

2 ALTERNATIVES, INCLUDING THE PROPOSED ACTION

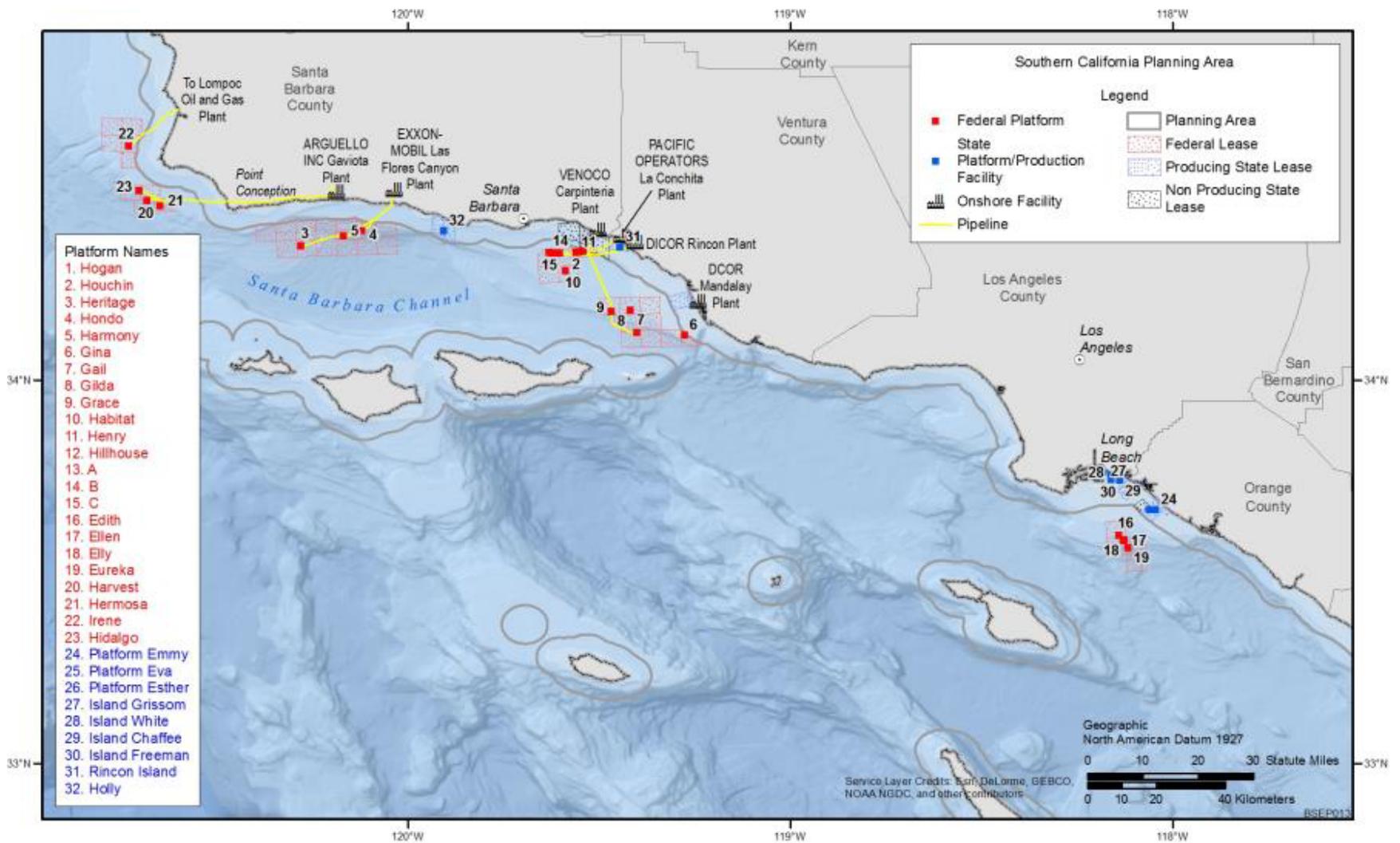
2.1 INTRODUCTION

The proposed action and alternatives evaluated in this PEA include well stimulation treatments (WSTs) that have been, or may be, employed at any of the production platforms operating on the 43 active leases on the POCS (Figure 2-1). For the purposes of this PEA, the 43 lease areas where WST activities may be carried out represent the project area for the proposed action. The WSTs evaluated in this PEA include fracturing and non-fracturing treatments that may be used for enhancing production from existing and new wells where formation permeability and decreasing reservoir pressure are limiting oil recovery.¹ These WSTs are commonly used at onshore wells in California and throughout the United States, and on occasion in wells in offshore Federal and State of California waters (Long et al. 2015a). An overview of the historic use of WSTs on the POCS and adjacent State waters is presented in Section 4.1.

A number of definitions of WST, acid WST, and hydraulic fracturing occur in the open scientific and industry literature, although many are largely similar in nature. This PEA adopts the definitions that are found in Sections 3152, 3157, and 3158 of State of California Senate Bill No. 4 (SB-4) Oil and Gas: Well Stimulation. Adoption of the SB-4 definitions was done for a number of reasons. First, SB-4 applies these definitions to hydraulic fracturing and other WST activities that are occurring in State of California waters and accessing the same formations as those being accessed by platforms on the 43 active Federal lease areas on the POCS. The SB-4 definitions also apply to WST activities that are being widely used on land in California. Second, adopting the SB-4 definitions will allow for more straightforward and clear comparisons of WST applications between Federal and State offshore operations and promoting the cumulative effects analysis. The following SB-4 definitions were adopted for use in this PEA:

- *Well Stimulation Treatment*—means any treatment of a well designed to enhance oil and gas production or recovery by increasing the permeability of the formation. Well stimulation treatments include, but are not limited to, hydraulic fracturing treatments and acid well stimulations (SB-4 Section 3157a). As defined in SB-4 Section 3157b, routine well cleanout work, routine well maintenance, routine removal of formation damage due to drilling, bottom hole pressure surveys, and routine activities that do not affect the integrity of the well or the formation are not considered as WSTs.
- *Hydraulic Fracturing*—means a WST that, in whole or in part, includes the pressurized injection of hydraulic fracturing fluid or fluids into an underground geologic formation in order to fracture or with the intent to

¹ 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.



