260AA

BANFF/97 PIPELINE WORKSHOP

Managing Pipeline Integrity - Planning for the Future

Workshop: April 16-18, 1997
Pre-Workshop Tutorials: April 15, 1997

Banff Centre for Conferences
Banff, Alberta, Canada

CAPP

CEPA

National Energy Board
CANADA

WORKSHOP PROCEEDING

OMAE Calgary Chapter

EUB
Alberta Energy and Utilities Board

IPL
Interprovincial Pipe Line Inc.

CAMPIPE

TransCanada

NOVA

IPSCO

Pipetronix

WILLIAMSON INDUSTRIES INC.

British Gas
Pipeline Integrity International

PanCanadian

Welland Pipe

CANMET

SUMMARY OF THE WORKSHOP AGENDA

Tuesday April 15		**Pre-Workshop Tutorials**
	8:30	The Essentials of SCC
	11:00	Critical Assessment of Cracks
	11:00	Land Use Planning Adjacent to Pipelines - An Overview
	13:45	Risk Management/Risk Assessment
Wednesday April 16	9:30	**Plenary Session**
	11:50	Lunch
	13:00	**Plenary Session**
	17:00	Adjournment for the Day
Thursday April 17	8:00	**Plenary Session**
	8:15	**Working Groups** - Session A
	10:30	**Working Groups** - Session B
	12:00	Lunch
	13:00	**Working Groups** - Session C
	15:30	**Working Groups** - Session D
	17:00	Adjournment for the Day
	18:30	**Reception**
Friday April 18	8:00	**Plenary Session**
	8:15	**Working Groups** - Session E
	9:20	**Plenary Session**
	12:25	Workshop Adjournment
	12:30	Lunch

SCHEDULE OF WORKING GROUPS ON THURSDAY, APRIL 17

Working Groups will meet at the times indicated with a ✓.

	8:15	10:30	13:00	15:30
Working Group #1: **New Technologies for Construction, Inspection, Repair & Rehabilitation**	✓	✓		
Working Group #2: **Stress-Corrosion Cracking**	✓	✓		
Working Group #4A: **Risk Assessment/Risk Management--General**	✓			
Working Group #4B: **Risk Management/Internal Corrosion--Producers**		✓	✓	
Working Group #4C: **Risk Assessment/Risk Management--Transmission**		✓	✓	
Working Group #4D: **Risk Assessment/Risk Management--Communications and Public Consultation**			✓	✓
Working Group #5: **Information Exchange and Networking**				✓
Working Group #6: **Land Use Planning/Encroachment**		✓		
Working Group #7: **External Corrosion**				✓
Working Group #8: **Abandonment**	✓			
Working Group #9: **In-Line Inspection**			✓	✓

