DEPARTMENT OF CONSERVATION
GEOLOGIC ENERGY MANAGEMENT DIVISION
PUBLIC HEALTH RULEMAKING

DRAFT RULE FOR PROTECTION OF COMMUNITIES AND WORKERS FROM HEALTH AND SAFETY IMPACTS FROM OIL AND GAS PRODUCTION OPERATIONS
PRE-RULEMAKING RELEASE FOR PUBLIC REVIEW AND CONSULTATION

New regulations and new text added to existing regulations is shown in underline.
Text deleted from existing regulations is shown in ~~strikethrough~~.

OPERATIVE DEFINITIONS FOR THIS DRAFT RULE:

"Setback exclusion area" means all land within 3,200 feet of a sensitive receptor.

"Setback mitigation area" means all land within 3,200 feet of a sensitive receptor.

"Sensitive receptor" means any residence including private homes, condominiums, apartments, and living quarters; education resources such as preschools and kindergarten through grade twelve (K-12) schools; daycare centers; any building housing a business that is open to the public; and health care facilities such as hospitals or retirement and nursing homes. A sensitive receptor includes long term care hospitals, hospices, prisons, and dormitories or similar live-in housing.

"[EFFECTIVE DATE]" – the date after the formal rulemaking process is complete and new requirements are set to go into effect.

CALIFORNIA CODE OF REGULATIONS, TITLE 14

DIVISION 2. DEPARTMENT OF CONSERVATION

CHAPTER 4. DEVELOPMENT, REGULATION, AND CONSERVATION OF OIL AND GAS RESOURCES

Subchapter 2. Environmental Protection

Article 3. Requirements

§ 1765. Setback Exclusion Area.

(a) After [EFFECTIVE DATE], CalGEM will not approve any Notice of Intention to drill a new well with a new surface location within the setback exclusion area, except a well, such as an intercept well or a pressure relief well, that must be drilled to alleviate an immediate threat to public health and safety or the environment.

(b) After [EFFECTIVE DATE], operators shall not install or construct new production facilities within the setback exclusion area, except if approved by the Division upon the Division's finding that:

(1) The production facilities are necessary for safe and effective operation of a well approved by the Division under subdivision (a);

(2) The production facilities are necessary for compliance with local, state, or federal requirements;

(3) The production facilities are necessary to public health and safety or the environment; or

(4) The production facility is replacing an existing facility of the same type with no resulting expansion of the geographic footprint.

(c) For the purposes of this section, "new well" means a new boring that involves installation of surface casing where none existed previously.

Authority: Sections 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, and 3270, Public Resources Code.

§ 1766. Leak Detection and Response Plan.

(a) An operator of a wellhead or other production facility located within the setback mitigation area, shall implement a Leak Detection and Response Plan. A Leak Detection and Response Plan is subject to review and approval by the Division and shall address all requirements of this section. After [EFFECTIVE DATE PLUS TWO YEARS], the operator shall suspend all production and injection operations in all areas within the setback mitigation area where a Leak Detection and Response Plan is not fully implemented.

(b) **Required Plan Elements.** The Leak Detection and Response Plan shall include all of the elements described in this subdivision and the elements shall adhere to the specifications of this subdivision.

(1) **Detection Target Identification Element**. The Detection Target Identification Element shall identify the chemical constituents that will be detection targets for the emission detection systems to ensure early detection of leaks that may result in emissions leaving the oilfield. The emission detection system under the Leak Detection and Response Plan shall detect for two target chemical constituents, as appropriate:

(A) Methane, or another easily detected substance that would be an effective leak indicator because it is likely to be present in large proportion in possible emissions within the area covered by the Leak Detection and Response Plan; and

(B) Hydrogen sulfide, if the geologic area where the operation is located is known to produce hydrogen sulfide.

(2) **Detection System Design Element.** The Detection System Design Element shall provide a design for an emissions detection system that will detect the target chemical constituents to identify leaks that may result in emissions leaving the oilfield.

(A) The emissions detection system shall include continuous in-field emissions detection of target chemical constituents within two feet of wellheads, production facilities, and other potential source of emissions within the area covered by the Leak Detection and Response Plan. The alarm trigger point for the in-field emissions detection system shall not exceed 100 parts per million of methane. If hydrogen sulfide detection is required, then the alarm trigger point for the in-field emissions detection system shall not exceed 5 parts per million of hydrogen sulfide.

(B) The emissions detection system shall include a fenceline emissions detection system to identify emissions of target chemical constituents that have traveled or have the potential to travel to sensitive receptors. The fenceline detection system is not required to be positioned on the property line but shall be positioned between the wellheads and production facilities subject to the requirements of this section and the sensitive receptors. The alarm trigger point for the fenceline detection system shall not exceed 50 parts per million of methane. If hydrogen sulfide detection is required, then the alarm trigger point for the fenceline detection system shall not exceed 0.1 parts per million of hydrogen sulfide.

(C) Methane detection equipment utilized in the emissions detection system shall be sensitive enough to detect methane at a level of two parts per million. If hydrogen sulfide detection is required, then hydrogen sulfide detection equipment utilized in the emissions detection system shall be sensitive enough to detect hydrogen sulfide at a level of 0.1 part per million.

(D) The emissions detection system shall include an alarm system that effectively, immediately, and reliably alerts the operator when triggered. If the operator is able to demonstrate background levels of the target constituents in the area covered by the plan, then the Division may approve alarm set points higher than those prescribed in paragraphs (A) and (B) to account for those demonstrated background levels.

