DCOR

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BY: .....

March 13, 2020

Dustin Hubbard
Office of Pipeline Safety (OPS)
Pipeline & Hazardous Materials Safety Administration (PHMSA)
12300 W Dakota Ave., Suite 110
Lakewood, CO 80228

RE: Corrective Actions for CPF 5-2020-7001M
Notice of Amendment for Platform A and Rincon Onshore Separation Facility (ROSF)

Dear Mr. Hubbard:

DCOR, LLC (Company) submits the following corrective actions addressing the inadequacies found in the Company's plans or procedures during the 2019 DOT pipeline inspections of Platform A and Rincon Onshore Separation Facility (ROSF).

Our corrective action to each apparent inadequacy is as follow:

1. §195.452 Pipeline integrity management in high consequence areas.

(a) ...
(f) ***What are the elements of an integrity management program?*** **An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum each of the following elements in its written integrity management program:**
(1) ...
(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);...

DCOR Corrective Action

DCOR Procedure IMP-HL6, "Preventive & Mitigative Measures" was updated to reference the document (spreadsheet) titled "DCOR IM Program". A copy of the document was provided to the inspector at the time of the inspection. This document tracks the Company's risk analysis and continual mitigation efforts as required by 49 CFR Part 195.452.

A copy of Platform A's oil and gas pipeline risk analysis tracking titled "Risk Questionnaire & Determination" has been attached to this letter.

DCOR, LLC
290 Maple Court, Suite 290 • Ventura, CA 93003-3517 • 805-535-2000 • Fax 805-535-2100

2. §195.452 Pipeline integrity management in high consequence areas.

(a) ...
(j) ***What is a continual process of evaluation and assessment to maintain a pipeline's integrity?***
(1) ...
(2) ***Evaluation.*** An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

DCOR Corrective Action

DCOR Procedure IMP-HL6, "Preventive & Mitigative Measures" was updated to specify a frequency of evaluation of every 3 years as based on risk factors specific to the pipeline.

Additionally, the Company performs an in-line inspection of Platform A's oil and gas pipelines every two years as required by the Bureau of Safety and Environment Enforcement (BSEE) . Results are evaluated and submitted to BSEE for approval.

Should you have any questions or require additional information, please call Jerry Palo Jr. at (805) 535-2088.

Sincerely,

Robert L. Garcia
VP – Facilities & Process Engineering

Enclosure:

(1) DCOR Integrity Management Program Procedure, IMP-HL6 " Preventive & Mitigative Measures
(2) Integrity Management Program "Risk Questionnaire & Determination for Platform A"

cc: Office of Pipeline Safety (OPS)
Pipeline & Hazardous Materials Safety Administration (PHMSA)
Marion Garcia

cc: J. Penny
R. Bautista
J. Parcher
S. Knight
D. McDermott
J. Palo Jr.

PREVENTIVE & MITIGATIVE MEASURES

49 CFR Part 195.452(i)

6.1 Summary
6.2 General Requirements and Risk Analysis Criteria
6.3 Leak Detection
6.4 Emergency Flow Restricting Devices (EFRDs)
6.5 Mitigative Options
6.6 Implementation
6.7 Records
6.8 Related References and Documents

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49 CFR Part 195.452(i)

6.1 Summary

An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect an HCA and USA. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of CP where corrosion is a concern, establishing shorter inspection intervals, installing Emergency Flow Restricting Devices (EFRD) and leak detection systems (LDS), providing additional training to personnel on response procedures, conducting drills with local emergency responders, and adopting other management controls.

All Company hazardous liquid pipelines originating in the Pacific OCS Region (POCSR) are reassessed for integrity every two years as required by the Bureau of Safety and Environmental Enforcement (BSEE).

All Company hazardous liquid pipelines originating in State Waters (California) are reassessed for integrity every year as required by the State Lands Commission (SLC).

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6.2 General Requirements and Risk Analysis Criteria

The Company (DCOR, LLC) shall conduct a risk analysis of the pipeline system based on dominant risk factors. The risk analysis will be updated when information of these dominant risk factors changes significantly. When conducting the mitigative options risk analysis, the Company will include the benefits (e.g., risk reduction, reduction in threat to integrity, etc.) that preventive and mitigative measures are expected to produce.

