energy API

Offshore Operators Committee

NOIA
America's Offshore Energy Industry

July 10, 2017

Submitted via www.regulations.gov

Water Division
US Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Mail Code: 6EN
Dallas, TX 75202-2733

RE: <u>Joint Trades Comments</u>
Notice of Proposed NPDES General Permit
Permit for New and Existing Sources and New Dischargers in the Offshore Subcategory of the Oil and Gas Extraction Category for the Western Portion of the Outer Continental Shelf in the Gulf of Mexico (GMG290000)
Docket ID No. EPA-R06-OW-2017-0217

The Offshore Operators Committee (OOC), the American Petroleum Institute (API), and the National Ocean Industries Association (NOIA), hereinafter referred to as "the Joint Trades," appreciate the opportunity to provide detailed comments on the above-captioned NPDES General Permit. Comments submitted on behalf of the Joint Trades are submitted without prejudice to any member's right to have or express different or opposing views. It is from this perspective that these comments have been developed.

The Joint Trades

API is a national trade association representing more than 625 member companies involved in all aspects of the oil and natural gas industry. API's members include producers, refiners, suppliers, pipeline operators, marine transporters, and service and supply companies that support all segments of the industry. API and its members are dedicated to meeting environmental requirements, while economically and safely developing and supplying energy resources for consumers. API is a longstanding supporter of offshore exploration and development and the process laid out in the Outer Continental Shelf Lands Act ("OCSLA") as a means of balancing and rationalizing responsible oil and gas activities and the associated energy security and economic benefits with the protection of the environment.

NOIA is the only national trade association representing all segments of the offshore industry with an interest in the exploration and production of both traditional and renewable energy resources on the U.S. Outer Continental Shelf (OCS). The NOIA membership comprises more than 325 companies engaged in a variety of business activities, including production, drilling, engineering, marine and air transport, offshore construction, equipment manufacturing and supply, telecommunications, finance and insurance, and renewable energy.

OOC is an organization of 41 producing companies and 53 service providers to the industry who conduct essentially all oil and gas exploration and production activities in the Gulf of Mexico (GOM) OCS.

Founded in 1948, the OOC is a technical advocate for the oil and gas industry regarding the regulation of offshore exploration, development and producing operations in the GOM.

Comments

The Joint Trades' detailed technical comments are included in the attachment. The Joint Trades believe the information included in the attached comments is important and critical to providing a final permit that is protective of water quality in the GOM, as well as a practical permit that allows the continued development of our nation's energy resources. The attached comments are structured to include suggested edits to the proposed permit language and justification for the suggested change.

Cooling Water Intake Structure Entrainment Monitoring

One concern that the Joint Trades would like to highlight is the continued requirements for cooling water intake structure entrainment monitoring (see Comment 37 in the attachment for more details). The Joint Trades strongly object to the continued requirement to conduct ongoing entrainment monitoring. The Joint Trades request the removal of entrainment monitoring/sampling requirement and the addition of language requiring permittees to submit a SEAMAP data report annually.

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.

Our request is based on the results of 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. 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 Gulf of Mexico Cooling Water Intake Structure Entrainment Monitoring Study was conducted for the purposes of informing policy and permit requirements with sound science. The conclusions of the study are clear – there are no meaningful impacts. Yet, the science presented in the study is not being utilized to inform changes to permit requirements.

Regulatory Reform Initiatives

In addition to the detailed, technical comments included with this letter, the Joint Trades also plan to engage EPA Headquarters in discussions regarding the impact of the recent Presidential Executive Orders 13771, *Reducing Regulation and Controlling Regulatory Cost*, and 13795, *Implementing an America-First Offshore Energy Strategy*, on the renewal of NPDES Permit GMG290000. As presented in the attached detailed comments, the Joint Trades offer several positions that question the necessity of changes proposed in the draft permit. The proposed changes, taken in their entirety, do not appear to be in keeping with the intent of E.O. 13771 and E.O. 13795. Therefore, it is our intent to engage EPA on the need for the proposed changes, whether the proposed changes provide any benefits for water quality of the Gulf of Mexico, and if the proposed changes comply with the Executive Orders.

Also, the Joints Trades, through OOC, will be contacting EPA Region 6 staff, after the comment period closes, to request a meeting to review the attached technical comments, and answer any clarifying questions the agency may have regarding the information provided here.

The Joint Trades appreciate EPA's efforts regarding the draft permit, and look forward to working with the agency on the important issues included in our comments as the permit is finalized. If you have any questions or require additional information, please contact Mr. Greg Southworth at greg@offshoreoperators.com, or Mr. James Durbin at james.durbin@c-ka.com.

Sincerely,

Greg Southworth

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Amy Emmert

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cc (via email):

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Draft NPDES General Permit for New and Existing Sources and New Dischargers 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)

GMG290000 May 11, 2017 Draft Renewal Permit, Docket # EPA-R06-OW-2017-0217 – The Joint Trades 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.	Current or Revised Permit Language /Clarifications/Issue	Rationale
1	Notice of Intent	Part I.A.2	"A Notice of Intent (NOI) must be filed ~~24-hour~~ in advance to cover specific discharges prior to commencement of specified discharges."	<u>The Joint Trades request</u> that the 24-hour requirement of this condition be removed. 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. Due to potentially sudden and unforeseen changes in operational priority, weather conditions, asset availability/functionality, an operator will not always know about commencement of discharging 24-hours in advance. For example, a lift boat conducting well work operations within a specific field is unexpectedly being reprioritized due to any, or all, of the unforeseen factors mentioned above. This requirement could result in additional costs for the operator up to, and including, the day rate for a drill ship or vessel, approximately $1 million per day. <u>The Joint Trades feels</u> that removing the 24-hour notification is more feasible for compliance, while still obtaining proper NPDES coverage prior to discharging. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
2	Notice of Intent	Part I.A.2	The primary operator must file an electronic Notice of Intent (eNOI) for discharges directly associated with oil/gas exploration, development or production activities to be covered by this permit. A separate eNOI is required for each lease block and that eNOI shall include all discharges controlled by the primary operator within the block. Other operators or vessel operators must file an eNOI to cover discharges which are directly under their control ~~but are not directly associated with exploration, development or production activities, only if such discharges are not covered by eNOIs filed by the primary operator~~. Individual coverage by this permit becomes effective when a complete eNOI is signed and submitted.	<u>The Joint Trades request</u> striking the red text language. 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 direct control. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
3	Notice of Intent	Part I.A.2	"~~Note 2: Facilities connected with a bridge (i.e., complex) must file separate eNOIs (i.e., one eNOI for each facility) if both facilities have outfalls for the same type of discharges (e.g., both facilities have outfalls to discharge produced water).~~"	<u>The Joint Trades request</u> clarification on why a separate NOI would now be needed for bridged facilities with duplicate discharges. • BOEM and BSEE recognize bridged facilities as one complex with a single assigned ID number. • Historically, operators have always reported the worst case for multiple discharges within one permitted outfall or feature (PF), whether reporting by lease block or by structure. (i.e. multiple types of miscellaneous discharges, or multiple outlets of one discharge on stand-alone platforms are reported under a single PF number, and one DMR).

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				- The total number of permit exceedances will continue to be reported as required for one PF number limit set DMR, including all discharge points on the facility whether bridged or stand alone. - Covering and reporting multiple bridged facilities separately will generate more Permitted Feature numbers and additional DMRs to be managed by the electronic reporting system, not to mention additional costs associated with the additional coverage reporting. Therefore, the Joint Trades request that the proposed requirement for separate NOIs be removed from the proposed permit language. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
4	Notice of Intent	Part I.A.2	"Operators who filed eNOIs under the previous permit, issued on September 28, 2012, (2012 issued permit) are required to file new eNOI within 90 days from the effective date of this general permit. All existing eNOIs under the 2012 issued permit expire 90 days after the effective date of this general permit. If the eNOI system is unavailable ~~During the down time of the eNOI system~~, operators may submit a short paper NOI which includes information a) through f) listed below or via email~~s~~ to R6_GMG29TEMPeNOI@epa.gov. The stamp date and time of the sent email is evidence of delivery for coverage. An o~~O~~fficial eNOI~~s~~ shall be filed within 45-days of when the eNOI system becomes available."	The Joint Trades are requesting changes and additions to the permit language to provide clarity when eNOI system is unavailable and thus allowing a short paper NOI submittal. In addition, the Joint Trades are requesting a 45-day time-period for submittal of the official eNOI via the eNOI system in-order to provide clarity of expectations. The current language can imply as soon as the system is available an eNOI must be submitted. Since submitting the short paper NOI will allow for coverage under the permit, a 45-day period to submit the official eNOI is simply administrative. It is not clear as to the timeframe when EPA will update the applicable systems (i.e. eNOI and NetDMR) with the information that is submitted. The Joint Trades request clarification and an estimated schedule of when the applicable systems will be ready for use. The Joint Trades are requesting an email address correction based on beta testing issues with EPA Region 6 where it was determined the wrong address was listed in the draft permit. Not accepting the proposed permit language is onerous on operators and an additional burden to the O&G Industry with no apparent additional protection to the environment.
5	Notice of Intent	Part I.A.2	"Facilities which are located in lease blocks that are either in or adjacent to "no activity" areas or require live bottom surveys are required to submit both an eNOI that specifies they are located in such a lease block and a notice of commencement of operations ~~(e.g., drills, installations, discharges, ...)~~"	The Joint Trades request striking out information such as "drills, installations, discharges…". The information is covered in Part 1. A.2 (a through l). The information regarding drills is covered in the drilling permits to BOEM. Also, it is unclear how this information would be added to the eNOI system. The eNOI system already keeps track of the types of discharges that are being planned. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
6	Notice of Termination	Part I.A.3	3. Termination of NPDES Coverage Lease holders or the authorized registered operators shall submit a notice of termination (NOT) to the Regional Administrator within one year~~60 days~~ of termination of lease ownership for lease blocks assigned to the operator by the Department of Interior. (Request for time extension and justification to retain the permit coverage beyond the one year ~~60-day~~ limit shall be sent to the address listed in the subsection 5 below.) In the case of temporary operations such as hydrostatic testing, well or facility abandonment or any other contractual or legal requirement the NOT shall	The Joint Trades request 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 1-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.

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			be submitted within one year ~~60 days~~ of termination of operations. The discharge monitoring report (DMR) for the terminated lease block may be either submitted with the NOT, or submitted on the reporting schedule. The NOT shall be effective upon the date it is received by EPA.	The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
7	Other Reporting Requirements	Part I.A.5	"All NOIs must be filed electronically. Instruction for use of the electronic Notice of Intent (eNOI) system is available in EPA Region 6's website at http://www.epa.gov/region6/6en/w/offshore/home.htm. Operators shall either mail all temporary paper NOIs, NOTs, notices of transfer agreements, notice of merger/acquisition, notice of commencement and all subsequent paper reports under this permit to the following address: Water Enforcement Branch (6EN-WC) U.S. Environmental Protection Agency Region 6 1445 Ross Avenue Dallas, TX 75202 or email pdf documents to an email address at R6_GMG29TEMPeNOI@epa.gov~~).~~ If the eNOI system is unavailable, operators may submit a short paper NOI which includes information a) through f) listed in Part I.A.2 via email to R6_GMG29TEMPeNOI@epa.gov. The stamp date and time of the sent email is evidence of delivery for coverage. An official eNOI shall be filed within 45 days of when the eNOI system becomes available. Additional information regarding these reporting requirements may be found at: http://www.epa.gov/region6/6en/w/offshore/home.htm"	The Joint Trades are requesting an email address correction based on beta testing issues with EPA Region 6 where it was determined the wrong address was listed in the draft permit. The Joint Trades are requesting the additional language to this section of the permit to provide clarity when eNOI system is unavailable and thus allowing a short paper NOI submittal. In addition, OOC is requesting a 45 day time for submittal of the official eNOI via the eNOI system in order to provide clarity of expectations. Further, it should be noted that the EPA website listed is not currently active. The Joint Trades request that this website be activated prior to the effective date of the permit. Additionally, the Joint Trades request the ability to review the electronic NOI instructions prior to them being finalized to allow for clarification and edits as necessary. It is not clear as to the timeframe when EPA will update the applicable systems (i.e. eNOI and NetDMR) with the information that is submitted. The Joint Trades request clarification and an estimated schedule of when the applicable systems will be ready for use. The Joint Trades request that in addition to the electronic NOI instructions, a set of instructions also be made available for DMRs and NOTs. Similar to the electronic NOI instructions requested above, OOC further requests the ability to review the electronic NOT and DMR instructions prior to them being finalized to allow for clarification and edits as necessary. See comment # 41 for additional information regarding NetDMR. The lack of active website, email address and NOI, NOT and DMR instructions is very onerous on operators and the burden to the O&G Industry does not have any apparent additional protection to the environment.
8	Non-Aqueous Based Drilling Fluid - Retention of Cuttings and BMP	Part I.B.2.c.2	Base Fluids Retained on Cuttings. Monitoring shall be performed at least once per day when generating new cuttings, except when meeting the conditions of the Best Management Practices described below. Operators conducting fast drilling (i.e., greater than 500 linear feet advancement of the drill bit per day using non aqueous fluids) shall collect and analyze one set of drill cuttings samples per 500 linear feet drilled, with a maximum of three sets per day. Operators shall collect a single discrete drill cuttings sample for each point of discharge to the ocean. The weighted average of the results of all discharge points for each sampling interval will be used to determine compliance. See Part I, Section D.1~~2~~3 of this permit. b) BMP Plan Requirements The BMP Plan may reflect requirements within the pollution prevention requirements required by the ~~Minerals Management Service~~ Bureau of	The Joint Trades are requesting the changes to reference the correct section of the permit and the agency that replaced Mineral Management Service.

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			Safety and Environmental Enforcement (BSEE) (see 30 CFR 250.300) or other Federal or State requirements and incorporate any part of such plans into the BMP Plan by reference.	
9	Produced Water	Part I.B.4.a	"The addition of dispersants or emulsifiers downstream of treatment system to the overboard produced water discharge lines is prohibited.~~ 40 CFR § 110.4.~~"	The Joint Trades agree that the use of dispersants or emulsifiers downstream of the treatment system for the purpose of preventing detection of a sheen is prohibited. In the 1989 API Paper (attached as Appendix A): Chemical Treatments and Usage in Offshore Oil and Gas Production Systems, by Hudgins, the use of dispersants is discussed. Dispersants are added to scale control agents and corrosion inhibitors to increase performance. As proposed, EPA would inadvertently be limiting the use of scale control agents, corrosion inhibitors, and emulsifiers from being used both upstream and in the produced water treatment system. The Joint Trades do not believe this was the intent and request the requirement be clarified to only prohibit the addition of dispersants or emulsifiers downstream of the produced water treatment system. The following is copied from the 1989 API paper mentioned above, from the "Emulsion Breakers" section on page 20 of the report. "However, the use of emulsifiers in the treatment system are necessary in the separation phase. Emulsion breakers work by attacking the droplet interface. They may cause the dispersed droplets to aggregate intact (flocculation) or to rupture and coalesce into larger droplets. Either way, the density difference between the oil and water then causes the two liquid phases to separate more rapidly. In addition, solids present will usually tend to accumulate at the liquid level interface (between the bulk oil and water phases) and form a semi-solid mass. If these solids are not dispersed into the oil phase or water wetted and removed with the water, the interface detector in the control system will ultimately malfunction, causing water to be dumped into the oil pipeline or oil to be carried over to the produced water system. Proper selection and application of emulsion breaker will minimize this accumulation and the resulting problems" (Hudgins, C. M., Jr. (1989). CHEMICAL TREATMENTS AND USAGE IN OFFSHORE OIL AND GAS PRODUCTION SYSTEMS. Houston, TX). The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
10	Produced Water – Oil and Grease	Part I.B.4.b.2	"2) Oil and Grease. Samples for oil and grease monitoring shall be collected and analyzed a minimum of once per month. In addition, a produced water sample shall be collected, within ~~thirty (30) minutes~~ two 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. The sample type for all oil and grease monitoring shall be either grab, or a composite which consists of the arithmetic average of the results of grab samples collected at even intervals during a period of 24-hours or less. If only one sample is taken for any one month, it must meet both the daily maximum and monthly average limits. Samples for oil and grease monitoring shall be collected prior to the addition of any seawater to the produced water waste stream. The analytical method is that specified at 40 CFR Part 136."	The Joint Trades strongly disagree with taking a sample within 30 minutes of a sheen. The first response by operators is determining the cause or source of the sheen and deciding if the system needs to be shut down. By taking a sample within 30 minutes, operators will be more focused on taking a sample instead of stopping the sheen. The uncertainty of the origin of the sheen could cause operations to be in a state of higher risk of uncertainty and may lead to unduly endangering the health and safety of the facility personnel, the facility, and the environment. Also, the PW O&G kits are not always located in areas that are easily accessible. It might take an operator over 30 minutes to grab a kit, collect ice, complete paperwork, and take a sample. By not taking a sample within the 30-minute time frame, this will now put operators in possible violation of the permit. The Joint Trades request that time allowed to take a produced water sample after a sheen is observed remain at two hours.

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				Additionally, the Joint Trades request the language for sample type remain as is in the current permit. Some operators elect to collect grab samples over a 24-hour period and determine the arithmetic average for compliance with the daily maximum limit. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
11	Produced Water – Toxicity	Part I.B.4.b.3	"Toxicity. A 7-day toxicity testing shall be performed ~~twice~~ once per calendar year. ~~Toxicity testing must be conducted at least 90 days apart~~. The results for both species shall be reported on the next quarterly DMR following testing. See Part I, Section D.3 of this permit for WET testing requirements."	The Joint Trades request the current produced water toxicity testing frequency and language remain the same. The majority of operators test for produced water on an annual frequency. Therefore, we strongly encourage EPA to maintain the annual produced water toxicity testing frequency as there is not enough justification for an increased frequency of toxicity testing. Per EPA's proposed permit fact sheet, EPA is removing the frequency reduction allowance for toxicity testing based on the Bureau of Safety and Environmental Enforcement (BSEE)'s suggestion. BSEE's basis of "difficulty of tracking" is completely invalid as once per calendar year is much easier to track than twice per calendar year and at least 90 days apart. EPA acknowledges in their proposed permit's fact sheet that the number of available, experienced, and qualified laboratories for this 7-day produced water analysis is limited. We agree with this statement. Given the number of facilities requiring testing, the available laboratories cannot handle doubling the number of 7-day toxicity analyses that EPA/BSEE is proposing. This in turn could cause false toxicity or quality control issues. Laboratories only culture so many test age organisms. Increasing the number of required testing in short time frame is not possible. With the current annual required toxicity testing there are issues collecting and analyzing 100% of samples due to limited laboratory availability. There are only 3 laboratories that can perform testing on offshore oil and gas produced waters. Inability to predict extended platform downtime periods (i.e. intermittent production), logistics issues for these specific monitoring and testing requirements, and weather (i.e. hurricanes and other tropical storms) can also be problematic with an increase in testing. Doubling the number of required toxicity testing samples would not only increase the burden on the operator and the testing laboratories, but it will increase the operator's risk for additional missed samples resulting in administrative non-compliances. An annual testing frequency allows operators and laboratories to work together on scheduling around shut-in, weather, organism availability and laboratory testing schedules. Currently, the permit requires that the toxicity sample has to be representative of produced water discharges. Annual toxicity tests are inclusive to all activity performed on the facility; therefore, it is a representative sample. Daily production rate changes and additions of flow back fluids are not only unpredictable and hard to track, but these changes in production are monitored monthly by conducting a representative sample for an oil and grease analysis on produced water. The language throughout the permit requires representative samples be collected. As an example, Section II.C.2 of the permit requires *"Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity."* This proposed frequency increase will be a significant economic burden for offshore operators currently on an annual frequency as well. These additional toxicity tests would be an increase for routine produced water discharges in operating expenses with negligible value. Considering the very low number of toxicity test failures based on actual lab results, there is no environmental benefit to justify this increased expense.

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				The Joint Trades request an effective date for produced water toxicity testing of January 1, 2018 and continue on a calendar year basis. This assumes the permit will become effective on October 1, 2017. Operators have 90 days to apply for coverage under the new permit, and then can plan a reasonable schedule for testing. See also Comments No. 12-13 for additional discussion and information. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
12	Produced Water – Toxicity	Part I.B.4.b.3	"Toxicity testing for new discharges shall be conducted within 90 days ~~30 days~~ after the discharge begins and then continue on the appropriate calendar year ~~follow the twice per calendar year~~ schedule."	EPA has not provided rationale for decreasing the time to conduct toxicity tests for new discharges. The Joint Trades request the 90-day time period be left unchanged for the following reasons: • New produced water discharges typically occur early in the life of the facility. The PW discharge rates are typically very low and ramp up over time at a rate dependent on the reservoir(s). • At these low produced water rates, the produced water treatment system needs time to be fully commissioned. • The critical dilution is set based on the highest monthly average discharge rate for the three months prior to the month in which the test sample is collected. Testing within the first 30 days would not allow for even one monthly average discharge rate in which to base critical dilution. See Comments No. 11 and 13 for additional discussion and information. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
13	Produced Water – Toxicity	Part I.B.4.b.3	"Toxicity testing for existing discharges under the 2012 issued permit shall conduct the first toxicity test within 6 months from the ~~effective~~ date of obtaining coverage under the permit." "Samples taken in Year 2017 prior to the effective date of this permit can be reported for 2017."	The Joint Trades request the permit change to provide clarity and a more realistic approach with what we believe is the intent of the proposed permit language. Operators have 90 days from the effective date of the permit to apply and obtain coverage under the new permit. Requiring existing discharges to conduct the first test within 6 months from the effective date of the permit is problematic. 6 months from the effective date of the permit would mean that first test for all existing discharges must be tested by the end of March 2018. Again, this is problematic for operators that do not apply for coverage until the end of the 90 days. Thus, nearly all of the produced water toxicity tests would have to be completed in a short time frame. As discussed in Comment No. 11, there are a limited number of qualified testing laboratories that test offshore produced waters. The testing laboratories could become overwhelmed with that amount of produced water testing to be done in a short time frame. All existing produced water discharges would have to be tested in approximately 3 months. From a transportation and logistics point of view, this would be very problematic and cause a financial burden to both the operator and the testing laboratories. Thus, potentially leading to false toxicity results and quality control issues. Laboratories only produce so many test age organisms, increasing the number of required testing in a short time frame is not possible.

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				Additionally, the Joint Trades request the additional language to clarify that samples taken in 2017 during the transition period can be reported for 2017, as compliance with the existing permit. See Comments No. 11-12 for additional discussion and information. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
14	Produced Water – Toxicity	Part I.B.4.b.3	"Samples also shall be representative of produced water discharges when hydrate inhibitors, scale inhibitors, corrosion inhibitors, biocides, paraffin inhibitors, well completion fluids, workover fluids, well treatment fluids, and/or hydrate control fluids are used in operations. ~~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 Joint Trades request striking the requirement to conduct a new toxicity test if the sample used for the previous test did not represent an application of TCW or hydrate control fluids. At some locations, hydrate control fluids are routinely used as production treatment chemicals. The current permit already requires that samples are representative. EPA did not provide rationale as to why hydrate control fluids should be treated differently from other production chemicals. This new requirement is overly burdensome with the following challenges: • The TCW study is not complete. OOC requests that TCW discharges planned to be commingled with produced water be included in the TCW study scope. • For facilities with third-party wells tied back to the production system, there is the added challenge of the host facility knowing exactly when these fluids were commingled with the produced water discharge to determine when a representative sample can be obtained. Although it may be communicated by a third-party in advance, there is the uncertainty of how long it will take these fluids to reach the facility and be treated before impacting the produced water discharge. • Toxicity testing timing is coordinated well in advance with testing laboratories. This enables the testing lab to 1). coordinate and send toxicity test kits to the facility in alignment with existing transportation schedules and 2). have organisms prepped and available for the toxicity test. The addition of samples for TCW and hydrate control fluids, which may not be known in advance, is overly burdensome and may result in non-compliance due to inability to obtain samples and start the toxicity testing within hold times. • 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. • The permit language is very broad and lacks clarity. Operational scenarios frequently change. As worded, 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. For additional discussion and information, see Comments 19-21. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
15	Produced Water – Toxicity	Part I.B.4.b.3 and Part I.D.3.e	Part I.B.4.h.3 "If a test fails the survival or sub-lethal endpoint at the critical dilution in any test, the operator must perform monthly retest until it passes. The operator shall take corrective actions which may include conduction of Toxicity Reduction Evaluation (TRE), adjustment of discharge rate, addition	The Joint Trades agree with Part I.B.4.b.3, once a test fails, the operator should conduct monthly retests until passing. To be consistent, the Joint Trades also request EPA change the language in Part 1.D.3.e as indicated. Historically, when a facility passes the first toxicity test, they pass the second and third toxicity test as well. Performing three consecutive monthly toxicity tests adds no value and becomes redundant.

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			of diffusers, or other remedy actions after the failure of the first retest. Failing the toxicity test is considered violation of the permit.” Part I.D.3.e “If the effluent fails the survival endpoint or the sub-lethal endpoint at the critical dilution, the permittee shall be considered in violation of the WET limit. Also, when the testing frequency stated above is less than monthly and the effluent fails either endpoint at the critical dilution, the monitoring frequency for the affected species will increase to monthly until such time as compliance with the NOEC effluent limitation is demonstrated, ~~for a period of three consecutive months,~~ at that time the permittee may return to the testing frequency in use at the time of the failure. During the period the permittee is out of compliance, test results shall be reported on the DMR for that reporting period.”	
16	Produced Water – Visual Sheen	Part I.B.4.b.4	“…~~The operator shall report “sheen” whenever a sheen is observed during the day and must conduct an inspection of treatment process and investigation of~~ 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 sheens and findings and make the records available for inspector’s review.”	The Joint Trades request that the language be modified as indicated to provide clarification. Operators are required to keep adequate records to assure proper reporting of produced water sheens under the permit per Part II.C and II.D. A produced water sheen may be easily attributed to a change in operations (e.g., well management) thus making an inspection of the system unnecessary. The proposed permit language is vague and overly burdensome. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
17	Produced Water and Other – Visual Sheen reporting to NRC	Part I.B.4.b.4 & Part I.C.7	Part I.B.b.4 ~~“A visual observation of a sheen is presumed to be a discharge within the meaning of 33 U.S.C. §§ 1321(a)(2) and (b)(3), and must be reported to the National Response Center (NRC) pursuant to 40 CFR § 110.6”~~ Part I.C.7 “This permit does not preclude permittees from reporting ~~discharges/~~releases to the National Response Center (NRC). ~~A visual observation of a sheen is presumed to be a discharge within the meaning of 33 U.S.C. §§ 1321(a)(2) and (b)(3), and must be reported to the National Response Center (NRC) pursuant to 40 CFR § 110.6”~~	The Joint Trade strongly disagree that discharges from permitted outfalls should be reported to the NRC. Thus, the Joint Trades request deletion of the text from Part I.B.b.4 and Part I.C.7. Additionally, the Joint Trades request deletion of the term “discharges” from the text at Part I.C.7. The statements at Part I.B.b.4 and Part I.C.7 are contrary to law. Based on Congressional intent and prior interpretations by the EPA and USCG, NPDES discharges are covered by section 402 of the Clean Water Act and are not subject to reporting as oil spills under section 311. Therefore, requiring an operator to report sheens from permitted discharge points to the NRC is contrary to law, and this requirement must be removed from the proposed permit. The following citations from 33 U.S.C. (the Clean Water Act), historical EPA and USCG documents, and EPA’s current website are provided to support this conclusion. ***1. 33 U.S.C. § 1321 Excludes Certain Situations from the Definition of “Discharge”*** Parts I.B.b.4 and I.C.7 include new requirements for an operator to report sheens from permitted discharge points to the NRC. The proposed permit cites 33 U.S.C. § 1321(a)(2) and (b)(3) as the basis for such reporting. However, 33 U.S.C. § 1321(a)(2) and (b)(3), are the exact paragraphs that explain that **NPDES discharges are excluded from the definition of “discharge**” and do not have to be reported to the National Response Center. Paragraph 33 U.S.C. § 1321(b)(3) states,

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				"The discharge of oil or hazardous substances (i) into or upon the navigable waters of the United States, adjoining shorelines, or into or upon the waters of the contiguous zone, or (ii) in connection with activities under the Outer Continental Shelf Lands Act [43 U.S.C. 1331 et seq.] or the Deepwater Port Act of 1974 [33 U.S.C. 1501 et seq.], or which may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson-Stevens Fishery Conservation and Management Act [16 U.S.C. 1801 et seq.]), in such quantities as may be harmful as determined by the President under paragraph (4) of this subsection, is prohibited, except (A) in the case of such discharges into the waters of the contiguous zone or which may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson-Stevens Fishery Conservation and Management Act), where permitted under the Protocol of 1978 Relating to the International Convention for the Prevention of Pollution from Ships, 1973, and (B) where permitted in quantities and at times and locations or under such circumstances or conditions as the President may, by regulation, determine not to be harmful. Any regulations issued under this subsection shall be consistent with maritime safety and with marine and navigation laws and regulations and applicable water quality standards." The key term in the paragraph is "discharge" – which is defined in 33 U.S.C. § 1321 (a)(2), *"discharge" includes, but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying or dumping, but excludes (A) discharges in compliance with a permit under section 1342 of this title, (B) discharges resulting from circumstances identified and reviewed and made a part of the public record with respect to a permit issued or modified under section 1342 of this title, and subject to a condition in such permit,,[1] (C) continuous or anticipated intermittent discharges from a point source, identified in a permit or permit application under section 1342 of this title, which are caused by events occurring within the scope of relevant operating or treatment systems, and (D) discharges incidental to mechanical removal authorized by the President under subsection (c) of this section;* This definition excludes from the definition of "discharge" sheens that occur from permitted discharge points, as these are covered by the exclusions described in 1321(a)(2) (A), (B), or (C). Therefore, sheens from permitted discharges are excluded from the definition of "discharge" under 33 U.S.C. § 1321. ***2. EPA Clarified the Reporting Requirements in the 1981 Permit Fact Sheet – Sheens from Permitted Point Sources are Exempt from Reporting*** This position is further supported by a 1981 *Federal Register Notice* (46 FR 20284, April 3, 1981) regarding the *Issuance of Final General NPDES Permits for Oil and Gas Operations in Portions of the Gulf of Mexico; Fact Sheet*, hereinafter referred to as "the 1981 Fact Sheet." *Paragraph J, Oil Spill Requirements*, of the 1981 Fact Sheet states, *"Section 311 of the Act prohibits the discharge of oil and hazardous materials in harmful quantities. In the 1978 amendments to section 311, Congress clarified the relationship between this section and discharges permitted under section 402 of the Act. It was the intent of Congress that routine discharges permitted under*

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				section 402 be excluded from section 311. Discharges permitted under section 402 are not subject to section 311 if they are: 1. *In compliance with a permit under section 402 of the Act;* 2. *Resulting from circumstances identified, reviewed and made part of the public record with respect to a permit issued or modified under section 402 of the Act, and subject to a condition in such permit; or* 3. *Continuous or anticipated intermittent discharges from a point source, identified in a permit or permit application under section 403 of this Act, which are caused by events occurring within the scope of the relevant operating and treatment systems.* *To help clarify the relationship between discharges under section 402 and section 311 discharges, EPA has compiled the following list of discharges which it considers to be regulated under section 311 rather than under a section 402 permit. The list is not to be considered all-inclusive.* 1. *Discharges from a platform or structure on which oil or water treatment equipment is not mounted,* 2. *Discharges from burst or ruptured pipelines, manifolds, pressure valves or atmospheric tanks,* 3. *Discharges from uncontrolled wells,* 4. *Discharges from pumps or engines,* 5. *Discharges from oil gauging or measuring equipment,* 6. *Discharges from pipeline scraper, launching, and receiving equipment,* 7. *Spill of diesel fuel during transfer operations,* 8. *Discharge from faulty drip pans,* 9. *Discharges from well heads and associated valves,* 10. *Discharges from gas-liquid separators, and* 11. *Discharged from flare lines."* It is clear from the 1981 Fact Sheet discussion that EPA clarified, **based on Congressional intent**, that point sources covered by an NPDES permit are not subject to section 311 of the Clean Water Act; meaning such discharges are not reportable to the NRC. ***3. USCG District 8 (1998) Issued a Memorandum Explaining Sheens from Permitted Discharges are not Subject to NRC Reporting*** Furthermore, in September 1997 members of the Offshore Operators Committee met with U.S. Coast Guard District 8 staff to clarify proper reporting procedures for sheens from permitted point sources (section 402 events) versus oil spills (section 311 events). The Commander of the Eighth Coast Guard District issued a memorandum (dated April 3, 1998) that states, *"…It was agreed by all in attendance that Section 311 of the Clean Water Act does not define oil discharges from NPDES-permitted sources (whether the system is operating correctly or not) as reportable oil discharges. This conclusion is supported by Commandant Decisions on Appeal. The attendees agreed that the proper policy is for sources to report discharges in violation of their NPDES-permitted processes to the Environmental Protection Agency and Minerals Management Service (if appropriate) and not to the Coast Guard. Discharges of oil resulting from other activities not part of a NPDES process will still be reported to the Coast Guard National Response Center."*

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				This USCG memorandum, has not been rescinded and is still in effect. This District 8 policy is clearly in alignment with 33 USC §1321 and the 1981 Fact Sheet. ***4. EPA Response to Comments for the 2007 GMG290000 Renewal*** EPA Region 6 addressed the issue of reporting sheens to the USCG National Response Center directly in the Response to Comments when the agency issued the Final NPDES General Permit for Discharges from 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). The following text is taken directly from the Response to Comments: *"Comment Number 1:* *The Offshore Operators Committee (OOC) requested clarification of the permit's oil spill requirements to state that sheens resulting from permitted discharges are not defined as spills.* *Response:* *EPA has previously worked with the U.S. Coast Guard to determine when a sheen would be considered a spill. Sheens from non-permitted discharges were determined to be spills which are under the jurisdiction of the U.S. Coast Guard. Sheens which result from permitted discharges were determined to be under EPA jurisdiction and are not considered to be spills. The requested clarification is consistent with that determination and has been made in the final permit."* It is apparent that EPA has reviewed this reporting issue in previous iterations of the GMG290000 permit and made the determination that sheens from permitted discharges are not oil spills. The permit and agency processes ensure sheens from permitted discharge points are reported through the Discharge Monitoring Reports. ***5. EPA's Current Website Describes the Types of Discharges Exempt from 33 U.S.C. § 1321*** Finally, EPA's current website (https://www.epa.gov/oil-spills-prevention-and-preparedness-regulations/oil-spills-do-not-need-be-reported) contains information on *"Oil Spills that Do Not Need to be Reported"* which includes a section on *"NPDES-Permitted Releases"* that provides yet another summary of the definition of discharge in 33 U.S.C. § 1321 (a)(2): *"Three types of discharges subject to the National Pollutant Discharge Elimination System (NPDES) are exempt from oil spill reporting:* *1. Discharges in compliance with a permit under section 402 of the Clean Water Act, when the permit contains:* • *Either an effluent limitation specifically applicable to oil, or* • *An effluent limitation applicable to another parameter that has been designated as an indicator of oil;* *2. Discharges resulting from circumstances identified and reviewed and made part of the public record with respect to a permit issued or modified under section 402 of the Clean Water Act, and subject to a condition in such permit. This exclusion addresses situation where the source, nature, and amount of a potential oil discharge was identified, and a treatment system capable of preventing that discharge was made a permit requirement.*

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				• *For example, if a discharger has a drainage system that will route spilled oil from a broken hose connection to a holding tank for subsequent treatment and discharge, the treatment system must be sufficient to handle the maximum potential spill from that source. Spills larger than those contemplated in the public record are not exempted; and* 3. *Continuous or anticipated intermittent discharges from a point source, identified in a permit or permit application under section 402 of the Clean Water Act, which are caused by events occurring within the scope of relevant operating or treatment systems. This exclusion applies to chronic or anticipated intermittent discharges originating in the manufacturing or treatment systems of a facility or vessel, including those caused by periodic system failures.* • *Discharges caused by spills or episodic events that release oil to the manufacturing or treatment systems are not exempt from reporting."* The information above provides additional clarity on the intent of 33 U.S.C. § 1321 (a)(2). Clearly, point source discharges in compliance with permit requirements are exempt from section 311 reporting. Also, limitations described for various point source discharges included in the GOM NPDES permit are part of the public record, including the fact that sheens may occur from these discharges. Lastly, Item 3 from the website description above makes it clear that episodic events caused by **"periodic system failures,"** for example a sheen from deck drainage or the produced water treatment process, are also exempt from section 311 reporting. ***6. Conclusion*** Based on Congressional intent and prior interpretations by the EPA and USCG, 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. Therefore, the requirement to report sheens from permitted discharge points to the NRC must be removed from the proposed permit. Reporting of sheens from permitted discharge points is managed through the Discharge Monitoring Reports, and such events will be reported to EPA as permit excursions/violations. However, sheens from permitted discharge points need not be reported to the NRC. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
18	Well Treatment Fluids, Completion Fluids, Workover Fluids – Priority Pollutants	Part I.B.6.a	"Vendor ~~certification~~ declaration or statement indicating ~~the fluids contain no~~ the vendor does not add or has not intentionally added priority pollutants to the fluids is acceptable for meeting this requirement. ~~In case either a vendor certification is not available or the present of priority pollutants is in doubt, "Trace amounts" shall mean the amount equal to or less than the most sensitive method detection limit listed in 40 CFR Part 136 for the applicable parameter or as sensitive as MQLs listed in Appendix E of the permit.~~"	The Joint Trades request rewording the first sentence to clarify that the vendor declaration is that no priority pollutants are intentionally added to the materials added downhole as well treatment, completion, or workover fluid TCW. If priority pollutants were not intentionally added to the formulation of the product, then they are considered to be in there only in trace quantities. Further, the Joint Trades request the deletion of the last sentence. The proposed EPA Region 6 language contradicts the 1993 ELG decision to regulate priority pollutants with oil and grease only. The documentation and the effluent limitation guidelines development document (in tables X-12, X-13, X14) clearly document that the EPA recognized trace amounts of priority pollutants in these fluids above the detection methods. Imposing MDL limits on all 138 priority pollutants will result in significant non-water quality impacts associated with transportation, discharge, disposal, and excess treatment. The method detection limits

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				referenced in Appendix E are achievable for samples in clean water effluents but due to matrix effects may not be applicable to the analyses of products or TCW discharges. A certification program would be burdensome and unsuitable for 138 priority pollutants and all products used in completion fluids systems. There is no apparent environmental benefit over the current system of regulatory control for the significant costs that this would entail. Consequently, an unintended certification program would result in non-water quality impacts which will result in additional treatment and discharges. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
19	Well Treatment Fluids, Completion Fluids, Workover Fluids – Fluids Commingled with Produced Water	Part I.B.6.b	"When well treatment, completion or workover fluids are commingled and discharged with produced water, the discharges are considered produced water ~~and a 7-day toxicity test shall be conducted for produced water commingled with well treatment, completion or workover fluids for monitoring and reporting purposes~~."	The Joint Trades request deleting the 7-day toxicity test requirement. As outlined in the rationale in Comment No. 14 for Part I.B.4.b.3, this requirement is overly burdensome. Toxicity testing for these discharges should be included in the scope of the TCW study. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
20	Well Treatment Fluids, Completion Fluids, Workover Fluids – Characteristic Assessments	Part I.B.6.c	Operators must conduct well treatment fluids, well completion fluids, and workover fluids assessments whenever they apply those fluids. Such assessments shall be conducted for each applicable well by operators either corporately or individually. The general information of a specific well treatment, well completion or workover fluid could be used for assessment purposes. Each fluid assessment shall include the following information: 1) Lease and block number 2) API well number 3) Type of well treatment or workover operation conducted 4) Date of discharge 5) Time discharge of TCW fluids commenced 6) Duration of discharge of TCW fluids 7) Volume of well treatment 8) Volume of completion or workover fluids used 9) The identity, as listed on the applicable SDS, and nominal concentration of each chemical constituent intentionally added to the well treatment, completion, or workover fluid used. ~~The common names and chemical parameters for all additives to the fluids~~ ~~10) The volume of each additive~~ ~~11) Concentration of all additives in the well treatment~~ ~~12) Concentration of all additives in the completion, or workover fluid~~ 10) The No Observable Effect Concentration (NOEC) of 48-hour acute Whole Effluent Toxicity (WET) test for ~~well treatment~~ TCW fluids used. ~~discharged separately from the produced water discharge~~	The Joint Trades request 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, the Joint Trades request 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, the Joint Trades request 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.

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			Operators shall use the following methods to perform the 48-hour Acute Whole Effluent Toxicity Test Method: a) The permittee shall utilize the Mysidopsis bahia (Mysid shrimp) acute static renewal 48-hour definitive toxicity test using EPA-821-R-02-012. A minimum of five (5) replicates with eight (8) organisms per replicate must be used in the control and in each effluent dilution of this test. b) The permittee shall utilize the Menidia beryllina (Inland Silverside minnow) acute static renewal 48-hour definitive toxicity test using EPA-821-R-02-012. A minimum of five (5) replicates with eight (8) organisms per replicate must be used in the control and in each effluent dilution of this test. c) The NOEC is defined as the greatest effluent dilution which does not result in lethality that is statistically different from the control (0% effluent) at the 95% confidence level. 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 6. 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.	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, the Joint Trades are requesting that EPA Region 6 incorporate the OSHA Hazard Communication trade secret criteria by reference in the proposed GMG290000 permit. Under this proposed change, EPA Region 6 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 withheld 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. The Joint Trades request that TCW toxicity testing be conducted on the total TCW job constituents prepared either by the company performing the job or the toxicity testing laboratory that is representative of all fluids used in the job in lieu of sampling the discharge. There are several challenges with collecting a representative sample during discharges. 1. In order to obtain an optimum dilution series, a range finder will likely be needed. Without a rangefinder, the NOEC may not be representative of actual NOEC. Due to the logistics of catching a sample, transporting to testing laboratories, conducting a rangefinder, and then setting up a testing with the optimum dilution series, the sample hold times will likely by exceeded. Due to the short duration of these types of discharges, pulling another sample may not be possible. 2. In the event that the sample is compromised in anyway during transportation or toxicity tests are inconclusive or invalid, having the opportunity of collecting another sample may not be possible. This is because these discharges are short in duration. 3. TCW jobs are performed in stages. The composition of the discharge varies throughout the TCW job. The Joint Trades believe that testing the toxicity of the total TCW job constituents would provide EPA with the data needed to assess the toxicity of TCW fluids without the burden of sampling the actual discharge. The Joint Trades are also proposing to add clarifying language regarding when and how this information should be reported to EPA Region 6 and clarifying language on Fluid Assessment Information (below).

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				Fluid assessment Information, clarification: 3) Type of well treatment or workover operation conducted. The Joint Trades would like clarification on what information and examples regarding the type of well treatment or workover operations conducted EPA is requesting. 7 & 8) Clarify if this is the volumes of fluids discharged (not pumped downhole). The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
21	Well Treatment Fluids, Completion Fluids, Workover Fluids – Fluids Commingled with Produced Water Well Treatment Fluids, Completion Fluids, Workover Fluids – Industry – Wide Study Alternative	Part I.B.6.c	"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 nominal chemical composition and the variability of the nominal chemical composition and toxicity. The study area should include a ~~statistical valid~~ representative number of samples of wells located in the Western and Central Areas of the GOM and may include the Eastern Gulf of Mexico (GOM) under the permitting jurisdiction of EPA Region 4, 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 ~~plan~~ would be required to be submitted to EPA for approval within ~~six months~~ 2 years after the effective date of this permit. Once a permittee has committed financially to participate in the study it shall constitute compliance with the monitoring and reporting requirements of Part I.B.6.c. 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 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. The final study report date is to be determined. The portion which is achievable by March 30, 2022 must be identified in the plan.~~must be submitted no later than March 30, 2022."~~	1. The Joint Trades are 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. The Joint Trades request striking "of varying depths (shallow, medium depth and deep depths)" and replacing simply with "discharging well treatment, completion, and/or workover fluids". Due to the current level of activity, all wells would probably have to be sampled as the jobs arise to ensure compliance with the study window. In other words, the study participants would not have the luxury per se of picking and choosing well TCW jobs to sample. * Therefore, specifying varying depths overly constrains the study from the start. Additionally, it is unclear what EPA means by this term (is it water depth, well depth to reservoir, discharge depth?) * This is the same approach EPA Region VI approved for the recent WBM dissolved metals study i.e. sampling the WBM as each drilling job came along. 3. The Joint Trades are 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. 4. As stated above the Joint Trades request that TCW toxicity testing be conducted on the total TCW job constituents prepared either by the company performing the job or the toxicity testing laboratory that is representative of all fluids used in the job in lieu of sampling the discharge. The Joint Trades believe that testing the toxicity of the total TCW job constituents would provide EPA with the data needed to assess the toxicity of TCW fluids without the burden of sampling the actual discharge. 5. Change the planning time from 6 months to 2 years. The goals and objectives of the proposed TCW characterization are not transparent. To be technically sound, effort should be first focused on a problem formulation phase where diverse set of subject matter experts (SMEs) for various affected organization (e.g., suppliers, operators, Region 6, Region 4, testing laboratories, etc.) come together to clarify the intent, the goals and the objectives of such a study. This should be followed by a data gap analysis

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				and information gathering phase. The working group could then reconvene and consider the findings, identify and resolve how to address the difficult aspects of the study and agree upon how to address the "simpler aspects of the study". After taking time to consider how to tackle the difficult tasks another meeting could then be convened to reach general agreement on a path forward with the difficult aspects. Though three meetings have been identified, quite possibly more will be needed. Once the problem formulation phase is completed then 6 months for plan development seems reasonable. Depending on what comes out of the problem formulation phase, a hard date of March 30, 2022 may not be realistically achievable for completion and reporting. The portion of the study that is decided by the SMEs, during the problem formulation phase, as reasonable to achieve by March 30, 2022 should be all that is due and can be written into the plan. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
22	Sanitary Waste (Facilities Continuously Manned for 30 or more consecutive days by 10 or More Persons) - Prohibitions	Part I.B.7.a	"Solids. No floating solids may be discharged to the receiving waters. Observation must be made daily during daylight in the vicinity of sanitary waste outfalls. If floating solids are observed at other times in addition to the daily monitoring, it must be recorded. ~~Observation of floating solids must be recorded whenever floating solids are observed during the day.~~ The number of days solids are observed must be reported."	The Joint Trades are requesting this change to provide clarification with the requirement and for consistency with the requirements outlined in Appendix F, Table 1 of the permit.
23	Sanitary Waste (Facilities Continuously Manned for 30 or more consecutive days by 10 or More Persons) – Limitations	Part I.B.7.b	"Residual Chlorine. Total residual chlorine (TRC) is a surrogate parameter for fecal coliform. Discharge of TRC must meet a minimum of 1 mg/l ~~and shall be maintained as close to this concentration as possible~~. A grab sample must be taken once per month and the concentration recorded. The approved methods are either Hach CN-66-DPD or EPA method specified in 40 CFR part 136 for TRC." "[Exception] Any facility operator which 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 in compliance with permit prohibitions and limitations for sanitary waste. The MSD shall be tested yearly for proper operation and the test results maintained for three years at the facility or at an alternate site if not practicable."	The Joint Trades request that the exception for the MSD be added back to the permit. The removal of the MSD exception creates an additional burden on the regulated community. The regulated community should be able to demonstrate proper operation and maintenance as required by the permit. The language for TRC limitation "and shall be maintained as close to this concentration as possible" is vague, and the Joint Trades request that it be struck. For MODUs, The US Coast Guard conducts annual inspections of MSDs in order to issue the 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]. The Joint Trades requests that industry be able to demonstrate proper operation and maintenance via maintenance logs/records and any other records of annual inspections by Coast Guard. The monthly TRC requirement increases administrative and financial burden to operators by requiring purchasing additional test kits, training personnel in the use of test kits, and added recordkeeping burden. Additionally, some MODUs have MSDs that do not utilize chlorine as a disinfectant, for example some use bromine biological treatment systems due to reduced usage of chlorine based

Comment No.	Type/Category	Permit Section Ref.	Current or Revised Permit Language /Clarifications/Issue	Rationale
				treatment systems in other parts of the world. The Joint Trades request a similar approach to demonstration of meeting the requirement via US Coast Guard approval, annual inspections, Class/Flag State inspections and/or the ISPPC and maintenance logs/records. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
24	Sanitary Waste (Facilities Continuously Manned for thirty or more consecutive days by 9 or Fewer Persons or Intermittently by Any Number)	Part I.B.8.a	“Solids. No floating solids may be discharged to the receiving waters. Observation must be made daily during daylight in the vicinity of sanitary waste outfalls. If floating solids are observed at other times in addition to the daily monitoring, it must be recorded. ~~Observation of floating solids must be recorded whenever floating solids are observed during the day.~~ The number of days solids are observed must be reported.” “[Exception] Any facility operator which 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 in compliance with permit prohibitions and limitations for sanitary waste. The MSD shall be tested yearly for proper operation and the test results maintained for three years at the facility or at an alternate site if not practicable.”	The Joint Trades are requesting this change to provide clarification with the requirement and for consistency with the requirements outlined in Appendix F, Table 1 of the permit. Additionally, the Joint Trades request that the exception for the MSD be added back to the permit. The removal of the MSD exception creates an additional burden on the regulated community. The regulated community should be able to demonstrate proper operation and maintenance as required by the permit. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
25	Domestic Waste – Monitoring Requirements	Part I.B.9.b	“Solids. No floating solids may be discharged to the receiving waters. Observation must be made daily during daylight in the vicinity of domestic waste outfalls. If floating solids are observed at other times in addition to the daily monitoring, it must be recorded. ~~Observation of floating solids must be recorded whenever floating solids are observed during the day~~. The number of days solids are observed must be reported.”	The Joint Trades are requesting this change to provide clarification with the requirement and for consistency with the requirements outlined in Appendix F, Table 1 of the permit.
26	Miscellaneous Discharges – Discharge List	Part I.B.10.i	(i) Filtered and Slurry: Desalinization Unit Discharge, Diatomaceous Earth Filter Media, Mud, Cuttings, and Cement (including cement tracer) at the Seafloor, and Excess Cement Slurry ~~[Note: Discharges of cement slurry used for testing cement handling equipment are not authorized.]~~	The Joint Trades request that discharges of cement used for testing be authorized by striking this “Note” and adding clarifying language under Miscellaneous Discharges: “Unused Cement Slurry”. Rationale included in Comment No. 30 for Part I.B.10.a. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
27	Miscellaneous Discharges – Discharge List	Part I.B.10.iv	“(iv) Subsea Discharges:~~ Blowout Preventer Control Fluid~~, Subsea Wellhead Preservation Fluid, Subsea Production Control Fluid, Umbilical Steel Tube Storage Fluid, Leak Tracer Fluid, Riser Tensioner Fluid, and Pipeline Brine (used as piping or equipment preservation fluids).” “()Blowout Preventer Control Fluid	The Joint Trades request that Blowout Preventer Control Fluid discharges not be confined to only the “subsea discharges” re-categorized portion of miscellaneous discharges. OOC requests that Blowout Preventer be categorized as stand alone. This request also provides clarity. Blowout Preventer Control Fluid is discharged subsea, but can also be discharged at the surface (such as when required function tests are being conducted).
28	Miscellaneous Discharges – Discharge List	Part I.B.10 - Notes	~~“Note 2: Operators must flush and capture the chemicals (e.g., hydrate control fluids or pipeline brine) contained in pipelines, umbilical, or jumpers before or at the time of abandonment.”~~	The Joint Trades request that the proposed language in Part 1.B.10 “Note 2: Operators must flush and capture the chemicals (e.g., hydrate control fluids or pipeline brine) contained in pipelines, umbilical, or jumpers before or at the time of abandonment” be deleted from the text. EPA has reviewed toxicity data and information regarding hydrate inhibitor use submitted by OOC in the past and determined that the hydrate control fluid permit limitations in place in the current permit are appropriate for these types of operations. In Part 1.A.1 under Operations Covered discharges relating to abandonment and decommissioning operations are covered. *“This permit establishes effluent limitations, prohibitions, reporting*

Comment No.	Type/Category	Permit Section Ref.	Current or Revised Permit Language /Clarifications/Issue	Rationale
				requirements, and other conditions on discharges from oil and gas facilities, and supporting pipeline facilities, engaged in production, field exploration, developmental drilling, facility installation, well completion, well treatment, well workover, and abandonment/decommissioning operations." Discharges of hydrate control fluids (ethylene glycol and methanol) or chemically treated seawater occur during pipeline, umbilical, and jumper decommissioning and installation processes and are covered under the NPDES permit as miscellaneous discharges of hydrate control fluids or chemically treated seawater miscellaneous discharges. Such discharges must comply with the applicable permit limits. After a pipeline or umbilical has been abandoned in place, any leak or spill of hydrate control fluid from that pipeline or umbilical would not be covered under the NPDES permit as stated under Part II Section B.7 *"This general permit does not authorize discharges, including spills or leaks, caused by failures of equipment, blowout, damage of facility, or any form of unexpected discharge."* The Joint Trades do not feel any changes to the current permit are necessary to address discharges of hydrate control fluids or chemically treated miscellaneous discharges that occur during pipeline, umbilical, and jumper decommissioning and installation processes. The permit GMG290000 recognizes and authorizes the discharge of hydrate inhibitors in these types of operations as a "Miscellaneous Discharge - Hydrate Control Fluid" (part I.B.10). The permit limit for these discharges is "no free oil" and monitoring required is sheen observations. This provision was added to the permit in the 2004 renewal (69 FR No. 194, p. 60150). Any discharges of methanol greater than 20 bbls or of ethylene glycol greater than 200 bbls within a 7 day period would have to meet the current additional toxicity testing requirements. On April 8, 2011, the OOC Environmental Sub-Committee provided to EPA summary information regarding hydrate inhibitor use in GOM during oil and gas operations at EPA's request. It addressed the discharge of hydrate inhibitors (methanol, glycol, LDHI, and brine) when disconnecting subsea equipment. On May 7, 2012, the OOC submitted comments on the proposed general permit GMG290000. Attachment A of the comments providing supporting information on the regulation of hydrate inhibitor discharges and included toxicity information on methanol and ethylene glycol. On page 18 of EPA's Response to Comments dated September, 28, 2012, regarding the draft reissued NPDES permit publicly noticed in the Federal Register on March 7, 2012, EPA in responding to the OOC's comments in (e), EPA states: *Commenter requested that the permit allow discharges of methanol and ethylene glycol less than 200 bbl/d and waive toxicity test requirements for hydrate control fluids. Response: The models were re-run and the concentrations calculated and compared to the NOEC's for growth and mortality listed for methanol and ethylene glycol in the submitted comment addenda. The modeling runs submitted to justify the 200 bbl/d value, model an exceedance of the NOEC in case 21 of the submitted modeling package for methanol. Further, the actual density of methanol cannot be input to CORMIX. In addition, the subsequent concentrations and possible synergistic effects posed by discharges of produced water and hydrate inhibitors are not substantiated by the comment. Therefore, based on the Agency's review of the modeling submitted and a suitable margin of safety, the Agency will waive toxicity test requirements for neat methanol less than 20 bbl/d and neat ethylene glycol less than 200 bbl/d. All other hydrate control fluids will meet the requirement of the permit as stated.* The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
29	Miscellaneous Discharges – Discharge List	Part I.B.10 - Notes	"(vii) Non-specified Discharges: Any discharge that is not specified in this permit is not authorize."	The Joint Trades request the additional language be added to the permit.

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			Add to this section: "Small quantity discharges not addressed elsewhere in this permit, may be discharged after a notification to EPA that includes the following: • Proposed date(s) of activity • Description of activity (e.g., connection of flowline to structure) • Expected materials and quantities to be discharged • Description of potential impacts on the environment"	There are activities that might result in a small quantity discharge to enter the water. Many times, the quantities are hard to estimate and are very small, but however there doesn't appear to be method for these to be reported or addressed under the permit. Potential activities included but are not limited to: • Application of materials subsea that might migrate into the receiving waters (e.g., connector fluid/gel to ensure proper connections to minimize possible discharge of operational or production fluids). • Non-oil materials that migrate from a line when being connected to another part of the structure. An example is connecting a (preserved) flowline to a tree. • The removal of a cap may result in the inadvertent mixing of contents of the wet-parked line with the ambient water of the receiving water. Not accepting the proposed permit language is onerous on operators and an additional burden to the O&G Industry with no apparent additional protection to the environment.
30	Miscellaneous Discharges – Unused Cement	Part I.B.10.a	"Unused Cement Slurry - ~~Unused cement slurry due to equipment failure during the cementing job – such discharges are~~ Each type of unused cement slurry discharge is limited to once per cementing job .~~calendar year per facility~~. ~~Unused cement slurry due to off-specification during the cementing job – such discharges are limited to one discharge per well. In either case,~~ The operator shall report date, identification of well or facility, volume of cement, and cause of the discharge in their NetDMR."	1. The Joint Trades support the addition of unused cement slurry as a new discharge under Miscellaneous Discharges: "Unused Cement Slurry". The Joint Trades propose that the definition below be added to Part II.G. The addition of these discharges is critical to mitigating well control issues if the cement system cannot be returned to service quickly. *"Unused cement slurry- cement slurry used for testing of equipment or resulting from cement specification changes or equipment failure during the cementing job."* Summarizing the details of OOCs recent submittals to EPA Region VI related to this issue are as follows: 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 now provide a substantive justification for now prohibiting such discharges), and 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). This also consumes limited onshore disposal facility capacity for essentially benign materials. Finally, the transport of these materials will involve environmental consequences including increased air emissions from marine and road transport.

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				The Joint Trades present 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. Other Discharges of Unused Cement Slurry o 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: o 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. o 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. The Joint Trades estimate this occurrence is rare on a per rig basis. In 2012, a high activity year, there were ~ 99 rigs working in the GOM (2) (as of June 23, 2017 there were only 22 rigs active in the GOM). Using the 2012 rig count and assuming one event per year per rig this equates to ~500-10,000 bbls/year of slurry discharged. o 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 during high activity cycles. 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 2000-10,000 total bbls/year

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				Total= 3100 - 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. 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 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. As an alternative, the Joint Trades request a joint industry study be performed to assess the overall environmental and safety impacts of this discharge to better inform the decision before considering a prohibition, in the next permit cycle. 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 4. http://www.gomr.boemre.gov/PDFs/2009/2009-016.pdf 2. The Joint Trades request that Unused cement frequencies included: "such discharges are limited to per calendar year per facility" and "one discharge per well" should be removed and the statement should read, *Unused Cement Slurry - Each type of unused cement slurry discharge is limited to once per cementing job. The operator shall report date, identification of well or facility, volume of cement, and cause of the discharge in their NetDMR.* The language proposed in the draft is overly burdensome and introduces complexity for tracking and assuring compliance with a once per facility and once per well limitation. These restrictions may also limit the operator from mitigating well control issues if the cement system cannot be returned to service quickly during each cementing job. Each facility has multiple wells flowing to it and each well may require multiple cementing jobs. The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.