(E) The Detection System Design Element shall include design of a new, or use of an existing, meteorological system with the ability to continuously record measurements. The meteorological system shall continuously record wind speed and wind direction, ambient temperature, ambient pressure, and relative humidity data in a manner that can be matched with every alarm of the detection system. Meteorological data collection shall be done from a location that is representative of conditions at potential leak sources within the area covered by the Leak Detection and Response Plan. The data for each alarm shall be time stamped consistent with the national time standard in order to match each alarm with collected meteorological data.

(3) **Alarm Response Protocol Element.** The Alarm Response Protocol Element shall provide for immediate action to rapidly identify and correct the source of the emissions. The operator's alarm response protocol for all gas detection systems under a Leak Detection and Response Plan shall meet all of the following requirements:

(A) The alarm response protocol shall provide for immediate action to rapidly identify and correct the source of the emissions. If the source of

<u>the emissions is a leak from a well or production facility, the operator shall suspend use of the well or production facility until the leak has been corrected and the Division has approved the resumption of use. Where the operator can demonstrate to the Division that the source of the emissions is not related to the oil and gas operation, the Division may waive any additional actions required under the alarm response protocol.</u>

<u>(B) In the event that the source of the emissions is not identified and the leak stopped within 48 hours, the alarm response protocol shall include a communication plan for notification of people in the community including notification in languages that are easily understood by the affected community, local emergency responders and public health authorities, and the Division.</u>

<u>(C) The operator shall consult with local emergency response entities when preparing the alarm response protocol and shall engage in drills as deemed necessary by the local emergency response entity. The operator's consultation with emergency response entities shall address lower flammability limit alarm set points and protocols for response to detection of target constituents that exceed lower flammability limits. The alarm response protocol shall document input received from local emergency response entities and how the protocols respond to that input.</u>

<u>(D) The alarm response protocol shall provide for collection and testing of a sample of the emissions content when a continuous alarm event indicates that emissions may have traveled into the community. When developing the alarm response protocol, the operator shall consult with the local public health authority to identify appropriate sampling and testing methodologies, such as U.S. EPA Method TO-14A "Compendium of</u>

Methods for the Determination of Toxic Organic Compounds in Ambient Air," most recent edition.

(E) The alarm response protocol shall provide for compliance with all local, state, and federal requirements for reporting gas leaks.

(4) **Development and Update Element.** The Development and Update Element shall include information about the qualifications of the personnel that developed the Leak Detection and Response Plan and processes for continuing evaluation and updating of the plan.

(A) The Development and Update Element shall include documentation demonstrating that the Leak Detection and Response Plan is developed in consultation with professionals with the necessary education, experience, and expertise to:

(i) Interpret chemical test data and identify chemical constituents that may pose a risk to public health.

(ii) Model chemical dispersion and assess the risk of impact to public health.

(iii) Design and implement detection systems that will meet the requirements of this section.

(B) The Development and Update Element shall include protocols for continuing evaluation of the efficacy of the Leak Detection and Response Plan and identification of possible improvements to the plan. The protocol for continuing evaluation shall provide for an update to the Leak Detection and Response Plan at least once every five years to incorporate new findings.

(c) General Requirements. The operator shall adhere to the following requirements for the detection systems required under this section:

(1) Gas detection systems shall be operational at all times. The operator shall continuously monitor the gas detection systems for alarms and shall be prepared at all times to implement an alarm response protocol that meets the requirements of subdivision (b).

(2) All gas detection equipment shall be calibrated, tested, and maintained according to the manufacturer's specifications.

(3) The operator shall maintain digital records of emissions detections alarms, associated meteorological data, records of equipment testing and calibration, and evidence of continuous operation of all gas detection systems for a minimum of 10 years and shall provide those records to the Division upon request.

Authority: Sections 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, and 3270, Public Resources Code.

§ 1766.1. Vapor Venting Prevention.

(a) All permanent and temporary equipment located within the setback mitigation area that emits vapors, including tanks, vessels, separation facilities, gas processing units, and other equipment holding petroleum liquids or produced water, shall have a vapor venting prevention system that ensures that no venting to atmosphere occurs. Vapor venting prevention systems are subject to all of the following requirements:

(1) Vapor venting prevention systems shall be designed by a professional engineer or the design shall be approved by a professional engineer.

(2) The operator shall be able to demonstrate to the Division that each vapor venting prevention system is effectively recovering all vapors from the production facility.

(3) The operator shall inspect each vapor venting prevention system at least once a year and the inspection shall be in accordance with US EPA Reference Method 21. The operators shall provide the Division documentation of the results of each vapor venting prevention system inspection within 60 days of completion. Inspection under requirements of a local air quality or air pollution control district may be relied upon for compliance with this paragraph, provided results of the inspection are provided to the Division within 60 days of completion.

(4) The operator shall document the volume and disposition of all vapors recovered by vapor venting prevention systems and shall report that information to the Division at least annually.

(b) A vapor venting prevention system permitted or otherwise approved by a local air quality or air pollution control district will be accepted for compliance with this section if the operator demonstrates to the Division that the system meets the standards of this section.

(c) For operations within the setback mitigation area, required vapor venting prevention systems must be installed and operational by [EFFECTIVE DATE PLUS TWO YEARS]. For all other operations, required vapor venting prevention systems must be installed and operational by [EFFECTIVE DATE PLUS FIVE YEARS].

Authority: Section 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, and 3270, Public Resources Code.

§ 1766.2. Baseline Water Sampling and Testing.

(a) Before commencing any work that requires a Notice of Intention under Public Resources Code section 3203, the operator shall contact property owners and tenants within a 1500-foot radius of the wellhead or within 500 feet of the surface representation of the horizontal path of the subsurface parts of the well in writing with a record of delivery and offer to sample and test water wells or surface water on their property before and after drilling.

