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SUMMARY OF PROCEEDINGS AND PRESENTATIONS

Proceedings of the 1998 International Workshop on

OFFSHORE PIPELINE RISK ASSESSMENT & MANAGEMENT

Edited By:

Robert Bea &
Botond Farkas

March 1999

Marine Technology & Management Group
University of California, Berkeley

Proceedings of the 1998 International Workshop on

Pipeline Risk Assessment and Management

Summary of Proceedings and Presentations

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This publication is a compilation of materials submitted and developed at the 1998 International Workshop on Pipeline Risk Assessment and Management held at the offices of Amoco Corporation at Clear Lake, Texas on November 5 and 6. This compilation is published by the Marine Technology & Management Group at the University of California at Berkeley as a courtesy to the participants and industry. The University of California is not responsible for the content of the materials nor does the University of California make any representations as to the accuracy of the materials contained herein.

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March 1999

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"Government and Industry Partnering for Risk Management," Gary Zimmerman, Equilon, Houston, Texas

"Offshore Platform Structural Integrity Management," Patrick O'Conner, Amoco Corporation, Houston, Texas

"Qualitative Risk Assessment as a Basis for Pipeline Integrity Maintenance Planning," Kent Muhlbauer, WKM Consultancy, Houston, Texas

"Quantitative Risk Assessment as a Basis for Pipeline Integrity Maintenance Planning," Mark Stephens, C-Fer Technologies, Inc, Edmonton, Canada

"Risk Assessment & Management of Marine Pipelines: RAM Pipe," Robert Bea, University of California, Berkeley, California

"Corrosion Modeling of Mitigation Impacts on Risk," Dallas Thill, Baker Pertolite, Calgary, Canada

"3rd Part Damage Prevention & Detection," Harvey Haines, Gas Research Institute, Chicago, Illinois

"Selection of Optimal Risk Mitigation Strategies," John Conroy, URS Greiner Woodward Clyde, San Francisco, California

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Discussion I

"Reliability Assessment and Management Systems Applicability Offshore"

Panel Leader	Johannes Rosenmoller, H. Rosen Engineering
Panel Members	Anne Doucet, Amoco Corporation
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	Patrick O'Connor, Amoco Corporation
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	Mark Stephens, C-Fer Technologies, Inc.
	Robert Bea, University of California at Berkeley
	Alex Alvarado, Minerals Management Service

Discussion II

"The Links: Risk Assessment and Modeling of Mitigation Impacts"

Panel Leader	Sam Mishael, Chevron Research & Technology Co.
Panel Members	Kent Mulbauer, WKM Consultancy
	Mark Stephens, C-Fer Technologies, Inc.
	Robert Bea, University of California at Berkeley
	Dallas Thill, Baker Pertolite
	Harvey Haines, Gas Research Institute
	John Conroy, URS Greiner Woodward Clyde

Discussion III

"Risk Assessment and Management Applications Offshore: Ways Forward"

Panel Leader	Ray Ayres, Shell E & P Technology
Panel Members	Sam Mishael, Chevron Research & Technology Co.

Wally Orisamolu, Martec Inc.

Dave McKeehan, INTEC Engineering

Winston Revie, CANMET Materials Technology Laboratory

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"Quantification of Risks in Pipeline Reliability and Risk Assessment", Wally Orisamolu and Yong Bai (presentation)

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Sponsors

- **Minerals Management Service**
- **Amoco Corporation**
- **Chevron Research & Technology Company**
- **H. Rosen Engineering**
- **University of California at Berkeley**

1. Executive Summary

Today, there are approximately 30,000 miles of pipelines offshore the United States. Many of these pipelines have been in service for more than 20 years. These pipelines have had a remarkable record of safety and reliability, and both industry and government want to maintain this record.

The primary goal of this workshop was to define alternative Risk Assessment and Management (RAM) approaches to maintain existing pipelines and to determine how they might best be applied to marine pipelines.

The two key objectives of this workshop were to:

1. compare alternate pipeline RAM systems, with emphasis on the analytical modeling aspects of these systems, and
2. define ways forward that can lead to improved applications and development of these systems for marine pipelines.

Eight keynote presentations summarized the current state-of-practices and state-of-arts in RAM of onshore and offshore pipelines and one keynote paper addressed maintenance of the integrity of offshore platforms. Five presentations addressed RAM of refinery pipeline systems and onshore transmission pipelines, qualitative, quantitative, and mixed qualitative-quantitative pipeline RAM approaches. Three presentations addressed modeling of mitigation impacts including corrosion, third party damage, and determination of optimum RAM strategies.

The three panels addressed key aspects of pipeline RAM including applicability of the three alternative approaches, the links between risk assessments and modeling of impacts, and how these developments might best be utilized in development and implementation of procedures to maintain the safety and reliability of marine pipelines.

The keynote presentations indicated that there are a variety of methods and approaches that can be used to help maintain the safety and reliability of existing pipelines. There is a substantial body of existing technology that has been and is being implemented at the present time to maintain pipeline systems. The presentations and the panel discussions clearly indicated that all of these methods have a role in maintaining pipeline safety and reliability, and each has its advantages and limitations.

The presentations indicated that protection against corrosion, third-party damage, and natural hazards appear to be primary challenges for both onshore and offshore pipelines. Work is underway in several organizations to improve corrosion and third party damage prediction, detection, characterization, assessment, and protection.

The panel discussions indicated important differences between onshore and offshore pipelines including inspectability, consequences of loss of containment, the products transported, and the pipeline environments. Because of these differences, it is to be expected that there will be some important differences in details of the RAM of marine pipelines compared with RAM of onshore pipelines.

The concluding panel, 'RAM applications offshore: ways forward' developed important recommendations from the presentations and deliberations during the workshop. These recommendations included:

- Perform additional analyses of available data on performance of marine pipelines (e.g. MMS pipeline database) to improve insights into current and evolving challenges, identify other data that might be collected to provide information to help better manage pipelines, and to verify analytical models and RAM approaches.
- Develop projects for synthesis of lessons from onshore experiences to offshore processes, guidelines for development of inspection, maintenance, repair, and operations plans, and demonstration projects for testing and validating guidelines and procedures.
- Development of procedures and guidelines that clearly demonstrate to management the benefits that both government and industry stand to gain.

2. Development and Application of Risk Based Inspection for the Refining and Petrochemical Industries - Anne B. Doucet

The following paper discusses the risk management practices of the refining and petrochemical industry, and highlights the important components of the risk management systems in use. Attention is given to the fact that the current API methods are not dynamic, but are being reviewed to include a knowledge base that can utilize resources in the most effective manner possible.

In order to maximize resources, the petrochemical industry has also been moving towards risk based inspections (RBI) and therefore in the future there is an expected cost savings for operations. Currently there is also an API joint industry project on RBI methods, which is sponsored by 21 companies that desire to obtain a better grasp on the risk management problem. Finally, the importance of consequence estimation is also highlighted, which plays an important part in calculating the costs incurred when a failure occurs.

Development and Application of Risk Based Inspection for the Refining and Petrochemical Industries

Anne B. Doucet
Amoco Corporation
Worldwide Engineering & Construction
Houston, Texas

Amoco WE&C

Current state of inspection planning

- Pressure vessels - inspection frequency mandated by API 510, maximum of

  1/2 remaining life or 10 years

- Piping - inspection frequency mandated by API 570, depending on piping classification

  1/2 remaining life

  or

  5 years - Class 1

  10 years - Class 2 or 3

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Current state of inspection planning

- Mandated inspection intervals do not take into consideration:
  - Likelihood of failure based on active corrosion/damage mechanisms.
  - Consequence of failure (although API 570 attempts to address this in the classification system).
  - Effectiveness of various inspection programs to accurately detect and characterize damage (for example, local vs. general corrosion)

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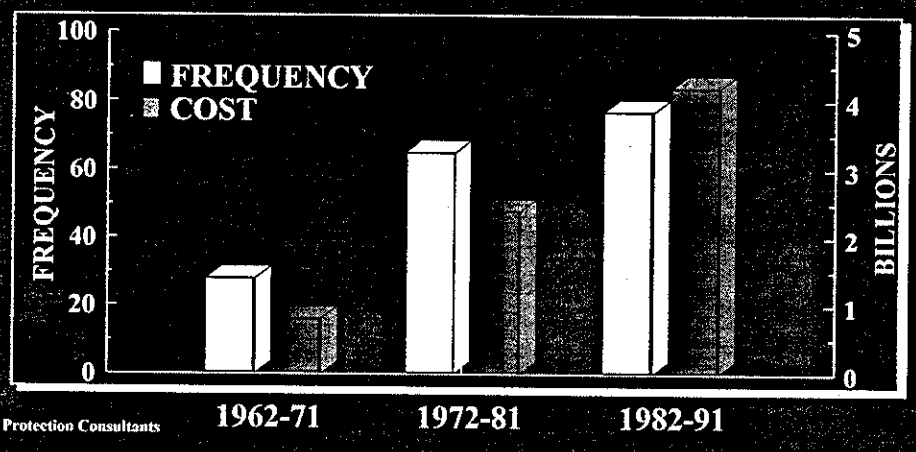
Frequency and Cost of Major Property Losses in the Refining Industry



M&M Protection Consultants

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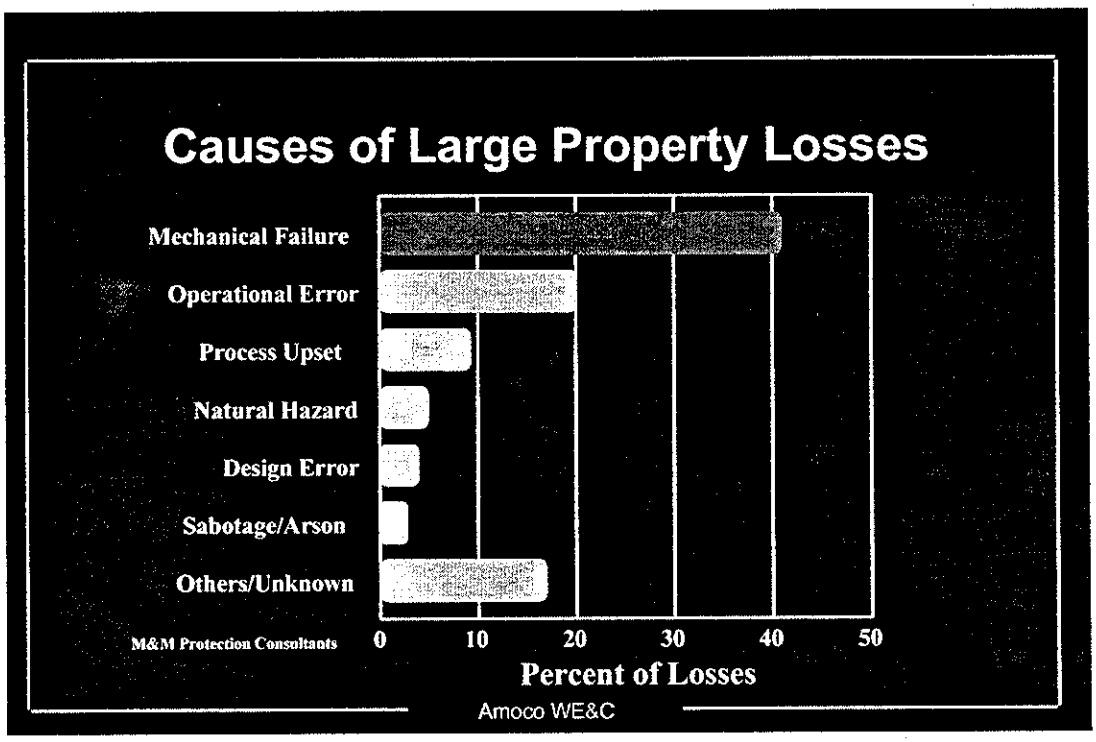
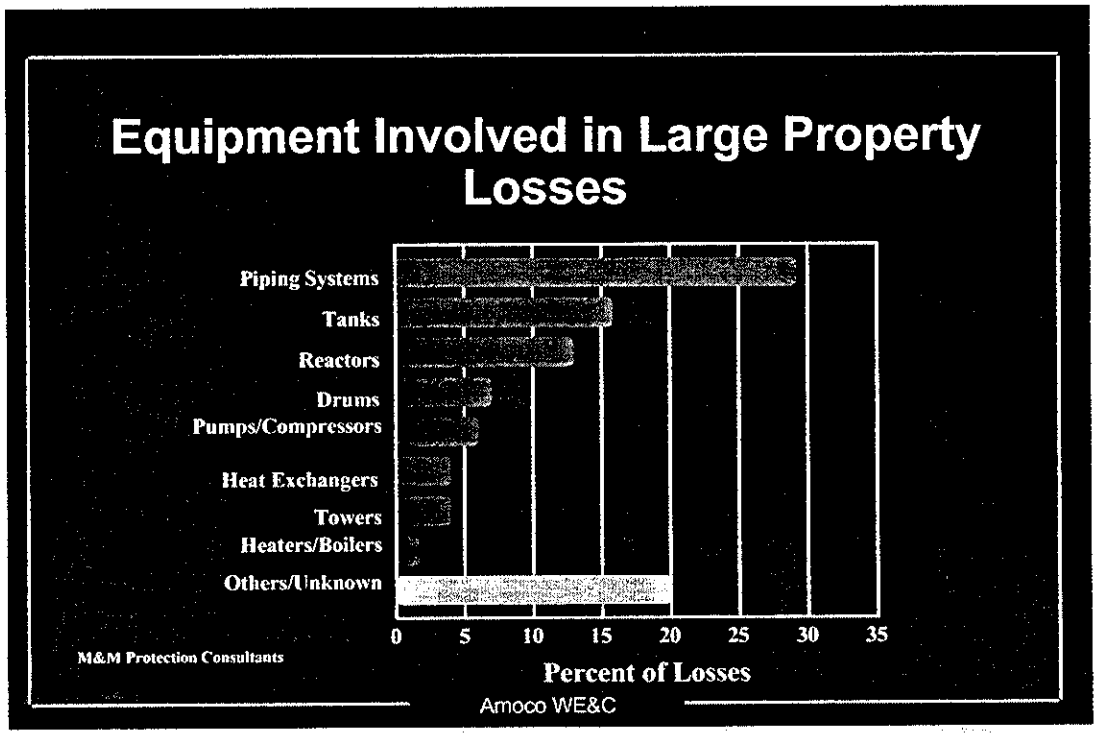

Causes of Large Property Losses
Mechanical Failure
Operational Error
Process Upset
Natural Hazard
Design Error
Sabotage/Arson
Others/Unknown
M&M Protection Consultants
0
10
20
30
40
50
Percent of Losses
Amoco WE&C


Equipment Involved in Large Property Losses
Piping Systems
Tanks
Reactors
Drums
Pumps/Compressors
Heat Exchangers
Towers
Heaters/Boilers
Others/Unknown
M&M Protection Consultants
0
5
10
15
20
25
30
35
Percent of Losses
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Current Status of Inspection Planning

ò The best inspection programs currently address:

- **Potential damage mechanisms**
- **Estimated remaining life**
- **Available inspection methods**
- **Available manpower resources**
- **Turnaround schedules**
- **Code compliance**

ò Risk Based Inspection uses all these features and adds the element of consequence of failure.

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What is Risk Based Inspection?

A strategic, multi-disciplinary process that factors risk into inspection decision making,

where

Risk =

Likelihood of failure X Consequence of failure

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What does RBI involve?

- Systematic assessment of degradation mechanisms and inspection effectiveness for individual items of equipment.
- Integration of the knowledge and experience of corrosion/materials, inspection and process specialists.

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Benefits & deliverables of RBI

- A sound basis for the allocation of inspection resources within a facility.
- Risk prioritization for each piece of equipment.
- Understanding of the effect of inspection (frequency and type) and monitoring on likelihood of failure (and risk).
- Identification of mitigation techniques to reduce consequence of failure (and lower risk).

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Benefits & deliverables of RBI

- ò Fewer inspections on low risk equipment (lower cost).
- ò Carefully selected, more focused inspections on higher risk equipment (lower risk).
- ò Reduction in inspections designed merely for code compliance.

Result:

Increased safety and utilization of equipment.

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Current Refining and Petrochemical Industry Efforts in RBI

- ò API JIP for Risk Based Inspection (DNV)
- ò API RP 580 - Recommended Practice for Risk Based Inspection
- ò API Publication 581 on RBI

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Current industry activities

ò API Joint Industry Project on RBI
- **funded by 21 oil and petrochemical companies**
- **developed RBI technology and software**
- **developed 4 levels of analysis:**
  - û ***Level 0 - Qualitative unit screening***
  - û ***Level I - Qualitative equipment screening***
  - û ***Level II - Semi-quantitative risk ranking***
  - û ***Level III - Semi-quantitative risk analysis***

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Companies Participating in API RBI Technology Development

AMOCO	TEXACO	ARCO	MARATHON	
EXXON	CHEVRON	SUN	PHILLIPS	
SHELL	PENNZOIL	UNOCAL	ASHLAND	
MOBIL	CONOCO	BP	PETRO-CANADA	
CITGO	KOCH	DOW	FINA	DSM

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Current industry activities

- ò API Task Force on Risk Based Inspection
  - **Draft Publication 581 is offerred for purchase.**
  - **Writing draft Recommended Practice RP 580 on Risk Based Inspection.**
- ò API 510/570 has successfully balloted wording which recognizes RBI analysis as a tool to increase or decrease the mandated maximum inspection intervals set by the codes.

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RBI Calculates:

- ò Likelihood of Failure based on
  - **material of construction**
  - **corrosion rate from**
    - **û inspection results**
    - **û expert opinion**
    - **û technical modules**
  - **effectiveness of inspection**

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RBI Calculates:

ò Consequence of Failure based on
- process stream and phase (gas or liquid)
- toxic content (H_2S, HF, etc.)
- temperature
- pressure
- isolation and mitigation systems

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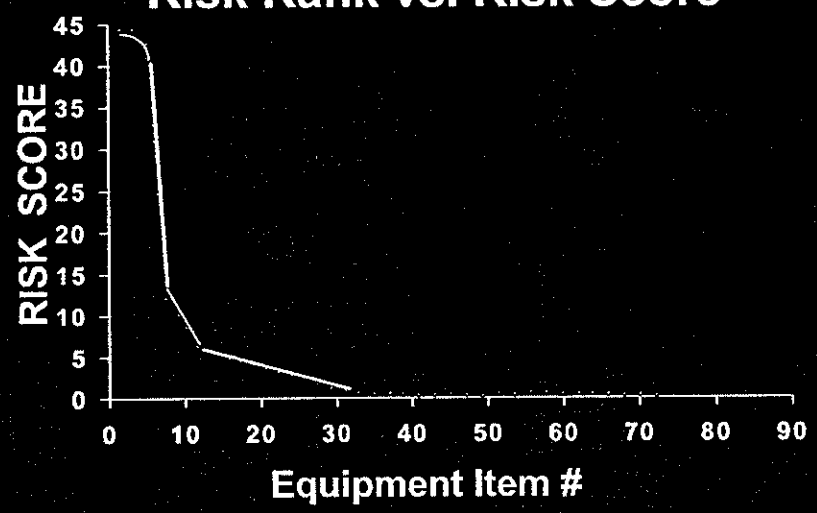
Risk Rank vs. Risk Score



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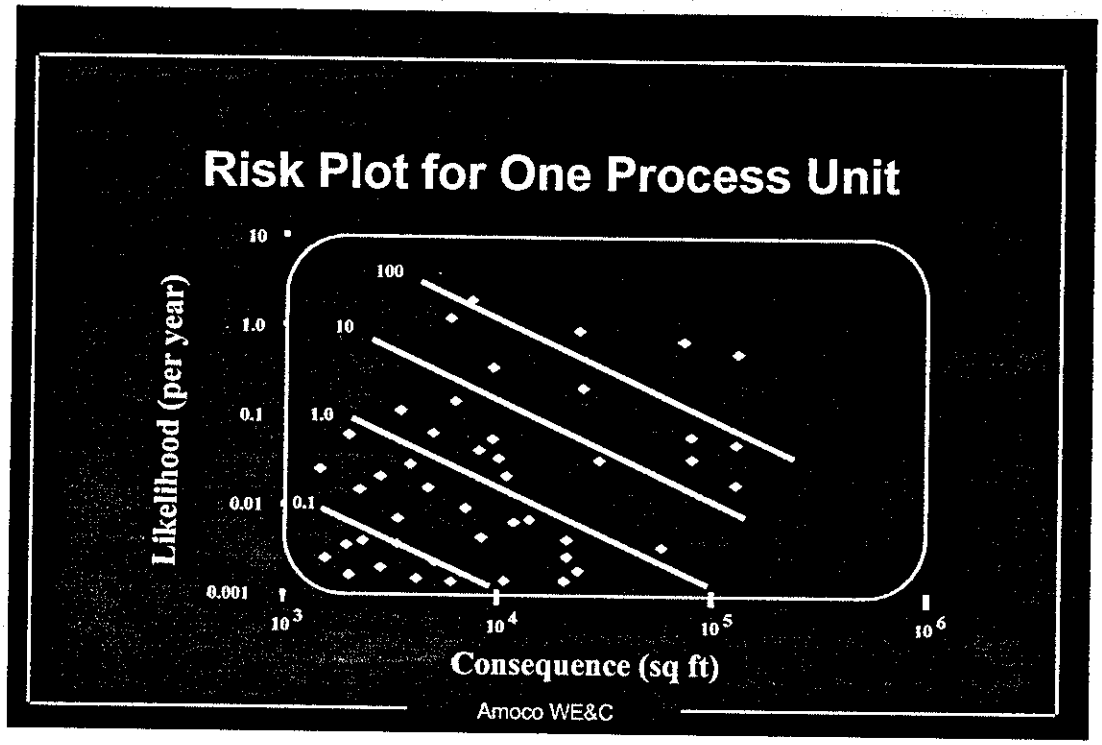
Risk Plot for One Process Unit
Likelihood (per year)
10
1.0
0.1
0.01
0.001
100
10
1.0
0.1
10^3
10^4
10^5
10^6
Consequence (sq ft)
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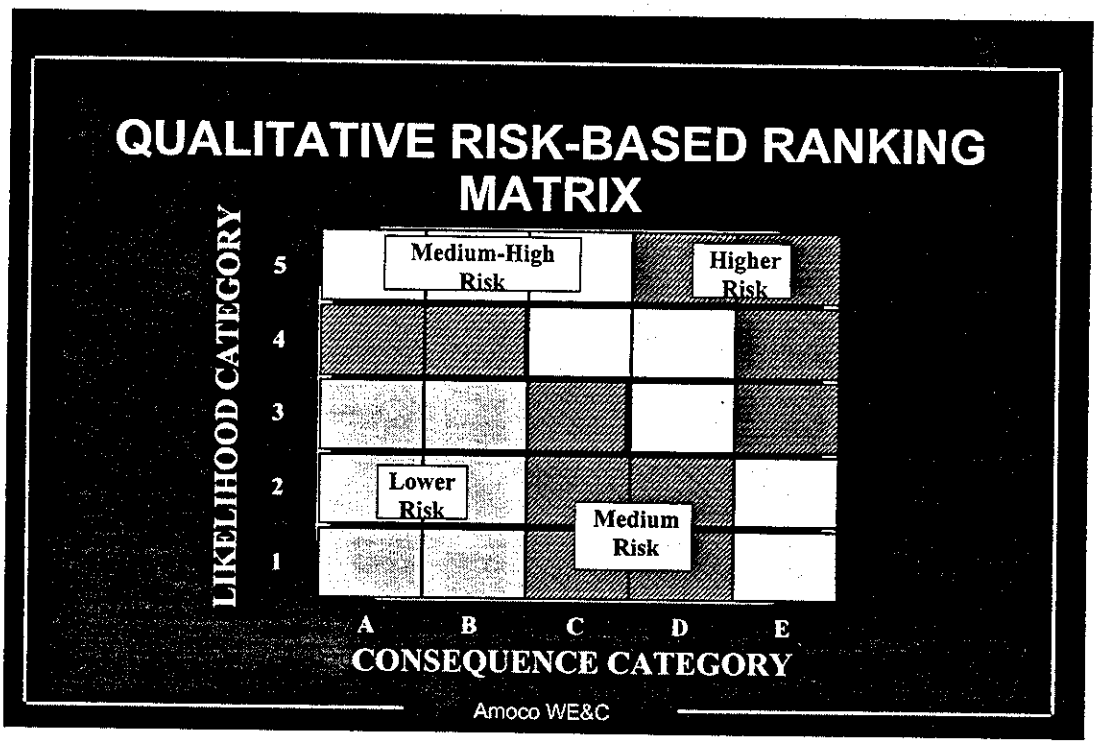
QUALITATIVE RISK-BASED RANKING MATRIX
LIKELIHOOD CATEGORY
5
4
3
2
1
Medium-High Risk
Higher Risk
Lower Risk
Medium Risk
A
B
C
D
E
CONSEQUENCE CATEGORY
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Changing Risk through Inspection

ò The risk posed by an individual piece of equipment can be changed by altering inspection

- Frequency
- Thoroughness - % coverage or number of locations
- Tools / Techniques - ultrasonics or radiography
- Practices - internal, external, scanning

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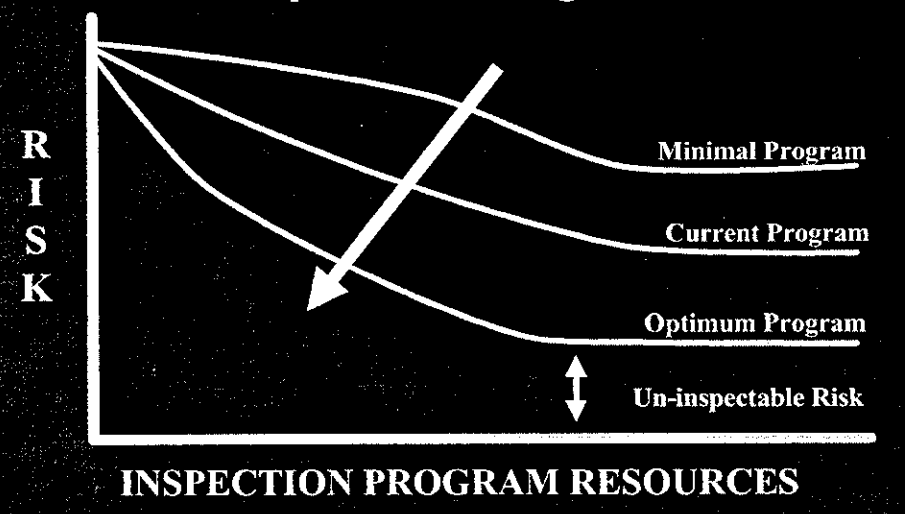
Three Inspection Programs vs. Risk



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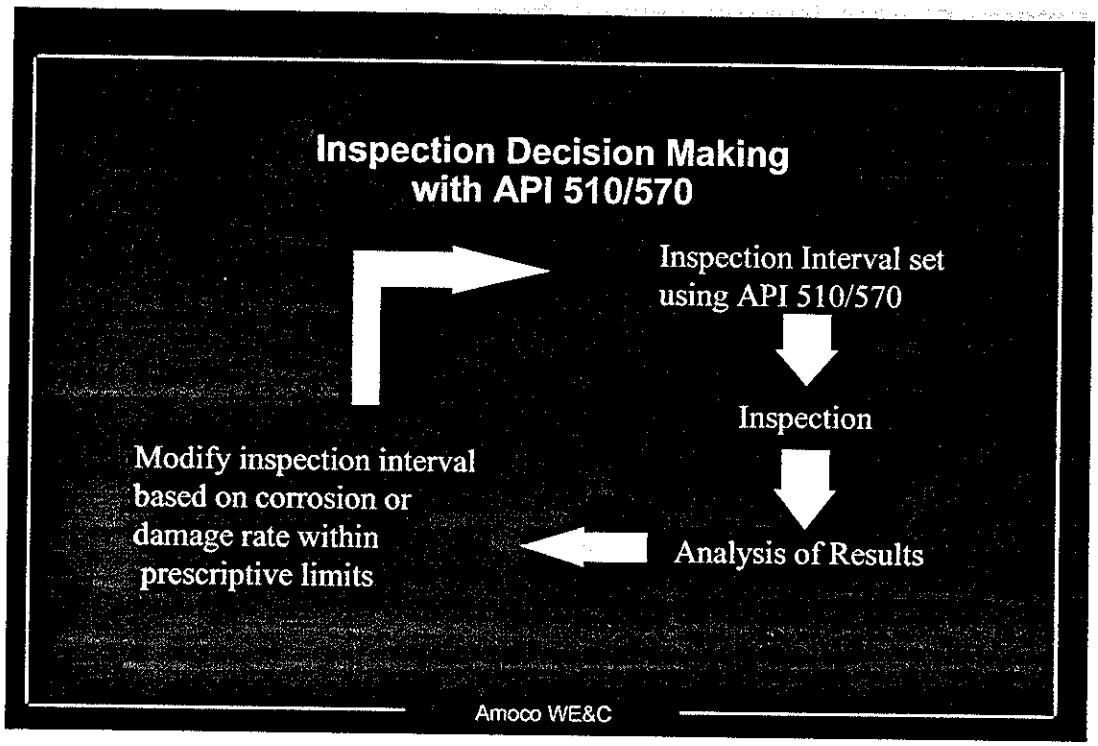
Inspection Decision Making
with API 510/570
Inspection Interval set
using API 510/570
Inspection
Analysis of Results
Modify inspection interval
based on corrosion or
damage rate within
prescriptive limits
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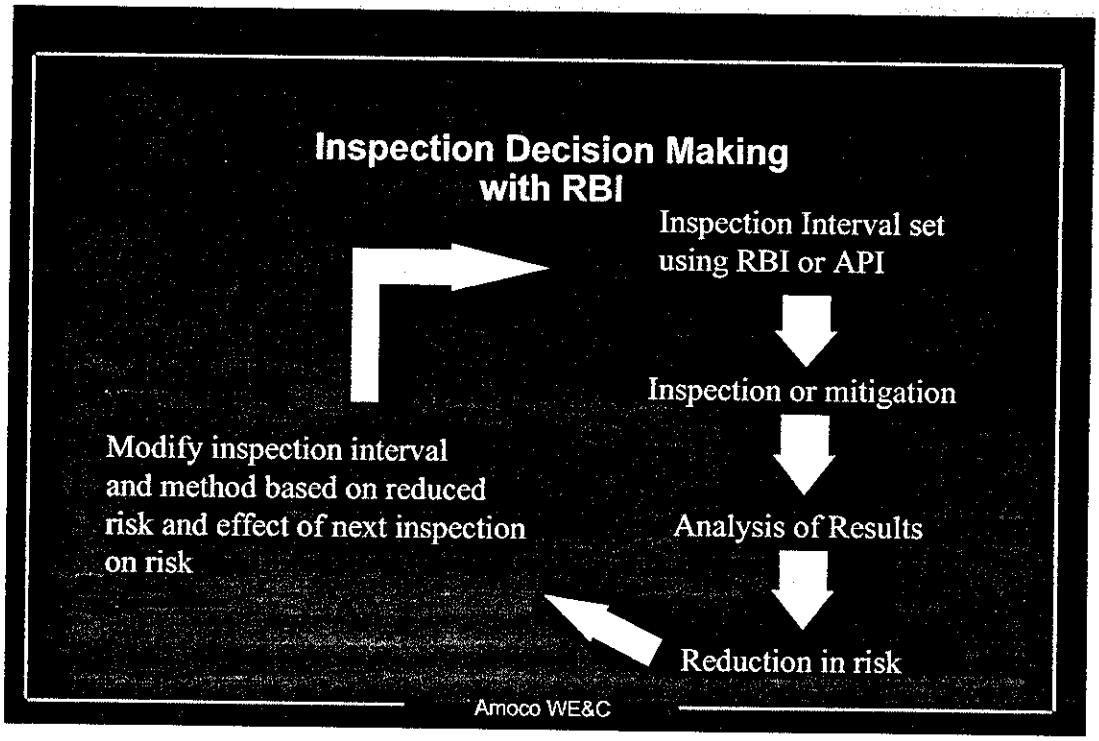
Inspection Decision Making
with RBI
Inspection Interval set
using RBI or API
Inspection or mitigation
Analysis of Results
Reduction in risk
Modify inspection interval
and method based on reduced
risk and effect of next inspection
on risk
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3. Government and Industry Partnering for Risk Management - Gary Zimmerman

This report discusses how government and industry partnering to resolve risk management problems for onshore pipelines has resulted in positive results and many companies are seeing the benefits of a risk management program. The major topics of the program are to see how the regulatory framework can be utilized in the most efficient manner, how program standards can be developed to obtain maximum performance, and finally to see how the communication between involved parties can be maximized.

The current joint effort between government and industry is described, along with the finer details of developing a risk management program for onshore pipelines. The outline of risk management for onshore pipelines includes risk issues like emergency response coordination, proposed and actual safety improvements, regulatory relief for onshore pipelines, and communication issues.

GOV'T-INDUSTRY PARTNERING FOR RISK MANAGEMENT

By Gary L. Zimmerman
Equilon Pipeline Company LLC

glz-Equilon

1. DOT-OPS RISK MANAGEMENT DEMONSTRATION PROGRAM
2. SPLC (EQUILON) DEMO PROJECT
3. EXPERIENCE SO FAR
4. FUTURE EXPECTATIONS

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1. DOT-OPS RISK MANAGEMENT DEMONSTRATION PROGRAM

- Beginnings
- Program "Rules"
- Current Status

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Beginnings

- OPS/Industry dilema - trend towards more & more prescriptive regs
- Gas/Liq p/l industries partner with OPS to explore "risk management" approach
- RM holds promise, BUT only with appropriate "rules" and "checks & balances"
- RAQT teams created "rules & checks"

glz-Equilon

Program Rules

- Regulatory Framework
  - How OPS behaves
- Program Standard
  - How the operator behaves
- Performance Measures
  - How to measure success
- Communication Plan
  - How stakeholders are involved

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Current Status

- 10 "trial" operators allowed
- Began late '97
- 12 applicants currently
- EQPC, Mobil, Phillips, NGPL approved or near-approved

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2. EQPC (old-SPLC) Demo Project

- Objectives
- Project Description
- Risk Issues
- Safety Improvements
- Regulatory Relief

Objectives

- Improve safety & enviro performance
- Expand 1 system in most risk-prudent manner
- Improve our internal risk management process
- Influence the "rules of the game"

Project Description

- LOI submitted in May '97
- Application submitted in Dec '97
- Systems selected
  - » 200 mi. of 12" ethylene pipeline
  - » 260 mi. of 30" CO2 pipeline

Risk Issues

- Avoidance of third party damage
- Extent of past third party damage
- Emergency response coordination
- Throughput expansion of 30" CO2 p/l
  - » Operate 25-mi. segment at ~ 80% SMYS
  - » Technical validations
  - » Safety offsets

Safety Improvements

- Smart pig
- Close interval CP surveys
- Depth-of-cover surveys
- Enhanced surveillance
- Localized One-Call sponsorship
- Vehicle barriers

Safety Improvements

- Warning mesh & improved line markers
- Enhanced community/public awareness
- Improved emergency response preparedness
  - » Dispersion modeling
  - » Simulation drills
  - » Coordination with LEPC's

Regulatory Relief

- CO2 pipeline
  - » Operate 25-mi. segment over 72% SMYS
  - » Add HP at existing station; avoid new station at virgin site
- Ethylene pipeline
  - » None

3. Experience So Far

- External Process
- Internal Process
- Public Communications

External Process

- Good dialogue with OPS & State reps
- Much info written for public consumption
- Some questions from other stakeholders and the general public
- Much more discussion about our "thought process", assumptions, and rationale

Internal Process

- Valuable findings using structured risk assessment
- More creative & innovative solutions discussed and to be tried
- Comfort factor increased
- More complete accountability realized

Public Communications

- Prospectus, Federal Register Notices, Public Meetings, FEMA Broadcast
- Fear of effort needed to respond to questions
- Fear of increased accessibility to info/data
- Few comments to date outside of DOT review process

4. Future Expectations

- Program Expanded Within EQPC
- Program Institutionalized Within OPS
- **True Partners For Safety**

Program Expanded Within EQPC

- Remaining segments of demo p/l's
- Parallel propylene p/l
- Remaining p/l systems based on risk "screening" process
- Improve our risk assessment process

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Program Institutionalized Within OPS

- Annual updates on Program performance
- Program "rules" refined
- Final report to Congress will show benefits to all parties
- Program offered to all p/l operators

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TRUE PARTNERS FOR SAFETY

- Increased dialogue and understanding of risks
- More meaningful discussion of risks
- More innovation by operators
- Risks reduced through site- and situation-specific activities
- Resources more appropriately allocated

glz-Equilon

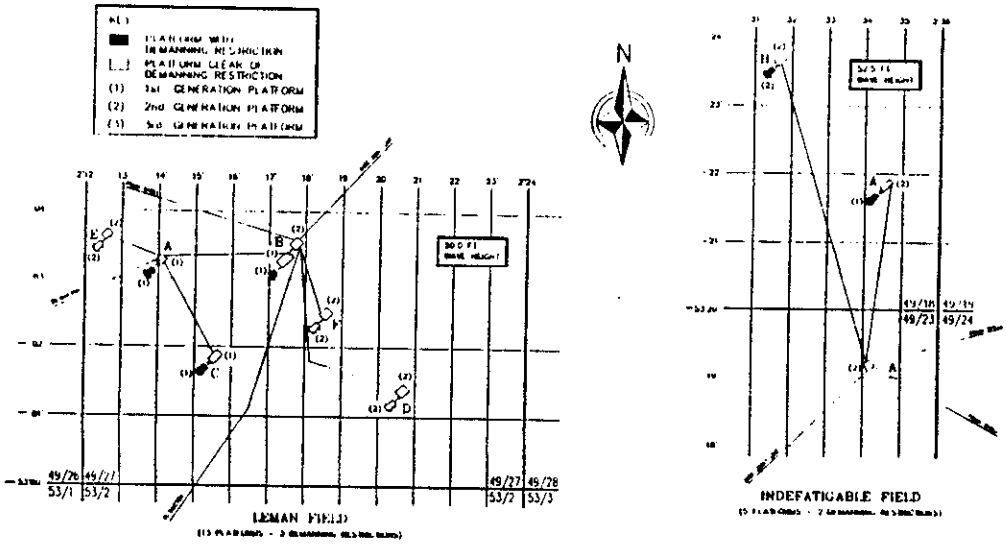
4. Risk Management Systems for Offshore Platforms - Patrick O'Connor

The following paper discusses the application of risk assessment methods for offshore platforms. The fundamental load-resistance reliability model is highlighted as the preferred method of risk assessment for platforms, and the various areas of application of the model are highlighted. Another major topic that is discussed is the structural integrity management of offshore platforms, and what the major components of a structural integrity management system are.