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31	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.	The Joint Trades request 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. Not accepting the proposed permit language is onerous on operators and an additional burden to the O&G Industry with no apparent additional protection to the environment.
32	Miscellaneous Discharges of Seawater and Freshwater which have been chemically treated - Limitations	Part I.B.11.a	**“a. Limitations** Treatment Chemicals. The concentration of treatment chemicals in discharged seawater or freshwater shall not exceed the most stringent of the following three constraints: 1) the maximum concentrations and any other conditions specified in the EPA product registration labeling if the chemical is an EPA registered product 2) the maximum manufacturer's recommended concentration 3) 500 mg/l [Note: The above concentration limits are based on each constituent that make up the treatment chemical in the discharge.]	The Joint Trades request the addition of the note to provide clarification that the chemical concentration limits are based on each constituent that make up the treatment chemical in the discharge. Additionally. the Joint Trades request EPA provide clarification regarding the following related to “Treatment Chemical Concentration” : • What if a treatment chemical degrades over time or is reacted away (e.g., acid, biocide) before discharge occurs? Would the discharge be considered as chemically treated? Not accepting the proposed permit language is onerous on operators and an additional burden to the O&G Industry with no apparent additional protection to the environment.
33	Miscellaneous Discharges of Seawater and Freshwater which have been chemically treated - Limitations	Part I.B.11.a	“[Note: Discharges treated by bromide, chlorine, or hypochlorite or which contain only electrically generated forms of chlorine, hypochlorite, copper ions, iron ions, and aluminium ions are not required for toxicity tests.]”	The Joint Trades request revising the text to include copper, iron, and aluminium ions to account for the fact that not only is electric current used to generate active chlorine from seawater, but also there are systems which use sacrificial anodes to generate other anti-biofouling ions (such as, iron, copper and aluminium). Examples of several systems and related information can be found at the following links: http://www.farwestcorrosion.com/cathelco-marine-pipework-anti-fouling-systems-for-fpsos.html https://cathodicme.com/mgps-systems/marine-growth-prevention-system/ http://www.cathelco.com/mgps-overview/how-a-marine-growth-prevention-system-works/ http://www.blumeworldwideservices.com/ Additionally, the Joint Trades are providing a current Copper Ion system installation and maintenance document in use (see attachment Appendix B). The Joint Trades do not expect the discharge will have a toxic impact on the environment as these systems operate in the part per billion concentration range. It is also noted that these

Comment No.	Type/Category	Permit Section Ref.	Current or Revised Permit Language /Clarifications/Issue	Rationale
				systems are in use in the marine industry. Based on review of the manufacturer information, these systems operate with a copper in solution of less than 2 ppb. At less than 2 ppb in solution, a 100% effluent discharge would have a copper concentration that is lower than that of the EPA marine chronic and acute criteria. When compared using the existing critical dilutions and NOECs from recent testing, the copper concentration is even lower than at 100% effluent discharge and thus would be lower than the EPA marine chronic and acute criteria. Further, it should be noted that there is no marine water quality criteria for Aluminium. However, it is expected that the concentration of aluminium in solution will be less than the copper concentration, based on manufacturer information. The Joint Trades are submitting toxicity testing information to support no toxic impact from these systems. Data collected from electric current generated ion treated seawater discharges under current general permits GEG460000 and GMG290000 demonstrate no reasonable potential for toxicity at the critical dilution and should be excluded from the monitoring requirement. These data include electric current generated copper, iron and aluminium ions and are hereby submitted as Appendix C. Additionally, the Joint Trades are requesting this change be made to be consistent with the Draft Region 4 permit GEG4600000. This permit includes the exemption for electrically generated forms of chlorine, hypochlorite, copper ions, iron ions, and aluminium ions. Ref.: *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.* Not accepting the proposed permit language is onerous on operators and an additional burden to the O&G Industry with no apparent additional protection to the environment.
34	Miscellaneous Discharges of Seawater and Freshwater which have been chemically treated – Monitoring Requirements	Part I.B.11.b	"Flow Volume. Once per ~~quarter~~ month, an estimate of ~~total~~ flow (bbl/day) ~~volume of discharges (bbl) during the quarterly reporting period must be reported~~ recorded. ~~(The operator shall keep records of discharge events.)~~"	The Joint Trades request clarification on the reason for the change of Chemically Treated Miscellaneous Discharge volume from highest "Monthly Average per monitoring period" (quarter) to "Total volume per quarter" when all other permit requirements for chemically treated volume (i.e. frequency and critical dilution) remain and are based on "highest monthly average". • Discharge volume reported on toxicity lab reports currently reflects the volumes needed to determine critical dilution and frequency of testing, providing a clear record of why the test was conducted at the frequency and applicable critical dilution (as determined by the current required volume limitations). • Keeping track of two different types of measurements could potentially cause confusion and possibly result in testing done at an incorrect frequency or critical dilution. • This reporting requirement has not changed since Chemically Treated Miscellaneous Discharge requirements were added to the permit in 1998. • And historically, the discharge volume reporting requirement has remained the "highest monthly average" for all discharges requiring volume reporting (and toxicity testing). The Joint Trades request that the proposed change to chemically treated volume reporting not be incorporated into the reissued permit and remain as stated in the current permit.

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<tr><th>Comment No.</th><th>Type/Category</th><th>Permit Section Ref.</th><th>Current or Revised Permit Language /Clarifications/Issue</th><th>Rationale</th></tr>
<tr><td></td><td></td><td></td><td></td><td>The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.</td></tr>
<tr><td>35</td><td>Cooling Water Intake Structure Requirements – Information Collection</td><td>Part I.B.12.a.1</td><td>“New fixed facilities must have ~~submit~~ source water baseline biological characterization data, source water physical data, cooling water intake structure data, and velocity information:”</td><td>The Joint Trades are requesting this change to provide consistency with the first sentence found under Part 1.B.12.a and Section VII.E of the proposed Fact Sheet.

Part I.B.12.a states <i>“The owner or operator of a new offshore oil and gas extraction facility must retain</i> [emphasis added] <i>the following information with the facility and make it available for inspection.”</i> .

Section VII.E of the proposed Fact Sheet states <i>“EPA also proposes to reduce application information collections from new facilities as identified in the current permit Part I.B.12.a. Instead of submitting such information to EPA, the new facility operator shall keep those information (either paper or electronic document) accessible for inspection. The operator of new facility still shall report basic information, such as facility location, design intake capacity, and intake velocity, in NOI as required in permit Part I.A.2, but shall keep the records of details and all calculations or drawings with the facility and make it available for inspection. New facilities which have any intake structure with a designed intake velocity greater than 0.5 ft/sec are not authorized to discharge cooling water under this permit.”</i>

The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.</td></tr>
<tr><td>36</td><td>Cooling Water Intake Structure Requirements – Velocity Monitoring Requirements</td><td>Part I.B.12.c.1.ii
Part I.B.12.c.2.iii
Part I.B.12.c.3.ii</td><td>Part I.B.12.c.1.ii
“ii. Velocity monitoring. The operator must monitor intake flow velocity across the intake screens to ensure the maximum intake flow velocity does not exceed 0.5 ft/s. The intake flow velocity shall be monitored ~~daily~~ quarterly if the most recently reported intake flow velocity is less than 0.30 ft/s; monthly if the most recently reported intake flow velocity is 0.30 to 0.38 ft/s; and daily if the most recently reported intake flow velocity exceeded 0.38 ft/s. A downtime, up to two weeks, for periodic maintenance or repair is allowed and must be reported in the DMRs. When replacement parts cannot be obtained within the two-week time period, the down time can be extended in increments of two weeks until the replacement parts or equipment can be obtained by the facility. In addition to the initial two-week downtime allowance, each additional two-week increment for downtime must be reported in the DMRS indicating reasons why the additional increment(s) was needed.”

Part I.B.12.c.2.iii
“iii. Velocity monitoring. The operator must monitor intake flow velocity across the intake screens to ensure the maximum intake flow velocity does not exceed 0.5 ft/s. The intake flow velocity shall be monitored ~~daily~~ quarterly if the most recently reported intake flow velocity is less than 0.30 ft/s; monthly if the most recently reported intake flow velocity is 0.30 to 0.38 ft/s; and daily if the most recently reported intake flow velocity exceeded 0.38 ft/s. A downtime, up to two weeks, for periodic maintenance or repair is allowed and must be reported in the DMRs. When replacement parts cannot be obtained within the two-week time period, the down time can be extended in increments of two weeks until the</td><td>The Joint Trades are requesting a tiered approach to velocity monitoring versus the current daily monitoring requirement. Namely,

<table>
<tr><th>If the Most recent intake flow velocity (ft/s)</th><th>Then Monitoring Frequency Should be</th></tr>
<tr><td><0.300</td><td>Quarterly</td></tr>
<tr><td>0.300 – 0.38</td><td>Monthly</td></tr>
<tr><td>>0.38</td><td>Daily</td></tr>
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Velocity monitoring consists of a demonstration requirement based on the facilities’ proposed design and a compliance monitoring requirement that verifies the velocity limitation is being met. There is agreement with the purpose of inspection, but not the frequency.

The tiered velocity monitoring approach is based upon a statistical analysis of six separate CWIS operated in the GOM during 2015. The analysis is based on the rate-of-change in daily velocity monitoring data (attached as Appendix D). An ANOVA indicates no statistical difference in the rate of change in intake velocity among the five intakes ($P < 0.05$). The data are approximately normally distributed with a mean change in velocity equal to 0.0001 (ft/s)/day and a standard deviation equal to 0.0106 (ft/s)/day. Based on these data, there is a 95% probability that the mean velocity increase over any 30-day period will be less than 0.11 (ft/s)/day; and a 95% probability that the mean velocity increase over any 90-day period will be less than 0.20 (ft/s)/day. Therefore, 95% of all monthly intake velocity measurements will be less than 0.5 ft/s provided that the previous month’s velocity measurement was less than 0.39 ft/s. Similarly, 95% of all quarterly velocity measurements will be less than 0.5 ft/s provided that the previous quarter’s measurement was less than 0.30 ft/s.</td></tr>
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<tr><th>Comment No.</th><th>Type/Category</th><th>Permit Section Ref.</th><th>Current or Revised Permit Language /Clarifications/Issue</th><th>Rationale</th></tr>
<tr><td></td><td></td><td></td><td>replacement parts or equipment can be obtained by the facility. In addition to the initial two- week downtime allowance, each additional two-week increment for downtime must be reported in the DMRS indicating reasons why the additional increment(s) was needed."

Part I.B.12.c.3.ii
"ii. Velocity monitoring. The operator must monitor intake flow velocity across the intake screens to ensure the maximum intake flow velocity does not exceed 0.5 ft/s. The intake flow velocity shall be monitored ~~daily~~ quarterly if the most recently reported intake flow velocity is less than 0.30 ft/s; monthly if the most recently reported intake flow velocity is 0.30 to 0.38 ft/s; and daily if the most recently reported intake flow velocity exceeded 0.38 ft/s. A downtime, up to two weeks, for periodic maintenance or repair is allowed and must be reported in the DMRs. When replacement parts cannot be obtained within the two-week time period, the down time can be extended in increments of two weeks until the replacement parts or equipment can be obtained by the facility. In addition to the initial two -week downtime allowance, each additional two-week increment for downtime must be reported in the DMRS indicating reasons why the additional increment(s) was needed."</td><td>We note this data makes sense relative to visual inspection information presented elsewhere- the rate of biogrowth on intakes is quite low and so the rate of change of intake velocity would also be expected to be quite low, hence allowing for reduced monitoring frequencies (using a tiered approach to ensure compliance with the 0.5 fps standard for any CWIS design).

Further, the Joint Trades are requesting the additional language be included to account for times when replacement parts and equipment cannot be obtained from a manufacturer in a two-week time frame. Sometimes these items are on backorder and require additional time to receive.

The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.</td></tr>
<tr><td>37</td><td>Cooling Water Intake Structure Requirements – Entrainment Monitoring Requirements</td><td>Part I.B.12.c.2.ii</td><td>ii. The permittee must submit a SEAMAP data report annually to meet the requirements of 40CFR125.137. ~~Entrainment monitoring/sampling. The operator must collect 24-hour entrainment samples from water withdrawn at all CWISs at the following frequency and duration based on the depth of the intake structure:~~

<table>
<tr><td>~~Intake Screen or Opening Locates Below Water Surface~~</td><td>~~<= 100 Meters (M)~~</td><td>~~>100 M, but<= 200 M~~</td><td>~~>200 M~~</td></tr>
<tr><td>~~Frequency~~</td><td>~~Three samples per Year~~</td><td>~~Two Samples per Year~~</td><td>~~One Sample per Year~~</td></tr>
<tr><td>~~Months~~</td><td>~~March or April, and June, and December~~</td><td>~~March and April and June~~</td><td>~~March and April~~</td></tr>
<tr><td>~~Reporting~~</td><td colspan="3">~~Entrainment per Sample Event and Total Annual Entrainment~~</td></tr>
</table></td><td>The Joint Trades strongly objects to the continued requirement to conduct ongoing entrainment monitoring.

The Joint Trades request the removal of entrainment monitoring/sampling requirement and the addition of language requiring permittees to submit a SEAMAP data report annually.

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.

Our request is based on the results of 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 (attached as Appendix E). 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 following is a brief summary of key findings of the industry entrainment monitoring study:</td></tr>
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Comment No.	Type/Category	Permit Section Ref.	Current or Revised Permit Language /Clarifications/Issue	Rationale
				1. Study results provide data for enumeration of entrainment losses by species and for total egg and larval losses as required by the Permit. 2. Estimated entrainment impacts on ichthyoplankton are insignificant. A. Entrainment monitoring/sampling is required during the primary period of reproduction, larval recruitment, and peak abundance for each species, specifically, identified as part of the Source Water Biological Baseline Characterization Study (SWBBCS); however, the SWBBCS found no evidence to suggest CWIS would impact selected species of socioeconomic and ecological importance. B. In this study, catches of SWBBCS selected species were too low to statistically model (all exhibited >90% zeroes across tows; some 100% zeroes). C. Thus, no meaningful impacts from entrainment on these species are expected to occur. D. Daily entrainment was extremely small compared to the corresponding daily reference abundances drifting past each facility; thus, no meaningful impacts are expected for any species. 3. Temporal and environmental influences on ichthyoplankton densities. A. While no impacts are expected to occur at any intake depth, the most prevalent influence was sampling depth, whereby densities declined exponentially with increasing depth. B. In general, the lowest densities occurred during the fall and greatest densities during the spring. 4. Using SEAMAP data to estimate entrainment loss. A. Ichthyoplankton densities also declined exponentially with total water column depth; all study sites were deeper than the shallower depths (about ≤ 200 m) where sharp increases in densities began in the shoreward direction. B. For each of the study sites and across months, forecasted densities based on SEAMAP data were consistently 1½ to 2 times greater than those observed during this study. C. No impacts are expected based on densities estimated from either dataset. D. Thus, SEAMAP data appear adequate for future estimates of impacts on the ichthyoplankton community. The results of recent quarterly on-platform entrainment monitoring studies conducted (attached as Appendix E) are fully consistent with the results of the Entrainment Monitoring Study. The concentrations of larvae of key socioeconomic and ecological important species were typically zero in these measurements. This is consistent with industry's views that (1) cooling water

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				intake structures on offshore facilities present an insignificant risk to fisheries, (2) the quarterly monitoring requirement is providing no new useful information and (3) the requirement should be dropped entirely. Platform-specific monitoring in the Gulf of Mexico shows that data collected from actual cooling water systems indicates that fish egg and larval concentrations are equivalent to or much lower than those in the SEAMAP database for the same fishery zones (See Appendix F). The Joint Trades believe that a requirement for periodic reports based on the updated SEAMAP database are appropriate to the risk as demonstrated in the SWBBCS and entrainment monitoring studies. 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. • 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. Although striking this requirement in its entirety is the Joint Trades' preference, should EPA Region VI continue to insist on platform entrainment monitoring, The Joint Trades are requesting that the entrainment monitoring be no longer required after two years' entrainment data demonstrates the number of entrained species is lower or close to SEAMAP data. Suggested alternate wording would be: *"Facilities with two years of entrainment data demonstrating that the number of entrained species is lower or close to SEAMAP data are no longer required to conduct entrainment monitoring. Permittees shall submit a certification that the entrainment data is less than or close to SEAMAP data prior to discontinuing entrainment monitoring."*

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				The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
38	Other Discharge Limitations – Floating Solids or Visible Foam	Part I.C.1	"Floating Solids or Visible Foam~~ or Oil Sheen~~"	The Joint Trades are requesting the deletion of "or Oil Sheen" from this section. The deletion is requested for the following reasons: • The permit already restricts oil sheens from discharges through the various requirements for no "Free Oil". • Section 311 of the Clean Water Act prohibits the discharge of oil. • Listing "Oil Sheen in the title of this part leads to confusion on the intent of the part. The Joint Trades believe it was not the intent to allow the discharge of "trace amounts" of oil and/or oil sheen. Not accepting the proposed permit language is onerous on operators and an additional burden to the O&G Industry with no apparent additional protection to the environment.
39	Other Discharge Limitations – Dispersants, Surfactants, and Detergents	Part I.C.3 And Part I.B.4.a	Part I.C.3 "The discharge of dispersants, surfactants, and detergents is prohibited except when it is incidental to their being used to comply with safety requirements of the Occupational Safety and Health Administration and the Bureau of Safety and Environmental Enforcement." Part I.B.4.a "The addition of dispersants or emulsifiers to produced water discharges is prohibited when used for purposes that could circumvent the intent of the permit's produced water sheen monitoring requirements. ~~40 CFR § 110.4.~~"	The Joint Trades agree with the comments in VII.J on pages 26 and 27 of the fact sheet that surfactants should not be added to the produced water discharge to prevent detection of a sheen on the receiving water and circumvent the permit's produced water sheen monitoring requirements. However, the Joint Trades are concerned that the proposed changes to the permit language regarding the discharge of dispersants, surfactants, and detergents may have unintended prohibitions on the use of surfactants (detergents, dispersants) in the context of the use of surface active substances in the formulation of chemicals used in the offshore oil and gas industry to impart specific properties to the formulations (see attached document Surfactants in Oil & Gas Drilling provided as Appendix G and also API's Offshore Effluent Guidelines Steering Committee paper Chemical Treatments and Usage in Offshore Oil and Gas Production Systems, Hudgins, October 1989) (attached as Appendix A). The Joint Trades recommend keeping the current permit language in Section I.C.3. The Joint Trades request the changes to the proposed language in Part I.B.4.a as noted in the proposed red text. See Comment No. 8 for additional information and discussion on this requested change.

Comment No.	Type/Category	Permit Section Ref.	Current or Revised Permit Language /Clarifications/Issue	Rationale
				The draft permit language is more onerous on operators and the additional burden to the O&G Industry does not have any apparent additional protection to the environment.
40	Spill Prevention Best Management Practices	Part II.B.7	"This general permit does not authorize discharges, including spills or leaks, caused by failures of equipment, blowout, damage of facility, or any form of unexpected discharge. If a permittee seeks a conditional exemption to the discharge restrictions of this permit, the permittee must demonstrate to the Regional Administrator the potential environmental impacts and/or benefits of the proposed discharge. Approval from the Regional Administrator must be obtained prior to commencement of such discharge and the Regional Administrator will establish appropriate discharge limitations based upon the evidence provided by the permittee."	The Joint Trades request adding the suggested language in red text to provide a mechanism for EPA to approve unique and novel discharges that may not be covered by the existing permit conditions, but may be necessary for a variety of operational reasons. By adding the attached language, a permittee and EPA can evaluate such situations based on sound science and information. EPA can then make an appropriate decision after completing a review. Not accepting the proposed permit language is onerous on operators and an additional burden to the O&G Industry with no apparent additional protection to the environment.
41	Reporting Requirements - Discharge Monitoring Reports (DMR) and Other Reports	Part II.D.4	"If for some reason the electronic submittal is not accepted or the NetDMR system is not available, the permittee would be required to submit the paper DMR. The permittee has up to 60 days to submit paper DMRs. "NOTE: As soon as NetDMR is available, the permittee must file their DMRs electronically. The paper DMRs serve as evidence the permittee attempted to meet their submission deadline when NetDMR was not available. The evidence will be the mail receipt (e.g., FedEx, UPS, USPS, etc.) showing EPA received the paper DMRs." "Operators shall mail all paper DMRs and all paper DMR attachments to the following address: Water Enforcement Branch (6EN-WC) U.S. Environmental Protection Agency Region 6 1445 Ross Avenue Dallas, TX 75202" "Instructions for completing DMRs in accordance with the permit requirements are available in EPA Region 6's website at http://www.epa.gov/region6/6en/w/offshore/home.htm." "Other required reports shall be submitted electronically with NetDMR. EPA may request a paper copy of any report in addition to the electronic report." "If discharge is not applicable for a facility, "no discharge" must be reported for that facilityk until an NOT is submitted. "	The Joint Trades are requesting the additional language to: • Provide clarity when the NetDMR system is not available • Provide an official address for submittal of the paper DMRs. Additionally, the Joint Trades are requesting a set of instructions for completing DMRs in accordance with the requirements of the permit the effective date of the permit. The instructions should utilize the permit requirements first and provide clarification when there are limitations or input variables with the electronic system and DMRs. The Joint Trades cannot stress the importance that the instructions and DMR be built around the permit requirements and not vice versa. The permit requirements are what an operator is held accountable to and not the limitations and data inputs of the electronic system. These detailed instructions would eliminate multiple DMR errors and create more consistency and should eliminate most of the BSEE inspector's questions and confusion during offshore inspections. The instructions should include information on DMR reporting during the transition of coverage from the 2012 permit to the new 2017 permit. An operator has 90 days from the effective date to submit an NOI for coverage of existing permit coverage under the 2012 permit. It is unclear which timeframe and how to properly report on DMRs between each permit once a NOI is submitted within the 90 days for coverage under the new permit. Since the NetDMR system encompasses many different permit types, not all of the No Data Indicator Codes (NODI) are applicable to the Region 6 DMRs. Therefore, the Joint Trades are requesting the instructions also include guidance and clarification on which NODI codes are applicable and in what context they should be used in accordance with the permit requirements. The Joint Trades request the ability to review and comment on the DMR instructions prior to them being finalized to allow for clarification and edits as necessary. The Joint Trades are requesting that the DMR be corrected to reflect the correct permit requirements outlined in the permit for each parameter. The current DMR contains numerous typos and inconsistencies with the permit requirements. OOC has outlined several of these in the attachment provided in Appendix H. The Joint Trades are also correcting a typo that was found in the last sentence.

Comment No.	Type/Category	Permit Section Ref.	Current or Revised Permit Language /Clarifications/Issue	Rationale
				The lack of active website, email address and NOI, NOT and DMR instructions is very onerous on operators and the burden to the O&G Industry does not have any apparent additional protection to the environment.
42	Reporting Requirements – Signatory Requirements (Certification)	Part II.D.10.c	" 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 gathered and evaluated 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."	The Joint Trades are requesting the deletion in the certification statement because it is not consistent with the certification statement found at 40CFR 122.22.d. The correct certification statement found in the regulations is: *"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 am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."*
43	Reporting Requirements – Electronic Signatures	Part II.D.10.d	"Electronic Signatures: Please visit http://www.epa.gov/region6/6en/w/offshore/home.htm for instructions on obtaining electronic signature authorization to sign eNOIs, eNOTs, and NetDMRs."	The Joint Trades request that this website be activated prior to the effective date of the permit and that all applicable instructions be uploaded to it. The EPA website listed is not currently active. The lack of active website, email address and NOI, NOT and DMR instructions is very onerous on operators and the burden to the O&G Industry does not have any apparent additional protection to the environment.
44	Section G. Definitions	Part II.G	*Unused cement slurry- cement slurry used for testing of equipment or resulting from cement specification changes or equipment failure during the cementing job.*	The Joint Trades request adding this definition for "Unused Cement Slurry". The rationale for this addition is included in Comment No. 30 for Part I.B.10.a. Not accepting the proposed permit language is onerous on operators and an additional burden to the O&G Industry with no apparent additional protection to the environment.
45	Section G. Definitions	Part II.G.86	"Uncontaminated Freshwater" means freshwater which is discharged without the addition or direct 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 released during training and testing of personnel in fire protection, ~~and~~ (4) water used to pressure test or flush new piping or pipelines, and (5) potable water and off-specification potable water.	To provide clarification, the Joint Trades request adding the addition of "potable water and off-specification potable water" to the definition for "Uncontaminated Freshwater". Not accepting the proposed permit language is onerous on operators and an additional burden to the O&G Industry with no apparent additional protection to the environment.
46	Appendix F – Table 1	Appendix F – Table 1	Appendix F – Table 1	The Joint Trades request that once all edits and changes to the permit text language is complete, Table 1, Appendix F requirements should be updated accordingly to match. The Joint Trades would prefer that Table 1 be removed completely from the permit because EPA has historically stated that the permit text holds precedent over Table 1, and because of potential inconsistencies between the permit language and Table 1. Not accepting the proposed permit language is onerous on operators and an additional burden to the O&G Industry with no apparent additional protection to the environment.

APPENDICES

APPENDIX A

COMMENT NO. 9 & 39

CHEMICAL TREATMENTS AND USAGE
IN OFFSHORE OIL AND GAS PRODUCTION SYSTEMS

[redacted]

Prepared for

AMERICAN PETROLEUM INSTITUTE

Offshore Effluent Guidelines
Steering Committee

by

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October, 1989

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SUMMARY

REFERENCES

ACKNOWLEDGEMENT

The author would like to express his gratitude to the companies and individuals who have contributed so much in helping to make this report an accurate and broad perspective of current practices in offshore operations. Many cooperated in the original 1985 survey, some were only involved in updating and expanding the survey in 1989 ("), and others contributed to both efforts (#). The following companies and individuals were interviewed regarding the chemical properties and applications:

Conoco, Inc.:# D.D. Caudle#, D. Barber, A.L.G. Bisso, M. Williams#, W.K. Kewley, F. Laskowski"

Exxon Co., USA:# T. Michie, F.P.H. LeBlanc, M. Parker", M. Barrilleaux", D. Brown", D.KalZ"

Shell Offshore, Inc.#: RJ. Redweik, B. Gordon, V. Edwards, T. Randolph", G. Doucet", B. Stringfield", K. Myers", L. Crane

Texaco Inc.#: M.T. Stephenson#, U.M. Corso#, F. Fraker

Dowell Schlumberger": e. Crowe"

Exxon Chemical#: SJ.Wangerin, M.W. Eiser, M. Fefer, W.e. Whiteside, R.F. Richter", K.T. Allford#

Halliburton": J. Chatterji", R. Bechtel", M. Misak"

Nalco Chemical Co.#: M. Littman, D. Kroll, G. Chappel#, D. Deshazo, S. Allenson, R.K. Gable'

NL Treating Chemicals: K.T. Allford#

Petrolite Corporation#: TJ . Robichaux#, G. Cary#, DRorstmann, T.E. Gerst, D. Zienty, E. French, H.M. Hilliard#, K. Barker", F. E. Mange"

Union Carbide Corp.#: S.E. Foster, W.M. Snellings", R. Jarvis"

Welchem, [nc.#: D.V. Agafon, H.S. Carson#, e.E. Johnson, NJ. Mundhenk'

In addition some information and data was obtained from the following suppliers through operating companies: Ashland Chemical Co., Baker Performance Chemicals; Inc., B J - Titan Services, Champion Chemicals, Inc., Coastal Chemical Company, DataChem, [nc., OSCA, Tetra Resources, [nc., Western Company of North America, X-Chem.Inc.

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1985, Offshore Operators Committee, Industrial Technical Advisory Group, Dan Caudle, Coordinator
1989, American Petroleum Institute, Offshore Effluent Guidelines Steering Committee,
Michael Stephenson, Coordinator.

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While the assistance and information provided by all of the above parties is expressly acknowledged, the final responsibility for the selection, organization, and interpretation is the author's.

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ABSTRACT

This report reviews the chemicals used to help control many operating problems encountered in U.S. offshore oil and gas production. The discussions cover all chemicals used, including production treating chemicals, gas processing chemicals, and stimulation and workover chemicals. Each topic includes problem description, generic chemical types, solubility and treatment methods and concentrations.

A portion of these chemicals will dissolve in the produced water. Most of the water produced with oil and gas in offshore operations in the U.S. is treated to remove dispersed oil and grease, then discharged to the sea. The discussion on environmental aspects provides information on the aquatic toxicity, solubility, and treatment practices for chemicals used for each purpose. Actual environmental impact must include site specific factors, such as water depth, current, temperature, etc., which are outside the scope of this report.

Acute aquatic toxicity and solubility information was provided by the chemical suppliers for the production treating chemicals, including biocides, scale and corrosion inhibitors, emulsion breakers, etc. Aquatic toxicity data for the gas processing chemicals (methanol, glycols) was primarily obtained from the literature. No aquatic toxicity data was obtained for the stimulation and workover chemicals from the suppliers. Typical treatment methods and system configurations were obtained from operators and chemical suppliers. No assessment of the quality of this data is included.

INTRODUCTION

OBJECTIVE

The objective of this report is to examine the purpose, chemical nature, properties, and treatment methods for the broad range of chemicals used in offshore oil and gas production in the U.S. An important part of this examination will be a summarization of the available data on acute aquatic toxicity of those chemical constituents which are likely to end up in produced water being discharged to the ocean. Evaluation of environmental impact involves factors other than the nature and concentration of chemicals added in production operations and is beyond the scope of the study. The report is not primarily a literature search, but data references and illustrative articles and books are listed.

Considerable attention continues to be focused on the effects of offshore oil and gas producing operations on the marine environment. One aspect being examined is the discharge of produced water into the ocean. Removal of produced oil from water has long been recognized as an essential step with strict standards having been established by the Environmental Protection Agency[1,2]. The 1976 requirements for best practical technology (BPT) had been scheduled to expire on June 30, 1984 but were extended. Proposed revisions for best professional judgment/best available technology published for review in 1985[2] did not alter the regulations on produced water discharge. Revised New Source Performance Standards (NSPS) were included in the revised National Pollutant Discharge Elimination System (NPDES) permits for the Gulf of Mexico[3] issued in 1986. The regulations concerning oil content of the produced water were modified. Present EPA permits do not limit treating chemicals in the produced water discharges. Governmental and intergovernmental agencies in other areas of the world (e.g. North Sea, Baltic Sea, Mediterranean Sea, etc.) are considering preapproval of treating chemicals in produced water discharges.

Constituents of produced water have previously been evaluated. Studies by Middleditch[4], Zimmerman and DeNagy[5], the API[6], the Offshore Operators Committee (OOC)[7], and others[8] have considered various aspects of the treating chemicals in produced water streams. This study is an update of the 1985 OOC report, but expanded to include the broad range of chemicals used in offshore oil and gas production operations in the U.S.

Table 1 provides a concise overview of the offshore oil and gas industry in the U.S. All of these numbers were considered preliminary by the sources, subject to revision. The water production data probably has the greatest uncertainty. However, even these data are sufficiently accurate to give a good perspective of the industry. It is apparent that the Gulf of Mexico is the major offshore producing area by any of the statistics. Corresponding emphasis has been placed on that area in this survey.

1988 Offshore Oil and Gas Statistics

	Gulf of Mexico	Calif.	Alaska	Total
Wells[9]				
Oil	5,892	2,On	333[a]	8,297
Gas	4,n2	18	22[a]	4,762
Operating	10,614	2,090	355[a]	13,059
Shut in	2,344	537	36[a]	2,917
Production:	Barrels/day or MMSCFD @ 15.000 psia			
Oil[10]	819,000	86,000	43,000	948,000
Water[11]	1,502,230[b]	877,534	93,963	2,473,727
Gas[11]	13,456	143	160	13,769

a. Offshore not broken out, assumed 25%.
b. State water production not available, assumed IOX of federal water production.

Table 1. Summary of Statistics on Offshore Oil and Gas Production Industry in U.S.

SCOPE

Chemicals that may be used in routine offshore producing operations in the United States are included in the scope of this report. For purposes of discussion, these chemicals have been arbitrarily placed into three groups. The production treating chemicals are those routinely added to the produced fluids or to seawater or other source water that is injected for waterflooding. These chemicals are added for various purposes (such as corrosion or scale inhibition). The gas processing chemicals discussed are those used for freeze point depression of gas hydrates or for dehydration of produced gas. Hydrogen sulfide and carbon dioxide are not normally removed from gas offshore and these sweetening chemicals and processes are not covered in this report. The third group consists of the stimulation and workover chemicals, including the acids and dense brines, along with their associated additives. Each of these groups will be defined more fully in the following section and examined in greater detail in later sections.

APPROACH

The objectives of this paper can only be met by utilizing a variety of sources of information. The nature of the problems and control methods have been discussed in the technical literature from time to time but are constantly undergoing change as products and treatment methods are improved. Most of the production treating chemicals are highly complex mixtures rather than pure compounds and are usually considered proprietary, with the best descriptions often being found in the patent literature. Actual treatment methods and concentrations vary substantially between operators, fields, and even wells within a field. Results of aquatic toxicity tests on the proprietary formulations are not routinely published or reported. On the other hand the gas treating chemicals are relatively pure chemical compounds. Aquatic toxicity of these chemicals are available in the literature for a few species. The acids are also relatively pure, but there is considerable uncertainty in the concentration of unreacted acid remaining in the discharged fluids.

It was decided that the best overall results could be obtained using a three faceted approach: interviewing chemical suppliers and operating companies plus a literature search.

Interview Chemical Suppliers. Discussions were held with technical specialists with three major suppliers of production treating chemicals. Composition of products, recommended application procedures, water vs oil solubilities, and the aquatic toxicity of products in the marine environment were discussed. Further discussions were held with other suppliers with respect to aquatic toxicity information. Their contributions and review of the paper have supported the general points or brought out additional information. Information on acids and workover fluids and additives was obtained from several suppliers. Aquatic toxicity data on the gas treating chemicals were obtained primarily from the literature, plus one supplier.

Interview Operating Companies. Discussions were held with representatives of four major operating companies. Technical specialists concerned with environmental factors and engineers responsible for operations and treatment of oil and gas production offshore were interviewed. Application, treatment, and monitoring procedures for the treating chemicals were discussed as well as methods of disposing of produced water. In the 1985 survey these four companies operated 2223 (34%) of the 6525 wells in the OCS and state waters in the Gulf of Mexico (1983)12 and produced approximately 42% of the liquid hydrocarbons (1984)13. In 1988 these companies operated 3844 (36%) of the 10,614 wells and produced 36% of the liquid hydrocarbons and 49% of the produced water in the Gulf of Mexico. Two of the companies also have operations offshore California and Alaska. While this experience directly reflects actual operating practices for about one third of the US offshore operations, review of this paper by representatives from other operating companies has confirmed the general conclusions or brought out other practices.

Literature Review. Computer searching of several data bases indicated that general searching for offshore pollution and toxicology was impractical due to the large number of references pertinent to oil spills and cleanup. The cited references resulted from more specific searches and/or were provided by the technical specialists in the various fields. Relatively little information on aquatic toxicity of production treating chemicals was found in the literature. Useful information was found for the gas treating chemicals.

At the outset of the 1985 study, it was apparent that it would neither be feasible nor necessary to try to list the properties of every production treating chemical sold for offshore use. That conclusion is still valid, including the gas processing, stimulation, and workover fluids. Many of the products within the various suppliers' lines for a specific purpose are similar (though not necessarily identical) and are built around the same basic chemical structures. In some instances these generic chemical types are specific chemical compounds, e.g., methanol. The general consensus was that the study should focus on the relatively few generic chemical types of materials that are used for the various purposes in offshore operations. Consequently, most of the discussions will be directed at generic chemical types on an individual basis. However, the aquatic toxicological studies were performed on specific product formulations. These data are considered to be indicative of the properties of a particular generic type, but it should be recognized that the additives in a formulation can have significant effects of their own.

DEFINITIONS, USAGE OF TERMS

PRODUCTION TREATING CHEMICALS

Treatment Purpose. Any treating chemical used in producing operations will be added for a specific purpose, to reduce or mitigate some type of operating problem. Unless that problem becomes significant, the chemical will not be added for obvious economic as well as technical reasons. None of the **operating companies interviewed encountered such** a broad range of problems that all types of treating chemicals listed below were necessary. However, it was often necessary to add more than one treating chemical in a system. Alternate technology can be and often is used to control the various problems, **either alone or in conjunction with chemical treatments.**

Chemical treatments are often the only effective and/or economical method for some types of problems. The following listing of problem areas and treating chemicals are generally accepted nomencla**ture. However, there are some variations between** companies and individuals. For example, 'water clarifiers' was used for the reverse breakers,etc. Each of these problem areas will be discussed separately later.

Problem	Treating Chemical
Mineral scale deposits	Scale inhibitor
Equipment corrosion	Corrosion inhibitor Oxygen scavengers
Bacterial fouling	Biocide
Water-in-oil emulsion	Emulsion breaker
Oil-in-water emulsion	Reverse breaker Coagulants, flocculants
Solids removal	Coagulants, flocculants
Foaming, oil or water	Antifoam
Paraffin deposits	Paraffin inhibitor, or solvent

Generic Chemical Types. Virtually all oilfield treating chemicals are complex mixtures manufactured from impure raw materials. There can be dozens of different molecular compounds of similar chemical and/or biological activity in a batch of reaction product. These individual compounds will differ slightly in the number of carbon atoms or perhaps in branching in a long chain, factors which usually have little effect on the chemical activity. Minor amounts of unreacted raw materials and reaction byproducts may also be present. Yet within this complexity, there is a central chemical functional group that imparts the primary properties of the specific mixture. It is this central chemical functional group that will be used to define the *generic chemical type.* These *generic chemical types* are sub-classes within the chemical families used in the oilfield. Undoubtedly many other chemicals can contain this same chemical functional group, yet have totally different properties resulting from other parts of those molecules. Those chemicals are not used in the oilfield and are excluded from this definition.

The specific mixture obtained from the reproducible but impure raw materials under carefully controlled reaction conditions is often called a *compound* for convenience. [Italic *compound* will be used to differentiate this usage from the normal chemical definition.] For example, the simplest form of a corrosion inhibitor *compound* may be suitable in one type of production system (e.g., high gravity paraffin crude with low water content) but may be much less efficient at higher water content even in the same field. Thus, the *compound* will often be modified to change the phase distribution behavior somewhat to allow the *compound* to be effective over a broader range of water/oil ratios. A common way to adjust this distribution is the reaction of the *compound* with ethylene or propylene oxide. Ethylene oxide increases water solubility of a *compound* with low water solubility. Propylene oxide increases the hydrocarbon solubility of a *compound* with low oil solubility. The oxides may be reacted into the *compound* during its initial formation or by reaction with an intermediate *compound.*

Solubility is an extremely important factor in oilfield treating chemicals. In some cases the chemical can only work to fulfill its purpose at the interface between two of the phases, i.e., the *compound* must be surface active. This surface activity can often be enhanced by limiting the solubililty of the *compound* in the oil and in the water phases to the minimum that is still adequate to carry the *compound* through the bulk fluids to the interface. Various ratios of ethylene and propylene oxide are commonly used to accomplish this goal, resulting in the desired oleophilic/hydrophilic balance. These **balancing factors are critical in emulsion breakers,** for example; even though virtually all of the emulsion breakers end up in the oil phase. The balance is not important for chemicals with other purposes, such as biocides and scale inhibitors, which have high solubilities in water and stay in the water phase.

Formulations, Additives. The products sold by the chemical supply companies, which we will call formulations, usually contain materials other than the one *compound*. Any materials in the formulation other than the *compounds* for the primary purpose will be considered additives in this paper. As a minimum there will be a solvent, as most of the *compounds* would be extremely viscous, solid, or even unstable at concentrations approaching 100%. The other materials may be different *compounds* for the same specific purpose, small amounts of *compounds* for another purpose, other solvents, or other chemicals added for specific reasons to allow better achievement of the primary purpose. For example, a surfactant may have a substantial beneficial effect on the efficiency of a corrosion inhibitor *compound* but will be considered an additive. It should be noted that most chemical suppliers consider the active content of a formulation to include everything except totally inert solvent(s). Important exceptions are the paraffin solvents, which are essentially 100% solvent *compound* plus a small amount of surfactant.

The objective of the more detailed listing of the components in this paper is to allow estimation of the ranges of concentration of various *compounds* and additives in the treated fluids and in the water discharged to the ocean. In many instances, the formulation will include more than one *compound* from the same generic chemical type or *compounds* from two or more generic chemical types for the same purpose. This approach is often necessary to obtain optimum effectiveness, such as better emulsion breaker efficiency. For example, from a dozen intermediate *compounds* of three generic chemical types, a chemical supplier could prepare a hundred different formulations by blending different ratios of different *compounds*. Perhaps a tenth of these formulations have relatively broad application to many oilfields with the remainder being more or less formulated for one, two, or a few specific oilfields.

Additives are placed in the formulation for specific purposes. Solvents, usually the major additive, are required to provide fluidity for the normally viscous *compounds*. Water is the obvious choice for water soluble *compounds*, with refinery cuts of hydrocarbons (heavy aromatic naptha, etc.) used for oil soluble *compounds*. Methanol, isopropyl alcohol, and ethylene glycol are other common additives used to provide cosolvency, freeze protection, lower viscosity and/or pour point, etc. They may be essential to maintain a uniform, stable, and usable formulation in the drum. Typically other additives function after the formulation is in the system. For example, addition of a surfactant to a biocide or corrosion inhibitor allows better penetration through deposits. A small amount of emulsion breaker or antifoam may be added to a corrosion inhibitor to minimize adverse effects on the oil or gas separation process.

Multipurpose Formulations. Often there are two or three problems in a producing system which require chemical treatment. The operator may add three formulations independently, allowing each chemical to be optimized separately. Alternately, a single formulation containing all three chemicals for the three purposes may be added with a single pump. Both technical and economic factors must be considered in choosing the best approach. In either approach, it is important that the *compounds* for the various purposes do not interfere with each other, by direct reaction or otherwise. The need for compatibility is even more stringent in multipurpose formulations because the components must all be mutually soluble and non-reactive in the drum.

An example of a multipurpose formulation for treating water for injection could include an oxygen scavenger and a quaternary amine for corrosion control and a phosphonate for scale control. The percent of each *compound* is likely to be lower than in the comparable single purpose formulation but the overall treating concentration probably will be higher to achieve about the same concentration of active *compound* in the system.

The effect of the individual components of the multipurpose formulations on and in the environment will be similar to their effect in single purpose formulations. Hence, these types of formulations will not be discussed separately. It is important to note again, however, that aquatic toxicity tests are normally conducted on actual formulations as sold to the operating companies. The test results will reflect any interaction effects on the test species.

GAS PROCESSING CHEMICALS.

The high cost of space and operations on offshore platforms greatly restricts the amount of gas processing done offshore. Only processing or treatment is done that is required to get the gas to shore safely. It is sometimes necessary to add a chemical to reduce the freezing point of gas hydrates. In some instances operators choose to remove virtually all of the water from the gas on the platform before sending it through the pipeline to shore.

Hydrate Inhibition Chemicals. Natural gas hydrates are ice-like solids consisting of a mixture of water, hydrocarbon gas molecules, and particularly carbon dioxide and hydrogen sulfide gases if present. These solids can form in equipment under certain conditions, blocking or breaking lines similar to frozen water pipes. However, they differ from ice in that they can form above 32 F, even above 80 F, depending on the gas composition and pressure. Solidification temperature increases with higher pressures, higher molecular weight hydrocarbon gases, and higher acid gas concentrations. Some liquid water must be present for hydrates to form. Condensed water vapor is usually sufficient, but produced formation brines can also result in hydrate formation. However, a high salt concentration in produced water lowers the hydrate freezing point, similar to the way salt lowers the freezing point of water.

Freezeups can be prevented by adding chemicals when required. These chemicals are called hydrate inhibitors or freeze point depressants. The two most common chemicals are methanol and ethylene glycol. However, in many instances the gas remains too warm for hydrates to form and no treatment is required. In other instances, hydrates may form seasonally during cold weather, requiring continuous treatment only during part of the year. Batch treatments may be required during shutdowns. In a few instances hydrates are a serious problem at all times. Continuous treatment may be required as part of a low temperature process to remove heavier hydrocarbons from gas. In this instance or for large systems, the hydrate inhibitor may be recovered and recycled. For most cases it is not economical to recover the chemical.

Dehydration Chemicals. A large fraction of the water vapor can be removed from natural gas by absorbing it into a solvent. Triethylene glycol is the most common chemical used in natural gas dehydration. The gas contacts the glycol in a tall absorption column at high pressure and ambient temperature. The dry gas is sent to the pipeline with a water dew point typically below 20 F. The wet glycol is heated and sent to a low pressure desorber. The water is flashed off and the glycol is cooled and pumped back to the absorption column. Some makeup glycol has to be added to compensate for volatility and spray losses, but there is no continuous discharge. Sidestream filtration and purification allow the glycol charge to be regenerated almost indefinitely. Occasionally it may be necessary to discard a batch of glycol because of severe contamination or degradation.

STIMULATION, WORKOVER CHEMICALS

Acids and Additives. During the life of a producing or injection well it may become necessary to stimulate flow by removing deposited accumulations from the wellbore, perforations, and formation. The accumulations may be due to scale deposits of calcium carbonate or various corrosion products such as iron sulfide, oxide or carbonates. These solids can partially block the flow paths through the formation rock. These materials are all soluble in hydrochloric acid, the most commonly used oilfield acid. Since calcium carbonate is also a common companeol of reservoir rock, the acid may also increase the size of the original flow channels. Acidizing is also frequently used during the initial completion of the well if the formation composition and permeability are appropriate. Fine sand or clay particles may migrate through the formation until they lodge at some point, also blocking flow. A mixture of hydrochloric acid and hydrofluoric acid (mud acid) is used to dissolve these solids. Other acids are sometimes used.

There is always at least one additive used in an acid stimulation job, the corrosion inhibitor. All of these acids are severely corrosive to the steels used in wells, piping and production equipment. Other chemicals may also be dissolved in the acid or in fluids used in conjunction with the acid on the stimulation job. Surfactants are often used, especially if the oil gravity is low or paraffin deposits are likely. Paraffin solvents may be required in severe cases. Clay stabilizers are sometimes required, as are iron sequestrants or scale inhibitors. Chemicals to prevent emulsification of oil and acid or sludging of the oil may be necessary.

Workover Fluids and Additives. Brines are often used during workovers and completion operations. The density of the brine must be high enough for the hydrostatic head of the fluid column to contain the formation pressure. Clear brines are preferred to muds so that the solid particles will not cause permanent plugging of the formation around the wellbore. Seawater (8.4 lb/gal) is sometimes used for flushing or for low pressure formations. Densities to 10 lb/gal are available with sodium chloride brines, and to about 11.5 lb/gal with calcium chloride. These systems provide adequate density for most wells (perhaps 95% or more). Mixtures of calcium chloride and calcium bromide extend the range to about 15.4 lb/gal. Calcium bromide and zinc bromide mixtures up to 19 lb/gal are available for those last few wells with extremely high pressures.

A wide range of additives can be used, depending on the operation. Untreated seawater may be used to flush the bulk of the fluid from the tubing/casing annulus when the well is reopened. Corrosion inhibitors and bactericides may be added to brines that are to be left in the annulus as packer fluids. Thickening agents and dissolvable particles (e.g., salt, calcium carbonate) may be added to prevent excessive volumes of brine from draining into the formation during the workover. Thickeners may also be used to help suspend sand being pumped into the well during gravel packing. These sand grains are too large to enter the formation but restrain unconsolidated formation sand during production.

TYPICAL SYSTEMS

PRODUCTION PROCESS FLOW SCHEMES

The process flow scheme, equipment, and operating conditions can and do vary widely, depending on the properties of the hydrocarbon fluids and the size and producing rate of the reservoir. While no one system is truly typical, there are similarities. The highly simplified diagram in Figure 1 shows a scheme with many of the components that are typical of offshore oil production systems, although most systems will not contain all of the equipment shown. This figure is intended to provide a general guide to terminology used in the paper as well as illustrate some of the system factors which affect the chemical treatments and disposal of produced water.

Several producing wells are connected to production manifolds which carry the produced fluids to the appropriate separators. Those wells with the highest pressure are routed through the high pressure manifold to the high pressure separator (e.g., 1500 psig). Most of the gas is separated and the combined oil and water stream is sent to the intermediate pressure separator. Wells with intermediate pressure flow through the intermediate manifold directly to the intermediate separator (e.g., 500 psi). Much of the remaining dissolved gas is flashed as it enters this separator. The combined oil and water then flow to the low pressure separator (e.g., 50 psig), often called a free water knock out (FWKO). Most of the remaining gas is flashed and the free water is separated. The oil, still containing a few percent of water as a dispersed emulsion, flows to the bulk oil treater (e.g., 15-30 psig) where the water content is reduced to sales/pipeline specification. A high pressure separator may not be required in all fields, with the manifolds then connecting to the intermediate and FWKO respectively. Later in the life of a field, the operating pressures of the high and/or intermediate pressure separators may be reduced to maintain the desired deliverability from the wells. Electrostatic grids may be incorporated in the bulk oil treater to improve the removal of water from the oil. Occasionally, the oil is sent to the pipeline directly from the bulk oil treater (with or without pumping) while in other instances an atmospheric pressure tank is used to release more gas (with pumping obviously being required).

The high pressure gas may flow directly through dehydration facilities into a pipeline to shore. Compression is required for the intermediate and low pressure gas and must often be added for the high pressure gas as the field gets older and the pressure decreases. Some of the gas is usually used as fuel on the platform and/or to gas lift low pressure oil wells. Glycol dehydration is the most common method for removing water from the gas. The gas flows upwards through a tower, contacting a falling stream of dry glycol on trays. The water in the gas is absorbed into the glycol, usually triethylene glycol (TEG). The wet TEG is heated and sent to a second low pressure tower. The water is flashed off and the TEG is cooled and pumped back to the contactor tower. The TEG is not consumed, but is continuously recycled in a closed loop.

Produced water is collected from the free water knock out (sometimes from the high pressure separator and any atmospheric pressure tanks) and sent to the produced water treating system. The first vessel in the system is often a surge/skim tank to collect free oil and smooth out flow variations. This tank may allow discharge specifications to be met in some instances, especially with very light oils or condensate. Further processing equipment varies, e.g., a corrugated plate interceptor (CPI) unit and/or a multistage flotation cell are sometimes used. This equipment will reduce suspended solids and oil concentration to low levels to meet requirements but have essentially no effect on water soluble materials. Offshore, produced water is discharged to the sea after this treatmenr.

Most production systems will include a test separator(s). Since measurement of two or three phase flow is extremely difficult, manifolding and valving is included so that production from any one well can be isolated to the test separator(s) and each phase measured separately. The fluids are then recombined.

Even this simplified scheme can have several variations, depending on the nature of the field. All of the wells may be on the same platform (or bridge-connected) with the processing equipment. In some cases, however, the design concept calls for production from several multi-well platforms to be sent to a central processing complex, with only a test separator on the wellhead platforms. This situation has also developed late in the life of some fields when production rates become too low to justify operating costs for the separation equipment for an outlying platform. The equipment was bypassed and the fluids were sent to the central facilities. In other instances, the design calls for the water to be sent to shore along with the oil, with final oil-water separation performed at the shore facility. This approach eliminates the platform space and weight requirements for the water treating and oil treating equipment but requires additional pipeline capacity. Finally, some recent systems for very deep water have used a captive tanker to provide processing space and interim storage, with oil shipment to market via shuttle tanker. This latter approach is not yet common and has no additional impact on produced water disposal. The first three do have a significant impact on the disposal of treated produced water and will be discussed in more detail.

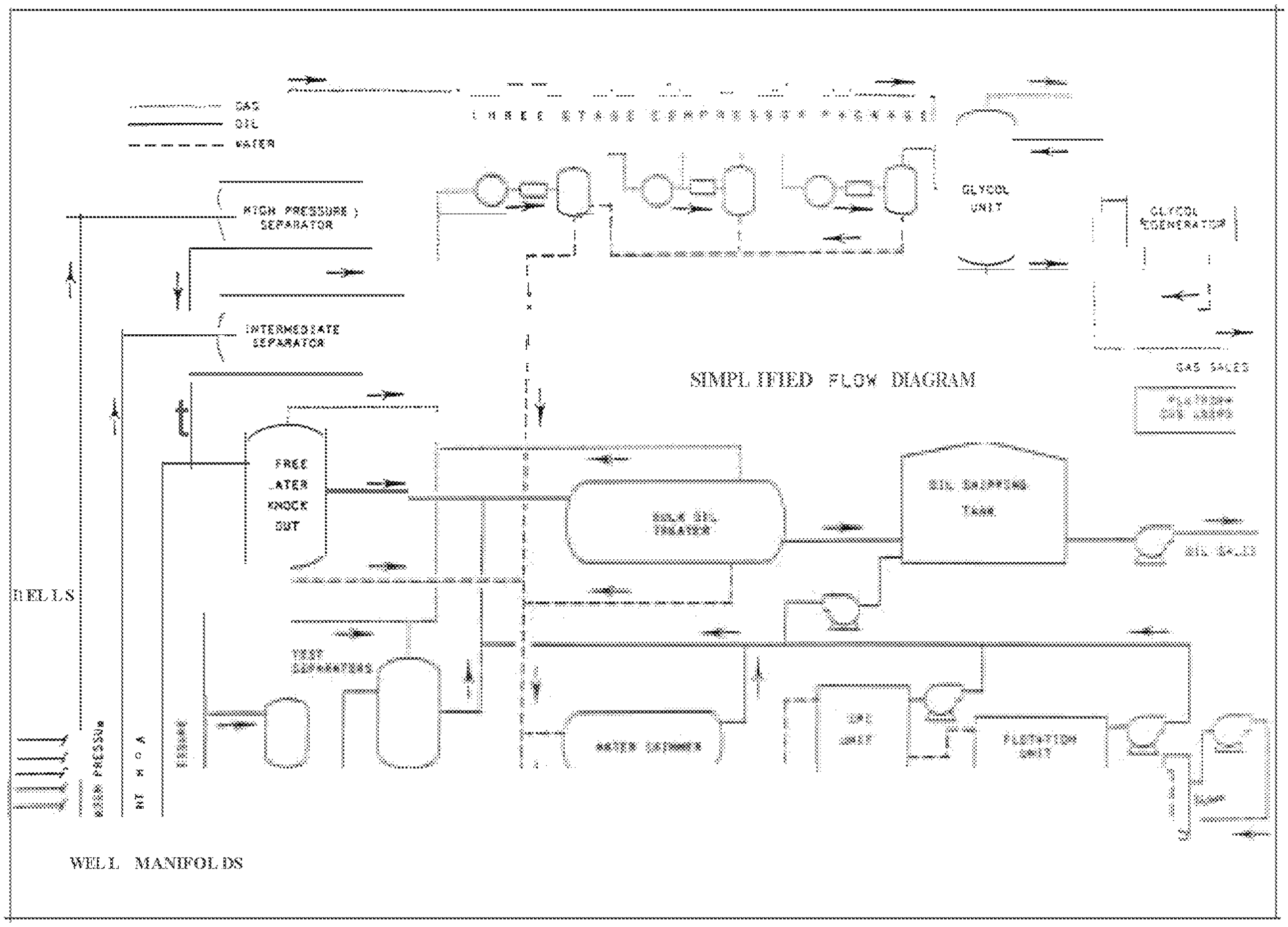


Figure 1. Simplified typical process diagram for an offshore platform in an oilfield.

Processing of gas wells (from gas fields or gas wells in an oil field) is similar yet different. Most of the gas wells operated by the companies surveyed produce relatively little liquid. The entrained liquids are removed in separators. If all wells do not produce at pressures above pipeline pressure, an intermediate separator and gas compressors are required. The gas may be dehydrated in a glycol unit and sold to a gas transmission pipeline company at the platform. The liquids (light oil, hydrocarbon condensate, and small amounts of water) are sometimes processed and sent to shore separately from either the gas or oil from the area, depending on technical and contractual factors. In other instances the gas, oil and produced water are sent to shore in the same pipeline for all processing. In the 1985 survey one operator noted that only one of their twenty-three gas platforms had a water discharge. The other platforms had no water production or the water went to shore with the hydrocarbon condensate to three receiving plants, which injected a total of about 5500 BPO water into disposal wells. On the other hand, another operator had produced water discharges on all twenty-six of its gas platforms. These situations have not changed substantially in the intervening four years.

SINGLE COMPLETE PLATFORM

If the field is geographically compact, it may be feasible to drill all of the wells from one platform. Locating the processing equipment on the same or a bridge-connected platform allows all operations to be done with minimal boat support, etc. Usually there will be ten or more producing wells on a platform. Platforms in deeper water are generally more expensive and have more producing wells, with more than fifty being provided for in some instances. Any batch treatment or slug treatment of the production from any one well will be diluted with the production from the remaining wells, reducing the effective concentration of the treating chemical in the produced fluids flowing to the separators and, hence, in the discharged water. All or even most of the wells could not be treated simultaneously because of excessive pump and/or manpower requirements and the adverse effects on overall production rates. Even if these restraints were not present, all wells would not be treated simultaneously because of the increased risk of high concentrations of treating chemicals causing an upset of the separation equipment.

In some circumstances, outlying single wells are brought directly to the processing platform. This approach was more common earlier in shallow water with shallow reservoirs. Directional drilling could not reach the edge of the reservoir and free standing wellheads were feasible. Subsea completions are now feasible for deeper water. In either case, the concentration of treating chemical from any kind of batch- or squeeze-type treatment will still be diluted in the processing equipment by the production from the remaining wells. A separate line may be required to send hydrate inhibitor to remote wells continuously or intermittently to prevent hydrate plugging.

CENTRALIZED PROCESSING PLATFORM

Large fields may require several drilling/production platforms to provide adequate access to all areas of the reservoir. Processing equipment on these platforms can range from a high pressure test separator through a complete processing system. In most such fields, however, it has been common for most of the processing to take place on the production platform, essentially the same as the previously described system. As some platforms in a field approach their economic limit, equipment on outlying platforms is being bypassed and production sent to a central platform for processing and for shipping of the oil and gas to shore. The produced water is also treated and discharged at this central facility.

In this configuration, a high concentration of treating chemical from anyone well will not only be diluted with the production from other wells on that platform but also by the production from other platforms. High concentrations of corrosion inhibitor or biocide used in treating gathering lines from an outlying platform will be diluted by production from other platforms. Multiple platforms make it even less likely that a high percentage of the wells sending water to a common discharge could undergo batch or squeeze treatments simultaneously.

ONSHORE PROCESSING

There are several systems where all or part of the processing is performed after the produced fluids are brought to shore. The most common scheme is to separate the gas offshore and send it to shore through a different pipeline. Oil and produced water are not separated offshore but flow to shore in a common pipeline. Chemical concentrations in the liquids resulting from well treatments would be diluted by the total production. One such system has over 150 producing wells, which would dilute chemicals used in anyone well by about two orders of magnitude. For example, a concentration of 1500 ppm corrosion inhibitor at the wellhead after a squeeze treatment might be reduced to 10-15 ppm by the time it is discharged from the central facilities. Even batch treatment of equipment on any platform would be diluted by at least one order of magnitude.

Sending the oil and water to shore increases the risk of problems in the pipelines. Pigs are sent through the lines to prevent accumulation of solids, paraffin, or corrosion product in the lines, all of which could contribute to pitting-type corrosion as well as reduce throughput capacity. Chemical treatment is used to minimize corrosion. In one system, a dose of biocide is used behind the pig to kill sulfate reducing bacteria, with a subsequent slug of corrosion inhibitor supplementing a low continuous treatment. The batch treatment of chemicals are diluted by a factor of five to ten as it moves through the water treating equipment on shore.

GAS PROCESSING

It is sometimes necessary to add a hydrate inhibitor to prevent solid natural gas hydrates from forming in high pressure gas lines. The ice-like solids can form at temperatures well above 32F. The inhibitor, normally methanol, is usually added continuously at the wellhead to prevent the hydrate from forming in the system until the water can be removed from the gas stream. Addition may be required only in the winter when temperatures of air and seawater are lower.