(b) The operator shall contact property owners and tenants as specified in subdivision (a) at least 30 days prior to commencing drilling. If a property owner or tenant requests sampling and testing of a water well or surface water, then drilling may not commence until a baseline water sample has been collected, provided that the owner's or tenant's request is delivered in writing with a record of delivery to the operator within 20 calendar days from the date notice is provided and the surface property owner makes necessary accommodations to enable the collection of a water sample within 10 days. The operator shall have a follow-up water sample collected no sooner than 30 days, and no later than 60 days after drilling is complete. The costs of sampling and testing required under this section shall be borne by the operator.

(c) Prior to commencing drilling, the operator shall provide the Division documentation of the effort to identify and notify property owners and tenants as required under subdivision (a).

(d) Water sampling and testing under this section, both baseline and follow-up, shall be done in accordance with all of the following requirements:

(1) Water quality sampling shall be conducted by appropriately qualified personnel in a manner consistent with standard environmental industry practice and chain-of-custody protocols. Documentation of the sampling

process shall accurately describe the location that the sample was taken from and the process for collecting the sample.

(2) Water quality analytical testing shall be performed by a laboratory which has been certified under the State Water Resources Control Boards' Environmental Laboratory Accreditation Program.

(3) Water quality testing shall include baseline measurements prior to the commencement of the drilling, and follow-up measurements after drilling is completed.

(A) Liquid analysis required under this section shall include testing for all of the following: total dissolved solids; total petroleum hydrocarbon as crude oil; major cations (Ca, Mg, Na, K, Fe, Mn, Sr, B); major anions (Cl, SO_4, HCO_3, CO_3, Br, I, NO_3); any constituents listed in California Code of Regulations, title 22, section 66261.24, subdivision (a)(2)(A) and (B); appropriate indicator chemicals for drilling mud and fluids used for well cleanout total alkalinity and hydroxide; electrical conductance; pH; and temperature.

(B) The Division may require testing for additional constituents on a case-by-case basis.

(4) Within 120 days after drilling is complete, the results of any baseline and follow up water quality testing shall be provided to the Division, the appropriate Regional Water Quality Control Board, the State Water Resources Control Board, the surface property owner, and the requesting tenant.

(5) The appropriate Regional Water Quality Control Board shall be notified at least five working days prior to collecting a sample under this section so that Regional Water Quality Control Board staff may witness the sampling.

(6) Water quality data collected under this section shall be submitted to the State Water Resources Control Board and the appropriate Regional Water Quality Control Board in an electronic format that follows the guidelines detailed in California Code of Regulations, title 23, chapter 30 within 120 days after drilling is complete.

(e) If the property owner or tenant is unable to provide the necessary access to perform baseline or follow-up testing under this section, then failure to do the testing is not a violation of this section. The requirements of this section can be waived if the operator demonstrates that the delay in well work associated with the requirements of this section is likely to result in damage to life, health, property, or natural resources. The operator is not required to sample or test water under this section if the operator demonstrates to the Division that the water is not freshwater or USDW.

Authority: Section 3013 and 3106, Public Resources Code. Reference: Sections 3011 and 3106, Public Resources Code.

§ 1766.3. Sound Controls.

(a) If oil and gas production operations are within the setback mitigation area, then all of the following sound control requirements shall apply to all operations occurring between 8:00 pm and 7:00 am:

(1) Sound levels from oil and gas production operations shall not exceed 45 decibels, as measured anywhere on the property line.

(2) Diesel engine vehicles shall not enter or exit the property within the setback mitigation area except in an emergency where immediate action is necessary to prevent damage to life, health, property, and natural resources.

(3) Vehicle back-up alarms shall be disabled unless prohibited by law.

(4) No oil shall be removed by truck from the site.

(5) The operator shall conduct continuous monitoring of sound levels at property boundaries nearest to sensitive receptors during restricted hours. Records of sound levels showing continuous operation of sound monitoring equipment from 8:00 pm to 7:00 am shall be maintained for 10 years and provided to the Division upon request.

(b) Within the setback mitigation area, the use of diesel engines to power pumping units is prohibited at all times of day.

Authority: Section 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, and 3270, Public Resources Code.

§ 1766.4. Lighting Controls.

(a) Light generated by oil and gas production operations within the setback mitigation area shall be minimized to reduce light traveling beyond property boundaries.

(1) Except as needed in emergency circumstances, operators shall use only such lighting as is necessary to provide the minimum intensity and coverage for safety and basic security between the hours of 8 pm and 7 am.

(2) Lighting shall be hooded or otherwise directed so that it shines onto only the operator's property and not onto adjacent properties or into the sky.

(b) Operators shall make necessary operational and physical changes to field lighting to comply with these requirements by [EFFECTIVE DATE PLUS ONE YEAR].

Authority: Section 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, and 3270, Public Resources Code.

§ 1766.5. Dust Control.

(a) Within the setback mitigation area, operators of oil and gas operations shall employ operational measure to prevent dust and particulates from migrating beyond property boundaries. Dust control measures to be employed within property boundaries shall include, but are not limited to:

(1) Limiting vehicle speeds on unpaved roads to 15 miles per hour or less; and

(2) Containing or covering stored sands, drilling muds, and excavated soil.

Authority: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3011 and 3106, Public Resources Code.

§ 1766.6. Gas Sampling and Analysis.

(a) Operators shall have a representative gas analysis for each field or distinct geologic area in which the operator produces gas within the setback mitigation area. The gas sample analyzed shall be representative of the gas content of all the wells in a field or distinct geologic area. If a well is known or suspected to have hydrogen sulfide, sampling and analysis of gas from the specific well is also required.