2-2

1
2 **FIGURE 2-1 Locations of Current Lease Areas and Platforms (shown in red) Operating on the POCS (Also shown [in blue] are**
3 **platforms and production facilities in offshore State waters adjacent to the Federal OCS.)**
4

1 fracture the formation, thereby causing or enhancing [...] the production of oil
2 or gas from a well (SB-4 Section 3152).

3
4 *Acid Well Stimulation Treatment*—means a WST that uses, in whole or in
5 part, the application of one or more acids to the well or underground geologic
6 formation (SB-4 Section 3158). The acid well stimulation treatment may be at
7 any applied pressure and may be used in combination with hydraulic
8 fracturing treatments or other well stimulation treatments. Acid well
9 stimulation treatments include acid matrix stimulation treatments and acid
10 fracturing treatments. Acid matrix stimulation treatments are well stimulation
11 treatments conducted at pressures lower than the applied pressure necessary to
12 fracture the underground geologic formation (and thus are not fracturing
13 WSTs).

14
15 This PEA refers to all treatments included in the proposed action and alternatives
16 collectively as WSTs. Accordingly, a “fracturing WST” hereafter refers to a WST in which
17 WST fluids are injected at pressures required to fracture the formation (i.e., greater than the
18 formation fracture pressure), while any WST in which the WST fluid is injected at less than the
19 pressure required to hydraulically fracture the formation is referred to as a “non-fracturing
20 WST.”

21 22 23 **2.2 PROPOSED ACTION AND OTHER ALTERNATIVES CONSIDERED**

24 25 26 **2.2.1 Alternative 1: Proposed Action—Allow Use of WSTs**

27
28 Under this alternative, BSEE technical staff and subject matter experts will continue to
29 review APDs and APMs and, if deemed compliant with performance standards identified in
30 BSEE regulations at 30 CFR 250 subpart D, approve the use of fracturing and non-fracturing
31 WSTs at the 22 production platforms located on the 43 active leases on the POCS (Figure 2-1).
32 Alternative 1 includes three fracturing WSTs (diagnostic fracture injection tests, hydraulic
33 fracturing, and acid fracturing) and a single non-fracturing WST (matrix acidizing). These
34 four WSTs are described in the following sections.

35
36 Both the fracturing and the non-fracturing WSTs are used to increase the flow of
37 hydrocarbons from the reservoir to the producing well. The fracturing WSTs do so by creating
38 fractures in the oil-bearing formation along which hydrocarbons may flow to the well, while the
39 non-fracturing WSTs dissolve materials in existing pathways or create new pathways for
40 hydrocarbon flow to the well.

41 42 43 **2.2.1.1 Fracturing WSTs Included in the Proposed Action**

44
45 The three fracturing WSTs all have one thing in common; they are performed with
46 injection pressures that exceed the formation fracture pressure. This results in the creation of

1 fractures within the formation which increase conductivity of fluid (e.g., oil) from the reservoir
2 to the wellbore. Three types of hydraulic fracture treatments are considered in this PEA: the
3 diagnostic fracture injection test, the hydraulic fracture, and the acid fracture.
4
5

6 **Diagnostic Fracture Injection Test.** The Diagnostic Fracture Injection Test (DFIT) is a
7 widely used procedure which goes by many names in the industry, such as Data Frac, Mini-Frac,
8 Mini Fall-off, and DFIT. A DFIT is used to estimate key reservoir properties and parameters that
9 are needed to optimize the main fracture job, such as fracture closure pressure, fracture gradient,
10 fluid leakoff coefficient, fluid efficiency, formation permeability, and reservoir pressure
11 (SPE 2013; PetraCat Energy Services 2015). It is a short duration procedure that involves the
12 injection of a small volume of fluid (typically less than 4,200 gal [100 bbl]) at pressures high
13 enough to initiate a fracture. Once a fracture is formed, the well is closed and pressure is
14 measured as it dissipates over time, typically within a day or two. Key parameters are estimated
15 based upon the volume of fluid injected and the pressure profile within the well during pressure
16 dissipation (Halliburton 2015). The fluid used in a DFIT is typically the fluid that would be used
17 in the main fracture treatment but with no proppant² added, thus allowing the fracture to close
18 naturally as pressure is released.
19
20

