AB 1420 PIPELINE TESTING REGULATIONS

15-DAY PUBLIC COMMENT PERIODS

COMMENT SUMMARIES AND RESPONSES

DEPARTMENT OF CONSERVATION

DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

INTRODUCTION

The following comments, objections, and recommendations were made regarding the modified text of the proposed regulations during two separate public comment periods. The first 15-day public comment period was held from December 5, 2017 to December 20, 2017. Due to an error in the public notification process, the Department of Conservation (Department) made the **identical** modified text of the proposed regulations available for public comment for an additional 15-day period. This second public comment period was held from February 5, 2018 to February 20, 2018.

Over the course of the two public comments period, the Division of Oil, Gas, and Geothermal Resources (Division) received a total of five email submissions from interested parties. Three email submissions were received during the first 15-day public comment period, and two email submissions were received during the second 15-day public comment period.

To facilitate the process of reviewing and responding to comments, the Division assigned to each comment a unique numerical signifier. This signifier consists of three components: first, a unique code number assigned to each commenter entity; second, a separating hyphen; third, a sequential number assigned to each comment from the identified commenter entity.

The comment summaries are categorized by the sections of the proposed regulations to which they correspond and are arranged in groups under one or more corresponding numerical signifiers. Responses to comments appear below the respective comment summaries, in italicized text.

To distinguish between the two public comment periods, the comment summaries have been separated by the time period which they were received. Because the comment summaries and responses are all related to the **identical modified text**, the Department compiled all comment summaries and responses in one document.

COMMENTERS (RECEIVED DECEMBER 5, 2017 – DECEMBER 20, 2017)

Number	Name and/or Entity
0001	California Independent Petroleum Association
0002	Western States Petroleum Association
0003	Macpherson Oil Company

<u>COMMENT SUMMARIES AND RESPONSES</u>

<u>SECTION 1760. DEFINITIONS</u>

0001-1
The commenters propose to amend the definition of "pipeline" in subsection (m) so that pipelines under the jurisdiction of the State Fire Marshal, as specified by the Elder Pipeline Safety Act of 1981 (commencing with § 51010 of the Government Code, and the regulations promulgated thereunder); the Pipeline and Hazardous Materials Safety Administration, per Title 49 Code of Federal Regulations Parts 192 and 195; or, under Cal/OSHA per CCR Title 8 chapter 14 article 9 section 6533 and Title 8 chapter 15 article 16 section 6845 are exempt from this definition. All pipelines under the jurisdiction of the federal and state agencies noted above are subject to strenuous mechanical integrity standards and are regularly audited for compliance.

Response: *Rejected. The California Department of Industrial Relations, Division of Occupational Safety and Health (Cal/OSHA), regulates pipelines from the perspective of employee health and safety. Cal/OSHA designates pipelines carrying natural gas as Class 2 pipelines. (Cal. Code of Regulations, title 8, § 6533, subd. (b)(3)(B)(2).) As such, these pipelines need only be inspected on a representative sampling, and "[t]he inspection interval shall not exceed 10 years or half the remaining life as determined from the corrosion rate calculation, whichever is less." (Cal. Code of Regulations, title 8, § 6533, subd. (b)(4)(B)(2).) The Department's proposed regulations require a more stringent annual inspection regime for those active gas pipelines in sensitive areas. This better protects the public and the environment from the ill effects of leaking gases. Further, the proposed regulations do not prevent operators from complying with the requirements of Cal/OSHA's statutes and regulations.*

The US Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) is the federal agency primarily responsible for pipeline regulation and safety. (49 USC, § 108, subd. (b), (f).) It adopts regulations that prescribe minimum pipeline safety standards for the pipeline transportation of natural gas and hazardous liquids. (See 49 CFR, §§ 190-192, 195.) PHMSA requires operators to conduct MIT testing in intervals of 7, 10, or 20 years, depending upon the specific yield strength of the pipeline. (See 49 CFR, § 192, App. E.) The two-year testing regime in the proposed regulations for active gas pipelines in sensitive areas is more stringent than the federal counterpart, and the proposed regulations do not prevent operators from complying with both sets of regulations.

The Office of the State Fire Marshal (SFM) has regulatory and enforcement authority over the safety of intrastate hazardous liquid pipelines. (Gov. Code, § 51010.) Through SFM's limited definition of "pipeline" and a Memorandum of Agreement with the Division, the Division, and not SFM, has authority over all pipelines "attendant to" oil and gas production, including pipelines within the administrative boundaries of oil and gas fields or that exist on the lease between the wellhead and custody transfer point. (See Gov. Code, § 51010.5, subd. (a).) The proposed regulations only affect Division-regulated gas pipelines; therefore, none of these regulations are inconsistent or incompatible with SFM regulations.

0001-4
The commenter recommends clarifying the definition of an "active gas pipeline" in Section 1760, subdivision (s), to include a single-phase gas line and exclude services such as multi-phase (water/oil/gas) flowlines.

Response: *Rejected. Public Resources Code section 3270.5, subdivision (c)(2), defines "active gas pipeline" to mean "an in service gas pipeline regardless of diameter that is within the division's jurisdiction." Most oil production from a well contains multiple phases and both oil and gas well production must be processed to meet sales specifications for each commodity. Because of this, pipelines that carry gas may at times also carry liquids or solids. The definition "active gas pipeline" in section 1760, subdivision (a), further elaborates on the statutory definition to be clear that a pipeline that carries gas is still a gas pipeline, even if it carries some amount of liquids or solids. Excluding multiphase pipelines or pipelines within processing plants from the definition "active gas pipeline" would be inconsistent with the statutory definition and inconsistent with the purpose of this rulemaking, which is to ensure that pipelines that carry gas in sensitive areas are subject to regular inspection and testing.*

0001-5
The commenter recommends striking Section 1760, subdivision (t)(2). The commenter believes the existing language to be arbitrary and capricious; and Section 1760, subdivisions (t)(1) and (3), provide protection.