PIPELINE LIFECYCLE REGISTRATIONS
Banff, Alberta
April 16 - 18, 1997

Attendee	Corporation	Address	Phone	Fax
Abes, Jake	National Energy Board	311 - 10 Ave SW, Calgary, AB T2P 3N2	403 299-2777	
Afaganis, Alex	Stelco Inc.	PO Box 2030, Hamilton, ON L8N 4E7	905 527-8335	905 308 7012
Aikens, A. Ernie	Fleet Technology	311 Legget Drive, Kenata, ON K2K 1Z8	613 592-2830	613 592-4950
Allen, Hugh	Northwestern Utilities Limited	10035 - 105 Street, Edmonton, AB T5J 2V6	403 420-7505	403 420-7364
Alvarado, Alexander	Minerals Management Service	1201 Elmwood Park Blvd., New Orleans, LA 70123-2394		
Anderson, Barry W.	BC Gas Utility Inc.	1975 Springfield Rd., Kelowna BC V1Y 7V7	250 868-4572	250 763-8912
Andersson, Roland	MIACC	600, 265 Carling Ave., Ottawa, ON K1S 2E1	613 232-4435	613 232-4915
Arulanandam, Sarah	University of Alberta (Mech Eng.)	4-9 Mech. Eng. Bldg., Edmonton, AB T6G 2G8	403 492-3598	403 492-2200
Ashworth, Blaine	TransCanada Pipelines	111 - 5th Avenue S.W., Calgary, AB T2P 3Y6	403 267-6397	403 267-6225
Atherton, David	Queen's University	Queens University, Kinston, Ontario K7L 3N6	613 545-2701	613 545-6463
Avallet, Michel	Gaz de France	367 Av. President Wilson 1BP 33, La Paine Saint Denis, France 93211	33 7 4922 5875	33 7 4922 5653
Bailey, William D.		1628 - 49 Ave. SW, Calgary, AB T2T 2T7	403 287-1245	403 287-1927
Baines, Fred	BC Gas Utility Inc.	16705 Fraser Highway, Surrey, BC V3X 2X7	604 576-7006	604 576-7105
Ball, Ken	Alberta Economic Development	13 Fl., 10155 - 102 St., Edmonton, AB T5J 4L6	403 427-6616	403 422-2091
Banks, Steve	Westcoast Energy Inc.	Bag Service 6180, Fort St. John, BC V1J 4H7	250 262-3480	250 262-3450
Batchelore, Errol	Westcoast Energy Inc.	3985 - 22 Ave., Prince George, BC V2N 1B7	250 960-2022	250 960-2002
Baxandall, Daryl	Neocorr Engineering Ltd.	1600, 736 - 6th Ave. SW, Calgary, AB T2P 3T7	403 531-4349	403 531-1927
Beavers, John A.	CC Technologies Laboratories Inc.	6141 Avery Road, Dublin, Ohio 43016-8761	614 761-1214	614 761-1633
Beck, John	Sure Seal Protection System Ltd.	5918 Roper Rd., Edmonton, AB T6B 3E1	403 466-3178	403 468-5904
Becker, Glenn	Champion Technologies Ltd.	830, 550 - 6th Ave SW, Calgary, AB T2P OS2	403 234-7881	403 264-3018
Belanger, Rory	Ludwig & Associates Engineering Ltd.	7925 Davies Rd., Edmonton, AB T6E 4N1	403 468-3030	403 468-3056
Bell, Arnold	Federated Pipelines	1600, 324 - 8th Ave. SW, Calgary, AB T2P 2Z5	403 232-7414	403 232-7075
Bell, Michael	Westcoast Energy Inc.	PO Box 1150, Hope, BC VOX 1LO	604 869-5550	604 869-5580
Benoit, Ken	Seagull Energy Canada Ltd.	PO Box 2870, Calgary, AB T2P 2M7	403 261-3630	403 261-5461
Bhatia, Arti	Interprovincial Pipeline Inc.	10201 Jasper Ave., Box 398, Edmonton, AB T5J 2J9	403 420-8438	403 420-8157
Billinton, Chris	BC Gas Utility Ltd.	1111 West Georgia St, Vancouver, BC V6E 4M4	604 443-6842	604 443-6850
Boivin, Joseph	Cormetrics Limited	56 Hawkwood Pl. NW, Calgary, AB T3G 1X6	403 258-2853	403 255-5171
Brien, Pierre	D'Aragon, Desbiens et Halde	555 Boulevard Rene Levesque O, Montreal, PQ H4J 1L8	514 398-0544	514 956-0568
Britten, David	IPSCO Inc.	PO Box 1670, Regina, SK S4P 3C7	306 924-7392	306 924-7380
Brown, Lonnie	Corrpro Canada Inc.	PO Box 241, Bowden, AB TOM OKO	403 224-3645	403 224-3645
Burke, Jim	NOVA Gas Transmission Ltd.	P.O. Box 2535, Station M, Calgary, AB T2P 2N6	403 290-7831	403 290-7227
Carlson, Lorne	Alliance Pipeline	400, 605 - 5th Ave. SW, Calgary, AB T2P 3H5	403 232-0303	403 266-4495
Carnes, Bob	University of Texas-Austin	Mail Code #R7000, Austin, TX 78712 USA	512 475-8860	512 232-1655
Carr, Keith	Morrison Petroleums Ltd.	Suite 3000, 400 3rd Avenue S.W., Calgary, AB T2X 3J2	403 750-3012	403 750-3236
Charest, Eileen	Centre for Eng. Research Inc. (C-FER)	200 Karl Clark R., Edmonton, AB T6N 1H2	403 450-3300	403 450-3700
Chen, Qishi	Centre for Eng. Research Inc. (C-FER)	200 Karl Clark Rd., Edmonton, AB T6N 1H2	403 450-4300	403 450-3700
Cheng, J.J. Roger	University of Alberta (Civil Eng.)	Edmonton, Alberta T6G 2G7	403 492-2992	403 492-0249
Chiasson, Wayne	Alberta Energy and Utilities Board	30 Sir Winston Churchill Ave., St. Albert, AB T8N 3A3	403 460-3821	403 460-3802
Chow, Geoff	Greenpipe Industries Ltd.	1600, 715 - 5th Ave., SW, Calgary, AB T2P 2X6	403 260-6738	403 260-6701
Christensen, Frank		846 Royal Dornach Drive, Qualicum Beach, BC V9K 2J9	250 752-1467	250 752-1457
Cicansky, Kevin	TransCanada Pipelines	P.O. Box 1000, Station M, Calgary, AB T2P 4K5	403 267-6312	403 267-6225
Clapham, Lynann	Queen's University	Queens University, Kinston, Ontario K7L 3N6	613 545-2701	613 545-6463
Clark, Doug	Gulf Canada Resources Limited	1680 102 Avenue, Edmonton, AB T6P 1V7	403 464-9111	403 467-5046