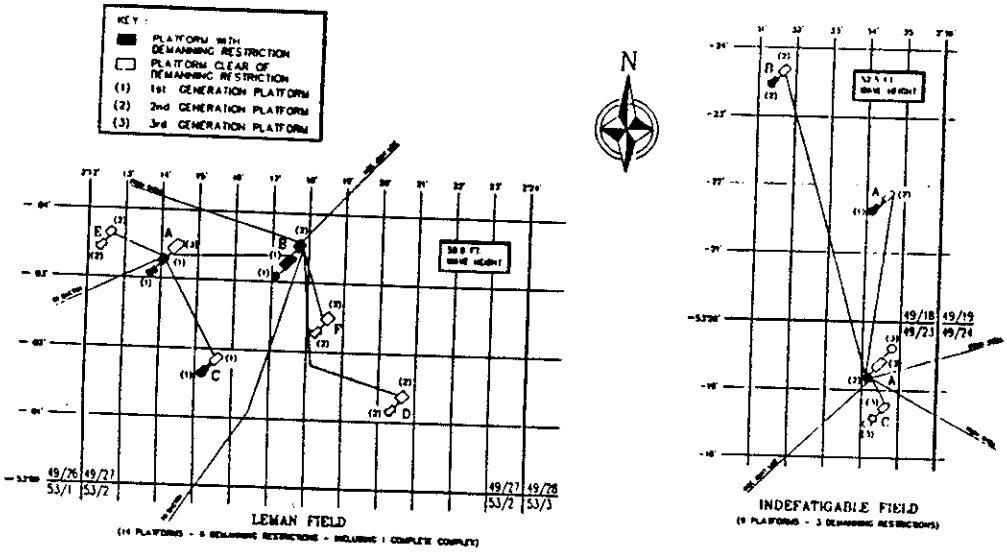
Finally, an example of a qualitative method for calculating the reliability of platforms is presented with supporting data from the North Sea. The assessment of the likelihood and consequence of failure are also described to assist in gaining more insight into the platform risk assessment system, as well as to provide parallels for the offshore pipeline industry.

Risk Management Systems for Offshore Platforms

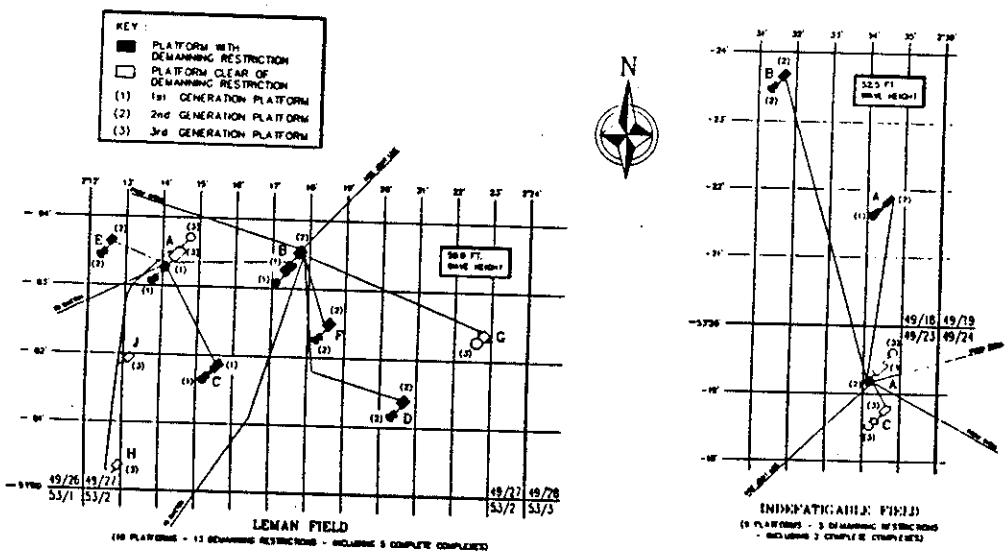
Patrick O'Connor



DEMANNING – SOUTHERN NORTH SEA 1975
(COMMENCEMENT OF MANDATORY CERTIFICATION)

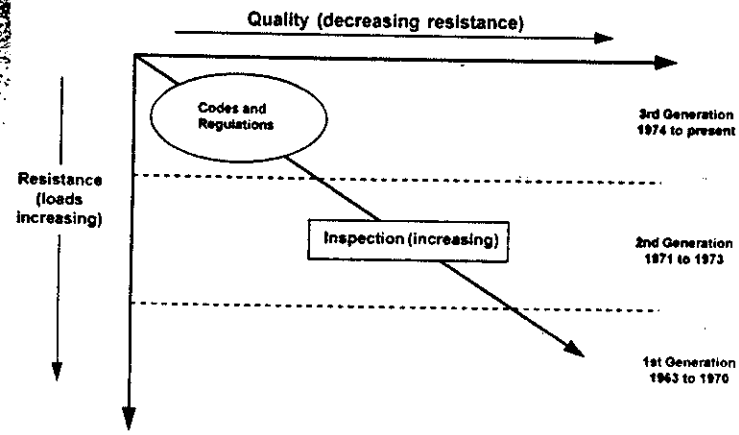


DEMANNING - SOUTHERN NORTH SEA - 1980
(SITUATION ARISING FROM ONGOING FIELD DEVELOPMENT)

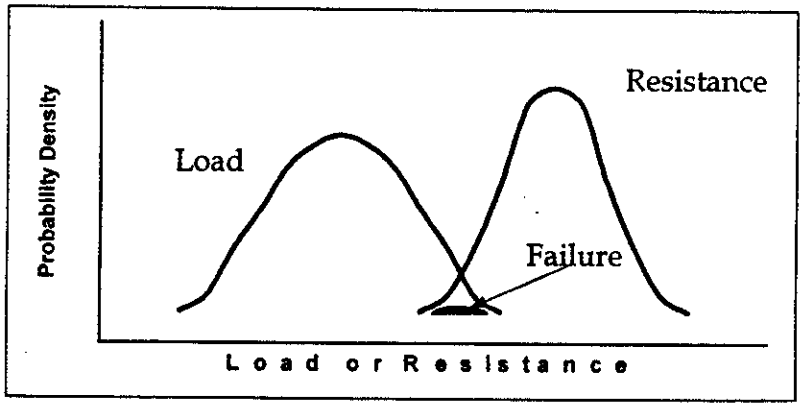


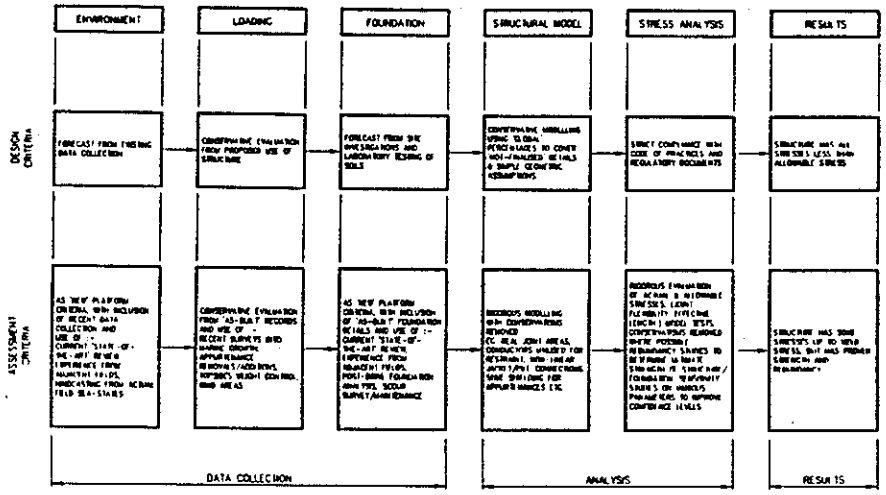
DEMANNING - SOUTHERN NORTH SEA - 1985
(PROJECTED SITUATION WITHOUT ASSESSMENT)

Platform Performance Evolution
Amoco Classification System



Fundamental Reliability Formulation





FLOWLINE DIAGRAM - STRUCTURAL ASSESSMENTS

FIELD	WAVE HEIGHT (FT)		
	ORIGINAL DESIGN	PRESENT DESIGN (NEW STRUCTURES)	PRESENT ASSESSMENT (1) (EXISTING STRUCTURES)
INDEFATIGABLE	45.0 TO 55.0	52.5	49.2
LEMAN	43.0 TO 55.0	49.5	46.3
MONTROSE	92.0	83.5	78.0
N.W. HUTTON	98.4	98.4 (2)	98.4 (2)

(1) DIRECTIONAL MAXIMA
(2) CURRENTLY UNDER ASSESSMENT - REVISED VALUE = 88.6FT

COMPARISON OF CERTIFIED WAVE HEIGHTS
ORIGINAL DESIGN Vs. PRESENT EVALUATIONS

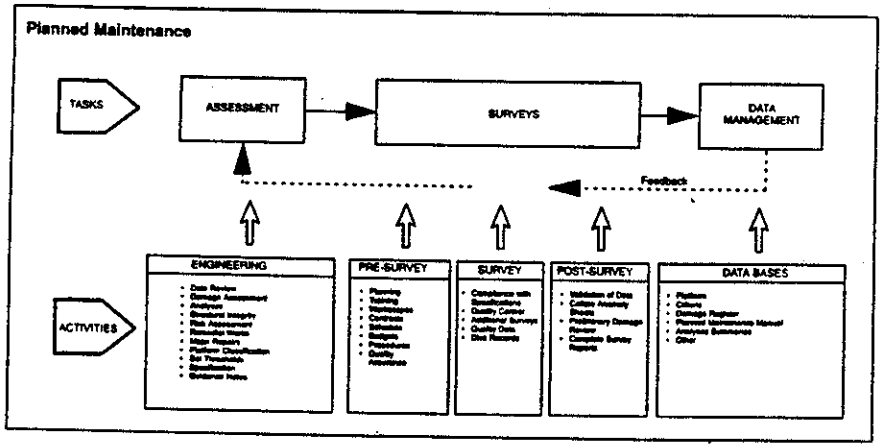
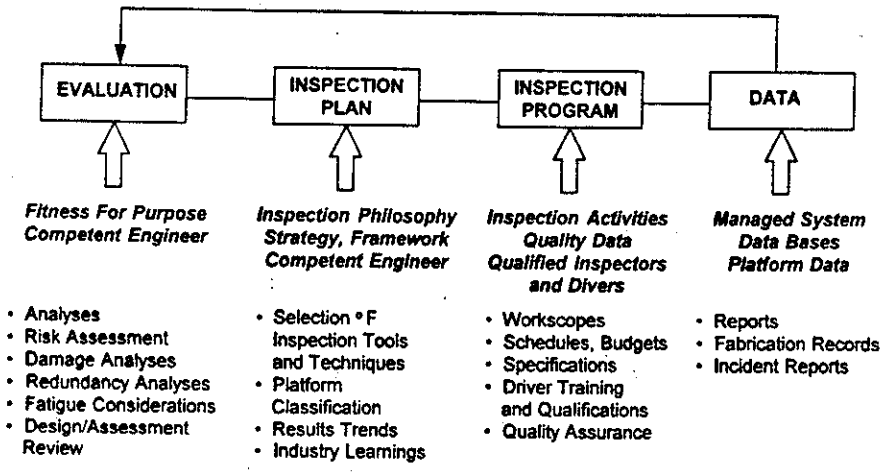
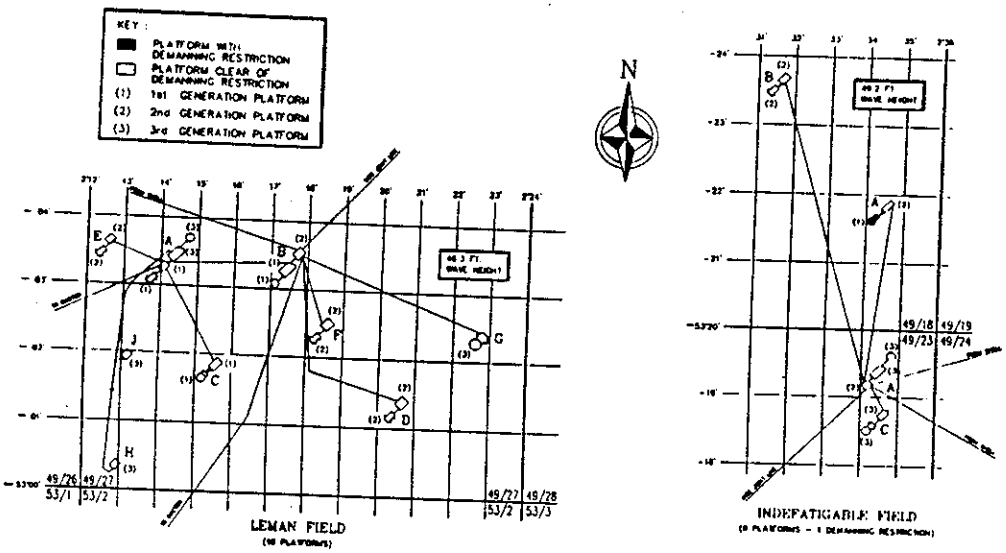


Fig. 2



(ISO) STRUCTURAL INTEGRITY MANAGEMENT



DEMANNING - SOUTHERN NORTH SEA - 1987
(PRESENT STATUS)

UNDERWATER STRUCTURAL INSPECTION - 10 YEAR INSPECTION CYCLE - SOUTHERN NORTH SEA (UK SECTOR)

	PLATFORM	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
INDE	49/18 AP *	R	MS	R	R	IS	R	MS	R	R	IS
	49/18 AR *		MS			IS		MS			IS
	49/18 BP *	R	MS	R	R	IS	R	MS	R	R	IS
	49/18 BD *	-	MS	-	-	IS	-	MS	-	-	IS
	49/23 AQ *	-	MS	-	-	IS	-	MS	-	-	IS
	49/23 AC *	-	MS	-	-	IS	-	MS	-	-	IS
	49/23 AT *	R	MS	R	R	IS	R	MS	R	R	IS
	49/23 CP *	R	IS	R	R	MS	R	IS	R	R	MS
	49/23 CD *	-	IS	-	-	MS	-	IS	-	-	MS
	49/23 D	R	IS	R	R	MS	R	IS	R	R	MS
	49/27 AQ *	-	MS	-	-	IS	-	MS	-	-	IS
	49/27 AC *	R	MS	R	R	IS	R	MS	R	R	IS
	49/27 AP *	R	MS	R	R	IS	R	MS	R	R	IS
	49/27 AD *	-	MS	-	-	IS	-	MS	-	-	IS
	49/27 AX *	-	MS	-	-	IS	-	MS	-	-	IS
	49/27 BT	R	IS	R	R	MS	R	IS	R	R	MS
LEMAN	49/27 BP	R	IS	R	R	MS	R	IS	R	R	MS
	49/27 BD	-	IS	-	-	MS	-	IS	-	-	MS
	49/27 CP	R	IS	R	R	MS	R	IS	R	R	MS
	49/27 CD	-	IS	-	-	MS	-	IS	-	-	MS
	49/27 DP	R	IS	R	R	MS	R	IS	R	R	MS
	49/27 DD	-	IS	-	-	MS	-	IS	-	-	MS
	49/27 EP	R	MS	R	R	IS	R	MS	R	R	IS
	49/27 ED	-	MS	-	-	IS	-	MS	-	-	IS
	49/27 FP	R	MS	R	R	IS	R	MS	R	R	IS
	49/27 FD	-	MS	-	-	IS	-	MS	-	-	IS
	49/27 G	R	IS	R	R	MS	R	IS	R	R	MS
	49/27 H	R	IS	R	R	MS	R	IS	R	R	MS
	49/27 J	R	IS	R	R	MS	R	IS	R	R	MS
CAMELOT 53/1-CA		R	IS	R	R	MS	R	IS	R	R	MS
CAMELOT 53/1-CB		R	IS	R	R	MS	R	IS	R	R	MS

LEGEND

MS = MAJOR SURVEY

IS = INTERMEDIATE SURVEY

R = RISER SURVEY (ROV)

KEY:

1st GENERATION PLATFORMS

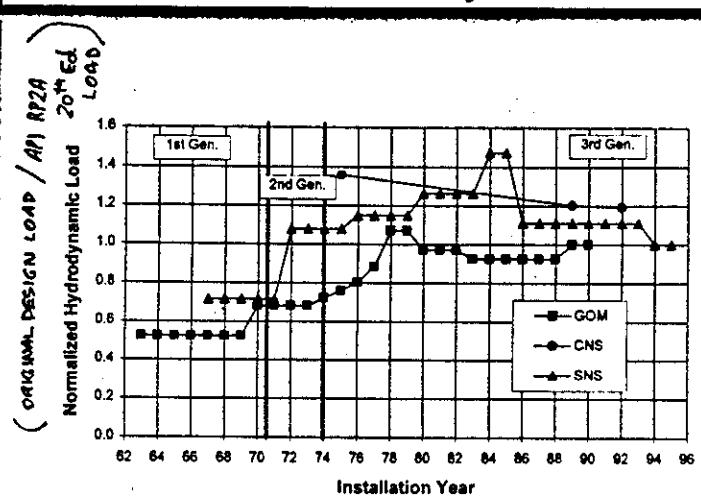
2nd GENERATION PLATFORMS

3rd GENERATION PLATFORMS

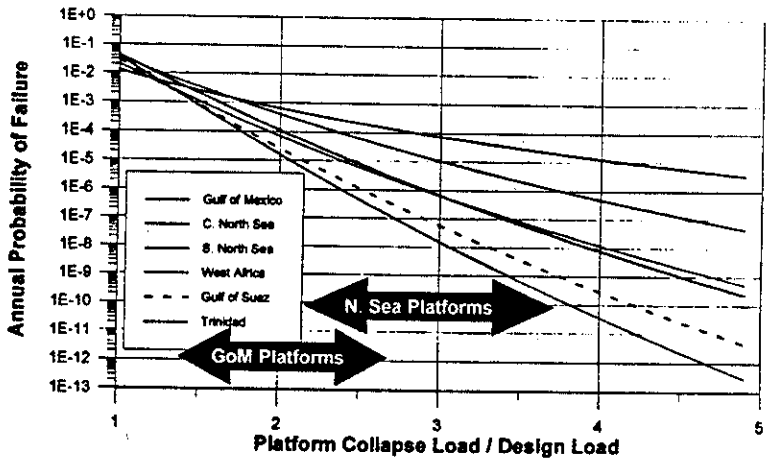
* MANNED PLATFORMS

TABLE 7

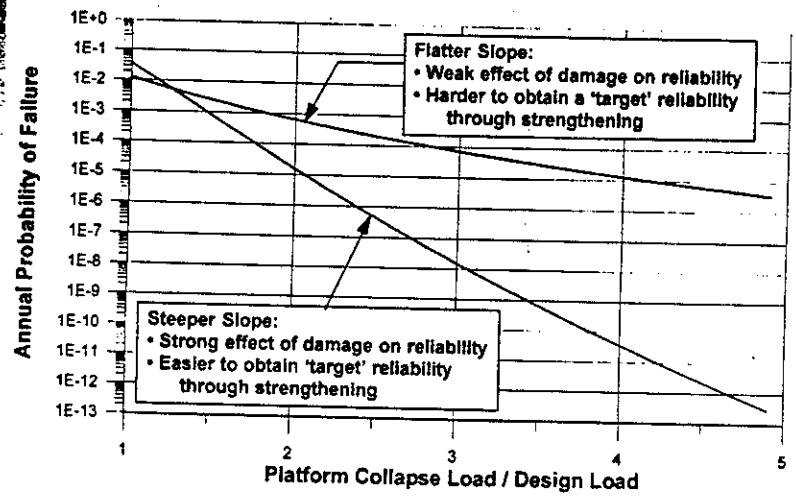
Metocean Load History



Platform Reliability in Amoco Operational Areas

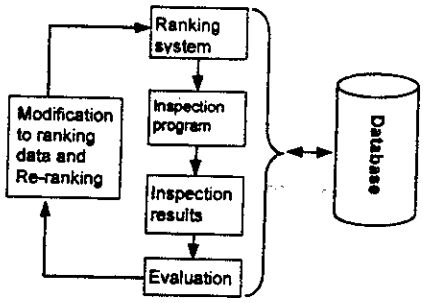


Reliability vs. Reserve Strength



Objective

- To develop a platform-level ranking system for underwater jacket inspections.
  - Identify which platforms deserve the most inspection effort
  - Base system on qualitative risk
  - Use platform-level information



Likelihood Scoring

- Factors that affect:
  - loads
  - resistance
  - systems
- Rule-based
- Weighted sum - importance

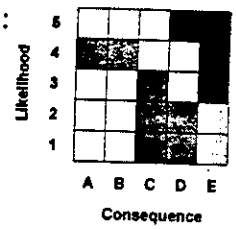
Factor	Weight
Damaged members	10.5
Bracing system and no. of legs	10.0
Designed for design earth quake	8.0
Time since last inspection –inspection type	8.0
Minimum remaining wall	7.5
Marine growth	6.0
Flooded members	6.0
Year Load and Location	5.0
Design practice in design year	5.0
Grouted piles	5.0
Scour	2.0

Consequence Scoring

- Total loses:
  - Safety
  - Environment
  - Business
- Score is calculated in "abstract dollars"
  - Measures safety, environmental and business loses with a common yardstick
  - Dollar amount converted to a category A-E

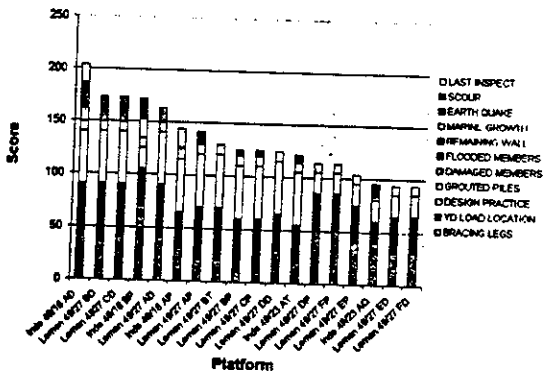
Overall approach

- Categorization systems:
  - Likelihood - 1 (low probability) to 5 (high probability).
  - Consequence - A (low failure loss) to E (high failure loss)
  - Five × Five matrix:



North Sea Preliminary Likelihood Results

- Highest Likelihood - Inde 49/18 AD



North Sea Preliminary Likelihood Results

- Lowest Likelihood
  - Leman 40/27 G

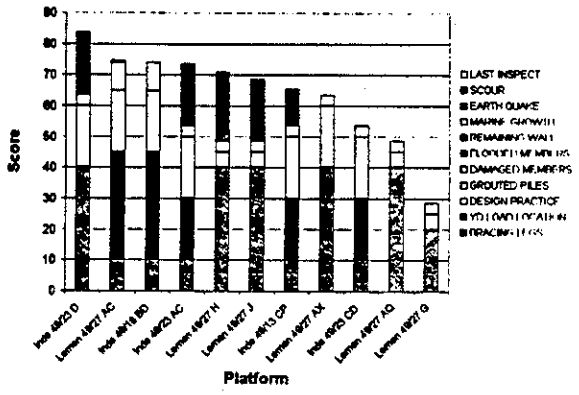


TABLE 14.4.2
GUIDELINE SURVEY INTERVALS

Level	I	II	III	IV
Manned, Non-Evacuated	1 yr	3 thru 5 yrs	6 thru 10 yrs	*
Manned-Evacuated	1 yr	5 thru 10 yrs	11 thru 15 yrs	*
Unmanned	1 yr	5 thru 10 yrs	*	*

** Surveys should be performed as indicated in paragraphs 14.3.2 and 14.3.3.*

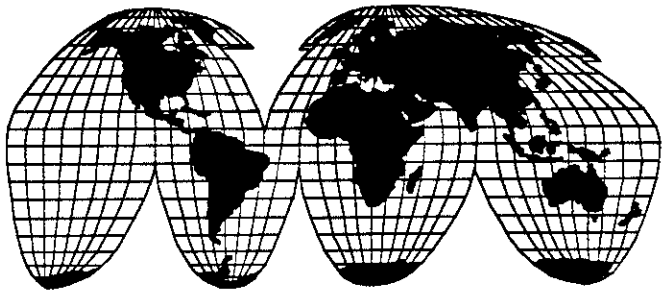
5. Qualitative Risk Assessment for Pipelines - Kent Muhlbauer

In this paper the qualitative risk assessment methods are highlighted, starting with a description of informal risk management and how risk management was applied in the past. The important components of a good risk management system are also talked about as well as lessons that the author learned through his consulting practice for risk management. Cause and effect relationships are highlighted as being the keys to assessing the origin of risk correctly, the user is encouraged to abstain from complexity and is encouraged to use computers wisely.

The use of a risk assessment method requires the operator to closely examine his or her pipeline, and in order to do this the author outlines several important factors that any operator should observe before choosing a risk assessment system. Finally, general indexing methods for risk assessment as well as analyzing the bottom line of consequence and cost are highlighted, and it is highly recommended that the user be thorough and study his or her results obtained from the model.

Lessons Learned In Pipeline Risk Assessment

Kent Muhlbauer



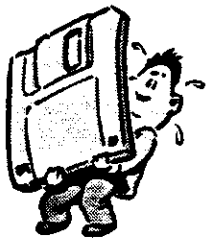
Historical (Informal) Risk Mgmt

ADVANTAGES:

- simple/intuitive
- consensus is often sought
- utilizes experience and engr judgment
- successful

Historical (Informal) Risk Mgmt

REASONS TO CHANGE:



- more at stake from mistakes
- inefficiencies/subjectivities
- lack of consistency
- need to consider complicated factors

Risk Management Objectives

Increase understanding

- decision support tool
- resource allocation tool

Reduce risks

Reduce costs

Risk Management Process

I. Perform a risk assessment

assign values to all conditions and activities

II. Establish Risk Targets

benchmarking

III. Allocate Resources Accordingly

Desired Output

Pipeline XYZ, having conditions...

A

B

.

.

...and operated as...

D

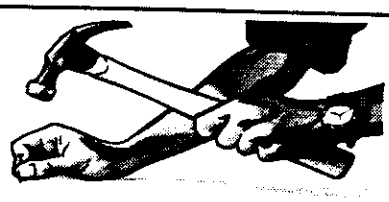
E

.

.

...has a risk of failure of _____

Tools



HAZOPS

event trees

fault trees

FMEA

scenarios

The Role of Statistics

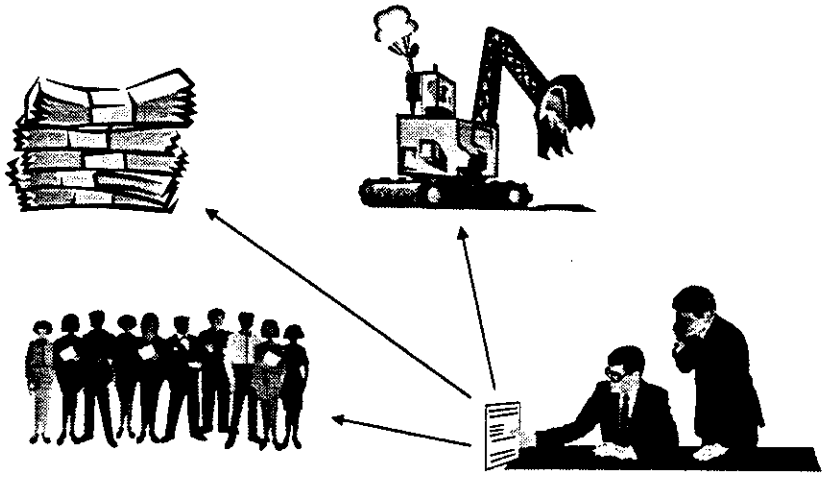
Probably the single best decision support available

Problems:

- Historical data usefulness in current situation
- Small amount of data in rare-event situations

VI. Study your results

Resource Allocation Modeling



Management Options

Resource Allocation Choice	Cost Impact	Risk Impact
Increase Public Education	+ $4000	- 0.8%
Perform Close Interval Survey	+ $11000	- 2.6%
Reduce Air Patrol	- $7600	+ 1.1%
Perform Hydrostatic Test	+ $67000	- 8.2%

Conclusions

- RA/RM should be cost effective
- Few roadmaps to follow
- Manage as any large project
- PL RAM is worthwhile

6. Quantitative Risk Assessment as a Basis for Pipeline Integrity Maintenance Planning - Mark Stephens

The quantitative risk assessment method for pipelines is potentially the most accurate approach, that is if accurate data about the pipeline can be collected. C-FER is currently working with several large onshore pipeline-operating companies to develop a comprehensive quantitative risk assessment system that will be able to reduce operating costs significantly. The major issues addressed are: 1) what is the operating risk associated with the pipeline in its present state, 2) what effect would each candidate maintenance strategy have on the operating risk, and 3) what is the lowest cost maintenance option that meets acceptable safety and environmental constraints.

The author discusses several examples of risk assessment model application, that help to guide the reader visualize the quantitative risk assessment method. One example highlights probability of failure calculations given x number of flaws, another discusses failures due to impact, and a third example looks at consequence analysis given a failure. Finally risk estimation and control methods are described, and how decision analysis can be incorporated into the system.

Quantitative Risk Assessment as a Basis for Pipeline Integrity Maintenance Planning

The PIRAMID Approach

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Background to PIRAMID Approach

- A multi-year Joint Industry Program
- Sponsored by
  - BC Gas Utility
  - Foothills Pipe Lines
  - Interprovincial Pipe Line
  - NOVA Corporation
  - TransCanada PipeLines
  - British Gas
  - Gas Research Institute
  - Canadian Geological Survey
  - U.S. Minerals Management Service
- Parallel development
  - models for onshore and offshore pipeline systems

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Program Goal

Develop Models and Software to:

- Make optimal maintenance decisions
  - Ensure acceptable risk levels
  - At the lowest possible cost
- Explain rationale behind decisions
  - Internally within company
  - Externally to regulators and the public

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Issues To Be Addressed

- What is the operating risk associated with the pipeline in its present state
- What effect would each candidate maintenance strategy have on the operating risk
- What is the lowest cost maintenance option that meets acceptable safety & environmental constraints

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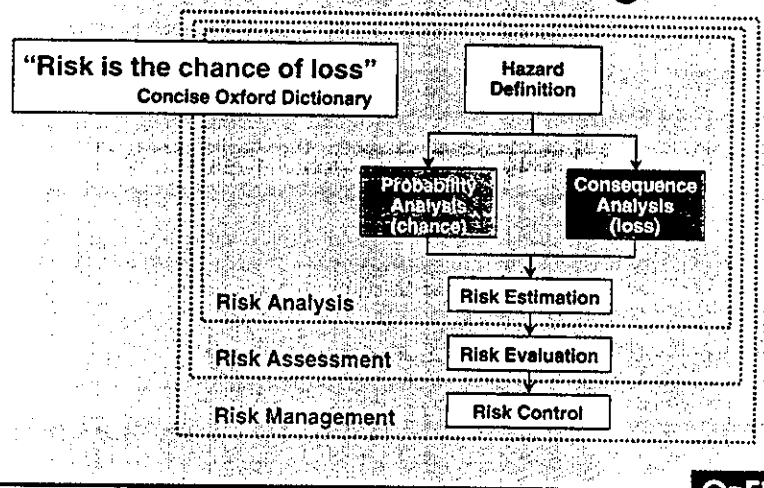
Risk-Based Decision Making



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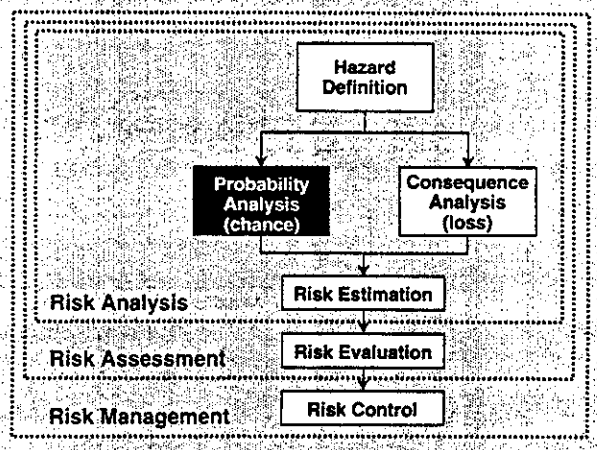
Probability Analysis



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Probability Analysis

- **Purpose**

  To quantify the uncertainty associated with the hazardous event

  > Definition: Probability is a number measuring the degree of belief that the event will occur

- **Available Methods**
  - Direct approach using historical data
  - Indirect approach using models

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Probability Analysis -
Statistical Approach Based on Historical Data

- **Calculation approach**

  Failure Probability = (historical failure rate) x (segment length)

- **Advantages**
  - Simple and easy to understand
  - Convincing because its based on real data
- **Limitations**
  - Dependent on availability of <u>relevant</u> data
  - Not necessarily pipeline-specific
  - Difficult to account for effect of maintenance actions

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Probability Analysis -
Analytical Approach Based on Models

- Calculate failure probability based on
  - Deterministic failure prediction model
  - Statistical data on model inputs
    - line condition
    - pipe properties
    - model uncertainties

Uncertain Input Parameters → Deterministic Failure Condition → Probability of Failure

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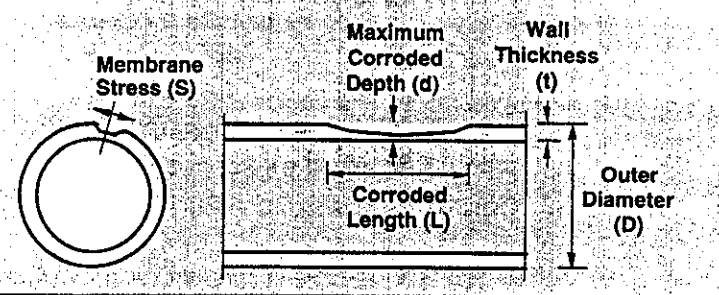
Example 1 - Model Based Approach

Failure probability of a pipeline with metal loss corrosion



Failure probability = (No. defects) x (Failure probability per defect)

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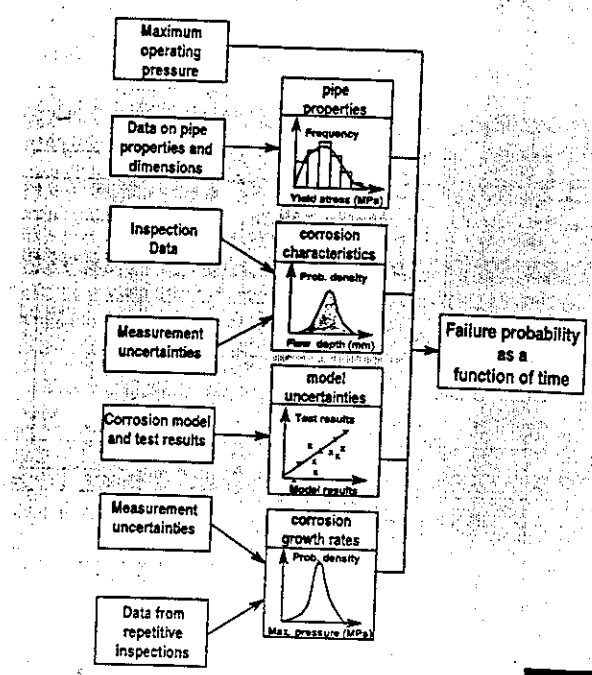
Failure Probability per Defect



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Number of Corrosion Defects

- Line condition data obtained from
  - results of line condition surveys
  - in-line inspection results
  - experience with similar pipelines

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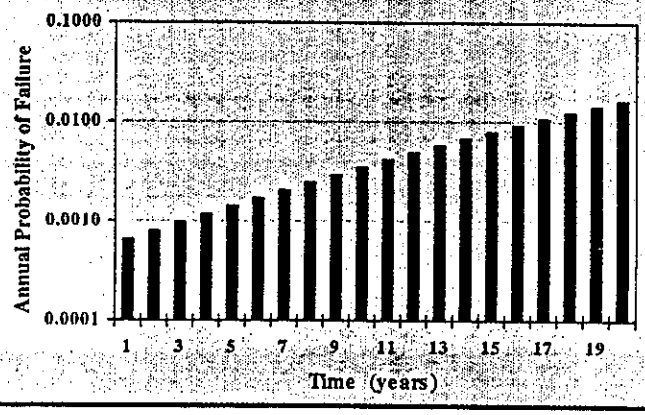
Results of Analysis - Probability of Failure Versus Time



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Effect of Maintenance Actions on Probability of Failure

- Inspection & repair modifies defect population
  - Reduces number of defects per unit line length
  - Shifts defect size distribution toward smaller values

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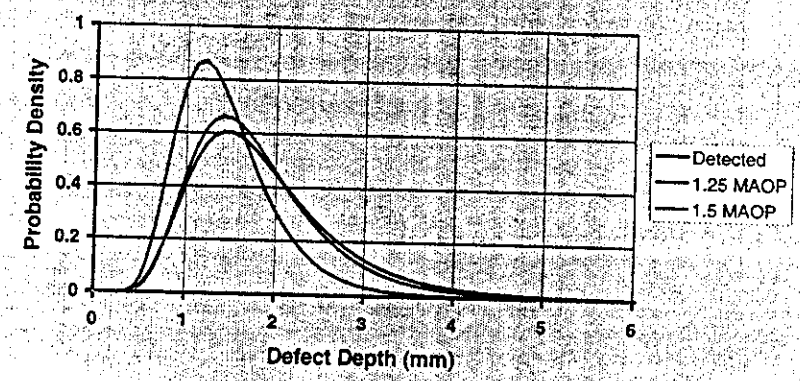
Effect of Maintenance - Modified Defect Size Distributions



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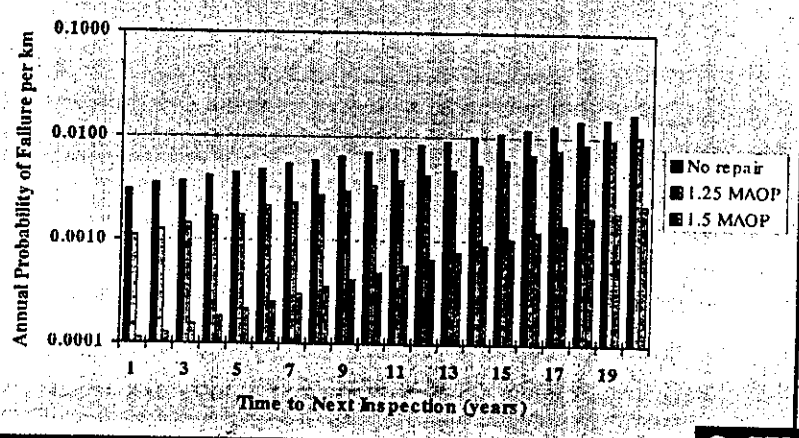
Effect of Maintenance - Reduction in Probability of Failure



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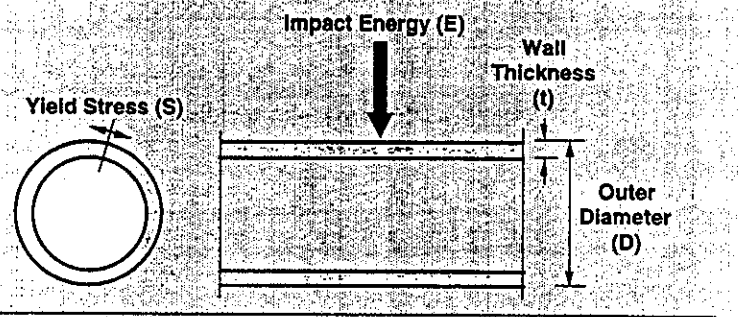
Example 2 - Model Based Approach

Failure probability of a pipeline due to mechanical damage



Failure probability = (No. line hits) x (Failure probability per hit)

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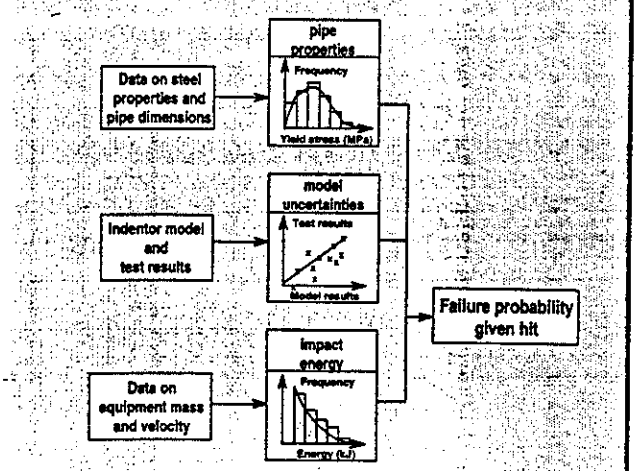
Failure Probability given line hit