Dehydration is normally the only gas processing performed offshore. Primarily this choice is necessitated by the high cost of platform space and much higher operating costs than onshore facilities. Dehydration is desirable to reduce the risk of corrosion and hydrate formation in the pipelines to shore. However, in some instances untreated gas is sent to shore, with corrosion and hydrate inhibitors added to prevent problems. However, there is at least one offshore location where gas is sweetened ($H2S$ and CO_2 removed).

Glycol dehydration using triethylene glycol (TEG) is the only process used to remove water from gas in offshore operations (Figure 2). In some systems the hot produced gas will be cooled prior to entering the glycol unit. Some of the water will be condensed and then separated in the inlet knockout vessel, reducing the size of the glycol facilities. The knockout vessel greatly reduces the risk of any produced liquids being carried into the contactor, where it could contaminate the TEG. The gas

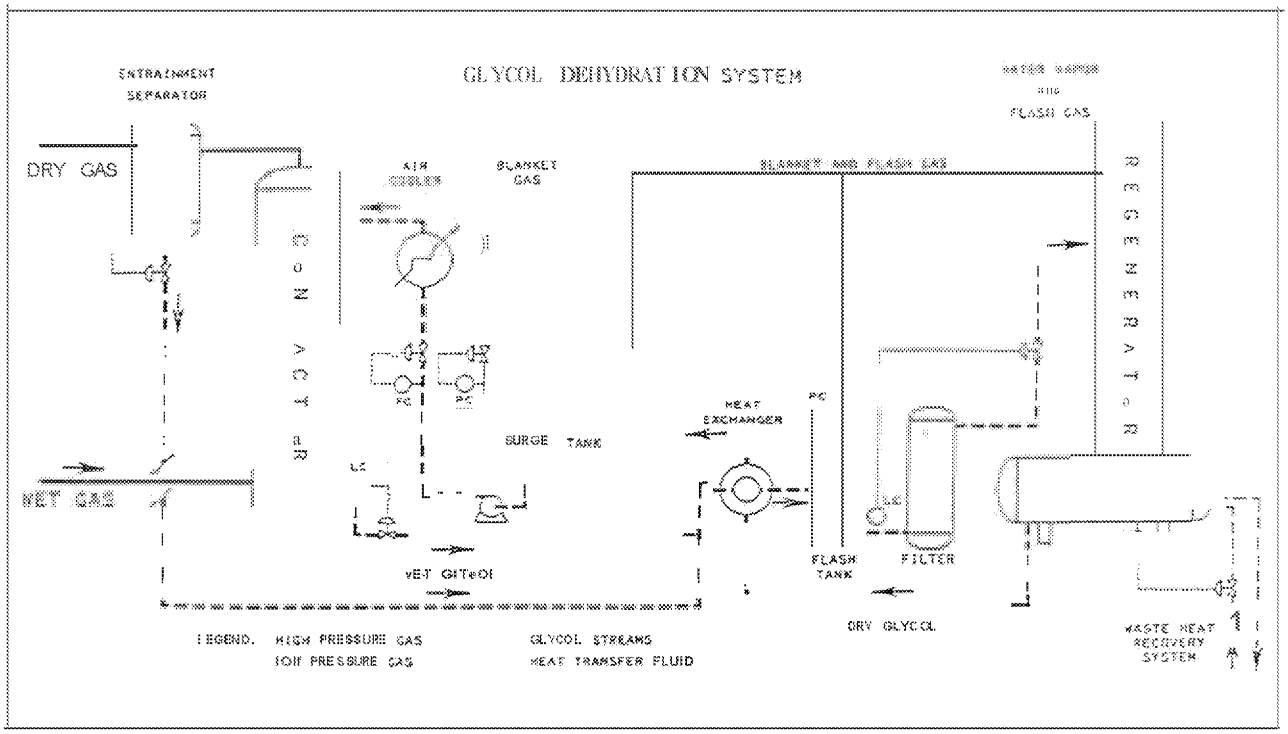


Figure 2. Simplified Process Diagram for a glycol dehydration unit using waste heat recovery.

enters the bottom of the tall contactor tower. As it flows upwards through a series of trays the gas is intimately mixed with a falling stream of TEG. Some water is absorbed into the TEG on each tray and the gas becomes progressively drier. The gas exiting the top of the contactor has been dried sufficiently so that liquid water will not condense as the gas flows to shore.

The TEG leaving the bottom of the contactor is rich in water and saturated with natural gas. The TEG flows through a heat exchanger, flash tank, and filter before it enters the regenerator tower. The water is boiled from the TEG in the regenerator, reducing the water content to 0.2% or less. Heat is normally supplied from waste heat recovery units on offshore platforms to eliminate the safety risk of direct fired heaters. The hot, dry TEG flows back through the heat exchanger to a surge tank. A recycle pump sends the TEG through a cooler back to the top of the contactor.

In addition to providing consistently dry gas economically, a key factor in the acceptance of this process is the low consumption rate for the TEG. Very little TEG is lost with the dry gas flowing to the pipeline. An entrainment separator minimizes spray carryover and the TEG is used because of its low vapor pressure. Similarly, very little TEG is lost in the regenerator overhead.

WATERFLOODING

Waterfloods are not as common in offshore operations as in US onshore operations but neither are they unusual. The water comes from source wells in many instances, but seawater is also used. Source wells completed in non-hydrocarbon aquifers are desirable because very little surface equipment and treatment is required. However the aquifer must be sufficiently large to provide all of the required water and should be highly permeable to minimize the number of source wells. Whenever possible, a source water will be selected that is chemically compatible with the formation water in the oil zone(s), minimizing scaling problems in the producing wells. Since high concentrations of barium, strontium and calcium are frequently present in produced water from the Gulf of Mexico and offshore California, source waters with low sulfate ion concentrations are preferable. The advantages of source wells must be balanced against their cost, uncertainty in their delivery capacity, and ongoing lifting costs.

Seawater is an obvious water source for waterflooding, with unlimited capacity. More processing equipment and chemicals are needed but well costs are eliminated and injection costs may be lower. Corrosion control and prevention of injection well plugging are the primary process objectives. Rigorous oxygen removal (mechanical deaeration by gas stripping followed by chemical oxygen scavenging) provides corrosion protection for most of the system. Corrosion resistant materials are used in that portion of the system handling aerated seawater. Removal of suspended solids by filtration is usually required, but cartridge filters are often adequate in river outfalls or deep water remote from shore where suspended solids concentration may be less than 1 mg/L. Scale inhibition is usually not required. Biological control to prevent corrosion and fouling of the equipment and injection wells is accomplished by a combination of chlorination, deaeration, and biocide treatment. Essentially all of the processed seawater is injected into the oil reservoir. However, seawater is not widely used in the Gulf of Mexico and offshore California because of probable severe scaling in producing wells. The high concentration of sulfate in seawater entering the wellbore via more permeable reservoir streaks will react with barium, strontium or calcium entering from less permeable streaks.

In the Gulf of Mexico waterflooding is not normally required. Even when it is needed, produced water is not normally used for waterflooding offshore for three main reasons:

1. In the early life of the field when water injection can usually achieve maximum recovery, there is often little or no produced water to reinject; hence, an alternate source must be developed.
2. Later in the life when quantities of produced water become more substantial, it is very expensive to retrofit or add additional processing equipment. Mixing of produced water with any original supply water greatly increases the risk that scale will be formed and plug the injection wells.
3. Any dispersed oil interferes with solids removal processes, making it very difficult and expensive to reach low concentrations of either material. Concentrations of 5 ppm or less solids and oil are often necessary to avoid wellbore plugging.

STIMULATION AND WORKOVERS

Stimulation and workover operations entail several kinds of activities designed to maintain or increase production from an existing producing zone in an existing well. Recompletions to a new zone normally involve drilling operations and are beyond the scope of this report. This discussion will be directed to those operations and practices related to fluids and byproducts that might end up in the water streams. For clarification of the scope of this report, it will be helpful to describe a "typical" scenario for completing an offshore well. The discussion is necessarily general, with specific practices varying with the individual wells and areas. For example, the general practices described by Wedel14 are representative of practices for most wells in the Cook Inlet of Alaska. Higher density fluids must be used in geopressured gas wells in the Gulf of Mexico. Otherwise, many of his comments are equally applicable to the Gulf of Mexico.

Figure 3 is a simplified diagram of a typical offshore producing well. After the well is drilled to total depth, the production casing string is cemented in place. Excess cement is drilled out and the inside of the casing cleaned with casing scrapers, etc. Completion begins with the drilling mud and solid debris with seawater and/or dense brine, which is called the completion fluid. The completion fluid is often circulated and filtered for many passes until the fluid is free of solids. It is very desirable that the completion fluid be very clean, as solid particles could plug the formation around the wellbore. The hydrostatic head of this completion fluid must be high enough to contain the formation pressure when perforating guns blow holes in the casing into the producing zone (A). This requirement often necessitates using a dense brine.

If the producing formation is unconsolidated, as is common in the Gulf of Mexico and sometimes off California, it is necessary to control sand production. A gravel pack is a very common practice for this purpose. A slurry of coarse grained sand or manufactured ceramic or synthetic plastic granules is pumped down the well and into the perforations. The 'packer' at the bottom of the tubing string is then set, isolating the tubing-casing annulus from the producing zone (B). Several zones may be perforated and gravel packed during the completion operations to facilitate changing to another zone after the initial zone is depleted. With suitable downhole hardware, it is possible to displace the completion fluid from the annulus with another fluid. The fluid remaining in the annulus during production is called the packer fluid and may or may not be the same as the completion fluid.

After the well is completed it may be desirable to stimulate the well so that the production rate will be higher. Stimulation is normally accomplished offshore by pumping acid into the well. The acid dissolves solids and opens or increases the size of flow paths. Hydraulic fracturing, another type of stimulation, is extremely rare in offshore operations. The unconsolidated sands in the Gulf of Mexico are not amenable to this type of stimulation. The enormous logistic problems of assembling the pumping equipment and supplies usually preclude it in other offshore areas as well.

The brines used as completion or packer fluids are seawater, sodium chloride, calcium chloride, calcium bromide, zinc bromide, and mixtures of

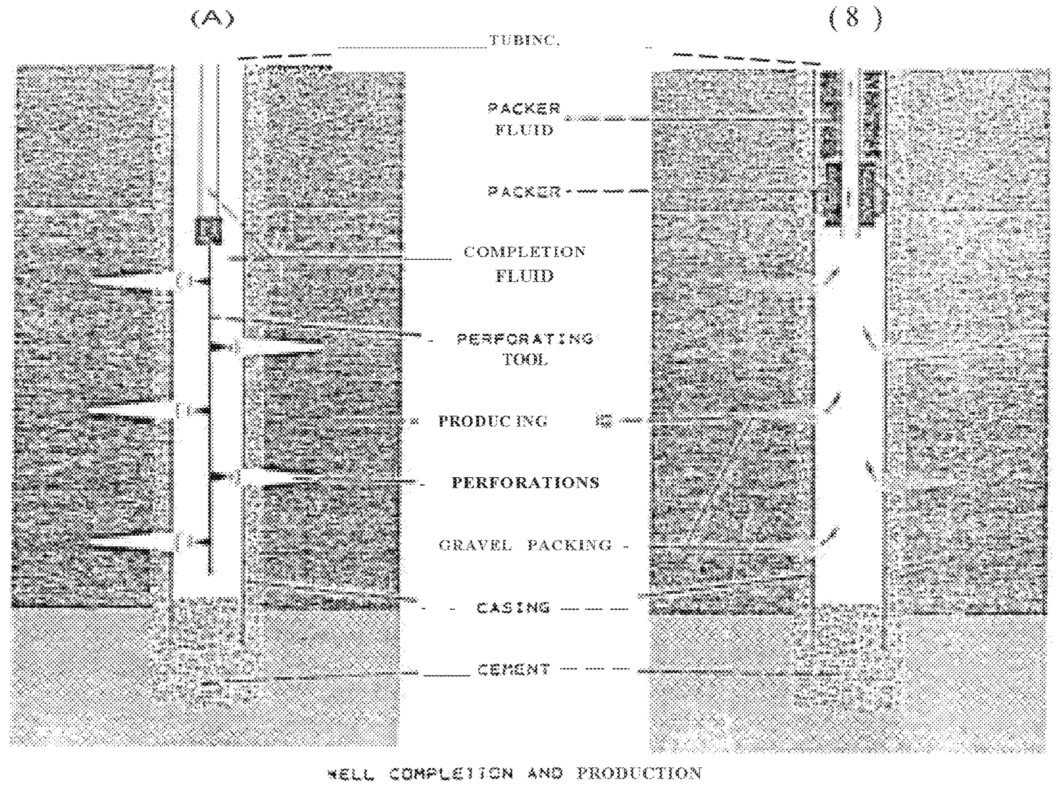


Figure 3. Simplified well diagram illustrating components in well completion operations.

these salts. In certain circumstances, potassium chloride or ammonium chloride may also be added to the above. Zinc bromide is almost always used in conjunction with calcium bromide and is rarely left in the annulus as a packer fluid. It is more corrosive and expensive and is usually circulated out and returned to shore for later use in other high pressure wells.

After the well is producing, further stimulation operations may be as simple as jetting accumulated sand from a producing well, but more commonly involve pumping acid into the producing zone to dissolve accumulated solids. Workover operations may require pulling the tubing string to replace defective downhole components or performing a new full gravel pack to control sand production. In many cases, however, several operations will be done, especially if it is necessary to bring a pulling unit to the platform. The costs of the unit are so high that any anticipated preventive work will be performed while the pulling unit is on location.

The acids used for stimulation are primarily hydrochloric and hydrofluoric acids. The hydrochloric acid dissolves most corrosion products and calcium carbonate, while the hydrofluoric acid can dissolve fine particles of clay and sand. A pre-flush and post-flush of ammonium chloride is often used to prevent precipitation of calcium fluoride. An acid stimulation is often an integral part of a sand control job, to insure maximum production rate. The larger sand grains in the gravel pack are usually pumped down dispersed in thickened brine.

For many workovers it will be necessary for the fluid in the wellbore to be dense enough to contain formation pressure, i.e., kill the well. The same brines listed above are used for this purpose. However, it is important to note that as the formation pressure decreases during the life of the zone, the required density will decrease. It is possible to pump down a "pill" of thickened saturated sodium chloride brine containing a dispersion of solid sodium chloride particles. The solid salt will prevent the dense brine from seeping out into the formation during the workover, but will readily dissolve in formation water when the well is returned to production. Fine particles of calcium carbonate are also used, but require an acid wash to unblock the flow channels.

Mechanical workovers include such things as pulling the tubing to replace a leaking joint, downhole components such as gas lift mandrels, or a leaking packer. In some instances gas lift valves, subsurface safety valves, and other small items may be retrieved through the wellhead with a wireline unit, avoiding the necessity of killing the well and pulling the tubing.

PRODUCTION TREATING CHEMICALS

Chemicals can be and are used for a wide variety of purposes in oil and gas production. It cannot be overemphasized, however, that these uses are normally in response to actual problems. The direct cost of the chemical is only a part of the cost of using them. Purchase of injection equipment, transportation, contracting for application services, proportional cost of employee time for application and monitoring, and value of deferred or lost production for some types of treatments are all major parts of the real cost of chemical treatments. The cost of the space for pumps and chemical storage may be the largest single factor on some offshore platforms. Treatments are not normally initiated unless the costs or risks for the problem are significant or expected to become significant. Because conditions are continually changing during the life of a field, any treatments should be frequently reviewed to determine if they are necessary and cost effective. Treatments will be modified or even discontinued to keep overall costs and problems at a minimum.

All types of chemicals used in treating offshore production are discussed in the following sections. None of the operators interviewed used all these chemicals in their operations, much less all on one platform or system. On the contrary, addition of only one or two chemicals on anyone platform or in a system is far more common, with many instances where no treatment is performed on a platform.

SCALE INHIBITORS

Problem Description. Deposition of inorganic compounds from the produced water associated with hydrocarbon production can have a severe impact on operations. These deposits can actually seal off a producing formation and stop all production. Deposition can occur within the pores in the formation itself, in the perforations, or in the tubing. Deposits in surface flow lines can reduce the throughput capacity or require higher inlet operating pressures to maintain the same throughput. Deposits on heater tubes reduce heat transfer, requiring higher fuel consumption and increasing the risk of corrosion failure of the tube element itself and a resulting fire. Deposits in valves can prevent movement or complete closure which can interfere with proper control or cause major equipment failure. Such valve failures would pose a serious risk to personnel or cause oil spills. Clearly it is necessary to control scale deposition for safe and proper offshore operations.

Fortunately, there are only a few common types of scale deposits in oilfield operations. The type of scale (if any) found in a particular field will depend on the composition of the water(s) and the system characteristics. Calcium carbonate is probably the most common scale. It is less soluble as the pressure decreases, even above the bubble point. If the pressure drops below the bubble point, some CO_2 flashes off, increasing the pH and causing more deposition. Mixing of incompatible waters (one high in calcium, the other high in carbonate) causes deposition. In addition, increasing the temperature causes calcium carbonate to deposit. Fortunately, calcium carbonate is very soluble at low pH and can be dissolved by acidizing.

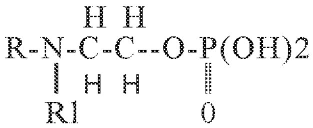
Calcium sulfate (gypsum) will deposit when the pressure decreases or incompatible waters are mixed. It has a maximum solubility around 105F, with deposition possible at higher or lower temperatures. Strontium sulfate is most commonly formed when incompatible waters are mixed. The solubility decreases at higher temperatures and lower pressures. Barium sulfate also commonly occurs if incompatible waters are mixed. It has a lower solubility at lower temperatures and pressures. Deposition can occur as temperature and pressure decrease when the water flows up the tubing.

The actual solubility of any of these scale compounds is a complex function of temperature, salinity, pressure and composition. Fortunately, reasonably good solubility calculation methods are available: calcium carbonate[15,16], calcium sulfate (gypsum)[17], barium sulfate[18], and strontium sulfate[19]. These methods suggest whether scale deposition is possible and the most likely places where deposits will form. These calculation methods are based on experimental data showing the effect of temperature, pressure, and concentration of dissolved salts and gases in the water. Coupled with experience, the calculation methods allow many scale problems to be anticipated. The iron compounds (iron carbonate, iron sulfide, and iron oxide) are usually related to corrosion problems and are controlled with corrosion inhibitors or other corrosion control methods.

In most instances, nothing can be done to modify the conditions causing scale deposition. The scale compounds of interest are all less soluble at lower pressures. A water saturated with calcium sulfate or calcium carbonate in the reservoir can start to deposit scale in the formation as the pressure decreases[20]. A water saturated with barium sulfate will start to deposit scale as it cools off[18]. 'However, there are occasions when system design and operating procedures can reduce or even eliminate scale problems. As an example, scale problems associated with incompatible waters (e.g., one containing high barium and a second with high sulfate concentrations) can sometimes be avoided by using subsurface supply wells instead of seawater. Fortunately, most produced waters on anyone platform in the Gulf of Mexico are compatible. Electrostatic separators can be used to aid in separation of water from oil, eliminating the hot heater tube surface where scaling could occur. Nevertheless, chemical treatment can be required to control scaling problems.

Chemical Description. All of the chemicals used to control scale deposition in oil and gas production systems work by interfering with crystal growth. The two most commonly used *compounds* are based on organic phosphorus chemistry, with a polymer type comprising the remainder. Inorganic phosphate inhibitors are no longer used in offshore operations. Treating concentrations for all these types are about the same, with 1-10 ppm usually providing satisfactory scale control. Higher concentrations may be required for more severe scaling tendencies. Higher **concentrations may be encountered in produced water after a squeeze treatment. However, squeeze** treatments are unusual in U.S. offshore operations except for the few seawater floods.

Phosphate esters. This generic chemical type contains the phosphate esler functional group, the carbon-oxygen-phosphorus linkage:

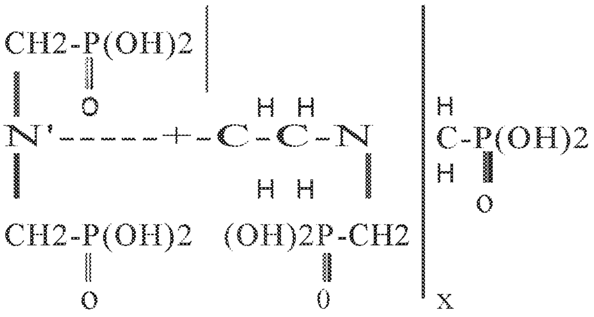


$$\mathrm{R{-}\underset{R1}{N}{-}\overset{H}{\underset{H}{C}}{-}\overset{H}{\underset{H}{C}}{-}{-}O{-}\underset{\overset{\|}{0}}{P}(OH)2}$$

Typical phosphate structure

A variety of raw materials can be reacted with the phosphate but most *compounds* involve an amine nitrogen. The exampie shown is a disubstituted ethanolamine. The selection of the raw material is based on the final effectiveness of the *compound* as a scale inhibitor and the cost of the raw material. The R groups may be identical or different. In many instances, the R groups will contain functional groups such as amine or alcohol which contribute to high water solubility. The acid groups are normally partially neutralized with caustic, ammonium hydroxide, **or other inorganic base. These materials** can not normally be used above 200F because the ester linkage hydrolyzes at high temperatures and the hydrolysis products are poor scale inhibitors.

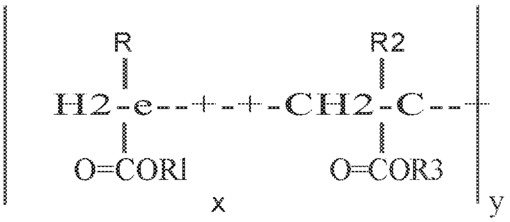
Phosphonates. The key functional group in this generic type is the direct carbon-phosphorus bond. Almost all of the raw materials contain amine groups, with the generalized structure being similar to that shown below:



Generalized phosphonate structure

Carlberg's[21] studies on ethylene diamine tetra (methylene phosphonic acid), the active ingredient **in several commercial scale inhibitors, indicate further** that multiple active chemical functional groups can be present within the same compound.

Polymers. Acrylic acid polymers and/or copolymers are the normal base materials. The *compounds* have the generalized structure shown, where the Rs may all be different or identical. All the Rs are H in acrylic acid polymers.



Substituted acrylic acid copolymer

The scale inhibitor *compounds* are usually not modified by oxyalkylation, etc. as is common with emulsion breakers, as will be seen later.

Formulations can contain 10-50% active *compound* of one of these three generic chemical types in a water solvent. Ethylene glycol or methanol can be present from 0-20% to reduce the viscosity and/or to prevent freezing. There are normally no other additives. Some unreacted phosphoric and/or hydrochloric acid may be present also.

Soluhility. All of the scale inhibitor *compounds* and additives are highly water soluble, in excess of 30-40%. The solubility or dispersibility in oil is extremely low. It is reasonable to expect that all of the formulation produced from a well or added to the fluids on the surface will be separated from the oil in the separators or skim tanks and be retained in the aqueous phase except for that contained in the small amount of water emulsified in the oil phase.

Application. To work properly, scale inhibitor must be present in the water at effective concentrations when scale first starts to form. The minimum effective concentration is usually in the 3-10 ppm range but can be higher in severe cases. Only two application methods are used offshore - continuous injection or squeeze treatments. The scale inhibitor remains with the water phase in both methods.

In continuous injection, chemical is added with a pump at a constant dosage rate to achieve the desired concentration. In some instances, the chemical will be pumped down a small diameter capillary or macaroni tubing string to the bottom of the well to prevent scaling in the producing tubing as well as the surface equipment. Often, the scale inhibitor is added just upstream of the choke at the wellhead, which is especially effective against the most common scale, calcium carbonate. Alternately, the inhibitor will be added on the manifold if the problem is due to mixing of waters. Only the surface equipment is protected in the latter two methods but that is often the only problem area.

Squeeze treatments must be used when scale deposition is occurring in the producing formation, in perforations, in the wellbore below the tubing, or in the producing tubing string (when a macaroni string is not available). In squeeze treatments, a relatively large volume of scale inhibitor (diluted in water to 2-10%) is pumped into the formation, followed by more excess water. Some of the inhibitor is absorbed onto the formation surface and/or otherwise retained in the pores within the formation. When the well is returned to service, a part of the inhibitor is produced back quickly within a few days as a slug. The remainder is produced back slowly at much lower concentrations over a period ranging from two to twelve months, providing protection until the concentration drops to the 3-10 ppm minimum and the well is resqueezed.

Scaling problems have not been widespread in offshore operations for the operators interviewed, with most systems not requiring treatment. Fortunately, downhole scale problems are rare. Squeeze treatments are not common, with the operators having much concern about formation damage in the relatively unconsolidated Miocene sands in the Gulf of Mexico. One of the squeeze applications was in a gas well producing considerable formation water (an unusual situation). Normally, continuous treatment on the surface was only used in the water processing equipment in those cases where the scaling was serious enough to warrant continuous treatment. Periodic (e.g., quarterly) removal of scale from flotation equipment was used in several instances.

CORROSION INHIBITORS

Problem Description. Control of corrosion is one of the most serious problems in offshore operations. Coatings, cathodic protection, and materials selection are used to control external corrosion, with corrosion inhibitors supplementing these same three methods for internal corrosion. All of the corrosion inhibitors used in treating produced fluids are organic compounds that form protective layers on the metal surface.

The use of various grades of low alloy carbon steel as the material of construction is an economic necessity for most of the production system. Different grades would be selected for fabricating vessels, tanks, or piping on the platform, with still other grades (primarily differing in strength level) being selected for pipeline and downhole tubular goods. All of these steels have very similar corrosion resistance with the exception that higher strength downhole tubular goods (and other high strength materials) can be susceptible to sulfide stress cracking. Small accessories such as instruments, valves, pumps, etc. are often fabricated from high alloys or have high alloy trim to prevent corrosion of critical surfaces which would impair the function. Vessels, tanks, flowlines, and downhole tubular goods can be coated to reduce the risk of rupture due to excessive metal loss over large areas. However, there is still concern about corrosion at defects in the coatings.

The corrosivity of produced fluids is usually related to dissolved gases - oxygen, hydrogen sulfide, and carbon dioxide. Produced fluids from the wells normally do not contain oxygen and every effort is made to keep air out of the treating equipment. Fortunately, the hydrogen sulfide content of produced fluids in most offshore fields is usually very low and H2S is not a significant factor, providing that bacterial generation of H2S is minimized. Production from recent developments in the Mobile Bay area does contain considerable hydrogen sulfide, with essentially all processing being performed onshore. Corrosion control and monitoring are very important design aspects of those systems. Carbon dioxide is the most common and serious corrodent, although naturally occurring organic acids can be a contributing factor.

The experience of the operators interviewed is that corrosion has been much less severe in oil wells than in gas wells probably due to the oil phase providing an inherent protective oily film on the steel. In both cases, corrosion is more likely to become a problem when water production increases.

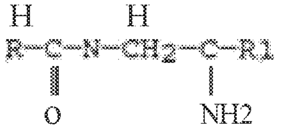
Even if corrosion resistant alloys and/or coatings are utilized in parts of a system, corrosion inhibitors may still be required to protect some bare steel areas. By temporarily adsorbing onto the surface, the inhibitor can drastically reduce the corrosion rate, often by more than 90%. Hence, corrosion inhibitors are widely used in preventing or minimizing internal corrosion in offshore production systems.

Chemical Description. The corrosion inhibitors used in petroleum production operations generally contain nitrogen in the key functional group. The nitrogen-containing material is usually reacted with a carboxylic acid under different conditions to form a *compound* with properties optimized for various types of applications. While the carboxylic acid may have a low molecular weight for greater water solubility (e.g., acetic, propionic, or maleic), it is more frequently a complex mixture of higher molecular weight materials. Tall oil mixtures of variable compositions are often used, because of superior corrosion inhibition properties and low raw material cost. Table 2, from an NACE publication[22] gives an example of the complexity of a typical carboxylic half of inhibitor *compounds*, with the nitrogen-containing half potentially having comparable complexity.

It is readily apparent that the corrosion inhibitor *compounds* are extremely complex mixtures. Further complicating the situation, different *compounds* can often be formed from the same raw materials by varying the reacting conditions, quite distinct from modifications such as ethoxylation. Testing of specific *compounds* and formulations is normally required to define inhibition properties but general **trends with molecular structures can be made.** Similarly toxicity testing is likewise normally conducted on defined *compounds* as intermediates or on final formulations.

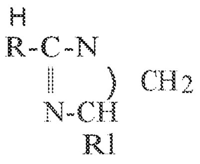
Oilfield inhibitors can be grouped in several different fashions but a common generic chemical classification similar to Bregman's[23,24] is useful for our purposes.

Amides/Imidazolines. Perhaps the single most common generic chemical type used in the petroleum industry is formed by condensing a long chain fatty acid with a primary amine, often a diamine or polyamine. The fatty acid is often derived from raw or refined tall oil and is composed primarily of fatty and resin acids as shown in Table 2. As an example, consider that the reacting amine is a substituted (R1) ethylene diamine. The amide would be formed **under less severe conditions (lower temperatures,** shorter times, etc.) with the imidazoline predomi**nate under more severe conditions. Some of each** *compound* may be present as a product in a single batch reaction. An imidazoline can hydrolyze to the **corresponding amide on exposure to water under** the proper conditions.



$R-\underset{\underset{O}{\|}}{\overset{H}{C}}-\overset{H}{N}-CH_2-\underset{\underset{NH_2}{|}}{C}-R1$

Amide



Imidazoline

Amines and Amine Salts. Amines (primarily monoamines) with long chains (e.g., C10-C18) also **have corrosion inhibiting properties. However,** better inhibitors can usually be obtained by reacting the amine with a long chain fatty acid (e.g., stearic acid), but often the dimer or trimer acid. Reaction conditions are milder than amide/imidazoline conditions and the salt is formed:

$$CH_3(CH_2)_{11}NH_2$$

Dodecyl Amine

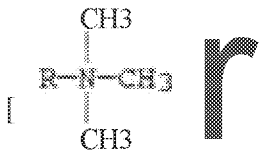
+

$$[CH_3(CH_2)_{11}NH_3]\ [CH_3(CH_2)_{16}CO_2]$$

Dodecyl Ammonium Stearate

If the acid has a long tail of carbon atoms, ionization will be very slight and the inhibitor *compound* is essentially oil soluble. Water solubility can be substantially increased by using a low molecular weight acid (e.g., acetic acid) if the system pH is also low. Ethoxylating active sites increases the water solubility irrespective of the pH. Diamines and dicarboxylic acids can also be used.

Quaternary Ammonium Salts. Replacement of all of the hydrogen on the ammonia nitrogen with carbon or R groups results in a quaternary ammonium compound:



$\left[R-\underset{\underset{CH_3}{|}}{\overset{\overset{CH_3}{|}}{N}}-CH_3\right]$ r

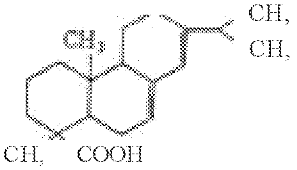
Trimethylalkyl ammonium chloride

In the example, a long chain amine (e.g., R is C18 mixture) is reacted with methyl chloride as the quaternizing agent. Other alkyl halides or mixtures can be used to obtain more complex quaternary ammonium *compounds*. All quaternary ammonium salts are highly ionized, with resulting high solubility in water and low solubility in oil. However, ethoxyla**tion is sometimes used to improve solubility in concentrated brines.**

Composition % by Gas Chromatographic Analysis(1)

Fatty Acid	Caprylic	Capric	Lauric	Myristic	Palmitic	Stearic	Oleic	Linoleic	Linolenic
Carbon No.	8	10	12	14	16	18	18	18	18
Double Bonds	0	0	0	0	0	0	1	2	3
Source									
Coco	8	7	48	18	9	5	5	-	-
Soya	-	-	-	1	14	6	24	50	5
Tallow	-	-	-	3	27	17	47	4	1
Tall Oil	60-70% Fatty Acids, 30-40% Rosin Acids								

Rosin Acids(2)



Abietic Acid 25-35%

Remaining Resin Acids are Abietic Acid Derivatives Shown Below

Abietic Derivatives	%	Modification			
		Double Bond Isomerization	Hydrogenation	Dehydrogenation	Methylation
P,lustric acid	12-17	x			
Neoabietic	7-13	x			
Dehydroabietic	10-14			x	
Dihydroabietic	2-12		x		
Tetrahydroabietic	2-12		x		
Levopimaric	1	x			
Dextropimaric	3-13	x			x
Isodextropimaric	3-13	x			x

(1) **Emery Industries,** Specifications and Characteristics or Fatty Acids
(2) T. Uoyd-Jones, Corrosion Inhibitors, Cor. Prew and Control, p.II (1966) August.

Table 2. Composition of fatty and rosin acids.

Nitrogen Heterocyclics. The nitrogen may also be incorporated into an aromatic or aliphatic ring structure. A typical example is pyridine, with substitution on the ring being possible also. The ring nitrogen in pyridine can be quaternarized, while aliphatic nitrogens may also form amides.

Formulations of corrosion inhibitors are among the most complicated of oilfield treating chemicals, perhaps second only to emulsion breakers. The total composition depends on the relative amounts of the fluids being treated (oil, water, and gas) as well as the nature of the corrodents (CO_2, H_2S, O_2, and/or organic acids). The presence of dissolved oxygen will sharply reduce the effectiveness of these inhibitors. Oil soluble inhibitors are used most frequently because they normally give better corrosion inhibition. The concentration of the *compound* is usually in the 30-40% range. A heavy aromatic naphtha (HAN) refinery cut is a common solvent (40-60%), although other hydrocarbons can be used, depending on the *compound*. Oil *soluble* sulfonates can be included to improve oil dispersibility of *compounds* with limited oil solubility into a high gravity paraffinic crude for example. Dispersants such as nonyl phenol ethoxylates may be used to disperse the *compound* in high water-cut systems so the *compound* can be transported to the oil phase. Isopropyl alcohol, ethylene glycol, etc. may be added to reduce the pour point for cold weather applications. Emulsion breakers may be incorporated to minimize emulsion separation problems; similarly, antifoam: chemicals may also be included. These latter two materials are added, especially if the inhibitor is primarily applied with batch, squeeze, or tubing displacement methods. They counteract effects of **high concentration inhibitor slugs. rather than**

treatment of ongoing emulsion or foaming problems.

Water soluble inhibitors may be used in water injection systems, gas transmission lines, and wet oil lines with high water content. Quaternary amines and amine (or amide) acetate salts are most commonly used. *Compound* concentration is in the 10-50% range, with water as the primary solvent (30-50%). Methyl or isopropyl alcohol may also be included (5-20%) to improve stability in the drum and/or low temperature handling characteristics. A surfactant (0-10%) such as nonyl phenol ethoxylate may be included to help the inhibitor reach the metal surface and to clean solids from the system. Water soluble inhibitors may be effective in gas systems where water may be produced or condensed and little hydrocarbon liquid is present. For gas gathering and trunk lines to shore, the corrosion inhibitor may consist of more than one type of *compound:* a quaternary ammonium salt for any liquid water that might collect and flow along the bottom, an amide "oil soluble" type for better long-term effectiveness, and even a low molecular weight amine (e.g., ethylene diamine) to neutralize some of the acid gases. Triethylene glycol or a similar solvent with low volatility is necessary in these gas lines to assure that the inhibitor formulation remains fluid and is carried along to shore.

Solubility. The distribution of corrosion inhibitors between the oil and water phases is highly variable. Most of the corrosion inhibitors used in the petroleum production offshore are oil soluble and are expected to follow the oil to the refinery. Some small fraction will be carried into the water in oil carryover but would constitute a negligible fraction of the allowable hydrocarbon concentration in the disposal water. On the other hand, the quaternary ammonium *compounds* would essentially all end up in the water phase.

Application. Different treatment methods are used to apply corrosion inhibitors in offshore operations.

Continuous treatments are used in some wells (especially gas wells) where a small diameter macaroni or capillary line is available[25], similar to the scale inhibitor. In fact, multipurpose scale and corrosion inhibitor formulations have been developed for this specific circumstance. Continuous treatments at the wellhead or surface facilities are also used if downhole corrosion is negligible and/or if supplemental surface protection is deemed necessary. If corrosivity measurements indicate protection is needed, water soluble inhibitors can be added continuously to waterflood injection water. Recommended treatments for waterfloods are typically in the 5-15 ppm range. Treatments for gas wells are usually higher, perhaps up to 100 ppm based on total liquid production rate. Concentrations in the liquids may range up to a thousand ppm in unusual wells with very high gas volumes and very low liquid volumes. Some oil pipeline systems receive 10 ppm.

Displacement-type treatments are the most common method for downhole treatment of producing wells. With a liquid displacement for an oil well, a calculated volume of inhibitor (e.g., 55 gal) is diluted with sufficient hydrocarbon solvent (crude, diesel) to fill the tubing string down to the formation. The mixture is pumped in, allowed to contact the tubing for a short time, then produced back as the well is returned to service. With gas wells, the inhibitor may only be diluted to 5-10%, pumped in, and allowed to fall to the formation. The downtime for treatment and risk of killing the well with excessive hydrostatic head has led to increased use of nitrogen in the treatments. Typically, the concentrated inhibitor (perhaps slightly diluted with solvent) is atomized into a nitrogen stream and displaced to the formation face with more nitrogen. Displacement is usually much faster and the wells are usually returned to service almost immediately. In all types of displacement treatments, a substantial fraction of the inhibitor is retained on the tubing walls, with some part being produced at relatively high concentrations when the well is first returned to service. Experience of one operator indicated that only very minor amounts of the inhibitor were returned with the initial production after a treatment.

Squeeze treatments have also been used, similar to those described for scale inhibitors. The inhibitor is diluted to 5-10% in an organic solvent and injected into the formation. While there will be an initial return slug of several thousand ppm concentration in the oil for a day or two[26], most of the inhibitor is produced back at a much lower concentration (less than 100 ppm) over periods up to six months. Squeeze treatments are becoming less common because of concern for permeability damage around the wellbore, down-time, and risk of killing the wells.

Concentrations of the oil soluble inhibitors in the produced water discharged to the ocean are expected to be quite low and would be included in the total hydrocarbon measurement. The highest concentration in the discharged water would follow displacement or squeeze treatments. All wells on a platform or in the system will not be treated simultaneously for four reasons:

The treatments will normally be effective for different durations.

Treatment of all wells simultaneously causes major upsets in the separation equipment.

Sufficient equipment and operating personnel are not available.

Shutting in many wells simultaneously has an adverse effect on total production.

Typically, no more than 10-20% of the wells feeding into a separation system would be treated with a batch or squeeze treatment simultaneously. Thus, the peak concentration in the composite oil would only be a few hundred ppm. As an example, a carryover of 40 ppm of oil containing 500 ppm of inhibitor following a batch or squeeze treatment would only lead to 0.020 ppm inhibitor in the water. Even allowing a 20X concentration of the inhibitor due to possible accumulation at the oil/water emulsion interface, the concentration of 0.4 ppm is still very low, even prior to the immediate dilution at the point of discharge.

Oxygen Scavengers. One other type of chemical is used in production operations to control corrosion. Corrosion caused by dissolved oxygen in produced fluids is often controlled by reacting the oxygen with an oxygen scavenger. The scavenger does not form a protective layer. All of the scavengers in use are a form of sulfite, with ammonium bisulfite being commonly used offshore because it is available as a concentrated (60%) stable aqueous solution. The reaction with oxygen is:

$$2\ NH_4HSO_3 + O_2 \rightarrow 2\ NH_4HSO_4$$

The sulfate product is also highly water soluble, although the sulfate ion can react with high concentrations of calcium, barium, or strontium to form a solid deposit. Neither the scavenger nor the products will end up with the oil. At use concentrations (< 100 ppm added), neither the reactants nor the products pose any pollution risk to marine life (seawater already contains about 2700 ppm sulfate). Furthermore, the most important application is for treating injection waters, which are not normally discharged to the sea.

Corrosion inhibition practices for the four companies interviewed had similarities and differences. None were adding corrosion inhibitor to waterflood injection Water. Three did not normally treat oil wells downhole. However, one of these three did continuously add 10 ppm corrosion inhibitor to a large wet oil pipeline to shore, augmented by periodic batch treatment associated with pigging and biocide treatment. Another company regularly treated many of 150 oil wells feeding into a single pipeline (75-80% water), with 8-10 ppm of a water soluble corrosion inhibitor being continuously added to the line. Gas wells were treated on a selective basis by all operators, depending on results of corrosion monitoring programs and experience. Nitrogen displacement was becoming the preferred treatment method for one operator, but liquid displacements were more common for the other three. Squeeze treatments were being used in some instances but were becoming less common.

BIOCIDES

The purpose and use of biocides in the offshore petroleum industry has been previously discussed[5-7]. This section will review those papers briefly to add perspective to this paper. A few additional points will be included as well.

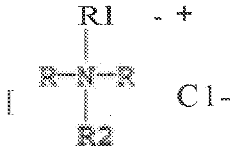
Problem Description. Of the various kinds of biological problems encountered in offshore production, sulfate reducing bacteria (SRB) are of primary concern. These bacteria reduce sulfate ion to hydrogen sulfide, which contributes to corrosion damage to the system and fouling of equipment with iron sulfide. The corrosion damage most commonly encountered is pitting of steel which can cause leaks and failures. Sulfide corrosion cracking can also lead to sudden catastrophic failure of high strength carbon steels and many high strength alloys. The iron sulfide presence increases the need for frequent vessel cleanout and also causes problems in oil and water separation. The iron sulfide particles become oil-wet, stabilizing emulsions and making it more difficult" to obtain pipeline quality oil. Also, the oil carryover into the water is increased, making it more difficult to remove the oil from the water. Iron sulfide can spontaneously ignite if allowed to dry in the air, increasing the risk of fire during shutdowns, workovers, etc. SRB can also be a problem in pipelines connecting platforms or in the main pipelines to shore, especially since pitting corrosion can lead to oil leaks. Of course, hydrogen sulfide can be a severe safety hazard to operating personnel if vented or if contacted during maintenance of equipment. Control of bacterial growth can clearly be necessary for safe and efficient operations. Biocides were used from time to time on approximately one fourth of the platforms in the Thirty Platform Study[4].

Biocides may also be required in waterflood operations to prevent SRB growths from causing corrosion of the equipment and/or plugging of the injection wells. Slug treatments are the normal treatment method, whether source wells or seawater is used. One aspect not considered in the EPA[5] or API[6] biocide survey papers is the treatment of seawater for injection (or utility) use. Such systems often use electrochemically generated sodium hypochlorite to control marine and microbial growth in the intake portions of the water treatment or utility systems handling aerated seawater. Dissolved oxygen must be removed from the seawater prior to injection in waterfloods by mechanical and/or chemical means. Since chemical oxygen scavengers also react with any residual hypochlorite, sulfate reducing bacteria then must be controlled with organic biocides in injection systems downstream of the treatment section to prevent corrosion and plugging of the reservoir rock. In either case (source wells or seawater), essentially all of the biocide is injected into the formation.

Alternate biological control methods have had limited application, but chemical treatment has the best success ratio. Copper-based alloys can be used in some limited situations (e.g., intake screens) to reduce or prevent accumulations of marine growth but are economically and technically unsuited for most of the equipment. Removal of bacterial deposits can be difficult and is usually incomplete. Scraper pigs may remove most of the growths from pipelines, for example, but are usually used in conjunction with a biocide program to obtain more effective results when bacteria are known to be a problem.

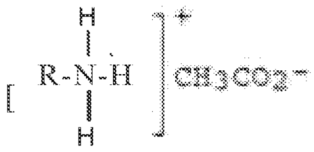
Chemical Description. The biocides commonly used in offshore producing operations can be broken into four generic chemical types.

Quaternary amine salt and amine acetate. These two types of generic compounds are similar and have the following general structures:



$\left[R-\overset{R1}{\underset{R2}{N}}-R\right]^{+} Cl^{-}$

Quaternary amine salt

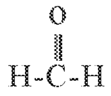


$\left[R-\overset{H}{\underset{H}{N}}-H\right]^{+} CH_3CO_2^{-}$

Amine acetate

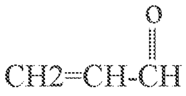
The base amine may be a primary, secondary, or tertiary amine. One of the R groups is usually a long chain alkyl group, C10-C20. The other R groups are usually C1 or C2, formed by reacting with low molecular weight alkyl halides. The variation in chain length and ratios of the halides are the major modifications in the generic *compounds*. Quaternary amine *compounds* remain ionized and highly water soluble at all pH values. If there are three or fewer carbons bonded to the nitrogen, an amine salt can be formed by reaction with an acid, e.g., acetic acid in the example shown. The salt is ionized at low pH, but the N-H bond breaks at higher pH, forming the free amine, which is less water soluble and usually less effective as a bactericide. The formulations of these amine salts are usually relatively simple, a 10-50% solution of *compound* in water. Alcohols may be added for freeze protection or viscosity reduction.

Aldehydes. Three types of aldehydes are used as biocides in the oilfield. These materials are much purer than most other oilfield treating chemicals, with well defined properties. All are highly water soluble and very reactive chemically. The formulations usually contain an inhibitor to prevent polymerization. Formaldehyde and glutaraldehyde are sold as 20-50% concentrated aqueous solutions. The acrolein is sold as an anhydrous liquefied gas under a pressurized nitrogen blanket and is fed directly from the cylinders. It should be noted that use of formaldehyde and acrolein has decreased in the last two years due to concerns for personnel safety.



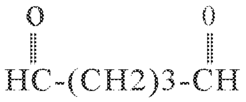
$H-\overset{O}{\overset{\|}{C}}-H$

Formaldehyde



$CH_2=CH-\overset{O}{\overset{\|}{C}}H$

Acrolein



$H\overset{O}{\overset{\|}{C}}-(CH_2)_3-\overset{O}{\overset{\|}{C}}H$

Glutaraldehyde

Other. Organic-sulfur compounds such as thiocarbamates, isothiazolin, etc. and one halogenated organic compound (2,2 dibromo-3-nitrilo-propionamide) are used in offshore producing systems to some extent. The use of electrolytically generated sodium hypochlorite in seawater systems has already been mentioned.

Solubility. The biocides are all highly water *soluble*, with very limited solubility in the oil. Hence, the biocides are expected to remain with the water.

Application. Biocides are used in production operations to minimize operating problems by controlling growth. It is not feasible nor is it necessary to obtain a completely sterile system. Experience through the years has shown that short periodic slug treatments at higher concentrations are technically and economically more effective in maintaining biological control inside the system than continuous treatment at lower concentrations. Less biocide is used; hence, less is discharged to the ocean. Slug treatments are optimized for each system but a typical program includes concentrations in the 100-200 ppm range for 2-6 hours on a weekly to biweekly basis. Thus, average usage for a 150 ppm, 4 hour weekly slug would be 4 ppm, compared to 10-20 ppm requirement for continuous treatment. More frequent slug treatments may be required to obtain control initially but rarely more than every other day. Hypochlorite used in seawater systems is added continuously, with 0.5 ppm residual usually being sufficient to control marine and microbiological growth.

Essentially all of the biocide used in waterflooding is injected into the formation with the water. Little or none will be discharged to the ocean. Because of reactivity and adsorption on surfaces in the reservoir, none of the biocide is expected to reach the producing wells.

All of the four operating companies used biocide to some extent, but only in response to problems detected by operations personnel and/or monitoring programs (H_2S increase, high SRB concentrations, FeS, etc). None of the operators treated wells downhole, although one indicated that flowlines from remote single well jackets were slug treated weekly (100 ppm for a couple of hours) on an as-needed basis. Treatment on the platforms was usually restricted to the water processing equipment, again in response to problems or monitoring. One wet oil pipeline to shore receives a weekly 4 hour slug of glutaraldehyde (50 ppm, active basis) in conjunction with pigging. In another wet oil line, only the water processing equipment on shore is slug treated with 100 ppm acrolein[6]. No acrolein was detected in the discharge from the facility due to dilution and reaction. Biocides were not normally required on any platforms in gas fields.

EMULSION BREAKERS

Problem Description. Virtually all of the oil production in offshore operations contains produced water and dissolved or free gas. Major parts of the offshore facilities are involved in separating these three phases. Separation of the gas from the oil and water is relatively straightforward, although foaming can be a problem. As mentioned earlier, most of the gas wells produce very little water, with the liquid hydrocarbon being easily separated from the gas.

Separation of the oil and water in oil fields is usually a more difficult task. While systems vary widely depending on the nature and age of the producing wells, two or more stages of separation are common. Most of the gas is removed in the high pressure separator, with the water and oil both being sent to the intermediate (or low pressure) separator through the same line, usually in an emulsified form. With a low water cut, water droplets are dispersed in the continuous oil phase, called a normal emulsion. At high water cuts the oil droplet is suspended in the continuous water phase, called a reverse emulsion. Oil and water are not miscible and normally will rapidly separate if some type of emulsifying agent is not present. Naturally occurring constituents of the produced fluids such as asphaltenes, resins, organic acids, clays, etc. can stabilize emulsions, as can certain materials such as corrosion inhibitors, biocides, or corrosion products that are introduced during producing operations. The emulsifying agents concentrate at the oil/water interface, preventing dispersed droplets from coalescing and separating.

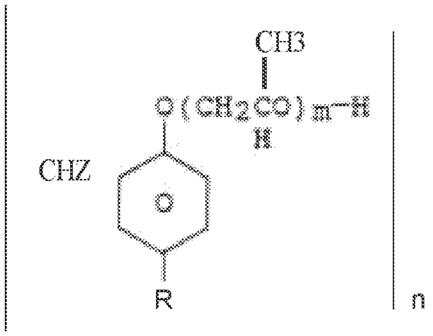
The oil entering the low pressure separator usually contains some free water plus dispersed droplets of water, stabilized to some extent by emulsifying agents. Free water is removed in the low pressure separator (or FWKO) and the oil flows to the bulk oil treater. This oil is treated to pipeline specifications in the treater. Oily water and any wet oil is sent to other systems for further treatment.

Separation of the emulsified water from the oil in the treater can be improved with longer residence times, warmer fluid temperatures, electric fields, and/or chemical additives called emulsion breakers or demulsifiers. Excessive residence time is not economically feasible because of the high cost of space and weight on offshore structures, especially in deeper water. The produced fluids are commonly heated in direct fired heater-treaters in onshore systems, but the increased risks associated with fire on an offshore structure makes this approach less desirable. Electrostatic fields in the treater are used extensively to improve separation, but it is still often necessary to use an emulsion breaker. Separation of water from very light oils and gas condensate is usually much easier; electrostatic separation is rarely used and emulsion breakers may not be needed.

Emulsion breakers work by attacking the droplet interface. They may cause the dispersed droplets to aggregate intact (flocculation) or to rupture and coalesce into larger droplets. Either way, the density difference between the oil and water then causes the two liquid phases to separate more rapidly. In addition, solids present will usually tend to accumulate at the liquid level interface (between the bulk oil and water phases) and form a semi-solid mass. If these solids are not dispersed into the oil phase or water-wetted and removed with the water, the interface detector in the control system will ultimately malfunction, causing water to be dumped into the oil pipeline or oil to be carried over to the produced water system. Proper selection and application of emulsion breaker will minimize this accumulation and the resulting problems.

Chemical Description. Several different generic chemical *compounds* are used in emulsion breakers. Usually there are two or more *compounds* involved in any formulation.

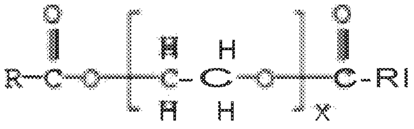
Oxyalkylated Resins. The resins are usually alkyl phenol formaldehyde types, with R, m, and n being



Alkyl phenol formaldehyde resin

R = C_4 - C12 , n = 7-12 , m = 1 to large varied. The phenolic hydrogens are essentially all oxyalkylated, usually with ethylene and/or propylene oxide. Propylene oxide is used in the example. Variation of n and m govern the oil solubility and wetting characteristics of the *compound.*

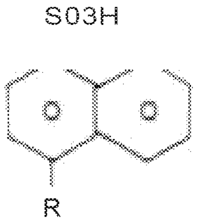
Polyglycol esters. Glycols such as ethylene glycol, di- or tri-ethylene glycol, glycerine, etc. are reacted with alkyl carboxylic acids to obtain the desired properties. Using polyethylene glycol as an example:



Dialkyl polyethylene glycol

Variation of Rand R1 governs the solubilities but the *compounds* used are all much more soluble in oil than in water. These *compounds* can also be modified by esterifying with dibasic acids (e.g., maleic anhydride) to form even higher molecular weight esters.

Alkyl Aryl Sulfonates. The third major type of *compound* used in demulsifiers are the sulfonates, frequently a substituted naphthlalene sulfonate:



Substituted naphthalene sulfonate

The R group is usually a straight chain group. The *compounds* are similar to the dodecyl benzene sulfonate used in many household detergents but have different alkyl or aryl substitutions for higher oil and lower water solubilities.

There are a few other different types of *compounds* that are occasionally used but the above types probably constitute 95+% of those used in offshore operations.

Formulations. Probably 90-95% of the product formulations used in the oilfields will consist of mixtures of two or more of the above *compounds.* There may be two *compounds* from the same generic type or *compounds* from different generic types. Mixtures are usually required to obtain the best balance of reaction speed, cleanliness of oil, and clarity of water. In addition to these generic types, many formulations also include a water soluble wetting agent. Probably the most commonly used *compound* is the sodium or ammonium salt of dodecyl benzene sulfonic acid, the household detergent mentioned earlier. Ethoxylated nonyl phenol, another surfactant, is also used. The base solvent for virtually all of the demulsifiers is a heavy aromatic naphtha cut. Methyl alcohol, isopropyl alcohol, or similar solvents are used to obtain stability in the drum and/or freeze protection or viscosity reduction for cold weather applications.

Formulations will usually contain 30-50% total of the various demulsifier *compounds.* The bulk of the remainder will be the heavy aromatic naphtha. The wetting agent (e.g., dodecylbenzene sulfonate) is a very minor constituent (e.g., <0.01%) used to help the demulsifier migrate through water into the oil phase. This migration is especially important in wells producing a high percentage of water. When alcohols are added for freeze protection, the *compound* concentrations may drop below the 30% normal lower limit.

Solubility. The three primary demulsifier *compounds* listed are all highly oil soluble as is the aromatic solvent. Very little of these *compounds* will remain in the water phase except as a contaminant in oil carryover as described for the corrosion inhibitors. The alkyl aryl sulfonates would probably have the highest water solubility. One vendor had data for one crude oil indicating that 92% of a formulation containing only this generic type of *compound* went into the oil, with only 8% (including the methyl and isopropyl alcohol cosolvents) of the formulation going into the water.

Application. During normal operations, demulsifiers are added continuously, either upstream of the low pressure separator (or FWKO) or just before the treater. Concentrations (based on oil production rate) range from 10 to 200 ppm, with most treatments requiring less than 30 ppm. The higher concentrations would usually only be required to cope with an abnormal situation, such as a well workover, where unusually high solids concentrations help to stabilize emulsions. High concentrations of other treating chemicals (e.g., corrosion inhibitors) can increase emulsion stability also, but some emulsion breaker is often incorporated into those formulations to minimize the emulsification tendencies.

Treating concentrations based on total oil and water production will obviously be lower, depending on the water cut. A normal maximum of 50 ppm (oil) would be 25 ppm (total) if an equal volume of water were produced. If 90% goes with the oil, only 5 ppm of total formulation would be present in the water.

REVERSE BREAKERS

Problem Description. After the primary oil-water separation occurs, some finely dispersed oil may be carried along with the water as an oil-in-water emulsion, commonly called a reverse emulsion in the oilfield. It is usually necessary to clean up this water before it is discharged to the ocean or injected into a waterflood or disposal well. The oil itself must be reduced to approximately 48 mg/l for overboard disposal[1]. While the oil may directly contribute to injection problems, the solids frequently associated with the oil will cause plugging of formations. The injection rate will then decrease, the required pressure will increase (higher fuel consumption) or the well must be worked over (acidized, backflowed, underreamed, redrilled, etc.) to maintain injectivity.

Probably the most common offshore produced water treating systems include efficient gravity settlers (e.g., corrugated plate interceptors, CPI) and/or flotation cells, although many systems may also have a small surge/skim tank as well. The tank (if present) allows "free" oil and gas to separate from the water, easing the load on the downstream equipment. The CPI units provide better separation because the plates drastically reduce turbulence, allowing smaller droplets to separate, coalesce, and migrate to the surface for skimming. In many systems with condensate or light oil, the CPI unit alone will suffice for oil removal for overboard disposal, often without chemical treatment. However, reverse breakers can be added to facilitate gravity separation in the skim tank and CPI units. For heavier oils, many operators have found that flotation equipment is the most effective approach. A second chemical or a different formulation may be required to obtain maximum efficiency in the flotation cell. Granular media filters may also be used for removal of oil and solids, especially if the produced water is to be injected. Different generic types or formulations of treating chemicals may be required for this equipment (See F). Filters have not been used extensively in offshore produced water treatment because of the extra space and weight requirements for cleanup of the backwash water (as compared to CPI and/or flotation cells).

Chemical Description. Most of the oil droplets in **reverse emulsions have a net negative charge.** Hence the treating chemicals usually will have positive charges to neutralize the droplet charge and cause particles to aggregate. The reverse breaker *compound* will have surfactant properties to reduce the interfacial tension, allowing the oil droplets to coalesce into large drops.

Polyamines. Low molecular weight amines or mixtures of amines are moderately polymerized to make these *compounds*.

$$NH_2-(R-NH)_n-R-NH_2$$

Simple polyamine

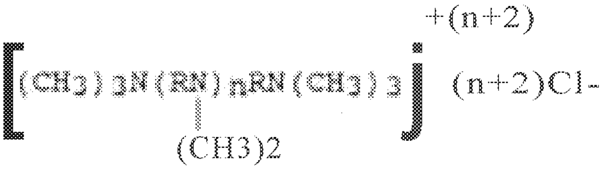
$$NH_2-(R-NH)_n-R1-NH-R-NH_2$$

Mixed polyamine

The R and R1 groups may have 2-8 carbon atoms to vary the charge density, with the molecular weight of the polymer usually in the 2000-5000 range. In some instances, the R groups are crosslinked to form a more compact *compound* structure. The *compounds* are usually present in the salt form in the drum (halide, acetate).

The reverse breaker *compounds* are distinguished from the coagulants in the following section primarily by modification to provide surface tension lowering properties. This property is usually obtained by reaction with a long chain fatty acid to form either an amide or an ester, but may also be obtained by oxyalkylation. Only a small weight fraction of the *compound* (e.g., 5-10%) will be **modified, as too much reduction in surface tension** can either stabilize or form emulsions during usage.

Polyamine Quaternary Compounds. Virtually any of the above polyamines can be quaternized with methyl chloride or other desired agents to **obtain the corresponding quaternary ammonium** halide:



$$\left[(CH_3)_3N\underset{\displaystyle (CH3)2}{(RN)}{}_nRN(CH_3)_3\right]^{+(n+2)} (n+2)Cl^-$$

These two generic types comprise most of the reverse breakers used. Many of the coagulants and flocculants discussed in the following section contain **similar *compounds* and sometimes are also used to** aid in oil removal as well as the combined removal of oil and suspended solids.

Formulations usually consist of 20-40% of *compound* in water solvent. Metal salts (aluminum, iron, or zinc chloride) may be included in the formu**lation in some instances, as discussed under coagu**lants. Methyl or isopropyl alcohol is used for viscosity reduction or freeze protection when appropriate.

