**TERRY D. BOSS**
VICE PRESIDENT, ENVIRONMENT, SAFETY & OPERATIONS

Attn: Docket PHMSA–2008–0255
Department of Transportation, PHMSA
1200 New Jersey Ave, SE
E22-328
Washington, DC 20590

**INGAA Comments to**
**Pipeline Safety: Workshop on Anomaly Assessment and Repair**

INGAA would like to file the following information to docket PHMSA–2008–0255 in order to clarify the INGAA position discussed in the previously filed document.

There has been Corrective Action Orders (CAO) published recently (Columbia Gas 420071017H and Transco 120081004H ) that addressed the evaluation, response, repair and mitigation of anomalies found during in-line inspection. In addition PHMSA has proposed and finalized criteria in the rulemaking titled "**Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines".**

INGAA is concerned that these positions by PHMSA vary from accepted consensus standards and practices of the natural gas transmission pipeline industry. Also, it appears that the PHMSA positions vary between the recently published CAOs (e.g. Remedial Work Plans) and even with the newly published rule even though they are addressing the same technical issues.

INGAA held a meeting with PHMSA representatives on June 12, 2008 to explain the technical, operational and regulatory basis for the consensus practices and the results of those practices. PowerPoint slides that document the INGAA presentations at the meeting have been previously filed in this docket.

Attached is a white paper that INGAA authored on the "**Evaluation, Response, Repair and Mitigation of Anomalies Found During In-Line Inspection**". This paper describes the position of INGAA on this subject and provides additional justification for the positions that were discussed on June 12, 2008. While some of the positions that INGAA supports in this paper have no apparent conflict with specific sections of the recently released rulemaking on increasing MAOP, it does address conflicts with recently issued CAOs.

Respectfully Submitted by,

Terry D Boss

**INGAA Proposed Approach to the Evaluation, Response, Repair and Mitigation of Anomalies Found During In-Line Inspection**

## Introduction

Interstate Natural Gas Association of America (INGAA) members, representing approximately two-thirds of the gas transmission pipeline mileage in the United States, met recently with PHMSA to explore outstanding issues and work toward a common understanding and agreement regarding the evaluation, response timing, repair and mitigation requirements for time-dependent anomalies found by in-line inspection on natural gas transmission pipelines. In this paper, INGAA sets forth an approach to managing time-dependent anomalies identified using in-line inspection (ILI) with a technical rationale for each element of the proposal that has a foundation in a consensus standard, research and where possible the regulations.

INGAA members are committed to preventing failures on their pipeline systems. They believe that consistency of approach to addressing anomalies on pipelines enhances safety. In general, INGAA members have elected to manage anomalies and make repairs using American Society of Mechanical Engineers (ASME) B31.8S as the technical foundation, whether in an HCA, or a non-covered segment, i.e., outside of an HCA. INGAA believes this approach is also valid for pipelines operating under Maximum Allowable Operating Pressure (MAOP) or "class location" Special Permits, and ultimately under a regulation addressing design and operation using higher design factors [as set in the Final Rule for Increasing the MAOP in Gas Transmission Pipelines, October 17, 2008]. INGAA also believes this approach is applicable to the work completed to support extending of integrity management reassessment intervals longer than seven years.

## Background

This proposal addresses two topical areas:

1. Time-Dependent Anomaly evaluation and response, and
2. Defect repair and mitigation.

**Anomaly evaluation and response** pertains to the activities that occur after receiving a report from an ILI vendor, including evaluation of anomalies and pipeline data to determine which anomalies require action "are actionable"), and responding in a prudent and diligent manner. **Defect repair and mitigation** refers to those activities related to examining the pipe and subsequent repair and mitigation; including long-term preventive and mitigative measures.

The time-dependent anomalies under consideration have been further subdivided into two groups, one of which is a relatively recent consideration for natural gas transmission pipeline integrity considerations. The two groups are,

1. Time-dependent anomalies that can result in rupture of a natural gas transmission pipeline and,
2. Time-dependent anomalies that can produce leaks in natural gas transmission pipelines.

*Time-dependent anomalies resulting in ruptures.*
Anomalies that can result in ruptures are the focus of the integrity management regulations, 49 CFR 192, Subpart O. The anomaly evaluation methods noted in the regulations, primarily B31G and RSTRENG, provide the operator with guidance on the calculation of predicted rupture pressure of a pipeline in the presence of a corrosion defect (time dependent). The standard relied upon frequently in the Subpart O regulations, referred to as ASME B31.8S, also provides guidance, in Figure 4 and accompanying material, on response timing to corrosion anomalies based on their calculated failure pressure ratio, again, using the calculated rupture pressure. This standard is based on research, empiracle data and is reasonable, understandable, and was thoroughly discussed and vetted during the development of the Subpart O regulations.

A pipeline rupture is the event the integrity management regulations are designed to prevent. It constitutes the highest rates of energy release from a pipeline, the potential highest consequences, and has been the event given the most attention by PHMSA. A rupture is much more likely to rise to the level of a reportable incident, as defined in the regulations. Incidents must be telephonically reported within a few hours of occurrence, and require at least one written report, which has become more and more detailed over the years. Incidents may also result in regulatory actions, in the form of Corrective Action Orders, which require both actions and periodic reporting by the operator.

There has been some misunderstanding regarding the applicability of these analytical methods, such as RSTRENG, to relatively short, deep corrosion pits. Such pits are much more likely to result in leaks rather than ruptures. Generally, RSTRENG and B31G are not used on features deeper than 80% of the wall thickness. This is not, however, because the calculations become invalid at that point. The calculated failure pressures (ruptures) are still valid. Rather, a decision was made to limit the application of these methods to no more than 80% penetration because it was believed that remaining pipe wall thickness was close enough to perforation that an operator would have to take some action regardless of the result. However, the actions a natural gas transmission pipeline operator may take could be very different from those a natural gas distribution operator would take, due to the safety implications. A single, prescriptive approach between these two applications is not appropriate or justified here.

*Time dependent anomalies resulting in leaks.*
Historically, leaks on natural gas transmission pipelines have been regarded as not nearly the integrity threat nor the safety risk as ruptures. Recent INGAA analysis of the PHMSA reportable incident database confirms that belief. "Serious" and "Significant" incidents that are caused by these anomalies are reported to and cataloged by PHMSA and have been used as a data reference. This is not to say that they are disregarded or viewed as acceptable or not constituting any risk. There are many requirements in the regulations and in the underlying standards that provide guidance on surveying for and dealing with leaks. Examples are the leak surveys required as part of pipeline patrols and continuing surveillance, the instrumented leak detection surveys required in specific locations, the information on recognizing, reporting and responding to leaks that is required to be part of the public awareness programs, and the requirement that potentially hazardous leaks be repaired.

Natural gas transmission leaks are not ignored. However, historically, the management of potential leaks has been different than the management of potential ruptures. This is clear from the differential PHMSA reporting requirements and categorization. In contrast to the attention given ruptures that rise to the level of a reportable incident, a leak typically does not rise to that level and is reported on the PHMSA natural gas transmission pipeline annual report. Additionally, If a leak occurs in a high consequence area, it is also reported on the semiannual gas transmission integrity management program report. The differentiation is also clear from the PHMSA regulatory treatment of pipeline casings. PHMSA has noted that an operator, after unsuccessfully attempting to clear a cathodic protection electric short, may sniff the casing to detect leaks at a moderately increased frequency from normal rather than taking more drastic action. Also, during the development of the natural gas transmission integrity management regulations, leaks were not considered in the determination criteria of high consequence areas. Elevating leaks as an integrity and safety concern on natural gas transmission pipelines to the same level a ruptures is a bit problematic at this time, as guidance and criteria similar to those applied to ruptures have not been developed.

In comparison, leaks are a prime focus on distribution systems. Distribution systems are typically pipelines of a size and operating pressure that minimizes the probability of rupture. These pipelines are also much more likely to be in close proximity to occupied structures, other utilities and other concentrations of population. Further, the much lower operating pressures make a readily-identifiable blowing leak, such as may be experienced on a transmission line, much less likely, while more likely resulting in a difficult to detect underground migration of the escaping low pressure gas.

While it is technically correct and reasonable to have a different assessment of leaks depending on whether they are on a transmission or distribution line, there may be some commonalities. Distribution operators typically grade leaks depending on proximity to occupied structures. A similar approach may be valid for transmission lines, perhaps utilizing criteria such as those already developed for reporting a safety-related condition.

## ***Anomaly Evaluation and Response***

**INGAA Proposal: Anomaly response and evaluation will be managed using Figure 4 and Table 3 of ASME B31.8S. Anomalies with a failure pressure ratio (FPR) of 1.1 or less will be managed as an immediate. In addition, anomalies greater than 80% in depth but with an FPR > 1.1 will be managed as a near-term potential leak and be evaluated per safety-related condition type criteria or managed as a scheduled response condition, whichever is more stringent.**

***Technical basis:*** Time dependent anomalies with an FPR < 1.1 require immediate examination as per ASME B31.8S. Time dependent anomalies greater than 80% in depth but with an FPR > 1.1 do not require immediate examination. The basis for establishing the 80% threshold is that the corrosion evaluation methods are not typically applied above a limit of 80% through wall, as stated in ASME B31G, Part 2[1], because the anomaly is believed to be near perforation and should be evaluated as a potential leak, if not overridden by a low FPR.

It is important to understand the basis for the use of 1.1xMAOP. The basis or the 1.1 relies on the requirements for over pressure protection at 192.201(a)(i). That is, the pipe will not ever see more than 1.1xMAOP, as the OPP will moderate the pressure. This provides time for the operator to schedule an examination.

**INGAA Proposal: Anomalies with a FPR greater than 1.1 and less than the SMYS equivalent will be scheduled using Figure 4. In addition, when the operator has information that corrosion rates in a segment are greater than the basis used for Figure 4, the operator will develop a schedule for excavation of anomalies that applies the more conservative corrosion rate[2].**

***Technical basis:*** While Figure 4 was developed to be conservative in most instances and to provide a basis for a simple, prescriptive approach, there is a concern that there can be situations where Figure 4 is not sufficiently conservative. The developers of ASME B31.8S foresaw this possibility and in paragraph 7.2.4 required the operator to perform analyses to assure that the time-dependant defect will not grow to a critical size before the scheduled response.

***Additional Discussion:*** INGAA members are sensitive to the concern raised by PHMSA personnel regarding the potential for short, deep anomalies to grow to a depth of 80% faster than they may grow in depth and length to 1.1xMAOP. However, knowing PHMSA's commitment to being data driven, INGAA is unaware of the specific data or experience driving PHMSA's concern in this regard. In submitting this, INGAA formally requests PHMSA to provide the data and analysis of the actual known events.

The remaining life methods are typically not applied above this limit of 80% of depth, not because the calculations no longer apply, but rather because such features are much more likely to result in leaks rather than ruptures. The behavior of short, deep anomalies was considered in the initial development of Figure 4 and its use with B31.8S. It was

[1] - The limit of 80% is a limit of application from a practical standpoint rather that a limitation of accuracy (Kiefner).

[2] - Segment specific knowledge can be applied for rates that are known to be slower than the rate derived from Figure 4; however, operators will not apply this approach until there are at least two completed ILI runs on the segment.

acknowledged that given the nature of corrosion pits that an anomaly can grow to 80% depth sooner than it may grow in length and depth to reach the 1.1xMAOP threshold. It is important to note that when very short, deep anomalies grow, they grow in depth, will perforate, and result in a leak. Short, deep anomalies that grow in length and depth will likely grow in a manner that is modeled by the methods applied in Figure 4, and should be identified before they result in a rupture.