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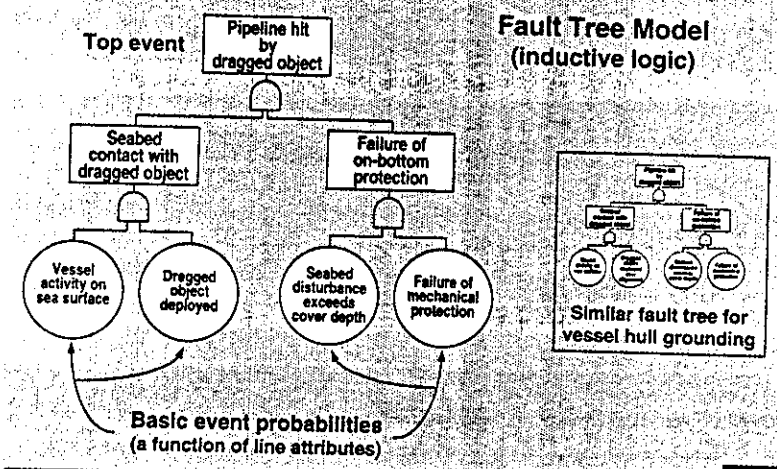
Frequency of Line Hits



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Effect of Preventative Maintenance Actions on Probability of Failure

- Candidate actions will affect probability of hit
  (by altering basic event probabilities in fault tree)
- For example
  - Enhance awareness of pipeline location
  - Modify cover depth inspection frequency
  - Increase pipeline burial depth
  - Introduce mechanical protection

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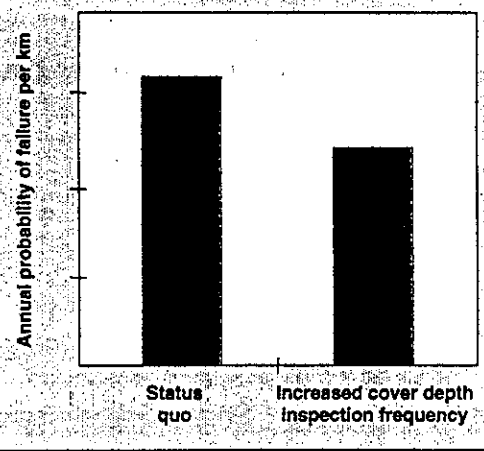
Effect of Maintenance - Reduction in Probability of Failure



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Probability Analysis - Based on Models

- Advantages:
  - Pipeline-specific estimates (reflect line conditions)
  - Can account for time-dependent deterioration
  - Can reflect impact of maintenance activities
- Limitations:
  - Dependent on availability and quality of models
  - Requires line condition data

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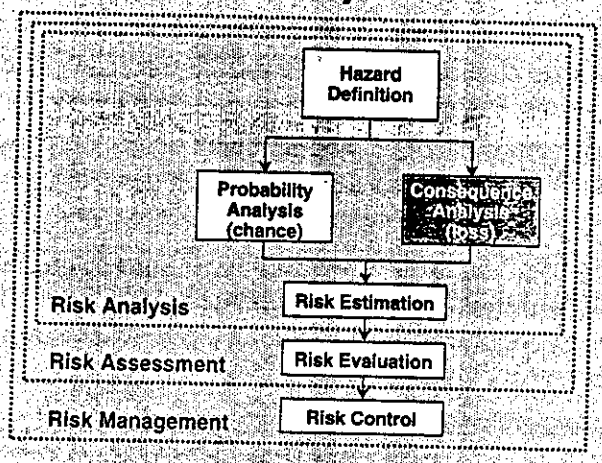
Consequence Analysis



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Consequence Analysis

- Purpose
  - To quantify the loss associated with a given hazardous event
- Available Methods
  - Direct approach using historical data
  - Indirect approach using models

Consequences can generally be categorized as

- Financial (loss of investment, property or revenue)
- Safety related (loss of life or health)
- Environmental (damage to natural resources)

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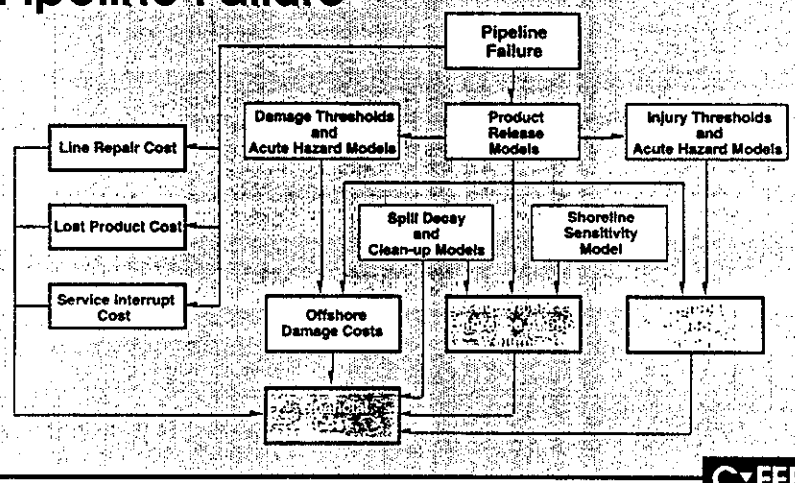
Potential Consequences of Pipeline Failure



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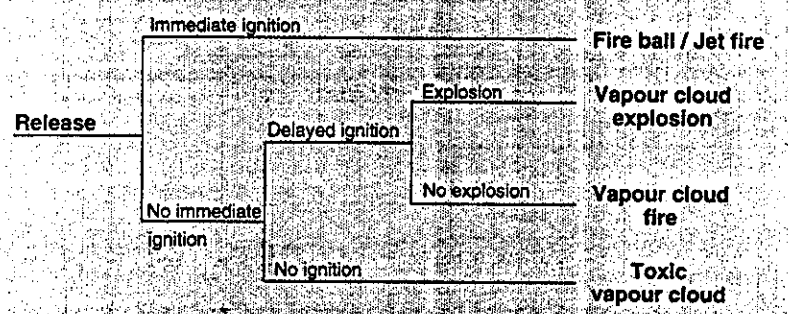
Example - Consequence Analysis

Consequences of Acute Release Hazards

Step 1 - Use event tree analysis (logic model) to estimate relative likelihood of all conceivable release hazards



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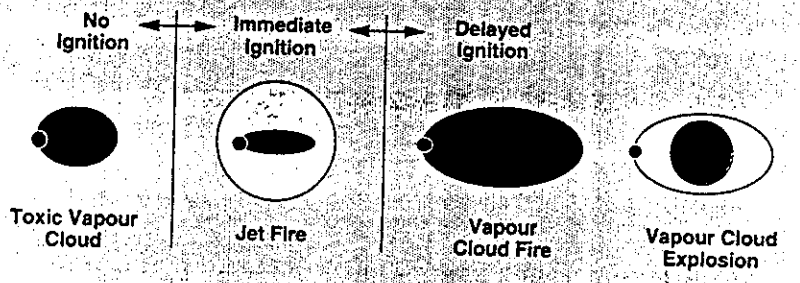
Example - Consequence Analysis

Consequence of Acute Release Hazards

Step 2 - Use hazard characterization models to estimate size of affected areas



Step 3 - Estimate no. of people at risk (= Hazard area x Population density)
Estimate property damage cost (= Hazard area x Property density)

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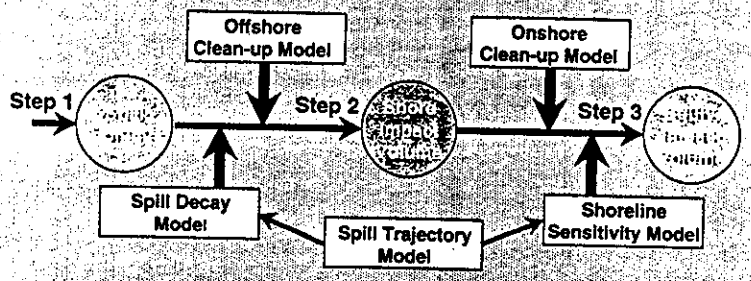
Example - Consequence Analysis

Long-term Consequences of Product Release Hazard



Step 4 - Assess clean-up costs
Estimate extent of natural resource damage

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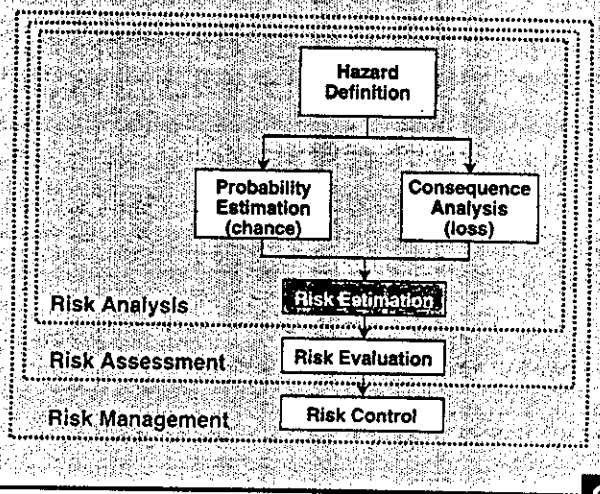
Risk Estimation



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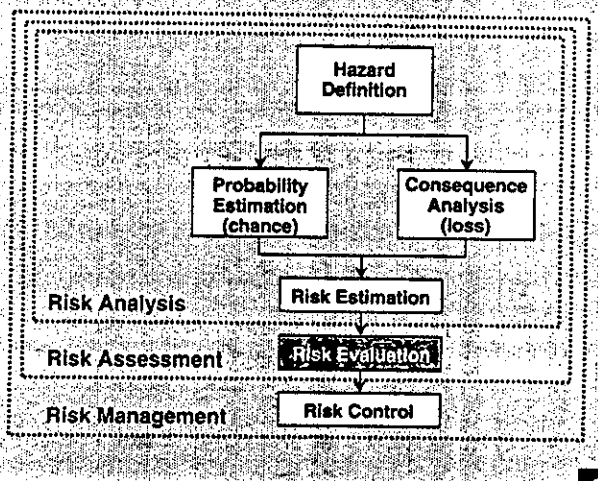
Risk Evaluation



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Risk Evaluation

Purpose

To determine whether the risk level is acceptable or tolerable given the context of the situation

Approaches

- Comparison with risks from other activities
- Guidelines and regulations
- Corporate policy

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Evaluation - by Comparison

Risk Level*	
1 in 1000	*- risk of death, all causes (ages 25 - 45)*
1 in 1000	- risk of death at work, 'high risk' industry
1 in 10,000	- risk of death in a traffic accident
1 in 100,000	- risk of death at work, 'safe' industry
1 in 1 million	- risk of death at home from gas explosion
1 in 10 million	- risk of death by lightning

*approximate average annual probability (UK HSE 1992)

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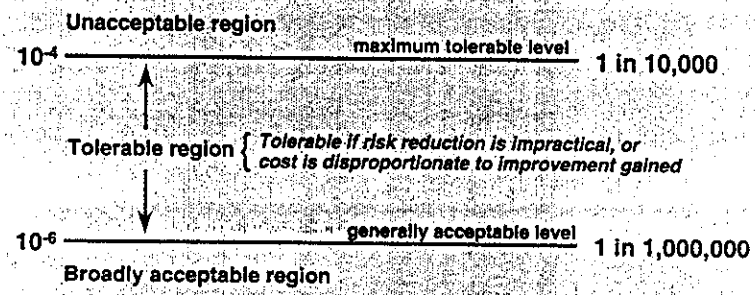
Evaluation -Based on Regulation

Safety risk associated with nuclear power stations
(UK Health and Safety Executive, 1988)



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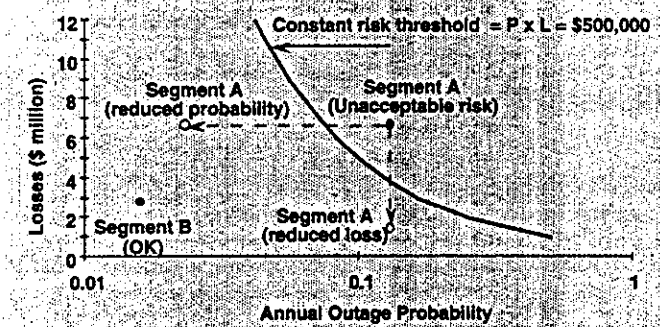
Evaluation - Based on Corp. Policy

Prioritization of pipeline repair



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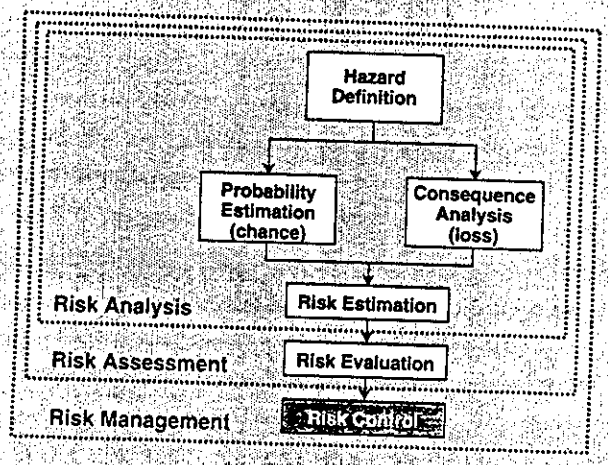
Risk Control



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Risk Control

Purpose

To select and implement measures to ensure an acceptable level of operating risk

Questions answered

- How much should the risk be reduced?
- What methods can achieve the required reduction?
- At what cost?

Note: The optimal risk control strategy achieves an acceptable level of risk at the minimum cost

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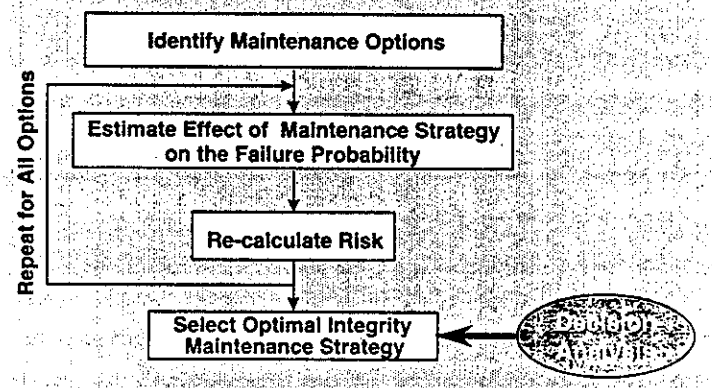
Risk Control Process



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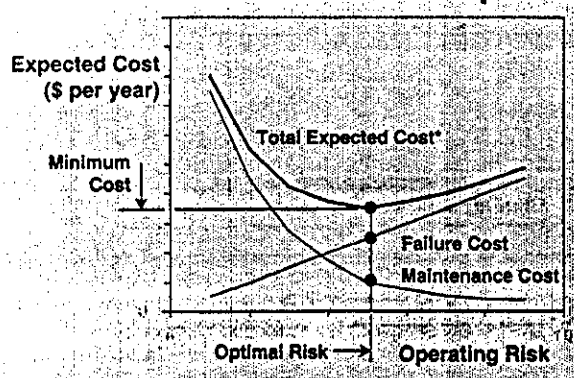
Example of Decision Analysis

Risk Control Based on Cost Optimization



*Total Expected Cost = Failure Cost + Maintenance Cost

Failure Cost = probability of failure x cost of failure

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PIRAMID

OFF SHORE

Pipeline Risk Analysis for Maintenance and Inspection Decisions

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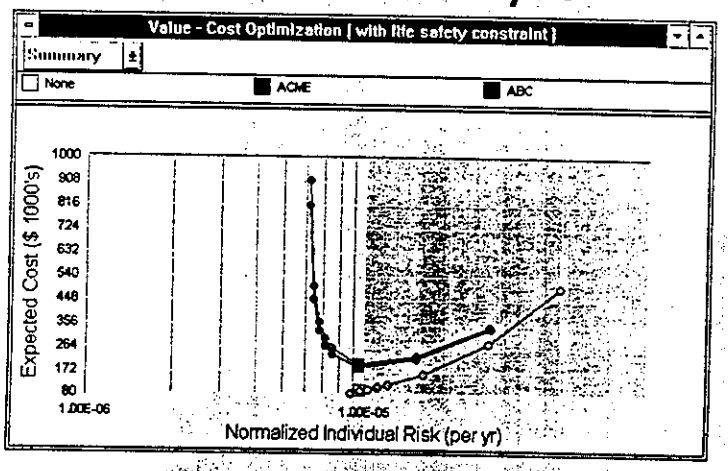
PIRAMID - Decision Analysis



Optimizes inspection tool, inspection interval and repair criterion

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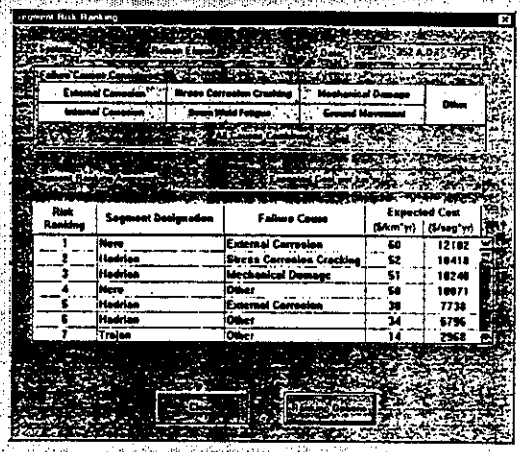
PIRAMID - Prioritization

Pipeline segment ranking with respect to total risk



Risk Ranking	Segment Designation	Failure Cause	Expected Cost ($/km*yr)	Expected Cost ($/seg*yr)
1	Nova	External Corrosion	50	12182
2	Hadrian	Stress Corrosion Cracking	52	18418
3	Hadrian	Mechanical Damage	51	18248
4	Nova	Other	50	18071
5	Hadrian	External Corrosion	38	7738
6	Hadrian	Other	34	6796
7	Trojan	Other	14	2968

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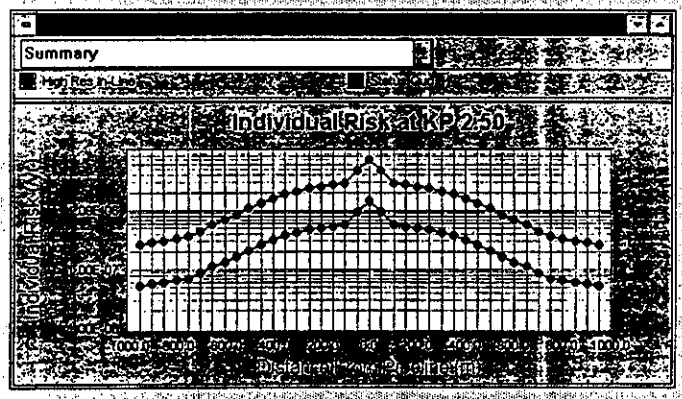
PIRAMID - Risk Assessment



Individual risk contours at any location along the line

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Conclusions

- Quantitative Risk Assessment
  - a basis for objective integrity maintenance planning
  - ensure acceptable operating risk at minimum cost
- Requirements
  - relevant historical incident data, or
  - analytical models and line condition data
- Benefits
  - Gives pipeline-specific solutions
  - Addresses time dependent failure mechanisms
  - Quantifies the impact of maintenance activities

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7. Qualitative and Quantitative Risk Assessment and Management - Robert Bea

This paper is about the conglomeration of qualitative and quantitative risk assessment methods and how a mixed system can be best utilized for an offshore pipeline. To accurately assess the problem, existing failure statistics are analyzed and trends are demonstrated, and an example is presented for applying the mixed risk assessment method to corroded pipelines. Since in the case of corrosion risk one of the important components is measuring the size and depth of the flaws, a case is also made for correctly assessing flaw sizes with current pigging technology.

The concept of bias is also introduced, which is the ratio of true versus predicted values for a certain criteria. For example the bias of true versus predicted burst pressure for a pipeline are analyzed to highlight trends that might be present in the data. Once the bias is calculated for a set of data, it is included in the analysis in order that the analysis results are more true to reality. In summary it is recommended that more work on mixed or level 2 risk assessment methods be performed due to the fact that this type of system offers the highest flexibility for the analyst.

Risk Assessment & Management of Marine Pipelines: RAM Pipe

Robert Bea

Marine Technology & Management Group

University of California at Berkeley

Topics

- Attributes
- Philosophy
- Approach
- Level 2 example: corrosion
  - Un-instrumented
  - Instrumented

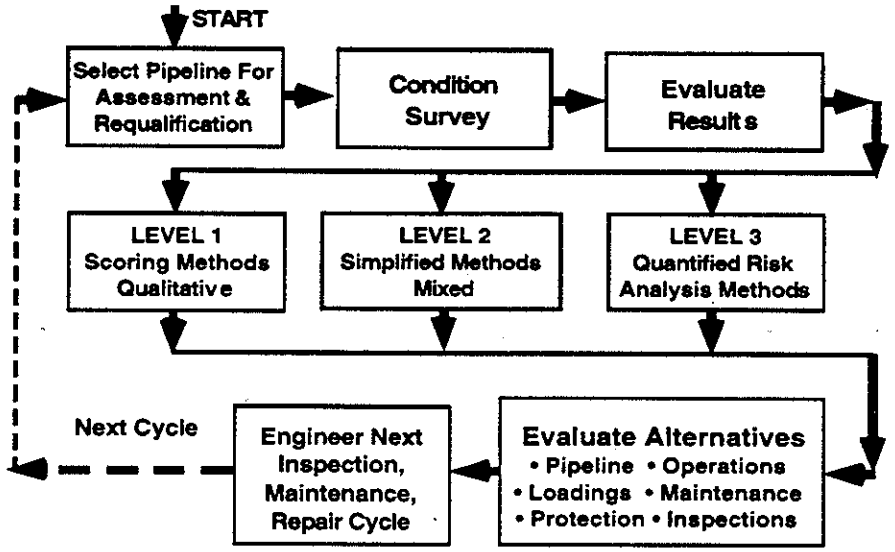
RAM Pipe Attributes

- Simplicity
- Versatility
- Compatibility
- Workability
- Consistency

RAM Pipe Strategies

- Keep in service - Inspections, Maintenance, Repairs (IMR)
- Progressive and priority based remediation
- Risk based management: likelihoods, economics - benefits

RAM Pipe Approach



Level 2 Method

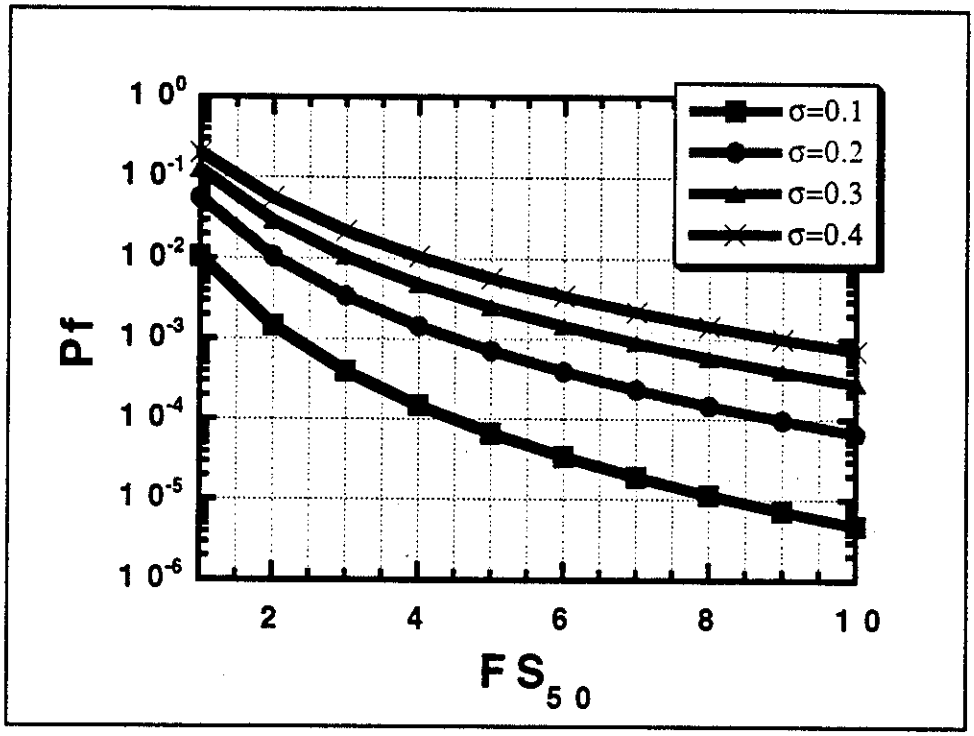
- Base on physics - mechanics
- Simplified models
- RAM approach
- Performance databases
- Test data verified
- Instrumented & un-instrumented
- Linguistic & quantitative variables

Level 2 Burst Capacity - Damaged / Defective

- Intact: $p_B = S_U (t / R)$
- Corrosion: $p_B = S_U (t_{min} / R)$
- Dented / Notched : $p_B = (S_U/SCF) (t / R)$
  - SCF dent = $1 + 6(H/t)$
  - SCF notch = $1 + 2(h/r)^{0.5}$

Probability of Failure - Pf

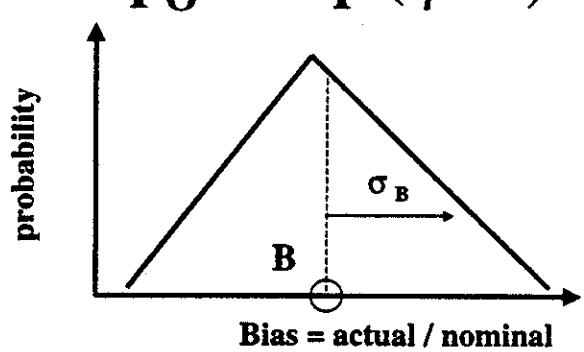
- $Pf = P (p_O \geq p_B)$
- $Pf = 1 - \Phi\{ [\ln (p_{B50} / p_{O50})] / [(\sigma^2_{pB} + \sigma^2_{pO})^{0.5}]\}$
- $\beta = \ln (p_{B50} / p_{O50}) / \sigma = \ln (FS_{pB/O\ 50}) / \sigma$

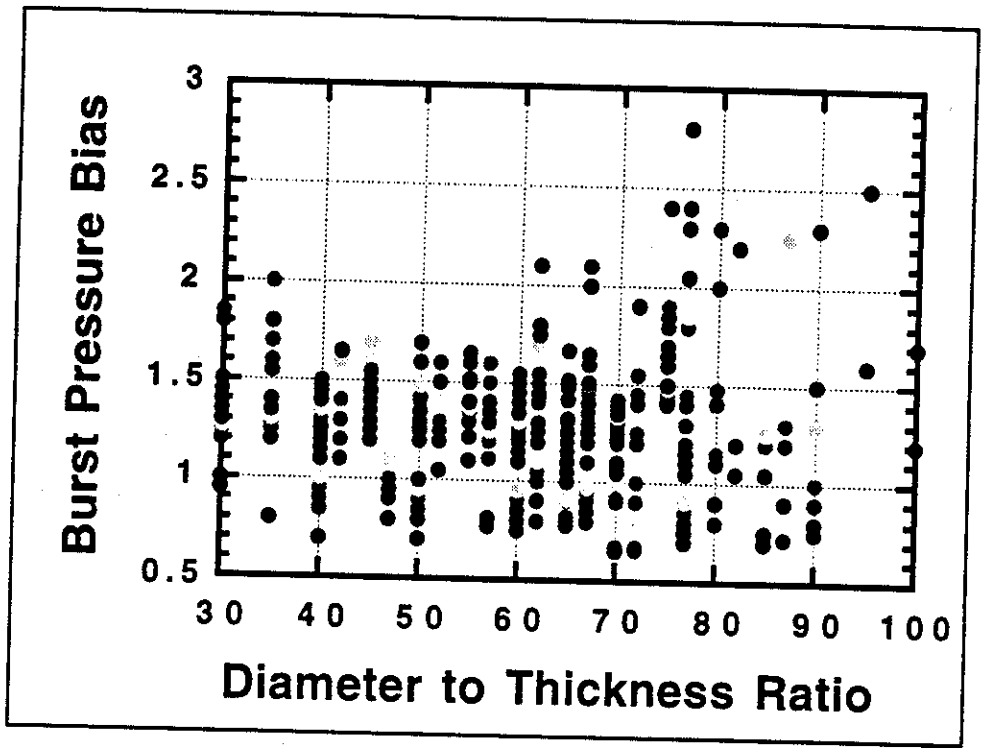


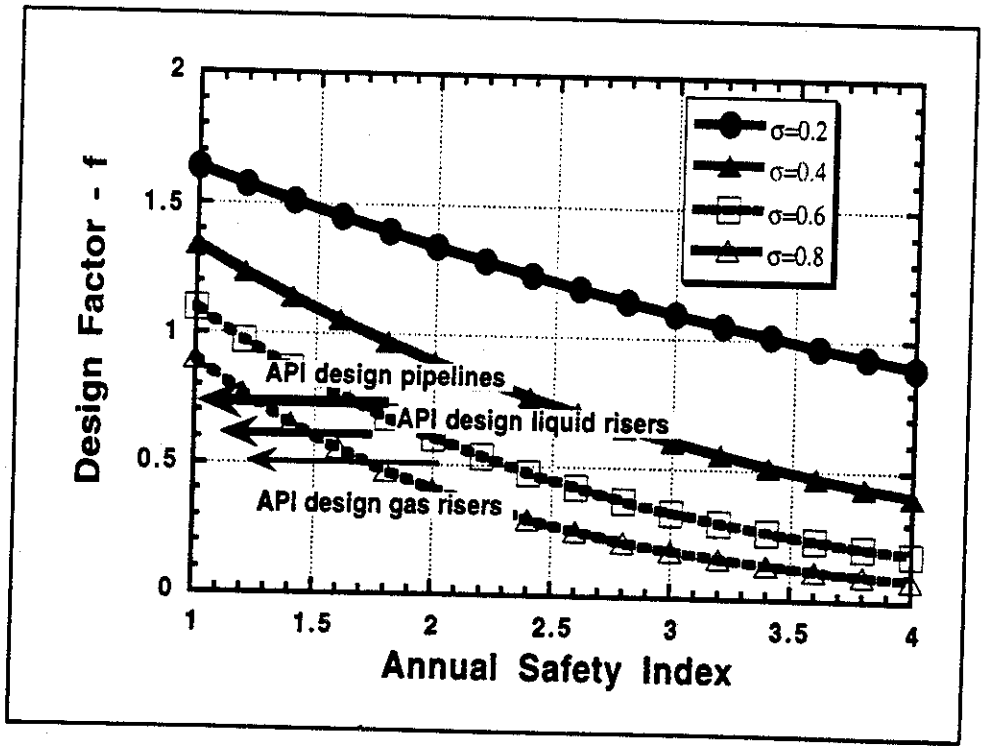
Nominal Values & Biases

$$p_B = p_O \, (B_{pO} / B_{pB}) \exp(\beta \sigma)$$

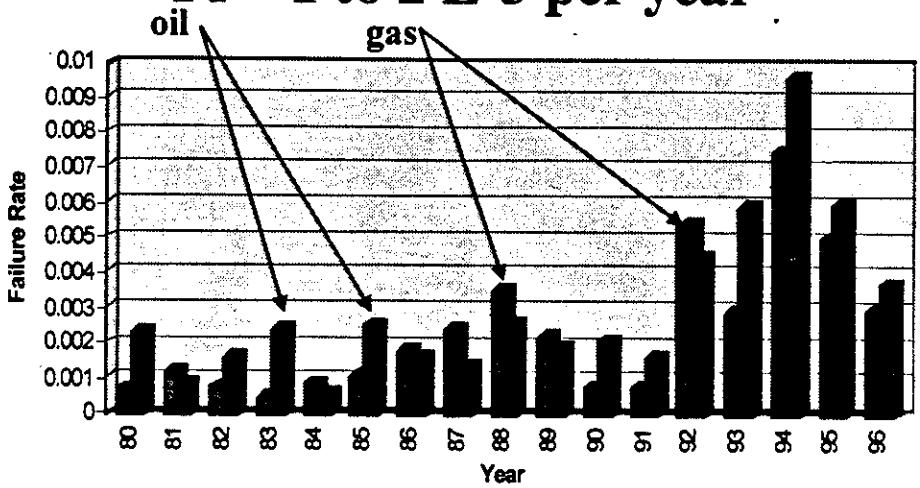
$$= p_O \, B \exp(\beta \sigma)$$



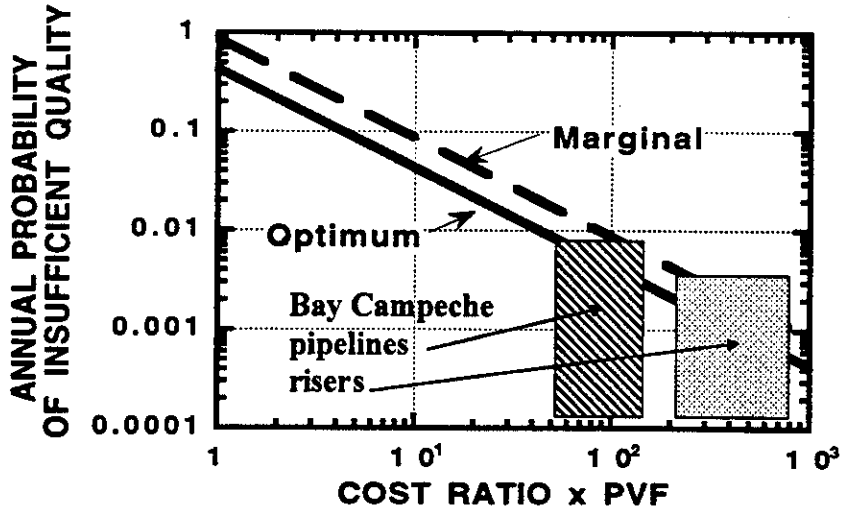

Burst Pressure Bias
3
2.5
2
1.5
1
0.5
30
40
50
60
70
80
90
100
Diameter to Thickness Ratio


Design Factor - f
2
1.5
1
0.5
0
1
1.5
2
2.5
3
3.5
4
Annual Safety Index
σ=0.2
σ=0.4
σ=0.6
σ=0.8
API design pipelines
API design liquid risers
API design gas risers

Gulf of Mexico Pipelines: Pf ≈ 1 to 2 E-3 per year

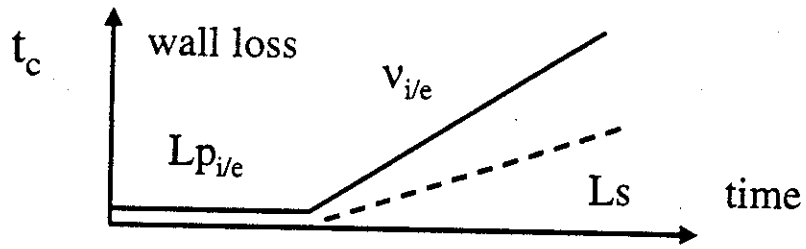


Cost - Benefit Analysis: Bay of Campeche Pipelines

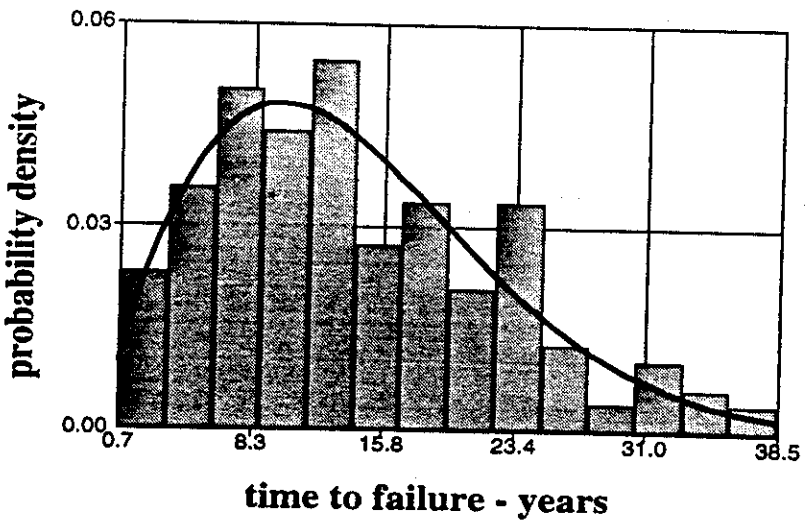


Corrosion: Un-instrumented *loss in wall thickness model*

- $t_c = t_{ci} + t_{ce}$
- $t_{ci/e} = \alpha_{i/e}\, \nu_{i/e}\, (Ls - Lp_{i/e})$

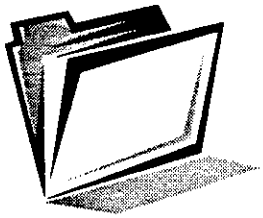


Corrosion Rates from Database



Project Completion

- documenting all aspects
- assigning responsibilities
- measuring improvement
- re-visiting processes
- management of change



(see DOT documentation, "Admin Elements")

Lessons Learned

1. Work from general to specific
2. Think 'organic'
3. Avoid complexity
4. Use computers wisely
5. Build the program as you would build a new pipeline
6. Study your results

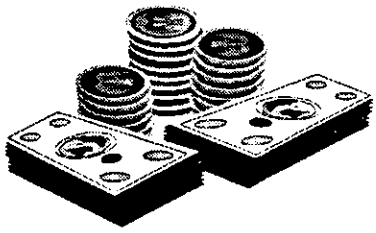
The Ideal Risk Model

simple/easily understandable
comprehensive
accurate predictor
expandable
cheap

Risk Assessment Program Costs (initial)

Study A: 200 miles of pipeline and 8 stations in 5 months

Study B: 700 miles of pipeline and 20 stations per month



A Very Simple Model

Pipeline Index = C + W + A + Cl + S

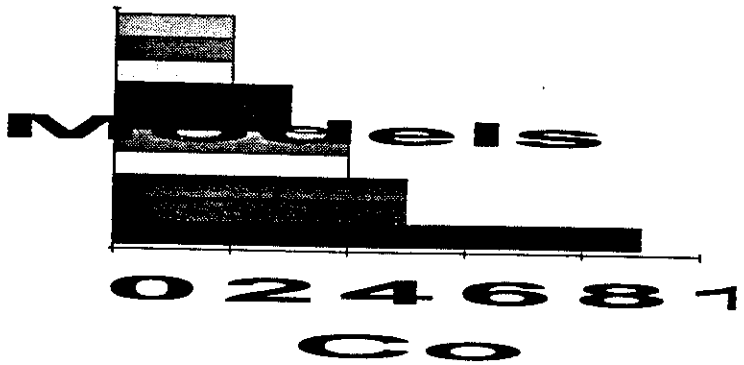
where

- C = Coating
- W = Wall Thickness
- A = Age
- Cl = Class location
- S = Security of Thruput

Issues in risk modeling

sources of information
cost/benefit of the analysis
"objectivity"
reproducible results
defensible

