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Via E-Mail and Overnight Mail

Mr. Larry T. White
Hearing Officer
Office of the Chief Counsel
Pipeline and Hazardous Materials Safety Administration
US Department of Transportation
1200 New Jersey Ave. S.E.
Washington, DC 20590

Re: Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order, CPF 4-2007-1007 Post-Hearing Response

Dear Mr. White:

We appreciate you, acting as the hearing officer for the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), and the Southwest Region of PHMSA ("SW Region") taking the time to discuss the issues involved in the above-referenced Notice of Probable Violation ("NOPV") with El Paso Pipeline Group ("EPPG") and ANR Pipeline Company ("ANR") at the informal hearing held on April 30, 2008.

This letter responds to the questions raised at the hearing and provides additional information for your consideration. EPPG and ANR request this letter and its attachments be added to the hearing file as a supplement to the previously provided materials. In addition, EPPG and ANR request a copy of any additional material added to the file by the PHMSA or its Counsel.

For all of the reasons discussed herein, EPPG and ANR respectfully request that the above-referenced NOPV, along with its compliance order and proposed penalties, be dismissed in its entirety.

El Paso Corporation
1001 Louisiana Street Houston, Texas 77002
PO Box 2511 Houston, Texas 77252.2511

I. Applicable Legal Standards

At the hearing, it was clear different opinions exist between the SW Region on one hand, and EPPG and ANR on the other, as to the meaning and requirements of the regulations at issue. It was equally clear the SW Region's position on these topics had not been captured in any prior guidance or advisory document, but instead was first articulated to EPPG and ANR in the NOPV.

These facts lead to three essential legal questions. First, have the opinions articulated by the SW Region risen to the level of creating a new substantive obligation on the part of EPPG and ANR such that a rulemaking process must be followed to make the obligations binding? Second, if not, what level of deference would courts give to PHMSA's oral interpretation of the meaning of the regulations at issue? Third, if the courts found no deference was accorded the PHMSA positions, would the courts find the interpretations to be procedurally defective, arbitrary or capricious in substance, or manifestly contrary to the statute or regulation being interpreted?

A. Has PHMSA created new substantive obligations for EPPG and ANR?

If PHMSA's interpretation is substantive in nature, then PHMSA must undertake the rulemaking process set forth in Section 553 of the Administrative Procedure Act (APA) before the pronouncement can become binding on EPPG, ANR, or other pipeline operators. 5 U.S.C. §§ 553, et seq. Indications that a particular agency position is substantive in nature -- rather than being a policy or interpretive statement – include whether the pronouncement is prospective in application, whether it purports to impose rights and obligations on an operator, and whether the pronouncement binds the agency and its decision-makers to a particular outcome. *American Bus Association v. U.S.*, 627 F.2d 525, 531-533 (D.C. Cir. 1980).

Here, the SW Region's position as to the specific, but unpublished definition of the word "cluster" (NOPV Item No. 1) or the asserted need to "multiply" rather than add interactive threats to meet the regulations' requirements (NOPV Item No. 2), or a new defect repair criteria (NOPV Item No. 4) create new substantive requirements because these positions impose new obligations on EPPG and ANR, and likely other operators, that were not present before. Accordingly, a court is likely to strike the imposition of these new additional substantive requirements as unlawfully promulgated because there was no notice and comment rulemaking process as required by the APA.

B. Is PHMSA's interpretation entitled to any deference by the courts?

If a court found the position of the SW Region was not substantive in nature, but rather was merely interpretative in nature, then the question becomes to what degree of deference, if any, is the agency's articulation of its opinion entitled?[1]

Generally, an agency's construction of the statutory scheme it is entrusted to administer is given considerable weight. *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 844-845, 104 S. Ct. 2778, 2783, 81 L.Ed.2d 694 (1984). When Congress has left a gap for an agency to fill with its interpretation, the ensuing regulation is generally upheld in the courts unless it is found to be procedurally defective, arbitrary or capricious in substance, or is manifestly contrary to the statute. *Id.* at 843-844.[2]

Not all interpretations made by the agency, however, are entitled to *Chevron* deference. For instance, agency interpretations contained in policy statements, agency manuals, and enforcement guidelines generally are not entitled to such *Chevron* deference. *United States v. Mead Corp.*, 533 U.S. 218, 212, 121 S.Ct. 2164, 150 L.Ed.2d 292 (2001) (holding tariff classification ruling was not entitled to any deference); see also *Christensen v. Harris County*, 529 U.S. 576, 587-589, 120 S.Ct. 1655, 146 L.Ed.2d 621 (2000) (holding opinion letter from Department of Labor interpreting application of regulation had no claim to Chevron deference).

Nonetheless, courts have recognized interpretations and opinions of the agency do constitute a body of experience and informed judgment to which the courts may grant deference, but only to the degree a court finds the agency's interpretation persuasive. The level of deference depends upon (i) the thoroughness evidenced in the consideration by the agency; (ii) the validity of its reasoning; (iii) its consistency with earlier and later pronouncements, and (v) other factors which give the agency the power of persuasion. *Skidmore v. Swift & Co*, 323 U.S. 134, 139-140, 65 S.Ct. 161, 89 L.Ed. 124 (1944) (finding that Administrator's action did not merit such deference).

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1 The APA exempts from the requirements of notice and comment rulemaking "interpretative rules" and "general statements of policy." APA §553 (b)(A).

2 The presence of the rulemaking process in the development of the agency's interpretation is good reason for the courts to apply the Chevron deference to the agency action. *United States v. Mead*, 533 U.S. 218 (2001). Here, however, PHMSA's interpretation of the regulations set forth in writing for the first time in the NOPV was not arrived at using the rulemaking process of the APA, and therefore is unlikely to be entitled to *Chevron* deference by the courts.

As is described more fully below, EPPG and ANR respectfully submit the evidence presented at the hearing demonstrates that PHMSA's interpretations leading to the NOPV are not entitled to *Chevron* deference nor entitled to any level of deference because the positions were not thoroughly considered by the agency, the reasoning does not withstand technical scrutiny, and lastly, the interpretations are inconsistent with prior Agency action.

C. Without deference, would PHMSA's interpretations fail?

If the courts grant no deference to the SW Region's interpretation, the question becomes whether the court's independent review will find the interpretations are procedurally defective, arbitrary or capricious in substance, or is manifestly contrary to the statute or regulation. As discussed below, we respectfully believe each of the NOPV items would fail on these grounds.

For all these reasons, we believe a court is unlikely to uphold the imposition of the proposed penalties or the compliance plan set forth in the NOPV.

II. Item No. 1: The Meaning of a "Cluster" of Buildings

Discussions at the hearing related to the first item in the NOPV centered on a difference of opinion as to how to implement 49 C.F.R. 192.5(c)(2) with particular emphasis on what is meant by the word "cluster" as it is contained in that regulation.