Solubility. The quaternary ammonium *compounds* are all highly soluble in water, with very little being **carried into the oil except through water carryover.** The pOlyamines are highly soluble in water at low pH, but oil solubility will increase at higher pH values. The exact distribution between the phases will depend on the specific *compound*, but *compounds* with smaller R chains and more amino nitrogens per molecule (higher charge density) will be more water soluble at any given pH. If the produced water pH is as high as 8, quaternary ammonium *compounds* will generally provide greater efficiency at lower costs. Some of both types of *compounds* will accumulate on the surface of oil droplets and be skimmed with the oil.

Application. Reverse breakers are usually added continuously to the water leaving the low pressure separator and/or treater before it enters the water cleanup system. Concentrations will vary with the difficulty of breaking the reverse emulsion but 5-15 ppm based on the water flow rate is typical. Overtreating is both technically and economically undesirable. Excess breaker often can cause re-emulsification.

COAGULANTS AND FLOCCULANTS

These materials are chemically similar to the reverse breakers but generally do not cause lowering of the surface tension. They are primarily used for removal of solids from injection water but may also be used to improve oil removal for overboard discharge. Nomenclature varies between the supplier and operating companies interviewed.

Problem Description. Suspended solids in water can cause plugging problems in injection or disposal wells. These solids can also stabilize both normal and reverse emulsions, making it more difficult to obtain saleable oil and/or properly treated water. Reverse breakers are primarily used to clean up oily produced water for discharge, but a coagulant (and/or flocculant) may be required to get the solids concentration down to very low levels to prevent injection well plugging.

Chemical Description. The coagulants have the same generic chemical description as the cationic polymers commonly used for the reverse breakers: low molecular weight polyamines or quaternarized polyamines. Little or no modification is made to the basic structure. The high charge density provided by amine groups on short chains allows efficient neutralization of the negatively charged solid particles and some growth into larger particles. Aluminum, iron, and zinc chlorides can also be used as coagulants. These materials work by precipitation, with the precipitate both neutralizing and entrapping suspended solids particles.

Coagulant formulations may be solely polymers (typically 20-30% active in water), inorganic salts (20-50% active), or mixtures (primarily inorganic salts with 5-10% polymer). Water is the solvent, but methyl or isopropyl alcohol can be added to the polymers for freeze protection.

The flocculants are very high molecular weight polymers. Cationic types are the most common but anionic and non-ionic are available. The molecular weights are in the 0.5 to 20 million range, a hundred to a thousand times higher than the coagulants. The charge density is much lower than the coagulants as well. These materials help solids removal by bridging between particles or aggregates of particles, with relatively minor neutralization of charges. The drastic difference in molecular weight and charge density is obtained by adding a few active sites to a relatively large inert polymer. For example, a high molecular weight phenol-formaldehyde resin can be formed with sufficient ethoxylation to maintain water "solubility'. A few amine groups (salt or quaternary ammonium form) can be added to form a cationic polymer, or a few carboxylic acid groups added to form an anionic polymer. Formulations are in the 10-30% active range.

Solubility. The coagulants and flocculants are all highly water soluble with very little expected to be carried into the oil except as an impurity in emulsified water. In most applications, however, these agents would become rather tightly attached to the particles, becoming essentially insoluble in either the water or oil. They would then follow the solids.

Application. Coagulants can be added to speed up gravity separation in a tank or CPI unit or improve the performance of a granular media filter. Typical treatment concentrations for settling are in the 5-10 ppm range. Treatments below 1 ppm have been effective in the filtration of relatively clean (1-10 ppm TSS) seawater (North Sea, Arabian Gulf, California, etc.), but higher concentrations may be required with higher suspended solids concentrations (e.g., in the Cook Inlet when glacial silt concentrations may reach 1000 ppm TSS during spring runoff).

Flocculants are usually more economically and technically effective when the original suspended solids consists of relatively few large particles or after a coagulant has been used to aggregate most of the small particles. For example, the original, small, negatively charged particles could be neutralized into a few positively charged aggregates by a moderate overtreatment with a cationic coagulant. The aggregates could then be further bridged into very large aggregates with an anionic flocculant to cause rapid settling in a tank or CPI unit. Flocculants can also be used to aid in removal of oil from oil-coated sands.

None of the operators interviewed were using coagulants or flocculants in treating of injection water. Some of the operating personnel felt that the chemicals added upstream of the flotation units were best classified as coagulants or flocculants as opposed to reverse breakers.

ANTIFOAM

Problem Description. Foaming can be a significant problem in separation of gas from liquids in both high and low pressure separators. Excessive liquid carryover into the gas can cause problems in downstream compression and/or gas processing equipment. Inlet scrubbers installed to protect such equipment are usually sized to catch minor amounts of spray, not large quantities of foam.

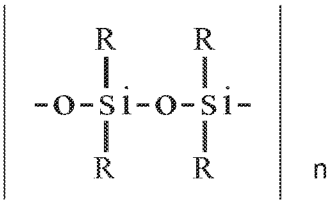
Foaming problems can be reduced by decreasing the throughput, increasing the operating pressure, or adding an antifoam chemical. Decreasing the flow through the separators would decrease total production which could have serious economic and technical implications. Maintaining a higher operating pressure on the high pressure separator would reduce the amount of gas released and the volume of gas in the vapor phase, thereby providing more time for the foam to collapse. However, the higher pressure may decrease the production from the lowest pressure wells and will increase the volume of gas to be handled in the low pressure separator. The change will also affect the amount of condensate in the gas phase.

Addition of antifoam chemicals (usually upstream of the high pressure separator) can drastically reduce both the quantity and stability of the foam. Besides eliminating possible restrictions in production rates and/or gas processing problems caused by foam, the separator operating pressures can then be adjusted to obtain the most efficient distribution of condensate liquids.

Foaming can be a problem and a benefit in water processing. Foaming can adversely affect vacuum deaerators, significantly reducing oxygen removal efficiency. Some foam is helpful in removal of suspended solids and oil in flotation cells, but excessive foam is detrimental to both the original separation and subsequent handling of the waste stream from the unit.

Chemical Description. Two generic types of *compounds* are used as antifoams: silicones and polyglycol esters. Variations of both types can be used in either hydrocarbon or water processing. The *compounds* work by accumulating at the gas/liquid interface and disrupting the foam layer and must have low solubility in the liquid phase to function in this manner.

Silicones. This class of chemicals is based on silicon, often with substitution of carbon-based organic radicals on the silicon atom.

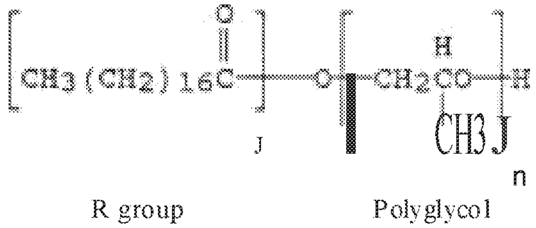


$$\left[-O-\underset{R}{\overset{R}{Si}}-O-\underset{R}{\overset{R}{Si}}-\right]_n$$

The degree of polymerization (n) can be varied as well as the organic group R on the silicon. Larger values of n and larger R groups increase the molecular size and the viscosity, which is often used to characterize the basic *compound.*

Lower molecular weight silicones with low viscosities may be sold and applied as pure *compounds* without a solvent. Mixtures of *compounds* also can be blended for optimum efficiency for specific applications. Some formulations use a hydrocarbon solvent to lower the *viscosity* of a high molecular weight silicone for easier handling and pumping. Colloidal silica (e.g., extremely small particles of sand) is included in some formulations to improve the effectiveness of the silicone. Finally, emulsions of silicones in water (with or without colloidal silica) are available for use in water-based systems. A surfactant and sometimes an alcohol are required to maintain emulsion stability in the drum.

Polyglycol esters. These materials are obtained by reacting fatty acids (e.g., stearic acid) with a relatively high molecular weight polyglycol. Using polypropylene glycol and stearic acid as the R group:



$$\left[CH_3(CH_2)_{16}\overset{O}{\overset{\|}{C}}\right]-O-\left[CH_2\underset{CH_3}{\overset{H}{C}}O\right]_n-H$$

A surfactant is often included in the formulation to improve dispersibility of the *compound* in the liquid phase. The surfactant may be different depending on whether the liquid phase is primarily hydrocarbon or water. Methyl or isopropyl alcohol may also be included in the formulation to improve stability in the drum and/or provide freeze protection.

Solubility. The antifoam *compounds* have very limited solubility in either hydrocarbon or water. The formulation would usually be diluted with hydrocarbon before injection in production separators to improve dispersion into the stream. Since the water phase is below the oil/gas interface where foaming occurs, most of the antifoam *compound* will go with the oil phase, even though it is not soluble in the oil. Emulsified silicones and/or polyglycols used in deaeration towers obviously carry along with the water and are injected. The *compound* used in a flotation system mostly goes with the oily froth, ultimately following the oil to sales.

Application. The antifoam *compound* must be added continuously to control foam. The required concentration for production systems can range from a few ppm up to about 25 ppm. Substantially lower concentrations have proven effective in seawater vacuum deaerators, about 0.2 ppm of both generic types[27,28]. Thorough dispersion of the formulation into the main process stream is necessary for optimum effectiveness. Predilution in kerosine, diesel, water, etc. is a commonly used method to aid mixing, but care is required to assure that separation does not occur in the intermediate dilution stream.

The operating companies interviewed had encountered very few foaming problems that warranted treatment with antifoam chemicals. No more than a half dozen production separators (total) required treatment in all of their operations. One operator reported they used antifoam occasionally on flotation cells.

SURFACTANTS

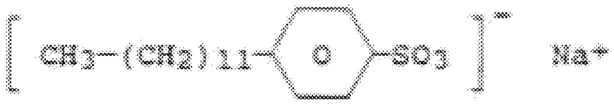
Problem Description. Surfactants are widely used in offshore operations to remove small amounts of oil or grease from the platform and/or equipment. Accumulations of hydrocarbon would undoubtedly increase the risk of damage due to fires. Oily deck surfaces or equipment can become extremely slippery and will lead to injury to personnel. The Minerals Management Service (MMS) requires that all offshore facilities be washed down regularly to minimize these potential hazards. Surfactants are also used to remove oil films prior to touchup painting, although sandblasting may be required in many instances.

In some instances, surfactants are used to aid in mitigating corrosion and/or bacterial problems in systems. The surfactant supplements the detergent properties of the inhibitor and/or biocide to allow those *compounds* to penetrate to the metal surface and may also help dislodge deposits from tubing, pipelines, or vessels.

Surfactants may also be needed to clean up granular media filters that have become contaminated with oil, solid hydrocarbon deposits, and occasionally even non-hydrocarbon materials. Such treatments are usually not required on seawater filters because hydrocarbon contamination is extremely rare. In a similar application, surfactants may be used to water-wet produced sand and/or clays, releasing the oil for recovery and allowing discharge of oil-free solids to the ocean.

Chemical Description. Both of the commonly used types of surfactant *compounds* are widely used in other industrial and domestic applications.

Alkyl aryl sulfonates. This generic type of *compound* is an anionic surfactant, usually in the neutralized form:



The example shown, dodecyl benzene sulfonate, illustrates the common structure of the alkyl group . a moderately long straight alkane. The chain lengths of any *compound* will vary somewhat, and different average lengths may be used to obtain somewhat different properties. Numerous earlier studies have shown that the straight chain was biologically degraded far more quickly and extensively than branched chains. The higher molecular weight sulfonates described under Emulsion Breakers are usually not used as surfactants for system cleanup.

Formulations are usually concentrated solutions of *compounds* in water.

Ethoxylated Alkyl phenols. These materials are formed by ethoxylating phenol or substituted phenols.

The size of the R group (a straight chain alkane with Oto 18 carbons) and the degree of ethoxylation (n) controls the solubility of the surfactants. A large R and a moderate n allows the surfactant to be soluble in hydrocarbon for certain applications (e.g., cleaning storage tanks or vessels) yet be highly water dispersible for washdown purposes. A smaller R group and/or more ethoxylation allows the surfactant to be highly water soluble and easily diluted and/or applied with water. onyl phenol is widely used because it is readily available, low in cost, and easily modified to achieve the desired properties.

Formulations can vary substantially, depending on the purpose. One oil-soluble version is available with 2-20% surfactant in hydrocarbon solvent to facilitate tank/vessel cleanout. Water soluble versions are available as more concentrated forms (20-*50% compound)* in water, with alcohols or ethylene glycol added for solvency and/or pour point depression.

Solubility. As discussed earlier, the sulfonates are water soluble while the phenol-based materials can be made oil soluble and water dispersible as well as water soluble. Oil soluble surfactants used to clean tanks are drained or pumped directly to the oil stream and would probably continue with the oil to the refinery. Otherwise, the surfactants would be expected to go with water into the processing stream. Some of this surfactant would be expected to move with dislodged oil back to the oil stream from the CPI or flotation cell, but most of the water soluble surfactant would remain in the water phase and be discharged to the sea.

Application. Process applications require low concentrations (5-25 ppm) to alter the surface tension and water-wet produced sand for example. Treatmel!tto clean up an "il/water interface emulsion stabilized by solids is usually a batch operation, with the emulsion breaker treatment preferably being altered to prevent a frequent recurrence. Similarly, cleanup of contaminated filters is usually a batch process not involving continuous addition of surfactant.

Housekeeping cleanup of the external surface of equipment and the platform itself probably involves as many procedures as there are housekeepers. In principle, a 1-10% dilution of surfactant in water is wiped, sprayed, mopped, brushed, etc. onto the surface and allowed to soak. Subsequently, the surface is hosed down with copious amounts of seawater, sometimes followed by a freshwater rinse. The surfactant would be drastically diluted, but it would be difficult to impossible to give probable ranges. After the released oil is separated in the sump, the water is discharged to the ocean.

None of the operators continuously added surfactant to any process stream nor did any have media filters in service which might require cleanup. Surfactants were used on an as-needed basis (not a common occurrence) for cleanup of oil wet solids and/or disposal of the interface in separators. Various surfactants and cleaners are frequently used for housekeeping and maintenance purposes.

PARAFFIN TREATING CHEMICALS

Problem Description. The liquid hydrocarbon phase produced from many reservoirs becomes unstable after it leaves the formation. Decreasing pressure and temperature causes a solid hydrocarbon to deposit on the walls of the tubing, flow lines and surface equipment. The deposits will progressively block flow through piping and fill process vessels and tanks. Excessive deposits can interfere with operation of valves and instrumentation.

The composition of this solid depends on the original oil composition, but it is usually called *paraffin* in the oilfield. Straight or branched chain hydrocarbons, similar to the paraffin homologous series defined by chemists, are usually deposited from paraffinic crudes. Polynuclear aromatic hydrocarbons, sometimes referred to as asphaltenes, are usually deposited from asphaltic or aromatic crudes. These various solid deposits have different solubilities in organic solvents. Unfortunately, *paraffin* deposits are so complex that no calculation methods exist to predict when they will deposit. Experience in the field with similar crudes is the best method to anticipate problems. Deposition of *paraffin* from fresh, pressurized bollom hole samples can be a useful indicator also.

Physical methods can be used to control *paraffin* problems in many instances. Scrapers and 'pigs' can be pumped through flow lines and pipelines, pushing accumulated deposits before them. Pumping hot oil through lines is a common remedial method onshore, but is less common offshore because of safety concerns. Thermal insulation for subsea lines and platform piping will reduce the deposition rate and sometimes prevent any deposition under normal operating conditions.

Chemical methods are used alone or in combination with physical methods. Solvents can be used to dissolve the *paraffin* or keep it in solution. Continuous addition of solvent to the total production stream is often prohibitively expensive. However, solvents are frequently used to remove *paraffin* during workovers involving acidizing, gravel packing, etc. *Paraffin* inhibitors can be effective in preventing the solid particles from aggregating or depositing on the walls of the piping and equipment.

Chemical Description. Solvents used to control are normally impure refinery cuts for economic reasons. The paraffinic or aromatic nature of the solvent is selected to obtain maximum solubility of the *paraffin*. Cuts approximating xylene mixtures are the closest to a definable structure.

Chemical suppliers submitted information on three types of *compounds* used as *paraffin* inhibitors. The available information is not considered sufficiently defined to show structures. The three types are vinyl polymers, sulfonate salts, and mixtures of alkyl polyethers and aryl polyethers.

Solubility. The solvents and inhibitors are all highly soluble in oil, with very limited solubility in water. Consequently, it is expected that almost all of the *paraffin* chemicals will remain in the oil phase.

Application. Paraffin solvents are used in batch treatments occasionally in offshore systems to aid in cleaning out lines or vessels. Some operators have used a small batch (50-100 gallons) in front of pigs to aid in paraffin removal or help soften deposits if the pig becomes stuck.

Paraffin inhibitors are used more commonly and are added continuously. Treatment concentrations are usually in the 50-300 ppm range, based on oil production. Crudes with mild to moderate paraffin deposition tendencies may require treatment only during the winter months when air and water temperatures are lower.

SOLVENTS AND ADDITIVES

This section is concerned with components of the formulations that are not related to the functional use or uses of the chemical, primarily solvents and some surfactants.

Solvents. Hydrocarbon solvents are used with those chemicals that usually end up in the oil phase - emulsion breakers, oil-soluble corrosion inhibitors, and anti-foam chemicals. In all instances, this solvent is a complex refinery cut, not a simple compound. "Heavy aromatic naphtha" is the term most commonly used by the suppliers, emphasizing the key requirements. The aromaticity enhances the solvent properties of the naphtha cut with respect to the various chemical *compounds,* while the "heavy" reflects the high molecular weight and low volatility needed to meet flash point restrictions for safe handling.

These solvents all have very high solubility in the oil phase and very low solubility in the water. Essentially all of the hydrocarbon solvent is expected to go with the oil.

Other Solvents. Methyl and isopropyl alcohols are the most common other organic solvents. As pointed out earlier, their primary purposes are to provide lower viscosity or freeze protection in the drum. While both are completely soluble in water in all proportions, they also have substantial solubility in hydrocarbons. Consequently, they are also incorporated into some formulations to obtain a completely miscible stable formulation in the drum. Miscibility can be a particularly important aspect in multipurpose formulations, such as one containing a corrosion inhibitor, biocide, and scale inhibitor. Glycerine and low molecular weight glycols are also used in some formulations. It is expected that these solvents will primarily end up in the water phase in most applications.

Surfactants. Relatively small amounts of surfactants are incorporated into some formulations to increase stability and dispersibility in the drum, with less than one percent being adequate in most cases. In other formulations, surfactant may be added in comparable or slightly higher concentrations to improve the performance of the primary *compound.* For example, surfactant may be added to help the corrosion inhibitor penetrate to the pipe surface. Chemically, the surfactants are similar or identical to those described previously.

GAS PROCESSING CHEMICALS

HYDRATE INHIBITION CHEMICALS

Natural Gas Hydrates. Natural gas hydrates are ice-like solids that can form in natural gas in the presence of liquid water under certain conditions. These solid deposits can form at temperatures well above 32F, even above *80F.* Hydrates can block flow of fluids and cause rupture of pipe, fittings, or valves. Chunks of hydrates moving through piping can cause catastrophic failures at elbows or tees. Compressors can be destroyed by the impact of pieces of solids, including hydrates. Clearly, hydrates can be a severe problem in producing or shipping natural gas. However, hydrates frequently are not encountered in shallow waters in Gulf of Mexico operations. Deeper waters are expected to be more severe, as are the colder West Coast and Alaskan waters.

Numerous factors affect the temperature at which the solid hydrates will form. Hydrates form at higher temperatures if the pressure is higher and the gas contains more ethane, propane and butane. Figure 4 from an early publication[29] shows these trends. These curves indicate that hydrates should be expected above 3000 psia if the temperature of most natural gases drops below about 75F. Most gas wellhead pressures in the Gulf of Mexico are above this value for much of the producing life of the well. However, the situation is complicated if carbon dioxide or hydrogen *sulfide* is present in significant

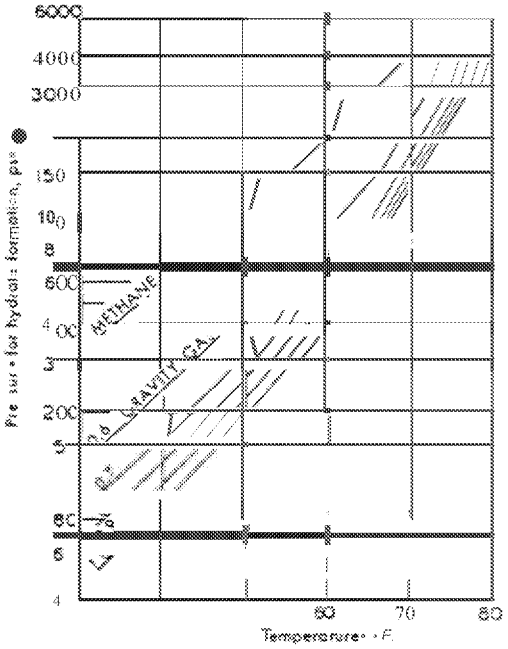


Figure 4. Conditions favorable for formation of natural gas/ freshwater hydrates.

concentrations. These gases allow hydrates to form at even higher temperatures. On the other hand, high concentrations of salts or other materials dissolved in the water depress the hydrate temperature considerably.

Temperatures below 75F are not uncommon. Surface water temperatures in the Gulf of Mexico range from about 65F in February to about 85F in August[30]. However, it is the development of deepwater prospects that is currently of greatest concern to operators in this area[31]. Average annual temperature at 1000 feet is 54F, decreasing to about 41F at 3000 feet. Seawater temperatures off the West Coast are perhaps 10-15 F cooler than the Gulf of Mexico for comparable depths and seasons. Alaskan waters drop to the 28F freezing point in many areas during **the winter in water, with ice being even colder.** Ambient air temperatures in all areas can drop below seawater temperatures.

The hydrates can form wherever and whenever the gas is cooled below the solidification temperature in the presence of liquid water. The natural gas in the reservoir is hot (150-350F), far above the hydrate formation temperatures. However, the gas cools as it flows up the wellbore, through the equipment, and to shore. One problem area occurs at the choke valve. Most gases cool as the pressure is reduced from wellhead pressure to pipeline pressure. Another problem can develop if the gas flows through a subsea flowline from a remote well or platform to a central processing platform. The gas will be cooled by the seawater or mud on the sea bottom. When the gas is flowing, hydrates can form only if the seawater or mud temperature is below the hydrate point *and* if heat transfer is sufficient to actually cool the gas to the hydrate temperature. High flow rates and the corrosion and weight coatings on subsea flowlines sometimes restrict cooling sufficiently in short lines to prevent hydrate formation. However, when flow from a well or platform is stopped for a sufficient time for any reason, the gas will *cool* to the temperature of the surrounding water, mud or air. Hydrates can form, even blocking the flowline completely. Blockage can cause serious problems when the system is brought back into production.

Prevention of Hydrates. The formation of hydrates can be controlled mechanically or chemically. The choice depends on the system and on the temperature **and pressure conditions. Thermal insulation** can be used to minimize heat loss mechanically and keep the gas warm as long as possible. However, there will be times when flow is reduced or stopped for extended periods. If the surrounding temperature is below the hydrate point and liquid water is present, hydrates could form and cause problems. The situation is similar to protecting the cooling **water in a car. Parking the car in an unheated** garage may provide satisfactory protection if the outside temperature only drops to 30 F overnight. If it stayed cold for several days, the water might freeze and rupture the radiator or engine. More reliable protection can be obtained chemically by adding "antifreeze" to the water.

The "antifreeze- added to the car works exactly the same way that hydrate inhibitors work. In fact, the ethylene glycol commonly used in car radiators is occasionally also used in gas systems. More antifreeze must be added to the radiator to protect against lower temperatures and more chemical must be added to the gas to get greater freeze point depressions of the hydrates. Methanol (methyl alcohol) is more commonly used in gas systems because it is normally much less expensive than the glycols.

Methanol. Methanol (CH30H) is used much more frequently than any other chemical when hydrate inhibition is required offshore. It is much less expensive per pound than the glycols but more pounds are required to obtain the same freeze point depression. A large fraction of the methanol will remain in the vapor phase, depending on the temperature and pressure of the gas in the system. **Moreover, substantial concentrations of methanol** are still required in the water to obtain significant depression in the freeze point. Figure 5 illustrates the approximate values of concentration of methanol in the water calculated from the Hammerschmidt equation[32], a common guide. While actual require**ments may differ somewhat in practice, it is still** quite apparent that substantial concentrations (10-*50%)* will be present in treated water separated from the gas.

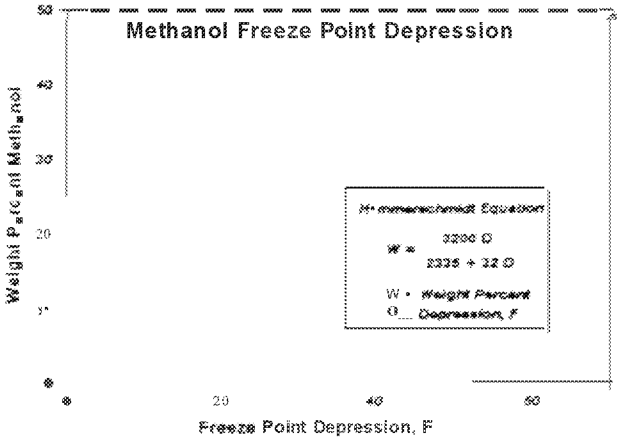


Figure 5. Approximate methanol concentrations in water required for freeze point depressions of natural gas/ freshwater hydrates.

Treatment is usually only economically feasible when little or no liquid water is produced from the reservoir. In this situation only the condensed water must be treated to prevent hydrate formation. Even so on the order of 5-15 gallons per MMSCF may be required to inhibit hydrates for moderate Gulf of Mexico conditions. One of the operators surveyed used an *average* of 9.5 gal. per MMSCF to treat the half of the gas requiring hydrate inhibition. Thus a remote 50 MMSCFD platform might require several hundred gallons per day methanol during cold weather conditions, with 50% or more remaining in the gas under many conditions.

Ethylene Glycol. In certain circumstances ethylene glycol (CH20HCH20H) may be the inhibitor of choice. It has a very low vapor pressure, essentially keeping all of the inhibitor in the water phase. If only small depressions are needed, elimination of the vapor losses may offset the higher price per pound.

DEHYDRATION CHEMICALS

Triethylene Glycol (TEG). As discussed earlier triethylene glycol, (CH20CH2CH20Hh, is used almost exclusively for offshore gas dehydration. Since the dehydration system is normally a closed recirculation system, discharges are limited to abnormal occurrences. Typical makeup requirements are only about 0.05-0.3 gal per MMSCFJ3. This loss is almost totally spray or vapor carryover into the gas line to shore. One operator had a total makeup of 0.75 gal/MMSCF, with none of their systems requiring changeout during 1988. The higher than average losses probably reflect higher than average throughput fluxes to minimize space and weight requirements on the platforms.

Disposal of TEG is rare, as it usually does not become seriously contaminated. The greatest risk of contamination is carryover of liquids from the upstream separators. While hydrocarbon liquids are the most likely to be carried over, all but the very heaviest would be vaporized during the regeneration of the TEG. Very heavy liquids would collect on the surface of the accumulator, while solids would be removed by filtration. Carryover of corrosion inhibitors might cause a foaming problem, but antifoam chemicals can be added to minimize that problem. Carryover of salt water is unlikely, but does pose a serious problem if it occurs. The salt can ooly be removed by vaporizing the TEG in reclaimer units, which are normally not installed offshore. The TEG usually must be replaced if salt accumulation becomes severe. The TEG is normally drained into containers for reclamation or disposal onshore, but is sometimes dumped overboard with the water discharge.

Other Glycols. Diethylene glycol (DEG). O(CH2CHzOHh, and tetraethylene glycol, O(CH2CH20CH2CH20H)2, could be used for dehydration instead of TEG. The DEG would be used for processing cold gas to maintain a lower viscosity and better efficiency in the contactor. The tetraethylene glycol would normally only be used with unusually hot gases to minimize vaporization losses. One operator noted that some of their glycol systems contained a fraction of tetraethylene glycol in the TEG.

STIMULATION AND WORKOVER CHEMICALS

ACIDS

Hydrochloric Acid. Hydrochloric acid is the workhorse acid for oilfield stimulations, offshore and onshore. The concentration may vary for different situations, but 15% is the most common form. All types and concentrations will contain an acid corrosion inhibitor to minimize damage to the tubular goods and downhole hardware. The objective of the **acid is to dissolve calcium and magnesium carbonates** and/or iron corrosion products that are blocking flow paths. This acid is somewhat more expensive than sulfuric acid, but the latter can not be used. Calcium sulfate would precipitate, offsetting the dissolution of calcium carbonate, etc. Post-precipitation can be a problem even with hydrochloric acid, sometimes requiring special additives.

The acid will normally react rapidly because downhole temperatures are high. The acid will be largely neutralized within an liour or two, provided sufficient carbonate or corrosion product materials are present in the area contacted by the acid. However, paraffin or asphaltene coatings can prevent the acid from contacting the surface of these **materials. In these instances a detergent or solvent** may be required to clean the surface to allow rapid **reaction.**

Most acid jobs require several solutions being pumped down in series. A pre-flush solution, often 3-5% ammonium chloride, is used to push the hydrocarbon and formation water back away from the wellbore. If necessary, a detergent or solvent wash to clean surfaces is the next stage. The acid slug is then pumped in, followed by a post-flush solution. The post-flush solution pushes the acid further into the formation, allowing more efficient use of the acid. After the desired time, the "spent" acid and solutions are produced back to the surface, along with the dissolved materials.

The fluids produced from the formation after an acid job will consist of the "spent" acid, flush fluids, formation water, and hydrocarbon. These fluids must be processed before the oil can be shipped and the waters discharged. It is not uncommon for these fluids to form a very stable emulsion, making it important to avoid upsetting treatment of the rest of the production. When the appropriate equipment is available, many operators will process fluids from this particular well through the test separator until production is again normal. In other instances the fluids are produced into a "bad oil" tank first, and then slowly blended with incoming production over an extended period. In almost all instances the spent acid and associated aqueous fluids from the job are blended with the produced water stream and discharged overboard. However, these fluids will be pumped into the pipeline with other production in those systems where all oil/water separation is performed onshore.

Operators normally do not perform detailed analyses or monitor to determine the amount of unreacted acid in the returns. In some instances the returns are checked and excessive acidity is neutralized. Most of the specialists interviewed believed that the acid was probably 95%+ reacted downhole, with further neutralization occurring when spent fluids were mixed with produced water. The carbonate/bicarbonate buffering system in seawater will ultimately neutralize any unreacted acid. In the absence of analytical data it would not be feasible to estimate the pH in the receiving water vs dilution volume.

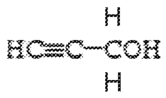
Hydrofluoric Acid. Hydrofluoric acid is the second most common acid used in the oilfield. More specifically this acid is used as a mixture with hydrochloric acid and is commonly referred to as "mud acid". Concentrations may range as high as 12% hydrochloric acid and 3% hydrofluoric acid. Typical concentrations used in the Gulf of Mexico by the participating companies are 7.5% hydrochloric acid and 1.5% hydrofluoric acid. In addition some ammonium bifluoride may be added to increase the effectiveness. Mud acid is used because it can also dissolve sand and clays. The fine clays in drilling mud were added to prevent drilling fluids from flowing into the formation by forming a filter cake. However, some of the clay goes into the formation and can cause severe plugging. The mud acid is frequently used in the original well completion to remove these solids. However, it is also used later in the life of the well to remove fine sand or clay particles in the formation that may have migrated towards the wellbore and are blocking flow paths.

Mud acid treatments always involve a series of fluids, similar to that described above. Calcium fluoride is quite insoluble so it is necessary to prevent the mud acid from contacting a formation or formation water containing calcium. A typical sequence includes a 3-5% ammonium chloride preflush, followed by 5-15% hydrochloric acid. This acid dissolves any solid calcium carbonate, etc. A second ammonium chloride flush pushes this acid and dissolved calcium further into the reservoir, separating it from the mud acid slug which follows. A final postflush solution of ammonium chloride or 3-5% hydrochloric acid pushes mud acid back for more efficient utilization of the fluoride. The spent acid and associated fluids are produced back in the same manner as described for hydrochloric acid.

Other Acids. Acetic, formic and citric acid are sometimes used in acidizing. The citric acid may actually be added to any of the acid systems to act as a chelating agent to keep dissolved iron in solution. The first two acids are being used in wells completed with duplex alloy tubing for corrosion resistance. These alloys may be subject to chloride cracking failure at high chloride concentrations, especially under acid conditions at high temperature. Since both of these acids are weaker than hydrochloric acid, they will react slower with carbonates or corrosion products. Slower reaction rates may be an advantage at very high downhole temperatures to allow the acid to penetrate further back into the formation.

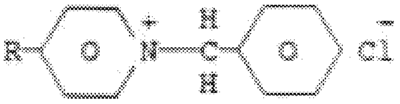
Additives. Additives other than corrosion inhibitor are only used when tests or experience indicates that specific problems are likely. Most have the potential of causing problems as well as preventing them. Obviously all will add to the cost of the acid job.

Corrosion inhibitors for acids will often consist of a mixture of types of *compounds*. Acetylenic alcohols, such as propargyl alcohol ($CHCCH_2OH$) or alkyl substituted derivatives, are a common component. Alkyl pyridine quaternary ammonium *compounds* are also used. The strong acidity may limit solubility of some of these components, requiring a dispersant. Alkyl phenol ethoxylates or other surfactants may be used for this purpose.



$$HC{\equiv}C{-}\overset{H}{\underset{H}{C}}OH$$

Propargyl Alcohol



Alkyl pyridine benzyl ammonium chloride

Solvents can be used to dissolve paraffin or asphaltene deposits, allowing faster acid attack. Both aliphatic and aromatic hydrocarbon solvents are used, depending on the nature of the deposits. These solvents and deposits usually go into the pipeline with the oil, with virtually no carryover into the water discharge. Mutual solvents, such as oxyalkylated alcohols and ethylene glycol N-butyl ether, are also used on occasion. Some of these solvents will partition into the water phase.

Anti-sludging agents are primarily intended to prevent any hydrocarbon solids from being generated. Sludging is more likely to be encountered in heavier asphaltic crudes. [f some solids are formed, these agents are intended to keep them highly dispersed. Oil soluble long chain alkyl benzene sulfonates are one type of *compound* used for this purpose. These formulations can include hydrocarbon solvents, alcohols, and surfactants in proprietary formulations. It is likely that some components could be partitioned into the water. Paramn control is a similar problem, with ethylene vinyl acetate resins being used to prevent deposition.

Surfactants can be used for these same purposes but can lead to severe emulsification of the oil and treating fluids, potentially throwing both oil and water streams out of specification. Selection of the specific surfactant can minimize the problem, with fatty acid ethoxylates being one type of *compound.* [t is not uncommon to add a second demulsifier chemical to offset the emulsification. The demulsifier may be added with the acidizing fluids or into the returned fluids at the surface, depending on various circumstances. The same types of *compounds* are used as discussed for production treating chemicals.

Scale control agents are also used to prevent inorganic problems. Citric acid or ethylene diamine tetraacetic acid (EDTA) are used to prevent reprecipitation of iron compounds. Scale inhibitors like those used for produced fluids keep the calcium in solution. Clay stabilizers are used to stabilize clays, preventing swelling and permeability reduction. Water solutions of potassium, ammonium or aluminum salts are used. Longer term stabilization can be obtained with poly quaternary ammonium *compounds*. Dispersants are used to keep solids from aggregating and aid in their return. Fatty amido amines and propoxylated amines have been used for this purpose.

Acid diverters are used to improve the efficiency of the acid. Most of these are some form of an oil soluble resin. These finely dispersed solid particles are carried down with the acid, progressively blocking the more permeable streaks. This forces the acid into less permeable layers of the producing formation. Many of these resins are based on terpene. When the well returns to production, the oil dissolves the resin and restores the permeability. Recently foamed acid has been used. The foam reduces the hydrostatic head and may prevent fracturing of some reservoirs. The foam is more viscous, which helps divert some of the acid to less permeable streaks. Alkyl phenol ethoxylates and fatty alkyl quaternary ammonium salts are used as foaming agents.

DENSE BRINES AND ADDITIVES

Chloride Brines. Seawater has adequate density (8.5 pounds per gallon, ppg) to contain formation pressure in many cases and is used wherever possible. Seawater is also used extensively to flush residual mud or solids from the well. As greater density is required in workovers other brines are used. [n most instances the brines are brought to the platform as liquids. However solid sodium chloride and calcium chloride are often available for making minor adjustments to the concentration and density. Solid sodium chloride can be used for small density increases for seawater but mixtures with liquid sodium chloride solutions are more common.

Sodium chloride brines are available up to about 10 ppg and are the most widely used purchased brine. [n addition to use as completion and packer fluids, they also are used for special purposes. Solid sodium chloride particles can be added to saturated sodium brine to act as fluid loss control agents.[34] [n contrast to clay and barites used in drilling muds, the salt crystals will readily dissolve in produced water when the well is returned to production. Thickening agents (viscosifiers) can be added to improve the suspension of sand during gravel pack operations.

Calcium chloride brines provide densities up to about 11.5 ppg. Ideally these brines would only be required when densities between 10 and 115 ppg are required. Practically some operators use calcium chloride more extensively because of the uncertainty during planning as to whether 10 ppg will be adequate. One operator used calcium chloride as a standard for all wells if densities greater than seawater density is anticipated.

Potassium or ammonium chloride salts are used to minimize clay damage. Straight potassium chloride (to 9.7 ppg) may be required for especially sensitive formations, but is more expensive than sodium chloride. Often a few percent of either salt is added to other brines to obtain clay stabilization at a more moderate cost.

Bromide Brines. Calcium bromide is used for the next increment of density, up to 15.4 ppg. Because of its higher cost, these brines will often contain considerable calcium chloride. Less chloride salt can be included as the density requirement increases.

Zinc bromide is capable of the highest density, up to 19 ppg. However it is also the most expensive and can be corrosive.[35] Zinc is also classed as a hazardous substance by the EPA, requiring special handling. Fortunately only a very few wells require use of zinc bromide. Even then it is virtually always used in mixtures with calcium bromide, sometimes calcium chloride too. The operating companies surveyed normally used brines containing zinc only as completion or workover fluids. This zinc brine is then displaced with a lower density brine to be left as a packer fluid and returned to shore for reconditioning. One operator indicated that only two wells had required zinc in the last several years, none in 1988. However, other operators do use packer fluids containing zinc.

Sodium bromide (to 12.4 ppg) and potassium bromide (to 10.8 ppg) are especially useful when the formation contains high concentrations of sulfate or bicarbonate ions. Potassium may be required if sensitive clays are present.

Brine Additives. The variety of additives used with workover fluids can be grouped according to their function.

Corrosion inhibitors are added by most operators. For the lighter sodium chloride brines, water soluble *compounds* similar to the production treating chemicals can be used. A sulfite oxygen scavenger is also commonly added. Biocides may also be added. The heavier calcium and zinc brines are more difficult because few of the above *compounds* are soluble in 30-60% calcium brines. Thiocyanate, thioglycolic acid and derivatives have been used. Since calcium sulfite has limited solubility one supplier has a substituted carbohydrazine for scavenging oxygen.

Fluid loss control with completion and packer fluids is a different problem than with drilling fluids. Any materials added to reduce fluid loss to the formation must be easily removed. Otherwise a major advantage of brines will be lost. The use of solid sodium chloride has already been mentioned. A fine dispersion of calcium carbonate powder is also used, but requires acid stimulation as the final step of the workover to obtain maximum well productivity. In both instances the object of the suspended solids is to deposit an impermeable filter cake on the surface of the formation. The filter cake prevents loss of expensive completion/packer fluid and avoids damage to the formation.

Viscosifiers are used to increase the ability of the brines to suspend solids. These suspended solids may be the fluid loss agents above or debris being circulated from the well. However, a major use is for suspending a graded gravel/sand mixture being pumped down in a gravel packing job. This mixture must be properly placed at the formation face to prevent fine sand and clay from being produced from the formation. If the gravel and sand become mixed during the pumpdown stage, the job has less chance of success. HEC (hydroxyethyl cellulose), guar gum, and polysaccharide derivatives are used. Some synthetic polymers are required for higher temperatures.

ENVIRONMENTAL ASPECTS

GENERAL CONSIDERATIONS

Prediction of Environmental Impact. The prediction of the impact of discharge of any stream on the receiving environment is an extremely complex problem. The environmental section of this report will be directed towards properties of chemicals and aspects of their use in offshore operations which will be pertinent to determining environmental impact. This report will not discuss the impact itself nor conditions past the end of the discharge pipe, except for the following brief comments.

Any prediction of environmental impact must characterize the discharge stream and the receiving environment. Both requirements are particularly demanding for discharge of produced water from offshore platforms into the ocean. The produced waters, including the added treating chemicals, are highly variable. Formation water compositions are different and treating chemical requirements are not constant. The nature of the hydrocarbon and the relative water/hydrocarbon ratio also affect the fraction of the chemicals that will remain in the discharged water. Similarly, the relevant characteristics of the ocean are constantly changing. Winds, currents, salinity, dissolved oxygen, etc. are variable. The major study at the Buccaneer Field offshore Texas is an example of the effort required.[36]

Laboratory Toxicity Testing. Laboratory testing of the effects of constant concentrations of chemicals on specific organisms, either in static or flow through tests, allows investigators to learn much about the relative effects of the chemicals and relative susceptibility of various species to the chemicals. Conditions must still be closely controlled to improve the statistical reliability of the results and allow meaningful comparisons between different test results. Direct extrapolation of results of static tests to other organisms, chemicals, and environments is often not feasible and can be misleading. Nevertheless, useful results can be obtained.37

Acute aquatic toxicity tests are the most common laboratory evaluation. Test organisms of a chosen species are exposed to several different concentrations of the chemical. The number of surviving organisms is determined after prescribed intervals, e.g., 3, 12, 24, 48, 96, 168 hours. Results are analyzed statistically to determine the toxicity of the chemical to the organism. The most common reporting parameter is the LC50 for 96 hours, the maximum concentration at which half of the test organisms will survive for 96 hours. In general, half will survive longer at concentrations lower than the 96 hour LC50. Conversely, at higher concentrations half can only survive for shorter times.

Round robin testing[38] by three governmental, three commercial, and three industrial laboratories has shown that good reproducibility can be obtained for acute aquatic toxicity testing if a clearly defined protocol were strictly adhered to. A ratio of *only* 2.6 between maximum and minimum indicated LC50 values was obtained for the effluent for the species tested. The use of different protocols is probably a major cause of the variability in the aquatic toxicity data presented later in this report.

It is widely recognized that short term acute toxicity tests and observations can not totally assess the long term effects of particular contaminants or variations on the environment. Longer term factors include sub-lethal chronic effects on particular specimens or subsequent generations of the species. Longer term chronic toxicity testing involves observations on species exposed to the altered environment to detect changes, sometimes after several generations. Rigorous determination of chronic toxicity of a single pure chemical compound on single species is both time-consuming and expensive. Definition of the combined effects of the range of commercial *compounds* and natural constituents on the wide range of species in a highly complex and variable ecosystem such as the Gulf of Mexico would be a challenging and difficult task. It does not appear that such a massive effort is justified nor would it result in any significant improvement in the environment. Kimerle[39,40] has studied many acute aquatic toxicity test results for various chemicals, species, and toxicological tests.

Solubility. Solubility of the various chemicals in water and/or oil is an important property in use as well as in testing. In fact, definition of solubility and development of meaningful test procedures were matters of serious concern with the specialists interviewed in both supplier and operating companies. While test methods are beyond the scope of this paper, some aspects are pertinent to the interpretation and applicability of the data. Experienced chemists can make reasonable semi-quantitative predictions of the solubility or distribution of pure compounds between an aqueous and liquid hydrocarbon phases. However, behavior of impure mixtures is very complicated. Most commercial formulations are complex mixtures of solvents and homologues of one or more *compounds.* For example, what is the effective solubility (or distribution coefficient) of such a formulation if the 15% isopropyl alcohol primarily goes into the water phase and the 35% imidazoline corrosion inhibitor plus 50% naphtha solvent primarily goes into the oil? Distribution between phases of the components in a formulation will probably be a function of dosage. It certainly will be affected by the compositions and ratios of the oil and water phases.

The effects of these kinds of factors on testing of biodegradability of insoluble chemicals have been called into question by Boething.[41] He suggested that variability in procedures for adding and dispersing insoluble chemicals can significantly affect test results. While Boething was primarily addressing biodegradability, it would appear that his concerns would also be applicable to aquatic toxicity testing.

Chemical characterization. Characterization of the specific chemical compounds and/or functional groups responsible for toxicity is highly desirable. Identification might *allow* objectionable components to be eliminated from a formulation without sacrificing the functional objective. In addition, more complete chemical characterization and pertinent analytical methods would be very useful in refining cause/effect observations in site studies.

Biodegradability. The tendency of a chemical to accumulate in the environment is its persistency. Conversely, destruction of the chemical by biological mechanisms is called biodegradation, which can be roughly measured by biochemical oxygen demand tests (BODs). Data presented by Robichaux for biocides (see Table 5) indicated that all were degraded to near 100% of theoretical within five days, with the exception of the chlorinated phenols. The latter are no longer used because of this poor biodegradability. BODs data were available for many of the specific formulations in Table 6 for company B. Many of the formulations were nearly 100% degraded within five days, with most of the remainder being consumed within 20 days. Three emulsion breakers exhibited the poorest biodegradability, perhaps reflecting Boething's[41] concern about testing of insoluble chemicals. However, it is important to remember that these oil soluble materials go to the oil pipeline rather than being discharged to the ocean.

AQUATIC TOXICITY DATA

Production Treating Chemicals. An integral part of the discussions with the supply companies was concerned with aquatic toxicity data for the various kinds of chemicals described earlier. In general, only limited amounts of such data were available. The toxicity data summarized in the following tables were obtained on a wide variety of species, accounting for much of the variability in the data for any particular formulation. In addition, the testing protocols may not have been identical. Because of these factors, care must be taken in making direct comparisons between specific test results. These data are, however, useful in showing order of magnitude aquatic toxicity of the various treating chemicals. *All* concentrations in the data obtained from

Table 3. Acute Aquatic Toxicity Data (LC50) of Biocides (1,2)

Generic Type	Company	Generic Chemical Type	Fresh water				Salt water			
			Sheepshead Minnows	Bluegill	Rainbow Trout		Oysters	Shrimp		
Aldehydes		Glutaraldehyde (25%)		37.6	42.1	16.9*	2.1*	41	92	
				26.42	24.33	*)		1000)	65	(45l,75j)
		Glutaraldehyde (50%)		22.4	23.7	11.5*				
		Formaldehyde	41.9k							
			42k	37,840	680,230	180		3300,10000		100-330
Formaldehyde/ mixture	0	Formaldehyde+heterocyclic polyamine		41.4	73.3		2.9	338	>1000	
	0	Formaldehyde+alkyldimethyl benzyl quat		1.79	2.34		0.47	12	290	
	0			1.51	1.41		0.28	7.6		
Quaternary		Ethoxy quaternary		0.76	1.32		28	1740	1000	
		Di cocoamine	0.55,0.42k	0.7	9**			240	0.40	1.21,0.55e
				0.3				40		*)
Amine Salt	0	Cocodiamine acetate		0.88	1.6	0.11		4.20	99.6	1.11,0.49e
	C		0.448	0.822			0.71'	2.39a		
				0.65	0.66	0.44*	55j	11.'C	79	
	0	Cocodiamine fatty acids		0.73	0.92		0.32	12	670	
		1 alkyl (C6-C18) amino-3 aminopropane acetate		0.65	0.34		184	31.7C	1ll	
		1 (alkyl amino)-3 aminopropane acetate		0.7.	0.91	0.26*	422	24	.0	
		Coco propane diamine hydroxy acetate+ Trichlorophenol		1.35	1.61					
		N-Coco-1,3 propane diamine benzoate	1.0			0.09				
	0	Alkyl propylene diamine+2 ethylhexanol		0.71	0.75				49	
Other		Metronidazole		>1000	>100			1800		
		1,1-Dibromo-3-nitrilopropionamide	0.151	*9		4.5*	2.8-5*	90,37.3c	70	>1000g,100n*
	C	Dithiocarbamates	1.29					1.38b		
	C	Isothiazalin	40.6				66.1	217a		
	D							81	4000	
	1	2,4,5-Trichlorophenate		1.26	0.86					
References NOT USED IN PRODUCTION OPERATIONS		Bis tri-n-butyltin oxide. alkyl dimethyl benzyl quaternary		0.046	0.046					
		Toxaphene pesticide		0.042	0.036					

NOTES:

(1) Concentration (ppm, as sold) for 50% survival for 96 hours, except * are for 48 hrs. Direct data comparisons may not be valid because of different species, strains, and/or test protocols.

(2) All data are unpublished and were furnished by the participating chemical supply companies.

a - White Shrimp
b - Brown Shrimp
c - Grass Shrimp
d - Mysid Shrimp
e - Sheepshead Minnow
f - Large Mouth Bass Fingerlings
g - Asiatic Clams
h - Brackish Water Clams
i - Plaice
j - Stickleback
k - Fathead Minnows
m - Flounder
n - Atlantic Salmon
o - Channel Catfish
p - Armed Bullhead
q - Green Sunfish

vendors in this report are presented on an "as sold" basis (Tables 3, 6, 7). The concentration basis in Tables 4 and 5 is not known for certain. Because considerable attention has previously been focused on the biocides, they will be discussed separately.

Biocides. Information obtained directly from the suppliers in this survey is shown in Table 3. The widely used aldehyde class of compounds exhibited relatively high LC50 concentrations compared to the other biocides. Mixtures of other types of biocides with formaldehyde are common and appear to reduce the LC50 values to the same range as the added biocide. It should be noted that many of the salt water toxicity tests were run on shrimp, crabs, and oysters only. In a few cases where data also included fish species, the fish appeared to be less tolerant of the biocides. The quaternary ammonium and amine salts are significantly more toxic to fresh water species than the aldehydes or the other biocides used in production operations. As a comparison, two materials not used in production operations are also listed. The toxaphene pesticide is included as a reference test material by some laboratories as a control reference pollutant. The tributyltin/quaternary is sometimes used in closed loop cooling systems.

Table 4 is taken from Zimmerman and deNagy,S summarizing acute toxicity and four chronic toxicity data for several biocides used in oilfield applications (production and/or drilling). Note that their concentrations are in ppb (parts per billion), not ppm (parts per million) or ppb (pounds per barrel, a common drilling fluid unit). Other data in their paper plus information from companies interviewed in this survey indicate that the various forms of thiocarbamates and bis (tributyltin) oxide are not widely used in production operations. Glutaraldehyde, formaldehyde (and paraformaldehyde), various quaternary ammonium salts, amine salts, and mixtures of these are far more common. Acrolein has been used in some applications but its use is apparently decreasing. It is significant to note that these "production" biocides generally have higher aquatic toxicity LCSO values than the thiocarbamates which apparently are more common in drilling operations.

In 1975 Robichaux[42] reported the aquatic toxicity of some biocides used in drilling and completions (Table 5). Some of these generic chemical types are similar or identical to those used in production operations.

Generic Chemical Type	LeSO * Salt water
Aldehydes	50-400
Chlorinated Phenols*·	0.2-'
Quaternaries	0.2-5
Amines	0.4-4

* Concentration (ppm, as sold) for 50% survival for 96 hours. Data on fish, shrimp, crab and oyster species. Direct data comparisons may not be valid because of different species and/or test protocols.

** Not used in offshore production operations in U.S. since early 1970s. CMM

Table 5. Aquatic Toxicity Data for Several Classes of Biocides

Direct and detailed comparison of acute toxicity **data between various sources and investigators can** be virtually meaniogJess unless species, temperature, procedures, etc. are similar and well defined_ Even with this reservation, the range of acute toxicity for the "production treating chemicals" in Table 4 is about 0.2-2 ppm. This range is about the same as the 0.2-1.6 range for fresh water found in this survey (Table 3) and reported by Robichaux (Table 5). The 2,2-dibromo-3-nitrilopropionamide (4-8 ppm) and formaldehyde (10-50 ppm) LC50 values are significantly higher. Much of the salt water acute toxicities were only determined on shrimp, crab and oysters. The LC50 values in the fish tests obtained in this survey were neither consistently higber nor lower than those species. The larval brown shrimp **were one of the most sensitive of the species tested** in the Buccaneer Field study, which also included fish.

Other Production Treating Chemicals. The available data on other types of production treating chemicals from the suppliers interviewed are summarized in Table 6. While essentially all of this data was accumulated on specific formulations, many of the formulations contained only a single type of *compound* as an active ingredient. However, solvents and minor additives in the formulations can result in substantially different solubility characteristics and correspondingly large effects on aquatic toxicity. Hence, this data is insufficient to draw finn conclusions on absolute toxicity of the various types of generic *compounds* discussed earlier. There are some gross differences and trends, however.

First, LC50 (96 hour) values for most of the production treating chemical formulations in Table 6 are substantially higher than those values for biocides in Tables 3, 4 and 5. While the same **reservations on comparisons of aquatic toxicity** data are still applicable, some of the corrosion inhibitors and the water soluble polyamine quaternary ammonium coagulant are clearly in the same fresh or salt water toxicity range as the quaternary ammonium and amine biocides.

Second, all of the other production treating chemicals are about one to three orders of magnitude less toxic.

Third, available data is insufficient to represent all *compounds* and combinations of *compounds* in the multitude of formulations used for various purposes in offshore production operations.

Gas Processing Chemicals. Aquatic toxicity data for the chemical compounds used in hydrate control and dehydration obtained from the literature and from one supplier are given in Table 7. It is readily apparent that these chemicals are relatively nontoxic, with LCSO values of 10,000 ppm (1%) or more being common. In fact, these compounds are often used in aquatic toxicity testing to aid in dissolving materials with limited water solubility.[43] It is very unlikely that discharge concentrations of this order of magnitude would ever be encountered in offshore operations. Methanol added to any one well during a startup would be diluted by produced water from other wells prior to discharge. However, one area of particular concern to the operating companies is the potential use of methanol for hydrate control in deep or northern waters where the water is always cold. Continuous methanol addition could be necessary, especially if the subsea flowlines were long.

Table 4. Aquatic Toxicities and Recommended Application Concentrations for Chemicals in the Host Uidely Distributed Biocides in Calendar Year 1981 *

CHEMICAL NAME	LOWEST REPORTED 1 ACUTE TOXICITIES (ppb) **	LOWEST REPORTED : CHRONIC TOXICITIES (ppb) **	RECOMMENDED APPLICATION CONCENTRATIONS
Paraformaldenyde	2.000 fl		0.5 to 1.0 lb. per barrel (595-1200 ppm) continnous 0.1 to 0.25 Ids/barrel (120-300 ppm)
Acrolein[2]	55 MI 68 ff	100 MI 21 FF	Initial dosage - 10 ppm. Continuous treatment - 1-15 00H
Clycollc acid	No data available	No data available	
Glutaraldehyde[J]	2,tao MI		Siuo treatment - 500 ppm, continuous treatment - 30 ppm
Oxydiethylene bis (alkyl dimethyl 3 ammonia chloride)	No data available	No data available	SluO treatment - 500 ppm. Continuous treatment - 30 ppm
1_(alkyl a.lnol-J a.lnoorooane acetate	340 FF 120 FI		
3-alkoxy-2-hydroxypropyl trimethyl ammoni.. chloride	350 MI 980 FF		Waterflood & salt water disposal systems - 50-100 ppm continuous at Ilrst. Follow-up with 10-15 ppm continuous to maintain control. May also be led intermittently at a rate of 50-200 ppm lor 4-8 hrs. a day, one to lour times a week.
	127 MI	43 MI	1 pint to 1 quart per 1000 barrels (3-6 ppm).
Sodium dimethyl-dithiocarbamate[4]	127 MI		1 pint to 1 quart per 1000 barrels ()-6 ppm).
1_(alltyla.lnol_ 3-aminooropane[5]	No data available	No data available	
Potassium N-methyldithio-carbamate	180 fF 182 fI		Slug treatment 1.5 to 3 II. oz. per 1.000 gal. (It 7_2) POHD. Subsequent treatment 01 0.5 to 3.0 II oz. per 1,POO gal. (4.0 - 22 pp.) should be made every 1 to 5 days.
01sodium cyanothioimido-carbonate	180 ff 182 FI		Slug treatment 1.5 to 3 II. oz. per 1,000 gal. (11.3 - 23 ppm). Subsequent treatment of 0 5 to J.O II. oz. per 1.000 gal. (4.0 - 23 ppm) should be made every 1 to 5 days
2-(thlocyano-methylthlol Denzoth'azole	29 FF		for secondary recovery: 0.1 to oz. per 1.000 gal. (3-30 ppm). For drilling mud: to 0.25% 01 total volume 01 material.
1-(alkylamino)_ 3-a.ino propane adipate	300 FF 250-160 MI		for secondary recovery: initial treatment use 6.3 to 25.4 II. oz. per 1,000 gal. (23-94 ppm a.i.) Subsequent treatment: use 1.3 to).2 II. oz. per 1.000 gal. 5-12 ppm a.i.
Potassium dimethyldlth10_ carbamate		3.8 MI	for secondary recovery: 0.83 to 1.66 II. oz. per 100 barrels (6-IJ ppm). For drilling mud: O6 to J.O 01.1 per 100 barrels (143-714 ppm).
2,2-dibromo-J-nltrilipro-pionamide			Continuous feed initial treatment: use 1 to 2.2 II. oz. 01 product per 1.000 gl. 01 water (2_16 ppm a.I.J Subsequently, use 0.' to 1.3 II. oz. of product per 1.000 gal. (0.1 -) ppm a.i.). For intermittent treatment: 2-16 ppm [illegible] For slug treatment 40 ppm [illegible]
Acetic acid	No data available	No data available	
Alkyldiamine-monobenzoate	No data available	No data available	
8ls(tributyltln) oxide	0.96 MF		

* Entire table Is from Itelerence 5. Zimmerman, E. and deNagy, S.. -8i0cides In use on Offshore 01l and Gas Plattorms and Rigs". EPA Draft paper. April 11 1984.

ppb Is parts per billion, presumably by weight. CMH

Toxicity data lor: fI - Freshwater invertebrate MI _ Marine invertebrate
FF - Freshwater Fish MF - Marine Fish

Documented impacts to fish and divers from the discharge 01 this chemical durlno the Buccaneer Field study.

Chemical in use on oUshore platforms based on 30 platform study in the CUll 01 mexico.

Chemical approval for use on production platform In Alaska requested Iro.. Reg. x by manufacturer.

Chemical in use on drilling rlos and platforms based on 74 well survey in Gulf 01 mexico.

