FACT SHEET AND SUPPLEMENTAL INFORMATION
FOR THE FINAL REISSUANCE OF
THE NPDES GENERAL PERMIT FOR NEW AND EXISTING SOURCES
IN THE OFFSHORE SUBCATEGORY OF
THE OIL AND GAS EXTRACTION POINT SOURCE CATEGORY FOR
THE WESTERN PORTION OF THE OUTER CONTINENTAL SHELF OF
THE GULF OF MEXICO (GMG290000)

September 18, 2017

U.S. Environmental Protection Agency

Region 6

1445 Ross Ave.

Dallas, TX 75202

I. Legal Basis

The Clean Water Act (CWA or the Act), renders it unlawful to discharge pollutants to waters of the United States from any point source, except as authorized by the Act, which may include issuance of an NPDES permit. 33 U.S.C. §§ 1311(a), 1342(a). CWA section 402, 33 U.S.C. section 1342, authorizes the Environmental Protection Agency (EPA) to issue National Pollutant Discharge Elimination System (NPDES) permits allowing discharges on the condition they will meet certain requirements, including CWA sections 301, 304, 306, 401 and 403. Those statutory provisions require NPDES permits include effluent limitations for authorized discharges that: (1) meet standards reflecting levels of technological capability; (2) comply with the EPA-approved state water quality standards; (3) comply with other state requirements adopted under authority retained by states under CWA section 510, 33 U.S.C. section 1370; and, (4) cause no unreasonable degradation to the territorial seas, waters of the contiguous zone, or the oceans.

CWA section 301 requires compliance with "best conventional pollution control technology" (BCT) and "best available pollution control technology economically achievable" (BAT) no later than March 31, 1989. CWA section 306 requires compliance with New Source Performance Standards (NSPS) no later than the effective date of such standards. Accordingly, three types of technology-based effluent limitations are included in the proposed permit. With regard to conventional pollutants, i.e., pH, BOD, oil and grease, TSS, and fecal coliform, CWA section 301(b)(1)(E) requires effluent limitations based on BCT. With regard to nonconventional and toxic pollutants, CWA sections 301(b)(2)(A), (C), and (D) require effluent limitations based on BAT. For New Sources, CWA section 306 requires effluent limitations based on New Source Performance Standards (NSPS). Final effluent guidelines specifying BCT, BAT, and NSPS for the Offshore Subcategory of the Oil and Gas Point Source Category (40 CFR 435, Subpart A) were issued January 15, 1993, and were published at 58 FR 12454 on March 4, 1993. Those guidelines were modified on January 22, 2001 (see 66 FR 6850, January 22, 2001), to include technology based treatment standards for discharges associated with the industry's use of synthetic based drilling fluids.

II. Regulatory Background

On April 3, 1981 (see 46 FR 20284), the EPA published the final general NPDES permit, TX0085642, which authorized discharges from facilities located seaward of the outer boundary of the territorial seas off Louisiana and Texas, an area commonly known as the Outer Continental Shelf. The 1981 general permit implemented "Best Practicable Control Technology Currently Available" (BPT), as established by effluent guidelines for the Offshore Subcategory (see 40 CFR 435). The permits expired April 3, 1983.

The EPA reissued the general permit on September 15, 1983 (48 FR 41494), with an expiration date of June 30, 1984. The permit was issued for a short period of time because promulgation of National Effluent Limitations Guidelines for Best Available Technology Economically Achievable were expected by 1983 and again by 1984. The limitations contained in the permit were unchanged in the 1984 reissuance; however, some changes were made for facilities located near the Flower Garden Banks.

On July 9, 1986 (51 FR 24897), the EPA reissued the general permit. In that action the EPA Region 6 issued a joint permit with Region 4 authorizing discharges from facilities located in the OCS throughout the Gulf of Mexico. That permit, numbered GMG280000, prohibited discharge of oil based drilling fluids, oil contaminated drilling fluids, drilling fluids containing diesel oil, and drill cuttings generated using oil based drilling fluids. New limits were included in the permit for suspended particulate phase toxicity in drilling fluids, the drilling fluid discharge rate near areas of biological concern, and for free oil in drilling fluids and drill cuttings. The permit expired on July 1, 1991.

On November 19, 1992, the EPA Region 6 reissued the NPDES general permit for the Western Gulf of Mexico Outer Continental Shelf (57 FR 54642), GMG290000, covering operators of lease blocks in the Offshore Subcategory of the Oil and gas Extraction Point Source Category located seaward of the outer boundary of the territorial seas of Texas and Louisiana. As a part of that reissuance, new limits for produced water toxicity were added, as well as new limits for cadmium and mercury in stock barite, and a prohibition on the discharge of drilling fluids to which mineral oil has been added. That general permit was modified on December 3, 1993, to implement Offshore subcategory effluent limitations guidelines promulgated March 4, 1993 (58 FR 12504), and to include more accurate calculations of produced water critical dilutions. A general permit covering New Sources in that same area of coverage was issued and combined with the Western Gulf of Mexico Outer Continental Shelf general permit on August 9, 1996 (61 FR 41609). The permit expired on November 19, 1997, and was reissued in two parts on November 2, 1998 (63 FR 58722), and April 19, 1999 (64 FR 19156).

In the 1998 reissuance, the EPA Region 6 authorized new discharges of seawater and freshwater to which treatment chemicals, such as biocides and corrosion inhibitors, have been added. The maximum discharge rate limit for produced water was removed. To account for advances in drilling fluid technology, the permit was modified on December 18, 2001 (66 FR 65209), to authorize discharges associated with the use of synthetic based drilling fluids. Additional monitoring requirements were also included at that time to address hydrostatic testing of existing piping and pipelines and those discharges were authorized. That permit expired on November 3, 2003.

The general permit was reissued on October 7, 2004 (69 FR 60150). With that reissuance, the EPA included produced water monitoring requirements for facilities located in the hypoxic zone. The permit was issued for a three-year term rather than the typical five-year term so that the results from the produced water hypoxia study could be addressed in a timely manner if additional permit conditions were found to be warranted. In the 2007 permit reissuance (72 FR 31575), requirements to comply with new cooling water intake structure regulations were included. Sub-lethal effects were required to be measured for whole effluent toxicity testing. New testing methods were allowed for monitoring cadmium and mercury in stock barite. That permit expired September 30, 2012.

The EPA reissued the permit on September 28, 2012 (77 FR 61605). Operators are required to file electronic Notice of Intent and Discharge Monitoring Reports. The permit required characterization studies for produced water and water-based drilling fluids, respectively, so the EPA could evaluate whether those discharges might contribute heavy metals at a level toxic to aquatic life. Other major changes included toxicity testing requirements for hydrate control fluids, spill prevention best management practices, and allowing the discharge of limited amount of drilling fluids with cuttings due to the testing of subsea safety valves. The permit will expire September 30, 2017.

The EPA proposed permit renewal in the Federal Register Notice of May 11, 2017. In the proposed permit renewal, the EPA proposed several major changes, discussed in the document entitled "Fact Sheet And Supplemental Information For The Proposed Reissuance Of The NPDES General Permit For New And Existing Sources In The Offshore Subcategory Of The Oil And Gas Extraction Point Source Category For The Western Portion Of The Outer Continental Shelf Of The Gulf Of Mexico (GMG290000)" dated April 7, 2017. A 60-day public comment period ending July 10, 2017, was provided. The EPA received comments from seven entities: 1) the Joint Trades, 2) BP Exploration and Production Inc., 3) Environmental Planning Specialists, Inc., 4) International Association of Drilling Contractors, 5) Element-Lafayette, 6) Petroleum Equipment and Services Association, and 7) Center for Biological Diversity. While most of comments from regulated communities focus on operation requirements, comments from CBD mainly focus on regulatory requirements.