As confirmed during the hearing, PHMSA does not have any published definition or guidance on how to implement paragraph 192.5(c)(2) for calculating class location boundaries, nor has PHMSA provided any lasting guidance on what the word "cluster" means in this regulation. The only evidence presented at the hearing concerning any earlier definitions was the introduction of the term "a single cluster" in June of 1996, which was retracted a month later.

EPPG and ANR have a well-developed and detailed plan about how to determine when a cluster exists for purposes of determining class location. Up until the receipt of the NOPV in July 2007, EPPG and ANR had every reason to believe that its plan met the standards applied by PHMSA. In fact, PHMSA has inspected EPPG and ANR on numerous prior occasions without voicing a concern about EPPG and ANR's definition of the word "cluster." The NOPV provided the first notice of a different interpretation of the term "cluster" and the precise nature of that interpretation remains unclear.

As discussed above, the legal questions are twofold. Is PHMSA creating a new binding substantive requirement on EPPG and ANR? We believe that is the case and accordingly, PHMSA should follow the rulemaking requirements of the APA. If not, would the courts accord PHMSA's previously unwritten interpretation of the word "cluster" to include the eight additional structures any deference? We believe the courts would not.

There is no evidence of the requisite thoroughness of consideration given to this matter. The only recent discussions about defining a cluster appear to have occurred at the hearing. There is no record of any data gathering from the industry or discussion of the impact of a new "cluster" interpretation. Moreover, the proposed interpretation is not consistent with earlier actions by the Agency. The industry, including EPPG and ANR, has been utilizing cluster definitions for the past 37 years without the agency voicing concerns about the approach used. Also, with no agency action since 1996 on this issue before the interpretation put forward in this NOPV, we submit a court would not grant PHMSA's interpretation any deference, and would find the PHMSA interpretation is procedurally defective and manifestly contrary to the intent of the regulation.

II. Item No. 2: Statistical Analysis

The issue here is whether EPPG and ANR appropriately complied with the requirements of 49 CFR 192.907. This regulation requires operators to conduct an HCA identification process and have the framework for the process in place by December 17, 2004.

The discussions at the hearing concentrated on the statistical analysis performed by EPPG. Because EPPG provided more information to PHMSA than required, it appears PHMSA's own statistical analysis inadvertently overstated the number of missing HCAs – which likely led to this item being in the NOPV. When the corrected statistics were reviewed at the hearing, it became apparent that only a few HCAs were misclassified in 2004.

We appreciate PHMSA's recognition that EPPG and ANR had a good process and framework in place by December 17, 2004, as required by the regulations. Moreover, we appreciate the recognition that EPPG and ANR have continued to make improvements to the process. As the evidence demonstrated, EPPG and ANR acted in 2005 to re-classify those areas which had earlier been misclassified as non-HCAs in 2004 and are treating any newly-identified HCAs the same as those identified in 2004 from a Baseline Assessment Plan timing perspective. All 2005 HCAs will be part of the Baseline Assessment Plan to be completed by December 17, 2012, thereby mitigating any safety concern related to this issue.

We submit that EPPG and ANR met the requirements of the regulation because EPPG and ANR developed a detailed and comprehensive HCA Identification processes, and undertook a good faith, comprehensive implementation of these processes prior to

December 17, 2004. These actions met the intent of the rule, as PHMSA described in the preamble of the rule, the July 2003 Advisory Bulletin, in 192.907, and in 192.911(p). EPPG and ANR should neither be penalized for continuing to improve the HCA identification processes nor for the human errors involved in the initial implementation.

IV. Item no. 3: Assessment of Interactive Threats

All parties involved in the hearing agreed the regulations require operators to address interactive threats by considering "more than one threat occurring on a section of pipeline at the same time." This means that if external corrosion and third-party damage are both a threat, the segment of pipeline would rank higher in an operator's risk ranking and threat evaluation processes than if only one of those threats were present.

EPPG's method of addressing these interactive threats is to assign a numerical value to each of the different threats and then add those values together for purposes of ranking the threat level. The SW Region disagrees with this methodology. Instead, the SW Region believes the proper method to quantify the additional risk involved is to multiply, rather than add, the interactive threats. Unfortunately, the SW Region has not articulated the scientific or regulatory basis for their opinion, nor how to derive an appropriate multiplier for the task.

Again, the legal question presented is whether this unwritten interpretation by the SW Region to require multiplication rather than addition would be afforded any deference by the courts? We believe the courts would not.

There is no evidence suggesting any prior discussion within the agency on this topic, nor any evidence of any thoroughness of consideration given to the matter. There is no record of any data gathering from the industry on this topic. Moreover, there is some question to the validity of the interpretation because, as PHMSA's lack of a particular number would indicate, there is no reason to believe a multiplied answer is any more effective in promoting public safety than an answer derived by addition. Too, other operators in the industry have been utilizing the same interpretation as EPPG since the interactive threat regulation came into existence. Given this factual predicate, we submit a court would not grant PHMSA's interpretation any deference, but on the contrary, would find the agency's interpretation is procedurally defective and arbitrary or capricious in substance.

As requested at the hearing by PHMSA, we are providing information to demonstrate the descriptions set forth at Slides 41, 42 and 43 of the EPPG and ANR presentation at the hearing. This information is attached as Appendices A-3, A-4, and A-5. The processes highlighted are the same that were in effect during the 2006 audit.

V. Item No. 4: Anomaly repair in a Class +1 situation

This item turns on utilizing the appropriate defect repair criteria once an anomaly has been evaluated in the ditch after a "class bump" has occurred. A "class bump" is when the class location for a particular pipeline segment is re-classified. For instance, a segment might move from Class 2 to Class 3. This is also referred to as a "class +1 change." The regulations in Section 192.611(a) permit an operator to make a "class +1 change" on a pipeline segment without requiring a change in the MAOP or design factor for purposes of defect repair criteria. This is because a class location change, alone, does not affect the safety, reliability or structural integrity of the pipe in the ground.

This issue was one of several topics discussed at some length at a recent technical summit meeting held in Washington DC with PHMSA and industry representatives from virtually every major natural gas transmission pipeline company in attendance. Based on discussions at that summit, there appears to be agreement that the design factor used to establish the original MAOP is the appropriate design factor to be used in establishing the "safe maximum pressure" of the corroded pipe per ASME B31G, Part 4. Representatives from each of the operating companies said that it was their practice to apply the design factor for the original design when making repairs, as EPPG and ANR do.

EPPG applauds and shares PHMSA's strong commitment to public safety. We believe this topic, along with the more difficult topic of anomaly evaluation (which was also discussed at the summit) is ripe for further discussions to ensure industry and its regulatory stakeholders find the answers most likely to promote public safety while honoring the science behind the tasks.