ASME B31G also specifically addresses short deep anomalies. One of the steps in the evaluation process is the determination of the maximum allowable longitudinal extent of corrosion, as described in Figure 1-2, page 6. If the length of the corrosion is less than or equal to the value calculated in Part 2 (or found from the table), then the operator is to arrest further corrosion and return to service.

While the results of many of the ILI runs that have conducted on natural gas transmission systems within the past decades have shown the long term effectiveness of the corrosion protection systems in mitigating corrosion, the industry has chosen to utilize conservative default corrosion (not protected by corrosion protection systems) rates where additional information is not available.

Consider an example with 30-inch diameter pipe with 0.281-inch nominal wall thickness. This is a worst-case example of a typical pipeline that will utilize ILI technology, as this example has a higher diameter/thickness ratio of 107 than most pipelines in service and therefore has less wall thickness. PHMSA personnel have expressed concern about the growth of even a 60% of wall thickness deep pit to a leak or failure prior to the next ILI assessment. The anomaly that is 60% in depth has approximately 112 mils of pipe wall material remaining.

If one uses a conservative corrosion growth rate of 12[3] mils per year, this results in 9.3 years to perforation (leak), and with 9 mils per year, this results in 12.4 years to perforation; both of which are greater than default seven years assement period required by the IMP rule, so

[3] Typical corrosion rates for unprotected, pipe with a coating defect have been observed in the range of 1 to 6 mils per year. PHMSA personnel frequently quote 16 mils per year used in the NACE ECDA RP 0502. The rate of 16 mils was to be applied as a default rate where no other information were available; 12 mils could be used where the system had been under cathodic protection for much of its life. It is important to note that the rate used in the NACE RP was selected through consensus to represent a very conservative position since ECDA was a new method. It is inappropriate, or at best overly conservative to apply these rates when evaluating ILI data.

these corrosion anomalies would be observed again during a future ILI run, prior to the possibility of perforation (leak) due to non-protection by corrosion protection systems. A refined and localized “assumed corrosion rate” can be utilized to optimize this determination but additional location specific information is needed.

In developing this proposal, INGAA considered a number of examples and found that while the timeframe to grow to 80% in depth may be shorter may be slightly shorter than to rupture, given the conservatism built into Figure 4 and the fact that the growth is developed to 1.1xMAOP, and not to failure, use of timing in Figure 4 is appropriate.

After considering the historical perspective, available data and the conservative nature of the approach, INGAA believes **reaffirmation of Figure 4 for scheduling anomalies remains a sufficiently conservative and appropriate basis.**

To further provide clarity on this subject, the ASME B31 Committee will consider an (AI) on this topic. INGAA members believe that this type of change is best undertaken through the deliberative process undertaken under the ANSI-based consensus standards development code. INGAA expects that members of the Committee (including PHMSA) and INGAA staff will apprise PHMSA of progress. In addition, the Committee will benefit from the presence of Mr. Mike Israni, of the PHMSA staff, on this and others matters under consideration as a member of the Committee.

It is important to understand that the current consensus standards and PHMSA regulations recognize that leaks will occur and are managed by operators. INGAA recognizes the concern with leaks that might be hazardous to people and property. The current regulations address management of leaks through prevention, patrolling and leak surveys. In addition, in the MAOP NOPR, PHMSA proposed more stringent design construction operation and maintenance requirements to address corrosion issues. One of those practices is more frequent patrolling as well as more frequent leak surveys. INGAA members agree that the frequency must be increased and provided specific criteria in their comment responses.

***Differences between discovered anomalies in High Consequence Areas (HCAs) versus non-covered segments, i.e., those outside of HCAs.***

In general, there are none. INGAA members expect to treat time-dependent anomalies the same. **It is important to note that for non-covered segments, i.e., outside of HCAs, the standards and regulation are performance based, and do not specifically require the use of B31.8S.** INGAA members' offering to apply Figure 4 outside of HCAs is not required by PHMSA and is believed to be prudent. As such, while members have largely elected to adopt the use of B31.8S, and specifically Figure 4 and Table 3 for anomaly evaluation and response, operators can modify their approach, even relying on B31.8S to account for local conditions, predicted corrosion rates and other factors.

## ***Repair and Mitigation***

**INGAA Proposal: Time dependent anomalies identified by the "anomaly evaluation and reponse process" will be visually examined and those found to have a safe operating pressure less than or equal to MAOP will be repaired or cut out. Time-dependent anomalies that are found to have a safe operating pressure greater than MAOP can be recoated, backfilled and returned to service.**

***Technical Basis:*** The examined pipe will be repaired to maintain integrity based on the Specified Minimum Yield Strength (SMYS), which is a conservative measure of the strength of the material. For pipe that has a safety design factor of 72% the repair threshold would be 1.39xMAOP. Conversely, for a 0.6 design factor it would be 1.67xMAOP and 2.0xMAOP for a 0.5 design factor. Under all circumstances, the pipe, whether repaired, cut out and replaced, or left in place following examination, is recoated with brand new materials, reestablishing the first line of defense in corrosion control and be subject to a review of the effectiveness of the corrosion protection system.

**INGAA Proposal: In areas where the "class bump" has been taken to maintain the original MAOP as provided for in 49 CFR 192.611, the repair will be made to SMYS based on the established MAOP.**

***Technical Basis:*** The basis for this is established in ASME B31G, Part 4.

***Differences between defects in High Consequence Areas (HCAs) versus non-covered segments, i.e., those outside of HCAs.***
The repair criteria are the same. There are differences in the preventive and mitigative measures used within HCAs, as they are managed to a higher standard, a greater level of care. The preventive and mitigative measures are set forth in ASME B31.8S, Section 7.7, and specifically in Table 4, and in 49 CFR 192.935. It is important to note that there are preventive and mitigative measures that are applied in non-covered segments as established in ASME B318 and 49 CFR 192, Subpart I – Requirements for Corrosion Control, including requirements for coating, cathodic protection, monitoring of cathodic protection, isolation and management of interference currents and periodic testing of potentials to ensure adequate coverage. In either case, there is a broad array of preventive and mitigative measures used.

## Summary

In summary, INGAA concludes and recommends the following:

1. ASME B31.8S Figure 4 and accompanying material are valid the timing of responses to corrosion anomalies found by ILI.

2. RSTRENG and ASME B31G are valid methods for determining the calculated failure pressure of corrosion anomalies and defects.

3. Short, deep features (> 80% wall loss) with a relatively high FPR should be treated as a near term leak and evaluated using criteria similar to those for reporting a safety-related condition. Further, if the operator has information suggesting such features are stable rather than active, and they do not meet the action criteria, they may be treated as monitored.

# Anomaly Evaluation, Response, and Repair Summit

Presentation by

INGAA

June 3, 2008

# Context of Today's Meeting

- Basis for Anomaly evaluation and response has become an issue on:
  - Enforcement
    - Integrity Management Audits
    - Correction Action Orders
  - Special Permits
    - MAOP
    - Class Change
  - Extending Re-assessment Interval
  - Inspections
    - O&M
    - Integrity Management

# Concerns

- Varying opinions from PHMSA
- Lack of technical basis for some opinions
- Substantial impact of varying opinions
- Concern about bypassing regulatory and standards process
- Some concerns voiced in INGAA comments to “Interim Final Rulemaking” and “80% Rulemaking”

# Our Goal Is Incident Free Operation

-

# Sequence of Presentation

- What are we doing now
- What we think the regulations and standards mean
- What the research says
- No apparent increase in safety risk
- Large Impact on pipeline companies

# Presentation Agenda and Presenters

1. "Standards and Regulations"- Chris Bullock, CenterPoint
2. "Current Practices in INGAA Companies" - Bob Travers, Spectra Energy
3. Break
4. "Research" - Dave Johnson, Panhandle Energy, Mike Rosenfeld, Kiefner and Associates, Inc. and Keith Leewis, P-PIC
5. "Safety Risk" - Frank Dauby, PG&E
6. "Impact of Change" - Chris Whitney, El Paso

# Standards and Regulations

**Chris Bullock**
CenterPoint Energy

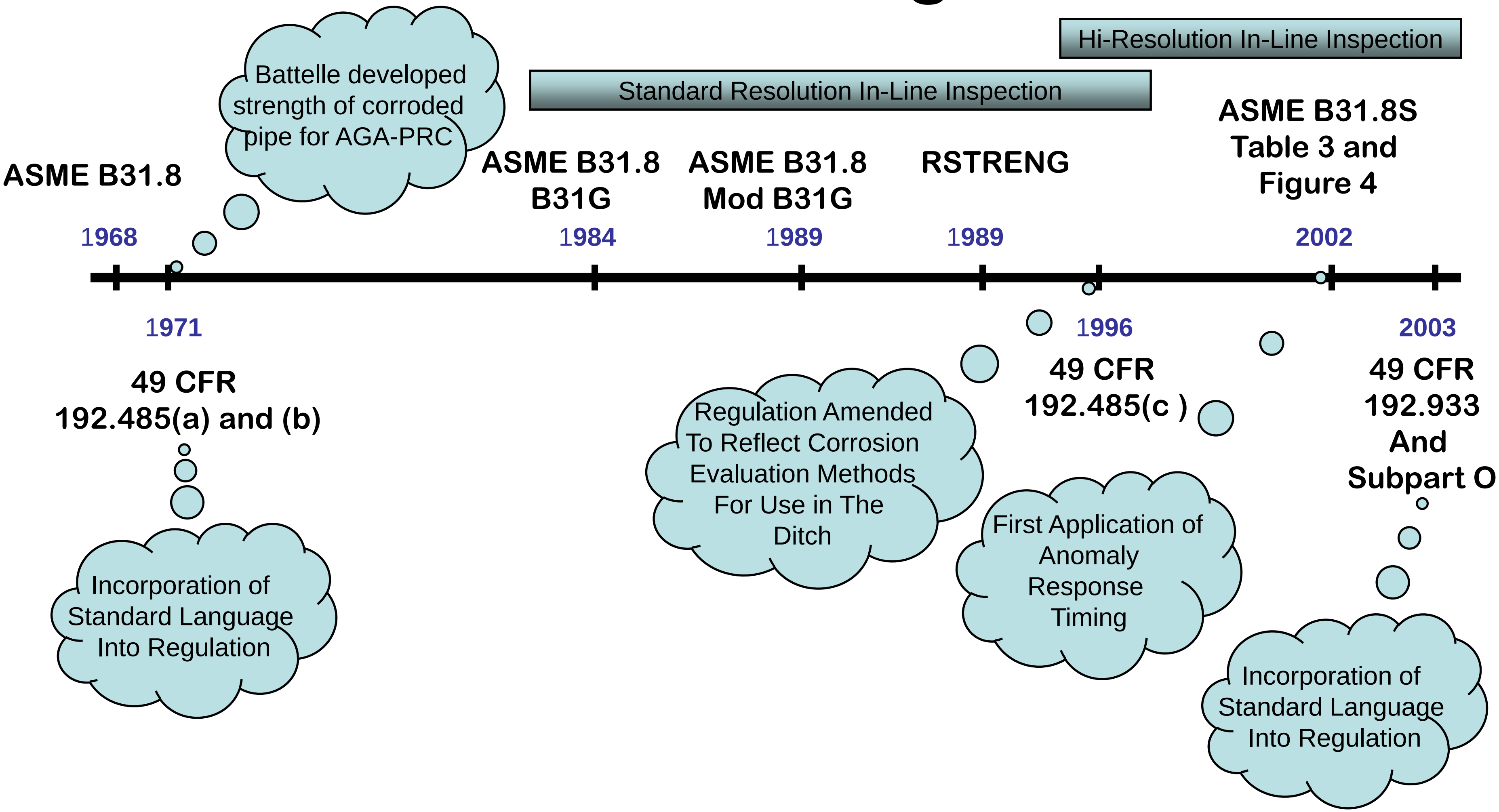
# Definitions

- Anomaly Response Criteria
  - Applies to ILI after receipt of ILI log/report
  - How soon must the anomaly be investigated?
- Defect Repair Criteria
  - Applies to actions in the bell hole
  - What defects must be repaired?