III. Coverage of Facilities and Locations

A facility means a platform, rig, ship, and any surface/sub-surface fixed or mobile structure from where exploration, development, or production operations are performed. The permit coverage area consists of lease areas that are located in and discharging to Federal waters in the Gulf of Mexico specifically located in the Central to Western portions of the Gulf of Mexico (GMG290000). The lease areas under Region 6 that begin in the Central portion include: Chandeleur, Chandeleur East, Breton Sound, Main Pass, Main Pass South and East, Viosca Knoll (but only those blocks under Main Pass South and East; the Viosca Knoll blocks between Main Pass and Mobile are under the EPA Region 4 jurisdiction), South Pass, South Pass South and East, West Delta, West Delta South, Mississippi Canyon, Atwater Valley, Lund, and Lund South. These named lease areas and all lease areas westward are part of Region 6. If facilities located in the Louisiana or Texas territorial seas want to discharge to the Outer Continental Shelf, operators need to file Notice of Intent (NOI) under the authority of this permit, GMG290000. But, facilities located in the Louisiana or Texas territorial seas and discharges to territorial seas must be covered under LAG260000 or TXG260000, respectively. Facilities located in the Louisiana or Texas territorial seas are not authorized to discharge drilling fluids and drill cuttings pursuant to the Offshore Subcategory guidelines (40 CFR 435.13 and 435.14).

IV. Types of Discharges Covered

The discharges proposed to be authorized by the reissued permit are listed below. The definitions of the waste streams are based on those given in the Offshore Subcategory Effluent

Limitations Guidelines (40 CFR 435, Subpart A), except for miscellaneous discharges which were not covered by those guidelines. Most of the authorized waste streams are retained from the current 2012 issued permit.

A. Drilling fluids - the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. Classes of drilling fluids are:

(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, enhanced 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.

B. Drill cuttings - the particles generated by drilling into subsurface geologic formations including cured cement 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. Drill cuttings are generally generated from solids control equipment and settle out and accumulate in quiescent areas in the solids control equipment or other 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 CFR 435, Subpart A.

C. Deck drainage - any waste resulting from deck washings, spillage, rainwater, and runoff from gutters and drains including drip pans and work areas within facilities subject to this permit. A use of biocide for sump/drain systems to comply with proper operation and maintenance requirements is permitted and toxicity test for such a discharge of drainage is not required.

D. Produced water - the water 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 generated from the monoethylene glycol (MEG) reclamation processes including salt slurry generated from the salt centrifuge unit is regulated as produced water. However, separate monitoring requirements must be complied with if such salt slurry is not mixed and discharged with produced water waste stream.

E. Produced sand - slurried particles used in hydraulic fracturing, the accumulated formation sands, and scale particles generated during production. Produced sand also includes desander discharge from produced water waste stream and blowdown of water phase from the produced water treatment system.

F. Well treatment, completion fluids and workover fluids - well treatment fluids are any fluids used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled; well 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; and workover fluids are salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair or abandonment procedures.

Packer fluids, low solids fluids between the packer, production string and well casing, are considered to be workover fluids and must meet the effluent requirements imposed on workover fluids. The 2012 permit clarified that propping agents returned with well treatment fluids or produced water meet the definition of produced sands. Fracking fluids are considered well treatment fluids under this permit.

G. Sanitary waste - human body waste discharged from toilets and urinals.

H. Domestic waste - material discharged from galleys, sinks, showers, safety showers, eye wash stations, hand washing stations, fish cleaning stations, and laundries.

I. Miscellaneous discharges –

Aqueous film forming foam (AFFF) - AFFF must be collected and stored for onshore disposal unless the vessel uses a non-fluorinated or alternative foaming agent.

Blowout preventer control fluid - fluid used to actuate the hydraulic equipment on the blow-out preventer. This permit action clarifies that this discharge includes fluid from the subsea wireline "grease-head."

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

Bulk transfer operations powder - de minimis amounts of bulk product (e.g., barite, cement, etc.) that may be released during transfers from supply boats to a drilling rig.
Desalinization unit discharge - wastewater associated with the process of creating freshwater from seawater.
Diatomaceous earth filter media - filter media used to filter seawater or other authorized completion fluids and subsequently washed from the filter.
Excess cement slurry - the excess mixed cement pumped to wells, including additives and wastes from equipment washdown, after a cementing operation. Mixed cement for equipment testing purposes does not meet the definition of excess cement slurry.
Hydrate control fluids - fluids used to prevent, retard, or mitigate the formation of hydrates in and on drilling equipment, process equipment and piping.
Mud, cuttings and cement at the sea floor - discharges that occur at the seafloor prior to installation of the marine riser and during marine riser disconnect, well abandonment and plugging operations.
Pipeline brines - brines used for pipeline/equipment preservation.
Source water and source sand - water from non-hydrocarbon bearing formations for the purpose of pressure maintenance or secondary recovery including the entrained solids.
Subsea production discharges - include: subsea wellhead preservation fluids, subsea production control fluid, umbilical steel tube storage fluid, leak tracer fluid, and riser tensioner fluids.
Uncontaminated or treated ballast/bilge water - seawater added or removed to maintain proper draft (ballast water) or water from a variety of sources that accumulates in the lowest part of the vessel/facility (bilge water) without contact with or addition of chemicals, oil, or other wastes, or being treated for removal of contaminants prior to discharge. These definitions are modified from the current definitions to distinguish ballast water and bilge water and to add the treated ballast water and bilge water to the definition.
Uncontaminated freshwater - freshwater which is discharged without the addition or contact of treatment, chemicals, oil, or other wastes; included are: (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 used during training and testing of personnel in fire protection; and (4) water used to pressure test new piping.
Uncontaminated seawater - seawater which is returned to the sea without the addition or contact of treatment chemicals, oil, or other wastes. Included are: (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 the training and testing of personnel in fire protection; (4) seawater used to pressure test piping; (5) once through noncontact cooling water which has not been treated with biocides, and (6) seawater not treated by chemicals used during Dual Gradient Drilling.

J. Chemically Treated Seawater and Freshwater - seawater or freshwater to which corrosion inhibitors, scale inhibitors, and/or biocides have been added. The existing permitted discharges in the current permit include:

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 piping and pipelines,
5. Ballast water,
6. Once through non-contact cooling water,
7. Seawater used as piping or equipment preservation fluids, and
8. Seawater used during Dual Gradient Drilling.

The seawater used during Dual Gradient Drilling (DGD) is a practice of maintaining two effective fluid gradients in the wellbore annulus while drilling. The denser gradient is below the sea floor and the less dense gradient is above the sea floor. There are two discharges associated with DGD: one is seawater used to provide hydraulic power to Mud Lift Pump; and another is seawater used to provide static head in riser during DGD. Depending on the system design, corrosion inhibitors and biocides may need to be used to prevent corrosion and properly operate and maintain the DGD system.

For a sub-sea discharge of chemically treated seawater or freshwater used for piping and equipment preservation, where to collect discharge samples is not practical, the EPA authorizes those discharges by permitting the operator to conduct the required toxicity tests prior to the use of the product.