In the meantime, however, EPPG respectfully submits that this item of the NOPV should be dismissed. The SW Region's interpretation of defect repair criteria when in the ditch is contrary to the scientifically validated criteria and clearly has substantative impact on pipeline operators. To be binding, however, any change to the current defect repair criterion in the ditch needs to go through a notice and comment rulemaking process. This is a topic requiring much more extensive discussion to ensure any change is scientifically valid. For these reasons, we believe a court would not give the SW region interpretation any deference, but instead would strike it as procedurally defective and arbitrary or capricious in substance.

In answer to a question at the hearing about how the proposed SW Region interpretation on this issue may affect EPPG and ANR, we are providing the following information:

(1) SNG operates approximately 4.2% of its system with MAOPs established per 49 CFR 192.611(a) or grandfathered pressures (greater than 72% SMYS). This is approximately 310 miles for SNG.

(2) EPPG and ANR (per records at the time of ANR's sale to TransCanada) operate approximately 6% of the system with MAOPs established per 192.611(a) or grandfathered pressures (greater than 72% SMYS). This is approximately 2,800 miles for EPPG/ANR in total.

(3) Using the SW Region interpretation would require unnecessary excavations, repairs or pipe replacements. In the specific SNG examples under discussion, for instance, even a corrosion pit of 10% depth and 0.5" long, roughly the size of a dime, would require a sleeve repair, pipe replacement, or lowering of the MAOP if the Class Location factor of 0.5 was applied to the burst pressure calculation rather than the existing 0.6 design factor.

Again, for these reasons, we believe the impact of the SW Region's interpretation would cause a court to find the new interpretation to require substantive changes permitted only under a rulemaking process.

VI. Pipes Act of 2006: Expansion or Clarification?

Thank you for sharing Mr. Ben Fred's memorandum articulating PHMSA's position. We appreciate that PHMSA has taken the position that the Pipes Act of 2006 merely clarified authority PHMSA already possessed to use compliance orders and civil penalties to enforce the Integrity Management Plan ("IMP") regulations.

We continue to assert, however, the best evidence that PHMSA lacked authority to use compliance orders and penalties to enforce the IMP regulations prior to the December of 2006, is the fact that Congress changed the language in the statute in the PIPES Act of 2006. Moreover, a court in interpreting statutory language would look first to the plain meaning of the words. We read the plain meaning of the operative words in the regulation -- i.e. "the Secretary shall act under section 60108(a)(2)" – to mean just what it says. For these reasons, we submit PHMSA had no authority to use the NOPV, fines, and compliance orders to address its concerns with EPPG or ANR's integrity management program.

VI. Conclusion

We appreciate you taking the time to discuss these important issues with EPPG and ANR. We understand, and share, PHMSA's commitment to ensuring the public safety through appropriately and effectively managing and protecting pipeline integrity across the country while delivering natural gas to the nation.

If you have any additional questions or need additional information please contact David Waterson at (713)420-3968.

Sincerely,

Dan Martin
Senior Vice President Operations
El Paso Pipeline Group

On Behalf of ANR Pipeline Company

David Montemurro
Vice President
Engineering and Operations Services
TransCanada

Attachments:
1 - NOPV Post Hearing attachment - Appendix A-3 Stress Corrosion Cracking (SCC) Threat
2 - NOPV Hearing attachment - Appendix A-4 Manufacturing Threat Checklist
3 - NOPV Hearing attachment - Appendix A-5 Construction Threat Checklist

cc:	D. Chittick	C. Childs
	D. Waterson	D. Bowmaster
	B. Friis	P. Carey
	J. Soto	C. Whitney
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This Appendix includes the process described on slide 43 of the EPPG and ANR presentation to PHMSA at the 4/30/2008 NOPV hearing See page 4.

Appendix A-3 Stress Corrosion Cracking (SCC) Threat – Checklist

Definition and Scope

Stress Corrosion Cracking (SCC) is defined for the Integrity Management Plan as cracking of pipeline steel caused by application of tensile stress in a specific corrosive chemical environment (glossary of the Corrosion Manual). This is specific to SCC on the carrier pipe.

Data Requirements

The data specific to the stress corrosion cracking threat is identified in the "List of IMP Data Requirements" in the appendix. This includes data description, sources of data, party responsible for validating the data, and assumption made when no data is available.

Threat Checklist and Prioritization

The SCC Threat Identification Process is attached to this checklist. It defines the step by step process to determine:

1. If this HCA is susceptible to the SCC threat?
2. If the answer is yes then the process describes whether the threat is prioritized as high or low susceptibility.

Another factor and question that will be considered during the Subject Matter Expert phase of threat identification and prioritization is:

	Default Answer
1. Do the evaluations and results of SCCDA indicate susceptibility to SCC in this HCA?	No

If the answer to this factor is different than the default then we will reevaluate the threat susceptibility answer and the threat priority.

	Quarterly Re-evaluation	Next Annual Re-evaluation
* Leak or failure caused by SCC in the HCA or in the buffer area (defined in TIP)	X	
SCC is found in the HCA or in the buffer area (defined in TIP).	X	
As recommended by Area Operations or Pipeline Services.		X

*Hydrostatic testing shall be conducted within a period of 12 months

Assessment Method Options

The following integrity assessment methods apply toward SCC corrosion:

- In-Line Inspection
- Pressure Test
- Stress Corrosion Cracking Direct Assessment (SCCDA)

The assessment method table and details on choosing an assessment method for each HCA see Chapter 4.

Other Items:

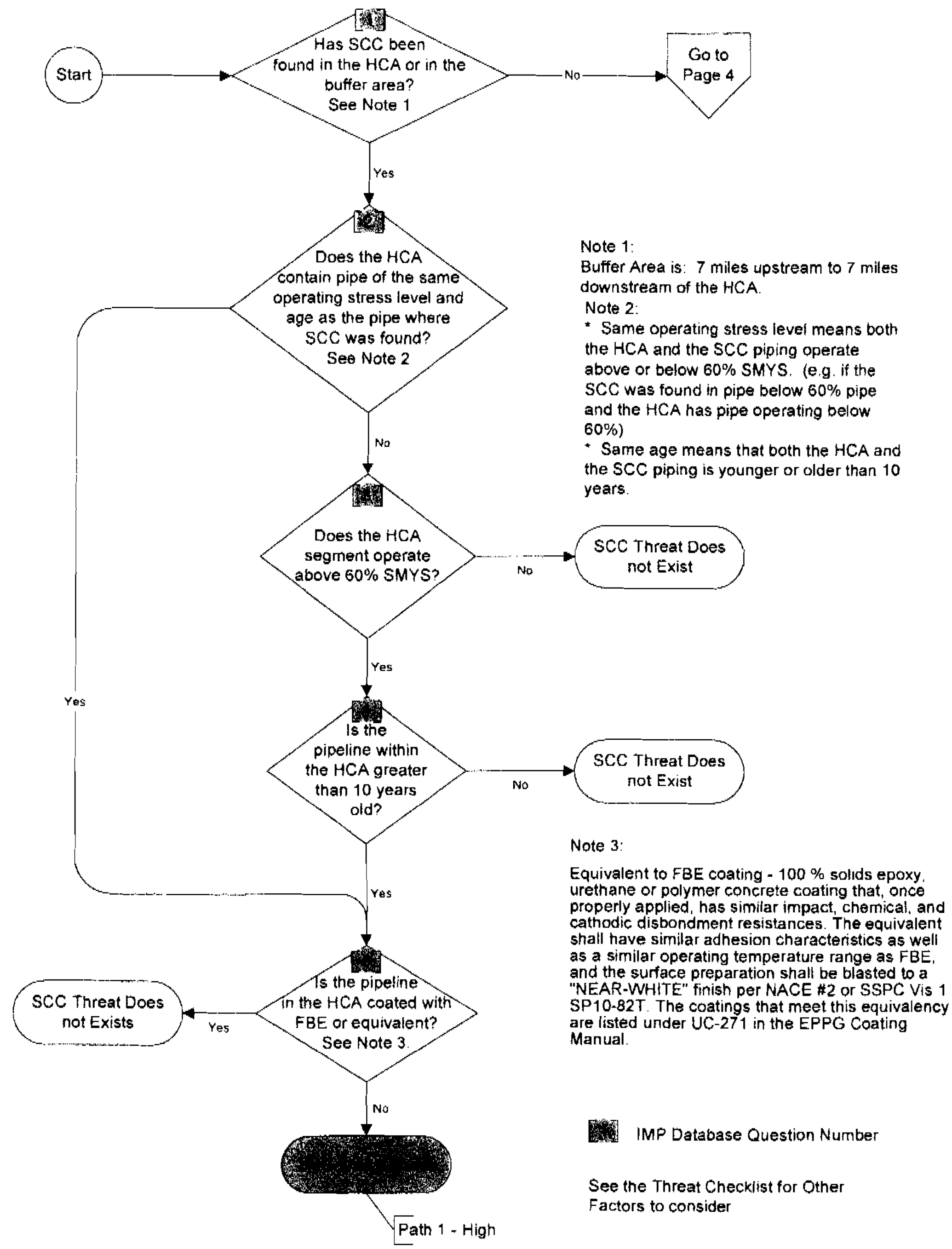
For determining preventive and mitigative measures appropriate for the SCC threat, see Chapter 12.

For determining the re-assessment interval for an HCA see Chapter 11.

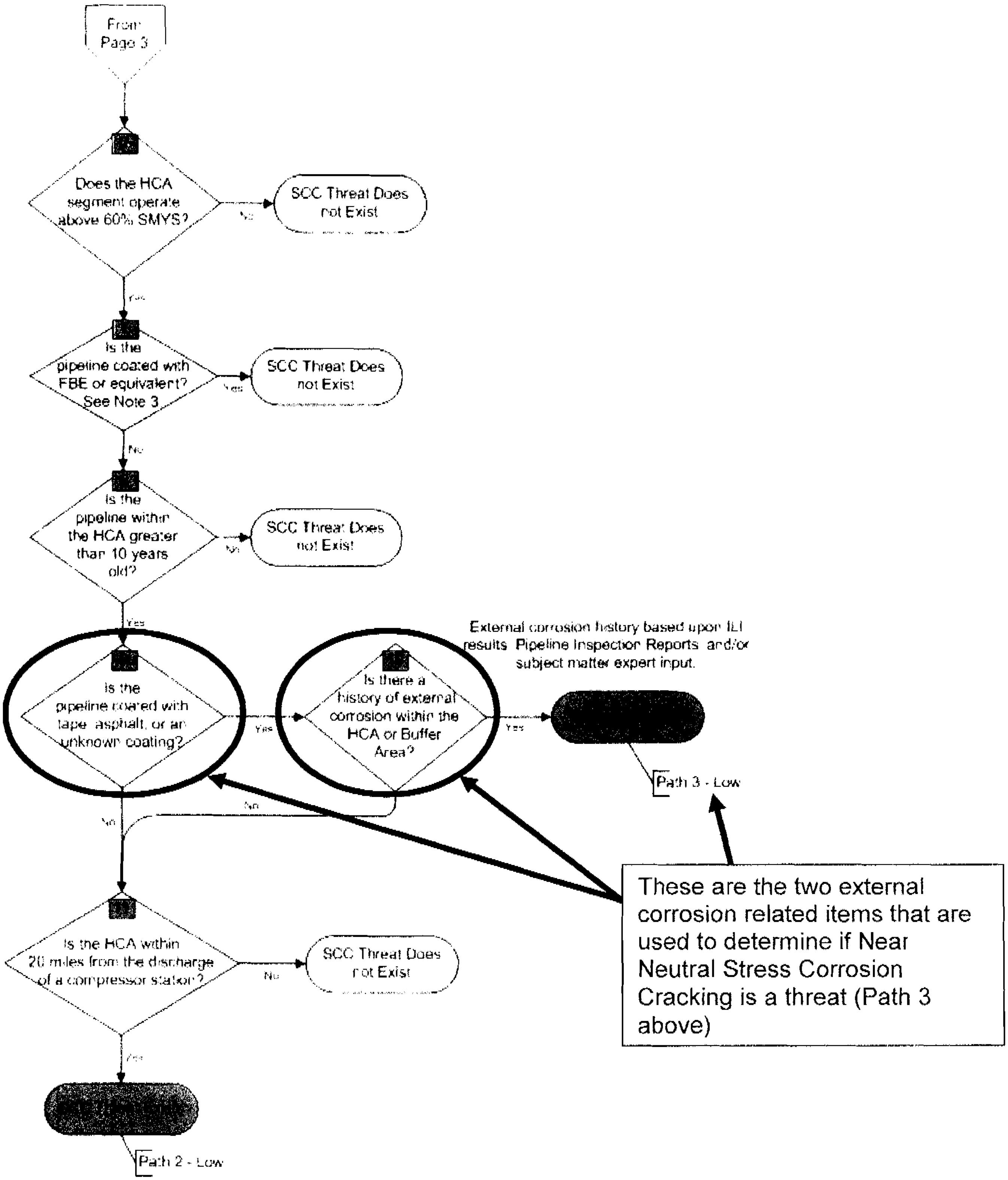
Performance measures specific to this threat are identified in Chapter 13.

Appendix A-3 Stress Corrosion Cracking (SCC) Threat - TIP Chart

This threat pertains to SCC on the carrier pipe.



Appendix A-3 Stress Corrosion Cracking (SCC) - TIP Chart (continued)



This Appendix includes the process described on slide 41 of the EPPG and ANR presentation to PHMSA at the 4/30/2008 NOPV hearing See page 2, 4, 5, and 6

Appendix A-4 Manufacturing Threat Checklist

Definition and Scope

The manufacturing threat is defined for the Integrity Management Plan to include pipe body defects related to manufacturing and pipe seam issues.

