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Via email to pocswellstim@anl.gov

Re: Joint Trade Association Comments on the *Programmatic Environmental Assessment of the Use of Well Stimulation Treatments on the Southern California Outer Continental Shelf*

The American Petroleum Institute (API), the Offshore Operators Committee (OOC), the California Independent Petroleum Association (CIPA), and the National Ocean Industries Association (NOIA) appreciate the opportunity to provide comments on the *Programmatic Environmental Assessment of the Use of Well Stimulation Treatments on the Southern California Outer Continental Shelf* (the "EA"). As you are aware, our organizations represent member companies who are significant stakeholders in offshore oil and natural gas production, and who are experts in well stimulation treatments.

Our significant comments are summarized below. In addition, specific editorial comments are also included in the table in Attachment A.

Support for the Conclusions of the EA

API, OOC, CIPA, and NOIA (the "joint trades") fully support the conclusion and recommendation of the EA for the continued use of well stimulation treatments (Alternative 1). Well stimulation treatments (WSTs), and associated discharge of WST-related fluids, is a long-standing practice within the oil and natural gas production industry in the Southern California Outer Continental Shelf (OCS), as well as other producing regions around the world. The industry's track record is sound and the risks from WST-related operations are well understood and manageable. Allowing the use of WSTs is the only feasible and logical recommendation.

Scope of the EA

The joint trades feel it is important, however, to make it clear that while the overall conclusion above would also be justified in other offshore environments, the technical scope of this particular EA is limited to the Southern California OCS. Some of the supporting data and recommendations presented in the EA are specific to the Southern California OCS, and may not be applicable to other producing areas, such as the Gulf of Mexico. We feel it is important to clarify the scope of the EA so that potential future studies in other producing areas do not inadvertently limit the use of WSTs based on erroneous assumptions about the facts of the Southern California OCS production also being present in other locations.

Impacts within the 100 m Mixing Zone and Essential Fish Habitat

References to impacts within the 100-meter mixing zone (defined under the US EPA NPDES permit) indicate qualitatively that there could be temporary, localized minor decreases in water quality (see EA pps ES-11, 4-10, 4-25, and 4-34). We suggest that the EA also note in the appropriate locations within the document, that the effects of discharges of all platforms in the Pacific OCS, inside their respective 100-meter mixing zones has been evaluated by US EPA and by the dischargers with regard to produced water and drilling related discharges. While the EA focuses on WST discharge related impacts and not specifically produced water, WST fluids are commonly commingled with produced water, such that any studies done on produced water should be instructive for the review of WST related discharges.

To that end we offer the following summary of the US EPA's prior evaluation for consideration of inclusion in the document to further support the conclusion that impacts from discharges, inside the 100-meter mixing zone are very minor and insignificant.

In 2000, USEPA commissioned SAIC to conduct a Biological Evaluation and an Essential Fish Habitat (EFH) assessment for the re-issuance of a NPDES General Permit for offshore oil and gas facilities in southern California. The overall conclusions of the EFH assessment were that the continued discharge from the 22 platforms located in federal waters offshore California will not adversely affect EFH outside the mixing zones, described as a 100 m radius from the discharge point.

The assessment further concluded that while there may be effects on EFH from certain discharges, such as drilling fluids and produced water within the mixing zone near an outfall, these effects should be minor overall given the very small area which may be affected relative to the size of the EFH off the Pacific Coast, and the mitigation provided by the various effluent limitations proposed at that time for the NPDES permit.

The EPA provided a copy of the EFH assessment to the National Marine Fisheries Service (NMFS) to initiate their required consultation. As a result of the consultation, the NPDES General Permit incorporated a requirement that the permittees conduct a study of the direct lethal, sublethal, and bioaccumulative effects of produced water on federally managed fish species on the Pacific OCS at key life stages that occupy the mixing zone of produced-water discharges. The permit further required that the permittees model results describing the dilution and dispersion plumes from each point of discharge of produced water (for all platforms covered by the permit) to determine the extent of the area in which federally managed fish species may be adversely affected. The permit also required the permittees to propose mitigation measures if either of the studies indicated substantial adverse effects to federally managed fish species or EFH occur.

In response, a single comprehensive report was submitted by the permittees, prepared by MRS in 2005. It provided a detailed quantitative assessment of potential impacts from produced-water discharges on federally managed fish species from each of the California OCS dischargers. Although maximum contaminant concentrations beyond the 100-m mixing zone are usually well within NPDES permit limits, the study focused on the toxicity and bioaccumulation potential of produced-water discharges to the fish populations that reside within the 100-m mixing zone beneath the platforms.