# Applicable Consensus Standards and Regulations

- Anomaly Response Criteria
  - General - ASME B31.8S, §7.2, Table 3 and Figure 4; 49 CFR 192.933
- Defect Repair Criteria
  - General - ASME B31.8, §851.4, §862.213; 49 CFR 192.711, 713, 485. ASME B31.8S, §7.2 (and Table 4); 49 CFR 192.713

# Evolution of Standards and Regulations



# ASME B31G – 1984, 1991, 2004

- 1.6 THE MEANING OF ACCEPTANCE

  (a) Any corroded region indicated as acceptable by the criteria of this Manual for service at the established MAOP is capable of withstanding a hydrostatic pressure test that will produce a stress of 100% of the pipe SMYS.
- 4.2 COMPUTATION OF P’

  P’ is a function of P

  P equals the greater of either the established MAOP (192.611 or 619) or 2*S*t*F*T/D
- 4.3 MAOP AND P’

  If the established MAOP is equal to or less than P’, the corroded region may be used for service at that MAOP. If it is greater than P’ then a lower MAOP should be established not to exceed P’ or the corroded region should be repaired or replaced.

# ASME B31.8

- 862.213 Repair of Corroded Pipe. If the extent of corrosion has reduced the strength of a facility below its maximum allowable operating pressure, that portion shall be repaired, reconditioned, or replaced, or the operating pressure shall be reduced, commensurate with the remaining strength of the corroded pipe. For steel pipelines operating at hoop stress levels at or above 40% of the specified minimum yield strength, the remaining strength of corroded pipe may be determined in accordance with Appendix L. For background information on Appendix L, refer to ANSI/ASME B31G, titled Manual for Determining the Remaining Strength of Corroded Pipelines.

# General Regulations – In The Ditch

- Sec. 192.485 Remedial measures: Transmission lines.
  (a) General corrosion. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

# ASME B31.8S-2001, 2004

- 7.2.1 Metal Loss Tools for Internal and External Corrosion. Indications requiring immediate response are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. This would include any corroded areas that have a predicted failure pressure level less than 1.1 times the MAOP as determined by ASME B31G or equivalent.

  Indications in the scheduled group are suitable for continued operation without immediate response provided they do not grow to critical dimensions prior to the scheduled response. Indications characterized with a predicted failure pressure greater than 1.10 times the MAOP shall be examined and evaluated according to a schedule established by Fig. 4.

# ASME B31.8S

- Developed for managing system integrity (HCAs and non-HCAs)
- Operators can elect to use Table 3 and Figure 4 as basis for anomaly response timing

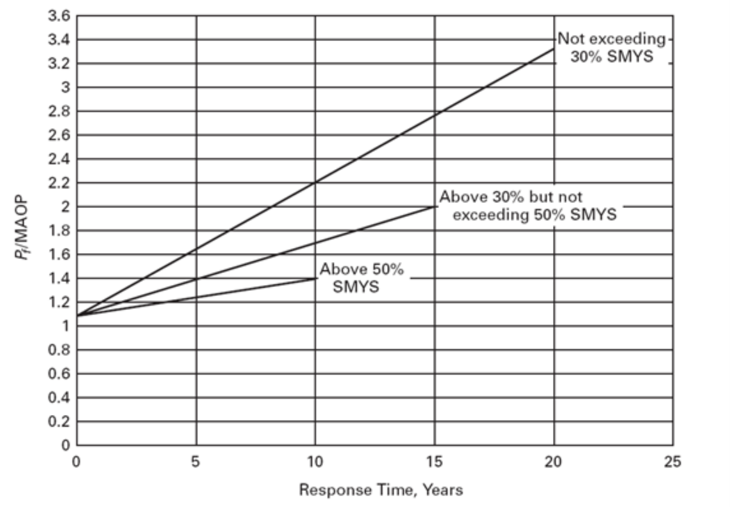



Fig. 4 Timing for Scheduled Responses: Time-Dependent Threats, Prescriptive Integrity Management Plan

# ASME B31.8S

## Table 3 defines assessment methods and end points

Table 3 Integrity Assessment Intervals:
Time-Dependent Threats, Prescriptive Integrity Management Plan

| Inspection Technique | Interval (Years) [Note (1)] | Criteria: At or Above 50% SMYS | Criteria: At or Above 30% up to 50% SMYS | Criteria: Less Than 30% SMYS |
|---|---|---|---|---|
| Hydrostatic testing | 5 | TP to 1.25 times MAOP [Note (2)] | TP to 1.4 times MAOP [Note (2)] | TP to 1.7 times MAOP [Note (2)] |
| | 10 | TP to 1.39 times MAOP [Note (2)] | TP to 1.7 times MAOP [Note (2)] | TP to 2.2 times MAOP [Note (2)] |
| | 15 | Not allowed | TP to 2.0 times MAOP [Note (2)] | TP to 2.8 times MAOP [Note (2)] |
| | 20 | Not allowed | Not allowed | TP to 3.3 times MAOP [Note (2)] |
| In-line inspection | 5 | $P_f$ above 1.25 times MAOP [Note (3)] | $P_f$ above 1.4 times MAOP [Note (3)] | $P_f$ above 1.7 times MAOP [Note (3)] |
| | 10 | $P_f$ above 1.39 times MAOP [Note (3)] | $P_f$ above 1.7 times MAOP [Note (3)] | $P_f$ above 2.2 times MAOP [Note (3)] |
| | 15 | Not allowed | $P_f$ above 2.0 times MAOP [Note (3)] | $P_f$ above 2.8 times MAOP [Note (3)] |
| | 20 | Not allowed | Not allowed | $P_f$ above 3.3 times MAOP [Note (3)] |
| Direct assessment | 5 | Sample of indications examined [Note (4)] | Sample of indications examined [Note (4)] | Sample of indications examined [Note (4)] |
| | 10 | All indications examined | Sample of indications examined [Note (4)] | Sample of indications examined [Note (4)] |
| | 15 | Not allowed | All indications examined | All indications examined |
| | 20 | Not allowed | Not allowed | All indications examined |

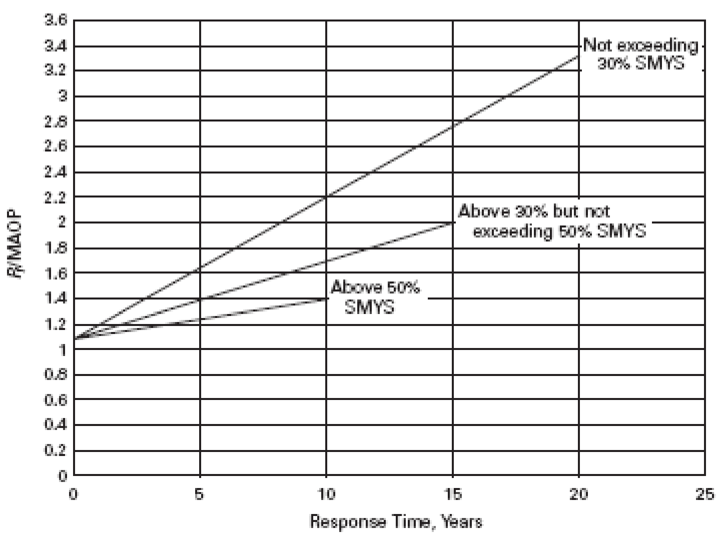



Fig. 4 Timing for Scheduled Responses: Time-Dependent Threats, Prescriptive Integrity Management Plan

## Figure 4 provides basis for scheduling responses

# 68 FR 4306, Jan 28, 2003

## What Actions Must Be Taken To Address Integrity Issues?

- *180-day evaluation*. Except for conditions listed in ‘‘immediate repair’’ conditions of this section, an operator must complete evaluation and schedule remediation of the following within 180 days of discovery of the condition:
  - Calculation of the remaining strength of the pipe shows a predicted failure pressure between 1.1 times the established maximum operating pressure at the location of the anomaly, and the ratio of the predicted failure pressure to the MAOP shown in Figure [4] of ASME B31.8S to be appropriate for the stress level of the pipe and the reassessment interval. For example, if the pipe is operating at 50% SMYS and the reassessment interval is ten (10) years, then the predicted failure pressure ratio for scheduling examination and remediation during that ten year period would be 1.39.

# 49 CFR 192.933, Dec. 15, 2003

(c) *Schedule for evaluation and remediation*. An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (ibr, *see § 192.7),* Section 7*,* Figure 4.

# Applicable FAQs
# FAQ-225 [1/4/2005]

**Question: Must I fix anomalies found in non-covered segments?**

**Answer:** Yes. Operators may find problems in non-covered segments while performing assessment of covered segments (e.g., because non-covered segments are also inspected during an ILI assessment) and must take appropriate actions to meet the requirements in 192.485, 192.703(b), 192.711, 192.713, 192.715, 192.717, and 192.719 as applicable. The provisions and requirements in Section 192.933(d) apply only to covered segments. In non-covered segments, operators are responsible for determining the appropriate criteria and schedule for remediating anomalies, consistent with the significance of the identified problem.

# Applicable FAQs
# FAQ-224 [3/9/2005]

**Question:** What actions must I take on non-covered segments if I find corrosion during an assessment of segments in HCA?

**Answer:** ...The special scheduling requirements and requirements to reduce pressure or take other action of Section 192.933(d) do not apply to non-covered segments. OPS expects operators to take action to address these segments in a timely manner, consistent with the importance to safety of the potentially degraded condition of the pipeline.

# Applicable FAQs
# FAQ-66 [5/17/2004]

**Question:** If a covered segment is relatively short (e.g., only 2 miles in length), yet the operator internally inspects a longer portion around this segment (e.g., 50 miles from pig launcher to receiver), do the repair schedules in 192.933 apply to the covered segment or the entire distance over which the pig is run?