Number of Consequence Factors Considered



Most Common Conseq Factors

Class location (or equivalent)
Security of Thruput

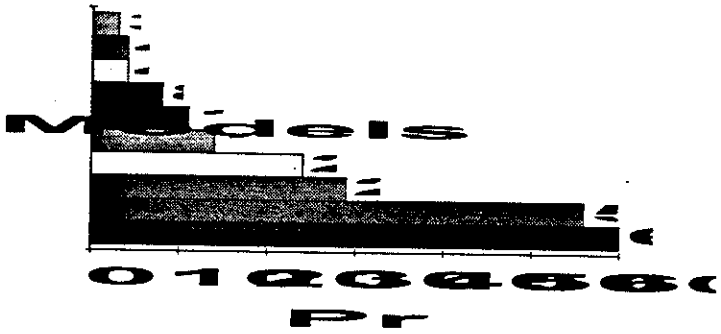
Some Other Common Prob Factors

- SCC
- Pressure
- Diameter
- Soil Condition
- Joint Type

More Exotic Prob Factors

- Transition Temp
- Op Training
- Drug Testing
- Goodwill Factor
- Public Education
- Manufacture Plant
- Sabotage Hist
- Repair Access
- Mining Activity
- Cycles
- AC Power

Number of Probability Factors Considered



Favorite Prob Factors

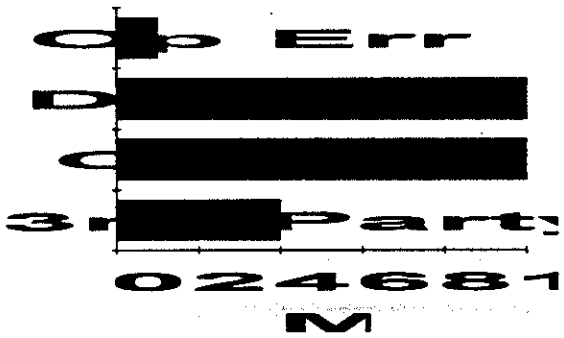
Coating type/condition
Age
Wall Thickness
Hydrotest
Leak Hist
CP Hist

Indexing Analysis

traffic volume/type	30%
barrier type	40%
distance from roadway	30%

Review of 10 Indexing Models

Failure categories covered



PRA Event Sequence

High MV Vehicle on Road %Probability

Vehicle leaves road %Probability

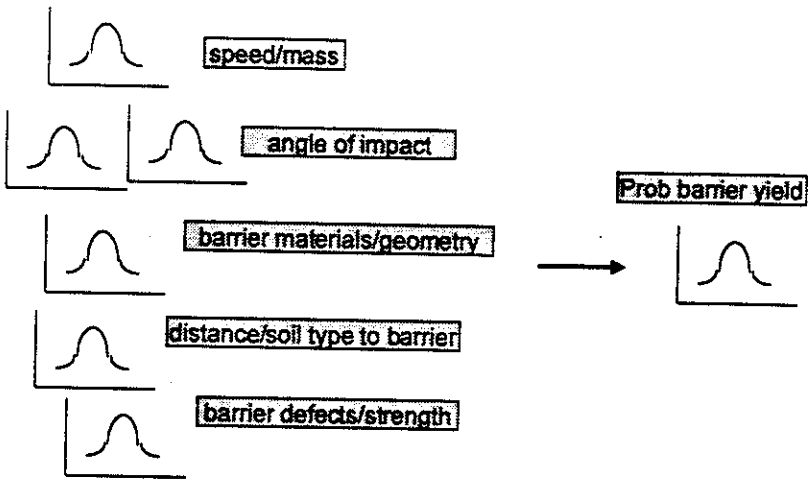
Vehicle hits barrier %Probability

Barrier yields %Probability

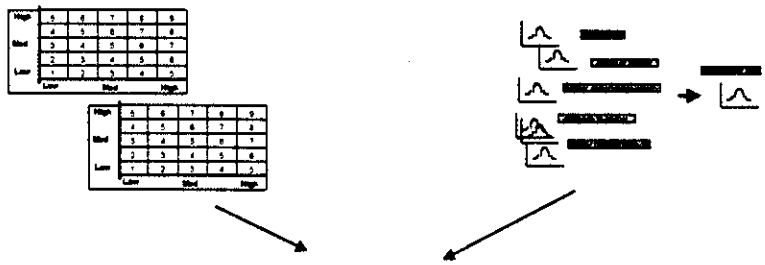
Vehicle hits pipe %Probability

Pipe ruptures likelihood

PRA Factor Analysis



Index Analysis



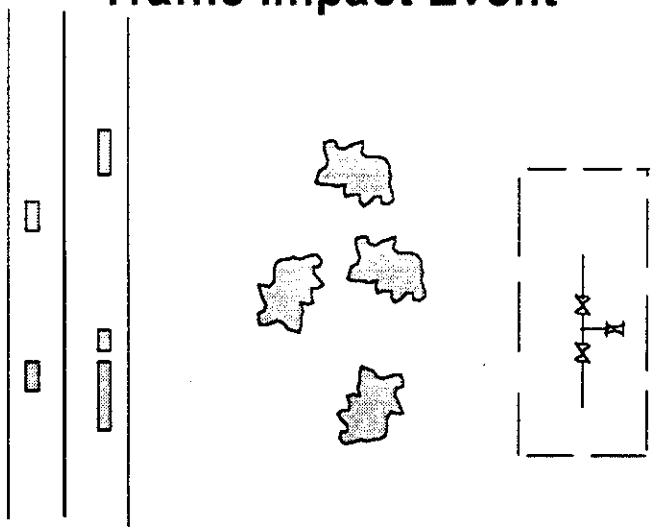
•Most important factors

•Relative contribution to risk picture

↓

Index Model

Traffic Impact Event



Balancing

Uncertainty

vs

Statistics

(how much reliance to place on predictive power of limited data)

Balancing

Flexibility

vs

Situation-specific model

(ability to use same model for variety of products, geographical locations, facility types, etc)

Balancing

Identifying an exhaustive list of contributing factors

vs

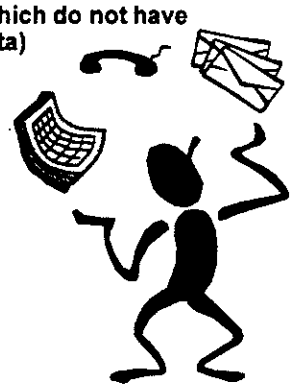
Choosing the critical few to incorporate in a model

(comprehensive vs complex vs simple)

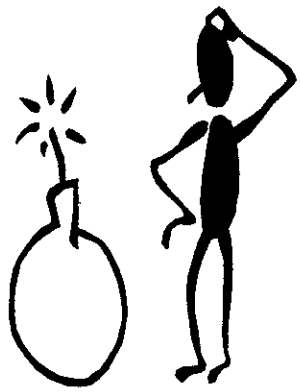
Balancing

"Hard" data and engineering judgement

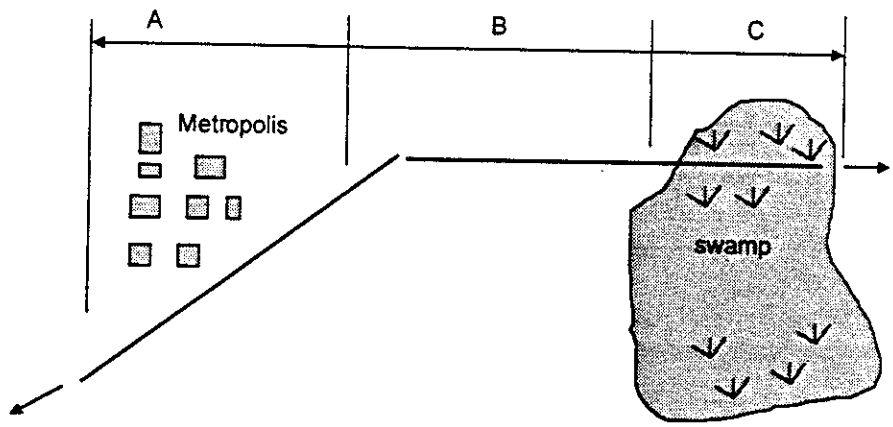
(how to incorporate widely-held beliefs which do not have supporting statistical data)



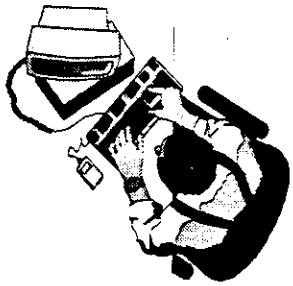
Picking a PL Risk Assessment Approach

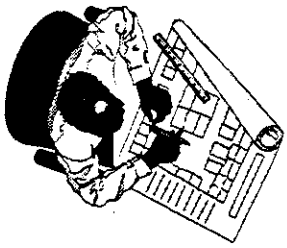


Sectioning



V. Build the program as you would build a new pipeline



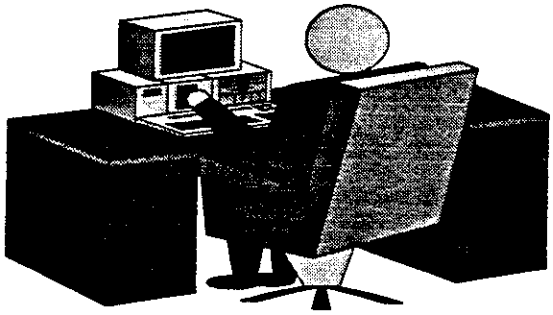


Project Phases

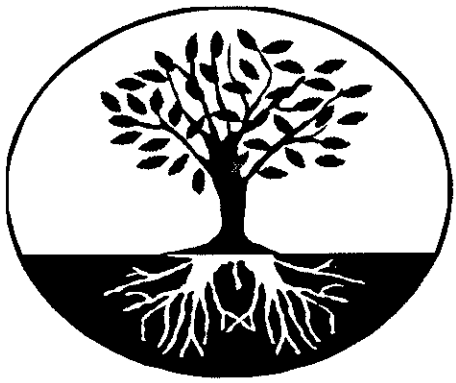
- Conceptualize
- Route selection
- Design
- Material procurement
- Construction
- Commissioning
- Project completion files

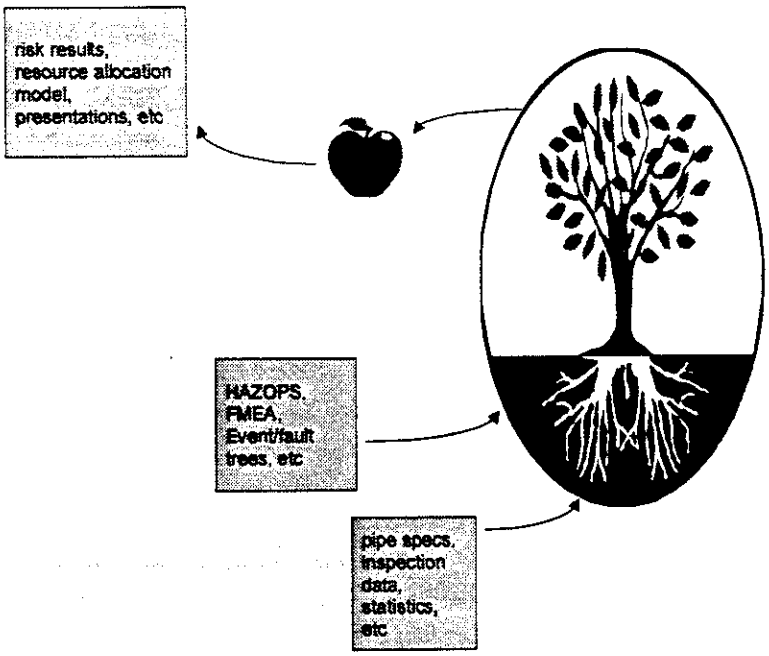
III. Avoid complexity

IV. Use computers wisely



II. Think "organic"

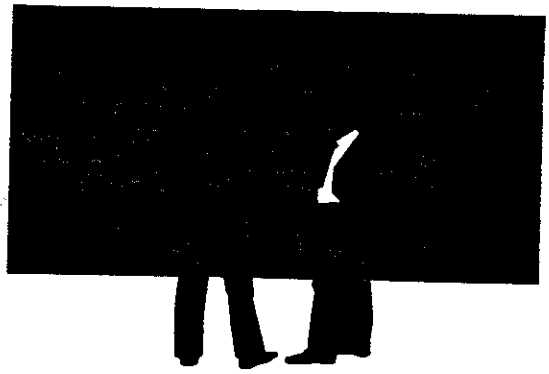




Lessons Learned

1. Work from general to specific
2. Think 'organic'
3. Avoid complexity
4. Use computers wisely
5. Build the program as you would build a new pipeline
6. Study your results

I. Work from general to specific



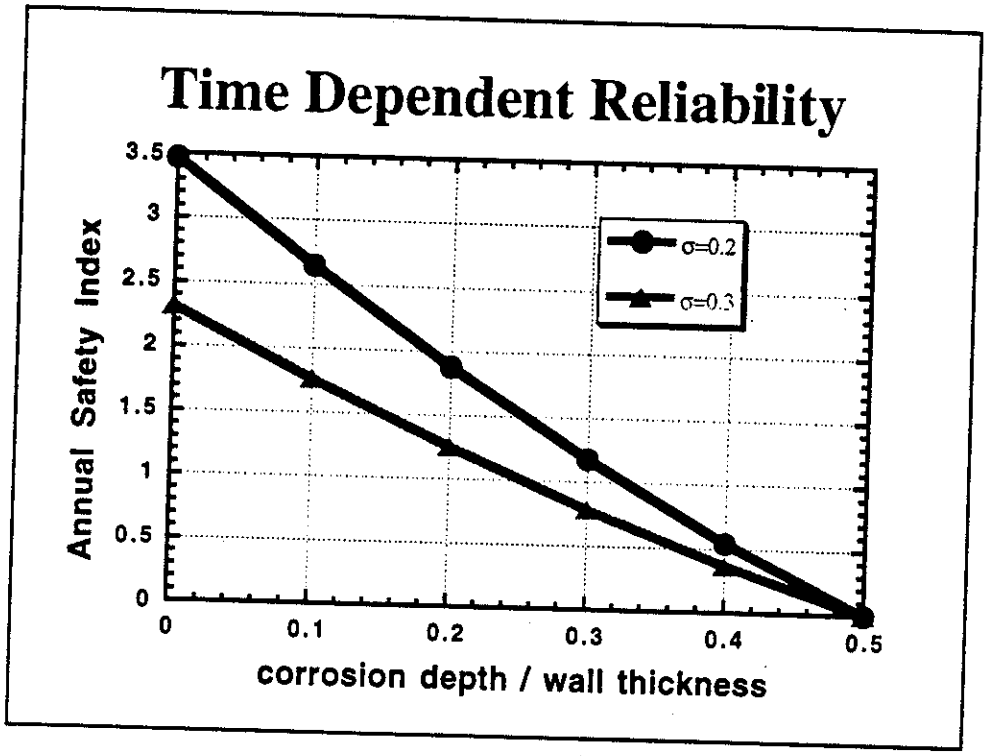
Corrosion Rates & Variabilities

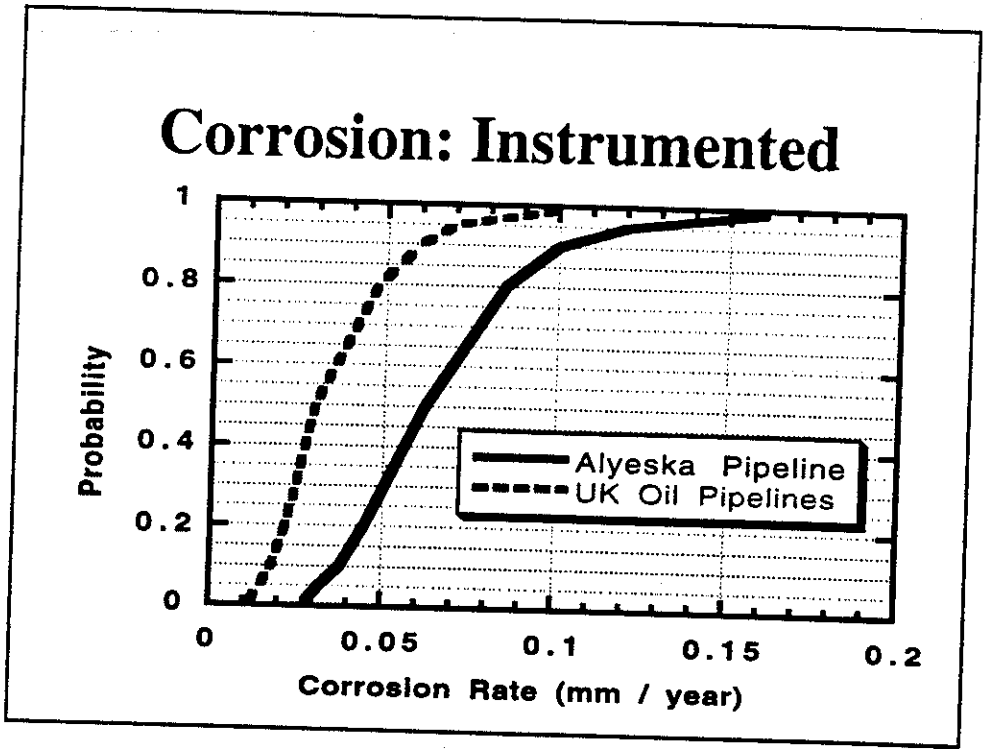
Descriptor	Corrosion Rate mm/year	Corrosion Rate Variability - %
Very Low	0.001	10
Low	0.01	20
Moderate	0.1	30
High	1.0	40
Very High	10.0	50

Protection & Inhibition

Descriptor	Inhibitor Efficiency
Very Low	10.0
Low	8.0
Moderate	5.0
High	2.0
Very High	1.0

Descriptor	$Lp_{i/e}$ or Ls (years)
Very Short	1
Short	5
Moderate	10
Long	15
Very Long	≥ 20

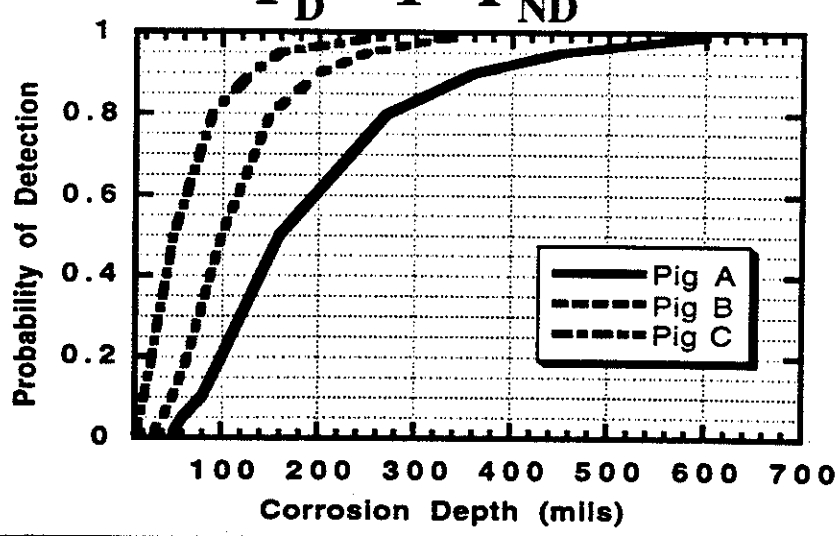

Time Dependent Reliability
Annual Safety Index
3.5
3
2.5
2
1.5
1
0.5
0
0
0.1
0.2
0.3
0.4
0.5
corrosion depth / wall thickness
σ=0.2
σ=0.3


Corrosion: Instrumented
Probability
1
0.8
0.6
0.4
0.2
0
0
0.05
0.1
0.15
0.2
Corrosion Rate (mm / year)
Alyeska Pipeline
UK Oil Pipelines

Probabilities of Failure:
detected & not detected

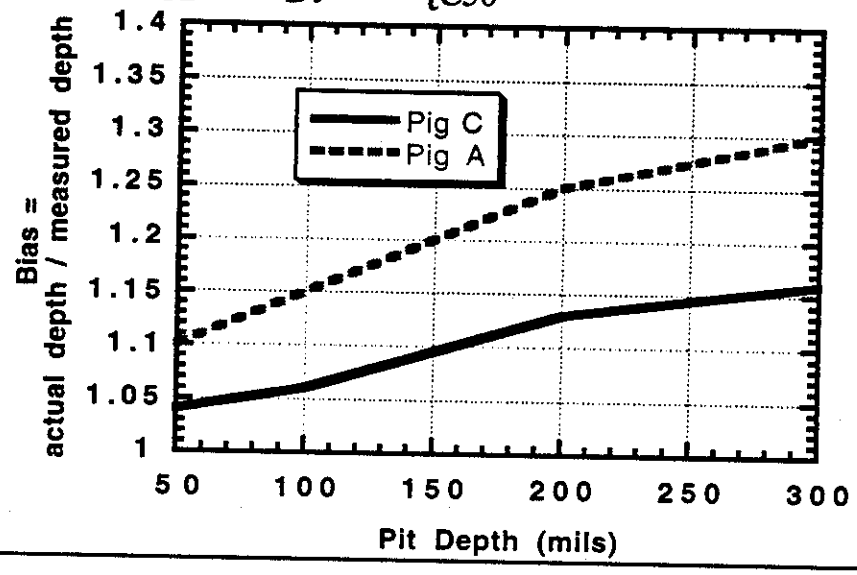
- $Pf = Pf_D + Pf_{ND}$
- $Pf_{D\&ND} = 1 - \Phi\{ [\ln (FS_{50})] / \sigma\}$
- $p_B = S (t - tc) / R$
- $po = K (MDP)$
  - $\sigma^2_{lnpB50} = \sigma^2_{lnS} + \sigma^2_{lnt} + \sigma^2_{lntc} + \sigma^2_{lnD}$

Probabilities of Detection
$P_D = 1 - P_{ND}$



Measurement Accuracy

$t_{C50} = t_{CD}\,(B_{Dt})$, V_{tC50} =25 % to 35 %

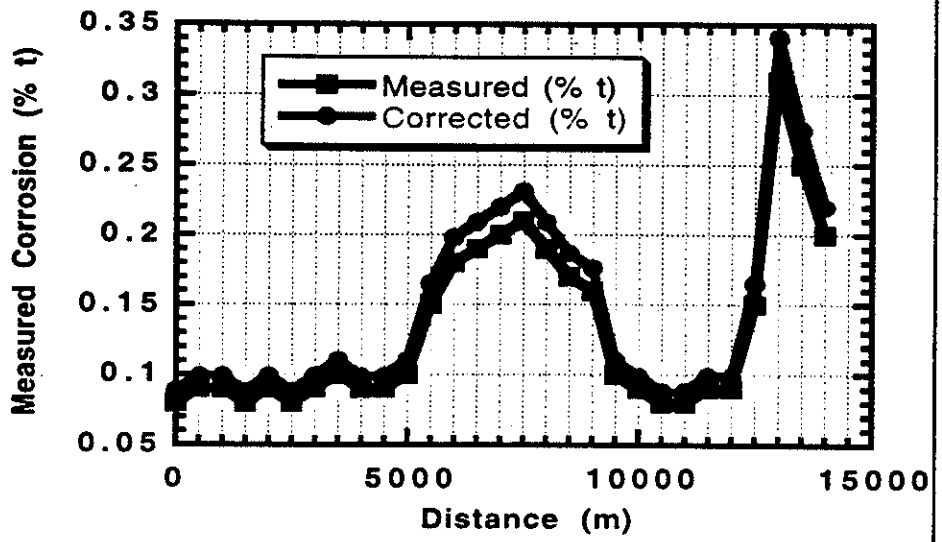


Pf_{ND}

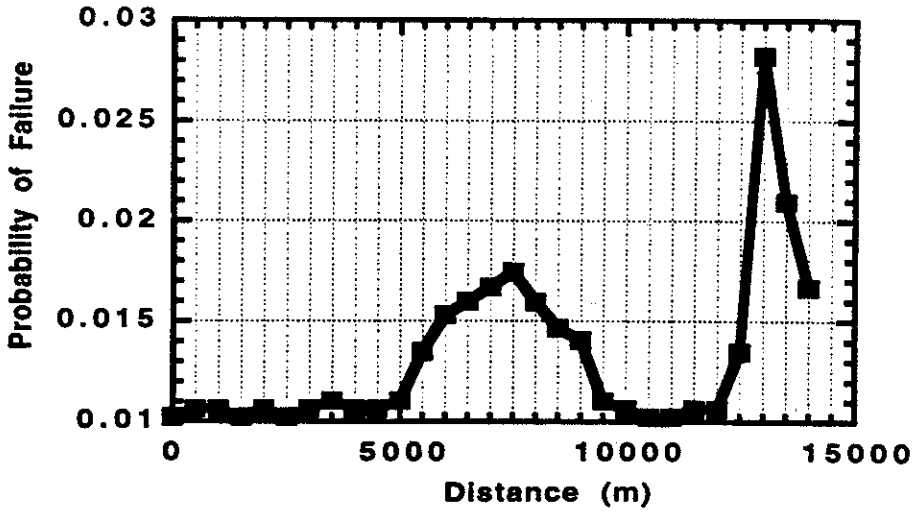
- $P[\,X \geq xo \mid ND\,] =$

  $P[\,X > xo\,]\,P[\,ND \mid X \geq xo\,] / P[\,ND]$
- $P[ND] = \Sigma\, P[ND \mid X > xo]\, P[X > xo]$
- $Pf_{ND} = \Sigma\, [Pf \mid X > xo]\, P[\,X \geq xo \mid ND]$

20-inch gas line instrumented Pig C



Probabilities of Failure:
Detected & Not Detected



Summary

- RAM Pipe approach for design and requalification of pipelines
- Three Level approach
  - Level 1 - Qualitative
  - Level 2 - Mixed - Simplified
  - Level 3 - Quantitative

Summary

- Level 2 approach for pipeline corrosion
  - Un-instrumented pipelines
  - Instrumented pipelines
- Database development and integration
- Continuing work on Level 2 approach

Proceedings Risk Assessment & Management of Marine Pipeline Systems Workshop
Houston, Texas
November 5 and 6, 1998

Risk Assessment & Management of Marine Pipelines: RAM PIPE

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INTRODUCTION

This paper addresses application of qualitative and quantitative analytical methods in the risk assessment and management of marine pipeline. Both qualitative and quantitative analytical methods have found widespread use in risk assessment and management of pipelines (Muhlbauer 1992; Kirkwood, Karam, 1994; Kulkarni, 1994; Nessim, Stephens, 1995; Collberg, Cramer, Bjornoy 1996; Office of Pipeline Safety, 1997; Zimmerman, et al 1998; Bai, Song, 1998).

This paper proposes a general engineering approach for risk assessment and management of marine pipeline systems (**RAM PIPE**) The approach is based on use of qualitative, quantitative, and mixed qualitative – quantitative analytical methods. This paper will outline the approach, its attributes and strategies, and further develop the qualitative – quantitative approach for design and reassessment of pipelines subjected to corrosion.

RAM PIPE ATTRIBUTES & STRATEGIES

Practicality is one of the most important attributes of an engineering approach. Industry experience indicates that a practical RAM PIPE approach should embody the following attributes:

- **Simplicity** – ease of use and implementation,
- **Versatility** – the ability to handle a wide variety of real problems,
- **Compatibility** – readily integrated into common engineering and operations procedures,
- **Workability** – the information and data required for input is available or economically attainable, and the output is understandable and can be easily communicated,
- **Feasibility** – available engineering, inspection, instrumentation, and maintenance tools and techniques are sufficient for application of the approach, and
- **Consistency** – the approach can produce similar results for similar problems when used by different engineers.

The RAM PIPE approach is founded on the following key strategies:

- Keep pipeline systems in service by using preventative and remedial IMR (Inspection, Maintenance, Repair) techniques. RAM PIPE attempts to establish and maintain the integrity of a pipeline system at the least possible cost.
- RAM PIPE procedures are intended to lower risks to the minimum that is practically attainable. Comprehensive solutions may not be possible. Funding and technology limitations may prevent implementation of ideally comprehensive solutions. Practicality implicates an incremental investment in identifying and remedying pipeline system defects in the order of the hazards they represent. This is a prioritized approach.

- RAM PIPE should be one of progressive and continued reduction of risks to tolerable levels. The investment of resources must be justified by the scope of the benefits achieved. This is a repetitive, continuing process of improving understanding and practices. This is a process based on economics and benefits.

RAM PIPE APPROACH

The fundamental steps of the RAM PIPE approach are identified in Figure 1. The steps may be summarized as follows:

1. **Identification** – this selection is based on an assessment of the likelihood of finding significant degradation in the quality (serviceability, safety, durability, compatibility) characteristics of a given pipeline system, and on an evaluation of the consequences that could be associated with the degradation in quality. The selection can be triggered by either a regulatory requirement or by an owner's initiative, following an unusual event, an accident, proposed upgrading of the operations, or a desire to significantly extend the life of the pipeline system beyond that originally intended.

2. **Condition survey** – this survey includes the formation of or continuance of a databank that contains all pertinent information the design, construction, operation, and maintenance of a pipeline system. Of particular importance are identification and recording of exceptional events or developments during the pipeline system history. Causes of damage or defects can provide important clues in determining what, where, how ,and when to inspect and/or instrument the pipeline system. This step is of critical importance because the RAM PIPE process can only be as effective as the information that is provided for the subsequent evaluations (garbage in, garbage out).

3. **Results assessment** – this effort is one of assessing or screening the pipeline system based on the presence or absence of any significant signs of degradation its quality characteristics. The defects can be those of design, construction, operations, or maintenance. If there appear to be no potentially significant defects, the procedure becomes concerned with engineering the next IMR cycle. If there appear to be potentially significant defects, the next step is to determine if mitigation of these defects is warranted. Three levels of assessment of increasing detail and difficulty are proposed: Level 1 – Qualitative (Scoring, Muhlbauer 1992; Kirkwood, Karam 1994), Level 2 – Simplified Qualitative – Quantitative (Bea, 1998), and Level 3 – Quantitative (Quantitative Risk Assessment, QRA, Nessim, Stephens 1995; Bai, Song 1998; Collberg, et al 1996).

   The basis for selection of one these levels is one that is intended to allow assessment of the pipeline with the simplest method. The level of assessment is intended to identify pipelines that are clearly fit for purpose as quickly and easily as is possible, and reserve more complex and intense analyses for those pipelines that warrant such evaluations. The engineer is able to choose the method that will facilitate and expedite the requalification process. There are more stringent Fitness for Purpose (FFP) criteria associated with the simpler methods because of the greater uncertainties associated with these methods, and because of the need to minimize the likelihood of 'false positives' (pipelines identified to FFP that are not FFP).

4. **Mitigation measures evaluation** – mitigation of defects refers to prioritizing the defects to remedied (first things first), and identifying practical alternative remedial actions. The need for the remedial actions depends on the hazard potential of a given pipeline system, i.e., the likelihood that the pipeline system would not perform adequately during the next RAM PIPE cycle. If mitigation appears to be warranted, the next step is to evaluate the alternatives for mitigation.

5. **Evaluating alternatives** – mitigation alternatives include those concerning the pipeline itself (patches, replacement of sections), its loadings (cover protection, tie-downs), supports, its operations (pressure de-rating, pressure controls, dehydration) maintenance (cathodic protection, corrosion inhibitors), protective measures (structures, procedures, personnel), and its information (instrumentation, data gathering). Economics based methods (Kulkarni, Conroy 1994;

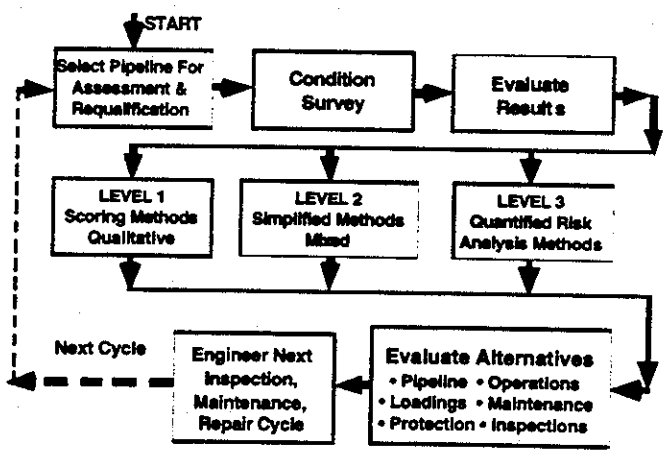

Figure 1 – RAM PIPE Approach

Nessim, Stephens 1995), historic precedents (data on the rates of compromises in pipeline quality), and current standards of practice (pipeline design codes and guidelines, and reassessment outcomes that represent decisions on acceptable pipeline quality) should be used as complimentary methods to evaluate the alternatives and the pipeline FFP. An important alternative is that of improving information and data on the pipeline system (information on the internal characteristics of the pipeline with instrumentation – 'smart pigs' and with sampling, information on the external characteristics of the pipeline using remote sensing methods and on-site inspections).

6. **Implementing Alternatives** – once the desirable mitigation alternative has been defined, the next step is to engineer that alternative and implement it. The results of this implementation should be incorporated into the pipeline system condition survey – inspection databank. The experiences associated with implementation of a given IMR program provide important feed-back to the RAM PIPE process.

7. **Engineering the next RAM PIPE cycle** – the final step concluding a RAM PIPE cycle is that of engineering and implementing the next IMR cycle. The length of the cycle will depend on the anticipated performance of the pipeline system, and the need for and benefits of improving knowledge, information and data on the pipeline condition and performance characteristics.

LEVEL 2 ASSESSMENT OF BURST CAPACITY

Formulation

To illustrate application of the foregoing developments, a Level 2 simplified qualitative – quantitative analysis approach will be utilized to evaluate in-place wall thickness requirements for pressure containment - burst capacity of a pipeline. In this approach, pipeline strength was formulated in terms of the capacity of the pipeline to withstand the imposed pressures (internal, external) without loss of containment (rupture). The strength was formulated as (DNV, 1996; ISO, 1996; BSI, 1993; API, 1993; Bai, et al, 1994; 1997; Sotberg et al, 1997; ASME 1991):

$$t / D = p / 2 S$$

where t is the existing minimum thickness of the pipeline, D is the diameter of the pipeline, p is the maximum net pressure (internal - external) that the pipeline must be capable of containing, and S is the ultimate strength of the steel in the pipeline.

The API guidelines (1993) specify burst strength as:

$$t / D = (p / 2 \text{ Sym } f)$$

where Sym is the specified minimum yield strength of the pipeline steel. The term 'f' represents the product of three terms: fd (design factor), fe (weld joint factor), and ft (temperature de-rating factor). The design factor is 0.72 for liquid and gas pipelines, 0.60 for liquid pipelines and risers on platforms, and 0.50 for gas pipelines and risers on platforms. The weld joint factor is specified as generally being 1.0 (when welding is conducted according to the specified codes and guidelines). The temperature de-rating factor is used for high temperature pipelines and the de-rating is specified by ASME guidelines (ASME B31.4 and ASME B31.8) (ASME, 1991). The 'f' factor can be interpreted as a factor-of-safety ($FS = f^{-1}$).

In the API guidelines, t is the nominal or design wall thickness of the pipeline or riser. The guidelines specify a number of measures that should be used to prevent corrosion or loss of wall thickness both inside and outside the pipeline or riser. Thus, this guideline is based on the assumption that the pipeline or riser operator will provide and maintain the pipeline so that little or no corrosion takes place. A corrosion allowance or thickness could be provided to recognize the need to allow some corrosion to take place without having to de-rate or replace the pipeline. This corrosion allowance is not specified in the API guidelines.

The DNV guidelines (DNV, 1996; Sotberg et al, 1996; Jiao, et al, 1997; Bai, et al, 1994; 1997) specify burst strength as:

$$t / (D-t) = p / (2 \,.\, 1.1 \,.\, S\, \eta_u)$$

where η_u is a usage factor that depends on the safety class of the pipeline or riser. For a High Safety Class, η_u = 0.67. For a Normal Safety Class, η_u = 0.70. For a Low Safety Class, η_u = 0.74. Given the 1.1 that is multiplied times S, these values are very close to those of API.

However, in this case, the 't' that is referenced is the net wall thickness after corrosion has taken place. Corrosion protection can be provided to make this 't' the same as is referenced in API. However, if no protection is provided, a corrosion allowance must be estimated and added to the nominal wall thickness of the pipeline or riser to define the design wall thickness.

A RAM based formulation of the foregoing developments can be developed as follows presuming that the demand (operating pressure) and capacity (pipeline burst pressure) are Lognormally distributed variables:

$$p_B = 2\,S\,t\,/\,D$$

where p_B is the pipeline burst pressure, S is the stress associated with the burst strength of the pipeline, t is the pipeline wall thickness, and D is the pipeline diameter.

$$Pf = P\,(\,p_O \geq p_B\,)$$

where Pf is the probability of failure, p_O is the maximum operating pressure, and P (X) is read as the probability of (X).

$$Pf = 1 - \Phi\{\,[\,\ln(p_{B50}\,/\,p_{O50})\,]\,/\,[\,(\,\sigma^2_{pB} + \sigma^2_{pO}\,)^{0.5}]\}$$

where Φ is the standard cumulative Normal distribution, p_{B50} is the 50th percentile (median) burst pressure, p_{O50} is the 50th percentile maximum operating pressure, σ_{pB} is the standard deviation of the logarithms of the burst pressure, and σ_{pO} is the standard deviation of the logarithms of the maximum operating pressures.

$$\beta = \ln(p_{B50}\,/\,p_{O50})\,/\,\sigma = \ln FS_{pB/O\,50}\,/\,\sigma$$

β is the Safety Index, $FS_{pB/O\,50}$ is the central or median Factor of Safety between the pipeline burst pressure and the maximum operating pressure, and σ is the total uncertainty in the pipeline burst pressure and operating pressure.

$$p_B = p_O\,(\mathbf{B}_{pO}\,/\,\mathbf{B}_{pB})\,\exp(\,\beta\,\sigma\,) = p_O\,\mathbf{B}\,\exp(\,\beta\,\sigma\,)$$

p_B is the 'nominal' burst pressure, p_O is the 'nominal' maximum operating pressure, $\mathbf{B}_{pO}$ is the median 'bias' in the nominal burst pressure, $\mathbf{B}_{pB}$ is the median bias in the nominal maximum operating pressure, and B is the resultant median bias in the nominal burst and operating pressures. Bias is defined as the ratio of the true value to the nominal (predicted, calculated) value. It is to be noted that for the premises of this development (Lognormally distributed independent demands and capacities) that this is an 'exact' expression.

A non-dimensional pipeline wall thickness to diameter ratio can be expressed as:

$$t\,/\,D = (p_O\,/\,2\,S\,)\,(\mathbf{B}\,\exp(\beta\,\sigma_{lnp/R})$$

In this development, the Bias in the demand is taken as Bp = 1.0. This bias presumes that on the average that the pipeline will be operated at the design maximum operating pressure.

