters and the majority of the Florida Middle Ground.

Spawning area: State and Gulf waters, including the Mississippi Sound and waters off of Tampa Bay; *March to October*

Nursery area: not in the area of the proposed permitted discharge

Spiny Lobster Fishery

Spiny Lobster

The principal habitat for the spiny lobster is offshore reefs and seagrass. Spiny lobsters spawn in offshore waters along the deeper reef fringes. Adults are known to inhabit bays, lagoons, estuaries, and shallow banks. According to the species distribution map, spiny lobsters use the lower half of Tampa Bay for nursery areas. According to the GMFMC, Tampa Bay seems to be the upper limit for spiny lobster abundance due to the higher salinities found south of the Bay. The Tampa Bay-specific distribution map indicates that spiny lobster in the Bay are rare. However, the Gulf distribution maps indicate that Tampa Bay is used as an adult area year round, and as a nursery area. Spiny lobster are known to occur in northern and western Gulf habitats, but these area are not designated EFH.

Spawning area: throughout the adult area, particularly north and south of Tampa Bay; *March to July*

Nursery area: lower half of Tampa Bay used as nursery; *year-round*

Coral and Coral Reefs

The three primary areas in the Gulf where corals are concentrated are the East and West Flower Garden Banks, the Florida Middle Grounds, and the extreme southwestern tip of the Florida Reef Tract. No coral reefs exist within the area of coverage for the proposed draft General Permit.

Highly Migratory Species

In addition to the managed fish species described in the previous section, another group of fish with highly migratory habits have also been examined. This group includes billfish (blue marlin, white marlin and sailfish), swordfish, tunas (yellow fin, bluefin and skipjack), and of sharks (black tip, bull, dusky, silky, mako, Atlantic sharpnose, tiger and longfin mako). Most are found beyond the 50, 100 and 200 meter contours. Considering their highly mobile nature and the minor amount of area affected by the draft permit, relative to the entire available habitat, significant effects to these species would be unlikely.

Assessment of Essential Fish Habitat and Habitat Areas of Concern in the Gulf of Mexico

Table 2 shows the categories of Essential Fish Habitat (EFH) and Habitat Areas of Particular Concern (HAPC) for managed species which were identified in the Fishery Management Plan Amendments of the Gulf of Mexico Fishery Management Council and which may occur in marine waters of the Gulf. These habitats require special consideration to promote their viability and sustainability.

Table 2. Essential fish habitat and habitat areas of particular concern in open ocean environments of the Gulf of Mexico identified in Fishery Plan Amendments of the Gulf of Mexico and presence in area affected by the proposed draft General Permit.

Essential Fish Habitat	**Presence**
Water column	Yes
Vegetated bottoms	Yes
Non-vegetated bottoms	Yes
Live bottoms	Yes
Coral reefs	No: solitary specimens may exist within affected area
Artificial reefs	Yes
Geologic features	Yes
Continental shelf features	Yes
Mississippi/Alabama shelf	Yes
West Florida shelf	Yes
Habitat Areas of Particular Concern	**Presence**

Florida Middle Grounds	No: located 50 nmi east of affected area
Florida Keys National Marine Sanctuary	No: located greater than 150 nmi south of affected area
Florida Bay	No: located greater than 150 nmi south of affected area
Flower Garden Banks National Marine Sanctuary	No: located greater than 300 nmi west of affected area
Apalachicola National Estuarine Research Reserve	No: located greater than100 nmi northeast of affected area
Rookery Bay National Estuarine Research Reserve	No: located greater than 100 nmi southeast of affected area
Weeks Bay National Estuarine Reserve	No: located greater than 20 nmi northwest of affected area
Grand Bay, Mississippi	No: located greater than 30 nmi northwest of affected area
Dry Tortugas	No: located greater than 150 nmi south of affected area
Grand Bay, Mississippi	No: located greater than 30 nmi northwest of affected area
Pulley Ridge	No: located greater than 50 nmi east of affected area
Madison-Swanson marine Reserve	No: located greater than 50 nmi east of affected area

A number of the habitat categories presented in Table 2 are not present in the area affected by the proposed draft General Permit. Impacts on habitats present or potentially present are discussed in the following paragraphs. Descriptions of the habitats were mostly excerpted from the "Generic Amendment for Addressing Essential Fish Habitat Requirements in the following Fishery Management Plans of the Gulf of Mexico."

Water Column

The major operational discharges resulting from exploration, development and production activities, drilling fluids and produced water, may have a minimum, short term effect on water column EFH.

Drilling Fluids: Federal water quality criteria are compared to effluent concentrations projected for the edge of a 100-m mixing zone to determine the ability of drilling fluid discharges to achieve sufficient mixing and occur at concentrations below criteria in the surrounding waters. Table 9-4 presents the results of calculating the minimum number of dilutions that will ensure that all criteria are met by drilling fluid discharges at 100 meters from the discharge point. The minimum number of dilutions to achieve sufficient mixing for drilling fluids is projected to be 118 (the number of dilutions required to meet the arsenic human health criterion). Compared to drilling fluids modeling results presented in Chapter 4, there appears to be significant probability that the criteria can be met by the edge of a 100-m mixing zone.

For comparison, the preferred option of the MMS EIS for this development and production project specifies a maximum 400 bbl/hr discharge rate; water depths for the proposed activity area range from approximately 30 m to 150 m. For the generalized drilling fluid modeling approach that had been performed for EPA Region 10, a 500 bbl/hr discharge in a water depth of 20 m resulted in a minimum projected dilution of 1,035; even at a 1,000 bbl/hr discharge rate the available dilution is 655 at a water depth of 20 m and 731 at a water depth of 40 m. For a 1,000 bbl/hr discharge in a 70-m water depth, the dilutions achieved at 100 meters is 1,721, 10-fold greater than the amount required to meet the most stringent Federal water quality criteria in the Gulf of Mexico.

The low toxicity of whole drilling fluids in addition to mud plume dilution of priority pollutants to levels below Federal water quality criteria within a designated 100-m mixing zone is expected to ensure minimal impacts to water column EFH.

Produced Water: Because hypersaline (salinities >150 ppt are not uncommon) produced waters are denser than ambient seawater, they tend to sink rapidly removing itself from most of the water column. Saline produced waters also dilute rapidly upon discharge to well-mixed marine waters. Dispersion modeling studies of the fate of produced water differ in specific details but all predict a rapid initial dilution of discharges by 30- to 100-fold within the first few tens of meters of the outfall, followed by a slower rate of dilution at greater distances. The fate of produced water discharged in the Gulf of Mexico modeled under typical Gulf of Mexico conditions showed that for a median produced water discharge rate of 115 m^3/d (772 bbl/d), a 500-fold dilution was predicted at 10 m from the outfall and a 1,000-fold dilutions was predicted at 100 m from the outfall. For a maximum discharge rate of 3,978 m^3/d (25,000 bbl/d), a 50-fold dilution was predicted at 100 m from the outfall.

The most abundant hydrocarbons of environmental concern in produced water are the light, one-ring aromatic hydrocarbons. Because they are volatile, they can be expected to evaporate rapidly from the water following produced water discharge. Studies (see *Ocean Discharge Evaluation for the National Pollution Discharge Elimination System General Permit for the Eastern Gulf of Mexico Outer Continental Shelf*, USEPA, 2003) reported that the maximum concentration of benzene measured in seawater immediately below the produced water discharge pipe at a production platform in the Buccaneer Field off Galveston, Texas showed a nearly 150,000-fold dilution compared to the concentration of benzene in the produced water effluent. Concentrations of total gaseous and volatile hydrocarbons, including BTEX aromatics (75 percent of the total) decreased from 22,000 ug/l in the effluent, to 65 ug/l at the air-water interface below the outfall, to less than 2 ug/l in the surface water about 50 m away, indicating very rapid evaporation and dilution of the volatile components of the produced water. Concentrations of volatile liquid hydrocarbons discharged with produced water (600 bbl/d) at the Buccaneer Field were reduced on the order of 10^{-4} to 10^{-5} within 50 m from the platform.

BTEX compounds are very volatile with half-lives in the water column of a few hours or days, depending on water temperature and mixing conditions.

The rapid sinking and dilution of produced water should minimize effects to water column EFH. In addition, the rapid volatilization of the light weight aromatic hydrocarbons reduces the probability of impacts to water column EFH.

Vegetated Bottoms

Seagrasses and macroalgae have long been recognized as important primary producers in marine habitats. Due to the depths of the areas affected by the proposed draft permit, seagrasses are unlikely to be present. The distribution of benthic algae is ubiquitous throughout the Gulf of Mexico from bays and estuaries out to depths of 200 m. It is a significant source of food for fish and invertebrates. The wide gently sloping continental shelf, particularly in the eastern Gulf, provides a vast area where benthic species of algae can become established and drift along the bottom and continue to grow even when detached from the substrate. Benthic algae also form large mats that drift along the bottom.

Non-Vegetated Bottoms

The Gulf of Mexico can be divided into two major sediment provinces, carbonate to the east of DeSoto Canyon and southward along the Florida coast, and terrigenous to the west of DeSoto Canyon past Louisiana to the Mexican border. Fine sediments are also strongly represented on the outer shelf beyond the 80-m isobath. Surface sediments may affect shrimp and fish distributions directly in terms of feeding and burrowing activities or indirectly through food availability, water column turbidity, and related factors. The discharge is expected to be buoyant and the constituents in the wastewater are not expected to come in contact with any non-vegetated bottoms.

Live Bottoms

Live bottoms are defined as those areas that contain biological assemblages consisting of such sessile invertebrates as sea fans, sea whips, hydroids, anemones, ascidians, sponges, bryozoans, seagrasses, or corals living upon and attached to naturally occurring hard or rocky formations with rough, broken, or smooth topography favoring the accumulation of turtles and fishes. These communities are scattered across the shallow waters of the west Florida Shelf and within restricted regions of the rest of the Gulf of Mexico. The Florida Middle Ground is probably the best known and most biologically developed of these areas with extensive inhabitation by hermatypic corals and related communities. This area is 160 km west-northwest of Tampa and outside the project area. The faunal assemblages of the eastern Gulf are markedly different from those of the rest of the Gulf. This difference is partially attributed to the calcareous sediments found east of DeSoto Canyon as opposed to the terrigeneous muds and sands of the central and western Gulf and the influence of the upwelling associated with the Loop Current.

Fishes associated with such live bottom habitats include the black sea bass, red grouper, white grunt, gray snapper and black grouper. The discharge is expected to be buoyant and the constituents in the wastewater are not expected to come in contact with the benthos.

Artificial Reefs

Two types of artificial reefs exist in the Gulf of Mexico, those structures intentionally placed in the water to serve as artificial reefs and those structures placed in the water to serve another purpose (oil and gas production) but still providing artificial habitat. Artificial reefs have been used to enhance fishing success in the Gulf of Mexico for many years. When the National Fishing Enhancement Act of 1984 was passed, serious attention was given to artificial reefs as fishery habitat enhancements. Florida has more than 587 sites permitted for artificial reefs on their west coast. Florida has several large general permit areas with one permit for 28,500 ha (70,395 ac). The total area permitted for artificial reefs on the west coast of Florida is 153,400 ha (378,898 ac). Historic materials used on Florida artificial reef sites have been ships, concrete rubble, oil platforms, reef modules, barges, tires, bridge spans, boxcars, car bodies, fiberglass boat molds, buses, obsolete military tanks, and airplanes. These materials are in water depths of 2 to 117 m and provide up to 27 m of relief at some sites. The reef sites off Florida vary in distance offshore, with some being near the beach while the furthest is located 87 km (47 nmi) offshore. Due to the buoyancy of the wastewater plume, it is not expected that wastewater will contact or impact these structures.

Geologic Features

Special geologic features in the project vicinity are discussed below in the discussion of the West Florida Shelf.

Continental Shelf Features

The Gulf of Mexico continental shelf varies in width from about 280 km off southern Florida to about 200 km off east Texas and Louisiana. The shelf narrows to 110 km off southwest Texas. The shelf is widest in southern Florida (300 km) and narrowest off the modern Mississippi River Delta (10 km). East of DeSoto Canyon, the shelf is mainly dominated by a thick accumulation of southeasterly trending carbonate rocks and evaporite sediments. This area has not been influenced by the massive terrigenous regime that has occurred in other parts of the Gulf. The continental shelf (0 - 200 m) occupies about 35.2 percent of the surface area of the Gulf, and provides habitats that vary widely from the deeper waters. The shelf and shelf edge of the Gulf of Mexico are characterized by a variety of topographic features. The value of these topographic features as habitat is important in several respects. Some of these features support hardbottom communities of high biomass and high diversity and an abundance of plant and animal species. These features are unique in that they are small, isolated, highly diverse areas within areas of much lower diversity. They support large numbers of commercially and recreationally important fish species by providing either refuge or food. Specific features in the project vicinity are discussed below in the discussion of the West Florida Shelf.

West Florida Shelf

The west Florida shelf is composed mainly of carbonate sediments. These sediments are in the form of quartz-shell sand (> 50 percent quartz), shell-quartz sand (< 50 percent quartz), shell sand, and algal sand. The bottom consists of a flat limestone table with localized relief due to relict reef or erosional structures. The benthic habitat types include low relief hardbottom, thick sand bottom, coralline algal nodules, coralline algal pavement, and shell rubble. The west Florida shelf provides a large area of scattered hard substrates, some emergent, but most covered by a thin veneer of sand, that allow the establishment of a tropical reef biota in a marginally suitable environment. The only high relief features are a series of shelf edge prominences that are themselves the remnants of extensive calcareous algal reef development prior to sea level rise and are now too deep to support active coral communities.

Along the west Florida shelf are areas with substantial relief. In an area south of the Florida Middle Grounds, in water depths of 46 to 63 m, is a ridge formed from limestone rock termed the Elbow, and it is about 5.4 km at its widest and has a vertical relief of 6.5 to 14 m. South of Panama City are two notable areas with high relief. The Whoopie Grounds (Madison Swanson Rocks) are located in 66 to 112 m of water and have rock ledges with 6 to 8 m of relief and are covered with coral and other invertebrate growth. The Mud Banks are formed by a ledge that has a steep drop of 5 to 7 m. The ledge extends for approximately 11 to 13 km in 57 to 63 m of water. The "3 to 5s", a series of ledges located southwest of Panama City, occur in water depths of 31 to 42 m of water. The ledges are parallel to the 36.5-m isobath and have relief of 5.5 to 9 m. The features listed above are part of a larger area of shelf-edge reefs that extend along the 75 meter isobath offshore of Panama City to just north of the Tortugus which also includes the Twin Ridges, The Edges, Steamboat Lumps (Koenig et. al: 2000). According to Koenig et. al, the northeastern portion of this area represents the dominant commercial fishing grounds for gag and contains gag and scamp spawning aggregation sites. Two of the areas (Madison/Swanson and Steamboat Lumps) were designated as marine reserves on June 19, 2002 for a four year period to protect a portion of the gag spawning aggregations and to protect a portion of the offshore population of male gag.

The areas discussed above are located along or near the eastern boundary (100 meter isobath) of the selected disposal site (see figure 1). However, due to the buoyancy of the wastewater plume, it is not expected that wastewater will contact or impact these structures.

Another west Florida shelf region with notable coral communities is bounded by the waters of Tampa Bay on the north and Sanibel Island on the south. The area consists of a variety of bottom types. Rocky bottom occurs at the 18 m contour where sponges, alcyonarians, and the scleractinians *Solenastrea hyades* and *Cladocora arbuscula* are especially prominent. This area is outside the limits of the selected disposal boundaries.

Impact Summary for Essential Fish Habitat and Federal Action Agency Determination

The Magnuson-Stevens Act implementing regulations (50 CFR 600.920(e)(3)) state that all EFH assessments must include the following information: 1) a description of the proposed action; 2) an analysis of the effects, including cumulative effects, of the proposed action on EFH, the managed species, and associated species, such as major prey species, including affected life history stages; 3) the Federal agency's view regarding the effects of the action on EFH; and 4) proposed mitigation, if applicable….

A description of the proposed action can be found on page 1 of this document. The low salinity of the treated wastewater and the mode of discharge will result in a buoyant plume spread over the water surface. Any potentially harmful physical characteristics and chemical constituents present at the time of discharge should disperse rapidly as the plume undergoes physical dilution processes. Because the wastewater plume will remain buoyant until all constituents are completely dispersed no mechanism for benthic exposure can be hypothesized. Adverse impacts to any benthic or demersal EFH are, therefore, unlikely to occur as a result of these discharges. The high degree temporal and spatial patchiness with regard to the distribution of plankton assemblages in the water column and the relatively small volume of highly concentrated effluent present within the disposal zone at any time should greatly limit plankton exposure to potentially harmful water quality conditions.

As a result of the analyses presented above, EPA has determined that the minimal short-term impacts associated with the discharge will not result in substantial adverse effects on EFH or managed species in any life history stage, either immediate of cumulative, in the project area. A summary of EPA's findings are presented in Table 3 below. Mitigation measures incorporated into the permit include:

> 1) The applicant is required to monitor the discharged treated wastewater to determine actual dilution rates achieved. If actual dilution rates are insufficient to meet federal marine water quality criteria in accordance with the Ocean Dumping Criteria (40 CFR Part 227), modifications to the discharge method will be made.
>
> 2) The applicant is required to monitor the ammonia concentrations in the treated wastewater and the toxicity of the wastewater. If dilution rates are insufficient to satisfy the requirement of the Ocean Dumping Criteria (40 CFR Part 227), modifications to the discharge method will be made.

Table 3. Summary of Potential Impacts to Essential Fish Habitat (EFH) and Geographically Defined Habitat Areas of Particular Concern

Essential Fish Habitat	**Presence**	**Impact Assessment**
Water column	Yes	No Significant Impact: WQC met for all constituents within mixing zone. Impacts will be of short duration and limited in scope.
Vegetated bottoms	Yes	No Significant Impact: No exposure
Non-vegetated bottoms	Yes	No Significant Impact: No exposure
Live bottoms	Yes	No Significant Impact: No exposure
Coral reefs	No	No Significant Impact: Not present
Artificial reefs	Yes	No Significant Impact: No exposure
Geologic features	Yes	No Significant Impact: No exposure
Continental shelf features	No	No Significant Impact: No exposure
Mississippi/Alabama shelf	No	No Significant Impact: Not present
West Florida shelf	Yes	No Significant Impact: No exposure to benthic communities.
Habitat Areas of Particular Concern		
Florida Middle Grounds	No	No Significant Impact: Avoided

Essential Fish Habitat	**Presence**	**Impact Assessment**
Florida Keys National Marine Sanctuary	No	No Significant Impact: Avoided
Florida Bay	No	No Significant Impact: Avoided
Flower Garden Banks National Marine Sanctuary	No	No Significant Impact: Avoided
Apalachicola National Estuarine Research Reserve	No	No Significant Impact: Avoided
Rookery Bay National Estuarine Research Reserve	No	No Significant Impact: Avoided
Weeks Bay National Estuarine Reserve	No	No Significant Impact: Avoided
Grand Bay, Mississippi	No	No Significant Impact: Avoided
Dry Tortugas	No	No Significant Impact: Avoided

References

Gulf of Mexico Fishery Management Council. *General Amendment for Addressing Essential Fish Habitat Requirements in the Fishery Management Plans of the Gulf of Mexico*. 1998 Oct.

Gulf of Mexico Fishery Management Council. Reef Fish Amendment 21, Continuation of Madison-Swanson and Steamboat Lumps Marine Reserves, to be Reviewed via Conference Call. News Release. April 8, 2003.

Koenig, CC, Coleman, CC, Grimes, CB, Fitzhugh, GR, Scanlon, KM, Gledhill, CT, Grace, M. *Protection of Fish Spawning Habitat for the Conservation of Warm-Temperate Reef-Fish Fisheries of Shelf-Edge Reefs of Florida*. Bulletin of Marine Science, 66(3): 593-616, 2000.

National Marine Fisheries Service. Essential Fish Habitat: *A Marine Fish Habitat Conservation Mandate for Federal Agencies*. St. Petersburg, FL; 2000 Oct.

National Marine Fisheries Service. 2015. Essential Fish Habitat – Gulf of Mexico. NOAA Southeast regional Office. Ver: 082015. http://sero.nmfs.noaa.gov/habitat_conservation/efh/guidance_docs/efh_gmfmc_ver082015.pdf

U.S. Department of Commerce and U.S. Department of Interior. Federal Inventory Sites of the Eastern Gulf of Mexico Region. http://www.mpa.gov/mpaservices/atlas/gom/gome.thml. > Accessed 2003 May 8.

U.S. Environmental Protection Agency Region 4. *Final Environmental Impact Statement for the Designation of an Ocean Dredged Material Disposal Site Located Offshore Tampa, Florida*. 1994 Sept.

United States Environmental
Protection Agency

Region 4
61 Forsyth Street, SW
Atlanta, GA 30303

October 2017

Preliminary
FINDING OF NO SIGNIFICANT IMPACT (FNSI)

National Pollutant Discharge Elimination System (NPDES) Permit for Eastern Gulf of Mexico Offshore Oil and Gas Exploration, Development, and Production

CONTENTS

TABLES

APPENDICES

1.0 STATEMENT OF PROPOSED ACTION

On July 14, 2016, the U.S. Environmental Protection Agency, Region 4 Regional Administrator signed the Draft Environmental Assessment (DEA) for the proposed National Pollutant Discharge Elimination System (NPDES) General Permit (GP). The draft GP and the DEA were made available for comments to the general public by notice in the Federal Register dated August 18, 2016 (FRL-9950-23-Region 4). The 30-day comment period closed September 18, 2016. The EPA Region 4 Regional Administrator is proposing to reissue the NPDES GP for the Outer Continental Shelf (OCS) of the Gulf of Mexico (General Permit No. GEG460000) for discharges in the Offshore Subcategory of the Oil and Gas Extraction Point Source Category. The draft GP pertains to discharges from exploration, development and production facilities located in and discharging, to all Federal waters of the eastern portion of the Gulf of Mexico (GOM) seaward of the outer boundary of the territorial seas. The GP covers existing and new source facilities with operations located on Federal leases occurring in water depths seaward of 200 meters occurring offshore the coasts of Alabama and Florida. The western boundary of the coverage area is demarcated by Mobile and Visoca Knoll lease blocks located seaward of the outer boundary of the territorial seas from the coasts of Mississippi and Alabama. Individual permits will be issued for operating facilities on lease blocks traversed by and shoreward of the 200-meter water depth.

As proposed, this final NPDES GP includes, best conventional pollutant control technology (BCT) and best available technology economically achievable (BAT) limitations for existing sources and new source performance standards (NSPS) limitations for new sources as promulgated in the effluent guidelines for the offshore subcategory. The final GP also includes the following changes to the expired permit: (1) New electronic reporting requirements: (2) new whole effluent toxicity testing sampling and reporting requirements for well treatment, completion. and workover fluids not discharged with produced wastewaters; (3) requirements to submit additional information pertaining to the chemicals and additives used in well treatment, completion and workover operations; and (4) clarification regarding types of operators. The EPA Region 4 is also making available the Preliminary Finding of No Significant Impact (FNSI) for review during the 30-day public comment period for this GP. The Preliminary FNSI addresses the substantive public comments for the 2016 DEA and draft GP and finalizes issues pertaining to the Endangered Species Act (ESA) and the Coastal Zone Management Act (CZMA).

2.0 DESCRIPTION OF PROPOSED ACTION

The proposed action is the EPA Region 4 reissuance of a NPDES GP for new and existing sources engaged in oil and gas exploration, development and production in EPA Region 4's jurisdictional area of the OCS in the Central and Eastern GOM. The GP implements effluent limitations, monitoring and reporting requirements, and other conditions for discharges from oil and gas facilities engaged in exploration, development, and production activities. The GP term is five (5) years from its effective date. Regulated waste streams include drilling fluids; drill cuttings; produced water; produced sand; well treatment, completion, and workover fluids; deck drainage; sanitary waste; domestic waste; and other miscellaneous wastes.

The existing NPDES GP, which became effective on April 1, 2010, expired on March 31, 2015. The GP has been administratively continued for existing users that requested continued coverage and will be replaced by the proposed GP when it becomes final and effective. The 2010 final GP and supporting documentation (e.g., fact sheets, draft permit, Ocean Discharge Criteria Determination Document, DEA, and Preliminary FNSI) are available on the EPA Region 4's website. EPA Region 4 intends to issue a GP that contains the same limitations and conditions as the 2010 GP, with several technical and administrative changes.

The purpose of this action is the reissuance of an existing NPDES GP authorizing discharges from existing and new source oil and gas facilities operating in the federal waters of the GOM where EPA Region 4 is the permitting authority. The proposed GP includes changes to the 2010 GP, of which EPA Region 4 considers only two as substantive changes:

- operators will be required to conduct whole effluent toxicity (WET) testing for well treatment, completion and workover (WTCW) fluids discharged outside of production operations.
- operators will be required to maintain an inventory of chemicals used in WTCW fluids and record the number and volumes of WTCW fluids discharges.

Changes in the proposed GP also include technical or administrative modifications that the EPA Region 4 does not consider material to its responsibilities under the National Environmental Policy Act (NEPA). These changes include:

- re-numbering of outfalls.
- allowing electronic submittals of discharge monitoring reports (DMRs).
- coverage for pipeline brines.

3.0 ALTERNATIVES EVALUATED IN THE DEA

3.1 Alternative A: Issue a Revised General Permit (Preferred and Selected Alternative)

Under Alternative A, the EPA Region 4 would issue a revised NPDES GP. The GP covers all existing and new source oil and gas facilities meeting the following requirements.

- The revised GP covers the same geographic areas as the 2010 GP:
    - Coverage includes all of the EPA Region 4 jurisdictional area of the Bureau of Ocean and Energy Management (BOEM) Central Planning Area seaward of the state waters of Mississippi and Alabama, and the Eastern Planning Area seaward of the state waters of Florida.
    - Coverage applies to waters seaward of the 200-meter depth contour seaward of Mississippi, Alabama, and Florida.
    - Coverage excludes discharges within 1,000 meters of Areas of Biological Concerns (ABCs) as designated by the EPA.
    - Coverage excludes areas under moratorium for oil and gas activities.
- The revised GP:
    - Includes a set of standard waste stream monitoring and performance conditions.
    - Modifies operating and reporting requirements for WTCW fluids that are not commingled with produced water; it requires WET testing of discharges, and requires operators to maintain an inventory of chemicals used to formulate these

fluids and, if there is a discharge of such fluids, reporting the chemical formulation of the discharges and discharge volumes with quarterly reports.

- The EPA Region 4 may issue individual permits that include appropriate specific waste streams, environmental monitoring and performance, and operating conditions and BAT and BCT effluent limits; permits for new sources include NSPS limitations, at a minimum.
- In accordance with §403 of the Clean Water Act (CWA), the EPA Region 4 may assess additional information about receiving water impacts from authorized discharges to ensure that permit issuance will result in no unreasonable degradation of the marine environment and may require additional permit conditions to comply with CWA§403.

3.2 Alternative B: Issue an NPDES General Permit Unchanged from the 2010 General Permit

Under Alternative B, the EPA Region 4 would reissue the 2010 NPDES GP in its present form. Coverage under the 2010 GP will be terminated. Operational and non-operational facilities currently covered by the 2010 administratively continued GP, as well as new operators or facilities will submit their notices of intent to be covered under the reissued GP. Operators also may apply for coverage under an individual permit, and the EPA Region 4 may require an operator to apply for an individual permit based on information received from surveys or other data. The reissued 2010 GP would cover all existing and new source oil and gas facilities.

3.3 Alternative C: No Action—No Issuance of Any NPDES General Permit

Under Alternative C, the EPA Region 4 would terminate the current 2010 GP; not issue a revised GP for existing or new sources; and issue individual NPDES permits:

- Alternative C applies to the entire EPA Region 4 jurisdictional area of the Central Planning Area and Eastern Planning Area, excluding areas under moratorium for oil and gas activities.
- Facilities currently covered by the 2010 GP will continue to have coverage if the applicant requested coverage to continue before the existing permit expired, and new facilities will be required to apply for individual permits.
- All oil and gas facilities, including facilities that are at or shoreward of the 200-meter isobath, are subject to individual agency and public reviews.
- Individual NEPA reviews include: appropriate waste stream, environmental monitoring and performance, and operating conditions; BAT and BCT effluent limits.
- Individual permits for new sources include, at a minimum, NSPS limitations.

Alternative C requires a case-by-case evaluation of potential impacts on environmental resources throughout the EPA Region 4 jurisdictional area that is not possible under Alternatives A and B. However, Alternative C fails to meet the requirement that the EPA issue GPs for offshore oil and gas activities (see Section 1.3.1 of the 2016 DEA, "NPDES General Permits").

4.0 ENVIRONMENTAL FACTORS CONSIDERED

The primary environmental factors potentially affected by the proposed action include physical resources and biological resources. The 2016 DEA considered other factors, such as socioeconomic resources (See Table 1). The discussion also included an evaluation of cumulative impacts. The development scenarios that were used to evaluate cumulative impacts were based on projected offshore oil and gas activity levels. One of the primary considerations of preparing the 2016 DEA was to provide an updated biological assessment of the baseline conditions following the Deepwater Horizon event which began on April 20, 2010.

5.0 PROJECT IMPACTS

The analyses in the 2016 DEA characterize the level of potential environmental impacts as: negligible, minor, moderate, or major. The majority of the resource impacts associated with the Deepwater Horizon event were minor, localized and/or temporary. Many studies are still ongoing so the long-term impacts on specific resources are unclear. Marine mammals and sea turtles are currently undergoing an unexplained mortality event. The Deepwater Horizon event is likely involved. However, the relationship among other potential contributing factors is not well understood. The proposed action with more protective permit conditions will minimize potential impacts to resources evaluated in the 2016 DEA.

Table 1: Resources Potentially Affected by the Deepwater Horizon Event, the Availability of Scientific Information That Suggest a Potential Change in the Environmental Condition of the Resource, and That Suggest a Potential Increased Sensitivity or Vulnerability of These Resources to the Waste Streams Authorized under the Proposed GP.

Potentially Affected Resources	Resource Condition Changed from 2009 EA	Significant Impacts to the Resource from the Proposed Action
Physical Resources		
Marine Water Quality	No	No
Sediment Quality	No	No
Air Quality	No	No
Coastal Barrier Beaches	No	No
Onshore Waste Management	No	No
Biological Resources		
Marine Mammals	Yes; not definitive	No
Sea Turtles	Yes; not definitive	No
Fish and Essential Fish Habitat	No	No
Birds	No	No
Deepwater Benthic Communities	No	No
Live Bottoms	No	No
Seagrasses	No	No
Wetlands	No	No
Socioeconomic Resources		
Commercial Fishing	No	No
Recreational Fishing	No	No
Human Health	No	No
Environmental Justice	No	No

6.0 CONCLUSIONS SUPPORTING THE FINDING

With the proposed permit provisions in place, drilling fluids and cuttings, proposed water, WTCW fluids and miscellaneous and other discharges may result in unavoidable, but local minor impacts to some of the resources examined. The potential impacts to environmental and resources from the activities proposed under the 2016 DEA is not considered to be significant based upon available scientific information. The EPA received public comments on the 2016 DEA that were considered as part of this determination. Updates and edits to the DEA are provided in the attached errata table (See Appendix A). The EPA Region 4 is issuing this preliminary FNSI in accordance with the requirements at 40 CFR §6.206(b) and will proceed with the action as proposed in accordance with 40 CFR §6.206(f).

The EPA evaluated the need for the preparation of an Environmental Impact Statement (EIS) and whether or not the proposed action would likely to have a significant effect on the quality of the human environment following the issuance of the 2016 DEA and draft GP and in consideration of the comments received from the public and other stakeholders. In defining the term "significantly" at 40 CFR §1508.27, the Council on Environmental Quality states that both the context and intensity of an impact must be evaluated. Ten criteria are provided in which are to be considered in evaluating the potential impacts and which are important in the decision to require an EIS. The following discussion of impacts under the ten criteria below were evaluated and utilized by the EPA Region 4 to inform a decision on the significance of the proposed action of re-issuing the GP. Based upon this evaluation, the EPA Region 4 has determined that an EIS is not required and that the proposed action will not have a significant impact on the environment.

1. Impacts that may be both beneficial and adverse. A significant effect may exist even if the Federal agency believes that on balance the effect will be beneficial.

The proposed permit will have a variety of effects on the quality of the human environment. The issuance of the NPDES GP for the Eastern GOM Offshore Oil and Gas Exploration, Development, and Production will have both beneficial effects and some adverse minor localized impacts on the environment. Continued development of Offshore Oil and Gas in the Eastern GOM will provide positive economic benefits though job creation and State and Federal tax revenues. In relation to impacts to the environment, the EPA Region 4 has proposed specific terms, conditions, and limitations to avoid or minimize potential impacts from drilling fluids and cuttings, including protective permit provisions that limit sediment toxicity, PAH, and oil content; and discharge rate and sensitive area restrictions. Produced water, WTCW fluids, and miscellaneous and other discharges are unlikely to result in significant impacts to the environment. Based on our review of available data, there is no information indicating a need for altering the terms, conditions, or limitations of the proposed GP. The existing provisions of the proposed permit represent what the EPA Region 4 considers a set of requirements that is highly protective of environmental resources of the GOM. The EPA Region 4 has determined that with the proposed permit provisions in place, drilling fluids and cuttings, produced water, WTCW fluids, and miscellaneous and other discharges may result in unavoidable, but local minor impacts to environmental resources. However, the EPA Region 4 does not consider the potential impacts to these resources from the activities proposed under this DEA and the GP to be significant based upon available scientific information.

2. Degree to which action affects public health and safety.

The EPA Region 4 jurisdictional area in the GOM cover source discharges from facilities located in and discharging to the GOM seaward of 200 meters in the Eastern Planning Area and seaward of the outer boundary of the territorial seas of the Central Planning Area for exploration, development, and production operations. The EPA Region 4 has determined that minimal impacts to public health and safety will result from the issuance of the GP. This conclusion is grounded in the fact that the GP has several specific terms, conditions, and limitations to avoid or minimize potential localized impacts. In addition, the authorized permit will cover areas a significant distance from people. The closest that the 200 meter isobaths boundary approaches a coastal beach is 73 kilometers (approximately 45 miles) from Pensacola Beach, Florida.

3. Unique characteristics of geographic area such as proximity to historic or cultural resources, park lands, prime farm lands, wetlands, wild and scenic rivers, or ecologically critical areas.

The proposed GP has been coordinated with multiple Federal, State and local agencies including the State Historic Preservation Offices. The agencies and offices received specific notice of the draft GP and DEA. No comments were received regarding impacts to historic and cultural resources, park lands, prime farm lands, wetlands, wild and scenic rivers, or ecologically critical areas. The EPA Region 4 GP has been designed over the permit cycles to include several specific terms, conditions, and limitations to avoid or minimize potential localized impacts to ecologically critical areas. The EPA Region 4 concluded several permit cycles prior that areas landward of the 200 meters isobaths line have the potential to include biologically sensitive areas (including coral structures), therefore, the GP has been designed to exclude coverage of these ecologically sensitive areas.

4. The degree to which effects on the quality of the human environment are likely to be highly controversial.

A summary of the comment letters received in response to the Public Notice is available in the attached summary of public comments. Generally, the EPA Region 4 received nine (9) comment letters (or emails) related to the GP and DEA. The majority of the comments received were from industry groups and related to specific permit conditions and language. The only comments received related to the action's potential controversial nature came from the Center for Biological Diversity (CBD). Most of the evidence provided by CBD related to the controversy of offshore fracking on the West Coast of the U.S. Based on comments the EPA Region 4 received on the proposed GP, we have determined that the proposed action is not highly controversial and does not meet the level of significance under NEPA.

5. The degree to which the possible effects on the human environment are highly uncertain or involve unique or unknown risks.

The extent of the possible effects on the human environment due to the issuance of the GP is relatively well known. The EPA Region 4 has conducted multiple previous NEPA reviews on the issuances of the Region 4 NPDES GP for Offshore Oil and Gas Activities in our jurisdictional area. These detailed environmental reviews have included an EIS in 1998, a Supplemental EIS in 2004, and an EA in 2009. Based on these previous analyses and the current DEA, the EPA Region 4 has determined that that the proposed action will potentially cause minimal localized impacts. This conclusion is grounded in the fact that the GP has several specific terms, conditions, and limitations to avoid or minimize the potential localized impacts.

6. The degree to which action may establish precedent for future actions with significant effects or represents a decision in principle about a future consideration.

The preferred alternative (revised GP) includes a set of standard waste stream monitoring and performance conditions, modifies operating and reporting requirements for WTCW fluids that are not commingled with produced water; it requires WET testing of discharges, and requires operators to maintain an inventory of chemicals used to formulate these fluids and, if there is a discharge of such fluids, reporting the chemical formulation of the discharges and discharge volumes with quarterly reports. The EPA Region 4 finds that the new permit conditions are more protective than the permit conditions in the 2010 GP. Therefore, the precedent being established under this new permit will provide for a more protective GP for future offshore oil and gas activities in the Eastern GOM.

7. Whether the action is related to other actions with individually insignificant but cumulatively significant impacts. Significance exists if it is reasonable to anticipate a cumulatively significant impact on the environment. Significance cannot be avoided by terming an action temporary or by breaking it down into small component parts.

The level of oil and gas activities in the Eastern GOM is substantially less than that of the Central and Western Planning Areas. The 2016 DEA and all previous NEPA documents for the EPA Region 4 Offshore Oil and Gas GP consider cumulative impacts of similar activities. The DEA provides discussions on cumulative impacts for the areas covered by the GP and the entire GOM. The EPA Region 4 has determined that the routine operations of the offshore oil and gas industry as a whole, such as are covered under the proposed GP, have minimal impacts on the environment. In the context of discharges covered under the previous GPs, environmental impacts from offshore oil and gas industry has been restricted to localized impacts (i.e., to within 100 meters of the discharge) as a result of discharge conditions and limitations imposed under NPDES permits covering these discharges (EPA, 1998; 2005; 2009). The EPA Region 4 maintains the position that the new permit conditions in the proposed GP will provide further protections to the environment and minimize potential cumulative impacts during the next 5-year permit cycle and beyond.

8. The degree to which action may adversely affect districts, sites, highways, structures, or objects listed in or eligible for listing in the National Register of Historic Places or may cause or destruction of significant scientific, cultural, or historic resources.

The proposed GP has been coordinated with multiple Federal, State and local agencies including the State Historic Preservation Offices. These agencies and offices received specific notice of the draft GP and DEA. No comments were received regarding impacts to historic and cultural resources.

9. The degree to which the action may adversely affect an endangered or threatened species or its habitat that has been determined to be critical under the ESA of 1973.

The EPA Region 4 has had on-going coordination with the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (USFWS) for the proposed action. A biological evaluation (BE) was prepared and included in the 2016 DEA in Appendix E and has been shared with the NMFS and USFWS. Prior to publicly noticing the GP, the EPA Region 4 prepared the 2016 DEA pursuant to NEPA and also engaged in informal consultation with the USFWS and the NMFS in accordance with the ESA. Since publication of the 2016 DEA, both Services were requested concurrence with the EPA's determination that issuance of the Offshore Oil and Gas GP as proposed would 'not likely to adversely affect' (NLAA) species or critical habitat under the ESA. The USFWS provided concurrence in a letter to the EPA dated January 19, 2017. The NMFS concurred with the EPA Region 4's Essential Fish Habitat assessment in a letter dated December 16, 2016. In addition, the EPA has determined that its proposed action will NLAA listed species under the purview of the NMFS and definitely will not likely jeopardize species and/or adversely modify critical habitat. In a letter dated August 7, 2017, the EPA Region 4 notified NMFS of its intent to reissue the GP in accordance with Section 7(a)(2) and Section 7(d) of the ESA. To avoid an irreversible or irretrievable commitment of resources, the reissued GP includes a specific re-opener clause that will enable the EPA Region 4 to modify the permit should further consultation reveal a need to formulate or implement reasonable and prudent alternative measures. This updated information regarding ESA consultation is reflected in this Preliminary FONSI and in the responsiveness summary to public comments.

10. Whether the action threatens a violation of Federal, State, or local law or requirements imposed for protecting the environment.

Section 301 of the Clean Water Act (CWA) provides that the discharge of pollutants into jurisdictional waters of the U.S. is unlawful except in accordance with an NPDES permit. The EPA's regulations authorize the issuance of GPs to categories of related discharges, such as discharges from the same type of source in a common geographic area (40 CFR §122.28). Moreover, as stipulated in 40 CFR §122.28(c)(1), the EPA Regional Administrator is required to issue GPs covering discharges from offshore oil and gas facilities within the Region's jurisdiction except as set forth below related to areas of biological concern (ABCs). The regulations provide that any owner or operator authorized to discharge by the GP may be excluded from coverage by applying for an individual permit. Also, the Regional Administrator may require any discharger authorized by a GP to apply for and obtain an individual NPDES permit (40 CFR §122.28). When operators comply with the permit conditions outlined in the proposed GP, the activity will be in compliance with applicable laws protecting the environment.

7.0 MITIGATION COMMITMENTS

See Chapter 2 (pages 2-14 and 2-15) of the 2016 DEA for the GP conditions and mitigation measures for waste streams such as drill fluids and cuttings, produced water and sand, WTCW fluids, sanitary and domestic waster, deck drainage, and miscellaneous discharges. See Chapter 6 (pages 6-1 thru 6-3) for other protective permit terms and conditions. For specific commitments, see the following link (https://www.epa.gov/npdes-permits/eastern-gulf-mexico-offshore-oil-gas-npdes-permits).

As a matter of public disclosure, the EPA is also highlighting the current ongoing mitigation plans and projects under the Resources and Ecosystems Sustainability, Tourist Opportunities, and Revived Economies of the Gulf Coast States Act and the Natural Resources Damage Assessment program of the Oil Pollution Act resulting from the legal cases involving the Deepwater Horizon event. Billions of dollars of restoration and mitigation projects are being planned and implemented over the next decade to help address the environmental harm to the GOM resulting from the oil spill. Numerous Federal agencies, including the EPA, and the Gulf States of Texas, Louisiana, Mississippi, Alabama and Florida are all directly involved with these mitigation and restoration efforts.

8.0 ANY UNRESOLVED ISSUES

None.

9.0 PUBLIC COMMENTS

Substantive public comments received on the 2016 DEA are addressed in a responsiveness summary included in this Preliminary FNSI (See Appendix B). Interested persons, groups, and agencies wanting to comment on this Preliminary FNSI may do so by calling or writing to: Mr. Christopher A. Militscher, Chief, NEPA Program Office, EPA Region 4, 61 Forsyth Street, SW, Atlanta, Georgia, 30303; (404) 562-9512. Interested persons, groups, and agencies are invited to submit written comments on this Preliminary FNSI to the above address within 30 days of the date of the publication of availability of this preliminary FNSI.

Onis "Trey" Glenn, III, Regional Administrator

DEC 11 2017

Date:

Appendix A

Errata Summary Table of Changes Made to the DEA and General Permit

Reopener Conditions of the GENERAL PERMIT (GP)

Two reopeners were added by the EPA to the GP as was generally described in the DEA. First, a reopener was added to make clear that the permit may be reopened and modified to add conditions necessary to comply with the ESA. Section 7(a)(2) of the ESA requires the EPA, in consultation with the FWS and the NMFS, to ensure that "agency action" such as the issuance of this NPDES Permit is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of their critical habitat. On October 28, 2016, EPA Region 4 notified FWS and NMFS of its determination that the issuance of the draft GP is not likely to adversely affect federally-listed species or designated critical habitat, and requested that those agencies concur in the Region's determination. The EPA Region 4 has received concurrence on the determination from FWS but has not concluded the consultation process with the NMFS.

Section 7(d) of the ESA prohibits any irreversible or irretrievable commitment of resources which has the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures that may be necessary to avoid jeopardy to a protected species or adverse effects to its critical habitat. The EPA has determined that it may proceed to issue the GP notwithstanding the ongoing ESA consultation with NMFS because the EPA will retain authority to revoke or modify the permit to the extent necessary to implement any reasonable and prudent alternative measures that are identified during the consultation process with NMFS, which may be necessary to avoid jeopardy to a protected species or adverse effects to its critical habitat. A specific reopener has been added to the GP to make clear that the EPA may modify the permit to add conditions that are necessary to effectuate any reasonable and prudent alternative measures identified by NMFS.

In addition, a second reopener was added to comply with 40 CFR § 125.123(d)(4), which requires that permits for offshore discharges include a condition stating, "In addition to any other ground specified herein, this permit shall be modified or revoked at any time if, on the basis of any new data, the director determines that continued discharges may cause unreasonable degradation of the marine environment." This regulatory requirement is applicable to the GP, and the required condition has therefore been added to the GP.

Other Conditions of the GP

2. Part I.A.4 – Notification Requirements, pages 15-16: Item w. was added, which requires operators to state their intention to participate in the alternative Industry-wide Study regarding WET Testing of WTCW Fluids (Part I.B.6.b, page 50). Language was also added to clarify operator options for submitting written, rather than electronic, NOI in the event the EPA's system receiving electronic submittals is not operational.

3. Part I.B.1.c.i – Drill Cuttings, page 24: The word "concentrations" was added to the sentence in order to clarify that operators must keep an inventory of the total volume, total mass as well as concentrations of constituents added for each well.

4. Part I.B.2.b.iv - Drill Cuttings, page 27: The first sentence was corrected to state that the limits for mercury and cadmium in the section apply to drill cuttings and not to drilling fluids.

5. Part I.B.2.c - Drill Cuttings, page 28: The title for this section was corrected to clarify that this part of the permit includes limits as well as monitoring conditions for drill cuttings generated from non-aqueous based drilling fluids.

6. Part I.B.3.b.ii - Produced Water, pages 34-36: This section was simplified by deleting the superfluous reference to the limiting permissible concentration (LPC), which is the same as the "No Observed Effect Concentration." Also, in order to ensure representative samples were obtained, new language was added to clarify that grab samples must be obtained once each discharge during a time of the maximum effluent flow rate.

7. Part I.B.6.a. - Well Treatment, Completions and Workover Fluids, page 42: The sentence pertaining to submittal of some information as "Confidential Business Information" (CBI) was deleted. Permittees cannot claim information on the specific chemical composition of any additives used as CBI. Also, the language pertaining to the toxicity testing for well treatment completion and workovers fluids was moved to subsection b. (i.e., section for monitoring requirements), since the permit requirement does not require operators to meet a permit limit.

8. Part I.B.6.b -Well Treatment, Completions and Workover Fluids, page 50: Language pertaining to the Industry-wide Alternative for WET Testing was revised to clarify that the study would gather effluent data from wells discharging well treatment, completion, and/or workover fluids from various well depths. The timeframe to submit the study plan was extended to up to 18 months in order to agree with the language in the EPA Region 6 offshore oil and gas general permit (GP).

9. Part I.B.10.b - Miscellaneous Discharges pages 54-55: The language was revised to clarify that operators must monitor for free oil during times when observation of a visible sheen is possible, unless monitoring is performed using the static sheen test. Also, to ensure representative samples are obtained, language was added to specify that grab samples shall be taken for toxicity testing of miscellaneous discharges when the maximum flow is being discharged.

10. Part I.B.11.a and c - Miscellaneous Discharges of Freshwater and Seawater to Which Chemicals Have Been Added, pages 56-57: The language was revised to clarify that operators must monitor for free oil during times when observation of a visible sheen is possible, unless monitoring is performed using the static sheen test. Also, to ensure representative samples are obtained, language was added to specify that grab samples shall be taken for toxicity testing of miscellaneous discharges when the maximum flow is being discharged.

11. Part I.D.3.d. - Monitoring Requirements for facilities with Cooling Water Intake Structures, pages 72-75: Language was revised to change the monitoring frequency from weekly to monthly and to clarify that "monthly" means at least once per month, even if the facility is at the location for less than one full month. Also, language was added to allow operators, after 24 months of monitoring at one location, the option to meet the requirements of annual reporting per 40 Code of Federal Regulations (CFR) Section 125.137, using data from the Southeast Area Monitoring and Assessment Program (SEAMAP).

12. Part II.13 - Signatory Requirement on page 100: The final permit contains a requirement that any person signing the NOI, Notice of Termination (NOT), and any reports (including any monitoring data) submitted to the EPA, in accordance with the proposed permit must include the certification statement in Part II. This certification statement includes an additional sentence than has not previously been included in this NPDES general permit. The sentence reads: "I have no personal knowledge that the information submitted is other than true, accurate, and complete." The EPA believes this addition to the certification language is necessitated by the recent decision in U.S. v. Robison, 505 F.3d 1208 (11th Cir. 2007). In Robison, the Court of Appeals struck down the defendant's conviction for a false statement on the grounds that the certification language did not require him to have personal knowledge regarding the truth or falsity of the information submitted to the EPA. Rather, the Court reasoned that the EPA's certification required the defendant to certify, in part, that he made an inquiry of the persons who prepared and submitted the information and, based on that inquiry, the information was accurate to the best of his knowledge. The Court further reasoned that there is no requirement in the certification that the person attest to his personal knowledge regarding the information submitted. The government had argued at trial that the defendant had personal knowledge that the facility had committed violations. As a result, the EPA has determined it is necessary to include language which clarifies that the signatory is certifying that he or she has no personal knowledge that the information submitted is other than true, accurate, and complete.

13. Part III.A - Monitoring Reports page 107: The language was changed to allow operators more time to prepare and submit monitoring reports. Operators now have up to the 58th day following the quarterly reporting period to submit a Discharge Monitoring Report (DMR).

14. Part V.A.15 - Whole Effluent Toxicity Testing, pages 151- 160: Language was added to clarify the frequency of toxicity testing for WTCW fluids. The new language also clarifies that a failure of a WET test for these discharges is not a violation of the permit and states that, based on test results, a toxicity reduction evaluation and/or toxicity identification evaluation may be required.

15. Part V.B – Definitions, page 174: The definitions for "Toxicity Reduction Evaluation" and Toxicity Identification Evaluation" were added.

formulation or implementation of any reasonable and prudent alternative measures that might be identified by NMFS pursuant to the consultation process. In the event that NMFS does identify necessary reasonable and prudent alternative measures that are necessary to prevent jeopardy to protected species or adverse impacts to critical habitat, the EPA has authority to modify the permit to include whatever conditions are necessary to implement such reasonable and prudent alternative measures. To avoid an irreversible or irretrievable commitment of resources, the reissued GP includes a specific re-opener clause that will enable the EPA Region 4 to modify the GP should further consultation reveal a need to formulate or implement reasonable and prudent alternative measures. This updated information regarding ESA consultation is reflected in our preliminary FONSI. The EPA Region 4 determined that formal consultation is not required (50 CFR § 402.14(b)(1)). This updated information regarding ESA consultation is reflected in our preliminary FONSI.

Comments for Cubic Image Environmental, LLC

Comment 1 (paraphrased): The Permit has no provision for characterization or treatment of naturally-occurring chemicals and dissolved contaminants in formation water prior to discharge. Parts I(B)3) and V(B)(67) of the GP fail to acknowledge that dissolved contaminants are washed out of crude oil and become dissolved in formation water, which is a component of PW. Pollutants such as benzene, toluene, ethylbenzene and xylenes (BTEX) and benzo(a)pyrene and naturally-occurring radioactive material (NORM) (i.e., radium 226 and 228) are considered to be human carcinogens and are also carcinogenic to marine fauna.

Response to Comment 1: The EPA acknowledges that pollutants present in formation water and produced water can include BTEX, polyromantic hydrocarbons, and NORM, and permit conditions have been developed to minimize the impacts of the discharge on human health and aquatic life. Impacts from chemical species, such as BTEX and PAH, are addressed using TBELs, water-quality based effluent limits (WQBELs), and BMPs. TBELs are established in EPA's effluent guidelines for the offshore industry (reference 40 CFR Part 435). In particular, the permit's oil and grease limit serves as an indicator for toxic pollutants in Produced Water and WTCW fluids waste streams based on the EPA's determination that toxic pollutants are largely controlled by removal of oil and grease. The permit also prohibits the discharge of free oil. Effluent limits and monitoring for WET are included in the permit for Produced Water discharges in order to protect aquatic life near the vicinity of the discharges. Lastly, the permit also includes BMPs to help address pollutants not controlled by effluent limits. The regulation of NORM under the NPDES program is complex. There are no TBELs or WQBELs which directly address this category of pollutants, which create potential radiation exposure risks to humans and the environment. Studies also have been done to determine whether produced water discharges have the potential to cause bioaccumulation of pollutants such as BETX and PAHs. Based on the results of those studies we have not found that additional permit limits are needed to prevent bioaccumulation and the associated impacts to human health from fish tissue consumption.

The EPA acknowledges that releases of NORM due to mining, drilling and other human activities are an environmental and human health concern. The Agency uses the term Technologically Enhanced Naturally Occurring Radioactive Material (TENORM), which is individual permits would have more protective permit conditions which would address and minimize any direct, indirect, and cumulative impacts to these areas, as necessary to meet relevant regulatory requirements. The cumulative impacts have been adequately considered in the proposed action. Chapter 4 of the DEA includes detailed discussion of environmental consequences for the proposed action for each resource area along with a detailed discussion on cumulative impacts for each resource area. In addition, anticipated cumulative impacts to benthic communities from the proposed action are discussed in Section 4.3.5.3.

Comment 34: The EPA also dismisses the cumulative impacts of the discharge of wastewater into the GOM on marine water quality because the impacts are low compared to the oil and gas industry as a whole. This misses the entire point of a cumulative impacts analysis. Cumulative impacts, by definition, may be relatively minor when viewed in isolation yet significant in combination. It is the combined effect that the EPA is required to analyze, not the comparative effect. The EPA's dismissal of such impacts on this basis is improper.

Response to comment 34: The EPA has determined that the permit conditions in previous GPs for offshore oil and gas development and the newly proposed GP is protective of water quality and marine life. Based on available data and research the EPA found that there are no "significant" cumulative impacts to water quality and marine life in the GOM due to authorization of the EPA Region 4 GP. In addition, see preliminary FONSI.

Comment 35: EPA cannot issue a FONSI. EPA must therefore prepare an EIS.

Response to comment 35: See Responses to CBD Comments-3, 22, 23, and 25. The EPA has determined that the requirements under 40 CFR Section 6.206(a) can be met regarding the issuance of a FONSI.

Comment 36: EPA cannot issue the permit unless and until formal Section 7 consultation is complete and any measures required to mitigate the harm to listed species or their critical habitat from the discharge of offshore oil and drilling wastes are including as binding conditions of the permit.

Response to comment 36: Prior to publicly noticing the GP, the EPA Region 4 prepared a DEA pursuant to the NEPA and also initiated consultation with the USFWS and the NMFS in accordance with the ESA. Since publication of the DEA, USFWS provided concurrence with the EPA Region 4's determination that issuance of the Offshore Oil and Gas GP is not likely to adversely affect species or critical habitat under the ESA. The USFWS provided concurrence in a letter to the EPA Region 4 dated January 19, 2017, and the NMFS concurred with the EPA Region 4's EFH assessment in a letter dated December 16, 2016. The EPA Region 4 has determined that its proposed action will NLAA listed species under the purview of the NMFS and will not likely jeopardize species and/or adversely modify critical habitat. The NMFS has not yet completed consultation or provided its concurrence on EPA's NLAA determination, but based on information in the record EPA anticipates that NMFS will concur with this determination. The EPA has determined that it can issue the GP prior to completion of consultation with NMFS in accordance with Section 7(a)(2) and Section 7(d) of the ESA because the issuance of the permit will not result in any irreversible or irretrievable commitment of resources which would have the effect of foreclosing the communities, and seagrasses. But, again, the EPA does not state, or analyze, what those impacts might be.

Response to comment 31: See Response to CBD-6 for response related to impacts of PW.

The EPA Region 4 has taken a "hard look" at the impact of produced water. The EPA Region 4 has evaluated the impact of PW in both multiple previous NEPA documents (EISs and EAs) and the current DEA for the proposed action. Specifically, Chapter 4 of the DEA analyzes impacts from produced water on the environment, including impacts to marine species, from the proposed action and reasonable alternatives.

Comment 32: The Proposed GP establishes a mixing zone of 100 m for each discharge location. But EPA fails to analyze any impacts within that mixing zone, or the impacts on migratory species that live in the GOM, including fish, sea turtles, whales, and dolphin, that may travel through multiple mixing zones in a single migration.

Response to comment 32: The volumes of PW discharged are not limited; however, the permit minimizes impacts to marine life by including several prohibitions regarding discharges near ABC and federally designated disposal sites, TBELs and WQBELs. Based on whole effluent toxicity data reported by permittees under the current R4 offshore permit, there have been no toxicity testing violations, hence no need at this time to impose further restrictions on produced waters. See Responses to CBD-10 and CBD-3 regarding mixing zones and ESA and EFH.