Response: *Rejected. The Division believes that this comment applies to Section 1760, subdivisions (r)(2) and (3), which are quoting the statutory language of Public Resources Code section 3270.5, subdivision (c)(2). The statutory language is quoted in the regulations to aid operators' understanding of the regulations by preventing unnecessary cross-referencing between the Public Resources Code and the California Code of Regulations.*

0001-6
The commenter recommends revising the language in Section 1760, subdivision (t)(3), to include chronic <u>reportable</u> leaks.

Response: *Rejected. In defining a sensitive area, Public Resources Code section 3270.5, subdivision (c)(2)(C), includes "An area determined by the supervisor to have an active gas pipeline that has a history of chronic leaks." The Division included this definition in the regulations without modification.*

0003-1
The commenter recommends that the definition of "active gas pipeline" only include pipelines within the Division's jurisdiction, and strike out any reference to materials carried in that pipeline.

Response: *Rejected. The regulations clearly only apply to pipelines within the Division's jurisdiction. Public Resources Code section 3270.5, subdivision (c)(1), already defines an "active gas pipeline" as "an inservice gas pipeline regardless of diameter that is within the division's jurisdiction." The definition "active gas pipeline" in section 1760, subdivision (a), further elaborates on the statutory definition to be clear that a pipeline that carries gas is still a gas pipeline, even if it carries some amount of liquids or solids.*

<u>SECTION 1774. PIPELINE CONSTRUCTION AND MAINTENANCE</u>

0001-7
The commenter recommends Section 1774, subdivision (d), should only be considered for a Special Flood Hazard Area. Additionally, clarity is requested on what determines feasibility for racks and supports.

Response: *Rejected. Section 1774, subdivision (d), is a previously existing regulation that is not within the scope of this rulemaking.*

0003-2
Related to newly installed pipeline design and construction, and all pipeline testing, operation, and maintenance; the commenter suggests placing an emphasis on good oil field practices found in ASME B31.3, B31.4, and B31; API Rec. Prac. 570; and Title 8, Cal. Code of Regulations, section 6533. The commenter suggests deleting specified references to the American Petroleum Institute (API) (API Rec. Prac. 1110, 3d Ed., Dec. 1991, and API Spec. effective 1990), American Society for Testing and Materials (ASTM) (ASTM Designation Stand. Spec., 1991), or Code of Federal Regulations 49, Part 192.

Response: *Accepted. The proposed regulations have deleted references to the American Petroleum Institute Rec. Prac. 1110, American Society for Testing and Materials, and Code of Federal Regulations 49, Part 192.*

SECTION 1774.1. PIPELINE INSPECTION AND TESTING

0001-10
The commenter recommends modifying the language in Section 1774.1, subdivision (f), to further clarify that the regulations apply to pipelines that are 4 inches in diameter or less.

Response: *Rejected. Public Resources Code section 3270.5 requires the Division to review, evaluate, and update, where appropriate, its existing regulations concerning all active gas pipelines that are located in sensitive areas, less than four inches in diameter and 10 or more years old. However, consistent with the Division's broader mandate under to Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources, these regulations require operators to test and inspect all active gas pipelines in sensitive areas that are 10 or more years old, regardless of diameter.*

Although existing regulations already require operators to test all urban pipelines over four inches in diameter, larger gas pipelines in non-urban areas are not addressed by existing regulation. (See Cal. Code Regs., tit. 14, § 1774.1, subd. (e).) If the Division's new inspection and testing requirements for active gas pipelines in sensitive areas were to only apply to pipelines that are less than four inches in diameter, then larger pipelines in non-urban sensitive areas, such as communities like Arvin, would not be subject to the Division's testing and inspection requirements. These larger active gas pipelines pose at least the same, and arguably greater, risk to the public because they carry greater volumes of gas that can be released. Therefore, in order to for the Division to address its broader mandate under Public Resources Code section 3106, it is necessary for these regulations to apply to apply to a broader set of pipelines than what is described in Public Resources Code section 3270.5, subdivision (a).

0001-17
The commenter recommends that all active gas pipelines be subject to leak surveys, using leak detection equipment at intervals not exceeding 4 ½ months, but at least four times a year.

Response: *Rejected. Although leak surveys are useful in detecting leaks in their infancy, they cannot be used as a method of preventative maintenance because they only detect hazardous chemicals that have already begun to contaminate the environment. In contrast, regular mechanical integrity testing can prevent leaks by demonstrating the wall thickness of the pipeline over time, giving the operator a chance to remediate any problems before a leak develops.*

0001-18

The proposed two-year MIT is not based on any industry accepted intervals or any intervals established by any federal or State government agencies.

Response: *Rejected. Existing regulations require mechanical integrity testing for oil gathering pipelines in environmentally sensitive areas and pipelines within urban areas every two years. (Cal. Code of Regs., tit. 14, § 1774.1, subd. (f).) The two-year testing frequency has proven to be effective under these long-standing requirements for ensuring the mechanical integrity of pipelines, and, responding to the mandate of Public Resources Code section 3270.5, subdivision (a), these same requirements are being applied to active gas pipelines ten or more years old in sensitive areas. However, operators may obtain approval from the Supervisor to test on an alternate frequency based on demonstrated wall thickness and remaining service life of the active gas pipeline over a period of at least two years. (Cal. Code of Regs., tit. 14, § 1774.1, subd. (f).)*

0001-2

The proposed regulations continue to require unreasonable and, in some instances, dangerous testing requirements. Greater testing flexibility would allow operators to take into account field specific conditions. The commenter believes that this flexibility would come with the ability to use above-ground leak surveys, and also by deleting the provision that provides for the Supervisors' approval to use nondestructive testing to determine wall thickness. DOGGR has indicated that NDT will only be acceptable when the test can provide complete coverage of the pipeline, which is virtually impossible, requiring further problematic pressure testing. Also, the commenter offers that pneumatic testing utilizing methane is inherently risky and recognized as being the least preferable method for integrity tests. The commenter recommends leakage testing and alternative forms of testing be recognized as appropriate and applicable in the regulation.