The Bias in the capacity was taken as B_R = 2.0. This bias is based on comparisons of pipeline burst strength tests compared with the burst strengths predicted by the hoop stress formulation used in this development (B_R = 1.7, Figure 2) (Bai, et al, 1994; Bai, Xu, Bea, 1997), and the strength of the steel at which the pipeline ruptures or looses containment (B_R = 1.2) (Jiao, et al, 1997). σ is the total Type 1 (natural, inherent) uncertainty in the demand and capacity elements:

$$\sigma^2_{lnp/R} = \sigma^2_{lnp} + \sigma^2_{lnR}$$

The uncertainty in the demand was evaluated to be σ_{lnp} = 0.10. This variability represents the

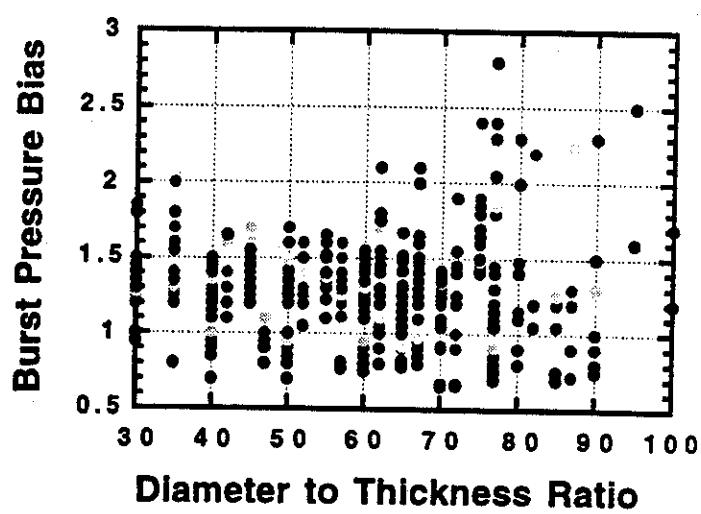

Figure 2 - Comparison of predicted and test burst pressures for pipelines with varying diameter to thickness ratios

natural or inherent variability in the pipeline or riser operating pressures (Bai, Xu, Bea, 1997; Sotberg, Leira, 1994). The uncertainty in the capacity was evaluated to be $\sigma_{lnR} = 0.20$. This uncertainty represents the natural or inherent variability in the pipeline burst capacity as influenced by the variability in steel and welding strength (pipeline strength), steel thickness, pipeline or riser diameter, and corrosion thickness. The total or resultant uncertainty was thus evaluated to be $\sigma_{lnp/R} = 0.22$.

Note that this resultant uncertainty has not taken into account the variability added by corrosion damage or defects in the pipeline. Because corrosion has a very high natural variability and the effect of this variability on the burst capacity is also high, the total or resultant uncertainty for a moderately corroded pipeline based on the burst capacity formulation used here could increase to $\sigma_{lnp/R} = 0.40$ to 0.50. For severely corroded pipelines, $\sigma_{lnp/R} = 0.60$ to 0.80.

The Safety Index (measure of reliability) could be expressed as:

$$\beta = \ln [(2\, \mathbf{B}\, S / p_o\, D)\, (t - t_{ci/e})] / \sigma_{lnp/R}$$

The reliability based dimensionless ratio of pipeline or riser wall thickness to diameter (t / D) exclusive of corrosion thickness allowances can thus be expressed as:

$$t / D = (p_o / 2\, S)\, [\mathbf{B} \exp (\beta\, \sigma_{lnp/R})]$$

$$t / D = (p_o / S)\, [(1.0 / 2.0 \cdot 2) \exp (\beta\, 0.22)]$$

$$t / D = p_o / S\, (0.25 \exp 0.22\, \beta)$$

This formulation allows the dimensionless thickness to diameter ratio of the pipeline or riser (t/D) to be expressed as a function of the dimensionless ratio of the expected maximum operating pressure to specified minimum steel yield strength (p / S) times the exponential of 0.22 times the annual Safety Index (β). The t / D ratio is graphed as functions of p_o / S and β in Figure 3 for the total uncertainty of 22 %.

For a given maximum operating pressure to specified minimum yield strength ratio (p/S), for the lower p/S ranges there are small differences between the t / D ratios for new and existing pipelines. There are relatively insignificant differences between the different pipeline Serviceability and Safety Classes. Significant differences show up only for the higher operating pressure to yield strength ratios. Note that the differences between new and existing pipelines shown in Figure 12 do not incorporate the larger uncertainties associated with existing corroded pipelines.

Figure 4 shows the results for a total uncertainty of 40%. There is dramatic increase in the required t/D ratios for given ratios of operating pressure to yield strength. In this case, the wall thickness that are referenced are those after corrosion; i.e. they are the minimum wall thickness in a given segment of a pipeline. The increase in required t/D ratios is one of the prices of allowing significant corrosion to develop inside or outside of a pipeline.

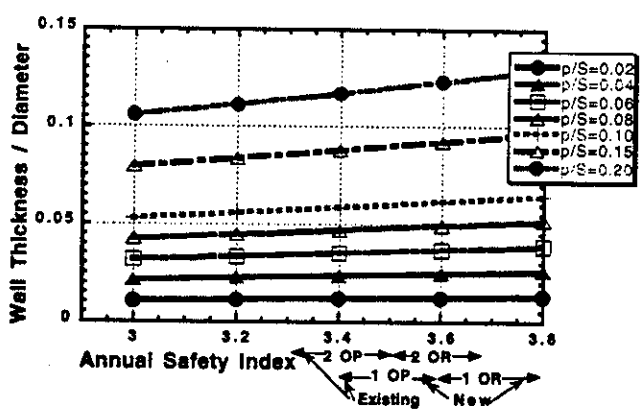

Figure 3 - Thickness to diameter ratio as function of ratio of maximum operating pressure to steel yield strength and annual Safety Index for total uncertainty of 22%

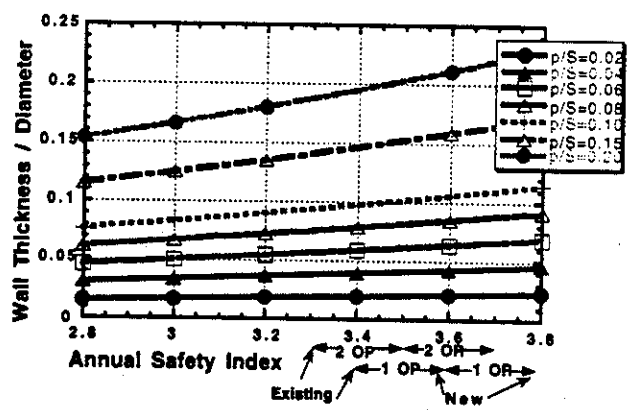

Figure 4 - Thickness to diameter ratio as function of ratio of maximum operating pressure to steel yield strength and annual Safety Index for total uncertainty of 40%

API Guideline Based Design Factors

The foregoing could be cast in the same form as the API guidelines as follows. Based on the RAM formulation:

$$t / D = (p_o / 2\,S)\,(\mathbf{B} \exp(\beta\,\sigma_{lnp/R}))$$

$$p_o = (2\,S\,t / D)\,(\mathbf{B} \exp(\beta\,\sigma_{lnp/R}))^{-1}$$

Based on the API guidelines:

$$t / D = (p_o / 2\,S\,f)$$

$$p_o = (2\,S\,t / D)\,(f)$$

Thus,

$$f = (\mathbf{B} \exp(\beta\,\sigma_{lnp/R}))^{-1}$$

The API based risk assessment and management formulation for the design factor 'f' is summarized in Figure 5. Also shown are the API design factor guidelines for liquid and gas pipelines and platform risers. For the uncertainties associated with new or uncorroded pipelines, the API guidelines result in very high reliability pipelines. However, the performance history of pipelines in the Gulf of Mexico for corrosion failures indicates corrosion failures of 'typical' pipelines at the rate of 2 E-2 to 5 E-2 per year (Mandke, 1990; Mandke, et al, 1995; marine Board, 1994; Elsayed, Bea, 1997). This is equivalent to annual Safety Indices in the range of β = 1.5 to 2. This Safety Index range is commensurate with the uncertainties associated with corroded pipelines. The analytical models indicate probabilities of failure that agree well with the performance history.

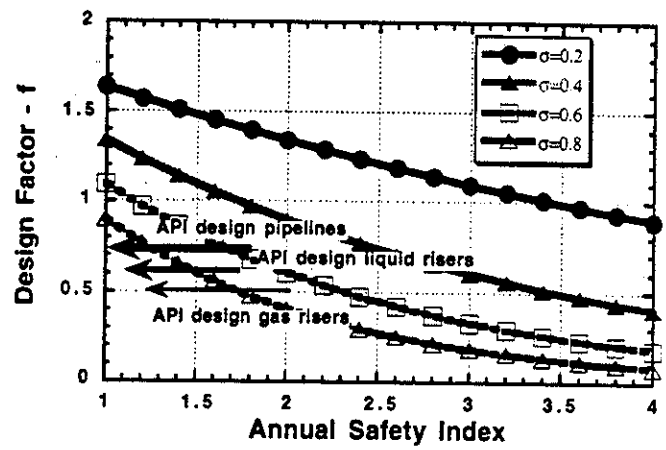

Figure 5 - API burst pressure design factor

The annual Safety Indices associated with the API design factors could be determined from:

$$\beta = \ln(1/f\,B) / \sigma_{lnp/R}$$

Given this development, and an assessment of a total uncertainty of 50% for API pipeline design (allowing for corrosion uncertainties), a median bias in the pipeline demand and capacity of B = 2.0, one could determine the annual Safety Index for pipeline design implied by the API guidelines as β = 2.0 (Pf ≈ 1 E-2 per year) for subsea oil and gas pipelines, β = 2.4 for oil risers, and β = 2.8 for gas risers. These values are in excellent agreement with the performance characteristics of pipelines and risers in the Gulf of Mexico (Pf ≈ 1 E-2 per year).

Corrosion – Un-Instrumented Pipelines

Experience with Gulf of Mexico pipelines and risers (oil and gas) has clearly shown that the primary operating hazard to the integrity of pipelines and risers is corrosion; primarily internal corrosion for pipelines, and external corrosion for risers (generally in the vicinity of the mean water level) (Elsayed, Bea, 1997; Marine Board, 1994; AME 1993; Mandake, 1990).

For un-instrumented pipelines, a combination of subjective judgement and database information from instrumented and un-instrumented pipeline performance must be used to evaluate corrosion. Figure 6 summarizes the causes of pipeline failures in the OCS waters of the Gulf of Mexico during the period 1980 through 1996. This summary includes 2,332 failures for 10,553 pipelines. Failure is defined as a loss of containment resulting in a substantial loss of hydrocarbons from the pipeline or riser). The primary cause of failure is corrosion; about 50 % of the failures are due to corrosion. Hurricanes (natural hazards) are responsible for about 25 % of the failures. The remaining 25 % of the failures can be attributed to Human and Organizational Factors (HOF) (Bea, 1994).

Based on the same database, Figures 7 and 8 shows the causes of pipeline failures for oil and gas pipelines, respectively. The distribution of the causes of failures is about the same for both oil and gas pipelines. Corrosion again accounts for about half of the failures. Most surprising was the large proportion of gas pipelines that fail due to corrosion. Improvements in gas dehydration could help reduce this source of failures.

The database contains information on the distribution of failures caused by external and internal corrosion. As summarized in Figure 9, in the case of risers, external corrosion accounts for about 85 % of the corrosion related failures. The vast majority of this corrosion is located at and above the mean sea level. In the case of submerged pipelines, internal corrosion accounts for about 75 % of the corrosion related failures The database did not indicate any significant differences between the failure rates for small and large diameter pipelines.

Figure 10 shows the distribution of times to corrosion failures for gas pipelines. The data includes gas pipelines with and without gas dehydration. The mean time to failure is about 10 years. The Coefficient of Variation (ratio of standard deviation to mean, COV) of the time to failure is about COV ≈ 100 %. This very large COV is due primarily to the natural or inherent variability in the corrosion rates and the differences in the dehydration of the gas carried by these pipelines.

Figure 11 summarizes the pipeline failure rate in the Gulf of Mexico OCS region during the period 1967-1997 due to all causes. The dramatic increase in the failure rate in 1992 was due primarily to hurricane Andrew.

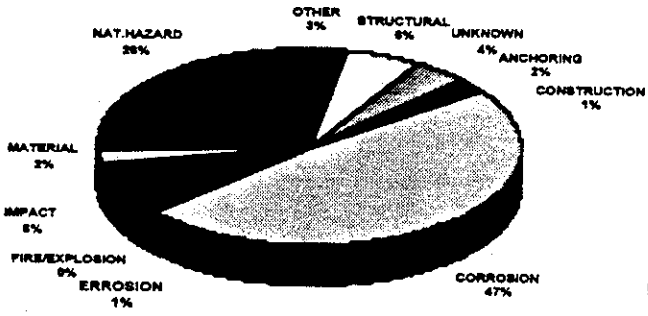

Figure 6 - Causes of failures of OCS pipelines in the Gulf of Mexico

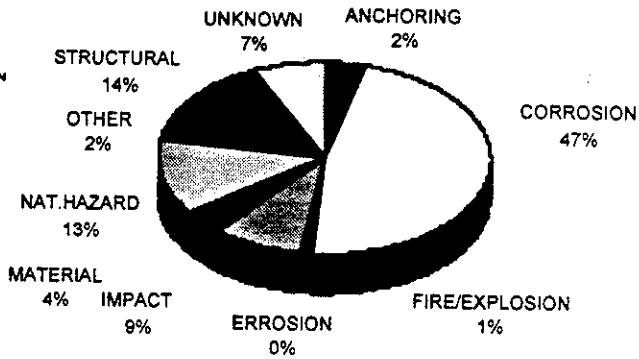

Figure 7 - Causes of failures in gas pipelines

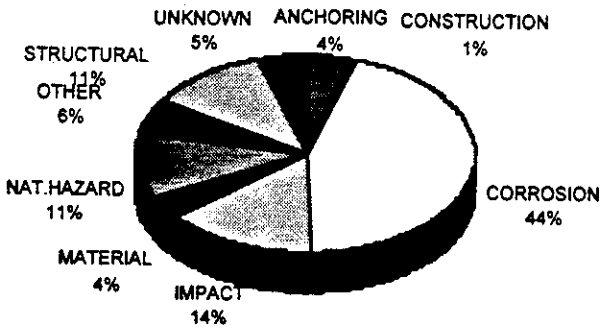

Figure 8 - Causes of failures in oil pipelines

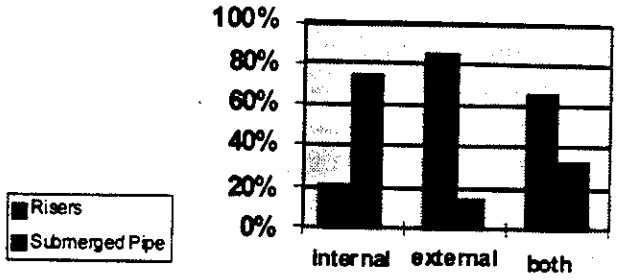

Figure 9 - Distribution of pipeline and riser failures due to internal and external corrosion

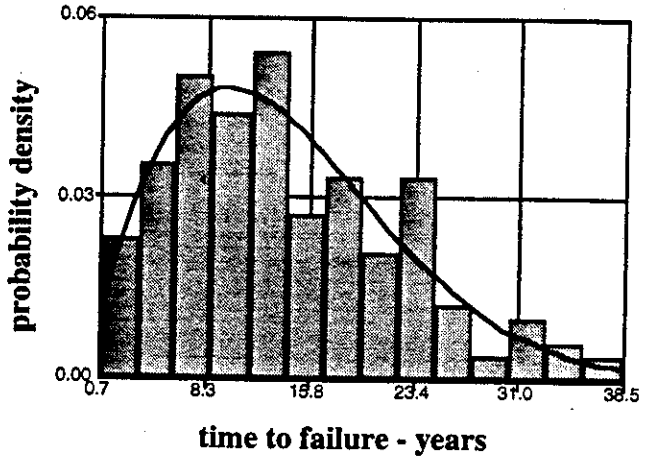

Figure 10 - Distribution of times to failure of gas pipelines due to internal corrosion

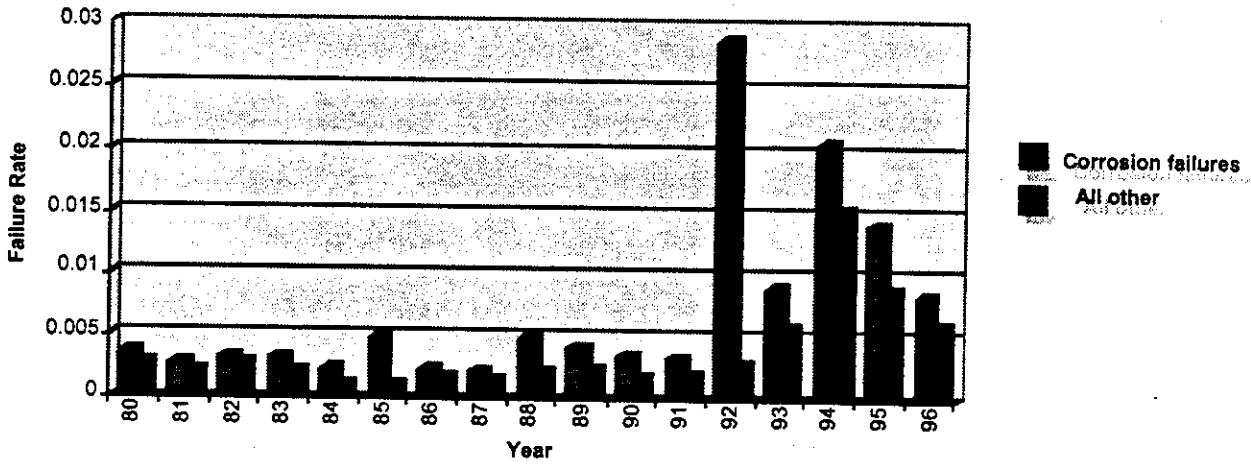

Figure 11 - Historic rate of failure (number of failures per mile - year) of Gulf of Mexico pipelines (OCS area, 1967-1997)

Since about 1992, there has been a dramatic increase in the number of pipeline failures due to corrosion. This is believed by some operators to be due primarily to cut-backs in pipeline maintenance budgets and efforts in the 1980's. The increase in failure rates has been noted, and the industry has taken effective measures to reduce the rates since 1994.

The failure rate has ranged from about 5 E-3 per mile-year to 2 E-2 (0.02) per mile-year. Given an 'average' pipeline in the Gulf of Mexico of 10 miles, this failure rate equates to about Pf = 5 E-2 per year to Pf = 2 E-1 per year for a 'typical' pipeline. Current operations indicate a total failure rate of about Pf = 0.01 per mile - year, or Pf = 1 E-1 = 0.1 per pipeline year.

The reference of the failure rate per pipeline per year will be discussed in the context of experience in the North Sea and current standards of practice (Sotberg, 1990). It is important to note that this failure rate has been accepted by industry, government, and public alike in the U. S. A failure rate is 'acceptable' when it has been accepted.

Figure 12 summarizes the historic rate of failure of Gulf of Mexico oil and gas pipelines. Oil pipelines generally have had a higher rate of failure, due chiefly to corrosion caused failures. Gas pipelines had a higher rate of failure in 1992 due to the effects of hurricane Andrew.

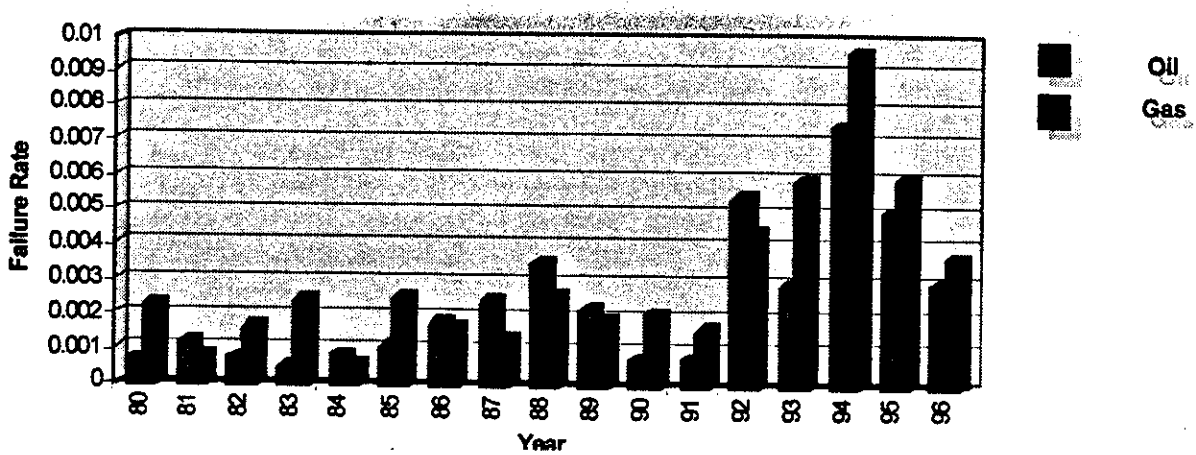

Figure 12 - Historic Rate of Failure of Gulf of Mexico Oil and Gas Pipelines (OCS area, 1967-1997)

Corrosion of steel in pipelines and risers is a function of what is transported in the pipeline or riser, what surrounds the exterior of the pipeline or riser, and how the corrosion is 'managed' (ASME, 1991; Bea, 1992; 1994). A variety of techniques can be used to reduce the rates of corrosion including internal or external coatings, cathodic protection (for continuously submerged segments of pipelines), dehydration of the gas or oil, and the use of inhibitors. Marine growth tends to inhibit or reduce corrosion of risers (NACE, 1992; Kvernvold, et al, 1992).

For this analysis, the loss of pipeline or riser wall thickness due to corrosion (t_c) was formulated as follows:

$$t_c = t_{ci} + t_{ce}$$

where t_{ci} is the loss of wall thickness due to internal corrosion and t_{ce} is the loss of wall thickness due to external corrosion.

The loss of wall thickness due to internal and/or external corrosion ($t_{ci/e}$) was formulated as follows (Elsayed, Bea, 1997):

$$t_{ci/e} = \alpha_{i/e}\, v_{i/e}\, (Ls - Lp_{i/e})$$

where $v_{i/e}$ is the average (mean during service life) corrosion rate, $\alpha_{i/e}$ is the effectiveness of the inhibitor or protection (1.0 is perfect protection, and 10.0 is little effective protection), Ls is the service life of the pipeline or riser (in years), and $Lp_{i/e}$ is the 'life' of the initial protection provided to the pipeline.

This model assumes that there are no inspections and repairs performed during the service life of the pipeline or riser to maintain the strength integrity of the pipeline to carry pressure. Maintenance is required to preserve the protective management measures employed (e.g. renew coatings, cathodic protection, and inhibitors). The corrosion management is 'built-in' to the pipeline or riser at the start of the service period. Inspections and maintenance are performed to disclose unanticipated or unknowable defects and damage (due to accidents).

Stated another way, when an existing pipeline is requalified for service, inspections should be performed to disclose the condition of the pipeline and riser, and then an assessment performed to determined if under the then 'present' condition of the pipeline that it is fit for the proposed service. Alternative management of the pipeline could be to de-rate it (reduce allowable operating pressures), protect it (inhibitors, cathodic protection), repair it (doublers, wraps), or replace it.

For design and requalification , the corrosion rate is based on the owner/operators evaluation of the corrosivity of the fluids and/or gases transported inside the pipeline or riser, and of the corrosivity of the external environment

conditional on the application of a certain protection or 'inhibition' program. Table 1 summarizes suggested median corrosion rates, their variabilities (standard deviations of the logarithms of the corrosion rates, approximately the coefficient of variation of the corrosion rates) and the linguistic variables used to describe these corrosion rates (Elsayed, Bea, 1997; NACE, 1992).

Table 1 - Internal (i) and External (e) Corrosion Rates (v) and Variabilities

Descriptor	Corrosion Rate mm/year	Corrosion Rate Variability - %
Very Low	0.001	10
Low	0.01	20
Moderate	0.1	30
High	1.0	40
Very High	10.0	50

For example, a dehydrated sweet gas would generally have a low to very low corrosion rate (0.001 to 0.01 mm/year), particularly if inhibitors were used to protect the steel. A 'normally' dehydrated sweet oil without inhibitors could have a moderate corrosion rate (0.1 mm/year). A pipeline transporting high temperature salt water could have a corrosion rate that would be High to Very High (1.0 to 10.0 mm/year). Sour wet gas without any inhibitors could have similar corrosion rates (in addition to degrading the steel material properties).

A riser in the splash zone in the Gulf of Mexico without coating protection could have a corrosion rate that is High (1 mm/year). This zone would extend from mean low water to about 4 m above mean low water. Below this zone, the corrosion rate would be Moderate (0.1 mm/year), although local riser connections and other elements that could lead to local corrosion or pitting could have a corrosion rate that would be High (1.0 mm/year). An unprotected pipeline could be expected to have an external corrosion rate that would be Moderate (0.1 mm/year), unless there were other factors that could increase this rate (very high water velocities, severe erosion caused by sediment movements).

In this development, the effectiveness of corrosion management is expressed with two parameters, the inhibitor efficiency ($\alpha_{i/e}$) and the life of the protection ($Lp_{i/e}$). If the inhibitor (e.g. coating, dehydration, chemical inhibitor, cathodic protection) were 'perfect', then $Lp_{i/e}$ would equal 1.0. If experience had indicated otherwise, then the inhibitor efficiency could be introduced as summarized in Table 2.

Table 2 - Internal (i) and External (e) Inhibitor Efficiency ($\alpha_{i/e}$)

Descriptor	Inhibitor Efficiency
Very Low	10.0
Low	8.0
Moderate	5.0
High	2.0
Very High	1.0

The life of the protection reflects the operator's decision regarding how long the protection that will be provided will be effective at preventing steel corrosion. For example, the life of high quality external coatings in the absence of mechanical damage can be 10 years, where the life of low quality external coatings with mechanical damage can be 1 year or less. Another example would be cathodic protection that could be reasonably provided to protect the pipeline for a period of 10 years, but the expected life of the pipeline was 20 years. Thus, there would be 10 years of life in which the cathodic protection was not provided and the steel would be 'freely' corroding. Table 3 defines the general categories of the life of protective systems. This same Table can be used to specify the expected service life of the pipeline or riser (Ls).

Given this information, pipeline owner / operators could define the expected life of the pipeline or riser (e.g. Very Long, Ls = 20 years), define the life of the protective management system that would be incorporated as a part of the pipeline or riser (e.g. Moderate, $Lp_{i/e}$ = 10 years), define the effectiveness of the protective management system (e.g. High, $\alpha_{i/e}$ = 2.0), and then based on the transported product and environment of the pipeline or riser, estimate the internal and external corrosion rates (e.g. vi = 0.1 mm/year, ve = 0.1 mm/year). The corrosion thickness allowance would then be determined as:

$$t_{ci/e} = \alpha_{i/e}\, v_{i/e}\, (Ls - Lp_{i/e}) = 2.0 \cdot 0.2 \text{ mm/y } (20 \text{ y} - 10 \text{ y}) = 4 \text{ mm} = 0.16 \text{ inch}$$

Table 3 - Expected Life of the Protective System ($Lp_{i/e}$)or the Service Life of the Pipeline or Riser (Ls)

Descriptor	$Lp_{i/e}$ or Ls (years)
Very Short	1
Short	5
Moderate	10
Long	15
Very Long	≥ 20

This formulation could be expressed in terms of 'effective' corrosion rates ($ve_{i/e}$) and 'exposed life' ($Le_{i/e}$) as follows:

$$t_{ci/e} = ve_{i/e}\ (Le_{i/e})$$

Time Dependent Reliability

Pipeline reliability is a time dependent function that is dependent on the corroded thickness of the pipeline ($t_{ci/e}$). The corroded thickness is dependent on the average rate of corrosion and the time that the pipeline or riser is exposed to corrosion. This time dependency can be clarified with the following (Bea, 1994):

$$\beta = \ln\ (Kp\ t - Kp\ t_{ci/e})) / \sigma_{lnp/R}$$

where:

$$Kp = (2\ B\ S / p\ D)$$

If one defines:

$$Kp\ t = FS_{50}$$

where FS_{50} is the median factor of safety in the burst capacity of the pipeline or riser. Then:

$$\beta = \ln\ (FS_{50} - FS_{50}\ (t_{ci/e} / t)) / \sigma_{lnp/R}$$

As the pipeline corrodes, the reduction in the pipeline wall thickness leads to a reduction in the median factor of safety that in turn leads to a reduction in the Safety Index (or an increase in the probability of failure). In addition, as the pipeline corrodes, there is an increase in the total uncertainty due to the additional uncertainties associated with the corrosion rates and their effects on the burst capacity of a pipeline.

An analytical model for the increase in total uncertainty as a function of the corrosion could be expressed as:

$$\sigma_{lnp/R}|t = \sigma_{lnp/R}|to\ (1 - t_{ci/e} / t)^{-1}$$

where $\sigma_{lnp/R}|t$ is the uncertainty at any given time 't', $\sigma_{lnp/R}|to$ is the uncertainty at time t = 0, $t_{ci/e}$ is the corroded thickness and t is the initial thickness. When $t_{ci/e} / t = 0.5$ the initial uncertainty would be increased by a factor of 2.

Results for $\sigma_{lnp/R}|to = 0.2$ and $= 0.30$ and $FS_{50} = 2.0$ (same as median bias used previously) are summarized in Figure 13.

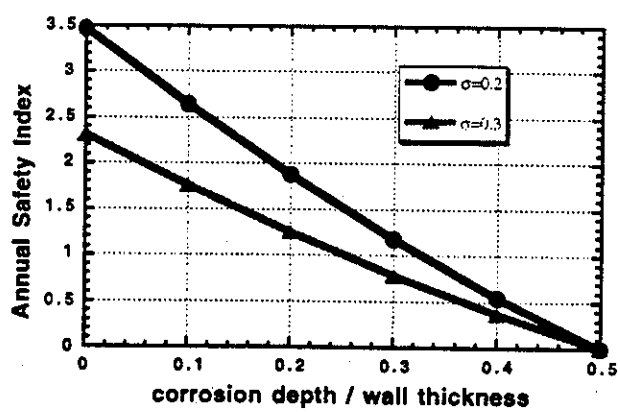

Figure 13 - Influence of Corrosion Depth and Uncertainty on Annual Safety Index

High quality assurance and control in the pipeline reliability management leads to lower uncertainty and higher reliability (Nordland, et al, 1997). Given corrosion, there is a decrease in the reliability of the pipeline as a function of time reflected in the depth of the corrosion normalized by the wall thickness. If the target reliabilities are defined as those that the pipeline should not be lower than during its life, then either corrosion protection must be provided to preserve the initial thickness of the pipeline or riser, or corrosion allowance must be added to the pipeline or riser initial thickness, or a combination of these two measures. For example, if an annual Safety Index of 2 during the pipeline life were desired, and the initial uncertainty associated with the pipeline demands and capacity were 20%, then the corrosion allowance would need to be 20% of the pipeline thickness. This would result in an initial annual Safety Index of 3.5. Given the projected corrosion rate for the life time of the pipeline or riser, the annual Safety Index would decrease to 2.0 by the end of the projected life.

Corrosion – Instrumented Pipelines

Instrumentation or 'smart pigs' can be used to help develop evaluations of corrosion rates and remaining wall thicknesses (Rosen Engineering Group, 1997). These measurements can be used to help make evaluations of corrosion in comparable pipelines that can not be instrumented. Figure 14 shows a probability distribution of corrosion rates determined for the Alyeska pipeline and North Sea oil pipelines. The median values of the corrosion rates are n = 0.06 and n = 0.03 for these two sets of pipelines.

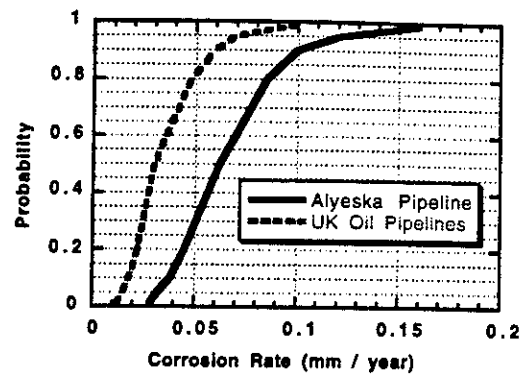

Figure 14 – Corrosion Rates for Two Oil Pipelines

It is important recognize that making evaluations of corrosion rates and wall thicknesses from the recordings have significant uncertainties (Bal, Rosenmoeller, 1997). The measurements can give both 'false positives' and 'false negatives.' The pigs can miss significant defects and indicate the presence of defects that are not present. Figure 15 shows a comparison of the Probability of Detection (POD) of corrosion depths (in mils, 50 mils = 1.27 mm) developed by three different 'smart pigs' (Magnetic Flux Leakage, MFL, based instrumentation). This information was based on comparing measured results from sections of the Trans Alaska pipeline that were pigged and then excavated and the true corrosion depths determined (Rust, et al 1996; Vieth, et al 1996). There is a dramatic difference in the performance characteristics of these three smart pigs. If this type of variability is to be avoided or minimized, then specifications and test runs must be developed to verify the ability of the pigs to detect corrosion damage. Specifications for intelligent pig inspections of pipelines need to be developed if consistent and repeatable results are to be realized (Shell International, 1996).

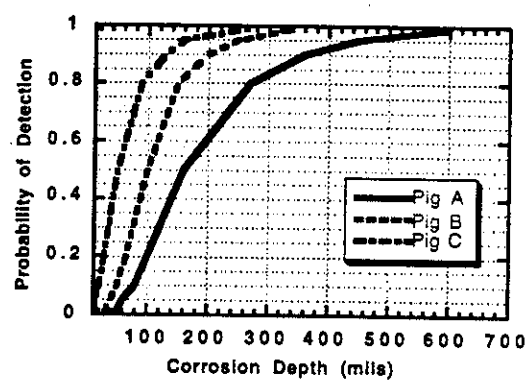

Figure 15 – Probability of Detection Curves for Three Smart Pigs

There are significant uncertainties in the depths of corrosion indicated by the pigs due to such factors as variable temperatures and degrees of magnetism, and the speed of movements of the pig (Bal, Rosenmoeller, 1997). Corrosion rates are naturally very variable in both space and time. Thus, if instrumentation is used to determine the wall thicknesses and corrosion rates, the uncertainties in these characteristics needs to be determined and integrated into the evaluations of the fitness for purpose of the pipeline. Figure 16 summarizes data for two of the smart pigs noted in Figure 14. Both pigs tend to under estimate the corrosion depth. The uncertainties associated with the measured depths ranged from 35 % (for 50 mils depths) to 25 % (for 200 mils depths).

For the instrumented pipelines, the expression for the probability of failure can be expressed as:

$$Pf = Pf_D + Pf_{ND}$$

where Pf_D is the probability of failure associated with the detected flaws and Pf_{ND} is the probability of failure associated with the non-detected flaws.

The detected depth of corrosion must be corrected to the median depth of corrosion (Figure 16):

$$t_{C50} = t_{CD} \, (B_{Dt})$$

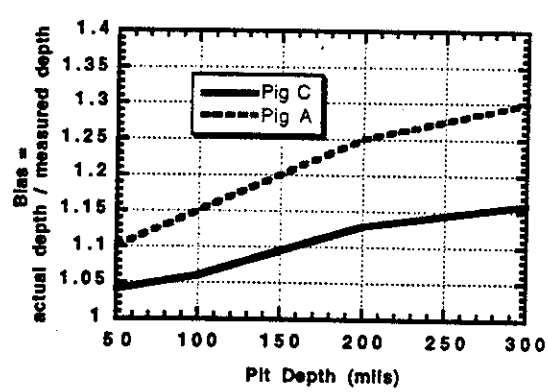

Figure 16 – Bias in measured corrosion depths

The detected depth of corrosion has a standard deviation of the Logarithms of the corrosion depths of:

$$\sigma_{lntc} = 0.25 \text{ to } 0.35$$

Pf_{ND}

The probability of failure associated with the detected depth of corrosion is:

$$Pf_D = 1 - \Phi\{ [\ln (p_{B50} / p_{O50})] / [(\sigma^2_{pB} + \sigma^2_{pO})^{0.5}]\}$$

where Φ is the standard cumulative Normal distribution, p_{B50} is the 50th percentile (median) burst pressure, p_{O50} is the 50th percentile maximum operating pressure, σ_{pB} is the standard deviation of the logarithms of the burst pressure, and σ_{pO} is the standard deviation of the logarithms of the maximum operating pressures.

The pipeline burst pressure is determined from:

$$p_B = 2 S (t - tc) / D$$

The median of the burst pressure is determined from the medians of the variables:

$$p_{B50} = 2 S_{50} (t_{50} - t_{C50}) / D_{50}$$

The uncertainty in the burst pressure is determined from the standard deviations of all of the variables:

$$\sigma^2_{lnpB50} = \sigma^2_{lnS} + \sigma^2_{lnt} + \sigma^2_{lntc} + \sigma^2_{lnD}$$

The probability of a corrosion depth, X, exceeding a lower limit of corrosion depth detectability, xo, is:

$$P[X \geq xo \mid ND] = P[X > xo] P[ND \mid X \geq xo] / P[ND]$$

P [X ≥ xo | ND] is the probability of no detection given X ≥ xo. P [X > xo] is the probability that the corrosion depth is greater than the lower limit of detectability (Figure 14). P [ND | X ≥ xo] is the probability of non detection given a flaw depth (Figure 15). P [ND] is the probability of non detection across the range of flaw depths (Figure 15) where:

$$P[ND] = 1 - P[D]$$

and:

$$P[ND] = \Sigma P[ND \mid X > xo] P[X > xo]$$

The probability of failure for non-detected flaws is the convolution of:

$$Pf_{ND} = \Sigma [Pf \mid X > xo] P[X \geq xo \mid ND]$$

Figure 17 shows results from an instrumentation of a 20-inch diameter gas line based on use of Pig C The measured and corrected corrosion expressed as a percentage of the wall thickness is shown. Based these results and foregoing developments, Figure 18 shows the probabilities of burst failure (detected and non-detected) of the pipeline. Two sections of the pipeline would be candidates for replacement.

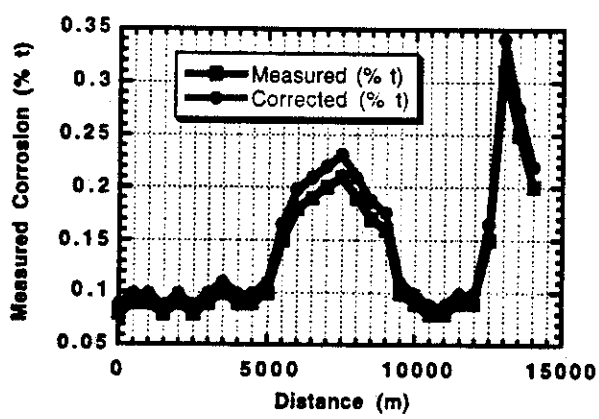

Figure 17 – Pig C measured and corrected corrosion readings

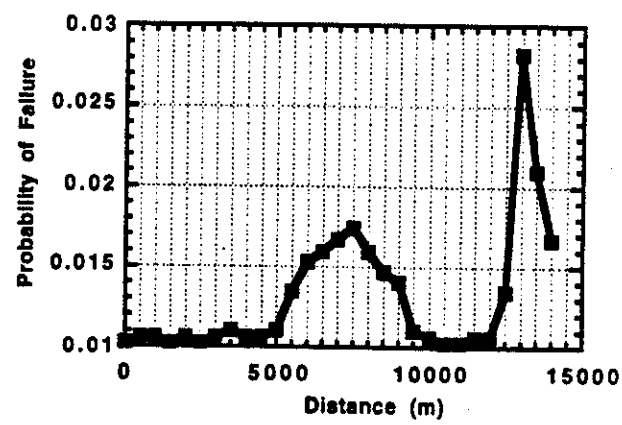

Figure 18 – Probabilities of burst pressure failure

Pressure Test and Relief Effects

None of these developments have taken account of the effects of pressure testing the in-place pipeline. Based on API guidelines (API, 1993), the pipeline is tested to 1.25 times the maximum design pressure (MDP) for oil pipelines and 1.5 times the MDP for gas pipelines. The maximum operating pressure (MOP) generally is set at 90 % of the MDP.