In identifying the need for additional preventive and mitigative measures, the Company will evaluate the likelihood of a pipeline release and how a release could affect the surrounding area (consequences). Data used in the analysis shall be current and accurate. All of the following risk factors taken from 49 CFR Part 195.452(i)(2) will be considered when evaluating preventive and mitigative measures. If any risk factors are excluded, the basis for exclusion will be documented.

*Use spreadsheet "**DCOR IM Program**" in conducting the risk analysis.*

Minimum Risk Factors to Consider

- Product and flow rate;
- Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;
- Elevation profile;
- Characteristics of the product transported;
- Amount of product that could be released;
- Possibility of a spillage in a farm field following the drain tile into a waterway;
- Ditches alongside a roadway the pipeline crosses;
- Physical support of the pipeline segment (saddles, suspension bridge);
- Exposure of the pipeline to operating pressure exceeding established maximum operating pressure;

The Company will also consider the following risk factors as a function of leak detection and volumes, product being transported and pump rates, pressures, proximity and location to HCA/USA and proximity to specific residential locations while considering leak identification characteristics such as detection times, nearest manned facilities or response personnel, leak history, and analysis results:

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- External corrosion;
- Internal corrosion;
- Third-party damage (TPD);
- Operator error;
- Equipment failures;
- Natural forces damage;
- Stress-corrosion cracking (SCC);
- Materials problems;
- Construction errors;
- Different operating modes;

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6.3 Leak Detection System (LDS)

The Company will evaluate the capability and effectiveness of the leak detection system (LDS) and the locations of valves and EFRDs (if available) on its pipeline. The Company will identify and evaluate leak scenarios to adequately determine the overall effectiveness of leak detection capability (e.g., "most likely" in addition to "maximum possible"). The evaluation will consider all modes of line operations including slack line, idled line, and static conditions.

If a computational pipeline monitoring (CPM) technique is part of the leak detection systems, the Company will follow API 1130, "Computational Pipeline Monitoring for Liquids", in design, maintenance, controller training, and record-keeping practices. The Company will also consider enhancements to existing leak detection capability (e.g., increasing the monitoring frequency of existing techniques).

Operator Actions and Reactions

The Company will document operator actions and reactions associated with its leak detection system. This documented process will be in the form of operational procedures, and/or training materials.

These procedures and/or training materials will be written to assure that required actions are accomplished and if varying modes of pipeline operations require controllers or other personnel to engage/activate or mute/disable certain attributes of the overall leak detection capabilities. This documentation will include integration of emergency response procedures and incident mitigation plans with associated leak detection indications.

The procedures and/or training will include a process to assure that operating personnel have the authority and responsibility to initiate reaction measures and to shutdown the pipeline if warranted. If procedures require that operating personnel contact Operations prior to initiating response actions and/or shutting down the pipeline, the Company will assure that Operations is always promptly available for contact.

Leak Detection Evaluation

The evaluation of the system LDS, as a minimum, must consider the following factors:

- Length and size of the pipeline;
- Type of product carried;
- Pipeline's proximity to high consequence areas (USAs);
- Ability of the leak detection to react;
- Location of nearest response personnel;

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49 CFR Part 195.452(i)

- Leak history;
- Risk assessment results;
- Leak detection performance during transient conditions, and a strategy to manage any short-term reduction in performance;
- Operational availability and reliability of the leak detection systems, and the operator's process to manage system failures.

In addition, the Company may also consider the following factors:

- The system operating characteristics (e.g., steady-state operation, high transient pressure and flow);
- Current leak detection method for HCA/USA;
- Thresholds for leak detection;
- Flow and pressure measurement;
- Specific procedures for lines that are idle but still under pressure;
- Specific consequences related to sole source water supplies regarding additional leak detection means
- Testing of leak detection means, such as physical removal of product from the pipeline to test the detection;
- Potential for third-party damage;
- Operational availability and reliability;
- ERW low frequency pipe or pipe susceptible to SCC;
- Any other characteristics that are part of the system leak detection.

Specifically, the Company will use the leak detection evaluation process described in PHMSA Hazardous Liquid Leak Detection Techniques and Processes Report, dated April 2003, Section 2.3, page 7.

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Techniques and Process

Based on this evaluation, consideration may be given for providing additional metering, pressure, or other leak related operating parameter as a method to enhance leak detection capability.