Comment 33: In addition, EPA's DEA fails to adequately consider the cumulative impacts of its proposal to adopt the preferred alternative and allow oil companies to dump toxic wastewater into the GOM. In particular, the EPA did not consider impacts to benthic communities based on its conclusory statements that impacts to benthic communities are unlikely because the Proposed GP would only cover activities seaward of the 200-m isobath; and that operations in water depths shallower than 200 meters will require coverage under NPDES individual permits. But the issuance of individual permits in this area is a reasonable foreseeable action that the EPA must consider as part of its cumulative impacts analysis.

Response to comment 33: The EPA Region 4 will be responsible for reviewing NPDES permit applications for individual permit coverage in waters beyond state authority in the Gulf, and maintains the right to issue individual permit in lieu of coverage under the GP. The general permit coverage area is Federal Waters of the Gulf of Mexico (1) seaward of 200-meter depth contour offshore of Alabama in the Destin Dome lease block, (2) seaward of the 200-meter depth contour offshore of Florida, and (3) in the Mobile and Viosca Knoll lease block areas offshore of Mississippi and Alabama. In areas of the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. All facilities must operate a minimum of 1000 m from sensitive marine habitats in pre-designated Areas of Biological Concern. In development of the DEA, the EPA Region 4 contemplated the cumulative impacts of individual permits within the areas inside the 200-m isobaths offshore Florida and in the Destin Dome lease block offshore of Alabama; however, the majority of these areas are currently under congressional moratoria for the anticipated GP period and any issued representative of the monitored activity. Also, see Responses to comments CBD-1 and CBD-10.

The EPA Region 4 has taken a "hard look" at the potential impacts to water quality and marine life. The EPA Region 4 evaluated impacts to water quality and marine life in multiple previous NEPA documents (EISs and EAs) and the current DEA for the proposed action. We do, however, acknowledge that more information regarding WTCW fluids would be useful to inform future permitting decisions and are proposing additional permit requirements under the new GP to address these gaps. Baseline conditions including water quality and aquatic life are described in Sections 3.1 to 3.3.6 of the DEA.

Comment 30: Testing of WCTW fluids does not prevent the chemicals from being dumped into the ocean in the first place; and because the monitoring requirement is at most quarterly or once every six months, testing is unlikely to coincide with discharge of well stimulation chemicals (nor is there a requirement that it do so). In addition, much of the testing is based on the concentrations at the edge of the mixing zone, not at the discharge location. The EPA arbitrarily ignores all impacts inside the mixing zone. Relatedly, the EPA fails to analyze whether any mixing zones will overlap, and what the impact of such overlap could be. Moreover, by focusing on impacts based on the mixing zone radius, the EPA largely ignores the effect of wastewater plumes on water quality. Yet, as explained above, the discharge of fracking chemicals can have myriad negative impacts on water quality, including impacts on marine species. The EPA's failure to take a hard look at the water quality impacts on this basis violates NEPA.

Response to comment 30: Any well stimulation fluids remaining in the formation after the well completion and stimulation phase of well construction naturally mix (comingle) with formation (produced) water. The comingled water is brought to the surface and discharged after treatment. The discharge of stimulation fluids mixed with produced water is continuous until the volume of stimulation fluids remaining in the formation is exhausted. Therefore, the prescribed monitoring frequency will be adequate to include stimulation fluids until it is completely removed from the producing formation.

See Response to CBD-10 regarding mixing zones. With respect to monitoring frequency, the NPDES permit requires quarterly samples for discharges of WTCW fluids not comingled with PW. The EPA has determined that this monitoring frequency is adequate.

See Response to CBD-29 regarding the "hard look" comment.

Comment 31: The Proposed GP authorizes the discharge of unlimited volumes of Produced Waters, including those mixed with fracking chemicals. But EPA has not meaningfully analyzed the massive volume of produced water that flows into the GOM from oil and gas operations. For example, the EPA's DEA states that "[d]ischarges are subject to dilution and dispersion that reduce the potential extent of acute water column impacts to within a few hundred meters of the discharge." Yet the EPA wholly fails to discuss what the impacts within a few hundred meters of the discharge will be. In addition, the EPA admits that the discharges authorized by the Proposed GP could potentially affect fish species through impacts to water and sediment quality, but EPA wholly fails to state what those impacts might be. The EPA makes similar statements for each species found in the Eastern Gulf, including marine mammals, sea turtles, birds, deepwater benthic communities, live bottom *and operational practices may have changed. Therefore, EPA Region 4 is requiring testing and reporting requirements for this waste stream beyond those of the 2010 GP."*

Therefore, the current DEA acknowledged the potential data gaps regarding WTCW fluids and analyzes the potential impacts of the proposed action which includes additional permit requirements under the new GP to address these gaps. Baseline conditions, including water quality and aquatic life, are described in Sections 3.1 to 3.3.6 in the DEA. One of the prime purposes of the EPA preparing the DEA was to identify any significant changes to the baseline conditions following the *Deepwater Horizon* incident.

Comment 27: EPA's study of the volume of PW is from 1983, which is also incredibly outdated. Fracking and other new information indicate that produced waters may have increased in volume. EPA records reveal that offshore oil and gas platforms in Region 6 discharged *more than 75 billion gallons* of produced waters in 2014. Failure to base its analysis on more recent information that adequately reflects the volume of discharges of produced water would also violate NEPA.

Response to comment 27: Comparisons of PW volumes between Regions 6 and 4 are not valid because there are significantly fewer production wells in Region 4. A 2005 report[1] of the produced water volumes from 50 operators in the GOM reported annual averages ranging from 3 bbl/d to 63,828 bbl/d. This is within the 134 bbl/d to 150,000 bbl/d range reported in the 1983 study referenced in the Ocean Criteria Discharge Evaluation.

[1] Veil, J.A., Kimmell, T.A., Rechner, A.C. 2005. Characteristics of Produced Water Discharged to the Gulf of Mexico Hypoxic Zone. U.S. Dept. of Energy. Contract W-31-109-Eng-38. 74pp.

Comment 28: The Proposed GP has no limits on the amount of well stimulation chemicals that can be discharged when combined with PW.

Response to comment 28: See Response to CBD-1 for a detailed description of the current GP protections and an explanation of the EPA Region 4's determination that the discharges covered under this GP will not result in an unreasonable degradation of the marine environment in the vicinity of the discharges. In addition, the direct, indirect and cumulative environmental impacts from issuance of the GP are appropriately analyzed in the DEA. As part of the broader analysis of the GP, the EPA Region 4 determined that there is currently no scientific basis for numerical limits on specific chemicals used in WTCW fluids discharged into the GOM.

Comment 29: The EPA ignores the impacts to water quality and marine life that will result from the discharge of chemicals used in fracking and other well stimulation treatments because the wastewater discharges will be subject to permit conditions, including toxicity testing. But NEPA clearly obligates EPA to look at *all* environmental impacts, and it cannot excuse itself from its NEPA hard look duty because a "facility operates pursuant to a…permit..." or because the impacts have been discussed in a non-NEPA document.

Response to comment 29: The NPDES permit requires quarterly samples for discharges of WTCW fluids not comingled with produced waters. The EPA Region 4 has determined that this monitoring frequency is adequate. The NPDES permit also requires that all samples be biological concern require separate permit conditions warranting the use of Individual Permits instead of coverage under a GP. However, 40 CFR § 128.28 makes clear that, absent such circumstances, the use of the EPA's general permit authority is an appropriate mechanism for permitting offshore oil and gas exploration and production facilities.

For these reasons, the EPA believes including an alternative that contemplates no NPDES permit (GP or Individual Permit) is not a feasible alternative and not consistent with the intent of the "no action" alternative definition under NEPA. In addition, where a choice of the "no action" would result in predictable actions by others, the consequence of the "no action" alternative should be included in the analysis (Reference: CEQ's 40 Most Asked NEPA Questions). This supports our determination that the "no action", no issuance of any NPDES GP, would result in the issuance of individual permits for existing and new dischargers for the same level of activity. Therefore, the DEA analyzed impacts from the proposed action and alternatives given that there is not a record basis for issuing no permit, and there is no distinction among any remaining alternatives (GP or individual permit) with respect to environmental consequences.

Comment 25: EPA's analysis fails to consider the direct, indirect, and cumulative impact of produced waters discharges and the impacts of discharging chemicals used in offshore fracking and other well stimulation treatments. Such failures violate NEPA.

Response to comment 25: The EPA Region 4 has considered the direct, indirect, and cumulative impacts of produce waters discharges and the impacts of discharging chemicals used in offshore fracking and other well stimulations treatments in the DEA for the proposed action. The EPA Region 4 has fully evaluated the OCS oil and gas NPDES GP and impacts on water quality through multiple EISs and EAs; including the current DEA for the proposed action. Previous NEPA documents and NPDES permits have contemplated the use of well stimulation and fracking activities and have evaluated the direct, indirect, and cumulative impact of these activities. Based on best available information, the EPA Region 4 has no reason to believe that conclusions in these NEPA documents are invalid or that the impacts associated with offshore well stimulation and fracking will cause significant impacts to the environment. The EPA Region 4 has determined that no significant environmental impacts are anticipated from the proposed action based on the analysis of the potential environmental impacts of the issuance of the GP in the preliminary FONSI.

Comment 26: Relying on data that is nearly three decades old is improper. NEPA requires EPA to "describe the environment of the areas to be affected or created by the alternatives under consideration." Thus, the establishment of the baseline conditions of the affected environment is a fundamental requirement of the NEPA process.

Response to comment 26: Based on WET data reported by permittees under the current EPA Region 4 offshore GP permit, there have been no toxicity limit violations. This data reflects the current operations with respect to toxicity of discharges.

The EPA Region 4 agrees that additional data should be collected to ensure that other discharge data also reflects current operations. As stated on Page 2-6 of the DEA: *"The number of WTCW jobs is not reliably known, especially with respect to current operations."* And: the *"EPA Region 4 recognizes this information is limited and dated (i.e., from 1988).*

Comment 23: EPA's DEA fails to analyze a reasonable range of alternatives. NEPA requires a "detailed statement" of alternatives to the proposed action." The purpose of this section is "to insist that no major federal project should be undertaken without intense consideration of other more ecologically sound courses of action, including shelving the entire project, or of accomplishing the same result by entirely different means."

Response to comment 23: The range of alternatives considered in the DEA is consistent with both 40 CFR § 1502.14 and past NEPA evaluations regarding issuance of an NPDES GP in the Region 4 jurisdictional area of the GOM. During the development of the DEA, the EPA Region 4 considered the alternative of "zero discharge" of WTCW to not be a feasible alternative and therefore, it was not considered in the range of alternatives analyzed in the DEA.

Comment 24: EPA's analysis of the no-action alternative is inadequate. The EPA states that if the EPA did not issue the Proposed GP, offshore oil and gas facilities would need to apply for an individual permit. Thus, according to the EPA the only difference between the no-action alternative with the action alternatives is the increased administrative burden on EPA. In other words, the no-action alternative encompasses the same potential impacts as a decision to issue the GP. But this approach "avoid[s] the task actually facing [EPA]. In assuming that, no matter what, the proposed activities would surely occur, [EPA is] neglecting to consider what would be a true 'no action' alternative." However, a true no-action alternative would examine and compare the impacts resulting from the cessation of the discharge of produced wastewater and other oil and gas drilling wastes. EPA should consider and disclose such impacts.

Response to comment 24: The "no action" alternative is not a feasible alternative in this case because there is no basis in the record for determining that issuance of the proposed general permit fails to meet applicable legal requirements (e.g., CWA NPDES or ESA). The EPA recognizes that, for offshore discharges such as those that would be authorized by the GP, no permit may be issued when the EPA determines that the discharges will not satisfy the ocean discharge criteria as set out in 40 CFR § 125.120-124 (Ocean Discharge Criteria). The Ocean Discharge Criteria prohibit the issuance of permits for discharges that will cause unreasonable degradation of the marine environment (*See* 40 CFR § 125.123(b)). As explained in EPA's Response to CBD Comment 1, however, the EPA has conducted an analysis of the proposed General Permit under the Ocean Discharge Criteria and determined that the GP may be issued consistent with the Ocean Discharge Criteria. This determination follows previous permit cycles where the required Ocean Discharge Criteria analysis was undertaken and the EPA has similarly found that the discharges will not cause significant degradation of the marine environment. Similarly, the EPA has determined that the general permit may be issued consistent with other regulatory requirements, such as the ESA.

In the absence of a record basis for determining that a general permit does not meet applicable CWA NPDES or other regulatory requirements, the "no action" alternative was structured in the DEA to satisfy the requirements of 40 CFR § 128.28 (c)(1), which states that "The Regional Administrator shall, except as provided below, issue GPs covering discharges from offshore oil and gas exploration and production facilities within the Region's jurisdiction." Those exceptions listed in 40 CFR § 128(c)(1) include circumstances where offshore areas of

Comment 21: The EPA appears to rely on the lack of information to find that there will not be significant impacts from allowing oil companies to dump fracking and other well stimulation fluids into the GOM. But as the 9th Circuit has made perfectly clear, "lack of knowledge does not excuse the preparation of an EIS; rather it requires the [agency] to do the necessary work to obtain it." In other words, the substantial data gaps that exist regarding the impacts of offshore fracking and acidizing on the marine environment necessitate the preparation of an EIS.

Response to comment 21: The EPA Region 4 has taken a 'hard look' at the potential impacts to the GOM based upon the analyses provided in the DEA. The EPA Region 4 in the DEA has determined that no significant environmental impacts are anticipated from the proposed action based on the analysis of the potential environmental impacts associated with the issuance of the GP. As mentioned above, the record, including information regarding impacts from discharges during prior permit cycles, does not contain evidence indicating that the discharges will cause "significant adverse changes" in ecosystem diversity, productivity or stability of the biological community as a result of the discharges and the record does not indicate that the discharges pose a threat to human health through direct exposure to pollutants or consumption of exposed aquatic organisms. Furthermore, the EPA has determined that there has been no loss of esthetic, recreational, scientific or economic values which is unreasonable in relation to the benefit derived from the discharges. Additionally, existing information, including information relating to the impacts of discharges during the previous GP term, is sufficient to support the EPA Region 4's determination that the discharges authorized in the GP will not result in unreasonable degradation of the marine environment. In addition, as described under response CBD-3, the EPA Region 4 has fully evaluated the OCS oil and gas NPDES GP and impacts on water quality through multiple previous EISs and EAs. These NEPA documents, including the most recent DEA on the proposed action, have all analyzed the impacts of oil and gas activities in the OCS covered under the NPDES GP in the EPA Region 4 jurisdictional area.

Comment 22: EPA's purpose and need statement fails to comply with NEPA. NEPA's implementing regulations provide that an environmental document should specify the underlying purpose and need to which the agency is responding in proposing the alternative including the proposed action. This purpose and need inquiry is crucial for a sufficient environmental analysis because "[t]he stated goal of a project necessarily dictates the range of 'reasonable' alternatives." Thus, an agency cannot define its objectives in unreasonably narrow terms" without violating NEPA.

Response to comment 22: The stated purpose and need in the DEA is consistent with both 40 CFR § 1502.13 and previous EAs and EISs supporting issuance of prior NPDES GPs for offshore oil and gas in the EPA Region 4 coverage areas. Additionally, the purpose and need of the reissuance "of an existing NPDES GP authorizing discharges from existing and new source oil and gas facilities operating in the federal waters of the GOM where the EPA Region 4 is the permitting authority" is consistent with the mandate outlined in 40 CFR § 128.28(C)(1).

4 has determined that it is not necessary to prepare an EIS for this proposed action. Please refer to the preliminary FONSI and Response CBD-3, above.

Comment 19: Several spills of fracking fluid from pipelines in Pennsylvania over the last few years also resulted in significant fish kills. Such contamination incidents are a real risk in the GOM given the EPA's Proposed GP that would allow oil companies to dump fracking chemicals into the Gulf. EPA must therefore prepare an EIS.

Response to comment 19: The EPA Region 4 is aware inland discharges of large volumes of fracking fluids into small volume enclosed waterways such as streams and rivers can result in significant impacts to resident aquatic life. However, the EPA Region 4 finds that discharges of relatively small volumes of WTCW fluids into the GOM do not present similar risks of significant adverse impact.

With regard to the request to prepare an EIS, the EPA Region 4 conducted multiple previous NEPA reviews in connection with prior issuances of the EPA Region 4 GP for Offshore Oil and Gas Activities in our jurisdictional area, including the development of EIS's. For this proposed action, the EPA Region 4 tiered off of previous NEPA documents as allowed under 40 CFR § 1502.20. Relevant information from these documents was updated. The EPA Region 4 determined that the analyses from these documents are still valid and are incorporated by reference, as appropriate, in the most recent DEA. In addition, based on the analysis of the potential environmental impacts associated with the issuance of the GP, the EPA Region 4 has determined that no significant environmental impacts are anticipated from the proposed action. Therefore, the EPA Region 4 has determined that it is not necessary to prepare an EIS for this proposed action. Also see Responses to CBD-3 and 18, above.

Comment 20: The oil industry claims offshore fracking has no adverse environmental impacts, while numerous scientists and reports have linked fracking to water contamination, air contamination, spills, and earthquakes. EPA's proposal to allow oil and gas companies to dump fracking wastewater into the GOM clearly constitutes a substantial public controversy. Indeed, it is hard to imagine an issue more fitting of this description than offshore fracking activities. An EIS is therefore required.

Response to comment 20: See Responses to CBD-3, 18 and 19, above. Based on the analysis of the potential environmental impacts of the issuance of the GP the EPA Region 4 has determined that no significant environmental impacts are anticipated from the proposed action. This determination considered both context and intensity, including "the degree to which the effects on the quality of the human environment are likely to be highly controversial." As supported by the DEA for the proposed action, the EPA Region 4 has neither observed nor discovered scientific evidence of:

(1) "significant adverse changes" in ecosystem diversity, productivity or stability of the biological community as a result of the discharges,
(2) a threat to human health through direct exposure to pollutants or consumption of exposed aquatic organisms, or
(3) a loss of esthetic, recreational, scientific, economic values which is unreasonable in relation to the benefit derived from the discharge.

consistent with other EPA permits. For example, the Beaufort OCS GP prohibits discharge of drilling fluids during bowhead whaling activities and no discharge near the Boulder Patch.

Response to comment 16: The EPA limits discharges under the GP to water depths greater than 200 m offshore of Florida and offshore of Alabama in the Destin Dome lease block, to avoid the most sensitive benthic habitats on the continental shelf. In addition, in the Mobile and Viosca Dome lease block areas offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth. EPA can review the survey and deny permit coverage to protect sensitive areas. Lastly, all facilities must operate a minimum of 1000 m from sensitive marine habitats in pre-designated Areas of Biological Concern.

Comment 17: Several significance factors are raised, clearly necessitating the preparation of an EIS. In particular, the Proposed GP—which allows the unlimited discharge of PW and well stimulation fluids into the GOM—impacts a geographically, ecologically, culturally important area; may have adverse environmental impacts, including impacts to ESA-listed species and their critical habitat; represents a substantial public controversy; and has unique or unknown risks.

Response to comment 17: The EPA has found that the potential impacts to the environment resulting from the proposed action do not require the preparation of an EIS. See CBD-3 Response above. For the 10 factors of significance, see preliminary FONSI.

Comment 18: EPA's Proposed GP allows oil companies to discharge unlimited quantities of produced water, and allows the chemicals used in fracking and other well stimulation treatments to be discharged into the GOM. EPA must prepare an EIS because the discharge of produced water, including the discharge of chemicals used in offshore fracking and acidizing, have adverse impacts, and may impact ESA-listed species and their critical habitat. While substantial data gaps exist regarding the impacts of these practices, what is known is cause for great alarm.

Response to comment 18: PW is addressed in the proposed GP with both technology-based and water quality based limits. The EPA Region 4 is confident that the conditions and limits in the proposed GP are sufficient to prevent long-term exposures to high concentrations of such chemicals. The ocean discharge criteria require that a waste stream cannot be permitted if the EPA Region 4 determines that the discharge of wastes will cause unreasonable degradation of the marine environment. The available evidence, including WET data reported by permittees under the current Region 4 offshore GP, indicates that PW water discharges made consistent with the GP's terms and conditions will not result in unreasonable degradation to the portion of the GOM affected by the proposed GP.

EPA Region 4 has determined that issuance of the Offshore Oil and Gas GP is not likely to adversely affect species or critical habitat under the ESA. With respect to the status of EPA Region 4's ESA consultation, see Responses CBD-1 and 4, above.

In addition, based on the EPA Region 4's analysis of the potential environmental impacts associated with the issuance of the GP, the EPA Region 4 has determined that no significant environmental impacts are anticipated from the proposed action. Therefore, the EPA Region in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama must submit a live bottom survey to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas It should also be noted that the Region 9 GP Produced Water volume limits range from 4,666 barrels per day (bbl/d) to 114,346 bbl/d. A 2005 report[1] of the produced water volumes from 50 operators in the GOM reported annual averages ranging from 3 bbl/d to 63,828 bbl/d.

Comment 14: EPA should require zero discharge of WTCW comingled with PW. Well treatment fluids contain toxic chemicals that are harmful for aquatic animals and water quality. Well treatment uses chemicals for a variety of functions, such as: dissolving acids, biocides, breakers, clay stabilizers, corrosion inhibitors, crosslinkers, foamers and defoamers, friction reducers, gellants, pH controllers, proppants, scale controllers, and surfactants. And, as explained above, modern hydraulic fracturing uses hundreds of chemicals that cause cancer or damage to the nervous, cardiovascular, and endocrine systems; and can be incredibly toxic to fish and other marine life. But the proposed permit authorizes the discharge of unlimited volumes of PW, including those mixed with fracking chemicals.

Response to comment 14: The EPA has found from past studies that a zero discharge is not feasible or necessary to protect the marine environment. See Responses to CBD-5, CBD-8 and CBD-12.

Comment 15: EPA should also require monitoring and reporting for additional chemicals in all types of discharges. For example, the Pacific OCS GP requires monitoring for specific chemicals, such as benzene, in produced water for each platform, for certain chemicals it also prescribes discharge limits. Here, given the new information about produced water and its potential toxicity, the EPA should require more robust monitoring for chemicals that could degrade the marine environment.

Response to comment 15: The EPA understands that the various discharges contain a variety of chemical compounds that have the potential to adversely impact the marine environment that will not be individually limited or monitored. The EPA has determined, however, that the limits and conditions in the GP will mitigate the potential toxicity of the discharge, and such limits and conditions (e.g., WET limits and WET monitoring) in the proposed GP are preferable to chemical-specific limits and monitoring, given the variability of composition. WET testing for well treatment fluids will commence with the authorization of the proposed permit as will reporting of chemicals used. Additionally, the permit will require the permittees to submit information on specific chemical constituents used during well treatment operations. This information may be used by the EPA in the future to determine if additional limits are warranted.

Comment 16: While discharges of well treatment fluids should be completely prohibited, if EPA nonetheless decides to allow such discharges, it must place numeric limits on the toxic chemicals that occur in well treatment fluids and require robust monitoring to ensure compliance. In addition to limits, the EPA should identify biologically sensitive areas or seasons to require zero discharge to protect sensitive species. For example, the EPA should restrict discharges in sea turtle critical habitat and Desoto Canyon. This would be more and drill cuttings within a 1000 m of an ABC or a federally designated dredged material ocean disposal site.

Regarding inclusion of BMPs to prohibit discharges, BMPs may be implemented in lieu of or in addition to numeric limits in some circumstances, for example if it is infeasible to calculate numeric limits BMPs limits may be appropriate. Alternatively, BMP-based limits may be appropriate when reasonably necessary to carry out the purposes of the CWA. See 40 CFR § 122.44(k). In this case, numeric technology-based limits for produced water and WCTW fluids have been established by the offshore oil and gas effluent guideline, which establishes the appropriate technology-based effluent limit for this category of discharges. A limit of zero discharge is not what is intended by a BMP, as it is a numeric effluent limit of zero, or a prohibition of discharge, which is inconsistent with the required federal effluent guideline-based numeric effluent limits in the GP. Additional limits based on water quality may be considered, but EPA has determined that the limits and conditions in the GP ensure that unreasonable degradation of the marine environment will not be caused by the authorized discharges.

Comment 13: The EPA must place a numeric volume limit for produced water allowed to be discharged. As explained above, produced water degrades water quality and introduces toxins into the marine environment. Well treatment activities may increase produced water discharges and extend the life of oil and gas operations; without a limit on produced water volume it is impossible for EPA to guarantee against the degradation of the marine environment and water quality. Already the amount of produced water that is discharged into the GOM is harmful, and the quantity could increase with new leases and changes in drilling and well stimulation practices. The proposed permit is more relaxed than other OCS GPs, and it is therefore arbitrary and inconsistent with other EPA GPs. For example, the Pacific OCS GP, the EPA set a limit of volume of produced water allowed for each platform.

Response to comment 13: The proposed GP covers produced water discharges only within the Region 4 jurisdictional area of the GOM. Within the Region 4 jurisdictional area EPA expects, during the approximate term of the permit from the year 2017 to 2022, an estimated 120 - 470 total wells, including about 60 - 235 production wells. Produced water is addressed in the proposed permit with both technology-based and water quality based limits. The ocean discharge criteria require that a waste stream cannot be permitted if EPA determines that the discharge of wastes will cause unreasonable degradation of the marine environment. The available evidence, including whole effluent toxicity data reported by permittees under the current R4 offshore permit, indicates that produced water discharges made consistent with the permit's terms and conditions will not result in unreasonable degradation to the portion of the GOM affected by the proposed permit. The EPA does not have information to justify imposing additional or more stringent limits.

It should be noted that, concerning the southern California offshore oil and gas facilities covered under the EPA Region 9 GP, most of the platforms are operating fairly close to shore in areas containing sensitive habitat in less than 100 meter depths. The proposed R4 GP will cover facilities in greater that 200 m depths offshore of Florida or in the Destin Dome lease block offshore of Alabama, most of which are expected to be located much further from shore in areas containing less biologically sensitive habitats. Further, facilities

Comment 11: While the inventory requirement that requires reporting of well treatment fluids to EPA with discharge monitoring reports is a step in the right direction, it does not prevent such chemicals from being discharged, and is thus inadequate to protect water quality. It is unclear whether the inventory requirement applies to well treatment fluids that are comingled with Produced Water. The Proposed GP states that discharge of WTCW fluids "shall be considered 'produced water when commingled with produced water." This appears to undermine the requirements to inventory and disclose the discharges thus failing to protect water quality when well treatments, such as fracking, result in flow back or otherwise dilute the discharges with produced water. Similarly, it is generally good to incentivize the industry-wide study and characterization of discharge of well treatment chemicals; but this does not assuage concerns that the discharges should be prohibited until proven safe.

Response to comment 11: The inventory requirement for WTCW fluids are targeted for discharges that occur prior to the production phase of the well. EPA is aware that there may be numerous discharges of WTCW fluids during well development, and the permit contains new WET testing monitoring only requirements applicable to WTCW fluids not commingled with PW in an effort to provide the EPA with new information in order to evaluate the extent to which these discharges ~~are~~ may be toxic. Based on current information, including information developed during previous permit terms, the EPA finds that the terms of the GP will ensure that the discharges do not cause unreasonable degradation of the marine environment. The chemical inventory and toxicity testing monitoring results will provide information to support future permitting decisions, including whether to add more stringent conditions, if warranted.

Comment 12: The discharge of pollution from offshore oil and gas drilling into this important habitat is unnecessary because a zero discharge permit is feasible. There are already oil and gas operations that meet zero discharge requirements. For example, coastal offshore drilling operations in the GOM already require zero discharge of produced water and treatment, workover, and completion fluids as well as drilling fluids, drill cuttings, and dewatering effluent. If the EPA does not implement the restriction as a technology-based effluent limitation, the BMPs should require the zero discharge requirement. BMPs are used to address the developments for which the effluent limitation guidelines have not kept pace.

Response to comment 12:

EPA is aware that some coastal states require zero discharge for oil and gas operations in near-shore coastal waters. Because EPA recognizes that shallower nearshore environments are most biologically productive and, therefore, more sensitive to direct exposure to pollutants from oil and gas operations, the proposed GP only covers operations seaward of the 200-meter isobaths offshore of Florida and in the Destin Dome lease block offshore of Alabama. These facilities will be considerably further from shallow nearshore environments. As a result, the greater distances make hauling operational discharges to onshore disposal site less feasible. The GP also requires facilities in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama to submit a live bottom survey to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. This will likely also steer facilities away from shallow and nearshore environments. In addition, the permit prohibits discharge of produced water, the discharges authorized in the GP will not result in unreasonable degradation of the marine environment.

The EPA Region 4 also notes that comparisons of the large-scale, induced hydraulic fracturing procedures used in onshore and off-shore California oil and gas operations for low-permeability reservoirs with well treatment operations carried out on the OCS in the GOM are misleading. Typical use of pressurized fluids for well treatment and well stimulation in the GOM are small-scale by comparison and use significantly smaller volumes of fracking fluids and the associated chemicals. In addition, the number of added chemicals is typically much smaller.

Comment 9: EPA claims that the conditions in the Proposed GP are sufficiently protective of the marine environment. But this conclusion is arbitrary—the existing permit conditions do not prevent undue degradation of the marine environment. In determining no undue degradation, EPA relies on the treatment of produced water and the toxicity testing required under the permit. But treatment of produced water is only oil-water separation, which does not remove any of the chemicals that flow back. Moreover, whole effluent testing is insufficient to ensure that discharges are not toxic because the testing is not required for discharge events, including the discharge of flowback from well treatment such as fracking. Most facilities are only required to test semi-annually, even those required to test bimonthly are not at the same time as a fracking event.

Response to comment 9: The EPA finds that past studies and NEPA documents support the conclusion that the proposed GP will be sufficient to protect the marine environment. See Responses CBD-4, CBD-5 and CBD-6.

Comment 10: The toxicity requirement that no observable effect concentrations should occur at the edge of the 100-m mixing zone is arbitrary. Rather, the no observable effect standard should be met at the outfall. Discharges must meet water quality and ocean discharge standards at the point of discharge. The WET testing of PW is good, but should be required to be conducted concomitant with discharges from well treatments, such as acidization, fracking, water flooding, gravel packing, etc.

Response to comment 10: The EPA does have some discretion with regard to the size of mixing zones used in NPDES permits, however, the EPA does not agree that the use of a 100-meter mixing zone to determine toxicity is arbitrary. Nor does EPA agree that a more restrictive mixing zone is necessary at this time. The concept for the 100 m mixing zone comes from 40 CFR § 125 Ocean Discharge Criteria: *"§125.121 (c)* Mixing zone *means the zone extending from the sea's surface to seabed and extending laterally to a distance of 100 meters in all directions from the discharge point(s) or to the boundary of the zone of initial dilution as calculated by a plume model approved by the director, whichever is greater, unless the director determines that the more restrictive mixing zone or another definition of the mixing zone is more appropriate for a specific discharge."* At present, the EPA does not have information that would justify a change in the size of the mixing zone prescribed in the proposed NPDES GP. The EPA will use the data acquired through the WET testing requirement for well treatment fluid discharges to determine whether a more restrictive mixing zone may be required.

which require the effluent concentration 100 m from the outfall to be less than the 7-day no observable effect concentration based on laboratory exposures. This will limit the impacts on nearby benthic resources.

Comment 7: Studies demonstrate that there are many unknowns regarding the impacts of the discharge of produced water on the marine environment, including on marine species, but what is known indicates that produced waters substantially degrade the marine environment. The EPA therefore cannot make the non-degradation finding for produced water. Available technologies exist that allow for zero discharge of such waters.

Response to comment 7: Available and cost-effective technologies exist for nearshore facilities. However, the EPA has determined that feasible technologies for offshore facilities that are at substantial distances from the shore are not available to the industry. See Responses CBD-4, CBD-5 and CBD-6.

Comment 8: The EPA's evaluation acknowledges that offshore fracking and other well stimulation occurs in the GOM. There are significant data gaps regarding the impacts of offshore fracking and acidization on the marine environment, and the best available scientific information indicates that the discharge of well treatment chemicals does not meet the ocean discharge criteria. Therefore, the EPA cannot permit the discharge of fracking and other well stimulation chemicals. The EPA cannot make a valid finding that the permit does not cause an unreasonable degradation of the marine environment because "insufficient information exists" regarding the impacts of well stimulation chemicals "to make a reasonable judgment" that the discharge satisfies all of the ocean discharge criteria. For example, an independent scientific review of offshore well stimulation by the California Council on Science and Technology found significant data gaps on basic questions regarding offshore fracking and acidizing.

Response to comment 8: The EPA Region 4 is aware that there is a significant body of information regarding chemicals used in hydraulic fracturing, demonstrating potential harm to aquatic communities in upland environments. The EPA Region 4 believes that chemicals used in offshore well stimulation fluids could be equally harmful to marine life if exposed to sufficiently high concentrations for sufficient periods of time or with repeated exposure to high concentrations. However, the EPA Region 4 is confident that the conditions and limits in the proposed GP are sufficient to prevent long-term exposures to high concentrations of such chemicals. The GP is protective of sensitive aquatic communities. In the Mobile and Viosca Knoll lease block areas offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. Additionally, the GP covers only facilities operating in depths of 200 m or more offshore of Florida and offshore of Alabama in the Destin Dome lease block. All facilities must operate a minimum of 1000 m from sensitive marine habitats in pre-designated Areas of Biological Concern. Due to high rates of dilution in the open ocean, exposure to high concentrations of added chemicals are likely to occur only for short durations in the discharge plume in the immediate vicinity of the outfall. The EPA Region 4 believes that exposures to concentrations high enough to cause biological effects will be brief and that no significant adverse impacts to marine life will result. Existing information, including information relating to the impacts of discharges during the previous GP term, is sufficient to support the EPA Region 4's determination that exposure suggest substantial impacts, such as loss of cell membrane integrity, gene expression changes, cytotoxicity, DNA damage, hepatic lipid composition, and reproductive disruption. Based on these studies, chronic exposure to even low concentrations of produced waters has negative consequences for the physiology of fish and invertebrates, Population and community effects are mostly unknown, as are the cumulative effects of chronic and acute produced water exposure.

Response to comment 5: The EPA is aware that produced water may contain a variety of substances that could be harmful to marine life if exposed to sufficiently high concentrations for sufficient periods of time or with repeated exposure to high concentrations. The EPA is aware that a number of biological responses have been documented in laboratory studies of controlled exposures to produced water. The EPA is confident that, due to high rates of dilution in the open ocean, such conditions as produced in controlled laboratory studies are likely to occur only for short durations in the discharge plume in the immediate vicinity of the outfall. The EPA finds that any exposures to concentrations high enough to cause biological effects will be brief and that no significant adverse impacts to marine life will result.

Comment 6: Habitat degradation due to produced waters is high near outfalls. Most PWs contain relatively high concentrations of several metals compared with clean sea water, with barium, iron, and manganese being the most abundant. These metals tend to rapidly precipitate from the plume, forming barium sulfate and oxides of iron and manganese on sediment surfaces over large areas around the produced water discharges. Evidence suggests that effects of discharges of PW in the water column and on the seabed in general have higher impacts within 1 or 2 kilometers from the outfall sources. However, the published literature has not yet been able to demonstrate with high confidence that the effects of PW are only local. Studies have shown that benthic communities require at least 5-10 years to recover from wastes accumulated on the seabed from produced waters.

Response to comment 6: The EPA agrees that some benthic impact may occur as a result of PW discharges that are made near the seafloor in relatively non-energy environments. Impacts may occur from direct contact of the concentrated discharge plume with the benthos and the accumulation of particulates that settle to the seafloor. Published studies show that PW impacts are highly variable with most being limited to within a few hundred meters from the outfall. It should be noted that the majority of studies that have shown an impact in the GOM concerned production wells in shallow (less than 30 meters) depths. The GP is protective of sensitive aquatic communities because, for facilities in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. Additionally, the GP covers only facilities operating in depths of 200 m or more offshore of Florida and offshore of Alabama in the Destin Dome lease block. All facilities must operate a minimum of 1000 m from sensitive marine habitats in pre-designated Areas of Biological Concern. Discharge models show that maximum plume concentrations occur from 8-12 m from the discharge point and plumes have been measured to dilute 100 times within 10 m of the discharge and 1,000 times within 103 m of the discharge.

Rapid dilution of the produced waters decreases the possible toxicity with distance from the outfall. Also, the proposed permit places restrictions on the discharge of produced water, the discharges of such wastewater is inherently dangerous and causes undue degradation of the ocean environment.

Response to comment 4: The EPA is aware that there is a significant body of information regarding chemicals used in hydraulic fracturing demonstrating potential harm to aquatic communities in upland environments. The EPA understands that chemicals used in offshore well stimulation fluids could be equally harmful to marine life if exposed to sufficiently high concentrations for sufficient periods of time or with repeated exposure to high concentrations. However, the EPA finds that the conditions and limits in the proposed permit are sufficient to prevent long-term exposures to high concentrations of such chemicals. The permit is protective of sensitive aquatic communities. In the Mobile and Viosca Knoll lease block areas offshore of Mississippi and Alabama , a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. Facilities offshore FL and offshore of Alabama in the Destin Dome lease block, will be in a minimum of 200 m water depths. All facilities must operate a minimum of 1000 m from sensitive marine habitat. Due to high rates of dilution in the open ocean, exposure to high concentrations of added chemicals are likely to occur only for short durations in the discharge plume in the immediate vicinity of the outfall. EPA finds that exposures to concentrations high enough to cause biological effects will be brief and that no significant adverse impacts to marine life will result.

All permitted discharges meet the no unreasonable degradation requirement as unreasonable degradation is defined in 40 CFR § 125.121(e)(1-3). The record, including information regarding impacts from discharges during prior permit cycles, does not contain evidence indicating that the discharges will cause "significant adverse changes" in ecosystem diversity, productivity or stability of the biological community. The record does not indicate that the discharges pose a threat to human health through direct exposure to pollutants or consumption of exposed aquatic organisms, and there has been no loss of esthetic, recreational, scientific or economic values which is unreasonable in relation to the benefit derived from the discharges. Existing information, including information relating to the impacts of discharges during the previous permit term, is sufficient to support EPA's determination that the discharges authorized in the GP will not result in unreasonable degradation of the marine environment.

Produced water discharges have technology-based and water quality-based limits. WTCW fluids are covered under the NPDES permit with technology-based effluent limits per the Effluent Guidelines. WTCW fluids commingled with produced waters have technology-based and water quality-based limits. WTCW fluids not commingled with produced waters discharged have technology-based effluent limits. The available data show no violations of WET limits. Both these waste streams, when discharged as permitted, do not cause any significant adverse impact to the marine environment in the GOM. The proposed final GP includes additional water quality based monitoring only condition for WTCW fluids that will provide information for future permitting decisions and enable EPA to identify environmental harm from the discharges that can be addressed through permit modification and in future permit cycles.

Comment 5: Studies show that exposure to produced wasters can cause a wide range of negative effects in fish and invertebrates. Several of the responses to produced water

EPA Region 4 has determined the proposed action is consistent with 40 CFR § 6.204 (a)(1)(iv).

In regards to consultation under ESA, the EPA Region 4 has had on-going coordination with NMFS and the USFWS for the proposed action. A biological evaluation (BE) was prepared and included in the DEA in Appendix E and has been shared with the NMFS and USFWS. Prior to publicly noticing the GP, the EPA Region 4 prepared a DEA pursuant to the NEPA and also engaged in consultation with the USFWS the NMFS in accordance with the ESA. Since publication of the DEA, USFWS provided concurrence with the EPA Region 4's determination that issuance of the Offshore Oil and Gas GP is not likely to adversely (NLAA) affect species or critical habitat under the ESA. The USFWS provided concurrence in a letter to the EPA Region 4 dated January 19, 2017. In addition, the NMFS concurred with the EPA Region 4's E S H assessment in a letter dated December 16, 2016. The EPA Region 4 has determined that its proposed action will NLAA listed species under the purview of the NMFS and will not likely jeopardize species and/or adversely modify critical habitat. The NMFS has not yet completed consultation or provided its concurrence on EPA's NLAA determination, but based on information in the record EPA anticipates that NMFS will concur with this determination. The EPA has determined that it can issue the GP prior to completion of consultation with NMFS in accordance with Section 7(a)(2) and Section 7(d) of the ESA because the issuance of the permit will not result in any irreversible or irretrievable commitment of resources which would have the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures that might be identified by NMFS pursuant to the consultation process. In the event that NMFS does identify necessary reasonable and prudent alternative measures that are necessary to prevent jeopardy to protected species or adverse impacts to critical habitat, the EPA has authority to modify the permit to include whatever conditions are necessary to implement such reasonable and prudent alternative measures. To avoid an irreversible or irretrievable commitment of resources, the reissued GP includes a specific re-opener clause that will enable the EPA Region 4 to modify the GP should further consultation reveal a need to formulate or implement reasonable and prudent alternative measures. This updated information regarding ESA consultation is reflected in our preliminary FONSI. The EPA Region 4 determined that formal consultation is not required (50 CFR § 402.14(b)(1)). This updated information regarding ESA consultation is reflected in our preliminary FONSI.

Comment 4: The Proposed GP does not comply with the Ocean Discharge Criteria or adequately protect water quality because it allows the unlimited discharge of Produced Waters. It allows the discharge of toxic fracking and other well treatment fluids and is less protective of water quality than other offshore oil and gas permits. It is wholly shocking that the EPA allows the oil and gas industry to dump its wastewater into the GOM. The EPA must implement substantial changes to the terms and conditions of the Proposed Permit prior to its issuance, including zero-discharge requirements for all produced wastewaters and well treatment fluids. Also, the EPA cannot make a valid finding that the permit does not cause an unreasonable degradation of the marine environment. The permit allows the unlimited discharge of produced wastewater, including the unlimited discharge of chemicals used in offshore fracking and other well stimulation treatments. There are significant data gaps on the impacts of these discharges on the marine environment, and what is known indicates that are necessary to prevent jeopardy to protected species or adverse impacts to critical habitat, EPA has authority to modify the permit to include whatever conditions are necessary to implement such reasonable and prudent alternative measures.

In a letter dated August 7, 2017, the EPA Region 4 notified NMFS of its intent to reissue the GP in accordance with Section 7(a)(2) and Section 7(d) of the ESA. To avoid an irreversible or irretrievable commitment of resources, the reissued GP includes a specific re-opener clause that will enable the EPA Region 4 to modify the GP should further consultation reveal a need to formulate or implement reasonable and prudent alternative measures. This updated information regarding ESA consultation is reflected in our preliminary Finding of No Significant Impact (FONSI).

Comment 2: The Center urges the EPA to prohibit the dumping of chemicals used in offshore fracking and other well stimulation into the Gulf, and implement a zero discharge requirement for wastewater generated by offshore oil and gas drilling activities. According to the Center, such action is necessary to ensure the Proposed GP does not result in an unreasonable degradation of the marine environment as required by the CWA.

Response to comment 2: All permitted discharges meet the no unreasonable degradation requirement. The term 'unreasonable degradation' is defined in 40 CFR § 125.121(e)(1-3). The record, including information regarding impacts from discharges during prior permit cycles, does not contain evidence indicating that the discharges will cause "significant adverse changes" in ecosystem diversity, productivity or stability of the biological community as a result of the discharges and there has been no threat to human health through direct exposure to pollutants or consumption of exposed aquatic organisms. Furthermore, the EPA has found that there has been no loss of esthetic, recreational, scientific or economic values which is unreasonable in relation to the benefit derived from the discharge.

Comment 3: Prior to issuing the permit, the EPA must prepare an environmental impact statement under the NEPA and must engage in formal consultation under the ESA. Such actions are necessary to protect imperiled marine species from the myriad dangerous pollutants discharged by offshore oil and gas activities. Failure to do so would violate NEPA and the ESA.

Response to comment 3:

The EPA Region 4 conducted multiple previous NEPA reviews on the issuances during prior permit cycles (NPDES permits may be issued for a maximum duration of five years) of the Region 4 NPDES GP for Offshore Oil and Gas Activities. These reviews have included an environmental impact statement (EIS) in 1998, Supplemental EIS in 2004, and an environmental assessment (EA) in 2009. For this proposed action, the EPA Region 4 tiered off of these previous NEPA documents as allowed under 40 CFR § 1502.20. Relevant information from these documents were updated and we determined that the analyses from these documents are still valid and therefore, are incorporated by reference, as appropriate, in the most recent DEA. Based on the analysis of the potential environmental impacts associated with the issuance of the GP, the EPA Region 4 determined that no significant environmental impacts are anticipated from the proposed action. Therefore, the EPA Region 4 does not believe it is appropriate to prepare an EIS for this proposed action. In addition, the

Waters of the Gulf of Mexico (1) seaward of the 200-meter depth contour offshore Alabama in the Destin Dome lease block, (2) seaward of the 200-meter depth contour offshore of Florida, and (3) in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama.

There are no applicable federal water quality criteria. However, the permit must comply with Ocean Discharge Criteria at 40 CFR Part 125. The permit's effluent limits ensure these discharges will cause no unreasonable degradations per CWA § 403(c) and Ocean Discharge Criteria (see 40 CFR Part 125, Subpart M). The 100-meter diameter mixing zone for toxicity is based on Ocean Discharge Criteria found at 40 CFR § 125.121(c). Based on WET data reported by permittees under the current R4 offshore NPDES GP, there have been no toxicity limit violations.

The EPA has not found that available toxicity test results or other available information would justify use of a more restrictive mixing zone as described in 40 CFR §125.121(c).

The permit includes a new requirement for permittees to monitor for toxicity for WTCW fluids not commingled with produced water. This information will allow the EPA to obtain additional/targeted data on possible impacts/toxicity of WTCW discharges and the information will inform future permitting decisions.

Lastly, all permittees are required to submit as part of NOIs for coverage under the GP technical information on the characteristics of the sea bottom. Specifically, in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. Operators must submit images for the Live Bottom Report using either digital high-resolution acoustic data (sidescan sonar) or photo documentation.

Prior to publicly noticing the GP, the EPA Region 4 prepared a DEA pursuant to the National Environmental Policy Act (NEPA) and also engaged in consultation with the US Fish and Wildlife Service (USFWS) and NMFS in accordance with the ESA. Since publication of the DEA, USFWS provided concurrence with the EPA Region 4's determination that issuance of the Offshore Oil and Gas GP is not likely to adversely (NLAA) affect species or critical habitat under the ESA. The USFWS provided concurrence in a letter to the EPA Region 4 dated January 19, 2017, and the NMFS concurred with the EPA Region 4's Essential Fish Habitat (ESH) assessment in a letter dated December 16, 2016. In addition, the EPA Region 4 has determined that its proposed action will NLAA listed species under the purview of the NMFS and will not likely jeopardize species and/or adversely modify critical habitat. The NMFS has not yet completed consultation or provided its concurrence on EPA's NLAA determination, but based on information in the record EPA anticipates that NMFS will concur with this determination. EPA has determined that it can issue the GP prior to completion of consultation with NMFS in accordance with Section 7(a)(2) and Section 7(d) of the ESA because the issuance of the permit will not result in any irreversible or irretrievable commitment of resources which would have the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures that might be identified by NMFS pursuant to the consultation process. In the event that NMFS does identify necessary reasonable and prudent alternative measures that

Response to Comment 29: No change made at this time in order for the EPA to gather more information about fate and transport of chemical constituents in brine and water-based mud proposed to be disposed of at the seafloor. This would allow us time to better determine appropriate permit parameters and conditions for this effluent.

Comment 30: The OOC requests that a change be made to the title and list for "Miscellaneous Discharges of Seawater and Freshwater which have been chemically Treated". This will be a word change from "Seawater" and "Freshwater" to "Water". This change will ensure that both "Seawater" and "Freshwater" are included in the chemically treated discharge list.

Response to Comment 30: No change made. The terminology used in the permit is clear.

Comment 31: The OOC requests a change to Table 1 regarding the references to the acute and chronic WET requirements.

Response to Comment 31: Change made. For simplification, Table 1 refers back to the permit for details.

Comments from the Center of Biological Diversity

Comment 1: While the Center of Biological Diversity (the 'Center') appreciates the EPA's new permit condition requiring oil companies to maintain an inventory of the chemicals used in offshore fracking and other well stimulation treatments, such condition does not go nearly far enough to protect Gulf ecosystems or marine species from these environmentally destructive practices.

Response to comment 1: The proposed GP is based upon current available data and federal standards. The EPA finds that the discharges covered under this permit will not result in an unreasonable degradation of the marine environment in the vicinity of the discharges. The GP contains prohibitions, technology-based effluent limits (TBELS), water-quality based requirements (i.e., WET limits on discharges of produced water, water-based drilling fluids, drill cuttings, and non-aqueous-based drill cuttings)]), to minimize water-quality impacts from the discharges. In addition, the GP includes whole effluent toxicity monitoring only requirements for WTCW fluid discharges. The WET monitoring for WTCW fluids will provide additional information regarding potential impacts from the discharge and inform future permit decision-making. The permit also prohibits bulk discharges of non-aqueous based drilling fluids (NAFs) including synthetic based drilling fluids (i.e., only de minimus discharges of NAFs are allowed), produced sand, oil based drilling fluids, oil contaminated drilling fluids, diesel oil, and priority pollutants contained in well treatment, completion, and workover fluids, which are prohibited except in trace amounts. The permit prohibits discharge of PW water, and drill cuttings within a 1000 meters of an Area of Biological Concern (ABC) or a federally designated dredged material ocean disposal site.

As noted, TBELs, WQBELS, and WET monitoring are included. The general permit authorizes discharges from oil and gas facilities and supporting pipeline facilities, engaged in exploration, development, and production operations located in and discharging to Federal

Response to Comment 25: The text was revised so that it now accurately refers to tables in Appendix A. The table "Vertical Port Separation to Avoid Interference", was inadvertently omitted in the draft GP, and was added to Appendix A.

Comment 26: The OOC requests the deletion of Tables 7 and 8 in the draft permit, which replace critical dilution tables for chemically treated waters and provide the "adjusted" critical dilution tables using uncertainty factors from Table 6. The OOC states it is unclear if the adjusted tables are to be used by the permittee in lieu of Tables 4 and 5 or what purpose these tables serve, as Tables 6, 7 and 8 are not discussed within the main text of the permit or the Appendix in this regard. In addition, the OOC requests the addition of the chemically treated seawater and freshwater critical dilution tables, which appear to have been deleted as an oversight from the draft permit. Reference to Table 7 within the permit text is made with regard to chemically treated freshwater. No mention of Table 8 is made within the text. References to these tables within the permit text should be revised or deleted accordingly.

Response to Comment 26: All tables referenced in Appendix A are mentioned in the text. Revisions were made so now all tables are included and labeled correctly.

Comment 27: The OOC requests that discharges of cement used for testing and unused cement slurry be authorized by adding a new discharge under Miscellaneous Discharges: "Unused Cement Slurry". As an alternative, the OOC recommends a joint industry study be performed to assess the overall environmental and safety impacts of this discharge.

Response to Comment 27: The comment requests that the permit authorize the discharge of unused cement slurry. No change will be made at this time in order for the EPA to gather more information about fate and transport of chemical constituents in the cement that will be ultimately disposed of at the seafloor. This would allow us time to better determine appropriate permit parameters and conditions for this effluent. The permit's prohibition on the discharge of excess cement slurry does not prevent testing of equipment. This prohibition has been included in the general permit for a number of years and presumably operators have tested and properly maintained cement systems and drilling equipment during that time. Excess cement can be hauled to shore for disposal.

Comment 28: The OOC requests that the Best Management Pollution Prevention Practice (BMP3) requirements be removed from the permit.

Response to Comment 28: No change made. BMP3s are central to many industrial permits. EPA understands that some provisions in a BMP3 plan for the NPDES permit may also be in BMPs for other regulatory agencies. For purposes of complying with the BMP3 provisions of Region 4's NPDES permit, operators can incorporate and rely on any duplicative compliance measures developed to comply with other regulatory authorities.

Comment 29: The OOC is requesting the addition of brine and/or water based mud discharge at the seafloor to the list of Miscellaneous Discharges.

Comment 21: The OOC requests changes to provide alignment and consistency between the text of the permit and the Tables in Appendix A. In addition, the OOC requests that all references to these tables be updated within the permit text. Table 3.A is listed in the Table of Contents, but not provided in the Appendix nor referenced in the text. Appendix A now includes four additional tables. With the addition of Table 3 into the Appendix, all other tables have been shifted in position. The OOC presents no opposition to the addition of Table 3; however, the OOC claims that the addition of Tables 6, 7 and 8 are unwarranted and/or has replaced tables that appear to be omitted as an oversight (see comments below).

Response to Comment 21: The text was revised so that it now accurately refers to tables in Appendix A.

Comment 22: The OOC requests correction of the misspelling of the word "Produced."

Response to Comment 22: The typographical error was corrected.

Comment 23: The OOC requests correction of the misspelling of the word "Produced." The OOC also states that the Results portion of Table 3, along with Figures 1 and 2 subsequently provided in the Appendix, might be better served in a supplemental document or fact sheet to the permit, as further comment may be necessary. This paragraph describes conditions that, based on uncertainty factors (Table 6), prompted the "adjusted" critical dilution tables provided as Tables 7 and 8. However, further information is needed regarding the uncertainty factors and how they are applied. In addition, references to Table 3 within the permit text should be revised or deleted.

Response to Comment 23: The typographical error was corrected. However, the tables were not moved.

Comment 24: The current permit references use of Table 5 by permittees with vertically aligned multiple discharge ports (vertical diffusers) and requirements for minimum port separation; however, this table has been omitted from the draft permit

Response to Comment 24: Change made. Corrections were made in the permit regarding references to Tables 4 and 5.

Comment 25: The OOC requests the deletion of Table 6 in the draft permit, which replaces critical dilution tables for chemically treated seawater and provides uncertainty factors for model simulations presented in Tables 4 and 5. The OOC states it is unclear how these uncertainty factors were calculated and how they are applied. Therefore, the addition of this table is confusing and unwarranted. In addition, the OOC requests the addition of the minimum vertical port separation table, which appears to have been deleted as an oversight from the draft permit. References to Table 6 within the permit text should be revised or deleted accordingly.

General Permit and demonstrated that cooling water intake structures on offshore oil and gas facilities have no significant impact on the selected species investigated." As the species studied were reliable indicators for overall entrainment, and given no species of concern were caught within the 60,376 individuals identified from 1,515 tows spread throughout the 24-month sampling period, the Agency has no basis to continue to require costly on platform monitoring at affected facilities. The OOC is therefore petitioning the EPA per their proposed language to reduce monitoring frequency to "none required". Summarizing and amplifying information previously submitted, the OOC suggests that Region 4 accept the results of the 24-month entrainment monitoring study completed for Region 4 as meeting, for the participating companies, the corresponding Region 4 requirement.

Response to Comment 19a: The EPA agrees with and has incorporated the OOC's proposed language, pursuant to which, after 24 months of entrainment monitoring, new fixed facilities that do not employ sea chests as intake structures may submit SEAMAP data annually to fulfill the requirements of 40 CFR § 125.137.

Comment 19b: As alternative to ongoing monitoring (after the initial 2 years of sampling) at affected facilities, the OOC suggests_using the SEAMAP database to establish the seasonality of entrainment potential, as required by 40 CFR § 125.137. Using the SEAMAP database for entrainment risk assessment is actually preferable to platform specific monitoring because:

- Data are collected and maintained over the long term, using consistent methodology for all sites, ensuring comparability of data over time
- The existing SEAMAP database already provides an assessment of seasonality of entrainment risk (as required by 40 CFR § 125.137) which can be periodically updated as new data are added to detect changes in risk over time.
- SEAMAP larval data could be selected for most common species in each region
- Approach is cost effective and appropriate to the low level of risk demonstrated in the 24-month Entrainment Monitoring Study and in a peer-reviewed study of entrainment risk from much larger water volumes in depths of 20-60 m where egg and larval densities are much higher.

Response to Comment 19b: The EPA agrees with and has incorporated the OOC's proposed alternative language, pursuant to which, after 24 months of entrainment monitoring, new fixed facilities that do not employ sea chests as intake structures may submit SEAMAP data annually to fulfill the requirements of 40 CFR § 125.137.

Comment 20: The OOC requests that visual inspections be required monthly for new fixed facilities that employ sea chests as intake structures. This request is backed by visual inspection data obtained in EPA Region 4. The observed rate of growth of biological material does not result in significant change over a one-week period. Changes are hard to discern over a monthly period. For a deep-water facility (does not employ a sea chest) monitored under the EPA Region 4 NPDES permit, the 2015 average rate of growth expressed as % screen coverage was 2.5% with a monthly range of 0-6% growth.

Response to Comment 20: See response to comment 17, above.

Response to Comment 15b: Partial changes made. Part V.15 was changed to clarify that for WTCW fluid discharges, monitoring only requirements apply. Test results shall be reported as pass or fail. A failure will not be considered a violation of the permit. The frequency was changed to agree with the frequency in Part I.B.6, which allows permittees to request reduced monitoring after the first year of the permit.

Comment 16: The OOC requests that the baseline study requirements be removed from the permit for operators that participate(d) in the 2012 Industry-Wide Source Water Biological Baseline Characterization Study (SWBBCS). This study was approved by US EPA Region 4 on 2/27/12.