The quantitative exposure assessment found a general absence of impacts from most of the major produced-water constituents noting that most produced-water constituents that would normally be of concern for the protection of marine organisms were below biological effects levels prior to discharge. Four constituents (benzene, cyanide, silver, and ammonia) had end-of-pipe concentrations that were slightly elevated in produced water compared to thresholds of potential effects in finfish. However, the produced-water discharges achieve high dilution almost immediately upon discharge. As a result, the plume volumes containing concentrations of potential biological significance were exceedingly small compared to the volume of habitat contained within the mixing zones.

In September 2005, EPA concurred with the overall conclusions of the study and forwarded them to NMFS as part of the EFH consultation required by the General Permit. In October 2005, NMFS notified EPA that the study met the intent of the conservation recommendations incorporated in the General Permit and that the EFH consultation was complete. Revisions to the NPDES General Permit, which included new compliance criteria for several of the platforms and a revision to the undissociated sulfide criterion, were approved in November 2009. Thus, potential impacts to finfish within the 100-m mixing zone are not likely to be significant.

Add References to the Hudgins Report

In regards to the various lists of chemical components in WST fluids shown in tables 4-11, 4-12, 4-13, and 4-14, and the associated discussion (especially in the narrative starting on p. 4-30), we acknowledge that the EA adequately addresses these appropriately. However, further scientific support for the conclusions already made in the EA, we suggest the authors of the EA also consider making appropriate reference to what is commonly referred to as "The Hudgins Report". This study, titled *Chemical Treatments and Usage In Offshore Oil and Gas Production Systems,* was commissioned by API and prepared by Charles M. Hudgins, Jr. and was used by USEPA in the early 1990s in generating discharge requirements in NPDES permits for produced water as well as WST fluids. Many of the chemicals listed in the EA, and/or their chemical families were specifically evaluated in the Hudgins Report and have already been considered by US EPA in administering the environmental protections in the NPDES permit system.

Well Stimulation Treatment vs. Acid Wash

We interpret the EA to base the key difference on whether the treatment is designed to increase the deliverability of the formation vs. damage removal that doesn't affect the integrity of the well / formation. Because the treatments include removal of carbonate fluid loss materials and formation fines generated during drilling, both HCl and HCl-HF acids are used. There are numerous locations in the EA that reference these types of treatments, not as WSTs, but as well cleanup or acid wash. The document specifically mentions very few acid WSTs had been conducted historically and have an expected low frequency in the future (e.g., see p. ES-10 first full paragraph; p. 2-6 end of first paragraph; and p. 4-3 2nd paragraph). In contrast, nearly all relevant wells require acid treatments (HCl and/or HCl-HF) to get appreciable production rates. If that is in fact the key difference, then the interpretation is that acid jobs are much more aligned with the latter case ("routine removal of damage") and go unaffected by the EA alternatives presented. This also seems to be supported by a definition (p. 2-8) of an "Acid Wash" that makes a similar distinction vs. "Matrix Acidizing".

Specific Editorial Comments – Attachment A

In addition to the comments discussed above, we have also included specific editorial comments in Attachment A for consideration.

If you have any questions, or require clarification, on any of the comments provided here by the joint trades, please contact any one of the following:

- API – Andy Radford, Senior Policy Advisor for Offshore, radforda@api.org
- OOC – Greg Southworth, Associate Director, greg@offshoreoperators.com
- CIPA – Rock Zierman, Chief Executive Officer, rock@cipa.org
- NOIA – Randall Luthi, President, rluthi@noia.org

Again, we appreciate the opportunity to provide these comments and feedback.

Yours truly,

Andy Radford
Senior Policy Advisor – Offshore
American Petroleum Institute

Rock Zierman
Chief Executive Officer
California Independent Petroleum Association

Greg Southworth
Associate Director
Offshore Operators Committee

Randall Luthi
President
National Ocean Industries Association

Attachment A

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API, OOC, CIPA & NOIA Comments to

Programmatic Environmental Assessment of the Use of Well Stimulation Treatments on the Southern California Outer Continental Shelf

Page #	Section #	Line(s)#	Original Text	Comments	Suggested Alternative Text
ES-1	ES.1	8	on the 43 current active leases and 23 operating platforms on the Southern California	Several references confuse the reader with regards to the number of platforms in the Pacific OCS. Specifically, p. ES-1 first paragraph refers to 23 operating platforms. This is confusing taken together with statements on last paragraph on p. ES-3 regarding 22 production platforms, and again on p. 1-1 in the second paragraph, noting 23 platforms (22 producing and one processing). In addition, the EA does not specifically address any potential future development or additions of new platforms.	See comments
ES-1	ES.1	10	hydrocarbon resources (i.e. oil)	Gas may also be produced.	Change text to read "hydrocarbon resources (i.e. oil and natural gas)"