Data Requirements

The data specific to the manufacturing threat is identified in the "List of IMP Data Requirements" in the appendix. This includes data description, sources of data, party responsible for validating the data, and assumption made when no data is available.

Threat Checklist and Prioritization

The manufacturing Threat Identification Process is attached to this checklist. It defines the step by step process to determine:

1. If this HCA is susceptible to the manufacturing threat?
2. If the answer is yes then the process describes whether the threat is prioritized as high, medium or low susceptibility.

Tables A-4-1 and Table A-4-2 are based upon the "Pre-1970 ERW, Lap Welded, and Flash Welded Line Pipe Integrity Review" dated 10/25/2006.

Table A-4-1: Pre-1970 ERW, Lap Welded, or Flash Welded Pipe with a Failure History

Manufacturer	Seam Type	In-Service Years	Diameters
A.O. Smith	FW	Prior to 1967	All
Jones & Laughlin	Lap Welded	Prior to 1952	8.625" or less
Kaiser	ERW	Prior to 1964	Less than 20"
Lonestar	ERW	Prior to 1968	Less than 20"
National Tube	Lap Welded	Prior to 1939	All
Republic Steel	ERW	Prior to 1961	Less than or equal to 16"
South Chester	Lap Welded	Prior to 1947	6.625"
Stupp	ERW	1965	12.75"
Youngstown Sheet & Tube	ERW	Prior to 1960	All

Table A-4-2: Other Pipe with a History of Manufacturing Failure

Manufacturer	Seam Type	In-Service Years	Diameters
Consolidated or Consolidated Western	DSAW	Prior to 1958	20" and greater
Kaiser	DSAW	Prior to 1957	30"
Kane	DSAW	Prior to 1956	30"
National Tube	DSAW	Prior to 1960	All
Republic Steel	DSAW	Prior to 1957	22" through 30"
Taylor Forge	DSAW	Prior to 1953	All
Tubacero	DSAW	1963 and 1964	36"
United States Steel	ERW-HF	1967 through 1982	16" and 20"

There are other factors and questions that will be considered during the Subject Matter Expert phase of threat identification and prioritization:

	Default Answer
1. Is there a history of pressure cycles that make this pipeline susceptible to cyclic fatigue?	No
2. Ask this question if this segment has never been hydrostatically tested or it has had a manufacturing failure after testing. Also ask it if the pipe is pre-1970 ERW, lap-welded, or FW pipe that has had a history of seam failure. Has this HCA's operating pressure increased over the maximum operating pressure experienced during the five years preceding identification of the HCA?	No
3. If there is a manufacturing threat, is this HCA in an area that could experience frost heave?	No

If the answer to any of these other factors is different than the default, then we will re-evaluate the threat susceptibility answer and the threat priority.

This is the process that considers pressure cycles interacting with the manufacturing threat.

Flags/Alerts that initiate a re-evaluation of this Threat

If any of the following events occur then the manufacturing threat will be re-evaluated for this HCA prior to the next scheduled "all threats" evaluation.

	Quarterly Re-evaluation	Next Annual Re-evaluation
Leak or failure caused by a manufacturing issue in the HCA or in the buffer area (defined in TIP)	X	
Has the HCA operated or are there plans to operate the pipeline above the 5-year high pressure recorded prior to the HCA being identified (917(e)(3&4)		X
The pipe in the HCA becomes subject to land movement or removal of supporting backfill.		X
As recommended by Area Operations or Pipeline Services.		X

Assessment Method Options

The following integrity assessment method applies toward the manufacturing threat:

- Pressure Test

The assessment method table and details on choosing an assessment method for each HCA see Chapter 4.

Other Items:

For determining preventive and mitigative measures appropriate for the manufacturing threat, see Chapter 12.

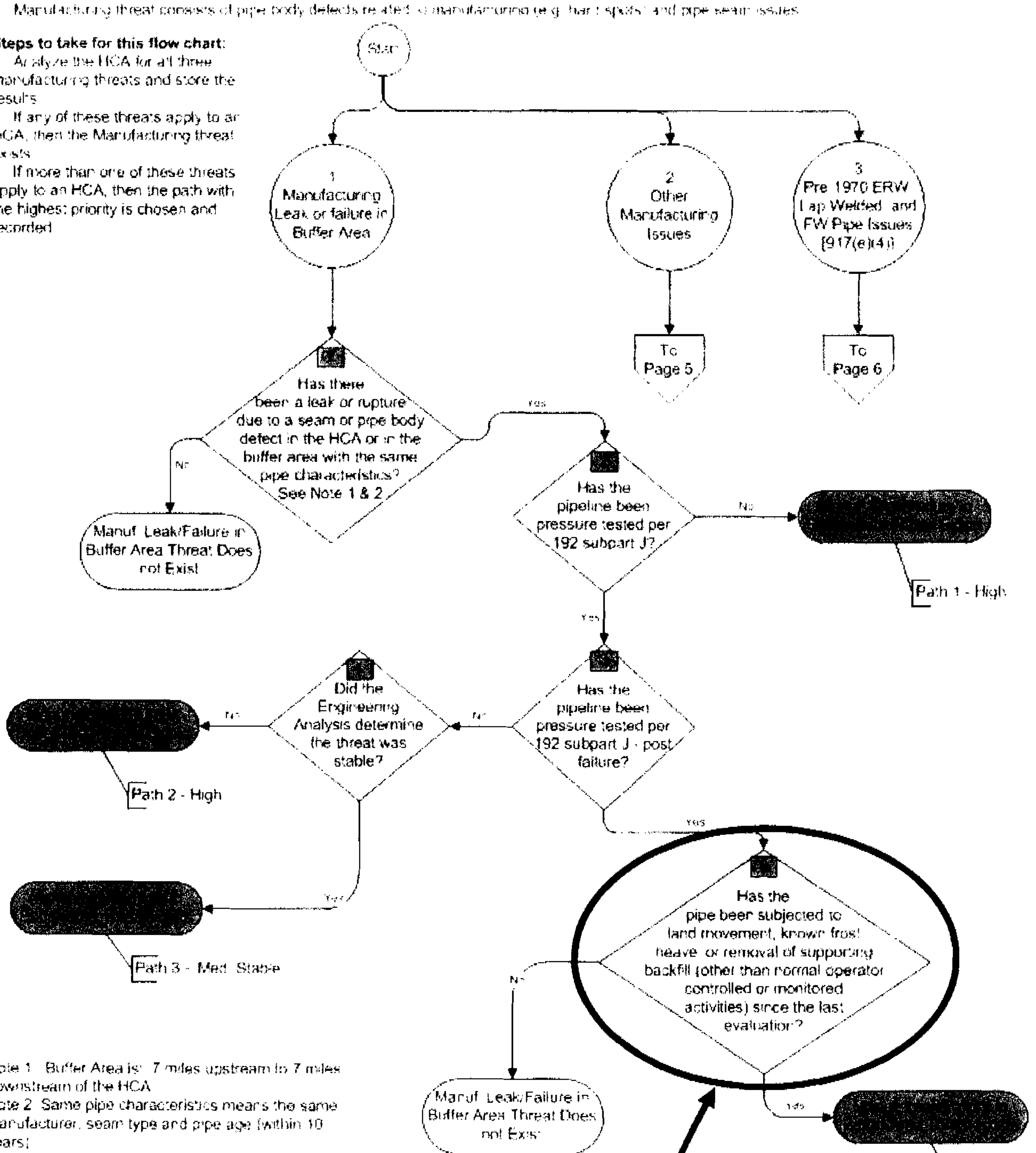
For determining the re-assessment interval for an HCA see Chapter 11.