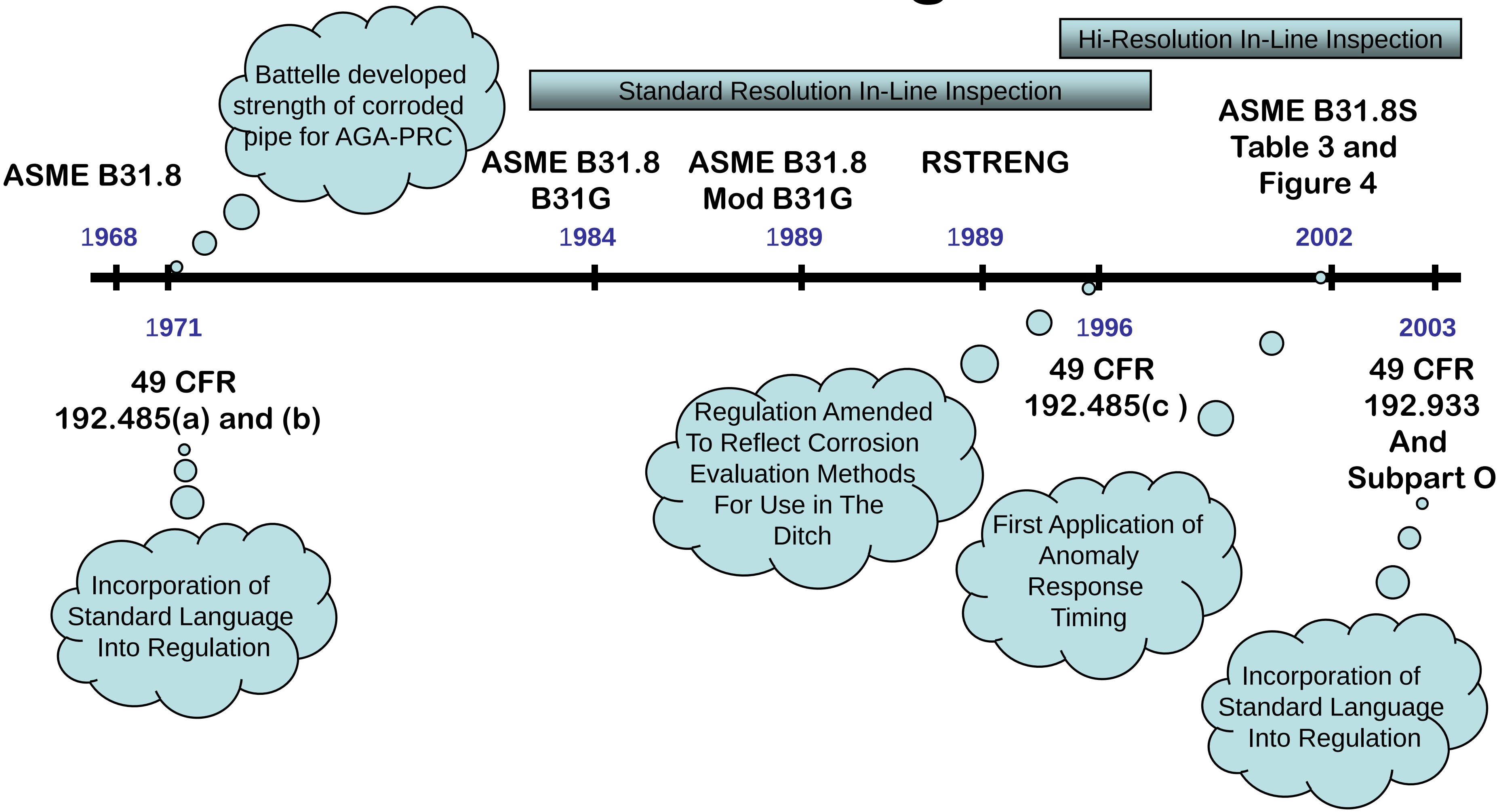
**Answer:** The repair schedules in 192.933 apply only to the covered segment. However, the operator is responsible for promptly addressing anomalies identified in the other portions of the pigged section in accordance with 192.703(b).

# Applicable FAQs
# FAQ-70 [5/17/2004]

**Question:** Must anomalies identified during pig runs not considered "baseline" or "re-assessments" under the rule be repaired in accordance with the rule's repair criteria?

**Answer:** ... The integrity management rule repair criteria apply to high consequence areas. If anomalies fall in a high consequence area the answer is yes. The integrity management rule requires a program that integrates all information regarding the integrity of the pipeline. Anomalies discovered in segments in high consequence areas after the effective date of the rule must be repaired in accordance with the criteria and schedules for repair conditions specified in 192.933. Anomalies discovered in segments in non high consequence areas must be repaired in accordance with existing rules in Subpart M, Maintenance, of Part 192.

# Evolution of Standards and Regulations



# Current Practices In INGAA Companies

**Bob Travers**

**Spectra Energy**

# Definitions

- Anomaly Response Criteria
  - Applies to ILI after receipt of ILI log/report
  - How soon must the anomaly be investigated?
- Defect Repair Criteria
  - Applies to actions in the bell hole
  - What defects must be repaired ?

# Response Criteria
## Evaluation of ILI Results

- Modified B31G or B31G generally applied to evaluate ILI results and calculate FPR values (failure pressure ratio)
- Some operators apply effective area methods (e.g.,RSTRENG, LAPA, etc.)

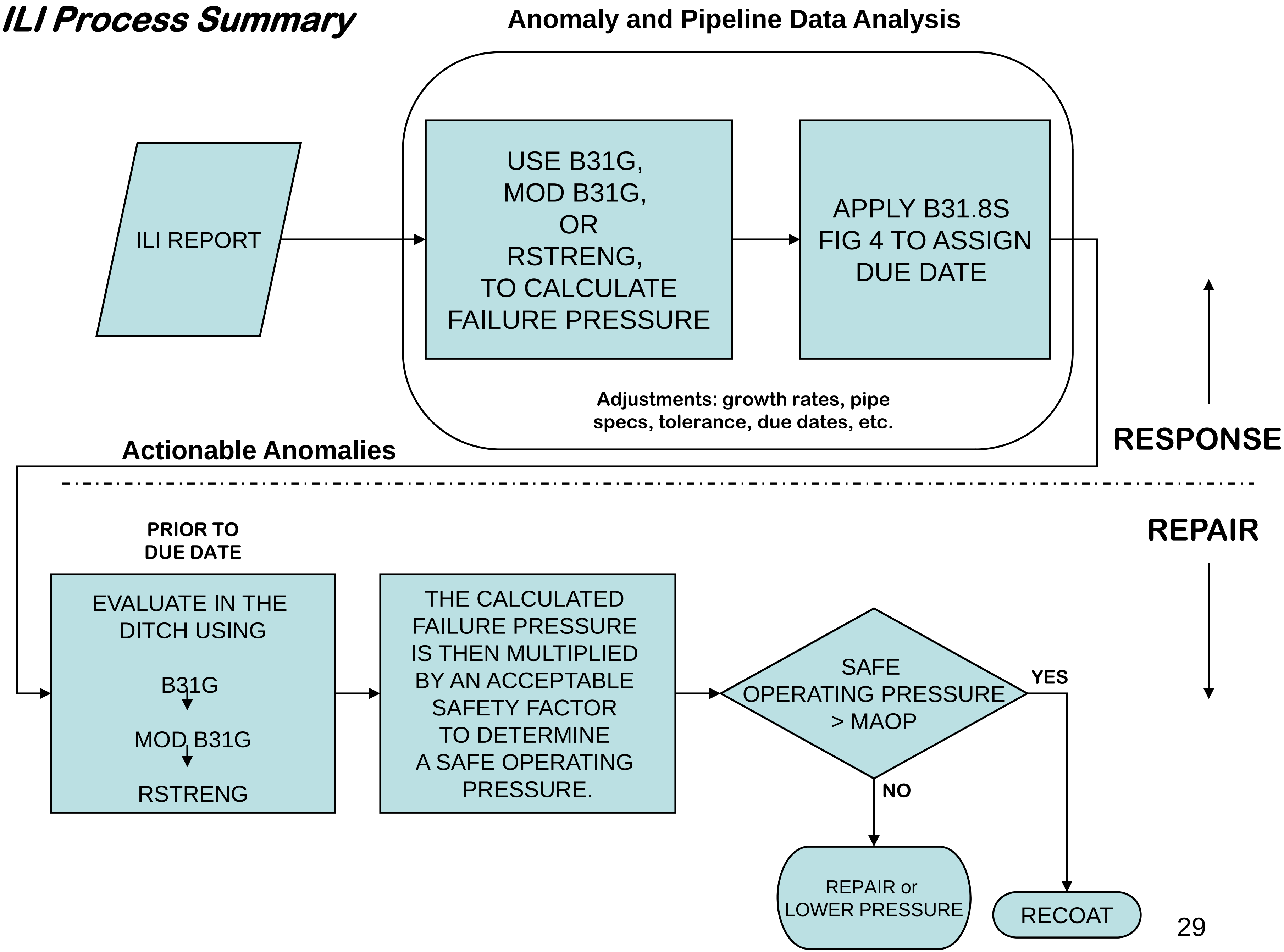
# Response Criteria
## B31.8S, Figure 4

- Figure 4 is then used to apply a due date for response to the anomalies
- Additional Considerations
  - Adjustments can be made to account for site specific characteristics such as actual pipe specs, estimated corrosion rates, tool tolerances, accelerated due dates, etc…

# Repair Criteria
## Bell Hole Assessments

- Multi-step Screening Process
  - B31G
  - Mod B31G or
  - RSTRENG (Effective Area Method - EAM)
- The calculated failure pressure is then multiplied by the appropriate safety factor to determine a safe operating pressure.
- Then the decision is made to repair or not.

## *ILI Process Summary*



# Break

-

# Research

Dave Johnson

Panhandle Energy

Mike Rosenfeld

Kiefner Associates, Inc.

Keith Leewis

P-PIC

# Research
## As Applied to
## Anomaly Response and Evaluation

- Development of Models
- Evolution of Models
- Validation of Models
  - PRCI – B31G, modB31G, RSTRENG
  - Advantica - independent evaluation for PHMSA

# Method Development

- B31G - original, simple two parameter model
- Modified B31G - application of flow stress and 0.85 effective area in the Folias factor to better reflect characteristics of actual corrosion
- RSTRENG or KAPA - effective area method, utilizes “River Bottom Profile”
- PRCI periodically funded validation work

# Model Development

- NG-18 Ln-Secant basis by Battelle in 1971
- B31G by ASME in 1984
- modB31G Kiefner and Veith (1989)
- RSTRENG Kiefner and Veith (1989)

# Pipe tests validated corrosion assessment methods

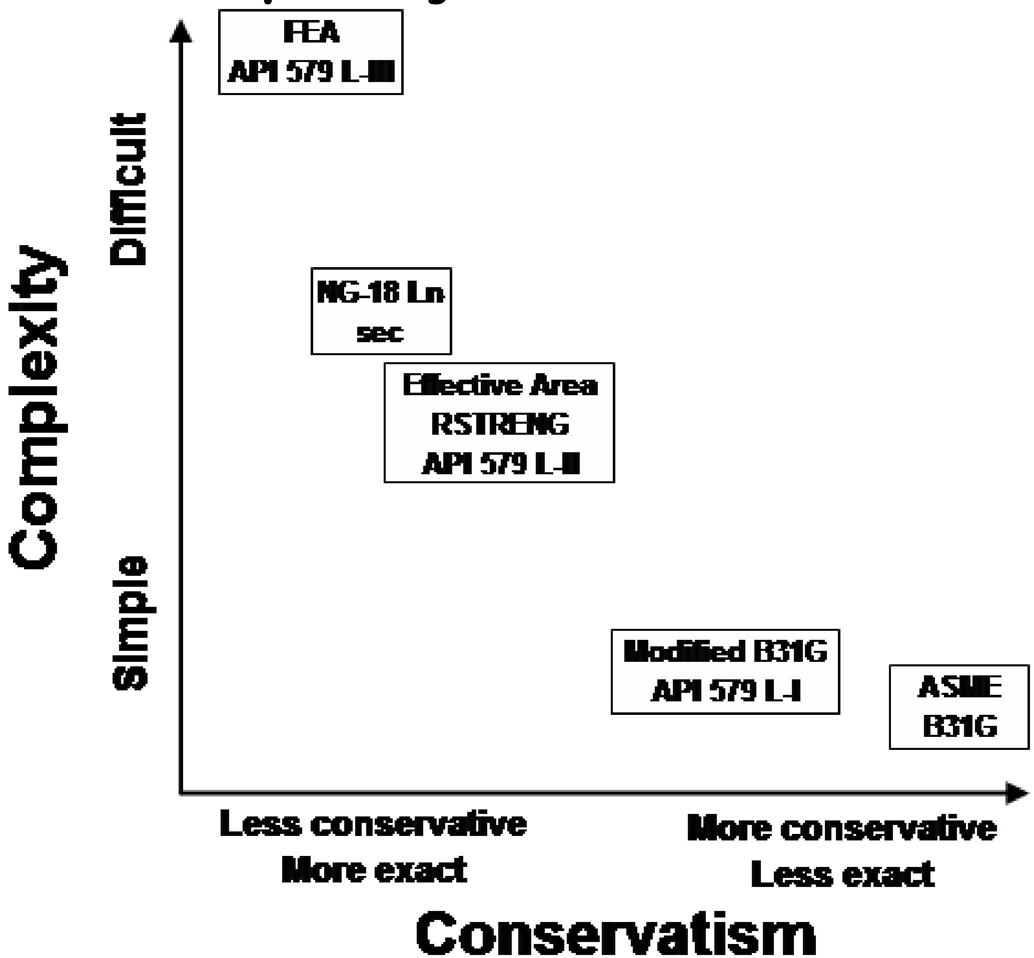
- 124 experiments, service failures, and test failures: Vieth, P.H. and Kiefner, J.F., "Database of Corroded Pipe Tests", AGA Pipeline Research Committee, PR-218-9206 (April 4, 1994).
- 90 additional experiments, service failures, and test failures: Kiefner, J.F., Vieth, P.H., and Roytman, I.R., "Continued Validation of RSTRENG", AGA Pipeline Research Committee, PR-218-9304 (Dec. 20, 1996).
- 322 experiments–from Grade B to x100 done all over the world, Advantica 6781 report

