CALIFORNIA STATE FIRE MARSHAL

PIPELINE SAFETY DIVISION

Requirements of Pipelines near an Environmentally and Ecologically Sensitive Area in the Coastal Zone Procedure

OBJECTIVE:

Assembly Bill (AB) 864 (Williams, Chapter 592, Statutes of 2015) was chaptered into law in 2015 and requires the Office of the State Fire Marshal (OSFM) to develop regulations by July 1, 2017 for the requirement of pipelines near an Environmentally and Ecologically Sensitive Area in the Coastal Zone.

AUTHORITY/JURISDICTION:

Government Code §51013.1 and Title 19, California Code of Regulations, Chapter 14, Article 2A.

PROCESS:

The OSFM requirements of pipelines near an Environmentally and Ecologically Sensitive Area in the Coastal Zone will ensure compliance with federal and State regulations, enhance public safety, protect California's vital natural resources, and reduce the risk of future jurisdictional hazardous liquid pipeline accidents. This procedure is intended to outline the requirements that hazardous liquid pipeline operator shall comply to reduce the consequence of jurisdictional hazardous liquid pipeline releases.

The process consists of the following components:

1. Determine "near" the Environmentally and Ecologically Sensitive Areas in the Coastal Zone.

Operators must review the identified Environmentally and Ecologically Sensitive Areas in the Coastal Zone to determine if their pipelines are ½ mile or less of distance from these environmentally and ecologically sensitive areas.

2. The Office of Spill Prevention and Response (OSPR) Mapping Data

The Environmentally and Ecologically Sensitive Areas in the Coastal Zone is identified and developed by the Office of Spill Prevention and Response (OSPR) and it can be downloaded from:
https://www.wildlife.ca.gov/OSPR/Science/GIS

3. Notice of Any New Construction or Retrofit of Pipeline

An Operator is required to notify the OSFM Pipeline Safety Division (PSD) of any new construction of a jurisdictional hazardous liquid pipeline, or for any replacement or retrofit of a jurisdictional hazardous liquid pipeline, located ½ mile or less from an environmentally and ecologically sensitive area.

The Operator is required to complete and submit for Form PSD-103 (Notice of Intrastate Hazardous Liquid Pipeline Construction) no later than 60 days before construction begins in order for the OSFM PSD to review the designs, construction plans, and procedures. OSFM PSD will conduct appropriate inspections. A copy of Form PSD-103 can be downloaded from:
http://osfm.fire.ca.gov/pipeline/pipeline

4. Risk Analysis Requirement

The risk analysis shall identify the potential applications of best available technology including, but not limited to, leak detection technology, automatic shutoff systems and remote controlled sectionalized block valves, Emergency Flow Restricting Devices (EFRD) or any combination of these technologies, and demonstrate these technologies achieve a satisfactory level of risk mitigation for an oil spill.

The operator shall use the results of their risk analysis to identify the best available technology which provides an adequate reduction of the amount of oil potentially released in a pipeline spill for their system.

When identifying the equipment or combination of equipment which constitutes best available technology, the operator shall consider the capabilities, benefits, risks, and limitations of each type or combination of equipment.

At a minimum, the following should be considered for each type of equipment:

a. Leak Detection System(s) (LDS) Risk Analysis Requirements

1. When conducting their risk analysis, the operator shall consider the consequences, likelihood, threats, frequency, and other risk factors identified in Annex A of American Petroleum Institute (API) RP 1175 (First Edition, December 2015).

2. The risk analysis shall identify the LDS, and or Computational Pipeline Monitoring (CPM) that will demonstrate a reduced response time.

3. When considering whether a Leak Detection System is the best available technology, the operator shall consider the guidelines and checklist contained in API RP 1175 Sections 4, 6.2, 6.6, 6.7, 6.8, Annex A, B, and API RP 1130 Section 1.5.

b. Automatic Shutoff System(s) Risk Analysis Requirements

1. When conducting their risk analysis, the operator shall consider the consequences, likelihood, threats, leak frequency, and other risk factors identified in their Automatic Shutoff System(s).

The risk analysis shall identify the Automatic Shutoff System(s) that will demonstrate a reduced impact to the environmentally sensitive areas in the coastal zone to protect state waters and wildlife.

2. When considering whether an Automatic Shutoff System is the best available technology, the operator shall consider whether the system can safely shutdown the pipeline system(s) without substantially increasing the risk of unintended consequences, such as system surge or overpressure.

c. Requirements for remote controlled sectionalized block valve(s) and EFRDs (as defined under Code of Federal Regulations, Title 49 195.450)

When considering remote sectionalized valves or EFRDs as the best available technology, the operator shall consider the following:

1. Swiftness of leak detection and shutdown capabilities
2. The volume that can be released

3. Topography or pipeline profile
4. Proximity to power sources
5. Location of nearest Operator's response personnel
6. Pipeline length
7. Risks of creating a surge situation
8. The availability of useable space for placement of remote controlled valves.
9. Factors in 49 CFR, 195.452(i).