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6.4 Emergency Flow Restricting Devices (EFRDs)

The Company will make evaluations to determine the need to install additional EFRDs on a pipeline segment to protect an HCA/USA. An EFRD is a check valve or remote control valve. The following factors will be considered:

- *Capability and swiftness of leak detection method to detect leak including consideration of system detection times, operator response times, remotely controlled valve response characteristics, and system isolation time assessments, as applicable;*
- *Time required to shut down pipeline;*
- *Type of commodity transported;*
- *Potential leak rate;*
- *Potential volume that could be released;*
- *Pipeline topography or elevation profile;*
- *Potential for ignition;*
- *Proximity to power sources;*
- *Location of nearest response resources;*
- *Terrain between release site and HCA/USA;*
- *Benefits expected by reducing spill volume;*
- *Relevant line specific factors;*

The Company will also consider additional relevant line-specific factors beyond those listed in 49 CFR Part 195.452(i)(4) as follows:

- *Relative reliability of existing or proposed EFRDs;*
- *Any relevant operating modes beyond nominal full flow conditions;*
- *Evaluation of the need for additional EFRDs to respond to releases during transient conditions;*

Consideration of the potential effects of additional EFRDs, including:

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49 CFR Part 195.452(i)

- *Conducting proper valve sequencing during intended EFRD activations;*
- *The operator's ability to promptly detect and react to inadvertent EFRD activations;*
- *Possible elevated pressures caused by transient conditions during EFRD activations;*

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6.5 Mitigative Actions

Mitigative actions can be identified during normal pipeline operation, initial risk assessment, implementation of the baseline assessment plan, or during subsequent testing. Priority in schedule and scope for additional actions will be given to the highest risk pipeline segments. Changes to both documented work processes (e.g., procedures, response plans) and physical changes will be considered. Additional preventive and mitigative actions for non-pipeline facilities (breakout tanks, pump stations, etc.) that can affect an HCA/USA will also be considered.

The mitigation activities presented in this section include information on:

- Prevention of Third-Party Damage [Section 6.5.1];
- Corrosion Control [Section 6.5.2];
- Detecting and Minimizing Unintended Pipeline Releases [Section 6.5.3];
- Pressure Reduction [Section 6.5.4];

6.5.1 Prevention of Third-Party Damage (TPD)

The following mitigation activities will be considered for prevention of third-party damage to Company pipelines:

- One-Call Utility Locating Systems;
-
- Improved Line Marking;
- Optical Electronic Detection;
- Increased Depth of Cover;
- Improved Public Education (ID of excavators, emergency responders and public officials);
- Right-of-Way Maintenance;
- More Frequent Right-of-Way Inspection;
- Mechanical Pipe Protection;
- Additional Pipe Wall thickness;

- Pipeline Marker Tape Over Pipeline;

One Call System "811"

The Company is a member of the State of California "811 One Call" system.

Improved Public Education

The Company implements a public awareness programs designed to meet requirements of current federal regulations. These programs educate the public, emergency responders, and persons engaged in excavation related activities as to the whereabouts, potential dangers, and appropriate emergency responses associated with pipeline right-of-ways. This program helps reduce the Company's pipeline exposure to TPD and enhance emergency response in the event of an incident.

API 1162, "Damage Prevention for Hazardous Liquid Pipelines", will be used as a guide in development of the Company's damage prevention procedures.

Right-of-Way Maintenance

- Control of vegetation on the right-of-way;
- Removal of trash, brush, and other items near the pipeline route;
- Control of impediments constructed above or below ground near the pipeline (including, but not limited to, buildings, engineered structures, pavement, pools, fences, etc.);
- Operation of heavy equipment over pipeline;
- Blasting near the pipeline;
- Crossing the pipeline;
- Excavation or boring near the pipeline;

Improved or More Frequent Right-of-Way Inspections

State and Federal pipeline regulations require regular right-of-way inspections and maintenance. These regular inspections enable the Company to identify activities that may encroach upon the right-or-way before the pipeline facility can be impacted.

6.5.2 Corrosion Control

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Pipe coating systems, combined with a cathodic protection system, provide effective corrosion control of external pipeline surfaces. Pipeline cathodic protection will be installed, monitored, and maintained in compliance with Federal requirements and NACE (National Association of Corrosion Engineers) Recommended Practice RP-01-69. Cathodic protection system data will be integrated with in-line inspection data and other information as described in the Company's Integrity Management Program (IMP).