Response to Comment 16: No change made. The EPA disagrees that new offshore operators should automatically be deemed to be in compliance with the baseline study requirements of the Cooling Water Intake Structure rule for New Sources based on previously submitted and now dated results of the Industry-Wide Study completed in 2012.

Comment 17: The OOC requests that visual inspections be required monthly for New non-Fixed Facilities. This request is backed by visual inspection data obtained in EPA Region 4. The observed rate of growth of biological material does not result in significant change over a one-week period. Changes are hard to discern over a monthly period. For a deep-water facility (does not employ a sea chest) that performed entrainment monitoring under the EPA Region 4 NPDES permit, the 2015 average monthly rate of growth expressed as % screen coverage was 2.5% with a monthly range of 0-6% growth.

Response to Comment 17: A change was made to requiring monitoring at least once per month (instead of weekly, as provided in draft permit) during the monitoring periods. For instance, operators must monitor at least once per month even if they are on location less than one month.

Comment 18: The OOC requests that visual inspections be required monthly for new fixed facility that do not employ sea chests as intake structures. This request is backed by visual inspection data obtained in EPA Region 4. The observed rate of growth of biological material does not result in significant change over a one-week period. Changes are hard to discern over a monthly period. For a deep-water facility (does not employ a sea chest) that performed entrainment monitoring under the EPA Region 4 NPDES permit, the 2015 average monthly rate of growth expressed as % screen coverage was 2.5% with a monthly range of 0-6% growth.

Response to Comment 18: See response to comment 17, above.

Comment 19a: The OOC strongly objects to the continued requirement to conduct ongoing entrainment monitoring (after initial two-year biweekly sampling). The OOC requests that the requirements for entrainment monitoring be removed from the permit for operators that participate(d) in the 2014 entrainment monitoring study. This request is further supported by EPA's own finding in the permit's Environmental Assessment, specifically, per section 6.2 of the DEA: *"EPA Region 4 has determined the study fulfills the requirements of the 2010*

Comment 13: The OOC recommends removing WTCW fluid discharges lasting four or more days from this section of the permit and adding a section specific to this type of discharge to ensure clarity, as presented in comment 14.

Response to Comment 13: A partial change was made. Chronic toxicity testing requirements apply to WTCW fluid discharges lasting four or more days. However, this is a monitoring only requirement and not an effluent limit. Clarifying language was added to Part V.A.15(a) to differentiate the monitoring chronic testing requirements for WTCW fluids from the chronic toxicity testing limits that apply for other waste streams.

Comment 14a: There are some requirements in Part V.A.15.a that are not applicable to the "monitoring only" requirements for WTCW fluid discharges lasting four or more days. The OOC is proposing the addition of this new section to only capture the requirements from Part V.A.15.a applicable to "monitoring only". The OOC has removed all language regarding permit violations. The OOC is proposing to strike the DMR language requiring reporting pass/fail due to this being a monitoring only requirement.

Response to Comment 14a: A clarification of violation language for these discharges was added. Test results will still be reported as pass or fail.

Comment 14b: The OOC has also requested clarifying language to indicate that repeat samples for invalid test results are only required if the discharge is still occurring and the additional sample can be obtained.

Response to Comment 14b: The permit now clarifies that retesting can only be done if an additional sample can be obtained.

Comment 14c: The OOC requests not including a frequency for testing in this section.

Response to Comment 14c: No change made. Testing frequency is needed to ensure a representative sample is obtained.

Comment 15a: The OOC is requesting to renumber this section and make changes to only capture the requirements applicable to "monitoring only."

Response to 15a: The permit is clear regarding where to find the appropriate acute and chronic WET testing requirements for WTCW fluids.

Comment 15b: The OOC requests removing the language at V.A.15.b.ii as applied to WTCW fluids. The frequency for testing has been addressed above under our comments for I.B.6 for well fluids. Additionally, the OOC states that Part V.A.15.b.ii "standard" frequency requirements, if left in the permit, would conflict with Part I.B.6 - to apply a recurring test frequency, and associated reduction criteria to "monitor only", short term, well specific fluid discharges is extremely confusing. The frequencies for this testing are adequately specified at I.B.6.

investment of time and resources that service providers make in developing proprietary products.

Response to 11d: No change made. See responses to comments 4c, 4d, and 5a.

Comment 11e: The OOC is requesting that the EPA Region 4 incorporate the OSHA Hazard Communication trade secret criteria by reference in the proposed GEG460000 GP.

Response to Comment 11e: No change made. The EPA disagrees with allowing submittal of information on an SDS as a substitute for keeping detailed information on chemicals being used because this information would not be sufficiently detailed to be useful for environmental analysis of the discharges or in the event of enforcement investigations conducted by the EPA inspectors; see response to comment 4d and 5a. With respect to CBI concerns, see response to Comment 4e.

Comment 12a: The OOC is requesting that "active" be struck. It is unclear what is intended by "active", and could, for instance, unintentionally exclude well jobs associated with initial completion and with abandonment. It is enough to simply reference well jobs where WTCW fluids will be discharged.

Response to Comment 12a: The word "active" has been deleted.

Comment 12b: The OOC requests striking "of varying depths (shallow, medium depth and deep depths)" and replacing simply with "discharging well treatment, completion, and/or workover fluids". It's unclear what the EPA means by this term (is it water depth, well depth to reservoir, discharge depth?)

Response to Comment 12b: No change made. The EPA wants to ensure that samples are representative of the various well depths. "Well depth" has been added for clarification to the permit.

Comment 12c: The OOC is requesting changes to the permit language to clarify that a financial commitment to participate in the Industry-Wide Study Alternative satisfies the chronic and acute monitoring requirements and the WTCW Reporting Requirements of the permit, and ensure consistency with prior approved industry studies. Further, the change allows the option for new permittees to benefit from the industry-wide study after initiation and completion of the study.

Response to Comment 12c: The EPA has worked with the industry on a number of similar industry-wide studies as alternatives to individual monitoring. The Agency prefers to allow the industry flexibility to determine how individual companies participate. Thus, the final permit does not address how operators participate in any industry-wide study that is conducted., which will be developed jointly between Region 4, EPA Headquarters and the OOC.

Response to Comment 10b: Partial change made. The EPA clarified that operators must take a grab sample at least monthly when the maximum flow rate of WTCW fluids is being discharged.

Comment 10c: The OOC requests that referenced corrections be incorporated into the permit regarding the CORMX Modeling parameters.

Response to Comment 10c: Changes made.

Comment 10d: The OOC requests adding "or calculated" to allow operators the flexibility to calculate discharge densities based on the average of all the fluids planned to be discharged. Discharge densities can vary throughout the discharge.

Response to Comment 10d: No change made. See response to comment 9e.

Comment 10e: The OOC requests removing the density ranges for well treatment, completion, and workover fluids as the proposed ranges may not cover the full range of densities of these types of fluids used. As the EPA stipulates that the operator must use the discharge density, the range is not necessary and could unduly limit the operator.

Response to Comment 10e: No change made. See response to comment 9f.

Comment 11a: The OOC requests updating the references for "additional toxicity testing requirements" to be consistent with the request to change language regarding acute and chronic WET testing of WTCW fluids.

Response to Comment 11a: No change made. See response to comments 11b-11d.

Comment 11b: Consistent with comments to Part I.A.4.u, the OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives.

Response to Comment 11b: No change made. See responses to comments 4c, 4d, and 5a.

Comment 11c: The OOC requests that the disclosure requirement allow for the use of a systems-style disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications) consistent with the approach that has been adopted for use in some jurisdictions and by "FracFocus."

Response to Comment 11c: No change made. See responses to comments 4c, 4d and 5a.

Comment 11d: The OOC requests that service providers be permitted to disclose the trade secret/CBI information directly to the EPA rather than requiring disclosure through the operators. Such independent disclosure is necessary in order to protect the substantial

Comment 9c: For Chronic WET requirements for WTCW fluids, clarify sample frequency. The OOC requests the EPA adopt a frequency of monthly.

Response to Comment 9c: The permit was changed to clarify that operators must take a grab sample at least once per month when the maximum flow rate of WTCW fluids will be discharged.

Comment 9d: The OOC requests that certain table reference corrections be incorporated into the permit.

Response to Comment 9d: Changes made.

Comment 9e: The OOC requests adding "or calculated" to allow operators the flexibility to calculate discharge densities based on the average of all the fluids planned to be discharged. Discharge densities can vary throughout the discharge. Being able to calculate a discharge density will allow operators to run CORMIX prior to the discharge to calculate the critical dilution factor. This will allow operators to identify the size of sample containers needed to obtain the appropriate volume of sample needed to run the toxicity test.

Response to 9e: No change made. The EPA does not see a need for calculated densities. For our purposes, a direct measurement is preferred and ensures consistency and accuracy.

Comment 9f: The OOC requests removing the density ranges for well treatment, completion, and workover fluids as the proposed ranges may not cover the full range of densities of these types of fluids used.

Response to Comment 9f: No change made. Any changes outside the density range should be noted on the electronic DMR submittal.

Comment 9g: The OOC requests the EPA consider requiring acute toxicity testing in lieu of chronic toxicity testing

Response to Comment 9g: The EPA disagrees with the use of acute testing requirements in lieu of chronic toxicity requirements. Chronic testing is more sensitive and is appropriate for longer term discharges.

Comment 10a: The OOC requests that these Acute WET requirements for WTCW fluids be moved to Part I.B.6.b to provide additional clarity that these are not limitations. The requirements under Part I.B.6.a.v are monitoring only requirements.

Response to Comment 10a: Change made.

Comment 10b: The OOC requests the EPA add clarifying text as shown for the less than four-day acute WET test trigger.

Comment 7: The OOC is requesting insertion of the phrase "or more recently approved methods" to Section I.B.1.b for consistency and alignment with GMG290000 where new methods are approved during the permit term.

Response to Comment 7: Change made. This revision will allow use of new analytical methods that are approved by the EPA during the permit term.

Comment 8a: The OOC requests text changes for consistency and alignment regarding record keeping requirements in Part I.A.4.u and Part II.C.5 of the permit.

Response to 8a: The language in Part I.A.4.u. was changed to clarify that the length of time operators must keep records is 5 years, which supersedes the general requirements for all NPDES permits in Part II.C.5 for operators to retain records for only three years.

Comment 8b: The OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives.

Response to Comment 8b: See Comments 4c, 4d and 5a.

Comment 8c: The OOC requests that the disclosure requirement allows for the use of a systems-style disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications) consistent with the approach that has been adopted for use in some jurisdictions and by "FracFocus."

Response to Comment 8c: See responses to comments 4c, 4d and 5a, above. The priority pollutant reporting requirements are part of the permits (no priority pollutants except in trace amount limits), and while some of the OOC's requests are appropriate for the chemical additive monitoring and study requirements, they do not appear to be adequate for this limit and reporting requirement.

Comment 9a: The OOC requests that the Chronic WET testing requirements for WTCW fluids be moved to Part I.B.6.b to provide additional clarity that these are not limitations The requirements shown under existing Part I.B.6.a.iv are monitoring only requirements.

Response to Comment 9a: Changes made. The permit language was moved from page 42 to page 45.

Comment 9b: The OOC requests the EPA verify the meaning of the language "lasting four or more consecutive days". A plain reading indicates this means a discharge to the ocean that is continuous over 24 hours per day and over four or more days.

Response to Comment 9b: Language was included to clarify that the meaning of a discharge "lasting four or more consecutive days" is a discharge that occurs for any amount of time during a 24- hour timeframe over four or more consecutive days storing, and transporting the chemical. Sections 1 through 8 contain general information about the chemical, identification, hazards, composition, safe handling practices, and emergency control measures. Sections 9 through 11 and 16 contain other technical and scientific information, such as physical and chemical properties, stability and reactivity information, toxicological information, exposure control information. Although Section 3 of an SDS requires information on a chemical's composition, if a trade secret is claimed, a company can omit the specific chemical identity and/or exact percentage (concentration) of composition.

The EPA R4 does agree with the OOC's suggestion to report the concentration because this information would be useful and it has been added to the permit.

5b: The OOC requests that the disclosure requirement be for composite chemical composition of all additives in the drilling fluids so as to conform to the system-style disclosure that has been adopted for use in many jurisdictions, including by the U.S. Department of Interior, and by "FracFocus."

Response to Comment 5b: No change made. See Responses to comments 4c, 4d and 5a.

Comment 6a: The OOC is requesting that WTCW Fluids Outfalls be combined into a single outfall as it is under the current permit. There is no reason to separate these outfalls. WTCW reporting requirements will provide detailed information on each discharge.

Response to Comment 6a: No change made. Requiring operators to report well treatment, well completions, and well workover fluids under separate outfalls does not pose a burden and is necessary for the EPA to more easily identify any possible toxic effluents from any of these three types of operations.

Comment 6b: The OOC is requesting an extension of the DMR reporting due date from the 28th day of the first month after the Quarter ends to the second month. Allowing OOC members more time to Quality Assurance/Quality Control the documents will ensure accurate information is reported to the EPA.

Response to Comment 6b: Change made.

Comment 6c: The OOC also requests that language be added to the permit addressing longer term issues (e.g. a Government Shutdown) where there is the possibility of a longer period of system unavailability (longer than a system refresh or update) and requests a grace period of 60 days from the date the system is back up and functioning.

Response to Comment 6c: Government shutdowns have historically been very infrequent and not an issue the EPA expects to be a burden for reporting.

such evaluation would be subject to interpretation and easily challenged. As the OOC pointed out in their above comment, SDS sheets could still be used to reverse engineer product formulas and would not provide a higher degree of protection.

Comment 4e: The OOC requests that service providers be permitted to disclose the trade secret/CBI information directly to the EPA rather than requiring disclosure through the operators.

Response to Comment 4e: Regarding submittal of CBI, such claims are not allowed regarding permit application information (see CWA § 402((j). As provided in 40 CFR § 122.28(b)(2), an NOI "fulfills the requirements for permit applications for purposes" of §§ 122.6, 122.21, and 122.26. See also, 40 CFR § 122.7, which provides that claims of confidentiality will be denied for permit applications, permit and effluent data and information required by NPDES application forms, including information submitted on the forms and any attachments. The information at issue is also ineligible for confidential treatment because it meets the definition of "effluent data" in 40 CFR § 2.302(a)(2). Effluent data is not eligible for confidential treatment pursuant to 40 CFR §§ 2.302(e) and (f). Facilities seeking to discharge pollutants into waters of the United States must be prepared to disclose information regarding the composition of their proposed discharge and such information must be made available to the public.

Comment 4f: The OOC requests deletion of the information requirement for biocide.

Response to Comment 4f: Region 4 needs information on biocides to determine the extent to which these substances may be toxic to the aquatic environment near the vicinity of the discharge and to determine whether any changes to the permit's current limits are needed to ensure that the permit is sufficiently protective of the environment.

Comment 5a: The OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives.

Response to Comment 5a: Some changes were made. The current language is clear and aligns with permit language developed by Region 9 for the Region 9 Offshore Oil and Gas GP. The EPA R4 disagrees with the use of information on a SDS as a substitute for keeping detailed information on chemicals being used because this information would not be in a form that would be useful for environmental analysis or in the event of enforcement investigations by the EPA inspectors. For instance, in the event of a toxicity test failure, the EPA would have immediate access to the specific chemical concentrations of probable toxicants in the effluent.

The SDSs are designed to provide information on materials in the event of worker exposure. The SDS includes information such as the properties of each chemical; the physical, health, and environmental health hazards; protective measures; and safety precautions for handling,

Comment 4a: The OOC request a text revision to provide clarity, alignment and consistency with GMG290000 (Part I.B.12) permit requirements.

Response to Comment 4a: No change made. The current language is clear and aligns with permit language developed by the EPA Headquarters and Region 9 for the Region 9 Offshore Oil and Gas GP.

Comment 4b: The OOC requests changes to include language that an operator is not required to submit annual information if the operator is participating in the Part I.B.6.b alternative study; which would include this information and for alignment with Part I.B.6 of the permit for discharges.

Response to Comment 4b: No change made. Operators will submit annual information even when enrolled in the study. The study has not been designed at this time.

Comment 4c: The OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the Safety Data Sheet (SDS) for relevant additives.

Response to Comment 4c: All operators under the Region 4 Offshore Oil and GP will have to comply with the permit requirements for submitting information on additives and chemical used in WTCW operations until the EPA and the industry develops and implements the alternative industry-wide study to investigate the composition and toxicity of these discharged fluids. This process could take months to complete.

EPA R4 disagrees with the use of information on an SDS as a substitute for keeping detailed information on chemicals being used because this information would not be sufficient in the event of enforcement investigations by the EPA inspectors or in order to fully inform future permitting decisions. Also see the EPA's response 4d and 5a, below.

Comment 4d: The OOC requests that the disclosure requirement allow for the use of a "systems-style" disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications), consistent with the approach that has been adopted for use in certain jurisdictions and by FracFocus. System-style disclosure would satisfy the objectives of the permit revision while potentially reducing the necessity for companies to make CBI claims on such disclosures. The process known as system-style disclosure lists all known chemical constituents in a fluid (or fluids, in the case of multiple disclosed applications), but decouples those constituents from their parent additives, thus improving protection of the proprietary chemistry used in hydraulic fracturing while promoting greater disclosure. At the same time, reverse engineering of product formulas may still be possible with the use of a systems-style disclosure.

Response to Comment 4d: Although the use of a systems-style disclosure of the chemical composition would provide some helpful information, it would not be sufficiently detailed to examine potential environmental impacts of discharges with a high degree of certainty. Any permit may affect a substantial number of small entities. Additionally, EPA previously found that the promulgation of the Offshore Subcategory guidelines on which many of the permit's effluent limitations are based, did not have significant impact on a substantial number of small entities; see 48 FR 12454 dated March 4, 1993, page 12492. The permit also contains limits based on CWA Section 403 (c), Ocean Discharge Criteria Evaluation, but these limits did not change from those in the 2015 permit based on that analysis.

B. Public Comments Received during the Public Comment Period:

The public notice announcing the proposed reissuance of EPA Region 4's General NPDES GP for Offshore Oil and Gas in the eastern GOM, No. GEG460000, as well as the Draft Environmental Assessment (DEA) and other support documents, was published at 81 Federal Register 55198 on August 18, 2016. The announcement was also published in six local newspapers in and along the Gulf coast. EPA Region 4 received six comment letters and three email messages. Written comments received during the comment period were considered in the formulation of a final determination regarding Region 4's final action on the reissuance of the general permit. Written comment on the draft GP, Fact Sheet, DEA, and CWA Section 403 documents are paraphrased below, along with EPA's response to each comment.

Comments from the Offshore Operators Committee (OOC):

Comment 1: The OOC requests additional language be added pertaining to notification requirements for e-reporting.

Response to Comment 1: Requested change made. The change clarifies that written NOIs will continue to be submitted beyond the stated date for transition to e-Reporting if the e-NOI system is not operational.

Comment 2: The OOC requests acceptance of certification letter, the opportunity to have input during the Network DMRs (NetDMR) development process, the ability to BETA test the system, electronic Notices of Intent, a copy of instructions be provided for NetDMR and No Data Indicator (NODI) codes and date alignment for accepting written NOI submittal.

Response to Comment 2: Partial change made. Permit language was changed to clarify when written NOIs are accepted. The EPA developers of NetDMR have been in contact with Region 6 in order to share lessons learned. The EPA will not be able to accept a Certification Letter in lieu of required electronic submittals. A link is provided in the permit for NetDMR instruction and NODI codes.

Comment 3: The OOC requests that the EPA provide a 60-day submittal for Quarterly DMRs.

Response to Comment 3: Change was made. The permit now allows operators up to the 58th day following the quarter reporting period to submit a DMR.

violate subsection (a)(2) of this section." The EPA has not completed consultation with the NMFS in connection with issuance of this permit. Accordingly, in order to ensure compliance with Section 7(a)(2) and 7(d) of the ESA, this permit may be revoked or reopened and modified at any time during the life of the permit if further consultation with NMFS results in the identification of reasonable and prudent alternative measures that are necessary to avoid jeopardy to an ESA threatened or endangered species or adverse effects to its critical habitat. Any such reasonable and prudent alternative measures may be added as conditions to this permit through the reopening and modification process."

18. **Part III.B. - Ocean Discharge Criteria Reopener** – The following reopener was added, as required by 40 CFR §125.123(d)(4), to address any additional permit conditions, if necessary, to comply with Section 403 of the CWA:

    "In addition to any other ground specified herein, this permit shall be modified or revoked at any time if, on the basis of any new data, the director determines that continued discharges may cause unreasonable degradation of the marine environment."

19. **Fact Sheet**: Language pertaining to the Paperwork Reduction Act and the Impact on Small Businesses was updated, as follows:

    Paperwork Reduction Act. The information collection required by this permit will reduce paperwork significantly through implementation of electronic reporting requirements. The EPA is working on an electronic notice of intent (eNOI) system which will allow applicants to file their NOIs online. The EPA estimates that it takes 10 to 15 minutes to fill in all information required by the eNOI for each lease block. It also takes much less time to add, delete, or modify eNOIs. In addition to the eNOI system, the EPA will incorporate an electronic discharge monitoring report (NetDMR) requirement into the permit. The time necessary for NetDMR preparation will be much less than that for paper DMR preparation. Both electronic filing systems will significantly reduce the mailing costs. The information collection activities in this permit is authorized by OMB, see ''ICR Supporting Statement Information Collection Request for National Pollutant Discharge Elimination System (NPDES) Program (Renewal) (EPA ICR No. 0229.22, OMB Control No. 2040-000)" with the exception if cooling water intake structures for new facilities which are addressed under a separate ICR, "Cooling Water Intake Structures at Phase III Facilities" (OMB Control No. 2040–0268, EPA ICR No. 2169.05). The ICR for Cooling Water Intake Structures at Phase III facilities expired on July 31, 2017. EPA is in the process of submitting information to OMB to have this ICR approved.

    Impact on Small Businesses. EPA analyzed the potential impact of today's permit on small entities and concludes that this permit reissuance will not have a significant impact on a substantial number of small entities. All changes from the 2015 permit results in either no or negligible incremental cost and no or negligible operational and/or economical burdens. In addition, there are not a substantial number of small entities affected by this permit as EPA understands that there are few, if any, small businesses that are owners or operators of facilities subject to this permit. EPA did not conduct a quantitative analysis of impacts for this permit, as that would only be appropriate if the sentence than has not previously been included in this NPDES general permit. The sentence reads: "I have no personal knowledge that the information submitted is other than true, accurate, and complete." The EPA believes this addition to the certification language is necessitated by the recent decision in U.S. v. Robison, 505 F.3d 1208 (11th Cir. 2007). In Robison, the Court of Appeals struck down the defendant's conviction for a false statement on the grounds that the certification language did not require him to have personal knowledge regarding the truth or falsity of the information submitted to the EPA. Rather, the court reasoned that the EPA's certification required the defendant to certify, in part, that he made an inquiry of the persons who prepared and submitted the information and based on that inquiry, the information was accurate to the best of his knowledge. The court further reasoned that there is no requirement in the certification that the person attest to his personal knowledge regarding the information submitted. The government had argued at trial that the defendant had personal knowledge that the facility had committed violations. As a result, the EPA feels it is necessary to include language which clarifies that the signatory is certifying that he or she has no personal knowledge that the information submitted is other than true, accurate, and complete.

14. **Part III.A - Monitoring Reports page 107:** The language was changed to allow operators more time to prepare and submit monitoring reports. Operators now have up to the 58th day following the quarterly reporting period to submit a DM).

15. **Part V.A.15 - Whole Effluent Toxicity Testing, pages 151- 160:** Language was added to clarify the frequency of toxicity testing for WTCW fluids. The new language also clarifies that a failure of a WET test for these discharges is not a violation of the permit and states that based on test results, a toxicity reduction evaluation and/or toxicity identification evaluation may be required.

16. **Part V.B – Definitions, page 174:** The definitions for "Toxicity Reduction Evaluation" and Toxicity Identification Evaluation" were added.

17. **Part III.B – Section 7(a) Endangered Species Reopener** - The following language was added to notify permittees that the permit may be reopened if the National Marine Fisheries Services (NMFS) Final Biological Opinion for the Gulf of Mexico (GOM) dictates additional permit conditions to protect endangered or threatened species under the Endangered Species Act:

> "Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA), EPA is required to consult with the U.S. Fish and Wildlife Service (FWS), and the National Marine Fisheries Service (NMFS) and ensure that "agency action" such as the issuance of this Clean Water Act (CWA) National Pollutant Discharge Elimination System (NDPES) permit does not jeopardize the continued existence of any endangered or threatened species or result in destruction or adverse modification of the critical habitat of such species. Section 7(d) of the ESA requires that, after initiation of consultation under Section 7(a)(2), the Federal agency "shall not make any irreversible or irretrievable commitment of resources with respect to the agency action which has the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures which would not

7. **Part I.B.3.b.ii - Produced Water, pages 34-36**: This section was simplified by deleting the superfluous reference to the LPC, which is the same as the "No Observed Effect Concentration." Also, in order to ensure representative samples were obtained, new language was added to clarify that grab samples must be obtained once each discharge during a time of the maximum effluent flow rate.

8. **Part I.B.6.a. - Well Treatment, Completions and Workover Fluids, page 42**: The sentence pertaining to submittal of some information as CBI was deleted. Permittees cannot claim information on the specific chemical composition of any additives used as CBI. Also, the language pertaining to the toxicity testing for well treatment completion and workovers fluids was moved to subsection b. (i.e., section for monitoring requirements), since the permit requirement does not require operators meet a permit limit.

9. **Part I.B.6.b -Well Treatment, Completions and Workover Fluids, page 50:** Language pertaining to the Industry-wide Alternative WET Testing was revised to clarify that the study would gather effluent data from wells discharging well treatment, completion, and/or workover fluids from various well depths. The timeframe to submit the study plan was extended to up to 18 months in order to agree with the language in the EPA Region 6 offshore oil and gas GP.

10. **Part I.B.10.b - Miscellaneous Discharges pages 54-55:** The language was revised to clarify that operators must monitor for free oil during times when observation of a visible sheen is possible, unless monitoring is performed using the static sheen test. Also, to ensure representative samples are obtained, language was added to specify that grab samples shall be taken for toxicity testing of miscellaneous discharges when the maximum flow is being discharged.

11. **Part I.B.11.a and c - Miscellaneous Discharges of Freshwater and Seawater to Which Chemicals Have Been Added, pages 56-57**: The language was revised to clarify that operators must monitor for free oil during times when observation of a visible sheen is possible, unless monitoring is performed using the static sheen test. Also to ensure representative samples are obtained, language was added to specify that grab samples shall be taken for toxicity testing of miscellaneous discharges when the maximum flow is being discharged.

12. **Part I.D.3.d. - Monitoring Requirements for facilities with Cooling Water Intake Structures, pages 72-75:** Language was revised to change the monitoring frequency from weekly to monthly and to clarify that "monthly" means at least once per month, even if the facility is at the location for less than one full month. Also, language was added to allow operators, after 24 months of monitoring at one location, the option to meet the requirements of annual reporting per 40 CFR § 125.137, using data from the SEAMAP.

13. **Part II.13 - Signatory Requirement on page 100:** The final permit contains a requirement that any person signing the NOI, NOT, and any reports (including any monitoring data) submitted to the EPA, in accordance with the proposed permit must include the certification statement in Part II. This certification statement includes an additional

Appendix B
Amended Fact Sheet and Responsiveness Summary

EPA Amendment to the Permit Fact Sheet at the Time of Issuance - National Pollutant Discharge Elimination System (NPDES) General Permit Number GEG460000

A. Substantive Changes from Draft Permit to Final Permit:

1. **Table of Contents:** The table, Produced Water (PW) Discharge Rates, was included in Appendix A of the permit as Table 3. This table was inadvertently omitted from the draft permit. The other tables in Appendix A were renumbered, accordingly.

2. **Part I.A.1**: The description of coverage area was revised, as follows, to more accurately denote the general permit coverage area.

"The general permit coverage area is Federal Waters (Federal Waters are those water that are three Nautical Miles seaward of the baseline marking the seaward limit of inland waters or, if there is no baseline, the line of ordinary low water along the portion of the coast that is in direct contact with the open sea) of the Gulf of Mexico (1) seaward of the 200 meter depth contour offshore of Alabama in the Destin Dome lease block, (2) seaward of the 200 meter depth contour offshore of Florida, and (3) in the Viosca Knoll and Mobile lease blocks offshore of Mississippi and Alabama.

3. **Part I.A.4 – Notification Requirements, pages 15-16**: Item w. was added, which requires operators to state their intention to participate in the alternative Industry-wide Study regarding Whole Effluent Toxicity (WET) Testing of Well Treatment, Completion and Workover (WTCW) Fluids (Part I.B.6.b, page 50). Language was also added to clarify operator options for submitting written, rather than electronic, Notices of Intent (NOI) in the event the EPA's system receiving electronic submittals is not operational.

4. **Part I.B.1.c.i – Drill Cuttings, page 24:** The word "concentrations" was added to the sentence in order to clarify that operators must keep an inventory of the total volume, total mass as well as concentrations of constituents added for each well.

5. **Part I.B.2.b.iv - Drill Cuttings, page 27:** The first sentence was corrected to state that the limits for mercury and cadmium in the section apply to drill cuttings and not to drilling fluids.

6. **Part I.B.2.c - Drill Cuttings, page 28:** The title for this section was corrected to clarify that this part of the permit includes limits as well as monitoring conditions for drill cuttings generated from non-aqueous based drilling fluids.

defined as, " naturally occurring radioactive materials that have been concentrated or exposed to the accessible environment as a result of human activities such as manufacturing, mineral extraction, or water processing." Not all oil and gas fields have TENORM accumulations, and EPA understands that if it is present, it may form a mineral scale on production piping, and other equipment, thereby increasing exposure to workers most likely via inhalation of dusts and direct radiation. Human protection from impacts of radiation is addressed in company occupational health and safety documents. The EPA has previously required monitoring of produced water discharges for Radium 226 and 288; however, data from that monitoring did not show that they were in sufficient concentrations to pose a potential environmental impact.

Comment 2 (paraphrased): The GP contains inadequate sampling requirements and analysis of oil and grease content and the toxicity of PW discharges, and it does not require permittees to quantify the mass of contaminants being discharged. Additionally, the GP requires testing of oil and grease using the gravimetric method instead of a more accurate gravimetric/mass spectrometry method. Toxicity is analyzed using a grab sample which has been diluted to a predicted critical dilution. The toxicity test does not analyze for target chemicals nor is the dilution of the sample protective enough.

Response to Comment 2: PW discharges are relatively long term and occur once the facility begins the production phase of operations. Based on the Best Professional Judgment (BPJ) of the permit writer, the permit requires grab samples to be analyzed monthly using an EPA-approved method in 40 CFR Part 136. The commenter did not provide specifics regarding he inadequacy of the current permit requirements; however, the EPA welcomes and will consider any data suggesting that the current sampling frequency and analytical method are inadequate.

The WET test is a gauge that the effluent will be protective of aquatic life, and it is designed to detect the synergistic impacts of chemicals. Only if the WET testing results show more than three failures in a row are operators required to perform additional testing to investigate the causative toxicant (i.e., individual chemical species). Since the receiving waterbody is large, it is reasonable to allow a mixing zone for certain waste streams.

Comment 3 (paraphrased): There is no provision in the GP for testing the corrosivity (i.e., pH) of PW prior to discharge, and the GP's contains an inadequate provision allowing operators to self-certify that there are no priority pollutants in chemicals used in these fluids. WTCW fluids are allowed to be commingled in PW prior to discharge. These fluids contain acids, biocides, friction reducers and viscosity enhancers, which are corrosive.

Response to Comment 3: Some WTCW fluids may be corrosive and commingled with PW prior to discharge. However, based on the EPA data, the pH of PW commingled with WTCW fluids is within a range of 6-9 standard units, which is protective of aquatic life. Therefore, there is no need to test pH of PW prior to discharge. Also, although the permit does not include a pH limit, permittees must sample and perform WET testing to demonstrate PW effluents are not toxic to aquatic life. By design, the NPDES permitting program requires permittees to self-monitor and self-certify. Permittees must sign certification statements that the information/data being submitting is accurate, including proper quality control of samples, and the regulations impose penalties for submitting false information. The permit requires permittees to self-certify that WTCW fluids contain priority pollutants in less than detectable amounts, which the EPA believes is a sufficient demonstration that the effluent will be protective of aquatic life.-

Comment 4 (paraphrased): The GP fails to include provisions for verifying actual chemical concentrations at the edge of the 100-m mixing zone using documented laboratory analysis with proper quality control.

Response to Comment 4: NPDES permit regulations require sampling only where the sample point is accessible and safe and, ultimately, it is the permittee's responsibility to provide a safe and accessible sampling point that is representative of the discharge. For practical reasons, in lieu of verifying actual chemical concentrations via sampling at the edge of the mixing zone in the GOM, the permit allows the use of a CORMIX model to predict concentrations.

Comment 5 (paraphrased): The EPA has a duty to uphold the CWA, specifically the regulations at 40 CFR § 125.122, which prevent the unreasonable degradation of the marine environment. The practice of ocean disposal of PW exists only because EPA excludes oil and gas industry wastes from Resource Conservation and Recovery Act regulations.

Response to comment 5: The permit address both Sections 402 and 403 of the CWA, and the EPA works with the federal and state agencies to insure that the permit will not adversely impact endangered species and coastal communities. A CWA Section 403 determination was prepared and publicly notice with the draft GP. The Section 403 determination addresses the potential for permitted discharges to cause an unreasonable degradation of the marine environment in the vicinity of the discharges. This document was transmitted separately to the US FWS and the NMFS for their review of potential impacts to Endangered Species and commercial fisheries. Additionally, the states of Mississippi, Alabama and Florida were contacted in order for coastal programs to provide input regarding potential impacts to coastal waterbodies. The permit allows the discharge of PW in accordance with the prescribed permit conditions for this waste stream, which the EPA has determined are protective of aquatic life.

Comments from the International Association of Drilling Contractors

Comment 1: The IADC shares the concerns and recommendations expressed by the Offshore Operator's Committee.

Response to Comment 1: Please refer to EPA Region 4's above responses to comments submitted by the OOC in its letter to EPA dated October 17, 2016.

Comments from the Petroleum Equipment and Service Association

Comment 1 (paraphrased): The permit notification language at Part I.A.4.u. should be revised to allow operators to disclose information on well treatment, completion and workover fluids based on information on SDSs. Operators should be allowed to claim some information pertaining to formulation of chemicals used as "Confidential Business Information" in accordance with 40 CFR Part 2.

Response to comment 1: A revision to this language was not made. EPA disagrees that the information on the SDS should be used to report information on the chemical composition of additives. Also, information submitted cannot be designated as "Confidential Business Information". (See EPA responses to the OOC comments 4,5, and 11, above.). Details of the industry-wide study have not been developed yet, but the EPA envisions different levels of participation. Participants may still have to report annual information regarding additives used in well treatment, completion and workover operations.

Comment 2 (paraphrased): The Drilling Fluids limitations language in Part I.B.1.b. should be revised to reflect the correct analytical method for mercury. Specifically, EPA method 245.7 should be changed to method 245.5.

Response to Comment 2: The requested correction was made regarding the EPA approved method for mercury analysis.

Comment 3 (paraphrased): The Drilling Fluids Inventory Documentation language in Part I.B.1.c.1 should be revised to require permittees to maintain a chemical usage of all products used rather than all constituents used. Drilling Fluid Chemical inventory for drilling operations is currently maintained using product names and quantities or products added to the drilling fluid. Use of the term products will maintain clarity and conformity of the records maintained by Drilling Fluid Specialist and Service company records provided to the operators for commercial, technical and permit compliance purposes.

Response to comment 3: No change made. The permit requires operators to maintain a record of chemicals added to each well drilled in order to determine which specific components may be toxic to the marine environment.

Comment 4 (paraphrased): The language in Part I.B.6.a.iii & b. for WTCW fluids and priority pollutants should be changed to delete specific requirements pertaining to reporting of information on priority pollutants.

Response to Comment 4: No change made. The EPA's proposed language is very similar to the language in the current permit. During the term of the current permit, EPA received no complaints regarding restrictions to discharge fluids with priority pollutants in less than "trace" amounts.

Comment 5 (paraphrased): Off-the-shelf toxicity testing requirements for well treatment, completion, and workover fluids not discharged with produced water may not be appropriate. Therefore, the EPA should work with industry to develop an objective-based approach to toxicity evaluation.

Response to Comment 5: The EPA requires offshore oil and gas operators to use current EPA-approved toxicity tests being used by many industries nationwide. Results of new toxicity testing information to be obtained in this permit will help determine if any changes to toxicity test methods for oil and gas operators is warranted.

Comment 6 (paraphrased): The current permit language pertaining to Test Procedures and Definitions for Formation Oil is redundant. The permit language should be more standardized.

Response to comment 6: No changes were made. The test for Formation Oil is contained in Pat V.9 and the EPA definition for Formation Oil is in Part B.38. Although both parts refer to where the operator can find the EPA approved test method, EPA does not believe the permit is redundant. The commenter did not present any information that suggests ambiguities or problems with operators understanding the required test method to be used based on the current language in the permit. Also, standardization of the language is not necessary. The EPA is unaware of any compliance difficulties or problems with operators using the current procedures in the permit pertaining to contamination of non-aqueous based drilling fluids. Lastly, the commenter did not present suggested revised language for consideration.

Commenter: Kathryn Dombey of Pensacola, FL; email dated August 18, 2016

Comment (paraphrased): I do not support a permit that continues to allow additional pollution of the GOM off the Florida and Alabama coast. It is to protect the precious resort areas for our grandchildren and great-grandchildren.

Response: The NPDES permit includes conditions to ensure that it does not result in unreasonable degradation of the marine environment and complies with federal regulations for point source discharges to waters of the U.S. and is protective of human health and aquatic life.

Commenter: Susan Patton of Tennessee; email dated October 4, 2016

Question 1: Is it true that the EPA plans to dump unlimited amounts of fracking chemicals into the GOM and if true why?

Response: The proposed NPDES GP authorizes discharges of PW and WTCW fluids from oil and gas exploration, development and production activities, including field exploration, drilling, and well treatment and completion activities (known as hydraulic fracturing). The GP is protective of sensitive aquatic communities. In the Mobile and Viosca Knoll lease block areas offshore of Mississippi and Alabama, a live bottom survey must be submitted to EPA for any areas that are less than 100 meters in depth, and EPA can review the survey and deny permit coverage to protect sensitive areas. Additionally, the GP covers only facilities operating in depths of 200 m or more offshore Florida and offshore Alabama in the Destin Dome lease block. All facilities must operate a minimum of 1000 m from sensitive marine habitats in pre-designated Areas of Biological Concern.

When issued, the permit term is 5 years. The NPDES permit includes conditions to ensure that it does not result in unreasonable degradation of the marine environment, complies with federal regulations for point source discharges to waters of the U.S. and is protective of human health and aquatic life.

Question 2: Does the EPA allow dumping of offshore fracking byproduct into the Gulf?

Response: Discharges of fluids used in fracking operations may occur during WTCW operations prior to oil and gas production. Such discharges are allowed but must meet conditions in the permit that ensure that the permit does not cause unreasonable degradation of the marine environment. The permit applies effluent guideline-based limitations and toxicity testing requirements limits on the discharge of WTCW fluids not commingled with PW.

Question 3: Is there any water quality monitoring associated with the dumping?

Response: The draft GP includes new WET monitoring requirements specifically for discharges resulting from well treatment fluid operations, including hydraulic fracturing. It also includes reporting requirements to better understand potential impacts of discharges, including location, volume of fluids used, chemical parameters and duration of discharge.

Commenter: Paul D. Steury; email dated October 5, 2016

Comment (paraphrased): Is the EPA thinking about allowing frack water to be disposed of in the GOM?

Response: Yes. The draft NPDES GP authorizes discharges of PW and WCTW fluids from oil and gas exploration, development and production activities, including field exploration, drilling, and well treatment and completion activities (known as hydraulic fracturing). The permit covers all discharges in the Eastern GOM (1) offshore of Florida in water depths seaward of 200 meters, (2) in the Destin Dome lease block offshore of Alabama in water depths seaward of 200 meters, and (3) in the Mobile and Viosca Knoll lease blocks offshore of Mississippi and Alabama. When issued, the permit term is 5 years. Discharges are allowed provided certain conditions are met. The permit applies effluent guideline-based limitations and toxicity limits on the discharge of well treatment, completion and workover fluids when discharged with produced water, and effluent guideline-based limitations and monitoring requirements apply to well completion and treatment fluid discharged separately.

The proposed GP includes new WET monitoring requirements specifically for discharges resulting from well treatment fluid operations, including hydraulic fracturing. It also includes reporting requirements to better understand potential impacts of discharges, including location, volume of fluids used, chemical parameters and duration of discharge.

The NPDES GP includes conditions to ensure that it does not result in unreasonable degradation of the marine environment, complies with federal regulations for point source discharges to waters of the U.S. and is protective of human health and aquatic life. The issuance of the GP is consistent with the requirements of the CWA and NEPA. The EPA will continue to engage in the required consultation with the appropriate agencies as required by various statutes, such as the ESA, in connection with issuance of the final GP.

Comments from the American Petroleum Institute, letter dated October 18, 2016.

Comment 1 (paraphrased): The API support's the OOC's detailed comments on the permit and adopt and incorporate those comments by reference.

Response to Comment 1: See the EPA's response to comments from the OOC on the draft permit.

Comment 2: The API supports the proposed findings of no significant impact within the draft Environmental Assessment; however, sections 1.3.4.2 and 3.6.3.3 should be made consistent.

Response to Comment 2: EPA reviewed section 1.3.4.2 (Scope of this NEPA Document) and 3.6.3.3 (Deepwater Horizon Impacts on Socioeconomic Resources-Human Health Impacts) of the DEA and did not note any inconsistences in the text.

Comment 3: EPA should modify the deadline for electronic reporting to ensure accuracy and operational functionality of the system, and we support the OOC's request to provide input during the NetDMR development process and beta testing prior to implementation.

Response to Comment 3: The deadline in the permit of December 21, 2016, is mandated by the regulation and cannot be extended. Beta testing has already begun by the EPA at the Headquarters level.

Comment 4: The API supports the OOC's request for the permit to clarify that toxicity monitoring only requirements be in the permit. We furthermore support the concerns the OOC has raised in regards to the CBI contained in the proposed reporting requirements.

Response to Comment 4: See the Responses to the OOC comment numbers 4 and 9.

Comment 5: The API supports the OOC's objection to continued ongoing entrainment monitoring and supports a two-year study for newly affected facilities and the use of SEAMAP data to show compliance with the CWA Section 316(b) requirements in lieu actual sampling.

Response to Comment 5: See the Response to the OOC comment number 19.

1220 L Street, Northwest
Washington, DC 20005-4070
Tel (202) 682-8372
Fax (202) 682-8270
E-mail emmerta@api.org

Amy Emmert
Senior Policy Advisor

October 18, 2016

Attn: Ms. Bridget Staples
WPD, U.S. EPA Region 4
NPDES Permitting Program
Sam Nunn Atlanta Federal Center
61 Forsyth Street SW
Atlanta, GA 30303-8960

Re: Draft National Pollutant Discharge Elimination System (NPDES) General Permit for the Eastern Portion of the Outer Continental Shelf (OCS) of the Gulf of Mexico (GEG460000) (81 Fed. Reg. 55,196 (August 18, 2016)).

Dear Ms. Staples,

The American Petroleum Institute (API) appreciates the opportunity to submit comments on the Draft National Pollutant Discharge Elimination System (NPDES) General Permit for the Eastern Portion of the Outer Continental Shelf (OCS) of the Gulf of Mexico (GEG460000).[1] API supports the goals of the (NPDES) program, and our members have been constructive participants in the NPDES permitting process.

API is a national trade association representing over 600 member companies involved in all aspects of the oil and natural gas industry, both onshore and offshore. API's members include producers, refiners, suppliers, pipeline operators, and marine transporters, as well as service and supply companies that support all segments of the industry. API and its members are dedicated to meeting environmental requirements while economically developing and supplying energy resources for consumers.

When evaluating this particular draft general permit, API also participated in discussions held by the Offshore Operators Committee (OOC), which represents approximately 90% of the oil and natural gas production in the Gulf of Mexico OCS. We support OOC's detailed comments on the permit, and we hereby adopt and incorporate those comments by reference, while highlighting four priority points below:

1. We support the proposed findings of no significant impact (FONSI) within the Draft Environmental Assessment (EA). However, we recommend sections 1.3.4.2 and 3.6.3.3 be made consistent.

---

[1] 81 Fed. Reg. 55,196 (August 18, 2016).

2. While we support electronic reporting systems and EPA's goal of implementing electronic reporting in Region 4 by end of the year, we encourage EPA to modify that deadline as necessary to ensure the accuracy and operational functionality of the system. API therefore respectfully supports OOC request for the opportunity to provide input during the NetDMR development process, and to beta test both the system and its associated tools prior to the final roll out of these systems – particularly in light of the lessons from the roll out of an identical program in Region 6.

3. With respect to toxicity testing of well treatment, completion, and workover fluids, OOC has requested modification of the permit language to clarify that chronic and acute testing requirements are monitoring only requirements, as opposed to limitations. API supports this change, the several clarifications which OOC has recommended to help implement the proposed toxicity testing and its frequency. API also supports the serious concerns which OOC has raised concerning the management of Confidential Business Information contained in the proposed reporting requirements.

4. According to section 6.1 of the Draft Environmental Impact Assessment, EPA concluded "*that cooling water intake structures on offshore oil and gas facilities have no significant impact on the selected species investigated;*" consequently, API echoes the OOC's objection to continuing the requirement to conduct ongoing entrainment monitoring. Like OOC, API supports two year study requirements for newly affected facilities. However, if existing sampling patterns over a 24 month period have not yielded species of concern, continued costly platform monitoring of this issue at affected facilities should not be required. At that point, the monitoring frequency should slow to either "none required" (see proposed language at Part I.D.3.d.ii, p. 70 of the draft permit) or to a more cost-effective approach using the SEAMAP database.

The OOC comments elaborate on each of these points, and also spotlight other concerns which we also fully affirm, but did not address in detail here in the interest of brevity. To that end, complete comments from the OOC – including its cover letter and table or recommended changes – are also attached.

Thank you for your consideration of these comments. We look forward to working with you on this important issue.

Sincerely,

Amy Emmert
Senior Policy Advisor

cc:
E. Milito, API
S. Meadows, API
P. Tolsdorf, API
K. Cauthen, API
G. Southworth, OOC

API-1	Comment noted. See the EPA's responses for the Offshore Operators Committee comments on the draft permit.
API-2	EPA reviewed sections 1.3.4.2 (Scope of this NEPA Document) and 3.6.3.3 (Deepwater Horizon Impacts on Socioeconomic Resources – Human Health Impacts) of the EA and did not note any inconsistences in the text.
API-3	The deadline in the permit of December 21, 2016, is mandated by the regulation and cannot be extended. Beta testing has already begun by EPA at the Headquarters level.
API-4	Comment noted. See EPA's responses to the OOC comments numbers 4 and 9.
API-5	Comment Noted. See EPA's response to the OOC comment number 19.

CENTER for BIOLOGICAL DIVERSITY

Via Electronic and First Class Mail

September 17, 2016

Bridget Staples, NPDES Offshore Oil and Gas Coordinator
Water Protection Division, NPDES Permits Section
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street, S.W.
Atlanta, Georgia 30303
Email: staples.bridget@epa.gov

RE: Draft NPDES Permit for Offshore Oil and Gas Operations in the Eastern Gulf of Mexico, General Permit No. GEG460000

Dear Ms. Staples:

CBD-1

CBD-2

The Center for Biological Diversity ("Center") submits the following comments to Region 4 of the Environmental Protection Agency ("EPA") on the Draft National Pollutant Discharge Elimination System ("NPDES") General Permit For Offshore Oil and Gas Activities in the Eastern Gulf of Mexico, General Permit No. GEG460000 ("Proposed Permit"). While the Center appreciates EPA's new permit condition requiring oil companies to maintain an inventory of the chemicals used in offshore fracking and other well stimulation treatments, such condition does not go nearly far enough to protect Gulf ecosystems or marine species from these environmentally destructive practices. The Center urges EPA to prohibit the dumping of chemicals used in offshore fracking and other well stimulation into the Gulf, and implement a zero discharge requirement for wastewater generated by offshore oil and gas drilling activities, including drill cuttings and fluids, well treatment fluids, and produced water. Such action is necessary to ensure the Proposed Permit does not result in an unreasonable degradation of the marine environment as required by the Clean Water Act ("CWA").

CBD-3

Moreover, prior to issuing the permit, EPA must prepare an environmental impact statement under the National Environmental Policy Act ("NEPA") and must engage in formal consultation under the Endangered Species Act ("ESA"). Such actions are necessary to protect imperiled marine species from the myriad dangerous pollutants discharged by offshore oil and gas activities. Failure to do so would violate NEPA and the ESA.

I. EPA's Proposed Permit Fails to Comply with the Clean Water Act

The Proposed Permit does not adequately protect water quality or the ocean environment and therefore fails to comply with the CWA. Congress enacted the CWA in order "to restore and maintain the chemical, physical, and biological integrity of the nation's waters;" to guarantee "water quality which provides for the protection and propagation of fish, shellfish, and wildlife and provides for recreation;" and to promptly eliminate water pollution.[1] To help meet these goals, the CWA establishes the NPDES permitting program. Specifically, under Section 301, "the discharge of any pollutant by any person shall be unlawful," unless the discharger meets one of several exceptions, which includes obtaining a permit issued pursuant to Section 402.[2] "The combined effect of sections 301(a) and 402 is that '[t]he CWA prohibits the discharge of any pollutant from a point source into navigable waters of the United States without an NPDES permit.'"[3]

Every NPDES permit must contain effluent limits sufficient both to "restore" and "maintain" the receiving waterbody.[4] In particular, the CWA requires EPA to set technology-based effluent limits that reflect the ability of available technologies to reduce and ultimately eliminate pollution discharges.[5] All sources and all pollutants must be subject to technology-based effluent limits,[6] unless more stringent water quality-based effluent limits are required to avoid exceedances of water quality standards.[7]

To implement the CWA's tech-based effluent limit requirements, EPA must establish national effluent limitations and guidelines ("NELGs") for industrial point sources, which establish an absolute minimum level of pollution control that must be achieved by industrial point sources.[8] EPA looks first to the NELGs when setting technology-based effluent limits.[9] Where NELGs do not exist for a particular pollutant or class of pollutants to be discharged from a point source, EPA is required to exercise their best professional judgment ("BPJ") to set case-by-case technology-based effluent limits for pollutants in NPDES permits.[10]

In addition, in order to provide enhanced protections for marine waters, Section 403 of the CWA establishes ocean discharge criteria.[11] Congress directed EPA to publish regulations and guidelines for determining degradation of the "waters of the territorial sea, the contiguous zone, and oceans…."[12] Under the ocean discharge criteria, EPA cannot issue a discharge permit where the discharge would cause "undue degradation of the marine environment."[13]

---

[1] 33 U.S.C. § 1251(a).

[2] 33 U.S.C. § 1301(a).

[3] *Nw. Evtl. Advocates v. EPA*, 537 F.3d 1006, 1010 (9th Cir. 2008) (citations omitted).

[4] *See* 33 U.S.C. § 1251(a).

[5] *See id.* §§ 1311 (establishing technology-based effluent limits),1342(a)(1) (requiring that NPDES permits incorporate technology-based effluent limits).

[6] *See id.* § 1311(b)(2)(A),.

[7] *See id.* § 1312(a).

[8] 33 U.S.C. §§ 1311(b), 1314(b); *See Natural Res. Def Council v. EPA*, 859 P.2d 156, 183 (D.C. Cir. 1988).

[9] *See id.*

[10] 33 U.S.C. §§ 1311(b)(2)(A); 1342(a)(1)(A), 40 C.F.R. § 125.3(c); *see also Am. Petroleum Inst. v. EPA*, 787 P.2d 965, 969 (5th Cir. 1986) ("Where EPA has not promulgated applicable technology-based effluent limitations guidelines, the permits must incorporate, on a case-by-case method, 'such conditions as the Administrator determines are necessary to carry out the provisions of the Act.'") (citations omitted).

[11] 33 U.S.C. § 1343

[12] *Id.* § 1343(c)(1).

[13]

CBD-4

The Proposed Permit does not comply with the ocean discharge criteria or adequately protect water quality because it allows the unlimited discharge of produced waters; it allows the discharge of toxic fracking and other well treatment fluids; and is less protective of water quality than other offshore oil and gas permits. It is wholly shocking that EPA allows the oil and gas industry to dump its wastewater into the Gulf of Mexico. This is a serious disloyalty to the public and its reliance on the agency to protect water quality. EPA must therefore implement substantial changes to the terms and conditions of the Proposed Permit prior to its issuance, including zero-discharge requirements for all produced wastewater and well treatment fluids.

A. EPA's Proposed Permit Fails to Comply with the Ocean Discharge Criteria

EPA's finding that the proposed permit meets the ocean discharge criteria is inadequate and flawed. Permits for ocean discharges comply with ocean discharge criteria.[14] EPA may issue a permit only if it concludes "on the basis of available information" that the discharge will not cause an unreasonable degradation of the marine environment.[15]

Unreasonable degradation is defined in 40 C.F.R. § 125.121(e)(1-3) as:

(1) Significant adverse changes in ecosystem diversity, productivity and stability of the biological community within the area of discharge and surrounding biological communities;
(2) Threat to human health through direct exposure to pollutants or through consumption of exposed aquatic organisms; or
(3) Loss of esthetic, recreational, scientific or economic values which is unreasonable in relation to the benefit derived from the discharge.

The following factors must be considered in the evaluation:[16]

(1) The quantities, composition and potential for bioaccumulation or persistence of the pollutants to be discharged;
(2) The potential transport of such pollutants by biological, physical or chemical processes;
(3) The composition and vulnerability of the biological communities which may be exposed to such pollutants, including the presence of unique species or communities of species, the presence of species identified as endangered or threatened pursuant to the Endangered Species Act, or the presence of those species critical to the structure or function of the ecosystem, such as those important for the food chain;
(4) The importance of the receiving water area to the surrounding biological community, including the presence of spawning sites, nursery/forage areas, migratory pathways, or areas necessary for other functions or critical stages in the life cycle of an organism.

---

[14] 33 U.S.C. § 1343.
[15] 40 C.F.R. § 125.123(a).
[16] 40 C.F.R. §125.122(a).

(5) The existence of special aquatic sites including, but not limited to marine sanctuaries and refuges, parks, national and historic monuments, national seashores, wilderness areas and coral reefs;
(6) The potential impacts on human health through direct and indirect pathways;
(7) Existing or potential recreational and commercial fishing, including finfishing and shellfishing;
(8) Any applicable requirements of an approved Coastal Zone Management plan;
(9) Such other factors relating to the effects of the discharge as may be appropriate;
(10) Marine water quality criteria developed pursuant to section 304(a)(1).

Section 403 prohibits EPA from issuing a NPDES permit that would allow the discharge of pollutants into the ocean where "insufficient information exists on any proposed discharge to make a reasonable judgment on any of the guidelines…."[17]

CBD-4 (Continued)

EPA cannot make a valid finding that the permit does not cause an unreasonable degradation of the marine environment. The permit allows the unlimited discharge of produced wastewater, including the unlimited discharge of chemicals used in offshore fracking and other well stimulation treatments. But there are significant data gaps on the impacts of these discharges on the marine environment; and what is known indicates that the discharge of such wastewater is inherently dangerous and causes undue degradation of the ocean environment.

1. The Discharge of Produced Water and Other Wastes Causes an Undue Degradation of the Marine Environment

EPA has not meaningfully analyzed the massive volume of produced water that flows into the Gulf of Mexico from oil and gas operations. EPA's study of the volume of produced from 1983 is outdated. Fracking and other new information indicate that produced waters may have increased in volume. For example, EPA records reveal that offshore oil and gas platforms in Region 6 discharged *more than 75 billion gallons* of produced waters in 2014.[18] The discharge of produced water—a complex pollutant associated with offshore oil productions—is incompatible with the ocean discharge criteria. Such wastewater can contain harmful substances like benzene, arsenic, lead, hexavalent chromium, barium, chloride, sodium, sulfates, and boron, and it also can be radioactive.[19] Produced water itself is potentially harmful to humans, aquatic life, and ecosystems—in fact, a study sponsored by the U.S. Department of Energy demonstrated that oil production yields "environmentally hazardous" produced water.[20]

Produced waters contain several chemicals that are toxic to aquatic life. These compounds include dispersed oils, aromatic hydrocarbons and alkylphenols, heavy metals, biocides, corrosion inhibitors, emulsion breakers, coagulants, oxygen scavengers, and naturally

---

[17] 33 U.S.C. § 1343(c)(2).

[18] *See* Excel Spreadsheet, Produced Water Discharges for Region 6 in 2014.

