Bois d’Arc Energy

Response to Notice of Amendment dated 11/17/2008

NOA Item 1:

§ 195.452(e) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?...

(i)(2) Risk analysis criteria. **In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:…**

DOT Statement:

A comprehensive procedure for risk analysis must be developed for monitoring internal corrosion in the pipeline. This procedure must have the capability to produce results that allow the operator to understand the overall risk to its pipeline system. The relative importance of threats and their associated consequences that make up this risk profile should also be understood to support effective decision-making regarding the overall management of pipeline risk.

Reply:

BDA has updated its Corrosion Control Plan that includes a process for monitoring internal corrosion in the company's pipelines. This process includes processes and procedures for corrosion control (atmospheric, external and internal) prevention (including monitoring) and maintenance. Inspection and test forms have been updated to better capture inspection and test data as well as any corrective actions or future maintenance (including prevention) activities associated with corrosion control.

Specific to internal corrosion, the information from these forms as well as the information from the company's operating practices and conditions, internal pipeline information database; the company's risk model (See NOA Item 3 below) takes the following factors regarding internal corrosion into consideration:

1. Year of installation
2. Bell hole results (if applicable)
3. Leak history
4. Wall thickness
5. Diameter
6. Past hydrostatic test information
7. Liquid analysis
8. Bacteria culture results
9. Corrosion detection devices (coupons, probes, etc.)
10. Operating parameters
11. Operating stress level (%SMYS)

The result of these continuous improvement efforts is that BDA has been able to tightly integrate the results of its corrosion control measures into its risk review, assessment and ranking model. This allows BDA to full integrate actual field data into its review, analysis and corrective actions associated with corrosion related threat potentials. Overall, this improves the effectiveness of its corrosion control program.

NOA Item 2:

§ 195.452(e) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?...

An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

***(g) What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure…**

***(i)(2) Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:…**

DOT Statement:

BDA must develop a process to ensure that their risk analysis model will provide consistent collection and integration of data and that a "could affect HCA" pipeline segment is defined such that meaningful results can be obtained. A numerical characterization of risk (likelihood x consequences) for a "could effect" segment based on the probability of failure will not be consistent with a relative risk methodology discussed during the audit.

Response:

The company's Integrity Management Plan now states in section 8 the methodology used to determine "could affect" pipeline segments to be incorporated into the company's plan. The highlights are:

1. The company uses the OSRAM model to determine if an offshore spill could reach the shore or any identified High Consequence Areas (HCA) and/or Environmentally Sensitive Areas (ESA).
2. An HCA / ESA impact probability of 25% within a 10 day period is the threshold used in calculations. If the probability of impact is 25% or higher the pipeline segment is considered a "Could Affect" pipe segment and is included in the Integrity Management Program.
3. Spill movement is calculated using the procedure in 40 CFR 112 Apx C and takes pipeline size, length, volume and other operating parameters into consideration.
4. Wind speed is calculated using NOAA average wind data for Lake Charles, LA.
5. The results of all modeling will produce impact maps.
6. Spill quantity is determined by the maximum drain down volume that could occur on the specific segment plus 15 minutes of maximum flow into the pipe before the pumps are shut

down. Based on operating conditions and facility staffing the 15 additional minutes over drain down should allow adequate time for identification and imitation of corrective measures (including the shutting in of the pipeline).

7. An elliptical-shaped spill shape is assumed and crude oil physical properties are used in the spill trajectory model.
8. A guillotine line rupture is assumed.
9. Quantity spilled, average spill thickness, and the area spilled are calculated using the "ARCHIE" program.

The data used by these calculations come from the company's internal pipeline records that are maintained in a database along with other risk factors of the pipeline. Reporting and analysis is much easier using this process.

The company's risk model (as described in NOA Item 3 response) fully incorporates the results of this analysis with the risk model elements to better characterize the actual likelihood and consequence of a threat potential as well as an overall threat score. Collectively, this process provides for a better integration of data, risk analysis and overall understanding of pipeline threat related risks.

NOA Item 3:

§ 195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

(i)(2) Risk analysis criteria. **In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:…**

DOT Statement:

BDA's risk analysis results did not adequately identify appropriate risk factors and must substantiate all pipeline threats. BDA must also expedite the integration of this information for providing meaningful results such as in threat/driver reports. As the risk analysis process evolves, BDA's must ensure that all input parameters are used to appropriately characterize threats to the integrity of the pipeline and include risk factors required by **§195.452(e)(1)**

Response:

BDA has reviewed its previous risk model and developed a new database risk model compliant with 195.452(f). This model incorporates nationwide pipeline failure data (as recommended in the audit) using proper probabilistic methods to determine a baseline probability. This baseline probability for a given threat is then increased and/or decreased depending on actual operating conditions and mitigating factors related to the pipeline segment being evaluated. This process has been developed in accordance with the data requirements of B31.8S-2004. We believe this will better reflect the accuracy of the risk model by incorporating actual pipeline data and conditions into the risk modeling and evaluation process while retaining the ability to account for all required factors.

The company will now be able to manage all acquired risk related pipeline information within the same database, allowing a tighter integration and analysis of the pipeline data set; thereby producing meaningful and specific reports based on threats, potential threats and overall threat summaries. This also allows for a change in a treat or overall threat rankings to occur when pipeline and / or external conditions change. Through this integrated risk identification and evaluation process, BDA can better manage the overall integrity management program (including risk identification, evaluation and corrective actions). The indices used in the database will be updated annually as the government releases pipeline incident statistics, which in turn will maintain and keep current the accuracy of the statistical analysis.

Based on the threat likelihood and consequence the pipeline rankings may or may not be changed. This methodology while using government published pipeline safety data sets is still considered a Relative Risk Model as it takes into consideration actual operating conditions and threats. From this point on, data will be integrated and updated periodically using the new model.

NOA Item 4:

(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?*

(3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors—length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

DOT Statement:

BDA's leak detection capability process must adequately specify procedures for acquiring data and its evaluation for assisting in the P&M decision basis and implement P&M measures. Evaluation of all modes of pipeline operation including slack line, static and transient conditions, lists for contacts, calls-outs and details regarding operator actions and reactions must be addressed in more detail and ensure it considers all of the factors in 195.452(i)(3).

Response:

The company has updated its procedures regarding leak detection in pipelines. For offshore hazardous liquids pipelines, the main parts are summarized below:

1. Right of Way surveys (visual) will be conducted a minimum of 26 times a year.
2. During these surveys, the surface conditions on or adjacent to each pipeline right of way will be checked for any or all of the following:
    a. Vegetation damage;
    b. Platform damage;
    c. Slicks;
    d. Boils; and / or
    e. Any other abnormality along the pipeline right of way.
3. Weather permitting, the pipeline right of way will be inspected each week by either aerial means or by boat during normal field operations and / or crew change.
4. In addition, the visual leak surveys, BDA balances its measured volumes from the departing facility to the inbound facility (within an acceptable margin of measurement error) to monitor r meter measurement variance that may indicate that the pipeline is experiencing fluid and / or pressure losses that may be associated with a pipeline failure.
5. Any identifiable condition that could result in a pipeline failure and/or release to the environment – the defined abnormal operating and emergencies would be initiated. It instructs the employee to take into consideration the type of product, size of pipeline, proximity to HCA, swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results in identifying and implementing its response actions.
6. These procedures define what steps to take in the event of a leak including but not limited to:

a. Leak detection,
b. Notification procedures (internal and external),
c. Situation Size up, safety and health precautions and initial response actions, and
d. Deployment of response resources (personnel and equipment).