21 **Hydraulic Fracturing.** In a hydraulic fracturing WST, fracturing fluid is injected at a
22 pressure (as typically determined by a DFIT) needed to induce fractures within the formation.
23 The process generally proceeds in three sequential phases. Initially, a fracturing fluid without
24 proppant (the “pad fluid”) is pumped into the formation to create fractures which extend out
25 from the well. Next, the pad fluid is followed by a slurry of fracturing fluid and proppant. As this
26 slurry reaches the end of the fractures, the proppant settles out, propping open the tips of the
27 fractures (this is referred to as tip screen out). After tip screen out is achieved, slurry injection
28 continues filling the fractures with proppant. Once the fractures are packed with proppant,
29 breakers³ are added to reduce the viscosity of the fracturing fluid (which allows the proppant to
30 remain in place). Lastly, the pressure is released, and the fracturing fluid is allowed to flow (the
31 flowback fluid) to the well and then up to the platform. On platforms on the POCS, the flowback
32 fluid is typically collected comingled with production water from the well undergoing the WST
33 and also with produced water from other wells on the platform. These combined fluids are then
34 treated and disposed of accordingly (e.g., U.S. Environmental Protection Agency [EPA] National
35 Pollutant Discharge Elimination System [NPDES]-permitted open water discharge, or
36 reinjection).
37

38 Different hydraulic fracturing processes use a variety of fracturing fluid types depending
39 upon the target formation properties, including water-based, oil-based, and acid-based fluids

2 A proppant is a solid material, typically sand, treated sand, or man-made ceramic materials, designed to keep an induced fracture open during or following a fracture treatment.

3 A breaker is a chemical that reduces the viscosity of the fracturing fluids by breaking long-chain molecules present in the fluid into shorter segments.

1 (Hodge 2011). Key fluid additives include polymer gels that increase the viscosity of the fluid
2 and allow it to more easily carry proppant into the fractures; crosslinker compounds that help
3 further increase the fluid viscosity and thus better carry the proppant into the fracture; and
4 breaker chemicals reduce the viscosity of the fluid and allow it to return more readily to the
5 surface while leaving the proppant behind after the hydraulic fracturing WST is completed.
6 Other important additives may include pH buffers, clay control additives, microbial biocides, and
7 surfactants to aid in fluid recovery. In marine environments, the base fracturing fluid is filtered
8 seawater.

9
10
11 **Acid Fracturing.** Acid fracturing is similar to a hydraulic fracturing except that instead
12 of using a proppant to keep fractures open, it uses an acid solution to etch channels in the rock
13 walls of the fractures, thereby creating pathways for oil and gas to more easily reach the well
14 (API 2014). Because the pathways are etched, no proppant is required in the fracturing fluid
15 (Long et al. 2015a).

16
17 As with a hydraulic fracturing WST, a pad fluid is first injected to induce fractures in the
18 formation. Next, the acid fracturing fluid is injected at pressures above the formation fracture
19 pressure and allowed to etch the fracture walls. The acid fracturing fluid is typically gelled,
20 cross-linked, or emulsified to maintain full contact with the fracture walls. Hydrochloric acid
21 (HCl) solutions are typically used in carbonate formations such as limestone and dolomite, while
22 hydrofluoric acid (HF) solutions and HCl/HF mixtures are used in sandstone and Monterey shale
23 formations. Mixtures of HCl and HF are also used in more heterogeneous geologic formations.
24 Acid concentrations in the fluids vary; 15% HCl is commonly used in acid fracturing. In addition
25 to the acid, the fracture fluid may include a variety of additives, such as inhibitors to prevent
26 corrosion of the steel well casing, and sequestering agents to prevent formation of gels or iron
27 precipitation which may clog the pores. The volume of acid fracturing fluid is generally
28 determined by the length of the fracture being treated; typical acid volumes range from 10 to
29 500 gal per foot (API 2014).

30 31 32 **2.2.1.2 Non-Fracturing WSTs Included in the Proposed Action**

33
34 The proposed action includes one non-fracturing treatment, the use of which is intended
35 to increase formation permeability so that hydrocarbons can flow more readily, or to recover
36 additional oil from a reservoir after initial production begins to decline as a result of decreasing
37 reservoir pressure. The non-fracturing treatment included in the proposed action is matrix
38 acidizing, which is specifically called out in SB-4 as an acid WST.

39
40 In matrix acidizing (also known as an acid squeeze), an acid solution is injected into a
41 formation (at pressures below the formation fracture pressure) where it penetrates pores in the
42 rock to dissolve sediments and muds (Ghali et al. 2007). By dissolving these materials, existing
43 channels or pathways are opened and new ones are created, allowing formation fluids (oil, gas,
44 and water) to move more freely to the well. Matrix acidizing also removes formation damage
45 around a wellbore, which also aids oil flow into the well.

1 Matrix acidizing differs from acid fracturing (see Section 2.2.1.1) in that in the former the
2 acid solution is injected at pressures below the formation fracture pressure and no new fractures
3 would be created, while in the latter it is injected at pressures above the formation fracturing
4 pressure in order to induce new fracture formation. As with acid fracturing, matrix acidizing in
5 carbonate reservoirs uses HCl solutions, while alternating HCl and HF solutions are used in
6 sandstone and Monterey shale formations on the POCS (Long et al. 2015a). Other acids that
7 have been used in matrix acidizing include acetic, formic, sulfamic, chloroacetic, phosphoric,
8 and erythorbic acids (Portier et al. 2007; Ghalambar and Economides 2002). Matrix acidizing
9 has had a relatively low level of use in onshore and offshore Monterey Formation fields in
10 California (Jordon and Heberger 2014).

