# CAL FIRE - OFFICE OF THE STATE FIRE MARSHAL

## Instructions for Form PSD-101 (July 1, 2016)

## CALIFORNIA INTRASTATE PIPELINE OPERATOR ANNUAL REPORT

**GENERAL INSTRUCTIONS**

All section references are to Title 49 of the Code of Federal Regulations (49 CFR) and the California Elder Pipeline Safety Act. The Office of the State Fire Marshal (OSFM) Form PSD-101 is required per Government Code §51015.1(a) and Title 19, California Code of Regulations, Chapter 14, Article 2.

By May 1st of each year, the OSFM will provide each California intrastate pipeline operator a Form PSD-101. The Form PSD-101 will be divided by OSFM Inspection Unit and will include each OSFM jurisdictional pipeline that was included in the OSFM Annual Questionnaire for the previous year. Please use a separate page to identify additional pipelines.

Each pipeline operator is required to annually complete and submit a Form PSD-101 to OSFM by July 1st that represents the operator's pipeline assets as of December 31st of the previous calendar year. The completed Form PSD-101 will identify scheduled projects for the next calendar year and will contain inspection data and validated inspection results from the previous calendar year for each jurisdictional pipeline. Operators must maintain documentation to substantiate the information provided in their Form PSD-101.

**SUBMISSION METHOD**

The OSFM will send an electronic version of each Form PSD-101 to the operator staff that has been designated to complete the annual OSFM Pipeline Questionnaire. The Form PSD-101 will be populated with the company information (Name, ID, Inspection Units, and CSFM Line ID) that is currently on file with the OSFM. If any information included in the form is incorrect, please enter the correct information using **RED** text to identify the change.

Each completed Form PSD-101 must be emailed to the Pipeline Safety Division Staff Service Analyst at FirstName.LastName@fire.ca.gov. If the operator is unable to email the Form PSD-101, the operator will need to print a copy and mail the form to the Pipeline Safety Division Lakewood Office at:

CAL FIRE – Office of the State Fire Marshal
Pipeline Safety Division
3950 Paramount Blvd., Suite 210
Lakewood, CA 90712

NOTE: Form PSD-101 must be post marked no later than July 1st.

**COMPANY INQUIRY** – The following questions refer to the operator's overall intrastate hazardous liquid pipeline systems.

## COMPANY OPERATIONS

| Annual Report Code |
|---|

CO.01 Have there been any asset acquisitions or divestitures in the last calendar year?

Select “Yes” from the drop-down menu, if the operator had an acquisition or divestiture of an OSFM jurisdictional hazardous liquid pipeline or facility during the previous calendar year.

CO.02 Are there any new construction projects scheduled for the next calendar year?

When answering question CO.02, operators must consider all new construction projects that are scheduled for the next calendar year. New construction projects include the design, construction, or testing of new pipelines, facilities, or breakout tanks that will be under the jurisdiction of the OSFM. Do not include replacement or relocation projects on existing pipelines. Replacement or relocation projects will be captured in the Annual Report Code PR.01 for each pipeline.

Select “Yes” from the drop-down menu, if the operator has a new construction project scheduled for the next calendar year.

CO.03 Are there any spill drills planned or scheduled for the next calendar year?

Select “Yes” from the drop-down menu, if the operator has planned or scheduled for the next calendar year a spill drill for any pipeline in this inspection unit.

**PIPELINE INQUIRY** – The following questions refer to each of the operator's intrastate hazardous liquid pipelines.

## PIPELINE OPERATIONS:

PIPELINE SPECIFICATIONS

PS.01 Total length of pipeline (miles)

Enter the total length of each pipeline measured in miles to 2 decimal places.

PS.02 Could the pipeline affect High Consequence Areas (HCA's)?

Select "Yes" from the drop-down menu, if any part of the pipeline could affect a High Consequence Area (HCA) as defined in Title 49 CFR, Part 195.450.

PS.03 If yes, what are the total miles that could affect HCA's?

Enter the total miles of each pipeline that could affect a HCA.

PS.04 What is the maximum temperature of the product being transported?