(b) Gas sampling and analysis required under this section shall be conducted by a certified laboratory employing gas chromatography or other analysis method approved by the Division that can identify the constituents of a gas. The appropriate district office shall be notified at least 24 hours before gas sampling so that Division staff may witness.

(c) Operator shall update all gas sampling and analysis on an annual basis and shall submit their gas analyses to the Division no later than January 31 each year.

(d) The requirements of this section do not apply to underground gas storage projects or gas storage wells.

Authority: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3011 and 3106, Public Resources Code.

§ 1766.7. Produced Water Sampling and Analysis.

(a) For produced water from wells within the setback mitigation area, the operator shall provide the Division representative chemical analyses for all produced water transported away from the oilfield where it was produced.

(b) Chemical analysis required under this section shall be in accordance with Section 1724.7.2 and shall be filed with the Division within three months of produced water being transported from the oilfield and whenever the source of produced water is changed.

(c) For the purposes of this section, the source of produced water is changed if the treatment process or additives are changed, if a contributing source is added or removed, or if there is a significant change to the relative contribution of individual sources such that the last chemical analysis is not representative of the produced water being transported from the oilfield.

Authority: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3011 and 3106, Public Resources Code.

§ 1766.8. Non-Emergency Spill Reporting.

(a) All spills of one-half barrel or more of oil or 10 barrels or more of produced water, that occur within the setback mitigation area, shall be reported to the Division within three days.

(b) The reporting required under this section is in addition to all other applicable federal, state, and local requirements and does not replace any other spill reporting or response requirements.

Authority: Sections 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, and 3270, Public Resources Code.

§ 1773.1. Production Facility Secondary Containment.

(a) All production facilities storing and/or processing fluids, except valves, headers, manifolds, pumps, compressors, wellheads, pipelines, flowlines and gathering lines shall have secondary containment. The exceptions for valves, headers, manifolds, pumps, compressors, and wellheads, do not apply if those production facilities are within the setback mitigation area. For wellheads within the setback mitigation area, operators shall comply with the requirements of Section 1773.1.1 during drilling, workover, and abandonment operations, and the requirements of this section do not apply until such operations are complete.

(b) Secondary containment shall be capable of containing the equivalent volume of liquids from the single piece of equipment with the largest gross capacity within the secondary containment. Within the setback mitigation area, gravel shall not be used as the sole means of secondary containment.

(c) Secondary containment shall be capable of confining liquid for a minimum of 72 hours.

(d) When not in use for rain water management, rain water valves on a secondary containment shall be closed and secured to prevent unauthorized use.

(e) Operators shall inspect secondary containment for identification of any tears, cracks, or other damage on a weekly basis. All damage to secondary containment shall be repaired immediately.

~~(f) The requirements of this section are not applicable until six months after the effective date of this regulation.~~

Authority cited: Sections 3013, 3106, and 3270, Public Resources Code.
Reference: Sections 3011, 3106 and 3270, Public Resources Code.

§ 1773.1.1. Wellhead Containment.

(a) If a well is within the setback mitigation area, then drilling, workover, and abandonment operations shall not occur unless there is containment around the wellhead, such as a well cellar or berm, to capture any fluids released. The containment shall be of adequate size to contain the potential volume of fluid that may be released.

(b) If a berm is used for compliance with this section, then there must be a ground covering around the well, such as an impervious or absorbent pad, that will catch any fluids which may escape into the berm and a ground covering must also be used under the rig.

(c) The Division may allow exceptions to the requirements of this section on a case-by-case basis based on a demonstration that no fluid release is possible during well operations.

(d) Fluids captured by wellhead containment shall be removed and disposed of in accordance with all applicable local, state, and federal requirements.

Authority: Sections 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, and 3270, Public Resources Code.

§ 1773.1.2. Stuffing Box Containment.

(a) If a wellhead is within the setback mitigation area and there is a pumping unit on the well, then the operator shall install and maintain a stuffing box containment unit that is capable of safely containing fluids leaking from the stuffing box. The stuffing box containment unit shall be equipped with an automatic shut-off that will activate and shut off the pumping unit in the event of a leak.

(b) In the event of a leak, the operator shall identify and correct the cause of the leak before reactivating the pumping unit.

(c) Fluids captured in the stuffing box containment unit shall be safely managed in accordance with all applicable local, state, and federal requirements.

Authority: Sections 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, and 3270, Public Resources Code.

§ 1773.2. Tank Construction and Leak Detection.

(a) All new tanks shall be constructed and designed to provide enough space between tanks to allow safe access for maintenance, inspection, testing, and repair.

(b) Foundations for new tanks shall be designed to support the tank, maintain the tank level, and drain fluid away from the tank, including fluids that may leak from the tank. The sub-base of the foundation shall include an impermeable barrier designed to prevent downward fluid migration and to allow leaks to drain away from the tank and be detected by visual inspection or through the use of a leak detection sensor, as each particular instance may require.
The foundation base shall be made of material that provides for support and drainage away from the tank.

(c) When a tank bottom is replaced, a leak detection system shall be installed and properly maintained that will either:

(1) Channel any leak beneath the tank to a location where it can be readily observed from the outside perimeter of the tank, or

(2) Accurately detect any tank bottom leak through the use of sensors.

(d) The Supervisor or district deputy may require a tank bottom leak detection system for any tank with a foundation that does not have an impermeable barrier after considering such factors as the age of the tank, fluid service, and proximity to groundwater.