13 2.2.1.3 Forecast of WST Use on the POCS

14
15 WSTs have been used infrequently on the POCS in the last four decades (see Section 4.1,
16 Historic Use of WSTs in Offshore Waters of Southern California). As noted in Table 4-1, in
17 certain years since 1982 there have been multiple WSTs implemented per year, while in other
18 years there has been no WST use. Over this period, the highest number of WSTs in a single year
19 is four hydraulic fracturing treatments (in 1997). Since 2000, no more than three WSTs have
20 been approved and implemented in any single year, and only six WSTs in total have been
21 approved and implemented on the POCS since 2000. Given the historic record of WST use on
22 the POCS and the indicated industry plans known at this time, the Bureaus have determined that
23 a reasonable forecast of WST use on the POCS in the future is up to five WST applications per
24 year.⁴ This estimate is conservative in its approach; it potentially overestimates the potential for
25 impacts since there is no year on record in which five WSTs were approved. Given the small
26 number of operating platforms and the current level of oil and gas activities generally on the
27 POCS, the Bureaus do not feel that a higher number of WSTs proposed in a single year is
28 reasonably foreseeable. Therefore, for purposes of this programmatic analysis, the Bureaus are
29 analyzing up to five WST approvals per year, and their potential impacts, in this PEA.

32 2.2.2 Alternative 2: Allow Use of WSTs with Subsurface Seafloor Depth Stipulations

33
34 Under this alternative, no fracturing WSTs would be allowed at depths less than 2,000 ft
35 (610 m) below the seafloor surface. Fracturing WSTs produce bilateral fractures from the well,
36 and well completions using fracturing WSTs are designed with an expected fracture half-wing
37 length.⁵ If a fracture produced during a WST were to intersect an existing fault, fracture, or well,
38 there is a potential for the creation of a pathway to the seafloor surface and a subsequent
39 hydrocarbon release to the ocean. Under Alternative 2, BSEE technical staff and subject matter
40 experts would continue to review APDs and APMs involving the use of any of the WSTs
41 included in the proposed action and, if determined to be compliant with performance standards
42 identified in BSEE regulations at 30 CFR 250 subpart D, these activities would be approved.

4 Four WST applications per year is defined to mean no more than five WST applications in a 365 day interval.

5 A fracture half-wing length is the length of one arm of a bilateral fracture.

1 However, applications for fracturing WST use at depths of less than 2,000 ft below the seafloor
2 would not be approved.

3
4 Because fracture wing lengths typically are in the range of tens to hundreds of feet in
5 length (Fisher and Warpinski 2012 as cited in Long et al. 2015a), the 2,000-ft depth limit with
6 Alternative 2 is intended to greatly reduce the already low likelihood of a fracture produced by a
7 WST resulting in a surface expression of hydrocarbons at the seafloor. Injection pressure is
8 continuously monitored during offshore fracturing operations on the POCS (Sinkula 2015).
9 Following fracture initiation, a lack of pressure buildup or a detectable pressure loss during
10 fracture propagation may indicate an unintended fluid leak off, suggesting that the fracture has
11 intercepted an existing fault, fracture, or well. In such a case, the injection of fracturing fluids
12 would cease and formation pressure would be allowed to return to pre-fracturing levels. The
13 return to pre-fracturing formation pressure, together with the pressure from the overlying 2,000 ft
14 of rock and the overlying hydrostatic pressure, would preclude the movement of hydrocarbons
15 from the new fracture to the seafloor, and thus greatly reduce the potential of a surface
16 expression of hydrocarbons at the seafloor to the ocean.

17
18 Although Alternative 2 would add potential restrictions to how a proposed WST is
19 implemented, nothing in this alternative would be expected to change the number of WSTs
20 expected to be proposed in any given year. Therefore, the Alternative 2 evaluation in this PEA
21 continues to analyze the potential impacts of up to five WSTs per year.

22 23 24 **2.2.3 Alternative 3: Allow Use of WSTs but No Open Water Discharge** 25 **of WST Waste Fluids**

26
27 Concerns have been raised by the public regarding the effects of open ocean disposal of
28 WST waste fluids. Currently, for most platforms on the POCS produced water generated at a
29 platform during hydrocarbon production is collected, often comingled with produced water from
30 other wells and platforms, and transported via pipeline to shore for treatment. Following
31 treatment, the produced water is either disposed of onshore by subsurface injection at permitted
32 waste disposal wells, or returned via pipeline to the platforms for disposal either by injection to a
33 reservoir or by open water discharge under NPDES General Permit CAG 280000 (administered
34 by the EPA's NPDES permit program). At some platforms, produced water treatment occurs at
35 the platform rather than at an onshore facility. Open ocean discharge from platforms is not
36 permitted in State waters (Long et al. 2015b).

37
38 Under Alternative 3, BSEE technical staff and subject matter experts would continue to
39 review the use of WSTs included in the proposed action and, if determined to be compliant with
40 performance standards identified in BSEE regulations at 30 CFR 250 subpart D, these activities
41 would be approved. The NPDES-permitted open ocean discharge of produced water would
42 continue under Alternative 3 for most drilling and production activities on the OCS, but there
43 would be no open ocean disposal of any WST-related waste fluids (such as the flowback) or of
44 produced water comingled with the waste fluids. Currently, disposal of produced water varies
45 widely among platforms and platform groupings on the POCS, even though the NPDES permit
46 allows open water disposal at all the platforms. For example, platforms Irene, Ellen, Eureka, and

1 Gail have been reported to inject 94% or more of their produced water (CCC 2013), while other
2 platforms inject less than 15% (Long et al. 2015b). Of the 23 platforms operating on the POCS,
3 13 discharge produced water under NPDES General Permit CAG 280000; the others use onshore
4 or offshore injection to dispose of produced water (see Section 4.2.3 and Table 4-2). Under
5 Alternative 3, operators that conduct NPDES-permitted open water discharge of produced water
6 would continue to conduct such open ocean disposal, except that produced water and other waste
7 fluids from the platform that contain WST-related chemicals would need to be removed from the
8 waste stream and disposed of differently (e.g., through injection). Additional injection wells
9 could be needed at one or more of the platforms where waste fluid disposal occurs only via
10 permitted open water discharge.