PIPELINE LIFECYCLE REGISTRATIONS
Banff, Alberta
April 16 - 18, 1997

Attendee	Corporation	Address	Phone	Fax
Coady, Sharon	National Energy Board	311 - 6th Ave. SW, Calgary, AB T2P 3H2	403 299-2793	403 292-5876
Collins, Laurie	IPSCO Inc.	PO Box 1670, Regina, SK S4P 3C7	306 924-7377	306 924-7424
Cook, Thomas J.	Pipetronix	50 A Caldari RD, Concord, Ontario L4K 4N8	905 541- 9818	905 335-9300
Cooper, Ron	Morrison Petroleums Ltd.	9908 - 107, Fort St. John, BC	250 785-6791	250 785-4005
Corbin, Patrick	Gaz de France	367 Av. President Wilson 1BP 33, La Paine Saint Denis, France 93211	33 7 4922 5875	33 7 4922 5653
Cox, Jamie	DuPont Canada Inc.	18 Shawner Cr. SW, Calgary, AB T2Y 1W3	403 254-6145	403 259-4129
Craft, Susan	CCCO Ltd.	318 Camelot Lane, Libertyville, IL 60048 USA	847 549-9133	847-549-0439
Craig, John R.	Pacific Northern Gas Ltd.	1400, 1185 W. Georgia, Vancouver, BC V6E 4E6	604 691-5857	604 691-5863
Cramm, John	Consumers Gas	PO Box 650, Scarborough, ON M1K 5E3	416 495-6444	416 495-5871
Cronin, Duane	University of Waterloo (Mech. Eng.)	200 University Ave., Waterloo, ON N2L 3G1	519 885-1211	519 888-6197
Currie, Don	Alberta Chamber of Resources	1410 Oxford Tower, 10235 - 101 St., Edmonton, AB T5J 3G1	403 420-1030	403 425-4623
Czyz, Jarek	BJ Pipeline Inspection Services	6920 - 36 St. SE, Calgary, AB T2C 2G4	403 531-5425	403 236-3476
Dakin, Nester	Suncor Inc. Resources Group	322 Kaska Rd., Sherwood Park, AB T8H 4G7	403 449-2608	403 467-6806
Danyluk, Len	Imperial Oil Resources Ltd.	Mail Box 1000, Swan Hills, AB TOG 2GO	403 333-7230	403 333-4100
DeGagne, Dave	Alberta Energy and Utilities Board	640 - 5th Ave SW, Calgary, AB T2P 3G4	403 297-3200	403 297-3520
Demoz, Alebachew	CANMET/Western Research Centre	#1 Oilpatch Drive, Devon, AB T9G 1A8	403 987-8607	403 987-8676
Desjardins, Guy	Morrison Scientific Inc.	815, 706 - 7th Ave. SW, Calgary, AB T2P OZ1	403 262-8160	403 264-3828
Dinkow, David	NOVA Gas Transmission Ltd.	P.O. Box 2535, Station M, Calgary, AB T2P 2N6	403 948-8149	403 948-8350
Dolbey, Mike	Ontario Hydro	800 Kipling Ave., Toronto, ON M8Z 5S4	416 207-6841	416 237-9285
Donini, John	CANMET/Western Research Centre	P.O. Bag 1280, Devon, Alberta TOC 1EO	403 987-8627	403 986-8676
Dowsett, Ian	Alberta Energy and Utilities Board	640 5 Avenue, Calgary AB T2P 3G4		
Dupois, Bruce	Foothills Pipe Lines Ltd.	3100, 707 - 8th Ave. SW, Calgary, AB T2P 3W8	403 294-4142	403 294-4175
Dye, Dale	Shaw Pipe Protection	1900, 144 - 4 Ave. SW, Calgary, AB T2P 3N4	403 218 8208	403 263-5587
Eiber, Bob	Robert J. Eiber Consultant Inc.	4062 Fairfax Dr., Columbus, Ohio 43220	614 538-0347	614 538-0347
English, D.C.	Amoco Canada Petroleum Co. Ltd.	240 - 4 Ave. S.W. P.O. Box 200, Stn M Calgary, AB T2P 2H8	403 233-1332	403 233-1195
Esak, Lynette	Can-Ag Enterprises Ltd.	10303 - 65 Avenue, Edmonton, AB T6H 1V1	403 434-0400	403 435-2908
Escobedo, Hugo	NOVA Gas International Ltd.	PO Box 2535, Stn M, Calgary, AB T2P 2N6	403 261-5295	403 290-6090
Etherington, Karen	NOVA Gas Transmission Ltd.	P.O. Box 2535, Station M, Calgary, AB T2P 2N6	403 290-7350	403 290-7227
Evans, P.M.	Pipetronix	50 A Caldari RD, Concord, Ontario L4K 4N8	905 738-7559	905 738-7561
Evoy, Fred	TransCanada Pipelines	P.O. Box 1000, Stn M, Calgary, AB T2N 0E4	403 267-6217	403 267-6225
Fawcett, Mark	SLRI Consultants Limited	314, 8616 - 51 Avenue, Edmonton, AB T6E 6E6	403 462-2434	403 462-8878
Feil, Wayne H.	Imperial Oil Resources Ltd.	237 4 Ave. S.W. P.O. Box 2480, Station M, Calgary,AB T2P 3M9	403 237-2470	403 237-3319
Fingerhut, Martin P.	RTD Quality Services	1431 - 70 Ave. Edmonton, AB T6P 1N5	403 440-6000	403 440-2538
Florence, Zack	Alberta Research Council	PO Bag 4000, Vegreville, AB T9C 1T4	403 632-8349	403 632-8379
Folder, Richard	US Dept. of Transportation (Pipeline Safet	Room 2335, 400-7th Ave. SW, Washington, DC 20590	202 366-4595	202 366-4566
Foroulis, Andy		33 Franklin Rd., Mendham, NJ 07945	201 543-2073	201 543-0320
Forster, Al	Williamson Industries Inc.	7731 - 16 Street, Edmonton, AB T6R 1M1	403 440-6637	403 440-1903
Fowlie, Bruce E.	Nu - Trac Management Consulting	16 Woodfield Road S.W. Calgary, AB T2W 4G7	403 251-0387	403 251-0387
Fraser, Ian	Imperial Oil Resources Ltd.	237 4 Ave. S.W. P.O. Box 2480, Station M, Calgary,AB T2P 3M9	403 237-2293	237-3319
Frost, Bernie	Alberta Energy and Utilities Board	Box 7048, Drayton Valley, AB T7A 1S3	403 542-5182	403 542-2540
Fukodo, Phil	Champion Technologies Ltd.	830, 550 - 6th Ave SW, Calgary, AB T2P OS2	403 237-7881	403 264-3018
Gerlitz, Lyle	JLG Engineering Ltd.	117 Edgebrook Rd. NW, Calgary, AB T3A 4N3	403 547-7136	403 547-7138
Gill, Kashmir	National Research Council Canada	Univ. of Alta, Mech. Eng. Bldg., Edmonton, AB T6G 2G8	403 492-0890	403 495-2174