[19] *See e.g.*, *Sierra Club, Lone Star Chapter v. Cedar Point Oil Co.*, 73 F.3d 546 (5th Cir. 1996); Mall, Amy, Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy at 8 (2010).

[20] C Tsouris, Oak Ridge National Lab., Emerging Applications of Gas Hydrates at 7.

occurring radioactive materials.[21] The most common metals in produced waters are arsenic, cadmium, copper, chromium, lead, mercury, nickel, and zinc.[22] In addition, produced waters can contain substantial amounts of organic material, inorganic salts, small particles, organic acids (e.g., acetic acid and propionic acid), and can have high levels of sulfur and sulphide.[23]

Several compounds in produced waters are known to have negative biological effects. Polycyclic aromatic hydrocarbons and alkylphenols, which are abundant in produced waters, are potent carcinogens causing DNA damage[24] and can lead to oxidative stress,[25] cardiac function defeats,[26] embryotoxicity in fish,[27] reduction of lysosomal membrane stability in kidney cells,[28] elevated hepatic activity,[29] and neoplasia of fish liver.[30] Other chemicals such as alkyl phenols at concentration found in produce waters have hormone-disrupting effects in fish,[31] can change the lipid composition in hepatic cells of free-living Atlantic cod and haddock,[32] lead to cytotoxicity

---

[21] Neff, J., K. Lee, and E. M. DeBlois. 2011. Produced water: overview of composition, fates, and effects. Pp. 3–54 Produced water. Springer.

[22] Bakke, T., J. Klungsøyr, and S. Sanni. 2013. Environmental impacts of produced water and drilling waste discharges from the Norwegian offshore petroleum industry. Marine Environmental Research 92:154–169.

[23] *Id.*

[24] Aas, E., T. Baussant, L. Balk, B. Liewenborg, and O. K. Andersen. 2000. PAH metabolites in bile, cytochrome P4501A and DNA adducts as environmental risk parameters for chronic oil exposure: a laboratory experiment with Atlantic cod. Aquatic Toxicology 51:241–258.

[25] Hasselberg, L., S. Meier, and A. Svardal. 2004. Effects of alkylphenols on redox status in first spawning Atlantic cod (Gadus morhua). Aquatic Toxicology 69:95–105; Sturve, J., L. Hasselberg, H. Fälth, M. Celander, and L. Förlin. 2006. Effects of North Sea oil and alkylphenols on biomarker responses in juvenile Atlantic cod (Gadus morhua). Aquatic toxicology 78:S73–S78.

[26] Incardona, J. P., T. K. Collier, and N. L. Scholz. 2004. Defects in cardiac function precede morphological abnormalities in fish embryos exposed to polycyclic aromatic hydrocarbons. Toxicology and applied pharmacology 196:191–205.

[27] Carls, M. G., L. Holland, M. Larsen, T. K. Collier, N. L. Scholz, and J. P. Incardona. 2008. Fish embryos are damaged by dissolved PAHs, not oil particles. Aquatic toxicology 88:121–127.

[28] Holth, T. F., J. Beckius, I. Zorita, M. P. Cajaraville, and K. Hylland. 2011. Assessment of lysosomal membrane stability and peroxisome proliferation in the head kidney of Atlantic cod (Gadus morhua) following long-term exposure to produced water components. Marine environmental research 72:127–134.

[29] Meier, S., H. Craig Morton, G. Nyhammer, B. E. Grøsvik, V. Makhotin, A. Geffen, S. Boitsov, K. A. Kvestad, A. Bohne-Kjersem, A. Goksøyr, A. Folkvord, J. Klungsøyr, and A. Svardal. 2010. Development of Atlantic cod (Gadus morhua) exposed to produced water during early life stages: Effects on embryos, larvae, and juvenile fish. Marine Environmental Research 70:383–394.

[30] Myers, M. S., J. T. Landahl, M. M. Krahn, and B. B. McCain. 1991. Relationships between hepatic neoplasms and related lesions and exposure to toxic chemicals in marine fish from the US West Coast. Environmental Health Perspectives 90:7.

[31] Arukwe, A., T. Celius, B. T. Walther, and A. Goksøyr. 2000. Effects of xenoestrogen treatment on zona radiata protein and vitellogenin expression in Atlantic salmon (Salmo salar). Aquatic toxicology 49:159–170; Arukwe, A., S. W. Kullman, and D. E. Hinton. 2001. Differential biomarker gene and protein expressions in nonylphenol and estradiol-17β treated juvenile rainbow trout (Oncorhynchus mykiss). Comparative Biochemistry and Physiology Part C: Toxicology & Pharmacology 129:1–10; Meier, S., T. E. Andersen, B. Norberg, A. Thorsen, G. L. Taranger, O. S. Kjesbu, R. Dale, H. C. Morton, J. Klungsøyr, and A. Svardal. 2007. Effects of alkylphenols on the reproductive system of Atlantic cod (Gadus morhua). Aquatic Toxicology 81:207–218.

[32] Grøsvik, B. E., S. Meier, B. Liewenborg, G. Nesje, K. Westrheim, M. Fonn, O. S. Kjesbu, H. Skarphéhinsdóttir, and J. Klungsøyr. 2010. PAH and biomarker measurements in fish from condition monitoring in Norwegian waters in 2005 and 2008. ICES.

in liver cells in rainbow trout (*Onchorhynchus mykiss*),[33] disrupt normal larval pigmentation and increase jaw deformities in Atlantic cod, which reduces feeding ability and results in larval mortality.[34]

Chemicals in produced water cause substantial negative and lethal effects under chronic and acute exposure. Studies of chronic exposure of adult sea scallops (*Placopecten magellanicus*) to different types and concentrations of diluted operational drilling fluids, under environmental representative conditions, have found reductions in somatic and reproductive tissue growth and mortality.[35] For example, chronic intermittent exposure of adult sea scallops to oil-based mud was highly lethal at concentrations as low as 1 mg/L.[36] Oil-based muds are chemically toxic and disrupt the physiological state and nutritional conditions of sea scallops resulting in low growth rate and survival.[37] Similarly, studies of chronic exposure of the blue mussel (*Mytilus edulis*, a common biomarker) to produced waters have shown DNA damages within 1 km of the outfalls.[38] However, current methods may not be sensitive enough to detect biological effects beyond few kilometers from the outfall.[39] Thus the idea that produced water impacts are largely localized is still unverified.

Fish may suffer the highest impacts of produced waters since some species are attracted to oil rigs and platforms. For example, samples collected from haddock (*Melanogrammus aeglefinus*) populations in areas with extensive oil and gas production in the North Sea show induction of biotransformation enzymes, oxidative stress, genotoxicity, and altered fatty acid composition.[40] Several studies have shown that fish exposed to alkylphenols and polyaromatic hydrocarbons in produced waters alter their endocrine physiology.[41] For example, a study of exposure of different developmental stages of Atlantic cod to several concentrations of produced waters collected from an oil platform in the North Sea found that alkylophenols (a chemical known to cause endocrine activity and commonly found in produced waters) bioaccumulate in tissue.[42] Concentration of produced waters of 1 percent disrupts normal larval pigmentation, reduces feeding by deforming jaw parts in larvae, and leads to mortality.[43]

---

[33] Tollefsen, K. E., R. C. Sundt, J. Beyer, S. Meier, and K. Hylland. 2011. Endocrine modulation in Atlantic cod (Gadus morhua L.) exposed to alkylphenols, polyaromatic hydrocarbons, produced water, and dispersed oil. Journal of Toxicology and Environmental Health, Part A 74:529–542; Meier et al. 2010.

[34] Meier et al. 2010.

[35] Cranford, P. J., D. C. Gordon Jr, K. Lee, S. L. Armsworthy, and G.-H. Tremblay. 1999. Chronic toxicity and physical disturbance effects of water-and oil-based drilling fluids and some major constituents on adult sea scallops (Placopecten magellanicus). Marine Environmental Research 48:225–256.

[36] *Id.*

[37] *Id.*

[38] Brooks, S., C. Harman, B. Zaldibar, U. Izagirre, T. Glette, and I. Marigómez. 2011. Integrated biomarker assessment of the effects exerted by treated produced water from an onshore natural gas processing plant in the North Sea on the mussel Mytilus edulis. Marine pollution bulletin 62:327–339.

[39] Bakke et al. 2013.

[40] Balk

[41] Tollefsen, et al. 2011.

[42] Meier et al. 2010.

[43] *Id.*

Alkylophenols have also endocrine effects and disrupt several reproductive parameters in fish, such as reduction of gonadal development,[44] induction of plasma vitellogenin in males and juveniles,[45] and prevention of spermatogenesis and oogenesis.[46] Serious reproductive disturbance has been demonstrated in first-time spawning Atlantic cod.[47] For example, acute exposure (1 to 5 weeks) of Atlantic cod to alkylophenols (via food) resulted in impaired oocyte development, reduction of estrogen levels, and substantial delay of spawning in females.[48] Males showed reduction of testosterone and impairment of testicular development.[49] Similarly, chronic exposure (e.g., over 14 weeks) of Atlantic cod to relative low doses of alkylophenols have led to similar results.[50] Other studies of chronic exposure (12 weeks) of Atlantic cod to produced waters with concentrations as low as 0.066 - 0.2 percent have shown impair oocyte development and reduce estrogen levels in pre-spawning females, and altered testicular development and reduction of sperm amount in males.[51] These endocrine disruptions occur at concentration found in plumes of produced waters and chemical compounds present in produced waters are likely to have stronger effects on fish closer to oil platforms.[52]

CBD-5

All these studies show that exposure to produced waters can cause a wide range of negative effects in fish and invertebrates. Several of the responses to produced water exposure suggest substantial impacts such as loss of cell membrane integrity, gene expression changes, cytotoxicity, DNA damage, hepatic lipid composition, and reproductive disruption. Based on these studies chronic exposure to even low concentrations of produced waters has negative consequences for the physiology of fish and invertebrates. Population and community effects are mostly unknown, as are the cumulative effects of chronic and acute produce water exposure are also unknown.[53]

i. Fate of Produced Waters and Habitat Degradation

Produced waters undergo several changes following discharge to the ocean including, dilution, biodegradation, adsorption, evaporation, and photooxidation (Fig. 1).[54] These transformation processes may produce other chemicals that are more bioavailable and toxic for marine organisms than the original chemicals. The rate of biodegradation of chemicals in

---

[44] Meier et al. 2007.

[45] White, R., S. Jobling, S. A. Hoare, J. P. Sumpter, and M. G. Parker. 1994. Environmentally persistent alkylphenolic compounds are estrogenic. Endocrinology 135:175–182.

[46] Weber, L. P., R. L. Hill, and D. M. Janz. 2003. Developmental estrogenic exposure in zebrafish (Danio rerio): II. Histological evaluation of gametogenesis and organ toxicity. Aquatic toxicology 63:431–446; Weber, L. P., Y. Kiparissis, G. S. Hwang, A. J. Niimi, D. M. Janz, and C. D. Metcalfe. 2002. Increased cellular apoptosis after chronic aqueous exposure to nonylphenol and quercetin in adult medaka (Oryzias latipes). Comparative Biochemistry and Physiology Part C: Toxicology & Pharmacology 131:51–59.

[47] Meier et al. 2007.

[48] *Id.*

[49] *Id.*

[50] Meier et al. 2011.

[51] Sundt, R. C., and C. Björkblom. 2011. Effects of produced water on reproductive parameters in prespawning Atlantic cod (Gadus morhua). Journal of Toxicology and Environmental Health, Part A 74:543–554.

[52] Bakke et al. 2013.

[53] Bakke et al. 2013.

[54] Neff 2002.

produced waters is thought to be variable and mostly unknown but it depends on the persistence of the chemicals in the water column.[55]

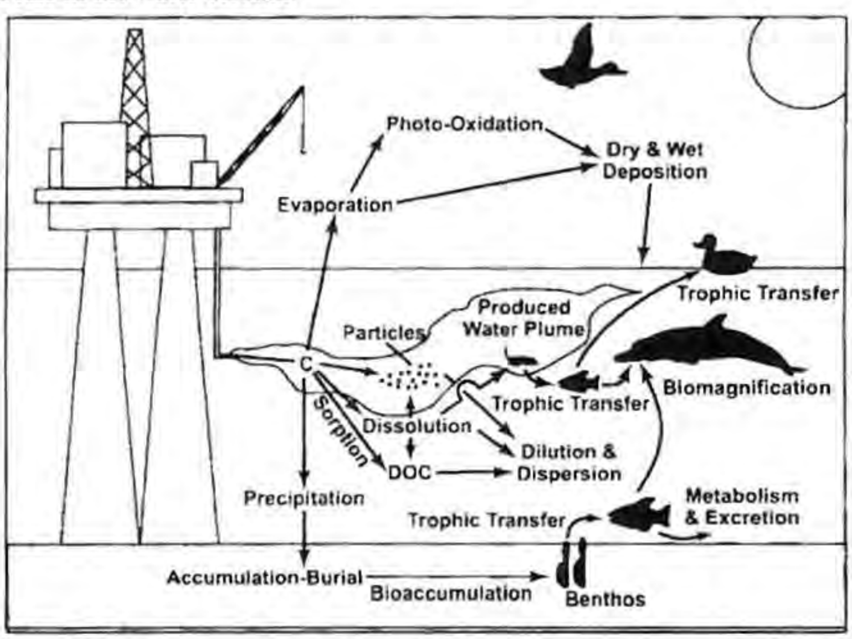


Figure 1. Environmental fates of inorganic and organic chemicals (C) from produced water in seawater following the discharge of treated produced water to the ocean. *Figure and legend after Neff (2002).*

CBD-6

Habitat degradation due to produced waters is high near outfalls. Most produced waters contain relatively high concentration of several metals compared with clean sea water, with barium, iron, and manganese being the most abundant.[56] These metals tend to rapidly precipitate from the plume, forming barium sulfate and oxides of iron and manganese on sediment surfaces over large areas around the produced water discharges. Evidence suggests that effects of discharges of produced waters in the water column and on the seabed in general have higher impacts within 1 or 2 km from the outfall sources.[57] However, the published literature has not yet been able to demonstrate with high confidence that the effects of produced waters are only local. Studies have shown that benthic communities require at least 5-10 years to recover from wastes accumulated on the seabed from produced waters.[58]

ii. Plume Size of Produced Water

The plume size of produce waters is directly related to dilution rates. Dilution rates and potential biological effects of produced waters following discharge to the ocean depends on several factors including discharge temperature, density of produced water, current speed, mixing regime, depth of the outfall, water column stratification, and seasonal environmental

---

[55] *Id.*

[56] Neff 2002.

[57] Bakke et al. 2013.

[58] Bakke, T., A. M. V. Green, and P. E. Iversen. 2011. Offshore Environmental Effects Monitoring in Norway–Regulations, Results and Developments. Pages 481–491 Produced Water. Springer; Bakke et al. 2013.

conditions.[59] For example, produced waters can dilute quickly upon discharge in well-mixed marine waters.[60] In general, modeling studies of dispersion of produced waters show a rapid initial dilution (e.g., 30 to 100 fold) within tens of meters of the outfall and slower dilution with distance.[61] Modeled dilutions of produced waters discharged to the Gulf of Mexico vary greatly depending on discharge rate and current speed.[62] Plume dilution generally slows down during slack currents and increases during strong currents.

Some produced waters are highly buoyant and the plume trends to spread as a thin layer of one or two meters thick on the ocean surface with limited vertical or lateral dispersion in very calm waters. In contrast, under high current and high winds the concentration of the produced water plumes are highly variable and shows variable concentration within the plume. However, it is safe to say that marine organisms close to discharge points are exposed to the highest chemical concentrations.[63] However, most studies today do not have the require sensitivity to detect impacts of produced water at very low concentrations.

CBD-7

These studies demonstrate that there are many unknowns regarding the impacts of the discharge of produced water on the marine environment, including on marine species, but what is known indicates that produced waters substantially degreed the marine environment. EPA therefore cannot make the nondegradation finding for produced water. Available technologies exist that allow for zero discharge of such wastes..

2. *The Discharge of Chemicals Used in Offshore Fracking and Other Well Stimulation Causes an Undue Degradation of the Marine Environment*

CBD-8

EPA's evaluation acknowledges that offshore fracking and other well stimulation occurs in the Gulf of Mexico.[64] There are significant data gaps regarding the impacts of offshore fracking and acidization on the marine environment, and the best available scientific information indicates that the discharge of well treatment chemicals does not meet the ocean discharge criteria. Therefore, EPA cannot permit the discharge of fracking and other well stimulation chemicals.

EPA cannot make a valid finding that the permit does not cause an unreasonable degradation of the marine environment because "insufficient information exists" regarding the impacts of well stimulation chemicals "to make a reasonable judgment" that the discharge satisfies all of the ocean discharge criteria.[65] For example, an independent scientific review of offshore well stimulation by the California Council on Science and Technology found significant data gaps on basic questions regarding offshore fracking and acidizing. Among these data gaps,

---

[59] Neff 2002.

[60] *Id.*

[61] Brandsma, M. G., and J. P. Smith. 1996. Dispersion modeling perspectives on the environmental fate of produced water discharges. Pages 215–224Produced Water 2. Springer; Washburn, L., S. Stone, and S. MacIntyre. 1999. Dispersion of produced water in a coastal environment and its biological implications. Continental Shelf Research 19:57–78.

[62] Brandsma and Smith 1996.

[63] Bakke et al. 2013.

[64] *See e.g.*, Ocean Discharge Criteria Evaluation Document at 3-32.

[65] *See* 33 U.S.C. § 1343(c)(2).

the study found inadequate reporting of well stimulation events, the composition of well stimulation fluid, and toxicity data for common chemicals in fracking and acidizing fluids. In fact, the review found that "no studies have been conducted on the toxicity and impacts of well stimulation fluids discharged in federal waters to the marine environment."[66] And, in discussing the impacts of the discharge of fracking chemicals into the ocean, the Bureau of Ocean Energy Management has previously noted that "[t]he lack of toxicity data for 31 of the 48 distinct chemicals was identified as a problem…, as was the lack of available data on chronic impacts of these chemicals in the marine environment…these issues [are] critical data gaps in the analysis of potential impacts of offshore discharges of WST waste fluids to sensitive marine species."[67]

What is known about the chemicals used in of offshore fracking and acidizing indicates that the Proposed Permit does not meet the ocean discharge criteria.[68] Harmful chemicals present in these fluids can include volatile organic compounds, such as benzene, toluene, xylenes, and acetone.[69] A Congressional Report sampling incomplete industry self-reports found that "[t]he oil and gas service companies used fracking products containing 29 chemicals that are (1) known or possible human carcinogens, (2) regulated under the Safe Drinking Water Act for their risks to human health, or (3) listed as hazardous air pollutants under the Clean Air Act."[70] One peer-reviewed scientific study examined a list of 944 fracking fluid products containing 632 chemicals, 353 of which could be identified with Chemical Abstract Service numbers.[71] The study concluded that more than 75 percent of the chemicals could affect the skin, eyes, and other sensory organs, and the respiratory and gastrointestinal systems; approximately 40 to 50 percent could affect the brain/nervous system, immune, and cardiovascular systems, and the kidneys; 37 percent could affect the endocrine system; and 25 percent could cause cancer and mutations.[72]

Another study reviewed exposures to fracking chemicals from onshore wells and noted that trimethylbenzenes are among the largest contributors to non-cancer threats for people living within a half mile of a well, while benzene is the largest contributor to cumulative cancer risk for people, regardless of the distance from the wells.[73] Another recent study has found increased arsenic and heavy metals in groundwater near fracking sites in Texas.[74] Moreover, researchers found greater hormone-disrupting properties in water located near hydraulic fracturing drilling sites than in areas without drilling, and they found that 11 chemicals commonly used for fracking

---

[66] *Id.*

[67] Bureau of Ocean Energy Management, Draft EA on Well Stimulation on the Pacific OCS at 4-35.

[68] *See, e.g.*, United States House of Representatives, Committee on Energy and Commerce Minority Staff, Chemicals used in hydraulic fracturing ("House Report") at 11-12 (2011); Colborn, Theo et al., Natural Gas Operations for a Public Health Perspective, 17 Human and Ecological Risk Assessment 1039 (2011) ("Colborn 2011") at 1039; McKenzie, Lisa et al., Human health risk assessment of air emissions form development of unconventional natural gas resources, Sci. Total Environ. (2012) ("McKenzie 2012").

[69] United States Environmental Protection Agency, *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (2011).

[70] House Report at 8.

[71] Colborn 2011 at 1.

[72] *Id.*

[73] McKenzie 2012 at 5.

[74] Fontenot, Brian E et al., An evaluation of water quality in private drinking water wells near natural gas extraction sites in the Barnett Shale Formation. Environmental Science & Technology (2013) ("Fontenot 2013"); U.S. GAO, *Information on Shale Resources, Development, and Environmental and Public Health Risks* (2012) ("US GAO 2012").

are endocrine disruptors.[75] Recent science on fracking shows that birth defects are more common in babies born to mothers living near fracked wells, according to researchers at the Colorado School of Public Health.[76]

The chemicals used in offshore fracking are alarming. An analysis[77] of chemicals used in 12 wells in the Pacific Ocean and disclosed by the voluntary reporting site FracFocus reveals that almost all of the chemicals used are suspected of causing gastrointestinal, respiratory, and liver hazards, as well as skin, eye, and sensory organ risks. More than half of the chemicals are suspected of being hazardous to the kidneys, immune and cardiovascular systems, and more than one third are suspected of affecting the developmental and nervous systems. Between one-third and one-half of the chemicals used are suspected ecological hazards.[78] For example, the chemical X-Cide used often in fracking operations is a hazardous substance under the Occupational Safety

---

[75] Kassotis, Christopher D., et al. Estrogen and Androgen Receptor Activities of Hydraulic Fracturing Chemicals and Surface and Ground Water in a Drilling-Dense Region. Endocrinology, doi 10.1210/en.2013-1697 (2013).

[76] McKenzie, Lisa, et al., Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado, Environmental Health Perspectives (2014).

[77]

Seven Harmful Chemicals used in 12 California Offshore Wells

Chemical	**Number of Wells Used**	**Known Health Effects**
Crystalline Silica (X-Cide)	All 12 wells	Harmful to skin, eyes and other sensory organs, respiratory system, immune system and kidneys; mutagen. Known human carcinogen.
Methanol	All 12 wells	Harmful to skin, eyes and other sensory organs, respiratory system, gastrointestinal system and liver, brain and nervous system, immune system, kidneys, reproductive and cardiovascular system; mutagen, developmental inhibitor and endocrine disruptor. Ecological risks.
Glyoxal	11 wells	Harmful to skin, eyes and other sensory organs, respiratory and reproductive system, gastrointestinal system and liver, brain and nervous system, immune system, cardiovascular system and blood, endocrine disruptor; mutagen, promoter of cancer. Ecological risks.
Sodium Tetraborate	All 12 wells	Harmful to skin, eyes and other sensory organs, respiratory system, gastrointestinal system and liver, brain and nervous system, kidneys, cardiovascular system. Ecological risks.
2-Butoxyethanol	3 wells	Harmful to skin, eyes and other sensory organs, respiratory system, gastrointestinal system and liver, brain and nervous system, immune system, kidneys, reproductive system and cardiovascular system; mutagen, developmental inhibitor and endocrine disruptor, linked to liver cancer. Also linked to adrenal tumors. Ecological risks.[77]
Merhyl-4-isothiazolin	All 12 wells	Harmful to skin, eyes and other sensory organs, respiratory, reproductive system, brain and nervous system, immune system; mutagen; developmental inhibitor. Ecological risks.
Ethoxylated nonylphenol	9 wells	Harmful to skin, eyes and other sensory organs, respiratory system, gastrointestinal system and liver, immune system, reproductive and cardiovascular system; developmental inhibitor and endocrine disruptor

[78] Colborn 2011.

and Health Act and the Comprehensive Environmental Response, Cleanup, and Liability Act. According to its Material Safety Data Sheet, the product is hazardous to both fish and wildlife.

In addition, scientific research has indicated that 40 percent of the chemicals used in fracking can harm aquatic animals and other wildlife.[79] For example, some of the chemicals used in fracking operations can break down into nonylphenol, a very toxic substance with a wide range of harmful effects that include the development of intersex fish and altered sex ratios at the population level.[80] Nonylphenol can also inhibit the development, growth, and survival of marine invertebrates, and has been shown to bioaccumulate in marine mammal species.[81]

Phenol formaldehyde resins are also used in offshore fracking. These resins are toxic and can cause cancer and mutations; if released into the marine environment, these pollutants have the potential to absorb other chemical compounds such as nonylphenol, increasing their toxicity to marine life.[82] Indeed, chemicals frequently used in offshore fracking are among the most toxic in the entire world with respect to aquatic life.[83]

Another recent study found that oil companies use dozens of extremely hazardous chemicals to acidize wells. Specifically, the study found that almost 200 different chemicals have been used and that at least 28 of these substances are F-graded hazardous chemicals—carcinogens, mutagens, reproductive toxins, developmental toxins, endocrine disruptors or high acute toxicity chemicals.[84] Each acidization can use as much as hundreds of thousands of pounds of some chemicals.[85] Moreover, acid treatments typically have a low pH that is incompatible with water quality criteria and maintenance of existing water quality especially in light of ocean acidification.

3. *Existing Permit Conditions Do Not Prevent Undue Degradation*

CBD-9

EPA claims that the conditions in the Proposed Permit are sufficiently protective of the marine environment. But this conclusion is arbitrary—the existing permit conditions do not prevent undue degradation of the marine environment.

In determining no undue degradation, EPA relies on the treatment of produced water and the toxicity testing required under the permit. But treatment of produced water is only oil-water separation, which does not remove any of the chemicals that flow back. Moreover, whole effluent testing is insufficient to ensure that discharges are not toxic because the testing is not

---

[79] CCST. 2014. Advanced Well Stimulation Technologies in California: An Independent Review of Scientific and Technical Information. August 28, 2014; The Center, Troubled Waters: Offshore Fracking's Threat to California's Ocean, Air and Seismic Stability, Sept. 2014, https://www.biologicaldiversity.org/campaigns/offshore_fracking/pdfs/Troubled_Waters.pdf.

[80] Diehl, J., et al. 2012. The distribution of 4-nonylphenol in marine organisms of North American Pacific Coast estuaries. Chemosphere 87:490-497.

[81] *Id.*

[82] Mato, Y. et al. 2001. Plastic resin pellets as a transport medium for toxic chemicals in the marine environment. Environmental Science & Technology 35:318-324.

[83] CCST. 2015, Vol. II at 76.

[84] Khadeeja Abdullah, Timothy Malloy, Michael K. Stenstrom & I. H. (Mel) Suffet. 2016. Toxicity of acidization fluids used in California oil exploration, Toxicological & Environmental Chemistry.

[85] *Id.*

CBD-9 *(Con't)*

required for discharge events, including the discharge of flowback from well treatment such as fracking. Most facilities are only required to test semi-annually, even those required to test bi-monthly are not at the same time as a fracking event.

CBD-10

Further, the toxicity requirement that no observable effect concentrations should occur at the edge of the 100-meter mixing zone is arbitrary. Rather, the no observable effect standard should be met at the outfall. Discharges must meet water quality and ocean discharge standards at the point of discharge. The whole effluent toxicity testing of produced water is good, but should be required to be conducted concomitant with discharges from well treatments, such as acidization, fracking, water flooding, gravel packing, etc.

CBD-11

In addition, while the inventory requirement that requires reporting of well treatment fluids to EPA with discharge monitoring reports is a step in the right direction, it does not prevent such chemicals from being discharged, and is thus inadequate to protect water quality. It is unclear whether the inventory requirement applies to well treatment fluids that are comingled with produced water. The Proposed Permit states that discharge of well treatment, completion, or workover fluids "shall be considered 'produced water when commingled with produced water.'"[86] This appears to undermine the requirements to inventory and disclose the discharges thus failing to protect water quality when well treatments, such as fracking, result in flow back or otherwise dilute the discharges with produced water. Similarly, it is generally good to incentivize the industry-wide study and characterization of discharge of well treatment chemicals; but this does not assuage concerns that the discharges should be prohibited until proven safe.

4. *The Permit Should Require Zero Discharge of Drill Cuttings, Drilling Fluids, Well Treatment Fluids, and Produced Water*

Given available information indicating that the discharge of water pollution form offshore oil and gas operations degrades the ocean environment, and the significant data gaps regarding the impacts of the discharge of offshore fracking and other well stimulation chemicals, EPA should revise the permit to disallow the discharge of water pollution from oil and gas drilling operations.[87] The receiving waters in the Gulf of Mexico are important habitat for endangered species, fish, and other wildlife. The discharge of pollution will degrade the marine environment.

The Gulf of Mexico is one of the most productive—and fragile—marine ecosystems in the nation. It supports a staggering array of marine life and represents an important contribution to the Gulf coast economy. The Gulf of Mexico is home to thousands of marine species, ranging from simple invertebrates such as gastropods and sponges to complex and highly evolved fish and marine mammals. It is estimated that there are thousands of species of invertebrates, at least 600 species of fish, and dozens of species of cetaceans in the Gulf. In addition, five of the world's eight species of sea turtles as well as tens of thousands of shore and coastal birds reside in or migrate to the Gulf of Mexico. More than 300 species of coral, combined with other hard-bottom communities, wetlands, seagrass beds, mangroves, and soft-bottom communities, provide the necessary habitat to support this rich assemblage of marine life. These diverse and highly

---

[86] Proposed Permit at 47.

[87] There could be an exception for emergency discharges.

complex habitats provide food, shelter, and spawning grounds for all of the Gulf's species at different points during their life history.

Many of the species that are found in the Gulf of Mexico are listed as threatened or endangered under the ESA. The Region is home to endangered sperm whales and endangered West Indian manatees; five threatened and endangered sea turtle species including green, hawksbill, Kemp's ridley, leatherback, and loggerhead turtles; ten bird species including endangered whooping cranes and red-cockaded woodpecker; and three listed fish species—Alabama sturgeon, the Gulf subspecies of Atlantic sturgeon, and smalltooth sawfish.[88] Critical habitat is designated in the Gulf for loggerhead turtles, Gulf sturgeon, smalltooth sawfish, West Indian manatees, and piping plovers.[89] And there are five coral species that are listed as threatened under the ESA—elkhorn, staghorn, lobed star, mountainous star, and boulder star corals.[90]

The Gulf of Mexico is also home to many species of marine mammals protected under the Marine Mammal Protection Act, including killer whales, dwarf and pygmy sperm whales, pygmy killer whales, several species of beaked whales, bottlenose dolphins, Atlantic and pantropical spotted dolphins, striped dolphins, Clymene dolphins, Fraser's dolphins, Risso's dolphins, and melon-headed whales.[91]

The Gulf of Mexico is also home to Bryde's whales, where the species exists as a small, resident population. It is the only baleen whale known to be resident to the Gulf. Recent abundance estimates put the population's size at fewer than 50 animals, and they are severely restricted in range, being found only in the northeastern Gulf, more specifically in the waters of the DeSoto Canyon. A recent study by the National Marine Fisheries Service suggests that the population is isolated and evolutionarily distinct from all other Bryde's whales examined to date, indicating that the species may be a distinct subspecies.[92]

CBD-12

The discharge of pollution from offshore oil and gas drilling into this important habitat is unnecessary because a zero discharge permit is feasible. There are already oil and gas operations that meet zero discharge requirements. For example, coastal offshore drilling operations in the Gulf already require zero discharge of produced water and treatment, workover, and completion fluids as well as drilling fluids, drill cuttings, and dewatering effluent.[93] If EPA does not implement the restriction as a technology-based effluent limitation, the best management plans ("BMP") should require the zero discharge requirement. BMPs are used to address the developments for which the effluent limitation guidelines have not kept pace.[94]

---

[88] BOEM, 2017-2022 Outer Continental Shelf Draft Proposed Program at 6-12 (Jan. 2015) ("DPP").

[89] *Id.*

[90] *Id.* at 6-11

[91] NOAA, Cetacean Data Availability, http://cetsound.noaa.gov/cda

[92] NRDC, *Petition to list the Gulf of Mexico Bryde's whale* (Balaenoptera edeni) *as endangered under the Endangered Species Act*, Sept. 2014, *available at* http://docs.nrdc.org/wildlife/files/wil_14091701a.pdf

[93] 61 Fed. Reg. 66,088 (December, 16, 1996).

[94] *See* 40 C.F.R. § 122.44(k)

5. *In the Alternative, the Permit Must Place Additional Restrictions on the Discharges to Protect Water Quality*

The permit should be for zero discharge; however, if EPA declines to adopt a zero discharge limitation for produced water, drilling fluids, and well treatment fluids then it must include additional limitations to prevent degradation of water quality. Specifically the permit should (1) limit the volume of produced water to be discharged; (2) prohibit the discharge of well treatment fluids; (3) require enhanced monitoring; and (4) if well treatment fluids are still permitted to be discharged or comingled with produced waters there should be a non-detect limit on priority pollutants and chemicals classified as hazardous at the discharge point.

CBD-13

First, EPA must place a numeric volume limit for produced water allowed to be discharged. As explained above, produced water degrades water quality and introduces toxins into the marine environment. Well treatment activities may increase produced water discharges and extend the life of oil and gas operations; without a limit on produced water volume it is impossible for EPA to guarantee against the degradation of the marine environment and water quality. Already the amount of produced water that is discharged into the Gulf of Mexico is harmful, and the quantity could increase with new leases and changes in drilling and well stimulation practices. The proposed permit is more lax than other OCS General Permits, and it is therefore arbitrary and inconsistent with other EPA General Permits. For example, the Pacific OCS general permit, EPA set a limit of volume of produced water allowed for each platform.[95]

CBD-14

Second, EPA should require zero discharge of well treatment fluids, and well treatment fluids comingled with produced water. Well treatment fluids contain toxic chemicals that are harmful for aquatic animals and water quality. Well treatment uses chemicals for a variety of functions, such as: dissolving acids, biocides, breakers, clay stabilizers, corrosion inhibitors, crosslinkers, foamers and defoamers, friction reducers, gellants, pH controllers, proppants, scale controllers, and surfactants. And, as explained above, modern hydraulic fracturing uses hundreds of chemicals that cause cancer or damage to the nervous, cardiovasculatory, and endocrine systems; and can be incredibly toxic to fish and other marine life.[96] But the proposed permit authorizes the discharge of unlimited volumes of produced waters, including those mixed with fracking chemicals.

CBD-15

Third, EPA should also require monitoring and reporting for additional chemicals in all types of dischrges. For example, the Pacific OCS permit requires monitoring for specific chemicals, such as benzene, in produced water for each platform, for certain chemicals it also prescribes discharge limits. Here, given the new information about produced water and its potential toxicity, EPA should require more robust monitoring for chemicals that could degrade the marine environment.

---

[95] Environmental Protection Agency, Reissuance of National Pollutant Discharge Elimination System (NPDES) General Permit for Offshore Oil and Gas Exploration, Development and Production Operations Off Southern California, 79 Fed. Reg. 1,643 (Jan 23, 2014) at 9.

[96] Colborn 2011.

CBD-16

Finally, while discharges of well treatment fluids should be completely prohibited, if EPA nonetheless decides to allow such discharges, it must place numeric limits on the toxic chemicals that occur in well treatment fluids and require robust monitoring to ensure compliance. In addition to limits, EPA should identify biologically sensitive areas or seasons to require zero discharge to protect sensitive species. For example, EPA should restrict discharges in sea turtle critical habitat and Desoto Canyon. This would be more consistent with other EPA permits. For example, the Beaufort OCS General Permit prohibits discharge of drilling fluids during bowhead whaling activities and no discharge near the Boulder Patch.[97]

II. Issuance of the Permit Requires Preparation of an Environmental Impact Statement under the National Environmental Policy Act

EPA's issuance of the Proposed Permit requires an environmental impact statement ("EIS") under the National Environmental Policy Act ("NEPA"). NEPA, America's "basic national charter for protection of the environment,"[98] requires federal agencies to take a "hard look" at the environmental consequences of their actions before taking action.[99] In this way, NEPA ensures that federal agencies "will have available, and will carefully consider, detailed information concerning significant environmental impacts" and that such information "will be made available to the larger [public] audience that may play a role in both the decisionmaking process and the implementation of the decision."[100]

To that end, NEPA requires federal agencies to prepare an EIS for all "major Federal actions significantly affecting the quality of the human environment."[101] NEPA's implementing regulations define "major federal action" to include the "[a]pproval of specific projects, such as construction or management activities located in a defined geographic area" and specify that "[p]rojects include actions approved by permit."[102]

NEPA's implementing regulations also specify factors that must be considered in determining when a major federal action may significantly affect the environment warranting the preparation of an EIS.[103] Specifically, in determining whether an action may have "significant" impacts on the environment, an agency must consider the "context" and "intensity" of the action.[104] "Context" means the significance of the project "must be analyzed in several contexts such as society as a whole (human, national), the affected region, the affected interests, and the locality."[105]

---

[97] EPA, AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES) FOR OIL AND GAS EXPLORATION FACILITIES ON THE OUTER CONTINENTAL SHELF AND CONTIGUOUS STATE WATERS IN THE BEAUFORT SEA, Permit No. AKG-28-2100, Oct. 23, 2012.

[98] 40 C.F.R. § 1500.1(a).

[99] *Kleppe v. Sierra Club*, 427 U.S. 390, 410, n. 21 (1976); 40 C.F.R. § 1500.1(a).

[100] *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989).

[101] 42 U.S.C. § 4332(2)(C).

[102] 40 C.F.R. § 1508.18.

[103] *See id.* § 1508.27(b).

[104] *Id.* § 1508.27.

[105] *Id.* § 1508.27(a).

The intensity of the action is determined by considering the ten factors enumerated in the regulations, which include: (1) impacts that may be both beneficial and adverse; (2) the degree to which the proposed action affects public health or safety; (3) unique characteristics of the geographic area such as proximity to ecologically critical areas; (4) the degree to which the effects on the human environment are likely to be highly controversial; (5) the degree to which the possible effects on the human environment are highly uncertain or involve unique or unknown risks; (6) the degree to which the action may establish a precedent for future actions with significant effects; (7) whether the action is related to other actions with individually insignificant but cumulatively significant impacts; (8) the degree to which the action may cause loss or destruction of significant scientific, cultural, or historical resources; (9) the degree to which the action may adversely affect a species listed under the ESA or its critical habitat; and (10) whether the action threatens a violation of federal, state or local environmental laws.[106]

The presence of even just "one of these factors may be sufficient to require preparation of an EIS in appropriate circumstances."[107] If "substantial questions as to whether a project . . . may cause significant degradation of some human environmental factor," an EIS must be prepared.[108] Accordingly, in order for a court to find that an EIS is warranted, "a plaintiff need not show that significant effects will in fact occur" only that there are "substantial questions whether a project may have a significant effect on the environment."[109]

CBD-17

Here, several significance factors are raised, clearly necessitating the preparation of an EIS. In particular, the Proposed Permit—which allows the unlimited discharge of produced wastewater and well stimulation fluids into the Gulf of Mexico—impacts a geographically, ecologically, culturally important areas; may have adverse environmental impacts, including impacts to ESA-listed species and their critical habitat; represents a substantial public controversy; and has unique or unknown risks.

A. <u>The Proposed Permit Affects Geographically and Culturally Unique Areas</u>

As explained above, the Gulf of Mexico is one of the most productive—and fragile—marine ecosystems in the nation. Hundreds of types of fish and shellfish inhabit the Mississippi Delta and Gulf of Mexico, many of which support fisheries. The warm waters are home to a vast array of wildlife and habitats, including many sensitive animals that are threatened by offshore drilling. There are five species of ESA-listed sea turtles and important nesting beaches dotting the coast; and there are five species of ESA-listed corals. Whales and dolphins live in the Gulf, which includes core habitat for endangered sperm whales. There are 3 million acres of wetlands with breeding, foraging and migratory habitat for more than 400 types of birds. These habitats and animals are being degraded and harmed by waste discharge from drilling operations, and some fish and shellfish may accumulate toxins that eventually wind up on our plates. Many other species in the Gulf of Mexico are listed as threatened or endangered under the ESA.

---

[106] *Id.* § 1508.27(b)(1)-(10).

[107] *Ocean Advocates v. U.S. Army Corps of Eng'rs*, 402 F.3d 846, 865 (9th Cir. 2005).

[108] *Idaho Sporting Congress v. Thomas*, 137 F.3d 1146, 1149 (9th Cir. 1998).

[109] *Nat. Resource Defense Council v. Winter*, 502 F.3d 859, 867 (9th Cir. 2007) (citations omitted).

As also explained above, produced wastewater can have several negative impacts due to the dangerous chemicals present in such discharges. Moreover, EPA's Proposed Permit allows oil companies to discharge chemicals used in offshore fracking and acidizing, which can also affect geographically and culturally unique areas in the Gulf. An EIS is therefore required.

B. The Proposed Permit May Have Adverse Impacts and May Impact ESA-Listed Species

CBD-18

EPA's Proposed Permit allows oil companies to discharge unlimited quantities of produced water, and allows the chemicals used in fracking and other well stimulation treatments to be discharged into the Gulf of Mexico. EPA must prepare an EIS because the discharge of produced water, including the discharge of chemicals used in offshore fracking and acidizing, have adverse impacts, and may impact ESA-listed species and their critical habitat.[110] While substantial data gaps exist regarding the impacts of these practices, what is known is cause for great alarm.

As explained above, scientific research indicates that produced wastewater may have substantial environmental impacts. Scientific research also indicates that 40 percent of the chemicals used in fracking can harm aquatic animals and other wildlife.[111] By example, some chemicals used in fracking operations can break down into nonylphenol, a very toxic substance with a wide range of harmful effects including the development of intersex fish and altered sex ratios at the population level.[112] Nonylphenol can also inhibit development, growth, and survival of marine invertebrates, and has been shown to bioaccumulate in marine mammal species.[113]

Contamination incidents have occurred that demonstrate that impacts to ESA-listed fish in the Gulf and wildlife harm is a real impact that must be considered. For example, in 2013, a company admitted to dumping wastewater from fracking operations into the Acorn Fork Creek in Kentucky, causing a massive fish kill.[114] In fact, "the discharges killed virtually all aquatic wildlife in a significant portion of the fork, including fish and invertebrates."[115] According to scientists, the abrupt and persistent changes in post-fracking water quality resulted in toxic conditions.[116] Among the species harmed was the blackside dace, a threatened minnow species.[117] The discharge of fracking wastewater into the Susquehanna River in Pennsylvania is suspected to be the cause of fish abnormalities, including high rates of spots, lesions, and

---

[110] 40 C.F.R. § 1508.27(b)(1), (9).

[111] CCST. 2014. Advanced Well Stimulation Technologies in California. An Independent Review of Scientific and Technical Information. August 28, 2014; The Center, Troubled Waters: Offshore Fracking's Threat to California's Ocean, Air and Seismic Stability, Sept. 2014, https://www.biologicaldiversity.org/campaigns/offshore_fracking/pdfs/Troubled_Waters.pdf.

[112] Diehl, J., et al. 2012. The distribution of 4-nonylphenol in marine organisms of North American Pacific Coast estuaries. Chemosphere 87:490-497.

[113] *Id.*

[114] Vaidyanathan, Gayathri, Fracking Spills Cause Massive Ky. Fish Kill, E&E News, Aug. 29, 2013, http://www.eenews.net/greenwire/2013/08/29/stories/1059986559.

[115] U.S. Fish and Wildlife Service, Office of Law Enforcement, Case at a Glance: U.S. v. Nami Resources Company, LLC, www.fws.gov/home/feature/2009/pdf/NamiInvestigation.pdf.

[116] Papoulias, D.M. and A.L. Velasco. (2013). Histopathological analysis of fish from Acorn Fork Creek, Kentucky, exposed to hydraulic fracturing fluid releases. Southwestern Naturalist 12 (Special Issue 4): 92-111.

[117] *Id.*

CBD-19

intersex.[118] Several spills of fracking fluid from pipelines in Pennsylvania over the last few years also resulted in significant fish kills.[119] Such contamination incidents are a real risk in the Gulf of Mexico given EPA's Proposed Permit that would allow oil companies to dump fracking chemicals into the Gulf. EPA must therefore prepare an EIS.

C. The Proposed Permit Represents a Substantial Public Controversy

EPA must prepare an EIS because the Proposed Permit would allow oil companies to dump offshore fracking wastewater directly into the Gulf of Mexico, which constitutes a substantial public controversy. In determining whether an action is significant, CEQ regulations also require an agency to consider "[t]he degree to which the effects. . . are likely to be highly controversial."[120] "Controversial" is "a substantial dispute [about] the size, nature or effect of the major Federal action."[121] A substantial dispute exists when evidence, raised prior to the preparation of an EIS or Finding of No Significant Impact casts serious doubt upon the reasonableness of an agency's conclusions.[122] "[A]n outpouring of public protest" has been held to satisfy the requirement of "substantial dispute."[123]

There as certainly been an "outpouring of public protest" about offshore fracking. including the dumping of fracking chemicals into the ocean. For example, when the public first learned that oil companies were fracking off the West Coast, demonstrations were held where the public protested offshore fracking and the federal government's approval of the practice.[124] And a number of conservation organizations sent letters to the Bureau of Ocean Energy Management urging the agency to place a moratorium on offshore fracking and other well stimulation treatments unless and until extensive environmental review was conducted and the practices proven safe.[125] Further, a number of organizations have expressed concern over EPA's NPDES permits for offshore oil and gas operations that allow the dumping of fracking wastewater into the ocean.[126] And there was an outpouring of public protest generated as the result of requests

---

[118] Piette, Betsy, BP Oil Spill, Fracking Cause Wildlife Abnormalities, Workers World (April 27, 2012) available at http://www.workers.org/2012/us/bp_oil_spill_fracking_0503/; Pennsylvania Fish & Boat Commission, Ongoing Problems with the Susquehanna River smallmouth bass, a Case for Impairment (May 23, 2012), www.fish.state.pa.us/newsreleases/2012press/senate_susq/SMB_ConservationIssuesForum_Lycoming.pdf.

[119] MIT Energy Initiative. (2011). "The future of Natural Gas, An Interdisciplinary MIT study." http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.

[120] 40 C.F.R. § 1508.27(b)(4).

[121] *Blue Mountains Diversity Project v. Blackwood*, 161 F.3d 1208, 1212 (9th Cir. 1998) (citations omitted).

[122] *Protect Our Water v. Flowers*, 377 F. Supp.2d 844, 861 (E.D. Cal. 2004).

[123] *Greenpeace Action v. Franklin*, 14 F.3d 1324, 1334 (9th Cir.1992).

[124] *See e.g.*, Fracking foes plan Coastal Commission rally today in Long Beach, OC Register, Mar. 11, 2014, http://www.ocregister.com/articles/fracking-605193-commission-beach.html; Hundreds of Tribal Representatives Join Huge Rally to Oppose Fracking, IC Magazine, Mar. 18, 2014, https://intercontinentalcry.org/hundreds-tribal-representatives-join-huge-rally-oppose-fracking-22513/

[125] *See e.g.*, Letter from the Center for Biological Diversity to BOEM and BSEE, Oct. 3, 2013, http://www.biologicaldiversity.org/campaigns/offshore_fracking/pdfs/LetterOnOffshoreFrackingMoratoriumNEPA_2013.pdf; Letter from Environmental Defense Center, et al. to BOEM and BSEE, Dec. 23, 2013, http://documents.coastal.ca.gov/reports/2014/2/W7a-2-2014.pdf, pg. 12.

[126] *See e.g.*, The Center, Legal Petition Urges EPA to Ban Dumping of Offshore Fracking Chemicals Into California's Ocean, Feb. 26, 2014, https://www.biologicaldiversity.org/news/press_releases/2014/fracking-02-26-2014.html.

under the Freedom of Information Act revealing the scope of offshore fracking permitted in the Gulf of Mexico and the quantity of produced water EPA allows to be dumped into the Gulf.[127]

CBD-20

Moreover, the oil industry claims offshore fracking has no adverse environmental impacts, while numerous scientists and reports have linked fracking to water contamination, air contamination, spills, and earthquakes.[128] EPA's proposal to allow oil and gas companies to dump fracking wastewater into the Gulf of Mexico clearly constitutes a substantial public controversy. Indeed, it is hard to imagine an issue more fitting of this description than offshore fracking activities. An EIS is therefore required.

D. The Proposed Permit Has Highly Uncertain, Unique, or Unknown Risks

EPA must prepare an EIS because the Proposed Permit involves highly uncertain, unique, or unknown risks.[129] For example, as explained above, an independent scientific review of offshore well stimulation by the California Council on Science and Technology found significant data gaps on basic questions regarding offshore fracking and acidizing.[130] And in discussing the impacts of the discharge of fracking chemicals into the ocean, the Bureau of Ocean Energy Management has previously acknowledged that there are critical data gaps in the analysis of potential impacts of the discharges of fracking chemicals and other well stimulation waste fluids on sensitive marine species.[131]

CBD-21

EPA appears to rely on the lack of information to find that there will not be significant impacts from allowing oil companies to dump fracking and other well stimulation fluids into the Gulf of Mexico. But as the Ninth Circuit has made perfectly clear, "lack of knowledge does not excuse the preparation of an EIS; rather it requires the [agency] to do the necessary work to obtain it."[132] In other words, the substantial data gaps that exist regarding the impacts of offshore fracking and acidizing on the marine environment necessitate the preparation of an EIS.[133]

---

[127] *See e.g.*, The Center, Obama Administration Permitted 1,200 Offshore Fracks in Gulf of Mexico, June 28, 2016, https://www.biologicaldiversity.org/news/press_releases/2016/offshore-fracking-06-28-2016.html; Mike Ludwig, This Map Shows Where Offshore Fracking Has Occurred in the Gulf of Mexico.
TruthOut, June 30, 2026, http://www.truth-out.org/news/item/36643-this-map-shows-where-offshore-fracking-has-occurred-in-the-gulf-of-mexico.

[128] *See e.g.*, Goebel, et al. 2016; Ellen Webb, et al. 2014. Developmental and reproductive effects of chemicals associated with unconventional oil and natural gas operations. Reviews on Environmental Health. Vol. 29, Issue 4, pp. 307–318, ISSN (Online) 2191-0308, ISSN (Print) 0048-7554. doi: 10.1515/reveh-2014-0057; California aquifers contaminated with billions of gallons of fracking wastewater, RT.com, Oct. 2014,
https://www.rt.com/usa/194620-california-aquifers-fracking-contamination/; Fontenot, Brian E, et al. 2013. An evaluation of water quality in private drinking water wells near natural gas extraction sites in the Barnett Shale Formation. *Environ. Sci. Technol.* 47 (17), pp 10032–10040; doi: 10.1021/es4011724.

[129] *See* 40 C.F.R. § 1508.27(b)(5).

[130] California Council on Science and Technology. 2015. An Independent Scientific Assessment of Well Stimulation in California: Volume III. Case Studies of Hydraulic Fracturing and Acid Stimulations in Select Regions: Offshore, Monterey Formation, Los Angeles Basin, and San Joaquin Basin, at 29.

[131] Bureau of Ocean Energy Management, Draft EA on Well Stimulation on the Pacific OCS at 4-35.

[132] *Nat'l Parks & Conservation Ass'n v. Babbitt*, 241 F.3d 722, 733 (9th Cir. 2001).

[133] To the extent EPA is relying on past EISs conducted on the issuance of previous iterations of the General Permit to authorize the new permit, that reliance fails to satisfy EPA's duties under NEPA because the EISs fail to consider the impacts of the discharge of chemicals used in fracking and other wells stimulation treatments into the Gulf.

III. EPA's Draft Environmental Assessment Fails To Comply with NEPA

In addition to the fact that EPA is in violation of NEPA by not preparing an EIS, EPA's Draft Environmental Assessment ("Draft EA") itself also runs afoul of NEPA. Similar to an EIS, an EA must contain a description of the purpose and need of the proposed action; an analysis of the environmental effects of the proposed action, including the direct, indirect and cumulative impacts; as well as a range of reasonable alternatives and the environmental effects of such alternatives.[134]

EPA's Draft EA does not comply with NEPA because it fails to properly define the purpose and need of the project; fails to properly define the environmental baseline; fails to adequately consider and analyze a reasonable range of alternatives to and the cumulative effects of the proposed action; fails to take a hard look at the impacts of permitted discharges, including offshore fracking and acidizing wastes; and is otherwise arbitrary and capricious.

A. EPA Failed To Properly Define the Purpose and Need of the Proposed Action

CBD-22

EPA's purpose and need statement fails to comply with NEPA. NEPA's implementing regulations provide that an environmental document should specify the underlying purpose and need to which the agency is responding in proposing the alternative including the proposed action.[135] This purpose and need inquiry is crucial for a sufficient environmental analysis because "[t]he stated goal of a project necessarily dictates the range of 'reasonable' alternatives."[136] Thus, "an agency cannot define its objectives in unreasonably narrow terms" without violating NEPA.[137]

EPA's stated purpose and need is "the reissuance of an existing NPDES General Permit authorizing discharges from existing and new source oil and gas facilities operating in the federal waters of the Gulf of Mexico where EPA Region 4 is the permitting authority."[138] Defining the purpose and need as the reissuance of an existing permit makes reissuing the permit with limited changes the only way to comply with such a need. Indeed, EPA admits that it made few substantive changes from the existing permit.[139] Such a narrow purpose and need is also inadequate because EPA necessarily considered an unreasonably narrow range of reasonable alternatives, including alternatives that would impose additional conditions to better protect the marine environment. The CWA seeks "to restore and maintain the chemical, physical, and biological integrity of the Nation's waters" and eliminate all discharges of pollution into navigable waters.[140] Accordingly, EPA should have focused their purpose and need inquiry on objectives that comport with these statutory duties.[141]

---

[134] 40 C.F.R. at § 1508.9(b).

[135] *Id.* § 1502.13.

[136] *Carmel-by-the-Sea v. U.S. Dep't of Transp.*, 123 F.3d 1142, 1155 (9th Cir. 1997).

[137] *Id.*

[138] Draft EA at 1-1.

[139] *Id.*

[140] 33 U.S.C. §§ 1251(a); 1251(a)(1).

[141] *See Citizens Against Burlington, Inc. v. Busey*, 938 F.2d 190, 196 (D.C. Cir. 1991) (observing that "agencies must look hard at the factors relevant to the definition of purpose," including the views of Congress in authorizing the agency to act, and define goals accordingly).

B. EPA Failed To Consider an Reasonable Range of Alternatives

CBD-23

EPA's Draft EA fails to analyze a reasonable range of alternatives. NEPA requires a "detailed statement" of "alternatives to the proposed action."[142] The purpose of this section is "to insist that no major federal project should be undertaken without intense consideration of other more ecologically sound courses of action, including shelving the entire project, or of accomplishing the same result by entirely different means."[143]

In the alternatives analysis, the agency must "provide sufficient evidence and analysis for determining whether to prepare an environmental impact statement or a finding of no significant impact."[144] The analysis must "rigorously explore and objectively evaluate all reasonable alternatives."[145] While an agency is not obliged to consider every alternative to every aspect of a proposed action, the agency must "consider such alternatives to the proposed action as may partially or completely meet the proposals goal."[146]

In its Draft EA, EPA examined only three alternatives: (A) issuance of the Proposed Permit (the preferred alternative); (B) issuance of a permit identical to the 2010 NPDES General Permit; and (C) no issuance of a NPDES permit (the purported "no-action" alternative). EPA's Draft EA states that the potential environmental impacts of Alternative A are identical to those anticipated under Alternative B.[147] In other words, the same activities would occur to the same degree under both Alternatives. There is no real difference between Alternative A and B such that Alternative B is not really an alternative at all.

Moreover, in examining only these alternatives, EPA failed to "rigorously explore" and "objectively evaluate" all reasonable alternatives. EPA failed to consider several alternatives that would better protect the marine environment from the dangerous discharges associated with offshore oil and gas activities, and better comply with EPA's duties under the CWA. For example, EPA failed to consider:

(1) an alternative that would prohibit the discharge of all produced wastewater, well treatment and completion fluids, and other drilling wastes (i.e., a "zero-discharge" standard), such as is currently required of coastal offshore drilling operations in the Gulf;[148]
(2) an alternative that would prohibit the discharge of chemicals used in offshore fracking and other well stimulation treatments into the Gulf of Mexico;
(3) an alternative that would require oil companies intending to use offshore fracking or other well stimulation treatments to get an individual permit, rather than being eligible for coverage under the General Permit;

---

[142] 42 U.S.C. § 4332(2)(c).

[143] *Environmental Defense Fund v. Corps of Engineers*, 492 F.2d 1123, 1135 (5th Cir. 1974).

[144] 40 C.F.R. § 1508.9.

[145] 40 C.F.R. § 1502.14.

[146] *Nat. Resources Defense Council, Inc. v. Callaway*, 524 F 2d. 79, 93 (2d Cir. 1975).

[147] Draft EA at 5-5

[148] 61 Fed. Reg. 66088 (December, 16, 1996).