Response: *Rejected. The Division believes that Section 1774.1 does provide the flexibility requested by the commenter. Subdivision (f) provides several methods for conducting mechanical integrity testing for pipelines, including the operator's ability to submit a testing method to the Supervisor for approval. The Division acknowledges that different testing methods may be appropriate in specific circumstances. For this reason, there is not a specific test that is required for all pipelines.*

0001-8, 0002-1

The commenters recommend amending Section 1774.1, subdivision (b), to reflect the original intent of AB 1420, by specifying that only active gas pipelines that are 4 inches or less are subject to the regulations. As written this section is in direct conflict with the intent of AB 1420.

Response: *Rejected. Public Resources Code section 3270.5 requires the Division to review, evaluate, and update, where appropriate, its existing regulations concerning all active gas pipelines that are located in sensitive areas, less than four inches in diameter and 10 or more years old. However, consistent with the Division's broader mandate under to Public Resources Code section 3106 to prevent damage to life, health, property, and natural resources, these regulations require operators to test and inspect all active gas pipelines in sensitive areas that are 10 or more years old, regardless of diameter.*

Although existing regulations already require operators to test all urban pipelines over four inches in diameter, larger gas pipelines in non-urban areas are not addressed by existing regulation. (See Cal. Code Regs., tit. 14, § 1774.1, subd. (e).) If the Division's new inspection requirements for active gas *pipelines in sensitive areas were to only apply to pipelines that are less than four inches in diameter, then larger pipelines in non-urban sensitive areas, such as communities like Arvin, would not be subject to the Division's testing and inspection requirements. These larger active gas pipelines pose at least the same, and arguably greater, risk to the public because they carry greater volumes of gas that can be released. Therefore, in order to for the Division to address its broader mandate under Public Resources Code section 3106, it is necessary for these regulations to apply to apply to a broader set of pipelines than what is described in Public Resources Code section 3270.5, subdivision (a).*

0001-9
The commenter recommends modifying Section 1774.1, subdivision (d), by deleting a requirement that pipelines will not be returned to service unless the pressure testing has been successfully completed and the integrity of the pipeline has been verified to the Division's satisfaction. The commenter suggests adding a reference to regulations setting forth what a reportable quantity is before removing pipelines from service. Presently, there are no thresholds as to what is considered a reportable quantity.

Response: *Rejected. The current language of the regulation does not require Division verification before placing a pipeline back into service. Rather, the pipeline must successfully pass a pressure test, and those test results must be provided to the Division within seven days.*

While the Division has not specifically defined what constitutes a reportable quantity, other statutory and regulatory schemes do have definitions. If an operator discovers a pipeline within the Division's jurisdiction that has leaked a quantity that triggers reporting requirements to another agency, the leak must also be reported to the Division.

0001-16
The commenters suggest modifying Section 1774.1, subdivision (f), to include any gas lines, active or not, in a tank facility located within secondary containment and/or buffers, to be exempted from the mechanical integrity testing requirement. This section adds another layer of regulations to these pipelines and would force a Process Safety Management mechanical integrity program on these facilities. Section 1774.1(a) already requires a visual inspection of above-ground lines that includes those located in sensitive areas which should be sufficient to identify active corrosion or leaks without the substantial cost of mechanical integrity testing.

Response: *Rejected. While visual inspection of above ground lines is valuable in detecting leaks after they have started, the goal of this rulemaking is the prevention of leaks in active gas pipelines in sensitive areas and mechanical integrity testing is essential to that goal. Section 1774.1, subdivision (b), allows operators to propose an alternate inspection frequency for approval by the Supervisor, and Section 1774.1, subdivision (f)(4), allows operators to propose alternate methods of mechanical integrity testing that ensure "mechanical integrity so as to protect life, health, property and natural resources." The Division will work with operators, where appropriate, to accept testing and inspection protocols, particularly those that meet existing requirements imposed by other regulatory agencies.*

0003-3
Related to the inspections required by Section 1774.1, subdivision (b), the commenter suggests deleting the reference to "all" active gas pipelines, while adding that the inspection is required for only those pipelines under the Division's jurisdiction.

Response: *Rejected. The regulations clearly only apply to pipelines within the Division's jurisdiction. Public Resources Code section 3270.5, subdivision (c)(1), already defines an "active gas pipeline" as "an inservice gas pipeline regardless of diameter that is within the division's jurisdiction." The definition "active gas pipeline" in section 1760, subdivision (a), further elaborates on the statutory definition to be clear that a pipeline that carries gas is still a gas pipeline, even if it carries some amount of liquids or solids.*

0003-4
The commenter suggests that testing of gas pipelines in sensitive areas are only be required on pipelines within the Division's jurisdiction. Additionally, instead of the Supervisor's approval, the commenter suggests the mechanical integrity testing be conducted based on industry practice or recognized industry standard such as from the American Petroleum Institute, American Society of Mechanical Engineers, the State Fire Marshal, or US Department of Transportation Pipeline Safety.