The EPA, in 2012, determined that toxicity tests are not required for miscellaneous discharges treated by bromide, chlorine, or hypochlorite. But, uses of bromide, chlorine, or hypochlorite are still required to be in compliance with the technology-based quantity limits.

V. Significant Changes from the Proposed Permit

Significant changes from the proposed permit include.

1. An operator is not required to file eNOI 24-hour in advance to obtain permit coverage;
2. In a case-by-case circumstance, the primary operator may require day-to-day or vessel operators to file their own eNOIs for dual coverages;
3. Drilling vessels performing jobs within the same lease block may file one NOI for coverage;
4. Bridged facilities may file one eNOI;
5. In the event the eNOI system is temporarily unavailable, a written temporary NOI filed with certification and signature is good for seven days from the day of filing, but must followed up with an eNOI;
6. Existing permittees covered under the 2012 permit will be covered by this permit until April 1, 2018, with eNOIs to continue coverage due on or before that date;
7. An operator may file Notice of Termination (NOT) up to one year after termination of lease ownership;

8. Monitoring exception for sanitary and domestic waste discharges using approved Marine Sanitation Device(MSD) from previous permit was reinstated;
9. An oil and grease confirmation sample shall be taken within two hours after sheen is observed from produced water discharge;
10. Operators are not required to report produced water sheen to the National Response Center, but must report all sheen observation events to the EPA;
11. Toxicity testing frequency for produced water discharges remains the same as in the previous permit;
12. Existing dischargers under the 2012 permit shall commence testing schedules in the 2017 permit as of the effective day of this permit;
13. Additional toxicity testing for produced water after an application of well treatment, completion or workover fluids is not required, as information on these discharges will be collected as part of the well treatment, completion, and workover fluids (TCW) Studies;
14. The deadlines for operators to submit the Industry-wide Study Plan and the final report for well treatment, completion, and workover fluids are changed;
15. A condition which requires operators to flush and capture hydrate control fluids or pipeline brine contained in pipelines, umbilical, or jumpers before or at the time of abandonment is removed from the final permit;
16. Fixed monitoring frequency is replaced with tier-approach monitoring frequency for intake velocity through the cooling water intake structure; and
17. An exception to allow operators to submit SEAMAP data instead of entrainment monitoring is added.

Change 1- An operator is not required to file eNOI 24-hours in advance to obtain permit coverage. The EPA proposed that operators file electronic Notice of Intent (eNOI) 24-hours in advance prior to any discharges. The Joint Trades requested that the requirement for a permittee to file a Notice of Intent (NOI) 24-hours in advance be removed from the permit because in certain situations, it is not always feasible for a permittee to file a Notice of Intent (NOI) 24-hours in advance to cover a discharge. Because it is not always feasible for drilling ship or vessel operators to file a NOI 24-hours in advance of discharging, the EPA decided to remove the proposed condition from the final permit. However, operators should be aware that an operator is not authorized to discharge until a complete NOI has been submitted. Therefore, the EPA advises operators to file an NOI for coverage as early as possible (at least 24-hours in advance) in case the eNOI system is temporarily not available or the NOI is incomplete and must be revised.

Change 2- In a case-by-case circumstance, the primary operator may require day-to-day or vessel operators to file their own eNOIs for dual coverages. The 2012 permit allowed either the primary operator or the day-to-day operator to file an NOI for a discharge. Because the primary operator (i.e., the lease holder or designated operator who registers with BOEM) possesses the lease for 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 contactors who conduct the actual work that results in discharges regulated by the permit, EPA believes that the primary operator does have operational control over day-to-day operations, and proposed requiring the NOI to be filed by the primary operator. The final permit will accept NOIs submitted by other operators (e.g., day-to-day operators or vessel operators) only for discharges that could not be controlled by the primary operators. This change will likely reduce unnecessary filing workloads due to changes of day-to-day operators.

The Joint Trades commented that there are instances where third-party operators are in direct control of discharges which are directly associated with exploration, development or production activities. There are also instances when third-party operators may be in direct control of the same type of discharges covered by the eNOI filed by the primary operator. This requirement puts the liability burden on the primary operator for discharges in which they have no, or incomplete, direct control. To address Joint Trades' concern, the EPA adds an additional statement in the final permit which reads: "In a case-by-case circumstance, the primary operator may require day-to-day or vessel operators to file their own eNOIs for dual coverages."

Change 3- Drilling vessels performing jobs within the same lease block may file one NOI for coverage. According to the industry, it is not uncommon for a drilling ship or vessel to make minor position adjustments when drilling more than one well from a common location. Therefore, the EPA proposed that an eNOI filed for a drilling vessel is valid for any drilling jobs with 1500 feet from the originally filed drilling location. The International Association of Drilling Contractors (IADC) commented that there may be instances where the vessel is still in the same lease block but farther than 1500 feet from the previous job site, and vice versa – that the vessel may be in a different lease block but actually less than 1500 feet from an adjoining lease block. For the final permit, drilling vessels are required to file an individual eNOI for drilling jobs only if not all discharges associated with the vessel are covered under the eNOI filed by the primary operator. When a vessel files an eNOI for itself, the vessel is considered a facility and the location of the facility needs to be identified. While the EPA considers 1500 feet apart to be close enough to be considered as the "same" location, jobs located at different blocks may become an issue because the vessel operator also needs to report the lease block code and designated operator information. After considerations of IADC's comment, for the final permit, an eNOI filed for a drilling vessel is valid for different drilling jobs within the same lease block if drilling jobs are performed for the same designated operator." However, ship/vessel operators are still required to update their NOI information for wells in different locations across the lease block, such as the expected/actual drill/discharge commence date, well locations, and the range of depth of water within the operation area or the estimated sea depths at wells.

Change 4- Bridged facilities may file one eNOI. The EPA proposed that each facility must file an eNOI for coverage. The reason the EPA proposed separate NOIs for bridged facilities was that only one discharge monitoring result could be reported for one permitted feature and the EPA understood that bridged facilities have different BOEM/BSEE assigned ID numbers. But, during the public comment period, the Joint Trades commented that BOEM and BSEE recognize bridged facilities as one complex with a single assigned ID number and operators have always reported the worst case for multiple discharges within one permitted outfall or feature. Because bridged facilities have the same BOEM/BSEE ID numbers, the final permit will accept one NOI for bridged facilities.

Change 5- In the event the eNOI system is temporarily unavailable, a written temporary NOI filed with certification and signature is good for seven days from the day of filing, but must followed up with an eNOI. The Joint Trades requested that the EPA allow a 45-day time-period for submittal of the official eNOI via the eNOI system when the eNOI system is unavailable and to allow for the filing of a temporary paper NOI when necessary. According to information available to the EPA, during the current permit term the system has gone down occasionally, but rarely for more than 24 hours. Individuals seeking to register to use the eNOI system, however, have occasionally experienced longer delays in approval of their registrations. The EPA will consider disruptions in both the eNOI filing and eNOI registration systems (including waiting on the EPA personnel to resolve issues) to fall under the meaning of the system being unavailable and thus allow the use of temporary paper NOIs if necessary. In response to the request for more time to file the official electronic NOI, taking into account that the system is rarely down for more than 24 hours, the final permit has been modified to allow submittal of the official eNOI within 7 days, with the ability to request a further extension if a system is still unavailable after 7 days. To assist in transition to the new eNOI system, temporary NOIs for new discharge authorization filed prior to April 1, 2018, can also have until April 1, 2018, if necessary, to file follow-up eNOIs. Submittal of the eNOI will populate the necessary information in the NetDMR system to allow required reporting, some of which may be required in less than 45 days. In any event, it is expected that the temporary NOI process will rarely, if ever, be necessary since the eNOI system is rarely down and most operators will likely file their NOIs far enough in advance to avoid needing to file a temporary paper NOI.