(e) <u>A tank bottom leak detection system is required for each tank located within the setback mitigation area whose foundation does not have an impermeable barrier. If a tank bottom leak detection system is required for a tank that was not required to have a tank bottom leak detection system prior to [EFFECTIVE DATE], then the operator shall install the tank bottom leak detection system by [TWO YEARS AFTER EFFECTIVE DATE].</u>

Authority: Sections 3013<u>, 3106,</u> and 3270, Public Resources Code. Reference: Sections <u>3011, </u>3106, 3224 and 3270, Public Resources Code.

§ 1773.4. Tank Testing and Minimum Wall Thickness Requirements.

(a) Tank wall thickness testing shall be conducted on in-service tanks at intervals not to exceed the following:

(1) If the corrosion rate of the tank is not known, at least once every five years.

(2) If the corrosion rate of the tank is known, an interval determined from corrosion rate calculations approved by the Supervisor, but not to exceed once every 15 years.

~~(3) Tank wall thickness testing shall be conducted within two years of the effective date of this regulation for tanks that have not had testing within the required interval.~~

(b) Insulated tanks shall have insulation removed to the extent necessary to determine the thickness of the tank walls or roof.

(c) The minimum thickness for a tank shell shall be 0.06 inch.

(d) In-service tanks shall be internally inspected and tested to determine bottom plate thickness no less than once every 20 years. ~~In-service tanks that have not been internally inspected within the 20 years preceding the effective date of this section must be internally inspected within two years after the effective date of this section.~~ A tank is exempt from this requirement if:

(1) The tank is not an environmentally sensitive tank, it is not in an urban area, ~~and~~ it is not located above subsurface freshwater, and is not located within the setback mitigation area; or

(2) The tank has a foundation that is designed and constructed in accordance with the requirements of Section 1773.2(b); or

(3) The tank has a properly installed, operating and maintained leak detection system as specified in Section 1773.2(c).

(e) The minimum bottom plate thickness shall meet the following criteria:

(1) 0.10 inch for tank bottom/foundation design with no means of detection and containment of a bottom leak;

(2) 0.05 inch for tank bottom/foundation design with adequate leak detection and containment of a bottom leak;

(3) 0.05 inch in conjunction with a reinforced tank bottom lining, greater than 0.05 inch thick.

(f) The Supervisor or district deputy may require that a tank that has had a leak resulting in the release of a reportable quantity be tested to verify integrity prior to being put back into service.

(g) A tank that is not repaired within 60 days of failing an inspection or test required by this section shall be taken out of service and designated as an Out-of-Service tank. The Supervisor or district deputy may grant one extension of up to 120 days if the operator shows to the satisfaction of the Supervisor or district deputy that there is no significant threat as a result of the extension.

(h) Tanks that are not susceptible to corrosion, such as non-metal tanks and tanks with liners, shall be inspected and tested according to the manufacturer's specifications or as requested by the Supervisor or district deputy.

(i) An operator may petition the Supervisor to allow a minimum tank wall or tanks bottom thicknesses that is lower than what is required in subdivisions (c) and (e) of this section. The Supervisor may grant such a petition if he or she is satisfied that based on the design and use of the tank a lower minimum thickness will ensure that the tank will operate as designed and will be capable of safely containing fluid.

(j) If a tank was not subject to internal inspection requirements under subdivision (d) prior to [EFFECTIVE DATE] and it has not been internally inspected since [18 YEARS BEFORE EFFECTIVE DATE], then the operator shall either complete internal inspection of the tank or take the tank out of service by [TWO YEARS AFTER EFFECTIVE DATE]. For all other in-service tanks, it is a violation of this section if internal inspection has not been completed in the past 20 years.

Authority: Sections 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106 and 3270, Public Resources Code.

§ 1773.5. Out-of-Service Production Facility Requirements.

(a) Within six months after the determination that a production facility is Out-of-Service, the following shall be required:

(1) Out-of-Service production facilities shall have fluids, sludge, hydrocarbons, and solids removed and shall be disconnected from any pipelines and other in-service equipment.

(2) Out-of-Service production facilities shall be properly degassed in accordance with local air district requirements.

(3) Clean-out doors or hatches on Out-of-Service tanks shall be removed and a heavy gauge steel mesh grating (less than 1" spacing) shall be secured over the opening to allow for visual inspection and prevent unauthorized access.

(4) Out-of-Service tanks and vessels shall be labeled with Out-of-Service or OOS. "Out-of-Service" or "OOS" shall be painted in bold letters at least one

foot high, if possible, on the side of the tank or vessel at least five feet from the ground surface, or as high as possible, along with the date it was taken out of service.

(5) Out-of-Service production facilities shall have valves and fittings removed or secured to prevent unauthorized use.

(6) Pipelines associated with Out-of-Service tanks and pressure vessels shall be removed or flushed, filled with an inert fluid, and blinded.

(b) Out-of-Service production facilities shall not be reactivated unless all needed repairs have been completed and the production facility is in compliance with all applicable testing and inspection requirements.

<u>(c) Out-of-Service production facilities located within the setback mitigation area shall either be restored to In-Service condition or completely removed within five years unless the surface rights owner takes ownership of the production facility. For production facilities that have been Out-of-Service for five years or more as of [EFFECTIVE DATE], the operator shall comply with the requirements of this subdivision no later than [TWO YEAR AFTER EFFECTIVE DATE].</u>

§ 1774.1. Pipeline Inspection and Testing.

(a) Operators shall visually inspect all aboveground pipelines for leaks and corrosion at least once a year.

(b) Operators shall inspect all active gas pipelines in sensitive areas that are 10 or more years old for leaks or other defects at least once a year, or at a frequency approved by the Supervisor and listed in the operator’s Pipeline Management Plan. The operator shall conduct the inspection in accordance with applicable regulatory standards or, in the absence thereof, an accepted industry standard that is specified by the operator and listed in the Pipeline Management Plan.