Response: *Rejected. The regulations clearly only apply to pipelines within the Division's jurisdiction. Public Resources Code section 3270.5, subdivision (c)(1), already defines an "active gas pipeline" as "an inservice gas pipeline regardless of diameter that is within the division's jurisdiction." The definition "active gas pipeline" in section 1760, subdivision (a), further elaborates on the statutory definition to be clear that a pipeline that carries gas is still a gas pipeline, even if it carries some amount of liquids or solids.*

All of the industry standards listed in the comment would be acceptable forms of mechanical integrity testing under the regulation. The Division has the authority to review and approve the testing methods on a case-specific basis to ensure that they are appropriate for the pipeline type and use.

0003-5
The commenter suggests deleting the requirement that operators notify DOGGR in writing of any pipeline taken out of service due to a test failure.

Response: *Rejected. Operators are currently required to notify the Division in writing of any pipeline taken out of service due to a test failure. While the form of the sentence was changed from passive to active voice, the substance of this portion of the regulation did not change.*

If a pipeline has been removed from service due to a test failure, the Division will want to ensure that appropriate steps were taken before the pipeline is placed back into service, such as repairing or replacing that portion of the pipeline. Further, in the event of a leak, it is important for the Division to have records of inservice and out-of-service pipelines for the purposes of investigation.

SECTION 1774.2. PIPELINE MANAGEMENT PLANS

0001-11
The commenter suggests Section 1774.2, subdivision (b)(4), be amended to strike the mapping requirement for all pipelines that pass through sensitive areas, environmentally sensitive areas, urban areas, and designated waterways. This additional mapping requirement is outside the express scope and intent of AB 1420 and drastically expands the scope to map all pipelines.

Response: *Rejected. The Division has broad authority under Public Resources Code section 3106 to supervise the operation and maintenance of facilities attendant to oil and gas operations. Requiring a list and maps identifying pipelines and their locations is necessary to meet this statutory mandate.*

Further, operators are already required to have lists and maps of all pipelines in their Spill Contingency Plans. (Cal. Code of Regs, tit. 14, § 1722.9.)

0002-2
Regarding data submissions generally, the commenter cites AB 1960 that states "The plan shall be provided to the Supervisor upon request." The commenter also offers the interpretation of that as meaning that "upon request" operators could either invite the Supervisor to see the database and the specific data requested or export a report to show the data for specific lines. The Pipeline Management Plan is often developed using Inspection Data Management software that can result in thousands of pages per plan. Therefore, it does not seem feasible to extract these entire databases; potentially thousands of pages, for submittal without putting a large burden on the operator as well as DOGGR to review and process such a request. To resolve these concerns we encourage DOGGR to establish a process through which the data submittals can be appropriately narrowed based on the nature of information being sought as opposed to automatically relying on boiler plate language that automatically requires a larger universe of data than is otherwise necessary. One possible approach would be to ensure the final regulation includes a statement that a Notice to Operators (NTO) will be developed in conjunction with implementation of the new regulations that allows for operators and DOGGR to consult on the specific nature of information needed for individual PMPs.

Response: *Rejected. Public Resources Code section 3270.5, subdivision (b), requires operators of active gas pipelines in sensitive areas to submit an up-to-date and accurate map identifying the location of their pipelines and other up-to-date locational information of the pipeline as determined and in a format specified by the Division as part of their Pipeline Management Plans. Based on this and the fact that operators are already required to have a Pipeline Management Plan, Section 1774.2, subdivision (a), now requires operators to submit their Pipeline Management Plans to the Division within one year of the effective date of this rulemaking. Operators may export reports from their data management software and/or propose alternative arrangements to provide this Pipeline Management Plan which may be more efficient for both the operator and the Division.*

SECTION 1774.3. GAS PIPELINE DATA SUBMISSIONS

0001-12, 0001-13, 0001-14, 0002-3
The commenters make provide suggestions for clarification, additions, and deletions to Section 1774.3. They also expressed concern that mapping active gas pipelines is too time consuming and costly.

Response: *There is no Section 1774.3 in these regulations and gas pipeline mapping data submissions required under Public Resources Code section 3270.5, subdivision (b), are not addressed in this rulemaking. The Division has conducted some initial pre-rulemaking stakeholder engagement on this topic, but the Division has not initiated rulemaking to date.*

ECONOMIC IMPACT ASSESSMENT

0002-4
The commenters suggest amending the economic impact analysis to modify the presumption that there will be 80% pneumatic testing. The commenters believe assuming that 80% of the pipelines will be pneumatically tested is unreasonable, and the percentage should actually be closer to 100 percent hydrostatic. Pneumatic tests are inherently risky and are recognized as being the least preferable

method for integrity testing in several codes and standards including the American Society for Mechanical Engineers B31.3, B31,4, B31,8 and Post Construction Code 2. Due to the safety risks and high level of management required to safely conduct such tests, pneumatic testing is unlikely to be utilized. The economic impact analysis should be modified to consider this presumption.

Response: *The Division's estimate of the percentage of operators choosing pneumatic testing is reasonable. The Division estimates that the majority of gas pipelines within a sensitive area to be less than 1,000 feet in length and most that pass through sensitive areas will be underground. The American Society of Engineers' ASME B31.8 code allows for pneumatic testing when the test pressure is below 30% of Specified Minimum Yield Strength (SMYS). Most sensitive area gas pipelines have lower operating pressures (below 30% SMYS) that will allow the use of pneumatic testing per these ASME guidelines. The Division estimates that most of these gas pipelines in sensitive areas will operate at or below 100 psi, are less than 1000 feet in length, are less than four inches in diameter, are underground which helps to dissipate stored energy during failure, and can have their physical condition assessed before choosing pneumatic pressure testing. For these reasons the Division believes that operators will choose pneumatic testing where they already have confidence in the condition of the pipeline and can perform the test safely. With a line assessed to be in good condition and meeting these other limits, it would be expected that the unlikely pipeline failure during pneumatic testing would be a limited failure where test medium gas is released, or blown down, over a measureable and significant time period. The American Society of Engineers allows this testing with significant margins of safety.*

0002-5

The commenter recommends that the economic impact analysis be re-analyzed to modify the presumption that methane could be used in pneumatic testing. The potential for the use of methane by operators raises the risk and would not be allowable per DOT/PHMSA codes for jurisdictional pipelines; it would trigger a "safety-related condition" as the pipeline would be subjected to >110% of the MAOP while still containing the flammable gas.