Change 6- Existing permittees covered under the 2012 permit will be covered by this permit until April 1, 2018, with eNOIs to continue coverage due on or before that date. In light of the need for operators to become familiar with the new eNOI system being developed for the GMG290000 permit and in case the new system is not available on the effective date of the permit, the Water Division Director of EPA Region 6 is notifying permittees authorized under the 2012 permit that they are automatically covered by the 2017 permit as of the effective date of the 2017 permit, provided they file an eNOI by April 1, 2018. 40 CFR 122.28(b)(2)(vi) allows Director to notify a discharger that they are covered by a general permit without submittal of an NOI.

Change 7- An operator may file Notice of Termination (NOT) up to one year after termination of lease ownership. The Joint Trades requested a one-year time frame for submittal of NOTs following termination of lease ownership. This request is to account for the many possible reasons a Permittee may be required to hold permit coverage following lease termination. Operators have up to one year from lease expiration to remove a facility. During this timeframe, there could be removal and/or abandonment operations that result in discharges authorized by the permit. A one-year time period reduces the number of NOTs and NOIs, where an operator terminates coverage and then has to reapply for coverage of discharges with in a one-year time frame. The final permit has been modified to extend the timeframe for submittal of NOTs to one year so that operators have ample time to remove facilities or perform associated removal jobs and have authorization for any covered discharges during that time.

Change 8- Monitoring exception for sanitary and domestic waste discharges using approved MSDs from previous permit was reinstated. New information provided to the EPA during the public comment period indicates that the US Coast Guard conducts annual inspections of MSDs in order to issue the Mobile Offshore Drilling Unit (MODU) a Certificate of Compliance. During this inspection, the Coast Guard confirms that the MSD is properly operational and fully functional. Additionally, an overwhelming majority of MODUs are internationally flagged. As such, their Class Society on behalf of Flag State conducts MSD inspections as a requirement for the International Sewage Pollution Prevention Certificate (ISPPC) pursuant to MARPOL, Annex IV [Regulations for the prevention of pollution by sewage from ships]. Therefore, the EPA decided to retain the MSD exception from the 2012 permit in the final permit and requires the operator to demonstrate proper operation of MSD via US Coast Guard approval, annual inspections, Class/Flag State inspections and/or the ISPPC and maintenance logs/records.

Change 9- An oil and grease confirmation sample shall be taken within two hours after sheen is observed from produced water discharge. After considerations of situations where the visual monitoring, supplies storage, and sampling points are located such that mobilizing for sampling within 30 minutes would not be possible, the EPA has retained the 2012 permit's requirement to collect a sample to monitor oil and grease compliance within 2-hours after a sheen is observed.

Change 10- Operators are not required to report produced water sheen to the National Response Center, but must report all sheen observation events to the EPA. The Joint Trades commented that it is clear that NPDES discharges are covered by section 402 of the Clean Water Act, and are not subject to reporting under section 311. Reporting of sheens from permitted discharge points is managed through the Discharge Monitoring Reports, and such events will be reported to the EPA as permit excursions/violations. However, sheens from permitted discharge points need not be reported to the NRC. The final permit does not require produced water sheens to be reported to the NRC as a permit requirement. However, operators have an independent duty to comply with any applicable reporting requirements of CWA §311. Because operators have only reported the maximum number of days for the worst case month of the reporting period under the current reporting requirement, the reporting value does not reflect the total number of sheen observed days during the reporting quarter. To ensure all sheens are properly reported, the final permit requires "total number of days of sheen observed during the reporting period" to be reported in the final permit.

Change 11- Toxicity testing frequency for produced water discharges remains the same as in the previous permit. The EPA proposed to change the produced water toxicity testing frequency from discharge rate-base (quarterly or annually based on discharge rate) to twice per year for all facilities regardless of the discharge rate. Industry requested to retain the current testing frequency in the 2012 permit because the majority of operators perform toxicity tests for produced water on an annual frequency and the proposed increase in frequency to twice a year will be a significant economic burden for offshore operators currently testing for toxicity on an annual basis. The EPA agrees to retain the current toxicity testing frequency in the final permit.

Change 12- Existing dischargers under the 2012 permit shall commence testing schedules in the 2017 permit as of the effective day of this permit. The Joint Trades requested that existing discharges, that are covered under the current permit issued in 2012, should be required to conduct a test within 6 months after they obtain coverage under the reissued permit. Because the final permit allows existing discharges be authorized under this permit as of the effective date of the permit, existing facilities could start a new schedule for toxicity tests. To eliminate confusion during transition to the 2017 permit and provide credit for tests already done during an overlapping monitoring period, the produced water toxicity testing requirement for the final permit includes the following: "Existing dischargers under the 2012 permit shall commence testing schedules in the 2017 permit as of the effective day of this permit. If the permittee qualified to monitor produced water toxicity at the reduced frequency of once per year under the 2012 permit, the required monitoring frequency shall remain at once per year as long as the discharge is compliant with the toxicity limits. Results of testing for any overlapping monitoring period that were done during the previous permit may also be used to satisfy that monitoring period under the 2017 permit."

Change 13- Additional toxicity testing for produced water after an application of well treatment, completion or workover fluids is not required; information on these discharges will be collected as part of the well treatment, completion, and workover fluids (TCW) Studies. The Joint Trades requested deletion of the following proposed condition: "The operator must conduct a new toxicity test if the sample used for the previous test did not represent an application of flow back of well completion fluids, workover fluids, well treatment fluids, or hydrate control fluids." The commenter stated that this new requirement is overly burdensome with challenges, such as 1) well treatment, completion and workover (TCW) fluids study has not been done; 2) uncertainty of how long it will take these fluids to reach the facility and be treated before impacting the produced water discharge and when to take samples; 3) toxicity testing timing needs to be coordinated well in advance with testing laboratories; 4) discrete instances of TCW fluids commingled with produced water are short in duration and careful planning would need to be in place in order to obtain a representative sample with no guarantee that can be accomplished; and 5) operational scenarios frequently change and as the proposed language is very broad and lack clarity, it will be almost impossible for an operator to determine daily whether the previous test was representative of current conditions and an additional toxicity test would need to be conducted. The EPA, after reconsidering this requirement, agrees with the commenters' concerns and has removed the proposed new requirement. However, it is the operator's responsibility to take representative samples to comply with the produced water toxicity testing requirement. The operator may not exclude monitoring at times flow back would be present. The results of the TCW fluids study will be considered in development of permit condition for the 2022 permit reissuance.

Change 14- The deadlines for operators to submit the Industry-wide Study Plan and the final report for well treatment, completion, and workover fluids are changed. The Joint Trades requested to change the planning time from 6 months to 2 years. The EPA agrees that more time than 6 months may be needed to adequately develop the industry-wide study plan. However, an allowance of 2 years to develop a study plan will not provide sufficient time to complete the study and make information available for use in developing the next permit reissuance. To accommodate concerns about additional time that may be needed, the permit has been changed to allow up to 18 months for development of the study plan. In order to allow sufficient time to utilize its results in development of the new permit, which must be proposed by March 2022, the deadline for submittal of the report is October 1, 2021.