Group	8:15 - 9:45	10:30 - 12:00	13:00 - 14:30	15:30 - 17:00
5: Information Exchange and Networking	Not Meeting	Not Meeting	Not Meeting	**PTAC: Concept and Activities** Eric Lloyd, PTAC **Internet** Grant Gordon, Objectworks **Networking among Pipeline Operators in Eastern Canada** Pierre Brien, D'Aragon, Desbiens et Halde (DDH) Ltée
6: Land Use Planning/ Encroachment	Not Meeting	**Perspectives of the Pipeline Industry, Regulators, and Planners** Dave English, Amoco; Dave DeGagne, AEUB; Allison Williams, County of Mountain View, Planning Department	Not Meeting	Not Meeting
7: External Corrosion	Not Meeting	Not Meeting	Not Meeting	**Scheduling Maintenance by Monitoring, Assessing, and Predicting External Corrosion: Pipeline Operators' Overview** Round Table Discussion of Current Status and Future Plans
8: Abandonment	**Ground Subsidence due to Pipeline Abandonment** Milos Stepanek, Geo-Engineering **Subsidence Issue from a Regulatory Perspective** Dennis Bratton, Alberta Environmental Protection **Liability of Abandoned Pipelines** Nick Schultz, CAPP	Not Meeting	Not meeting	Not Meeting
9: In-Line Inspection	Not Meeting	Not Meeting	**The Future of In-Line Inspection** Keith Grimes, BG Inspection Services, Inc. **Results of In-Line Inspection Using the UltraScan CD** Herbert Willems, Pipetronix GmbH	**EMAT-Based SCC Detection in Operating Pipelines** J.C. Hamilton, T.D. Williamson, Inc. **Speed Control Developments on the MFL Tool** Tom Sawyer, BJ Pipeline Inspection Services

Room Allocations for Working Groups

Group	Thursday				Friday
	8:15 - 9:45	10:30 - 12:00	13:00 - 14:30	15:30 - 17:00	8:15 - 9:15
1: New Technologies for Construction, Inspection, Repair & Rehabilitation	252	252	---	---	252
2: Stress-Corrosion Cracking	Max Bell Auditorium	Max Bell Auditorium	---	---	251
4A: Risk Assessment/ Risk Management: General	251	---	---	---	Max Bell Auditorium
4B: Risk Management/ Internal Corrosion: Producers	---	253	253	---	Max Bell Auditorium
4C: Risk Assessment/ Risk Management: Transmission	---	251	Max Bell Auditorium	---	Max Bell Auditorium
4D: Risk Assessment/ Risk Management: Communications and Public Consultation	---	---	251	251	Max Bell Auditorium
5: Information Exchange and Networking	---	---	---	150	Max Bell Foyer
6: Land Use Planning/ Encroachment	---	150	---	---	Max Bell Foyer
7: External Corrosion	---	---	---	Max Bell Auditorium	150
8: Abandonment	161	---	---	---	161
9: In-Line Inspection	---	---	252	252	253

Working Group Co-Chairs:

Working Group #1: **New Technologies for Construction, Inspection, Repair and Rehabilitation**
Co-Chairs: Reynold Hinger, Trans Mountain Pipe Line Company Ltd.
Paul Wong, NOVA Gas Transmission Ltd.

Working Group #2: **Stress-Corrosion Cracking**
Co-Chairs: Walter Kresic, Interprovincial Pipe Line Inc.
Martyn Wilmott, NOVA Research & Technology Corp.

Working Group #4A: **Risk Assessment/Risk Management -- General**
Co-Chairs: Ian Dowsett, Alberta Energy and Utilities Board
David Wilson, University of Alberta

Working Group #4B: **Risk Management/Internal Corrosion -- Producers**
Co-Chairs: Dave Kopperson, PanCanadian Petroleum Limited
Karol Szklarz, Shell Canada Limited

Working Group #4C: **Risk Assessment/Risk Management -- Transmission**
Co-Chairs: Blaine Ashworth, TransCanada PipeLines
Brian Griffin, Bercha Associates

Working Group #4D: **Risk Assessment/Risk Management -- Communications and Public Consultation**
Co-Chairs: Roland Andersson, Major Industrial Accidents Council of Canada (MIACC)
Brian Plesuk, Gulf Canada Resources Ltd.

Working Group #5: **Information Exchange and Networking**
Co-Chairs: Ken Ball, Alberta Economic Development and Tourism
Pierre Brien, D'Aragon, Desbiens et Halde (DDH) Ltée
John Donini, CANMET/Western Research Centre

Working Group #6: **Land Use Planning/Encroachment**
Co-Chairs: Dave English, Amoco Canada Petroleum Co. Ltd.
Joanne Nutter, Imperial Oil Resources Limited

Working Group #7: **External Corrosion**
Co-Chairs: Susan Miller, Interprovincial Pipe Line Inc.
Bob Worthingham, NOVA Gas Transmission Ltd.

Working Group #8: **Abandonment**
Co-Chairs: Karen Etherington, NOVA Gas Transmission Ltd.
Ron McKay, Novagas Clearinghouse Ltd.

Working Group #9: **In-Line Inspection**
Co-Chairs: Wayne Feil, Imperial Oil Limited
Terry Klatt, Foothills Pipe Lines Ltd.