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Page #	Section #	Line(s)#	Original Text	Comments	Suggested Alternative Text
ES-1	ES.3	1	This EA adopts the definitions that are found in State of California Senate Bill No. 4 (SB-4) Oil and Gas: Well Stimulation.	Initially, we believe that the draft EA needs to clarify what activities fit within the respective well stimulation treatment (WST) fracturing and non-fracturing definitions. As described, we see some potential overlap between these categories, and this overlap may cause confusion as to what category a specific WST activity fits within and whether permitting may ultimately proceed with respect to this particular activity pursuant to this draft EA. More specifically, we believe there is a discrepancy in the definition of non-fracturing WSTs. We view the second definition provided as being more consistent with the rest of the document: - Dissolve materials in existing pathways or create new pathways for hydrocarbon flow to the well (p. 2-3, end of section 2.2.1) - “By dissolving these materials, existing channels or pathways are opened and new ones are created … ” (bottom of p. 2-5, section 2.2.1.2) - First it describes “Matrix Acidizing” design in a way very similar to our acid jobs except for the part about penetrating the pores in the rock (vs. our jobs we believe stay mainly in the natural fractures; pg. ES-3) and then - It states that records show only three instances of matrix acidizing offshore California between 1985-2011 (and this was on only 2 of 23 platforms…) (pg. ES-8) - And then it states “routine removal of formation damage due to drilling” is excluded from “Well Stimulation Treatments” (pg. ES-2) We have specific concerns regarding the wholesale adoption of certain SB 4 definitions in the draft EA, namely (i) Well Stimulation Treatments, (ii) Acid Well Stimulation, and (iii) Acid Volume Threshold. Simply put, the S.B. 4 definitions reflect State concerns about onshore activities, which differ from the activities contemplated under the draft EA. They reflect California state political and policy choices, which do not and should not constrain the federal government. Should this EA be later referenced, adopted or otherwise given consideration in the GoM, the government would be indirectly importing California state law far beyond its borders.	See comments

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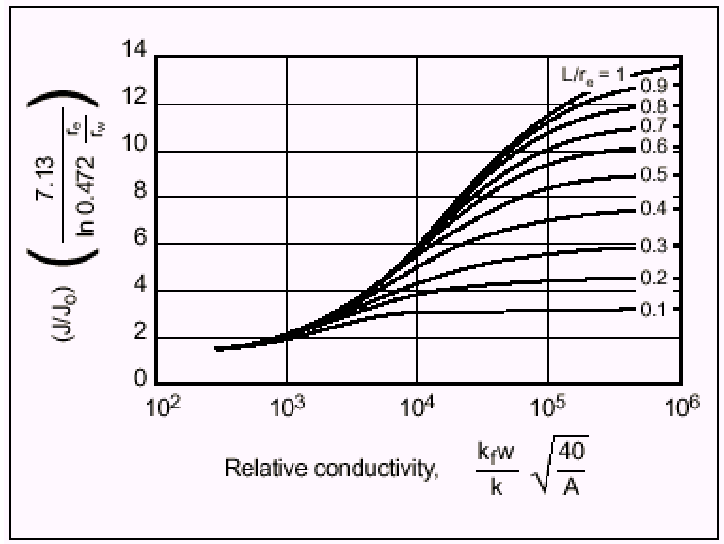
ES-1	ES.3	37-38	The WSTs evaluated in this EA include fracturing and non-fracturing treatments which may be used for enhancing production from existing or new wells where formation permeability and decreasing reservoir pressure are limiting oil recovery.	WST use should not be limited to enhancing production related to formation permeability or decreasing reservoir pressure. The current language creates a concern that BSEE approval for other types of WST operations may be limited or conditioned on other considerations.	Suggest ending sentence after "existing or new wells."
ES-2	ES.3	6	Well Stimulation Treatment definition	Consider revising the definition since hydraulic fracturing treatments do not increase the permeability of the formation - they create a high permeability fracture within the formation as a conduit into the well but they do not increase the formation permeability. The main focus of frac pack treatments is on sand control rather than on improving productivity although most frac pack treatments also improve productivity.	See comments
ES-2	ES.3	23- 24	as pressure is released.	Pressure is not released by any mechanical means, but is allowed to dissipate naturally into the reservoir.	Change to "as pressure dissipates into the reservoir over time."
ES-2	ES.3	26-41	Hydraulic Fracturing definition	Steps 2 and 3 are not necessarily sequential - the breakers may already be present in the fluids pumped in step 2 (or step 1). Some fluid is allowed to bleed off into the formation and some flows back to the platform. 100% of the injected fluid may not be recovered.	See comments
ES-3	ES.3	39-46	Alternative 1 description	Recommend that this description be made clearer that Alternative 1 still allows discharges that are precluded under Alts. 2 and 3.	Add the sentence "WSTs will continue to be discharged under the requirements of NPDES General Permit CAG280000."
ES-3	ES.3	39-46	Alternative 1	The Executive Summary needs to be clearer in identifying Alternative 1 as the agencies' recommendation and identifying the alternatives as less favorable. To help facilitate this it is recommended that the Executive Summary text be revised including renaming “Alternative 1” to “Recommendation” (or at least reflecting that Alternative 1 is the recommended alternative).	See comments
ES-2	ES.3	41	filtered seawater	There are many possible fracturing fluids, not just filtered seawater	Change to "base fracturing fluid is typically filtered seawater, but may also be a different brine based fluid."
ES-4	ES.3	2-3	Alternative 2	Instead of a depth stipulation of 2000 ft below the mudline (which is arbitrary and not linked to physical attributes in the subsurface environment which determine the likelihood of an expression at the seafloor), the following technical information is offered for incorporation into the discussion of Alternative 2:	See comments