Change 15- A condition which requires operators to flush and capture hydrate control fluids or pipeline brine contained in pipelines, umbilical, or jumpers before or at the time of abandonment is removed from the final permit. The permit has established effluent limitations and toxicity testing requirements for hydrate control fluids and pipeline brine, respectively. Because operators need to comply with discharge limitations for hydrate control fluids and for pipeline brine for such discharges anyway, and the EPA considers such limitations to be protective of aquatic life, requiring the operator to capture those fluids may not be necessary. The EPA removed the "flush and capture" requirement from the final permit.

Change 16- Fixed monitoring frequency is replaced with tier-approach monitoring frequency for intake velocity through the cooling water intake structure. The Joint Trades requested a tiered approach to velocity monitoring versus the current daily monitoring requirement for intake velocity through the cooling water intake structure. Namely,

If the Most recent intake flow velocity (ft/s)	Then Monitoring Frequency Should be
<0.300	Quarterly
0.300 – 0.38	Monthly
>0.38	Daily

Velocity monitoring consists of a demonstration requirement based on the facility's' proposed design and a compliance monitoring requirement that verifies the velocity limitation is being met. The EPA agrees that when a facility is operating at an intake velocity about 25% below the limit, a reduced monitoring frequency should still provide reasonable protections. The final permit includes the tiered monitoring approach.

Change 17- An exception to allow operators to submit SEAMAP data instead of entrainment monitoring is added. The Joint Trades requested the removal of entrainment monitoring/sampling requirement and the addition of language requiring permittees to submit a Southeast Area Monitoring and Assessment Program (SEAMAP) data report annually. The Joint Trades commented that 40 CFR 125.137.a.3 provides the Director the flexibility to reduce the frequency of monitoring following 24 months of bimonthly monitoring provided that "seasonal variations in species and the numbers of individuals that are impinged or entrained" can be detected. The report on the 24-month industry entrainment study (1) documents that many important Gulf of Mexico species were not detected at all in the regions where new facilities are expected to be installed so that entrainment impacts on these species will be zero; (2) provided documentation on the seasonal dependence of species and number of eggs and larvae available for entrainment, and (3) concludes that anticipated entrainment will have an insignificant impact on fisheries in any season. The Joint Trades believes that the intent of 40 CFR 125.137 has effectively been met and that the requirement for ongoing entrainment monitoring can be removed. The Joint Trades further stated that the request is based on the results of the recently completed Gulf of Mexico Cooling Water Intake Structure Entrainment Monitoring Study and reinforced by the quarterly entrainment monitoring reports by individual operators. The industry believes that these results warrant removal of the entrainment monitoring/sampling because (a) the study showed that no meaningful impacts from entrainment are expected; (b) no meaningful impact was found, therefore, the seasonality of the impact is a moot point; (c) the SEAMAP database provides a continually-updated source of information that is functionally equivalent to permit-required monitoring for the purpose of estimating entrainment impacts.

The EPA has modified the final permit to allow submittal of SEMAP reports in lieu of entrainment monitoring/sampling after the facility completes two years of entrainment monitoring/sampling. A statement: "[Exception] The permittees who completed or participated in the previous "Gulf of Mexico Cooling Water Intake Structure Entrainment Monitoring Study" or have performed entrainment monitoring for two years, may submit Southeast Area Monitoring and Assessment Program (SEAMAP) data, instead." is included in the final permit.

VI. Summary of Significant Changes from the Current (2012) Permit

The following Table provides a quick comparison of the 2012 permit with this 2017 permit.

Subject	**2012 Permit Conditions**	**Changes for 2017 Permit**	**Rationale for Change**
NOIs	Allowed option for one NOI for all facilities in the same lease block	One NOI for Each facility	See discussion below
NOIs	Content of NOI included basic information such as name of operator, mailing address, location and types of discharges, etc.	Added requirement to include company number and complex ID/API number assigned by or registered with the Bureau of Safety and Environmental Enforcement (BSEE)	See discussion below
NOIs	Ship/vessel operators may file NOI	Clarification: Ship/vessel operators file one NOI for all jobs within the same lease block	See Section V. Change 3 above
NOIs	Facilities engaged in Oil/Gas exploration, development and production are covered by the GP	Add: allow idle drilling ships/vessels (e.g., MODU) to be covered by the GP	See discussion below
NOIs	Existing operators are automatically covered under previous permit until January 31, 2013 (up to 120 days under Administrative Continued permit)	Existing operators get automatic coverage under new permit until April 1, 2018 (about 6 months from the effective date of the permit)	See Section V. Change 6 above

NOIs	Allows paper NOI for temporary coverage until eNOI system becomes available	Requires eNOI. Allows temporary paper NOI good for 7 days if eNOI system is unavailable.	See Section V. Change 5 above
NOTs	Operators file NOT within 60 days after termination of operation	Operators file NOT within 1 year after termination of operation	See Section V. Change 7 above
DMR	NetDMR due by 30 days after the quarterly reporting period	NetDMR due by 60 days after the quarterly reporting period	See discussion below
Drill Cutting	ELG-based limitations	No change	NA
Produced Water	Oil/grease; 29 mg/l avg./42 g/l max limits; 7-day toxicity; sheen report; flow report; report number of days with sheens observed.	Sheen report: total number of days sheen observed during the reporting period instead of during the worst month	See Section V. Change 10 above
Produced Water	If sheen observed, take oil/grease sample	Add: operator must record causes if sheen is observed	See discussion below
Produced Water	Toxicity testing requirements	No change.	NA
Produced Water and Drilling Fluids	Characterization studies	Studies completed- study requirements deleted	See discussion below
Miscellaneous Discharges	No free oil; Toxicity tests	Add coverage for "brine and water-based mud discharge at the seafloor for temporary well abandonment"	See discussion below
Pipeline Brine	Regulated under misc. discharges	Add toxicity testing requirement for pipeline brine	See discussion below
Unused Cement	Only excess cement left from cement job is authorized	Add limited discharges of unused cement from cement job due to emergency situation	See discussion below
Well Fluids	No free oil; no priority pollutants; 29 mg/l avg./42 g/l max. oil/grease limits	Add assessment requirements for well treatment, completion and workover fluids (TCW Study)	See discussion below
Cooling Water Intake Structure	Intake flow velocity limit and impingement monitoring requirement	Change: replace fix intake velocity monitoring frequency to tier monitoring frequency	See Section V. Change 16 above
Cooling Water Intake Structure	Entrainment study and monitoring requirement	Delete entrainment study and allow SEAMAP data to replace entrainment monitoring requirement	See Section V. Change 17 above
Certification	Basic certification.	Add a sentence "I have no personal knowledge that the information submitted is other than true, accurate, and complete." to the existing certification statement	See discussion below

One NOI for each facility. In order to effectively track operators and associated operations, and also because the EPA's eNOI system only assigns one feature number to a specific type of discharge (e.g., drilling fluids, produced water, desk drainage, etc.), the EPA proposed that operators must file an eNOI for each facility (e.g., platform, rig, drilling vessel, and etc.). Because many operators already filed separate NOIs for each facility under the 2012 permit, this change introduces negligible or no incremental cost and negligible or no operational or economical burdens when compared to having to provide the same information in one vs. multiple NOIs and the burden of having to ensure Notices of Termination do not accidentally terminate coverage for other facilities under one NOI - a burden avoided when separate NOIs are submitted for each facility. The final permit includes this provision.