Additional monitoring of cathodic protection systems utilizing close interval potential surveys and/or coating integrity surveys will be considered. Risk assessment, in-line inspection data, results of routine system monitoring, open-hole inspections and release history are factors which may indicate that a close interval potential survey is needed. External pipe coating systems will be evaluated, monitored, and maintained. Control of corrosion is highly dependent on the integrity of the external coating system.

6.5.3 Detecting and Minimizing Unintended Pipeline Releases

In the event of an unintended product release, it can be minimized by considering the following prevention and mitigative measures:

- Reducing the time required for detection of the release;
- Reducing the volume that can be released;
- Reducing the time required to locate the release;
- Reducing emergency response time;

Reducing Detection Time and Volume Lost From Unintentional Releases

Release detection system manufactures, and/or manufacturer's representatives will provide the Company with written descriptions of system capabilities and performance expectations for each specific pipeline segment application. The performance expectations will be described in terms of product volume released versus time for detection. Potential release detection system limitations, or concerns for specific service suitability, will also be provided to the Company.

The performance and reliability of the communications system(s) may significantly affect the performance and response times of some release detection systems. The Company will evaluate the communications process for critical systems where action must be taken within relatively short timeframes. Where applicable, improvements to these systems can reduce the time required to detect and respond to an unintended release, thus reducing the consequences.

All personnel responsible for monitoring release detection system data/alarm functions will be properly trained in the operation and maintenance of the system. Pipeline controller training will include the

process to recognize and analyze release detection alarms and basic concepts of pipeline hydraulics (steady-state and transient).

Improved Emergency Response

The Company will comply with all emergency response requirements contained in 49 CFR Part 195. In addition, the Company will take measures to improve the emergency response program to help prevent and mitigate the consequences of a pipeline failure that could affect an HCA/USA. These measures include providing additional training to personnel on response procedures, conducting drills with local emergency responders, and adopting other management controls as necessary.

Isolation and Control of the Release Source

Control measures may vary depending on the release volume, rate, location, and pipeline operational capabilities.

For an active unintended release, it can be controlled through:

- Reduction of pipeline operating pressure;
- Total shutdown of pipeline product flow and closure of release source area line valves, when applicable;
- Isolation of pipeline segment containing the release by closing main line block valves or other mechanisms;

Operations have the authority and responsibility to reduce operating pressures and /or stop flow of pipeline product in emergencies.

6.5.4 Pressure Reduction

Operating pressure reduction is used as both a temporary and occasionally permanent measure to reduce risk. A pressure reduction is a temporary, but immediate initiative action is to reduce risk until a defect can be evaluated by excavation, repaired or removed. In some cases, the Company may determine that the consequences of a failure are significant enough to design for a higher level of safety than normally afforded by ASME B31.4.

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6.6 Implementation

The Company will document and use the spreadsheet titled "***DCOR IM Program***" to implement this element. This document shall be evaluated every 3 years for any changes in the program.

6.7 Records

Document preventative and mitigative measures using one or more of the following:

- Spreadsheet "DCOR IM Program"
- Mitigative measures risk analysis including mitigative options taken, if any
- Decision processes, rational and assumptions
- OME maintenance activities
- Leak detection review and data on leak detection system (LDS), if any
- *EFRD review and data, if any*

6.8 Related References and Documents

1. 49 CFR Part 195.452(i)
2. API 1160, Managing System Integrity for Hazardous Liquid Pipelines, Section 10, Mitigation Options, pages 29-34, 1st Edition, November 2001
3. PHMSA Frequently Asked Questions (FAQs):
   Section 9, Leak Detection, EFRD, and Additional Risk Controls Sept 17, 2007
4. PHMSA IM Program Protocols
   Section 6 – Preventive and Mitigative Measures, Oct 2006

INTEGRITY MANAGEMENT PROGRAM - RISK QUESTIONNAIRE & DETERMINATION [PLATFORM A]

[23] A to Rincon 12" gross oil line - CSFM #0871 BSEE #6210241 ROW OCS-P 0552
[22] A to Rincon 12" gas line - BSEE #6320241 ROW OCS-P 0553