Enter the maximum temperature in Fahrenheit of the product transported in each pipeline.

PS.05 What is the highest Maximum Operating Pressure (MOP) on the pipeline?

Enter the highest MOP for the entire pipeline.

PS.06 What is the limiting factor for the MOP?

Enter the limiting factor that was used to determine the MOP of each pipeline. Use the drop-down menu to select from the following: Internal Design Pressure of the Pipe; Design Pressure of any other Component; 80% of the Test Pressure; 80% of the Factory Test Pressure of any component as defined in Title 49 CFR, Part 195.406.

What commodities are transported or contained in this pipeline?

Enter the commodity transported in each pipeline. Use the drop-down menu to select from the following: Crude Oil; Refined Products (non-HVL); Jet Fuel (only); Natural Gasoline; Natural Gas Liquids; Carbon Dioxide; Anhydrous Ammonia; Highly Volatile Liquid; Fuel Grade Ethanol; Biodiesel Blend; Water; Nitrogen; Drilling Mud; Natural Gas. If multiple commodities are transported or are contained in the pipeline, use PS.07 through PS.10 to select all commodities that apply as defined in Title 49 CFR, Part 195.2.

PS.07 Commodity #1
PS.08 Commodity #2
PS.09 Commodity #3
PS.10 Commodity #4

PS.11 Are there any Breakout Tanks associated with this pipeline?

Select "Yes" from the drop-down menu, if there are any Breakout Tanks that meet the definition in Title 49 CFR, Part 195.2 and are associated to this pipeline.

<u>MILES OF PIPE BY TYPE</u> – All miles of pipe shall be reported to 2 decimal places. Do not use feet to report miles of pipe.

MP.01 Buried Pipe

Enter the total miles of buried pipe for each pipeline.

MP.02 Aboveground Pipe

Enter the total miles of aboveground pipe for each pipeline.

MP.03 Coated Pipe

Enter the total miles of coated pipe for each pipeline.

MP.04 Bare Pipe

Enter the total miles of bare pipe for each pipeline.

MP.05 Insulated Pipe

Enter the total miles of insulated pipe for each pipeline.

MP.06 Pre-1970 Electric Resistance Welded (ERW) Pipe

Enter the total miles of pre-1970 ERW pipe for each pipeline.

MP.07 Operating at greater than 20% Specified Minimum Yield Strength (SMYS)

Enter the total miles of pipe operating at greater than 20% SMYS for each pipeline.

MP.08 Operating at less than or equal to 20% SMYS

Enter the total miles of pipe operating at less than or equal to 20% SMYS for each pipeline.

MP.09 Operating at an unknown stress level

Enter the total miles of pipe operating at an unknown stress level for each pipeline.

## INTEGRITY TESTING:

ASSESSMENT INFORMATION

IM.01 What is the continual Integrity Assessment method for the prior calendar year?

Enter type of integrity assessment that is performed on each pipeline according to the operators Integrity Management Plan. If the pipeline is not covered under Title 49 CFR, Part 195.452, use the required testing interval from the California Government Code, Section 51013.5.

Use the drop-down menu to select from the following: In-Line Inspection; Hydrostatic Pressure Test; Other.

IM.02 When is the next Integrity Inspection due?

Enter the date when the next integrity assessment is due according to the operators Integrity Management Plan. If the pipeline is not covered under Title 49, Part CFR 195.452, use the required testing interval from the California Government Code, Section 51013.5.

IN-LINE INSPECTIONS – If the continual Integrity Assessment method selected for question IM.01 was Hydrostatic Pressure Test or Other, skip questions IL.01 through IL.23.

IL.01 When was the most recent In-Line Inspection (ILI) completed?

Enter the date of the most recent ILI. If multiple ILI tool runs were conducted to complete the inspection of the entire pipeline, use the following format:

04/01/2009 (10"), 05/01/2010 (12"), 02/01/2009 (16")

IL.02 Has the final ILI evaluation report been received from the most recent ILI?

If No, answer the remainder of the questions in this section based on this previous ILI and its associated final ILI evaluation report.