(c) The Supervisor may order such tests or inspections deemed necessary to establish the reliability of any pipeline system. Repair, replacement, or cathodic protection may be required.

(d) Operators shall conduct pressure testing in accordance with subdivision (f)(2) on any pipeline that has had a leak resulting in the release of a fluid in a quantity that triggers reporting of the release under any regulatory, statutory, or other legal requirement, unless the spill is of such a small volume that reporting is only required under Section 1766.11. The pipeline shall not be returned to service unless the pressure testing has been successfully completed. Test results shall be provided to the Division for review within seven days following the test.

(e) Operators shall adhere to the following requirements when performing repairs on any portion of a pipeline located within the setback mitigation area:

(1) Record of pipeline repairs shall be maintained that include the date of all discovered pipeline leaks, clear identification of the pipeline and the location of the leak, and the date of all repairs with indication of whether they are permanent or temporary repairs. Pipeline repair record shall be retained for the life of the pipeline and shall be made available to the Division upon request.

(2) If a temporary repair is installed to address a reportable leak from a pipeline, then the pipeline shall not be returned to service until after a permanent repair is completed and pipeline is successfully tested as required under subdivision (d).

(3) All temporary repairs installed on pipelines shall be replaced with permanent repairs within 60 days after the temporary repairs is made.

(4) Pipe clamps, wooden plugs or screw-in plugs shall not be used for permanent repair of pipeline leaks. If requested by the Division, the operator shall provide manufacturer's specifications or applicable industry standards demonstrating that a product used for a permanent repair is fit for the pipeline's purpose, temperature, type, pressure, size, and rating or class.

(f) The operator shall perform periodic mechanical integrity testing on all active environmentally sensitive pipelines that are gathering lines, and all urban pipelines over 4″ in diameter, and all active gas pipelines in sensitive areas. The mechanical integrity testing shall be conducted every two years, or at an alternative frequency approved by the Supervisor based on demonstrated wall thickness and remaining service life over a period of at least two years. The testing frequencies shall be specified in the operator's Pipeline Management Plan. Pipelines less than 10 years old are exempt from the testing requirements of this subdivision. Subject to review and approval by the Division, the operator shall identify effective mechanical integrity testing methods based on pipeline type and use. The mechanical integrity testing methodology for compliance with this subdivision shall be specified in the operator's Pipeline Management Plan and shall include at least one of the following:

(1) Nondestructive testing using ultrasonic or other techniques approved by the Supervisor, to determine wall thickness;

(2) Pressure testing using:

(A) The guidelines recommended by industry standards, such as the American Petroleum Institute, American Society of Mechanical Engineers for oil or gas pipelines; or

(B) The method approved by the State Fire Marshal, Pipeline Safety Division for liquid pipelines or US Department of Transportation, Pipeline and Hazardous Materials Safety Administration for gas pipelines.

(3) Internal inspection devices such as a smart pig, as approved by the Supervisor; or

(4) Any other method approved by the Supervisor that ensures mechanical integrity so as to protect life, health, property, and natural resources.

Copies of mechanical integrity test results shall be maintained in a local office of the operator for ten years and made available to the Division, upon request. The operator shall assess all test results to determine continued safe operations and that risks identified in the Pipeline Management Plan are adequately addressed. The operator shall repair and retest or remove from service any pipeline that fails the mechanical integrity test. The operator shall promptly notify the Division in writing of any pipeline taken out of service due to a test failure.

(g) Vapor recovery pipelines are exempt from mechanical integrity testing under subdivision (f) if they are equipped with safeguards, such as oxygen detectors and are leak tested at least annually. The operator shall document the safeguards and inspection regime in its Pipeline Management Plan.

(h) A county board of Supervisors, a city council, or another state agency may petition the Supervisor to include other pipelines within their jurisdiction as environmentally sensitive or within a sensitive area. The request must be in writing and based on findings of a competent, professional evaluation that shows there is a probability of significant public danger or environmental damage if a leak were to occur.

(1) Within 30 days of receipt of a petition, the Supervisor shall notify any affected operator.

(2) Within 60 days of notification to the operators, the Supervisor shall schedule a hearing with the petitioner and operators to allow all parties to be heard.

(3) Within 30 days after the conclusion of the hearing, the Supervisor shall make a determination as to whether the areas or pipelines should be considered environmentally sensitive.

(i) For pipelines that are subject to mechanical integrity testing under subdivision (f), but that were not subject to mechanical integrity testing under subdivision (f) prior to January 1, 2018, mechanical integrity testing is not required to be completed until January 2, 2020. For these pipelines, mechanical integrity testing shall be scheduled, completed, and mechanical integrity test results documented per subdivision (f) prior to January 2, 2020.

Authority: Sections 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, 3270, and 3270.5, Public Resources Code.

§ 1776.1. Pipeline Cleanup and Abatement.

(a) Lease restoration required under Section 1776 shall include the following activities for remaining buried pipelines that are within the lease and within the setback mitigation area:

(1) All remaining buried pipelines shall be cut-off at burial depth, and short-length portions to surface piping removed.

(2) Remaining buried pipelines shall be purged of oil and gas, cleaned, filled with inert fluid or material, and plugged or capped. A final freshwater flush sample shall be used to demonstrate that not-visible solids and total hydrocarbon concentration are less than 15 parts per million. Remaining buried pipelines larger than six inches in diameter shall be inerted with non-

toxic impermeable material such as concrete grout or foamed concrete so as not to become future conduits for migration of fluids.