#	Segment	Risk Element	Risk Element Likelihood Question	Preventive and Mitigative Activities	S	L	T (S x L)	Risk	Comments and Recommendations	Additional Risk Mitigations
1	[23]	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	If a release occurs, what is the likelihood that a release will reach populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, or areas where people congregate?	1.1A Leak detection system. 1.1B PSHL 1.1C Corrosion and maintenance per O&M in good condition.	1	3	3	3	1. Environmental impact: remediation required 2. Potential national media attention	1 = 50% WT Loss or > 2 = 40% WT Loss or > 3 = 30% WT Loss or > 4 = 25% WT Loss or > 5 = < 25% WT Loss
	[22]				2	4	8	7		
2	[23]	Results from previous testing/inspection. [see 195.452(h)]	Based on results from previous testing/inspection, what is the likelihood that a leak will occur?	ILI conducted every two years	1	2	2	2	S:\ES&RC\ES&RC General\Pipelines\Smart Pig Reports	
	[22]	Results from previous testing/inspection. [see 192.905]			2	4	8	7		
3	[23]	Leak and repair history.	Based on leak and repair history, what is the likelihood that a leak will occur?	ILI, weekly pipeline patrol, ICCP, investigation of failures per O&M standard	1	3	3	3		
	[22]				2	4	8	7		
4	[23]	Cathodic protection history and known corrosion or condition of pipeline. [see 195.452(g)]	Based on cathodic protection history and known corrosion or condition of the pipeline, what is the likelihood a leak will occur?	CP survey, ICCP	1	4	4	4	All CP readings in compliance with -600 millivolt criteria. Continous monitoring and inspection per O&M procedures. 1999 Rectifier and deep well anode installed onshore at PRC 410 lease. The rectifier in right-of-way and the anode bed near PRC-410 office.	
	[22]	Cathodic protection history and known corrosion or condition of pipeline. [see 192.451]			2	4	8	7	All CP readings in compliance with -.800 mV criteria (offshore) and - .850 mV (onshore). Continuous monitoring and inspection per O&M procedures	
5	[23]	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Based on the quality and condition of pipe coating, what is the likelihood a leak will occur due to pipe coating malfunction?	ICCP	1	4	4	4	No problems with pipe coating except in the splash zone near platform (GRD II Mastic); New segments are coated in FBA (25 mils)	S:\ES&RC\ES&RC General\Pipelines\All-Pipelines Information.xls
	[22]				2	4	8	7		
6	[23]	Age of pipe.	Based on the age of the pipe, what is the likelihood a leak will occur?	ILI, weekly pipeline patrol, ICCP	1	1	1	1	S:\ES&RC\ES&RC General\Pipelines\All-Pipelines Information.xls	1 = > 30 years (DOT regulation passed) 2 = 21 -30 years 3 = 11 -20 years 4 = 5 -10 years 5 = <5 years
	[22]				2	1	2	2		

INTEGRITY MANAGEMENT PROGRAM - RISK QUESTIONNAIRE & DETERMINATION [PLATFORM A]

[23] A to Rincon 12" gross oil line - CSFM #0871 BSEE #6210241 ROW OCS-P 0552
[22] A to Rincon 12" gas line - BSEE #6320241 ROW OCS-P 0553