Response: *The Division's Economic Impact Analysis does not presume that methane would be used, only that it is an option when conducting pneumatic testing. The Economic Impact Analysis also identifies air and nitrogen as other general mediums for conducting a pneumatic test. Further, the Department of Transportation, Pipeline and Hazardous Materials Safety Administration allows for some pneumatic testing with lower maximum hoop stress limitations. (49 C.F.R. 192.503, subd. (c).) Section 1774.1, subdivision (f), gives the operator the flexibility to identify effective mechanical integrity testing methods based on the pipeline type and use. There are likely very few pipelines that are being addressed by this regulation with overlapping DOT/PHMSA jurisdiction. In instances where this does occur, alternative testing methods including those used to meet DOT/PHMSA may be proposed. Since the DOT/PHMSA testing is already occurring, the added cost will only be that caused by an increase in the testing frequency.*

0002-6

The commenter suggests DOGGR amend the economic impact analysis to calculate the true cost impacts of testing. The costs proposed by DOGGR are skewed to a much lower value than reality. Specifically, DOGGR's cost estimates for pneumatic tests are approximately 50% lower than the cost for an equivalent hydrostatic test. As noted above, the analysis should be based on the assumption that hydrostatic tests, not pneumatic tests, will be the primary testing method. When feasibility and safety considerations are factored in, DOGGR should estimate that virtually zero pneumatic tests will be performed. Further, it should be noted that DOGGR's analysis estimates a substantially lower cost to hydrostatically test buried pipelines than to hydrostatically test aboveground pipelines. WSPA does not concur with the assumption that the cost on a buried line would be half the cost of an aboveground line. If a round number of $15,000 per pressure test is used for all pipelines that DOGGR is estimating will be impacted by AB 1420 requirements, the new cost impact would more accurately be $69,135,000 for the first year. The values used by DOGGR for the hydrostatic testing costs appear to be very low. Other costs must be included such as water sourcing, equipment rentals for water storage, third-party testing companies, and disposal of the hydro testing water, so a higher average value should be applied to calculate the true cost impacts.

Response: *In developing the cost estimates, the Division consulted with experienced professionals, including contractors that conduct testing. Most sensitive area gas pipelines have lower operating pressures (below 30% SMYS) that will allow the use of pneumatic testing per ASME guidelines. The DOGGR estimate of the percentage of operators choosing pneumatic testing is reasonable. The Division used very conservative estimates and assumptions about both the number of pipelines covered by the regulations, as well as the testing that operators are already conducting. The Division concedes that the comment about the relative cost of a hydrostatic test for a buried pipeline may have merit. Even if the cost estimate of hydrostatic testing for buried pipelines is increased to that of the aboveground pipelines, the total cost estimate (ref. ISOR, App. A) for testing 802 buried pipelines increases from $3,321,082 to $6,314,146. This adjustment puts total testing cost estimate to be $17,621,696, which is still well below the SRIA cost threshold. Based on the number of lines reported to date, it appears that 802 buried lines is also conservatively high. The Department is reasonably confident that the existing cost estimates more than cover the potential costs imposed by these regulations.*

0002-8
The commenter believes DOGGR has ignored the economic infeasibility of operators having to develop three-dimensional models or multiple layers of two-dimensional images to represent each individual piping system contained within a "facility."

Response: *Operators are already required to have this basic design information for their pipelines or piping systems within a production facility per Cal/OSHA. More highly detailed two and three dimensional models are not intended or required. Existing plot plans, piping diagrams, or process flow diagrams that are part of the facility design documentation may be used to identify locations of pipelines with respect to sensitive locations. However, the specific requirements for Gas pipeline data submissions are not being addressed in this rulemaking. Those regulations are part of a separate regulation package that will be submitted to the Office of Administrative Law in 2018.*

0001-3, 0002-7
The commenters suggest DOGGR include the additional costs impacts of production curtailments to the operator to reflect the real costs of the regulation's current testing requirements. The commenters believe DOGGR has ignored the cost from loss of production if a pipeline or facility is shutdown to conduct the mechanical integrity testing on a two-year frequency, potentially for multiple days. Production curtailments without warranted mechanical integrity risk mitigation will cause an economic hardship on operators.

Response: *The Division's economic analysis is a static estimate of the costs of testing. However, the Division used conservative estimates with the knowledge that it may encompass some indirect costs that go beyond simply obtaining equipment and conducting the test. The Division disagrees that the testing is unwarranted. The affected active gas pipelines are primarily located in areas of human habitation.*

Biennial mechanical integrity testing helps to prevent pipeline leaks by detecting defects before they result in leaks. Given the location of the pipelines, this is necessary to protect the public and environment. Moreover, the operator may obtain the approval of the Supervisor to conduct mechanical integrity testing on an alternate frequency based on the demonstrated thickness and remaining service life of the pipeline over a period of at least two years. (Cal. Code of Regs., tit. 14, § 1774.1, subd. (f).)

0001-15, 0002-9
The commenters recommend DOGGR revisit its economic impact analysis and complete a Standardized Regulatory Impact Assessment (SRIA) on the regulations. The estimated costs associated with these regulations are expected to exceed the annual $50 million for California operators; requiring a SRIA, after accounting for possible increases in costs for testing and lost production. Also, DOGGR must understand that there is a cumulative economic impact associated with other oil and gas related rulemakings that are currently moving forward by DOGGR, in addition to regulations from other State agencies and Local governments that are already in place.