Performance measures specific to this threat are identified in Chapter 13.

Appendix A-4 Manufacturing Threat - TIP Chart

Manufacturing threat consists of pipe body defects related to manufacturing (e.g. hard spots) and pipe seam issues.

Steps to take for this flow chart:
1. Analyze the HCA for all three manufacturing threats and store the results
2. If any of these threats apply to an HCA, then the Manufacturing threat exists
3. If more than one of these threats apply to an HCA, then the path with the highest priority is chosen and recorded



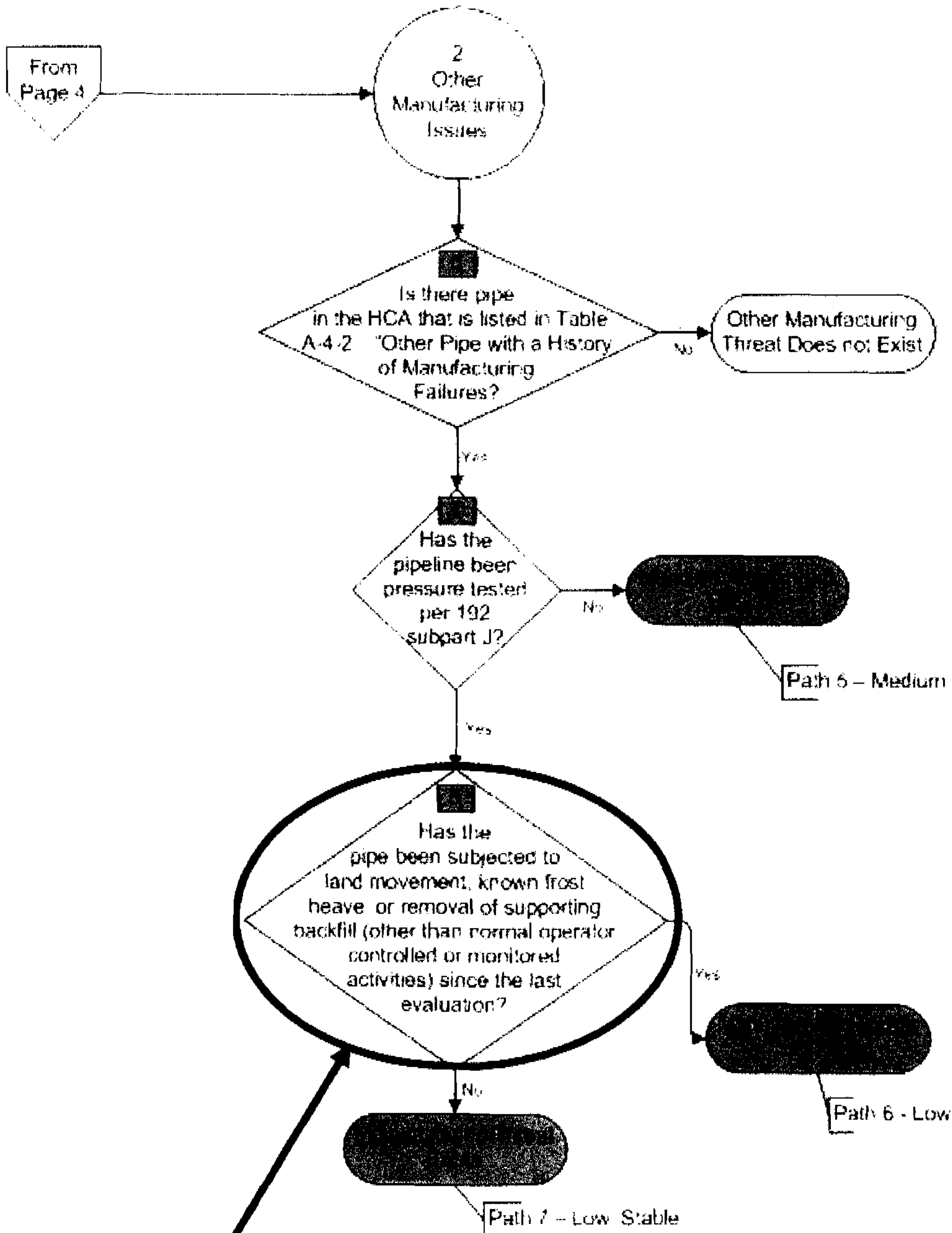
Note 1. Buffer Area is: 7 miles upstream to 7 miles downstream of the HCA
Note 2. Same pipe characteristics means the same manufacturer, seam type and pipe age (within 10 years)