The effect of pressure testing is to effectively 'truncate' the probability distribution of the pipeline burst pressure capacity below the test pressure (Figure 19). Pressure testing is a form of 'proof testing' that can result in an effective increase in the reliability of the pipeline.

There can be a similar effect on the operating pressure 'demands' if there are pressure relief or control mechanisms maintained in the pipeline. Such pressure relief or control equipment can act to effectively truncate or limit the probabilities of developing very high unanticipated operating pressures (due to surges, slugging, or blockage of the pipeline).

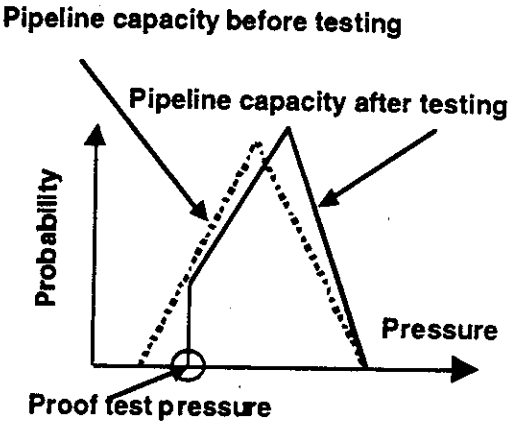

Figure 19 – Effects of proof testing on pipeline capacity distribution

This raises the issues associated with pressure testing and pressure controls on the required factors of safety or load and resistance factors (Hall, 1988; Grigoriu, Hall, 1984; Grigoriu, Lind, 1982). Figure 20 summarizes the results of pipeline proof testing on the pipeline Safety Index as a function of the 'level' of the proof testing pressure factor, K:

$$K = \ln (Xp / p_b) / \sigma_{lnpb}$$

where Xp / **pb** is the ratio of the test pressure to the median burst pressure capacity of the pipeline (test pressure deterministic, burst pressure capacity Lognormally distributed) and is the standard deviation of the Logarithms of the pipeline burst pressure capacities. These results have been generated for the case where the uncertainty associated with the maximum operating / incidental pressures is equal to the uncertainty of the pipeline burst pressures and for Safety Indices in the range of $\beta = 3$ to $\beta = 4.5$ (Fujino, Lind, 1977).

For example, if the median burst pressure of the pipeline were 2,000 psi and this had a Coefficient of Variation of 10 % ($\sigma_{lnpb} = 0.10$), there was a factor of safety on this burst pressure of 2 (f = 0.5) (maximum operating pressure = 1,000 psi), and the pipeline was tested to a pressure of 1.25 times the maximum operating pressure (Xp = 1,250 psi), the proof testing factor K = -4.7. The results in Figure 20, indicate that this level of proof testing is not effective in changing the pipeline reliability. Even if the pipeline were tested to a pressure that was 1.5 times the operating pressure, the change in the Safety Index would be less than 5 %.

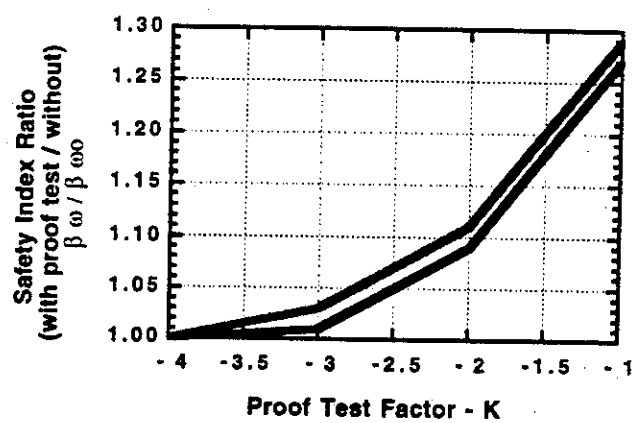

Figure 20 - Effects of proof testing on pipeline reliability

If the test pressure were increased to 75 % of the median burst pressure, the Safety Index would be increased by about 25 %. For a Safety Index of $\beta = 3.0$ (Pf = 1E-3), these results indicate a $\beta = 3.75$ (Pf = 1E-4) after proof testing. Very high levels of proof testing are required before there is any substantial improvement in the pipeline reliability. These results indicate that conventional pressure testing may not be very effective at increasing the burst pressure reliability characteristics. Such testing may be effective at disclosing accidental flaws incorporated into the pipeline due to human and organizational factors (e.g. poor welding).Additional studies are underway to further define the effects of pressure testing and operating pressure controls on the required factors of safety for both new and existing pipelines.

CONCLUSIONS

A general approach for design and requalification of pipeline systems has been proposed that utilizes qualitative, quantitative, and mixed qualitative -- quantitative approaches. These approaches are complimentary. The simpler approaches are used to design and requalify the vast majority of pipelines. The more complex approach is reserved for the more complex problems and situations.

The Level 2 approach has been further developed and applied to the evaluation of the burst capacity of corroded pipelines. This approach has addressed pipelines that can not be instrumented and those that can be instrumented. The approach for non-instrumented approach is mixed with qualified – calibrated expert judgement, information from databases on pipeline failures, and data from instrumented pipelines. The approach for instrumented pipelines requires the same information, but in this case, there is more direct information available on the pipeline corrosion characteristics. However, these corrosion characteristics must be carefully evaluated as they are influenced by different qualities of in-pipe instrumentation and the treatment and analysis of the instrumentation results. It is concluded that much more work is warranted to more further develop the Level 2 mixed qualitative - quantitative approaches, particularly for the requalification of existing pipelines.

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8. Discussion Panel I: Risk Assessment and Management System Applicability Offshore

General Overview

Risk assessment and management has been performed by various industries for many years, but always under a different title. "Risk assessment and management" is a new terminology that is currently the hot phrase in industry and is receiving a lot of attention from various levels of management. It is true that many different risk assessment methods are available, but each one requires different criteria to be applied effectively. The key for choosing the right risk assessment method is analyzing the problem at hand in order to decompose it into smaller more manageable components.

The problem that the industry has to decompose is how to apply risk assessment and management methods offshore. Before going further however it is crucial to define the various approaches available for risk assessment. The three approaches are:

- Qualitative
- Mixed (qualitative / quantitative)
- Quantitative

Each method has characteristics that make it optimum in a given environment, and some of these defining characteristics are tabulated in Table 1.

Characteristics	Qualitative	Mixed	Quantitative
Rigorousness	High	High	High
Quantitative Data Requirements	Low	Medium	High
Accuracy	Low	Medium	Low or High
Cost	Low	Medium	High
Complexity	Low	Medium	High

According to Table 1, there are certain advantages in using each method, but it is also fairly evident that at an early stage of planning, the qualitative method is the ideal method to use for attacking the risk assessment problem. This is especially true for the offshore industry where data to perform quantitative risk assessment is limited. The question is not whether risk assessment methods are applicable offshore, but rather which one is feasible. Obviously at this early stage, the quantitative model can not be applied to a full extent, but in the future the goal will be to move closer to a quantitative model. It is also true that a full quantitative model will not be feasible for all problems, because there are certain characteristics about operations, like human factors, that are difficult to quantify. In the future, the optimum model will probably be the mixed model, because it captures both the quantitative and the qualitative model benefits.

Therefore to apply risk assessment methods offshore, the first task it to decompose the system into components and then analyze each component to see what type of data requirements are necessary for each. For example, the risk caused by humans usually is difficult to quantify, but

the failure of a pipeline with a certain number of flaws in it, operating at a certain pressure can be quantified relatively easy. Once each potential failure mode is analyzed, it is important to define the data requirements for each. Taking the steps described above, the system can be analyzed in parts and a comprehensive risk assessment and management method can be developed.

The topic up to this point has been somewhat concentrated on how to develop models, but not on whether developing a model is feasible. To develop a comprehensive model for risk assessment and management, it is necessary to demonstrate that the recommended methodology is cost effective. Once cost effectiveness has been demonstrated, the methodology of risk assessment and management will be more readily accepted. So after decomposing the system, a feasible methodology has to be drafted that is able to perform in the chosen environment, given that there are only certain types of data available to run the model. The model chosen must reflect the constraints on the system as of today, but also anticipate future problems, to an extent. In other words the model has to be flexible.

Currently there are a lot of pipelines already installed on the continental shelf that can not be removed or upgraded because of cost constraints, and thus the first risk assessment approach should account for these constraints present on the system. On the other hand, new pipelines to be built in the future should be engineered for optimal maintenance and operation in mind. The natural cycle of any engineered structure is to progress from design to construction, operation and maintenance and finally decommissioning, which are all phases in the life of the structure that have to be designed for during the design stage. The risk assessment method chosen therefore will only be a framework that has all the right guiding principles, which are applied according to the type of system that an individual is dealing with. The younger systems will be more accurately assessed, while the assessment accuracy of the older systems will be dependent on the constraints present.

It is also understood that the best way to assess the feasibility of the risk assessment program is to apply it to pilot studies. Upon developing guidelines, certain operations can be chosen to test the developed methods, while others will be chosen as controls. However, since no two systems are identical, the 'test' and 'control' operations chosen should be fairly similar so that comparisons of the results can be more easily carried out. It is also important to choose more than just two pipelines to test the risk assessment and management program, in order that the randomness of the process does not invalidate the data.

The data for the models must also be collected in a uniform manner, which assures some consistency between data collected from one pipeline compared to another. Hopefully at this point, if everything was designed correctly, only data that is practical to collect is being collected. In the future, as was mentioned earlier, a larger variety of data can be collected, but for current systems data collection should concentrate on what is practical. It is important to work with the current constraints of pipeline systems, and to demonstrate that without altering the constraints, the risk assessment and management system proposed actually makes a difference. In essence this will demonstrate the effectiveness of the system, which is crucial for the acceptance of the risk assessment and management methodology by operators, regulators, and last but not least by the shareholders.

In summary the following topics must be addressed for demonstrating the cost effectiveness of risk assessment and management methods:

1. Work with constraints of systems to control cost of development

2. Make flexibility a priority
3. Develop uniform data collection methods and standards
4. Risk assessment and management system can focus effort toward collecting the appropriate data, therefore minimizing costs

Points of Contention

In the previous section it was outlined how the effectiveness of a risk management system can be demonstrated on a practical scale, but the question still remains as to how the industry can reach this stage. Currently there are several obstacles in the energy industry that were created a long time ago and were perpetuated by the intense competitive market that energy industries are a part of. One of the obstacles borne out of the past is secrecy. It is known and accepted that data for a proper risk assessment and management program is crucial. Currently however, due to the intense competition between oil companies, along with the extremely low oil prices, every edge that can be gained over competitors is guarded with extreme secrecy, including available data. Data collection is expensive however, therefore each company by itself is only capable of collecting a certain amount of data, which is usually not enough to develop a comprehensive model for risk assessment and management. It is only natural to look toward a joint industry effort for solving the risk assessment problem because with a joint effort, capital can be united along with experience, brains, and leverage of a united body. Therefore the whole in this case is more than the sum of its parts.

A united effort however does not mean that companies are forfeiting their competitive edge, because each pipeline system is different. The key however will be to develop a general risk assessment system that is applicable to every type of pipeline, and with how much rigor a company applies the methodology will be up to that company. This is analogous to the application of management techniques, where the general philosophy for managing a business is not a secret, but that does not mean that all businesses are managed in an equally effective manner. The same can be applied to risk assessment and management techniques. Each company takes the foundation that was developed by the joint effort and customizes it according to their needs and management's desire. In essence the platform for improved operations will be there, but who will be able to reap the benefits will be up to the individual companies.

If it is proven that a risk assessment and management system can save the industry money, and this is the direction that most clues are pointing to, it will be natural for a company to adopt a risk assessment and management system. To prove this however, it is necessary for the companies to come together and join forces and develop a comprehensive system. It is also important that all companies in the joint effort are represented equally, and that they contribute an amount of capital proportional to their size. In this sense, the larger companies pay more, but since they have more pipelines they also gain more, and vice versa for smaller companies.

Proving the effectiveness of a risk assessment and management system is heavily dependent upon cost, so a unified effort also has to be made to correctly define the cost of certain incidents. For example, how does the failure of a pipeline off the coast of Louisiana due to anchor dragging compare to the same incident off the coast of Texas. These questions will be more easily answered once databases of construction and maintenance costs become more robust and ubiquitous. The key to success in developing a comprehensive system will be planning and forethought.

In summary of the important topics presented in this section the following points have been outlined:

1. Energy companies have to work together (The whole is more valuable than the parts.)
2. Data sharing must take place (If industry gets better, everyone benefits.)
3. Failure incidents must be defined under one umbrella to establish consistency in evaluating costs due to failure
4. Companies must be represented appropriately during the decision processes

9. Corrosion Modeling of Mitigation Impacts on Risk - Dallas Thill

Corrosion is one of the biggest influencing factors for pipeline failures, which constitutes a large portion of maintenance costs for all types of pipelines. To tackle the problem of corrosion there are a variety of tasks that must be performed, and these include up front planning for design and construction, operations and control. Each of the tasks listed can then be further subdivided to obtain a better understanding of the problem. The key is to realize that all of the elements listed are interrelated in one way or another.

The two main corrosion problems for pipelines are that of external and internal corrosion, with internal corrosion usually dictating a larger portion of the failure percentage. In order to control the rate of corrosion, external or internal, the main task is to understand the mechanism of corrosion and to pinpoint where these mechanisms have the highest potential of occurring. In general, the corrosion knowledge has to be advanced, there must be good communication between designers and operators, management must be committed to solving the problem, and there must be a holistic or integrated approach developed that can be documented, reviewed and changed for the better as time progresses.

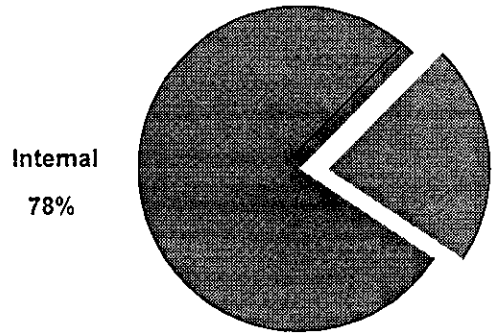
Corrosion Modeling of Mitigation Impacts on Risk

Ideal Situation of Corrosion Control and its' Impact on Risk (Likelihood and Consequences)

Dallas Thill

1

Corrosion Failures
Alberta
Source: AEUB Database 1980 - 96



2

Outline of Corrosion Control

- Integrated Comprehensive Approach
- Comprises
  - UP Front Planning
  - Ongoing Involvement/Communication with
    - Design & Construction
    - Operations (maintenance)
    - Control (monitoring, treatment)
  - Knowledge (Historical, Technological, Scientific)

3

Example System

Consider

- Well Production -> Characteristics
- Pipeline -> Characteristics

4

Corrosion Management

- >95% of Systems - Known Technology
- Common sense (knowledge - what, why)
- Forethought & Reflection
- Complacency
  - Time related
- Economics

5

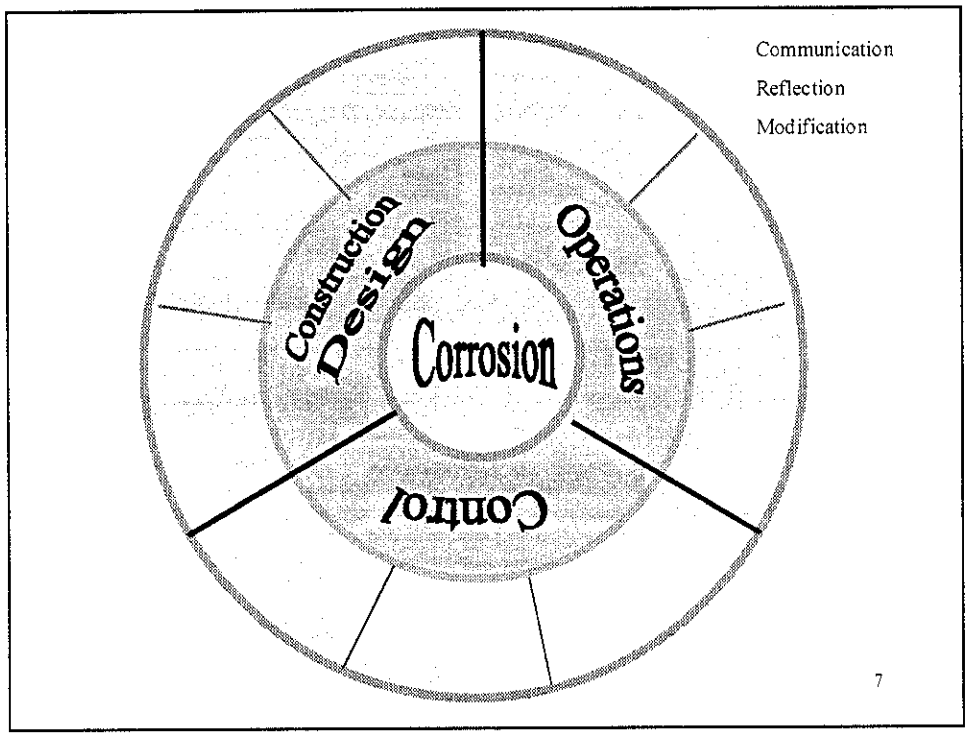
Corrosion Management

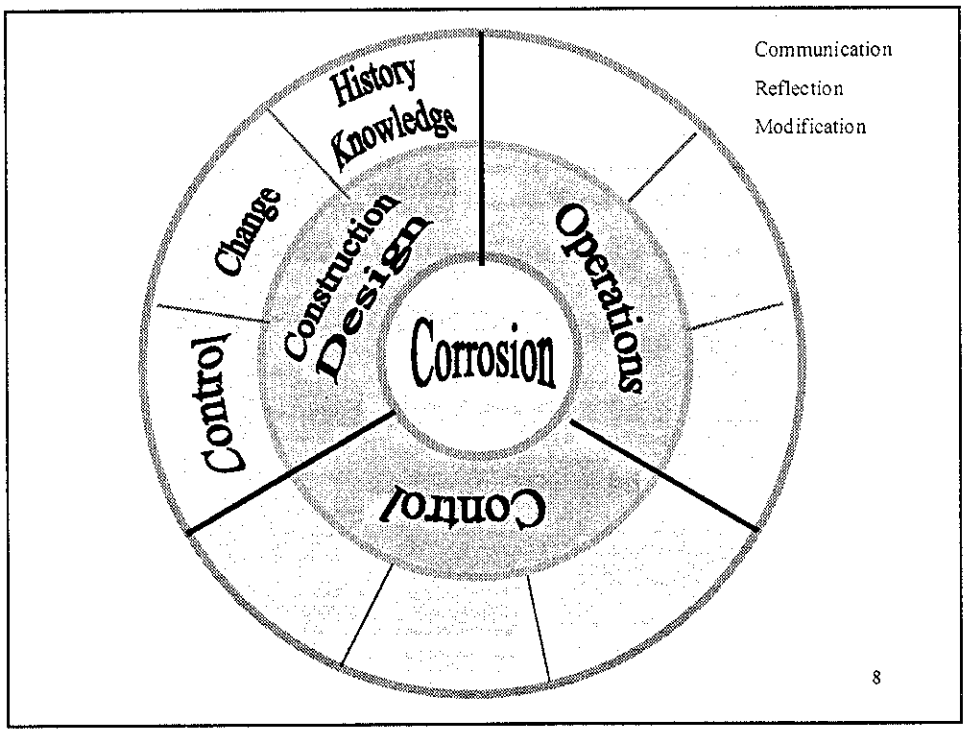
- Key Elements
  - Company Policies

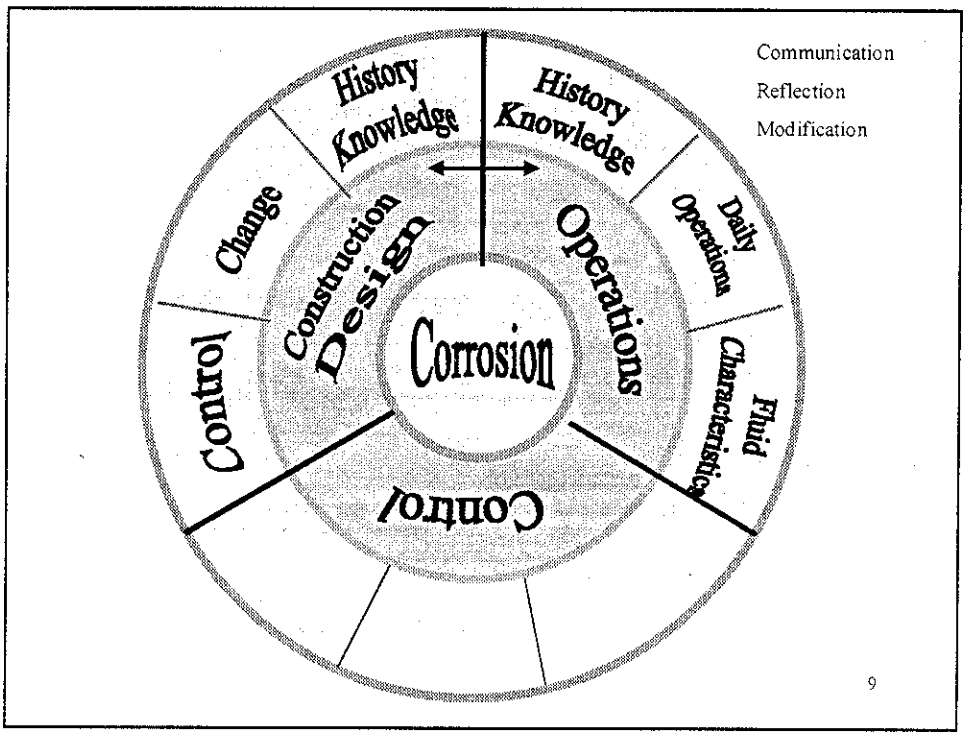
• Codes	Written
• Standards	by
• Recommended Practices	Industry
– Regulations	Written by
– Acts	Government

  - Unwritten Knowledge

6


Communication
Reflection
Modification
Construction
Design
Operations
Corrosion
Control
7


Communication
Reflection
Modification
History
Knowledge
Change
Control
Construction
Design
Operations
Corrosion
Control
8


Communication
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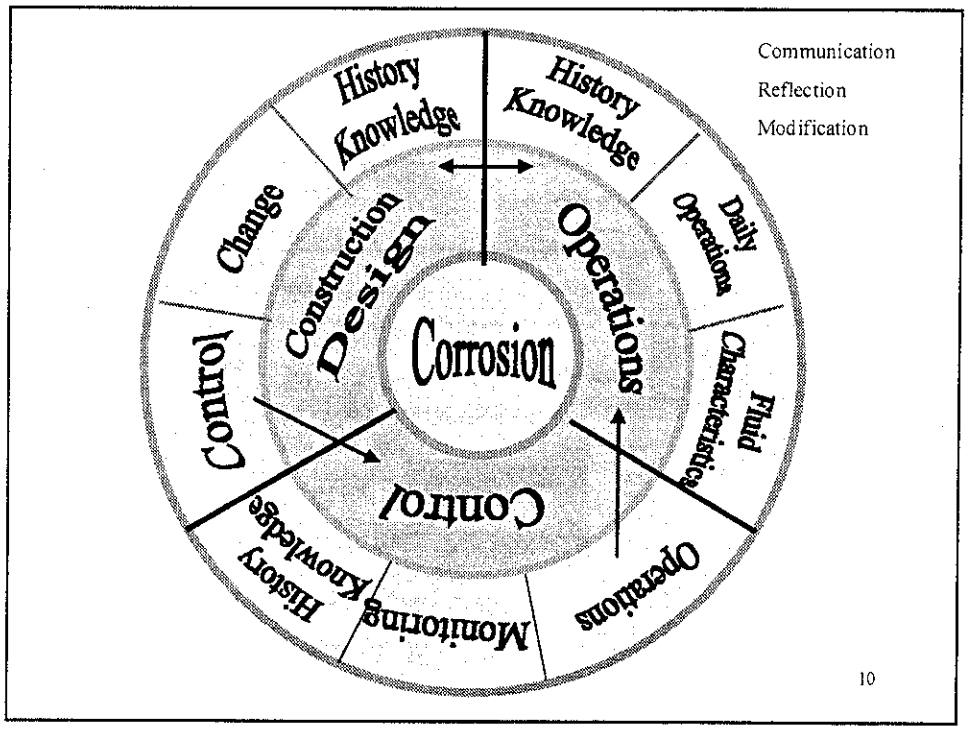
Corrosion
Fluid
Characteristics
Control
9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Corrosion
Fluid
Characteristics
Control
History
Knowledge
Monitoring
Operations
10

External/Internal

- Land Based background
  - Swamp, Muskeg, Rivers, Lakes
- Control done to decrease Risk

Note: Will cover only selected sample items

11

External
Sample

- Controllable (example) (managed)
  - Materials
    - CS
    - Al
- Non-controllable (example)
  - 2nd electrolyte
  - Environmental SCC (not part of discussion)

12

External
Design & Construction

Controllable

- System Knowledge
  - Coating
  - Current source/locations
  - Crossings (all)
  - Foreign current sources
    - some-times your own

13

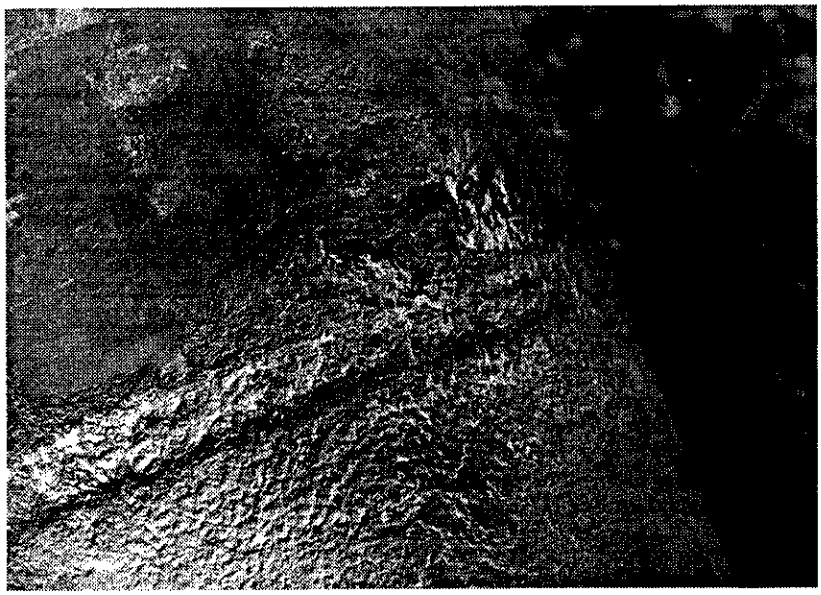
External
Design &Construction/Control/Operations

Controllable

- Annual surveys & reviews
  - Regular
  - Specialized (coating evaluation, current requirement ....)
- Monthly system checks
  - Actions taken
- Automation
- Splash zone, Air/soil

14

15



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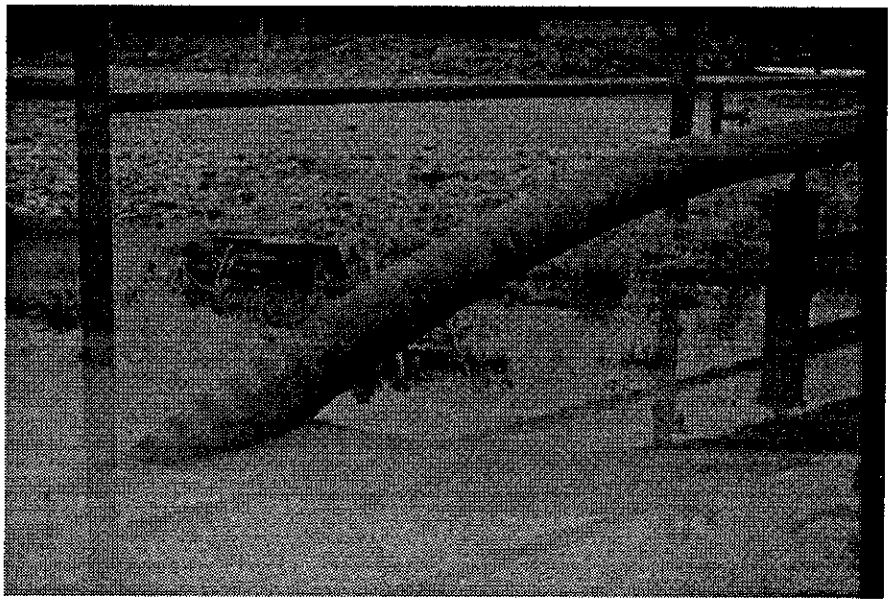

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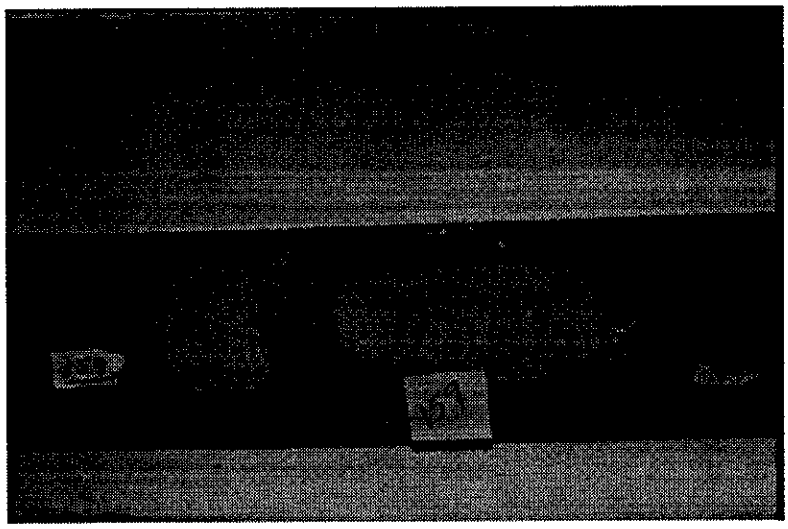
External

Design & Construction, Control

Non-controllable

- 2nd Electrolyte
  - Weld Cutback area
    - Smart Pig (self contained, tethered)
    - Design & Construction

18



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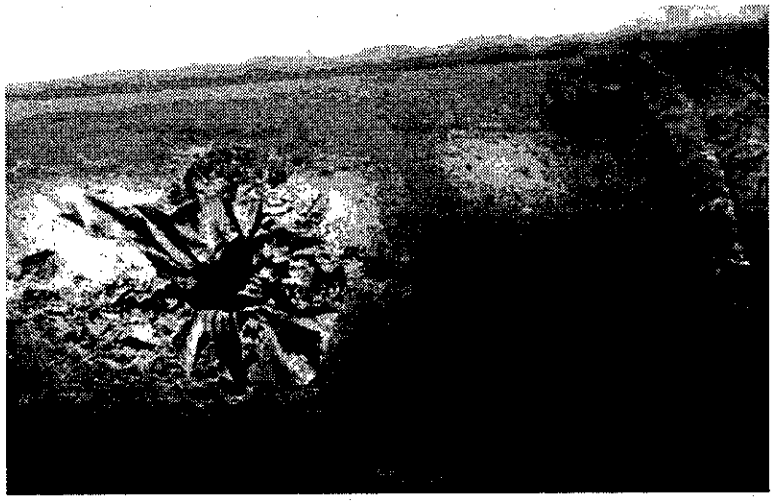

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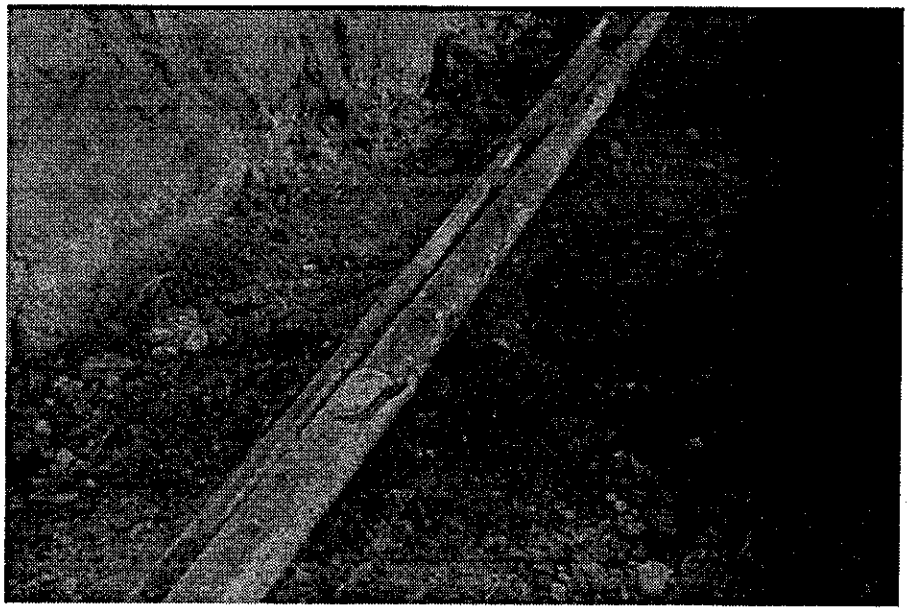
External

Design & Construction, Operations

- Operating temperature (now & future)
  - Coating for service
  - C/P system practical

21



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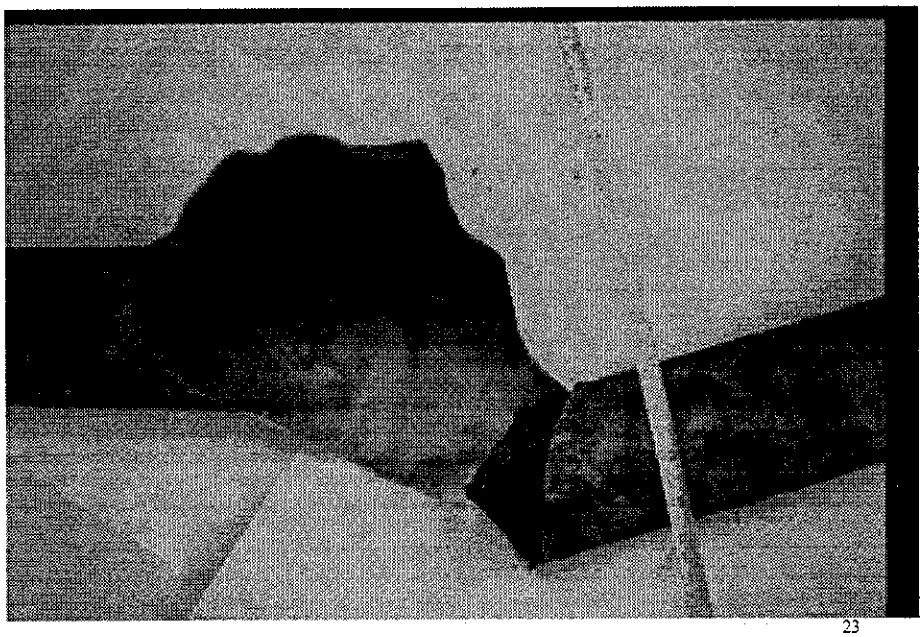

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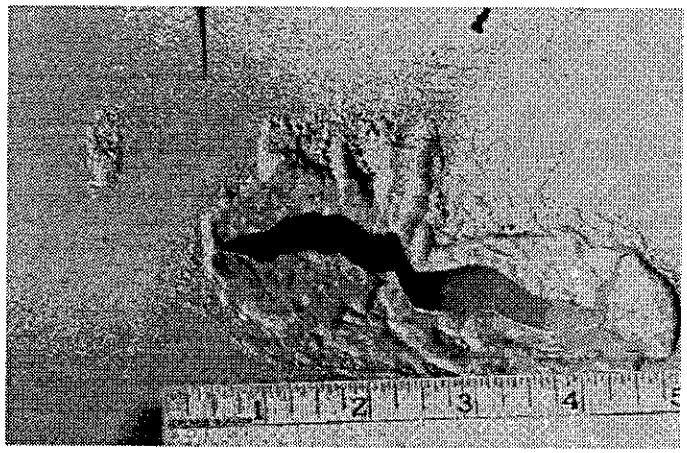
External

Design & Construction, Operations

- Design & Construction
  - Pipeline movement
    - Temperature
    - Buoyancy
  - Attachment damage
    - Weights (mechanical wear/erosion)

24



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External

Design & Construction, Operations

- Design & Construction
  - Pipeline movement
    - Temperature
    - Buoyancy
  - Attachment damage
    - Weights (mechanical wear/erosion)
  - Earth movement

26

External

- Guidelines That Help
  - Impressed current
    - Multiple small systems
    - Minimize electrical isolation
  - Coatings
    - Design for service (now & future)
    - Construction inspection
  - Sacrificial
    - Knowledge of Anode environment
    - Knowledge of Current requirement

27

Internal

Design & Construction/Operations/Control

Non-controllable

- Production Composition (characteristics)
  - Now
  - Future
- Personnel
- Topography

28

Internal

Design & Construction/Operations/Control

Non-controllable

- Production
  - Fluid Production Rate (now, future)
    - Hydrocarbon
      - Liquid
      - Gas
    - Water

29

Internal

Design & Construction/Operations/Control

Non-controllable

- Production
  - Fluid Composition Characteristics (now, future)
    - Gases
      - CO_2
      - H_2S
    - Water
      - SG, TDS, pH
    - Hydrocarbon
      - Gas
      - Liquids

30

Internal

Design & Construction/Operations/Control

Non-controllable

- Personnel
- Topography

31

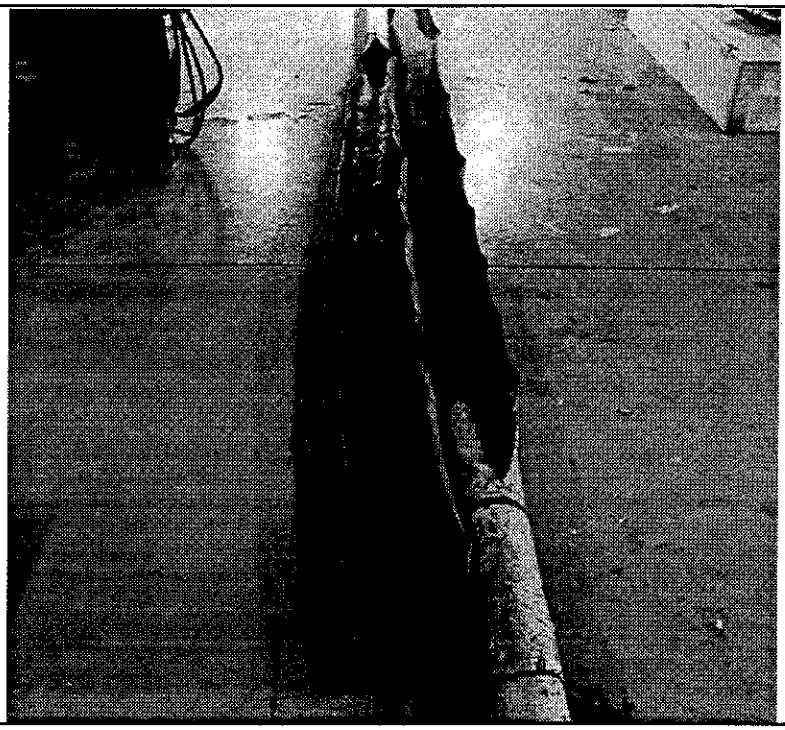
Internal

Design & Construction

Controllable

- Materials
  - Metals
    - Ferrous
    - Nonferrous
  - Non-metallic
- Installation
  - ERW weld position
    - 10:00 to 02:00