Schedule of Working Groups on Thursday, April 17, 1997

Group	8:15 - 9:45	10:30 - 12:00	13:00 - 14:30	15:30 - 17:00
1: New Technologies for Construction, Inspection, Repair & Rehabilitation	**Epoxy Sleeves** David Harper, Greg Toth, Trans Mountain Pipe Line	**Composite Sleeves** Phillip Nidd, AEC Pipelines	Not Meeting	Not Meeting
2: Stress-Corrosion Cracking	**In-Line Inspection for SCC Management**, Susan Miller, Interprovincial Pipe Line Inc., and Ravi Krishnamurthy, Mobil Oil Canada	**Development of SCC Management Protocols** Bob Sutherby, NOVA Gas Transmission	Not Meeting	Not Meeting
4A: Risk Assessment/ Risk Management: General	**Overview of Pipeline Workshops** John McCarthy, NEB **Integrated Risk Management, Risk Control Tools, Issues, Acceptability of Risk, Uncertainty in Risk Decisions** Ian Dowsett, AEUB David Wilson, U. of A. **Risk Analysis Techniques** Michael Zelinsky, Bovar Environmental	Not Meeting	Not Meeting	Not Meeting
4B: Risk Management/ Internal Corrosion: Producers	Not Meeting	**Acceptable Performance: Risk Matrix for Production Pipelines -- Probability & Impact** Dave Kopperson, PanCanadian Petroleum **Reliability of Existing Models for Predicting the Probability of Internal Corrosion** Dave Kopperson, PanCanadian Petroleum **Predicting Pitting Corrosion of High Water Cut Pipelines** Sankara Papavinasam and John Donini, CANMET	**Mitigation of Internal Corrosion: Design & Performance of Corrosion Inhibition Programs for Multiphase Pipelines** Baker Performance Chemicals, Champion Technologies, Energy Chemicals	Not Meeting
4C: Risk Assessment/ Risk Management: Transmission	Not Meeting	**Risk Assessment:** **SCC Report: Overview of Risk Assessment Issues** **Draft CSA Z662 RA Appendix** **Incident Databases (PRASC, SCC, ISAT)** **Future directions for RA**	**Risk Management: Incident response case histories, risk management issues**	Not Meeting
4D: Risk Assessment/ Risk Management: Communications and Public Con ation	Not Meeting	Not Meeting	**Background, Resources/ Tools; CAPP Guidelines** **Case Study: Upstream** **Submission** Recommendations	**Background, Resources/ Tools; MIACC Guidelines** **Case Study: Downstream** **Submission** Recommendations

__Thursday, April 17, 1997__

8:00 **Plenary Session -- Max Bell Auditorium**

8:15 __**Working Groups: Session A**__

Working Group #1: **New Technologies for Construction, Inspection, Repair and Rehabilitation**
Working Group #2: **Stress-Corrosion Cracking**
Working Group #4A: **Risk Assessment/Risk Management -- General**
Working Group #8: **Abandonment**

9:45 Break/Individual Contact Meetings

10:30 __**Working Groups: Session B**__

Working Group #1: **New Technologies for Construction, Inspection, Repair and Rehabilitation**
Working Group #2: **Stress-Corrosion Cracking**
Working Group #4B: **Risk Management/Internal Corrosion -- Producers**
Working Group #4C: **Risk Assessment/Risk Management -- Transmission**
Working Group #6: **Land Use Planning/Encroachment**

12:00 Lunch

13:00 __**Working Groups - Session C**__

Working Group #4B: **Risk Management/Internal Corrosion -- Producers**
Working Group #4C: **Risk Assessment/Risk Management -- Transmission**
Working Group #4D: **Risk Assessment/Risk Management -- Communications and Public Consultation**
Working Group #9: **In-Line Inspection**

14:30 Break/Individual Contact Meetings

15:30 __**Working Groups - Session D**__

Working Group #4D: **Risk Assessment/Risk Management -- Communications and Public Consultation**
Working Group #5: **Information Exchange and Networking**
Working Group #7: **External Corrosion**
Working Group #9: **In-Line Inspection**

17:00 Adjournment for the Day

18:30 **Reception**, Max Bell Foyer

__Friday, April 18, 1997__

8:00 **Plenary Session -- Max Bell Auditorium**

8:15 **__Working Groups: Session E__**

Working Group #1: **New Technologies for Construction, Inspection, Repair and Rehabilitation: Buoyancy Control in Muskeg Terrain**
Gord Simmonds, NOVA Gas Transmission Ltd.