Response: *The Division disagrees that this rulemaking requires a Standardized Regulatory Impact Assessment. The Division's Economic Impact Analysis estimated that 4,609 active gas pipelines would require testing under the proposed regulations. In developing this estimate, the Division deliberately used conservative assumptions concerning the number of locations that fall within the definition of a sensitive area, but not an urban area, and, therefore, the number of pipelines that will now need to be inspected and tested under these regulations.*

Further, although the regulations provide the flexibility for alternate testing and inspection frequencies, the Division's economic analysis also assumes that all of the testing costs will be new and incurred every two years and all of the inspection costs will be incurred every year. The Division anticipates accepting alternative testing types, as well as alternate testing and inspection schedules. Based on this, the Division believes that its cost estimates are actually substantially overestimated. Still, the estimated impacts are well below the threshold for requiring a Standardized Regulatory Impact Assessment.

COMMENTERS (RECEIVED FEBRUARY 5, 2018 – FEBRUARY 20, 2018)

Number	Name and/or Entity
0001	Dr. Tom Williams
0002	Citizens for Responsible Oil and Gas

COMMENT SUMMARIES AND RESPONSES

GENERAL CONCERNS

0002-2
The regulations should be drafted to clearly state that the proposed regulations apply to all pipelines, regardless of diameter, in oilfields, not governed by the State Fire Marshall.

Response: *Rejected. The Office of the State Fire Marshal (SFM) has regulatory and enforcement authority over the safety of intrastate hazardous liquid pipelines. (Gov. Code, § 51010.) Through SFM's limited definition of "pipeline" and a Memorandum of Agreement with the Division, the Division, and not SFM, has authority over all pipelines "attendant to" oil and gas production, including pipelines within the* *administrative boundaries of oil and gas fields or that exist on the lease between the wellhead and custody transfer point. (See Gov. Code, § 51010.5, subd. (a).) The proposed regulations only affect Division-regulated gas pipelines; therefore, none of these regulations are inconsistent or incompatible with SFM regulations.*

SECTION 1760. DEFINITIONS

0001-1
The definition of active gas pipeline should be revised to replace fractional with "less than one thousand parts per million because fractional is meaningless.

Response: *Rejected. The definition identifies that the main constituent or primary purpose of the pipeline is to carry gas in a gaseous or vapor phase, but acknowledges that lesser or fractional amounts of other substances may also be present in a gas pipeline.*

0001-2
The definitions of pipeline, urban pipeline, production facility, out-of-service, and in-service, should be revised to be specific to gas only.

Response: *Rejected. Although the focus of this rulemaking is requirements for pipelines that carry gas in sensitive areas, the Division generally regulates pipelines that carry liquid or gas.*

0001-3
The definition of secondary containment should be revised to include "impervious and gas-tight" and be specific to gas only. Additionally, as used in the in the definition of secondary containment, "impoundment" should be defined.

Response: *Rejected. This comment is not specifically directed at the agency's proposed action and, thus, is outside the scope of this rulemaking.*

0001-4
The definition of sensitive area should be revised to include production facility.

Response: *Rejected. Section 1760, subdivisions (r), quotes the statutory definition of "sensitive area" found in Public Resources Code section 3270.5, subdivision (c)(2). The statutory language is quoted in the regulations to aid operators' understanding of the regulations by avoiding unnecessary cross-referencing between the Public Resources Code and the California Code of Regulations.*

0001-6
The definitions for sump, drilling sump, evaporation sump, and operations sump must all be revised to be specific to gas only. Additionally, the term "impervious" (incorrectly spelled in the comment letter) must be added to the general definition of sump; redrilling must be added to the definition of drilling sump; the definition of evaporation sump must be revised to specify that it can only store water and not any fluid or it could be a pollution source and require other permits; and the definition of operations sump needs to be revised because rework and abandonment require the well to not be operating.

Response: *Rejected. This comment is not specifically directed at the agency's proposed action and, thus, is outside the scope of this rulemaking.*

0001-7
The definition of waste water must not apply to produced oil fluids. Additionally, merged and/or separated produced water must not be considered as a waste because it can be returned to the pool for pressure and ground surface maintenance. Also, the Division must require fluid reuse for gas injection and the UIC Program.

Response: *Rejected. This comment is not specifically directed at the agency's proposed action and, thus, is outside the scope of this rulemaking.*

0002-1
The definition of Environmentally Sensitive should address concerns related to environmental justice and water supply.

Response: *Rejected. This comment is not specifically directed at the agency's proposed action and, thus, is outside the scope of this rulemaking.*

SECTION 1774. PIPELINE CONSTRUCTION AND MAINTENANCE

0001-8
The first paragraph of section 1774 should be revised because it lacks definitions for newly, good, practice, and standards; and there is no differentiation between gas and all pipelines.

Response: *Rejected. The Division does not believe the definitions noted by the commenter will add clarity or value to the proposed regulation. Further, the Division did not intend to differentiate between gas and liquid pipelines. It requires operators to utilize good oil field practices and applicable standards when installing, testing, operating, and maintaining both liquid and gas pipelines within the jurisdiction of the Division. The Division believes this is more protective of the public and environment.*

0001-9
Section 1774, subdivisions (a) through (d), should be revised as this section does not quantify or define financial factors, does not define or quantify appropriate or spill zone minimum, does not define costs for prevention of a spill, and does not mention Risk Management or Emergency Response plans.