IL.03 When was the previous ILI completed?

Enter the date the previous ILI was completed. If multiple ILI tool runs were conducted to complete the inspection of the entire pipeline, use the following format:

04/01/2009 (10"), 05/01/2010 (12"), 02/01/2009 (16")

Type(s) of ILI tool(s) used:

If multiple ILI tools were used in the above referenced ILI, use the IL.04-IL.07 to select all that apply.

IL.04 Tool Type #1
IL.05 Tool Type #2
IL.06 Tool Type #3
IL.07 Tool Type #4

Enter type of ILI tool used in the last inspection. Use the drop-down menu to select from the following: Corrosion or Metal Loss Tool; Dent or Deformation Tools; Crack or Long Seam Defect Detection Tool; Other Internal Inspection Tool. If multiple ILI tool runs were conducted using different tool types to complete the inspection of the entire pipeline, please use a separate page to identify the different ILI tool types for each ILI tool run. [Title 49 CFR, Part 195.452(j)(5)]

IL.08 Were there any external corrosion anomalies identified from the last validated ILI evaluation based on the operator's repair criteria, both within a segment that could affect a HCA and outside of a segment that could affect a High Consequence Area (HCA)?

Select “Yes” from the drop-down menu, if there were any external corrosion anomalies identified based on the operator’s repair criteria even if those criteria are different from the repair criteria in Integrity Management (IM) regulations pursuant to Title 49 CFR, Part 195.452 applicable to anomalies in pipeline segments that could affect HCA per Title 49 CFR, Part 195.452 (i.e., require repair of damage more or less significant). The operator’s criteria for anomalies in segments that <u>could affect a HCA</u> must be at least as conservative as those required by the IM regulations.

IL.09 Were there any internal corrosion anomalies identified from the last validated ILI evaluation based on the operator's repair criteria, both within a segment that could affect a HCA and outside of a segment that could affect a HCA?

Select “Yes” from the drop-down menu, if there were any internal corrosion anomalies identified based on the operator’s repair criteria even if those criteria are different from the repair criteria in IM regulations applicable to anomalies in pipeline segments that could affect HCA per Title 49 CFR, Part 195.452 (i.e., require repair of damage more or less significant). The operator’s criteria for anomalies in segments that <u>could affect a HCA</u> must be at least as conservative as those required by the IM regulations.

IL.10 Were there any dent or gouge anomalies identified from the last validated ILI evaluation based on the operator's repair criteria, both within a segment that could affect a HCA and outside of a segment that could affect a HCA?

Select "Yes" from the drop-down menu, if there were any dents or gouges identified based on the operator's repair criteria even if those criteria are different from than the repair criteria in IM regulations applicable to anomalies in pipeline segments that could affect HCA per Title 49 CFR, Part 195.452 (i.e., require repair of damage more or less significant). The operator's criteria for anomalies in segments that could affect a HCA must be at least as conservative as those required by the IM regulations.

IL.11 Were there any cracks or crack-like anomalies identified from the last validated ILI evaluation based on the operator's repair criteria, both within a segment that could affect a HCA and outside of a segment that could affect a HCA?

Select "Yes" from the drop-down menu, if there were any cracks or crack-like anomalies identified based on the operator's repair criteria even if those criteria are different from than the repair criteria in IM regulations applicable to anomalies in pipeline segments that could affect HCA per 49 CFR 195.452 (i.e., require repair of damage more or less significant). The operator's criteria for anomalies in segments that could affect a HCA must be at least as conservative as those required by the IM regulations.

IL.12 Were there any manufacturer defect anomalies identified from the last validated ILI evaluation based on the operator's repair criteria, both within a segment that could affect an HCA and outside of a segment that could affect a HCA?

Select "Yes" from the drop-down menu, if there were any manufacturer defect anomalies identified based on the operator's repair criteria even if those criteria are different from than the repair criteria in IM regulations applicable to anomalies in pipeline segments that could affect HCA per 49 CFR 195.452 (i.e., require repair of damage more or less significant). The operator's criteria for anomalies in segments that could affect a HCA must be at least as conservative as those required by the IM regulations.