Working Group #2: **Stress-Corrosion Cracking**

Working Group #4: **Risk Assessment/Risk Management**

Working Group #5: **Information Exchange and Networking**

Working Group #6: **Land Use Planning/Encroachment**

Working Group #7: **External Corrosion**

Working Group #8: **Abandonment**

Working Group #9: **In-Line Inspection**

__Plenary Session__ -- Max Bell Auditorium

9:20 Working Group #1: Co-Chairs' Report and Discussion

9:35 Working Group #2: Co-Chairs' Report and Discussion

9:50 Working Group #4: Co-Chairs' Report and Discussion

10:30 Break/Individual Contact Meetings

11:00 Working Group #5: Co-Chairs' Report and Discussion

11:15 Working Group #6: Co-Chairs' Report and Discussion

11:30 Working Group #7: Co-Chairs' Report and Discussion

11:45 Working Group #8: Co-Chairs' Report and Discussion

12:00 Working Group #9: Co-Chairs' Report and Discussion

12:15 Workshop Wrap-Up, Distribution of Proceedings

12:25 Workshop Adjournment

12:30 Lunch

PIPELINE LIFECYCLE REGISTRATIONS
Banff, Alberta
April 16 - 18, 1997

Attendee	Corporation	Address	Phone	Fax
Girgis, Omnia	Centre for Eng. Research Inc. (C-FER)	200 Karl Clark Rd., Edmonton, AB T6N 1H2	403 450-3300	403 450-3700
Goeres, Wally	Alta. Econ. Develop. & Tourism	5th Fl. Commerce Pl., 10155-102 St. Edm., AB T5J 4L6	403 422-0957	403 427-5924
Goodfellow, Ray	Chevron Canada Resources	500 - 5th Ave. SW, Calgary, AB T2P OL7	403 234-5425	403 234-5223
Gray, Bruce	Novagas Clearinghouse Ltd.	707 - Eighth Ave. SW, Calgary, AB T2P 3V3	403 781-3190	403 781-3188
Gray, Delton	Northwestern Utilities Limited	10035 - 105 Street, Edmonton, AB T5J 2V6	403 420-7485	403 420-7364
Gray, Linda	Alberta Research Council	PO Box 8330, Edmonton, AB T6H 5X2	403 450-5457	403 450-5477
Greco, Paul	Union Gas Limited	PO Box 2001, 50 Reil Drive North, Chatham, ON	519 3542-3100	519 436-4655
Griffin, Jim	TransCanada PipeLines	111 - Fifth Ave. SW, PO Box 1000, Stn M, Calgary, AB T2P 4K5	403 267-6237	403 267-1029
Grimes, Keith	BG Inspection Services, Inc.	7105 Business Park Drive, Houston, TX 77041	713 849-6300	713 937-0740
Grissberbdt, Don	Amoco Canada Petroleum Co. Ltd.	PO Box 200, Stn. M, Calgary, AB T2P 2H8	403 233-1313	403 233-1195
Grondin, Gilbert	University of Alberta (Civil & Env. Eng.)	Edmonton, Alberta T6G 2G7	403 492-2794	403 492-0249
Haines, Harvey	Gas Research Institute	8600 W Bryn Mawr Avenue, Chicago Il 60631	773 399-8223	773 399-8326
Hannesen, Doug	Consumers Gas Company Ltd.	PO Box 650, Scarborough, ON M1K 5E3	416 594-5721	416 495-5871
Harland, Syd	Ontario Hydro	800 Kipling Ave., Toronto, ON M8Z 5S4	416 207-6430	416 237-9285
Harms, Art	Canadian Western Natural Gas Co.	909 11 Ave. S.W., Calgary, AB T2R 1L8	403 245-7314	403 245-7698
Harper, David	Trans Mountain Pipe Line Co. Ltd.	2355 W. Trans Canada Hwy, Kamloops, BC V1S 1A7	250 371-4030	250 371-4001
Harris, Bruce	Pembina Corporation	707 - 8th Ave. S.W. P.O. Box 1948 Calgary, AB T2P 2M7	403 231-7426	403 231-1177
Harrison, Terry	Canadian Western Natural Gas Co.	3055 - 37 Ave. NE, Calgary, AB T1Y 6A2	403 291-1288	403 250-6790
Hederman, William	IEA Internat. Centre for Gas Tech. Inform.	Suite 730N, 1131 Pennsylvania Ave. NW, Washington, DC	202 662-8991	202 393-6092
Hejian, Sun	CANMET Western Research Centre	One Oil Patch Drive, Devon, AB T9G 1A8	403 987-8609	403 987-8676
Hendershot, John	National Energy Board	311 - 6th Ave. SW, Calgary, AB T2P 3H2	403 299 2778	403 292-5503
Hill, Doug	Petro-Canada Oil & Gas	P.O. Box 134 Burstall, Saskatchewan S0N 0H0	403 838-8345	403 838 - 3969
Hill, Greg	Trans Mountain Pipe Line Co. Ltd.	Box 3198, Sherwood Park, AB T8A 2A6	403 449-5913	403 449-5901
Hill, Robert A.	Canadian Energy Pipeline Association	801 - 6th Ave. SW, Calgary, AB T2P 3W2	403 221-8777	403 221-8760
Hoffman, Catherine		5031 Corbina Way, Oxford, California 93035	805 389-7575	805 389-7592
Holdsworth, Rodger D.	Primatech	503 Patterson St., Suite #2, New Orleans, LA 70114	504 362-0099	504 362-9099
Hope, Jim	Canusa Div. of Shaw Industries	1900, 144 - 4th Ave. SW, Calgary, AB T2P 3N4	403 218-8207	403 264-3649
Horner, Jim	Trans Mountain Pipe Line Co. Ltd.	7815 Shellmont St., Burnaby, BC V5A 4S9	604 268-3000	604 268-3001
Huddlesteon, Paul	Trans Mountain Pipe Line Co. Ltd.	7815 Shellmont St., Burnaby, BC V5A 4S9	604 268-3011	604 268-3001
Ireland, Yvonna	TransCanada PipeLines	111 - Fifth Ave. SW, PO Box 1000, Stn. M, Calgary, AB T2P 4K5	403 267-4879	403 267-1029
Isliafson, Lyndon	Test Labs International Ltd.	276, 167 Lombard Ave., Winnipeg, MN R3G OT6	204 942-4424	204 943-9872
James, Norman E.	Alberta Energy and Utilities Board	640 5 Avenue SW, Calgary AB T2P 3G4	403 297-3538	403 297-3520
Jarvis, William	Williamson Industries Inc.	102 Armstrong Ave., Georgetown, ON L7G 4S2	905 873-2272	905 877-0362
Jeglic, Franci	National Energy Board	311 6th Avenue S.W. Calgary, AB T2P 3H2	403 299-2774	403 292-5876
Johanson, Gord	Canadian Western Natural Gas Co.	1052 - 10th St. SW, Calgary, AB T2R OG3	403 245-7574	403 245-7376
Johnson, Bert	Gulf Canada Resources Limited	Box 130, Calgary, AB T2P 2H7	403 233-3217	403 233-5522
Justice, Jim	Maritimes & Northeast Pipeline Proj.	190 Maplewood Road, Missisauga, Ont. L5G 2M6	905 274-3093	905 274-1486
Kacicnik, Anton	Consumers Gas Company Ltd.	PO Box 650, Scarborough, ON M1K 5E3	403 496-7130	403 496-7148
Kania, Richard	RTD Quality Services	1431 - 70 Ave. Edmonton, AB T6P 1N5	403 440-6000	403 440-2538
Karpiel, Ed	Sun-Canadian Pipeline Company Limited			
Kehoe, Grant	Travis Chemicals Ltd.	19th Floor 777 - 8 Avenue S.W. Calgary,AB T2P 3R5	403 263 8660	403 233-7011
Keith, Kyle	Foothills Pipe Lines Ltd.	3100, 707 - 8th Ave. SW, Calgary, AB T2P 3W8	403 294-4446	403 294-4175
King, Graeme	Greenpipe Industries Ltd.	1600, 715 - 5th Ave., SW, Calgary, AB T2P 2X6	403 260-6714	403 260-6701