Table 6. Acute Aquatic Toxicity Data (LC50) of Other Production Treating Chemicals (1,2)

Purpose	Company	Generic Chemical Type	Fresh water: Sheepshead Minnows	Fresh water: Bluegill	Fresh water: Rainbow Trout	Fresh water: Daphnia	Salt water: Oysters	Salt water: Shrimp	Salt water: Stickleback Others
Scale Inhibitor	A	Amine phosphate ester		>1000	>1000				
	C		>4309				>4309	>4309a	
	f			>700					
	f	Phosphonate						5350b	
	C		>10125				>10125	>10125	
	f		6027					2970c	
	f							1676a	5600k
	f					>200			
	O								1200
Corrosion Inhibitor		Amide/imidazoline	75h					300	500i
			7.37				52.6	5.18a	
			6.74				26	2.42a	
						52			
								50.00,617c	
								3.03b	
								23.90	
								2.12b	
		(2)				0.26			
	f	+ quaternary		1.3				1050b	
	C	Quaternary (water soluble)		1.50	2.80				
	f	Alkyl aryl ammonium salt+cyclic amine						5.96b	
	f	Alkyl aryl ammonium salt+alkyl amine						116b	
	C	...ine salt (water soluble)	0.86				.89	2.85a	
	f	Alkyl amine salts						7.30b	
	f	Alkyl amines + alkyl acids						1.98b	
	f	Cyclic amine + poly ether						2.69b	
	f	Cyclic amine, vinyl copoly_r						3.15b	
	C	Sulfonate						2200	
	f	Phenanthradine	6.1n						
	⊗	Aromatic heterocycle	6.1n						
	⊗	Pyridine salt + quaternary	2.16 2.26n						
	f	Alkyl morpholines						800, 10550	
	⊗	Quaternary+organosulfur+phos. ester	12n						
	⊗	Ammonium bisulfite	11	130					100-420
	C						77	788a	
	O	Sodium sulfite			7000				
Reverse Breaker	f	Cationic polyelectrolyte+metal salts		4.88		1.2			56
	C	Polyamine ester + zinc salt							1010i
	C	Polyacrylate	16713				15621		
	⊗	Cationic polyelectrolyte		1.1		1.2			56
Coagulant		Polyamine ester						>1000c	>1000k
		Polyacrylamide						148000	
		Phosphate ester						18000	
	⊗	Polyamine quaternary		0.52					
	C	Polyquaternary						21.01	
	O	Higher alcohol modified fatty acid			50				
	O	Tributyl phosphate							
Surfactant		Oxyalkylate							5.6g
	C		19				10		
	C		111				78.1		
	C		111				89.?		
	f	Alkoxylated phenol		.80					58.?
	f		75.0h			10			41
	f	Cationic (quaternary)						40.00	
	O	Glycol ether	183						
H_2S scavenger	C	Chelated zinc	243					235	
Atmos corr inh	C	Over-based calcium sulfonate	2290					>2635	

NOTES:

(1) Concentration (ppm, as sold) for 50% survival for 96 hours. Direct data comparisons may not be valid because of different species, strains, and/or test protocols.

(2) Low molecular weight.

(3) All data is unpublished and was furnished by the participating chemical supply companies.

- White Shrimp
- Brown Shrimp
- Grass Shrimp
- Pink Shrimp
- Mummichog

Stickleback
Bull Minnows
Fathead Minnows
Plaice
Fiddler Crab
- Mysid Shrimp

CONTINUED

Table 6. Acute Aquatic Toxicity Data (LC50) of Other Production Treating Chemical' (1.2)

· · · CONTINUED · · ·

			Fresh Water				Salt Water		
Purpose	Company	Generic Chemical Type	Sheepshead Minnows	Bluegill	Rainbow Trout	Daphnia	Oysters	Shrimp	Stickleback Others
Emulsion Breaker	B	Oxyalkylated dipropylene glycol			40f				
	B	Oxyalkylated phenol formaldehyde resin		24		80		3.8c	28,19.4j
	C	"	5.26					3.24b	
	C	"						5.4c	6.7e
	B	"							40.0
	B	"		24.0				3.8c	28.0
	}	"						3.56b	
	}	Phenol formaldehyde resi" + polyethers			}88				
	}	Phenol formaldehyde resin			16.0				
	}	"			25.4				
	B	Alkyl aryl sulfonate		}00		""}00			18
Paraffin Inhibitor	B	Not provided		17		25-44		13.3C	32,37.4j
	B	Not provided	39.9n			32.2			
	B	Vinyl polymer	42.0					2.7k	
	B	Sulfonate salt		11.0		25.1			37.4j
	}	Alkyl polyether + aryl polyether						,.55b	

NOTES:

(1) Concentration (ppm, as sold) 10' 50% survival 10' 96 hours. Direct data comparisons may not be valid because of different species, strains, and/or test protocols.

(3) Low molecular weight.

(4) Al data is unpublished and was furnished by the participating chemical supply companies.

a _ White Shrimp
b _ Brown Shrimp
c ~ Grass Shrimp
d ~ Pink Shrimp
e _ Mysid Shrimp
f ~ Stickleback
g · Bull Minnows
h · Fathead Minnows
i · Plaice
j _ Fiddler Crab
k - Mummichog

Table 7. Acute Aquatic Toxicity Data (LeSO) of Gas Treating ChemicaLs *

			Chemical Concentration mg/liter							
			Fresh Water					Salt Water		
Chemical Name	Purpose	Re	Sheepshead Minnows	Bluegill	Rainbow Trout	Daphnia	Others	Oysters	Shrimp	Others
Methanol	Hydrate Inhibitor	44	4000a.0.1	17000a,100.1	8000.2	>10000,2			10000m.1	
		45							120000	2a0000
		81								>200000
		47	>100 1	>1000		>100				
Ethylene Glycol	Hydrate Inhibitor	44	5000f,1							
		48				50000,1	10-200000			
		49	>10000			>10000,2			>20000,2	
		H	>10000e			>10000,2	>10000g			
		H					49300h			
Diethylene Glycol	Hydrate Inhibitor			>5000,1	>32000c,1					
Triethylene Glycol	Dehydration	44	>5000f,1							
		43							>1000n,23	>1000r,28
		H	>10000e			>10000,2	62600n 7			

Data are from the literature, references at the end of the report, except for that contributed by participating chemical supplier H.

NOTES:

TOXICITY data are LC50, 96 hr EXCEPT

} } day, 24 hr test conc '()' 0% fatalities
} } day, 48 hr test 100 Conc '()' 100% fatalities
} } day test
23 23 day test
28 28 day test

EXAMPLE. 5000l 100.2 l, 2 day test **in goldfish. 5000 ppm caused 100% fatalities.

SPECIES are identified by letters

FRESH	BRINE
a - Creek chub	- Brine Shrimp
b - ceriodaphnia d/a	n ...ysid shrimp
c - Mosquito fish	o _ Copepod
d 5 other species	Bleak
Fathead m'noo_s	J gastropods
Goldfish	Silversides
Sewage bacteria	

Stimulation and Workover Fluids. Essentially no data were obtained on the aquatic toxicity of any of the stimulation or workover fluid chemicals. The various companies contacted indicated that neither they nor their suppliers had run any such tests. No useful data was found during the literature search. A limited amount of pertinent data were included in a recent summary of toxicity of drilling fluid additives50. These data were taken using the protocol specifically designed for drilling muds (40 CFR 435, 26 Aug. 1985) and the concentration basis and results are not comparable to data presented in this report. Those materials likely to be used in completion or packer fluids appeared generally to have LC50 values well above the 30,000 ppm limit applicable to drilling muds and that protocol, indicating they are environmentally acceptable.

PRACTICAL ASPECTS

System Effects. The fraction and concentration of various chemicals in the effluent water depend on several factors. For example the point where a production treating chemical is added is important. Corrosion inhibitors added to gas pipelines are carried to shore and removed at the processing plant, usually being sent to disposal wells. Scale inhibitors added to offshore water treating equipment will primarily be discharged with the water. The solubility characteristics of various formulations (while usually not precisely definable) are generally such that almost all of the formulation is expected to go either to the oil or to the water phase. Notable exceptions are low molecular weight alcohols and glycols added to oil soluble formulations (to provide low temperature protection and drum stability) which will normally partition into water.

Specifications on the water discharges and on oil sales pipelines affect the overall disposition of chemicals. Surface discharges of water are restricted to a monthly average of 48 mg/l total 'oil and grease", of which only a tiny fraction (e.g., 20-100 ppm in that oil) would be oil soluble treating chemicals. On the other hand, oil sales specifications usually allow 0.25-1.0% (2,500-10,000 ppm) water in the oil. Thus, more of a water soluble treating chemical can be carried with the oil. Furthermore, a significant (albeit unknown) fraction of the water soluble chemicals with surfactant properties will tend to collect at the oil/water interface in separators and in the skimmings or froth in the water treating equipment, usually being carried along as a part of the allowable water in the sales oil. The effective concentration of water soluble treating chemicals in this water is thus likely to be substantially greater than in the bulk water phase being discharged. Thus, less water soluble chemicals will be discharged than might otherwise be expected.

Production Treating Chemicals. The environmental aspects of the various types of production treating chemicals will be briefly summarized in the same order as presented earlier.

The required scale inhibitor concentration of 3-10 ppm is far below the LCSO values of 1000 ppm or greater. Although none of the operators contacted used squeeze treatments offshore, such treatments potentially could lead to initial high discharge concentration immediately after a treatment. The peak return concentration from a well conceptually could be the same as the injected concentration (2-10%). More likely it will be diluted by at least five to ten times by the flush water and by produced water from other layers within the same well. Thus, a peak slug concentration from a well would probably not exceed 1% (10,000 ppm) from the well, dropping rapidly to a few hundred ppm within a few days, depending on the producing rate. All of the wells producing into a single production separation system will not be squeeze treated at the same time. Hence, the combined discharge water stream will have a substantially lower concentration of scale inhibitor than from any individual well. Even a 10:1 dilution by other wells drops the peak concentration to the same level as the LC50 values. Continuing developments in squeeze technology, e.g., precipitation squeezes,21 allow longer treatment life with better chemical utilization (lower peak slug concentrations). It is apparent that discharge concentrations of scale inhibitors are below LC50 ranges.

Corrosion inhibitors exhibit a wide range of aquatic toxicity. The most commonly used inhibitors are predominantly oil soluble, with many having LC50 values of 20-500 ppm. This is equal to or greater than the normal continuous dosage of 10-20 ppm. However, others have LC50 values below 10 ppm and have greater potential adverse effect when discharged. Peak concentrations of 1000 ppm from batch-type treatments may be seen from individual wells but would be diluted by other wells. Furthermore, a large percentage of the inhibitor *compound* probably goes into the oil phase and is not discharged with the water. The lower molecular weight formulation in Table 6 is classed as oil soluble, water insoluble, and is primarily recommended for continuous addition into gas wells. Hence, its treatment concentration will be relatively low (e.g., 20-50 ppm maximum) and essentially all would go with the hydrocarbon condensate or produced oil. The phenanthradine formulation contains a surfactant to allow the concentrated inhibitor to be dispersed in water for treatment but only be oil soluble after application in the system (continuous injection in gas wells). The water soluble inhibitors are significantly more toxic, probably because they are of the same generic type as some of the biocides. However, these inhibitors are not applied as squeeze or slug

slug treatments. The ammonium bisulfite toxicity is probably totally due to the scavenging of all dissolved oxygen and would.be completely negated by a 1:1 dilution with aerated seawater at discharge. With the exception of the water soluble inhibitors, the combination of high oil solubility and low probable concentration indicates that most corrosion inhibitors will be near or below their LCSO values.

The biocides are the most toxic of the various types of production treating chemicals. The application concentrations for the commonly used formaldehyde and glutaraldehyde formulations are generally in the same range as the LC50 values in Tables 3 and 5 (10-400 ppm), although Zimmerman'sS values (Table 4) are significantly lower (2 ppm). Acrolein is more toxic but is also more reactive and can be neutralized with bisulfite prior to discharge[SI]. The chlorinated phenols (Tables 4, 5) are no longer used in U.S. offshore operations. Quaternary ammonium and amine salts have lower LC50 values than the aldehydes but can become deactivated by adsorption onto surfaces of suspended solids particles.[6] The remaining biocides (thiocarbamates, etc.) also had low LC50 values (Table 4) but constituted only about a sixth of the products in use in the Thirty Platform survey.[6] Because of high water solubility, relatively high concentrations during batch treatments, and probable treatment of the full discharge stream, it appears likely that discharge concentrations will equal or exceed typical LC50 values in many instances, although some of the biocides can be deactivated by solids or specific treatments.

Emulsion breaker toxicity data were provided by Company B for three formulations with a single generic *compound*. An alkyl aryl sulfonate showed an LC50 7-10 ppm for the species tested. The oxyalkylated phenol formaldehyde resin formulations showed 4-80 ppm, while the oxyalkylated dipropylene glycol had a 40 ppm LC50 for a fresh water species. Formulations from the other suppliers were in the same order of magnitude, even when mixtures of *compounds* were present. With a normal maximum treatment rate of about SO ppm (based on oil) and at least 90% going with the oil, only 5 ppm or less of the total formulation would be carried over into the water. This concentration is at or below the LCSO for most of the available data.

Reverse breakers, coagulants, and flocculants are similar in chemical composition and application. The limited toxicity data indicates that LC50 values are relatively high in comparison to use concentrations (1-10 mg/l) except for the polyamine quaternary ammonium formulation. Ironically, that specific formulation is also approved for use in municipal water treating plants! All three types of chemicals are expected to aggregate on the surfaces of oil droplets or solid particles in flotation cells and will tend to be carried with the oil skimmings or froth and be recycled to the oil streams. The concentration of chemical in the effluent water will be substantially reduced. In fact, if more oil or solids were redispersed in the same water, another dose of chemical would be required to achieve separation again. The concentration of chemical is apparently too low to be effective. Aluminum and iron salts are the more commonly used inorganic agents with LCSO values (for the ions) of 10 and 21 ppm respectively for crustaceans4(p2Jl. Zinc salts are also used, with LC50 values of 0.1-60 ppm for a number of species[4(p234l]. Based on the relatively high LC50 values and the strong adherence to particles and oil droplets, discharge concentrations for most will be near or below their LCSOvalues.

Antifoam aquatic toxicity data were available for **two materials. The normal treating concentrations** 0.2-2 ppm in water, 5-20 ppm in oil) are lower than the LC50 concentrations for both of these formulations. Toxicity data were not available on the two classes discussed earlier. It was pointed out, however, that both the silicone and polyglycol ester generic compounds do have applications in the food processing industries.

Surfactants used in offshore cleanup operations are usually very similar chemically to those used in household detergents and other industrial cleaning formulations. The indicated LC50 values are mostly above 50 ppm (Table 6) for the two primary generic types. Since these materials are primarily used for required housekeeping and maintenance purposes, it is difficult to suggest a discharge concentration. **However, such uses are certainly not a continuous or** every day activity.

Paraffin treating chemicals, both inhibitors and solvents, would be expected to go with the oil. It is unlikely that significant quantities would be carried with the effluent water.

__Treatment/Toxicity Summary.__ **Treatment** dosages, system dilution ratios, and LC50 values of the various functional types of production treating chemicals have been presented. The variation of each of these factors has been discussed. Table 8 has been prepared to tabulate these variables, recognizing fully that it is a simplistic, general summary. The "discharge conc: is an estimated concentration range in the discharge pipe. The top group are all water soluble and expected to be primarily in the water phase. The biocides are the only type where the discharge concentration is likely to be above the LC50 values, and then only for periodic short durations. The corrosion inhibitors are the most complex type, as *compounds* and formulations are made to be water soluble, oil soluble, or mixed solubility / dispersibility. The water soluble *compounds* are most likely to resemble the biocides chemically. These inhibitors are most likely to be added to injection water or gas pipelines and not be discharged to the ocean continuously. The oil soluble corrosion inhibitors will be at or below the LC50 value, except possibly for short periods after squeeze or batch treatments. The predominantly oil soluble emulsion breakers and paraffin inhibitors will be at or below the LC50 values, except possibly for short periods after squeeze or batch treatments. The predominantly oil soluble emulsion breakers and paraffin inhibitors will be at or below their LC50 values in the discharged water.

Function Type	Use Conc. ppm	Discharge Conc. ppm	LC50 ppm
Scale Inhib	3-10 Normal 5000 Squeeze	3-10 50-500	1200->12000 90% > 3000
Biocides	10-50 Normal 100-200 Slug	10-50 100-200	0.2->1000 90% > 5
Reverse Breakers	1-25 Normal	0.5-12	0.2-15000 90% > 5
Surfactant Cleaners	??	??	0.5-429 90% > 5
Corrosion Inhib (1)	10-20 Water 10-20 Oil 5000 Squeeze	5-15 2-5 25-100	0.2-5, 90%>1 2-1000, 90% > 5
Emulsion Breakers	80 oil	0.4-4	4-40, 90% >5
Paraffin Inhib	50-300	0.5-3	1.5-44 90% > 3

(1) "Water" indicates a water soluble inhibitor, not usually squeezed or slug. "Oil" is mostly oil soluble. "Squeeze" is maximum concentration in returns after squeeze or batch.

Table 8. Rough Comparison of Usage, Discharge, and LC50 (96 hour) Values.

Overall Consumption Estimate. Unfortunately, data are not available on the total quantity of these various treating chemicals used in offshore operations. Most of the operating companies apparently do not summarize or report the amount of these chemicals used in their operations. The chemical supply companies are not always sure where their chemicals are actually being used. Hence, only rough estimates can be made for total chemical usage.

Two of the participating operating companies determined usage of production treating chemicals in their operations during 1988. As pointed out earlier, distribution of the chemicals between oil and water streams is an educated guess by the operating and chemical company specialists and the author. These data are summarized in Table 9.

While the absolute and relative consumption of the various types of treating chemicals will certainly vary between operating companies, the major uses are probably indicated with reasonable accuracy. Of the total estimated 1988 usage, only about 40% (138,070 gal.) are expected to be water soluble, with perhaps about a third actually going to the water phase. Only about 7,828 gal. of the estimated usage of 3,077,791 gal. are biocides, the chemical with greatest potential risk to the environment.

A substantial fraction of the material going to the water will be consumed in performing the specific function, i.e., corrosion inhibitors adsorbing onto steel surfaces, scavenger reacting with oxygen, biocide reacting with bacterial cells, etc. Thus, the overall fraction of treating chemical actually ending up in the discharged water will be about 25% or less, although the exact fraction is not known.

A total estimated 1988 chemical usage-for the Gulf of Mexico is also shown in Table 9. The operations covered by this specific data produced 8% of the gas, 11% of the oil and 17% of the water from 7% of the wells in the Gulf of Mexico. Since it is not obvious which percentage would be most appropriate for estimating the total usage, the average of the four (11%) was used.

The total estimated volume of 3,077,791 gallons of chemical purchased per year corresponds to about 8,432 gallons per day (gpd). About 3,439 gpd

Production Treating Chemical Usage

		CHEMICALS USED, US GALLONS			
COMPANY		1	2	SUBTOTAL	TOTAL
No. Wells		358	386	744	10,514
Oil Prod., mgpy*		554	847	1,401	12,554
Gas Prod., MMSCFD		876	218	1,094	13,466
Water Prod., mgpy*		1,799	2,114	3,913	23,029
FUNCTION	SOLUBILITY				Estimated*
Scale Inhibitor	Water	16,476	15,998	32,474	295,218
	Oil	0	0	0	0
Corrosion Inhibitor	Water	5,549	9,305	14,854	135,036
	Oil	36,880	28,090	64,970	590,636
Bactericide	Water	111	7,717	7,828	71,164
	Oil	0	245	24	2,227
Reverse Breaker, etc	Water	4,791	56,298	61,089	555,355
	Oil	0	8,660	8,660	78,727
Oxygen Scavengers	Water	0	0	0	0
	Oil	0	0	0	0
Surfactants, Cleaners	Water	19,290	2,162	21,452	195,018
	Oil	0	0	0	0
Emulsion Breakers	Water	0	373	373	3,391
	Oil	34,718	26,569	61,287	557,155
Paraffin control	Water	0	0	0	0
	Oil	54,145	11,180	65,325	593,864
Total Chemicals	Water	46,217	91,853	138,070	1,255,182
	%	27	55	41	41
	Oil	125,743	74,744	200,487	1,822,609
	Both	171,960	166,597	338,557	3,077,791

* Liquid production in millions of gallons per year. 1,000,000 BPD = 15,330 mgpy; 10,000 mgpy = 652,000 BPD

Estimated total chemical usage assumes companies' usage was 11% of total usage. See text.

Table 9. Production Treating Chemicals Used in the Gulf of Mexico during 1988.

goes into the water phase, with an even smaller volume (estimated 2,100 gpd) actually being discharged to the Gulf of Mexico. This volume of chemical is diluted with about 63,000,000 gpd of produced water, for an average discharge concentration of about 30 ppm. This total volume is distributed through many widely scattered discharge points.

Gas **Processing** Chemicals. Data on consumption of the gas processing chemicals were obtained from two companies, which had very different processing requirements. Company 1 processed very little gas offshore, perhaps less than 10% of the 320,000 MMSCF produced in 1988. Their consumption of 6,316 gallons TEG and 17,652 gallons of methanol is relatively low but meaningless without definition of the quantities of gas actually treated. Company 2 consumed 52,833 gallons of TEG in dehydrating 90% of their 79,500 MMSCF gas, or 0.74 gallons/MMSCF. This averaged about 11 gallons/day for each dehydration system, essentially all of which carried over into the gas to shore. None of their systems were changed out in 1988. Hydrate inhibition required 370,049 gallons of methanol to treat about 39,000 MMSCF, mostly during the cooler part of the year. This treatment rate averages just under 10 gallons/MMSCF.

It is not felt that the available data warrants any estimation of total consumption of gas treating chemicals. However, some significant observations can be drawn from the Company 2 data. It is apparent that the TEG losses to the gas pose little environmental risk. Even if all the TEG were carried into a proportionate amount of their produced water, it would only amount to 28 ppm, far below the LC50 of 10,000 ppm or more. Even the larger volume of methanol amounts to only 357 ppm if all were dissolved in 49% of the produced water. Again this average concentration is far below the LC50 values of 10,000 ppm or higher. Furthermore, a substantial portion of the methanol will end'up in the gas and oil phases, not in the water. Since the methanol concentration in the water must have been in the percentage ranges to provide effective inhibition, a high degree of dilution occurs prior to discharge. Obviously such generalizations and averages can be misleading, but the gas treating and processing are rather uniformly scattered throughout the Company 2 operations. It seems very unlikely that the gas processing chemicals will pose a risk to the environment, but use of methanol will require evaluation for platforms with little or no produced water to dilute the treated condensed water.

Stimulation and Workover Chemicals. Moore[9] recently compiled a summary of well service activity for the oil production industry in 1988. The survey provided a breakdown as to types of activities and geographical area. While it is difficult to be sure that the various classifications are consistent with those used by the participants in this current survey, Moore's data provides a solid basis for a reasonable estimate of total chemical consumption. Pertinent statistics from his summary are shown in Table 10. As noted, the offshore Alaskan data were not broken out.

It is apparent from Table 10 that over 80% of the offshore wells in the US are in the Gulf of Mexico, partial justification for the heavy emphasis of the area in this report. About 2% of the wells are being stimulated by acidizing each year, with another 2% being completed or recompleted. Most of the artificiallift repair work will be performed on gas lift wells, which usually does not require pulling the tubing or using brine kill fluids. Repair of tubulars (1-2%) will require pulling the tubing, but mayor may not require using kill fluids.

Acidizing chemical data were obtained from all four companies covering at least part of their operations (Table 11). The data covered operations of 1,666 wells in the Gulf of Mexico, or 16% of the total wells. The 145 acid jobs represents 56% of the total jobs reported by Moore. The 259 total jobs per year corresponds to about five per week in the Gulf of Mexico. The various concentrations and types of acids were converted to the equivalent volume of

WELL SERVICING ACTIVITY

	Gulf of Mexico	Offshore Calif.	Alaska[a]
Total Wells	10614	2090	355
Stimulation	259 (2.4)[b]	28 (1.3)	3 (1.6)
Completions	162 (1.5)	36 (1.7)	30 (8.5)
Artificial Lift Install, Repair	1401 (13.2)	180 (8.6)	53 (14.9)
Tubular Repair	91 (0.9)	44 (2.1)	5 (1.4)
Total Jobs % Wells	1917 (18.0)	288 (13.8)	86 (24.0)
Recompletions, Not included	320 (3.0)	24 (1.1)	3 (0.8)

a. Estimate only, based on 25% of wells and service offshore. Data not broken into offshore/onshore categories.
b. Values in parenthesis are percent of wells in region.

Table 10. Summary of Offshore Stimulation and Workover Activity in the U.S.

15% hydrochloric acid, based on available hydrogen ion. The conversion did not take density differences or chemical activity coefficients into consideration.

The total acid used in the Gulf in 1988 is estimated to range from 541,000 gal. based on number of jobs to 1,890,000 gal. based on number of wells. The average job was about 2,000 gal. Most of this acid will have been reacted downhole, but some small, unknown fraction will be discharged. Residual acidity is apparently not routinely measured by the operators. This spent acid will be commingled with produced water from other layers in that well and further diluted with produced water from other wells before it is discharged. The corrosion inhibitor would be partially adsorbed in the formation as well as being similarly diluted. It seems unlikely that small amounts of remaining acidity, the corrosion inhibitor, or the calcium and iron reaction products would cause any adverse effect. Larger amounts of unreacted acid could cause a significant temporary pH shift in the vicinity of the discharge.

Workover fluid usage was less well defined. The distinction between drilling and workovers as defined in this report does not necessarily match other definitions in the industry. Records for the operating companies apparently do not summarize the quantities of brines used for either. In many instances the brines used are mixtures, so purchases of specific materials may not be directly related to volumes used. Furthermore, dry salts are often added to purchased brines to make fine adjustments to density or compensate for dilution by produced water. Many wells only require seawater to contain the pressure.

ACIDIZING IN THE GULF OF MEXICO

Company/Area	1	2	3	4	Total
Number Wells	358	386	600	322	1666
No. Acid Jobs	19	19	80	27	145
% Acidized	5.3	4.9	13.3	8.4	8.7
Acids Used, equivalent gal. 15% HCl					
Hydrochloric	10741	46300	168000	4509	229550
Hydrofluoric	0	8363	61320	0	69683
Acetic	0	3660	0	0	3660
Total Acid	10741	58323	229320	4509	302893
Average Job	565	3070	2867	167	2089

Table 11. Summary of Acids Used in Stimulation in the Gulf of Mexico

It is not felt that the data are sufficiently defined to make any estimates of total consumption. Yet some significant conclusions can be drawn from the information submitted by three companies. Company 1 purchased only 44,683 gallons total brines for their 358 wells, but noted that seawater was adequate for most workovers. Company 2 provided data on amounts of purchased chemical and number of jobs (28 on 386 wells) involving the brines (Table 12). Company 3 provided estimates on the approximate number and types of chemicals used for an average size job (8400 gal.) in an average year (85 jobs on 600 wells); zinc salts had apparently only been used on one or two wells in their entire operating history.

The combined data for these three companies indicate that more than 95% of the workover fluids will be seawater, sodium chloride, or calcium chloride brines. Some potassium chloride or occasionally some ammonium chloride may be added to minimize clay swelling. The seawater already contains about 19,000, 10,500, 380, and 65 ppm of chloride, sodium, potassium and bromide ions respectively. Thus only zinc or very high concentrations of bromide ions are of major concern. The zinc bromide brines are used in very few wells, probably less than 1% overall, and are normally displaced and returned to shore after completion operations are finished. The brines containing calcium bromide are used slightly more frequently, perhaps a few percent. Of the additives that might be present in the brine, only biocide seems likely to pose any significant risk. Mixing with produced water from that well or other wells will dilute the brines substantially prior to discharge.

Company	2		3	
Brine	US Gal.	%	Jobs	%
Sodium/Potassium Chloride	498,960	57	57	67
Calcium Chloride	174,048	20	19	22
Calcium Bromide/Chloride	149,940	17	9	11
Zinc/Calcium Bromide	54,054	6	<1	<1
Total	8n,002	100	85	100

Table 12. Summary of Data on Dense Brines Used in the Gulf of Mexico

SUMMARY

Treating chemicals can be and are used for a number of different purposes in offshore oil and gas production operations. These chemicals are normally only used in response to observed operational problems. Required doses are usually minimized based on results of monitoring programs and operational results. Most of these chemicals are proprietary mixtures of complex compounds. Alternative technology is being used in many instances when appropriate, but chemical treating is often the only effective approach.

Evaluation of pertinent data and practices indicate that only low concentrations of the production treating chemicals in the produced water will normally be discharged. Many of the commonly used chemicals are oil soluble, with perhaps only a fourth of the total production treating chemicals used actually ending up in the effluent water discharge stream. Comparison of available aquatic toxicity data (96 hour LC50) and use concentrations indicates that most of the chemical concentrations in the effluent stream will be at or below the LC50 values prior to discharge to the ocean.

The gas treating chemicals are used at higher concentrations. The dehydration chemicals are used in closed systems and rarely reach the discharge stream at all. Methanol used as a hydrate inhibitor may be discharged with the produced water at higher concentrations than the production treating chemicals. However, the LC50 value is much higher.

Disposal of stimulation and workover fluids is not a routine occurrence. Only about 9% of the wells were acidized in 1988 in the Gulf of Mexico. The acidizing chemicals conceptually could cause a shortterm lowering of the pH near the discharge point if substantial volumes of unspent acid are discharged without neutralization. The dense sodium and calcium brines used in workovers will not pose a significant risk after even minor dilution. The zinc bromide brines have the greatest potential impact, but are not commonly used and are banned from discharge. When displaced from a well, they are returned to shore for cleanup and reuse. Aquatic toxicity information on the additives used in stimulation and workover fluids are very limited. However, it appears likely that most will have similar toxicities and use concentrations to the production treating chemicals.

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48 Ewell, W.S., Gorsuch, J.W., Kringle, R.O., Robillard, K.A., and Spiegel, R.C., 'Simultaneous Evaluation of the Acute Effects of Chemicals on Seven Aquatic Species', *Environmental Toxicology and Chemistry*", Vol. 5 (1986) p.831.

49 Cowgill, U.M., Takahashi, LT., and Applegath, S.L., 'A Comparison of the Effect of Four Benchmark Chemicals on *Daphnia magna* and *Ceriodaphnia dubia-affinis* Tested at Two Different Temperatures", ***Environmental Toxicology** and Chemistry,* VolA (1985) p.41S-n.

50 Conway, RA., Waggy, G.T., Spiegel, M.H., and Berglund, R.L., "Environmental Fate and Effects of Ethylene Oxide", *Environ. Sci. Technol.*, voU7, No.2 (1983) p.107.

51 Middleditch, B.S., "Biocides", p.55-7 in Ref. 36.

APPENDIX B

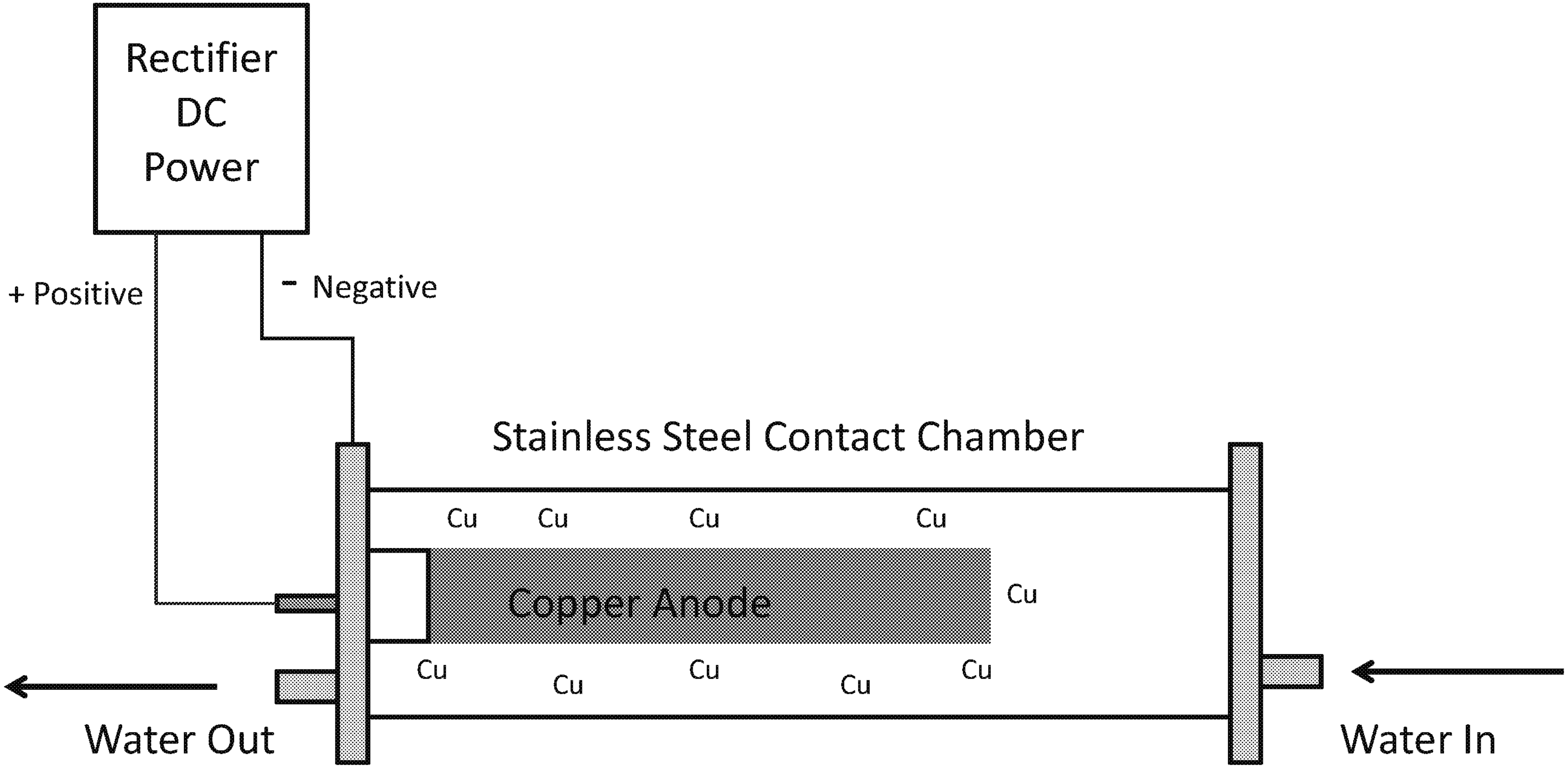
COMMENT NO. 33

Copper Ion Systems

For the Prevention of Marine Growth on Submersible Pumps

Installation and Maintenance

How the Copper Ionizer Works

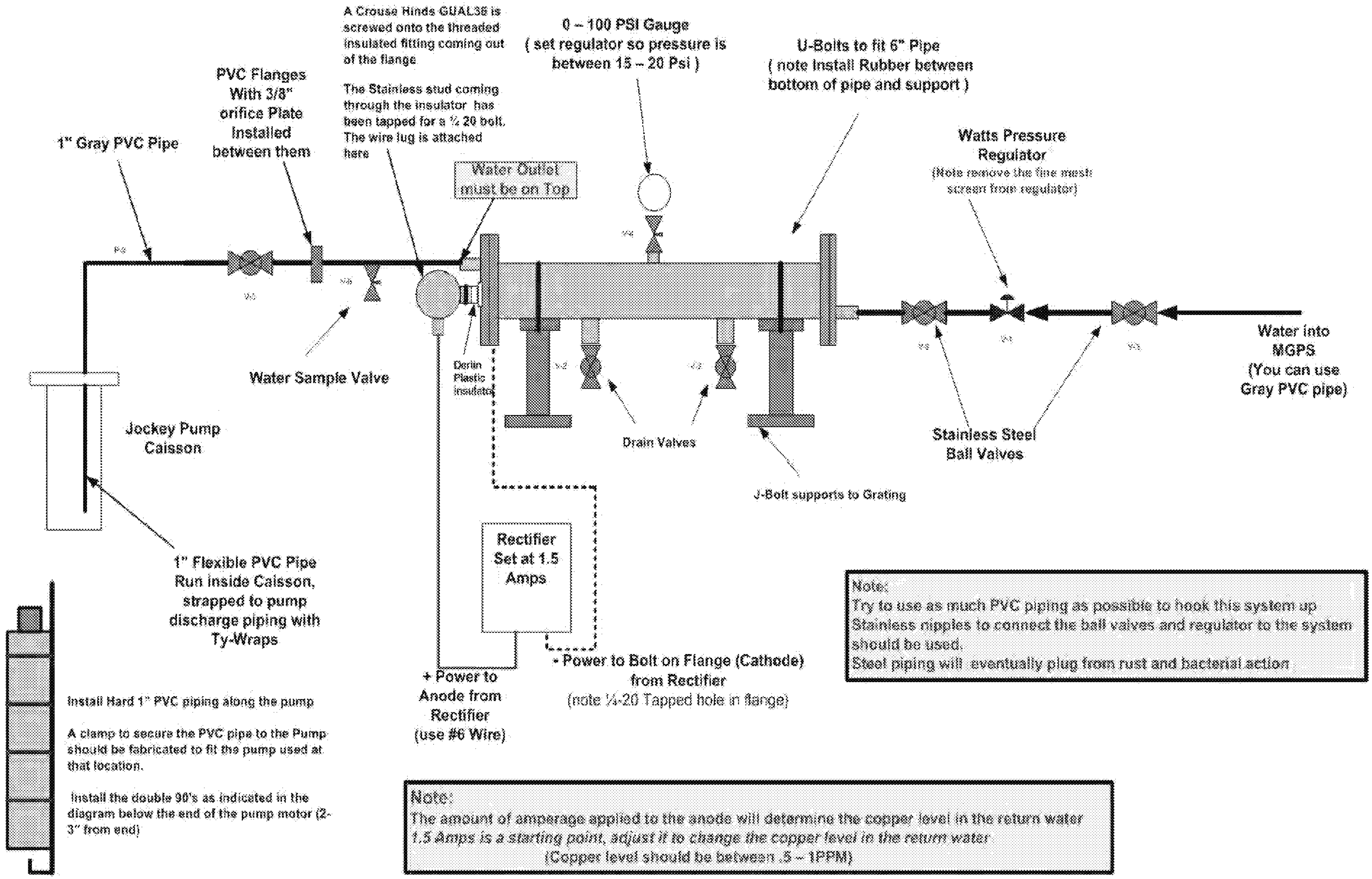


This is basically an electrolysis process. Electrical Current flows between the Copper Anode and Stainless Steel Tank we call a Contact Chamber. The Water flowing through the Contact Tank picks up the Copper Ions which is discharged below the Submersible Pump.

This Copper laden water flowing over the pump prevents marine growth from attaching itself to the pump.

We have found that a .05 – 1PPM level of copper is all that is required to prevent fouling

Marine Growth Prevention
Copper Ionizer System
Installation Guide



Install Hard 1" PVC piping along the pump

A clamp to secure the PVC pipe to the Pump should be fabricated to fit the pump used at that location.

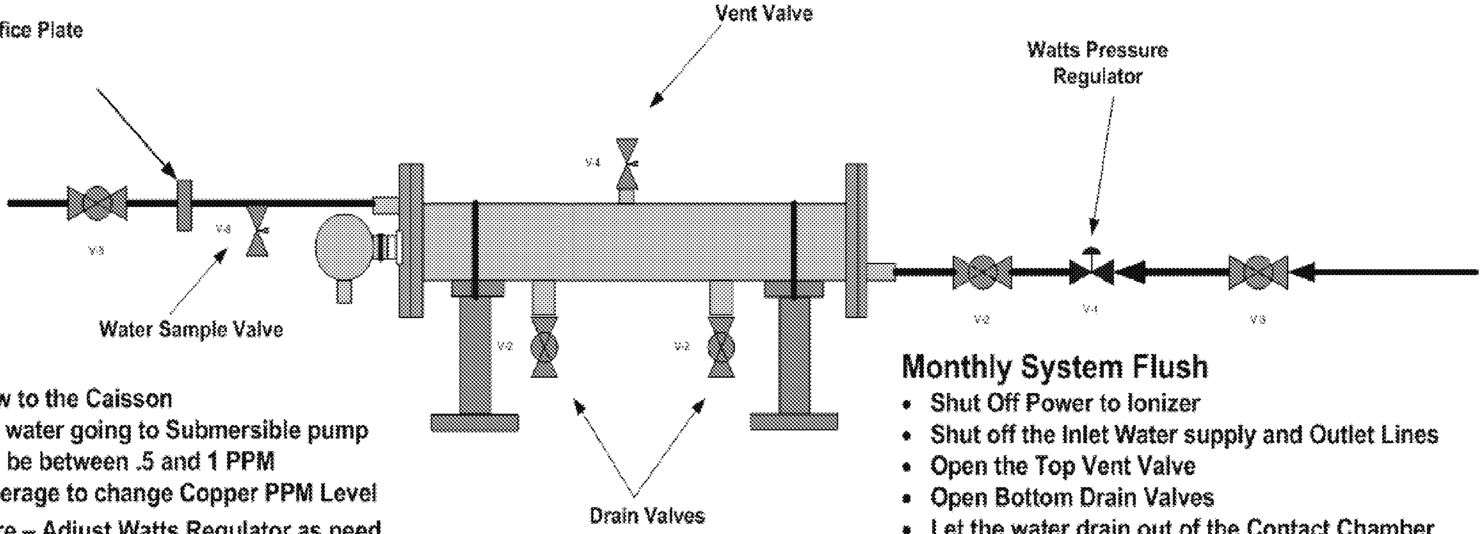
Install the double 90's as indicated in the diagram below the end of the pump motor (2-3" from end)

Note:
Try to use as much PVC piping as possible to hook this system up
Stainless nipples to connect the ball valves and regulator to the system should be used.
Steel piping will eventually plug from rust and bacterial action

Note:
The amount of amperage applied to the anode will determine the copper level in the return water
1.5 Amps is a starting point, adjust it to change the copper level in the return water
(Copper level should be between .5 – 1PPM)

Copper Ion System Mainteance

Note:
Anytime the system is being serviced
Cut off the Electrical Power and follow Proper LOTO Procedures.
This is an Electrical Hazzard and should be serviced by
Authorized Personnel Only



Weekly

- Check the Water Flow to the Caisson
- Test Copper Level in water going to Submersible pump
- Copper Level should be between .5 and 1 PPM
- Adjust Rectifier Amperage to change Copper PPM Level
- Check Water Pressure – Adjust Watts Regulator as need

Note:
The WATTS Regulator is just used to step down the Fire Water System Pressure going into the Contact Chamber
The Orifice Plate controls the flow out of the Contact Chamber and pressure on it.
Too Large an Orifice and the pressure will be low
Too Small or if it is getting plugged the pressure will go up
Copper will sometimes build up on the orifice plate plugging it

Monthly System Flush

- Shut Off Power to Ionizer
- Shut off the Inlet Water supply and Outlet Lines
- Open the Top Vent Valve
- Open Bottom Drain Valves
- Let the water drain out of the Contact Chamber
- Close Vent Valve Off
- With both bottom drains open, open the water inlet
- Let the water flow out of the Contact Chamber until Clean
- Record how much sediment is washed out

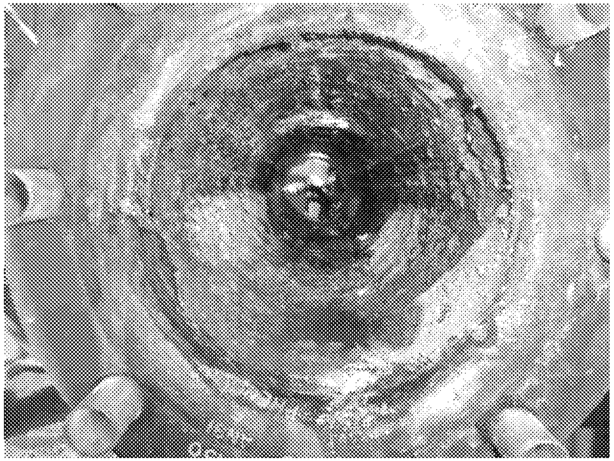
Failure to Flush Sediment May Cause it to Short Out Internally and Cause a Failure or Sever Electrolysis of the Units Housing and Premature Anode Failure

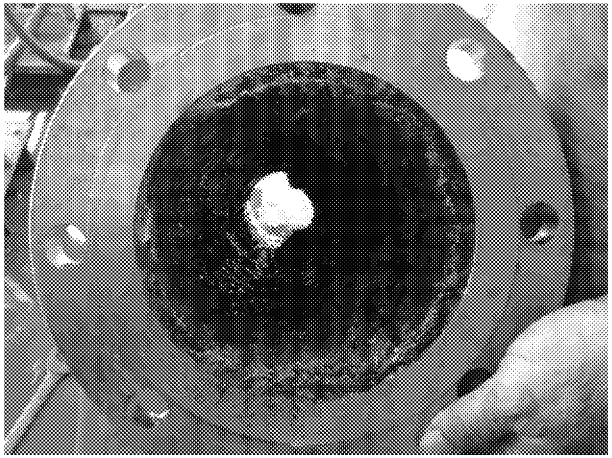
Yearly

- Shutdown the System and Flush
- Remove the Inlet Piping and Flange
- Inspect the Internal Condition of the Contact Chamber
- If significant build up is found on the walls of the Contact Chamber remove the outlet Piping and Flange/Anode Assembly
- Examine the condition of the Copper Anode – How much is left
- Replace Anode as condition warrants

Note: If you do not want to service the System in the field it can be shipped into EXTERRAN's Shop for Rebuilding

Examples of Internal Build Up



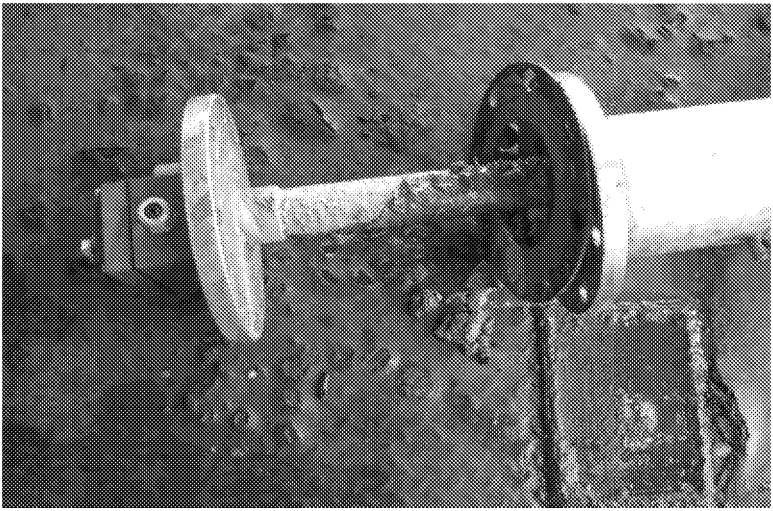


Build Up on Walls of Contact Chamber

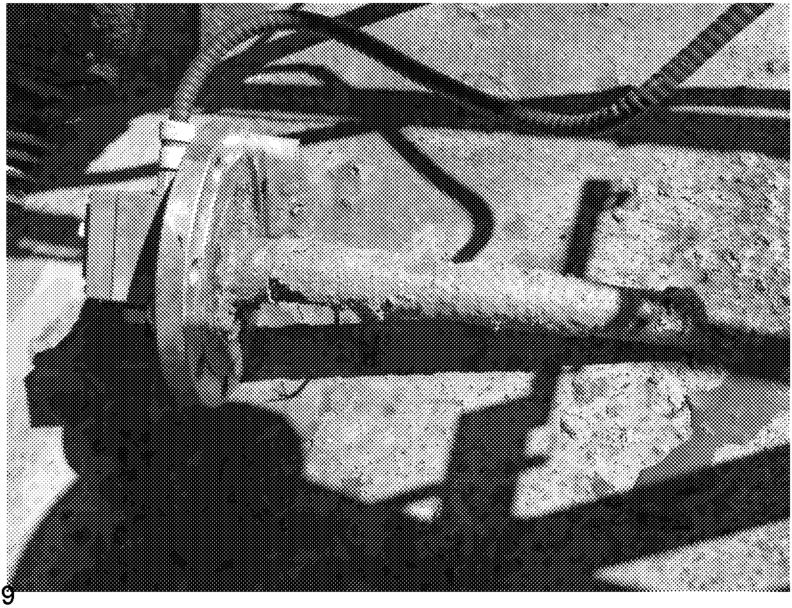
As Part of the Electrolysis Process Copper will build up on the Inside of the Stainless Steel Contact Chamber
Other Sediment and Build up comes from Organics in the Seawater

Copper Anode Images

Anode Assembly backed out
Notice the sediment



This is Normal Build Up on the Anode

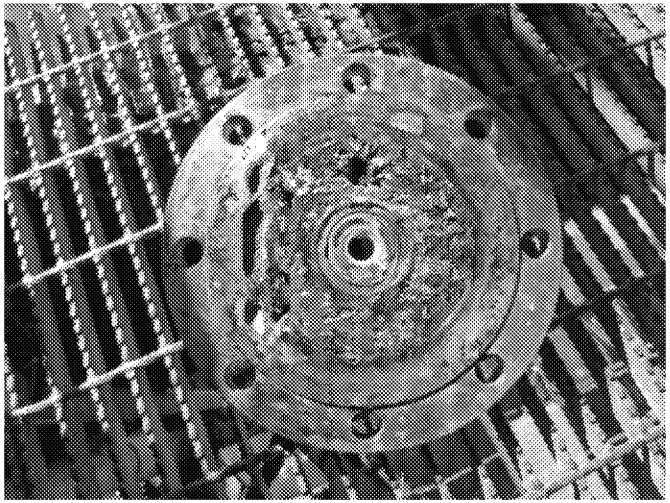


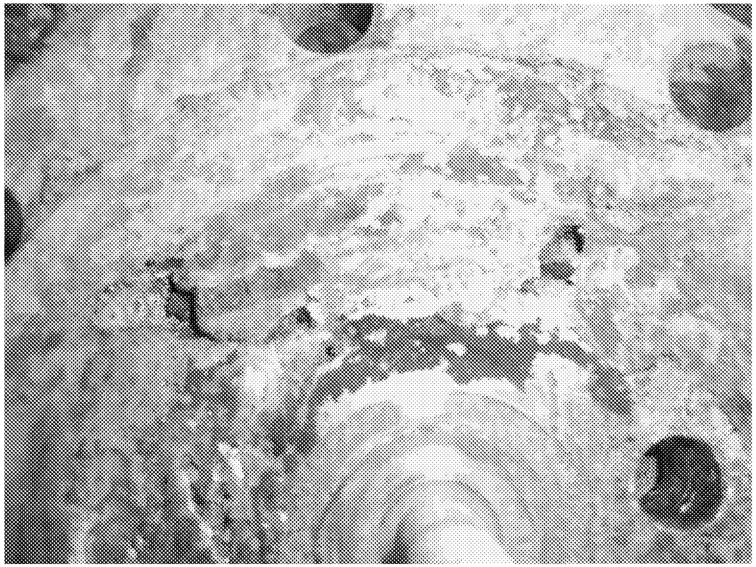
Tiers 8&9

Flange Failure

Failure to Flush Sediments from the Tank will cause severe electrolysis between the Flange and Anode or the Anode and Tank

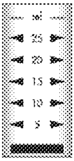
Below are two examples of Flange Failures



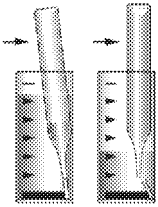


Testing for Copper PPM Level

Copper CHEMets®
0 - 1 & 1 - 10 ppm

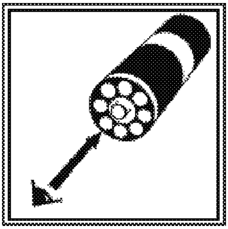


1. Fill the sample cup to the 25 mL mark with the sample (fig 1).



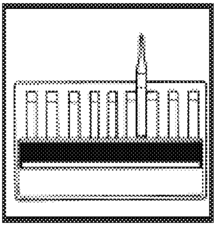
2. Place the CHEMet ampoule in the sample cup. Snap the tip by pressing the ampoule against the side of the cup. The ampoule will fill leaving a small bubble to facilitate mixing (fig 2).

3. Mix the contents of the ampoule by inverting it several times, allowing the bubble to travel from end to end each time. Wipe all liquid from the exterior of the ampoule. Wait **2 minutes for color** development.



4. Use the appropriate comparator to determine the level of copper in the sample. If the color of the CHEMet ampoule is between two color standards, a concentration estimate can be made.

a. Place the CHEMet ampoule, flat end downward into the center tube of the low range comparator. Direct the top of the comparator up toward a source of bright light while viewing from the bottom. Rotate the comparator until the color standard below the CHEMet ampoule shows the closest match

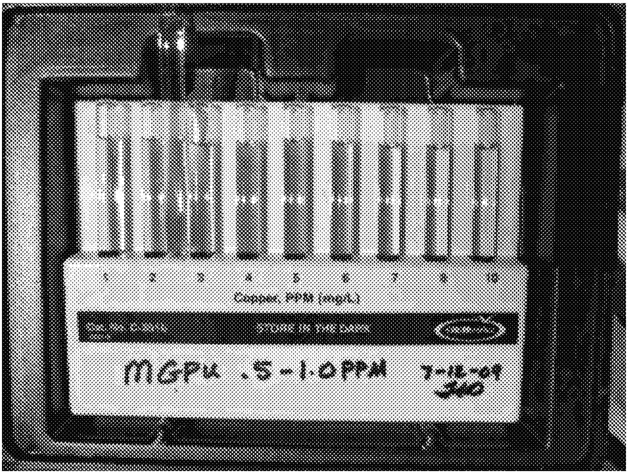


b. Hold the high range comparator in a nearly horizontal position while standing directly beneath a bright source of light. Place the CHEMet ampoule between the color standards moving it from left to right along the comparator until the best color match is found

Reorder Information	**Cat. No.**
Test Kit, complete	***K-3510***
Refill, 30 CHEMet ampoules	***R-3510***
Sample Cup, 25 mL, package of six	***A-0013***
Comparator, 0-1 ppm	***C-3501***
Comparator, 1-10 ppm	***C-3510***

CHEMetrics, Inc., 4295 Catlett Road, Calverton, VA 20138-0214 U.S.A.
Phone: (800) 356-3072; Fax: (540) 788-4856; E-Mail: orders@chemetrics.com
www.chemetrics.com Jan. 07, Rev. 5

Example of Copper Test Reading



Copper PPM Level is Between 2-3 PPM
Need to adjust Amperage Setting so that PPM Level is between .5 and 1 PPM

8&9

Universal
RECTIFIERS, INC.

BASIC OPERATING INSTRUCTIONS FOR RK19 SOLID STATE CONTROL RECTIFIERS CURRENT LIMIT

MANUAL OPERATION

1. Auto - Manual switch must be in manual position.
2. Link bars must be in lowest setting.
3. Turn rectifier on.
4. Observe output. Adjust link bars to desired output.

NOTE: Solid state controls have no effect in manual mode and need not be adjusted. Solid state printed circuit boards may be removed for inspection or repair in manual mode. Unit will remain operational.

CURRENT LIMIT - CONSTANT CURRENT OPERATION

NOTE:
The CURRENT LIMIT is factory set at rated output of rectifier. If different current limit is desired then proceed with the following steps.

1. With the Auto-Manual Control switch in the Manual position, increase link bars to obtain a current output slightly higher than required, but still within the rating of the rectifier.
2. Turn Rectifier OFF and adjust CURRENT LIMT knobs fully clockwise.
3. Place the Auto-Manual switch in the AUTO mode.
4. Turn Rectifier on. Output should return to the output as adjusted in step one above.
5. Adjust CURRENT LIMIT control counter clockwise (decrease) to desired current output. Rectifier will maintain this current setting with nominal circuit resistance changes. If there is an extreme change in external load circuit resistance, link bars may need to be at a higher setting to maintain the preset current. Constance current operation is a function of the current limit feature of this unit

TROUBLE SHOOTING HINTS

NOTE: A wiring diagram for use by experienced personnel is provided. Only experienced electrical personnel should attempt location and repair of electrical difficulties, should they occur. Some symptoms of elementary trouble and the possible remedy are as follows:

1. **NO D.C. CURRENT OR D.C. VOLTAGE OUTPUT.**
CHECK: A.C. overload protection for blown fuses or tripped breaker. Check A.C. power supply.(Is desired potential maintained?) If desired potential is maintained then unit has automatically cut back output of rectifier to maintain potential.

2. **D.C. VOLTAGE BUT NO D.C. CURRENT READING.**
CHECK: D.C. ammeter. Check D.C. connections and external D.C. circuit for electrical continuity.

3. **D.C. CURRENT READING BUT NO D.C. VOLTAGE READINGS.**
CHECK: Check D.C. voltmeter.

4. **MAXIMUM RATED D.C. VOLTAGE CANNOT BE ATTAINED.**
CHECK: A.C. line voltage. Check link bar adjustments for maximum.
Check accuracy of D.C. voltmeter. Check that unit is not operating against a preset voltage and or current limit.

5. **MAXIMUM RATED D.C. CURRENT CANNOT BE ATTAINED.**
CHECK: Load resistance of external D.C. circuit. Check that unit is not operating against a preset voltage and or current limit.

6. **REFERENCE METER PEGGED FULL SCALE AND NO D.C. OUTPUT.**
CHECK: Electrode and Structure connections and external reference circuit for electrical continuity.

NOTE: Give model and serial numbers when writing or calling Universal Rectifiers Inc. in reference to this rectifier.