(4) an alternative that would require oil companies to provide advance notice of their use of well stimulation to the public and require public disclosure of the chemicals used in well stimulation treatments;

(5) an alternative that would place the burden on the oil companies to prove a chemical is ecologically safe before being permitted to use and discharge it; or

(6) an alternative that would require monitoring or WET testing of effluent when discharging chemicals used in fracking or other well stimulation treatments, and continued testing for a certain amount of time after the discharge.

CBD-24

Moreover, EPA's analysis of the no-action alternative is inadequate. EPA states that if EPA did not issue the Proposed Permit, offshore oil and gas facilities would need to apply for an individual permit.[149] Thus, according to EPA the only difference between the no-action alternative with the action alternatives is the increased administrative burden on EPA.[150] In other words, the no-action alternative encompasses the same potential impacts as a decision to issue the General Permit. But this approach "avoid[s] the task actually facing [EPA]. In assuming that, no matter what, the proposed activities would surely occur, [EPA is] neglecting to consider what would be a true 'no action' alternative."[151] However a true no-action alternative would examine and compare the impacts resulting from the cessation of the discharge of produced wastewater and other oil and gas drilling wastes. EPA should consider and disclose such impacts.

C. EPA's EA Fails To Take a Hard Look at the Impacts of the Discharge of Oil and Gas Wastewater, Including Offshore Fracking and Other Well Stimulation Wastewater

In conducting an environmental assessment under NEPA, EPA must consider and describe the direct, indirect and cumulative impacts.[152] Direct, indirect and cumulative impacts are distinct from one another: direct effects are "caused by the action and occur at the same time and place."[153] Indirect effects are caused by the action but, "are later in time or farther removed in distance, but are still reasonably foreseeable. Indirect effects may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effect on air and water and other natural systems, including ecosystems."[154]

CBD-25

Cumulative impacts are those impacts that "result from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time."[155] But EPA's analysis fails to consider the direct, indirect, and cumulative impact of produced waters discharges and the impacts of discharging chemicals used in offshore fracking and other well stimulation treatments. Such failures violate NEPA.

---

[149] Draft EA at 5-2 to 5-3

[150] *Id.*

[151] *Conservation Council of Hawaii v. NMFS*, 97 F. Supp. 3d 1210, 1236 (D. Haw. 2015).

[152] 40 C.F.R §§ 1502.16, 1508.7, 1508.8; *Northern Plains Resource Council v. Surface Transportation Board*, 668 F.3d 1067, 1072-73 (9th Cir. 2011).

[153] 40 C.F.R. § 1508.8(a).

[154] *Id.* § 1508.8(b).

[155] 40 C.F.R. § 1508.7

1. EPA Inappropriately Relies on Outdated Information

CBD-26

EPA's Draft EA fails to take a hard look at the impacts of offshore fracking and other well stimulation on the Gulf environment because it relies on woefully inadequate and outdated data. Specifically, EPA relies on a study conducted in 1988 to estimate the scope of offshore fracking and acidizing occurring in the Gulf.[156] Relying on data that is nearly three decades old is improper. NEPA requires EPA to "describe the environment of the areas to be affected or created by the alternatives under consideration."[157] Thus, the establishment of the baseline conditions of the affected environment is a fundamental requirement of the NEPA process. "Without establishing the baseline conditions which exist in the vicinity. . . there is simply no way to determine what effect the proposed [project] will have on the environment and, consequently, no way to comply with NEPA."[158]

The use of fracking has increased dramatically in recent years, and this trend is expected to continue. Indeed, according to a representative of Baker Hughes (which operates about one-third of the world's offshore fracking fleet), fracking in the Gulf of Mexico is expected to increase due to the fact that the industry is now targeting increasingly deeper wells in the Gulf.[159] Moreover, the latest fracking techniques, including the high volume, high-pressure use of the chemical fracking fluid combined with horizontal drilling, have been in use for only about a decade, yet in that time have transformed the oil and gas industry and led to drilling booms around the country by facilitating production from shale formations that could not previously be economically developed.

EPA must obtain, disclose, and analyze the full scope of offshore fracking and other well stimulation in the Gulf of Mexico. The Bureau of Safety and Environmental Enforcement ("BSEE")—the entity charged with permitting offshore drilling activities in federal waters—should have information on the scope of such activities permitted in the waters within the jurisdiction of Region 4 of EPA. For example, a recent request pursuant to the Freedom of Information Act revealed that BSEE permitted offshore fracking more than 1,200 times at more than 600 wells in the Gulf of Mexico OCS Region.[160] Failure to obtain this information would make it impossible for EPA to comply with the hard look requirements of NEPA.

CBD-27

Similarly, EPA's study of the volume of produced water is from 1983, which is also incredibly outdated. Fracking and other new information indicate that produced waters may have increased volume. EPA records reveal that offshore oil and gas platforms in Region 6 discharged *more than 75 billion gallons* of produced waters in 2014.[161] Failure to base its analysis on more

---

[156] Draft EA at 2-6.

[157] 40 C.F.R. § 1502.15.

[158] *Half Moon Bay Fisherman's Mark't Ass'n v. Carlucci*, 857 F.2d 505, 510 (9th Cir. 1988).

[159] David Wethe, Bloomberg News, *Deep Water Fracking Next Frontier for Offshore Drilling*, Aug. 27, 2014, http://www.bloomberg.com/news/articles/2014-08-07/deep-water-fracking-next-frontier-for-offshore-drilling.

[160] The Center, Obama Administration Permitted 1,200 Offshore Fracks in Gulf of Mexico, June 28, 2016, https://www.biologicaldiversity.org/news/press_releases/2016/offshore-fracking-06-28-2016.html; Mike Ludwig, This Map Shows Where Offshore Fracking Has Occurred in the Gulf of Mexico.

[161] See Appendix A, attached.

recent information that adequately reflects the volume of discharges of produced water would also violate NEPA.

2. *EPA's Draft EA Otherwise Fails To Take a Hard Look at the Impacts of Offshore Fracking and other Well Stimulation Treatments*

EPA's Draft EA otherwise fails to consider the direct, indirect, and cumulative impacts of the discharge of chemicals used in offshore fracking and other well stimulation treatments. Indeed, the Draft EA hardly mentions the practices at all, except when referring to the 1988 data. CBD-28 The Proposed Permit has no limits on the amount of well stimulation chemicals that can be discharged when combined with produced water. CBD-29 Nevertheless, EPA ignores the impacts to water quality and marine life that will result from the discharge of chemicals used in fracking and other well stimulation treatments because the wastewater discharges will be subject to permit conditions, including toxicity testing. But NEPA clearly obligates EPA to look at *all* environmental impacts, and it cannot excuse itself from its NEPA hard look duty because a "facility operates pursuant to a…permit..." or because the impacts have been discussed in a non-NEPA document.[162]

CBD-30 Further, such testing does not prevent the chemicals from being dumped into the ocean in the first place; and because the monitoring requirement is at most quarterly or once every six months, testing is unlikely to coincide with discharge of well stimulation chemicals (nor is there a requirement that it do so). In addition, much of the testing is based on the concentrations at the edge of the mixing zone, not at the discharge location.[163] EPA arbitrarily ignores all impacts inside the mixing zone. Relatedly, EPA fails to analyze whether any mixing zones will overlap, and what the impact of such overlap could be. Moreover, by focusing on impacts based on the mixing zone radius, EPA largely ignores the effect of wastewater plumes on water quality. Yet, as explained above, the discharge of fracking chemicals can have myriad negative impacts on water quality, including impacts on marine species. EPA's failure to take a hard look at the water quality impacts on this basis violates NEPA.

3. *EPA Otherwise Failed To Take A Hard Look at the Impacts of Wastewater Discharges, Including Impacts To Marine Species*

CBD-31 The Proposed Permit authorizes the discharge of unlimited volumes of produced waters, including those mixed with fracking chemicals. But EPA has not meaningfully analyzed the massive volume of produced water that flows into the Gulf of Mexico from oil and gas operations.

For example, EPA's Draft EA states that "[d]ischarges are subject to dilution and dispersion that reduce the potential extent of acute water column impacts to within a few hundred meters of the discharge."[164] Yet EPA wholly fails to discuss what the impacts within a few hundred meters of the discharge will be. In addition, EPA admits that the discharges

---

[162] *S. Fork Band of W. Shoshone v. U.S. Dep't of Interior*, 588 F.3d 718, 726 (9th Cir. 2009).

[163] *See e.g.*, Draft EA at 2-15 (stating that WET testing is required at the edge of the mixing zone for well treatment fluids); Proposed Permit at 34 (produced water discharges testing based on edge of mixing zone).

[164] Draft EA at 4-5.

CBD-31 *(Cont'd)*

authorized by the Proposed Permit could potentially affect fish species through impacts to water and sediment quality.[165] But EPA wholly fails to state what those impacts might be. EPA makes similar statements for each species found in the Eastern Gulf, including marine mammals,[166] sea turtles,[167] birds,[168] deepwater benthic communities,[169] live bottom communities,[170] and seagrasses.[171] But, again, EPA does not state, or analyze, what those impacts might be.

CBD-32

Moreover, the Proposed Permit establishes a mixing zone of 100 meters for each discharge location. But EPA fails to analyze any impacts within that mixing zone, or the impacts on migratory species that live in the Gulf, including fish, sea turtles, whales, and dolphin, that may travel through multiple mixing zones in a single migration.

CBD-33

In addition, EPA's Draft EA fails to adequately consider the cumulative impacts of its proposal to adopt the preferred alternative and allow oil companies to dump toxic wastewater into the Gulf of Mexico. In particular, EPA did not consider impacts to benthic communities based on its conclusory statements that impacts to benthic communities are unlikely because the Proposed Permit would only cover activities seaward of the 200-meter isobath; and that operations in water depths shallower than 200 meters will require coverage under NPDES individual permits.[172] But the issuance of individual permits in this area is a reasonable foreseeable action that EPA must consider as part of its cumulative impacts analysis.

CBD-34

EPA also dismisses the cumulative impacts of the discharge of wastewater into the Gulf of Mexico on marine water quality because the impacts are low compared to the oil and gas industry as a whole.[173] This misses the entire point of a cumulative impacts analysis. Cumulative impacts, by definition, may be relatively minor when viewed in isolation yet significant in combination.[174] It is the combined effect that EPA is required to analyze, not the comparative effect. EPA's dismissal of such impacts on this basis is improper.

IV. EPA Cannot Issue a Finding of No Significant Impact

CBD-35

EPA's failure to properly define the purpose and need, failure to fully review all direct, indirect and cumulative impacts, failure to consider a reasonable range of alternatives and failure to otherwise take a hard look at the impacts of issuance of the permit renders the Draft EA legally deficient. As such, EPA cannot issue a FONSI.[175] EPA must therefore prepare an EIS.

---

[165] *Id.* at 4-17.

[166] *Id.* at 4-14.

[167] *Id.* at 4-16.

[168] *Id.* at 4-19.

[169] *Id.* at 4-21.

[170] Draft EA at 4-22.

[171] *Id.* at 4-24.

[172] Draft EA at 4-6 to 4-7.

[173] *Id.* at 4-5.

[174] 40 C.F.R. § 1508.7.

[175] *C.f.*, Draft EA at 7-2 (stating that EPA will prepare a Final EA and that "[a] FONSI will be issued that will document the end of the NEPA process and EPA's final permit decision.")

In addition to properly defining the purpose and need of the proposed action and considering the direct, indirect, and cumulative impacts as well as a reasonable range of alternatives in an EIS, EPA's EIS must also include an adequate mitigation plan to minimize or eliminate all potential impacts, including those from the discharge of offshore fracking chemicals.[176] "[O]mission of a reasonably complete discussion of possible mitigation measures would undermine the 'action-forcing' function of NEPA. Without such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects."[177]

V. EPA Must Comply with its Consultation Obligations Under the Endangered Species Act Prior to Approving the Proposed Project

Approval of the General Permit would also require consultation under Section 7 of the ESA. In enacting the ESA, Congress recognized that certain species "have been so depleted in numbers that they are in danger of or threatened with extinction."[178] Accordingly, a primary purpose of the ESA is "to provide a means whereby the ecosystems upon which endangered species and threatened species depend may be conserved, [and] to provide a program for the conservation of such . . . species."[179]

To reach these goals, Section 9 of the ESA prohibits any person, including any federal agency, from "taking" any endangered species without proper authorization through a valid incidental take permit.[180] The term "take" is statutorily defined broadly as "to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or to attempt to engage in any such conduct."[181] The definition of "harm" has been defined broadly by regulation as "an act which actually kills or injures wildlife. Such act may include significant habitat modification or degradation where it actually kills or injures wildlife by significantly impairing essential behavioral patterns, including breeding, feeding or sheltering."[182] Courts have found federal agencies liable for take of listed species where agency authorized activities resulted in the killing or harming of ESA-listed species.[183]

Additionally, Section 7(a)(2) of the ESA requires federal agencies to "insure that any action authorized, funded, or carried out by such agency . . . is not likely to jeopardize the continued existence of any endangered species or result in the destruction or adverse modification of [the critical] habitat of such species."[184] "Action" is broadly defined to include "all activities or programs of any kind authorized, funded, or carried out, in whole or in part" by

---

[176] 40 CFR §§ 1502.14(f); 1502.16(h).

[177] *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 353 (1989).

[178] 16 U.S.C. § 1531(a)(2).

[179] *Id.* § 1531(b).

[180] 16 U.S.C. § 1538(a)(1)(B); *see also* 50 C.F.R. § 17.31(a) (extending the "take" prohibition to threatened species managed by the U.S. Fish and Wildlife Service)..

[181] 16 U.S.C. § 1532(19).

[182] 50 C.F.R. § 17.3; *see also Babbitt v. Sweet Home Ch. Of Communities for a Great Oregon*, 515 U.S. 687 (1995) (upholding regulatory definition of harm).

[183] *See e.g., Defenders of Wildlife v. Envtl. Prot. Agency*, 882 F.2d 1294, 1300-01 (8th Cir. 1989), *Strahan v. Coxe*, 127 F.3d 155, 163 (1st Cir. 1997).

[184] 16 U.S.C. § 1536(a)(2); 50 C.F.R. § 402.14(a).

federal agencies and include granting permits and licenses, as well as actions that may directly or indirectly cause modifications to the land, water, or air.[185]

To facilitate compliance with Section 7(a)(2), an "agency shall . . . request" from the Services information regarding whether any listed species "may be present" in a proposed action area, and if so, the "agency shall conduct a biological assessment" to identify species likely to be affected.[186] The agency must then initiate formal consultation with the Services if a proposed action "may affect" any of those listed species.[187]

After formal consultation, the Services issue a biological opinion to determine whether the agency action is likely to "jeopardize" any species' existence. If so, the opinion may specify reasonable and prudent alternatives ("RPAs") that avoid jeopardy.[188] If the Services conclude that the action or the RPAs will not cause jeopardy, the Services will issue an incidental take statement ("ITS") that specifies "the impact, i.e., the amount or extent, of . . . incidental taking" that may occur.[189] When those listed species are marine mammals, the take must first be authorized pursuant to the MMPA, and the ITS must include any additional measures necessary to comply with the MMPA take authorization. *Id.* The take of a listed species in compliance with the terms of a valid ITS is not prohibited under Section 9 of the ESA.[190]

EPA's Draft EA and biological evaluation acknowledge that wastewater discharges from offshore oil and gas operations under the Proposed Permit might impact ESA-listed species. For example, EPA's Draft EA and biological evaluation state that sea turtles in the Gulf of Mexico, and the Kemp's ridley in particular, appear to be under stress and that the discharges permitted under the General Permit, including produced water and well treatment fluids, could result in "local minor impacts to sea turtles."[191] Similarly, EPA admits that the discharges may result in "local minor impacts" to fish, including ESA-listed Gulf sturgeon and smalltooth sawfish.[192]

CBD-36

Yet EPA's Draft EA and biological evaluation state that the agency believes issuance of the permit is not likely to adversely affect sea turtles, Gulf sturgeon, smalltooth sawfish, or any other listed species. Such a determination is arbitrary and capricious. EPA cannot issue the permit unless and until formal Section 7 consultation is complete and any measures required to mitigate the harm to listed species or their critical habitat from the discharge of offshore oil and drilling wastes are including as binding conditions of the permit.

VI. Conclusion

In sum, the Proposed Permit does not comply with the ocean discharge criteria or adequately protect water quality because it allows the unlimited discharge of produced waters; it

---

[185] 50 C.F.R. § 402.02.

[186] 16 U.S.C. § 1536(c).

[187] 50 C.F.R. § 402.14(a); 51 Fed. Reg. 19,926 (June 3, 1986) ("may affect" broadly includes "[a]ny possible effect, whether beneficial, benign, adverse or of an undetermined character").

[188] 16 U.S.C. § 1536(b); 50 C.F.R. § 402.14(h)(3).

[189] 50 C.F.R. § 402.14(h)(3)

[190] 16 U.S.C. §§ 1536(b)(4), (o)(2); 50 C.F.R. § 402.14(i)(5).

[191] Draft EA at 4-5; Appx. E at E-5

[192] Draft EA at 4-17

allows the discharge of toxic fracking and other well treatment fluids; and is less protective of water quality than other offshore oil and gas permits. EPA must therefore implement substantial changes to the terms and conditions of the Proposed Permit prior to its issuance.

Moreover, prior to issuing the Proposed Permit, EPA must prepare an EIS under NEPA and must ensure formal consultation under Section 7 of the ESA. Such actions are necessary to ensure EPA adequately examines the myriad environmental harms from the discharge of offshore oil and gas drilling wastes and that the General Permit includes adequate measures to mitigate against such harms and better protect the ocean environment and imperiled marine species from these harmful effects.

Sincerely,

/s/ Kristen Monsell

Kristen Monsell, Staff Attorney
Center for Biological Diversity
kmonsell@biologicaldiversity.org

/s/ Miyoko Sakashita

Miyoko Sakashita, Oceans Program Director
Center for Biological Diversity
miyoko@biologicaldiversity.org

CBD-1	The proposed permit is based upon current available data and federal standards. In EPA's opinion, the discharges covered under this permit will not result in an unreasonable degradation of the marine environment in the vicinity of the discharges. The General Permit contains prohibitions, technology-based effluent limits (TBELS), water-quality based requirements (i.e., whole effluent toxicity (WET) limits on discharges of produced water, water-based drilling fluids, drill cuttings, and non-aqueous-based drill cuttings), to minimize water-quality impacts from the discharges. In addition, the General Permit includes whole effluent toxicity monitoring only requirements for well treatment, completion and workover (WTCW) fluid discharges. The WET monitoring will for WTCW fluids will provide additional information regarding potential impacts from the discharge and inform future permit decision-making. The permit also prohibits bulk discharges of non-aqueous based drilling fluids (NAFs) including synthetic based drilling fluids (only de minimus discharges of NAFs is allowed), produced sand, oil based drilling fluids, oil contaminated drilling fluids, diesel oil, and priority pollutants contained in well treatment, completion, and workover fluids, except in trace amounts. The permit prohibits discharge of produced water, and drill cuttings within a 1000 meters of an Area of Biological Concern (ABC) or a federally designated dredged material ocean disposal site. As noted, TBELs, WQBELS, and WET monitoring are included. The discharges are to federal waters in water depths greater than 200 meters, and there are no applicable federal water quality criteria. However, the permit must comply with Ocean Discharge Criteria at 40 CFR Part 125. The permits effluent limits ensure these discharges cause no unreasonable degradations per Clean Water Act (CWA) Section 403(c) and Ocean Discharge Criteria (see 40 CFR Part 125, Subpart M). The 100-meter diameter mixing zone for toxicity is based on Ocean Discharge Criteria found at 40 CFR Part 125.12l(c). Based on WET data reported by permittees under the current R4 offshore NPDES permit, there have been no toxicity limit violations. The EPA has not found that available toxicity test results or other available information would justify use of a more restrictive mixing zone as described in 40 CFR Part 125.121(c). The permit includes a new requirement for permittees to monitor for toxicity for WTCW fluids not commingled with produced water. This information will allow EPA to obtain additional/targeted data on possible impacts/toxicity of WTCW discharges and the information will inform future permitting decisions. Lastly, permittees are required to submit as part of Notices often for coverage under the general permit technical information on the characteristics of the sea bottom. For facilities in less than 100-meters water depth to be located offshore of Mississippi and Alabama, a Live-Bottom Survey is required. This information is reviewed by EPA, and the agency has the authority to deny or revoke coverage based on the concerns identified. Prior to publicly noticing the permit, EPA prepared a DEA pursuant to the National Environmental Policy Act and also engaged in formal consultation with the US Fish and Wildlife Service (US FWS) and the National

	Marine Fisheries Service (NMFS) in accordance with the Endangered Species Act (ESA). Since publication of the DEA, USFWS provided concurrence with the EPA Region 4's determination that issuance of the Offshore Oil and Gas GP is not likely to adversely (NLAA) affect species or critical habitat under the ESA. The US FWS provided concurrence in a letter to EPA dated January 19, 2017. The NMFS also concurred with the EPA's Essential Fish Habitat assessment in a letter dated December 16, 2016. In addition, the EPA Region 4 has determined that its proposed action will NLAA listed species under the purview of the NMFS and will not likely jeopardized species and/or adversely modify critical habitat. The NMFS has not yet completed consultation or provided its concurrence on EPA's NLAA determination, but based on information in the record EPA anticipates that NMFS will concur with this determination. EPA has determined that it can issue the GP prior to completion of consultation with NMFS in accordance with Section 7(a)(2) and Section 7(d) of the ESA because the issuance of the permit will not result in any irreversible or irretrievable commitment of resources which would have the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures that might be identified by NMFS pursuant to the consultation process. In the event that NMFS does identify necessary reasonable and prudent alternative measures that are necessary to prevent jeopardy to protected species or adverse impacts to critical habitat, EPA has authority to modify the permit to include whatever conditions are necessary to implement such reasonable and prudent alternative measures. In a letter dated August 7, 2017, the EPA Region 4 notified NMFS of its intent to reissue the GP in accordance with Section 7(a)(2) and Section 7(d) of the ESA. To avoid an irreversible or irretrievable commitment of resources, the reissued GP includes a specific reopener clause that will enable the EPA Region 4 to modify the GP should further consultation reveal a need to formulate or implement reasonable and prudent alternative measures. This updated information regarding ESA consultation is reflected in our preliminary Finding of No Significant Impact (FONSI).
CBD-2	All permitted discharges meet the no unreasonable degradation requirement in that, as per definition of unreasonable degradation in 40 CFR §125.121(e)(l-3). EPA has neither observed nor discovered scientific evidence of "significant adverse changes" in ecosystem diversity, productivity or stability of the biological community as a result of the discharges, no threat to human health through direct exposure to pollutants or consumption of exposed aquatic organisms and, no loss of esthetic, recreational, scientific or economic values which is unreasonable in relation to the benefit derived from the discharge.

CBD-3	The EPA Region 4 has conducted multiple previous NEPA reviews on the issuances of the Region 4 NPDES GP for Offshore Oil and Gas Activities in our jurisdictional area. These reviews have included an EIS in 1998 and Supplemental EIS in 2004. For this proposed action, EPA Region 4 has tiered off of previous NEPA documents as allowed under 40 C.F.R. § 1502.20. Relevant information from these previous NEPA documents has been updated. The EPA Region 4 has determined that the NEPA determinations from previous EISs and EAs are still valid and incorporated by reference in this EA. Therefore, EPA does not believe it is appropriate to prepare an additional EIS for this proposed action. In addition, EPA Region 4 has determined the proposed action is consistent with 40 C.F.R. Section 6.204 (a)(l)(iv). In regards to consultation under ESA, EPA Region 4 has had on-going coordination with NMFS and the USFWS for the proposed action. A biological evaluation was prepared and included in the DEA and has been shared with the NMFS and USFWS. Prior to publicly noticing the permit, EPA prepared a DEA pursuant to the National Environmental Policy Act and also engaged in formal consultation with the US Fish and Wildlife Service (US FWS) and the National Marine Fisheries Service (NMFS) in accordance with the Endangered Species Act (ESA). Since publication of the DEA, USFWS provided concurrence with the EPA Region 4's determination that issuance of the Offshore Oil and Gas GP is not likely to adversely (NLAA) affect species or critical habitat under the ESA. The US FWS provided concurrence in a letter to EPA dated January 19, 2017. The NMFS also concurred with the EPA's Essential Fish Habitat assessment in a letter dated December 16, 2016. In addition, the EPA Region 4 has determined that its proposed action will NLAA listed species under the purview of the NMFS and will not likely jeopardized species and/or adversely modify critical habitat. The NMFS has not yet completed consultation or provided its concurrence on EPA's NLAA determination, but based on information in the record EPA anticipates that NMFS will concur with this determination. EPA has determined that it can issue the GP prior to completion of consultation with NMFS in accordance with Section 7(a)(2) and Section 7(d) of the ESA because the issuance of the permit will not result in any irreversible or irretrievable commitment of resources which would have the effect of foreclosing the formulation or implementation of any reasonable and prudent alternative measures that might be identified by NMFS pursuant to the consultation process. In the event that NMFS does identify necessary reasonable and prudent alternative measures that are necessary to prevent jeopardy to protected species or adverse impacts to critical habitat, EPA has authority to modify the permit to include whatever conditions are necessary to implement such reasonable and prudent alternative measures. In a letter dated August 7, 2017, the EPA Region 4 notified NMFS of its intent to reissue the GP in accordance with Section 7(a)(2) and Section 7(d) of the ESA. To avoid an irreversible or irretrievable commitment of resources, the reissued GP includes a specific reopener clause that will enable the EPA Region 4 to modify the GP should further consultation reveal a need to formulate or implement reasonable and prudent alternative measures. This updated information regarding ESA consultation is reflected in our preliminary Finding of No Significant Impact (FONSI).

CBD-4	The EPA is aware that there is a significant body of information regarding chemicals used in hydraulic fracturing demonstrating potential harm to aquatic communities in upland environments. The EPA understands that chemicals used in offshore well stimulation fluids could be equally harmful to marine life if exposed to sufficiently high concentrations for sufficient periods of time or with repeated exposure to high concentrations. However, the EPA finds that the conditions and limits in the proposed permit are sufficient to prevent long-term exposures to high concentrations of such chemicals. All facilities covered under the proposed permit will be in a minimum of 200-meter water depths and operate a minimum of 1000 meters from sensitive marine habitat. Due to high rates of dilution in the open ocean, exposure to high concentrations of added chemicals are likely to occur only for short durations in the discharge plume in the immediate vicinity of the outfall.

	EPA finds that exposures to concentrations high enough to cause biological effects will be brief and that no significant adverse impacts to marine life will result. All permitted discharges meet the no unreasonable degradation requirement in that, as per definition of unreasonable degradation in 40 C.F.R. § 125.121(e)(1-3). EPA has neither observed nor discovered scientific evidence of "significant adverse changes" in ecosystem diversity, productivity or stability of the biological community as a result of the discharges, no threat to human health through direct exposure to pollutants or consumption of exposed aquatic organisms and, no loss of esthetic, recreational, scientific or economic values which is unreasonable in relation to the benefit derived from the discharge. Existing information, including information relating to the impacts of discharges during the previous permit term, is sufficient to support EPA's determination that the discharges authorized in the General Permit will not result in unreasonable degradation of the marine environment. Produced water discharges have technology-based and water quality-based limits. Well treatment completion and workover (WTCW) fluids are covered under the NPDES permit with technology-based effluent limits per the Effluent Guidelines. WTCW fluids commingled with produced waters have technology-based and water quality-based limits. WTCW fluids not commingled with produced waters discharged have technology-based effluent limits. The available data on produced waters submitted by permittees during the current permit term show no violations of WET limits. Both these waste streams, when discharged as permitted, do not cause any significant adverse impact to the marine environment in the Gulf of Mexico (GOM). The proposed final permit includes additional water quality based monitoring only condition for WTCW fluids.
CBD-5	The EPA is aware that produced water may contain a variety of substances that could be harmful to marine life if exposed to sufficiently high concentrations for sufficient periods of time or with repeated exposure to high concentrations. The EPA is aware that a number of biological responses have been documented in laboratory studies of controlled exposures to produced water. EPA is confident that, due to high rates of dilution in the open ocean, such conditions as produced in controlled laboratory studies are likely to occur only for short durations in the discharge plume in the immediate vicinity of the outfall. EPA finds that any exposures to concentration high enough to cause biological effects will be brief and that no significant adverse impacts to marine life will result.
CBD-6	EPA agrees that some benthic impact may occur as a result of produced water discharges that are made near the seafloor in relatively non-energy environments. Impacts may occur from direct contact of the concentrated discharge plume with the benthos and the accumulation of particulates that settle to the seafloor. Published studies show that produced water impacts are highly variable with most being limited to within a few hundred meters from the outfall. It should be noted that the majority of studies that have shown an impact in the GOM concerned production wells in shallow (less than 30 meters) depths. The proposed permit covers only facilities operating in depths of 200 meters or more. Discharge models show that maximum plume concentrations occur from 8-12 meters from the

	discharge point and plumes have been measured to dilute 100 times within 10 m of the discharge and 1,000 times within 103 m of the discharge. Rapid dilution of the produced waters decreases the possible toxicity with distance from the outfall. Also, the proposed permit places restrictions on the discharge of produced water, which require the effluent concentration 100 m from the outfall to be less than the 7-day no observable effect concentration based on laboratory exposures. This will limit the impacts on nearby benthic resources.
CBD-7	Comment noted. See responses CBD-4, CBD-5 and CBD-6.
CBD-8	The EPA is aware that there is a significant body of information regarding chemicals used in hydraulic: fracturing, demonstrating potential harm to aquatic communities in upland environments. The EPA believe that chemicals used in offshore well stimulation fluids could be equally harmful to marine life if exposed to sufficiently high concentrations for sufficient periods of time or with repeated exposure to high concentrations. However, the EPA is confident that the conditions and limits in the proposed permit are sufficient to prevent long-term exposures to high concentrations of such chemicals. All facilities covered under the proposed permit will be in a minimum of 200-meter water depths and operate a minimum of 1000 meters from sensitive marine habitat. Due to high rates of dilution in the open ocean, exposure to high concentrations of added chemicals are likely to occur only for short durations in the discharge plume in the immediate vicinity of the outfall. EPA believes that exposures to concentrations high enough to cause biological effects will be brief and that no significant adverse impacts to marine life will result. Existing information, including information relating to the impacts of discharges during the previous permit term, is sufficient to support EPA's determination that the discharges authorized in the General Permit will not result in unreasonable degradation of the marine environment. The EPA also notes that comparisons of the large-scale, induced hydraulic : fracturing procedures used in onshore and off-shore California oil and gas operations for low-permeability reservoirs with well treatment operations carried out on the.OCS in the Gulf are misleading. Typical use of pressurized fluids for well treatment and well stimulation in the GOM are small-scale by comparison and use significantly smaller volumes of fracking fluids and the associated chemicals. In addition, the number of added chemicals is typically much smaller.
CBD-9	Comment noted. See responses CBD-4, CBD-5 and CBD-6.
CBD-10	The EPA does have some discretion with regard to the size of mixing zones used in NPDES permits, however, the EPA does not agree that the use of a 100-meter mixing zone to determine toxicity is arbitrary. Nor does EPA agree that a more restrictive mixing zone is necessary at this time. The concept for the 100 m mixing zone comes from 40 CFR §125 Ocean Discharge Criteria: *"§125.121 (c)* Mixing zone *means the zone extending from the sea's surface to seabed and extending laterally to a distance of 100 meters in all direction from the discharge point(s) or*

	to the boundary of the zone of initial dilution as calculated by a plume model approved by the director, whichever is greater, unless the director determines that the more restrictive mixing zone or another definition of the mixing zone is more appropriate for a specific discharge. "At present, the EPA does not have information that would justify a change in the size of the mixing zone prescribed in the proposed general NPDES permit. The EPA will use the data acquired through the WET testing requirement for well treatment fluid discharges to determine whether a more restrictive mixing zone may be required.
CBD-11	The inventory requirement for WTCW fluids are targeted for discharges that occur prior to the production phase of the well. EPA is aware that there may be numerous discharges of WTCW fluids during well development, and the permit contains new WET testing monitoring only requirements applicable to WTCW fluids not commingled with produced waters in an effort to provide the EPA with new information in order to evaluate the extent to which these discharges are may be toxic. Based on current information, including information developed during previous permit terms, EPA finds that the terms of the General Permit will ensure that the discharges do not cause unreasonable degradation of the marine environment. The chemical inventory and toxicity testing monitoring results will provide information to support future permitting decisions, including whether to add more stringent conditions, if warranted.
CBD-12	The EPA consulted with the NMFS regarding the proposed GP to insure the protection of marine species listed as threatened or endangered under the ESA. We also solicited comments on the permit from the US Fish and Wildlife Service. The Service provided concurrence with EPA's determination that issuance of the Offshore Oil and Gas general permit is not likely to adversely affect species or critical habitat under the BSA. EPA is aware that some coastal states require zero discharge for oil and gas operations in near-shore coastal waters. Because EPA recognizes that shallower nearshore environments are most biologically productive and, therefore, more sensitive to direct exposure to pollutants from oil and gas operations, the proposed GP only covers operations seaward of the 200-meter isobaths, these facilities will be considerably further from shallow nearshore environments. As a result, the greater distances make hauling operational discharges to onshore disposal site less feasible. The permit prohibits discharge of produced water, and drill cuttings within a 1000 meters of an ABC or a federally designated dredged material ocean disposal site. Regarding inclusion of best management practices (BMPs) to prohibit discharges, BMPS may be implemented in lieu of or in addition to numeric limits in some circumstances, for example if it is infeasible to calculate numeric limits BMPs limits may be appropriate. Alternatively, BMP based limits may be appropriate when reasonably necessary to carry out the purposes of the CWA. See 40 CFR 122.44(k). In this case, numeric technology-based limits for produced water and WCTW fluids have been established by the offshore oil and gas effluent guideline, which establishes the appropriate technology-based effluent limit for this category of discharges. A limit of zero discharge is not what is intended by a BMP, as it is a

	numeric effluent limit of zero, or a prohibition of discharge, which is inconsistent with the required ELG-based numeric effluent limits in the General Permit. Additional limits based on water quality may be considered, but EPA has determined that the limits and conditions in the General Permit ensure that unreasonable degradation of the marine environment will not be caused by the authorized discharges.
CBD-13	The proposed permit covers produced water discharges only within the Region 4 jurisdictional area of the GOM. Within the Region 4 jurisdictional area EPA expects, during the approximate term of the permit from the year 2017 to 2022, an estimated 120 - 470 total wells, including about 60 - 235 production wells. Produced water is addressed in the proposed permit with both technology-based and water quality based limits. The ocean discharge criteria require that a waste stream cannot be permitted if EPA determines that the discharge of wastes will cause unreasonable degradation of the marine environment. The available evidence, including whole effluent toxicity data reported by permittees under the current R4 offshore permit, indicates that produced water discharges made consistent with the permit's terms and conditions will not result in unreasonable degradation to the portion of the GOM affected by the proposed permit. EPA does not have information to justify imposing additional or more stringent limits. It should be noted that, concerning the southern California offshore oil and gas facilities covered under the EPA Region 9 General Permit, most of the platforms are operating fairly close to shore in areas containing sensitive habitat in less than 100 meter depths. The EPA Region 4 General Permit will cover facilities in greater that 200 meter depths, most of which are expected to be located much further from shore in areas containing less biologically sensitive habitats. It should also be noted that the EPA Region 9 General Permit produced water volume limits range from 4,666 barrels per day (bbl/d) to 114,346 bbl/d. A 2005 report of the produced water volumes from 50 operators in the GOM reported annual averages ranging from 3 bbl/d to 63,828 bbl/d.
CBD-14	Comment noted. See responses to CBD-5, CBD-8 and CBD-12
CBD-15	The EPA understands that the various discharges contain a variety of chemical compounds that have the potential to adversely impact the marine environment that will not be individually limited or monitored. EPA has determined, however, that the limits and conditions in the General Permit will mitigate the potential toxicity of the discharge, and such limits and conditions (e.g., WET limits and WET monitoring) in the proposed General Permit are preferable to chemical-specific limits and monitoring, given the variability of composition. WET testing for well treatment fluids will commence with the authorization of the proposed permit as will reporting of chemicals used. Additionally, the permit will require the permittees to submit information on specific chemical constituents used during well treatment operations. This information may be used by EPA in the future to determine if additional future limits are warranted.

CBD-16	The EPA limits discharges under the General Permit to water depths greater than 200 meters to avoid the most sensitive benthic habitats on the continental shelf. In addition, the permit contains a live bottom survey requirement for all operations under its jurisdiction and a 1000-meter buffer to further protect Areas of Biological Concern and other critical marine habitat.
CBD-17	Comment noted. See CBD-3 Response Above.
CBD-18	The EPA consulted with the NMFS regarding the proposed General Permit to insure the protection of marine species listed as threatened or endangered under the ESA. The Service provided concurrence with EPA's determination that issuance of the Offshore Oil and Gas general permit is not likely to adversely affect species or critical habitat under the ESA.
CBD-19	The EPA is aware inland discharges of large volumes of fracking fluids into small volume enclosed waterways such as streams and rivers can result in significant impacts to resident aquatic life. However, the EPA finds that discharges of relatively small volumes of WTCW fluids into the GOM do not present similar risks of significant adverse impact. With regards to the request to prepare an EIS, EPA Region 4 has conducted multiple previous NEPA reviews on the issuances of the Region 4 General Permit for Offshore Oil and Gas Activities in our jurisdictional area. These reviews have included an EIS in 1998 and Supplemental EIS in 2004. For this proposed action, EPA Region 4 has tiered off of previous NEPA documents as allowed under 40 CFR §1502.20. Relevant information from these previous NEPA documents has been updated. EPA Region 4 determined that the NEPA determinations from previous EISs and EAs are still valid and incorporated by reference in this EA. Therefore, EPA does not believe it is appropriate to prepare an additional EIS for this proposed action. In addition, EPA Region 4 has determined the proposed action is consistent with 40 CFR Section 6.204 (a)(l)(iv).
CBD-20	Comment noted. See CBD-3 Response Above.
CBD-21	EPA disagrees that we have taken the position of relying on a "lack of information" to support the finding of no significant impact for this proposed action. In fact, as described under response CBD-3, EPA Region 4 has fully evaluated the OCS oil and gas NPDES General Permit and impacts on water quality through multiple EISs and EAs. These NEPA documents have all contemplated the impacts of oil and gas activities in the OCS covered under the NPDES General Permit in the EPA Region 4 jurisdictional area.
CBD-22	EPA disagrees with the comment that "EPA's purpose and need statement fails to comply with NEPA." The stated purpose and need in the EA is consistent with previous EAs and EISs supporting issuance of NPDES General Permits for offshore oil and gas in EPA Region 4. The reissuance "of an existing NPDES General Permit authorizing discharges from existing and new source oil and gas

	facilities operating in the federal waters of the Gulf of Mexico where EPA Region 4 is the permitting authority" is consistent with the mandate outlined in 40 CFR §128.28(C)(l).
CBD-23	EPA Region 4 disagrees that the "EA fails to analyze a reasonable range of alternatives." The alternatives considered in the EA are consistent with past NEPA evaluations regarding issuance of a NPDES General Permit in the Region 4 jurisdictional area of the Gulf of Mexico. EPA Region 4 considered the alternative of "zero discharge" of well treatment and completion fluids to not be a feasible alternative therefore eliminated it from further consideration.
CBD-24	The "no action" alternative is structured in the EA to satisfy the requirements of 40 CFR § 128.28 (C)(l) which states that "The Regional Administrator shall, except as provided below, issue General Permits covering discharges from offshore oil and gas exploration and production facilities within the Region's jurisdiction." Those exceptions listed in 40 CFR §128(C)(l) include issuance of an Individual Permit. Therefore, EPA Region 4 believes including an alternative that contemplates no NPDES permit (General Permit or Individual Permit) not a feasible alternative and not consistent with the intent of the "no action" alternative definition under NEPA.
CBD-25	EPA Region 4 disagrees with the statement that " ... EPA's analysis fails to consider the direct, indirect, and cumulative impacts of produce waters discharges and the impacts of discharging chemicals used in offshore fracking and other well stimulations treatments." EPA Region 4 has fully evaluated the OCS oil and gas NPDES General Permit and impacts on water quality through multiple EISs and EAs. Previous NEPA documents and NPDES permits have contemplated the use of well stimulation and fracking activities and have evaluated the direct, indirect, and cumulative impact of these activities. At this time, EPA has no reason to believe that previous conclusions in these NEPA documents are invalid or that the impacts associated with offshore well stimulation and fracking will cause significant impacts to the environment.
CBD-26	Based on whole effluent toxicity data reported by permittees under the current EPA Region 4 offshore permit, there have been no toxicity limit violations. This data is sufficiently recent and reflective of current operations with respect to toxicity of discharges. However, EPA agrees that additional data should be collected to ensure that other discharge data also reflects current operations. As stated on Page 2-6 of the *DEA:* *"The number of WTCW jobs is not reliably known, especially with respect to current operations."* And: *"EPA Region 4 recognizes this information is limited and dated (i.e., from 1988), and operational practices may have changed Therefore, EPA Region 4 is requiring testing and reporting requirements for this waste stream beyond those of the 2010 General Permit."* One of the functions of a NEPA document is to indicate the extent to which environmental effects are essentially unknown or the record is incomplete. In the

	current EA we acknowledge data gaps regarding WTCW fluids and are proposing additional permit requirements under the new GP to address these gaps.
CBD-27	Comparisons of produced water volumes between EPA Regions 6 and 4 are not valid because there are significantly fewer production wells in EPA Region 4. A 2005 report[1] of the produced water volumes from 50 operators in the GOM reported annual averages ranging from 3 bbl./d to 63,828 bbl./d. This is within the 134 bbl./d to 150,000 bbl./d range reported in the 1983 study referenced in the ODCE. [1] Veil, J.A., Kimmell, T.A., Rechner, A.C. 2005. Characteristics of Produced Water Discharged to the GulfofMexico Hypoxic Zone. U.S. Dept. of Energy. Contract W-31-109-Eng-38. 74pp.
CBD-28	There is currently no scientific basis for specific numerical limits on specific chemicals used in WTCW fluids discharged into the GOM. See response to CBD-1.
CBD-29	The NPDES permit requires quarterly samples for discharges of WTCW fluids not comingled with produced waters. EPA has determined that this monitoring frequency is adequate. The permit also requires that all samples be representative ofthe monitored activity. Also see responses to comments CBD-1 and CBD-10. EPA disagrees that we have not taken "hard look" at the potential impacts to water quality or marine life. In fact, EPA has contemplated impacts to these resources in multiple previous NEPA documents (EISs and EAs). We do however acknowledge data gaps regarding WTCW fluids and are proposing additional permit requirements under the new GP to address these gaps.
CBD-30	Any well stimulation fluids remaining in the formation after the well completion and stimulation phase of well construction naturally mix (comingle) with formation (produced) water. The comingled water is brought to the surface and discharged after treatment. The discharge of stimulation fluids mixed with produced water is continuous until the volume of stimulation fluids remaining in the formation is exhausted. Therefore, the prescribed monitoring frequency will be adequate to include stimulation fluids until it is completely removed from the producing formation. See Response to CBD-10 regarding mixing zones. With respect to monitoring frequency, the NPDES permit requires quarterly samples for discharges of WTCW fluids not comingled with produced waters. EPA has determined that this monitoring frequency is adequate. See CBD-29 regarding "hard look" comment.
CBD-31	See response to CBD-6 for response related to impacts of produce water. EPA disagrees that we have not taken a "hard look" at the impact of produce water. In fact, EPA has evaluated the impact of produce water in multiple previous NEPA documents (EISs and EAs). Analysis and conclusions from these previous

	documents were considered during the decision making process for this proposed action.
CBD-32	The volumes of produced water discharged are not limited; however, the permit minimizes impacts to marine life by including several prohibitions regarding discharges near ABC and federally designated disposal sites, TBELs and WQBELs. Based on whole effluent toxicity data reported by permittees under the current R4 offshore permit, there have been no toxicity testing violations, hence no need at this time to impose further restrictions on produced waters. See Response to CBD-10 regarding mixing zones.
CBD-33	EPA maintains the right to issue individual permit in lieu of coverage under the general permit. EPA does not agree that impacts from separate individual permits for facilities not authorized to discharge under the General Permit should be considered as cumulative impacts from the General Permit. EPA Region 4 disagrees that cumulative impacts have not been adequately considered in the proposed action. Chapter 4 of the EA includes detailed discussion of environmental consequences for the proposed action for each resource area along with a detailed discussion on cumulative impacts for each resource area. In addition, anticipated cumulative impacts to benthic communities from the proposed action are discussed in Section 4.3.5.3.
CBD-34	EPA is confident that the permit conditions in previous General Permits for offshore oil and gas development and the newly proposed General Permit is protective of water quality and marine life. Based on available data and research the EPA found that there are no "significant" cumulative impacts to water quality and marine life in the Gulf of Mexico due to authorization of the EPA Region 4 General Permit.
CBD-35	Comment noted. See responses CBD-3, 22, 23, and 25
CBD-36	As part of the permitting process, EPA engaged in formal consultation with the US Fish and Wildlife Service and the National Marine Fisheries Service (NMFS) in accordance with the Endangered Species Act (ESA). Both Services provided concurrence with EPA's determination that issuance of the Offshore Oil and Gas general permit is not likely to adversely affect species or critical habitat under the ESA.

CUBIC IMAGE ENVIRONMENT, LLC
5720 Citrus Blvd., #10314, New Orleans, LA 70123
www.cubic-image.com

CERTIFIED 7015 3010 0002 2684 7181

October 12, 2016

Ms. Bridget Staples
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, GA 30303

Re: NPDES General Permit No. GEG460000

Dear Ms. Staples,

Cubic Image Environment, LLC has the following comments regarding proposed NPDES Permit No. GEG460000:

1. Parts I(B)(3) and V(B)(67) of the Permit fail to acknowledge that formation water, a component of produced water (PW), includes dissolved contaminants that come up from the subsurface with oil. At the 2016 American Association of Petroleum Geologists (AAPG) Annual Convention & Exhibition, a presentation by Ms. Ranya Algeer entitled, "Is Water Washing an Important Petroleum System Process," concluded that benzene, toluene, ethylbenzene, and xylenes (BTEX), polycyclic aromatic hydrocarbons (PAHs), and phenol compounds are washed out of crude oil and become dissolved in formation water. In addition, formation water is known to contain naturally-occurring radioactive material (NORM), including radium 226 and 228. The NPDES Permit has no provisions for characterization or treatment of these naturally-occurring chemicals in formation water prior to ocean discharge. Benzene, benzo(a)pyrene (a PAH compound), and NORM are considered human carcinogens. There are data that indicate human carcinogens are also carcinogenic to marine fauna, including whales and dolphins (Wise et al., 2008) (Wise et al., 2014).

2. The sampling requirements for PW include only Oil and Grease, and Toxicity. These tests are inadequate to characterize PW prior to ocean discharge. The test for Oil and Grease is done by the gravimetric method only, not the more accurate gravimetric/mass spectrometry method. The gravimetric method is done with a simple field test kit, with no documented quality control. The test for Toxicity is a grab sample of diluted water. It simply measures mortality of one or two species after 7 days; the test includes no analysis of target chemicals. The test is essentially conducted to find a Critical Dilution of PW at which mortality does not occur, such that ocean discharge is justified. It does not quantify the mass of contaminants being discharged to the ocean. The NPDES Permit includes no quantitative laboratory analysis of PW with documented

quality control. The sampling frequency of these tests is also inadequate, but this point is made moot due to the reasons stated above. The self-reporting of monitoring data by operators is also problematic, but again this is moot for the same reasons.

3. The NPDES Permit allows well treatment, completion, and work over fluids to be commingled in PW for ocean discharge. The NPDES Permit requires only that operators self-certify that there are no priority pollutants in chemicals used in these fluids. These fluids include acids, biocides, friction reducers and viscosity enhancers. Large volumes of hydrofluoric (HF) acid, considered a "super acid," are commonly used to acidize wells during all phases of work. HF is so corrosive that if spilled, it can absorb into the skin, eventually working its way to the bone. There is no provision in the NPDES Permit for testing corrosivity (pH) of PW prior to ocean discharge. Ocean dumping of HF and other acids used in the offshore oil and gas industry likely have a greater effect on water quality than ocean acidification due to atmospheric CO_2.

4. The NPDES Permit requires compliance at the edge of a 100-meter mixing zone. Operators are encouraged to use the program, CORMIX, to forward-model contaminant concentrations in PW at the Critical Dilution. As such, the premise of the NPDES Permit is entirely theoretical. There are no provisions in the NPDES Permit for verifying actual chemical concentrations at the edge of the mixing zone, as determined through documented laboratory analysis with proper quality control. This procedure is inconsistent with the Scientific Method, and should be a priority action item for EPA.

5. The practice of ocean disposal of PW exists only because EPA specifically excludes oil and gas industry wastes from Resource Conservation, and Recovery Act (RCRA) regulations that apply to all other industries. However, EPA still has a duty to uphold the Clean Water Act, specifically regulations at 40 CFR 125.122, to "prevent the unreasonable degradation of the marine environment." How does EPA reconcile the allowed practices described in Comments 1 through 4 above with the requirement to prevent the unreasonable degradation of the marine environment?

In the process of revising the proposed NPDES Permit, Cubic Image Environment, LLC urges EPA to be consistent with the Oslo-Paris (OSPAR) Commission, to the extent possible. The OSPAR Commission is an independent organization of Contracting Parties setting environmental goals and improving management mechanisms with regard to offshore oil and gas activities. The goals of OSPAR are to prevent and eliminate pollution and take the necessary measures to protect the OSPAR maritime area against the adverse effects of offshore activities so as to safeguard human health and to conserve marine ecosystems and, when practicable, restore marine areas which have been adversely affected. The current Contracting Parties include Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, The Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and United Kingdom, together with the European Union. The success of the OSPAR program is attributed to the fact it is completely independent of the oil industry.

Cubic Image Environment, LLC has accepted this assignment on a pro-bono basis to protect the interests of the Asian American community which relies on subsistence fishing in the Gulf of Mexico. We hope you take these comments in the manner in which they were intended, to modernize EPA regulations so they are more protective of the environment. We request the favor of a personal reply to our comments.

Sincerely,

Frieda M. Wales

Ms. Frieda M. Wales, PhD
Marine Biologist

References:

Wise, J.P., S.S. Wise, S. Kraus, F. Shaffiey, M.Grau, T.L. Chen, C. Perkins, W.D. Thompson, T. Zheng, Y. Zhang, T. Romano, and T. O'Hara. 2008. Hexavalent chromium is cytotoxic and genotoxic to the North Atlantic right whale (*Eubalaena glacialis*) lung and testes fibroblasts. *Mutation Research* 650 (2008) 30-38. https://www.ncbi.nlm.nih.gov/pubmed/18006369.

Wise J.P. Jr., J.T.F. Wise, C.F. Wise, S.S. Wise, C. Gianios Jr., H. Xie, W.D. Thompson, C. Perkins, C. Falank, and J.P. Wise Sr. 2014. Concentrations of genotoxic metals, chromium and nickel, in whales, tar balls, oil slicks, and released oil from the Gulf of Mexico in the immediate aftermath of the Deepwater Horizon oil crisis: is genotoxic metal exposure part of the Deepwater Horizon legacy? *Environ. Sci. Technol.* 2014, 48(5), 2997-3006. https://www.ncbi.nlm.nih.gov/pubmed/24552566.

CIE-1	EPA acknowledges that pollutants present in formation water and produced water can include benzene, toluene, ethylbenzene and xylenes (BTEX), polyromantic hydrocarbons, and natural occurring radioactive materials (NORM), and permit conditions have been developed to are minimize the impacts of the discharge on human health and aquatic life. Impacts from chemical species, such as BTEX and PAH, are addressed using technology-based effluent limits (TBELs), water-quality based effluent limits (WQBELs), and Best Management Practices (BMP). TBELs are established in EPA's effluent guidelines for the offshore industry (reference 40 CFR Part 435). In particular, the permit's oil and grease limit serves as an indicator for toxic pollutants in produced water and well treatment, workover and completion fluids waste streams based on EPA's determination that toxic pollutants are largely controlled by removal of oil and grease. The permit also prohibits the discharge of free oil. Effluent limits and monitoring for whole effluent toxicity (WET) are included in the permit for produced water discharges in order to protect aquatic life near the vicinity of the discharges. Lastly, the permit also includes Best Management Practices to help address pollutants not controlled by effluent limits. The regulation of NORM under the NPDES program is complex. There are no TBELs or WQBELs which directly address this category of pollutants, which create potential radiation exposure risks to humans and the environment. Studies also have been done to determine whether produced water discharges have the potential to cause bioaccumulation of pollutants such as BETX and PAHs. Based on the results of those studies we have not found that additional permit limits are needed to prevent bioaccumulation and the associated impacts to human health from fish tissue consumption. The EPA acknowledges that releases of NORM due to mining, drilling and other human activities are an environmental and human health concern. The Agency uses the term Technologically Enhanced Naturally Occurring Radioactive Material (TENORM), which is defined as,"naturally occurring radioactive materials that have been concentrated or exposed to the accessible environment as a result of human activities such as manufacturing, mineral extraction, or water processing." Not all oil and gas fields have TENORM accumulations, and EPA understands that if it is present, it may form a mineral scale on production piping, and other equipment, thereby increasing exposure to workers mostly likely via inhalation of dusts and direct radiation. Human protection from impacts of radiation is addressed in company occupational health and safety documents. The EPA has previously required monitoring of produced water discharges for Radium 226 and 288; however, data from that monitoring did not show that they were in sufficient concentrations to pose a potential environmental impact.
CIE-2	Produced water discharges are relatively long term and occur once the facility begins the production phase of operations. Based on the Best Professional Judgment (BPJ) of the permit writer, the permit requires grab samples be analyzed monthly using an EPA-approved method in 40 CFR Part 136. The commenter did not provide specifics regarding he inadequacy of the current

	permit requirements; however, EPA welcomes any data suggesting the current sampling frequency and analytical method are inadequate. Regarding the toxicity test, the WET test is a gauge that the effluent will be protective of aquatic life, and it is designed to detect the synergistic impacts of chemicals. Only if the WET testing results show more than three failures in a row are operators required to perform additional testing to investigate the causative toxicant (i.e., individual chemical species). Since the receiving waterbody is large, it is reasonable to allow a mixing zone for certain waste streams.
CIE-3	Some WTCW fluids may be corrosive and commingled with PW prior to discharge. However, based on EPA data, the pH of PW commingled with WTCW fluids is within a range of 6-9 units, which is protective of aquatic life. Therefore, there is no need to test pH of PW prior to discharge. Also, although the permit does not include a pH limit, permittees must sample and perform WET testing to demonstrate PW effluents are not toxicity to aquatic life. By design, the NPDES permitting program requires permittees to self-monitor and self-certify. Permittees must sign certification statements that the information/data being submitting is accurate, including proper quality control of samples, and the regulations impose penalties for submitting false information. The permit requires permittees to self-certify that WTCW fluids contain priority pollutants in less than detectable amounts, which EPA believes is a sufficient demonstration that the effluent will be protective of aquatic life.
CIE-4	NPDES permit regulations require sampling only in where the sample point is accessible and safe, and ultimately, is the permittee's responsible for providing a safe and accessible sampling point that is representative of the discharge. For practical reasons, in lieu of verifying actual chemical concentrations via sampling at the edge of the mixing zone in the Gulf of Mexico, the permit allows the use of a CORMIX model to predict concentrations.
CIE-5	The permit address both sections 402 and 403 of the CWA, and EPA works with the federal and state agencies to insure that the permit will not adversely impact endangered species and coastal communities. A CWA Section 403 determination was prepared and publicly notice with the draft permit to discuss the potential for permitted discharges to cause an unreasonable degradation of the marine environment in the vicinity of the discharges. This document was transmitted separately to the US Fish and Wildlife Services and the Marine Fisheries Service for their review of potential impacts to Endangered Species and commercial fisheries. Additionally, the states of Mississippi, Alabama and Florida were contacted in order for coastal program to provide input regarding potential impacts to coastal waterbodies. The permit allows the discharge of PW in accordance with Section 402 of the permit, and the prescribed permit conditions for this waste stream are protective of aquatic life.

IADC

www.iadc.org

18 October 2016

WPD
U.S. EPA-Region 4
NPDES Permitting Section
Sam Nunn Atlanta Federal Center
61 Forsyth Street SW
Atlanta, GA 30303-8960
Attention: Ms. Bridget Staples

Submitted via email to: Staples.Bridget@epa.gov

Re: Draft NPDES General Permit for Eastern Portion of Gulf of Mexico (GEG460000)

To whom it may concern:

The International Association of Drilling Contractors is a trade association representing the interests of drilling contractors, onshore and offshore, operating worldwide. Our membership includes all drilling contractors currently operating mobile offshore drilling units (MODUs) in the areas subject to the jurisdiction of the United States.