(3) All remaining buried pipelines shall have a permanent identifier tag that is durable and resistant to corrosion attached to each remaining buried end. The tag shall identify the pipeline, the date of abandonment, the operator's name, and a contact name and phone number.

(4) All remaining buried pipelines shall be located by longitude and latitude of each remaining end and all of the following information shall be provided to the Division within 60 days of abandonment:

(A) Documentation of the locations of the remaining ends with a horizontal position accuracy of three meters.

(B) The name or identification number of the abandoned pipeline.

(C) The diameter of the abandoned pipeline.

(D) The service contents (e.g. oil, gas, or produced water) of the abandoned pipeline.

(E) The date of abandonment.

(5) Where there is evidence of naturally occurring radioactive materials or no screening for these materials has previously taken place at the operation, remaining buried pipelines shall be screened for such materials. Where screening identifies natural occurring radioactive materials of 50 milli-Roentgens per hour or higher, the operator shall report to the Division with a plan for remediation or removal, or a risk assessment showing that the material can safely remain in place.

(6) In fields which operated before 1978 and which have not previously been screened for polychlorinated biphenyls, operators shall screen gas

pipelines for polychlorinated biphenyls before abandonment. Where screening identifies the presence of polychlorinated biphenyls in any quantity, the operator shall remove or abandon contaminated pipelines consistent with the requirements of the U.S. Environmental Protection Agency and California Department of Toxic Substances Control.

Authority: Section 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, 3208, and 3270, Public Resources Code.

§ 1777. Maintenance and Monitoring of Production Facilities, Safety Systems, and Equipment.

(a) Operators shall maintain production facilities in good condition and in a manner to prevent leakage or corrosion and to safeguard life, health, property, and natural resources.

(b) Operators shall establish and comply with a written preventative maintenance program plan for prevention of corrosion and leakage and shall maintain documentation of steps taken to follow the plan. Such a preventative maintenance plan shall include, but not be limited to, the following factors:

(1) The level of usage and wear to which the production facilities are exposed.

(2) The age of the production facilities.

(3) Climate conditions where the production facilities are located.

(4) Industry standards for maintenance and corrosion prevention.

(5) Maintenance recommendations or guidelines from the manufacturers of the production facilities.

(c) Maintenance of production facilities shall include, but not be limited to the following:

(1) Operators shall conduct external visual inspections at least once a month of aboveground production facilities, excluding pipelines, for leaks and corrosion~~.~~ except that, within the setback mitigation area, operators shall conduct such inspections on a daily basis and shall carry a portable multi-gas detection meter while conducting the inspections. Operators shall document any identified leakage, corrosion, or damage and retain the records per 1777.3. Facilities that are not operating properly or are leaking shall be repaired ~~or replaced~~, replaced, or safely isolated within seven days of identification or in accordance with other applicable requirements, whichever is sooner.

(2) Weeds and debris shall be removed from secondary containment areas or catch basins, and the integrity of all berms shall be inspected monthly. Fluids, including rainwater, shall be removed.

(3) Well cellars shall be covered and kept drained. Grating or flooring shall be installed and maintained in good condition so as to exclude people and animals. Cellars should be protected from as much runoff water as practical.

(4) Injection lines shall be disconnected from injection wells unless there is current approval from the Division for injection of fluid.

(d) All equipment and facilities in urban areas shall be enclosed individually or with perimeter fencing in accordance with Section 1778(a) or Section 1778(e) where it is necessary to protect life and property. Enclosures in nonurban areas shall be constructed in accordance with Section 1778(a) or Section 1778(b) where necessary to protect life and property.

(e) The Supervisor may order the operator to inspect and test safety systems and equipment associated with consolidated production facilities. The frequency of the inspection and testing may be based on the manufacturer's recommendation.

Authority: Sections 3013, 3106, and 3270, Public Resources Code. Reference: Sections 3011, 3106, 3224 and 3270, Public Resources Code.

Subchapter 1. Onshore Well Regulations

Article 3. Requirements

§ 1722.4. Cementing Casing.

(a) Surface casing shall be cemented with sufficient cement to fill the annular space from the shoe to the surface. Intermediate and production casings, if not cemented to the surface, shall be cemented with sufficient cement to fill the annular space to at least 500 feet above oil and gas zones, and anomalous pressure intervals. Sufficient cement shall also be used to fill the annular space to at least 100 feet above the base of the freshwater zone, either by lifting cement around the casing shoe or cementing through perforations or a cementing device placed at or below the base of the freshwater zone. All casing shall be cemented in a manner that ensures proper distribution and bonding of cement in the annular spaces. The appropriate Division district deputy may require a cement bond log, temperature survey, or other survey to determine cement fill behind casing.

(b) After [EFFECTIVE DATE], for all drilling, redrilling, deepening, sidetracks, or reworks of a well within the setback mitigation area, where casing is being cemented across a USDW or freshwater zones, the operator is required to perform a cement log, temperature survey, or other survey approved by the

Division to determine cement fill behind casing and submit a report of the results to the Division within 60 days of completing operations.

(c) If it is determined that the casing is not cemented adequately by the primary cementing operation, the operator shall recement in such a manner as to comply with the above requirements. If supported by known geologic conditions, an exception to the cement placement requirements of this section may be allowed by the appropriate Division district deputy.

(d) After [EFFECTIVE DATE], wells drilled, redrilled, deepened, sidetracked, or reworked with new intermediate or production casing within the setback mitigation area shall be cemented with sufficient cement to fill the annular space from the shoe to the surface. The Division will allow exceptions on a case-by-case basis based on a demonstration that compliance would be impracticable.

Authority: Section 3013 and 3106, Public Resources Code. Reference: Sections 3011, 3106, 3220, and 3222-3224, Public Resources Code.