For Parts and Service

Replacement Anodes and Parts or for Shop Repair

EXTERRAN

Craig Clements
Belle Chasse, La
Phone: 504-392-2600

Rectifier Parts

Universal Rectifiers, Inc.
P.O. Box 1640
1631 Cottonwood School Rd.
Rosenberg, Texas 77471
(281) 342-8471 - (281) 342-0292 Fax:
www.universalrectifiers.com

For Technical Information
Scott Reppel
Lead Principal Investigator
Chevron USA
Eastern Gulf of Mexico
Harvey Office
Phone: 504-263-6890
Cell: 504-289-1701

APPENDIX C

COMMENT NO. 33

	Ion	Pipe Dia	Critical	Collection	*M. beryllina Survival*			*M. bahia Survival*			Copper Ion analysis	
Area & Block	**Treatment**	**(in)**	**Dilution (%)**	**Date**	**NOEC**	**LOEC**	**Pass/Fail**	**NOEC**	**LOEC**	**Pass/Fail**	**(mg/L)**	***Comment***
Mobile 904 AQ	Cu	6	1.48	06/09/14	5.92	>5.92	P	5.92	>5.92	P	0.5	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 904 AQ	Cu	6	1.48	08/04/14	5.92	>5.92	P	5.92	>5.92	P	0.99	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 904 AQ	Cu	6	1.48	10/27/14	5.92	>5.92	P	5.92	>5.92	P	Not measured	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 904 AQ	Cu	6	1.48	01/05/15	5.92	>5.92	P	5.92	>5.92	P	Not measured	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 904 AQ	Cu	6	1.48	07/13/15	5.92	>5.92	P	2.96	5.92	P	Not measured	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 904 AQ	Cu	6	1.48	01/11/16	5.92	>5.92	P	5.92	>5.92	P		
Mobile 904 AQ	Cu	6	1.48	06/15/16	2.96	5.92	p	5.92	>5.92	P		
Mobile 904 AQ	Cu	6	1.48	09/01/16	5.92	>5.92	p	5.92	>5.92	P		
Mobile 904 AQ	Cu	6	1.23	03/09/17	4.92	>4.92	p	4.92	>4.92	p		
Mobile 916 AP	Cu	2	0.29	01/13/14	1.16	>1.16	P	1.16	>1.16	P	Not measured	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 916 AP	Cu	2	0.29	04/07/14	1.16	>1.16	P	1.16	>1.16	P	Not measured	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 916 AP	Cu	2	0.29	06/17/14	1.16	>1.16	P	1.16	>1.16	P	Not measured	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 916 AP	Cu	2	0.29	07/14/14 07/28/14	1.16	>1.16	P	1.16	>1.16	P	BDL	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 916 AP	Cu	2	0.29	01/05/15	1.16	>1.16	P	1.16	>1.16	P	Not measured	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 916 AP	Cu	2	0.29	07/13/15	1.16	>1.16	P	1.16	>1.16	P	Not measured	Copper Ion treatment only EPA Region 4/7-Day NOEC testing
Mobile 916 AP	Cu	2	0.29	01/11/16	1.16	>1.16	P	1.16	>1.16	P		
Mobile 916 AP	Cu	2	0.29	06/15/16	1.16	>1.16	P	1.16	>1.16	P		
Mobile 916 AP	Cu	2	0.29	09/01/16	1.16	>1.16	P	1.16	>1.16	P		
MP 142 C	Cu	3	12.4	12/25/13	49.6	>49.6	P	49.6	>49.6	P	Not measured	Copper Ion treatment only
MP 142 C	Cu	3	12.4	01/14/14	49.6	>49.6	P	49.6	>49.6	P	Not measured	Copper Ion treatment only
MP 144 A	Cu	3	12.4	12/25/13	24.8	49.6	P	12.4	24.8	P	Not measured	Copper Ion treatment only
MP 144 A	Cu	3	12.4	01/14/14	49.6	>49.6	P	49.6	>49.6	P	Not measured	Copper Ion treatment only
MP 300 B	Cu	3	12.4	12/25/13	49.6	>49.6	P	49.6	>49.6	P	Not measured	Copper Ion treatment only
MP 300 B	Cu	3	12.4	01/14/14	49.6	>49.6	P	49.6	>49.6	P	Not measured	Copper Ion treatment only
MP 42 M	Cu	2	11.2	01/26/14	11.2	22.4	P	22.4	44.8	P	Not measured	Copper Ion treatment only
MP 42 M	Cu	2	11.2	04/15/14	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
MP 42 M	Cu	2	11.2	05/13/14	44.8	>44.8	P	44.8	>44.8	P	BDL	Copper Ion treatment only
MP 42 M	Cu	2	11.2	06/03/14	44.8	>44.8	P	44.8	>44.8	P	BDL	Copper Ion treatment only
MP 42 M	Cu	2	11.2	07/01/14	44.8	>44.8	P	44.8	>44.8	P	BDL	Copper Ion treatment only
MP 42 M	Cu	2	11.2	08/05/14	44.8	>44.8	P	44.8	>44.8	P	BDL	Copper Ion treatment only
MP 42 M	Cu	2	11.2	09/02/14	22.4	44.8	P	22.4	44.8	P	BDL	Copper Ion treatment only
MP 42 M	Cu	2	11.2	10/15/14	11.2	22.4	P	11.2	22.4	P	Not measured	Copper Ion treatment only
MP 42 M	Cu	2	11.2	11/12/14	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
MP 42 M	Cu	2	11.2	12/11/14	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
MP 42 M	Cu	2	11.2	01/06/15	11.2	22.4	P	11.2	22.4	P	Not measured	Copper Ion treatment only
MP 42 M	Cu	2	11.2	02/03/15	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
MP 42 M	Cu	2	11.2	03/01/16	44.8	>44.8	P	44.8	>44.8	P		
SMI 236 A	Cu	2	11.2	12/16/13	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	01/21/14	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	04/08/14	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	05/06/14	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	06/03/14	44.8	>44.8	P	44.8	>44.8	P	BDL	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	07/08/14	44.8	>44.8	P	22.4	44.8	P	BDL	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	08/05/14	44.8	>44.8	P	44.8	>44.8	P	BDL	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	11/25/14	11.2	22.4	P	22.4	44.8	P	BDL	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	12/09/14	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	01/06/15	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only

SMI 236 A	Cu	2	11.2	02/03/15	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	03/03/15	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
SMI 236 A	Cu	2	11.2	01/05/16	44.8	>44.8	P	44.8	>44.8	P		
SMI 236 A	Cu	1.5	11.2	01/10/17	44.8	>44.8	P	44.8	>44.8	P		
SMI 236 A	Cu	1.5	11.2	03/28/17	44.8	>44.8	P	44.8	>44.8	P		
ST 151 P1	Cu	2	12.4	01/16/14	49.6	>49.6	P	49.6	>49.6	P	Not measured	Copper Ion treatment only
ST 37 J	Cu	>6	14	09/16/15	56	>56	P	56	>56	P	Not measured	Copper Ion treatment only
ST 37 J	Cu	>6	14	10/12/15	56	>56	P	56	>56	P		
ST 37 J	Cu	>6	14	11/04/15	56	>56	P	56	>56	P		
ST 37 J	Cu	>6	14	12/17/15	56	>56	P	56	>56	P		
ST 37 J	Cu	>6	14	03/02/16	56	>56	P	56	>56	P		
ST 37 J	Cu	>6	14	05/12/16	56	>56	P	56	>56	P		
ST 52 A	Cu	2	12.4	01/15/14	49.6	>49.6	P	49.6	>49.6	P	Not measured	Copper Ion treatment only
ST 52 A	Cu	2	11.2	04/08/14	22.4	44.8	P	11.2	22.4	P	Not measured	Copper Ion treatment only
ST 52 A	Cu	2	11.2	07/10/14	44.8	>44.8	P	22.4	44.8	P	Not measured	Copper Ion treatment only
ST 52 A	Cu	2	11.2	10/16/14	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
ST 52 A	Cu	2	11.2	02/05/15	44.8	>44.8	P	44.8	>44.8	P	Not measured	Copper Ion treatment only
ST 52 A	Cu	2	11.2	02/10/16	44.8	>44.8	P	44.8	>44.8	P		
VK 900 A	Cu	3	12.4	01/22/14	49.6	>49.6	P	49.6	>49.6	P	Not measured	Copper Ion treatment only
WD 109 A	Cu	3	12.4	12/30/13	49.6	>49.6	P	49.6	>49.6	P	Not measured	Copper Ion treatment only
WD 109 A	Cu	3	12.4	01/22/14	49.6	>49.6	P	49.6	>49.6	P	Not measured	Copper Ion treatment only
GC 338 (Front Runner)	Cu & Al	16	20	01/16/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	02/13/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	03/06/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	04/24/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	05/20/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	06/10/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	07/08/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	08/13/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	09/18/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	10/28/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	11/05/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	12/09/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC 338 (Front Runner)	Cu & Al	16	20	11/18/15	80	>80	P	80	>80	P		
GC 338 (Front Runner)	Cu & Al	16	20	11/22/16	80	>80	P	80	>80	P		
MC 736 (Thunder Hawk)	Cu & Fe	14	20	01/15/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	02/13/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	03/06/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	04/24/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	05/20/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	06/10/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	07/08/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	08/11/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	09/11/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	10/09/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	11/06/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	12/03/14	80	>80	P	80	>80	P	Not measured	Copper and Iron Ions
MC 736 (Thunder Hawk)	Cu & Fe	14	20	11/19/15	80	>80	P	80	>80	P		
MC 736 (Thunder Hawk)	Cu & Fe	8	20	08/26/16	40	80	P	20	40	P		
AT618	Cu	5.9	23	10/28/14	92	>92	P	92	>92	P	Not measured	Copper Ion treatment only
AT618	Cu&Al	11.8	20	10/28/14	40	80	P	80	>80	P	Not measured	Copper and Aluminum Ions
AT618	Cu&Al	17.7	14	10/28/14	56	>56	P	56	>56	P	Not measured	Copper and Aluminum Ions
AT618	Cu	5.9	23	11/07/14	92	>92	P	92	>92	P	Not measured	Copper Ion treatment only
AT618	Cu&Al	9.8	20	11/07/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
AT618	Cu&Al	17.7	14	11/07/14	64	>64	P	64	>64	P	Not measured	Copper and Aluminum Ions
GC610	Cu&Al	9.8	20	11/20/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC610	Cu	5.9	23	11/20/14	92	>92	P	92	>92	P	Not measured	Copper Ion treatment only
GC610	Cu	9.8	20	11/20/14	80	>80	P	80	>80	P	Not measured	Copper Ion treatment only
GC653	Cu	20	20	12/01/14	80	>80	P	80	>80	P	Not measured	Copper Ion treatment only
GC653	Cu	5.9	23	12/29/14	92	>92	P	92	>92	P	Not measured	Copper Ion treatment only
GC653	Cu&Al	9.8	20	12/29/14	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC610	Cu	9.8	20	01/28/15	80	>80	P	80	>80	P	Not measured	Copper Ion treatment only
GC610	Cu&Al	5.9	23	01/28/15	92	>92	P	92	>92	P	Not measured	Copper and Aluminum Ions
GG610	Cu	5.91	23	02/26/15	92	>92	P	92	>92	P	Not measured	Copper Ion treatment only
GC653	Cu&Al	11.81	20	02/26/15	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC653	Cu	4.5	23	03/25/15	92	>92	P	92	>92	P	Not measured	Copper Ion treatment only

GC653	Cu&Al	10	20	03/25/15	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC653	Cu	4.5	23	04/01/15	90	>92	P	92	>92	P	Not measured	Copper Ion treatment only
GC653	Cu&Al	10.7	20	04/01/15	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC653	Cu	11.8	20	04/01/15	80	>80	P	80	>80	P	Not measured	Copper Ion treatment only
GC609	Cu&Al	11.8	20	04/28/15	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC609	Cu&Al	17.7	24.6	04/28/15	98.4	>98.4	P	98.4	>98.4	P	Not measured	Copper and Aluminum Ions
GC609	Cu	11.8	20	04/28/15	80	>80	P	80	>80	P	Not measured	Copper Ion treatment only
GC609	Cu&Al	17.7	24.6	05/31/15	98.4	>98.4	P	98.4	>98.4	P	Not measured	Copper and Aluminum Ions
GC609	Cu	5.91	23	05/31/15	92	>92	P	92	>92	P	Not measured	Copper Ion treatment only
GC609	Cu&Al	9.84	20	05/31/15	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC609	Cu&Al	17.72	20	06/01/15	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC609	Cu&Al	17.7	24.6	06/01/15	98.4	>98.4	P	98.4	>98.4	P	Not measured	Copper and Aluminum Ions
GC609	Cu	5.91	23	06/01/15	92	>92	P	92	>92	P	Not measured	Copper Ion treatment only
GC609	Cu	6	23	07/01/15	92	>92	P	92	>92	P	Not measured	Copper Ion treatment only
GC609	Cu&Al	12	20	07/01/15	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC609	Cu&Al	12	20	07/01/15	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC609	Cu	5.91	23	08/05/15	92	>92	P	92	>92	P	Not measured	Copper Ion treatment only
GC609	Cu&Al	17.72	20	08/05/15	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions
GC609	Cu&Al	17.72	20	08/05/15	80	>80	P	80	>80	P	Not measured	Copper and Aluminum Ions

BDL- Below Detection limit (<0.01 mg/L)

APPENDIX D

COMMENT NO. 36

Tiered Intake Velocity Monitoring Methodology Justification

The Offshore Operators Committee (OOC) commissioned CK Associates (CK) to evaluate if the velocity monitoring frequency, proscribed for CWIS (intakes) by GMG290000, could be reduced from daily to a lesser frequency while remaining protective of species subject to impingement mortality (IM).

CK evaluated one year of data (2015) from six separate CWIS, located in the GOM, for analysis. The intake velocity data are presented on Figure 1. The data presented in Figure 1 show a range of intake velocities measured throughout the year with a minimum velocity equal to 0.02 ft/s, a maximum intake velocity equal to 0.45 ft/s and a mean intake velocity equal to 0.172 ft/s (excluding days of zero intake flow). Gaps in the plots indicate days for which the intake was not operating. Each of the six CWIS maintained intake velocities below the 0.5 ft/s regulatory threshold (zero exceedances) during the calendar year. There is no general trend of increasing velocity for the intakes as a whole. Intake velocities tend to increase and decrease randomly due to fluctuating cooling water needs rather than an accumulation of biomass blocking the screens.

The daily intake velocities were converted to rates-of-change in intake velocity for this analysis. The results are presented as an individual value plot on Figure 2 and represent 1,290 individual velocity monitoring events. Two criteria were used to create the rate-of-change results. Missing data are omitted for purposes of the analysis (not assumed to be zero); any rate-of-change requires two consecutive non-zero velocity measurements. This analysis resulted in 1,290 data points upon which the remainder of the analysis is based. The data show a minimum rate-of-change in intake velocity equal to -0.14 (ft/s)/day, a mean of 0.00 (ft/s)/day, and a maximum of 0.20 (ft/s)/day.

An ANOVA was used to determine if any individual intake differed statistically from the others based on rates-of-change. Interval plots for each intake can be found on Figure 3. No statistically significant differences in rates-of-change were identified for any intake ($P < 0.05$). Individual comparison plots using Tukey's Method can be found on Figure 4.

The rate-of-change data were combined for all subsequent analyses because they do not differ statistically. The combined data set is plotted as a histogram with a normal distribution overlain on Figure 5. The data are approximately normal. However, the spread of the data is less than would be expected of a perfectly normal distribution. Therefore, the normal distribution will provide conservative estimates of mean rates-of-change throughout the remainder of the analysis.

As shown on Figure 5, the mean rate-of-change in intake velocity for the combined data set is equal to 0.00004651 (ft/s)/day with a standard deviation equal to 0.01073 (ft/s)/day. These values were used to calculate the upper 95th percentile value for mean velocity increase over 1 day, 30 days, and 90 days. The results can be found in Table 1. Based on this analysis, a given intake will exhibit an increase in velocity equal to 0.115 ft/s or less during any 30-day period at the 95% confidence level. A given intake will exhibit an increase in velocity equal to 0.200 ft/s or less during any 90-day period at the 95% confidence level.

Table 1: Velocity increase for intakes as a function of days between velocity monitoring events.

Interval Between Consecutive Velocity Monitoring Events (days)	Upper 95% Confidence Interval for Daily Average Velocity Increase (ft/s)/day	Upper 95% Confidence Interval for Velocity Increase during the Interval (ft/s)
1	0.021	0.021
30	0.00384	0.115
90	0.00222	0.200

The information found in Table 1 was used to develop a tiered velocity monitoring frequency that is equally protective of species that are susceptible to IM as the current daily velocity monitoring requirement proscribed in the GMG290000.

Table 2: Tiered intake velocity monitoring frequency based on most-recent intake velocity monitoring data.

If the most recently reported intake velocity was: (ft/s)	Interval between most recent velocity monitoring event, and next monitoring event (days)	95% Velocity at the end of the interval	Proposed Permit Monitoring Frequency
<0.300	90	<0.300 + <0.200 = <0.500	Quarterly
0.300 – 0.384	30	<0.384 + <0.115 = <0.500	Monthly
>0.384	1	<0.500	Daily

The following points summarize the arguments in support of the tiered intake velocity monitoring frequency approach:

- Of the six intakes included in this evaluation, zero exceeded the 0.5 ft/s intake velocity threshold during 2015 (Figure 1);
- Intake velocity does not monotonically increase over time (Figure 1);
- There is no statistically significant difference in rate-of-change for intake velocity across the six intakes included in the study ($P < 0.05$). Therefore a general approach to all intakes, as opposed to a site-specific monitoring methodology, is appropriate (Figures 2 – 5); and
- The tiered approach presented in Table 2 ensures that intake velocity measurements will be made prior to exceeding the 0.5 ft/s regulatory threshold. Therefore, the tiered velocity monitoring frequency is equally protective of species susceptible to IM as is the current daily intake velocity monitoring requirement proscribed in the GMG290000.

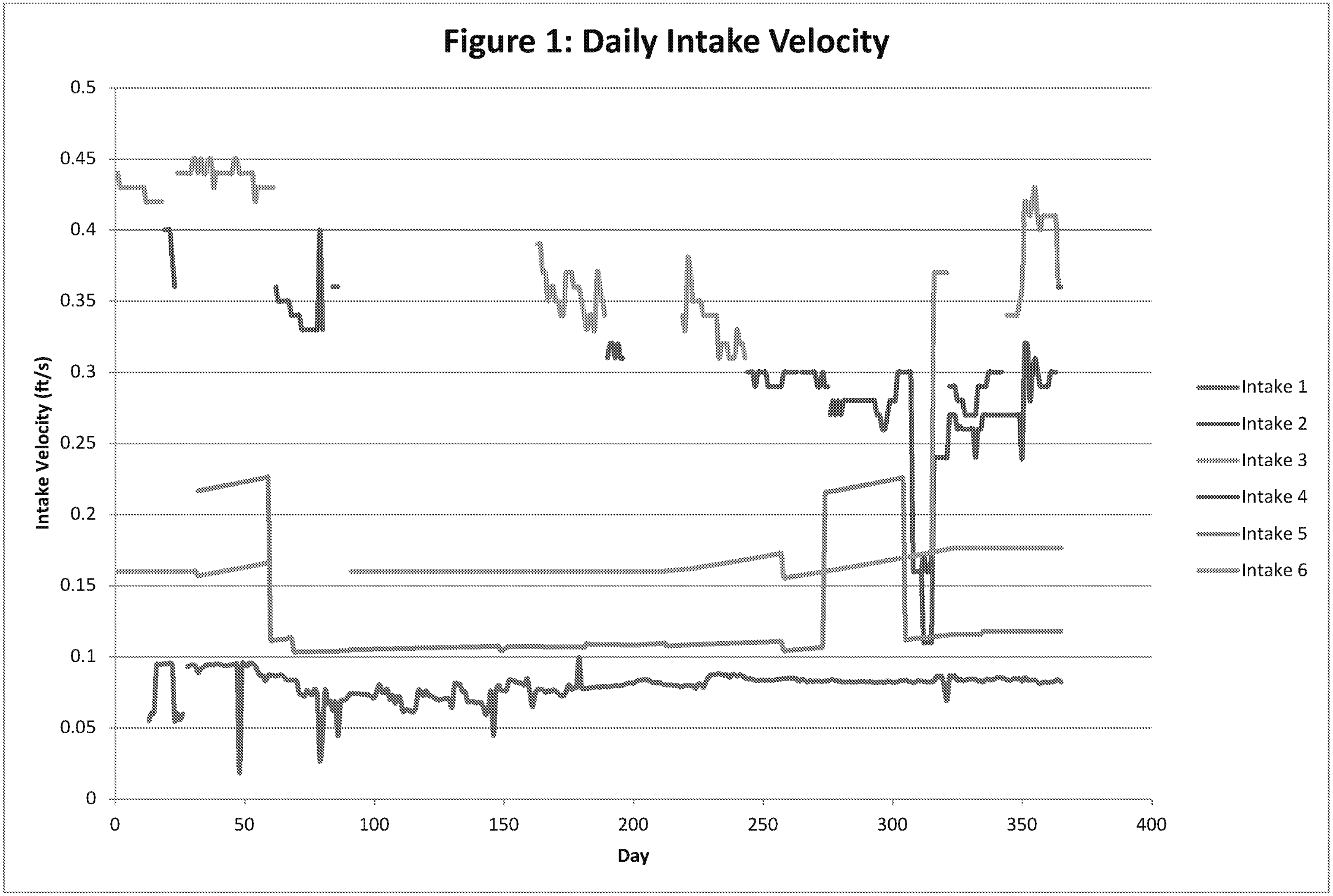
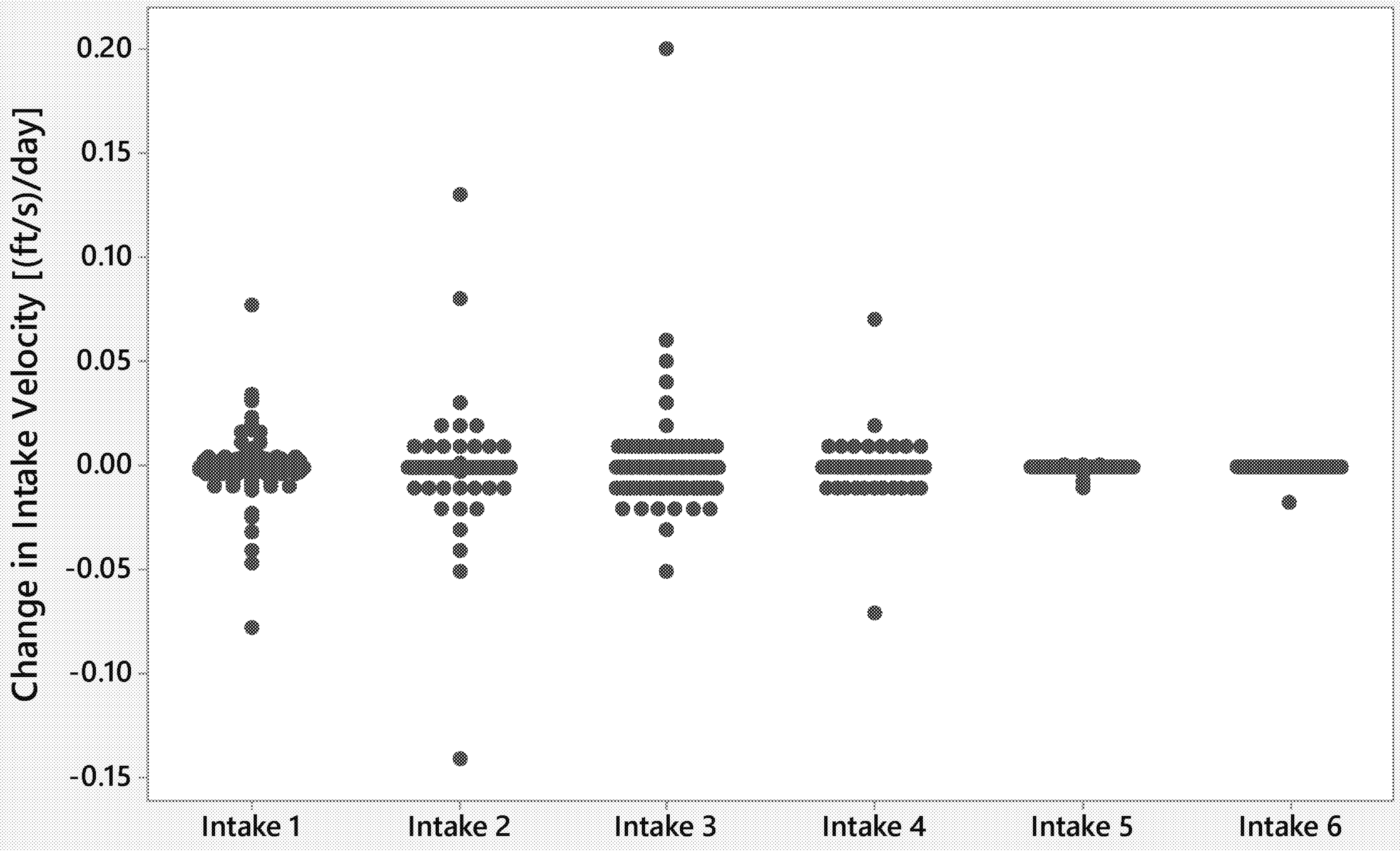


Figure 1: Daily Intake Velocity
Intake Velocity (ft/s)
0.5
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
50
100
150
200
250
300
350
400
Day
Intake 1
Intake 2
Intake 3
Intake 4
Intake 5
Intake 6

Figure 2: Individual Value Plot of Daily Changes in Intake Velocity



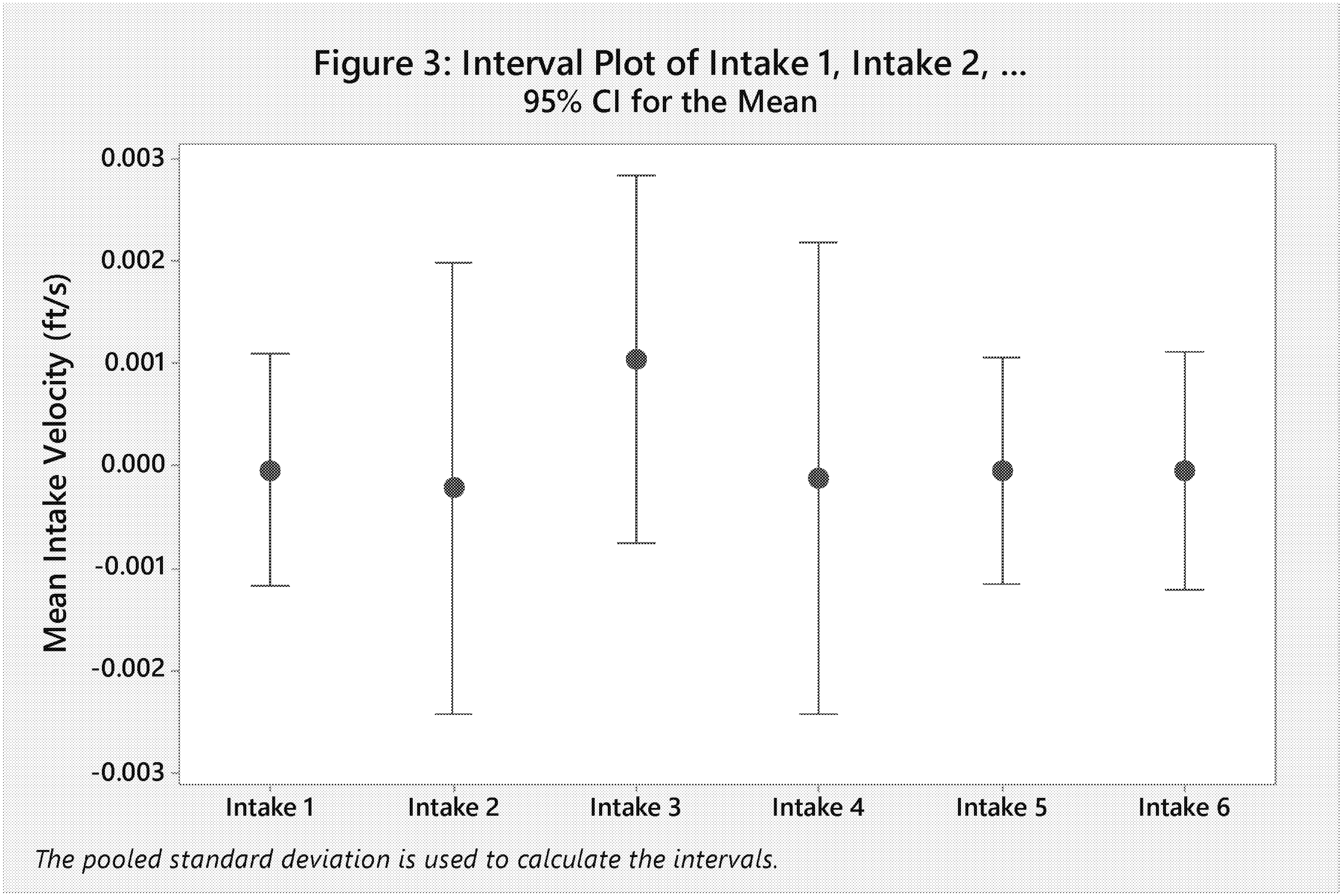
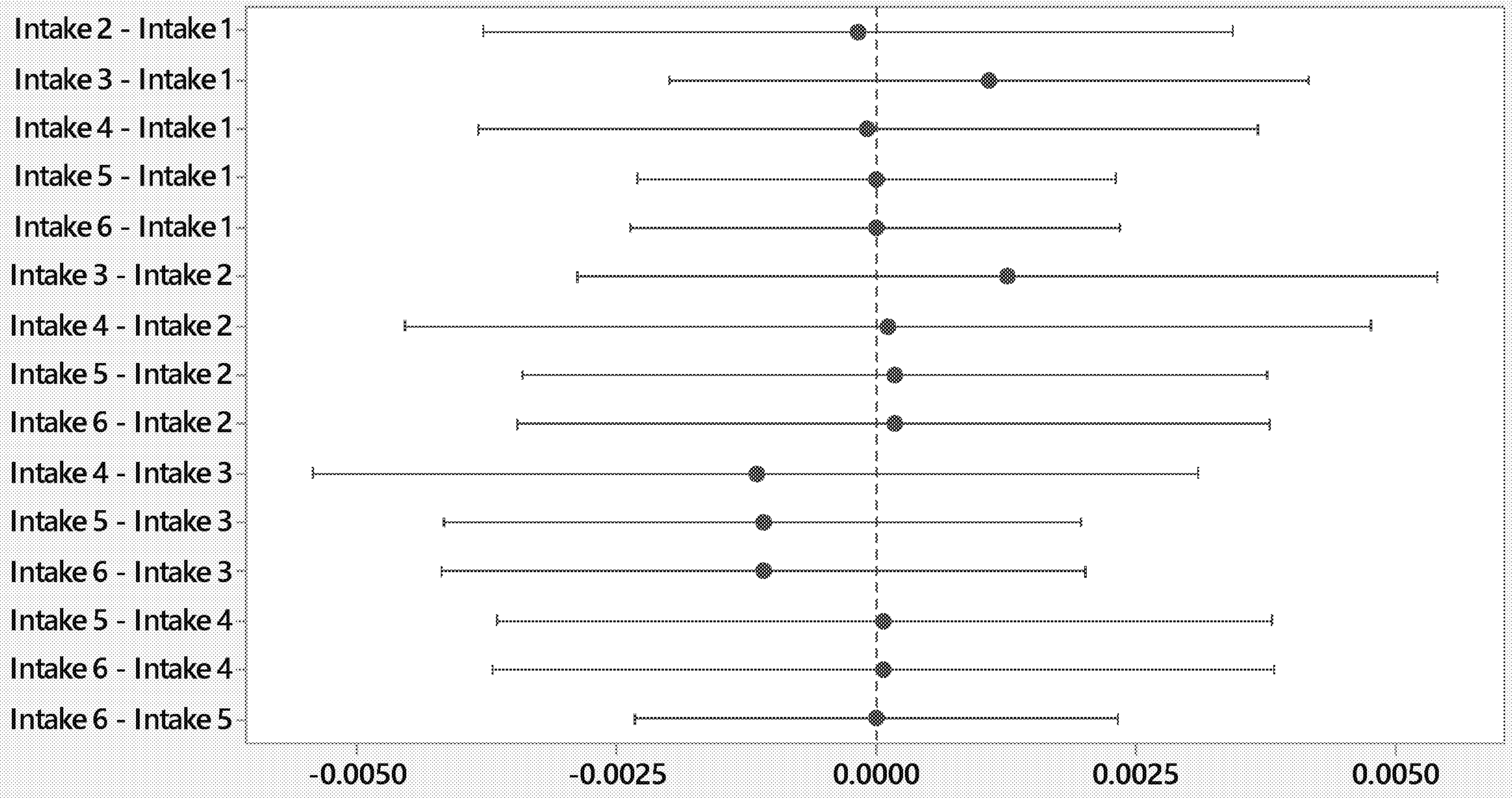


Figure 3: Interval Plot of Intake 1, Intake 2, ...
95% CI for the Mean
Mean Intake Velocity (ft/s)
0.003
0.002
0.001
0.000
-0.001
-0.002
-0.003
Intake 1
Intake 2
Intake 3
Intake 4
Intake 5
Intake 6
The pooled standard deviation is used to calculate the intervals.

Figure 4: Tukey Simultaneous 95% CIs
Difference of Means for Intake 1, Intake 2, ...



If an interval does not contain zero, the corresponding means are significantly different.

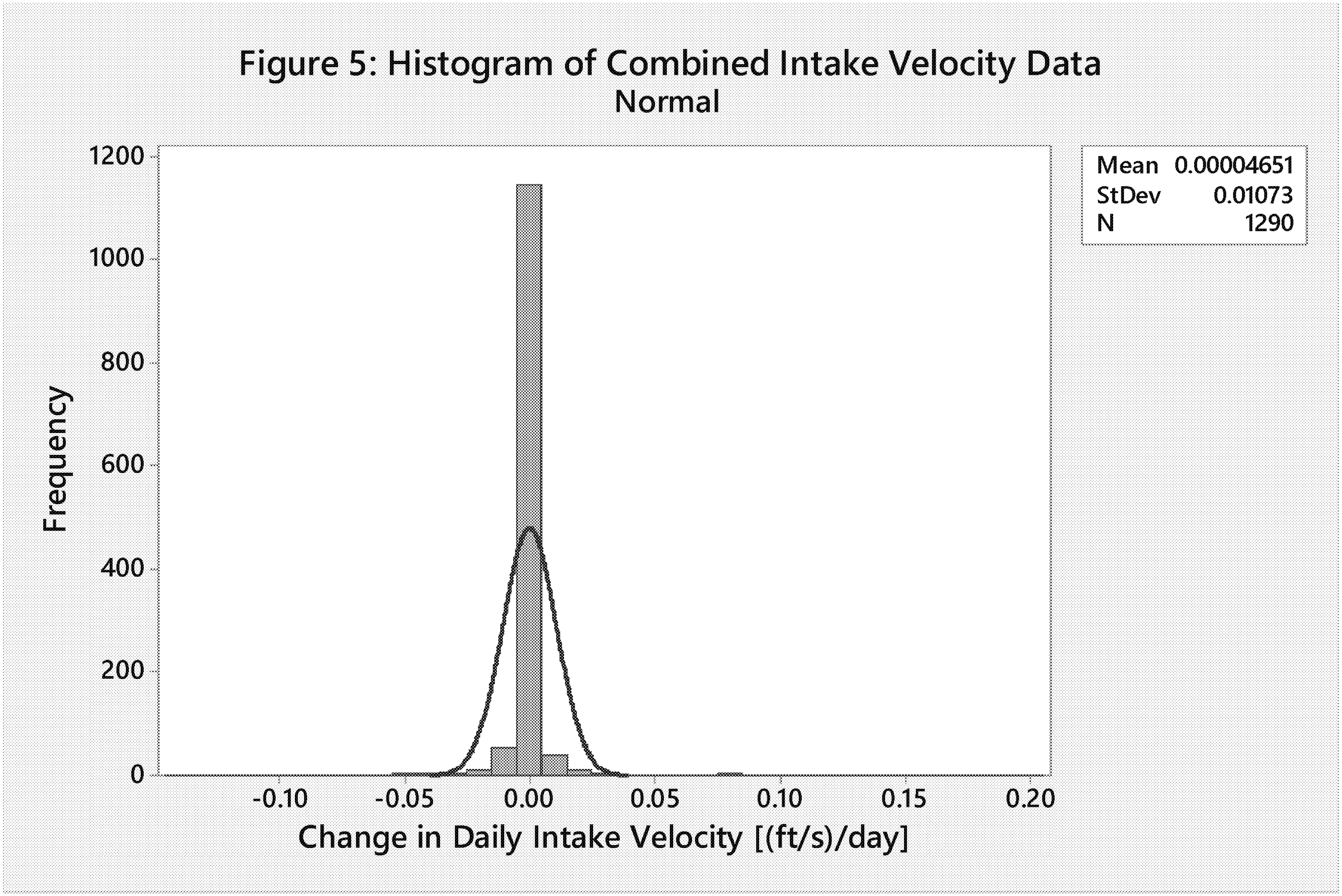


Figure 5: Histogram of Combined Intake Velocity Data
Normal
Mean 0.00004651
StDev 0.01073
N 1290
Frequency
1200
1000
800
600
400
200
0
-0.10
-0.05
0.00
0.05
0.10
0.15
0.20
Change in Daily Intake Velocity [(ft/s)/day]

APPENDIX E

COMMENT NO. 37

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PHONE (318) 797-8636
FAX (318) 798-0478

July 9, 2014 **Sent Via Email**

Chevron USA
17000 Katy Freeway
Houston, TX 77094
Attn: Ms. Kathy Dahl

Re: Second Quarter 2014 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Ms. Dahl:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the second quarter 2014 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a new fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit).

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 14:15 on June 27, 2014 and lasted until 14:15 on June 28, 2014. The EMD was operated continuously during the sampling period at a flow rate of 13.2 gallons per minute resulting in an entrainment sample volume of 19,000 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate accounts to zero eggs/larvae per cubic meter and approximately zero species of concern entrained per day. A summary of the entrained species of concern is included in Table 2. Entrained organisms that were not listed as species of concern, but that were found in the entrainment samples included copepods, decapods, chaetognatha, and various phytoplankton. These organisms should not be included as part of the discharge monitoring report submittal because they do not represent species of commercial, recreational, or forage concern.

Conclusions

Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at Chad.Cristina@C-KA.com.

Sincerely yours,
CK Associates

Chad Cristina Ph.D, P.E

Chad M. Cristina Ph.D., P.E.
Senior Environmental Engineer

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
2	2014	6/27/2014 14:15	6/28/2014 14:25	13.2	0.019	24-hr Continuous

Table 2
Entrainment Summary by Quarter

Quarter	Year	Species/Family	Total Collected	Sample Volume (MG)	Total # Entrained[1]
2	2014	*Thunnus albacares*(yellowfin tuna)	0	0.019	0
2	2014	*Lutjanus campechanus*(red snapper)	0	0.019	0
2	2014	Total	0	0.019	0

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

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September 18, 2014 **Sent Via Email**

Chevron USA
17000 Katy Freeway
Houston, TX 77094
Attn: Ms. Kathy Dahl

Re: Third Quarter 2014 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Ms. Dahl:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the third quarter 2014 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a new fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit).

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 03:00 on August 4, 2014 and lasted until 03:00 on August 5, 2014. The EMD was operated continuously during the sampling period at a flow rate of 13.2 gallons per minute resulting in an entrainment sample volume of 19,000 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate accounts to zero eggs/larvae per cubic meter and approximately zero species of concern entrained per day. A summary of the entrained species of concern is included in Table 2. Entrained organisms that were not listed as species of concern, but that were found in the entrainment samples included copepods, decapods, chaetognatha, and various phytoplankton. These organisms should not be included as part of the discharge monitoring report submittal because they do not represent species of commercial, recreational, or forage concern.

Conclusions

Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at Chad.Cristina@C-KA.com.

Sincerely yours,
CK Associates

Chad Cristina Ph.D, P.E

Chad M. Cristina Ph.D., P.E.
Senior Environmental Engineer

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
3	2014	8/4/2014 03:00	8/5/2014 03:00	13.2	0.019	24-hr Continuous

Table 2
Entrainment Summary by Quarter

Quarter	Year	Species/Family	Total Collected	Sample Volume (MG)	Total # Entrained[1]
3	2014	*Thunnus albacares*(yellowfin tuna)	0	0.019	0
3	2014	*Lutjanus campechanus*(red snapper)	0	0.019	0
3	2014	Total	0	0.019	0

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

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December 29, 2014 **Sent Via Email**

Chevron USA
17000 Katy Freeway
Houston, TX 77094
Attn: Ms. Kathy Dahl

Re: Fourth Quarter 2014 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Ms. Dahl:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the fourth quarter 2014 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a new fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit).

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 03:00 on August 4, 2014 and lasted until 03:00 on August 5, 2014. The EMD was operated continuously during the sampling period at a flow rate of 13 gallons per minute resulting in an entrainment sample volume of 19,000 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero species of concern entrained per day. A summary of the entrained species of concern is included in Table 2. Entrained organisms that were not listed as species of concern, but that were found in the entrainment samples included polychaets, pteropods, copepods, chaetognaths, amphipods, and five fish species. None of these organisms should not be included as part of the discharge monitoring report submittal because they do not represent species of commercial, recreational, or forage concern.

Conclusions

Zero organisms of commercial, recreational, or forage concern were identified in entrainment samples collected from the JSM FPU during its first three calendar quarters of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at Chad.Cristina@C-KA.com.

Sincerely yours,
CK Associates

Chad Cristina Ph.D, P.E

Chad M. Cristina Ph.D., P.E.
Senior Environmental Engineer

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
4	2014	11/24/2014 0300	11/25/2014 0300	13.2 (est)	0.019	24-hr Continuous

Table 2
Entrainment Summary by Quarter

Quarter	Year	Species/Family	Total Collected	Sample Volume (MG)	Total # Entrained[1]
2	2014	*Thunnus albacares* (yellowfin tuna)	0	0.019	0
2	2014	*Lutjanus campechanus*(red snapper)	0	0.019	0
3	2014	*Thunnus albacares* (yellowfin tuna)	0	0.019	0
3	2014	*Lutjanus campechanus*(red snapper)	0	0.019	0
4	2014	*Thunnus albacares* (yellowfin tuna)	0	0.019	0
4	2014	*Lutjanus campechanus*(red snapper)	0	0.019	0
Total	**2014**	***Thunnus albacares* (yellowfin tuna)**	**0**		**0**
Total	**2014**	***Lutjanus campechanus*(red snapper)**	**0**		**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

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FAX (318) 798-0478

July 23, 2015 **Sent Via Email**

Chevron USA
17000 Katy Freeway
Houston, TX 77094
Attn: Ms. Kathy Dahl

Re: Revised First Quarter 2015 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Ms. Dahl:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the first quarter 2015 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a new fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit).

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 15:00 on January 18, 2015 and lasted until 11:00 on January 19, 2015. The EMD was operated continuously during the sampling period at a flow rate of 13.2 gallons per minute resulting in an entrainment sample volume of 16,000 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero species of concern entrained per day. A summary of the entrained species of concern is included in Table 2. Entrained organisms that were not listed as species of concern, but that were found in the entrainment samples included polychaets, pteropods, copepods, chaetognaths, amphipods, ctenophores and two fish species. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent species of commercial, recreational, or forage concern.

Conclusions

Zero organisms of commercial, recreational, or forage concern were identified in entrainment samples collected from the JSM FPU during its first calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at Chad.Cristina@C-KA.com.

Sincerely yours,
CK Associates

Chad Cristina Ph.D, P.E

Chad M. Cristina Ph.D., P.E.
Senior Environmental Engineer

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
1	2015	1/18/2015 1500	1/19/2015 1100	13.2 (est)	0.016	Composite

Table 2
Entrainment Summary by Quarter

Quarter	Year	Species/Family	Total Collected	Sample Volume (MG)	Total # Entrained[1]
1	2015	*Thunnus albacares* (yellowfin tuna)	0	0.016	0
1	2015	*Lutjanus campechanus*(red snapper)	0	0.016	0
Total	**2014**	***Thunnus albacares* (yellowfin tuna)**	**0**		**0**
Total	**2014**	***Lutjanus campechanus*(red snapper)**	**0**		**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

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SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

July 23, 2015 **Sent Via Email**

Chevron USA
100 Northpark Blvd.
Houston, TX 70433
Attn: Jim Floyd

Re: Revised Second Quarter 2015 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Ms. Dahl:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the second quarter 2015 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a new fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit).

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 03:00 on April 6, 2015 and lasted until 21:00 that evening. The EMD was operated continuously during the sampling period at a flow rate of 13.2 gallons per minute resulting in an entrainment sample volume of 16,000 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero species of concern entrained per day. A summary of the entrained species of concern is included in Table 2. Entrained organisms that were not listed as species of concern, but that were found in the entrainment samples included copepods, pteropods, amphipods, chaetognaths, ctenophores. Additionally, one damaged fish larva was observed, although the species was unable to be identified. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent species of commercial, recreational, or forage concern.

Conclusions

Zero organisms of commercial, recreational, or forage concern were identified in entrainment samples collected from the JSM FPU during its first calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at Chad.Cristina@C-KA.com.

Sincerely yours,
CK Associates

Chad Cristina Ph.D, P.E

Chad M. Cristina Ph.D., P.E.
Senior Environmental Engineer

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
2	2015	4/6/15 0300	4/6/15 2100	13.2 (est)	0.016	Composite

Table 2
Entrainment Summary by Quarter

Quarter	Year	Species/Family	Total Collected	Sample Volume (MG)	Total # Entrained[1]
1	2015	*Thunnus albacares* (yellowfin tuna)	0	0.016	0
1	2015	*Lutjanus campechanus*(red snapper)	0	0.016	0
2	2015	*Thunnus albacares* (yellowfin tuna)	0	0.016	0
2	2015	*Lutjanus campechanus*(red snapper)	0	0.016	0
Total	**2015**	***Thunnus albacares* (yellowfin tuna)**	**0**	**N/A**	**0**
Total	**2015**	***Lutjanus campechanus*(red snapper)**	**0**	**N/A**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

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July 23, 2015 **Sent Via Email**

Chevron USA
100 Northpark Blvd.
Houston, TX 70433
Attn: Jim Floyd

Re: Third Quarter 2015 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Mr. Floyd:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the third quarter 2015 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a new fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 13:00 on July 4, 2015 and lasted until 07:00 July 5, 2015. The EMD was operated continuously during the sampling period at a flow rate of 11.0 gallons per minute resulting in an entrainment sample volume of 12,000 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero species of concern entrained per day. A summary of the entrained species of concern is included in Table 2. Entrained organisms that were not listed as species of concern, but that were found in the entrainment samples included chaetognatha, copepods, amphipods, Lucifer faxoni. Additionally, three scaridae larvae was observed, although the species was unable to be identified. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent important commercial and recreational species of concern.

Conclusions

Zero organisms of important commercial and recreational species of concern were identified in entrainment samples collected from the JSM FPU during its third calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
3	2015	7/4/15 1300	7/5/15 0700	11.0 (est)	0.012	Composite

Table 2
Entrainment Summary by Quarter

Quarter	Year	Species/Family	Total Collected	Sample Volume (MG)	Total # Entrained[1]
1	2015	*Thunnus albacares* (yellowfin tuna)	0	0.016	0
1	2015	*Lutjanus campechanus*(red snapper)	0	0.016	0
2	2015	*Thunnus albacares* (yellowfin tuna)	0	0.016	0
2	2015	*Lutjanus campechanus*(red snapper)	0	0.016	0
3	2015	*Thunnus albacares* (yellowfin tuna)	0	0.012	0
3	2015	*Lutjanus campechanus*(red snapper)	0	0.012	0
Total	**2015**	***Thunnus albacares* (yellowfin tuna)**	**0**	**N/A**	**0**
Total	**2015**	***Lutjanus campechanus*(red snapper)**	**0**	**N/A**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment A - Example Data Sheet
Cooling Water Intake Structure Entrainment Sampling and Monitoring Procedures
Chevron North America Exploration and Production Company Deepwater
Jack St. Malo Platform

Collection Date	7/4 - 7/5/15
Project Number	
Names of Personnel Collecting Samples	John Berry, Isaac Newman
Sample Collection Flow Rate	11 gal/min
Sample Event Start Time and Date	1 pm 7/4/15
Sample Event End Time and Date	7 Am 7/5/15
Weather Conditions during each cycle	Calm
Number of Sample Jars Filled	4
Sample Collection Method	every 6 hours for 24 total hours
Other Notes Relevant to Sampling Event	

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY
AND
ANALYTICAL REQUEST RECORD

Page ______ of ______

CLIENT: Chevron N.A. Jack St. Malo
P.O. NUMBER: N/A
SAMPLED BY: Isaac Newman
PROJECT NO.: ______
LABORATORY*: CK Associates
DATE: 7/8/15

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
Sample #1	7/8/15	7/4/15 @ 1300	Sea-water	1 of 4	10% formain	Provide information on species Composition, abundance, and size of entrained organisms
Sample #2	7/8/15	7/4/15 @ 1900	Sea-water	2 of 4	10% formain	
Sample #3	7/8/15	7/5/15 @ 0100	Sea-water	3 of 4	10% for main	
Sample #4	7/8/15	7/5/15 @ 0700	Sea-water	4 of 4	10% for main	
		↓				
		Dates and written on	times sample			
		containers				~~Lab ID JSM15070801~~ cez 7.8.15
						Lab ID JSM15070801

Relinquished by:	**(Name)** Clint Ward	**Date** 7-8-15	**Time** 8:00	**Received by:**	**(Name)** Kasten Despay	**Date** 7/8/15	**Time** 1047
	(Signature)	**Date** 7-8-15	**Time** 8:00		**(Signature)**	**Date** 7/8/15	**Time** 1047
Relinquished by:	**(Name)** Kasten Despay	**Date** 7-8-15	**Time** 11:18	**Received by ~~Laboratory~~:**	**(Name)** Jenifer Thibodaux	**Date** 7/8/15	**Time** 11:18
	(Signature)	**Date** 7-8-15	**Time** 11:18		**(Signature)**	**Date** 7/8/15	**Time** 11:18

Method of Shipment: HotShot
Condition of Samples upon receipt at laboratory:
Temperature upon receipt

7/8/15 13:58 Robert Waddell 7-8-15 1358

Please send results and invoice to the attention of ______ in our ☐ Baton Rouge, ☐ Lake Charles, ☐ Shreveport, ☐ Houston Office

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

CK-100

ATTACHMENT C
FIELD OBSERVATIONS DURING SAMPLING

Subject: JSM Entrainment Sample-Attachment A

From: Rodrigue, Clay W. (wrod) [mailto:WROD@chevron.com]
Sent: Thursday, July 09, 2015 3:56 PM
To: Kunjappy, Raj
Subject: RE: JSM Entrainment Sample-Attachment A

Raj, Speaking with John Berry.

1. No obstructions in the meter or the hoses.
2. The assembly has no devices that require calibration, the flow meter is a replaceable type and is functioning now.
3. See above.
4. Both gentlemen report that the screen was intact during the collection procedure.
5. No incident or situation occurred that would that draw any attention to the lowered count. Pumps stayed online with no shut-ins or swaps.

Both indicated a light coating of the material was noted. Let me know if you feel another sample is needed.

From: Kunjappy, Raj
Sent: Thursday, July 09, 2015 3:03 PM
To: Rodrigue, Clay W. (wrod)
Cc: Floyd, Jim
Subject: RE: JSM Entrainment Sample-Attachment A

If we can evaluate the sample procedure and ensure none of the following occurred:

(1) possible flow meter obstruction due to aquatic vegetation or other debris on the propeller
(2) malfunctioning or damaged flow meters;
(3) any equipment used that requires calibration and is not properly calibrated;
(4) damaged (torn) screening found after a sample is collected;
(5) any incident or situation which may result in the collection of unreliable data;

I am leaning towards having the lab analyze if we can confirm the above.

Thank you,
Raj Kunjappy
HES Specialist- Water/NPDES

Gulf of Mexico Business Unit
Chevron North America Exploration and Production Company
(a Chevron U.S.A. Inc division)
100 Northpark Boulevard (COV114/122B)
Covington, LA 70433
O: 985-773-7283
C: 985-377-6991
raj.kunjappy@chevron.com

From: Rodrigue, Clay W. (wrod)
Sent: Thursday, July 09, 2015 2:50 PM

To: Kunjappy, Raj
Subject: RE: JSM Entrainment Sample-Attachment A

Raj, I just spoke with Isaac and he commented that he noticed little was caught in the sample he recovered. Also spoke with John separately and he noted the same. Neither felt the necessity to include it in the note section, though they both said it was just out of the ordinary.

From: Kunjappy, Raj
Sent: Thursday, July 09, 2015 2:05 PM
To: Rodrigue, Clay W. (wrod)
Subject: JSM Entrainment Sample-Attachment A

Clay,
Do you have a document referred to as "Attachment A" that was filled out? If you do, could you send it to me? See the second page of the attachment.

Thank you,
Raj Kunjappy
HES Specialist- Water/NPDES

Gulf of Mexico Business Unit
Chevron North America Exploration and Production Company
(a Chevron U.S.A. Inc division)
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July 23, 2015 **Sent Via Email**

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Attn: Jim Floyd

Re: Third Quarter 2015 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Mr. Floyd:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the third quarter 2015 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a new fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 13:00 on July 4, 2015 and lasted until 07:00 July 5, 2015. The EMD was operated continuously during the sampling period at a flow rate of 11.0 gallons per minute resulting in an entrainment sample volume of 12,000 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero species of concern entrained per day. A summary of the entrained species of concern is included in Table 2. Entrained organisms that were not listed as species of concern, but that were found in the entrainment samples included chaetognatha, copepods, amphipods, Lucifer faxoni. Additionally, three scaridae larvae was observed, although the species was unable to be identified. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent important commercial and recreational species of concern.

Conclusions

Zero organisms of important commercial and recreational species of concern were identified in entrainment samples collected from the JSM FPU during its third calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates

James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
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Table 2
Entrainment Summary by Quarter

Quarter	Year	Species/Family	Total Collected	Sample Volume (MG)	Total # Entrained[1]
1	2015	*Thunnus albacares* (yellowfin tuna)	0	0.016	0
1	2015	*Lutjanus campechanus*(red snapper)	0	0.016	0
2	2015	*Thunnus albacares* (yellowfin tuna)	0	0.016	0
2	2015	*Lutjanus campechanus*(red snapper)	0	0.016	0
3	2015	*Thunnus albacares* (yellowfin tuna)	0	0.012	0
3	2015	*Lutjanus campechanus*(red snapper)	0	0.012	0
Total	**2015**	***Thunnus albacares* (yellowfin tuna)**	**0**	**N/A**	**0**
Total	**2015**	***Lutjanus campechanus*(red snapper)**	**0**	**N/A**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment A - Example Data Sheet
Cooling Water Intake Structure Entrainment Sampling and Monitoring Procedures
Chevron North America Exploration and Production Company Deepwater
Jack St. Malo Platform

Collection Date: 7/4 - 7/5/15

Project Number:

Names of Personnel Collecting Samples: John Berry, Isaac Newman

Sample Collection Flow Rate: 11 gal/min

Sample Event Start Time and Date: 1 pm 7/4/15

Sample Event End Time and Date: 7 Am 7/5/15

Weather Conditions during each cycle: Calm

Number of Sample Jars Filled: 4

Sample Collection Method: every 6 hours for 24 total hours

Other Notes Relevant to Sampling Event:

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page ____ **of** ____

CLIENT: Chevron N.A. Jack St. Malo
P.O. NUMBER: N/A
SAMPLED BY: Isaac Newman
PROJECT NO.: ____
LABORATORY*: CK Associates
DATE: 7/8/15

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
Sample #1	7/8/15	7/4/15 @ 1300	Sea-water	1 of 4	10% formain	Provide information on species Composition, abundance, and size of entrained organisms
Sample #2	7/8/15	7/4/15 @ 1900	Sea-water	2 of 4	10% formain	
Sample #3	7/8/15	7/5/15 @ 0800	Sea-water	3 of 4	10% formain	
Sample #4	7/8/15	7/5/15 @ 0700	Sea-water	4 of 4	10% formain	
		Dates and written on	times sample			~~Lab ID JSM15070801~~ cez 7.8.15
		containers				Lab ID JSM15070801

		Date	Time			Date	Time
Relinquished by:	**(Name)** Clint Ward	7-8-15	8:00	**Received by:**	**(Name)** Kasten Despay	7/8/15	1047
	(Signature)	7-8-15	8:00		**(Signature)**	7/8/15	1047
Relinquished by:	**(Name)** Kasten Despay	7-8-15	11:18	**Received by ~~Laboratory~~:**	**(Name)** Jenifer Thibodaux	7/8/15	11:18
	(Signature)	7-8-15	11:18		**(Signature)** Thibodaux	7/8/15	11:18

Method of Shipment: HotShot
Condition of Samples upon receipt at laboratory:
Temperature upon receipt

Jenifer Thibodaux 7/8/15 13:58 Robert Waddell 7-8-15 1358

Please send results and invoice to the attention of ____ in our ☐ Baton Rouge, ☐ Lake Charles, ☐ Shreveport, ☐ Houston Office

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

CK-100

ATTACHMENT C
FIELD OBSERVATIONS DURING SAMPLING

Subject: JSM Entrainment Sample-Attachment A

From: Rodrigue, Clay W. (wrod) [mailto:WROD@chevron.com]
Sent: Thursday, July 09, 2015 3:56 PM
To: Kunjappy, Raj
Subject: RE: JSM Entrainment Sample-Attachment A

Raj, Speaking with John Berry.

1. No obstructions in the meter or the hoses.
2. The assembly has no devices that require calibration, the flow meter is a replaceable type and is functioning now.
3. See above.
4. Both gentlemen report that the screen was intact during the collection procedure.
5. No incident or situation occurred that would that draw any attention to the lowered count. Pumps stayed online with no shut-ins or swaps.

Both indicated a light coating of the material was noted. Let me know if you feel another sample is needed.

From: Kunjappy, Raj
Sent: Thursday, July 09, 2015 3:03 PM
To: Rodrigue, Clay W. (wrod)
Cc: Floyd, Jim
Subject: RE: JSM Entrainment Sample-Attachment A

If we can evaluate the sample procedure and ensure none of the following occurred:

(1) possible flow meter obstruction due to aquatic vegetation or other debris on the propeller
(2) malfunctioning or damaged flow meters;
(3) any equipment used that requires calibration and is not properly calibrated;
(4) damaged (torn) screening found after a sample is collected;
(5) any incident or situation which may result in the collection of unreliable data;

I am leaning towards having the lab analyze if we can confirm the above.

Thank you,
Raj Kunjappy
HES Specialist- Water/NPDES

Gulf of Mexico Business Unit
Chevron North America Exploration and Production Company
(a Chevron U.S.A. Inc division)
100 Northpark Boulevard (COV114/122B)
Covington, LA 70433
O: 985-773-7283
C: 985-377-6991
raj.kunjappy@chevron.com

From: Rodrigue, Clay W. (wrod)
Sent: Thursday, July 09, 2015 2:50 PM

To: Kunjappy, Raj
Subject: RE: JSM Entrainment Sample-Attachment A

Raj, I just spoke with Isaac and he commented that he noticed little was caught in the sample he recovered. Also spoke with John separately and he noted the same. Neither felt the necessity to include it in the note section, though they both said it was just out of the ordinary.

From: Kunjappy, Raj
Sent: Thursday, July 09, 2015 2:05 PM
To: Rodrigue, Clay W. (wrod)
Subject: JSM Entrainment Sample-Attachment A

Clay,
Do you have a document referred to as "Attachment A" that was filled out? If you do, could you send it to me? See the second page of the attachment.

Thank you,
Raj Kunjappy
HES Specialist- Water/NPDES

Gulf of Mexico Business Unit
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(a Chevron U.S.A. Inc division)
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C: 985-377-6991
raj.kunjappy@chevron.com

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LAKE CHARLES, LA
PHONE (337)625-6577
FAX (337)625-6580

SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

October 30, 2015

Sent Via Email

Chevron USA
100 Northpark Blvd.
Houston, TX 70433
Attn: Jim Floyd

Re: Fourth Quarter 2015 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Mr. Floyd:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the fourth quarter 2015 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a new fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 19:00 on October 5, 2015 and lasted until 19:00 on October 6, 2015. The EMD was operated continuously during the sampling period at a flow rate of 19.0 gallons per minute resulting in an entrainment sample volume of 27,360 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero species of concern entrained per day. A summary of the entrained species of concern is included in Table 2. Entrained organisms that were not listed as species of concern, but that were found in the entrainment samples included ctenophores, copepods, pteropods amphipods, *Lucifer faxoni*. Additionally, one Stomatopod (mantis shrimp) probably *Squilla empusa* stage II larvae, one Xanthidae crab probably *Hexapanopeus angustifrons* Megalop stage, two *Brevooitia spp.* larvae, and two Haemulidae larvae too damaged to identify. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent important commercial and recreational species of concern.