The purpose of this letter is to respond to the EPA's 18 August 2016 (81 FR 55196) *Federal Register* Notice of Reissuance of the NPDES General Permit for the Eastern Portion of the Gulf of Mexico (GEG460000).

These comments are offered without prejudice to comments that may also be addressed directly by IADC members.

IADC-1

IADC shares the concerns and recommendations expressed by the Offshore Operator's Committee in the comments they have provided on 17 October 2016 in response to this rulemaking.

IADC appreciates the opportunity to provide our support to the OOC comments regarding this notice and asks that they be given due consideration. Should you have any questions, please contact me by phone at (713) 292-1945 Ext.203.

Sincerely,

John Pertgen
Director, Offshore Technical and Regulatory Affairs

IADC-1	Please refer to EPA Region 4's responses to comments submitted by the Offshore Operators Committee in its letter to EPA dated October 17, 2016.

From: Staples, Bridget
To: Holliman, Daniel
Cc: Militscher, Chris; Ferry, Rol
Subject: FW: Public notice No. 16AL00001 Date August 18, 2016
Date: Thursday, October 20, 2016 11:16:58 AM

Citizen Comment

Bridget Staples M.P.H.
Environmental Scientist
US EPA Region 4 NPDES
Water Protection Division
61 Forsyth Street
Atlanta GA 30303
(404) 562-9783

From: James Dombey [mailto:jdombey54@gmail.com]
Sent: Thursday, August 18, 2016 12:40 PM
To: Staples, Bridget <Staples.Bridget@epa.gov>
Subject: Public notice No. 16AL00001 Date August 18 2016

Dear Ms. Staples:

KD-1

I don't need to cite specific details of the proposed reissuance and extension of the permit to continue and add to the pollution of the Gulf of Mexico off the Florida and Alabama coast. You know quite well that it is not the right thing to do considering what has happened in the past and how important it is to protect the precious resort areas for our grandchildren and great-grandchildren. The EPA doesn't seem to understand that, so please do what you can to inform them.

You must be thinking ahead now, way ahead. Please do.

Sincerely,
Kathryn Dombey
Pensacola

KD-1	The NPDES permit complies with federal regulations for point source discharges to waters of the U.S. and is protective of human health and aquatic life.

Offshore Operators Committee

October 17, 2016

Water Protection Division
U.S. EPA Region 4
Sam Nunn Atlanta Federal Center
NPDES Permits Section
61 Forsyth Street SW
Atlanta, GA 30303
Attention: Ms. Bridget Staples, NPDES Offshore Oil and Gas Coordinator

RE: Offshore Operators Committee Comments
Notice of Proposed National Pollutant Discharge Elimination System (NPDES) General Permit for New and Existing Sources in the Offshore Subcategory of the Oil and Gas Extraction Category for the Eastern Portion of the Outer Continental Shelf (OCS) of the Gulf of Mexico (GEG460000), Public Notice No. 16AL00001.

Dear Ms. Staples:

The Offshore Operators Committee (OOC) appreciates the opportunity to submit detailed comments on the proposed general permit. OOC member companies represent approximately 90% of the oil and gas production in the Gulf of Mexico OCS, and the proposed changes to the NPDES permit have the potential to impact existing and future operations of all our member companies.

The OOC's comments are shown in the attached Table, supported by additional attachments. Comments submitted on behalf of the OOC are submitted without prejudice to any member's right to have or express different or opposing views. The OOC has reviewed the Draft Environmental Assessment (EA) and supports the proposed findings of no significant impact (FONSI). The only recommended change to the EA is consistency within sections 1.3.4.2 and 3.6.3.3 (Deepwater Horizon impact).

OOC believes all of the comments are of importance to provide a protective and practical permit. We wish to draw attention to three of the comments that are of particular importance to OOC Members. Provided below is an overview summary of each:

1. **Electronic NOI/NOT/DMR – Comments 1-3 and 6**

   EPA's proposal to implement electronic reporting by a deadline of 12/31/2016 to end all paper submittals seems unrealistic and not feasible to ensure the system is properly coded and operational. Extensive experience with implementing identical programs in EPA

LOUISIANA OFFICE
One Lakeway-3900 N. Causeway, Blvd., Suite 700,
Metairie, Louisiana 70002
(504) 934-2159 Office / (504) 455-0868 Fax

TEXAS OFFICE
10777 Westheimer Rd., Suite 700
Houston, Texas 77042
(713) 589-6710 Office / (504) 455-0868 Fax

Region 6 revealed that adequate time and IT support are required. OOC would like the opportunity to provide input during the NetDMR development process and to Beta test the eNOI system and NetDMR tool before the systems are rolled out for final use. Our comments detail further information as well as additional requests related to permitting and reporting.

2. **Toxicity Testing of Well Treatment, Completion & Workover Fluids – Comments 9-10, 4, 8, 11 & 13-15**

OOC is requesting the permit language be modified to clarify that the chronic and acute toxicity testing requirements are not limitations, but monitoring only requirements. OOC is also proposing several practical clarifications to help implement the proposed toxicity testing. Further, OOC is proposing conservative simplifications around toxicity testing frequencies to support implementation. Finally, we have grave concerns related to managing Confidential Business Information proposed in the well fluid constituent reporting requirements. Our comments detail further information as well as additional requests related to this testing and reporting.

3. **CWIS Entrainment Monitoring – Comment 19**

OOC strongly objects to the continued requirement to conduct ongoing entrainment monitoring (after initial two year biweekly sampling). EPA's own conclusion (section 6.1 of the Draft Environmental Assessment) , is "*that cooling water intake structures on offshore oil and gas facilities have no significant impact on the selected species investigated*". As the species studied were reliable indicators for overall entrainment, and given no species of concern were caught within the 60,376 individuals identified from 1,515 tows spread throughout the 24 month sampling period, the Agency has no basis to continue to require costly on platform monitoring at affected facilities.

OOC is therefore petitioning the EPA per their proposed language at Part I.D.3.d.ii.(page 70 of draft permit) to reduce monitoring frequency to "none required". If EPA still feels monitoring in some form is required OOC is proposing to use the SEAMAP database, which will provide a more comprehensive, cost-effective mechanism for gauging the seasonality of entrainment potential over time. Such SEAMAP reporting could be done by the Agency's review of this data set or by a permit requirement for industry to submit annual reports on the SEAMAP data.

To be clear, OOC is not requesting deletion or change to the two year study requirements for newly affected facilities.

Our comments also detail further information as well as additional requests related to the CWIS portions of the draft permit.

OOC can coordinate and schedule a face to face meeting to discuss our comments, answer questions and provide any needed clarifications.

We appreciate your time and efforts regarding the draft permit. If you have any questions or if additional information is needed, please contact me at (504) 934-2159 or at greg@offshoreoperators.com or Mr. James Durbin, CK Associates, at (225) 923-6925 or at james.durbin@c-ka.com .

Yours truly,

Greg Southworth

Greg Southworth
Associate Director
Offshore Operators Committee

Draft NPDES General Permit for New and Existing Sources in the Offshore Subcategory of the Oil and Gas Extraction Category for the Eastern Portion of the Outer Continental Shelf of the Gulf of Mexico (GEG460000)

GEG460000 August 18, 2016 Draft Renewal Permit, Public Notice No. 16 AL00001 – Offshore Operators Committee Comments

General Note – all permit text is shown in quotations. All suggested revisions to the proposed permit text are shown in red and ~~strikethroughs~~ within OOC's comments.

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
1	Notification Requirements (Existing Sources and New Sources)	Part I.A.4	"EPA will accept a written NOI until December 31, 2016. Beginning January 1, 2017 through the expiration date of this permit, all NOI must be submitted electronically. However, if the electronic NOI system is not operational by January 1, 2017, or at any time through the expiration date of this permit, EPA will accept a written NOI. Once the system becomes operational, an electronic NOI will need to be submitted. For an NOI submitted in writing, the effective date of coverage will be the postmarked date of the NOI, or if the postmarked date is illegible, the effective date of coverage will be two days prior to the receipt date of the NOI. Beginning January 1, 2017, the effective date of coverage submitted electronically will be the date of the request. EPA will notify the applicant within 21 days of the receipt date regarding the new permit coverage number(s) and effective date of permit coverage. If an NOI is determined to be incomplete, EPA will notify the applicant within 21 days of receipt of the NOI regarding any discrepancies, and or possible termination of coverage. Information regarding electronic submittals of NOIs is contained in Part III of this permit."	OOC requests additional language be added to text. EPA is proposing to require electronic Notice of Intent and Termination Forms and Discharge Monitoring Reports be in use as of January 1, 2017. While OOC understands the Region's push to go electronic for all reporting a deadline of 12/31/2016 to end all paper submittals seems unrealistic. Currently Region IV requires 22 points of data for each eNOI, the current system in use in Region VI requires half as many if Cooling Water Intake is included. It does not seem feasible that a revamped form can be coded by the Government contractors correctly in less than 6 months, not to mention the expense of computer system updates. Requiring paper NOIs at the time of permit issuance and then electronically by the end of the year would mean double work for both the Agency and permittees. Also, it is unclear how written NOIs submitted prior to December 31, 2016 will be available for reporting in the NetDMR system.
2	Electronic Reporting	Part III.A	"Electronic Reporting. Due to the e-reporting regulations which require electronic submittal of NPDES reports and forms, EPA will accept but not process any written NOI after December 31, 2016. Upon availability, but no later than January 1, 2017, permittees will be able to electronically submit NOIs and NOTs via the eNOI system ~~and NOTs via email~~. However, if the electronic eNOI system is not operational by January 1, 2017, or at any time through the expiration date of this permit, EPA will accept a written NOI and NOT. Once the system becomes operational, an electronic NOI NOT will need to be submitted. Additionally, DMRs must be submitted via the Network Discharge Monitoring Report (NetDMR) tool. If the NetDMR tool is not operational by January 2017 or at any time through the expiration date of this permit, a Certification Letter can be submitted in lieu of the electronic copy. The postmark on the Certification Letter on or before the DMR due date would demonstrate timely reporting was attempted while the system is down. Once the NetDMR tool becomes operational, an electronic DMR will need to be submitted. Once finalized, instructions for all electronic submittals will be posted on EPA website at http://www.epa.gov/aboutepa/about-epa-region-4-southeast	1. OOC is requesting that rather than duplicate work by submitting both paper and electronic DMRs for a quarter where the system is unavailable, a Certification Letter be acceptable. The Certification Letter would contain the permit certification statement and a list of Permitted Feature ID numbers for which reporting is required for that quarter. A paper DMR will not be submitted. Once the NetDMR tool is available, the electronic DMR will be submitted. 2. OOC requests the opportunity to have input during the NetDMR development process to share lessons learned from Region VI since 2012. Our past experience has been that the longer the eNOI system and NetDMR tool can be BETA tested, the more likely an efficient and correct outcome. Region VI is still waiting for funds to make corrections that were noted in 2012 when the NetDMR tool was tested and other changes that have been identified during the last four years. Time is also needed for the Agency to compile a detailed set of DMR Instructions to avoid the misapplication of NODI codes and reporting discrepancies experienced in Region VI. The lack of instructions has caused confusion for operators and BSEE inspectors. 3. OOC requests the ability to BETA test the eNOI system and NetDMR tool before the systems are rolled out for final use. 4. OOC requests that a copy of instructions be provided for NetDMR and NODI Codes.

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
			Until such time, signed copies of these and all other reports required by Part II.D. shall be submitted to the following address: Director Water Protection Division U.S. EPA Region 4 Sam Nunn Atlanta Federal Center 61 Forsyth Street, S.W. Atlanta, GA 30303-8960"	5. OOC requests that NOIs should go through the electronic reporting system and not e-mail. This will ensure consistency with all other electronic reporting requirements. When using e-mails as a way to file electronic submissions, they can be deleted or misplaced which could lead to enforcement for missing DMR reporting deadlines. 6. OOC requests EPA align the dates for accepting written NOI submittal between parts I.A.4 (December 31, 2016) and III.A (December 16, 2016)
3	Monitoring Reports	Part III.A	"Monitoring Reports" "Monitoring results obtained for each 3-month period (i.e., quarter), starting with the first month of coverage under this permit, shall be summarized for that timeframe and reported on either a DMR form (EPA No. 3320-1) or optional EPA Region 4 approved form, and shall be postmarked no later than ~~the 28th day of the month~~ 60 days following the completed quarterly period. For example, for coverage beginning on January 1, data for January 1 to March 31 shall be submitted by ~~April 28th~~ May 30th"	The OOC requests that EPA provide a 60 day submittal for Quarterly DMRs. Currently the permit allows for submittal of DMR's 28 days after the Quarter ends. There is a large amount of data that must go through QA/QC before the data can be inputted into NetDMR and once populated the Industry must review for correctness. There are multiple Companies and Consultants that have to submit **between 2,500 and 4,000 DMRs a quarter between Region 4 and Region 6**. The extension of 60 days from 30 days will allow the industry to populate NetDMR with quality data.
4	Notification Requirements (Existing Sources and New Sources)	Part I.A.4.u	u. Information on the identity, as listed on the applicable SDS, and concentration of each ~~specific~~ chemical ~~composition~~ constituent, intentionally added to the well treatment, completion of work over fluid ~~of any additives~~ currently being used and discharged or proposed for use and discharge in well treatment, completion or workover operations ~~or as biocides for sump drain systems~~. If the information on the additive is not known at the time of the submittal of this NOI, operators shall include the information in a report that shall be submitted on to EPA Region 4 on September 30th of each year or with the alternative study report of Part I.B.6.b. If an operator participates in the alternative study, then annual information submittal is not required. Operators may submit this information marked as "Confidential Business Information" or other suitable form of notice or may have service providers independently submit this information marked as such if necessary. The information so marked shall be treated as information subject to a business confidentiality claim pursuant to 40 CFR Part 2. Aside from submitting this information with the NOI, this information is also required to be recorded and retained on site for no less than five years from the issuance date of the permit, except for Confidential Business Information which may be maintained securely offsite by the operator or relevant service provider, for no less than five years from the issuance date of the permit. See Part I.B.6.a.iii.	OOC requests this revision to provide clarity, alignment and consistency with GMG290000 (Part I.B.12) permit requirements. Additionally, OOC requests changes to include language that an operator is not required to submit annual information if the operator is participating in the Part I.B.6.b. alternative study; which would include this information and for alignment with Part I.B.6 of the permit for discharges. Also, OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives. Additionally, OOC requests that the disclosure requirement allow for the use of a "systems-style" disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications), consistent with the approach that has been adopted for use in certain jurisdictions and by FracFocus. System-style disclosure would satisfy the objectives of the permit revision while potentially reducing the necessity for companies to make confidential business information claims on such disclosures. The process known as system-style disclosure lists all known chemical constituents in a fluid (or fluids, in the case of multiple disclosed applications), but decouples those constituents from their parent additives, thus improving protection of the proprietary chemistry used in hydraulic fracturing while promoting greater disclosure. At the same time, reverse engineering of product formulas may still be possible with the use of a systems-style displosure. A chemist or chemical engineer who knows the industry and the well treatment process will be familiar with the types of chemicals (usually a limited number) that have typically been used in a particular type of additive. The chemist or chemical engineer will be able to determine in most cases what role each chemical in the list plays in the overall product formulation and would be able to identify the ingredients included in the proprietary product. The chemist or chemical engineer will also be able to determine the general proportions that each ingredient would constitute of the whole (again with assistance from information on the product's Safety Data Sheet which include additional concentration information for various hazardous ingredients). Therefore, in order to protect the substantial investment of time and resources in developing proprietary products, it is

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
				critical that operators and service companies have the ability to protect proprietary information as Confidential Business Information even when using a systems-style approach. Also, OOC requests that service providers be permitted to disclose the trade secret CBI information directly to EPA rather than requiring disclosure through the operators. Such independent disclosure is necessary in order to protect the substantial investment of time and resources that service providers make in developing proprietary products. Chemical additives play a critical role in the safety, efficiency and productivity of offshore wells, and access to newly-developed, ever-improving chemicals – be they "greener," more efficient or more effective – is in turn critical to continued improvements in offshore operations. Lastly, OOC requests deletion of the information requirement for biocide. From the below information and SDS, the small amount of biocides used in sump drain systems will have a minimal risk to the environment and it does not warrant reporting in the NOI or in an annual report (Note that GMG 290000 does not require this reporting). a) Biocide Fate in Drain Sump Systems: The most common types of biocides used in the OCS for drain sump treatment are: Gluteraldehyde (GLUT) and Tetrakis hydroxymethyl phosphonium sulfate (THPS). Dosage and frequency of use ranges from infrequent, small volumes to weekly dosing at 5-20 gallons into either drains or the skim pile or associated pre-sumps. The biocides are applied as aqueous solutions ranging from 20-100% concentrations. Note that low-hydrocarbon potential drains (e.g. from non-process areas) would not typically be treated with biocide. It is important to recognize that treatment with biocide does not equal direct discharge of biocide to the environment. Because these systems are intermittent in flow and oxygenated, the biocide will adhere to pipe walls, reside in low points and pre-sumps, collect at the top of the skim piles all while undergoing oxidation and dilution. If sufficient water is routed to the system (e.g. a rain) then it will be diluted further before migration into the sea. Along the way, biocides will react with their intended target, bacterial growth, so only residual amounts of unreacted biocide may be discharged. For systems with skim piles, these piles typically reach well into the water column (20-90 feet is typical depending on water depth, with depths up to 200' below sea level for facilities located in deeper water) and communicate with the sea primarily via wave and tide forces (versus intermittent bulk flow of water through the pile such as during rain events). The MMS (Feb 2001) developed profiles number 4, 5 and 6 (pgs. 163-182) for three biocides including evaluation of fate and effect in the marine environment. The information presented in the MMS report is extensive and so not repeated here. However, of note the report included evaluation of spills and available toxicological information and risk characterization. OOC notes that these spill models are representative (in fact conservative representations) of the intermittent discharges that could occur from periodic biocide treatments. The MMS evaluated spills of 500 gallons of 20-25% solutions of these biocides. The resultant risk was characterized as low (modeled concentrations were below toxicological effect levels). As noted above, biocide treatments of drains sump systems are usually treated with 5-20 gallons at a time, therefore the risk associated with offshore treatment of drain sumps systems would be reasonably even lower than MMS determined. The MMS further found that GLUT and THPS are not expected to

Comment No.	Type/Category	Permit Section Ref	Revised Permit Wording	Comment/Rationale
				persist in the marine environment (chemical degradation rates were relatively rapid and both chemicals are biodegradable). THPS specific information. (EPA 2011 and MMS 2001). At pH above 8 (basic conditions), THPS degrades within 7 days. The degradation products have been identified as trishydroxymethyl phosphine (THP) and subsequently trishydroxymethyl phosphine oxide (THPO). An open literature study also shows that THPS degrades in artificial seawater (ph 7.9) with a half-life of 6 days. MMS 2001 states that THPS degrades to the less toxic THPO with a half-life of about 6 hours. EPA's EPI Suite model indicates that THPS is easily biodegradable (fast biodegradability); ultimate biodegradability is fast as well. Primary biodegradation half-life is estimated at hours days. Its estimated Log Kow varies from -4.42 to -20.39; it is not likely to bioaccumulate in aquatic organisms. Gluteraldehyde specific information. (EPA 2007 and MMS 2001). When glutaraldehyde is introduced into the environment, it is most likely to remain in the aquatic compartment, given the small air water partition and soil water partition coefficients. Aquatic metabolism, under aerobic and anaerobic conditions, is a major route of dissipation of glutaraldehyde. Glutaraldehyde was more than 30% biodegraded in less than 5 days in a standard BOD (Biological Oxygen Demand) test. Glutaraldehyde meets the (Organization for Economic Cooperation and Development) OECD criteria for classification as readily biodegradable in freshwater environments and as having the potential to be biodegradable in marine environments. In addition, the metabolism of glutaraldehyde is rapid and proceeds via the formation of glutaric acid as an intermediate to complete mineralization. Because of its biodegradation, glutaraldehyde is not likely to contaminate surface and ground waters. Summary. Biocides are necessary for the sump drain systems to meet the proper operation and maintenance requirements (over and above other cleaning options) of BOEM regulations and the NPDES permit, prevent permit noncompliances, present minimal risk to the marine environment and are not practical for sampling. References MMS, 2001 Deepwater Program: Literature Review Environmental Risks of Chemical Products Used in Gulf of Mexico Deepwater Oil and Gas Operations EPA 2011. Tetrakis (Hydroxymethyl) Phosphonium Sulfate (THPS) Summary Document: Registration Review. Docket # EPA-HQ-OPP-2011-0067 EPA 2007, Reregistration Eligibility Decision for Glutaraldehyde, EPA 739-R-07-006 Attachment A.pdf Attachment B.pdf

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
5	Drilling Fluids - Monitoring	Part II.B.1.c.i	"i. Drilling Fluids Inventory. The permittee shall maintain ~~a precise chemical usage record of all constituents and their total volume and mass added for each well.~~ information on the identity, as listed on the applicable SDS, and concentration of each chemical constituent intentionally added to the drilling fluids. Information shall be recorded and retained for the term of the permit, except for Confidential Business Information which may be maintained securely offsite by the operator or relevant service provider."	OOC requests this change for consistency and alignment with Part I.A.4.u, Part I.B.6.a.iii, and Part II.C.5 of the permit. Also, consistent with the above-referenced comments, OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives. Additionally, consistent with comments to Part I.A.4.u, OOC requests that the disclosure requirement be for composite chemical composition of all additives in the drilling fluids so as to conform to the system-style disclosure that has been adopted for use in many jurisdictions, including by the U.S. Department of Interior, and by FracFocus. System-style disclosure would satisfy the objectives of the permit revision while reducing the necessity for companies to make confidential business information claims on such disclosures. The process known as system-style disclosure lists all known chemical constituents in a fluid, but decouples those constituents from their parent additives, thus improving protection of the proprietary chemistry used in the application while promoting greater disclosure.
6.	Monitoring Reports and Permit Modification	Part III.A	**Part III. Monitoring Reports and Permit Modification** **A. Monitoring Reports** The operator shall be responsible for submitting monitoring results for each permitted facility (e.g., well) within the lease block. If there is more than one type of wastewater for each well, the discharge outfalls shall be designated in the following manner: 001 for Water-based Drilling Fluids 002 for Water-based Drill Cuttings 003 for Synthetic-based Drill Cuttings 004 for Produced Water 005 for Deck Drainage 006 for Well Treatment, Completion, and Workover Fluids ~~007 for Completion Fluids~~ ~~008 for Workover Fluids~~ ~~009~~ 007for Sanitary Discharges ~~010~~ 008 for Domestic Waste Discharges ~~011~~ 009 for Miscellaneous Discharges ~~012~~ 010 for Miscellaneous Discharges in Which Chemicals Have Been Added ~~013~~ 011 for Status Updates for Required Studies and Plans ~~014~~ 012 Process water generated from the Monoethylene glycol reclamation process and discharged separately from produced water via outfall 004 Monitoring results obtained for each 3-month period (i.e., quarter), starting with the first month of coverage under this permit, shall be summarized for that timeframe and reported on either a DMR form (EPA No. 3320-1) or optional EPA Region 4 approved form, and shall be postmarked no later than the 28th day of the second month following the completed quarterly period. For example, for coverage beginning on January 1, data for January 1 to March 31 shall be submitted by ~~April~~ May 28th. If the NetDMR tool is unavailable during the month when DMRs are due, the DMR will become	1. OOC is requesting that Treatment, Completion, and Workover Fluids Outfalls be combined into a single outfall as it is under the current permit. There is no reason to separate these outfalls. TCW reporting requirements will provide detailed information on each discharge. 2. OOC is requesting an extension of the DMR reporting due date from the 28th day of the first month after the Quarter ends to the second month. Allowing OOC members more time to QA/QC the documents will ensure accurate information is reported to the EPA. The permit language already requires that notification to EPA be made within 24 hours for any noncompliance which may endanger health or the environment (Section D, Reporting Requirements). As per anti-backsliding, the OOC is not requesting a revision of technology based limitations, effluent limitations based on state treatment or changes to water quality standards, this request is based on reporting submittals. 3. OOC also requests that language be added to the permit addressing longer term issues (e.g. a Government Shutdown) where there is the possibly of a longer period of system unavailability (longer than a system refresh or update) and requests a grace period of 60 days from the date the system is back up and functioning.

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
			due 60 days following the completed quarterly period. A further extension of 60 days can be granted by the EPA Region IV Enforcement Branch in the case where the system remains shutdown. If a failure of any permit limitation occurs, the permittee must report the incidents to the EPA Director, or their designated representative, orally within 24 hours and file a written report with the Director in accordance with the requirements in 40 C.F.R. Part 122.	
7.	Drilling Fluids - Limitations	Section I.B.1.F	"…Analysis for cadmium shall be conducted using EPA methods 200.7, 200.8, or EPA method 3050 B followed by 6010B or 6020, or more recently approved methods and the results expressed as mg kg (dry weight) of stock barite. Analyses for mercury shall be conducted using EPA Method 245.5 Method 7471 A, or more recently approved methods and the results expressed in mg kg (dry weight) of stock barite."	OOC is requesting this change for consistency and alignment with GMG290000 where new methods are approved during the permit term. Ref: Final permit decision and response to comments received on the draft reissued NPDES permit publicly noticed in the Federal Register on March 7, 2012 Date: September 28, 2012
8.	Well Treatment, Completion and Workover Fluids Priority Pollutants	Part I.B.6.a.iii	"….Information on the ~~specific chemical composition of any additives~~ identity, as listed on the applicable SDS, and concentration of each chemical constituent intentionally added to the well treatment, completion, or workover fluid currently being used and discharged in well treatment, completion or workover operations including fluids containing priority pollutants, shall be recorded and submitted as part of the NOI (see part I.A.4.u). Any updated information regarding chemical composition of new formulations that contain priority pollutants and that will be used and discharged shall be submitted to EPA Region 4 annually no later than September 30th. Operators may submit this information marked as "Confidential Business Information" or other suitable form of notice or may have service providers independently submit this information marked as such, if necessary. The information so marked shall be treated as information subject to a business confidentiality claim pursuant to 40 CFR Part 2. Except for Confidential Business Information which may be maintained securely offsite by the operator or relevant service provider, Gcopies of these records should also be kept on the rig while the rig is on the permitted location and thereafter at the permittee's shore base or office no less than five years from the issuance date of the permit. Records can be scanned and saved electronically, and electronic records are acceptable for an inspector's review. These record retention requirements supersede those found in Part II.C.5. of this permit."	OOC requests this change for consistency and alignment with Part I.A.4.u and Part II.C.5 of the permit. Also, consistent with comments to Part I.A.4.u, OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives. Additionally, consistent with comments to Part I.A.4.u, OOC requests that the disclosure requirement allows for the use of a systems-style disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications) consistent with the approach that has been adopted for use in some jurisdictions and by FracFocus. System-style disclosure would satisfy the objectives of the permit revision while potentially reducing the necessity for companies to make confidential business information claims on such disclosures. The process known as system-style disclosure lists all known chemical constituents in a fluid, but decouples those constituents from their parent additives, thus improving protection of the proprietary chemistry used in the applications while promoting greater disclosure. At the same time, in order to protect the substantial investment of time and resources in developing proprietary products, it is critical that operators and service companies have the ability to protect proprietary information as Confidential Business Information even when using a systems-style approach. Also, consistent with comments to Part I.A.4.u, OOC requests that service providers be permitted to disclose the trade secret CBI information directly to EPA rather than requiring disclosure through the operators. Such independent disclosure is necessary in order to protect the substantial investment of time and resources that service providers make in developing proprietary products. Chemical additives play a critical role in the safety, efficiency and productivity of offshore wells, and access to newly-developed, ever-improving chemicals – be they "greener," more efficient or more effective – is in turn critical to continued improvements in offshore operations.
9.	Well Treatment, Completion and Workover Fluids Monitoring	Part I.B.6.a.iv	"iv. Chronic Whole Effluent Toxicity for Well Treatment, Completion or Workover fluids. ~~Permittees~~ Permittees with discharges of well treatment fluids, completion or workover lasting four or more consecutive days must monitor and report the No Observable Effect Concentration (NOEC) relative	1. OOC requests that these requirements be moved to Part I.B.6.b to provide additional clarity that these are not limitations. The requirements shown under existing Part I.B.6.a.iv are monitoring only requirements.

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
	Requirements Industry Wide Study Alternative		to the predicted effluent concentration at the edge of a 100-meter mixing zone. A grab sample must be taken at least once per month when discharging. Predicted effluent concentrations, referred to as critical dilutions, are presented in Tables ~~3~~ 4 and 4 5 of Appendix ~~B~~ A for a range of discharge rates and pipe diameters. Permittees discharging well treatment wastewater at conditions other than those covered in Tables ~~3~~ 4 and 4 5 of Appendix A (e.g., at a rate greater flows, pipe diameters, or discharge densities) shall determine the critical dilution using the appropriate CORMIX model with the input parameters shown below. Permittees shall retain the model runs as part of the NPDES records. The critical dilution shall be determined using the CORMIX model using the highest daily average discharge rate for the three days prior to the day in which the test sample is collected, the discharge pipe diameter, the measured or calculated discharge density, and the depth difference between the discharge pipe and the sea bottom. Input Parameters: Density Gradient = 0.163 kg/m³/m Ambient seawater density = 1023.0 kg/m³ ~~Well Treatment wastewater density = 1030.0 – 1680.0 kg/m³~~ ~~Completion and workover fluids = 1030.0 – 1680.0 kg/m³~~ Current speed = 5 cm/sec (< 200 m water depth); 15 cm/sec (> 200 m water depth) The NOEC shall be calculated by conducting 7-day chronic toxicity tests in accordance with methods published in *Short Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Water to Marine and Estuarine Organisms* (EPA 821-R-02-014), or most current edition. The results for both species shall be reported on the DMR. See Part V.A.15.b of this permit for Whole Effluent Toxicity Testing Requirements. Samples must be taken at the nearest accessible location prior to discharge. All modeling runs shall be retained by the permittee as part of its NPDES records."	2. OOC requests EPA verify the meaning of the language "lasting four or more consecutive days". A plain reading indicates this means a discharge to the ocean that is continuous over 24 hours per day and over four or more days. Our members however felt there was room for different interpretations and so want to be sure of EPA's intent is the above plain reading. 3. To clarify sample frequency, OOC requests EPA adopt a frequency of monthly. Mandating a sampling frequency of monthly ensures toxicity testing is completed at various stages through-out the well job (and is identical to monthly oil and grease sampling frequency). 4. OOC requests the noted Table reference corrections be incorporated into the permit. 5. OOC requests adding "or calculated" to allow operators the flexibility to calculate discharge densities based on the average of all the fluids planned to be discharged. Discharge densities can vary throughout the discharge. Being able to calculate a discharge density will allow operators to run CORMIX prior to the discharge to calculate the critical dilution factor. This will allow operators to identify the size of sample containers needed to obtain the appropriate volume of sample needed to run the toxicity test. 6. OOC requests removing the density ranges for well treatment, completion, and workover fluids as the proposed ranges may not cover the full range of densities of these types of fluids used. As EPA stipulates that the operator must use the discharge density, the range is not necessary and could unduly limit the operator. 7. OOC requests EPA consider requiring acute toxicity testing in lieu of chronic toxicity testing. An acute toxicity test based on an appropriate acute to chronic ratio is considered an equivalent test to a chronic toxicity test. A ten to one acute to chronic ratio is the normal ratio for most industrial effluents and has been used in other NPDES permits where the effluent is highly diluted in the receiving stream and an acute test is required in place of a chronic test. In addition, the acute test is less burdensome to permittees because it is less costly than a chronic test and because the acute test will be run on less dilute effluent there is less chance for laboratory error. Consistently requiring a monthly acute toxicity test, regardless of well job duration, will simplify sample planning and eliminate the need to pull an additional sample in well jobs that exceed four days duration unexpectedly.
10	Well Treatment Completion and Workover Fluids Monitoring Requirements Industry Wide Study Alternative	Part I.B.6.a.x	"x) Acute Whole Effluent Toxicity Testing for Well Treatment, Completion or Workover Fluids - The following Acute Whole Effluent Testing requirements apply to discharges of well treatment fluids that last less than 4 days. A grab sample must be taken at least once per month when discharging. Permittees must monitor and report the acute critical dilution (ACD) at the edge of a 100 meter mixing zone. The ACD is defined as 1.0 times the LC₅₀. The ACD and the predicted effluent concentration at the edge of a 100 meter mixing zone must be reported on the DMR. Predicted effluent concentrations, referred to as "critical dilutions," are presented in Tables 3 4	1. OOC requests that these requirements be moved to Part I.B.6.b to provide additional clarity that these are not limitations. The requirements under Part I.B.6.a.x are monitoring only requirements. 2. OOC requests EPA add clarifying text as shown for the less than four day toxicity test trigger. Often, a specific well job will last many days, and be sprinkled with short duration low volume discharges at various times through-out the job. Sampling every small, discrete discharge would be an excessive burden on offshore Operators logistically. To balance this- similar to OOC's recommendation for ≥ 4 day discharges- OOC requests mandating a sampling frequency of monthly. This ensures acute toxicity testing is completed at various stages through-out the job (identical to monthly oil and grease sampling frequency).

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
			and ~~4~~ 5 of Appendix A for a range of discharge rates and pipe diameters. Critical dilution shall be determined using Tables ~~3~~ 4 and ~~4~~ 5 of this permit based on the most recent discharge rate, discharge pipe diameter, and water depth between the discharge pipe and the ocean bottom. LC$_{50}$ shall be calculated by conducting 48-hour, non static renewal, toxicity tests once per discharge using *Mysidopsis bahia* and *Menidia beryllina* (Inland silverside minnow). Additional acute toxicity testing requirements are contained in Part V.A.15.c of this permit. Permittees discharging well treatment wastewater at conditions other than those covered in Tables ~~3~~ 4 and ~~4~~ 5 of Appendix A (e.g., at a rate greater flows, pipe diameters, or discharge densities) shall determine the critical dilution using the appropriate CORMIX model with the input parameters shown below. Permittees shall retain the model runs as part of the NPDES records. The critical dilution shall be determined using the CORMIX model using the highest daily average discharge rate for the three days prior to the day in which the test sample is collected, the discharge pipe diameter, the measured or calculated discharge density, and the depth difference between the discharge pipe and the sea bottom. Input Parameters: Density Gradient 0.163 kg m^3 m Ambient seawater density 1023.0 kg m^3 ~~Well Treatment wastewater density – 1030.0 1680.0 kg m3~~ ~~Completion and workover fluids – 1070.0 1680.0 kg m3~~ Current speed 5 cm sec (200 m water depth), 15 cm sec (200 m water depth) Permittees shall retain the model runs as part of the NPDES records. Samples for the acute WET tests shall be obtained at the nearest accessible point after final treatment and prior to discharge to surface waters."	3. OOC requests the noted Table reference corrections be incorporated into the permit 4. OOC requests adding "or calculated" to allow operators the flexibility to calculate discharge densities based on the average of all the fluids planned to be discharged. Discharge densities can vary throughout the discharge. See additional rationale above. 5. OOC requests removing the density ranges for well treatment, completion, and workover fluids as the proposed ranges may not cover the full range of densities of these types of fluids used. As EPA stipulates that the operator must use the discharge density, the range is not necessary and could unduly limit the operator.
11.	Well Treatment, Completion and Workover Fluids Monitoring Requirements Industry Wide Study Alternative	Part I.B.6.b	"Well Treatment Completion and Workover Reporting Requirements. Operators of leases where well treatment, completion, or workover fluids are discharged shall collect and report the information listed below. This information shall be reported with the discharged monitoring report for the quarter in which the discharge is made. If discharges commence in one	OOC requests updating the references for "additional toxicity testing requirements" to be consistent with proposed changes. Also, consistent with comments to Part I.A.4.a, OOC requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. Proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives.

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
			quarter and cease in the following quarter, reporting should be done in the later quarter. For each well in which operations are conducted that result in the discharge of well treatment, completion, or workover fluids the following shall be reported with the discharge monitoring report for the quarter in which the activity is done: • Lease and block number • API well number • Type of well treatment or workover operation conducted • Date of discharge • Time discharge commenced • Duration of discharge • Volume of well treatment • Volume of completion or workover fluids used • The identity, as listed on the applicable SDS, and concentration of each chemical constituent intentionally added to the well treatment, completion, or workover fluid used ~~• The volume of each additive~~ ~~• Concentration of all additives in the well treatment~~ ~~• Concentration of all additives in the completion, or workover fluid~~ • Results of Whole Effluent Toxicity (WET) tests for well treatment fluids discharged separately from the produced water discharge. Additional toxicity testing requirements are contained in Part V.A.15.b and Part V.A.15.c of this permit. Information collected for this reporting requirement shall be submitted as an attachment to the DMR or in an alternative format requested by the operator and approved by EPA Region 4. Operators may submit this information marked as "Confidential Business Information" or other suitable form of notice or may have service providers independently submit this information marked as such, if necessary. The information so marked shall be treated as	Additionally, consistent with comments to Part I.A.4.u, OOC requests that the disclosure requirement allow for the use of a systems-style disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications) consistent with the approach that has been adopted for use in some jurisdictions and by FracFocus. System-style disclosure would satisfy the objectives of the permit revision while potentially reducing the necessity for companies to make confidential business information claims on such disclosures. The process known as system-style disclosure lists all known chemical constituents in a fluid (or fluids, in the case of multiple disclosed applications), but decouples those constituents from their parent additives, thus improving protection of the proprietary chemistry used in the applications while promoting greater disclosure. At the same time, in order to protect the substantial investment of time and resources in developing proprietary products, it is critical that operators and service companies have the ability to protect proprietary information as Confidential Business Information even when using a systems-style approach. Also, consistent with comments to Part I.A.4.u, OOC requests that service providers be permitted to disclose the trade secret CBI information directly to EPA rather than requiring disclosure through the operators. Such independent disclosure is necessary in order to protect the substantial investment of time and resources that service providers make in developing proprietary products. Chemical additives play a critical role in the safety, efficiency and productivity of offshore wells, and access to newly-developed, ever-improving chemicals – be they "greener," more efficient or more effective – is in turn critical to continued improvements in offshore operations. Without these changes, this proposed requirement creates challenges for companies that may manufacture products which contain proprietary components or trade secrets. Companies with trade secrets could experience significant negative economic impacts if a proprietary additive was "reverse engineered" based on information submitted to EPA as part of this requirement. The Occupational Safety and Health Administration (OSHA) has addressed similar challenges in its Hazard Communication requirements. Specifically, OSHA has provided criteria that allow manufacturers to deem a chemical component as a "trade secret" on a Safety Data Sheet (SDS) (see 29 CFR 1910.1200(i)). Under the OSHA Hazard Communication requirements, a proprietary chemical component that has been designated as a trade secret is listed on the SDS in a generic manner, such "Proprietary Component A." Given the above, OOC is requesting that EPA Region 4 incorporate the OSHA Hazard Communication trade secret criteria by reference in the proposed GEG460000 permit. Under this proposed change, EPA Region 4 would still have access to information that priority pollutants are present or not in a particular additive, and the proprietary nature of certain additives would be protected. This added language would also bring the two regulatory programs into alignment, making compliance straightforward and consistent. If a specific identity of a chemical compound can be obscured on an SDS while still communicating sufficient information to ensure the safe handling, use and disposal of the chemical compound, then it is reasonable to allow it to be withheld from the reporting of fluid discharges wherein the chemical compound is greatly diluted. This approach aligns with the disclosure of hydraulic fracturing chemicals used in the onshore oil and gas industry. The FracFocus Chemical Disclosure Registry (www.fracfocus.org) allows chemicals in the registry to be designated as proprietary if the chemical has been determined to meet the OSHA trade secret criteria.

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
			information subject to a business confidentiality claim pursuant to 40 CFR Part 2.	
12.	Well Treatment, Completion and Workover Fluids Monitoring Requirements Industry Wide Study Alternative	Part I.B.6.b	"Industry-Wide Study Alternative Alternatively, operators who discharge well treatment, completion, and/or workover fluids may participate in an EPA-approved industry-wide study as an alternative to conducting monitoring of the fluids characteristic and reporting information on the associated operations. That study would, at a minimum, provide a characterization of well treatment, completion, and workover fluids used in a representative number of ~~active~~ wells discharging well treatment, completion, and/or workover fluids ~~of varying depths (shallow, medium depth and deep depths)~~. In addition, an approved industry-wide study would be expected to provide greater detail on the characteristics of the resulting discharges, including their chemical composition and the variability of the chemical composition and toxicity. The study area should include a statistical valid number of samples of wells located in the Eastern Gulf of Mexico (GOM) and may include the Western and Central Areas of the GOM under the permitting jurisdiction of EPA Region 6, and operators may join the study after the start of and completion of the study~~date~~. The study plan should also include interim dates milestones. A plan for an industry- wide study would be required to be submitted to EPA Region 4 for approval within six months after the effective date of this permit. Once a permittee has committed financially to participate in the approved study it shall constitute compliance with the monitoring and reporting requirements of Part I.B.6.b. If the Region does not approve the study plan or a permittee does not sign up to participate in the study, compliance with all the monitoring and reporting requirements for well treatment, completion and workover fluids is required. ~~If the Region approves an equivalent industry-wide well treatment fluids discharge monitoring study, the monitoring conducted under that study shall constitute compliance with those monitoring requirements for permittees who participate in such the industry-wide study.~~ Once approved, the study plan will become an enforceable part of this permit. The study must commence within six months of EPA's approval. ~~If the Region does not approve the study plan or if a permittee does not participate in the study, compliance with all the monitoring requirements for well, completion, and workover fluid is required (see above).~~ The final study report must be submitted no later than three years from the effective date of this permit."	1. OOC is requesting that "active" be struck. It is unclear what is intended by "active", and could, for instance, unintentionally exclude well jobs associated with initial completion and with abandonment. It is enough to simply reference well jobs where TCW fluids will be discharged. 2. OOC requests striking "of varying depths (shallow, medium depth and deep depths)" and replacing simply with "discharging well treatment, completion, and/or workover fluids fluids" The number of wells discharging TCW fluids in Region IV by members of OOC is small, due to few wells in, and limited development plans for, the Region. Even using wells from Region VI, to ensure adequate numbers of samples, all wells would probably have to be sampled as the jobs arise to ensure compliance with the three year study window. In other words, the Study Operators wouldn't have the luxury per se of picking and choosing well discharges to sample.* Therefore, specifying varying depths overly constrains the study from the start. Additionally, it's unclear what EPA means by this term (is it water depth, well depth to reservoir, discharge depth?) * This is the same approach EPA approved for the recent WBM dissolved metals study i.e. sampling the WBM as each drilling job came along. 3. OOC is requesting changes to the permit language to clarify that a financial commitment to participate in the Industry-Wide Study Alternative satisfies the chronic and acute monitoring requirements and the Well Treatment, Completion, and Workover Reporting Requirements of the permit, and ensure consistency with prior approved industry studies. Further, the change allows the option for new permittees to benefit from the industry-wide study after initiation and completion of the study.
13.	Well Treatment, Completion and Workover Fluids Monitoring Requirements	Part V.A.15.a	(a) The following Chronic Whole Effluent Toxicity testing requirements apply to: 1) Produced Water Discharges; ~~2) Well Treatment, Well Completion or Well Workover Fluid Discharges lasting four or more days~~; 2) Miscellaneous Discharges of Seawater and Freshwater to which chemicals have been added; and 3) Chemicals used in subsea operations, including but not limited to, Subsea Wellhead Preservation Fluids, Subsea Production	There are some requirements in this section that are not relevant to Well Treatment, Well Completion, or Well Workover Fluid Discharges lasting four or more days. OOC recommends removing Well Treatment, Well Completion, or Well Workover Fluid Discharges lasting four or more days from this section of the permit and adding a section specific to this type of discharge to ensure clarity, as presented in this table (the next line item below).

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
	Industry Wide Study Alternative		Control fluids, Umbilical Steel Tube Storage Fluid, Leak Tracer Fluids and Riser Tensioner Fluids	
14.	Well Treatment, Completion and Workover Fluids Monitoring Requirements Industry Wide Study Alternative	Part V.A.15.b (New Section)	(b) The following Chronic Whole Effluent Toxicity testing requirements apply to Well Treatment, Well Completion or Well Workover Fluid Discharges lasting four or more days. The control and dilution water will be natural or synthetic seawater at 25 ppt salinity as described in EPA-821-R-02-014, Section 7, or the most current edition. A standard reference toxicant quality assurance chronic toxicity test shall be conducted concurrently with each species used in the toxicity tests and the results included in summary laboratory report, which is to be submitted with the DMR. Alternatively, if monthly QA/QC reference toxicant tests are conducted, these results must be included in the summary laboratory report. The permittee shall submit a full laboratory report upon specific request of EPA or as agreed to in the study. Any deviation from the bioassay procedures outlined or cited herein shall be submitted in writing to the EPA for review and approval prior to use. i. The permittee shall conduct a mysid, *Mysidopsis bahia*, Survival and Reproduction test and an Inland silverside minnow, *Menidia beryllina*, Larval Survival and Growth test. All tests shall be conducted using a control (0% effluent) and the following dilution concentrations: 0.25 times the critical dilution (CD), 0.5 times the CD, the CD, two times the CD and, four times the CD. The measured endpoints will be the survival and growth No Observed Effect Concentration (NOEC) concentration for each species. The survival and growth responses will be determined based on the number of *Mysidopsis bahia* or *Menidia beryllina* larvae used to initiate the test. ii. For each set of tests conducted, a grab sample of final effluent shall be collected and used to initiate the test within 36 hours of collection. iii. If control mortality exceeds 20% in any test, the test(s) with that species (including the control) shall be repeated if an additional sample can be obtained. For either species, a test will be considered valid only if control mortality does not exceed 20%. Each test must meet the test acceptability criteria for each species as defined in EPA-821-R-02-014, Section 13.12 for *Menidia beryllina* and Section 14.12 for *Mysidopsis bahia* or the most current edition. Additionally, all test results must be evaluated and reported for concentration-response relationship based on "Method Guidance and Recommendations for Whole Effluent Toxicity (WET) Testing (40 CFR Part 136)," EPA 821-B-00-004 (http://water.epa.gov/scitech/methods/cwa/wet/upload/2007_07_10_methods_wet_disk2_atx.pdf), or the most current edition. If the required concentration-response review fails to yield a valid relationship per EPA 821-B-00-004 (or the most current edition), that test shall be repeated if an additional sample can be obtained. Any test initiated but terminated prior to completion must be reported with a complete explanation for the termination. If the conditions of test acceptability are met as described above	As stated above, there are some requirements in Part V.A.15.a that are not applicable to the "monitoring only" requirements for Well Treatment, Well Completion or Well Workover Fluid Discharges lasting four or more days. OOC is proposing the addition of this new section to only capture the requirements from Part V.A.15.a applicable to "monitoring only". OOC has removed all language regarding permit violations. OOC is proposing to strike the DMR language requiring reporting pass/fail due to this being a monitoring only requirement. OOC has also added clarifying language to indicate that repeat samples for invalid test results are only required if the discharge is still occurring and the additional sample can be obtained. <u>Finally OOC requests</u> n not including a frequency for testing in this section. The frequency for testing has been addressed above under our comments for I.B.6 for well fluids. Additionally, the V.A.15.a.ii "standard" frequency requirements, if left in the permit, would conflict with Part I.B.6 -the former were written for PW and other routine discharges- to apply a recurring test frequency, and associated reduction criteria to "monitor only", short term, well specific fluid discharges is extremely confusing. The frequencies for this testing are adequately specified at I.B.6 (with OOC comments noted for that section above)

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
			and in Part V 15.4, and the percent survival of the test organism is equal to or greater than 80% in the critical dilution concentration and all lower dilution concentrations, the permittee shall report a survival NOEC of not less than the critical dilution in the DMR. The summary laboratory reports shall include, as a minimum, the following information: (1) Permittee's Name (2) Name of test and test method number (3) Name of test species (4) Outfall identification designation and type of wastewater (5) Name of biomonitoring laboratory (6) Date sample was collected (7) Date and time test initiated (8) Critical Dilution (9) Indicate if test is "valid." If not, state reasons why (10) For each species, the percent effluent corresponding to each NOEC for both the growth test and the survival test v. An NOEC of less than CD % effluent in any valid routine or additional definitive Survival or Growth test for either species will not be a violation of this permit. vi. This permit may be reopened to require chemical specific effluent limits, additional testing and or other appropriate actions to address toxicity	
15.	Well Treatment, Completion and Workover Fluids Monitoring Requirements Industry Wide Study Alternative	Part V.A.15.b	(b) The following Acute Whole Effluent Toxicity testing requirements apply to Well Treatment, Well Completion or Well Workover Fluid Discharges lasting less than four consecutive days. Acute toxicity shall be used to determine the concentration of effluent that results in mortality of the test organisms during a 48-hour exposure. The control and dilution water will be natural or synthetic seawater at 25 parts per thousand salinity as described in EPA's acute WET test methods (2002), "Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters to Freshwater and Marine Organisms. EPA-821-R-02-012 *(hereafter EPA's acute test methods)*, Section 7. (http: water.epa.gov scitech methods cwa wet upload 2007 07 10 methods wet disk2 atx.pdf) or the most current edition. A standard reference toxicant quality assurance acute toxicity test shall be conducted concurrently with each species used in the toxicity tests and the results included in summary laboratory report, which is to be submitted with the discharge monitoring report (DMR). Alternatively, if monthly quality assurance quality control (QA QC) reference toxicant tests are conducted, these results must be included in the summary laboratory report. The permittee shall submit a full laboratory report ~~in the event a failure occurs (WET test demonstrates toxicity that would result in an exceedance of a NPDES WET compliance level for any test, or~~ upon specific request of EPA	OOC is requesting to renumber this section and make changes to only capture the requirements applicable to "monitoring only". OOC has removed all language regarding permit violations. OOC is proposing to strike the DMR language requiring reporting pass fail due to this being a monitoring only requirement. OOC has also added clarifying language to indicate that repeat samples for invalid test results are only required if the discharge is still occurring and the additional sample can be obtained due to the short duration of the discharge. Finally OOC requests removing the language at V.A.15.b.ii as applied to TCW fluids. The frequency for testing has been addressed above under our comments for I.B.6 for well fluids. Additionally, the V.A.15.b.ii "standard" frequency requirements, if left in the permit, would conflict with Part I.B.6 - to apply a recurring test frequency, and associated reduction criteria to "monitor only", short term, well specific fluid discharges is extremely confusing. The frequencies for this testing are adequately specified at I.B.6 (with OOC comments noted for that section above).

.Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
			or as agreed to in the study. Any deviation from the EPA promulgated WET test methods (40 CFR Part 136) outlined or cited herein shall be submitted in writing to the EPA for review and approval prior to use. (i). The permittee shall conduct a mysid, *Mysidopsis bahia*, Lethality test and an Inland silverside minnow, *Menidia beryllina*, Lethality test, for the duration of a discharge of well treatment, well completion, or well workover fluids, based on an effluent grab sample. All tests shall be conducted using a control (0% effluent) and the following dilution concentrations: 0.25 times the critical dilution (CD), 0.5 times the CD, the CD, two times the CD and, four times the CD. The measured endpoints will be the survival and growth Lethal Concentration for 50% of the test organisms (LC_{50}) for each species. The endpoints will be determined based on a comparison of *Mysidopsis bahia* or *Menidia beryllina* responses in the control (0% effluent) and in each of the five dilutions. For each set of tests conducted, a grab sample of final effluent shall be collected and used to initiate the test within 36 hours of collection. If control mortality exceeds 10% in any test, the test(s) with that species (including the control) shall be repeated if an additional sample can be obtained. For either species, a test will be considered valid only if control mortality does not exceed 10%. Each WET test must meet the required EPA WET test method's Test Acceptability Criteria (TAC) for each species as defined in the EPA's acute WET test method, (2002) EPA-821-R-02-012, Section 9, or the most current edition. Additionally, all WET test results must be evaluated and reported for concentration-response relationship based on EPA's (2000) "Method Guidance and Recommendations for Whole Effluent Toxicity (WET) Testing (40 C.F.R. Part 136)," EPA 821 B-00 004 (http://water.epa.gov/scitech/methods/cwa/wet/upload/2007_07_10_methods_wet_wetguide.pdf) or the most current edition. If the recommended concentration-response review produces an inconsistent dose-response curve per EPA 821 B-00 004 (or the most current edition), the test is not considered an invalid test but should be repeated if an additional sample can be obtained. Any WET test initiated but terminated prior to completion must be reported with a complete explanation for the termination. If the requirements of EPA's WET test method's TAC are met as described above ~~and in Part V.15(b).4.~~, and the percent survival of the test organism is equal to or greater than 90% in the critical dilution concentration and all lower dilution concentrations, the ~~survival test shall be considered to be passing and the~~ permittee shall report a LC_{50} greater than the critical dilution in the DMR. ~~(ii) The permittee may reduce monitoring frequency to once per discharge for the duration of the permit for Well Treatment, Completion or Workover fluid discharges after two consecutive valid tests. These tests are referred to as "routine" tests.~~	

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
			Results from ~~routine~~ WET tests shall be reported according to EPA's acute WET test methods (2002), EPA-821-R-02-012, Section 12, or the most current edition. ~~All results shall also be recorded and submitted on the DMR in the following manner: If the LC_{50} of a test species is less than or equal to the CD% effluent, and enter "1" shall be entered on the DMR for that species. If the LC_{50} of a test species is greater than the CD% effluent, and "0" shall be entered on the DMR.~~ The summary laboratory reports shall include, as a minimum, the following information: (1) Permittee's Name (2) Name of WET test and EPA WET test method number (3) Name of WET test species (4) Outfall identification designation and type of wastewater (5) Name of biomonitoring laboratory (6) Date sample was collected (7) Date and time test initiated (8) Critical Dilution (9) Indicate if test is "valid." If not, state reasons why (i.e., what EPA WET test methods TAC not met). (10) For each species, the percent effluent corresponding to each LC_{50} for both the growth test and the survival test. (iii) An LC_{50} of less than or equal to the CD % effluent in any valid routine or additional definitive Survival or Growth WET test for either species will not be a violation of this permit. ~~If an LC_{50} of less than CD % effluent is found in a routine WET test, the permittee shall conduct two valid additional WET tests on each species indicating the violation and report each LC_{50} obtained. A valid additional definitive WET test result cannot be used to negate a permit violation based on failure of a routine WET test.~~ ~~The first valid additional WET test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 0.0625 times the CD, 0.125 times the CD, 0.25 times the CD, 0.5 times the CD and the CD. The dilution series may be modified in the second valid WET test to more accurately identify the toxicity endpoints.~~ ~~For each additional WET test, the sample collection requirements and the required EPA WET test method's TAC must be met and the recommended concentration-response relationships (i.e., dose response curve) specified in sections 1.b and c above, respectively, must be met for the additional WET test to be considered valid. The first additional WET test shall begin within one day of the end of the routine WET test failure, and shall be conducted every other day thereafter until two consecutive additional passing WET tests are completed.~~	

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
			~~Results from additional WET tests, required due to an acute toxicity violation in a routine WET test, shall be submitted in a single report prepared according to EPA's acute WET test methods (2002), EPA-821-R-02-012, Section 12, or the most current edition and submitted within 30 days of completion of the second valid additional test.~~ ~~After compliance is demonstrated for the two consecutive additional WET tests, the permittee may return to the testing frequency prior to the non-compliance.~~ (iv) This permit may be reopened to require chemical specific effluent limits, additional WET testing and or other appropriate actions to address toxicity.	
16.	Cooling Water Intake Structure	Part I.D.3.a Baseline Study Requirements	**a. Baseline Study Requirements** These baseline study requirements are effective one year after the effective date of this permit. Operators of new facilities must submit sufficient information to characterize the biological community of commercial, recreational, and forage base fish and shellfish in the vicinity of the intake structure and to characterize the effects of the cooling water intake structure's operation on aquatic life. This biological characterization must include any available existing information along with field studies to obtain localized data. At a minimum, the information must include: i. A list of the data required by this section that are not available and efforts made to identify sources of the data; ii. A list of species (or relevant taxa) for all life stages and their relative abundance in the vicinity of the cooling water intake structure; iii. Identification of the species and life stages that would be most susceptible to impingement and entrainment. Species evaluated should include the forage base as well as those most important in terms of significance to commercial and recreational fisheries; iv. Identification and evaluation of the primary period of reproduction, larval recruitment, and period of peak abundance for relevant taxa; v. Data representative of the seasonal and daily activities (e.g., feeding and water column migration) of biological organisms in the vicinity of the cooling water intake structure; vi. Identification of all threatened, endangered, and other protected species that might be susceptible to impingement and entrainment at the cooling water intake structures; vii. If the information above is supplemented with data from field studies, the supplemental data must include a description of all methods and quality assurance procedures for sampling and data analysis including a description of the study area; taxonomic identification of sampled and evaluated biological assemblages (including all life stages of fish and shellfish); and sampling and data analysis methods. The sampling and or data analysis methods you use must be appropriate for a quantitative survey and based on consideration of methods used in other biological studies performed within the same source water body. The study area should include, at a minimum, the area of influence of the cooling water intake structure.	OOC requests that the baseline study requirements be removed from the permit for operators that participate(d) in the 2012 industry-wide Source Water Biological Baseline Characterization Study (SWBBCS). This study was approved by US EPA Region IV on 2/27/12 (email documentation provided below and as Attachment C) SWBC Study Final.pdf

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
			Alternative to the baseline study requirements, operators may participate in the industry-wide Source Water Biological Baseline Characterization Study (SWBBCS) completed in 2012. Operators may opt to participate in the industry-wide study at any time.	
17.	Cooling Water Intake Structure	Part I.D.3.d.i-New non-Fixed Facilities	i. The operator must conduct either visual inspections or use remote monitoring devices (e.g., remotely operated vehicles (ROV), subsea cameras, or other monitoring device) during the period the cooling water intake structure is in operation. The operator must conduct visual inspections at least ~~weekly~~ monthly, or at a lesser frequency as approved by the Director, to ensure that the required design and construction technologies are maintained and operated so they continue to function as designed. Alternatively, the operator must inspect using remote monitoring devices to ensure that the impingement and entrainment technologies are functioning as designed.	OOC requests that visual inspections be required monthly. This request is backed by visual inspection data obtained in EPA Region VI. The observed rate of growth of biological material does not result in significant change over a one week period. Changes are hard to discern over a monthly period. For a deepwater facility(does not employ a sea chest) that performed entrainment monitoring under the EPA Region VI NPDES permit, the 2015 average monthly rate of growth expressed as "% screen coverage was 2.5% with a monthly range of 0-6% growth.
18.	Cooling Water Intake Structure	Part I.D.3.d.i-New Fixed Facilities that do not employ sea chests as intake structures	i. The operator must conduct either visual inspections or use remote monitoring devices (e.g., remotely operated vehicles (ROV), subsea cameras, or other monitoring device) during the period the cooling water intake structure is in operation. The operator must conduct visual inspections at least ~~weekly~~ monthly, or at a lesser frequency as approved by the Director, to ensure that the required design and construction technologies are maintained and operated so they continue to function as designed. Alternatively, the operator must inspect using remote monitoring devices to ensure that the impingement and entrainment technologies are functioning as designed.	OOC requests that visual inspections be required monthly. This request is backed by visual inspection data obtained in EPA Region VI. The observed rate of growth of biological material does not result in significant change over a one week period. Changes are hard to discern over a monthly period. For a deepwater facility(does not employ a sea chest) that performed entrainment monitorine under the EPA Region VI NPDES permit, the 2015 average monthly rate of growth expressed as "% screen coverage was 2.5% with a monthly range of 0-6% growth.
19.	Cooling Water Intake Structure	Part I.D.3.d.ii-New Fixed Facilities that do not employ sea chests as intake structures	ii. The operator must monitor for entrainment. The operator must collect samples to monitor entrainment rates (simple enumeration) for each species over a 24-hour period and no less than biweekly during the primary period of reproduction, larval recruitment, and peak abundance identified during the Source Water Baseline Biological Characterization Study. Representative species may be utilized for this monitoring consistent with their use in the Source Water Baseline Characterization Study. The operator must collect samples only when the cooling water intake structure is in operation. Alternative to the 2 year entrainment monitoring requirements, operators may participate in the industry-wide entrainment monitoring requirements completed in 2014. Operators may opt to participate in the industry-wide study at any time. After 24 months of monitoring, no further monitoring is required. Or alternate proposed language- After 24 months of monitoring the permittee may submit SEAMAP data annually to meet the requirements of 40CFR125.137. This report may be done in conjunction with other Operators subject to these requirements.	OOC strongly objects to the continued requirement to conduct ongoing entrainment monitoring (after initial two year biweekly sampling) OOC requests that the requirements for entrainment monitoring be removed from the permit for operators that participate(d) in the 2014 entrainment monitoring study. This request is further supported by EPA's own finding in the permit's Environmental Assessment, specifically, per section 6.2 of the Draft EA: "*EPA Region 4 has determined the study fulfills the requirements of the 2010 General Permit and demonstrated that cooling water intake structures on offshore oil and gas facilities have no significant impact on the selected species investigated.*" As the species studied were reliable indicators for overall entrainment, and given no species of concern were caught within the 60,376 individuals identified from 1,515 tows spread throughout the 24 month sampling period, the Agency has no basis to continue to require costly on platform monitoring at affected facilities. OOC is therefore petitioning the EPA per their proposed language to reduce monitoring frequency to "none required". Summarizing and amplifying information previously submitted, OOC suggests that Region IV accept the results of the 24 month entrainment monitoring study completed for Region VI as meeting, for the participating companies, the corresponding Region IV requirement. As alternative to ongoing monitoring at affected facilities, OOC suggests using the SEAMAP database to establish the seasonality of entrainment potential, as required by 40CFR125.137. Using the SEAMAP database for entrainment risk assessment is actually preferable to platform specific monitoring because: • Data are collected and maintained over the long term, using consistent methodology for all sites, ensuring comparability of data over time • The existing SEAMAP database already provides an assessment of seasonality of entrainment risk (as required by 40CFR125.137) which can be periodically updated as new data are added to detect changes in risk over time.