§ 1722.6. Drilling Fluid Program.

(a) The operational procedures and the properties, use, and testing of drilling fluid shall be such as are necessary to prevent the uncontrolled flow of fluids from any well and to prevent degradation of water quality of USDW or freshwater. Drilling fluid additives in sufficient quantity to ensure well control shall be kept readily available for immediate use at all times. Oil-based drilling muds shall not be used within the setback mitigation area unless approved by the Division as necessary to safely conduct the proposed well operations in the specific geologic setting.

(b) Fluid, including drilling muds and additives, which does not exert more hydrostatic pressure than the known pressure of the formations exposed to the well bore or has potential to degrade water quality of USDW or freshwater, shall not be used in a drilling operation without prior approval of the supervisor.

(c~~a~~) Before removal of the drill pipe or tubing from the hole is begun, the drilling fluid shall be conditioned to provide adequate pressure overbalance to control any potential source of fluid entry. Proper overbalance shall be confirmed by checking the annulus to ensure that there is no fluid flow or loss when there is no fluid movement in the drill pipe or tubing. The drilling fluid weight, the weight and volume of any heavy slug or pill, and the fact that the annulus was checked for fluid movement shall be noted on the driller's log. During removal of the drill pipe or tubing from the hole, a hole-filling program shall be followed to maintain a satisfactory pressure overbalance condition.

(d~~b~~) Tests of the drilling fluid to determine viscosity, water loss, weight, and gel strength shall be performed at least once daily while circulating, and the results of such tests shall be recorded on the driller's log. Equipment for measuring viscosity and fluid weight shall be maintained at the drill site. Exceptions to the test requirements may be granted for special cases, such as shallow development wells in low pressure fields, through the field rule process.

(e~~c~~) Disposal of drilling fluids shall be done in accordance with Section 1775, Subchapter 2 of these regulations.

(f) Operators shall employ vapor recovery systems to ensure that vapors do not escape from containers or fluid supply ponds used for drilling, completion, or workover operations on wells located within the setback mitigation area. All vapors collected shall be safely disposed in accordance with applicable local, state, and federal requirements.

Authority: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3011, 3106, 3219, and 3220, Public Resources Code.

§ 1723. Plugging and Abandonment - General Requirements.

(a) Cement Plugs. In general, cement plugs will be placed across specified intervals to protect oil and gas zones, to prevent degradation of usable waters, to protect surface conditions, and for public health and safety purposes. Cement may be mixed with or replaced by other substances with adequate physical properties, which substances shall be approved by the Supervisor. The application of these mixed materials and other substances to particular wells shall be at the discretion of the district deputy.

(b) Hole Fluid. Mud fluid having the proper weight and consistency to prevent movement of other fluids into the well bore shall be placed across all intervals not plugged with cement, and shall be surface poured into all open annuli.

(c) Plugging by Bailer. Placing of a cement plug by bailer shall not be permitted at a depth greater than 3,000 feet. Water is the only permissible hole fluid in which a cement plug shall be placed by bailer.

(d) Surface Pours. A surface cement-pour shall be permitted in an empty hole with a diameter of not less than 5 inches. Depth limitations shall be determined on an individual well basis by the district deputy.

(e) Blowout Prevention Equipment. Blowout prevention equipment may be required during plugging and abandonment operations. Any blowout prevention equipment and inspection requirements determined necessary by the district deputy shall appear on the approval to plug and abandon issued by the Division.

(f) Well Clean Out. The operator shall make a diligent effort to clean out the well to the depth necessary for plugging and abandonment to isolate all oil-bearing or gas-bearing strata encountered in the well, and to protect all USDW and freshwater from the infiltration or addition of any detrimental substance and to prevent subsequent damage to life, health, property, and other resources.

(g~~f~~) Junk in Hole. Diligent effort shall be made to recover junk when such junk may prevent proper plugging and abandonment either in open hole or inside casing. In the event that junk cannot be removed from the hole and fresh-saltwater contacts or oil or gas zones penetrated below cannot therefore be properly abandoned, cement shall be downsqueezed through or past the junk and a 100-foot cement plug shall be placed on top of the junk. If it is not possible to downsqueeze through the junk, a 100-foot cement plug shall be placed on top of the junk.

(h) Statutory Standard. A well is not properly plugged and abandoned in accordance with Public Resources Code section 3208 if the well is not plugged and abandoned so as to isolate all oil-bearing or gas-bearing strata encountered in the well, and to protect all USDW and freshwater from the infiltration or addition of any detrimental substance and to prevent subsequent damage to life, health, property, and other resources.

(i~~g~~) Lost Radioactive Tool. In the event that a source containing radioactive material cannot be retrieved from the hole, a 100-foot standard color dyed (red iron oxide or equivalent red cement dye) cement plug shall be placed on top of the radioactive tool, and a whipstock or other approved deflection device shall be placed on top of the cement plug to prevent accidental or intentional mechanical disintegration of the radioactive source. In addition, the operator shall comply with the California Department of Health Services regulations in

Section 30346 of Title 17, Division 1, Chapter 5, Subchapter 4, Group 3, Article 7, of the California Code of Regulations.

(j) Cement to Surface. In addition to all other requirements for plugging and abandonment of wells, for wells plugged and abandoned or reabandoned after [EFFECTIVE DATE] within the setback mitigation area, cement shall be placed from cleanout depth to surface. The Division will allow exceptions on a case-by-case basis based on a demonstration that compliance would be impracticable.

Authority: Sections 3013 and 3106, Public Resources Code. Reference: Sections 3011, 3106, 3219, and 3228, Public Resources Code.