Conclusions

Zero organisms of important commercial and recreational species of concern were identified in entrainment samples collected from the JSM FPU during its fourth calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
4	2015	10/5/15 1900	10/6/15 1900	19.0 (est)	0.027	Composite

Table 2
Entrainment Summary by Quarter

Quarter	Year	Species/Family	Total Collected	Sample Volume (MG)	Total # Entrained[1]
1	2015	*Thunnus albacares* (yellowfin tuna)	0	0.016	0
1	2015	*Lutjanus campechanus*(red snapper)	0	0.016	0
2	2015	*Thunnus albacares* (yellowfin tuna)	0	0.016	0
2	2015	*Lutjanus campechanus*(red snapper)	0	0.016	0
3	2015	*Thunnus albacares* (yellowfin tuna)	0	0.012	0
3	2015	*Lutjanus campechanus*(red snapper)	0	0.012	0
4	2015	*Thunnus albacares* (yellowfin tuna)	0	0.027	0
4	2015	*Lutjanus campechanus*(red snapper)	0	0.027	0
Total	**2015**	***Thunnus albacares* (yellowfin tuna)**	**0**	**N/A**	**0**
Total	**2015**	***Lutjanus campechanus*(red snapper)**	**0**	**N/A**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment A Data Sheet
Cooling Water Intake Structure Entrainment Sampling and Monitoring Procedures
Chevron North America Exploration and Production Company Deepwater
Jack St. Malo Platform

Collection Date	10/6/2015 ~~7am~~ ~~10/6/2015 0100, 0700, 1300~~ 1AM, 7AM, 1PM, 7PM
Project Number	JSM
Names of Personnel Collecting Samples	ISAAC NEWMAN / JOHN BERRY
Sample Collection Flow Rate	≈16-19 GPM
Sample Event Start Time and Date	10/5/2015 7:00 PM
Sample Event End Time and Date	10/6/2015 ~~1:00~~ 7:00 PM
Weather Conditions during each cycle	CALM ; 4-5 FT SEAS ;
Number of Sample Jars Filled	4
Sample Collection Method	ENTRAINMENT MONITORING DEVICE
Other Notes Relevant to Sampling Event	

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K
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ENVIRONMENTAL & ENGINEERING
CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page 1 **of** 1

CLIENT: Chevron Jack St Malo **P.O. NUMBER:** NA **SAMPLED BY:** John Berry / ISAAC Newman

PROJECT NO.: 10726 **LABORATORY*:** CK Associates **DATE:** 10-6-15

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
Plankton	10-6-15	01:00	Sea water	4	10% Formalin	Provide information on species composition
Plankton	10-6-15	07:00	Sea water	4	10% Formalin	abundence, and size of entrained organisms.
Plankton	10-6-15	13:00	Sea water	4	10% Formalin	
Plankton	10-6-15	19:00	Sea water.	4	10% Formalin.	JSM 15100701

Relinquished by:	**(Name)** John Berry	**Date** 10/7/15	**Time** 13:08	**Received by:**	**(Name)** ELSON RICHARD	**Date** 10-7-15	**Time** 13:08
	(Signature)	**Date** ↓	**Time** ↓		**(Signature)** Elson Richard	**Date** ↓	**Time** 1:08P
Relinquished by:	**(Name)** ELSON RICHARD	**Date** 10-7-15	**Time** 15:27	**Received by Laboratory:**	**(Name)** Gus Zieske	**Date** 10.7.15	**Time** 1527
	(Signature) Elson Richard	**Date** ↓	**Time** 3:27P		**(Signature)**	**Date** ↓	**Time** ↓

Method of Shipment:	**Condition of Samples upon receipt at laboratory:**	**Temperature upon receipt**

Please send results and invoice to the attention of ______________________ **in our** ☐ **Baton Rouge,** ☐ **Lake Charles,** ☐ **Shreveport,** ☐ **Houston Office**

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

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CK ASSOCIATES
Environmental Consultants

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FAX (337) 625-6580

SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

February 2, 2016 **Sent Via Email**

Chevron USA
100 Northpark Blvd.
Covington, LA 70433
Attn: Jim Floyd

Re: First Quarter 2016 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Mr. Floyd:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the first quarter 2016 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 0600 hours on January 6, 2016 and lasted until 0000 hours on January 7, 2016. The EMD was operated continuously during the sampling period at a flow rate of 19.0 gallons per minute resulting in an entrainment sample volume of 20,520 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero species of concern entrained per day. A summary of the entrained species of concern is included in Table 2. Entrained organisms that were not listed as species of concern, but that were found in the entrainment samples included ctenophores, copepods, pteropods chaetognaths. Additionally, one Scaridae larva and three Mugilidae larvae. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent important commercial and recreational species of concern.

Conclusions

Zero organisms of important commercial and recreational species of concern were identified in entrainment samples collected from the JSM FPU during its first calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates

James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
1	2016	01/6/16 0600	01/7/16 0000	19.0 (est)	0.020	Composite

Table 2
Entrainment Summary by Quarter

Quarter	Year	Species/Family	Total Collected	Sample Volume (MG)	Total # Entrained[1]
1	2016	*Thunnus albacares* (yellowfin tuna)	0	0.020	0
1	2016	*Lutjanus campechanus*(red snapper)	0	0.020	0
Total	**2016**	***Thunnus albacares* (yellowfin tuna)**	**0**	**N/A**	**0**
Total	**2016**	***Lutjanus campechanus*(red snapper)**	**0**	**N/A**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment A Data Sheet
Cooling Water Intake Structure Entrainment Sampling and Monitoring Procedures
Chevron North America Exploration and Production Company Deepwater
Jack St. Malo Platform

Collection Date	1/6/2016
Project Number	10726
Names of Personnel Collecting Samples	Kent Ertan, Clark Bergeron, Clint Ward
Sample Collection Flow Rate	≈ 19 GPM
Sample Event Start Time and Date	1-6-2016 0600 AM
Sample Event End Time and Date	1-7-2016 1200 AM
Weather Conditions during each cycle	5'---7' seas Clear sky 75 degrees
Number of Sample Jars Filled	4
Sample Collection Method	Side Stream
Other Notes Relevant to Sampling Event	Normal operations. No facility upset Sea water Lift Pump on line entire time. Flow Rate unknown. Operators commented valves were open as on the last sample

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page_____ of_____

CLIENT: Chevron NA, Jack ST. Malo **P.O. NUMBER:** Not Appicable **SAMPLED BY:** Clint Ward

PROJECT NO.: 10726 **LABORATORY*:** CK Associates **DATE:** 1-6-2016

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
Plankton	1-6-16	6:00am	Sea water	1	10% Formalin	Provide information on Species Composition abundance and size of entrained organism
Plankton	1-6-16	12:00pm	Sea water	1	10% Formalin	" "
Plankton	1-6-16	6:00pm	Sea water	1	10% Formalin	" "
Plankton	1-7-16	12:00am	Sea water	1	10% Formalin	" "
						JSM16010701

Relinquished by:	(Name) George Oky	Date 1-7-16	Time 2:00pm	**Received by:**	(Name) LEWIS CULLEY	Date 1-7-16	Time 1401
	(Signature)	Date 1-7-16	Time 2:00pm		(Signature) Lewis Culley	Date	Time
Relinquished by:	(Name) LEWIS CULLEY	Date 1/7/16	Time 1552	**Received by Laboratory:**	(Name) Bertin Schexnayder	Date 1-7-16	Time 1555
	(Signature) Lewis Culley	Date	Time		(Signature) Bert J Schexnayder	Date	Time
Method of Shipment: BERTIN SCHEXNAYDER Bert J Schexnayder		**Condition of Samples upon receipt at laboratory:** 1/7/16 1825				**Temperature upon receipt**	

Please send results and invoice to the attention of ______________________ in our ☐ Baton Rouge, ☐ Lake Charles, ☐ Shreveport, ☐ Houston Office

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CK ASSOCIATES
Environmental Consultants

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FAX (337) 625-6580

SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

May 10, 2016 **Sent Via Email**

Chevron USA
100 Northpark Blvd.
Covington, LA 70433
Attn: Jim Floyd

Re: Second Quarter 2016 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Mr. Floyd:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the second quarter 2016 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 2000 hours on April 5, 2016 and lasted until 2000 hours on April 6, 2016. The EMD was operated continuously during the sampling period at a flow rate of 7.0 gallons per minute resulting in an entrainment sample volume of 10,080 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as key representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero key species of concern entrained per day. A summary of the entrained key species of concern is included in Table 2. In addition to any key species of concern identified, there were other ichthyoplankton observed in the sample. Two additional fish eggs were found; however, they could not be identified because of the lack of development structures. There were no additional fish larvae observed in the sample, see Table 3. Other entrained organisms that were not listed as key species of concern and are not ichthyoplankton, but that were found in the entrainment samples included Amphipods, Mysid shrimp, polychaetes, ctenophores, copepods, pteropods, chaetognaths, see Table 4. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent key important commercial and recreational species of concern.

Conclusions

Zero organisms of key important commercial and recreational species of concern were identified in entrainment samples collected from the JSM FPU during its second calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Sample Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
2	2016	04/5/16 2000	04/6/16 2000	7.0 (est)	0.010	Composite

Table 2
Entrainment Summary by Quarter
(Key Important Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	*Thunnus albacares* (yellowfin tuna) *Lutjanus campechanus*(red snapper)	0 0	0 0	0.020	0 0	0 0
2	2016	*Thunnus albacares* (yellowfin tuna) *Lutjanus campechanus*(red snapper)	0 0	0 0	0.010	0 0	0 0
Total	**2016**	***Thunnus albacares* (yellowfin tuna)**	**0**	**0**	**N/A**	**0**	**0**
Total	**2016**	***Lutjanus campechanus*(red snapper)**	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 3
Other Ichthyoplankton
(Non Key Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	*Scaridae* *Mugilidae*	0 0	1 3	0.020	0 0	121,940 365,820
2	2016	*N/A*	2 0	0 0	0.010	487,760 0	0 0
Total	**2016**	***Eggs***	**2**	**0**	**N/A**	**487,760**	**0**
Total	**2016**	***Larvae***	**0**	**4**	**N/A**	**0**	**487,760**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 4
Other Non-Ichthyoplankton Entrained Organisms

Amphipods	Chaetognaths	Copepods	Ctenophores
Polychaetes	Mysid shrimp		Pteropods

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment A Data Sheet
Cooling Water Intake Structure Entrainment Sampling and Monitoring Procedures
Chevron North America Exploration and Production Company Deepwater
Jack St. Malo Platform

Collection Date 4-6-16

Project Number 10726

Names of Personnel Collecting Samples Clint Ward

Sample Collection Flow Rate 7 gpm

Sample Event Start Time and Date 4-5-16 20:00

Sample Event End Time and Date 4-6-16 20:00

Weather Conditions during each cycle Calm Seas Clear Sky

Number of Sample Jars Filled 4

Sample Collection Method online Screen sample.

Other Notes Relevant to Sampling Event

Preservation Fluids had leaked out of Jars. Marks on Sample Bottles indicate amount of preservatives before Adding Seawater Sample.

All Samples went well.. No Issues.

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page 1 of 1

CLIENT: Chevron NA Jack St Malo

P.O. NUMBER: —

SAMPLED BY: Celie Milton / Clint Ward

PROJECT NO.: 10726

LABORATORY*: Ck Associates

DATE: 4/6/16

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
Plankton	4-6-16	0200	seawater	1	100% Formalin	Provide info on Species Composition Abundance + Size
Plankton	4-6-16	0800	seawater	1	100% Formalin	"
Plankton	4-6-16	1400	seawater	1	100% Formalin	"
Plankton	4/6/16	2000	seawater	1	100% Formalin	"
						JSM16040701

		Date	Time			Date	Time
Relinquished by:	(Name) Clay W. Rodrigue	4-7-16	8:00 am	**Received by:**	(Name) Gary Wegner	4-7-2016	0820
	(Signature) Clay W. Rodrigue	4-7-16	8:00 am.		(Signature) Gary Wegner	4-7-16	08:20
Relinquished by:	(Name) Gary Wegner	4-7-16	1025	**Received by Laboratory:**	(Name) Robert Waddell	4-7-16	1151
	(Signature) Gary Wegner	4-7-16	1025		(Signature)	4-7-16	1151

Method of Shipment: Commercial Carrier

Condition of Samples upon receipt at laboratory: iced

Temperature upon receipt

Robert Waddell 4-7-16 1430

Please send results and invoice to the attention of ____________ **in our** ☐ **Baton Rouge,** ☐ **Lake Charles,** ☐ **Shreveport,** ☐ **Houston Office**

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

CK-100

CK ASSOCIATES
Environmental Consultants

17170 PERKINS ROAD
BATON ROUGE, LA 70810
PHONE (225) 755-1000
FAX (225) 751-2010
http://www.c-ka.com

HOUSTON, TX
PHONE (281) 397-9016
FAX (281) 397-6637

LAKE CHARLES, LA
PHONE (337)625-6577
FAX (337)625-6580

SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

August 8, 2016

Sent Via Email

Chevron USA
100 Northpark Blvd.
Covington, LA 70433
Attn: Jim Floyd

Re: Third Quarter 2016 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Mr. Floyd:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the third quarter 2016 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 0900 hours on July 4, 2016 and lasted until 0900 hours on July 5, 2016. The EMD was operated continuously during the sampling period at a flow rate of 34.4 gallons per minute resulting in an entrainment sample volume of 49,536 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as key representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero key species of concern entrained per day. A summary of the entrained key species of concern is included in Table 2. In addition to any key species of concern identified, there were other ichthyoplankton observed in the sample. One additional fish egg was found. There were no additional fish larvae observed in the sample, see Table 3. Other entrained organisms that were not listed as key species of concern and are not ichthyoplankton, but that were found in the entrainment samples included Amphipoda, *Acetes americanus carolinae*, Ctenophores, copepods, pteropoda, Chaetognatha, see Table 4. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent key important commercial and recreational species of concern.

Conclusions

Zero organisms of key important commercial and recreational species of concern were identified in entrainment samples collected from the JSM FPU during its third calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Sample Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
3	2016	07/4/16 0900	07/5/16 0900	34.4 (est)	0.049	Composite

Table 2
Entrainment Summary by Quarter
(Key Important Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	*Thunnus albacares* (yellowfin tuna)	0	0	0.020	0	0
		Lutjanus campechanus(red snapper)	0	0		0	0
2	2016	*Thunnus albacares* (yellowfin tuna)	0	0	0.010	0	0
		Lutjanus campechanus(red snapper)	0	0		0	0
3	2016	*Thunnus albacares* (yellowfin tuna)	0	0	0.049	0	0
		Lutjanus campechanus(red snapper)	0	0		0	0
Total	**2016**	***Thunnus albacares* (yellowfin tuna)**	**0**	**0**	**N/A**	**0**	**0**
Total	**2016**	***Lutjanus campechanus*(red snapper)**	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 3
Other Ichthyoplankton
(Non Key Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	Scaridae	0	1	0.020	0	121,940
		Mugilidae	0	3		0	365,820
2	2016	N/A	2	0	0.010	487,760	0
3	2016	Clupeidae	1	0	0.049	49,771	0
Total	**2016**	**Eggs**	**3**	**0**	**N/A**	**537,531**	**0**
Total	**2016**	**Larvae**	**0**	**4**	**N/A**	**0**	**487,760**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 4
Other Non-Ichthyoplankton Entrained Organisms

Acetes americanus carolinae	Amphipoda	Chaetognatha
copepods	Ctenophores	pteropods

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment A Data Sheet
Cooling Water Intake Structure Entrainment Sampling and Monitoring Procedures
Chevron North America Exploration and Production Company Deepwater
Jack St. Malo Platform

Collection Date	7/4/2016
Project Number	10726
Names of Personnel Collecting Samples	Kent Ertan / Joel Vidrine
Sample Collection Flow Rate	34.4
Sample Event Start Time and Date	09:00 / 7/4/2016
Sample Event End Time and Date	09:00 / 7/5/2016
Weather Conditions during each cycle	Calm / Sunny
Number of Sample Jars Filled	4
Sample Collection Method	Filtered Screen / Q6HR
Other Notes Relevant to Sampling Event	

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K
ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY
AND
ANALYTICAL REQUEST RECORD

Page_____ **of**_____

CLIENT: Chevron / Jack St. Melo
P.O. NUMBER: N/A
SAMPLED BY: Kent Ertan / Joel Vidrine
PROJECT NO.: 10726
LABORATORY*: CK Associates
DATE: 7/4/16

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
Plankton	7/4/16	15:00	Sea-Water	1	Kent Ertan	Provide information of Species composition.
Plankton	7/4/16	21:00	Sea-Water	2	Joel Vidrine	–
Plankton	7/5/16	03:00	Sea-Water	3	Joel Vidrine	–
Plankton	7/5/16	09:00	Sea-Water	4	Kent Ertan	–
						JSM16071101

Relinquished by:	(Name) Kent Ertan	Date 7/6/16	Time 11:00	**Received by:**	(Name) Taylor Griffin	Date 7/6/16	Time 11:00
	(Signature)	Date 7/6/16	Time 11:00		(Signature)	Date 7/6/16	Time 11:00
Relinquished by:	(Name) ~~Kent~~ Taylor Griffin	Date 7/6/16	Time 1233	**Received by Laboratory:**	(Name) Chris Weld	Date 7-11-16	Time 1450
	(Signature) Taylor Griffin	Date 7/[illegible]/16	Time 1233		(Signature)	Date 7-11-16	Time 1450

Method of Shipment: Fed Ex, USPS or Commercial Carrier

Condition of Samples upon receipt at laboratory: Intact

Temperature upon receipt

Please send results and invoice to the attention of George Obey 1-985-773-5173 **in our** ☐ **Baton Rouge,** ☐ **Lake Charles,** ☐ **Shreveport,** ☐ **Houston Office**

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

CK-100

CK ASSOCIATES
Environmental Consultants

17170 PERKINS ROAD
BATON ROUGE, LA 70810
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LAKE CHARLES, LA
PHONE (337) 625-6577
FAX (337) 625-6580

SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

November 4, 2016 **Sent Via Email**

Chevron USA
100 Northpark Blvd.
Covington, LA 70433
Attn: Jim Floyd

Re: Fourth Quarter 2016 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Mr. Floyd:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the fourth quarter 2016 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 1815 hours on October 21, 2016 and lasted until 1215 hours on October 22, 2016. The EMD was operated continuously during the sampling period at a flow rate of 13.4 gallons per minute resulting in an entrainment sample volume of 14,472 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as key representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero key species of concern entrained per day. A summary of the entrained key species of concern is included in Table 2. There were no additional ichthyoplankton (eggs/larvae) observed in the sample see Table 3. Other entrained organisms that were not listed as key species of concern and are not ichthyoplankton, but that were found in the entrainment samples included copepods, Chaetognatha, *Callinectes sapidus* (two - megalopa) see Table 4. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent key important commercial and recreational species of concern.

Conclusions

Zero organisms of key important commercial and recreational species of concern were identified in entrainment samples collected from the JSM FPU during its fourth calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Sample Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
4	2016	10/21/16 1815	10/22/16 1215	13.4 (est)	0.014	Composite

Table 2
Entrainment Summary by Quarter
(Key Important Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	*Thunnus albacares* (yellowfin tuna)	0	0	0.020	0	0
		Lutjanus campechanus(red snapper)	0	0		0	0
2	2016	*Thunnus albacares* (yellowfin tuna)	0	0	0.010	0	0
		Lutjanus campechanus(red snapper)	0	0		0	0
3	2016	*Thunnus albacares* (yellowfin tuna)	0	0	0.049	0	0
		Lutjanus campechanus(red snapper)	0	0		0	0
4	2016	*Thunnus albacares* (yellowfin tuna)	0	0	0.014	0	0
		Lutjanus campechanus(red snapper)	0	0		0	0
Total	**2016**	***Thunnus albacares* (yellowfin tuna)**	**0**	**0**	**N/A**	**0**	**0**
Total	**2016**	***Lutjanus campechanus*(red snapper)**	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 3
Other Ichthyoplankton
(Non Key Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	Scaridae	0	1	0.020	0	121,940
		Mugilidae	0	3		0	365,820
2	2016	N/A	2	0	0.010	487,760	0
3	2016	Clupeidae	1	0	0.049	49,771	0
4	2016	N/A	0	0	0.014	0	0
Total	**2016**	**Eggs**	**3**	**0**	**N/A**	**537,531**	**0**
Total	**2016**	**Larvae**	**0**	**4**	**N/A**	**0**	**487,760**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 4
Other Non-Ichthyoplankton Entrained Organisms

copepods	Chaetognatha	*Callinectes sapidus* (2 - megalopa)

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment A - Example Data Sheet
Cooling Water Intake Structure Entrainment Sampling and Monitoring Procedures
Chevron North America Exploration and Production Company Deepwater
Jack St. Malo Platform

Collection Date 10/21/2016

Project Number 10726

Names of Personnel Collecting Samples 4

Sample Collection Flow Rate 13.4

Sample Event Start Time and Date 6:15PM 10/21/2016

Sample Event End Time and Date 12:15PM 10/22/2016

Weather Conditions during each cycle 4FT SE WINDS 12KNOTS

Number of Sample Jars Filled 4

Sample Method Entrainment Kit

Other Notes Relevant to Sampling Event

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page 1 of 1

CLIENT: Chevron / Jack St. Malo
P.O. NUMBER: Not Applicable
SAMPLED BY: Kent Ertan / Clark Bergeron
PROJECT NO.: 10726
LABORATORY*: CK Associates
DATE: 10/21/2016

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
Plankton	10-21-16	6:15PM	SEA-WATER	1	100% Formalin	Provide information on species composition, abundance and size entrained organisms.
Plankton	10-22-16	12:15AM	SEA-WATER	2	100% Formalin	Provide information on species composition, abundance and size entrained organisms.
Plankton	10-22-16	6:15AM	SEA-WATER	3	100% Formalin	Provide information on species composition, abundance and size entrained organisms.
Plankton	10-22-16 ~~12:15PM~~	12:15PM	SEA-WATER	4	100% Formalin	Provide information on species composition, abundance and size entrained organisms.

		Date	Time			Date	Time
Relinquished by:	(Name) George Obey	10-24-16	9:00 AM	**Received by:**	(Name) Christy Potts	10/24/16	9:00 am
	(Signature) George Obey	10-24-16	9:00 AM		(Signature) Christy Potts	10/24/16	9:00 a.m.
Relinquished by:	(Name) Christy Potts	10/24/16	10:08 a.m	**Received by Laboratory:**	(Name) Shane Boutte	10/24/16	10:08 am
	(Signature) Christy Potts	10/24/16	10:08 a.m		(Signature) Shane Boutte	10/24/16	10:08 am

Method of Shipment: relinquished by → Shane Boutte
Condition of Samples upon receipt at laboratory: 10/24/16 1216
Temperature upon receipt: Ambient

received by lab: Chris Welch 10-24-16 1216

Please send results and invoice to the attention of ____________________ in our ☐ Baton Rouge, ☐ Lake Charles, ☐ Shreveport, ☐ Houston Office

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

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LAKE CHARLES, LA
PHONE (337)625-6577
FAX (337)625-6580

SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

April 12, 2017

Chevron USA
100 Northpark Blvd.
Covington, LA 70433
Attn: Jim Floyd
Jim.floyd@chevron.com

Re: First Quarter 2017 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Mr. Floyd:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the first quarter 2017 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 2100 hours on January 5, 2017 and lasted until 2100 hours on January 6, 2017. The EMD was operated continuously during the sampling period at a flow rate of 20.0 gallons per minute resulting in an entrainment sample volume of 28,800 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as key representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero key species of concern entrained per day. A summary of the entrained key species of concern is included in Table 2. There were additional ichthyoplankton larvae observed in the sample, see Table 3. One possible Gempylidae, however only the head was present and it was difficult to identify any further. Additionally, there were three Haemulidae and two Sparidae, but again both were too damaged to be identify further. There were no ichthyoplankton eggs observed in the sample see Table 3. Other entrained organisms that were not listed as key species of concern and are not ichthyoplankton, but that were found in the entrainment samples included copepoda, ctenophora, Chaetognatha, Amphipoda, *Lucifer faxoni*, *Branchiostoma floridae*, Cladoceran, Polychaete, bivalve and pteropoda see Table 4. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent key important commercial and recreational species of concern.

Conclusions

Zero organisms of key important commercial and recreational species of concern were identified in entrainment samples collected from the JSM FPU during its first calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Sample Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
1	2017	01/5/17 2100	01/6/17 2100	20.0 (est)	0.029	Composite

Table 2
Entrainment Summary by Quarter
(Key Important Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2017	*Thunnus albacares* (yellowfin tuna)	0	0	0.029	0	0
		Lutjanus campechanus (red snapper)	0	0		0	0
Total	**2017**	***Thunnus albacares* (yellowfin tuna)**	**0**	**0**	**N/A**	**0**	**0**
Total	**2017**	***Lutjanus campechanus* (red snapper)**	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 3
Other Ichthyoplankton
(Non Key Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2017	Gempylidae	0	1	0.029	0	84,097
		Haemulidae	0	3		0	252,290
		Sparidae	0	2		0	168,193
Total	**2017**	**Larvae**	**0**	**6**	**N/A**	**0**	**504,580**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 4
Other Non-Ichthyoplankton Entrained Organisms

copepoda	Ctenophora	Chaetognatha
Amphipoda	*Lucifer faxoni*	*Bronchiostoma floridae*
Cladoceran	Polychaete	Bivalve
pteropoda		

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment A - Data Sheet
Cooling Water Intake Structure Entrainment Sampling and Monitoring Procedures
Chevron North America Exploration and Production Company Deepwater
Jack St. Malo Platform

Collection Date	1/~~6~~5/17 - 1/6/17 CR
Project Number	10726
Names of Personnel Collecting Samples	Josh Jaques / Billy Spinner
Sample Collection Flow Rate	20 GPM
Sample Event Start Time and Date	~~03:00 AM~~ 2100 CR 1/~~6~~5/17 CR
Sample Event End Time and Date	21 00 1/6/17
Weather Conditions during each cycle	Calm and Sunny into Dark w/ Rough Seas 10-12'
Number of Sample Jars Filled	4
Sample Method	
Other Notes Relevant to Sampling Event	Cold Front Moved Thru Air Temp 76° — 56° Wind Speed 15-18 Thru 35-38 Knots Other Than weather, No Significant Events occured during The Sample

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page____ of ____

CLIENT: Chevron N.A. Jack St Malo **P.O. NUMBER:** N/A **SAMPLED BY:** Josh Jaques / Billy Spinner

PROJECT NO.: 10726 **LABORATORY*:** C.K. Associates **DATE:** 1/6/2017

SAMPLE IDENTIFICATION	DATE (CR)	TIME (CR)	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
Plankton	1/~~6~~ 5/17	~~[illegible]~~ 21:00	Sea Water	1	100% Formalin	
Plankton	1/6/17	09:00	Sea Water	2	100% Formalin	
Plankton	1/6/17	15:00	Sea Water	3	100% Formalin	JSM 17011101
Plankton	1/6/17	21:00	Sea Water	4	100% Formalin	

Relinquished by:	(Name) Clay W. Rodrigue	Date ~~12-11-15~~ 1-11-17	Time 05:00	**Received by:** CVX	(Name) ROBIN L ROGERS	Date 1/11/17	Time
	(Signature) Clay W Rodrigue	Date ~~12-11-15~~ 1-11-17	Time 10:25am		(Signature) Robin L Rogers	Date 1/11/17	Time 10:25
~~Relinquished by:~~ REC	(Name) Edward Morgan	Date 1/11/17	Time 1230	**~~Received by Laboratory:~~** REC CVX	(Name) ROBIN L ROGERS	Date 1/11/17	Time 1230
	(Signature) Edward Morgan	Date 1/11/17	Time 1230		(Signature) Robin L Rogers	Date 1/11/17	Time 1230

Method of Shipment: Hotshot

Condition of Samples upon receipt at laboratory: Recd @ lab 1.11.17 1500 hrs samples intact

Temperature upon receipt: Ambient

Please send results and invoice to the attention of ________________ in our ☐ Baton Rouge, ☐ Lake Charles, ☐ Shreveport, ☐ Houston Office

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

CK-100

CK ASSOCIATES
Environmental Consultants

17170 PERKINS ROAD
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FAX (225) 751-2010
http://www.c-ka.com

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FAX (281) 397-6637

LAKE CHARLES, LA
PHONE (337) 625-6577
FAX (337) 625-6580

SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

July 1, 2016

Ms. Ellen Thomson
Anadarko Petroleum Corporation
1201 Lake Robbins Drive
The Woodlands, TX 77380
Ellen.Thomson@anadarko.com

Re: Second Quarter 2016 Entrainment Monitoring Report for the Heidelberg Spar Production Facility
CK Project No. 13096

Dear Ms. Thomson:

CK Associates (CK) is providing this letter report to Anadarko Petroleum Corporation (Anadarko) to summarize the findings of the second quarter 2016 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Heidelberg Spar production facility (HSPF). The HSPF is a fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the HSPF CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Anadarko personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s) and seawater basket strainers. The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the HSPF cooling water system downstream of the initial slip stream collection location.

The sampling process began at 0815 hours on June 9, 2016 and lasted until 0815 hours on June 10, 2016. The EMD was operated continuously during the sampling period (24 hours) at a flow rate of 14.0 gallons per minute resulting in an entrainment sample volume of 20,160 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified as key representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the HSPF CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero key species of concern entrained per day. A summary of the entrained key species of concern is included in Table 2. In addition to any key species of concern identified, there were no ichthyoplankton observed in the sample, see Table 3. Other entrained organisms that were not listed as key species of concern and are not ichthyoplankton, but that were found in the entrainment samples included chaetognaths, copepods and polychaetes, see Table 4. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent key important commercial and recreational species of concern.

Conclusions

Zero organisms of key important commercial and recreational species of concern were identified in entrainment samples collected from the HSPF during its second calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the HSPF CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Sample Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
2	2016	06/9/16 0815	06/10/16 0815	14.0 (est)	0.020	Composite

Table 2
Entrainment Summary by Quarter
(Key Important Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	*Thunnus albacares* (yellowfin tuna) *Lutjanus campechanus*(red snapper)	0 0	0 0	0.20	0 0	0 0
2	2016	*Thunnus albacares* (yellowfin tuna) *Lutjanus campechanus*(red snapper)	0 0	0 0	0.020	0 0	0 0
Total	**2016**	***Thunnus albacares* (yellowfin tuna)**	**0**	**0**	**N/A**	**0**	**0**
Total	**2016**	***Lutjanus campechanus*(red snapper)**	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 3
Other Ichthyoplankton
(Non Key Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	*N/A*	0 0	0 0	0.20	0 0	0 0
2	2016	*N/A*	0 0	0 0	0.020	0 0	0 0
Total	**2016**	***Eggs***	**0**	**0**	**N/A**	**0**	**0**
Total	**2016**	***Larvae***	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 4
Other Non-Ichthyoplankton Entrained Organisms

Chaetognaths	Copepods	Polychaetes

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

ATTACHMENT A

Attachment C - Sampling Data Sheet
Cooling Water Intake Structure Entrainment Sampling Procedures
Anadarko Petroleum Corporation
Heidelberg Spar Production Facility

Collection Dates 6/9 - 6/10/2016

Name(s) of Personnel S. McElhany
Collecting Samples S. McElhany

Sample Event Start Time 0815; 6/9

Flow reading after 1 min 14 gallons

Sample Event End Time 0815; 6/10

Total Time Sampled 24hrs

Sequential Sample Number HSPF - 2 QTR 2016

Number of Jars per Sample 4

Other Notes Relevant to Sampling Event

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K
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ENVIRONMENTAL & ENGINEERING
CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page____ of ____

CLIENT: Anadarko - HSPF
P.O. NUMBER: N/A
SAMPLED BY: S. McElhany
PROJECT NO.: Heidelberg CWIS 2QTR
LABORATORY*: CK
DATE: 6/16/2016

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
HSPF-2QTR2016	6/10	0815	SW	4	10% formalin	Species composition and abundance of target species
						HS16061001

Relinquished by:	(Name) Steven McElhany	Date 6/16/16	Time	**Received by:**	(Name)	Date	Time
	(Signature)	Date 6/16/16	Time		(Signature)	Date	Time
Relinquished by:	(Name)	Date	Time	**Received by Laboratory:**	(Name) Gus Zieske	Date 6.17.16	Time 1000
	(Signature)	Date	Time		(Signature)	Date ↓	Time ↓

Method of Shipment: GZ 6.17.16 ~~CK~~ Commercial Courier

Condition of Samples upon receipt at laboratory: Intact

Temperature upon receipt Ambient

Please send results and invoice to the attention of ____________________ in our ☐ Baton Rouge, ☐ Lake Charles, ☐ Shreveport, ☐ Houston Office

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

CK-100

CK ASSOCIATES
Environmental Consultants

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FAX (318) 798-0478

October 24, 2016

Ms. Ellen Thomson
Anadarko Petroleum Corporation
1201 Lake Robbins Drive
The Woodlands, TX 77380
Ellen.Thomson@anadarko.com

Re: Third Quarter 2016 Entrainment Monitoring Report for the Heidelberg Spar Production Facility
CK Project No. 13096

Dear Ms. Thomson:

CK Associates (CK) is providing this letter report to Anadarko Petroleum Corporation (Anadarko) to summarize the findings of the third quarter 2016 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Heidelberg Spar production facility (HSPF). The HSPF is a fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the HSPF CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Anadarko personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s) and seawater basket strainers. The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the HSPF cooling water system downstream of the initial slip stream collection location.

The sampling process began at 1030 hours on September 23, 2016 and lasted until 1030 hours on September 24, 2016. The EMD was operated continuously during the sampling period (24 hours) at a flow rate of 4.0 gallons per minute resulting in an entrainment sample volume of 5,760 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified as key representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the HSPF CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero key species of concern entrained per day. A summary of the entrained key species of concern is included in Table 2. In addition to any key species of concern identified, there were no ichthyoplankton observed in the sample, see Table 3. Other entrained organisms that were not listed as key species of concern and are not ichthyoplankton, but that were found in the entrainment samples included chaetognaths, copepods, polychaetes and ctenophores, see Table 4. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent key important commercial and recreational species of concern.

Conclusions

Zero organisms of key important commercial and recreational species of concern were identified in entrainment samples collected from the HSPF during its third calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the HSPF CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Sample Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
3	2016	09/23/16 1030	09/24/16 1030	4.0 (est)	0.006	Composite

Table 2
Entrainment Summary by Quarter
(Key Important Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	*Thunnus albacares* (yellowfin tuna)	0	0	0.20	0	0
		Lutjanus campechanus(red snapper)	0	0		0	0
2	2016	*Thunnus albacares* (yellowfin tuna)	0	0	0.020	0	0
		Lutjanus campechanus(red snapper)	0	0		0	0
3	2016	*Thunnus albacares* (yellowfin tuna)	0	0	0.006	0	0
		Lutjanus campechanus (red snapper)	0	0		0	0
Total	**2016**	***Thunnus albacares* (yellowfin tuna)**	**0**	**0**	**N/A**	**0**	**0**
Total	**2016**	***Lutjanus campechanus*(red snapper)**	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 3
Other Ichthyoplankton
(Non Key Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	*N/A*	0	0	0.20	0	0
			0	0		0	0
2	2016	*N/A*	0	0	0.020	0	0
			0	0		0	0
3	2016	*N/A*	0	0	0.006	0	0
			0	0		0	0
Total	**2016**	***Eggs***	**0**	**0**	**N/A**	**0**	**0**
Total	**2016**	***Larvae***	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 4
Other Non-Ichthyoplankton Entrained Organisms

Chaetognaths	Copepods	Ctenophores	Polychaetes

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment C - Sampling Data Sheet
Cooling Water Intake Structure Entrainment Sampling Procedures
Anadarko Petroleum Corporation
Heidelberg Spar Production Facility

Collection Dates 9/23 - 9/24/2016

Name(s) of Personnel S. McElhany

Collecting Samples S. McElhany

Sample Event Start Time 1030; 9/23

Flow reading after 1 min ~~[illegible]~~ 4 gallons

Sample Event End Time 1030; 9/24

Total Time Sampled 24 hrs

Sequential Sample Number HSPF - 3QTR2016

Number of Jars per Sample 4

Other Notes Relevant to Sampling Event

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page ____ **of** ____

CLIENT: Anadarko - HSPF

P.O. NUMBER: N/A

SAMPLED BY: S. McElhany

PROJECT NO.: 13096

LABORATORY*: CK

DATE: 9/24/16

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
HSPF-3QTR2016	9/24	1030	SW	4	10% formalin	Species composition & abundance of target species
						HS16092401

Relinquished by:	(Name) Steven McElhany	Date 9/26	Time 10:46	**Received by:**	(Name)	Date	Time
	(Signature)	Date	Time		(Signature)	Date	Time
Relinquished by:	(Name)	Date	Time	**Received by Laboratory:**	(Name) Gus Zieske	Date 10.21.16	Time 0700
	(Signature)	Date	Time		(Signature)	Date	Time

Method of Shipment: Hotshot

Condition of Samples upon receipt at laboratory: Intact

Temperature upon receipt Ambient

Please send results and invoice to the attention of ______________________ **in our** ☐ **Baton Rouge,** ☐ **Lake Charles,** ☐ **Shreveport,** ☐ **Houston Office**

CK ASSOCIATES
Environmental Consultants

17170 PERKINS ROAD
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PHONE (337) 625-6577
FAX (337) 625-6580

SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

January 16, 2017

Ms. Ellen Thomson
Anadarko Petroleum Corporation
1201 Lake Robbins Drive
The Woodlands, TX 77380
Ellen.Thomson@anadarko.com

Re: Fourth Quarter 2016 Entrainment Monitoring Report for the Heidelberg Spar Production Facility
CK Project No. 13096

Dear Ms. Thomson:

CK Associates (CK) is providing this letter report to Anadarko Petroleum Corporation (Anadarko) to summarize the findings of the fourth quarter 2016 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Heidelberg Spar production facility (HSPF). The HSPF is a fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the HSPF CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Anadarko personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s) and seawater basket strainers. The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the HSPF cooling water system downstream of the initial slip stream collection location.

The sampling process began at 0925 hours on December 17, 2016 and lasted until 0925 hours on December 18, 2016. The EMD was operated continuously during the sampling period (24 hours) at a flow rate of 8.0 gallons per minute resulting in an entrainment sample volume of 11,520 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified as key representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the HSPF CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero key species of concern entrained per day. A summary of the entrained key species of concern is included in Table 2. There were no additional ichthyoplankton (eggs/larvae) observed in the sample see Table 3. Other entrained organisms that were not listed as key species of concern and are not ichthyoplankton, but that were found in the entrainment samples included Chaetognaths, copepods and pteropods, see Table 4. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent key important commercial and recreational species of concern.

Conclusions

Zero organisms of key important commercial and recreational species of concern were identified in entrainment samples collected from the HSPF during its fourth calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the HSPF CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Sample Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
4	2016	12/17/16 0925	12/18/16 0925	8.0 (est)	0.012	Composite

Table 2
Entrainment Summary by Quarter
(Key Important Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	*Thunnus albacares* (yellowfin tuna) *Lutjanus campechanus*(red snapper)	0 0	0 0	0.20	0 0	0 0
2	2016	*Thunnus albacares* (yellowfin tuna) *Lutjanus campechanus*(red snapper)	0 0	0 0	0.020	0 0	0 0
3	2016	*Thunnus albacares* (yellowfin tuna) *Lutjanus campechanus* (red snapper)	0 0	0 0	0.006	0 0	0 0
4	2016	*Thunnus albacares* (yellowfin tuna) *Lutjanus campechanus* (red snapper)	0 0	0 0	0.012	0 0	0 0
Total	**2016**	***Thunnus albacares* (yellowfin tuna)**	**0**	**0**	**N/A**	**0**	**0**
Total	**2016**	***Lutjanus campechanus*(red snapper)**	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

Table 3
Other Ichthyoplankton
(Non Key Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2016	*N/A*	0 0	0 0	0.20	0 0	0 0
2	2016	*N/A*	0 0	0 0	0.020	0 0	0 0
3	2016	*N/A*	0 0	0 0	0.006	0 0	0 0
4	2016	*N/A*	0 0	0 0	0.012	0 0	0 0
Total	**2016**	***Eggs***	**0**	**0**	**N/A**	**0**	**0**
Total	**2016**	***Larvae***	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

Table 4
Other Non-Ichthyoplankton Entrained Organisms

Chaetognaths	copepods	pteropods

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment C - Sampling Data Sheet
Cooling Water Intake Structure Entrainment Sampling Procedures
Anadarko Petroleum Corporation
Heidelberg Spar Production Facility

Collection Dates 12-17 - 12-18-2016

Name(s) of Personnel Collecting Samples N. Comeaux

Sample Event Start Time 9:25AM 12-17-2016

Flow reading after 1 min 8gpm

Sample Event End Time 9:25AM 12-18-2016

Total Time Sampled 24 hrs.

Sequential Sample Number HSPF - 4QTR 2016

Number of Jars per Sample 4.

Other Notes Relevant to Sampling Event None

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K
ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page_____ of _____

CLIENT: Anadarko - HSPF **P.O. NUMBER:** NA **SAMPLED BY:** N. Comeaux

PROJECT NO.: 13096 **LABORATORY*:** CK **DATE:** 12-18-16

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
HSPF-4QTR2016	12-17-16- 12-18-16	9:25AM- ~~9:35AM~~	SW	4	10% Formalin	Species composition and abundance of target species
		9:25AM	MH			
						HS 16121801

Relinquished by:	(Name) Nicky Comeaux	Date 12-20-16	Time 8:08Am	**Received by:**	(Name)	Date 12-20-16	Time 8:08AM
	(Signature) Nicky Comeaux	Date 12-20-16	Time 8:08Am		(Signature)	Date 12-20-16	Time 8:08AM
Relinquished by:	(Name) Tyler Abshire	Date 12/20/16	Time 1027hr	**Received by Laboratory:**	(Name) D. L. Sauce	Date 12-20-16	Time 10:27
	(Signature)	Date 12/20/16	Time 1027hr		(Signature)	Date 12-20-16	Time 10-27
Method of Shipment: Hotshot		**Condition of Samples upon receipt at laboratory:** Robert Waddell 12-20-16 @1230 iced				**Temperature upon receipt**	

Please send results and invoice to the attention of NA in our ☐ Baton Rouge, ☐ Lake Charles, ☐ Shreveport, ☐ Houston Office

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

CK-100

CK ASSOCIATES
Environmental Consultants

17170 PERKINS ROAD
BATON ROUGE, LA 70810
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LAKE CHARLES, LA
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FAX (337)625-6580

SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

April 21, 2017

Ms. Sofia Lamon
Anadarko Petroleum Corporation
1201 Lake Robbins Drive
The Woodlands, TX 77380
sofia.lamon@anadarko.com

Re: **First Quarter 2017 Entrainment Monitoring Report for the Heidelberg Spar Production Facility**
CK Project No. 13096

Dear Ms. Lamon:

CK Associates (CK) is providing this letter report to Anadarko Petroleum Corporation (Anadarko) to summarize the findings of the first quarter 2017 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Heidelberg Spar production facility (HSPF). The HSPF is a fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the HSPF CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Anadarko personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s) and seawater basket strainers. The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the HSPF cooling water system downstream of the initial slip stream collection location.

The sampling process began at 1316 hours on March 15, 2017 and lasted until 1317 hours on March 16, 2017. The EMD was operated continuously during the sampling period (24 hours) at a flow rate of 11.0 gallons per minute resulting in an entrainment sample volume of 15,840 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified as key representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the HSPF CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae per cubic meter and zero key species of concern entrained per day. A summary of the entrained key species of concern is included in Table 2. There were no additional ichthyoplankton (eggs/larvae) observed in the sample see Table 3. Other entrained organisms that were not listed as key species of concern and are not ichthyoplankton, but that were found in the entrainment samples were Copepods, see Table 4. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent key important commercial and recreational species of concern.

Conclusions

Zero organisms of key important commercial and recreational species of concern were identified in entrainment samples collected from the HSPF during its first calendar quarter of entrainment monitoring for 2017. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the HSPF CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Sample Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
1	2017	03/15/2017 1316	03/16/2017 1317	11.0 (est)	0.016	Composite

Table 2
Entrainment Summary by Quarter
(Key Important Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2017	*Thunnus albacares* (yellowfin tuna) *Lutjanus campechanus*(red snapper)	0 0	0 0	0.016	0 0	0 0
Total	**2017**	***Thunnus albacares* (yellowfin tuna)**	**0**	**0**	**N/A**	**0**	**0**
Total	**2017**	***Lutjanus campechanus* (red snapper)**	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

Table 3
Other Ichthyoplankton
(Non Key Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2017	*N/A*	0 0	0 0	0.016	0 0	0 0
Total	**2017**	***Eggs***	**0**	**0**	**N/A**	**0**	**0**
Total	**2017**	***Larvae***	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter.

Table 4
Other Non-Ichthyoplankton Entrained Organisms

Organism	Total Number Collected
Copepods	6

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment C - Sampling Data Sheet
Cooling Water Intake Structure Entrainment Sampling Procedures
Anadarko Petroleum Corporation
Heidelberg Spar Production Facility

Collection Dates 3/15/17

Name(s) of Personnel A. Ochoa
Collecting Samples S. Mcelhany

Sample Event Start Time 1:16pm; 3/15/17

Flow reading after 1 min 11 gallons

Sample Event End Time 1:17pm; 3/16/17

Total Time Sampled 24hours, 1minute

Sequential Sample Number

Number of Jars per Sample 4

Other Notes Relevant to Sampling Event N/A

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page 1 of 1

CLIENT: Anadarko-HSPF **P.O. NUMBER:** NA **SAMPLED BY:** A. Ochoa

PROJECT NO.: 13096 **LABORATORY*:** CK **DATE:** 3/16/17

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
HSPF-1Q2017	3/16/17	~~1:54~~pm		4	10% Formalin	Species composition & abundance of target species
		1:17 pm JCN				
						CK ID: HS17032101

Relinquished by:	(Name) Ariana Ochoa	Date 3/16/17	Time 1:54pm	**Received by:**	(Name) Courtney Talbert	Date 3/21/17	Time 1300
	(Signature) ACOchoa	Date 3/16/17	Time 1:54pm		(Signature) Courtney Talbert	Date ↓	Time ↓
Relinquished by:	(Name)	Date	Time	**Received by Laboratory:**	(Name) TALAT FAROOQI	Date 3/29/2017	Time
	(Signature)	Date	Time		(Signature) Talat Farooqi	Date 3/29/2017	Time
Method of Shipment: Fed EX		**Condition of Samples upon receipt at laboratory:** Sealed + preserved				**Temperature upon receipt** —	

Please send results and invoice to the attention of NA in our ☐ Baton Rouge, ☐ Lake Charles, ☐ Shreveport, ☐ Houston Office

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

CK-100

CK ASSOCIATES
Environmental Consultants

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SHREVEPORT, LA
PHONE (318) 797-8636
FAX (318) 798-0478

May 5, 2017

Chevron USA
100 Northpark Blvd.
Covington, LA 70433
Attn: Jim Floyd
Jim.floyd@chevron.com

Re: Second Quarter 2017 Entrainment Monitoring Report for the Chevron Jack and St. Malo Floating Production Unit
CK Project No. 10726

Dear Mr. Floyd:

CK Associates (CK) is providing this letter report to Chevron USA (Chevron) to summarize the findings of the second quarter 2017 entrainment monitoring event for intake water collected from the cooling water intake structure (CWIS) aboard the Jack and St. Malo (JSM) floating production unit (FPU). The JSM FPU is a fixed facility, for which construction was commenced after July 17, 2006. Therefore, quarterly entrainment monitoring is required for the JSM FPU CWIS in accordance with section 12.c.2.ii of the *NPDES General Permit for New and Existing Sources and New Dischargers 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)* (general permit), effective October 1, 2012.

Sample Collection

Entrainment samples were collected by Chevron personnel from a slip stream of the cooling water system. The slip stream begins downstream of the CWIS intake screens and upstream of the facility heat exchanger(s). The slip stream is passed through an entrainment monitoring device (EMD) consisting of a closed conduit with a 330 micrometer screen in line with the flow after which the stream is returned to the JSM cooling water system downstream of the facility heat exchanger(s).

The sampling process began at 0700 hours on April 4, 2017 and lasted until 0700 hours on April 5, 2017. The EMD was operated continuously during the sampling period at a flow rate of 10.0 gallons per minute resulting in an entrainment sample volume of 14,400 gallons. Sample collection data are summarized in Table 1. Upon sampling termination, the screen was removed from the EMD and washed of entrained particles into sample jars containing 10% buffered formalin. The sample jars were packed in an ice chest and shipped to CK for processing and species identification by a fisheries biologist. See attachments A and B for a copy of the field data sheet and chain of custody documentation respectively.

Sample Results

Samples were analyzed for the presence of eggs and larvae from yellowfin tuna, and red snapper. These species were identified in the FPU's general permit application as key representative commercial and recreational species of concern because eggs and larvae of these species are considered to be most likely to be entrained in the JSM CWIS.

Zero yellowfin tuna eggs/larvae and zero red snapper eggs/larvae were identified during sample analysis. When normalized to the total facility flow, this entrainment rate amounts to zero eggs/larvae of key species of concern per cubic meter entrained per day. A summary of the entrained key species of concern is included in Table 2. There was an additional non-target ichthyoplankton larvae observed in the sample, see Table 3. One Microdesmidae, however the larvae was too damaged to identify further. There were no additional non-target ichthyoplankton eggs observed in the sample see Table 3. Other entrained organisms that were not listed as key species of concern and are not ichthyoplankton, but that were found in the entrainment samples included several Copepoda, see Table 4. None of these organisms should be included as part of the discharge monitoring report submittal because they do not represent key important commercial and recreational species of concern.

Conclusions

Zero organisms of key important commercial and recreational species of concern were identified in entrainment samples collected from the JSM FPU during its first calendar quarter of entrainment monitoring. Based on the analysis of the entrainment monitoring samples, engineering controls installed at the JSM FPU CWIS have successfully minimized the potential for environmental, socioeconomic, and ecological damage due to entrainment in the facility CWIS.

If you have any questions or comments regarding this report, please do not hesitate to contact me at (255) 755-1000 or via email at James.Durbin@c-ka.com .

Sincerely yours,
CK Associates
James L. Durbin
James L. Durbin
Senior Environmental Scientist

Attachments: As referenced

Table 1
Sample Collection Data Summary by Quarter

Quarter	Year	Start Date and Time	Stop Date and Time	Sample Flow Rate (gal/min)	Sample Volume (MG)	Collection Method
1	2017	01/5/17-2100	01/6/17-2100	20.0 (est)	0.029	Composite
2	2017	04/04/17-0700	04/05/17-0700	10.0 (est)	0.014	Composite

Table 2
Entrainment Summary by Quarter
(Key Important Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2017	*Thunnus albacares* (yellowfin tuna)	0	0	0.029	0	0
		Lutjanus campechanus (red snapper)	0	0		0	0
2	2017	*Thunnus albacares* (yellowfin tuna)	0	0	0.014	0	0
		Lutjanus campechanus (red snapper)	0	0		0	0
Total	**2017**	***Thunnus albacares* (yellowfin tuna)**	**0**	**0**	**N/A**	**0**	**0**
Total	**2017**	***Lutjanus campechanus* (red snapper)**	**0**	**0**	**N/A**	**0**	**0**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 3
Other Ichthyoplankton
(Non Key Commercial and Recreational Species of Concern)

Quarter	Year	Species/Family	Total Collected Eggs	Total Collected Larvae	Sample Volume (MG)	Total # Eggs Entrained[1]	Total # Larvae Entrained[1]
1	2017	Gempylidae	0	1	0.029	0	84,097
		Haemulidae	0	3		0	252,290
		Sparidae	0	2		0	168,193
2	2017	Microdesmidae	0	1	0.014	0	174,200
Total	**2017**		**0**	**7**	**N/A**	**0**	**678,780**

[1] Projected number of organisms entrained per quarter based on an average cooling water flow equal to 26.8 MGD for a 91-day quarter

Table 4
Other Non-Ichthyoplankton Entrained Organisms

Copepoda

ATTACHMENT A
DATA SHEET FOR SAMPLE EVENT

Attachment A - Example Data Sheet
Cooling Water Intake Structure Entrainment Sampling and Monitoring Procedures
Chevron North America Exploration and Production Company Deepwater
Jack St. Malo Platform

Collection Date	4/5/2017
Project Number	10726
Names of Personnel Collecting Samples	Cedric Milton
Sample Collection Flow Rate	10GPM
Sample Event Start Time and Date	0700 4/4/17
Sample Event End Time and Date	0700 4/5/17
Weather Conditions during each cycle	Seas 4 to 6 Winds 10 to 12 Knots
Number of Sample Jars Filled	4
Sample Method	Entrainment
Other Notes Relevant to Sampling Event	

ATTACHMENT B
CHAIN-OF-CUSTODY FOR SAMPLE EVENT

C-K
ASSOCIATES • LLC
ENVIRONMENTAL & ENGINEERING CONSULTANTS

CHAIN OF CUSTODY AND ANALYTICAL REQUEST RECORD

Page 1 of 1

CLIENT: Chevron U.A. Jack St Malo **P.O. NUMBER:** Not Applicable **SAMPLED BY:** Cedric Milton

PROJECT NO.: 10726 **LABORATORY*:** CK Associates **DATE:** 4/5/17

SAMPLE IDENTIFICATION	DATE	TIME	MATRIX	NO. OF CONTAINERS	PRESERVATIVE	ANALYSES AND INSTRUCTIONS
Plankton	4/4/17	0700	seawater	—	—	—
Plankton	4/5/17	0700	seawater	4		Provide info on species composition 10% Formalin abundance + size of entrained organisms
						JSM 17040501

CT 4/5/17

		Date	Time			Date	Time
Relinquished by:	(Name) Cedric Milton	4/5/17	13:30	**Received by:**	(Name) Ronald Comeaux	4/5/17	1330
	(Signature) Cedric Milton	4/5/17	13:28		(Signature) Ronald Com	4/5/17	1330
Relinquished by:	(Name) Ronald Comeaux	4/5/17	1545	**Received by Laboratory:**	(Name) Courtney Tolbert	4/5/17	1545
	(Signature) Ronald Com				(Signature) Courtney Tolbert	4/5/17	1545

Method of Shipment: United Vision

Condition of Samples upon receipt at laboratory: sealed

Temperature upon receipt 04/24/17 11:45-AM

Relinquished: Courtney Tolbert 4/24/17@1145 Received:

Please send results and invoice to the attention of ______________________ **in our** ☐ Baton Rouge, ☐ Lake Charles, ☐ Shreveport, ☐ Houston Office

WHITE COPY TO ACCOMPANY SAMPLE • RETAIN YELLOW COPY FOR FILES • RETAIN PINK COPY FOR FIELD SUPERVISOR

CK-100

Tiers 8&9

Environmental Resources Management

CityCentre Four
840 West Sam Houston
Parkway North, Suite 600
Houston, Texas 77024-3920
T: 281-600-1000
F: 281-520-4625

Memorandum

To: Ms. Sofia Lamon, Ms. Ellen Thomson

Company: Anadarko

From: Kurtis Schlicht, Bill Stephens, Emily Lantz

Date: 10 April 2015

Subject: Quarter 1 (January-March) 2015 Entrainment Sampling Results

---

The Environmental Protection Agency (EPA) regulates discharges from exploration, development, and production facilities located in and discharging to federal waters of the Gulf of Mexico offshore of Louisiana and Texas under National Pollutant Discharge Elimination System (NPDES) General Permit number GMG 290000 (General Permit). The General Permit provides authorization to discharge wastewater and storm water in the western outer continental shelf (OCS) regions of the Gulf of Mexico with conditions that the permittee agrees to a variety of effluent limitations, monitoring, reporting, and cooling water intake structure (CWIS) requirements.

Samples were collected from the Lucius Truss Spar (Lucius) in accordance with the General Permit quarterly entrainment sampling requirements for Quarter 1 2015 (Q1 2015). A description of the sampling procedures and analytical results of the Q1 2015 event are presented in the following paragraphs

Procedure

ERM staff travelled to Lucius under Anadarko supervision on March 9, 2015. Sampling began at 00:00 on the morning of March 10, 2015. Samples were collected every six hours (06:00, 12:00, 18:00) until four 25 m^3 entrainment sample volumes were collected representing a 24-hour sample period. Samples remained in the possession of the sample team during the transport to shore.

Once onshore, entrainment samples were shipped within 24 hours to Ecological Associates, Inc. (EAI), with chain-of-custody documentation included in the shipment. Samples were processed by EAI during a 45-60 day period.

In the laboratory, EAI technicians separated debris or material from aquatic organisms and sorted the organisms by life-stage to the lowest possible taxonomic level.

Sampling Results

A total of 2,597 organisms were present in the 100m^3 of water sampled. Of these organisms, 21 were fish and shellfish (also known as "Target" organisms, per EAI nomenclature): 2 fish larvae and 19 fish eggs. Table 1 below indicates the types, numbers, and lifestages of the fish within the March 10, 2015 sample. Table 2 below indicates the types, numbers, and lifestages of the non-fish species within the March 10, 2015 sample.

Table 1. Laboratory Analysis of Ichthyoplankton Samples Collected During Event 1 on March 10, 2015 at the Anadarko Lucius Truss Spar Platform: Target Organisms.

Taxa	**CRI/Non-CRI Invertebrates**	**Lifestage**	**Sample 1**	**Sample 2**	**Sample 3**	**Sample 4**	**Total**
Collection time			**00:00**	**06:00**	**12:00**	**18:00**	
Fish							
Aulostomus maculatus		Post Yolk-Sac Larvae		1			1
Unidentified fish - damaged		Post Yolk-Sac Larvae				1	1
Fish total				**1**		**1**	**2**
Fish Eggs							
Unidentified eggs - No embryos		Egg	3	3	1	12	19
Fish Eggs Total			**3**	**3**	**1**	**12**	**19**
Total Combined			**3**	**4**	**1**	**13**	**21**

*CRI = Commercially or Recreationally Important Decapod Crustaceans. None present in samples.

Table 2. Laboratory Analysis of Ichthyoplankton Samples Collected During Event 1 on March 10, 2015 at the Anadarko Lucius Truss Spar Platform: Non-target Organisms.

Taxa	**CRI/Non-CRI Invertebrates**	**Lifestage**	**Sample 1**	**Sample 2**	**Sample 3**	**Sample 4**	**Total**
		Collection time	**00:00**	**06:00**	**12:00**	**18:00**	
Crustaceans							
Amphipoda	Non-CRI	Other			1	1	2
Portunus sp.	Non-CRI	Megalops				1	1
Decapod shrimp	Non-CRI	Other	6	10	18	35	69
Crustacean Total			**6**	**10**	**19**	**37**	**72**
Decapods							
Pleocyemata	Non-CRI	Megalops			1	2	3
Pleocyemata	Non-CRI	Zoea			7		7
Decapods Total					**8**	**2**	**10**
Ostracods							
Ostracoda	Non-CRI	Other	87	149	182	187	605
Ostracods Total			**87**	**149**	**182**	**187**	**605**
Polychaetes							
Polychaeta	Non-CRI	Other	3	1	3	1	8
Polychaete Total			**3**	**1**	**3**	**1**	**8**
Arthropods							
Copepoda	Non-CRI	Other	244	380	533	705	1,862
Arthropod Total			**244**	**380**	**533**	**705**	**1,862**
Chaetognatha							
Chaetognatha	Non-CRI	Other	2	5	8	4	19
Chaetognatha Total			**2**	**5**	**8**	**4**	**19**
Total Combined			**342**	**545**	**753**	**936**	**2576**

Environmental Resources Management

CityCentre Four
840 West Sam Houston
Parkway North, Suite 600
Houston, Texas 77024-3920

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F: 281-520-4625

Memorandum

To: Ms. Sofia Lamon, Ms. Ellen Thomson

Company: Anadarko

From: Kurtis Schlicht, Bill Stephens, Emily Lantz

Date: 17 August 2015

Subject: Quarter 2 (April-June) 2015 Entrainment Sampling Results

---

The Environmental Protection Agency (EPA) regulates discharges from exploration, development, and production facilities located in and discharging to federal waters of the Gulf of Mexico offshore of Louisiana and Texas under National Pollutant Discharge Elimination System (NPDES) General Permit number GMG 290000 (General Permit). The General Permit provides authorization to discharge wastewater and storm water in the western outer continental shelf (OCS) regions of the Gulf of Mexico with conditions that the permittee agrees to a variety of effluent limitations, monitoring, reporting, and cooling water intake structure (CWIS) requirements.