IL.13 Are the same repair criteria utilized in HCA's and non-HCA's?

Select "Yes" from the drop-down menu, if the operator uses the same repair or response criteria for anomalies identified in HCA's and non-HCA's. Select "No" from the drop-down menu, if the operator uses different repair/response criteria for anomalies identified in HCA's and non-HCA's.

**For the following questions,** include all actions taken during the previous calendar year that resulted from information obtained during an ILI inspection. This should also include actions taken as a result of ILI inspections conducted during prior years and for which all required actions were not completed during the year of the inspection.

IL.14 The total number of anomalies excavated in the previous calendar year because they met the operator's criteria for excavation.

Enter the total number of anomalies excavated in the previous calendar year based on the operator's criteria for excavation. Enter a value for each pipeline, using zero (0) as appropriate.

IL.15 Total number of anomalies repaired in the previous calendar year that were identified by ILI based on the operator's repair criteria, both within a segment that could affect an HCA and outside of a segment that could affect a HCA.

Enter the total number of anomalies repaired based on the operator's repair criteria even if those criteria are different from than the repair criteria in IM regulations applicable to anomalies in pipeline segments that could affect a HCA per 49 CFR 195.452 (i.e., require repair of damage more or less significant). The operator's criteria for anomalies in segments that <u>could affect a HCA</u> must be at least as conservative as those required by the IM regulations.

Include in the total only those anomalies actually repaired, not those for which other mitigated actions, such as recoating, were taken or those anomalies eliminated by pipe replacement.

Enter a value for each pipeline, using zero (0) as appropriate.

IL.16 Was a pressure reduction taken or the pipeline shut down in response to remediating a condition identified from an integrity assessment?

Select "Yes" from the drop-down menu, if a pressure reduction was taken or the pipeline was shut down in response to remediating a condition identified from an integrity assessment. Select "No" from the drop-down menu, if there was no need to reduce the pressure or shutdown the pipeline in response to remediating a condition identified from an integrity assessment.

Total number of conditions repaired WITHIN A SEGMENT THAT COULD AFFECT AN HCA meeting the definition of:

IL.17 1. "Immediate repair conditions" [49 CFR 195.452(h)(4)(i)]

Report only the anomalies in pipeline segments that could affect an HCA that were repaired because they met the "immediate repair conditions" criteria in the IM regulations 49 CFR 195.452(h)(4)(i). Enter a value for each pipeline, using zero (0) as appropriate.

IL.18 2. Other repair conditions required by 49 CFR 195.452

Report only the anomalies in pipeline segments that could affect an HCA that were repaired because they met the a repair criteria in the IM regulations 49 CFR 195.452(h)(4) <u>other than</u>

an “immediate repair conditions". Enter a value for each pipeline, using zero (0) as appropriate.

IL.19 Is the operator waiting for permits to remediate anomalies?

Select “Yes” from the drop-down menu, if the operator is waiting for permits to remediate an anomaly identified on the pipeline during the last ILI evaluation.

If Yes:

IL.20 1. How many days has the permitting process been in progress?

Enter the number of days since the operator has submitted the permit to remediate the anomaly. If there are multiple anomalies on this pipeline waiting on permits to be remediated, than enter the information for the anomaly that has been in the permit process the longest.

IL.21 2. Has the pressure reduction exceeded 365 days?

Select “Yes” from the drop-down menu, if a pressure reduction taken on this pipeline in response to remediating a condition identified from an integrity assessment exceeded 365 days.

If Yes:

IL.22 1. Has the operator notified PHMSA or OSFM?

Select “Yes” from the drop-down menu, if the operator has notified PHMSA and OSFM of a pressure reduction taken on this pipeline in response to remediating a condition identified from an integrity assessment that exceeded 365 days.

IL.23 COMMENTS:

Use this text box to further explain or clarify answers given in the IN-LINE INSPECTIONS Section.