5. Assessment of Risk Analysis

To assess the adequacy of the operator's risk analysis, the OSFM shall consider the following:

a. Use the guidelines and checklist contained in API RP 1175, Sections 6.6, 6.7, 6.8, Section 7, Annex A, Annex B, and API RP 1130 (Third edition, December 2007, reaffirmed April 2012), Section 1.5
b. Review and evaluate the risk analysis performed on the pipeline
c. Consider the effectiveness and engineering feasibility of the best available technology
d. The overall Leak Detection Program, where applicable
e. The effectiveness of the Automatic Shutoff System
f. Provide a written notification to the operators after review of the Risk Analysis

6. Leak Detection System Testing Requirements

For LDS, the operator shall test the leak detection capability and leak limitation effectiveness every 3 years in accordance to API RP 1175, Section 8 (Testing) from the date of installation or initial operation. If there is a CPM that is used as part of the LDS, the operator shall test according to API RP 1130, Section 6 (CPM Operation, Maintenance, and Testing).

7. Automatic Shutoff System Testing Requirements

The operators shall annually test the components of the system and the overall effectiveness of the system. Where applicable, Operators shall have a procedure to adequately test the system(s) and system(s) components and will be developed utilizing industry best practices along with equipment manufacturer recommendations.

Operators shall actuate field equipment at least once a year for testing of the physical components, not to exceed 15 months. Testing may be done while the system is static to verify the actuation of remote command logic without causing undue strain on the pipeline.

8. Test Failures

a. If an LDS or CPM system fails to detect a leak or activate as designed for the pre-determined test, the operator will have the opportunity to correct the problem(s) and retest. If the system fails the retest, it will be counted as a second failure. As a result, Section 2029(c) of Tittle 19, California Code of Regulations (CCR) will apply, which requires a new risk analysis and review of best available technology.

b. Failure of individual field components during a test will not be considered a failure, the field component must be replaced as soon as practicable and the test restarted. If a component continues to fail, a system review must be conducted and modifications made in a judicious manner to correct the issue. A re-test must be performed. Additional failures will then be considered a failure.

c. Annual test of the LDS or CPM is required for the next 3 years, if the test results indicate a failed or impaired leak detection capability.

9. Leak Detection System Training Requirements

When providing training for LDS or CPM systems the operators shall use API RP 1175, Section 11 (Roles, Responsibilities, and Training) and where applicable, API RP 1130, Section 6.5 (Pipeline Controller Training and Retraining).

10. Record Retention

a. Operator shall maintain the Risk Analysis for the life of the pipeline.

b. For the purpose of this regulation, the operator(s) shall maintain records, other than the Risk Analysis, for OSFM to review during annual inspections to demonstrate compliance.

c. Test failures shall be retained for two testing cycles. Operators shall retain at a minimum the following test records: (1) the most current test data. (2) Prior test data.

d. Operator(s) shall maintain the required annual test records for a period of six years.

11. Exemption for Pipeline Located Outside of the Coastal Zone

a. The request for an exemption from the provisions of this chapter shall be submitted to the OSFM at least 180 days prior to the July 1, 2018 deadline.

b. The risk analysis shall include, but not be limited to, the following factors:
(1) A pipeline shall be considered to have the potential to impact an Environmentally and Ecologically Sensitive Area based on the geographical and locational aspects of the pipeline route and operations. Such aspects shall include, but not be limited to, proximity to an Environmentally and Ecologically Sensitive Area, land contour and local drainage properties.
(2) Terrain surrounding the pipeline. Operators shall consider the contour of the land profile and if it could allow the liquid from a release to enter a Coastal Zone.
(3) Drainage systems such as small streams and other smaller waterways that could serve as a conduit to the Coastal Zone.
(4) Crossing of roadways with ditches along the side. The ditches could carry a spillage to a waterway.
(5) The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.) Highly volatile liquids develop into a gaseous state when exposed to the atmosphere. A spillage could create a vapor cloud that could settle into the lower elevation of the ground profile.
(6) Physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance.
(7) Operating conditions of the pipeline (pressure, flow rate, etc.). Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure.
(8) The hydraulic gradient of the pipeline.
(9) The diameter of the pipeline, the potential release volume, and the distance between the isolation points.
(10) Potential physical pathways between the pipeline and the Coastal Zone.
(11) Response capability (time to respond, nature of response).
(12) Potential natural forces inherent in the area like flood zones, earthquakes, subsidence areas, etc.
(13) Natural and manmade barriers.