#	Segment	Risk Element	Risk Element Likelihood Question	Preventive and Mitigative Activities	S	L	T (S+L)	Risk	Comments and Recommendations	Additional Risk Mitigations
7	[23]	Product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Based on the product transported, what is the likelihood that the public health could be affected?	ICCP, PSH/LSH, ILI	1	3	3	3	Heavy crude, approximately 24 API gravity	1 = highly volatile and flammable. Examples: Propane, butane, NGL, ammonia 2 = highly toxic. Examples: Benzene, high level H2S in crude (>100 ppm) 3 = Flammable with flashpoint <100 degrees F. Examples: Gasoline, JP4, high API crude 4 = Low flammability, 100-150 degrees F Examples: Diesel, fuel oil, kerosene, JP5, high API crude 5 = Non flammable, 150 degrees F Examples:
	[22]				2	4	8	7		
8	[23]	Pipe wall thickness (thicker walls give a better safety margin).	Based on pipe wall thickness, what is the likelihood a leak will occur?	ILI	1	2	2	2	Schedule 40	1 = less than schedule 20 pipe 2 = schedule 20-40 pipe 3 = schedule 41-80 pipe 4 = schedule 81-160 pipe 5 = > 160 schedule pipe
	[22]				2	2	4	4		
9	[23]	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	Based on amount of product transported, what is the likelihood that public health or safety could be affected?	Leak Detection System (LDS)	1	2	2	2	4494 bbls estimated worst case scenario from Oil Spill Response Plan	OIL: (severity) 1 = >1000 bbls 2 = 100 - 1000 bbls 3 = 2 - 100 bbls (MMS reportable) 4 = < 2 bbls
	[22]			Continuing surveillance, PSH/LSH, Damage Prevention Program	2	2	4	4		GAS: (release severity in cost) 1 = >than $50,000 (DOT) 2 = $40-49,999 3 = $30-39,999 5= <=$29,000
10	[23]	Local environmental factors that could affect the pipeline	Based on local envirnomental factors, what is the likelihood that a leak would occur?	Weekly boat and onshore patrol	1	3	3	3	Seismic Zone 4, other ground movement potential is negligible.	
	[22]				2	3	6	6		
11	[23]	Security of throughput (effects on customers if there is failure requiring shutdown).	Based on security of throughput, what is the likelihood of affecting customers supplies?	Weekly pipeline patrol (ROSF)	4	5	20	10	70% of DCOR production flows through these lines	
	[22]				4	5	20	10		
12	[23]	Time since the last internal inspection/pressure testing.	Based on the time since the last internal inspection or pressure test, what is the likelihood that a leak will occur?	ILI conducted every two years	1	3	3	3	Pipeline Data - Risk Ranking	1 = >5 years (requires OPS approval) 2 = 4 - 5 years 3 = 2 - 4 years 4 = 1 - 2 years 5 = 1x/year or less
	[22]				2	3	6	6		

INTEGRITY MANAGEMENT PROGRAM - RISK QUESTIONNAIRE & DETERMINATION [PLATFORM A]

[23] A to Rincon 12" gross oil line - CSFM #0871 BSEE #6210241 ROW OCS-P 0552
[22] A to Rincon 12" gas line - BSEE #6320241 ROW OCS-P 0553

#	Segment	Risk Element	Risk Element Likelihood Question	Preventive and Mitigative Activities	S	L	T (SAL)	Risk	Comments and Recommendations	Additional Risk Mitigations
13	[23]	Previously discovered defects/anomalies, including type, growth rate, and size.	Based on previously discovered anomolies, what is the likelihood that a leak will occur?	ILI conducted every two years;data is analyzed by Pipeline Safety Engineer, Construction Foreman and third-party vendor	1	3	3	3	Pipeline Group 1	1 = see IMP immediate repair condition 2 = see IMP 60 day repair condition 3 = see IMP 180 day repair condition 4 = see IMP other conditions 5 = insignificant anlomolies
	[22]				2	3	6	6		
14	[23]	Operating stress levels in the pipeline. Exposure of pipeline to exceed MOP	Based on operating stress levels, what is the likelihood that a leak will occur?	ILI, PSH/LSH, LDS	1	3	3	3	S:\ES&RC\ES&RC General\Pipelines\All-Pipelines Information.xls	1 = > 75 - 80% SYMS 2 = 30 - 75 % SYMS 3 = 20 - 30 % SYMS 4 = 5 - 20 % SYMS 5 = < 5 % SYMS
	[22]				2	3	6	6		
15	[23]	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose).	Based on location of the pipe and the company's ability to detect and respond, what is the likelihood that a leak will occur?	Weekly pipeline patrol	1	4	4	4		
	[22]				2	3	6	6		
16	[23]	Physical support of the segment such as by a cable suspension bridge.	Based on physical supports of this segment, what is the likelihood a leak will occur?	Offshore pipeline ROV inspections performed every 2 years	1	4	4	4		
	[22]				2	4	8	7		
17	[23]	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	If the company used non-standard construction practices, what is the likelihood a leak will occur?	No non-standard practices followed	1	4	4	4		
	[22]				2	4	8	7		
18	[23]	Terrain surrounding the pipeline including elevation profile, farm drain tiles, conduits.	Based on the terrain surrounding the HCA segment, what is the likelihood a leak would reach the HCA?	Leak Detection System (LDS); Pressure and ILI tests	1	3	3	3	Offshore pipeline segment is within HCA area; onshore pipeline segment is in residential and commercial areas	
	[22]			Gas Leak Survey; Pressure and ILI test	2	3	6	6	Pipeline segment is in class 1 location that crosses Highway 101	