Page #	Section #	Line(s)#	Original Text	Comments	Suggested Alternative Text
				In general shallow marine formations are immature meaning they tend to be unconsolidated. This leads to the formation targeted for stimulation as having a high fracture toughness and a low modulus. Fracture Toughness is a mechanical rock property that contributes to a general resistance to fracture propagation. As for the modulus, it is presented in the parametric equations below from MFrac, one of the industry's most popular hydraulic fracturing simulators. Modulus appears in the form of "E" in these equations. With modulus appearing in the numerator of the equation for length (L) and the denominator of the equation for width (W), this indicates that a lower modulus rock like that found in shallow marine formations will tend to yield a shorter, wider hydraulic fracture. $L \approx \left[\frac{E Q^{-\eta'} V^{2\eta'+2}}{\left(1-\upsilon^2\right) k' H^{\eta'+2}} \right]^{\frac{1}{2\eta'+3}}$ $W \approx \left[\frac{\left(1-\upsilon^2\right)}{E} \frac{k' Q^{n'} V}{H^{n'}} \right]^{\frac{1}{2\eta'+3}}$ Shallow immature formations have less geologic time to compress and form diagenic, porosity-filling compounds. This will tend to yield a formation with higher permeability. The chart below is from the classic study performed by McGuire & Sikora in 1960. It models the production response of various fracture lengths with respect to the conductivity contrast between the fracture and the target formation. In high permeability formations, the curve responses are represented on the left side of the chart. On the high formation permeability side of the chart, all of the different fracture lengths converge together, indicating that post fracture treatment production response in high permeability formations do not respond to fracture length, but instead to increased fracture conductivity, or greater fracture width. In general, the design target for high permeability formations is fracture geometry that limits length propagation and increases width. These sorts of designs incorporate a tip screen out design that arrests fracture length propagation in the early stages of the treatment thereby forcing the volume injected into the fracture to preferentially increase width.	

Page #	Section #	Line(s)#	Original Text	Comments	Suggested Alternative Text
				 In these shallow marine formations, treatments will usually incorporate a small volume hydraulic fracture treatment to bypass near wellbore formation damage and reconnect to the high quality reservoir. As stated above, these formations naturally tend to resist fracture length propagation due to the nature of their mechanical rock properties. By design or nature, nearly all treatments pumped into these formations will be on the order of 30 feet in fracture length from the wellbore, plus or minus tens of feet. It is therefore unnecessary to eliminate treatments in shallow formations (less than 2000 ft from the mudline) as the risk of surface breaches is highly unlikely.	
ES-4	ES.3	16-20	When WST-related chemicals are present, produced water would need to be disposed by alternative means such as through injection. Additional injection wells could be needed at one or more of the platforms where disposal currently occurs only via permitted open water discharge.	Injection wells may not always be technically feasible because injected fluids must be compatible with the formation characteristics to achieve injectivity, among other reasons.	Change to " Additional injection wells could be needed at one or more of the platforms where disposal currently occurs only via permitted open water discharge, or WST-related fluids may need to be transported to shore for disposal."