Inclusion of BOEM/BSEE Identification Numbers in NOI. The proposed permit required operators to report company number and complex ID/API number assigned by or registered with the Bureau of Safety and Environmental Enforcement (BSEE) with their eNOIs, so that EPA and BSEE may quickly cross reference to identify a specific facility. This change introduces negligible incremental cost and negligible operational or economical burdens. The final permit includes this provision.

Allow idle drilling ships/vessels the option to be covered by the permit. Some companies requested the option to obtain coverage for discharges from oil and gas facilities that are located in the area of coverage, but not currently conducting oil and gas extraction activities. Any of the discharges, such as deck drainage and sanitary/domestic waste discharges, are the same as would otherwise be authorized by the permit when a facility is operational. Actual exploration and production related discharges would not be occurring during the times the idle facilities were between jobs. Since these facilities are the same as those currently covered by the permit except that the volume and concentration of pollutants in the discharges are expected to be less, it is appropriate that they can be covered under the general permit to avoid the burden on industry and the Agency of applying for and issuing individual permits or shipping wastewaters onshore for disposal. This change introduces no incremental cost and reduces operational or economical burdens. The final permit includes this option.

NetDMR reporting due by 60 days after the quarterly reporting period. The Offshore Operators Committee (OOC) requested the quarterly Discharge Monitoring Report (DMR) to be submitted within 60 days, instead of 30 days, after the end of the reporting period because some operators and consulting companies need to process quarterly DMRs for more than 1,000 facilities. Commenters indicated that tight schedule may compromise reporting's quality assurance/quality control. This change introduces no incremental cost and reduces operational or economical burdens. The final permit allows 60 days after the end of a monitoring period to submit DMRs.

Operators must record causes if produced sheen is observed. The 2012 permit requires the operator to collect a produced water sample for oil and grease analysis 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. The current permit Part II, Section B has a provision of Proper

Operation and Maintenance which requires that 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 permittee as efficiently as possible and in a manner which will minimize upsets and discharges of excessive pollutants and will achieve compliance with the conditions of this permit. The EPA proposed to require the operator, if sheen is observed, to conduct inspection of the treatment process (e.g., oil/water separator) and investigation of the cause of sheen, and keep a record of findings with the operator's daily log and make the record available for inspector's review. After consideration of comments provided by the Joint Trades, the EPA reworded the final permit to read: "If a sheen is observed in the course of required daily monitoring, or at any other time, the Operator must record the sheen and assess the cause of sheen. The operator must keep records of findings and make the record available for inspector's review. The operator must report total number of days of sheen observed during the reporting period."

The current permit also has a provision regarding visual sheen which states that "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." BSEE inspectors have concerns that an operator might interpret this provision to allow permittees to report "no sheen observed" if no sheen was observed in the required once per day visual monitoring, even if a sheen is observed later in the same day. Therefore, the EPA proposed to change the monitoring frequency from once per day to daily (which is not limited to once per day) during the daylight period and an observation of sheen must be recorded whenever a sheen is observed during the day in order to ensure proper operation and housekeeping are maintained all the time. This change introduces negligible incremental cost and negligible operational or economical burdens. The final permit requires daily observations for sheens.

Characterization studies for produced water and water-based drilling fluids are not required. <u>Water-based drilling fluids:</u> The previous permit required operators to conduct a water-based drilling fluid characterization study so that the EPA could evaluate whether or not to establish chemical-specific effluent limitations for drilling fluids necessary in order to further protect aquatic life. The EPA received 25 total metal data sets, 5 dissolved metal data sets, and 84 total metal data sets in solid phase. Based on dissolved metal data, a discharge of drilling fluid would be unlikely to cause exceedance of federal 304(a) recommended water quality criteria (which help inform the 403(c) analysis), which are established in dissolved metal form, at the edge of mixing zone. This change eliminates a monitoring and reporting provision, and thus reduces incremental cost and reduces operational or economical burdens. Accordingly, the EPA did not retain the current characterization study requirement.

Produced waters: The 2012 permit also requires operators to conduct a produced water characterization study so the EPA may evaluate whether discharges of produced water will cause exceedances of 304(a) recommended water quality criteria (which help inform the 403(c) analysis). The EPA received 10 individual reports and one joint (about 40 participants) report. Data have demonstrated that produced water discharges are unlikely to cause exceedance of water quality criteria, unless discharges are at a high discharge volume (> 50,000 bbl/day) to a shallow depth of waterbody. Then, there may be the potential to cause exceedance of water quality criteria at the edge of mixing zone. For instance, copper, cyanide, nickel and zinc may exceed the federal 304(a) recommended water quality criteria at the worst scenario of 11.72 % critical dilution. Because the EPA has used the 7-day chronic toxicity testing to detect an aggregate effect of produced water on aquatic life, and toxic metals or chemicals may be the cause of the excursion of toxicity testing requirements. In response to such excursions, the EPA the 2012 permit included an increased toxicity testing frequency from quarterly to monthly retest frequency for toxicity testing until a test result complies with the toxicity requirements. This permit retains the increased monitoring frequency provision, additionally, this permit also includes a provision to require a toxicity reduction evaluation (TRE) in cases where there is persistent toxicity and the operator could not quickly identify the specific parameter that causes the test excursion. The permit allows the operator to choose other alternatives to a TRE to resolve toxicity excursions (e.g., adjust the discharge rate, add a diffuser, etc.) and comply with the toxicity limits. As the requirement to conduct a TRE or otherwise mitigate the toxic effect of a discharge is expected to be rarely triggered, this change introduces negligible incremental cost and negligible operational or economical burdens.

Add coverage for brine and water-based mud discharge at the seafloor for temporary well abandonment. The Offshore Operators Committee (OOC) requested that "brine and water-based mud discharge at the seafloor for temporary well abandonment" be authorized by the reissued permit as miscellaneous discharges. The OOC states that 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 uppermost 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 would have been isolated in earlier stages of the abandonment with cement and plugs, and the tubing/annulus/casing would have 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 that no hydrocarbon content is allowed (for safety and performance reasons).

This activity does not appear likely to result in an environmental impact. These fluids also should have been demonstrated to be in compliance with the permit's limits to the time they were used. Thus the EPA proposes to add "brine and water-based mud discharge at the seafloor for temporary well abandonment" to the list of miscellaneous discharges that are authorized by the permit if such water based drilling fluid and brine have been demonstrated to comply with the permits conditions for their original use (e.g.: water based drilling fluids that have been shown to meet the permit's limits for SPP toxicity, free oil, and cadmium and mercury in stock barite). The proposed change has been included in the final permit. This change provides for an additional authorized miscellaneous discharge type requested by industry as an alternative to having to prevent such discharges, as such it introduces no incremental cost and reduces operational or economical burdens.

Add toxicity testing requirement for pipeline brine discharges. The EPA was concerned that if brine used for pipeline preservation contained much higher dissolved solids than the receiving water, it may be toxic to aquatic life at times when a high volume of such brine is discharged. The EPA proposed to add toxicity limitations for pipeline brine discharges. The EPA indicated that commenters could provide 7-day chronic toxicity testing results during the public comment period to demonstrate an acceptable discharge rate and total dissolved solids of brine that would reasonably substitute for the toxicity testing requirement. The proposed change has been included in the final permit. As the discharge of pipeline preservation brines is unusual and rarely expected to occur, this change introduces negligible incremental cost and negligible operational or economical burdens.