| Parameter | Attributes in Validation Tests | |
|---|---|---|
| | NG-18 In-sec Equation | Corrosion Methods |
| OD (inches) | 6.625 to 48.0 | 10.75 to 48 |
| Wall (inch) | 0.195 to 0.861 | 0.197 to 0.500 |
| D/t ratio | 26.4 to 104.3 | 40.6 to 100.0 |
| Actual YS (ksi) | 32.0 to 106.6 | 28.4 to 74.8 |
| Actual UTS (ksi) | 53.4 to 131.7 | 40.2 to 85.5 |
| CVN (ft-lb) | 15 to 100 | n/a |
| No. of tests | 130 | 215 |

# Corrosion Assessment Methods:

## Spectrum between

## complexity & conservatism

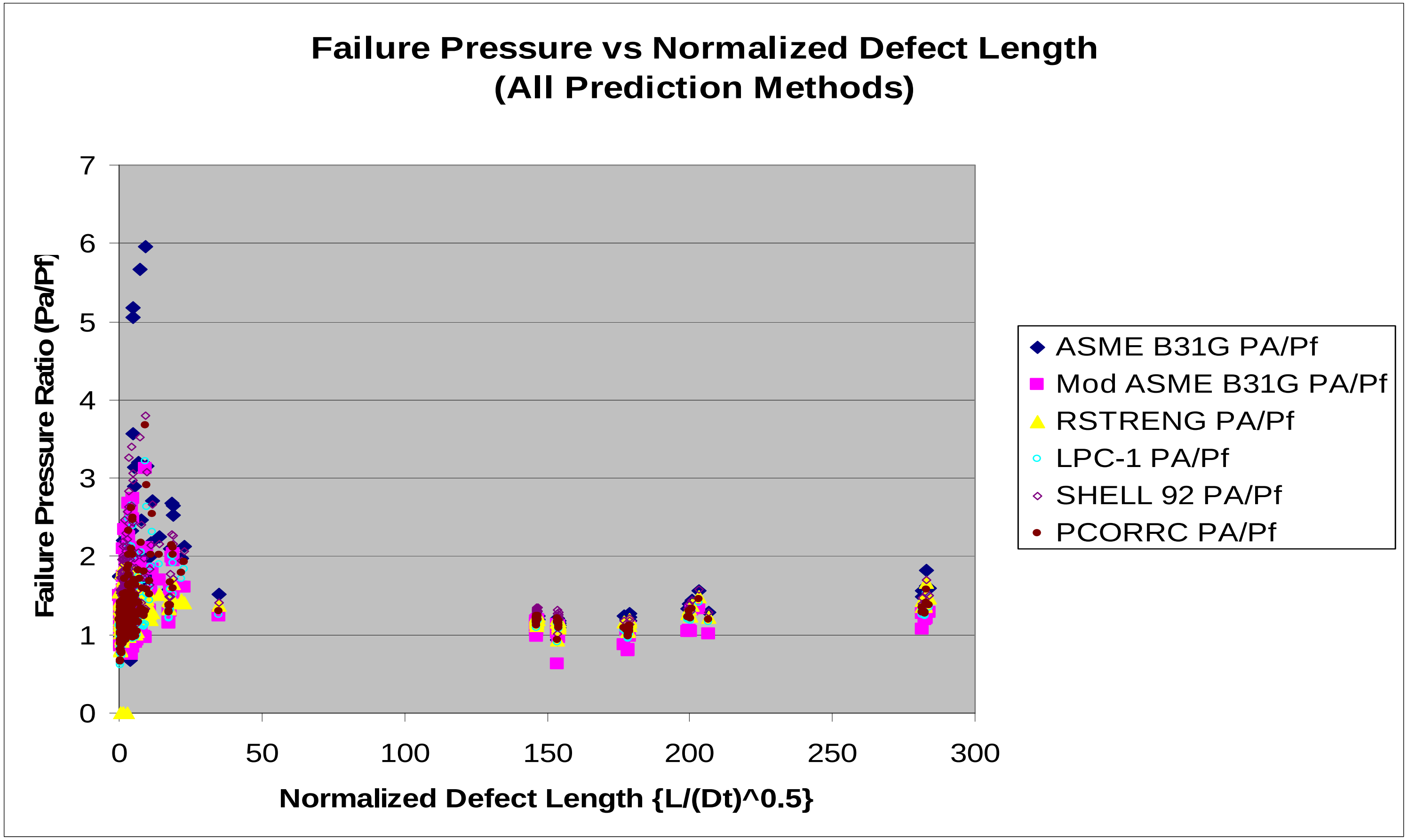


# Independent Evaluation Sponsored by PHMSA

## Considered two-parameter methods

- Case 1 - Flow stress based on recommendation made by each assessment methods, but using actual material properties
- **Case 2 - Flow stress based on recommendation made by each assessment methods, but using specified minimum material properties**
- Case 3 - Flow stress modified to equal actual tensile strength of pipe.
- Case 4 - Flow stress modified to equal specified minimum tensile strength of pipe.
- Case 5 - Flow stress modified to equal the mean of the actual yield and ultimate tensile strength.
- Case 6 - Flow stress modified to equal the mean of SMYS and ultimate tensile strength.

# All Two Parameter Methodologies Are Basically Conservative



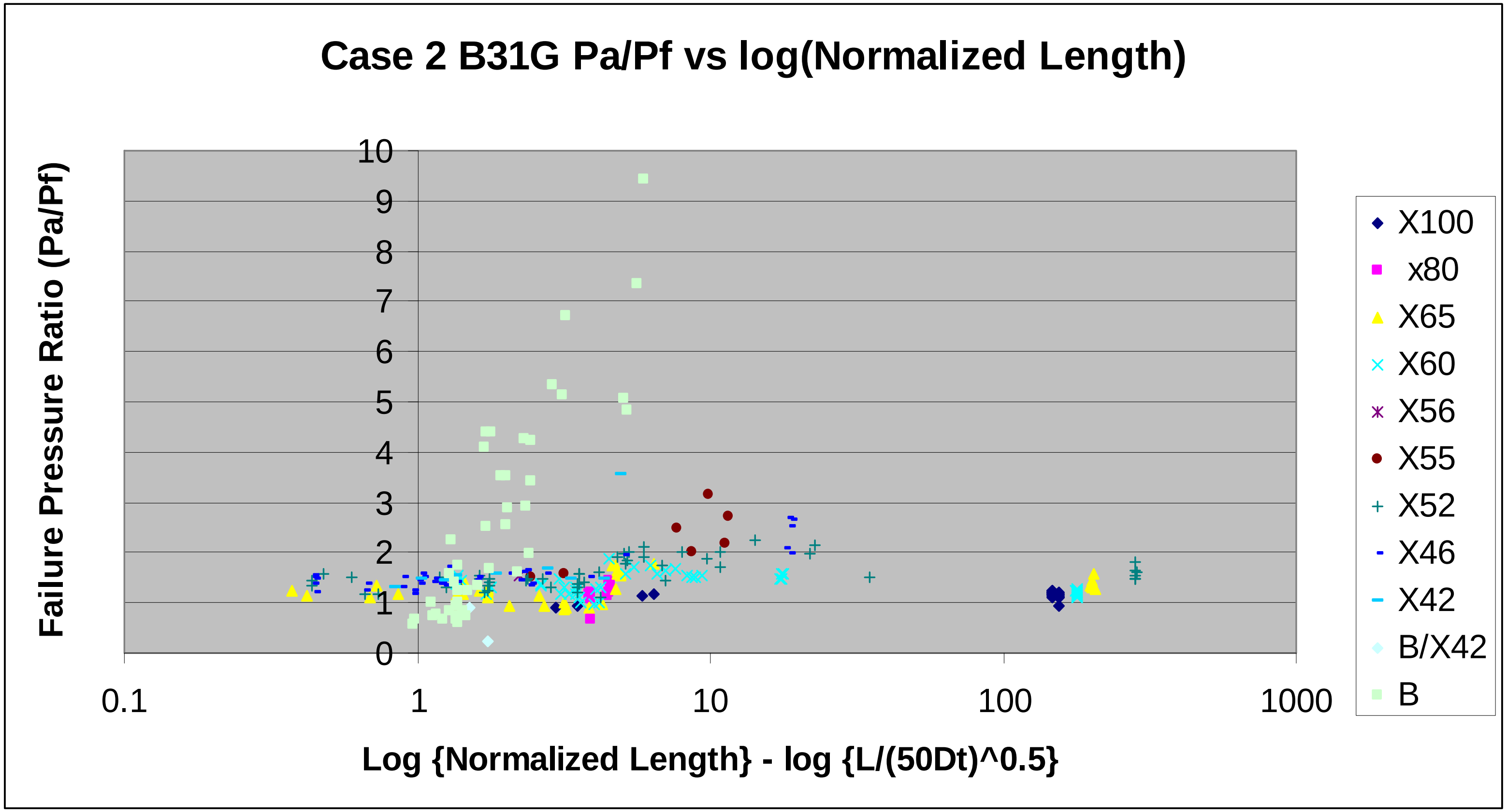

Using Advantica Report # 6781 for PHMSA

# Prediction Reliability (case 2- normal)

| Assessment Method | $P_A/P_f$ All Test Data | | $P_A/P_f$ All Test Data Minus Early Grade B Results | |
|---|---|---|---|---|
| | Mean | Standard Deviation | Mean | Standard Deviation |
| ASME B31G | 1.534 | 0.624 | 1.550 | 0.642 |
| Modified ASME B31G | 1.330 | 0.348 | 1.340 | 0.356 |
| RSTRENG | 1.305 | 0.178 | 1.322 | 0.168 |
| LPC-1 | 1.277 | 0.335 | 1.306 | 0.326 |
| PCORRC | 1.295 | 0.342 | 1.325 | 0.334 |
| SHELL92 | 1.562 | 0.436 | 1.592 | 0.432 |