INTEGRITY MANAGEMENT PROGRAM - RISK QUESTIONNAIRE & DETERMINATION [PLATFORM A]

[23] A to Rincon 12" gross oil line - CSFM #0871 BSEE #6210241 ROW OCS-P 0552
[22] A to Rincon 12" gas line - BSEE #6320241 ROW OCS-P 0553

#	Segment	Risk Element	Risk Element Likelihood Question	Preventive and Mitigative Activities	S	L	T [SxL]	Risk	Comments and Recommendations	Additional Risk Mitigations
19	[23]	Construction activity in the area.	Based on construction acitivity in the area, what is the likelihood of construction damage?	Offshore segments are patrolled weekly; Damage Prevention Program implemented for onshore segment	1	5	5	5		1 = class 4 per 192.5 2 = class 3 per 192.5 3 = class 2 per 192.5 4 = class 1 per 192.5 and onshore 5 = class 1 per 192.5 and offshore
	[22]				2	5	10	8		
20	[23]	General health and safety factors (employees and public)	What is the likelihood of health and safety exposure to the employees and public if a leak occurred?	Weekly pipeline patrol; Emergency Response Plan managed by ES&RC; Personnel Training/OQ	1	5	5	5	Minimal public exposure at shoreline due to remote rural location. HCA segment is located in the ocean. Onshore segment is around 1 mile in remote location	NFPA Health Definitions: 1 = NFPA 4 2 = NFPA 3 3 = NFPA 2 4 = NFPA 1 5= No hazard or minimal hazard
	[22]				2	5	10	8		
21	[23]	Environmental impacts	If a leak occurred, what are the environmental impacts levels?	Leak Detection System (LDS); Emergency Response Plan and annual drills conducted	1	2	2	2	Potential environmental impacts to Southern California beaches in Ventura & Carpinteria; onshore segment crosses major freeway	***Severity***: 1 = >$5MM 2 = >$1MM - $5MM 3 = >$100,000 - $1MM 4 = >$10,000 - $100, 000 5 = ≤$10,000
	[22]			ILI every two years	2	2	4	4		
22	[23]	Property damage	If a leak occurred, what are the property damage impact levels?	Leak Detection System (LDS); Emergency Response Plan and annual drills conducted	1	2	2	2	Potential environmental impacts to Southern California beaches in Ventura & Carpinteria; onshore segment crosses major freeway	***Severity***: 1 = >$5MM 2 = >$1MM - $5MM 3 = >$100,000 - $1MM 4 = >$10,000 - $100, 000 5 = ≤$10,000
	[22]			ILI every two years	2	2	4	4		
23	[23]	Local economic impact	If a leak occurred, what are the local economic impact levels?	Leak Detection System (LDS); Emergency Response Plan and annual drills conducted	1	2	2	2	Potential environmental impacts to Southern California beaches in Ventura & Carpinteria; onshore segment crosses major freeway that connects to Santa Barbara/Los Angeles	***Severity***: 1 = >$5MM 2 = >$1MM - $5MM 3 = >$100,000 - $1MM 4 = >$10,000 - $100, 000 5 = ≤$10,000
	[22]			ILI every two years	2	2	4	4		
24	[23]	Material of Construction (e.g. ERW -high or low freq, pre 1970)	What tools/methods are selected to determine the integrity of welds?	ILI, ICCP	1	2	2	2	Oldest segment of pipe is pre-1970 ERW	
	[22]				1	2	2	2		

INTEGRITY MANAGEMENT PROGRAM - RISK QUESTIONNAIRE & DETERMINATION [PLATFORM A]

[23] A to Rincon 12" gross oil line - CSFM #0871 BSEE #6210241 ROW OCS-P 0552
[22] A to Rincon 12" gas line - BSEE #6320241 ROW OCS-P 0553

#	Segment	Risk Element	Risk Element Likelihood Question	Preventive and Mitigative Activities	S	L	T (SxL)	Risk	Comments and Recommendations	Additional Risk Mitigations
				Total Risk Score			[23]	79		
							[22]	142		
				Average Risk Score			[23]	3.16		
							[22]	5.68		