Discharges of cement tracer and unused cement slurry. Discharge of cement tracers: OOC requested to include cement tracers in the list of miscellaneous discharges. OOC stated that cement tracers would help to clearly identify top of cement behind a wellbore casing and ensure the cemented casing meets technical and HSE requirements for the well. The tracer in question would be a very small quantity (~ 1 mCi) of Sc-46 embedded in inert beads suspended in a gel (~1 cup by volume total), placed in the first 50 bbls of cement pumped (and so may extrude to sea floor for top hole casings). Sc-46 decays by beta emission (with detectable gamma), with a half-life of ~84 days (so effectively gone after 5 half-lives or 420 days). The beads will not float or disperse, rather they will be encapsulated into the cement slurry as it solidifies (over 12-24 hours at the sea floor). Sc-46 beta emissions travel distance in water is estimated at 0.11 cm

Based on information provided by OOC, a small quantity of tracers is used for a job and most tracers will likely be encapsulated into the cement slurry as it solidifies. Also due to the short emission travel distance and short half-life of Sc-46, the proposed discharges are not expected to significantly impact the environment. The final permit adds cement tracers to the list of authorized miscellaneous discharges. This change provides for an additional authorized miscellaneous discharge type requested by industry, and as such it reduces operational or economical burdens.

Unused cement slurry: OOC requested that the permit authorize the discharge of cement slurry used for testing of equipment or resulting from cement specification changes. OOC listed three sources/causes of such extra cement slurry: commissioning of new units, equipment repairs, and off specification cement. OOC has stated that transportation safety is a concern because unused cement slurry must be transported to onshore for disposal before cement slurry becomes dry.

The EPA had concerns that disposal of unused cement slurry, which may add 50% or more cement disposal or application to seafloor, as OOC requested and estimated, may have potential to adversely affect seafloor habitats and/or other direct impact to aquatic life that intakes such substances. The EPA believes that operators may choose to perform commissioning tests at an onshore location, instead of at offshore, and many operators have chosen this approach already, so the final permit does not authorize discharges for equipment testing purposes. Equipment malfunctions could be identified either during routine maintenance or during an ongoing cementing job. The EPA understands if the cement equipment malfunctions during the cementing job, actions to fix the problem must be taken quickly to ensure timely completion of good cement jobs, which are vital in safe completion of wells and avoiding blowouts with their associated environmental, economic, and social costs. Therefore, the final permit does allow discharges of unused cement slurry for equipment repairs, if such a repair, or off specification cement, occurs during the cementing job. Since this would be in the nature of an emergency discharge not expected to be routinely occurring in the normal course of well-run operations, the authorization would be limited to once per calendar year per facility. The EPA proposed to authorize one discharge per well due to the reason of off-specification cement. In either case, as proposed, the operator shall provide date, identification of well or facility, volume of cement, and cause of the discharge with the quarterly report. Record of such discharges shall also be kept on site for inspection. The final permit includes limited discharges of unused cement slurry during the cement job. This change provides for an additional authorized miscellaneous discharge type requested by industry as an alternative to having to prevent such discharges, as such it introduces no incremental cost and reduces no operational or economical burdens.

Add assessment requirements for well treatment, completion and workover fluids (TCW Study). Hydraulic fracturing has led to a significant increase in access to previously inaccessible oil and gas resources and progress toward energy independence for the United States. The activity has also resulted in a high level of public concern across the country. Much of the hydraulic fracturing done in onshore oil and gas wells creates fractures in shale or other relatively impermeable rocks that allows hydrocarbon resources to more readily flow toward the well bore. That type of hydraulic fracturing requires great pressure and large amounts of fracturing fluids. Although hydraulic fracturing is a common practice for offshore oil and gas wells, there are significant differences in the operation compared to that done onshore. Offshore oil and gas in the Gulf of Mexico is currently extracted mostly from unconsolidated sands that have a high permeability. Oil and gas flow freely toward the well bore in those deposits and fracturing is not needed to increase permeability. Instead, hydraulic fracturing is done to repair formation damage near the well bore and prevent erosion of the sand as hydrocarbon flows to the well. Hydraulic fracturing of consolidated formations is also done in a manner different from onshore practices. According to the OOC, offshore hydraulic fracturing requires significantly lower volumes of hydraulic fracturing fluid and additives compared to most onshore wells.

Hydraulic fracturing fluids have been authorized to be discharged offshore under the category of well treatment fluids. Much of those fluids are also comingled with produced water from the formation and discharged with the produced water stream. No available information has been found that suggests that there have been major changes in the chemicals used offshore since the discharges and chemical additives were examined during development of the Effluent Limitations Guidelines; however, no detailed data gathering and analysis has been conducted since then. Because these discharges have not been studied in detail for a number of years and the EPA does not have extensive data showing currently used chemical additives, chemical reporting and toxicity testing requirements were included in the proposed permit. As proposed, the permit would require that the discharge be assessed for each well in which well treatment, completion, or workover operations are conducted and the fluids discharged. Such TCW assessments shall be conducted for each applicable well by operators either cooperatively corporately via participating in an industry-wide TCW study or individually. The assessments may be coordinated with the EPA Region 4 permittees also conducting a similar assessment.

This change adds monitoring and assessment requirements for well treatment, completion and workover fluids. In lieu of each company reporting individually, it allows for an industry-wide study, and furthermore allows for a combined study covering both Region 4 and Region 6 permits. It is expected that the regulated entities will avail themselves of the option to submit one study, as it is likely will result in greatly reduced burden and cost. EPA notes that while this study is new, the previous permit had a provision for a study of Produced Water and Drilling Fluids, EPA believes that these permit conditions impose studies of similar of cost, burden, and complexity, and thus replacing the 2012 study with TCW study in this permit results in negligible incremental cost negligible incremental cost and negligible operational or economical burdens.

Certification. The EPA proposed to add an additional sentence "I have no personal knowledge that the information submitted is other than true, accurate, and complete." to the required certification statement and has included the sentence in the final permit. Although not required by our regulations, the EPA has begun including this language in NPDES permits since the decision in U.S. v. Robison, 505 F.3d 1208 (11^{th} Cir. 2007) (denying conviction for false statement based on certification, despite personal knowledge that information in reports was false). This change introduces no incremental cost and no operational or economical burdens.

Section VII. Supplemental Information for Other Statutory and Regulatory Requirements

State Water Quality Standards and State Certification. The permit does not authorize discharges to State waters; therefore, the state water quality certification provisions of the Clean Water Act (CWA or 'the Act') Section 401 do not apply to this proposed action.

Coastal Zone Management Act. The Environmental Protection Agency determined that activities authorized by this reissued permit are consistent with the local and state Coastal Zone Management Plans. Both the Louisiana Department of Natural Resources and the Railroad Commission of Texas concurred with the EPA's consistency determination.

Oil Spill Requirements. CWA Section 311 prohibits the discharge of oil and hazardous materials in harmful quantities. Discharges authorized by NPDES permits are excluded from the provisions of Section 311. However, the permit does not preclude the institution of legal action or relieve permittees from any responsibilities, liabilities, or penalties for other, unauthorized discharges of oil and hazardous materials which are covered by Section 311 of the Act.

Ocean Discharge Criteria Evaluation. For discharges into waters of the territorial sea, contiguous zone, or oceans, CWA Section 403(c) requires the EPA to consider guidelines for determining potential degradation of the marine environment when issuing NPDES permits. These Ocean Discharge Criteria (40 CFR 125, Subpart M) are intended to "prevent unreasonable degradation of the marine environment and to authorize imposition of effluent limitations, including a prohibition of discharge, if necessary, to ensure this goal" (45 FR 65942, October 3, 1980). The EPA Region 6 determined that discharges in compliance with the Outer Continental

Shelf (OCS) general permit would not cause unreasonable degradation of the marine environment.