11
12 Although Alternative 3 would add potential restrictions to how a proposed WST is
13 implemented, nothing in this alternative would be expected to change the number of WSTs
14 expected to be proposed in any given year. Therefore, the Alternative 3 evaluation in this PEA
15 continues to analyze the potential impacts of up to five WSTs per year.

16 17 18 **2.2.4 Alternative 4: No Action—Allow No Use of WSTs**

19
20 Under this alternative, none of the four WSTs identified for the proposed action would be
21 approved for use in any current or future wells on the 23 platforms associated with active lease
22 areas on the POCS. However, BSEE technical staff and subject matter experts would continue to
23 review drilling, production, well workover, and routine maintenance on the platforms and their
24 wells and, if determined to be compliant with performance standards identified in BSEE
25 regulations at 30 CFR 250 subpart F, approve these activities. Under Alternative 4, without the
26 use of WSTs, production at some wells may be expected to decline sooner than under the
27 proposed action, as reservoir pressures continue to decline with primary production.

28
29 Under Alternative 4, routine well maintenance activities (e.g., wellbore cleanup) and
30 enhanced oil recovery techniques (e.g., water flooding) that fall outside of the SB-4 definition of
31 a WST (see SB-4, Section 3157b) would still continue (as they would under any of the other
32 three alternatives). Wellbore cleanup is routinely conducted on offshore and onshore wells to
33 remove cement residue, drilling mud particles, scale, perforation debris, and other materials that
34 are generated during normal drilling and production activities and which may cause formation
35 damage.⁶ On the Federal OCS, four wellbore cleaning operations are among 13 routine well
36 maintenance and workover operations conducted at wells with the tree⁷ installed, which may not
37 require specific BSEE approval before being commenced on a lease, as identified in
38 30 CFR 250.105 and 30 CFR 250.601. The four wellbore cleaning operations are the routine well

⁶ Formation damage refers to conditions that arise that may affect hydrocarbon flow into a well, primarily by blocking hydrocarbon flow. Formation damage may occur as a result of fines migration, clay swelling, scale formation, organic deposition, and mixed organic and inorganic deposition. Damage may also result from plugging caused by foreign particles in injected fluid, wettability changes, emulsions, precipitates or sludges caused by acid reactions, bacterial activity, and water block.

⁷ A tree (also commonly known as a Christmas tree) is an assembly of valves, spools, pressure gauges, and chokes fitted to the wellhead of a completed well to control production.

1 maintenance operations with potential environmental effects; these operations employ chemical
2 agents, such as acids or solvents, or mechanical action, and produce waste residuals requiring
3 disposal: (1) acid wash (a form of acid cleanup treatment); (2) solvent wash (a chemical method
4 of cutting paraffin); (3) casing scrape/surge (a method of scale or corrosion treatment and
5 swabbing); and (4) pressure/jet wash (a method of bailing sand and a scale or corrosion
6 treatment). Although well maintenance activities may not require an APM before commencing
7 operations, their use is considered during the plan and development approval stage. In addition,
8 if one of these routine operations requires the removal of the tree, it is no longer considered
9 routine and needs an approved APM before the operation can begin. The four routine wellbore
10 cleaning operations are described below; their potential environmental effects are analyzed in
11 Section 4.5.4.

12 13 14 **2.2.4.1 Acid Wash**

15
16 The removal of some scales, coatings, sludges, and other near-wellbore damage can often
17 be accomplished with an acid soak or wash, and such acid cleanup treatments are considered
18 routine operations (30 CFR 250.105). The basic procedure is to pump acid to the perforated
19 completion interval, and allow the acid solution to stand over the completion zone and
20 breakdown scale, sludges, and other materials that may be interfering with hydrocarbon flow into
21 the well. While superficially similar to matrix acidizing, the purpose of an acid wash is for well
22 cleanup and to remove formation damage in the immediate vicinity of the wellbore (which is
23 generally within 20 to 50 inches [50 to 130 cm] from the wellbore), and not to enhance oil
24 production by increasing the permeability of the formation (SB-4). Acid washing is often done
25 on carbonate formations of high permeability to reduce cement and drilling mud damage. The
26 acids used are normally HCl, HCl-HF acid (a mixture of HCl and HF acids), and, less frequently,
27 organic acids such as acetic and formic. The concentration of these acids for a cleanup treatment
28 varies from 3 to 15%.

29 30 31 **2.2.4.2 Solvent Wash**

32
33 Well cleanup can use a broad range of solvents to dissolve and disperse deposits (such as
34 paraffin, asphaltene, and oil sludge) in well bores; diesel, xylene, kerosene, and alcohols are
35 commonly used for this purpose. A solvent wash is a chemical method of cutting paraffin.
36 Treatments are administered as a low-volume soak or a slow injection. Typically, the volume of
37 the treatment is only slightly larger than the tubular volume across the treatment zone. Alcohols
38 and other mutual solvents are used to break emulsions, strip oil coatings, remove water blocks,
39 and alter wettability. Fresh or brine water is often used to remove salt or as a base fluid to carry
40 surfactants, alcohols, mutual solvents, and other products. Hydrocarbon solvents regularly used
41 include crude oil and condensate, as well as refined oils such as diesel, kerosene, xylene, and
42 toluene. Solvents are often effective where acid has little or no effect on the deposits.