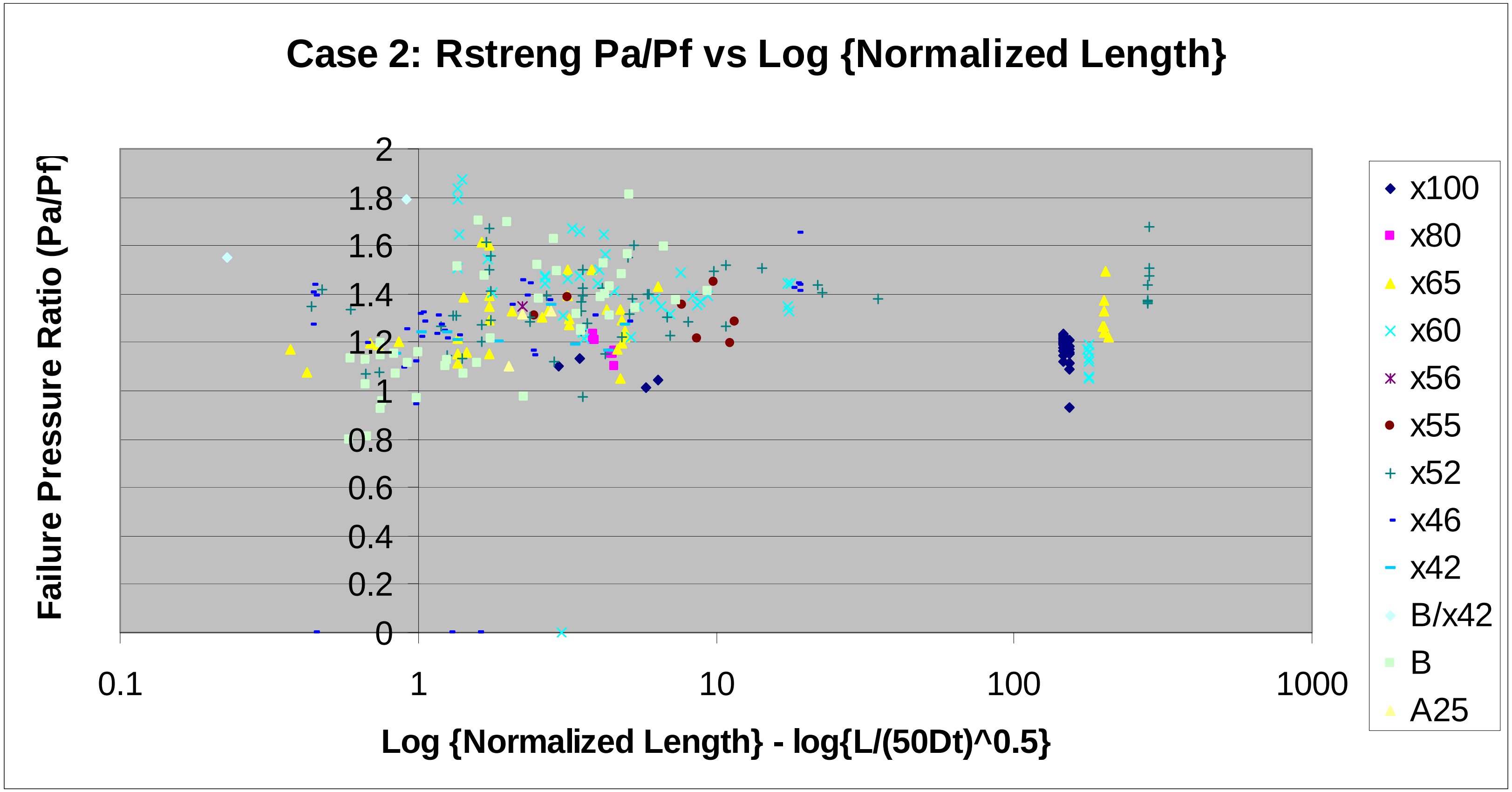
Advantica Report # 6781 for PHMSA

# ModB31G Performance




Using Advantica Report # 6781 for PHMSA

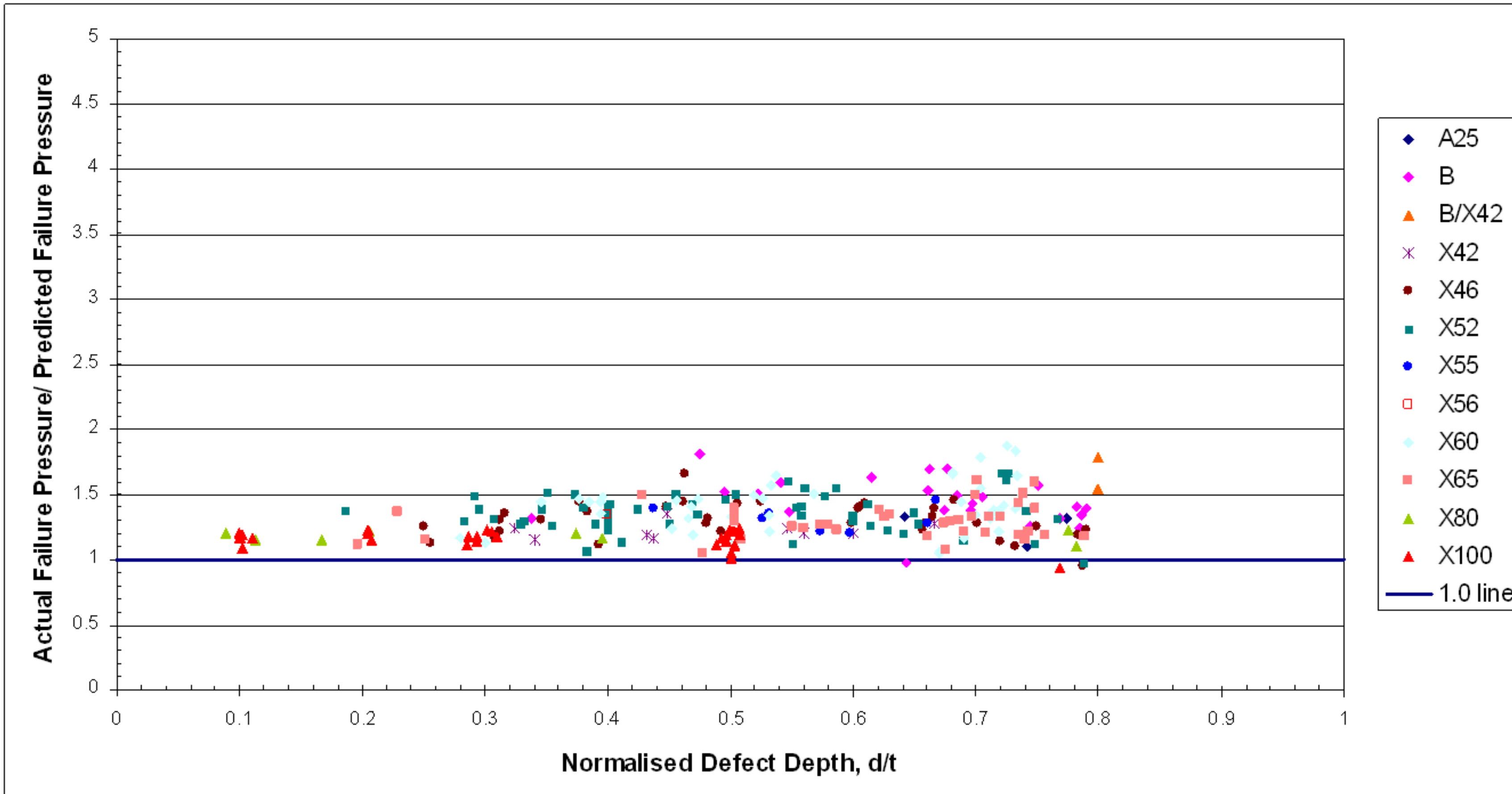
# RSTRENG Performance




Using Advantica Report # 6781 for PHMSA

# Comparison of Actual and Predicted Failure Pressures Using the RSTRENG Method

## (Case 2 Specified Minimum Material Properties)

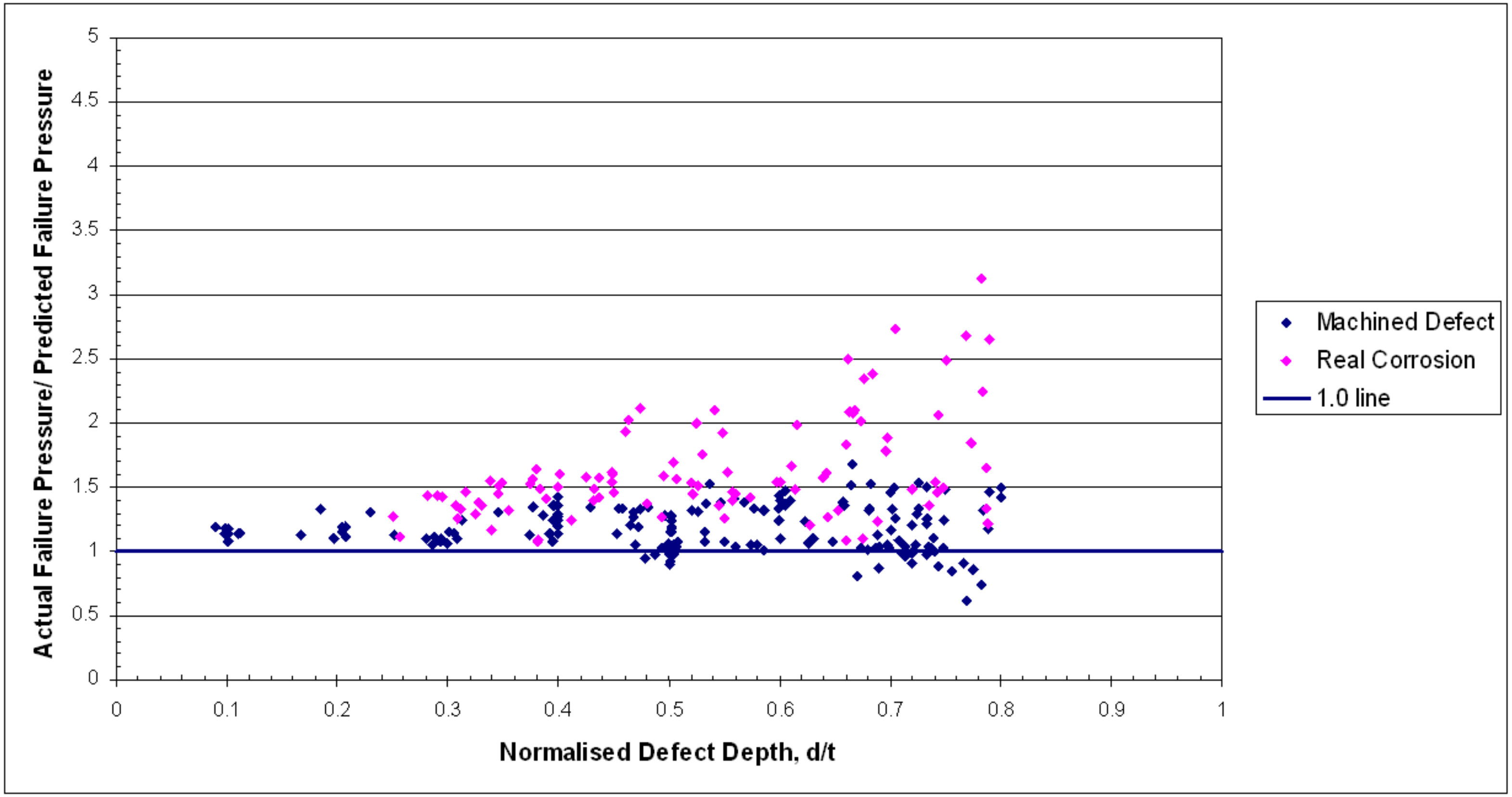



Advantica Report # 6781 for PHMSA

# Comparison of Actual and Predicted Failure Pressures Using the Modified ASME B31G Method

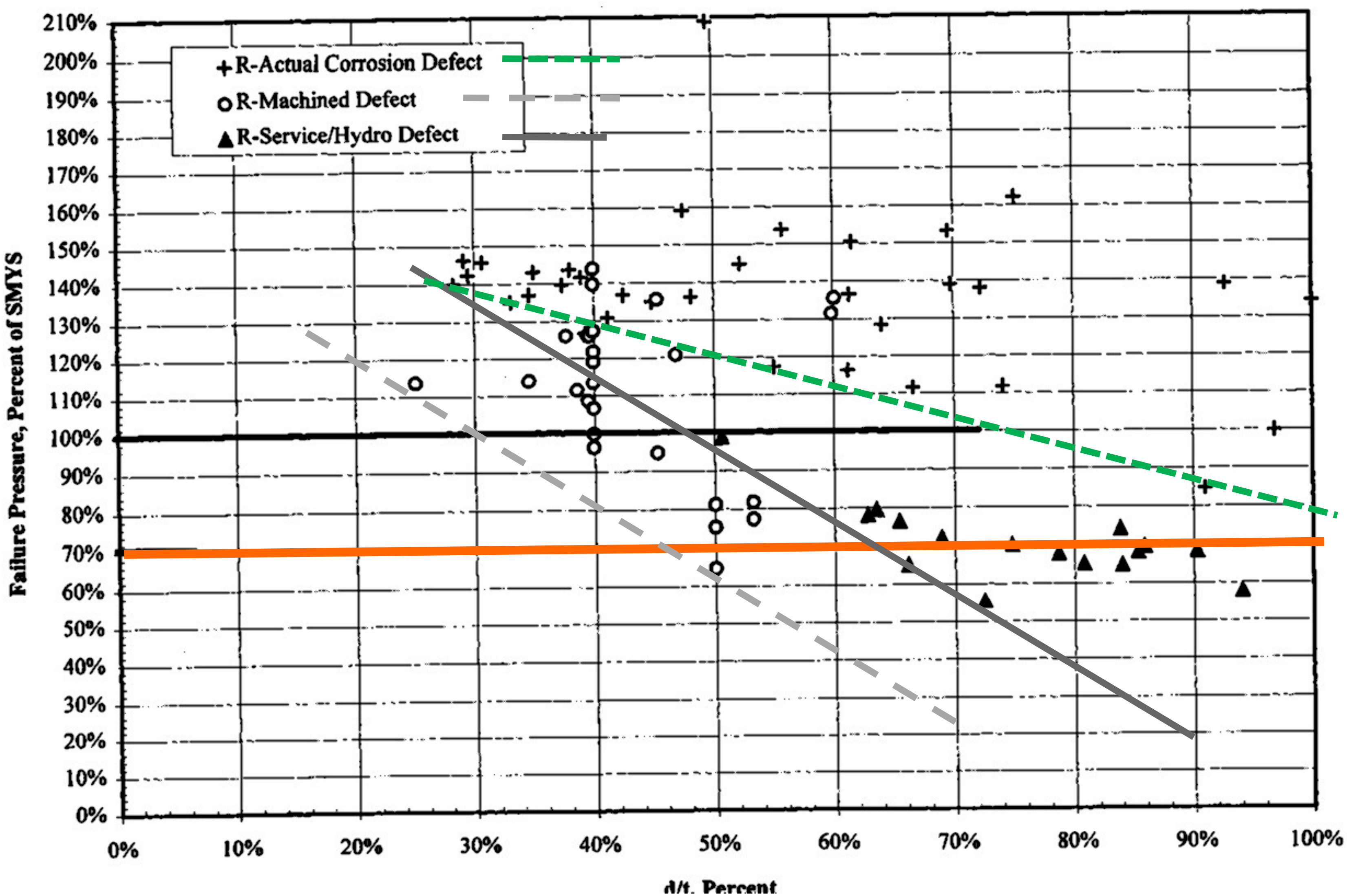
## (Case 2 Specified Minimum Material Properties, including Ring Expansion Tests) –

## Split Between Machined and Real Corrosion Defects



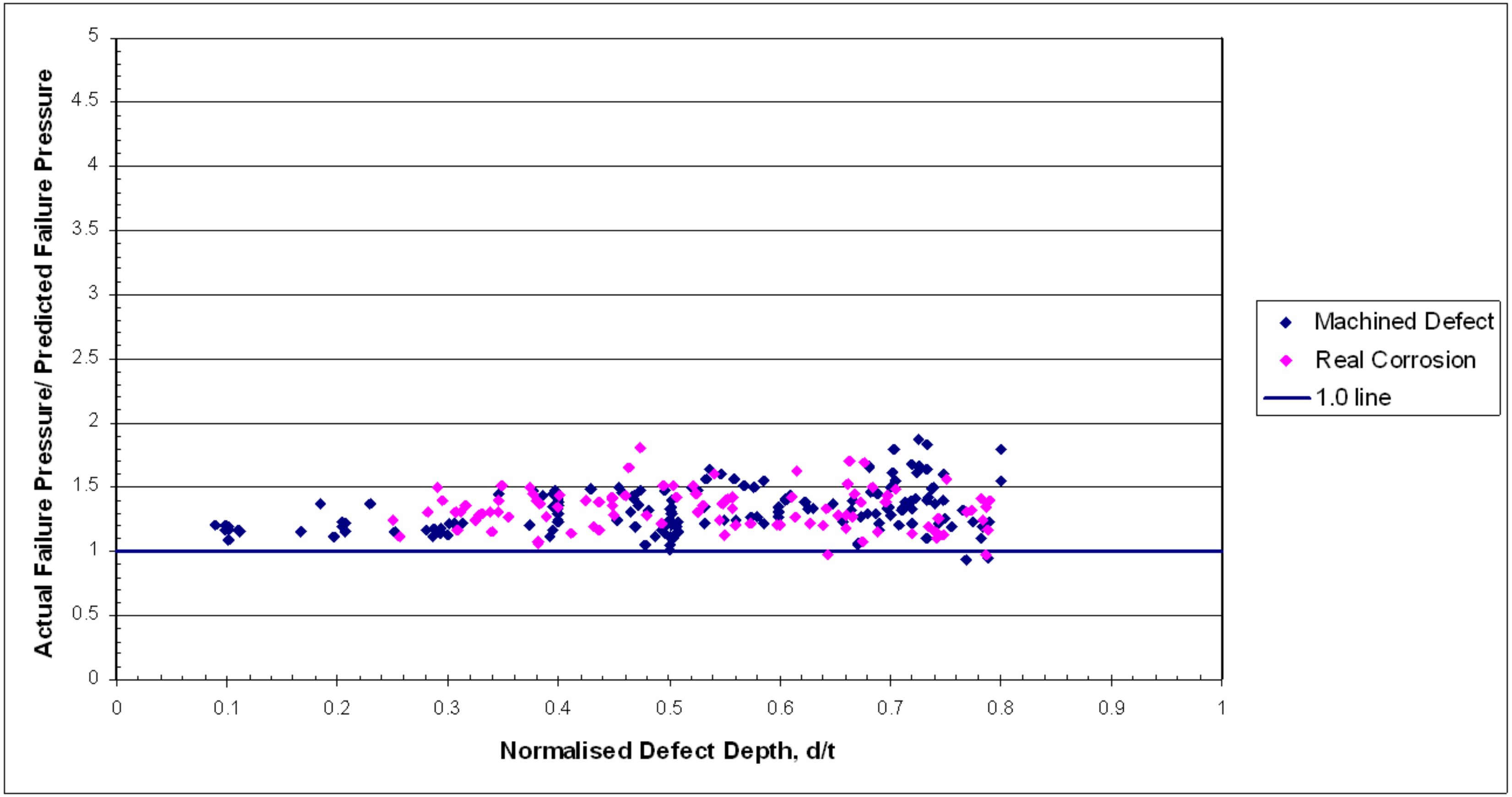

Advantica Report # 6781 for PHMSA

Testing showed that machined defects are worse than actual corrosion. Also d/t>50% for pipe to fail at normal operating stress levels.