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ES-4	ES.3	22-29	Alternative 4	Alternative 4 is incomplete. Just as Alternative 3 identifies that Operators may drill an extra injection well to handle the additional waste water, which comes with its' own environmental exposures, the banning of all WSTs would drive Operators to drill extra wells (or use vessel transfers, or install pipelines subsea, with attendant risks/emissions/discharges) to develop the same resource. The relative impacts of these alternatives could be significant, and therefore, it is incorrect to say that option 4 has no environmental exposures.	See comments
ES-4	ES.3	30	Alternative 4	Waterflooding typically occurs at pressures which also exceed fracture pressures (but with non-gelled fluids that are unlikely to sustain a significant fracture geometry).	See comments
ES-6	ES.4	7-8	Potential impacts due to contributions to elevated photochemical ozone from ozone precursor emissions from diesel pumps and support vessels	This seems to assume there are already "elevated" levels of photochemical ozone	Delete "elevated."
ES-7	ES.4	34-36	Archaeological Resources: The proposed action would not affect archaeological resources, except potential from bottom-disturbing activities that may occur under Alternative 3 or 4.	The purpose of this bullet list is to describe the potential effects that were evaluated, but here a conclusion is stated--that there were no effects on archeological resources. That conclusion seems out of place here, and it seems it should just say potential effects on archeological resources; and also implies that for all the other potential effects before that effects were found, including lethal effects.	See comments
ES-8	ES 5.1	1-45	Entire page	<u>Key Information about Environmental Fate of WST Fluids Missing from Summary:</u> The discussion that starts on page ES-8 and ends at the top of ES-9 omits important information that is included in the document. Acknowledging that this section is merely describing the WST operation and is an executive summary, we nevertheless believe it is important to include in the ES section a full summary of the essential technical points that tell the complete story. In that regard, we think all the facts about the fate of the WST fluids should be provided in this section. These are clearly articulated on pps 4-31, 4-33, 4-34, and 4-37. Specifically, the points that are missing from the ES discussion relate to the significant proportion of WST fluids that are retained in the reservoir, chemically neutralized by intended reaction within the reservoir and during flow to and from the reservoir, and the small portion of the WST fluid component relative to the overall flow of produced fluids that WST fluids are commingled with during flow-back and subsequent treatment, etc.	

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ES-9	ES.5.2	14-17	Required WST chemicals would be delivered to a platform via a PSV and transported in sealed steel containers designed for marine transport and in compliance with applicable packaging and shipping requirements.	Some acids are delivered by dedicated vessels, transported in the vessel's internal tanks. Larger volumes of acid are transported in this manner rather than from individual containers.	See comments
ES-9	ES 5.2	35-37	For the fracturing WSTs, accidental releases of WST chemicals and formation hydrocarbons may occur as a result of well casing failure during injection after repeated pressurization and depressurization events,	The paragraph discusses the way an accidental release of WST chemicals and formation hydrocarbons may occur. This description limits the occurrence to a well casing failure. However, there are necessarily two events that must occur simultaneously for the accidental release to occur. These would be the casing failure as noted, combined with a cement failure. A cement failure may be more related to installation issues rather than pressurization and depressurization.	See comments
ES-10	ES5.3	29	Alternative 4, No Action, would eliminate all impacts of WSTs	Should be "potential" impacts of WSTs	Change to "Alternative 4, No Action, would eliminate all potential adverse impacts of WSTs"
ES-11	Table ES-1	n/a	Alternative 1 - Water quality	Add the word “temporary” in the Alternative 1 discussion of potential effects on water quality so it reads “…slight localized, temporary reduction in water quality…”. The word “temporary” should also be added to Table 4-3 on pg. 4-10 under the “Potential Effects Included for Analysis” column for the permitted discharge activity.	See comments
ES-12	Table ES-1	n/a	Alternative 1 - Socioeconomics	The table states there are no WST-related impacts or benefits expected. However, it is expected that incremental oil recovery would provide a beneficial socioeconomic impact.	See comments
1-3	1.2	24-29	The purpose of the proposed action is to allow the use of certain WSTs (e.g., hydraulic fracturing) in support of oil production at platforms on the Pacific OCS	This seems different than the stated purpose and need in the Executive Summary.	Add the language from Section ES.2: "The purpose and need for the proposed action, to allow the use of certain WSTs (e.g., hydraulic fracturing) in support of oil production at platforms on the Pacific OCS, are to carry out BSEE and BOEM’s responsibilities under the Outer Continental Shelf Lands Act (OCSLA) for effectively managing resources on the Federal OCS. Under the OCSLA, the Secretary of the Interior is required to establish policies and procedures that expedite exploration and development of the