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
				- SEAMAP larval data could be selected for most common species in each region - Approach is cost effective and appropriate to the low level of risk demonstrated in the 24-month Entrainment Monitoring Study and in a peer-reviewed study of entrainment risk from much larger water volumes in depths of 20-60 m where egg and larval densities are much higher.* *Gallaway, B.J., W.J. Gazey, J.G. Cole, and R.G. Fechhelm (2007). "Estimation of Potential Impacts from Offshore Liquefied Natural Gas Terminals on Red Snapper and Red Drum Fisheries of the Gulf of Mexico: An Alternative Approach". Transactions of the American Fisheries Society (2007) 136:655-677. Given this finding, use of existing SEAMAP system for monitoring entrainment is a much more comprehensive, cost-effective mechanism for gauging the seasonality of entrainment potential over time. Such SEAMAP reporting could be done by the Agency's review of this data set or by a permit requirement for industry to submit annual reports on the SEAMAP data.
20.	Cooling Water Intake Structure	Part I.D.3.d.i-New Fixed Facilities that Employ Sea Chests as Intake Structures	i. The operator must conduct either visual inspections or use remote monitoring devices (e.g., remotely operated vehicles (ROV), subsea cameras, or other monitoring device) during the period the cooling water intake structure is in operation. The operator must conduct visual inspections* at least ~~weekly~~monthly, or at a lesser frequency as approved by the Director, to ensure that the required design and construction technologies are maintained and operated so they continue to function as designed. Alternatively, the operator must inspect using remote monitoring devices to ensure that the impingement and entrainment technologies are functioning as designed.	OOC requests that visual inspections be required monthly. This request is backed by visual inspection data obtained in EPA Region VI. The observed rate of growth of biological material does not result in significant change over a one week period. Changes are hard to discern over a monthly period. For a deepwater facility(does not employ a sea chest) monitored under the EPA Region VI NPDES permit, the 2015 average rate of growth expressed as % screen coverage was 2.5% with a monthly range of 0-6% growth.
21	CORMIX Tables	Appendix A and Table of Contents	The TOC should be updated with the proper table headings in order to be consistent with the revised Appendix A, as follows: ~~Table 3.A: Produced Water Critical Dilutions (% Effluent) for Water Depth Differences Between the Discharge Pipe and Sea Floor of Less than 200 Meters~~ **Table 3**: Produced Water Discharge Rates ~~CORMIX Predicted Critical Dilutions (Percent Effluent) for Discharges with a Depth Difference Between the Discharge Pipe Outlet and the Sea Floor of Greater than 12 Meters and in Waters Less than 200 Meters~~ **Table 4**: CORMIX Predicted Critical Dilutions (Percent Effluent) for Discharges with a Depth Difference Between the Discharge Pipe Outlet and the Sea Floor of Greater than 12 Meters and in Waters Less than 200 Meters ~~CORMIX Predicted Critical Dilutions (Percent Effluent) for Discharges with a Depth Difference Between the Discharge Pipe Outlet and the Sea Floor of Greater than 12 Meters and in Waters Equal to or Greater than 200 Meters~~ **Table 5**: CORMIX Predicted Critical Dilutions (Percent Effluent) for Discharges with a Depth Difference Between the Discharge Pipe Outlet and the Sea Floor of Greater than 12 Meters and in Waters Equal to or Greater than 200 Meters	OOC requests this revision to provide alignment and consistency. **In addition, all references to these tables should be updated within the permit text.** Table 3.A is listed in the TOC, but not provided in the Appendix nor referenced in the text. Appendix A now includes four additional tables. With the addition of Table 3 into the Appendix, all other tables have been shifted in position. The OOC presents no opposition to the addition of Table 3, however, the addition of Tables 6, 7 and 8 are unwarranted and or has replaced tables that appear to be omitted as an oversight (see comments below).

<table>
<tr><th>Comment No.</th><th>Type/Category</th><th>Permit Section Ref.</th><th>Revised Permit Wording</th><th>Comment/Rationale</th></tr>
<tr><td></td><td></td><td></td><td>~~Minimum Vertical Port Separation to Avoid Interference~~
Table 6: Minimum Vertical Port Separation to Avoid Interference
~~Critical Dilution (% Effluent) for Toxicity Limitations for Seawater to Which Treatment Chemicals Have Been Added~~
Table 7: Critical Dilution (% Effluent) for Toxicity Limitations for Seawater to Which Treatment Chemicals Have Been Added
~~Critical Dilution (% Effluent) for Toxicity Limitations for Freshwater to Which Treatment Chemicals Have Been Added~~
Table 8: Critical Dilution (% Effluent) for Toxicity Limitations for Freshwater to Which Treatment Chemicals Have Been Added</td><td></td></tr>
<tr><td>22.</td><td>CORMIX Tables</td><td>Appendix A
Table 2</td><td>The title of Table 2 should read as follows:

Table 2: Produced Water Discharge Pipe Diameters</td><td>OOC requests this correction for the misspelling of the word "Produced."</td></tr>
<tr><td>23.</td><td>CORMIX Tables</td><td>Appendix A
Table 3</td><td>The title of Table 3 should read as follows:

Table 3: Produced Water Discharge Rates</td><td>OOC requests this correction for the misspelling of the word "Produced."

The Results portion of this table, along with Figures 1 and 2 subsequently provided in the Appendix, might be better served in a supplemental document or fact sheet to the permit, as further comment may be necessary. This paragraph describes conditions that, based on uncertainty factors (Table 6), prompted the "adjusted" critical dilution tables provided as Tables 7 and 8. However, further information is needed regarding the uncertainty factors and how they are applied (see comment 14 & 15 below).

In addition, references to Table 3 within the permit text should be revised or deleted.</td></tr>
<tr><td>24.</td><td>CORMIX Tables</td><td>Appendix A
Tables 4 and 5</td><td>References to Tables 4 and 5 within the main text of the permit are incorrect.</td><td>The current permit references use of Table 5 by permittees with vertically aligned multiple discharge ports (vertical diffusers) and requirements for minimum port separation; however, this table has been omitted from the draft permit (see comment below).</td></tr>
<tr><td>25.</td><td>CORMIX Tables</td><td>Appendix A
Table 6</td><td>Table 6: ~~Uncertainty Factors Due to Variability in Currents and Seasonal Density Stratification~~
Minimum Vertical Port Separation to Avoid Interference
<table>
<tr><th>Port Discharge Rate</th><th>Waters Less than 200 meters</th><th>Waters Greater than 200 meters</th></tr>
<tr><td>(bbl/day)</td><td>(meters)</td><td>(meters)</td></tr>
<tr><td>>0 to 500</td><td>3.0</td><td>3.0</td></tr>
<tr><td>501 to 1000</td><td>3.0</td><td>6.0</td></tr>
<tr><td>1001 to 2000</td><td>4.0</td><td>6.0</td></tr>
<tr><td>2001 to 5000</td><td>5.0</td><td>6.0</td></tr>
<tr><td>5001 to 7000</td><td>5.5</td><td>6.0</td></tr>
<tr><td>7001 to 10,000</td><td>6.0</td><td>6.0</td></tr>
</table></td><td>OOC requests the deletion of Table 6 in the draft permit, which replaces critical dilution tables for chemically treated seawater and provides uncertainty factors for model simulations presented in Tables 4 and 5. It is unclear how these uncertainty factors were calculated and how they are applied. Therefore, the addition of this table is confusing and unwarranted.

In addition, the OOC requests the addition of the minimum vertical port separation table, which appears to have been deleted as an oversight from the draft permit.

References to Table 6 within the permit text should be revised or deleted accordingly.</td></tr>
<tr><td>26.</td><td>CORMIX Tables</td><td>Appendix A
Tables 7 and 8</td><td>Table 7: ~~Eastern Gulf of Mexico OCS Critical Dilutions (Percent Effluent) for Discharges with a Depth Difference Between the Discharge Pipe Outlet and the Sea Floor of Greater than 12 meters and in Waters Less than 200 meters~~</td><td>OOC requests the deletion of Tables 7 and 8 in the draft permit, which replace critical dilution tables for chemically treated waters and provide the "adjusted" critical dilution tables using uncertainty factors from Table 6. It is unclear if the adjusted tables are to be used by the permitee in lieu of Tables 4 and 5 or what purpose these tables serve, as Tables 6, 7 and 8 are not discussed within the main text of the permit or the Appendix in this regard.</td></tr>
</table>

<table>
<tr><th>Comment No.</th><th>Type/Category</th><th>Permit Section Ref.</th><th>Revised Permit Wording</th><th>Comment/Rationale</th></tr>
<tr><td></td><td></td><td></td><td>
Critical Dilutions (Percent Effluent) for Toxicity Limitations for Seawater to which treatment chemicals have been added
<table>
<tr><th>Water Depth</th><th>Discharge Rate (bbl/day)</th><th colspan="3">Pipe Diameter Range
(actual diameter modeled)</th></tr>
<tr><th></th><th></th><th>>0 to 2"
(1)</th><th>>2 to 4"
(3)</th><th>>4 to 6"
(5)</th></tr>
<tr><td>Less than 200 meters (shelf)</td><td>500 (0 to 1000)</td><td>0.29</td><td>0.81</td><td>1.23</td></tr>
<tr><td></td><td>1000 (1000 - 2000)</td><td>0.31</td><td>0.86</td><td>1.34</td></tr>
<tr><td></td><td>2000 (2000-4000)</td><td>0.34</td><td>0.88</td><td>1.43</td></tr>
<tr><td></td><td>4000 (4000-8000)</td><td>0.33</td><td>0.98</td><td>1.48</td></tr>
<tr><td></td><td>8000 (>8000)</td><td>0.29</td><td>1.02</td><td>1.68</td></tr>
<tr><td>Deeper than 200 meters (slope)</td><td>500 (0 to 1000)</td><td>0.32</td><td>1.03</td><td>1.65</td></tr>
<tr><td></td><td>1000 (1000-2000)</td><td>0.28</td><td>0.99</td><td>1.65</td></tr>
<tr><td></td><td>2000 (2000-4000)</td><td>0.24</td><td>0.89</td><td>1.57</td></tr>
<tr><td></td><td>4000 (4000-8000)</td><td>0.20</td><td>0.78</td><td>1.42</td></tr>
<tr><td></td><td>8000 (>8000)</td><td>0.17</td><td>0.66</td><td>1.24</td></tr>
</table>
Table 8: ~~Eastern Gulf of Mexico OCS Critical Dilutions (Percent Effluent) for Discharges with a Depth Difference Between the Discharge Pipe Outlet and the Sea Floor of Greater than 12 meters and in Waters Greater than 200 meters~~
Critical Dilutions (Percent Effluent) for Toxicity Limitations for Freshwater to which treatment chemicals have been added
<table>
<tr><th>Water Depth</th><th>Discharge Rate (bbl/day)</th><th colspan="3">Pipe Diameter Range
(actual diameter modeled)</th></tr>
<tr><th></th><th></th><th>>0 to 2"
(1)</th><th>>2 to 4"
(3)</th><th>>4 to 6"
(5)</th></tr>
<tr><td>Less than 200 meters (shelf)</td><td>500 (0 to 1000)</td><td>0.57</td><td>3.85</td><td>16.9</td></tr>
<tr><td></td><td>1000 (1000 - 2000)</td><td>0.44</td><td>3.20</td><td>16.7</td></tr>
<tr><td></td><td>2000 (2000-4000)</td><td>0.34</td><td>2.50</td><td>5.76</td></tr>
<tr><td></td><td>4000 (4000-8000)</td><td>0.35</td><td>1.86</td><td>4.66</td></tr>
<tr><td></td><td>8000 (>8000)</td><td>0.30</td><td>1.36</td><td>3.52</td></tr>
<tr><td></td><td>500 (0 to 1000)</td><td>0.67</td><td>11.6</td><td>29.9</td></tr>
</table>
</td><td>
In addition, the OOC requests the addition of the chemically treated seawater and freshwater critical dilution tables, which appear to have been deleted as an oversight from the draft permit. Reference to Table 7 within the permit text is made with regard to chemically treated freshwater. No mention of Table 8 is made within the text.

References to these tables within the permit text should be revised or deleted accordingly.
</td></tr>
</table>

<table>
<tr><th>Comment No.</th><th>Type/Category</th><th>Permit Section Ref.</th><th>Revised Permit Wording</th><th>Comment/Rationale</th></tr>
<tr><td></td><td></td><td></td><td><table>
<tr><td>Deeper than 200 meters (slope)</td><td>1000 (1000-2000)</td><td>0.40</td><td>6.69</td><td>29.1</td></tr>
<tr><td></td><td>2000 (2000-4000)</td><td>0.26</td><td>3.57</td><td>15.9</td></tr>
<tr><td></td><td>4000 (4000-8000)</td><td>0.22</td><td>1.96</td><td>9.14</td></tr>
<tr><td></td><td>8000 (>8000)</td><td>0.19</td><td>1.06</td><td>4.67</td></tr>
</table></td><td></td></tr>
<tr><td>27.</td><td>Excess Fluids</td><td>Part I.B.10 and Part V.B</td><td>Edit text:
"Excess Cement Slurry ~~[Note: Discharges of cement slurry used for testing cement handling equipment are not authorized.]~~"
Add to Miscellaneous Discharge List:
"Unused Cement Slurry"
Add to the Definitions in Part V.B.
""Unused Cement Slurry" means cement slurry used for testing of equipment or resulting from cement specification changes.""</td><td>OOC requests that discharges of cement used for testing and unused cement slurry be authorized by adding a new discharge under Miscellaneous Discharges: "Unused Cement Slurry".
Rationale
a) Equipment testing is critical to proper operation and maintenance of drilling systems. Without adequate testing, well control concerns (among others) can arise. Equipment that is not properly tested has the potential for a catastrophic environmental event. EPA must consider equipment testing commissioning as "proper operation and maintenance" since if permittees do not test commission equipment then a permittee cannot truly say that they are complying with this permit requirement.
b) The discharge of such fluids would meet all monitoring and limitations of the permit for those fluid types, and since such fluids had not been "used" they would have a lower pollutant potential than the used fluids (which are authorized for discharge).
c) Prior EPA determinations have been received which authorized such discharges (and the draft fact sheet does not new provide a substantive justification for now prohibiting such discharges).
d) Authorizing discharge will avoid substantive safety risks for managing bulk fluids back to shore including lifting large, heavy containers at sea, transportation risks at sea and on-land and tank container cleaning associated with solidified cement (It is difficult to inhibit cement from setting up. Therefore, transport to shore is expected to be solidified blocks in their containers). Safety incidents have occurred during the removal of hardened cement from cutting boxes using jack hammers. One operator had two reported hand finger injuries occur as a result of disposing the cement test mix from the commissioning of one cement unit on a new build drillship. This also consumes limited onshore disposal facility capacity for essentially benign materials. Finally, the transport of these materials involves environmental consequences including increased air emissions from marine and road transport.
OOC presents here additional information on the discharge quantities to support approval of these discharges. The following are typical volumes of cement for the subject issue:
1. New drilling units (MODU or platform rig) commissioning equipment testing: 100-200 bbls per ship. This is slurry used to test pumping functions and verify flow paths. Assuming 3-7 newly constructed drilling units per year enter the Gulf (1), this is equivalent to 600-1400 bbl/yr of slurry that may be discharged annually.
2. Out of the rigs that come to the GOM, some of those rigs operators choose to do their commissioning before they enter the GOM and cement slurry from the test mix is not discharged in the GOM. The percentage of rigs that choose to go this route could be as high as 50%.
3. When cement slurry from a test mix cannot be discharged it must be caught in metal containers (i.e. cutting box, etc). The container must be sent in to shore to be disposed of before the cement slurry "sets up" or gets hard. Any time a liquid is transported it creates a greater risk of loss of</td></tr>
</table>

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
				primary containment. The lifts that must be made to move this container from the rig to a boat and then to the shore also introduce a higher risk for an accident or injury. This in turn puts more personnel in the line of fire and increases exposure rate versus discharging the cement slurry test mix while mixing it on the rig. 4. Other Discharges of Unused Cement Slurry Repairs: when a cement system malfunctions or equipment must be upgraded or changed out for specific job, the existing cement must be removed, repairs made and testing conducted to ensure proper operation. There are two concerns in this case with a prohibition against the discharge: • If the malfunction occurs during a cementing job, the existing cement must be washed out quickly (before it sets), the repair made, the testing performed and then new cement mixed. Discharge is the most effective means to support rapid repair since typically weight and space constraints prevent holding empty containers offshore for such a contingency. This can involve potential well control issues if the cement system cannot be returned to service quickly. • More generally, even if no cement job is in progress, the testing after repair is critical to assure all systems work as designed and provide cement that can comply with well design requirements. Estimated volumes are 5-100 bbls per event. OOC estimates this occurrence is rare on a per rig basis. Currently there are 99 rigs working in the GOM (2). Assuming one event per year per rig this equates to 500-10,000 bbls year of slurry discharged. Cement not meeting the specifications for a well job: 20-100 bbls. OOC expects this to also be a rare occurrence. Note- if this occurs when a well is in a productive interval, the cement must be washed out of the unit to prevent setting. Then a new batch needs to be quickly mixed to prevent well control issues. Discharge is the most effective means to support rapid response since typically weight and space constraints prevent holding empty containers offshore for such a contingency. This can involve potential well control issues if the cement system cannot be returned to service quickly. A review of BOEM data (3, 4) indicate 100 wells per year are drilled in the Gulf. Assuming one event per well per year yields 2000-10,000 bbls yr of slurry discharged. In summary, annual expected discharges of the proposed "Unused Cement Slurry" could be on the order of: Commissioning of new drilling units s — 600-1400 total bbls year Repairs — 500-10,000 total bbls year Off spec cement — 1000-10,000 total bbls year Total — 2100 - 21,400 total bbl year Compare this to a single well's discharge of authorized Excess Cement Slurry (as authorized and defined in the permit): though highly variable depending on many factors, this is on the order of approximately 100-400 bbls (including pit cleanouts after a job). The majority of this is associated with riserless operations.

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
				Assuming 100 wells year are drilled in the Gulf, this yields approximately 10,000-40,000 bbls of Excess Cement Slurry already authorized by the current permit (and continued for authorization in the proposed permit) for discharge. The volumes shown above for the proposed Unused Cement Slurry are of the same order of magnitude as existing authorized excess cement slurry discharges (and are probably significantly lower). Given this, and typical discharge at or near the surface with immediate dispersion into the water column, the environmental impacts are expected to be insignificant. Note: The values provided in the above are based on worst case scenarios. Numbers to date may be lower based on current MODU activity in the Gulf of Mexico. As an alternative, OOC recommends a joint industry study be performed to assess the overall environmental and safety impacts of this discharge. References 1. Personal communication, Kuehn – Rigzone, 4 23 12. 2. Rigzone- Rig Report: Offshore Rig Fleet by Region http: www.rigzone.com data rig_report.asp?rpt_reg 3. http: www.boem.gov uploadedFiles BOEM Newsroom Offshore_Stats_and_Facts Gulf_of_Mexico_Region OCSDrilling.pdf
28	BMP3 Requirement	Part IV	Delete requirement to develop and implement BMP3	OOC requests that the BMP3 requirements be removed from the permit. OOC is providing the attached table (below and as Attachment D) outlining the BMP3 requirements and a cross reference to other regulations that require the same or redundant information. In summary: 1 CWIS are addressed in accordance with Part I.D.3 of permit 2 NAFs are addressed in Appendix 7 of 40 CFR Part 435 Subpart A and Part I.B.2.c 3 Maintenance Waste can be addressed as outlined in Part I.C.6 of GMG290000 as a standalone BMP 4 All other requirements are addressed in numerous other BOEM BSEE requirements. BMP3 Comparison to Other Federal Requir Therefore, to reduce administrative burden, OOC recommends all of Part IV be removed from the permit.
29	Miscellaneous Discharges	I.B.10	Add "brine and water based mud discharge at the seafloor for temporary well abandonment" to the list of Miscellaneous Discharges.	OOC is requesting the addition of brine and or water based mud discharge at the seafloor to the list of Miscellaneous Discharges. The final phases of many temporary well abandonments (a prelude to permanent abandonment) could involve the discharge of clean brine or water-based mud from the upper most portion of the well at the seafloor. This would occur because a riser is not present (or has been disconnected from the abandoned well). The producing reservoir has been isolated in earlier stages of the abandonment with cement and

Comment No.	Type/Category	Permit Section Ref.	Revised Permit Wording	Comment/Rationale
				plugs, and the tubing annulus casing has been scoured by prior well fluid circulations. Further, static sheen, oil and grease and priority pollutant limitations would have been already met on prior discharges of the brine (in earlier stages of the abandonment). Any water-based mud usage would have also been shown compliant by earlier drilling fluid monitoring. Finally, the brine and muds are engineered fluids, meeting detailed specifications; one of which is no hydrocarbon content is allowed (for safety and performance reasons).
30.	Miscellaneous Discharges of Seawater and Freshwater which have been chemically treated	Part I.B.11	Revise and reword section as follows: Excess ~~sea~~water which permits the continuous operation of fire control and utility lift pumps. Excess ~~sea~~water from pressure maintenance and secondary recovery projects. Water released during training of personnel in fire protection. ~~Seaw~~Water used to pressure test piping and pipelines. Ballast water. Once through non-contact cooling water. ~~Seaw~~Water used as piping or equipment preservation fluids, and ~~Seaw~~Water used during Dual Gradient Drilling. Water includes both seawater and freshwater discharges.	OOC requests that a change be made to the Title and list for "Miscellaneous Discharges of Seawater and Freshwater which have been chemically Treated". This will be a word change from "Seawater" and "Freshwater" to "Water". This change will ensure that both "Seawater" and "Freshwater" are included in the chemically treated discharge list.
31.	Summary of Effluent Limitations, Prohibitions, and Monitoring Requirements for the Eastern Gulf of Mexico NPDES General Permit for Existing Sources and New Sources (Refer to permit for specific, enforceable requirements)	Table 1 - Well Treatment, Completion, and Workover Fluids (includes packer fluids) Measurement Frequency	For chronic toxicity: Once 2 month when discharging~~(or semiannually after passing three consecutive bimonthly test~~ For acute toxicity: Once month when discharging ~~discharge (or semiannually after passing three consecutive tests)~~	OOC requests this change for consistency with requested changes in comments No. 9-10.

OOC-1	Requested change made. The change clarifies that written Notice of Intent (NOIs) will continue to be submitted beyond the stated date for transition to e-Reporting if the E-NOI system is not operational.
OOC-2	Partial change made. Permit language was changed to clarify when written NOIs are accepted. EPA developers of NetDMR have been in contact with EPA Region 6 in order to share lessons learned. EPA will not be able to accept a Certification Letter in lieu of required electronic submittals. A link is provided in the permit for NetDMR instruction and NODI codes.
OOC-3	No change was made. Eighty-five percent of DMRs for operators within EPA Region 4 are submitted with no data due to inactivity. With respect to active facilities, EPA does not agree that the data will be so voluminous that quarterly reports cannot be accurately prepared within 28 days after the end of a quarter. Operators have had to work under this reporting deadline for a number of years and there have been no evident problems meeting the requirement. Also, there are approximately 19 different companies operating in Region 4. Fourteen of the 19 have five or less wells.
OOC-4a	No change made. The current language is clear and aligns with permit language developed by EPA Headquarters and EPA Region 9 for the EPA Region 9 Offshore Oil and Gas General Permit.
OOC-4b	No change made. Operators will submit annual information even when enrolled in the study. The study has not been designed at this time.
OOC-4c	All operators under the EPA Region 4 Offshore Oil and Gas General Permit will have to comply with the permit requirements for submitting information on additives and chemical used in well treatment, completion, and workover (WTCW) operations until EPA and the industry develops and implements the alternative industry-wide study to investigate the composition and toxicity of these discharged fluids. This process could take months to complete. EPA Region 4 disagrees with the use of information on a Safety Data Sheet (SDS) as a substitute for keeping detailed information on chemicals being used because this information would not be useful in the event of enforcement investigations by EPA inspectors. Also see EPA Region 4's response 4d and 5a below.
OOC-4d	Although the use of a systems-style disclosure of the chemical composition would provide some helpful information, it would not be sufficiently detailed to examine potential environmental impacts of discharges with a high degree of certainty. Any such evaluation would be subject to interpretation and easily challenged. As the OOC pointed out in their above comment, SDS sheets could still be used to reverse engineer product formulas and would not provide a higher degree of protection.
OOC-4e	Regarding submittal of Confidential Business Information (CBI), such claims are not allowed regarding permit application information (see CWA Section 402(j)). As provided in 40 CFR Section 122.28(b)(2), an NOI "fulfills the requirements for permit applications for purposes" of §§ 122.6, 122.21, and 122.26. See also, 40 CFR Section 122.7, which provides that claims of confidentiality will be denied for

	permit applications, permit and effluent data and information required by NPDES application forms, including information submitted on the forms and any attachments. The information at issue is also ineligible for confidential treatment because it meets the definition of "effluent data" in 40 CFR Part 2.302(a)(2). Effluent data is not eligible for confidential treatment pursuant to 40 CFR 2.302(e) and (f). Facilities seeking to discharge pollutants into waters of the United States must be prepared to disclose information regarding the composition of their proposed discharge and such information must be made available to the public.
OOC-4f	R4 needs information on biocides to determine the extent to which these substances may be toxic to the aquatic environment near the vicinity of the discharge and to determine whether any changes to the permit's current limits are needed to ensure that the permit is sufficiently protective of the environment.
OOC-5a	Some changes made. The current language is clear and aligns with permit language developed by Region 9 for the Region 9 Offshore Oil and Gas general permit. EPA R4 disagrees with the use of information on a Safety Data Sheet (SDS) as a substitute for keeping detailed information on chemicals being used because this information would not be in a form that would be useful for environmental analysis or in the event of enforcement investigations by EPA inspectors. For instance, in the event of a toxicity test failure, EPA would have immediate access to the specific chemical concentrations of probable toxicants in the effluent. SDS are designed to provide information on materials in the event of worker exposure. The SDS includes information such as the properties of each chemical; the physical, health, and environmental health hazards; protective measures; and safety precautions for handling, storing, and transporting the chemical. Sections 1 through 8 contain general information about the chemical, identification, hazards, composition, safe handling practices, and emergency control measures. Sections 9 through 11 and 16 contain other technical and scientific information, such as physical and chemical properties, stability and reactivity information, toxicological information, exposure control information. Although Section 3 of an SDS requires information on a chemical's composition, if a trade secret is claimed, a company can omit the specific chemical identity and/or exact percentage (concentration) of composition. EPA Region 4 does agree with OOC's suggestion to report the concentration because this information would be useful and it has been added to the permit.
OOC-5b	No change made. See Comments 4c, 4d and 5a.
OOC-6a	No change made. Requiring operators to report well treatment, well completions, and well workover fluids under separate outfalls does not pose a burden and is necessary for EPA to more easily identify any possible toxic effluents from either of these three types of operations.
OOC-6b	No change made. See response to Comment 3. EPA does not anticipate permittees needing the requested time to submit reports due to QA/QC procedures.

OOC-6c	Government shutdowns have historically been very infrequent and not an issue EPA expects to be a burden for reporting.
OOC-7	Change made. This revision will allow use of new analytical methods for that are approved by EPA during the permit term.
OOC-8a	No change made to text.
OOC-8b	See Comments 4c, 4d and 5a.
OOC-8c	See responses to comments 4c, 4d and 5a, above. The priority pollutant reporting requirements are part of the permits (no priority pollutants except in trace amount limits), and while some of the OOC's requests are appropriate for the chemical additive monitoring and study requirements, they do not appear to be pertinent to this limit and reporting requirement.
OOC-9a	Changes made. Moved from page 42 to page 45.
OOC-9b	Language was included to clarify the meaning of a discharge "lasting four or more consecutive days."
OOC-9c	Partial change made to clarify sample type and frequency.
OOC-9d	Change made.
OOC-9e	No change made. EPA does not see a need for calculated densities. For our purposes, a direct measurement is preferred and ensures consistency.
OOC-9f	No change made. Any changes outside the density range should be noted on the electronic DMR submittal.
OOC-9g	EPA disagrees with the use of acute testing requirements in lieu of chronic toxicity requirements. Chronic testing is more sensitive and is appropriate for longer term discharges.
OOC-10a	Change made.
OOC-10b	Partial change made. EPA clarified the type of sample and the frequency should be taken.
OOC-10c	Change made.
OOC-10d	No change made. See Comment 9e.
OOC-10e	No change made. See Comment 9f.
OOC-11a	No change made. See Comments 11b-11d.
OOC-11b	No change made. See Comments 4c, 4d and 5a.
OOC-11c	No change made. See Comments 4c, 4d and 5a.
OOC-11d	No change made. See Comments 4c, 4d and 5a.
OOC-11e	No change made. EPA disagrees with allowing submittal of information on an SDS as a substitute for keeping detailed information on chemicals being used because this information would not be sufficiently detailed to be useful for environmental

	analysis of the discharges or in the event of enforcement investigations conducted by EPA inspectors; see response to comment 4d and 5a. With respect to CBI concerns, see response to Comment 4e.
OOC-12a	Active has been deleted.
OOC-12b	No change made. EPA wants to ensure that samples are representative of the various well depths. "Well depth" has been added for clarification to the permit.
OOC-12c	The EPA has worked with the industry on a number of similar industry-wide studies as alternatives to individual monitoring. We prefer to allow the industry flexibility to determine how individual companies participate. Thus, the final permit does not address how operators participate in any industry-wide study that is conducted., which will be developed jointly between Region 4, EPA HQ and the OOC.
OOC-13	Partial change made. Chronic toxicity testing requirements apply to WTCW fluid discharges lasting four or more days. However, this is a monitoring only requirement and not an effluent limit. Clarifying language was added to Part V.A.15(a) to differentiate the monitoring chronic testing requirements for WTC fluids from the chronic toxicity testing limits that apply for other waste streams.
OOC-14a	Clarification of violation language for these discharges was added. Test will still report as pass or fail.
OOC-14b	Clarification made that retesting can only be done if an additional sample can be obtained.
OOC-14c	No change made.
OOC-15a	The permit is clear regarding where to find the appropriate acute and chronic WET testing requirements for WTCW fluids. Language has been added see comment 14b.
OOC-15b	Partial changes made. Part V.15 was changed to clarify that for well treatment, well completion or well workover fluid discharges, monitoring only requirements apply. Test results shall be reported as pass or fail. A failure will not be considered a violation of the permit.
OOC-16	No change made. EPA disagrees that new offshore operators should automatically be deemed to be in compliance with the baseline study requirements of the Cooling Water Intake Structure rule for New Sources based on previously submitted dated results of the industry-wide study completed in 2012.
OOC-17	Change was made to require monitoring at least once per month (instead of weekly, as provided in draft permit) during the monitoring periods. For instance, operators must monitor at least once per month even if they are on location less than one month.
OOC-18	See response to Comment 17, above.
OOC-19a	EPA agrees with and has incorporated the OOC's proposed language, pursuant to which, after 24 months of entrainment monitoring, new fixed facilities that do not employ sea chests as intake structures may submit SEAMAP data annually to fulfill the requirements of 40 CFR Section 125.137.

OOC-19b	EPA agrees with and has incorporated the OOC's proposed alternative language, pursuant to which, after 24 months of entrainment monitoring, new fixed facilities that do not employ sea chests as intake structures may submit SEAMAP data annually to fulfill the requirements of 40 CFR 125.137.
OOC-20	See response to Comment 17, above.
OOC-21	The text was revised so that it now accurately refers to tables in Appendix A.
OOC-22	The typographical error was corrected.
OOC-23	The typographical error was corrected. Tables were not moved.
OOC-24	Change made. Corrections were made in the permit regarding references to Tables 4 and 5.
OOC-25	The text was revised so that it now accurately refers to tables in Appendix A. The table "Vertical Port Separation to Avoid Interference", was inadvertently omitted in the draft permit, and was added to Appendix A.
OOC-26	All tables referenced in Appendix A are mentioned in the text. Revisions were made so now all tables are included and labeled correctly.
OOC-27	The comment requests that the permit authorize the discharge of unused cement slurry. No change will be made at this time in order for EPA to gather more information about fate and transport of chemical constituents in the cement that will be ultimately disposed of at the seafloor. This would allow us time to better determine appropriate permit parameters and conditions for this effluent. The permit's prohibition on the discharge of excess cement slurry does not prevent testing of equipment. This prohibition has been included in the general permit for a number of years and presumably operators have tested and properly maintained cement systems and drilling equipment during that time. Excess cement can be hauled to shore for disposal.
OOC-28	No change made. Best management pollution prevention practices are central to many industrial permits. EPA understands that some provisions in a BMP3 plan for the NPDES permit may also be in BMPs for other regulatory agencies. For purposes of complying with the BMP3 provisions of Region 4's NPDES permit, operators can incorporate and rely on any duplicative compliance measures developed to comply with other regulatory authorities.
OOC-29	No change made at this time in order for EPA to gather more information about fate and transport of chemical constituents in brine and water-based mud proposed to be disposed of at the seafloor. This would allow us time to better determine appropriate permit parameters and conditions for this effluent.
OOC-30	No change made. The terminology used in the permit is clear.
OOC-31	Change made. For simplification, Table 1 refers back to the permit for details.

-----Original Message-----
From: drupal_admin@epa.gov [mailto:drupal_admin@epa.gov]
Sent: Sunday, October 02, 2016 6:42 PM
To: Maddox, Sherry <Maddox.Sherry@epa.gov>
Subject: Form submission from: About EPA Contacting EPA Region 4 (Southeast) form

Submitted on 10/02/2016 6:42PM
Submitted values are:

Name: Susan Patton
State: Tennessee
Email: pattonshipstore@aol.com
Comments:
Is it true that the EPA plans to dump unlimited amounts of fracking chemicals into the Gulf of Mexico and if true why?
Thanks, Susan 424-939-0235

SP-1	Yes. The draft NPDES general permit authorizes discharges of produced water from oil and gas exploration, development and production activities, including field exploration, drilling, and well treatment and completion activities (known as hydraulic fracturing). The permit covers all discharges in the Eastern Gulf of Mexico in water depths seaward of 200 meters occurring off the coasts of Mississippi, Alabama and Florida. When issued, the permit term is 5 years. Discharges are allowed provided certain conditions are met. The permit applies effluent guideline-based limitations and toxicity limits on the discharge of well treatment, completion and workover fluids when discharged with produced water. Monitoring requirements apply to well completion and treatment fluid discharged separately. The draft permit includes new Whole Effluent Toxicity (WET) monitoring requirements specifically for discharges resulting from well treatment fluid operations, including hydraulic fracturing. It also includes reporting requirements to better understand potential impacts of discharges, including location, volume of fluids used, chemical parameters and duration of discharge. The general permit is consistent with the requirements of the Clean Water Act and the National Environmental Policy Act (NEPA). The permit includes a number of toxicity limits and other conditions to ensure that the marine environment is protected. The EPA will consult with the appropriate Agencies as required by various Acts, such as the Endangered Species Act prior to issuing the final permit.

PESA

2500 CityWest Blvd. Suite 1110
Houston, TX 77042-3049
Office 713-932-0168
Fax 713-932-0497

October 19, 2016

The Honorable Heather McTeer Toney
Regional Administrator
EPA Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, GA 30303-8960

RE: Draft National Pollutant Discharge Elimination System (NPDES) general permit for the Outer Continental Shelf (OCS) of the Gulf of Mexico (General Permit No. GEG460000); Public Notice 16AL00001

Dear Administrator Toney

As the national trade association for the oilfield service, supply, and manufacturing sector, the Petroleum Equipment and Services Association (PESA) appreciates the opportunity to provide comments on the draft National Pollutant Discharge Elimination System (NPDES) general permit for the Outer Continental Shelf (OCS) of the Gulf of Mexico (General Permit No. GEG460000) for discharges in the Offshore Subcategory of the Oil and Gas Extraction Point Source Category.

PESA represents approximately 200 companies that develop and provide the services, technology, equipment, chemicals, and expertise necessary to safely and efficiently explore for and produce oil and natural gas. Many of these companies are involved as contracted vendors to exploration and production companies and/or drilling contractors working in the Gulf of Mexico, including Region 4.

PESA members are committed to conducting their work in a safe and environmentally responsible manner. The comments provided to EPA reflect the perspective of subject matter experts from numerous PESA member companies and are intended to ensure that the permit meets the shared goals of EPA and industry: Safe and environmentally responsible operations.

Should you have any questions, please do not hesitate to contact me directly.

Sincerely,

/s/

Ryan S. Bowley
Vice President, Operations & External Affairs

Notification Requirements (Existing Sources and New Sources) - Part I., A., 4., u.

PESA-1

Current Region 4 Proposed Permit Language:

"u. Information on the specific chemical composition of any additives currently being used or proposed for use in well treatment, completion or workover operations or as biocides for sump/drain systems. If the information on the additive is not known at the time of the submittal of this NOI, operators shall include the information in a report that shall be submitted on to EPA Region 4 on September 30th of each year Aside from submitting this information with the NOI, this information is also required to be recorded and retained on site for no less than five years from the issuance date of the permit. See Part I.6.a.iii."

PESA Revised Permit Wording/Clarification:

u. Information on the identity, as listed on the applicable SDS, and concentration of each chemical constituent, intentionally added to the well treatment, completion of work over fluid of currently being used and discharged or proposed for use and discharge in well treatment, completion or workover operations. If the information on the additive is not known at the time of the submittal of this NOI, operators shall include the information in a report that shall be submitted on to EPA Region 4 on September 30th of each year or with the alternative study report of Part I.B.6.b. If an operator participates in the alternative study, then annual information submittal is not required. Operators may submit this information marked as "Confidential Business Information" or other suitable form of notice or may have service providers independently submit this information marked as such if necessary. The information so marked shall be treated as information subject to a business confidentiality claim pursuant to 40 CFR Part 2. Aside from submitting this information with the NOI, this information is also required to be recorded and retained on site for no less than five years from the issuance date of the permit, except for Confidential Business Information which may be maintained securely offsite by the operator or relevant service provider, for no less than five years from the issuance date of the permit. See Part I.B.6.a.iii.

Justification and Supporting Documentation:

PESA requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. The proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives. Additionally, PESA requests that the disclosure requirement allows for the use of a "systems-style" disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications), consistent with the approach that has been adopted for use in certain jurisdictions and by FracFocus. System-style disclosure would satisfy the objectives of the permit revision while potentially reducing the necessity for companies to make confidential business information claims on such disclosures.

System-style disclosure lists all known chemical constituents in a fluid (or fluids, in the case of multiple disclosed applications), but decouples those constituents from their parent additives, thus improving protection of the proprietary chemistry used in hydraulic fracturing while promoting greater disclosure. At the same time, reverse engineering of product formulas may still be possible with the use of a systems-style disclosure. A chemist or chemical engineer who knows the industry and the well treatment process will be familiar with the types of chemicals (usually a limited number) that have typically been used in a particular type of additive. The chemist or chemical engineer will be able to determine in most cases what role each chemical in the list plays in the overall product formulation and would be able to identify the ingredients included in the proprietary product. The chemist or chemical engineer will also be able to determine the general proportions that each ingredient would constitute of the whole (again with assistance from information on the product's Safety Data Sheet which include additional concentration information for various hazardous ingredients). Therefore, in order to protect the substantial investment of time and resources in developing proprietary products, it is critical that operators and service companies have the ability to protect proprietary information as Confidential Business Information even when using a systems-style approach.

Also, PESA requests that service providers be permitted to disclose trade secret CBI information directly to EPA rather than requiring disclosure through the operators. Such independent disclosure is necessary in order to protect the substantial investment of time and resources that service providers make in developing proprietary products. Chemical additives play a critical role in the safety, efficiency and productivity of offshore wells, and access to newly-developed, ever-improving chemicals – be they "greener," more efficient or more effective – is in turn critical to continued improvements in offshore operations.

Drilling Fluids Limitations – Part I., B., 1., b.

PESA-2

Current Region 4 Proposed Permit Language:

"…Analyses for cadmium shall be conducted by EPA Methods 200.7, 200.8 or EPA Method 3050 B followed by 6010 B or 6020A (EPA SW 846), or more recently approved EPA methods, and results shall be expressed in mg/kg (dry weight) of stock barite. Analysis for mercury shall be conducted using EPA Method 245.7 or EPA method 7471 A (EPA SW 846), or most recently approved EPA methods, and expressed as mg/kg (dry weight) of stock barite…"

PESA Revised Permit Wording/Clarification:

"…Analysis for cadmium shall be conducted using EPA methods 200.7, 200.8, or EPA method 3050 B followed by 6010B or 6020, or more recently approved and validated methods and the results expressed as mg/kg (dry weight) of stock barite. Analyses for mercury shall be conducted using EPA method 245.5, method 7471 B, or more recently approved and validated methods and the results expressed in mg/kg (dry weight) of stock barite."

Justification and Supporting Documentation:

Method 245.7 proposed by EPA Region 4 is designed to measure mercury in water and is not designed to measure mercury in solids (barite). Therefore, the reference to 245.7 should be changed to method 245.5 which is designed for solids. The parallel method to 245.5 is Method 7471A which has been updated in 2007 to Method 7471B. (See documentation in Appendix Item 1). Therefore, the recommendation is to change 7471A to 7471B.

The information in the Appendix shows a split sample analysis from a lab with significant experience using Method 7471B. Previous internal studies developed a dual control system to ensure matrix interference issues were addressed so that two very long term controls yielded one control with a long term average of 0.62 mg/kg (below) the limit and another long term control with a long term average of 2.2 mg/kg (above the limit).

Within these control limits the use of method 7473 was tested and the comparison was favorable. Then a sample with much higher mercury of 7.5 mg/kg was tested using Method 245.5. The split sample results using method 7473 produced much lower results using two different instruments (average results 0.74mg kg, and 0.88 mg kg). These results, included in the Appendix, indicate that method 7473 requires additional investigation and validation for mercury analysis to avoid potential false negative results on some barite sources that have higher concentrations of mercury. Maintaining the proposed language in the permit ensures that other test methods may continue to be used.

There is some preliminary information available in the Appendix to indicate that Method 245.7 may be appropriate when combined with the extraction method 3051A. (See documentation in Appendix Item 1)

There is a potential concern that EPA method 7473 may not extract mercury from the barite matrix. This is noted as a possibility in the method scope and application. Since this method is not specifically listed by Region 4 it could be considered as an alternative "newer" method if the current Region 6 language "...or more recently approved methods..." is adopted (See documentation in Appendix Item 1). Because it may not recover as much of the mercury out of the barite matrix as does methods 245.5 and 7471B it needs additional validation and approval prior to use as an approved method in the permit.

Because the permit limitation for mercury and cadmium is on barite, a specific solid matrix, prior to any modifications the permit language the operator in cooperation with the Agency should validate and approve any alternative method.

Drilling Fluids Inventory Documentation – Part I., B., 1., c., I.

PESA-3

Current Region 4 Proposed Permit Language:

"i. Drilling Fluids Inventory. The permittee shall maintain a precise chemical usage record of all constituents and their total volume and mass added for each well. Information shall be recorded and retained for the term of the permit."

PESA Revised Permit Wording/Clarification:

i. Drilling Fluids Inventory. The permittee shall maintain a precise chemical usage record of all products and their total volume and mass added for each well. Information shall be recorded and retained for the term of the permit.

Justification and Supporting Documentation:

Drilling Fluid Chemical inventory for drilling operations is currently maintained using product names and quantities of products added to the drilling fluid. Use of the term products will maintain clarity and conformity of the records maintained by Drilling Fluid Specialist and Service company records provided to the operators for commercial, technical and permit compliance purposes.

Well Treatment, Completion and Workover Fluids, Priority Pollutants - Part I., B., 6., a., iii. & b."

PESA-4

Current Region 4 Proposed Permit Language:

"iii. Priority Pollutants. For well treatment fluids, completion fluids, and workover fluids, the discharge of priority pollutants is prohibited except in trace amounts. If multiple fluids are mixed, each fluid must be checked for priority pollutants. "Trace amounts" shall mean the amount equal to or less than the most sensitive method detection limit listed in 40 C.F.R. Part 136 for the applicable parameter. Vendor certification indicating the fluids contain no priority pollutants is acceptable for meeting this requirement.

PESA-4 *(cont'd)*

Information on the specific chemical composition of any additives containing priority pollutants shall be recorded and submitted as part of the NOI (see part I.4.u). Any updated information regarding chemical composition of new formulations that contain priority pollutants and will be used shall be submitted to EPA Region 4 annually no later than September 30th. Operators may submit this information marked as "Confidential Business Information," if necessary. Copies of these records should also be kept on the rig while the rig is on the permitted location and thereafter at the permittee's shore base or office. These record retention requirements supersede those found in Part II.C.5. of this permit.

Note: If materials added downhole as well treatment, completion, or workover fluids contain no priority pollutants as determined by using analytical methods in 40 C.F.R. Part 136, the discharge is assumed not to contain priority pollutants."

PESA Revised Permit Wording/Clarification:

Priority Pollutants. For well treatment fluids, completion fluids, and workover fluids, the discharge of priority pollutants is prohibited except in trace amounts. Information on the specific chemical composition of any additives containing priority pollutants shall be recorded. [Note: If materials added downhole as well treatment, completion, or workover fluids contain no priority pollutants, the discharge is assumed not to contain priority pollutants except possibly in trace amounts.]

Fluids Commingled with Produced Water. When fluids are commingled and discharged with produced water, the discharges are considered produced water and the operator may report "no discharge" for monitoring and reporting purposes.

Note: this is the same as current language in the Region 6 NPDES Permit.

Justification and Supporting Documentation:

During the development of the 1993 amendments to the Oil and Gas Extraction Effluent Guidelines and Standards (40 CFR Part 435), EPA researched and developed a significant amount of documentation reflecting industry practices and the materials used in the offshore drilling, well treatment, completion, and workover process. This work was recorded in the "Development Document for Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category" (January 1993, EPA 821-R-93-003, "Development Document"). Selected excerpts from that document are provided in the Appendix to these comments.

In the Development Document, EPA noted that Completion Fluids, Workover Fluids and Well Treatment Fluids were minor discharges. These fluids are not anticipated to contain priority pollutants other than in trace amounts. Recognizing that Zinc Bromide Brines used in some high density requirements for completion fluids, Region 6's NPDES permitting activity has appropriately focused attention on preventing the discharge of Zinc Bromide completion fluids. Other trace amounts of priority pollutants in low volume discharges were considered by the Agency in the development of technology-based standards.

It was determined that downhole sources are the most likely source of priority pollutants; therefore, there was no need to place specific controls in Completion Fluids, Workover Fluids and Well Treatment Fluids beyond the controls that applied to the waste streams in which the used completion, workover, and/or well treatment fluids could be present after use downhole. The BAT/BCT requirements were placed on these discharges in consideration that likely contaminants would be the same as those in produced water. EPA appropriately focused attention on oil and grease which is an appropriate surrogate for priority pollutants likely to come from downhole sources.

Since this Effluent Limitation Guidelines Review in the late 1980s and early 1990s, the technical basis for the agency's determination remains sound. Therefore, the existing BAT BCT limits continue to be appropriately focused on downhole contaminants in the form of oil and grease and not on the fluids used to service the well. This approach in regards to limits should be carried over into Region 4's final NPDES Permit while also incorporating the "system-style" disclosure as requested by PESA and other industry groups.

In addition to ensuring that focus continues to be placed on the most likely source of priority pollutants, it is important to consider the broader impact of the approach contained in the proposed permit. The extremely low levels of contamination triggered under proposed permit will cause companies operating in Region 4 to stop reuse of these frequently expensive fluids and instead haul them back to shore for treatment even when no oil or grease are present. Not only will this result in increased cost to industry, but also in increased fuel and associated emissions to haul brine fluids back to shore for treatment.

PESA members have noted that due to modern analytical techniques the most sensitive detection limit for zinc is 0.5 parts per billion (Appendix Item 3). If the 0.5 ppb discharge limit is applied to naturally occurring seawater, then unaltered seawater would not meet the discharge limit. (Appendix Item 4) This type of unobtainable regulatory control is not justified for a low volume discharge. Therefore, in order to prevent non-water quality impacts associated with discharge prohibitions, PESA requests that Region 4 reconsider its language in this part of the permit.

Well Treatment, Completion and Workover Fluids, Monitoring Requirements, Industry Wide Study Alternative - Part I.B.6. a. iv. to 6. c.

Current Region 4 Proposed Permit Language:

PESA-5

"iv. Chronic Whole Effluent Toxicity for Well Treatment, Completion or Workover fluids Permittees with discharges of well treatment fluids, completion or workover lasting four or more consecutive days must monitor and report the No Observable Effect Concentration (NOEC) relative to the predicted effluent concentration at the edge of a 100-meter mixing zone. Predicted effluent concentrations, referred to as critical dilutions, are presented in Tables 3 and 4 of Appendix B for a range of discharge rates and pipe diameters.

Permittees discharging well treatment wastewater at conditions other than those covered in Tables 3 and 4 of Appendix A (e.g., at a rate greater flows, pipe diameters, or discharge densities) shall determine the critical dilution using the appropriate CORMIX model with the input parameters shown below. Permittees shall retain the model runs as part of the NPDES records. The critical dilution shall be determined using the CORMIX model using the highest daily average discharge rate for the three days prior to the day in which the test sample is collected, the discharge pipe diameter, the measured discharge density, and the depth difference between the discharge pipe and the sea bottom.

Input Parameters:

Density Gradient = 0.163 kg m3 m

Ambient seawater density = 1023.0 kg m3

Well Treatment wastewater density 1030.0 - 1680.0 kg m3

Completion and workover fluids 1030.0 - 1680.0 kg m3

Current speed 5 cm sec (200 m water depth); 15 cm sec (200 m water depth)

The NOEC shall be calculated by conducting 7-day chronic toxicity tests in accordance with methods published in Short Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Water to Marine and Estuarine Organisms (EPA 821-R-02-014), or most current edition.

PESA-5 *(Cont'd)*

The results for both species shall be reported on the DMR. See Part V.A.15.a of this permit for Whole Effluent Toxicity Testing Requirements. Samples must be taken at the nearest accessible location prior to discharge. All modeling runs shall be retained by the permittee as part of its NPDES records.

v). Acute Whole Effluent Toxicity Testing for Well Treatment, Completion or Workover Fluids - The following Acute Whole Effluent Testing requirements apply to discharges of well treatment fluids that last less than 4 days. Permittees must monitor and report the acute critical dilution (ACD) at the edge of a 100 meter mixing zone. The ACD is defined as 1.0 times the LC50. The ACD and the predicted effluent concentration at the edge of a 100 meter mixing zone must be reported on the DMR. Predicted effluent concentrations, referred to as "critical dilutions," are presented in Tables 3 and 4 of Appendix A for a range of discharge rates and pipe diameters. Critical dilution shall be determined using Tables 3 and 4 of this permit based on the most recent discharge rate, discharge pipe diameter, and water depth between the discharge pipe and the ocean bottom. LC50 shall be calculated by conducting 48-hour, non static renewal, toxicity tests once per discharge using Mysidopsis bahia and Menidia beryllina (Inland silverside minnow). Additional acute toxicity testing requirements are contained in Part V.15.b of this permit.

Permittees discharging well treatment wastewater at conditions other than those covered in Tables 3 and 4 of Appendix A (e.g., at a rate greater flows, pipe diameters, or discharge densities) shall determine the critical dilution using the appropriate CORMIX model with the input parameters shown below. Permittees shall retain the model runs as part of the NPDES records. The critical dilution shall be determined using the CORMIX model using the highest daily average discharge rate for the three days prior to the day in which the test sample is collected, the discharge pipe diameter, the measured discharge density, and the depth difference between the discharge pipe and the sea bottom.

Input Parameters:

Density Gradient = 0.163 kg/m3/m

Ambient seawater density = 1025.0 kg/m3

Well Treatment wastewater density = 1030.0 - 1680.0 kg/m3

Completion and workover fluids = 1030.0 - 1680.0 kg/m3

Current speed = 5 cm/sec (< 200 m water depth); 15 cm/sec (> 200 m water depth) Permittees shall retain the model runs as part of the NPDES records.