# Comparison of Actual and Predicted Failure Pressure Using the RSTRENG Method
# (Case 2 Specified Minimum Material Properties) –

## Split Between Machined and Real Corrosion Defects




Advantica Report # 6781 for PHMSA

# Conclusions - Advantica

1. For the majority of the tests investigated in this report, standard assessment methods used by the pipeline industry give conservative failure predictions.
2. For a very small number of test points reviewed in this report, use of the ASME B31G and Modified ASME B31G methods resulted in non-conservative failure predictions. These were for test points with defects greater than 40% of the pipe wall and in line pipe of grade X52 and above.
3. RSTRENG is the most accurate method for predicting the failure pressure in pipelines. RSTRENG predicts conservative failure pressures for defect depths up to 80% of the pipe wall in line pipe of strength grades up to X100.

. . .

# Safety Risk

Frank Dauby
PG&E

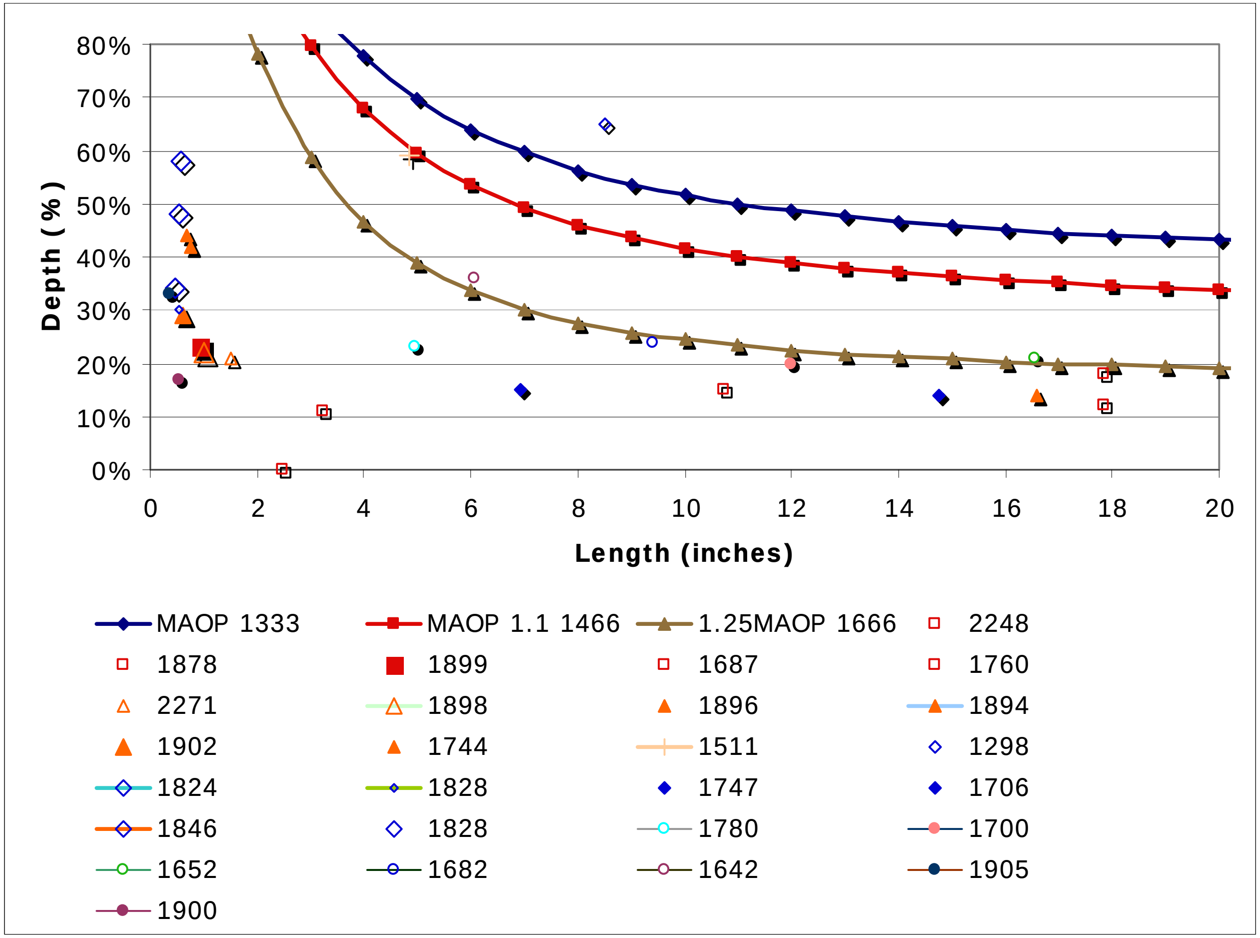
# Risk Posed By Remaining Anomalies

- Anomalies with FPR > 1.25
- Anomalies with FPR > 1.39
- What Are The Characteristics of These Anomalies?