See the Threat Checklist for Other Factors to consider

IMP Database Question Number

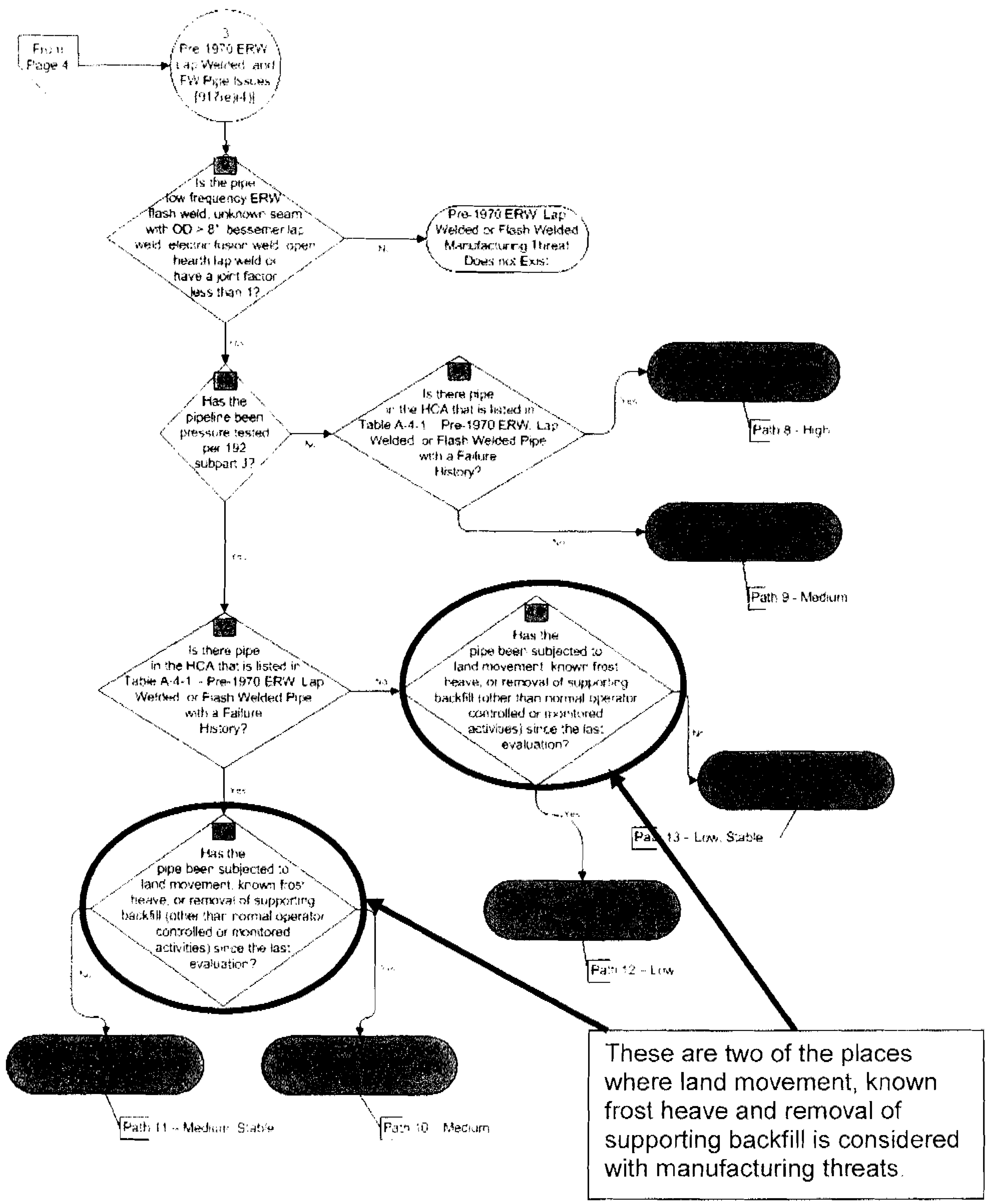
This is one of the places where land movement, known frost heave and removal of supporting backfill is considered with manufacturing threats.

Appendix A-4 Manufacturing Threat - TIP Chart (continued)



This is one of the places where land movement, known frost heave and removal of supporting backfill is considered with manufacturing threats.

Appendix A-4 Manufacturing Threat - TIP Chart (continued)



This Appendix includes the process described on slide 42 of the EPPG and ANR presentation to PHMSA at the 4/30/2008 NOPV hearing See page 1, 3, 4, and 5

Appendix A-5 Construction Threat Checklist

Definition and Scope

The Construction threat is defined for the Integrity Management Plan as defective pipe girth weld, defective fabrication weld, wrinkle bend or buckle, stripped threads, broken pipe, or coupling failure.

Data Requirements

The data specific to the construction threat is identified in the "List of IMP Data Requirements" in the appendix. This includes data description, sources of data, party responsible for validating the data, and assumption made when no data is available.

Threat Checklist and Prioritization

The Construction Threat Identification Process is attached to this checklist. It defines the step by step process to determine:

1. If this HCA is susceptible to the construction threat?
2. If the answer is yes then the process describes whether the threat is prioritized as high, medium or low susceptibility.

There are other factors and questions that will be considered during the Subject Matter Expert phase of threat identification and prioritization:

	Default Answer
1. Is there a history of pressure cycles that make this pipeline susceptible to cyclic fatigue?	No
2. Ask this question if this segment has never been hydrostatically tested or it has had a construction failure after testing. Has this HCA's operating pressure increased over the maximum operating pressure experienced during the five years preceding identification of the HCA?	No
3. Are there known or uninvestigated saddle pad reinforcement issues in this HCA?	No

If the answer to any of these other factors is different than the default, then we will reevaluate the threat susceptibility answer and the threat priority.

Flags/Alerts that initiate a re-evaluation of this Threat

If any of the following events occur then the construction threat will be reevaluated for this HCA prior to the next scheduled "all threats" evaluation.

This is the process that considers pressure cycles interacting with the construction threat.

	Quarterly Re-evaluation	Next Annual Re-evaluation
Leak or failure caused by a Construction issue in the HCA or in the buffer area (defined in TIP)	X	
Has the HCA operated or are there plans to operate the pipeline above the 5-year high pressure recorded prior to the HCA being identified (917(e)(3&4)		X
The pipe in the HCA becomes subject to land movement or removal of supporting backfill.		X
As recommended by Area Operations or Pipeline Services.		X

Assessment Method Options

The following integrity assessment method applies toward the construction threat:

- Pressure Test

The assessment method table and details on choosing an assessment method for each HCA see Chapter 4.

Other Items:

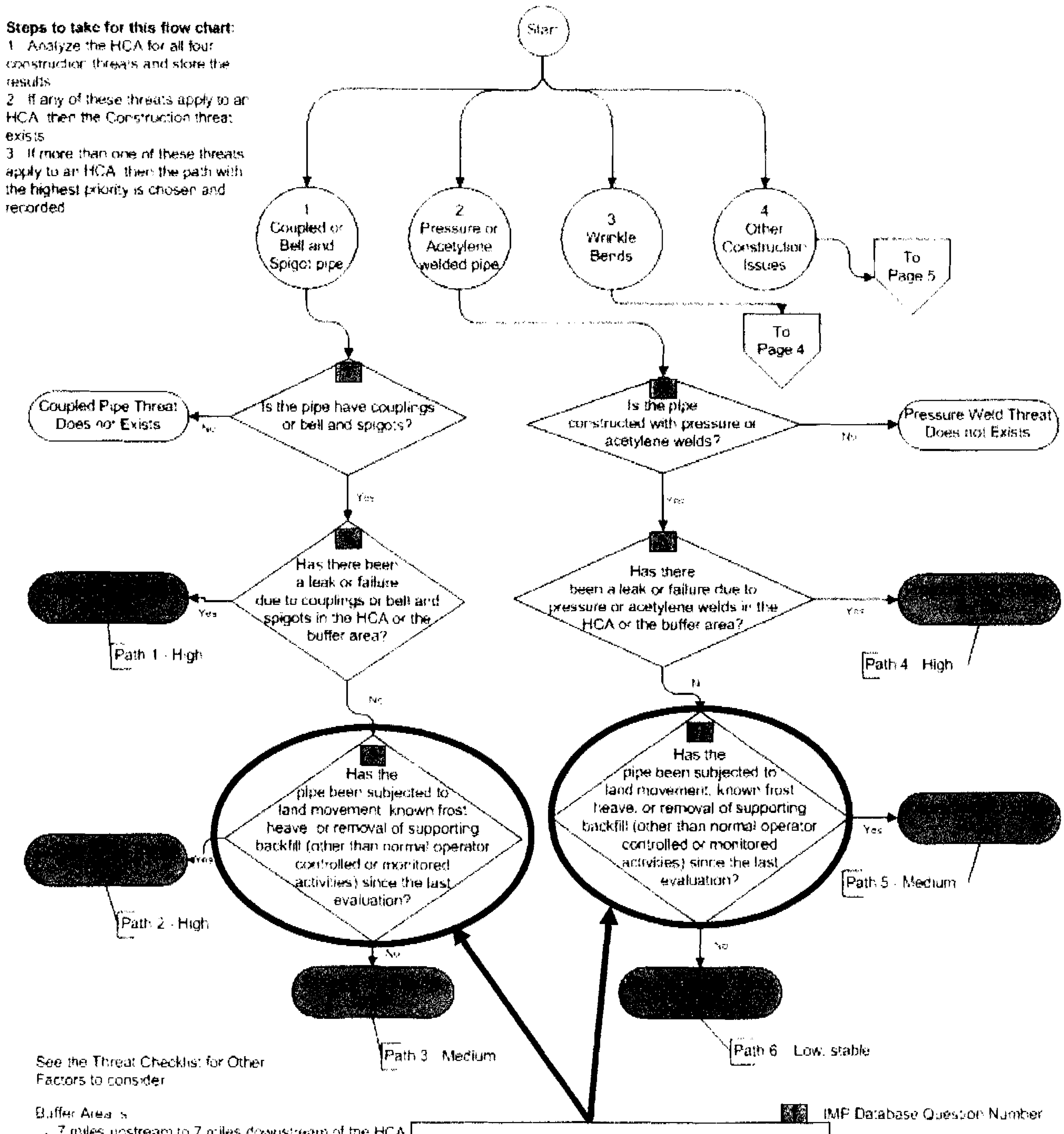
For determining preventive and mitigative measures appropriate for the construction threat, see Chapter 12.

For determining the re-assessment interval for an HCA see Chapter 11.

Performance measures specific to this threat are identified in Chapter 13.

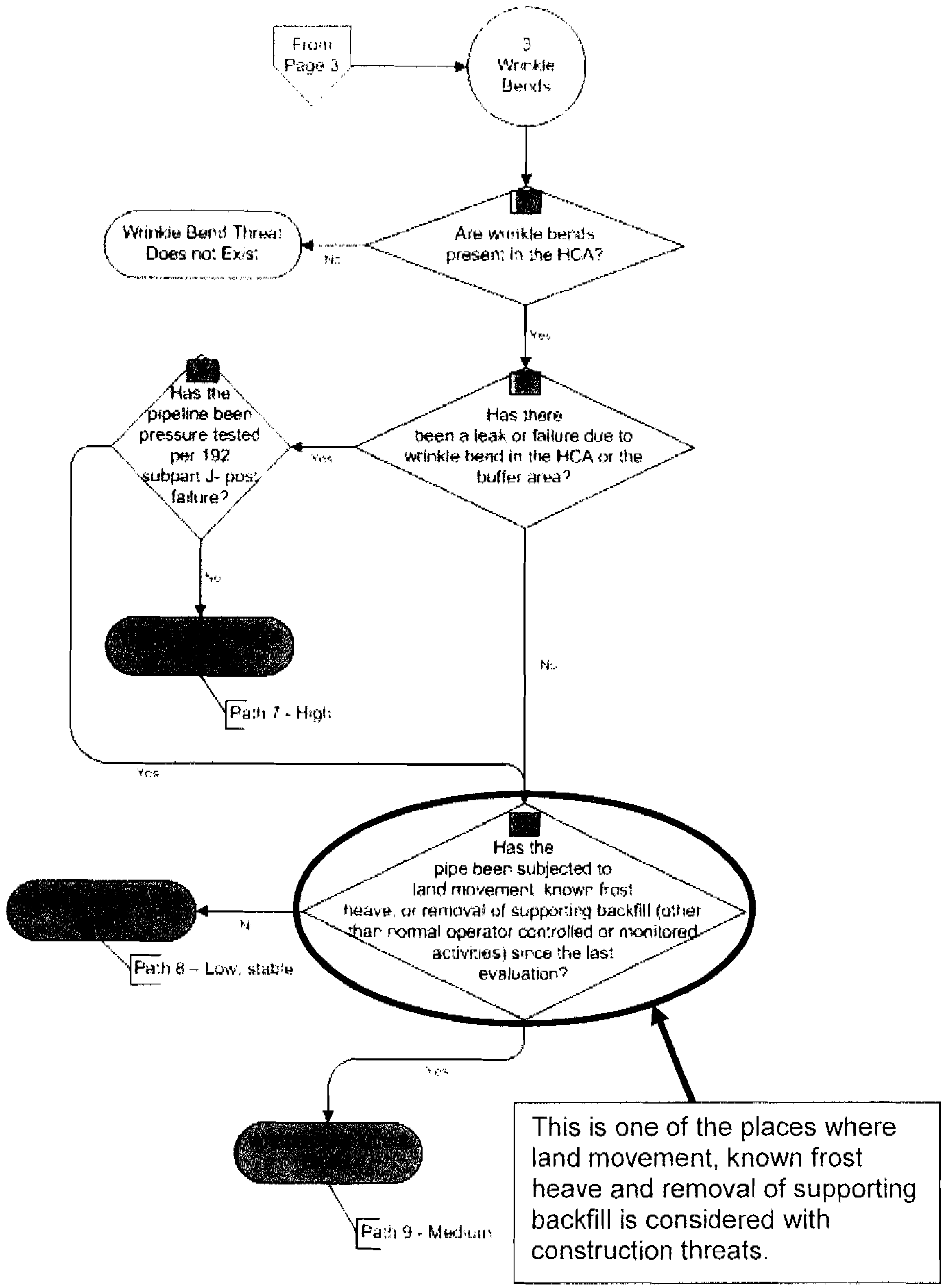
Appendix A-5 Construction Threat - TIP Chart

Construction threat is defined as: defective pipe girth weld, defective fabrication weld, wrinkle bend or buckle, stripped threads/broken pipe/coupling failure



These are two of the places where land movement, known frost heave and removal of supporting backfill is considered with construction threats.

Appendix A-5 Construction Threat - TIP Chart (continued)



Appendix A-5 Construction Threat - TIP Chart (continued)