Response: *Rejected. The purpose of Section 1774, and its subdivisions, is to provide minimum construction, operation, maintenance, and testing measures that facilitate corrosion protection, reduce potential spill volumes, and improve inspection, leak detection, and monitoring capabilities. These measures would be considered "good oilfield practices" when installing new pipelines. This section is not intended to address cost factors, and the Division does not believe that the suggested changes provide clarity or value to this regulation.*

Pipeline Management Plans are addressed in Section 1774.2, were already required in the regulations, and are designed to aid the operator and Division in assessing the possible risk that pipelines pose to the public, environment, and natural resources. Further, California Code of Regulations section 1772.9 already requires operators to have a spill contingency plan, which is an emergency response plan.

0002-3
Commenter suggests that Section 1774 should clearly state standards for the design, construction, testing, operation and maintenance of pipelines, rather than providing a list of possible standards. The commenter is concerned that the failure to clarify definite standards creates loopholes and could leave the term "good oilfield practices" open to wide interpretation. Additionally, it should be made clear that pipelines are subject to new rules and regulations that may be passed in the future.

Response: *Rejected. Section 1774 is intentionally written to acknowledge that there are a wide variety of circumstances and settings in which California oil and gas pipelines exist. What may be considered "good oil field practices" for one pipeline may not meet regulatory goals for another. Requiring very specific standards for all pipelines within the state ignores the fact that they could create undesirable consequences in some locations. The statutes, regulations, and industry standards included in the proposed regulations provide the public, environment, and natural resources with a standard level of protection and, thus, serve as a basis for "good oil field practices."*

SECTION 1774.1. PIPELINE INSPECTION AND TESTING

0001-10
Section 1774.1, subdivision (a), should be revised to include olfactory inspection, and the inspection period should be changed to either monthly or quarterly.

Response: *Rejected. Leak inspection shall be conducted in accordance with an accepted industry or regulatory standard for safety, accuracy, and reliability. The gases contained within these pipelines have not been injected with mercaptans and may not have a detectable odor, making olfactory detection of gases an unreliable leak inspection method. Additionally, leaks may occur at low concentrations, further rendering olfactory inspection unreliable.*

0001-11
Section 1774.1, subdivisions (b) and (c), should be revised to focus on gas only, and to add a definition for reliability.

Response: *Rejected. The Division does not intend for these subdivisions to only affect gas pipelines and believes that including liquid pipelines within the jurisdiction of the Division is more protective of the public and environment. It further believes that a definition for reliability does not add clarity or value to the regulation.*

0001-12
Section 1774.1, subdivision (d), should be revised to address the lack of definitions for leak, release, and quantity, and provide a basis of fluid leak from an active gas pipeline.

Response: *Rejected. The Division does not believe that the information contained in this comment would add clarity or value to the regulation.*

0001-13
Section 1774.1, subdivision (d), should be revised to require operators to control and stop the leak/release in the event of a leak or release.

Response: *Rejected. Section 1722, subdivision (b), and Section 1722.9 already require operators to have a spill contingency plan. Within the plan, operators are required to design methods for reporting, controlling, and stopping leaks, spills, or releases.*

0001-14
Section 1774.1, subdivision (f), should be revised to reflect that all pipeline management plans are specific to gas.

Response: *Rejected. Existing regulations already require Pipeline Management Plans for all pipelines, including gas pipelines. The Division intends for pipeline management plans to continue to include both oil and gas pipelines that are within the jurisdiction of the Division. It believes that inclusion of liquid pipelines under its jurisdiction within the Pipeline Management Plans is more protective of the public and environment.*

0001-15
The commenter suggests that an operator's method of pressure testing according to Section 1774.1, subdivisions (f)(2)(A) and (B), must be included and quantified in the Gas Pipeline Management Plan, and this section should be revised to be specific to gas.

Response: *Rejected. Operators are required to specify pressure testing methodologies and frequencies in their Pipeline Management Plans. The Division intends for Section 1774.1, subdivision (f), including all of its subparts, to pertain to both oil and gas pipelines within the jurisdiction of the Division.*

0001-16
When submitting information pursuant to Section 1774.1, subdivision (f)(4), the commenters suggests that the operator's integrity assurance must be included and quantified in the Gas Pipeline Management Plan. The commenter also believes this section should be revised to be specific to gas.

Response: *Rejected. The Division does not believe that the suggested addition in this comment would add clarity or value to the regulation.*

The Division intends for Pipeline Management Plans to continue to include both liquid and gas pipelines that are under the jurisdiction of the Division and believes that this is more protective of the public and environment.

0001-17
Regarding the requirement operator's assessment of tests, it is recommended that all promptly be defined.

Response: *Rejected. The Division does not believe that the suggestions within the comment provide clarity or value to the regulation.*

0002-4
How will the annual required inspection of pipelines by operators be enforced? And how much (length) of the pipeline must be inspected?

Response: *Enforcement is an important part of the Division's statutory mandate, and the Division has broad authority to order non-compliant operators to conduct required tests and inspections and may* *issue civil penalty orders, where appropriate. Specific enforcement directives, however, are outside the scope of the rulemaking. The regulations require operators to inspect the entire length of active gas pipelines in sensitive areas once a year, unless an alternate frequency has been approved by the Supervisor.*

0002-5
Pipelines should be inspected at least once a year, using clearly defined, up-to-date standards, without the ability to extend the timeframe.

Response: *Rejected. Providing flexibility in inspection methods allows operators to receive complete or partial credit for inspections conducted for other state or federal regulators and to use new and improved methods and equipment as inspection technology evolves. The Division will carefully review the inspection methods provided in an operator's Pipeline Management Plan to ensure that they are situationally suitable. Any reduced inspection frequency will be approved on a case-by-case basis after the Division's review of an operator's request that is supported by previous mechanical integrity testing and inspection data.*

0002-6
Following a repair, operators should be required to perform a visual, real-time inspection until a leak detection system is fully operational.