HYDROSTATIC PRESSURE TESTING

HP.01 Date of last pressure test (include CSFM Test ID)

Enter the date of the last pressure test completed on the entire pipeline and enter the CSFM Test ID assigned to this pressure test. If multiple hydrostatic pressure tests were conducted to complete the inspection of the entire pipeline, use the following format:

04/01/2009 (CSFM Test ID 00-000), 05/01/2010 (CSFM Test ID 00-000), 02/01/2009 (CSFM Test ID 00-000)

HP.02 Was a spike test completed?

Select “Yes” from the drop-down menu, if a spike test was completed during the last pressure test completed on the entire pipeline.

HP.03 Were there any pressure test failures (ruptures and leaks) during the last pressure test?

Select “Yes” from the drop-down menu, if a pressure test failure occurred on the last pressure test completed on the entire pipeline. Small leaks on pipe valves or flange gaskets are not considered a pressure test failure.

## PREVENTATIVE and MITIGATIVE MEASURES:

CONTROL ROOM MANAGEMENT/SCADA

CR.01 Is a Supervisory Control and Data Acquisition (SCADA) system used to monitor or control all or part of this pipeline?

Select “Yes” from the drop-down menu, if a Supervisory Control and Data Acquisition (SCADA) system, as defined by 49 CFR 195.2, is used to monitor or control all or part of the pipeline.

CR.02 Is there a control room, as defined in 49 CFR 195.2, associated with this pipeline?

If Yes,

CR.03 Where is the primary control center located?

Enter the City and State of the primary control center.

LEAK DETECTION SYSTEM

LD.01 Is a Computational Pipeline Monitoring (CPM) leak detection system used on this pipeline?

Select “Yes” from the drop-down menu, if a Computational Pipeline Monitoring (CPM) leak detection system, as defined by 49 CFR 195.2, is used on this system.

LD.02 If a CPM leak detection system is not used, describe how leaks are detected on the pipeline?

Use this text box to explain how leaks and ruptures are detected on this pipeline.

CORROSION CONTROL

CC.01 What type of cathodic protection is used on this pipeline?

Use the drop-down menu to select from the following: Galvanic Anode, Impressed Current; Both Galvanic Anode and Impressed Current; None.

CC.02 When was the last close-interval survey performed on this line?

Enter the date of the last close-interval survey (CIS) performed on any portion of the pipeline. Close interval surveys are a detailed potential survey conducted on a pipeline to assess the effectiveness of the cathodic protection system. Enter “Never”, if a CIS has not been conducted on this pipeline.

CC.03 Has the corrosive effect of the hazardous liquid on the pipeline been investigated?

Select “Yes” from the drop-down menu, if the operator has investigated the corrosive effect of the hazardous liquid transported in the pipeline.

CC.04 Are corrosion inhibitors used to mitigate internal corrosion?

Select “Yes” from the drop-down menu, if corrosion inhibitors are used to mitigate internal corrosion of the pipeline.

NATURAL FORCE RISKS

NF.01 Does this pipeline cross known active faults?

Select “Yes” from the drop-down menu, if the pipeline crosses a known active fault. The OSFM recommends the operator use the USGS Quaternary Fault and Fold Database to verify if the pipeline crosses an active fault. This is an online database found at http://Qfaults.cr.usgs.gov/ that contains information on faults and associated folds that are believed to be sources of earthquakes greater than magnitude 6 (M>6). The database is limited to structures with documented activity during the Quaternary (past 1.6 million years) because this period of geologic time is most relevant for studies of active earthquake faults

## PROJECTS

PROJECTS SCHEDULED (Next Calendar Year)

PR.01 Relocation/Replacement/Reconditioned Projects

Select “Yes” from the drop-down menu, if any of the following projects are scheduled for the next calendar year:

1) A relocation or replacement of any portion of the pipeline that is greater than 1,000 feet in total length.
2) A project to recondition or recoat any portion of the pipeline that is greater than 1,000 feet in total length.

PR.02 Cathodic Protection (CP) Projects

Select “Yes” from the drop-down menu, if a cathodic protection project is schedule for the next calendar year that is needed to comply with 49 CFR 195.571 and is anticipated to cost more than $50,000.