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					OCS for the production of resources (e.g., oil and natural gas) and to balance resource development with protection of the human, marine, and coastal environments, while simultaneously ensuring that the public receives an equitable return for these resources."
1-3	1.2	32-33	Natural gas is generally considered an environmentally preferable alternative to oil to generate electricity	Oil is now rarely used to generate electricity for consumers in the U.S. Suggest as an alternative to say "other fossil fuels".	See comments

Page #	Section #	Line(s)#	Original Text	Comments	Suggested Alternative Text
1-3 1-4	1.2	40-46 1-4	During initial recovery (primary recovery) of an oil and gas reservoir, production is a function of the naturally occurring pressure of the reservoir, as well as the porosity of the formation. During primary recovery, existing reservoir pressure drives the oil through naturally occurring pores, channels, and fractures in the formation and to the production well. As reservoir pressure decreases over time with production, the movement of oil to the production well also declines. Typically, about 30–35% of the oil present in the reservoir at the start of production is recovered during primary recovery (Hyne 2012). Advances in WSTs and the availability of enhanced oil recovery (EOR) techniques have allowed for continued production from onshore and offshore reservoirs where primary recovery has begun to decline as a result of declining reservoir pressures. The reservoirs associated with the 43 active leases on the Southern California OCS have been in production from 26 to 48 years, and reservoir pressures have been gradually declining with this production. The use of WSTs may support the continued recovery of oil as primary recovery declines with the 43 active lease areas.	This section seems to indicate that well stimulation is only a late life activity after significant production has occurred. Well stimulation takes place at the time of the very initial completion and can take place later in the life of the well.	See comments

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1-4	1.2	5-6	The use of WSTs may support the continued recovery of oil as primary recovery declines with the 43 active lease areas	This text only discusses production of oil.	Change to "The use of WSTs may support the continued recovery of oil and natural gas as primary recovery declines with the 43 active lease areas"
1-4	1.2	FN 2	These techniques fall into three major categories—thermal recovery, gas injection, and chemical injection.	Waterflooding is omitted as an EOR technique. The term "chemical injection" is vague and potentially misleading.	Change to "These techniques fall into four major categories—waterflooding, thermal recovery, gas injection, and liquid injection."
1-5	1.2	8	OPD will also look at the proposed fracture in relation to active faults and the location of other wellbores, staying at least 1000 ft away from either	As written, this text could be clarified.	Change to "OPD will also look at the proposed fracture in relation to active faults and the location of other wellbores. OPD checks and confirms that the fracture is at least 1000 ft away from active faults and other wellbores."
1-5	1.2	8	OPD will also look at the proposed fracture in relation to active faults and the location of other wellbores, staying at least 1000 ft away from either	This section seems to indicate a requirement to stay at least 1000 feet away from active faults and other wellbores. Rather than an arbitrary 1000 feet, perhaps consider basing decisions on local geology and formation characteristics.	See comments
2-1	2.1	39	Hydraulic Fracturing	This definition excludes water injection wells (whether frac packed or injected above fracture pressure in a cased and perforated well.)	See comments
2-1	2.1	31	enhance oil and gas production or recovery by increasing the permeability of	Only acid can alter the permeability of the reservoir; fracturing does not change the native permeability of the reservoir.	Change to "enhance oil and gas production or recovery by increasing the deliverability of"
2-1	2.1	FN1	Permeability refers to the ability of a formation's ability to transmit fluid; the higher its permeability, the more easily a fluid will flow through the formation. Formations such as sandstones are described as permeable and tend to have many large, well-connected pores and pathways. Impermeable formations such as shales and siltstones tend to be finer grained or of mixed grain size, with smaller, fewer, or less-	Typographical error.	Change to "Permeability refers to the ability of a formation to transmit fluid; the higher its permeability, the more easily a fluid will flow through the formation. Formations such as sandstones are described as permeable and tend to have many large, well-connected pores and pathways. Impermeable formations such as shales and siltstones tend to be finer grained or of mixed grain size, with smaller, fewer, or less-interconnected pores and pathways. "