Samples were collected from the Lucius Truss Spar (Lucius) in accordance with the General Permit quarterly entrainment sampling requirements for Quarter 2 2015 (Q2 2015). A description of the sampling procedures and analytical results of the Q2 2015 event are presented in the following paragraphs

Procedure

ERM staff travelled to Lucius under Anadarko supervision on June 01, 2015. Sampling began at 00:00 on the morning of June 02, 2015. Samples were collected every six hours (06:00, 12:00, 18:00) until four 25 m^3 entrainment sample volumes were collected representing a 24-hour sample period. Samples remained in the possession of the sample team during the transport to shore.

Once onshore, entrainment samples were shipped within 24 hours to Ecological Associates, Inc. (EAI), with chain-of-custody documentation included in the shipment. Samples were processed by EAI during a 45-60 day period.

In the laboratory, EAI technicians separated debris or material from aquatic organisms and sorted the organisms by life-stage to the lowest possible taxonomic level.

Sampling Results

A total of 120 "Target" (per EAI nomenclature) fish or shellfish organisms were present in the 100m^3 of water sampled: 2 fish larvae and 118 fish eggs. Table 1 below indicates the types, numbers, and lifestages of the fish within the June 02, 2015 sample.

Table 1. Laboratory Analysis of Ichthyoplankton Samples Collected During Event 1 on June 02, 2015 at the Anadarko Lucius Truss Spar Platform: Target Organisms.

Taxa	**CRI/Non-CRI Invertebrates**	**Lifestage**	**Sample 1**	**Sample 2**	**Sample 3**	**Sample 4**	**Total**
		Collection time	**00:00**	**06:00**	**12:00**	**18:00**	
Fish							
Carangidae		Post Yolk-Sac Larvae	1	0	0	0	1
Unidentified fish - damaged		Post Yolk-Sac Larvae	1	0	0	0	1
Fish total			**2**	**0**	**0**	**0**	**2**
Fish Eggs							
Unidentified eggs - No embryos		Egg	0	115	3	0	118
Fish Eggs Total			**0**	**115**	**3**	**0**	**118**
Total Combined			**2**	**115**	**3**	**0**	**120**

*CRI = Commercially or Recreationally Important Decapod Crustaceans. None present in samples.

Memorandum

Environmental Resources Management

CityCentre Four
840 West Sam Houston
Parkway North, Suite 600
Houston, Texas 77024-3920

T: 281-600-1000
F: 281-520-4625

To: Ms. Sofia Lamon, Ms. Ellen Thomson

Company: Anadarko

From: Kurtis Schlicht, Emily Lantz

Date: 15 December 2015

Subject: Lucius Truss Spar - Quarter 3 (July-September) 2015 Entrainment Monitoring Results

The Environmental Protection Agency (EPA) regulates discharges from exploration, development, and production facilities located in and discharging to federal waters of the Gulf of Mexico offshore of Louisiana and Texas under National Pollutant Discharge Elimination System (NPDES) General Permit number GMG 290000 (General Permit). The General Permit provides authorization to discharge wastewater and storm water in the western outer continental shelf (OCS) regions of the Gulf of Mexico with conditions that the permittee agrees to a variety of effluent limitations, monitoring, reporting, and cooling water intake structure (CWIS) requirements.

Entrainment samples were collected from the Lucius Truss Spar (Lucius) in accordance with the General Permit quarterly entrainment monitoring requirements for Quarter 3 2015 (Q3 2015). A description of the sampling procedures and analytical results of the Q3 2015 monitoring event are presented in the following paragraphs.

Sampling Procedures

ERM staff travelled to Lucius under Anadarko supervision on September 21, 2015. Sampling began at 18:00 on the evening of September 21, 2015. Samples were collected every following six hours (00:00, 06:00, 12:00) until four, 25 m^3 entrainment sample volumes were collected representing a 24-hour sample period. Sampling began at 18:00 in order to accommodate Lucius personnel request to have the entrainment sampling system (ESS) disassembled the day prior to crew change. Samples remained in the possession of the ERM sample team during the transport to shore, under the chain of custody protocol.

Once onshore, the entrainment samples were shipped within 24 hours to Ecological Associates, Inc. (EAI), with chain-of-custody documentation included in the shipment. Samples were processed by EAI during a 45-60 day period. The final results, dated December 11, 2015, were received via email on December 11, 2015.

In the laboratory, EAI technicians separated debris or material from aquatic organisms and sorted the organisms by life-stage to the lowest possible taxonomic level. During this quarter, EAI composited the four samples into two samples: one composite to represent the samples taken during the daytime (12:00 and 18:00, sunset occurred around 19:30); and one composite to represent the samples taken during the nighttime (00:00 and 06:00, sunrise occurred around 07:15). In Q1 and Q2 the four samples collected each quarter were individually processed in order to verify the amount of material (number of organisms) present in the samples. After these two quarters were utilized as a baseline, we have assumed that the samples will contain relatively low numbers and organism density. In Q3 and future quarterly sampling events, the samples will be composited into two samples (as described above), which is sufficient to show diel migration of organisms for analysis.

Sampling Results

A total of 28 "target" (per EAI nomenclature) fish or shellfish organisms were present in the 100m^3 of water sampled: 7 crustaceans; 3 fish larvae; and 18 fish eggs. Table 1 describes the types, numbers, and lifestages of the organisms of the 28 organisms present in the September 21, 2015 sample. Table 2 describes the lengths of captured fish organisms. Table 3 describes the density of organisms within the samples.

Table 1. Laboratory Analysis of Ichthyoplankton Samples Collected During Event 3 on September 21, 2015 at the Anadarko Lucius Truss Spar Platform.

Taxa	CRI*/Non-CRI Invertebrates	Lifestage	Nighttime Sample (00:00 and 06:00)	Daytime Sample (12:00 and 18:00)	Total
Crustaceans					
Penaeidae	CRI	Post Larvae	0	6	6
Sicyonia sp.	CRI	Mysis	0	1	1
Crustacean Total			**0**	**7**	**7**
Fish					
Diplogrammus pauciradiatus		Post Yolk-Sac Larvae	0	1	1
Unidentified fish - damaged		Post Yolk-Sac Larvae	2	0	2
Fish Total			**2**	**1**	**3**
Fish Eggs					
Unidentified eggs - No embryos		Egg	17	1	18
Fish Eggs Total			**17**	**1**	**18**
TOTAL			19	9	28

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

Table 2. Total Length (mm) of Ichthyoplankton Specimens Collected during Event 3 on September 21, 2015 at the Anadarko Lucius Truss Spar Platform.

Sample	**Taxa**	**Life Stage**	**Specimen Number**	**Total Length (mm)**
Nighttime Sample (00:00 and 06:00)	Unidentified fish-damaged	Post Yolk-Sac Larvae	1	N/A*
	Unidentified fish-damaged	Post Yolk-Sac Larvae	1	N/A*
Daytime Sample (12:00 and 18:00)	*Diplogrammus pauciradiatus*	Post Yolk-Sac Larvae	1	N/A*

* Specimen damaged, not measured.

Table 3. Densities (Number per m3 of Water Filtered) of Organisms Collected During Event 3 on September 21, 2015 at the Anadarko Lucius Truss Spar Platform.

Taxa	**CRI*/Non-CRI Invertebrates**	**Lifestage**	**Nighttime Sample (00:00 and 06:00)**	**Daytime Sample (12:00 and 18:00)**	**Total**
		Volume of filtered water (m^3)	**50.0**	**50.0**	**100.0**
Crustaceans					
Penaeidae	CRI	Post Larvae	0	0.120	0.060
Sicyonia sp.	CRI	Mysis	0	0.020	0.010
Crustacean Total			**0**	**0.140**	**0.070**
Fish					
Diplogrammus pauciradiatus		Post Yolk-Sac Larvae	0	0.020	0.010
Unidentified fish - damaged		Post Yolk-Sac Larvae	0.040	0	0.020
Fish Total			**0.040**	**0.020**	**0.030**
Fish Eggs					
Unidentified eggs - No embryos		Egg	0.340	0.020	0.180
Fish Eggs Total			**0.340**	**0.020**	**0.180**
TOTAL			**0.380**	**0.180**	**0.280**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

Memorandum

Environmental Resources Management

CityCentre Four
840 West Sam Houston
Parkway North, Suite 600
Houston, Texas 77024-3920

T: 281-600-1000
F: 281-520-4625

To: Ms. Sofia Lamon, Ms. Ellen Thomson

Company: Anadarko

From: Kurtis Schlicht, Emily Lantz

Date: 19 January 2016

Subject: Lucius Truss Spar - Quarter 4 (October-December) 2015 Entrainment Monitoring Results

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The Environmental Protection Agency (EPA) regulates discharges from exploration, development, and production facilities located in and discharging to federal waters of the Gulf of Mexico offshore of Louisiana and Texas under National Pollutant Discharge Elimination System (NPDES) General Permit number GMG 290000 (General Permit). The General Permit provides authorization to discharge wastewater and storm water in the western outer continental shelf (OCS) regions of the Gulf of Mexico with conditions that the permittee agrees to a variety of effluent limitations, monitoring, reporting, and cooling water intake structure (CWIS) requirements.

Entrainment samples were collected from the Lucius Truss Spar (Lucius) in accordance with the General Permit quarterly entrainment monitoring requirements for Quarter 4 2015 (Q4 2015). A description of the sampling procedures and analytical results of the Q4 2015 monitoring event are presented in the following paragraphs.

Sampling Procedures

ERM staff travelled to Lucius under Anadarko supervision on November 30, 2015. Sampling began at 18:00 on the evening of November 30, 2015, and ended at 12:00 on December 01, 2015. Samples were collected every following six hours (00:00, 06:00, 12:00) until four, 25 m^3 entrainment sample volumes were collected representing a 24-hour sample period. Sampling began at 18:00 in order to accommodate Lucius personnel request to have the entrainment sampling system (ESS) disassembled the day prior to crew change. Samples remained in the possession of the ERM sample team during the transport to shore, under the chain of custody protocol.

Once onshore, the entrainment samples were shipped within 24 hours to Ecological Associates, Inc. (EAI), with chain-of-custody documentation included in the shipment. Samples were processed by EAI during a less than 30 day period. The final results, dated December 17, 2015, were received via email on December 17, 2015.

In the laboratory, EAI technicians separated debris or material from aquatic organisms and sorted the organisms by life-stage to the lowest possible taxonomic level. Based on client feedback received from the third quarter 2015 monitoring results, EAI processed the four samples individually (similar to Q1 and Q2 samples), versus the Q3 2015 methodology that composited the four samples to results in two diel (daytime versus nighttime) samples. In Q4 and future quarterly sampling events, the samples will be processed individually rather than composited.

Sampling Results

A total of 27 "target" (per EAI nomenclature) fish or shellfish organisms were present in the 100m^3 of water sampled: 16 crustaceans; 1 fish larvae; and 10 fish eggs. Table 1 describes the types, numbers, and lifestages of the organisms of the 27 organisms present in the November 30- December 01, 2015 sample. Table 2 describes the lengths of captured fish organisms. Table 3 describes the density of organisms within the samples.

TABLE 1 - Laboratory Analysis of Ichthyoplankton Samples Collected During Event 4 on November 30- December 01, 2015 at the Anadarko Lucius Truss Spar Platform.

Taxa	**CRI*/Non-CRI Invertebrates**	**Lifestage**	**Sample 1**	**Sample 2**	**Sample 3**	**Sample 4**	**Total**
		Collection Time	**18:00**	**00:00**	**06:00**	**12:00**	
Crustaceans							
Euphausiacea	Non-CRI	Adult	0	2	0	0	2
Lophogastrida	Non-CRI	Adult	0	1	0	0	1
Pinnotheres spp.	Non-CRI	Megalops	3	0	0	0	3
Rimapenaeus spp.	CRI	Post Larvae	0	0	3	0	3
Sergestidae	Non-CRI	Adult	0	4	1	0	5
Xiphopenaeus kroyeri	CRI	Post Larvae	0	0	2	0	2
Crustacean Total			**3**	**7**	**6**	**0**	**16**
Fish							
Exocoetidae		Juvenile	0	0	1	0	1
Fish Total			**0**	**0**	**1**	**0**	**1**
Fish Eggs							
Unidentified eggs - No embryos		Egg	1	3	0	6	10
Fish Eggs Total			**1**	**3**	**0**	**6**	**10**
TOTAL			4	10	7	6	27

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

TABLE 2 - Total Length (mm) of Ichthyoplankton Specimens Collected during Event 4 on November 30- December 01, 2015 at the Anadarko Lucius Truss Spar Platform.

Sample	**Taxa**	**Life Stage**	**Specimen Number**	**Total Length (mm)**
Sample 1- 18:00	No Ichthyoplankton Present			
Sample 2- 00:00	No Ichthyoplankton Present			
Sample 3- 06:00	Exocoetidae	Juvenile	1	N/A*
Sample 4- 12:00	No Ichthyoplankton Present			

* Specimen damaged, not measured.

TABLE 3 - Densities (Number per m3 of Water Filtered) of Organisms Collected during Event 4 on November 30- December 01, 2015 at the Anadarko Lucius Truss Spar Platform.

Taxa	**CRI*/Non-CRI Invertebrates**	**Lifestage**	**Sample 1**	**Sample 2**	**Sample 3**	**Sample 4**	**Total**
Collection Time			**18:00**	**00:00**	**06:00**	**12:00**	
Volume of water filtered (m^3)			**25**	**25**	**25**	**25**	**100**
Crustaceans							
Euphausiacea	Non-CRI	Adult	0	0.08	0	0	0.02
Lophogastrida	Non-CRI	Adult	0	0.04	0	0	0.01
Pinnotheres spp.	Non-CRI	Megalops	0.12	0	0	0	0.03
Rimapenaeus spp.	CRI	Post Larvae	0	0	0.12	0	0.03
Sergestidae	Non-CRI	Adult	0	0.16	0.04	0	0.05
Xiphopenaeus kroyeri	CRI	Post Larvae	0	0	0.08	0	0.02
Crustacean Total			**0.12**	**0.28**	**0.24**	**0**	**0.16**
Fish							
Exocoetidae		Juvenile	0	0	0.04	0	0.01
Fish Total			**0**	**0**	**0.04**	**0**	**0.01**
Fish Eggs							
Unidentified eggs - No embryos		Egg	0.04	0.12	0	0.24	0.10
Fish Eggs Total			**0.04**	**0.12**	**0**	**0.24**	**0.10**
TOTAL			0.16	0.40	0.28	0.24	0.27

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

Memorandum

Environmental Resources Management

CityCentre Four
840 West Sam Houston
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Houston, Texas 77024-3920

T: 281-600-1000
F: 281-520-4625

ERM

To: Ms. Sofia Lamon, Ms. Ellen Thomson

Company: Anadarko

From: Bill Stephens

Date: 16 May 2016

Subject: Lucius Truss Spar - Quarter 1 (January-March) 2016 Entrainment Monitoring Results

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The Environmental Protection Agency (EPA) regulates discharges from exploration, development, and production facilities located in and discharging to federal waters of the Gulf of Mexico offshore of Louisiana and Texas under National Pollutant Discharge Elimination System (NPDES) General Permit number GMG 290000 (General Permit). The General Permit provides authorization to discharge wastewater and storm water in the western outer continental shelf (OCS) regions of the Gulf of Mexico with conditions that the permittee agrees to a variety of effluent limitations, monitoring, reporting, and cooling water intake structure (CWIS) requirements.

Entrainment samples were collected from the Lucius Truss Spar (Lucius) in accordance with the General Permit quarterly entrainment monitoring requirements for Quarter 1 2016 (Q1 2016). A description of the sampling procedures and analytical results of the Q1 2016 monitoring event are presented in the following paragraphs.

Sampling Procedures

ERM staff travelled to Lucius under Anadarko supervision on February 15, 2016. Sampling began at 18:00 on the evening of February 15, 2016, and ended at 12:00 on February 16, 2016. Samples were collected every following six hours (00:00, 06:00, 12:00) until four, 25 m^3 entrainment sample volumes were collected representing a 24-hour sample period. Sampling began at 18:00 in order to accommodate Lucius personnel request to have the entrainment sampling system (ESS) disassembled the day prior to crew change. Samples remained in the possession of the ERM sample team during the transport to shore, under the chain of custody protocol.

Once onshore, the entrainment samples were shipped within 24 hours to Ecological Associates, Inc. (EAI), with chain-of-custody documentation included in the shipment. Samples were processed by EAI during a less than 30 day period. The final results, dated March 7, 2016, were received via email on March 7, 2016.

In the laboratory, EAI technicians separated debris or material from aquatic organisms and sorted the organisms by life-stage to the lowest possible taxonomic level. The four samples were processed individually (not composited).

Sampling Results

A total of 73 "target" (per EAI nomenclature) fish or shellfish organisms were present in the $100m^3$ of water sampled: 67 crustaceans; 4 fish larvae; and 2 fish eggs. Table 1 describes the types, numbers, and lifestages of the organisms of the 73 organisms present in the February 15-February 16, 2016 sample. Table 2 describes the lengths of captured fish organisms. Table 3 describes the density of organisms within the samples.

TABLE 1 - Laboratory Analysis of Ichthyoplankton Samples Collected During Event 5 on February 15-February 16, 2016 at the Anadarko Lucius Truss Spar Platform

Taxa	CRI/Non-CRI Invertebrates*	LifeStage	Lucius-021516-Sample 1	Lucius-021616-Sample 2	Lucius-021616-Sample 3	Lucius021616-Sample 4	Total
		Collection Time	**18:00**	**0:00**	**6:00**	**12:00**	
Crustaceans							
Decapoda	Non-CRI	Post Larvae	7	2	2		**11**
Euphausiacea	Non-CRI	Post Larvae	13	8	19	9	**49**
Hepatus epheliticus	Non-CRI	Megalops			1		**1**
Hexapanopeus	Non-CRI	Megalops			1	1	**2**
Litopenaeus sp.	CRI	Post Larvae	1				**1**
Portunus sp.	Non-CRI	Megalops	1				**1**
Solenocera sp.	Non-CRI	Mysis	1				**1**
Solenocera sp.	Non-CRI	Post Larvae				1	**1**
Crustacean Total			**23**	**10**	**23**	**11**	**67**
Fish							
Unidentified fish		Post Yolk-Sac Larvae	1	1		2	4
Fish Total			**1**	**1**		**2**	**4**
Fish Eggs							
Unidentified eggs - No embryos		Egg		1		1	2
Fish Eggs Total				**1**		**1**	**2**
Total			**24**	**12**	**23**	**14**	**73**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

TABLE 2 - Total Length (mm) of Ichthyoplankton Specimens Collected during Event 5 on February 15- 16, 2016 at the Anadarko Lucius Truss Spar Platform

Sample Number	Taxa	Life Stage	Specimen Number	Total Length (mm)
Lucius-021516-Sample 1	Unidentified Fish	Post Yolk-Sac Larvae	1	N/A[1]
Lucius-021616-Sample 2	Unidentified Fish	Post Yolk-Sac Larvae	1	N/A[1]
Lucius-021616-Sample 3	**No Ichthyoplankton Present**			
Lucius-021616-Sample 4	Unidentified Fish	Post Yolk-Sac Larvae	1	N/A[1]
	Unidentified Fish	Post Yolk-Sac Larvae	2	N/A[1]

[1] Specimen damaged, not measured.

TABLE 3 - Densities (Number per m^3 of Water Filtered) of Organisms Collected During Event 5 on February 15-16, 2016 at the Anadarko Lucius Truss Spar Platform

Taxa	CRI/Non-CRI Invertebrates*	LifeStage	Lucius-021516-Sample 1	Lucius-021616-Sample 2	Lucius-021616-Sample 3	Lucius-021616-Sample 4	Total
		Collection Time	**18:00**	**0:00**	**6:00**	**12:00**	
Volume of Water Filtered (m^3)			**25.0**	**25.0**	**25.0**	**25.0**	**100.0**
Crustaceans							
Decapoda	Non-CRI	Post Larvae	0.28	0.08	0.08		**0.11**
Euphausiacea	Non-CRI	Post Larvae	0.52	0.32	0.76	0.36	**0.49**
Hepatus epheliticus	Non-CRI	Megalops			0.04		**0.01**
Hexapanopeus angustifrons	Non-CRI	Megalops			0.04	0.04	**0.02**
Litopenaeus sp.	CRI	Post Larvae	0.04				**0.01**
Portunus sp.	Non-CRI	Megalops	0.04				**0.01**
Solenocera sp.	Non-CRI	Mysis	0.04				**0.01**
Solenocera sp.	Non-CRI	Post Larvae				0.04	**0.01**
Crustacean Total			**0.92**	**0.4**	**0.92**	**0.44**	**0.67**
Fish							
Unidentified fish		Post Yolk-Sac	0.04	0.04		0.08	0.04
Fish Total			**0.04**	**0.04**		**0.08**	**0.04**
Fish Eggs							
Unidentified eggs - No		Egg		0.04		0.04	0.02
Fish Eggs Total				**0.04**		**0.04**	**0.02**
Total			**0.96**	**0.48**	**0.92**	**0.56**	**0.73**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

Memorandum

Environmental Resources Management

CityCentre Four
840 West Sam Houston
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Houston, Texas 77024-3920

T: 281-600-1000
F: 281-520-4625

ERM

To: Ms. Sofia Lamon, Ms. Ellen Thomson

Company: Anadarko

From: Bill Stephens

Date: 22 August 2016

Subject: Lucius Truss Spar - Quarter 2 (April-June) 2016 Entrainment Monitoring Results

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The Environmental Protection Agency (EPA) regulates discharges from exploration, development, and production facilities located in and discharging to federal waters of the Gulf of Mexico offshore of Louisiana and Texas under National Pollutant Discharge Elimination System (NPDES) General Permit number GMG 290000 (General Permit). The General Permit provides authorization to discharge wastewater and storm water in the western outer continental shelf (OCS) regions of the Gulf of Mexico with conditions that the permittee agrees to a variety of effluent limitations, monitoring, reporting, and cooling water intake structure (CWIS) requirements.

Entrainment samples were collected from the Lucius Truss Spar (Lucius) in accordance with the General Permit quarterly entrainment monitoring requirements for Quarter 2 2016 (Q2 2016). A description of the sampling procedures and analytical results of the Q2 2016 monitoring event are presented in the following paragraphs.

Sampling Procedures

ERM staff travelled to Lucius under Anadarko supervision on June 13-14, 2016. Sampling began at 18:00 on the evening of June 13, 2016, and ended at 12:00 on June 14, 2016. Samples were collected every following six hours (00:00, 06:00, 12:00) until four, 25 m^3 entrainment sample volumes were collected representing a 24-hour sample period. Sampling began at 18:00 to accommodate a Lucius personnel request to have the entrainment sampling system (ESS) disassembled the day prior to crew change. Samples remained in the possession of the ERM sample team during the transport to shore, under the chain of custody protocol.

Once onshore, the entrainment samples were shipped within 24 hours to Ecological Associates, Inc. (EAI), with chain-of-custody documentation included in the shipment. Samples were processed by EAI during a less than 30 day period. The final results, dated July 15, 2016, were received via email on July 15, 2016.

In the laboratory, EAI technicians separated debris or material from aquatic organisms and sorted the organisms by life-stage to the lowest possible taxonomic level. The four samples were processed individually (not composited).

Sampling Results

A total of 11 "target" (per EAI nomenclature) fish or shellfish organisms were present in the 100m^3 of water sampled: 6 crustaceans; 0 fish larvae; and 5 fish eggs. Table 1 describes the types, numbers, and lifestages of the organisms of the 11 organisms present in June 13- June 14, 2016 sample. Table 2 describes the lengths of captured fish organisms. Table 3 describes the density of organisms within the samples.

TABLE 1 - Laboratory Analysis of Ichthyoplankton Samples Collected During Event 6 on June 13 – June 14, 2016 at the Anadarko Lucius Truss Spar Platform

Taxa	**CRI/Non-CRI Invertebrates***	**LifeStage**	**Lucius-061316-Sample 1**	**Lucius-061416-Sample 2**	**Lucius-061416-Sample 3**	**Lucius061416-Sample 4**	**Total**
		Collection Time	**18:00**	**0:00**	**6:00**	**12:00**	
Crustaceans							
Decapoda	Non-CRI	Juvenile		1	1		**2**
Euphausiacea	Non-CRI	Juvenile		1	1		**2**
Euphausiacea	Non-CRI	Other	1			1	**2**
Crustacean Total			**1**	**2**	**2**	**1**	**6**
Fish							
Fish Total	No Ichthyoplankton Present						
Fish Eggs							
Unidentified eggs - No embryos		Egg	1	2	1	1	5
Fish Eggs Total			**1**	**2**	**1**	**1**	**5**
Total			**2**	**4**	**2**	**2**	**11**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

TABLE 2 - Total Length (mm) of Ichthyoplankton Specimens Collected during Event 6 on June 13-14, 2016 at the Anadarko Lucius Truss Spar Platform

Sample Number	Taxa	Life Stage	Specimen Number	Total Length (mm)
Lucius-061316-Sample 1	**No Ichthyoplankton Present**			
Lucius-061416-Sample 2	**No Ichthyoplankton Present**			
Lucius-061416-Sample 3	**No Ichthyoplankton Present**			
Lucius-061416-Sample **4**	**No Ichthyoplankton Present**			

[1] Specimen damaged, not measured.

TABLE 3 - Densities (Number per m³ of Water Filtered) of Organisms Collected During Event 6 on June 13-14, 2016 at the Anadarko Lucius Truss Spar Platform

Taxa	CRI/Non-CRI Invertebrates*	LifeStage	Lucius-061316-Sample 1	Lucius-061416-Sample 2	Lucius-061416-Sample 3	Lucius-061416-Sample 4	Total
		Collection Time	**18:00**	**0:00**	**6:00**	**12:00**	
Volume of Water Filtered (m^3)			**25.0**	**25.0**	**25.0**	**25.0**	**100.0**
Crustaceans							
Decapoda	Non-CRI	Juvenile		0.04	0.04		**0.02**
Euphausiacea	Non-CRI	Juvenile		0.04	0.04		**0.02**
Euphausiacea	Non-CRI	Other	0.04			0.04	**0.02**
Crustacean Total			**0.04**	**0.08**	**0.08**	**0.04**	**0.06**
Fish							
Fish Total	**No Ichthyoplankton Present**						
Fish Eggs							
Unidentified eggs		Egg	0.04	0.08	0.04	0.04	0.05
Fish Eggs Total			**0.04**	**0.08**	**0.04**	**0.04**	**0.05**
Total			**0.08**	**0.16**	**0.12**	**0.08**	**0.11**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

Memorandum

Environmental Resources Management

CityCentre Four
840 West Sam Houston
Parkway North, Suite 600
Houston, Texas 77024-3920

T: 281-600-1000
F: 281-520-4625

ERM

To: Mr. John Geng and Mr. Steven McElhany

Company: Anadarko

From: Bill Stephens

Date: 24 February 2017

Subject: Lucius Truss Spar - Quarter 3 (July-September) 2016 Entrainment Monitoring Results

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The Environmental Protection Agency (EPA) regulates discharges from exploration, development, and production facilities located in and discharging to federal waters of the Gulf of Mexico offshore of Louisiana and Texas under National Pollutant Discharge Elimination System (NPDES) General Permit number GMG 290000 (General Permit). The General Permit provides authorization to discharge wastewater and storm water in the western outer continental shelf (OCS) regions of the Gulf of Mexico with conditions that the permittee agrees to a variety of effluent limitations, monitoring, reporting, and cooling water intake structure (CWIS) requirements.

Entrainment samples were collected from the Lucius Truss Spar (Lucius) in accordance with the General Permit quarterly entrainment monitoring requirements for Quarter 3 2016 (Q3 2016). A description of the sampling procedures and analytical results of the Q3 2016 monitoring event are presented in the following paragraphs.

Sampling Procedures

ERM traveled to Lucius on September 19, 2016 to conduct a sample event. Sampling began at 18:00 hours on September 19, 2016 and after 15 minutes of sample run time, the sampling equipment exhibited a system failure and the sampling event was unable to be completed at that time. The sampling system was subsequently repaired and ERM staff travelled to Lucius on December 28, 2016 to conduct a make-up sample event for the previously uncompleted event. Sampling began at 18:00 hours on the evening of December 28, 2016, and ended at 12:00 hours on December 29, 2016. Samples were collected every following six hours (00:00, 06:00, 12:00) until four, 25 m^3 entrainment sample volumes were collected representing a 24-hour sample period. Sampling began at 18:00 to accommodate a Lucius personnel request to have the entrainment sampling system (ESS) disassembled the day prior to crew change. Samples remained in the possession of the ERM sample team during the transport to shore, under the chain of custody protocol.

Once onshore, the entrainment samples were shipped within 24 hours to Ecological Associates, Inc. (EAI), with chain-of-custody documentation included in the shipment. Samples were processed by EAI during a less than 30 day period. The final results, dated February 2, 2017, were received via email on February 2, 2017.

Texas Registered Engineering Firm F-2393
Texas Board of Professional Geoscientists Firm 50036

In the laboratory, EAI technicians separated debris or material from aquatic organisms and sorted the organisms by life-stage to the lowest possible taxonomic level. The four samples were processed individually (not composited).

Sampling Results

A total of 6 "target" (per EAI nomenclature) fish or shellfish organisms were present in the 100m^3 of water sampled: 5 crustaceans; 1 fish larvae; and 0 fish eggs. Table 1 describes the types, numbers, and lifestages of the organisms of the 6 organisms present in December 28- December 29, 2016 sample. Table 2 describes the lengths of captured fish organisms. Table 3 describes the density of organisms within the samples.

TABLE 1 - Laboratory Analysis of Ichthyoplankton Samples Collected During Event 7 on December 28 – December 29, 2016 at the Anadarko Lucius Truss Spar Platform

Taxa	CRI/Non-CRI Invertebrates*	Life Stage	Lucius-Q3 122816 Sample 1	Lucius-Q3 122916 Sample 2	Lucius-Q3 122916 Sample 3	Lucius-Q3 122916 Sample 4	Total
		Collection Time	**18:00**	**0:00**	**6:00**	**12:00**	
Crustaceans							
Caridea	Non-CRI	Other	2				**2**
Decapoda	Non-CRI	Other		2	1		**3**
Crustacean Total			**2**	**2**	**1**		**5**
Fish							
Unidentified fish-damaged		Post Yolk-Sac Larvae	1				1
Fish Total			1				1
Fish Eggs							
Fish Eggs Total	No eggs present						
Total			**3**	**2**	**1**		**6**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

TABLE 2 - Total Length (mm) of Ichthyoplankton Specimens Collected during Event 7 on December 28-29, 2016 at the Anadarko Lucius Truss Spar Platform

Sample Number	Taxa	Life Stage	Specimen Number	Total Length (mm)
Lucius-Q3 122816-Sample 1	Unidentified fish-damaged	Post Yolk-Sac Larvae	1	NA
Lucius-Q3 122916-Sample 2	**No Ichthyoplankton Present**			
Lucius-Q3 122916-Sample 3	**No Ichthyoplankton Present**			
Lucius-Q3 122916-Sample **4**	**No Ichthyoplankton Present**			

[1] Specimen damaged, not measured.

TABLE 3 - Densities (Number per m^3 of Water Filtered) of Organisms Collected During Event 7 on December 28-29, 2016 at the Anadarko Lucius Truss Spar Platform

Taxa	CRI/Non-CRI Invertebrates	LifeStage	Lucius-Q3 122816-Sample 1	Lucius-Q3 122916-Sample 2	Lucius-Q3 122916-Sample 3	Lucius-Q3 122916-Sample 4	Total
Collection Time			**18:00**	**0:00**	**6:00**	**12:00**	
Volume of Water Filtered (m^3)			**25.0**	**25.0**	**25.0**	**25.0**	**100.0**
Crustaceans							
Caridea	Non-CRI	Other	0.08				**0.02**
Decapoda	Non-CRI	Other		0.08	0.04		**0.03**
Crustacean Total			**0.08**	**0.08**	**0.04**		**0.05**
Fish							
Unidentified fish-damaged		Post Yolk – Sac Larvae	0.04				0.01
Fish Total			**0.04**				**0.01**
Fish Eggs							
Fish Eggs Total	**No eggs present**						
Total			**0.12**	**0.08**	**0.04**		**0.06**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

Memorandum

Environmental Resources Management

CityCentre Four
840 West Sam Houston
Parkway North, Suite 600
Houston, Texas 77024-3920

T: 281-600-1000
F: 281-520-4625

To: Mr. John Geng and Mr. Steven McElhany

Company: Anadarko

From: Bill Stephens

Date: 24 February 2017

Subject: Lucius Truss Spar - Quarter 4 (October-December) 2016 Entrainment Monitoring Results

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The Environmental Protection Agency (EPA) regulates discharges from exploration, development, and production facilities located in and discharging to federal waters of the Gulf of Mexico offshore of Louisiana and Texas under National Pollutant Discharge Elimination System (NPDES) General Permit number GMG 290000 (General Permit). The General Permit provides authorization to discharge wastewater and storm water in the western outer continental shelf (OCS) regions of the Gulf of Mexico with conditions that the permittee agrees to a variety of effluent limitations, monitoring, reporting, and cooling water intake structure (CWIS) requirements.

Entrainment samples were collected from the Lucius Truss Spar (Lucius) in accordance with the General Permit quarterly entrainment monitoring requirements for Quarter 4 2016 (Q4 2016). A description of the sampling procedures and analytical results of the Q4 2016 monitoring event are presented in the following paragraphs.

Sampling Procedures

ERM traveled to Lucius on December 28, 2016 to conduct a sample event. Sampling began at 12:00 hours on the evening of December 30, 2016, and ended at 06:00 hours on December 31, 2016. Samples were collected every following six hours (18:00, 00:00, 06:00) until four, 25 m^3 entrainment sample volumes were collected representing a 24-hour sample period. Sampling began at 12:00 to allow a 24-hour period between the 3rd quarter make-up sample event and the regularly-scheduled 4th quarter sample event. The entrainment sampling system (ESS) was disassembled prior to crew change. Samples remained in the possession of the ERM sample team during the transport to shore, under the chain of custody protocol.

Once onshore, the entrainment samples were shipped within 24 hours to Ecological Associates, Inc. (EAI), with chain-of-custody documentation included in the shipment. Samples were processed by EAI during a less than 30 day period. The final results, dated February 2, 2017, were received via email on February 2, 2017.

In the laboratory, EAI technicians separated debris or material from aquatic organisms and sorted the organisms by life-stage to the lowest possible taxonomic level. The four samples were processed individually (not composited).

Sampling Results

A total of 5 "target" (per EAI nomenclature) fish or shellfish organisms were present in the $100m^3$ of water sampled: 2 crustaceans; 2 fish larvae; and 1 fish egg. Table 1 describes the types, numbers, and lifestages of the organisms of the 5 organisms present in December 30- December, 31, 2016 sample. Table 2 describes the lengths of captured fish organisms. Table 3 describes the density of organisms within the samples.

TABLE 1 - Laboratory Analysis of Ichthyoplankton Samples Collected During Event 8 on December 30 – December 31, 2016 at the Anadarko Lucius Truss Spar Platform

Taxa	CRI/Non-CRI Invertebrates*	Life Stage	Lucius-Q4 123016 Sample 1	Lucius-Q4 123016 Sample 2	Lucius-Q4 123116 Sample 3	Lucius-Q4 123116 Sample 4	Total
Collection Time			**12:00**	**18:00**	**00:00**	**06:00**	
Crustaceans							
Euphausiacea	Non-CRI	Post Larvae				2	**2**
Crustacean Total						2	**2**
Fish							
Clupidae		Post Yolk-Sac Larvae		1			**1**
Syngnathidae		Post Yolk-Sac Lavae				1	**1**
Fish Total				**1**		**1**	**2**
Fish Eggs							
Unidentified eggs		Egg		1			
Fish Eggs Total							**1**
Total				**2**		**3**	**5**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

TABLE 2 - Total Length (mm) of Ichthyoplankton Specimens Collected during Event 8 on December 30-31, 2016 at the Anadarko Lucius Truss Spar Platform

Sample Number	Taxa	Life Stage	Specimen Number	Total Length (mm)
Lucius-Q4 123016-Sample 1	**No Ichthyoplankton Present**			
Lucius-Q4 123016-Sample 2	Clupidae	Post Yolk-Sac Larvae	1	3.0
Lucius-Q4 123116-Sample 3	**No Ichthyoplankton Present**			
Lucius-Q4 123116- Sample 4	Syngnathidae	Post Yolk-Sac Larvae	1	3.0

TABLE 3 - Densities (Number per m³ of Water Filtered) of Organisms Collected During Event 8 on December 30-31, 2016 at the Anadarko Lucius Truss Spar Platform

Taxa	CRI/Non-CRI Invertebrates*	Life Stage	Lucius-Q4 123016 Sample 1	Lucius-Q4 123016 Sample 2	Lucius-Q4 123116 Sample 3	Lucius-Q4 123116 Sample 4	Total
Collection Time			**12:00**	**18:00**	**00:00**	**06:00**	
Volume of Water Filtered (m^3)			**25.0**	**25.0**	**25.0**	**25.0**	**100.0**
Crustaceans							
Euphausiacea	Non-CRI	Post Larvae				0.08	**0.02**
Crustacean Total						**0.08**	**0.02**
Fish							
Clupidae		Post Yolk-Sac Larvae		0.04			**0.01**
Syngnathidae		Post Yolk-Sac Lavae				0.04	**0.01**
Fish Total				**0.04**		**0.04**	**0.02**
Fish Eggs							
Unidentified eggs		Egg		0.04			**0.01**
Fish Eggs Total				**0.04**			**0.01**
Total				**0.08**		**0.12**	**0.05**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

Memorandum

Environmental Resources Management

CityCentre Four
840 West Sam Houston
Parkway North, Suite 600
Houston, Texas 77024-3920

T: 281-600-1000
F: 281-520-4625

To: Mr. John Geng and Mr. Steven McElhany

Company: Anadarko

From: Bill Stephens

Date: 5 May 2017

Subject: Lucius Truss Spar - Quarter 1 (January-March) 2017 Entrainment Monitoring Results

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The Environmental Protection Agency (EPA) regulates discharges from exploration, development, and production facilities located in and discharging to federal waters of the Gulf of Mexico offshore of Louisiana and Texas under National Pollutant Discharge Elimination System (NPDES) General Permit number GMG 290000 (General Permit). The General Permit provides authorization to discharge wastewater and storm water in the western outer continental shelf (OCS) regions of the Gulf of Mexico with conditions that the permittee agrees to a variety of effluent limitations, monitoring, reporting, and cooling water intake structure (CWIS) requirements.

Entrainment samples were collected from the Lucius Truss Spar (Lucius) in accordance with the General Permit quarterly entrainment monitoring requirements for Quarter 1 2017 (Q1 2017). A description of the sampling procedures and analytical results of the Q1 2017 monitoring event are presented in the following paragraphs.

Sampling Procedures

ERM traveled to Lucius on March 27, 2017 to conduct the 1st Quarter sample event. The contractor Dolphin supported the assembly of the entrainment sampling system (ESS). Sampling began at 18:00 hours on the evening of March 27, 2017, and was completed following the end of the 12:00 hour event on March 28, 2017. Samples were collected every following six hours (00:00, 06:00, 12:00) until four, 25 m^3 entrainment sample volumes were collected representing a 24-hour sample period. The entrainment sampling system (ESS) was disassembled prior to crew change after the last event. Samples remained in the possession of the ERM sample team during the transport to shore, under the chain of custody protocol.

Once onshore, the entrainment samples were shipped within 24 hours to Ecological Associates, Inc. (EAI), with chain-of-custody documentation included in the shipment. Samples were processed by EAI during a less than 30 day period. The final results, dated April 10, 2017, were received via email on April 10, 2017.

In the laboratory, EAI technicians separated debris or material from aquatic organisms and sorted the organisms by life-stage to the lowest possible taxonomic level. The four samples were processed individually (not composited).

Sampling Results

A total of 5 "target" (per EAI nomenclature) fish or shellfish organisms were present in the 100m^3 of water sampled: 3 crustaceans; 2 fish larvae; and 0 fish eggs. Table 1 describes the types, numbers, and lifestages of the organisms of the 5 organisms present in March 27- March, 28, 2017 sample. Table 2 describes the lengths of captured fish organisms. Table 3 describes the density of organisms within the samples.

TABLE 1 - Laboratory Analysis of Ichthyoplankton Samples Collected During Event 9 on March 27 – March 28, 2017 at the Anadarko Lucius Truss Spar Platform

Taxa	CRI/Non-CRI Invertebrates*	Life Stage	Lucius-Q1 032717 Sample 1	Lucius-Q1 032817 Sample 2	Lucius-Q1 032817 Sample 3	Lucius-Q1 032817 Sample 4	Total
		Collection Time	**18:00**	**00:00**	**06:00**	**12:00**	
Crustaceans							
Euphausiacea	Non-CRI	Metanauplius	2				**2**
Euphausiacea	Non-CRI	Adult			1		**1**
Crustacean Total			**2**		**1**		**3**
Fish							
Myctophidae		Post Yolk-Sac Larvae		1			**1**
Blenniidae		Yolk-Sac Larvae				1	**1**
Fish Total				**1**		**1**	**2**
Fish Eggs							
No fish eggs collected							
Fish Eggs Total							
Total			**2**	**1**	**1**	**1**	**5**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

TABLE 2 - Total Length (mm) of Ichthyoplankton Specimens Collected during Event 9 on March 27-28, 2017 at the Anadarko Lucius Truss Spar Platform

Sample Number	Taxa	Life Stage	Specimen Number	Total Length (mm)
Lucius-Q1 032717-Sample 1	**No Ichthyoplankton Present**			
Lucius-Q1 032817-Sample 2	Mycotophidae	Post Yolk-Sac Larvae	1	N/A[1]
Lucius-Q1 032817-Sample 3	**No Ichthyoplankton Present**			
Lucius-Q1 032817- Sample 4	Blenniidae	Yolk-Sac Larvae	1	2.5

[1] Specimen damaged, not measured

TABLE 3 - Densities (Number per m³ of Water Filtered) of Organisms Collected During Event 9 on March 27-28, 2017 at the Anadarko Lucius Truss Spar Platform

Taxa	CRI/Non-CRI Invertebrates*	Life Stage	Lucius-Q1 032717 Sample 1	Lucius-Q1 032817 Sample 2	Lucius-Q1 032817 Sample 3	Lucius-Q1 032817 Sample 4	Total
		Collection Time	**18:00**	**00:00**	**06:00**	**12:00**	
		Volume of Water Filtered (m^3)	**25.0**	**25.0**	**25.0**	**25.0**	**100.0**
Crustaceans							
Euphausiacea	Non-CRI	Metanauplius	0.08				**0.02**
Euphausiacea	Non-CRI	Adult			0.04		**0.01**
Crustacean Total			**0.08**		**0.04**		**0.03**
Fish							
Myctophidae		Post Yolk-Sac Larvae		0.04			**0.01**
Blennidae		Yolk-Sac Lavae				0.04	**0.01**
Fish Total				**0.04**		**0.04**	**0.02**
Fish Eggs							
No Fish Eggs Identified							
Fish Eggs Total							
Total			**0.08**	**0.04**	**0.04**	**0.04**	**0.05**

*CRI = Commercially or Recreationally Important Decapod Crustaceans.

APPENDIX F

COMMENT NO. 37

Meeting the Requirements of 40 CFR.125.137 For Information on Seasonal Variation of Entrainment

Relevant Text from 40CFR.125.137

"After that time[24 months of bimonthly monitoring] , the Director may approve a request for less frequent sampling in the remaining years of the permit term and when the permit is reissued, if supporting data show that less frequent monitoring would still allow for the detection of any seasonal variations in the species and numbers of individuals that are impinged or entrained."

Proposed alternative to quarterly monitoring of a small number of regulated intakes

Approach

- Allow operators of regulated intakes to submit an initial report on seasonal densities of eggs and larvae from SEAMAP data base and follow up with updated reports periodically as data are added

Advantages

- Proposed approach is more effective at addressing regulatory requirement than existing method
- Data are collected and maintained over the long term
- Long term consistency of collection methods ensures comparability over time
- Data are suitable for detecting evolution of entrainment 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.*

*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

Gulf of Mexico Fishery Zones

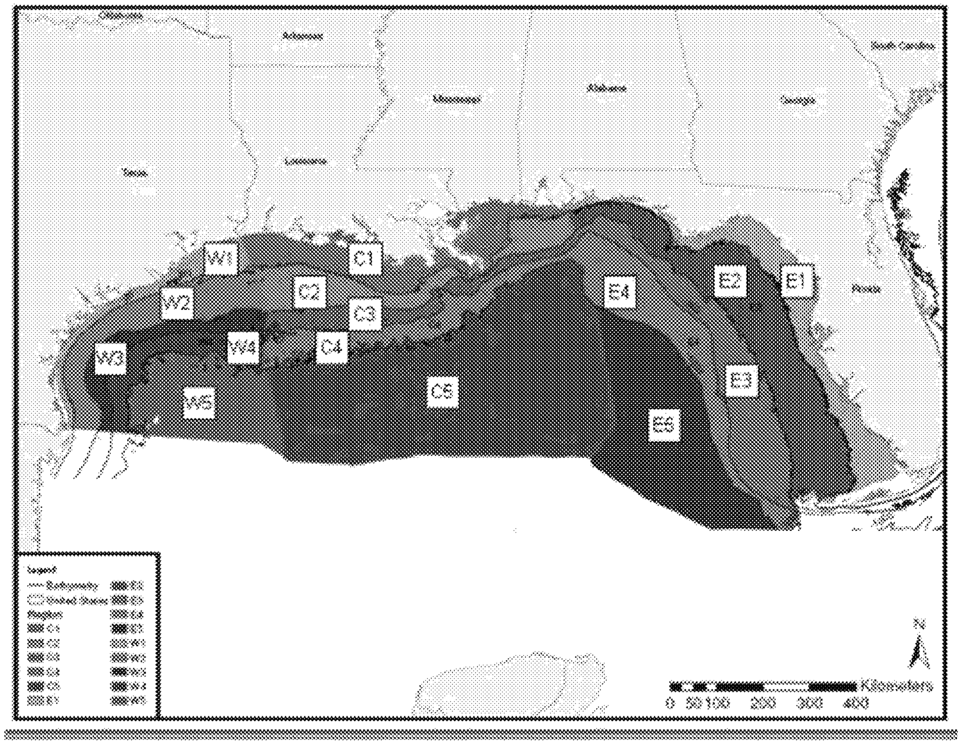
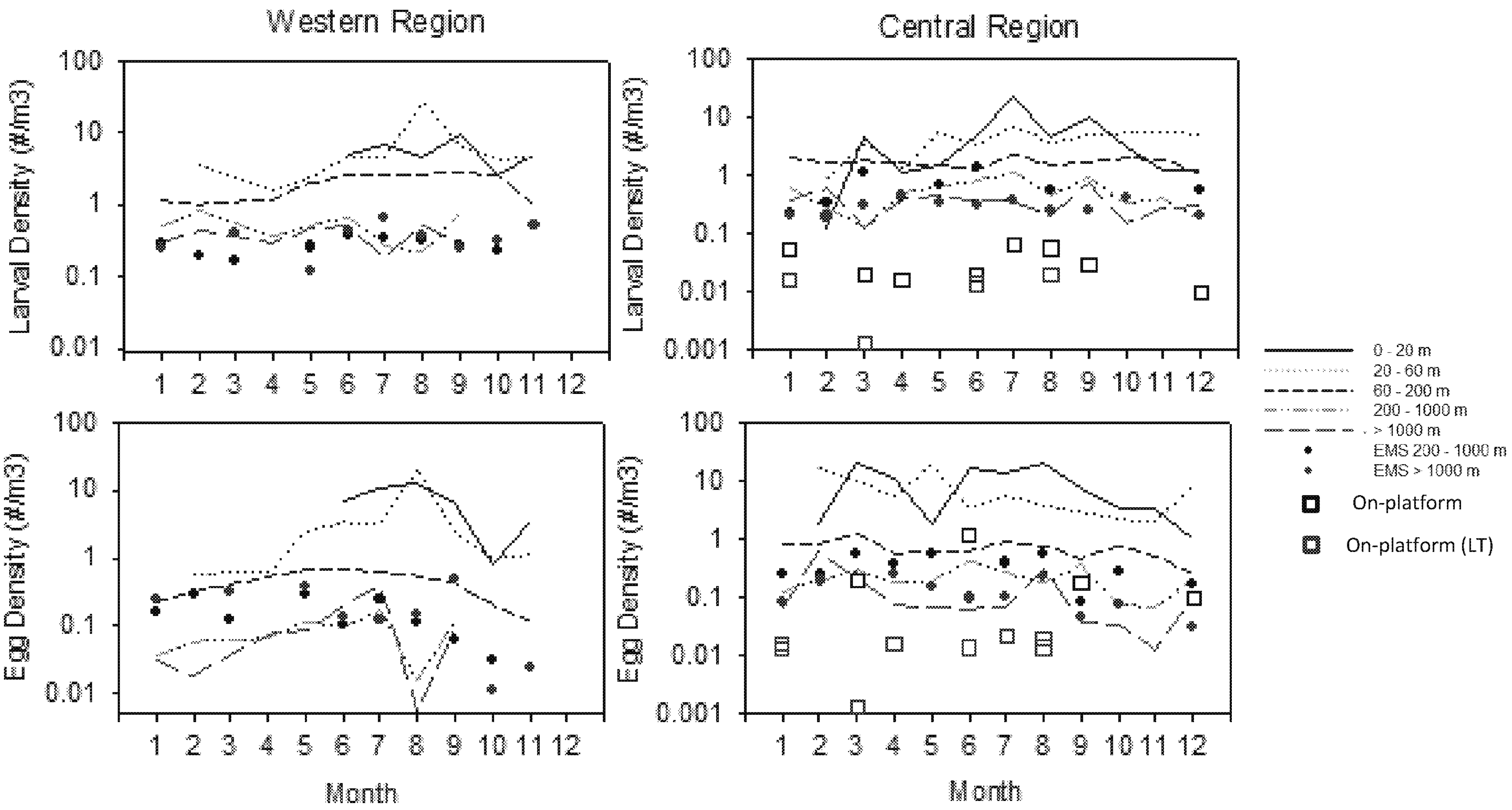


Figure E1. Zones for fishery data and water-use assessment.

- The Source Water Biological Baseline Characterization Study divided the GOM into 15 fishery zones organized by depth and longitude
- Each zone can be considered a homogenous unit for fishery analysis

Comparison of SEAMAP, EMS, and On-Platform Densities



*On--Platform (LT) means the values are "less than" the y-axis value. As an example, a 100 cubic meter sample in which there were no eggs found was plotted as having an egg density of less than 0.01 eggs/cubic meter.

Egg_and_larvae_mulitplots.jnb

APPENDIX G

COMMENT NO. 39

Issue

It is acknowledged that surfactants should not be used for purposes which "could circumvent the intent of the permit's produced water sheen monitoring requirements"(1).

Detergent vs Surfactant

It is important to differentiate between surfactants (detergents, dispersants) in the context of reducing oil content in a discharge stream vs the use of surface active substances in the formulation of chemicals to impart specific properties to the formulation. Detergents, dispersants, and soaps are surfactants or surfactant mixtures, whose solutions have cleaning properties (2). For example detergents alter interfacial properties so as to promote removal of a phase from solid surfaces (2). However, not all surfactants are detergents although their names are often used interchangeably. On the other hand, the cleaning ability of some surfactants is also required at some stages of the Petroleum Industry.

Use of Surfactants in the Oil Industry

Surfactants are used at all stages in the petroleum industry; from oil-well drilling and production, reservoir injection to surface plant processing, to pipeline and marine transportation of petroleum emulsions (2).

Surfactants are required in chemical formulations due to their unique property to break down the interface between water and oil and their ability to influence the properties of surfaces and interfaces (2). They are also defined as compounds that contain one part that has an affinity for polar media and the other has affinity for nonpolar media (3). They behave in this manner because they contain both a hydrophilic group, such as an acid anion (-CO2- or SO3-), and a hydrophobic group such as an alkyl chain.

These qualities make surfactants invaluable to the petroleum industry. Their relevance in various interfacial phenomena, such as adsorbed surfactant films, self-assembly, contact angle, wetting, foams and emulsions with regard to drilling, enhanced oil recovery, antifoaming, corrosion inhibition, oil spill clean-up, oil/water separation, and fluidization of highly viscous materials has been well documented has been well documented (3).

Use of Surfactants in Drilling Processes

The main applications of surfactants in oil based drilling fluids are emulsification and oil wetting of cuttings to ensure good suspension and transports. Emulsifiers have by definition surface active (surfactant) properties and they are an essential part of oil and synthetic based drilling fluids. The use of surfactants is at the core of invert emulsion technology from conventional mineral oil invert emulsion fluid system to high-performance organophilic clay-free synthetic based invert emulsion fluid system.

The function of the emulsifier is to lower the interfacial tension between oil and water resulting in the formation of a stable emulsion. This is achieved by having a mixture of oil and water in which one of the phases, the dispersed phase, occurs as droplets dispersed within the other (3). The emulsifier surrounds droplets of water as if encapsulating the water molecules, with the fatty acid component of the chemical dissolving in the oil phase of the mud. Emulsifiers used in drilling muds have been classified as primary and secondary; common primary emulsifiers include fatty acids, rosin acids and their derivatives, with secondary emulsifiers including amines, amides, sulphonic acids alcohols and related copolymers. The secondary emulsifiers improve the stability of the emulsion further from the primary or main emulsifier and aids.

Water based drilling fluids use a variety of surfactants (4) for specific applications such as lubrication and corrosion inhibition. Drilling lubricants often contain surfactants which are used to reduce friction during the drilling process and increase rate of penetration which is imperative for drilling long horizontal well depths. Without lubricants, some reservoir targets may not be reachable due to torque and drag limitations which lead to stuck pipe and possible well abandonment. These are especially important in applications using water or brine base fluids where there is minimal lubricity in comparison to oil based muds.

One common issue with water based drilling fluids when adding viscosifiers is the production of foam. The surfactants in defoamers (also known as anti-foamers) help reduce the interfacial tensions between fluid and air allowing the reduction in formed bubbles.

Other uses in water based drilling fluids include, inhibition of shale-swelling to prevent wellbore instabilities, prevention of cuttings sticking to the drill bit, prevention of differential sticking, inhibition of flocculation of clay particles and surfactant-polymer complexes for enhanced properties in fluids for low-pressure reservoirs.

Completion fluids are fluids used after the drilling process to complete the well before production begins. These fluids commonly consist of brine as the base fluid which is naturally corrosive. Therefore, it is common to use a corrosion inhibitor. Surfactants are now widely used in corrosion inhibitors by interacting with the metal surface. This is done by forming a film on the metal surface which in turn protects the metal through an absorption mechanism. Since completion brines are commonly used in the reservoir section, there is a need to ensure the brine/crude oil don't mix. Therefore, surfactants are commonly used to prevent emulsions from lowering the surface tension of the brine and interfacial tensions as previously explained.

Other surfactants are components in wellbore clean-up / cleaner chemicals for cleaning metal and/or formation surfaces both on surface and down hole.

Reservoir permeability (productivity or injectivity) can be severely adversely affected by drilling fluid and other residues coating metal surfaces. Surfactants are utilized to efficiently clean these metal surfaces of this debris and residue and therefore help protect the reservoir from damage.

A common down-hole usage is when displacing drilling fluids and other fluids from the well bore to clean metal surfaces downhole (e.g. production casing and tubing) and also for cleaning the marine riser at the end of the well, when the drilling and completion phase is finished. Occasionally, surfactants can be used to remove the drilling fluid filter cake from the face of the reservoir rock in order to re-establish optimal permeability pathways between the hydrocarbon reserves and the production tubing to surface.

At the surface, surfactants are used for cleaning of surface pits (tanks containing specialized fluids).

Summary

Surfactants are part of the composition of many chemicals and fluid systems used in the Gulf of Mexico. Toxicity tests in cuttings wastes containing both oil based muds and water based muds consistently meet the required limits, indicating that the presence of small concentration of these chemicals does not affect the toxicity of the discharge stream containing drilling fluids adhered to cuttings, as well as other fluids systems which may contain chemicals with surfactants in their make- up.

In summary chemicals with surfactant properties are currently used in the Gulf of Mexico and throughout the world in fluids systems which are discharged and meet regulatory requirements.

A complete ban in the discharge of surfactants would preclude the current discharge regime in the Gulf of Mexico.

References

(1) Fact sheet and supplemental information for the proposed reissuance of the NPDES general permit or 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); April 7, 2017

(2) Surfactants. Fundamentals and Applications in the Petroleum Industry. L. Schramm edition 2000.

(3) Surface Chemistry in the Petroleum Industry; James R. Kanicky, Juan-Carlos Lopez-Montilla, Samir Pandey and Dinesh O. Shah Chapter 11,

(4) Optimization of Water-based Drilling Fluid Using Non-ionic and Anionic Surfactant Additives. Procedia Engineering Volume 148, 2016, Pages 1184-1190Putri Yunitaa,*, Sonny Irawana, Dina Kaniab. Procedia Engineering 148 (2016) 1184 – 1190

APPENDIX H

COMMENT NO. 41

NeTDMR Inconsistences

Storet Code	Limit Set	Parameter	DMR	Permit	
85871	CW	Visual Frequency	Weekly	Monthly	
85868 R 85868 S 85868 T		Velocity Frequency	Instantaneous	Daily	
TQM3E	CT	Coeffecient of Variation	48 HR MN MO AV MN	DA MAX Not in permit	
TQM6B			48 HR MN MO AV MN	DA MAX Not in permit	
04239 T		Visuals - Untreated	See MD DMR		
22414 51726 TOP3E TOP6B TPP3E TPP6B TXP3E TXP6B TYP3E TYP6B	SS	Toxicity Reporting Units	Percentage	mg/L	
TLP3E TGP3E TOP3E TPP3E TYP3E TXP3E TOP6B TPP6B TXP6B	HF	Mysid species name	None Shown Americamysis bahia	Mysidopsis bahia	(see TQP3E - mysid. Bahia) for consistency
		Menidia species name	Menidia menidia	Menidia berryllina	(see TLP6B - Menidia for consistency
TLP3E TGP3E TOP3E TPP3E TYP3E TXP3E TOP6B TPP6B TXP6B	PR	Mysid species name	None Shown Americamysis bahia	Mysidopsis bahia	(see TQP3E - mysid. Bahia) for consistency
		Menidia species name	Menidia menidia	Menidia berryllina	(see TGP6B - Menidia for consistency
22414 51726 TLP3E TGP3E TOP3E TPP3E TYP3E TXP3E TOP6B TPP6B TXP6B	MD	Whole effluent toxicity	percentage	mg/L	
		Critical Dilution	percentage	mg/L	
		Mysid species name	None Shown Americamysis bahia	Mysidopsis bahia	(see TQP3E - mysid. Bahia) for consistency
		Menidia species name	Menidia menidia	Menidia berryllina	(see TGP6B - Menidia for consistency