32



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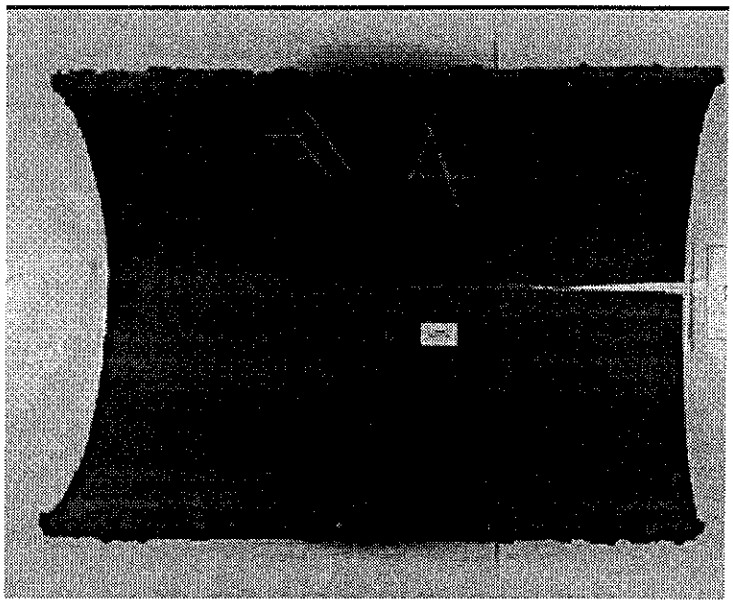

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Internal

Design & Construction

Controllable
Production
- Fluid Conditioning
  - Type
    - Separation
    - Dehydration
  - Location
    - Wellsite
    - Central

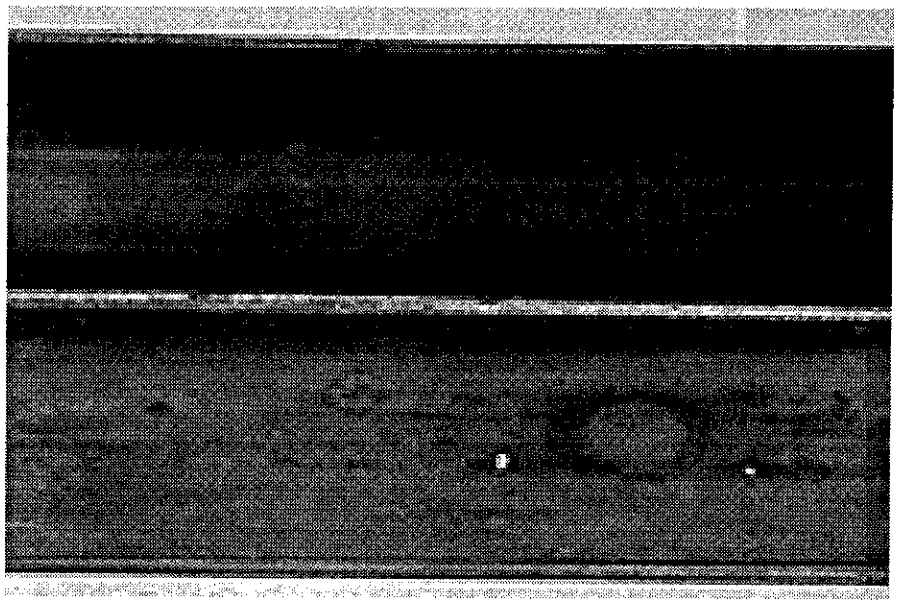
35

Internal

Design & Construction

Controllable (varying)
Production
- Fluid Compatibility
  - Scale
  - Asphaltene

36



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Internal

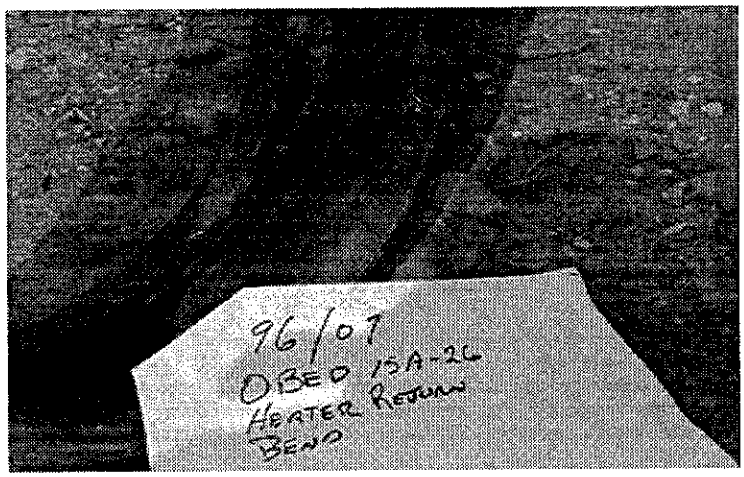
Design & Construction/Operations

Controllable (varying)

Production

- Fluid Compatibility
  - Scale
  - Asphaltene
- Solids
  - Formation fines
  - Sulphur

38



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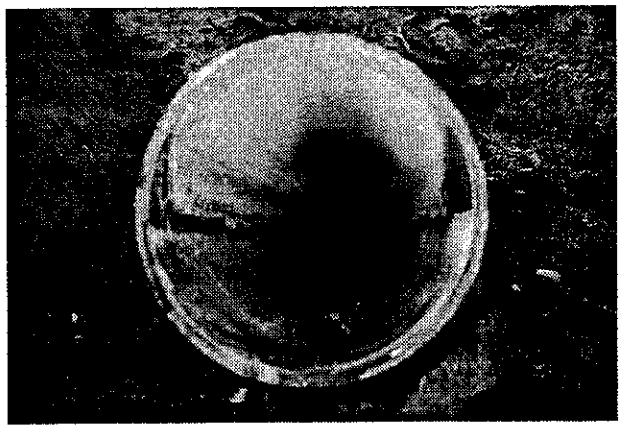

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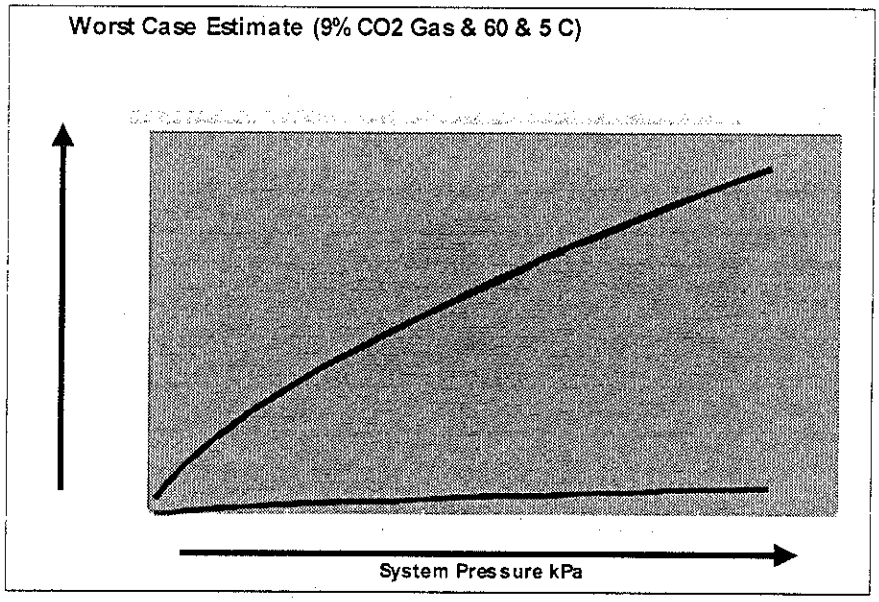
Internal

Design & Construction/Operations

Controllable (Varying)

- Operating Parameters
  - Temperature
  - Pressure

41



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Internal

Design & Construction Operations

Controllable (Varying)

- Operating Parameters
  - Temperature
  - Pressure
  - Housekeeping
    - Well work-over fluids
    - Pigging
  - Flow velocities

43

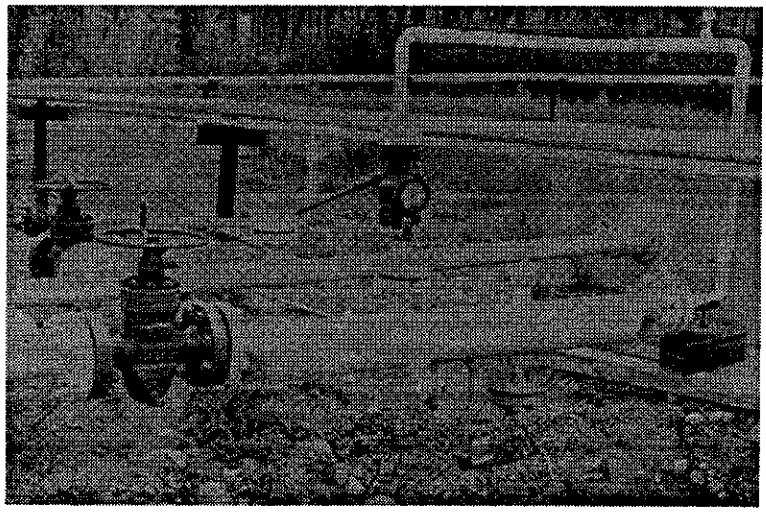
Internal

Design & Construction/Operations/Control

Controllable

- Monitoring
  - Rate Measurement
    - Pipeline Design
      - What do you want to simulate
      - Represent worst case
      - Equipment (initially best, retrofits poor)

44



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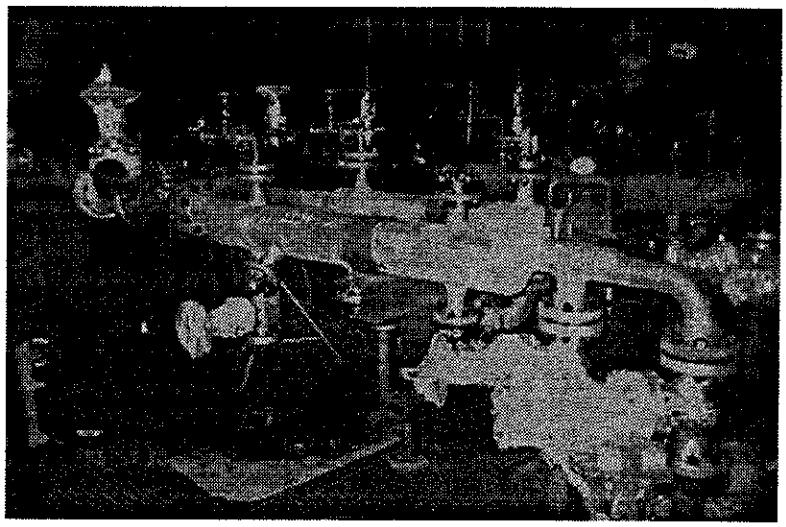

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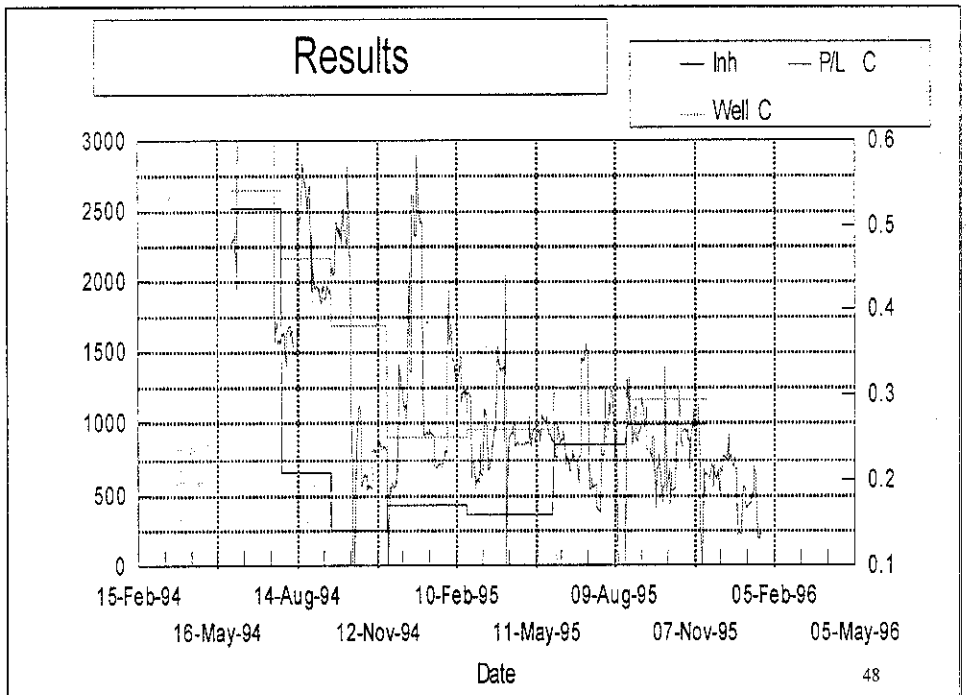
Internal

Design& Construction/Operations/Control Controllable

- Monitoring
  - Rate Measurement
    - Pipeline Design
      - What do you want to simulate
      - Represent worst case
      - Equipment (initially best, retrofits poor)
    - Measuring Tools
      - Coupons
      - Electrochemical
        - » LPR
        - » Noise (events)

47



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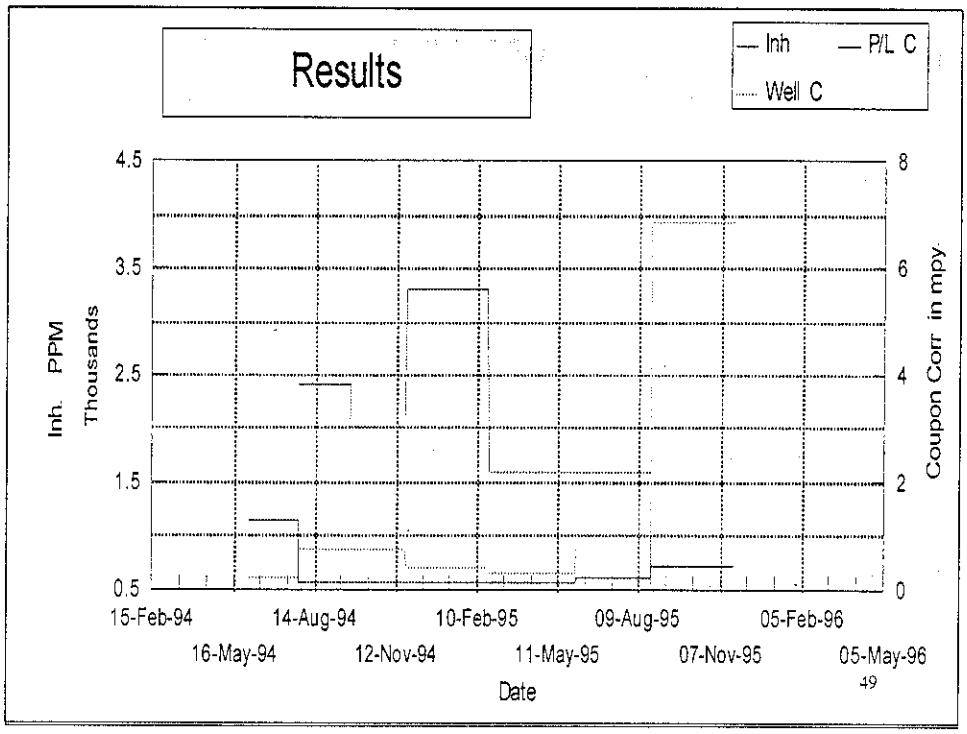
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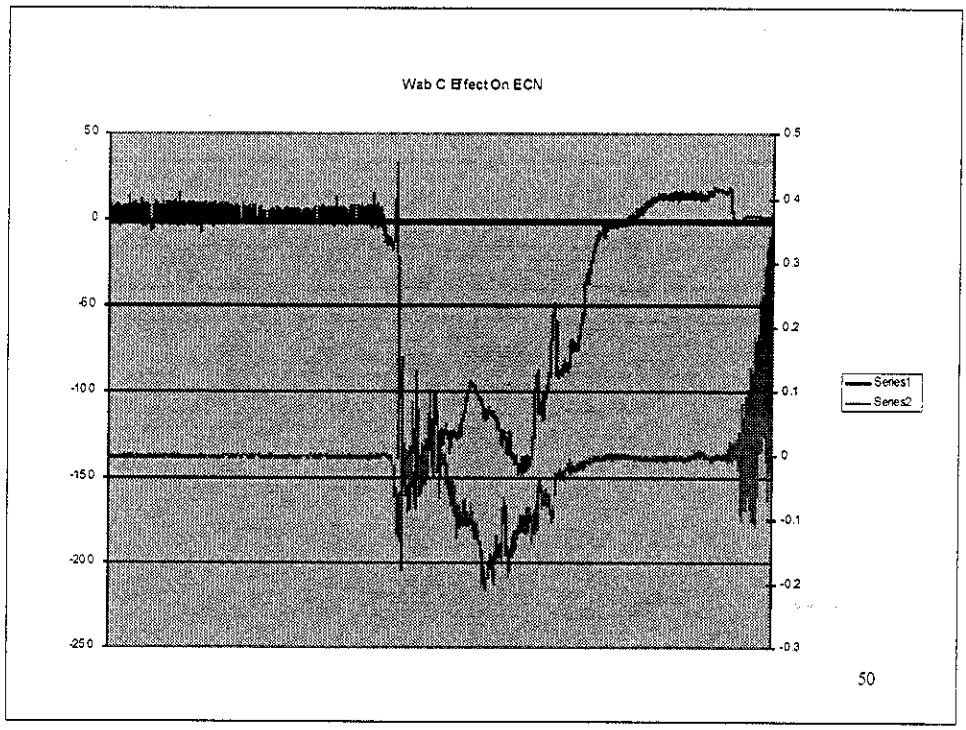
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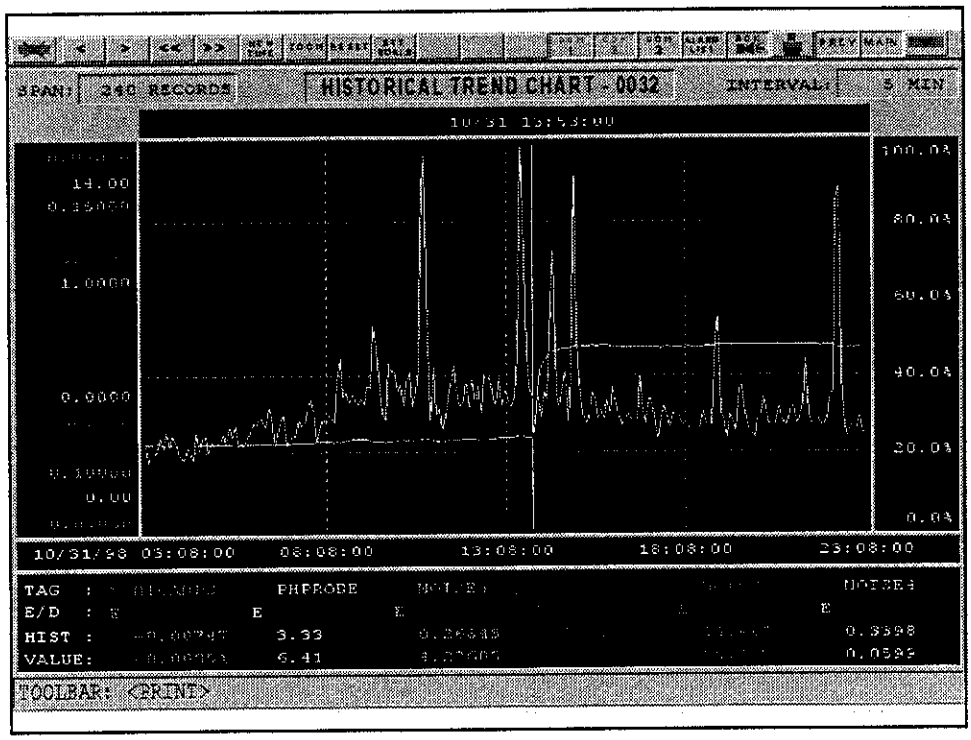
Series1
Series2
50


SPAN: 240 RECORDS
HISTORICAL TREND CHART - 0032
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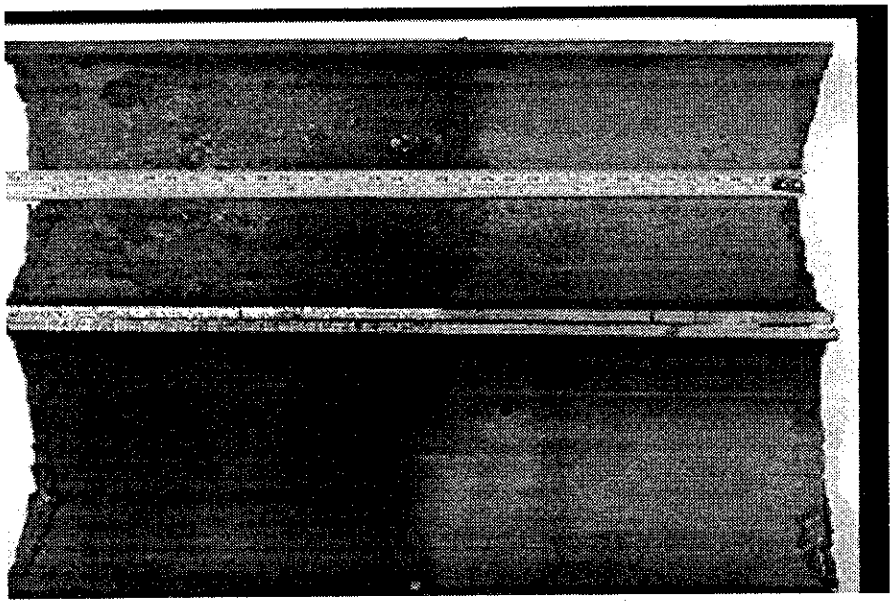

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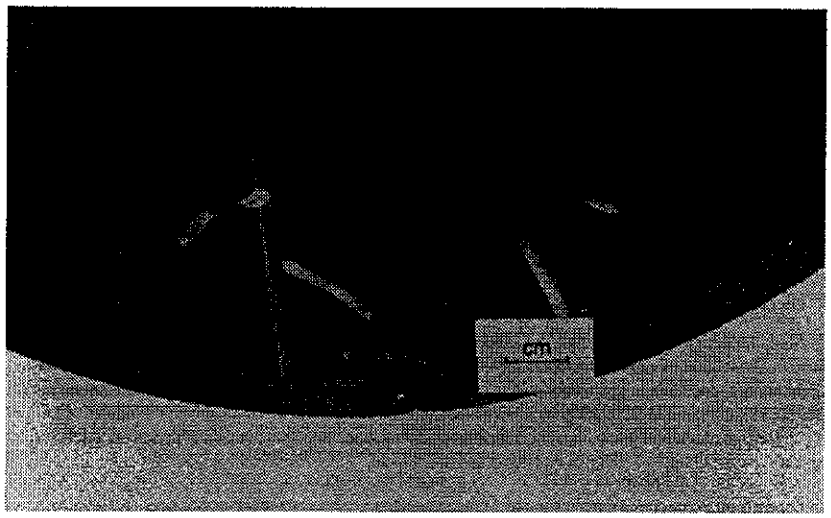

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Internal

Control/Operations

- Monitoring (cont'd)
  - NDE
    - Ultrasonic
      - Spot
      - Imaging
  - Other
    - Proprietary
    - Fluid analysis
      - Dew point analyzer
  - Automation
    - Degrees

54

Internal

- Functions that Help
  - Historical Trending
    - Production
    - Monitoring
    - Treatment
  - Responding to Change
    - Production
    - Operating parameters
  - Communication Loops
  - Knowledge Dissemination
  - > 3 Types of Monitoring
  - Automation

55

Internal

Functions that often Lead to Problems

- Un-managed Change
- Managing Compromises

56

Summary

System Management

- Knowledge
- Communication
- Guidelines (Regulations)
- Management Philosophy
- Management Commitment
- Dedication/Commitment (all levels)
- Holistic/Integrated Approach
- Documentation
- Planned Reviews

57

This Approach Too Idealistic?

- How much do your failures cost? Do you know?
- As a minimum
  - Train your Operators
  - Do high level RBI
  - Have a good consultant on call
  - Be prepared for a big incident now and then

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10. 3rd Party Damage Prevention and Detection - Harvey Haines

Third party damage prevention and detection is a serious concern for pipelines, offshore and onshore, due to the fact that in these scenarios innocent bystanders can be hurt. Events can result in a bad reputation for the operating company and thus also a considerable monetary loss. In order to minimize third party damage, three main areas of concern have been outlined. These areas are training, technology, and penalties.

Training can help by educating both workers and civilians about the dangers present at or near a pipeline. Individuals trained properly can react to a failure in a correct and timely fashion, therefore minimizing the impact of the failure on the environment around the pipeline. Technology can also help by detecting failure or damage to a pipeline at an early stage, therefore giving the operators advance knowledge in order that they may arrest the malfunction as soon as possible. An example of a technology that can be used to detect third party damage is one that utilizes acoustical methods. At the present however there are also certain obstacles that have to be overcome like noise filtration so that a clearer picture can be obtained about the pipeline. Penalties are the last form of prevention method that acts as a deterrent for companies neglecting their pipelines. In this case, the concept is relatively simple, and entails the operating company paying a certain sum of money every time there is an incident. The incentive in this case is to make it expensive for companies to neglect their pipelines so that they are deterred from doing thus.

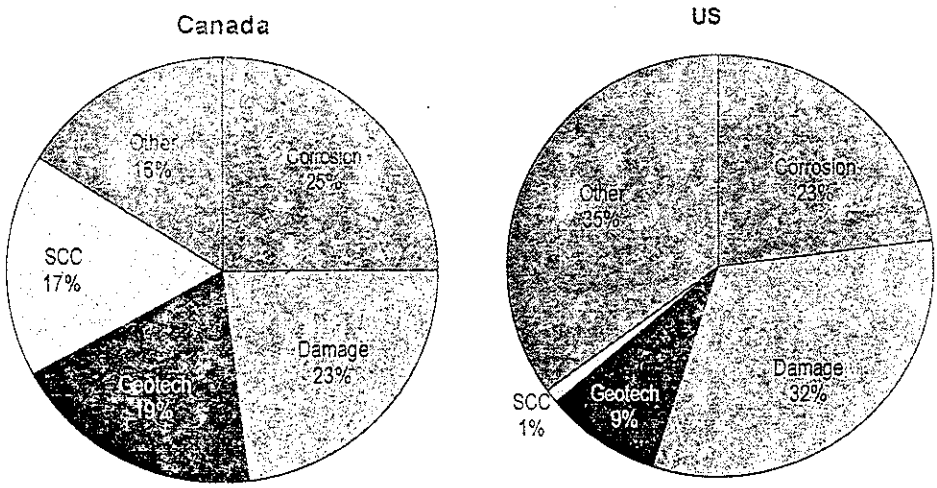
3rd Party Damage Prevention & Detection

Risk Assessment & Management of Marine Pipeline Systems Workshop

November 5-6, 1998

Harvey Haines
Gas Research Institute

Incidents

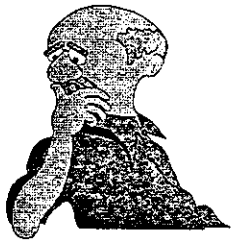


4 Ways to Prevent & Mitigate Damage

- Better One-Call Systems
- Right of Way Encroachment Monitoring
- Contact with Pipe Monitoring
- Detection & Characterization of Damage

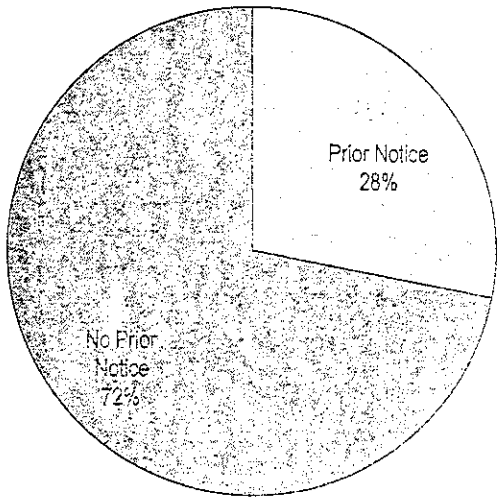
Better One-Call Systems

- Six Steps to Safe One Calls
  1. Requirement known?
  2. Call actually made?
  3. Utilities notified?
  4. Locators dispatched?
  5. Marking correct?
  6. Excavation appropriate?



Notices to One Call Centers

Resulting in DOT Reportable Incidents



Each Effected by Three General Categories

- Training
- Technology
- Penalties

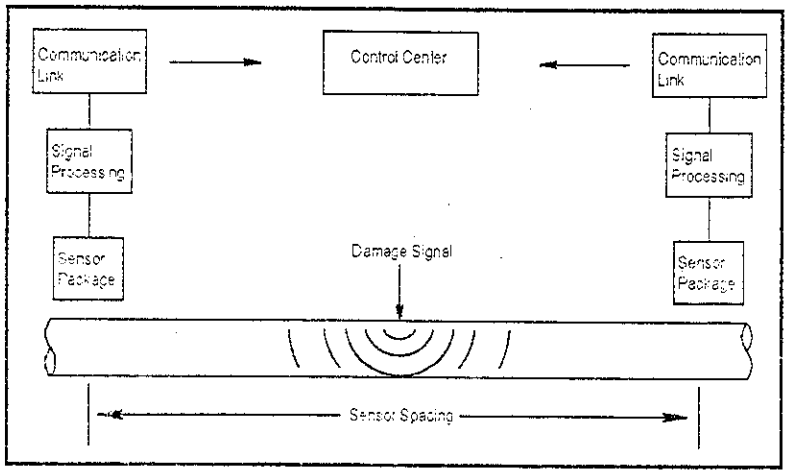
Right of Way Monitoring Survey

- A few gas pipelines Interested in ROW monitoring @ a cost of $1000/mi/yr
- Several stated no interest in paying for ROW monitoring
- GRI currently investigating interest in pilot project to examine potential techniques
  - Fiber optic cable - ground vibration
  - Infrared techniques - vehicle identification
  - Satellite imagery
  - Others

Real Time Monitoring of Hits to Pipelines

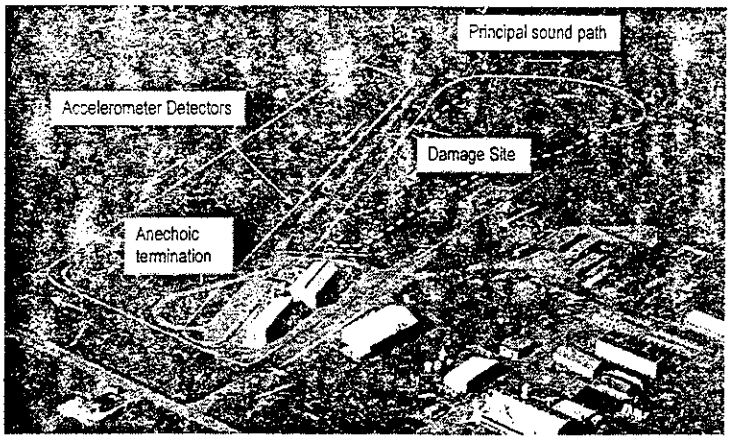
- Contact with a pipeline introduces an acoustic wave in the gas stream
- These Tube waves have been shown to travel for 3 miles in an abandoned pressurized pipeline
- Key for successful technology is separating signals from
  - hits to pipeline
  - normal operating noise in a pipeline

Elements of Real-Time Monitoring

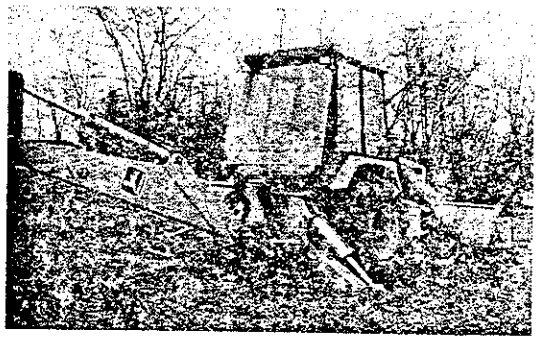


Pipeline Simulation Facility

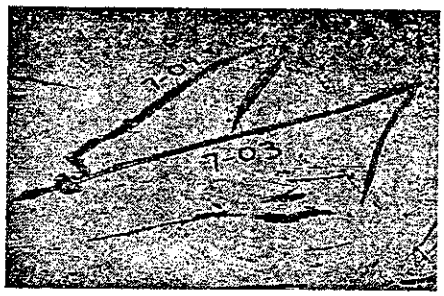
Real Time Monitoring Test Site

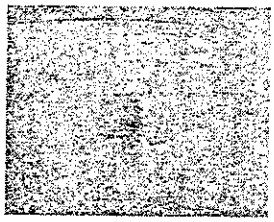


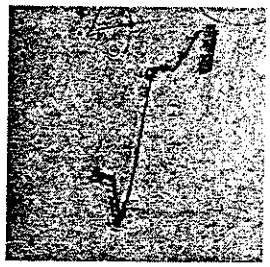
Signal Source: John Deere 310 D Backhoe



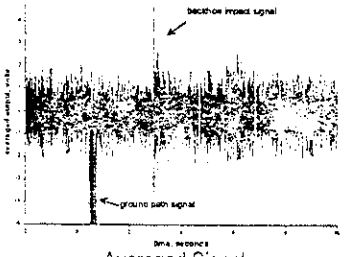
Results: Typical Damage to Pipe



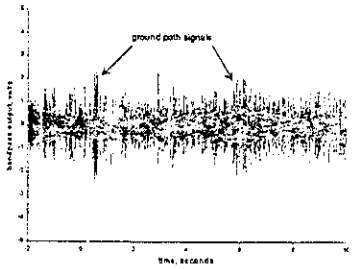




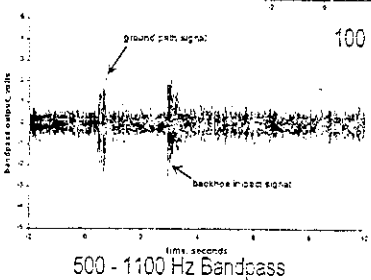
Bandpass Filtering of Off-Axis Backhoe Hit



Averaged Signal

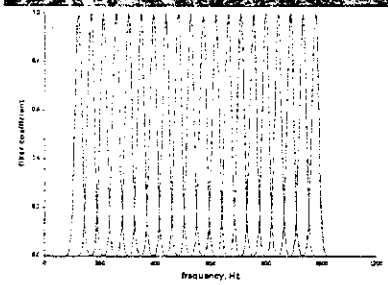


100 - 400 Hz Bandpass

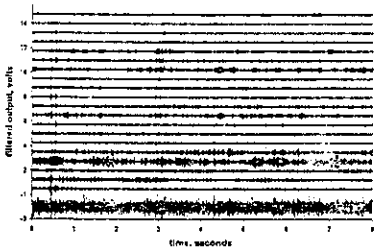


500 - 1100 Hz Bandpass

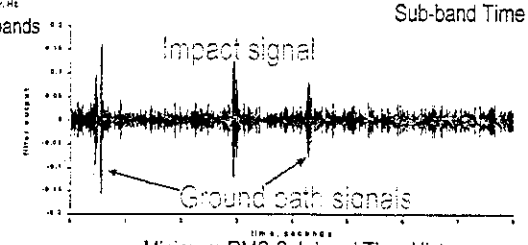
Split Spectrum Processing on Off-Axis Backhoe Hit



Frequency Sub-bands

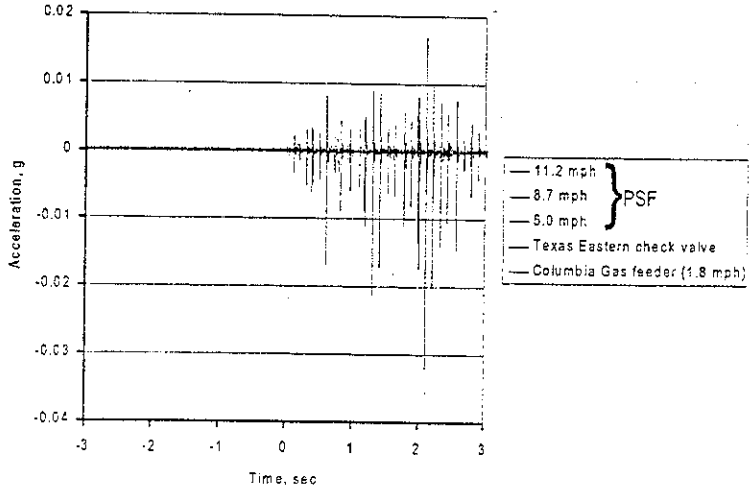


Sub-band Time Histories



Minimum RMS Sub-band Time History

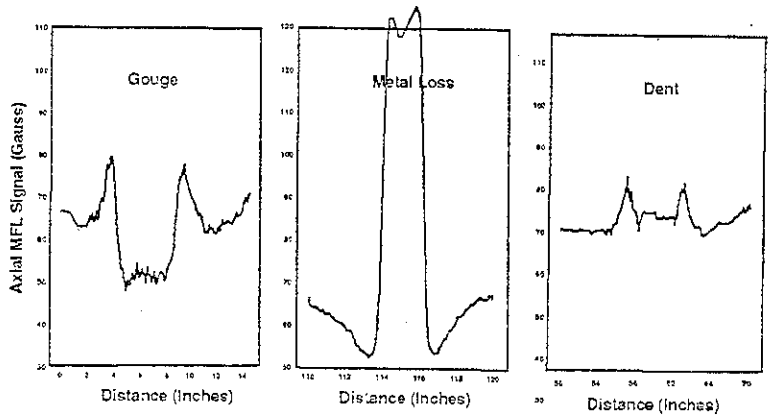
Overcoming Flow Noise
is the Key to Making Monitoring Work



Detection & Characterization of Damage

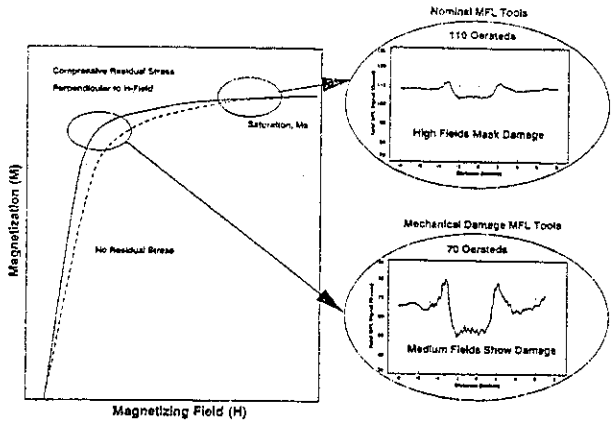
- Mechanical Damage Pig Development
  - Research Detection and Sizing Methods - DOT (Battelle)
  - Develop In-Line Inspection Pig-GRI (Tuboscope)
  - Perform Study on Impact of ILI Pig-GRI (Keifner)
  - Develop Critical Assessment Criteria-GRI