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			interconnected pores and pathways.		
2-3	2.2.1.1	44	The three fracturing WSTs all have one thing in common; they are performed with injection pressures that exceed the formation fracture pressure. This results in the creation of fractures within the formation which increase conductivity of fluid (e.g., oil) from the reservoir to the wellbore	Instead of an injection pressure stipulation or volume stipulations (which are arbitrary), focus on the physical constraints to fracture growth out of zone, such as demonstrating a minimum confining stress which is above the maximum fracture pressure (i.e. min 1000 psi confining stress margin between confining stress and fracture pressure). This would be similar to the 0.5 ppg drilling margin and would meaningfully inform out-of-zone fracture growth risk. If a minimum confining stress exists over and above maximum fracture pressure throughout the process, then the volume injected becomes unimportant. Comparison of the fracture pressure with original reservoir pressure could also be an easier way to reduce risk (If depletion is such that fracture pressures are below original reservoir pressures (which were contained), then out-of-zone fracture growth is not a risk.	See comments
2-4	2.2.1.1	17	naturally as pressure is released.	Pressure is not released by any mechanical means, but is allowed to dissipate naturally into the reservoir.	Change to "naturally as pressure dissipates into the reservoir over time."
2-4	2.2.1.1	20	Hydraulic Fracturing	Same comment as in ES about these three not being strictly sequential.	See comments
2-4	2.2.1.1	30-31	Once the fractures are packed with proppant, breakers are added to reduce the viscosity of the fracturing fluid (which allows the proppant to remain in place).	This section indicates that a final stage of breaker fluid is pumped after packing the frac. Typically, operators add breaker all throughout the frac pack (pad and slurry) stages. In addition, there is no mention of reversing out any remaining slurry once an annular pack is obtained and the well screens out. An operator typically reverses out excess slurry and discharges the fluid in accordance with applicable discharge permit requirements.	See comments
2-5	2.2.1.1	7-8	the base fracturing fluid is filtered seawater	There are many possible fracturing fluids, not just filtered seawater.	Change to "the base fracturing fluid is typically filtered seawater, but may also be a different brine based fluid."
2-5	2.2.1.1	11	Acid fracturing is similar to a frac-pac	The phrase “frac-pac” is used to describe a similar operation to acid fracturing (in the section titled “Acid Fracturing”). We could not find this term used prior to this point in the document so it appeared to be without definition or background explanation. Consider adding appropriate lead-in language or context/definition, such as:	See comments

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				"Sand control technologies have evolved and matured over the years, reaching their peak with the development of gravel packing technology in the early 1970's. Installing a gravel pack completion involves using specialized equipment to place what amounts to a sand filter (the same concept as using sand filters for treating drinking water) in the well at the depth of the productive formation to stop the production of sand. Over the years, operators learned that the bigger (thicker) the filter the better the well performed. The desire to create an even bigger "filter" is what led to the combination of hydraulic fracturing and gravel pack completion technologies into what is now called a "Frac Pack" completion. A conventional gravel pack completion uses relatively small volumes of sand, 1,000 to 20,000 pounds of sand is typical, depending on the size of the pipe placed across the productive formation (casing) and the thickness of that formation. Using specialized equipment (packer, cross-over tool, screen, tail-pipe) the sand is pumped into place. Pumping pressures are usually limited so they do not exceed the fracture pressure of the productive formation. A Frac Pack will use much larger volumes of sand (50,000 to over 250,000 pounds is now common) depending on the thickness of the productive formation. When performing a Frac Pack, pump pressures are intentionally increased by increasing the pump rate to exceed the fracture pressure of the formation and force sand outside the casing and well into the productive formation. During a Frac Pack the pumping equipment, sand (proppant) and additives are carried, mixed, and pumped from a specialized stimulation and treatment vessel. The base fluid that is used for the Frac Pack operation will typically be treated seawater, although other brines may be used if conditions dictate. The proppant and other additives are mixed as the Frac Pack is being performed. Since the formations that are being fractured offshore are very permeable (a measure of the ability of fluid to flow through the formation), the fracturing fluid will usually be more viscous and have a higher sand concentration than similar fluids used onshore. In the producing formation, the fracture network that is created can be expected to be less dense and usually will not extend as far from the well since it is far less brittle and more permeable than a shale or tight sand. A thick layer of proppant is placed in the formation, which facilitates the filtering function of the Frac Pack. After the fracturing and proppant placement portion of the operation is completed, a conventional gravel pack can be performed to ensure placement of sand inside the well in the annulus between the	