PIPELINE LIFECYCLE REGISTRATIONS
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Attendee	Corporation	Address	Phone	Fax
Kirkland, Lisa-Henri	University of Calgary/Golder Associates	19 Roselawn Cr NW, Calgary, AB T2K 1K7	403 216 2202	403 299-5606
Klatt, Terry	Foothills Pipe Lines Ltd.	3100, 707 - 8th Ave. SW, Calgary, AB T2P 3W8	403 294-4137	403 294-4175
Kliciak, Bob	Husky Oil Operations	Box 6525, Stn. D, Calgary, AB T5K 1H2	403 298-7078	403 298-6410
Kohut, George B.	Chevron Research & Technology Compan	P.O. Box 1627, Richmond, CA 94802	510 242-3245	510 242-4614
Kopperson, David	PanCanadian Petroleum Ltd.	PO Box 2850, 125 - 9th Ave. SW, Calgary, AB T2P 2S5	403 268-6647	403 268-6616
Kresic, Walter	Interprovincial Pipeline Inc.	10201 Jasper Ave., Box 398, Edmonton, AB T5J 2J9	403 420-8270	403 420-8157
Krishnamurthy, Ravi	Mobil Oil Canada	PO Box 100, Calgary, AB T2P 2J7	403 260-7117	403 260-4172
Kusen, Steven	Canadian Western Natural Gas Co.	909 11 Ave. S.W., Calgary, AB T2R 1L8	403 255-8852	403 255-8830
Kutzak, Robert A.	Wascana Energy Inc.	2500, 205 - 5th Avenue S.W., Calgary, AB T2P 2V7	403 260-6427	403 260-6442
Lai, Larry	NOVA Corporation	200, 6711 Mississauga R., Mississauga. ON L5N 2W3	403 542-6974	403 542-8075
Lamy, Denise	Alberta Research Council	PO Box 8330, Edmonton, AB T6H 5X2	403 450-5406	403 450-5477
Langen, Dennis	Interprovincial Pipeline Inc.	10201 Jasper Ave., Box 398, Edmonton, AB T5J 2J9	403 420-8765	403 420-8157
Lawson, V.B.	Westcoast Energy Inc.	1333 W. Georgia St., Vancouver B.C. V6E 3K9	604 691 5662	604 691 5887
Lee, Shu C.	Alberta Energy and Utilities Board	640 5 Avenue SW, Calgary AB T2P 3G4	403 297-8148	403 297-4117
Leewis, Keith	Gas Research Institute	8600 W Bryn Mawr Avenue, Chicago Il 60631	773 399-8112	773 399-8326
Lessard, Robert	Welland Pipe Ltd.	Box 99, Welland, Ontario L3B 5P2	905 735-8338	905 735-4387
Lillo, Harry O	Alberta Energy and Utilities Board	640 5 Avenue SW, Calgary AB T2P 3G4	403 297-3721	403 297-3520
Lloyd, Eric	PTAC Petroleum Technology Alliance Ca	801 - 6th Ave SW, Calgary, AB T2P 3W2	403 297-4384	403 297-8954
Lopez de Sheikh, Aida	Pembina Corporation	707 - 8th Ave. SW, P.O. Box 1948, Calgary, AB T2P 2M7	403 231-7449	403 266-1177
Maas, Ronald B.	Westcoast Energy Inc.	3985 - 22 Ave., Prince George, BC V2N 1B7	250 960-2011	250 960-2028
MacFarlane, Trevor	TransCanada PipeLines	111 - Fifth Ave. SW, PO Box 1000, Stn. M, Calgary, AB T2P 4K5	403 267-8930	403 267-1029
Maccagno, Terry	University of Alberta (Chem. & Materials	Edmonton, Alberta T6G 2G6	403 492-8628	403 492-2881
Maccagno, Terry	University of Alberta (Chem. & Mat. Eng.)	Edmonton, Alberta T6G 2G6	403 492-8628	403 492-2881
Macdonald, Doug	Kilborn Western Inc.	Suite 700, 205 Ninth Ave. SW, Calgary, AB T2G OR3	403 221-9388	403 221-0434
Mackintosh, Dr. E	ESG Inc.	361 Southgate Dr., Guelph, ON N1G 3M5	519 836-6050	519 836-2493
Mah-Paulson, May	O'Connor Associates Envir. Grp.	1000, 639 - 5 Ave. S.W. Calgary, AB T2P 0M9	403 294-4256	403 294-4240
Mao, Scott	University of Calgary (Mech. Eng.)	2500 Univ. Dr. NW, Calgary, AB T2N 1N4	403 220-7185	403 282-8406
Marreck, Peter	Rainbow Pipe Line Company Limited	330 Fifth Ave. SW, Calgary, AB T2G OR3	403 260-7313	403 260-4332
Mason, Patrick	Westcoast Energy Inc.	Box 90, Taylor, B.C. VOC 2HO	250 789-9514	250 789-9532
Masters, Andrew	Petrolite Canada Inc.	1406 - 8th St., Nisku, AB T9E 7M1	403 955-2222	403 955-7858
Maurier, Ron	Corpro Canada Inc.	10848 - 214 St, Edmonton, AB T5S 2A7	403 482-6919	403 447-1643
Maxwell, Larry	Alberta Energy and Utilities Board	30 Sir Winston Churchill Ave., St. Albert, AB T8N 3A3	403 460-3805	403 460-3802
Mayer, Ralph	Maritimes & Northeast Pipeline Proj.	PO Box 2001, 50 Keil Dr. N, Chatham, ON N7M 5M1	519 352-3100	519 436-4566
McCarthy, John	National Energy Board	311 - Sixth Ave. SW, Calgary, AB T2P 3H2	403 299-2788	403 292-5876
McClarty, Ed	Westcoast Energy Inc.	Bag Service 6180, Fort St. John, BC V1J 4H7	250 262-3463	250 262-3410
McDonald, Sandra J.	Canadian Western Natural Gas Co.	909 11 Ave. S.W., Calgary, AB T2R 1L8	403 245-7621	403 245-7698
McKay, Ron	Novagas Clearinghouse	707 - Eighth Ave. SW, Calgary, AB T2P 3V3	403 781-3218	403 781-3188
McMillan, Bain	Canadian Western Natural Gas Co.	909 11 Ave. S.W., Calgary, AB T2R 1L8	403 245-7495	403 245-7405
Meanwell, Paul	Union Gas Limited	PO Box 2000, 50 Keil Drive, Chatham, ON N7M 5M1	519 436-4604	519 436-5210
Melvin, Milu (Budd)	Travis Chemicals Ltd.	19th Floor 777 - 8 Avenue S.W. Calgary,AB T2P 3R5	403 263-8660	403 263-7011
Michailides, Phil	BJ Pipeline Inspection Services	6920 - 36 St. SE, Calgary, AB T2C 2G4	403 531-5171	403 236-8740
Miller, Gordon	Alberta Energy and Utilities Board	11th Fl., 10055 - 106 St., Edmonton, AB T5J 2Y2	403 472-4901	403 427-6970
Miller, Susan	Interprovincial Pipeline Inc.	10201 Jasper Ave., Box 398, Edmonton, AB T5J 2J9	403 420-8182	403 420-8157