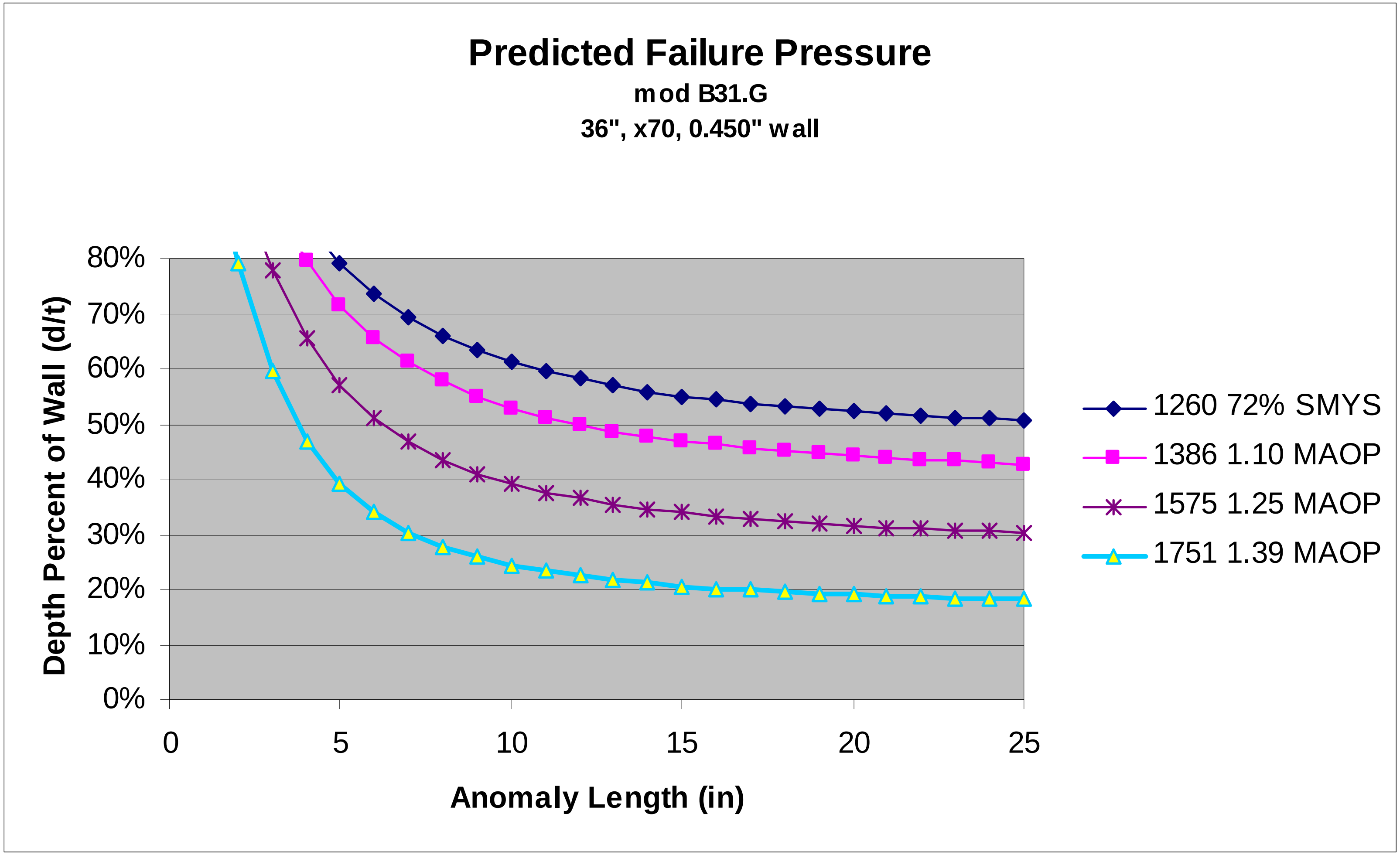
# Is There Safety Value in Examining Anomalies With Predicted Failure Pressure>SMYS?

- No Discernable Safety Value in Examining Anomalies > SMYS as those anomalies are:
  - Longer anomalies are not deep
  - Shorter anomalies are typically <60% and will leak not rupture

# Example ILI Data Set - Line To Operate at 80%



# Example at 72% SMYS



# Impact of Change

**Chris Whitney**

**El Paso Pipeline Group**

# Impacts

- Pipeline System
- Customer Needs
- Land Owner/Environmental

# Pipeline System Impacts

- Significant increase in excavation activities
  - Requiring operators to apply a design factor to the failure pressure ratio, will result in significant number of additional digs.
    - Practically all corrosion anomalies require investigation
    - Increased number of excavations does not equal increased safety
  - More opportunities for damage to pipe or other facilities
    - 1st, 2nd, 3rd party damage
    - Change stress profile of pipeline in ditch
      - Girth welds, wrinkle bends, dents, etc.
  - More disruption to CP system and coatings

# Class Bump Case Study

- An Operator Reported 86 miles of 26” pipeline
  - 13% Class 2 operating at 750 MAOP (67% SMYS) with class bump
  - No HCAs and no immediate digs
- ILI in 2007 resulted in 21 scheduled corrosion anomaly investigations
  - 11 < 1.39 (1.24 to 1.39)
  - 10 other involving metal loss in wrinkles or welds
- If evaluate Class 2 areas at 60% design factor, results in ~50 additional digs (1.4 to 1.67).

# Customer Impacts

- If FPR < 1.39 = Immediate
  - Increase in unscheduled pipeline disruption
  - Longer duration of pressure reduction
- Affects ability to meet firm demand
- Ability to fill storage in summer and meet power loads
- Potential to reduce amount of ILI in order to manage anomaly investigations

# Land Owner/Environmental Impacts

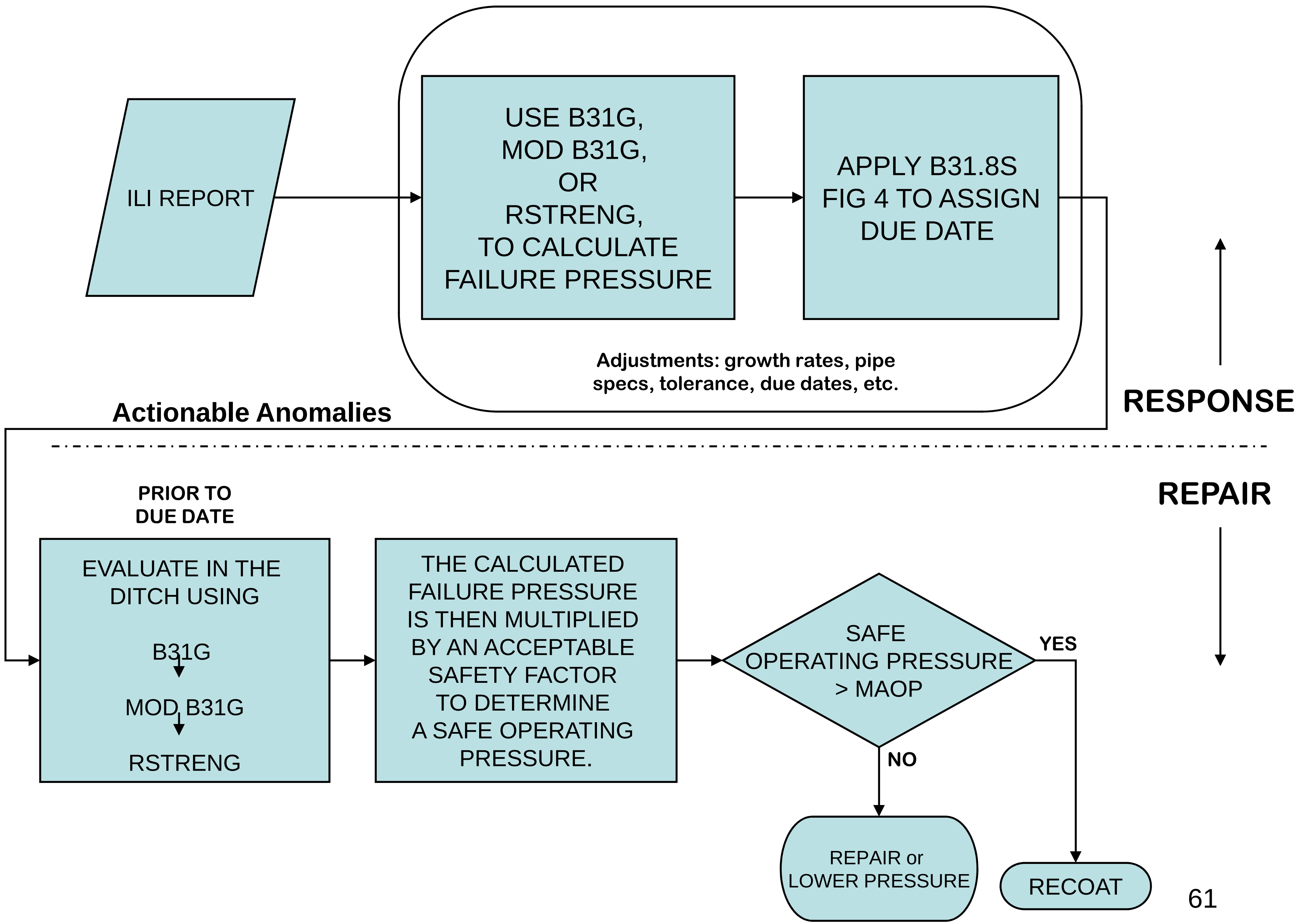
- Potential for significant impact to Land usage requirements – increased footprint and duration
- Significant issues with timing of work in sensitive environmental areas
  - Wetlands/Restrictive habitats
  - Recreational areas
  - Farm lands
  - Golf courses
- Excessive permit burden
  - Waiver requests to PHMSA
  - Local authorities

# Impact Conclusion

- Advantage of ILI is to understand what is happening and take appropriate action
- Eliminating unnecessary digs minimizes pipeline disruption and enhances our ability to meet market demands
- <u>Planned</u> execution of integrity work is essential for meeting customer reliability expectations

## *ILI Process Summary*

### Anomaly and Pipeline Data Analysis



# Thank You

## Questions And Discussion