Response: *Rejected. Section 1774.1, subdivision (d), requires operators to conduct pressure testing 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 before returning the pipeline to service. However, the majority of pipeline leak repairs are of the magnitude or type where installation of either leak detection or prevention equipment would not be considered practical. For this reason, leak detection or prevention equipment will not likely be installed following most pipeline leak repairs.*

0002-7
The Supervisor should not have discretion to lengthen time between mechanical integrity testing.

Response: *Rejected. Supervisor discretion in lengthening the time between mechanical integrity testing acknowledges that different conditions exist in different areas of the state. Granting reduced testing frequency will only occur on a case-by-case basis and after the Supervisor's review of an operator's request that is supported by previous test and inspection data and a showing of specific safeguards. This demonstration would likely require, at a minimum, the operator to conduct at least two prior mechanical integrity tests in order to compile the necessary data and safeguards that can be show to prevent degradation and leaks and/or detect leaks proactively on a more frequent basis.*

0002-8
How often are pipelines, less than ten years old, inspected?

Response: *Current regulations require all aboveground pipelines to be visually inspected for leaks and corrosion annually. Operators should use a procedure that will aid in detecting possible leaks, such as the application of soapy water. Gas pipelines that are located underground that are less than ten years old and constructed and installed per applicable standards and good oil field practice have a very low likelihood of leaking.*

0002-10
The reporting of test failures to a District Supervisor must be mandatory, and be made available to the public.

Response: *When a pipeline fails a mechanical integrity test, it is taken of out of service until it is retested successfully or repaired and successfully tested. Section 1774.1, subdivision (f), requires operators to notify the Division in writing when this occurs. Such reports are public record availably to the public either on the Division's website or upon request.*

0002-11
Vapor recovery pipelines should also be subject to mechanical integrity testing. A vapor recovery system is frequently a condition of a local land use permit and should therefore be required to be maintained in good working order.

Response: *Rejected. Based on the requirements of other regulatory bodies, the Division has modified Section 1774.1, subdivision (g), to exempt vapor recovery pipelines from mechanical integrity testing if they are equipped with certain safeguards and leak tested at least annually. This modification avoids unnecessary duplication of regulation. Moreover, the oxygen detectors on vapor recovery pipelines already provide a significant leak detection safeguard.*

SECTION 1774.2. GAS PIPELINE MANAGEMENT PLANS

0001-18
Vapor recovery lines are different from active gas pipelines unless specifically defined and quantified. The operator's "integrity", "testing", and "safeguards" and their frequency of testing must be included and quantified in the "Gas Pipeline Management Plan" and must be specific to "Gas" not for all vapors, fluids, or liquids.

Response: *Rejected. Vapor recovery lines are required to be included in an operator's Pipeline Management Plan, which includes information concerning age, design, leak and repair history, testing, and safeguards. Further, current regulations require Pipeline Management Plans to include both liquid and gas pipelines that are under the jurisdiction of the Division, and the Division intends for Plans to continue to include both liquid and gas pipelines that are under the jurisdiction of the Division. The Division believes that this is more protective of the public and environment.*

0001-19
Section 1774.2, subdivision (a), should be revised to provide standards for all elements and phases of gas pipelines and their facilities.

Response: *Rejected. The Division does not believe that this suggestion provides clarity or value to the regulation.*

0001-20
Section 1774.2, subdivisions (b)(1) through (5), should be revised to include additional information. Specifically, testing gas pressure and composition, release history, all testing methods, and a flow/pressure diagram. Further, the adjective "describe" should be used in place of indicate because indicate is meaningless. Additionally, the term "product" should be defined.

Response: *Rejected. Testing gas and composition only apply to pipelines undergoing pneumatic pressure testing. The operator may choose any appropriate test gas and test pressure when pneumatically pressure testing gas pipelines, provided that applicable statutes, regulations, and/or standards are followed, and the Division approves the testing methodology. However, test gas need not be documented in the pipeline management plan.*

Documentation of a pipeline's leak history is currently required by Section 1774.2, subdivision (b)(1). Documentation of testing frequency and methodology and schedules are currently required by Section 1774.2, subdivision (b)(2). Further, a fluid flow schematic is already required in an operator's spill contingency plan pursuant to Section 1772.9, subdivision (f)(10), and as construction information required pursuant to Section 1777.3. The Division does not believe that the substitution of "describe" for "indicate" or a definition of "product" would add clarity or value to the regulation.

0001-21
The commenter suggests deleting the reference to CCR Title 8, Section 6533 in section 1774.2, subdivision (d).

Response: *Rejected. The reference to California Code of Regulations, Title 8, Section 6533 provides operators with an option for achieving compliance with Cal/OSHA and the Division's regulatory schemes using the same Pipeline Management Plan, where appropriate. The Division will review a plan submitted pursuant to Cal/OSHA requirements on a case-by-case basis to ensure adequacy.*

OTHER COMMENTS

0001-5
"Environmental quality" should be added to the general life, property, and mineral resources goals of the Division.

Response: *This comment is not specifically directed at the agency's proposed action and, thus, is outside the scope of this rulemaking.*

0002-9
Periodic, possibly bi-annual, un-announced compliance reviews should be conducted, especially in areas with very old infrastructure, to ensure operators are conducting proper inspections and testing, and their reported results are accurate.

Response: *Enforcement is an important part of the Division's statutory mandate, and the Division has broad authority to order non-compliant operators to conduct required tests and inspections and may issue civil penalty orders, where appropriate. Specific enforcement directives, however, are outside the scope of the rulemaking.*

0002-12
All information submitted to the State by operators should be submitted under the penalty of perjury.

Response: *This comment is not specifically directed at the agency's proposed action and, thus, is outside the scope of this rulemaking.*