Mechanical Damage Signals



Gouge Signals

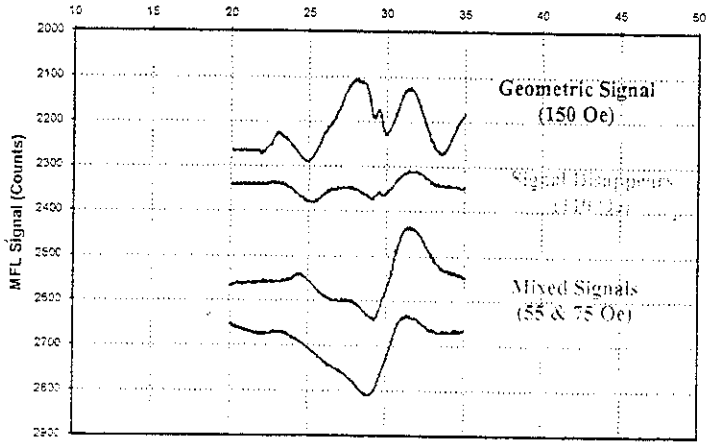
Amplified at Reduced Magnetic Field



MAGNETIZATION LEVEL

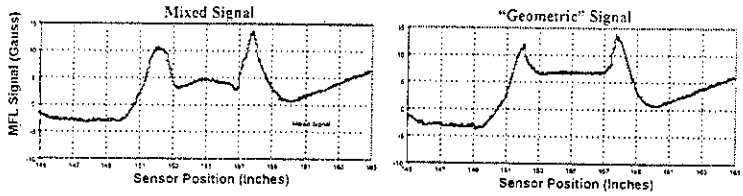
SIGNAL AMPLITUDE

Defect: D-00

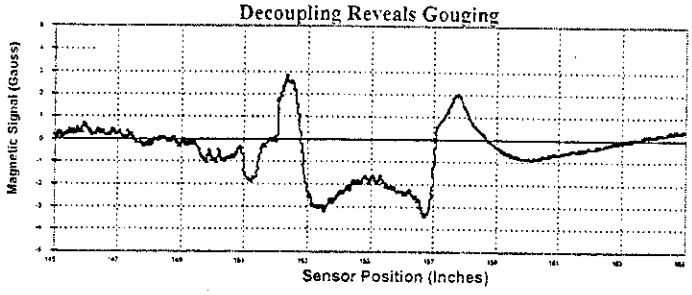


DECOUPLING MFL SIGNAL

GRI FLAT PLATE DEFECT: SIMPLE DENT

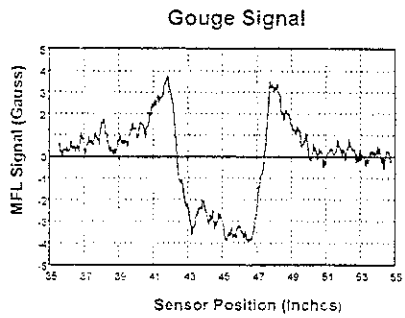


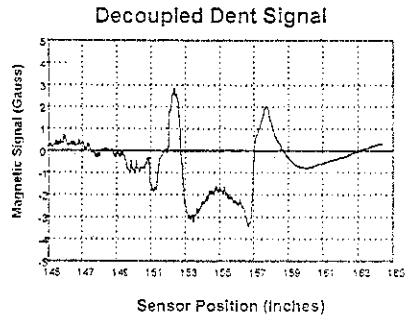
Decoupling Reveals Gouging



DECOUPLING REVEALS GOUGING

Gouge Defect and Dent With Similar Gouge Compared

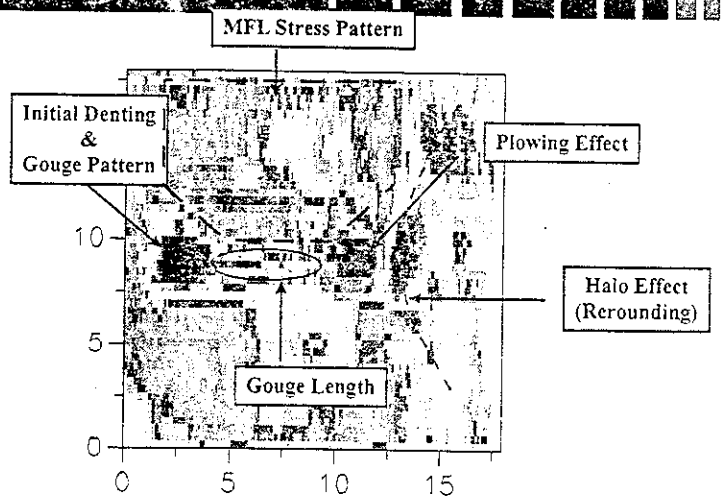




ADDITIONAL FEATURES IN THE 3-D DECOUPLED SIGNAL

- PLOWING EFFECT
- GOUGE LENGTH
- VISIBLE STRESS "PATTERN"

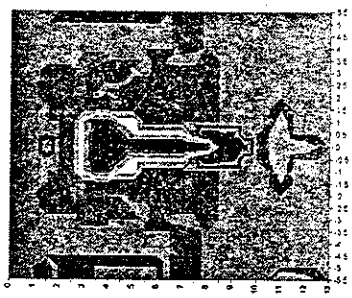
FEATURES IN DECOUPLED SIGNAL



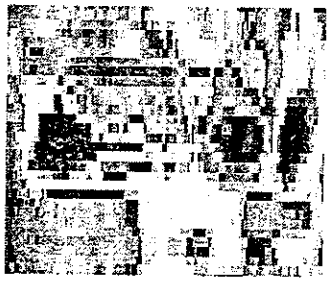
ADDITIONAL FEATURES: MODELING CHECK

SAME FEATURES APPEAR IN BOTH THE MODELING AND EXPERIMENTAL DATA

Simple Model

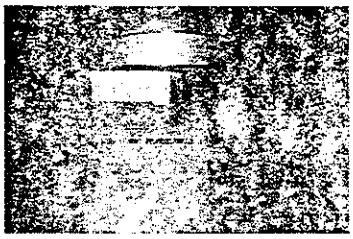


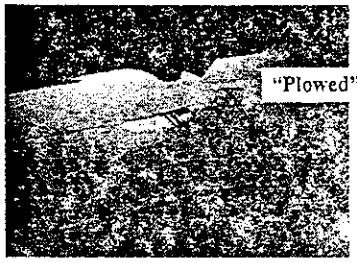
Pull Rig Defect



DD=3, DL=6, GD=10

PLOWING EFFECT





MFL(Plowing) ~ F_1(Load) x F_2(Gouge Depth) x F_3 (Gouge Length)

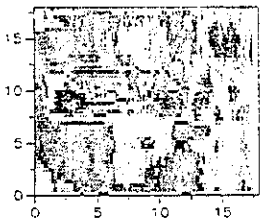
Related to Severity of Defect

Does Not Give Gouge Depth!

PLOWING: EXAMPLES

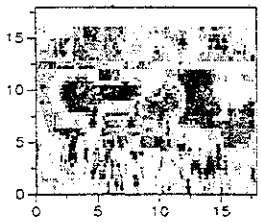
DEFECTS HAVE SAME *DL=6, DD=6, PM#36*, P-? CURVES
ONLY AMOUNT OF PLOWING (GOUGING) DIFFER

4-4

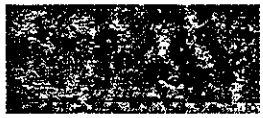


10 mil Deep

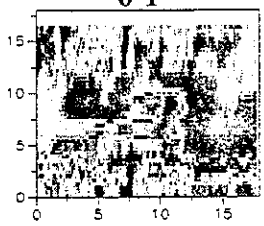
5-3



5 mil Deep

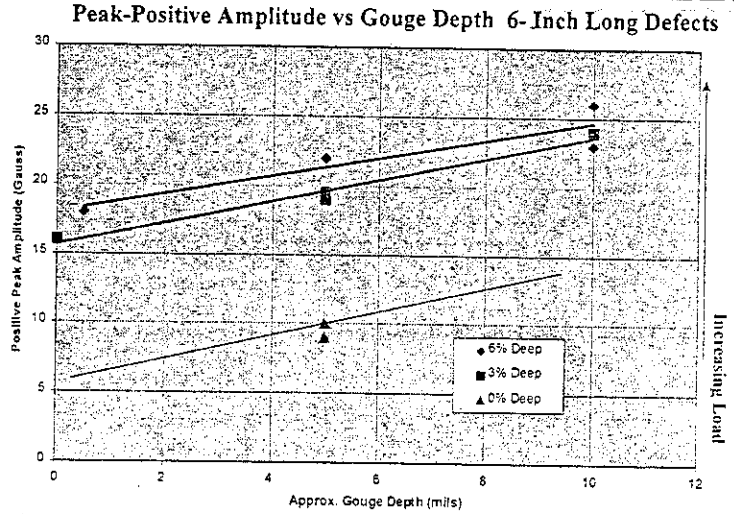


6-1

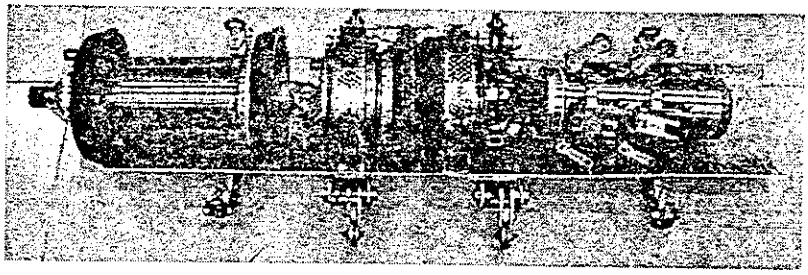


~1 mil Deep

PLOWING EFFECT



Mechanical Damage Pig Design



Primary Magnetizer

Up to 100 Shoes

Each with 9 Sensors

Can vary magnetization with electromagnet

Electronics

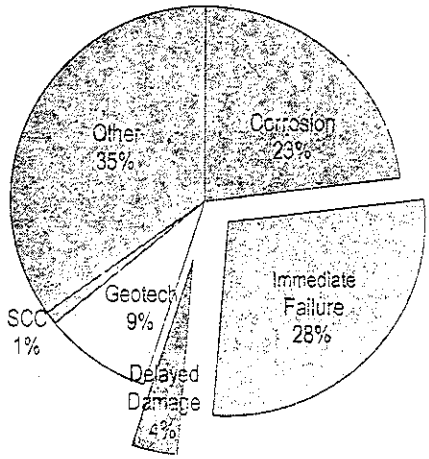
Up to 100 Shoes

Dent Transducers

Stress Sensor Detectors

Mechanical Damage Survey

- Kiefner reported 32% of all DOT incident are due to Mechanical Damage
- 4% of total incidents are due to delayed damage
- Delayed incidents tend to be more expensive than immediate failures because of incident like Edison, NJ



Summary

- Mechanical Damage is the largest cause of reportable incidents in North America
- Human Behavior modifications are needed to make One Call systems work better
- Improved Technology will help identify and characterize mechanical damage and its severity

11. Selection of Optimal Risk Mitigation Strategies - John Conroy

Once it has been decided that risk mitigation strategies are going to be employed, the next step is to decide how to optimally implement these strategies. It is important to look at various criteria like future conditions, cost issues, safety and environmental issues, and also reliability issues. Many times decision trees can be used effectively to represent interrelated decisions and for defining decision points and possible outcomes.

When the proper model for the decision process has been identified, all the outcomes of different mitigation measures can be calculated while dealing with uncertainties, and the potential life cycle cost of the pipeline can be assessed under each scenario. Costs include direct, business impact, and risk costs. URS Greiner Woodward Clyde has developed a program provides feedback on inspection spending, maintenance costs, and other issues like number of expected ruptures based on certain assumptions. The key with modeling however is making sure that the model correctly represents what is actually happening in the field and is dynamically assessing the condition of the pipeline.

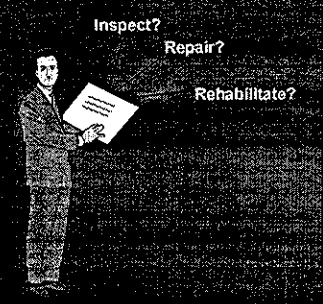
Selection of Optimal Risk Mitigation Strategies

By John Conroy

Pipeline Risk Assessment and Management Workshop

Houston, TX

November 6, 1998



URS Greiner Woodward Clyde

Selection of Optimal Risk Mitigation Strategies

Presentation Overview

- Challenges
- Methodology
- Illustrative Example
  - Model Validation
  - Input Data
  - Example Outputs

URS Greiner Woodward Clyde

Selection of Optimal Risk Mitigation Strategies

Challenges

- Continual Process, Not One-Time Decisions
- Current Decisions Dependent on Future Conditions
- Uncertainties in Outcome of Mitigation Decisions
- Multiple, Potentially Conflicting, Objectives
  - Cost
  - Safety, Environmental
  - Reliability
- Limited Data on Failures

URS Greiner Woodward Clyde

Selection of Optimal Risk Mitigation Strategies

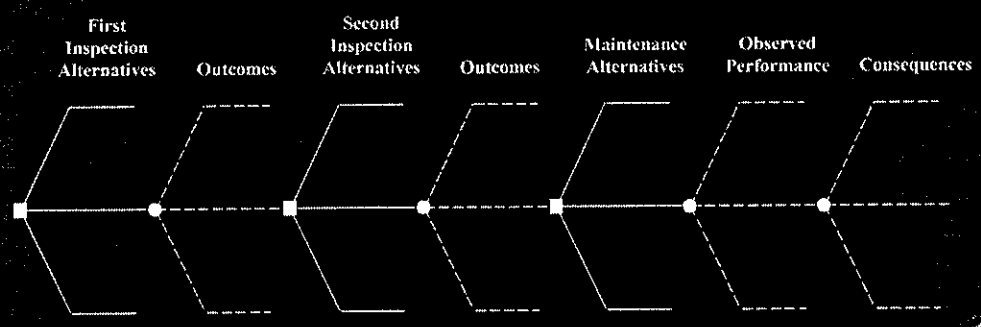
Methodology

- Use of Decision Trees Model
  - Effective for a Process of Interrelated Decisions
  - Explicit Definition of Decision Points and Possible Outcomes
  - Incorporates Uncertainty in Outcome

URS Greiner Woodward Clyde

Selection of Optimal Risk Mitigation Strategies

Decision Tree



URS Greiner Woodward Clyde

Selection of Optimal Risk Mitigation Strategies

Methodology

- Statistical Modeling of Pipe Defects
- Monetary Evaluation of All Impacts
  - Direct Costs
    (Inspection, Testing, Repair, Rehabilitation, ...)
  - Business Impact Costs
    (Loss of Revenue, Loss of Goodwill)
  - Risk Premiums for Incident Avoidance

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Selection of Optimal Risk Mitigation Strategies

Methodology

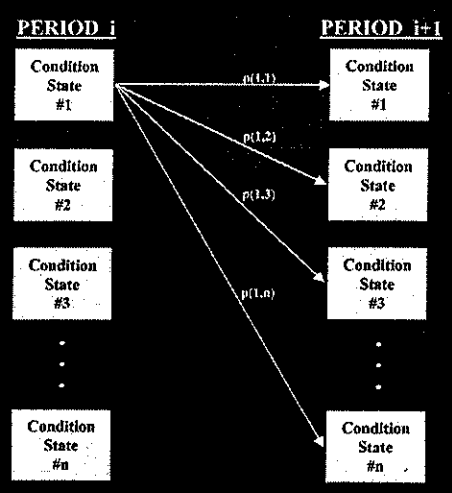
- Dynamic Programming to Analyze Decision Tree over Pipeline Lifetime to Find Least Life-Cycle Cost Strategy
- Identify Optimal Risk Mitigation Strategy based on Least Life-Cycle Cost
- Prioritize Projects Based on Benefit/Cost Ratio

URS Greiner Woodward Clyde

Selection of Optimal Risk Mitigation Strategies

DYNAMIC ANALYSIS

Define Transition Probabilities For Each Potential Action



Where

$$\sum p(1,i) = 1$$

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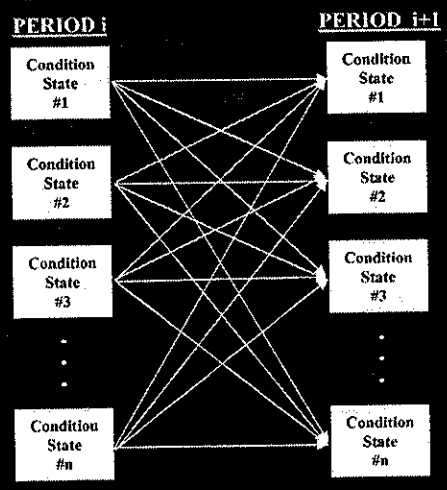
Selection of Optimal Risk Mitigation Strategies

DYNAMIC ANALYSIS



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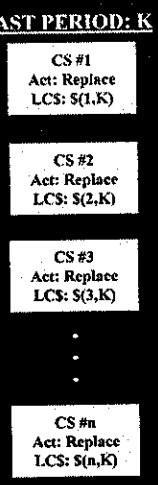
Selection of Optimal Risk Mitigation Strategies

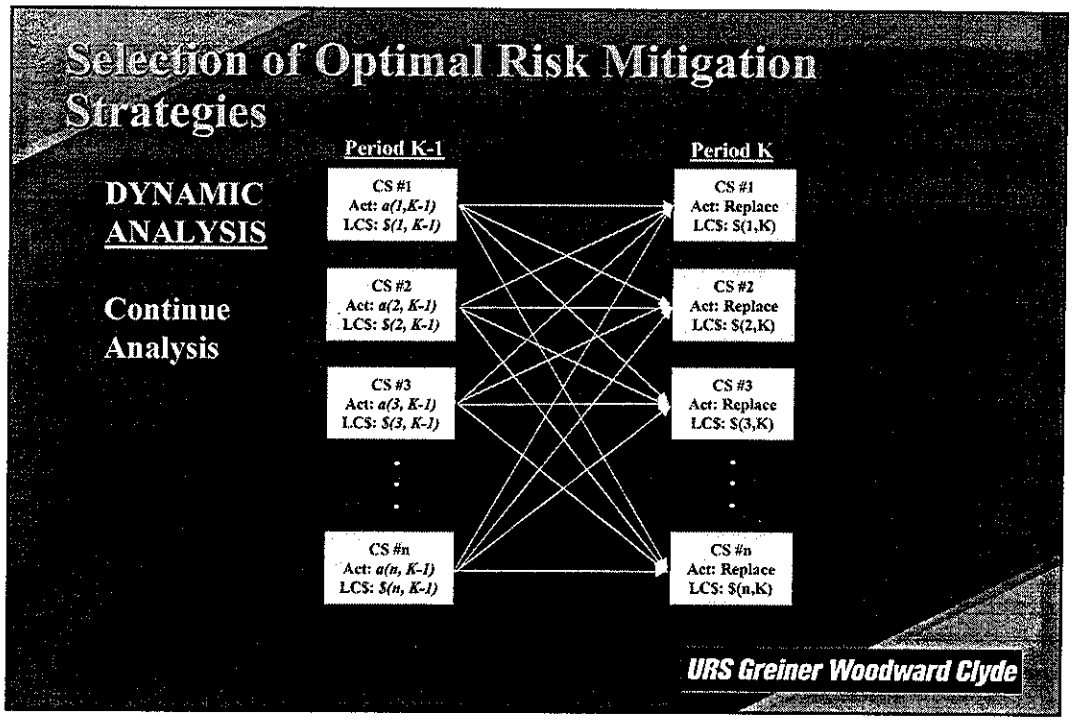
DYNAMIC ANALYSIS

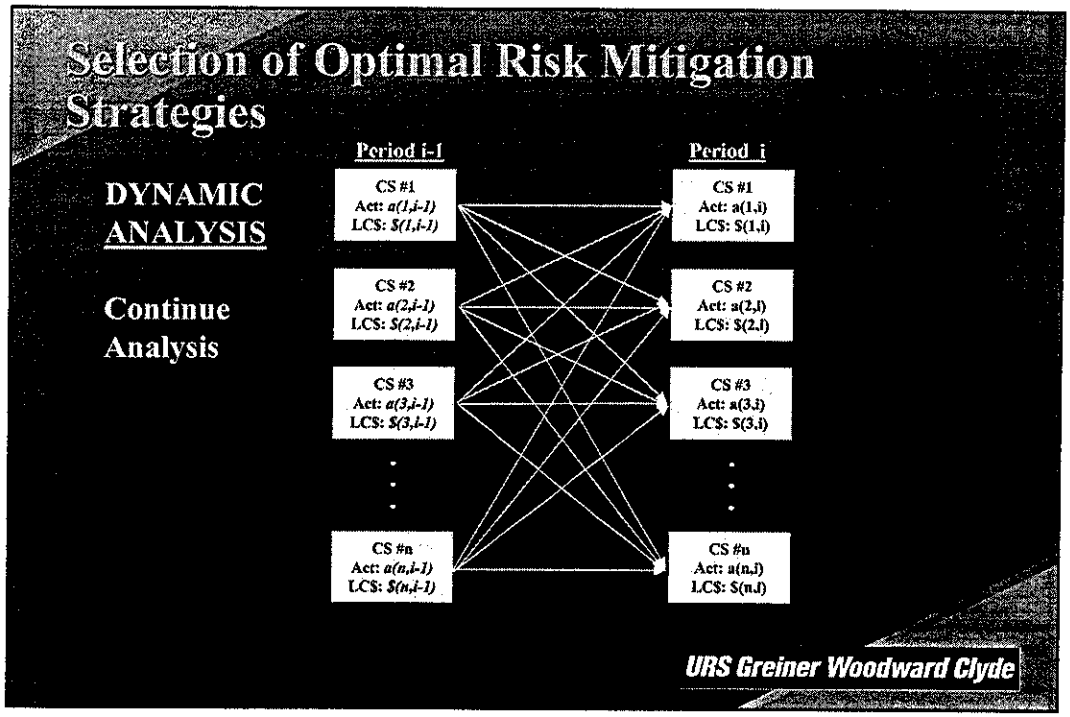
Define Boundary Condition

Start Analysis



URS Greiner Woodward Clyde


Selection of Optimal Risk Mitigation Strategies
DYNAMIC ANALYSIS
Continue Analysis
Period K-1
Period K
CS #1 Act: a(1,K-1) LCS: $(1, K-1)
CS #2 Act: a(2, K-1) LCS: $(2, K-1)
CS #3 Act: a(3, K-1) LCS: $(3, K-1)
CS #n Act: a(n, K-1) LCS: $(n, K-1)
CS #1 Act: Replace LCS: $(1,K)
CS #2 Act: Replace LCS: $(2,K)
CS #3 Act: Replace LCS: $(3,K)
CS #n Act: Replace LCS: $(n,K)
URS Greiner Woodward Clyde


Selection of Optimal Risk Mitigation Strategies
DYNAMIC ANALYSIS
Continue Analysis
Period i-1
Period i
CS #1 Act: a(1,i-1) LCS: $(1,i-1)
CS #2 Act: a(2,i-1) LCS: $(2,i-1)
CS #3 Act: a(3,i-1) LCS: $(3,i-1)
CS #n Act: a(n,i-1) LCS: $(n,i-1)
CS #1 Act: a(1,i) LCS: $(1,i)
CS #2 Act: a(2,i) LCS: $(2,i)
CS #3 Act: a(3,i) LCS: $(3,i)
CS #n Act: a(n,i) LCS: $(n,i)
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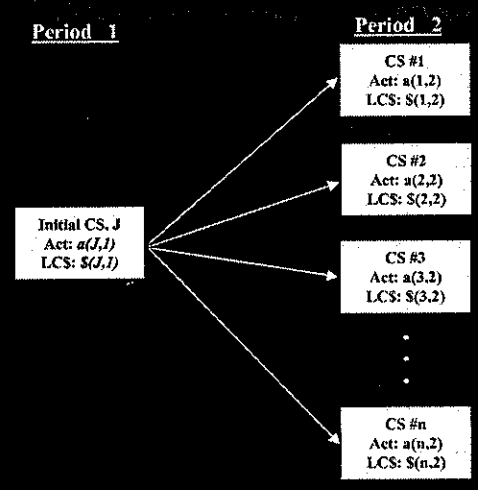
Selection of Optimal Risk Mitigation Strategies

DYNAMIC ANALYSIS

Conclude Analysis



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Selection of Optimal Risk Mitigation Strategies

Optimal Action Prioritization

Benefit = (Life Cycle Cost of Routine Maintenance) - (Life Cycle Cost of Optimal Action)

Cost = Action Implementation Cost

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Selection of Optimal Risk Mitigation Strategies

Illustrative Example

Pipeline Inspection and Maintenance Optimization System (PIMOS)

- ò Developed with Funding from Gas Research Institute
- ò Extensive Industry Participation
  - û Technical Advisory Group
  - û Data Provided
  - û Beta Testing
- ò Currently applying to 2 Chevron Pipelines

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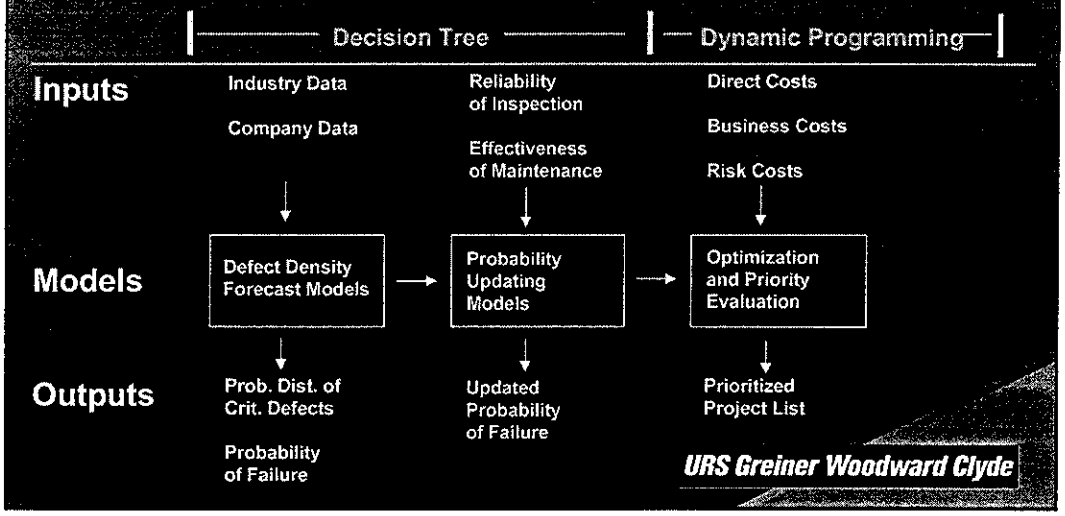
Selection of Optimal Risk Mitigation Strategies

PIMOS Flowchart



Selection of Optimal Risk Mitigation Strategies

Defect Types Analyzed in PIMOS

- External Corrosion
- Internal Corrosion
- Mechanical (Third Party) Damage
- Stress Corrosion Cracking
- Material/Construction Defects

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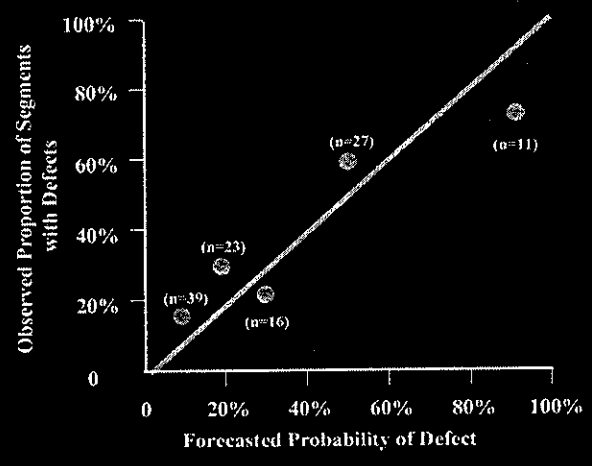
Selection of Optimal Risk Mitigation Strategies

DEFECT DENSITY FORECAST MODEL VALIDATION

External Corrosion



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Selection of Optimal Risk Mitigation Strategies

PIMOS Inputs

- Pipeline Segment Data
  - Inventory Characteristics
  - Operational Data
    - Inspection History
    - Maintenance History
    - Failure History
    - Operational Pressure History

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Selection of Optimal Risk Mitigation Strategies

PIMOS Inputs

- Cost Parameters
  - Direct Costs
  - Business Impact Costs
  - Incident Avoidance Premiums
- Model Parameters
  - Reliability of Inspection
  - Effectiveness of Maintenance

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Selection of Optimal Risk Mitigation Strategies

PIMOS Outputs

Tabular Reports

- Segment Susceptibility Scores
- Defect Predictions
- Segment Priorities
- Project Priorities
- Multi-Year Recommended Action List
- Life-cycle Cost

Forecasted Density of External Corrosion Defects

Segid	Length	Diam	Wall	Installed	Defects

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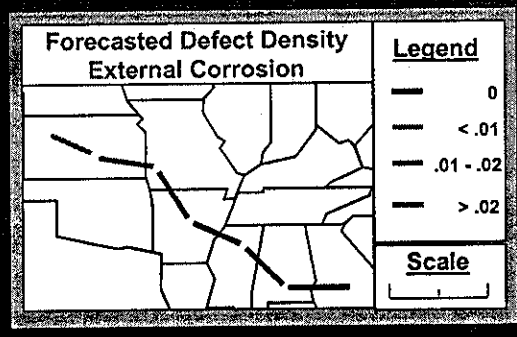
Selection of Optimal Risk Mitigation Strategies

PIMOS Outputs

Thematic Maps

- Diameter
- Installation Year
- Susceptibility Score
- Predicted Density of Defects
- Optimal Segment Action
- Recommended Project Action
- Expected Failures (Routine Maintenance)
- Expected Failures Avoided (Optimal Segment Action)



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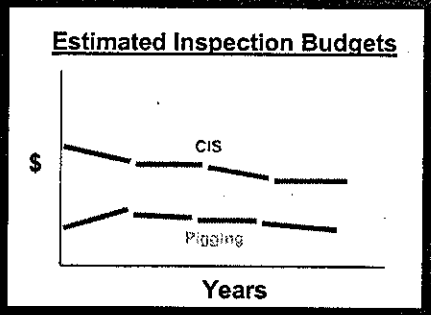
Selection of Optimal Risk Mitigation Strategies

PIMOS Outputs

Charts and Graphs

- Multi-Year Estimated Inspection Budgets
- Multi-Year Estimated Maintenance Budgets
- Multi-Year Expected Leaks
- Multi-Year Expected Ruptures
- Expected Performance by Total Proactive Budget
- Total Expected Life-Cycle Cost by Total Proactive Budget



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Selection of Optimal Risk Mitigation Strategies

In Conclusion

Successful Identification of Optimal Strategies

- Proper Modeling of Decision Process
- Forecast Pipeline Behavior under all strategies
- Deal with Uncertainties
- Consider Life-Cycle Costs incorporating:
  - Direct Costs
  - Business Impact Costs
  - Risk Costs

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12. Discussion Panel II: Risk Assessment and Modeling of Impacts

General Overview

There are several important questions that need to be answered at this point, which are: 1) How can we interpret the concept that a system has a failure probability of 10^{-5}? and 2) How can we translate certain failure events into a monetary value?

Dealing with the first question first, it becomes evident that standards are inherently necessary. This is true because in essence we want to be able to obtain the same probability of failure for pipelines in different geographical locations that are operating under the same conditions. This leads to the second question of how to convert the probability of failure into a dollar value, which is highly dependent upon the geographical location of the pipeline and the culture of the geographical area. In some cases the local government culture will set a failure probability limit that will be difficult to meet because of high costs, but at the same time it will be difficult to assess whether a company is meeting the criteria or not. This is true because most companies will employ a mixed method and it is difficult to compare quantitative and qualitative methods. Nonetheless, limits on the quantitative methods can be set, but set limits on the qualitative methods will be difficult to measure. Therefore requirements can be made as to what minimum procedures a certain company should follow, and then as incidents happen, the effectiveness of the risk management system can be assessed and recommendations made. The important concept to note at this juncture is that mixed systems must be carefully treated.

As was mentioned earlier, modeling the risk associated with a pipeline can be done through the method of decomposing the system into its individual components, but the impact of the actions performed are much harder to quantify. In order to correctly determine that an action performed had a direct consequence can be relatively tricky. In most cases, it will be apparent that upon the start of using inhibitors the corrosion rate slowed, but in other cases, like in the case of human organizational risk management the results will be less quantifiable. Therefore, the pilot studies will again help to assess the effectiveness of certain methodologies, which can be improved upon as the study progresses.

Analyzing the same problem in another way, human and organizational factors can also be evaluated by looking at the history of a pipeline before failure to assess whether management deliberately ignored certain facts when making decisions. For example, if the corrosion rate is high and in five years it is evident that the pipeline will have a serious corrosion problem, then management should start ordering the use of inhibitors. When the wall thickness of the pipe becomes small, the pipe fails, and the incident is logged as a corrosion failure. If this event occurs a certain amount of times in a given period, then it will be evident that someone is ignoring the signals. In another case, if the pipeline is piggable, flags can be raised when the wall thickness reaches about 40% that of the original, at which time the inspector can notify the operator.

It is also important to separate piggable and unpiggable pipelines because each have a different capability of being evaluated. Piggable pipelines can adopt the quantitative risk assessment methods much easier, as opposed to unpiggable pipelines, which tend to be harder to inspect.

At this point the various topics of concern for modeling impacts are outlined to help further the discussion. The major topics are:

1. Consistency in risk analysis for different pipelines
2. Evaluation of effectiveness of risk analysis / management system
3. Differences between piggable and unpiggable pipelines
4. Quantification of human error
5. Evaluation of cost associated with a certain type of failure and definition of failure types that have the largest effect on pipelines
6. Evaluation of the cost of a certain level of reliability

To tackle most of the topics listed above, it is recommended that a hierarchy of levels be constructed and different teams of individuals tackle each level. For example there would be one team for piggable pipelines and one for unpiggable pipelines and then each team would be divided once again into teams that analyze quantifiable and non-quantifiable areas related to the level above. In this way, a methodology for each major type of pipelines can be developed, which can then be used on that whole group. Still another solution can be to only develop methods for unpiggable pipelines at first, since these types of pipelines make up the majority of the pipeline population. Then as the technology becomes more advanced, the previous model can be improved upon. This in essence would be the same philosophy as is used when updating design codes for concrete design as new knowledge about concrete is obtained. The key however is to be aware of how the reliability model needs to change in the future, in order that it may accommodate change as it occurs.

Periodically the chosen teams would come together and present their work to their peers, who would then evaluate the progress and give positive feedback to each group. In this fashion all the components of the risk analysis system can be analyzed and improved upon. Once the work is done, the pilot programs would start up, and the developed systems would be evaluated. The key to the whole program will be effective leadership to guide the work of the various teams in the right direction. Therefore, before anything can happen, the right people must be chosen to part take in the program. The team however must be kept relatively small and should consist of individuals who are familiar with pipeline operations and at the same time reliability modeling. Individuals who have both skills will be the most effective at tackling the problems, because they have knowledge pertaining to both sides of the problem.

13. Quantification of Risks in Pipeline Reliability and Risk Assessment - I. R. Orisamolu & Yong S. Bai

One of the largest problems faced by the industry at this time is quantifying the risk associated with a specific pipeline. It is very important that the physics and mechanics of structures and systems not be compromised in such a manner that the results become distorted when compared to reality. It is true that many times the analysis of intricate systems utilize complex developments in material mechanics, but this should not alienate basic laws of physics which we know to be true. The more complex models are the greater is the chance of error, but at the same time if many checkpoints are used it is possible to establish very accurate results.

The author encourages the reader to be open to new ideas about looking at problems, like not necessarily measuring all consequences in the same units. Money is definitely one way to measure the impact of failure events, but at the same time consequences can also be measured in utils or some other type of unit. Finally however, the risk score of a pipeline is the combination of the likelihood of occurrence coupled with the consequence of that occurrence. To obtain a final total score however all units of consequence will need to have a common connection in order that they may be compared and combined. Therefore the bottom line is that the risk assessment has to be able to assist the decision maker in making practical decisions.

QUANTIFICATION OF RISKS IN PIPELINE RELIABILITY AND RISK ASSESSMENT

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MOTIVATION

- What is the Value of Human LIFE??
- Why Must We Measure Everything in $??

- Resolutions of Debates and Arguments on Answers to Above Questions

PREMISE

- Probabilistic Risk Assessment of Engineering Structures & Systems Must Be Based on Engineering Models
- Physics & Mechanics of Structures or Systems MUST Not Be Compromised
- Risk Is a Combination of Likelihood of Occurrence and Consequence
- Different Consequences Do Not Need to Be Measured in Same Units

RISK QUANTIFICATION - I

$$\text{Risk} = P_f * C_Q$$

$$\Downarrow$$

$$\text{Risk}(t) = P_f(t) * C_Q(t)$$

Risk is a Time-Dependent Quantity

RISK QUANTIFICATION - II

- Advocating a Risk Categorization Strategy That Permits Risk to Be Defined for Different Consequences:
  - Economic/Financial Loss (F)
  - Environmental Impact (E)
  - Loss of Corporate Prestige or Credibility (C)
  - Public Perception & Thrust (P)
  - Human Life (H)
- Why Do We Have to Measure Everything in $??

RISK QUANTIFICATION - III

- Vector Risk Model Proposed as Framework for Assessment:

$$\{Risk(t)\} = P_f(t) \times \{C_Q(t)\}$$

or

$$\{Risk(t)\} = P_f(t) \times \begin{Bmatrix} F(t) \\ E(t) \\ P(t) \\ C(t) \\ H(t) \\ \cdots \\ Q_n(t) \end{Bmatrix}$$

where n = Number of Consequences Considered

CONCLUSIONS

- Risk Categorization and Quantification Via Vector-Risk Approach Recommended as Framework for Accounting for Different Consequences

- Recommendation Should Aid the Application of Quantitative Risk Assessment in Practical Decision-Making

14. Discussion Panel III: Ways Forward

After evaluating the problems facing industry for implementing a risk assessment and management program, it is evident that certain key issues must be addressed. Before being able to even get the whole risk analysis and management project off the ground, certain key members of industry will need to be convinced that risk management is the right solution to today's problems. The following major topics have been outlined as originating points for further progress:

1. Projected economic benefit for risk management programs
2. Other industries are doing it at a benefit
3. Regulators are going to performance based systems
4. Safety and environmental excellence is needed for aging pipelines

After addressing the above topics and proving the cause for having risk assessment and management systems, a general approach must be drafted that includes the following topics:

1. Problem definition
2. Problem solving team formation
   - Key members of industry asked to solve problem
   - Key members breakdown problem into components
3. Evaluation of expectations
   - For each component of the problem, what is within reasonable limits
4. Guideline and methodology development
   - Development of practical risk assessment and management application for pipeline components
5. Pilot study
   - Test of developed guidelines, and evaluation of developments
6. Future planning and revaluation of existing progress
   - A reflection period to assess the effectiveness of the existing plan of action

The second issue on this list is the formation of a team that will address the problems at hand and come up with a solution that is beneficial for both the industry and the government. This step by far is the most crucial step in the whole process, because this team will be made up of the individuals who are going to be decomposing the problems and formulating solutions. Due to the fact that the problem of risk assessment and management is a very new topic for the pipeline industry, at this stage extreme caution must be exercised. All interested parties must be well represented, and the depth of talent that is available at the various companies must be utilized to its fullest. It is important that industry solves its own problem due to the fact that they know what they want and what their limits are.

15. Acknowledgement

This workshop was the result of the thought and work of a large number of people and organizations. The Editors would particularly like to acknowledge the support and contributions provided by Anne Doucet (Amoco Corporation), Sam Mishael (Chevron Research and Technology Company), Johannes Rosenmoller (H. Rosen Engineering), Charles Smith, Alex Alvarado, and Theresa Bell (Minerals Management Service). The workshop organizing committee would like to express their appreciation to Amoco Corporation for providing the workshop facilities and arrangements.