2.2.4.3 Casing Scrape/Surge

Casing scrape/surge is a form of scale or corrosion treatment as well as a form of swabbing. Mechanical casing scraping is used to remove drill mud solids, mill scale, cement, and corrosion particulates in wellbores, particularly in cases of severe sludge buildup. Scraping may be used to remove paraffin or barium sulfate scale, which can restrict the flow of oil, from well tubes. Scraping or other mechanical removal may be required when chemical treatment (i.e., acid or solvent wash) is not effective, such as when scale occurs as nearly pure deposit or as thick (>1/4 in., 6 mm) deposits in pipes.

2.2.4.4 Pressure/Jet Wash (water blasting)

A pressure/jet wash is a method of bailing sand, as well as a scale or corrosion treatment. In instances of severe sludge buildup, high-pressure water jetting may be used to clean out sand or fill. Water nozzles are lowered into the well where the buildup is located, and the sand is then removed by the high-pressure water. Water-blasting tools may also be used in gypsum deposit removal from tubing, especially when deposits are thickly encrusted.

2.2.5 Alternatives Considered but Eliminated from Further Evaluation

A number of other alternatives were considered but eliminated from further evaluation in this PEA. For these, the potential underlying concerns for their initial consideration were related to reducing the likelihood of either an accidental surface expression of hydrocarbon or an accidental release of WST-related chemicals, or to reducing the potential toxic effects of WST-related fluids. However, upon consideration it was determined that none of these alternatives would avoid or substantially lessen any potential effects of WST use on the POCS beyond those already considered in the four alternatives carried forward for analysis in this PEA.

2.2.5.1 Allow Use of WSTs Subject to Injection Pressure Stipulations

Under this alternative, BSEE technical staff and subject matter experts would continue to review the use of WSTs included in the proposed action and, if determined to be compliant with performance standards identified in BSEE regulations at 30 CFR 250 subpart D, these activities would be approved. However, the use of any of the fracturing WSTs (which require injection pressures above the existing reservoir pressure) would be subject to stipulations identifying maximum injection pressures that could be used during fracturing. The intent of such pressure stipulations is to reduce the potential for unexpected fracturing or for damaging a well bore casing, each of which could result in a seafloor surface expression of WST injection fluids and hydrocarbons.

Pressures needed for fracturing WST operations are based on the specific geology of the formation, the specific wellbore at which the WST would be implemented, and the completion design; therefore it is not possible to identify a pressure stipulation that would be appropriate and

1 applicable for all WSTs, wells, and formations. For example, a deep fracture operation may need
2 a much larger injection pressure to overcome hydrostatic pressure than would a shallow
3 operation, even if the planned fracture half-wing length is the same for both operations. All
4 downhole wellbore operations must use pressure-tested lines and tubing and casing that is rated
5 (with a safety factor usually 70%) to handle the planned pressures of the operation and comply
6 with BSEE regulations (see 30 CFR 250 subpart D, Oil and Gas Drilling Operations). During a
7 fracturing WST, the highest pressure buildup is the fracture initiation pressure, after which the
8 pressure drops off. While injection pressures for fracturing vary greatly depending on individual
9 circumstances (e.g., the formation structure and reservoir pressure), injection pressures must
10 always be within BSEE regulations (as all wellbore operations must be, not just those unique to
11 fracturing operations).

12
13 Because of the existing BSEE pressure rating requirements for all wells and associated
14 equipment, an alternative with injection pressure stipulations above and beyond pressure
15 requirements as specified in BSEE regulations (30 CFR 250 subpart D) would provide no added
16 protection against damaging a well bore casing. In addition, because of the case-by-case
17 specificity of required pressures for a fracturing WST, it is unlikely that any single pressure
18 stipulation would be applicable or appropriate for all fracturing WST cases. Thus, this alternative
19 was dropped from further evaluation.

20 21 22 **2.2.5.2 Allow Use of WSTs Subject to Fracturing Fluid Volume Stipulations**

23
24 This alternative would limit the total volume of injected fluid to 250,000 gal (5,952 bbl)
25 for a complete fracturing WST and thus potentially decrease the likelihood and magnitude of an
26 accidental seafloor surface expression of WST chemicals to the environment during injection.
27 Each of the fracturing WSTs included in the proposed action involves the injection of a
28 fracturing fluid, which typically is more than 99.5% filtered seawater and proppant (if used) and
29 0.5% WST fracturing chemicals (Tormey 2014). Fracturing WSTs are typically conducted in
30 multiple stages, each with a given injected volume of fluid. During each stage, the
31 WST chemicals (which are stored on the platform) are mixed with the filtered seawater during
32 injection; a fracturing job may consist of up to four or more stages, each injecting up to about
33 60,000 gal (about 1,430 bbl).

34
35 Historically, on the POCS the total volume of fracturing fluid used to complete a
36 fracturing WST has ranged from as little as 2,000 gal (48 bbl) up to 177,000 gal (4,200 bbl)
37 (BOEM 2015; Long et al. 2015b). To date, the largest total volume of WST fluids used on any of
38 the 23 platforms on the POCS was for a fracturing operation (at Platform Gail in 2010) and did
39 not exceed 180,000 gal (4,290 bbl) (BOEM 2015). By comparison, fluid volumes used in
40 offshore platforms and production facilities in State waters have ranged from about 3,000 to
41 210,000 gal (71 to 5,000 bbl) (Long et al. 2015b). Current total volume expectations for future
42 WST operations (based on past and reasonably foreseeable future operations) at platforms on the
43 POCS are around 240,000 gal (about 5,720 bbl), assuming no more than four stages in a
44 wellbore and 60,000 gal (1,430 bbl) per stage.