Marine Protection, Research, and Sanctuaries Act. The Marine Protection, Research and Sanctuaries Act (MPRSA) of 1972 regulates the transportation for dumping of materials into ocean waters and establishes permit programs for ocean dumping. This reissued permit does not authorize dumping under MPRSA.

In addition, the MPRSA establishes the Marine Sanctuaries Program, implemented by the National Oceanographic and Atmospheric Administration (NOAA). The program requires NOAA to designate certain ocean waters as marine sanctuaries for the purpose of preserving or restoring their conservation, recreational, ecological or aesthetic values. Pursuant to the MPRSA, NOAA has designated the Flower Garden Banks, an area within the coverage of the OCS general permit, a marine sanctuary. The OCS general permit prohibits discharges in areas of biological concern, including marine sanctuaries. The permit authorizes discharges incidental to oil and gas production from a facility which predates designation of the Flower Garden Banks as a National Marine Sanctuary. The EPA has previously worked extensively with NOAA to ensure that authorized discharges are consistent with regulations governing the Flower Garden Banks.

National Environmental Policy Act. In accordance with Section 102 of the National Environmental Policy Act of 1969 (NEPA), the Council on Environmental Quality (CEQ) regulations implementing NEPA (40 CFR parts 1500-1508) and the EPA' s Procedures for Implementing NEPA (40 CFR part 6), the EPA has conducted an independent review and evaluation of the BOEM's EIS for the *Gulf of Mexico OCS Oil and Gas 2017-2022 Multisale.* As a cooperating agency with responsibility for the reissuance of the National Pollutant Discharge Elimination System (NPDES) General Permit No. GMG290000 for existing and new sources and new dischargers in the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, located in and discharging to the OCS offshore Louisiana and Texas, the EPA provided subject matter expertise to the BOEM during the environmental review process. Based on its independent review and evaluation, the EPA has determined the EIS, including all supporting documentation, as incorporated by reference, adequately assesses and discloses the environmental impacts for the reissuance of the NPDES general permit, and that adoption of the EIS by the EPA is authorized under 40 CFR 1506.3. Accordingly, the EPA has adopted the Final EIS for the *Gulf of Mexico OCS Oil and Gas 2017-2022 Multisale* and takes full responsibility for the scope and content that evaluates the discharges under the NPDES general permit. A copy of the EPA Record of Decision may be found on EPA's website at: https://www.epa.gov/npdes-permits/support-documents-npdes-general-permit-offshore-oil-and-gas-operations-western-gulf.

Magnuson-Stevens Fisheries Conservation and Management Act. The Magnuson-Stevens Fisheries Conservation and Management Act requires that federal agencies proposing to authorize actions that may adversely affect essential fish habitat (EFH) consult with the National Marine Fisheries Service (NMFS). The entire Gulf of Mexico has been designated as EFH. The EPA prepared an Essential Fish Habitat Assessment Report and determined that the minimal short-term impacts associated with the permitted NPDES discharges would not result in substantial adverse effects on EFH or managed species in any life history stage, either immediate of cumulative, in the project area. NMFS concurred with the EPA's assessment and agreed that the proposed mitigation measures to be incorporated into the permit will minimize adverse impacts to EFH or federally managed fisheries species. A copy of the EPA Essential Fish Habitat Assessment and NMFS concurrence may be found on EPA’s website at: https://www.epa.gov/npdes-permits/support-documents-npdes-general-permit-offshore-oil-and-gas-operations-western-gulf.

Endangered Species Act (ESA). Section 7 of the Endangered Species Act (16 U.S.C. 1531 *et seq*.) requires Federal agencies to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. In assessing the effects of reissuance of this permit, the EPA considered the effects of activities being authorized by the permit. Unauthorized activities, such as discharges related to spills, are not within the scope of the permitting action and therefore are not an “action authorized, funded, or carried out” by the EPA.

By letter received by the EPA on June 29, 2017, NMFS reaffirmed its ongoing formal consultation with the Bureau of Ocean Energy Management (BOEM), the EPA, and the Bureau of Safety and Environmental Enforcement (BSEE), relating to all federal actions associated with offshore oil and gas activities throughout the Gulf of Mexico. For this consultation, BOEM is the lead action agency and the EPA and BSEE are co-federal action agencies. NMFS confirmed in its letter that the issuance of the NPDES permits is included as a subsect of the federal actions that make up the Proposed Action under the subject ESA section 7 consultation.

The EPA’s existing NPDES General Permit for oil and gas operations in the Western Gulf of Mexico will expire on September 30, 2017. The NMFS and the consulting agencies do not anticipate that the ESA consultation for the oil and gas activities in the Gulf of Mexico will be complete by this date. While more than 3,000 existing permitted facilities are covered by this General Permit, new facilities are unable to obtain coverage after September 30, 2017 until they either obtain an individual permit or the final General Permit is reissued. For these reasons, EPA has determined that it is of the utmost importance to issue the final GP while consultation is pending. Once consultation is complete, EPA will modify this permit should the Agency find that the consultation demonstrates that different permit limits or additional conditions to protect listed species or critical habitat are warranted. Any such change would require public notice and an opportunity for comment. The current permit would remain in effect during those proceedings.

EPA’s decision to issue this permit while consultation is ongoing is consistent with section 7(d) of the ESA because its issuance does not foreclose either the formulation by the Services, or the implementation by EPA, of any alternatives that might be determined in the consultation to be necessary to comply with section 7(a)(2). Furthermore, EPA has authority to modify the General Permit to include any conditions or restrictions on discharge that are identified as necessary by NMFS as a result of the consultation to protect endangered or threatened species or the habitats of such species. *See e.g.*, 40 C.F.R. § 122.62 and §§ 125.122-3. The EPA has inserted a "reopener" provision in the permit specifically stating that the permit will be reopened and modified if necessary to add conditions determined to be necessary to comply with the ESA following the completion of required consultation under Section 7(a)(2) of the ESA. *See* General Permit, Section F, 3. The General Permit fully apprises all permittees of this possibility. Given the authorities to modify or revoke a permit if the consultation process identifies reasonable and prudent alternative measures that are necessary for ESA compliance, an opportunity to impose reasonable and prudent alternative measures is not foreclosed by issuance of the General Permit. Moreover, the EPA has determined that the discharges authorized under the General Permit are not likely to adversely affect listed species and that the issuance of this permit pending the completion of consultation is not likely to jeopardize the continued existence of listed species or adversely modify designated critical habitat. These determinations are consistent with sections 7(a)(2) and 7(d) of the ESA. A copy of the EPA memo supporting this finding is may be found on EPA's website at: https://www.epa.gov/npdes-permits/support-documents-npdes-general-permit-offshore-oil-and-gas-operations-western-gulf.

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. 2040-0004) 'with the exception of information collection activities for 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. As discussed in Section VI. Summary of Significant Changes from the Current (2012) Permit, all changes from the 2012 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 that the promulgation of the Offshore Subcategory guidelines on which many of the permit's effluent limitations are based did not have a significant impact on a substantial number of small entities. (58 FR 12492, 1993). The permit also contains limits based on CWA 403(c) Ocean Discharge Criteria evaluation, but these limits did not change from the 2012 permit limits based on that analysis.