Samples for the acute WET tests shall be obtained at the nearest accessible point after final treatment and prior to discharge to surface waters.

b. Monitoring Requirements

Volume. The highest daily total discharge and the 3-month average discharge must be estimated and reported on the DMR in barrels per month.

Well Treatment Completion and Workover Reporting Requirements.

Operators of leases where well treatment, completion, or workover fluids are discharged shall collect and report the information listed below. This information shall be reported with the discharged monitoring report for the quarter in which the discharge is made. If discharges commence in one quarter and cease in the following quarter, reporting should be done in the later quarter.

For each well in which operations are conducted that result in the discharge of well treatment, completion or workover fluids the following shall be reported with the discharge monitoring report for the quarter in which the activity is done:

- Lease and block number

PESA-5 *(Cont'd)*

- API well number
- Type of well treatment or workover operation conducted
- Date of discharge
- Time discharge commenced
- Duration of discharge
- Volume of well treatment
- Volume of completion or workover fluids used
- The common names and chemical parameters for all additives to the fluids
- The volume of each additive
- Concentration of all additives in the well treatment
- Concentration of all additives in the completion, or workover fluid
- Results of Whole Effluent Toxicity (WET) tests for well treatment fluids discharged separately from the produced water discharge. Additional toxicity testing requirements are contained in Part V.15.b of this permit.

Information collected for this reporting requirement shall be submitted as an attachment to the DMR or in an alternative format requested by the operator and approved by EPA Region 4.

Industry-Wide Study Alternative

Alternatively, operators who discharge well treatment completion and or workover fluids may participate in an EPA-approved industry-wide study as an alternative to conducting monitoring of the fluids characteristic and reporting information on the associated operations. That study would, at a minimum, provide a characterization of well treatment, completion, and workover fluids used in a representative number of active wells of varying depths (shallow, medium depth and deep depths). In addition, an approved industry-wide study would be expected to provide greater detail on the characteristics of the resulting discharges, including their chemical composition and the variability of the chemical composition and toxicity. The study area should include a statistical valid number of samples of wells located in the Eastern Gulf of Mexico (GOM) and may include the Western and Central Areas of the GOM under the permitting jurisdiction of EPA Region 6, and operators may join the study after the start date. The study plan should also include interim dates milestones.

A plan for an industry wide study plan would be required to be submitted to EPA Region 4 for approval within six months after the effective date of this permit. If the Region approves an equivalent industry-wide well treatment fluids discharge monitoring study, the monitoring conducted under that study shall constitute compliance with these monitoring requirements for permittees who participate in such the industry-wide study. Once approved, the study plan will become an enforceable part of this permit. The study must commence within six months of EPA's approval. If the Region does not approve the study plan or if a permittee does not participate in the study, compliance with all the monitoring requirements for well, completion, and workover fluids is required (see above). The final study report must be submitted no later than three years from the effective date of this permit.

c. This discharge shall be considered "produced water" when commingled with produced water."

PESA-5 *(Cont'd)*

PESA Revised Permit Wording/Clarification:

EPA Region 4 will require development of appropriate toxicity testing strategies to determine a testing procedure that will address the following objectives for evaluation of these fluids. The options will be to:

1) Use EPA protocols already developed for produced water.
2) Develop alternative protocols as an individual operator.
3) Participate in an Industry Work Group to develop an appropriate method or methods meeting the following approach previously used to develop tests for synthetic-based mud cuttings.

Design parameters:

1) Maximum discriminatory power
2) Maximum repeatability of results
3) Practicality of implementation
4) Ranking of known test substances as expected
5) Ecological relevance
6) Government acceptance of the protocols

In a similar fashion, the following approach has been applied to the process of using the laboratory tests to qualify technologies for field application:

Development procedures:

1) Identify all of the available tests
2) Experimentally modify the tests to optimize them to meet the design objectives
3) Conduct screening tests to identify the strengths and weaknesses of the available test methods to meet the design objectives
4) Select a limited number of top contenders and further develop standardized protocols, maximize the positive qualities and minimize the negative qualities of the test
5) Select a top contender and propose the method
6) Validate the test methodology and develop a regulatory limit based on the test
7) Implement the test method in the field and correct any problems that affect the usefulness of the test.

Justification and Supporting Documentation:

The presumptive use of an off-the-shelf toxicity test designed for produced water may result in inappropriate and potentially counterproductive regulatory controls and technology applications. As such, PESA requests that EPA work with industry to develop an objective-based approach to toxicity evaluation that builds on the cooperative approach used during the development of tests for synthetic-based mud cuttings.

Examination of existing research highlights limitations in the proposed approach. For instance, it is well known that mysid shrimp have ion intolerance, therefore, any test for completion fluids and similar low solids/high salt solids free toxicity test are likely to primarily be driven by ion intolerance. Other targeted pollutants such as toxic pollutants or hydrocarbons, or surfactants other non-conventional pollutants would not be accurately monitored because the test would be blinded with ion toxicity. This issue was summarized in SPE 37909 which discussed using Salinity-Toxicity Relationships in Toxicity Identification Evacuation (TIEs) for Produced Water. In this paper, the authors identified that Toxicity Identification Evaluations could be enhanced by the use of a Salinity Toxicity Relationship. The conclusions reached included:

- Traditional Toxicity Identification Evaluations (TIE) methods are ineffective in isolating toxicity due to common ions such as chloride, potassium, Calcium etc.
- Salinity Toxicity Relationship (STR) models can accurately predict ion related toxicity in effluents. When combined with mock effluent studies, STRs provide important evidence in TIE investigations.
- STRs can be used for many different effluents.

In addition, SPE 37909 and other SPE papers have further developed the concept and understanding of the role ions have is conventional effluent discharge testing. These papers include SPE 35845, SPE29730, SPE 26007. Consequently, the development of appropriate tests instead of off-the-shelf tests designed for other purposes is appropriate in this case for evaluation potential toxicants in completion fluids and other high salt, low solids fluids.

Additional consideration needs to focus on before use and after use and also recovered use of these fluids. In many cases expensive completion fluids are recovered and reused from well to well.

Test Procedures and Definitions, Test Procedures, Formation Oil – Part V., A., 9.

Current Region 4 Proposed Permit Language:

"a. Contamination of Non-Aqueous Based Drilling Fluids

The approved test method for permit compliance is Gas Chromatography/Mass Spectrometry (GC/MS) contained in Appendix 5 of 40 C.F.R. Part 435, subpart A (or most current EPA approved method). This test shall be performed prior to drilling. The GC/MS method reports results for the GC/MS test as a percentage crude contamination when calibrated for a specific crude oil. In order to define an applicable pass/fail limit to cover a variety of crude oils, the same crude oil used in calibration of the Reverse Phase Extraction (RPE) test shall be used to calibrate the GC/MS test results to a standardized ratio of the target ION Scan 105 (or most current EPA approved method). Based on the performance of a range of crude oils against the standardized ratio, a value will be selected as a pass/fail standard which will represent detection of crude oil."

PESA-6

PESA Revised Permit Wording/Clarification:

a. Contamination of Non-Aqueous Based Drilling Fluids

The approved test method for permit compliance is Gas Chromatography/Mass Spectrometry (GC/MS) contained in Appendix 5 of 40 C.F.R. Part 435, subpart A (or most current EPA approved method). This test shall be performed prior to drilling. The GC/MS method reports results for the GC/MS test as a percentage crude contamination when calibrated for a specific crude oil. In order to define an applicable pass/fail limit to cover a variety of crude oils, the same crude oil used in calibration of the Reverse Phase Extraction (RPE) test shall be used to calibrate the GC/MS test results to a standardized ratio of the target ION Scan 105 (or most current EPA approved method). Based on the performance of a range of crude oils against the standardized ratio, the following modification will be used.

7.2.1 Crude Oil Reference- NIST 1582 or NIST 2779 Petroleum Crude Oil Standard Reference Material (U.S. Department of Commerce National Institute of Standards and Technology, NIST 2779 Petroleum Crude Oil Standard Reference Material (U.S. Department of Commerce National Institute of Standards and Technology)).

7.2.5 Crude oil drilling fluid calibration standards -Prepare a 4-point crude oil drilling fluid calibration at concentrations of 0% (no spike-clean drilling fluid), 0.5%, 1.0%, and 2.0% by volume according to the procedures outlined below using the Reference Crude Oils:

For NIST 1582

7.2.5.1 Label 4 vials with the following identification: Vial 1-0%Crude in NAF drilling fluid, Vial 2-0.5%Crude in NAF drilling fluid, Vial 3-1%Crude in NAF drilling fluid, and Vial 4-2%Crude in NAF drilling fluid.

7.2.5.2 Vial 1 will not be spiked with Reference Oil in order to retain a "0%" oil concentration, add 5 mL of clean NAF base fluid only.

7.2.5.3 Weigh 90.5 mg of NIST Crude Oil into Vial 2 and add 5 mL of clean NAF base fluid. This will be the 0.5% Crude equivalent in NAF mud standard.

7.2.5.4 Weigh 181 mg of NIST Crude Oil into Vial 3 and add 5 mL of clean NAF base fluid. This will be the 1.0% Crude equivalent in NAF mud standard.

7.2.5.5 Weigh 362 mg in NIST Crude Oil in Vial 4 and add 5 mL clean NAF base fluid. This will be the 2.0% Crude Equivalent in NAF mud standard

7.2.5.6 Thoroughly mix the contents of each of the 4 vial by shaking vigorously.

For NIST 2779

7.2.5.1 Label 4 vials with the following identification: Vial 1-0%Crude in NAF drilling fluid, Vial 2-0.5%Crude in NAF drilling fluid, Vial 3-1%Crude in NAF drilling fluid, and Vial 4-2%Crude in NAF drilling fluid

7.2.5.2 Vial 1 will not be spiked with Reference Oil in order to retain a "0%" oil concentration, add 5 mL of clean NAF base fluid only.

7.2.5.3 Weigh 24.4 mg of NIST Crude Oil into Vial 2 and add 5 mL of clean NAF base fluid. This will be the 0.5% Crude equivalent in NAF mud standard.

7.2.5.4 Weigh 48.9 mg of NIST Crude Oil into Vial 3 and add 5 mL of clean NAF base fluid. This will be the 1.0% Crude equivalent in NAF mud standard.

7.2.5.5 Weigh 97.7 mg in NIST Crude Oil in Vial 4 and add 5 mL clean NAF base fluid. This will be the 2.0% Crude Equivalent in NAF mud standard

7.2.5.6 Thoroughly mix the contents of each of the 4 vial by shaking vigorously.

12.1 Total Area Integration Method

12.1.1 Using C8 to C13 TIC area, the TCB area in the clean NAF sample and the TIC linear regression curve, compute the oil equivalent concentration of the C8 to C13 retention time range in the clean NAF. Note: The actual TIC area of the C8 to C13 is equal to the C8 to 116 C13 area minus the area of the TCB.

12.1.2 Using the corresponding information for the authentic sample, compute the oil equivalent concentration of the C8 to C13 retention time range in the authentic sample.

12.1.3 Calculate the concentration (% oil) of oil in the sample by subtracting the oil equivalent concentration (% oil) found in the clean NAF from the oil equivalent concentration (% oil) found in the authentic sample. The C8 to C13 TIC area will not work well for clean NAF samples that contain measurable amounts of paraffins in the C8 to C13 range.

PESA-6 *(Cont'd)*

12.2 EIP Area Integration Method

12.2.1 Using the ratio of the 105 EIP area to the TCB m/z 91 EIP area in the clean NAF sample, and the appropriate EIP linear regression curve, compute the oil equivalent concentration of the in the clean NAF.

12.2.2 Using the corresponding information for the authentic sample, compute its oil equivalent concentration.

12.2.3. If the ratio of the of the 105 EIP area to the TCB m/z 91 EIP area for the authentic sample is greater than that for the 1% formation oil equivalent calibration standard, the sample is considered contaminated with formation oil.

Justification and Supporting Documentation:

In the development of the GC/MS procedure for formation oil testing in Synthetic Based Drilling Fluids, it was documented to the Agency that there is a wide variety of crude oils in the GOM. Use of a single crude oil reference and calibration of the crude oil to be representative promotes a consistent and accurate approach to a pass/fail limit.

PESA-7

Standardization of Testing Methods & References

Permit Citation	Current Region 4 Proposed Permit Language:	PESA Revised Permit Wording/Clarification:
Part I Section 1.b.iii	"The analytical method is cited in 40 C.F.R. Part 435, Appendix 2 of subpart A, entitled, "Drilling Fluid Toxicity Test.""	The analytical method is cited in EPA Method 1619.
Part I Section 1.b.iv	"Monitoring shall be performed once per week using the Static Sheen Test method in accordance with the method provided in Part V.A.3, as published in 40 C.F.R Part 435, Appendix 1 of subpart A."	Monitoring shall be performed once per week using the Static Sheen Test method in accordance with the method provided in Part V.A.3. (EPA Method 1617).
Part I Section 2.b.iii	"The analytical method is cited in 40 C.F.R. Part 435, Appendix 2 of subpart A, entitled, 'Drilling Fluid Toxicity Test.'"	The analytical method is EPA Method 1619.
Part I Section 2.c.i.(1)	"Once prior to drilling using the gas chromatography/mass spectrometry (GC/MS) method specified in Appendix 5 of 40 C.F.R. Part 435, subpart A. Alternatively, the permittee may provide certification, as documented by the supplier(s) that the drilling fluid being used on the well contains no formation oil as determined using the	Once prior to drilling using the gas chromatography/mass spectrometry (GC/MS) EPA Method 1655. Alternatively, the permittee may provide certification, as documented by the supplier(s) that the drilling fluid being used on the well contains no formation oil as determined using the GC/MS EPA Method 1655.

	GC/MS method in Appendix 5 of 40 C.F.R. Part 435, subpart A."	
Part I Section 2.c.i.(2)	"Once per week during drilling using the Reverse Phase Extraction (RPE) test method specified in Appendix 6 of 40 C.F.R. part 435, Subpart A."	Once per week during drilling using the Reverse Phase Extraction (RPE) test method EPA Method 1670.
Part I Section 2.c.ii	"The approved test method is ASTM method no. E1367-92 (or the most current EPA approved method) and monitoring for this parameter shall be once per month per well."	The approved test method is EPA Method 1644 and monitoring for this parameter shall be once per month per well.
Part I Section 2.d.ii	"Monitoring for the parameter shall be performed at least once per year on each fluid blend using the 10-day LC50 sediment toxicity test specified in ASTM E1367-92 (or the most current EPA approved method), and reported on the DMR."	Monitoring for the parameter shall be performed at least once per year on each fluid using EPA Method 1644 and reported on the DMR.
Part I Section 2.d.iii	"Monitoring for the parameter shall be performed at least once per year on each fluid blend using International Standards Organization (ISO) Method 11734:1995 (or the most current EPA approved method) and results reported on the DMR."	Monitoring for the parameter shall be performed at least once per year on each fluid using EPA Method 1647 and results reported on the DMR.
Part V.A.2	"The approved sampling and test methods for permit compliance are provided in the final effluent guidelines published at 58FR 12507 on March 4, 1993, as Appendix 2 to subpart A of 40 C.F.R. Part 435."	The approved sampling and test methods for permit compliance is EPA Method 1619 (Drilling Fluids Toxicity Test).
Part V.A.3	"The approved sampling and test methods for permit compliance are provided in the final effluent guidelines published at 58 FR 12506 on March 4, 1993 as Appendix 1 of subpart A of 40 C.F.R. Part 435."	The approved sampling and test method for permit compliance is EPA Method 1617 (Static Sheen Test).
Part V.A.6	"The approved test method for permit compliance in identified as ASTM E1367-92 (or most current EPA approved method) entitled, Standard Guide Conducting 10-day Static Sediment Toxicity Test s with Marine	The approved test method for permit compliance is EPA Method 1644 (Sediment Toxicity Test for NAF and SBM) and sediment preparation procedures specified in EPA Method

PESA-7 *(Cont'd)*

	and Estuarine Amphipods (or the most current EPA approved method), with Leptocheirus plumulosus as the test organism and sediment preparation procedures specified in Appendix 3 of 40 C.F.R. Part 435, subpart A."	1646 (Procedure for Mixing Base Fluids with Sediments).
Part V.A.7	"The approved method for permit compliance is identified as International Standards Organization (ISO) 11734:1995 (or the most current EPA approved method) entitled, water quality Evaluation of the ultimate anaerobic biodegradability of organic compounds in digested sludge Method by measurement of the biogas production (1995 edition), supplemented with modification in Appendix 4 of 40 C.F.R. part 435, subpart A."	The approved method for permit compliance is EPA Method 1647 (Determination of the Amount of Non-Aqueous Drilling Fluid (NAF) Base Fluid from Drill Cuttings by a Retort Chamber (Derived from API Recommended Practice 13B 2)).
Part V.A.9.a	"The approved test method for permit compliance is Gas Chromatography Mass Spectrometry (GC MS) contained in Appendix 5 of 40 C.F.R. Part 435, subpart A (or most current EPA approved method)."	The approved test method for permit compliance is EPA Method 1655 (Determination of Crude Oil Contamination in Non-Aqueous Drilling Fluids by Gas Chromatography Mass Spectrometry (GC MS)).
Part V.A.9.b	"The approved test method for permit compliance is the RPE method in Appendix 6 of 40 C.F.R. Part 435, subpart A, which is applied to drilling fluid removed from drill cuttings. If the operator wished to confirm with results of the RPE method (Appendix 6 of 40 C.F.R. Part 435, subpart A), the operator may use the GC MS compliance assurance method (Appendix 5 of 40 C.F.R. Part 435, subpart A)."	The approved test method for permit compliance is EPA Method 1670 (Reverse Phase Extraction (RPE) Method for Detection of Oil Contamination in Non-Aqueous Drilling Fluids (NAF)), which is applied to drilling fluid removed from drill cuttings. If the operator wished to confirm with results of the RPE method (EPA Method 1670), the operator may use the GC MS compliance assurance method (EPA Method 1655).
Part V.A.10	"The approved test method for permit compliance is identified as ASTM E1367-92 (or the most current EPA approved method) entitled, Standard Guide Conducting 10-day Static Sediment Toxicity Test s with Marine and Estuarine Amphipods, with Leptocheirus plumulosus as the test organism and sediment preparation	The approved test method for permit compliance is EPA Method 1644 (Sediment Toxicity Test for NAF and SBM) and sediment preparation procedures specified in EPA Method 1646 (Procedure for Mixing Base Fluids with Sediments).

PESA-7 *(Cont'd)*

	procedures specified in Appendix 3 of 40 C.F.R. Part 435, subpart A."	
Part V.A.14	"Protocol for the Determination of Degradation of Non aqueous Base Fluids in a Marine Closed Bottle Biodegradation Test System: Modified ISO 11734."	This section should be removed as the procedures are outline in EPA Method 1647 (Protocol for the Determination of Degradation of Non-Aqueous Base Fluids in a Marine Closed Bottle Biodegradation Test System: Modified ISO 11734:1995).

Justification and Supporting Documentation:

The requested language change in the sections noted above ensures that there is standardization in testing methods across the permit. Further, this will reflect industry practices regarding testing terminology and references.

Appendix

Item 1:
Below is a summary of the test results for the barite samples using Method 7471B and the newer methods (7473), (245.7 +3051A).

Sample	Cold vapor AA Method 7471B Hg mg/kg	Method 7473 Instrument 3000 Hg mg/kg	Method 7473 Instrument 80 Hg mg/kg	Method 245.7 with Method 3051A digestion Hg mg/kg
Barite Samples 20151501	0.06		0.05	
Barite control sample with know .62 Mean Hg Value (API Control)	0.53		0.57	
Barite samples 20053089	0.57	0.714		
barite with known long term average value of 2.2 mg/kg (ViVi)	2		1.97	
Barite 20151609	7.5	0.734	0.89	8.01

Review of Method Scope and Application

Region 4 proposed and alternatives	Region 6 current
Analyses for cadmium shall be conducted by EPA Methods **200.7**, **200.8** or EPA Method **3050 B followed by 6010 B or 6020A** (EPA SW 846), or more recently approved EPA methods, and results shall be expressed in mg kg (dry weight) of stock barite. Analysis for mercury shall be conducted using EPA method **245.7 or EPA method 7471 A** (EPA SW 846), or most recently approved EPA methods and expressed as mg kg (dry weight) of stock barite	Analyses for mercury shall be conducted using EPA Method **245.5, Method 7471 A**, or more recently approved methods and the results expressed in mg kg (dry weight) Analysis for cadmium shall be conducted using EPA methods 200.7 200.8 or EPA method 3050 B followed by 6010B or 6020, or more recently approved methods and the results expressed as mg kg (dry weight) of barite
Method 245.7 - 1.1 Method 245.7 is for determination of mercury (Hg) in filtered and unfiltered water by cold-vapor atomic fluorescence spectrometry (CVAFS). **It is applicable to drinking water, surface and ground waters, marine water, and industrial and municipal wastewater.** IX 2008	**Method 245.5** 1.1 **This procedure measures total mercury (organic (1) + inorganic) in soils, sediments, bottom deposits and sludge type materials**
EPA METHOD 7471 a WAS REVISED TO EPA METHOD 7471b in 2007 7471B 1.1 This method is a cold-vapor atomic absorption procedure for measuring the following RCRA analyte in soils, sediments, bottom deposits, and sludge-type materials Analyte CAS Number	EPA METHOD 7471 a WAS REVISED TO EPA METHOD 7471b in 2007 7471B 1.1 This method is a cold-vapor atomic absorption procedure for measuring the following RCRA analyte in soils, sediments, bottom deposits, and sludge-type materials

Mercury, total (organic and inorganic) 7439-97-6 * Chemical Abstracts Service Registry Number	Analyte CAS Number* Mercury, total (organic and inorganic) 7439-97-6 * Chemical Abstracts Service Registry Number
EPA method 7473 1.1 This method is for the determination of the following RCRA analyte in solids, **aqueous samples, and digested solutions in both the laboratory and field environments:** aqueous samples, and digested solutions in both the laboratory and field environments Analyte CAS No a Mercury total (organic and 7439-97-6inorganic) Chemical Abstract Service Registry Number	

References:

Method 245.5 - Mercury in Sediment (Manual Cold Vapor Technique)

https://www.bucksci.com/catalogs/EPA%20Method%20-%20245_5%20-%20Mercury%20In%20Sediment%20Manual%20Cold%20Vapor.pdf

1.1 This procedure measures total mercury (organic (1) + inorganic) in soils, sediments, bottom deposits and sludge type materials.

Method 245.7 - Mercury in Water by Cold Vapor Atomic Fluorescence Spectrometry

https://nepis.epa.gov/Exe/ZyNET.exe/P1008IY8.txt?ZyActionD=ZyDocument&Client=EPA&Index=2000%20Thru%202005&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&UseQField=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5CZYFILES%5CINDEX%20DATA%5C00THRU05%5CTXT%5C00000025%5CP1008IY8.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpfr&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=4

Method 245.7 is for determination of mercury (Hg) in filtered and unfiltered water by cold-vapor atomic fluorescence spectrometry (CVAFS). **It is applicable to drinking water, surface and ground waters, marine water, and industrial and municipal wastewater**. The method is based on a method developed through a collaboration between EPA's Environmental Monitoring Systems Laboratory, EPA Region 4, and Technology Applications, Inc. (Reference 1), and on results from single-laboratory and interlaboratory validation studies. The method contains procedures for controlling contamination that are based on peer-reviewed, published procedures for the determination of mercury in aqueous samples, ranging from marine waters to effluents (References 2 6).

Method 7471B - Mercury in Solid or Semisolid Waste (Manual Cold-Vapor Technique)

https://www.epa.gov/sites/production/files/2015-07/documents/epa-7471b.pdf

"1.1 Method 7471 **is approved for measuring total mercury (organic and inorganic) in soils, sediments, bottom deposits, and sludge-type materials**. All samples must be subjected to an appropriate dissolution step prior to analysis. If this dissolution procedure is not sufficient to dissolve a specific matrix type or sample, then this method is not applicable for that matrix."

Method 7473 - Mercury in Solids and Solutions by Thermal Decomposition, Amalgamation, and Atomic Absorption Spectrophotometry

https://www.epa.gov/sites/production/files/2015-07/documents/epa-7473.pdf

"1.1 This method is for the determination of the following RCRA analyte in solids, aqueous samples, and digested solutions in both the laboratory and field environments:

Analyte CAS No.a Mercury total (organic and 7439-97-6 inorganic)
Chemical Abstract Service Registry Number

Integration of thermal decomposition sample preparation and atomic absorption detection reduces the total analysis time of most samples to less than 5 min in either the laboratory or field setting. Total mercury (organic and inorganic) in soils, sediments, bottom deposits, and sludge-type materials as well as in aqueous wastes and ground waters can be determined without sample chemical pretreatment using this method, except as noted. Alternatively, this method can be used for the detection of total mercury from total decomposition sample preparation methods, such as Method 3052, or for detection of extracted or leached mercury compounds or species from methods such as the 3000 series methods (as detailed in Chapter Three).

NOTE: For unique circumstances when mercury could be bound in silicates or other matrices that may not thermally decompose, validation of direct analysis of the solid should be confirmed with total decomposition with an appropriate method (such as Method 3052), followed by analysis with this method."

Method 3051A - Microwave Assisted Acid Digestion of Sediments, Sludges, Soils, and Oils

https://www.epa.gov/sites/production/files/2015-12/documents/3051a.pdf

"1.1 This microwave extraction method is designed to mimic extraction using conventional heating with nitric acid (HNO3), or alternatively, nitric acid and hydrochloric acid (HCl), according to EPA Method 200.2 and Method 3050. Since this method is not intended to accomplish total decomposition of the sample, the extracted analyte concentrations may not reflect the total content in the sample. This method is applicable to the microwave-assisted acid extraction/dissolution‡ of sediments, sludges, soils, and oils for the following elements:"

Method 3050 B - Acid Digestion of Sediments, Sludges, and Soils

https://www.epa.gov/sites/production/files/2015-06/documents/epa-3050b.pdf

"1.1 This method has been written to provide two separate digestion procedures, one for the preparation of sediments, sludges, and soil samples for analysis by flame atomic absorption spectrometry (FLAA) or inductively coupled plasma atomic emission spectrometry (ICP-AES) and one for the preparation of sediments, sludges, and soil samples for analysis of samples by Graphite Furnace AA (GFAA) or inductively coupled plasma mass spectrometry (ICP-MS). The extracts from these two procedures are not interchangeable and should only be used with the analytical determinations outlined in this section. Samples prepared by this method may be analyzed by ICPAES or GFAA for all the listed metals as long as the detection limits are adequate for the required end-use of the data. Alternative determinative techniques may be used if they are scientifically valid and the QC criteria of the method, including those dealing with interferences, can be achieved. Other elements and matrices may be analyzed by this method if performance is demonstrated for the analytes of interest, in the matrices of interest, at the concentration levels of interest (See Section 8.0). The recommended determinative techniques for each element are listed below:

FLAA/ICP-AES

- Aluminum
- Antimony
- Barium
- Beryllium
- Cadmium
- Calcium
- Chromium
- Cobalt
- Copper
- Iron
- Lead
- Vanadium
- Magnesium
- Manganese
- Molybdenum
- Nickel
- Potassium
- Silver
- Sodium
- Thallium
- Vanadium
- Zinc

GFAA/ICP-MS

- Arsenic
- Beryllium
- Cadmium
- Chromium
- Cobalt
- Iron
- Lead
- Molybdenum
- Selenium
- Thallium

Element		CAS Registry No.[a]
*Aluminum	(Al)	7429-90-5
*Antimony	(Sb)	7440-36-0
Arsenic	(As)	7440-38-2
*Barium	(Ba)	7440-39-3
*Beryllium	(Be)	7440-41-7
Boron	(B)	7440-42-8
Cadmium	(Cd)	7440-43-9
Calcium	(Ca)	7440-70-2
*Chromium	(Cr)	7440-47-3
Cobalt	(Co)	7440-48-4
Copper	(Cu)	7440-50-8
*Iron	(Fe)	7439-89-6
Lead	(Pb)	7439-92-1
*Magnesium	(Mg)	7439-95-4
Manganese	(Mn)	7439-96-5
Mercury	(Hg)	7439-97-6
Molybdenum	(Mo)	7439-98-7
Nickel	(Ni)	7440-02-0
Potassium	(K)	7440-09-7
Selenium	(Se)	7782-49-2
*Silver	(Ag)	7440-22-4
Sodium	(Na)	7440-23-5
Strontium	(Sr)	7440-24-6
Thallium	(Tl)	7440-28-0
*Vanadium	(V)	7440-62-2
Zinc	(Zn)	7440-66-6

Item 2:
Excerpts from "Development Document for Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category" (January 1993, EPA 821-R-93-003, AVAILABLE: https://www.epa.gov/sites/production/files/2015-06/documents/o_g_offshore_dd_1993.pdf):

3.2 COMPLETION

Completion operations include the setting and cementing of the production casing, packing the well and installing the production tubing. The completion process installs equipment in the well which allows hydrocarbons to be extracted from the reservoir. Completion methods are determined based on the type of formation, such as hard sand, loose sand, fine grain loose sand, and loose fine and coarse grain sands. Bridging agents are used to prevent fluid loss from the well to the formation.[6,7]

There are two types of completions, open hole and cased hole. Open hole completions are performed on consolidated formations. Cased hole completions are performed on unconsolidated formations. The majority of completions in the Gulf of Mexico are cased hole.[8] Figure IV-2 presents schematic diagrams of four common completion methods for different formation characteristics.

The completion process consists of the following steps: wellbore flush, production tubing installation, casing perforation, and wellhead installation. The following paragraphs give a brief description of each of these steps.

The initial wellbore flush consists of a slug of seawater that is injected into the casing. These fluids are considered cleaning or pre-flush fluids and can be circulated and filtered many times to remove solids from the well and minimize the potential for damage to the formation.[9] When the well has been cleaned, a second completion fluid termed a "weighing fluid" is injected. This fluid maintains sufficient pressure to prevent the formation fluids from migrating into the hole until the well completion is finished.

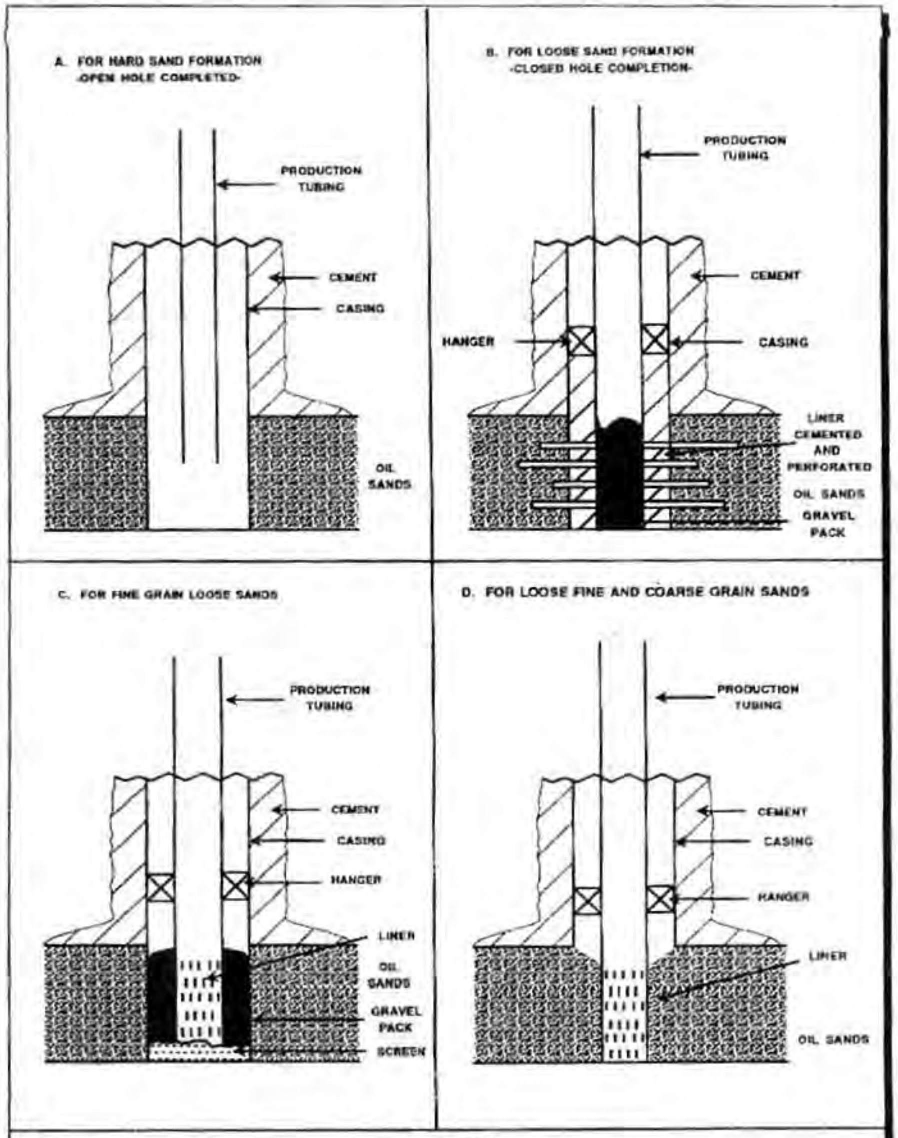


Figure IV-2
Typical Completion Methods

Production tubing is then installed inside the casing using a packer which is placed at or near the end of the tubing. The packer consists of pipe, gripping elements, and sealing elements made of rubber that keep the tubing in place and expand to form a pressure-tight seal between the production tubing and the well casing.[3,10] This seals off the annular space and forces the reservoir fluids to flow up the tubing and not into the well annulus.

Packer fluids are completion fluids that are trapped between the casing and the production tubing by the packer. They can provide long-term corrosion protection. Packer fluids are typically mixtures of a polymer viscosifier, a corrosion inhibitor, and a high concentration salt solution.[11] Packer fluids remain in place and may be removed during workover operations.[12]

The production tubing must then be perforated to allow the formation fluids to flow into the wellbore. The most common method of cased hole completion is perforation. The casing in the well is perforated to allow the hydrocarbons to flow from the reservoir to the well. Perforation may be accomplished with the use of a special perforating gun (usually lowered into the well by wireline) that fires steel bullets or shaped charges which penetrate the casing and cement. An additional means of perforation is achieved by suspending a small perforated pipe from the bottom of the casing.[3,10]

The final step in well completion is the installation of the "Christmas tree," a device that controls the flow of hydrocarbons from the well. The Christmas tree may be installed on the platform (a surface completion) or below the waterline on or below the seafloor (a subsea completion). When the valves of the Christmas tree are initially opened, the completion fluids remaining in the tubing are removed and fluid flow from the formation begins.

3.4 WELL TREATMENT

Well treatment is the process of stimulating a producing well to improve oil or gas productivity. There are two basic methods of well treatment, hydraulic fracturing and acid treatment. The specific method is chosen based on the characteristics of the reservoir, such as type of rock and water cut.[10] A well treatment job will enlarge the existing channels within the formation and increase the productivity of the formation. Typically, hydraulic fracturing is performed on sandstone formations,[10] and acid treatment is performed on formations of limestone or dolomite.[7]

Hydraulic fracturing injects fluids into the well under high pressure, approximately 10,000 pounds per square inch. This causes openings in the formation to crack open, increasing their size and creating new openings. The fracturing fluids contain inert materials referred to as "proppants," such as sand, ground walnut shells, aluminum spheres, and glass beads, that remain in the formation to prop the channels open after the fluid and pressure have been removed.[7,11] Hydraulic fracturing is rarely done in offshore operations because the unconsolidated sandstone formations in the Gulf of Mexico do not require fracturing and the operation requires significant logistical support (i.e., deck space, pumps, mixing equipment, etc.) that is expensive to provide offshore.[4]

Acid stimulation is done by injecting acid solutions into the formation. The acid solution dissolves portions of the formation rock, thus enlarging the openings in the formation. The two most common types of acid treatment are acid fracturing and matrix acidizing. Acid *fracturing utilizing high* pressures results in additional fracturing of the formation. Matrix acidizing uses low pressures to avoid fracturing the formation. The acid solution must be water soluble, safe to handle, inhibited to minimize damage to the well casing and piping, and inexpensive.[7]

In addition to well treatment using hydraulic fracturing and acidizing, chemical treatment of a well may also be performed. Well treatment with an organic solvent like xylene or toluene will remove paraffin or asphalt blocks from the wellbore. These deposits of solid hydrocarbons occur due to the decrease in temperature and pressure when the liquid hydrocarbons are extracted from the well.[14]

3.5 WORKOVER

Workover operations are performed on a well to improve or restore productivity, evaluate the formation, or abandon a well.[8] Loss of productivity can be the result of worn out equipment, restricted fluid flow due to sand in the well, corrosion, malfunctions of lift valves, etc. Several sources indicated that workover operations include well pulling, stimulation (acidizing and fracturing), washout, reperforating, reconditioning, gravel packing, casing repair, and replacement of subsurface equipment.[7,15,16] One source indicates that a well will require workover operations every 3-5 years[16] and another indicates that the average well receives treatment or is worked over approximately every 4 years.[6] The need for workover is related to the percentage of brine in the production fluids. Workover can be performed as often as every 2 years in wells producing greater than 50 percent brine.[9]

The four general classifications of workover operations are pump, wireline, concentric, and conventional.[8] Workovers can be performed using the original derrick from the drilling platform, a mobile workover rig, or by wireline. The operation is begun by forcing the production fluids back into the formation to prevent them from exiting the well during the operation. Then tools and devices can be attached to the wireline (a spool of strong fine wire) and lowered and pulled from the well to perform the require operations.

4.0 WELL TREATMENT, COMPLETION AND WORKOVER FLUIDS

In the Offshore Guidelines, EPA is controlling pollutants found in well treatment, completion and workover fluids commingled and treated with produced water by limiting oil and grease to 29 mg/l monthly average and a 42 mg/l daily maximum. Separate discharges of these wastes are limited by both the above oil and grease limitations and a prohibition on the discharge of free oil. These limitations represent the appropriate level of control under BAT and NSPS.

The pollutants identified to be present in well treatment, completion and workover fluids are summarized in Tables X-12, X-13, and X-14 for workover, completion and well treatment fluids.

Oil and grease serves as an indicator for toxic pollutants in the well treatment, workover and completion fluids waste stream, including, phenol, naphthalene, ethylbenzene, toluene, and zinc. EPA has determined that it is not technically feasible to control these toxic pollutants specifically, and that the limitations on oil and grease in well treatment, workover, and completion fluids reflect control of these toxic pollutants at the BAT and NSPS levels.

EPA has determined, moreover, that it is not feasible to regulate separately each of the constituents in well treatment, completion and workover fluids because these fluids in most instances become part of the produced water wastestream and take on the same characteristics as produced water. Due to the variation of types of fluids used, the volumes used and the intermittent nature of their use,

EPA believes it is impractical to measure and control each parameter. However, because of the similar nature and commingling with produced water, the limitations on oil and grease in the Offshore Guidelines will control levels of certain toxic priority and nonconventional pollutants for the same reason as stated in the previous discussion on produced water.

4.1 POLLUTANTS NOT REGULATED

While the oil and grease and, in certain instances, the no free oil limitations limit the discharges of toxic and nonconventional pollutants found in well treatment, completion and workover fluids, certain other pollutants are not controlled. EPA exercised its discretion not to regulate these pollutants because EPA did not detect them in more than a very few of the samples within the subcategory and does not believe them to be found throughout the offshore subcategory; and the pollutants when found are present in trace amounts not likely to cause toxic effects.

SECTION XIV

COMPLIANCE COST AND POLLUTANT LOADING DETERMINATION— WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

1.0 INTRODUCTION

This section presents the compliance costs for the final regulatory options for treatment and disposal of well treatment, workover, and completion fluids.

2.0 COMPLIANCE COSTS AND POLLUTANT REMOVAL CALCULATION METHODOLOGY

The compliance costs for the BCT, BAT and NSPS treatment options for well treatment, workover, and completion (TWC) fluids are based on volumes of TWC fluids generated and the size of the production platform where the fluids are being generated. Pollutant removals associated with the treatment options were not calculated because there is insufficient data on the chemical characteristics of well treatment, workover, and completion fluids and the fact that since these fluids vary from well to well, a generalized characterization of TWC fluids would be inadequate.

3.0 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS GENERATION RATES

The average volume of workover and completion fluids generated is 300 barrels per well. This volume accounts for a preflush and postflushing of the well and weighting fluid for a 10,000 foot well. According to industry comments and literature, workover and completion fluids are typically reused at least once, so if the same workover or completion is used for two wells, the fluid generated per well is reduced to 150 barrels. The average volume of treatment fluids generated is 250 barrels per well and treatment fluids are typically spent at the end of the job, and thus are not reused. Well workovers or treatment jobs were reported to occur approximately every four years. Well completions are a function of the number of development wells drilled.[1]

For the purpose of estimating the volumes of well treatment, workover, and completion fluids generated, EPA projected the occurrences of well treatments, workovers, and completions over a fifteen year period. Yearly volumes were calculated based on the yearly average of the total volumes generated over the fifteen year period.

4.0 BCT REGULATORY OPTIONS

The BCT limitations for the final rule prohibit the discharge of free oil. Compliance with this limitation is determined by the static sheen test. Because of a lack of sufficient data regarding the levels of conventional pollutants present in both treated and untreated well treatment, workover, and completion fluids, EPA only considered the BCT option as being equal to BPT. There are no costs or non-water quality environmental impacts associated with this BCT limitation.

5.0 BAT AND NSPS OPTIONS CONSIDERED

Well treatment, workover, and completion fluids may either stay in the hole, resurface as a concentrated volume (slug), or surface from the well dispersed with the produced water. Two options were considered for BAT and NSPS control for this waste stream: (1) establish the requirements equal to the current BPT limit of no discharge of free oil (with compliance determined by the static sheen test); or (2) meet the same limitations on oil and grease content as produced water.

In its preferred option for the March 1991 proposal, EPA presented effluent limitations for well treatment, completion, and workover fluids based on requiring zero discharge of any concentrated fluids slug along with a buffer volume preceding and following the fluids slug. Fluids which did not resurface as a distinct slug were proposed to comply with produced water limitations. EPA has since determined that a limitation which requires capturing a buffer volume on either side of a fluids slug is not technologically achievable because it is not always possible and may not be entirely effective. In commenting on the proposal, the industry characterized completion and workover fluid discharges as small volume discharges which occur several times during the workover or completion operations which can last between seven and thirty days. Based on this information, EPA no longer considers the discrete slug and buffer to be a proper characterization of the way workover, completion or treatment fluids resurface from the well. Since the fluids often resurface slowly and over a period of time, and are often commingled with produced water, EPA considers treatment of these fluids commingled with produced water in the produced water treatment system to be the appropriate technology.

The prohibition on the discharge of free oil and cotreatment with produced water requirement are both intended to reduce or eliminate the discharge of toxic pollutants. The method of compliance with the free oil prohibition is the static sheen test. For the no free oil limitation, EPA determined that there would be no incremental compliance costs. The incremental costs and pollutant removals for option 2 are discussed in Sections XIV 5. Pollutant removals are not calculated for option 2 because of the difficulty in characterizing this wastestream.

6.0 INCREMENTAL COST CALCULATIONS

Option 2 requires well treatment, workover, and completion fluids to meet the oil and grease limitations of produced water based on the technology of cotreating these fluids with the produced water treatment system. Treating these fluids with produced water is considered to incur no, or minimal, additional compliance costs. Costs to properly operate the produced water treatment system and monitor for compliance are accounted for in the compliance cost projections for produced water. However, some facilities may be unable to treat well treatment, workover, and completion fluids with the produced water and would incur compliance costs under this option. The following paragraphs discuss the costing methodology for those facilities.

Some facilities may not be able to commingle TWC fluids with the produced water stream for treatment because of the relative volume of produced water generated and/or the size of the produced water treatment system. In this case, the introduction of the TWC fluids to the produced water treatment system may dramatically affect the separation efficiency of the treatment system resulting in non-compliance with the NPDES permit and subsequent fines. A 1989 industry report stated that facilities with less than ten producing wells would most likely experience produced water treatment system upsets due to commingling of TWC fluids with the produced water stream for treatment. The report stated that facilities with greater than ten wells will have large enough treatment systems to provide sufficient dilution of the TWC fluids such that upsets will not occur. To account for the technical limitations of commingling TWC fluids, EPA developed compliance costs based on the technology of capturing and transporting the wastes to shore for treatment and/or disposal for facilities with fewer than ten well slots. The only platforms with fewer than ten well slots are located in the Gulf of Mexico. In the EPA's production profiles, these facilities are the model platforms Gulf 1a, 1b, 4, and 6. Onshore disposal costs for TWC fluids were developed for the Gulf 1a, 1b, 4, and 6 facilities currently discharging offshore, which is 67 percent since 37 percent of all structures in the Gulf are currently piping produced water to shore for treatment.[1]

6.1 VOLUMES GENERATED FROM EXISTING STRUCTURES

To calculate the volumes of well treatment and workover fluids generated from existing facilities (completions are considered new sources), EPA assumed that a well treatment or workover job would occur every four years. EPA also estimated the average volume generated from either a well treatment or workover job as being 200 barrels a job (This is the arithmetic average of typical volume generated from a well treatment, which is 250 barrels, and from a workover, which is 150 barrels). EPA developed a yearly well treatment/workover volume by dividing the average volume generated by four. The total volumes of well treatment and workover fluids generated were calculated by multiplying the average yearly volume by the total number of wells. Table XIV-1 presents the volumes of well treatment and workover fluids generated from the existing Gulf 1a, 1b, 4, and 6 model platforms.

TABLE XIV-1

TOTAL BAT WORKOVER AND TREATMENT VOLUME GENERATION ESTIMATES

Structure Type:	Total Structures Discharging Offshore	Number of Wells per Structure	Total Number of Producing Wells	Volume of Workover/Treatment Fluids Generated (barrels per year)	Onshore Reinjection Costs ($/yr)
Oil Facilities:					
Gulf 1a	89.55	2	89.55	4,477.5	53,730
Gulf 1b	13.23	2	13.23	661.5	7,938
Gulf 4	27.72	8	110.88	5,544	66,528
Gulf 6	11.97	12	71.82	3,591	43,092
Oil and Gas:					
Gulf 1a	139.86	2	139.86	6,993	83,916
Gulf 1b	61.74	2	61.74	3,087	37,044
Gulf 4	75.6	8	302.4	15,120	181,440
Gulf 6	80.01	12	480.06	24,003	288,036
Gas:					
Gulf 1a	332.01	2	332.01	16,600.5	199,206
Gulf 1b	170.1	2	170.1	8,505	102,060
Gulf 4	110.88	8	443.52	22,176	266,112
Gulf 6	100.8	12	604.8	30,240	362,880
Total:	1,213.47		2,819.97	140,998.5	1,691,982

6.2 VOLUMES GENERATED FROM NEW STRUCTURES

The constrained scenario drilling profiles were used to calculate the volumes of completion fluids generated from new sources. EPA identified the projected number of new wells drilled associated with the Gulf 1b, 4, and 6 model platforms. EPA determined that 1754 wells would be drilled under the constrained scenario from the Gulf 1b, 4, and 6 model platforms over the 15 year period following promulgation of this rule. For a more detailed discussion on the constrained scenario refer to the *Economic Impact Analysis* for this rule. A yearly average of wells drilled was calculated to determine the yearly number of completions and the yearly volume of completion fluids generated. The average number of wells drilled per year from a Gulf 1b, 4, and 6 model platform is 115.

The number of well treatment and workover jobs for new source wells was determined based on the fact that a well treatment or workover is done every four years and that 115 new wells are drilled per year. In the first four years of the fifteen year period, no treatment or completion jobs are done but in the fifth year 115 treatment or completion jobs are performed and in the subsequent years more treatment or workover jobs are performed as the population of existing wells increases. The average well treatment/workover fluid volume was used to determine the total treatment/workover fluid volumes generated from new sources.

Table XIV-2 presents the volumes of well treatment, completion, and workover fluids generated from new source Gulf 1b, 4, and 6 model platforms.

TABLE XIV-2

NSPS WORKOVER AND COMPLETION SCHEDULE, VOLUME ESTIMATES, DISPOSAL COSTS

Year	Number of Wells Drilled Per Year	Number of Workover/ Treatment Jobs Done Per Year	Number of Completion Jobs Done Per Year	Volumes of Workover/Treatment Fluids Generated (barrels per year)	Volumes of Completion Fluids Generated (barrels per year)	Workover/ Treatment Injection Costs ($ per year)	Completion Injection Costs ($ per year)	Total Onshore Injection Costs ($ per year)
1	115	0	115	0	17,250	0	207,000	207,000
2	115	0	115	0	17,250	0	207,000	207,000
3	115	0	115	0	17,250	0	207,000	207,000
4	115	0	115	0	17,250	0	207,000	207,000
5	115	115	115	23,000	17,250	276,000	207,000	483,000
6	115	115	115	23,000	17,250	276,000	207,000	483,000
7	115	115	115	23,000	17,250	276,000	207,000	483,000
8	115	115	115	23,000	17,250	276,000	207,000	483,000
9	115	230	115	46,000	17,250	552,000	207,000	759,000
10	115	230	115	46,000	17,250	552,000	207,000	759,000
11	115	230	115	46,000	17,250	552,000	207,000	759,000
12	115	230	115	46,000	17,250	552,000	207,000	759,000
13	115	345	115	69,000	17,250	828,000	207,000	1,035,000
14	115	345	115	69,000	17,250	828,000	207,000	1,035,000
15	115	345	115	69,000	17,250	828,000	207,000	1,035,000
Totals:	1,725	2,415	1,725	483,000	258,750	5,796,000	3,105,000	8,901,000
Average workover/treatment costs over 15 year period: 386,400 dollars per year								

6.3 STORAGE COSTS

EPA assumed that there would be no cost for the containment of the spent fluids prior to transporting them to shore for disposal. This assumption is based on the fact that during well treatment, workover, or completion, storage tanks currently exist on the platform or on tending workboats for fluid storage and separation. (To ensure compliance with the current BPT limitations prohibiting discharge of free oil, operators must maintain the capability to capture fluids which, if discharged, would cause a sheen on the receiving waters.) EPA believes that these tanks would provide adequate storage between capturing the fluids as they come out of the well and the time of transporting the fluids to shore.

6.4 TRANSPORTATION COSTS

EPA also did not assign any incremental costs to the transportation of the fluids to shore. Based on comments from industry, EPA determined that the volumes would be small and the regularly scheduled supply boats would have adequate space to transport the containers of spent fluids. As discussed in the above paragraph, EPA determined that the platforms would have adequate space for storage of the spent fluids for the periods when the supply boats are not scheduled for the platform or when offloading to the supply boats is infeasible due to weather conditions.

6.5 ONSHORE DISPOSAL COSTS

EPA determined the most common method of onshore treatment of spent fluids to be injection into underground formations at a centralized treatment facility. The disposal costs are estimated to be $12 per barrel. This cost includes the costs of transporting the fluids from an inland port transfer station to the disposal facility, solids removal if necessary, and reinjection.

6.6 BAT AND NSPS VOLUMES AND DISPOSAL COSTS

Table XIV-1 presents the BAT workover and treatment volume generation estimates and onshore disposal costs. Volume estimates and disposal costs for completion fluids are not included in the BAT costs because completion fluids are considered wastes from new sources and hence are only assigned to the NSPS costs.

Table XIV-2 presents the yearly NSPS workover, treatment, and completion generation volumes and disposal costs for the fifteen years following promulgation of this rule. Table XIV-2 also presents the average yearly workover and treatment fluid disposal costs for the 15 year period.

7.0 REFERENCES

1. Memorandum from Allison Wiedeman, Project Officer to Marv Rubin, Branch Chief. "Supplementary Information to the 1991 Rulemaking on Treatment/ Workover/Completion Fluids," December 10, 1992.

Item 3:

The most sensitive Zn detection limit can be as low as 0.5 ug/L (0.5 ppb).

TABLE IB—LIST OF APPROVED INORGANIC TEST PROCEDURES—Continued

Item 4 :

Mineral Makeup of Seawater
In order of most to least

ELEMENT	MOLECULAR WEIGHT	PPM IN SEAWATER	MOLAR CONCENTRATION
Chloride	35.4	18980	0.536158
Sodium	23	10561	0.459174
Magnesium	24.3	1272	0.052346
Sulfur	32	884	0.027625
Calcium	40	400	0.01
Potassium	39.1	380	0.009719
Bromine	79.9	65	0.000814
Carbon(inorganic)	12	28	0.002333
Strontium	87.6	13	0.000148
Boron	10.8	4.6	0.000426
Silicon	28.1	4	0.000142
Carbon (organic)	12	3	0.00025
Aluminum	27	1.9	0.00007
Fluorine	19	1.4	0.000074

N as nitrate	14	0.7	0.00005
Nitrogen (organic)	14	0.2	0.000014
Rubidium	85	0.2	0.0000024
Lithium	6.9	0.1	0.000015
P as Phosphate	31	0.1	0.0000032
Copper	63.5	0.09	0.0000014
Barium	137	0.05	0.00000037
Iodine	126.9	0.05	0.00000039
N as nitrite	14	0.05	0.0000036
N as ammonia	14	0.05	0.0000036
Arsenic	74.9	0.024	0.00000032
Iron	55.8	0.02	0.00000036
P as organic	31	0.016	0.00000052
Zinc	**65.4**	**0.014**	**0.00000021**
Manganese	54.9	0.01	0.00000018
Lead	207.2	0.005	0.000000024
Selenium	79	0.004	0.000000051
Tin	118.7	0.003	0.000000025
Cesium	132.9	0.002	0.000000015
Molybdenum	95.9	0.002	0.000000021
Uranium	238	0.0016	0.0000000067
Gallium	69.7	0.0005	0.0000000072
Nickel	58.7	0.0005	0.0000000085
Thorium	232	0.0005	0.0000000022
Cerium	140	0.0004	0.0000000029
Vanadium	50.9	0.0003	0.0000000059
Lanthanum	139.9	0.0003	0.0000000022
Yttrium	88.9	0.0003	0.0000000034
Mercury	200.6	0.0003	0.0000000015

Silver	107.9	0.0003	0.0000000028
Bismuth	209	0.0002	0.00000000096
Cobalt	58.9	0.0001	0.0000000017
Gold	197	0.000008	0.00000000004

0.014 ppm = 14 ppb
Source: https://web.stanford.edu/group/Urchin/mineral.html

PESA-1	A revision to this language was made. EPA disagrees that the information on the Safety Data Sheet should be used to report information on the chemical composition of additives. However, any information submitted can be designated as "Confidential Business Information." Details of the industry-wide study have not been developed yet, but EPA envisions different levels of participation. Participants may still have to report annual information regarding additives used in well treatment, completion and workover operations.
PESA-2	The requested correction was made regarding the EPA approved method for mercury analysis.
PESA-3	No change made. The permit requires operators to maintain a record of chemicals and products added to each well drilled.
PESA-4	No change made. EPA's proposed language is very similar to the language in the current permit, except that operators can submit information on chemical compositions as "CBI". During the term of the current permit, EPA received no complaints regarding restrictions to discharge fluids with priority pollutants in less than "trace" amounts.
PESA-5	Corrections were made to the language regarding the use of Tables 3 and 4 of Appendix A to predict critical dilutions for toxicity tests. EPA disagrees that operators should be allowed to use a different toxicity tests than the current EPA-approved chronic and acute toxicity tests, which are currently being used by many industries nationwide.
PESA-6	No changes made. EPA is unaware of any compliance difficulties or problems with operators using the current procedures in the permit pertaining to contamination of non-aqueous based drilling fluids.
PESA-7	No changes made. EPA is unaware of any ambiguities or problems with operators understanding the required test method to be used based on the current language in the permit.

From: Paul Steury [mailto:pauldsteury@gmail.com]
Sent: Wednesday, October 05, 2016 1:44 PM
To: Maloney, Kelsey <Maloney.Kelsey@epa.gov>
Subject: Frack water?

Hello Kelsey,

My name is Paul Steury and I've been in the field of environmental education for the past 25 years. I actually have taught graduate level Environmental Issue classes.

PS-1

I hope it is not true at this Truth Out website that you are thinking about allowing frack water to be disposed of in the Gulf of Mexico.

http://www.truth-out.org/news/item/37710-epa-plans-to-allow-unlimited-dumping-of-fracking-wastewater-in-the-gulf-of-mexico

Please get back with me to let me know what you are planning on doing with this water that is polluted with unknown chemicals.

Thanks,

Sincerely,
Paul D Steury
MS in Outdoor Resources Management with an emphasis in Environmental Education
Environmental Edu-tainer

pauldsteury@gmail.com
574 320 6062

What's so funny about peace, love and understanding? -Elvis Costello

PS-1	Please see EPA's response SP-1 above..