45

1 Limiting the total volume of injected fluid for a complete fracturing WST was considered
2 as a potential means of decreasing the likelihood of an accidental release of WST chemicals
3 (i.e., the fewer stages per completion, the fewer chances there are for an accidental release to
4 occur over the entire completion). However, the greatest potential for an accidental release of
5 WST chemicals into the environment is from an accident involving an individual storage tank on
6 the platform (see Section 4.3), the volume of which is independent of the total injection volume
7 of the fracturing WST. An alternative stipulating an injection volume would not avoid or
8 substantially lessen the potential for an accidental release of WST chemical from a platform
9 accident, or limit the magnitude of a potential accidental platform release of the WST chemicals.
10 Thus, this alternative was dropped from further evaluation.

11 12 13 **2.2.5.3 Allow Use of WSTs Subject to Stipulations on Injection Fluid Chemical** 14 **Constituents, Such as Limiting Use of Bioaccumulative Compounds or** 15 **Strong Acids** 16

17 Some WSTs use chemicals and strong acids with potentially toxic or corrosive properties.
18 An alternative was considered that would limit or prohibit the use of some chemical constituents
19 of the fracturing fluids, thereby limiting the potential for adversely affecting water quality and
20 marine biota during disposal of WST-related waste fluids to the open ocean. Ocean discharge
21 from platforms and production facilities in California State waters is prohibited under State law.
22 In contrast, ocean discharge of produced water and other waste fluids from platforms in Federal
23 waters of the POCS is not prohibited. It is regulated, however, by the EPA's NPDES permit
24 program, which controls water pollution by regulating point sources (including operating
25 platforms) that discharge into waters of the United States. Specifically, routine discharges from
26 platforms (which is where environmental exposure to any WST-related chemicals would likely
27 first occur) on the POCS are regulated by NPDES General Permit CAG280000. This permit
28 covers six categories of discharges (drilling fluid and cuttings; produced water; well treatment,
29 completion, and workover fluids; deck drainage; domestic and sanitary wastes; and
30 17 miscellaneous other discharge categories) and includes required monitoring and toxicity
31 testing of all surface discharges from the platforms.
32

33 WST fluids fall within the well treatment, completion, and workover fluids category of
34 the NPDES permit. In developing the current NPDES permit strategy, the EPA determined "...it
35 is not feasible to regulate separately each of the constituents in well treatment, completion and
36 workover fluids because these fluids in most cases become part of the produced water waste
37 stream and take on the same characteristics of produced water. Due to the variation in the types
38 of fluids used, the volumes used and the intermittent nature of their use, EPA believes it is
39 impractical to measure and control each parameter" (EPA 1995).
40

41 Following their use in a WST at a well, acids will be largely chemically consumed and
42 neutralized, and associated waste fluids would be collected, comingled, and diluted with
43 produced water from the well. This WST waste fluid-produced water mixture would then be
44 further diluted when combined with produced water from other wells at the platform, and
45 possibly further diluted if combined with the produced water waste stream from other platforms
46 (as occurs at some platforms; see Section 4.2.3). This produced water with highly diluted

1 WST-related waste chemicals would then be treated prior to any permitted open ocean discharge.
2 A portion of non-acid WST chemicals (over 90% in the case of hydraulic fracturing WSTs [see
3 Section 4.5.1.3]) is retained in the formation and is not recovered or recovered slowly in waste
4 fluids. As with WST acids, non-acid WST chemicals collected in the waste stream from a well
5 would be similarly diluted and treated prior to any permitted release to the ocean.
6

7 To ensure protection of water quality and marine biota, the NPDES permit for the OCS
8 platforms identifies concentration limits at the boundary of a 100-m (328-ft) mixing zone around
9 the discharge point, and no effects on water quality are expected beyond the mixing zone
10 (see Section 4.5.1.3). To address potential toxicity of unspecified WST constituents in
11 discharges, the NPDES permit requires quarterly whole effluent toxicity (WET) testing of
12 produced water, which would include any WST-related fluids and chemicals. The WET tests
13 evaluate chronic toxicity of the produced water and thus captures the cumulative risk of exposure
14 to groups of chemicals, which is how environmental exposure would occur (exposure would not
15 be on a chemical-by-chemical basis, but rather would be simultaneous to a mixture of all
16 chemical constituents in the discharged water).
17

18 At a well undergoing a WST, all WST waste fluids are highly diluted through mixing
19 with produced water from multiple wells and are subsequently treated prior to discharge. The
20 NPDES permit regulating ocean discharge from the platforms (which is where exposure to
21 WST-related chemicals would first occur) includes concentration limits for protecting water
22 quality as well as WET testing for evaluating the chronic toxicity of the contaminant mixture in
23 the permitted discharge. Because waste fluids containing WST-related chemicals would be
24 highly diluted and then treated prior to any permitted open ocean discharge, and because of
25 required compliance with the NPDES permit concentration limits and WET toxicity testing, an
26 alternative limiting the use of some chemicals would be expected to provide little further
27 protection to water quality and marine biota beyond that provided under the NPDES permit
28 currently regulating platform discharges on the OCS. If analysis of the alternatives finds impacts
29 on water quality or marine biota due to the presence of certain WST-related chemicals, then at
30 that point further alternatives could be developed that limit the use those WST chemicals that
31 contributed to the impacts.
32
33