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				casing and the production screen. Multiple productive formations can be Frac Packed in series, further improving operational efficiency and oil and gas recovery.	
2-7	2.2.4	44	Alternative 4, without the use of WSTs, production at some wells may be expected to decline	Any well that is produced will decline in production, it is disingenuous to imply that only some producers will decline.	Alternative 4, without the use of WSTs, production of all wells may be expected to decline as production continues.
2-12	2.2.5.3	1-46	Entire page	<u>Acknowledgment of Inclusion of Critical Information and Analysis</u> We appreciate the importance of all of the discussion points expressed clearly on page 2-12. These are significant factors that are very illustrative of the context and nature of the situation with regard to WST fluid discharges, as evaluated by US EPA and regulated under the NPDES permit program.	See comments
3-3 4-7	Table 3-1	n/a	Tranquillon Ridge Field	On pps. 3-3 and 4-7 the field name for Platform Irene is incorrectly shown as Tranquillon Ridge. This should be corrected to "Point Pedernales" as the primary production field source, or corrected to acknowledge the combined production from the Tranquillon Ridge and Point Pedernales fields.	See comments
3-12	3.2.3.2	30	(e.g., approximately 10,000 gal [238 bbl])	Section 3.2.3.2 references "larger volumes of acid" being approximately 10,000gal. This characterization is inconsistent with other volumes quoted in the EA and the resultant volumes you would get by applying 14 CCR 1761 to extended open hole completion intervals. It is recommended that the text be revised to avoid references to larger/smaller references.	See comments
3-31	3.4.21	n/a	Discharge Sources from Offshore Oil and Gas Activities	This section talks about Produced Water Specifically and chemical constituents in the produced water in Table 3-6, however, this section does not specify results for Chronic Whole Toxicity (WET). This information could be useful in showing that there was no impact to organisms.	See comments
4-5	4.2.1	8	additional PSVs and/or trips would be needed to bring required WST-related materials to a platform.	The number of incremental trips per job is probably lower. All of the WST fluids are brought out on a single vessel. Other related wellbore equipment is brought out with other well equipment and probably doesn't involve an extra vessel trip.	See comments
4-5	4.2.2	25	During a WST, chemical additives (e.g., biocides, surfactants) or proppant are mixed into a base injection fluid, filtered seawater	There are many possible fracturing fluids, not just filtered seawater.	Change to "During a WST, chemical additives (e.g., biocides, surfactants) and/or proppant are mixed into a base injection fluid, typically filtered seawater, but other fluids may also be used."
4-8	Table 4-2	n/a	Point Arguello Field	The process descriptions are incorrect for Platforms Hermosa, Hidalgo, and Harvest on pg. 4-8. These should be modified as follows to reflect the reconfiguration project completed in 1999 by Chevron: <u>Hermosa</u> – Receives non-stabilized dry oil from Platform Hidalgo and commingles it with dry oil from Hermosa for stabilization onboard the platform. Receives stabilized dry oil	See comments

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				from Harvest, commingles this stream with combined dry stabilized oil stream from Hermosa/Hidalgo and sends to onshore facility at Gaviota. <u>Hidalgo</u> – sends dry non-stabilized oil to Hermosa. Produced water remains at the platform. <u>Harvest</u> – sends dry stabilized oil to Hermosa. Produced water remains at the platform.	
4-11	4.3.1	15-18	They would be transported in sealed steel containers designed for marine transport and in compliance with U.S. Department of Transportation, International Maritime Dangerous Goods code9, U.S. Coast Guard, and BSEE packaging and shipping requirements.	Some acids are delivered by dedicated vessels, transported in the vessel's internal tanks. Larger volumes of acid are transported in this manner than from individual containers, but a release is less likely to occur.	See comments
4-14 4-43			Real Time Pressure Monitoring During WST	Additionally, there are several references to “real-time pressure monitoring during WST” that would identify contact with other wells, active faults, and casing failures and result in “immediate cessation” of the activity. Depending on the pressure response, this is not necessarily the case as WSTs frequently anticipate some level of pressure drop and may not necessarily lead to immediate suspension of operations. Some alternative text could be that “pre job planning efforts evaluate the risk of casing failure / contact with active faults / other wells and response plans are developed as needed. In many cases, real-time pressure monitoring can be used to identify potential issues and appropriate stopping points to mitigate the potential consequences of such an event.”	See comments
4-31	4.5.1.3	1-5	Because (1) WSTs are infrequent activities, (2) WST fluids contain <1% chemical additives, and (3) recovered WST fluids are mixed and highly diluted with much greater volumes of produced water, it is unlikely that the presence of WST chemical constituents at expected levels after mixing with produced water would alter the conditions observed near platforms, as reported in these studies of produced water discharges.	<u>Key Factors Discussed in Document but Missing from Important Related Conclusion</u> The first full paragraph on pg. 4-31 provides three reasons why it is unlikely that the presence of WST constituents at expected levels after mixing with produced water would alter the conditions near platforms in relation to produced water discharges. We recommend that additional factors in addition to the three noted, should be included. This would include acknowledgement of the retention, adsorption, and reaction/neutralization processes that occur within the reservoir. These dynamics are acknowledged on pg. 4-33 in the third full paragraph, and at the top of pg. 4-37, but are missing in the important conclusion made on pg. 4-31.	See comments

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4-32	4.5.13	Table 4-15		Consider adding Toxicity Testing for Produced Water in Table.	See comments