34 **2.3 ENVIRONMENTAL RESOURCES CONSIDERED IN THIS** 35 **ENVIRONMENTAL ASSESSMENT**

36
37 Based on a review of the environmental resources and of socioeconomic and
38 sociocultural (including environmental justice) conditions present in the vicinity of the platforms
39 on the POCS, together with the anticipated operational features of the WSTs included in the
40 proposed action, the following resources and conditions were determined to be in the vicinity of
41 the platforms and could potentially be affected by the proposed action, and thus were evaluated
42 in this PEA:
43

- 44 • *Air quality*: Potential impacts due to contributions to elevated photochemical
45 ozone from ozone precursor emissions such as nitrogen oxides (NO_x) and/or
46 volatile organic compounds (VOCs) from diesel pumps and support vessels

1 (crew transport and materials delivery) associated with WST activities;
2 contributions to visibility degradation from emissions of particulate matter
3 (PM) (e.g., elemental carbon [EC], organic carbon [OC]) and/or its precursors
4 (e.g., NO_x, sulfur oxides [SO_x]) from WST activities; and climate change
5 (albeit small) due to greenhouse gas emissions such as carbon dioxide (CO₂)
6 and methane (CH₄) associated with WST activities. Air quality may be
7 similarly affected by emissions during drilling of new injection wells that may
8 be needed as a result of Alternative 3.
9

- 10 • *Water quality*: Potential impacts of routine WST operations on water quality
11 and marine life from open ocean discharges of WST waste fluids as permitted
12 under the U.S. Environmental Protection Agency (EPA) National Pollutant
13 Discharge Elimination System (NPDES) General Permit; potential impacts on
14 water quality from the release of WST fluids or hydrocarbons from potential
15 accidents; and temporary and localized decreases in water quality that may
16 occur as a result of bottom- disturbing activities that may occur under
17 Alternative 3.
18
- 19 • *Geologic resources/seismicity*: While impacts on geologic resources are not
20 expected from the proposed action, there is concern that some WSTs may
21 stimulate seismic activity in seismically active areas such as the Santa Barbara
22 Channel, and thus result in an increase in seismic hazard in the vicinity of the
23 wells where fracturing WSTs are being implemented.
24
- 25 • *Benthic resources (including special status species)*: Potential lethal,
26 sublethal, or displacement impacts on benthic communities following ocean
27 disposal of WST waste fluids or the accidental release of WST fluids, and the
28 accidental discharge of hydrocarbons from a fault or damaged wellhead; and
29 contamination of Endangered Species Act (ESA)-designated critical habitat
30 with hydrocarbons and fracturing fluids following an accidental release.
31 Benthic resources may also be affected by bottom-disturbing activities
32 associated with Alternative 3.
33
- 34 • *Marine and coastal fish (including special status species) and essential fish*
35 *habitat*: Potential lethal, sublethal, or displacement impacts on fish following
36 ocean disposal of WST waste fluids or the accidental release of WST fluids,
37 and the accidental discharge of hydrocarbons from a fault or damaged
38 wellhead; contamination of Essential Fish Habitat (EFH) and ESA-designated
39 critical habitat with hydrocarbons and fracturing fluids following an
40 accidental release. Marine and coastal fish may also be affected by bottom-
41 disturbing activities that may occur as a result of Alternative 3.
42
- 43 • *Marine and coastal birds (including special status species)*: Potential lethal or
44 sublethal effects following ocean disposal of WST waste fluids or the
45 accidental release of WST fluids, and the accidental discharge of
46 hydrocarbons from a fault or damaged wellhead.

- 1 • *Marine mammals (including special status species)*: Potential lethal or
2 sublethal effects following ocean disposal of WST waste fluids or the
3 accidental release of WST fluids, the accidental discharge of hydrocarbons
4 from a fault or damaged wellhead; and vessel strikes, noise, and other
5 disturbances associated with WST operations. Marine mammals may also be
6 affected by noise from bottom-disturbing activities that may occur as a result
7 of Alternative 3.
8
- 9 • *Sea turtles*: Potential lethal or sublethal effects following ocean disposal of
10 WST waste fluids or the accidental release of WST fluids; the accidental
11 discharge of hydrocarbons from a fault or damaged wellhead; and vessel
12 strikes, noise, and other disturbances associated with WST operations. Sea
13 turtles may also be affected by bottom-disturbing activities that may occur as
14 a result of Alternative 3.
15
- 16 • *Commercial and recreational fisheries*: Potential impacts due to preclusion
17 from fishing areas due to interference with vessels transporting WST materials
18 and equipment, localized closure of fisheries due to accidental release of WST
19 fluids or of improperly treated wastewater, and reduced abundance of fishing
20 resources due to exposure to accidental release or routine disposal of WST
21 fluids.
22
- 23 • *Areas of Special Concern*: Potential impacts if water quality is affected; some
24 biological resources potentially affected as identified above.
25
- 26 • *Recreation and Tourism*: Potential impacts if area water quality is affected
27 and use of or access to recreational areas is affected.
28
- 29 • *Environmental Justice*: No disproportionate impacts to minority and low-
30 income populations anticipated even following accidental release of WST
31 fluids and waste fluids.
32
- 33 • *Archaeological Resources*: Archaeological resources are most at risk from oil
34 and gas (O&G) activities that physically disturb the seafloor. Because none of
35 the WSTs included in the proposed action involve seafloor-disturbing
36 activities, the proposed action would not affect Archaeological resources.
37 However, bottom-disturbing activities that may occur under Alternative 3,
38 affecting Archaeological resources where new injection wells could be
39 needed.
40
- 41 • *Socioeconomics*: No impacts expected from the use of WSTs, while some
42 impacts may occur with a WST-related accident.
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