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Attendee	Corporation	Address	Phone	Fax
Minchin, Robert	National Energy Board	311 - 6th Ave. SW, Calgary, AB T2P 3H2	403 299-2784	403 299-5876
Mitchell, Bruce	Shell Canada Limited	PO Box 100, Stn. M, Calgary, AB T2P 2H5	403 691-2689	403 266-6240
Mitchell, Jim	Camrose Pipe	PO Box 1810, Camrose, AB T4V 1X7	403 672-3116	403 679-0690
Mitskopaulos, Chris	Ucisco Canada Inc.	9020 - 24 St., Edmonton, AB T6P 1X8	403 467-9000	403 467-9009
Mohitpour, M.	NOVA Gas International	P.O. Box 2535, Station M, Calgary, AB T2P 2N6	403 261-5280	403 290-6090
Morrison, Tom	Morrison Scientific Inc.	815, 706 - 7th Ave. SW, Calgary, AB T2P OZ1	403 262-8160	403 262-3828
Morrissey, Richard	Northwestern Utilities Limited	10035 - 105 Street, Edmonton, AB T5J 2V6	403 240-5473	403 420-7364
Mowers, Janet	Oil & Gas Inquirer	9915 - 56 Avenue NW, Calgary, AB T6E 5L7	403 944-9333	403 944-9500
Moynidan, Ron	Kilborn Western Inc.	301 - 105 Ninth Ave. SE, Calgary, AB T2G OR3	403 221-9388	403 221-8758
Mukherjee, B.	Ontario Hydro - Tech. Services	800 Kipling Ave., Toronto, ON M8Z 5S4	416 207-6372	416 233-4131
Mulligan, Jean	William Leiss & Associates Ltd.	2421 - 14 St. SW, Calgary, AB T2T 3T7	403 228-9925	403 228-9925
Murray, David W.	University of Alberta (Civil Engineering)	Edmonton, Alberta T6G 2G7	403 492-5117	403 492-0249
Nibber, Norman	Alexander & Alexander	2700 One Palliser Square, Calgary, AB T2G OP9	403 267-7010	403 261-0897
Nichols, Steven	Univ of Texas - Ctre. for Electromech.	Mail Code R7000, Austin, TX	512 232-1628	512 475-7700
Nidd, Phillip	AEC Pipelines	P.O. Box 3319 Sherwood Park, AB	403 449-2219	403 449-2275
Nikiforuk, Larry	SLRI Consultants Limited	314, 8616 - 51 Avenue, Edmonton, AB T6E 6E6	403 462-2434	403 462-8878
Nordquist, Greg	NOVA Gas Transmission Ltd.	P.O. Box 2535, Station M, Calgary, AB T2P 2N6	403 261-8316	403 290-5952
Norris, John	TransCanada PipeLines	111 - Fifth Ave. SW, PO Box 1000, Stn. M, Calgary, AB T2P 4K5	403 267-8912	403 267-1029
Nutter, Joanne P.	Imperial Oil Resources Ltd.	237 4 Ave. S.W. P.O. Box 2480, Station M, Calgary,AB T2P 3M9	403 237-2429	403 237-2013
O'Hara, Randy	IPSCO Inc.	PO Box 1670, Regina, SK S4P 3C7	306 924-7384	306 924-7470
Orisamolu, Wally	Martec Limited	400, 1888 Brunswick St., Halifax, NS B3J 3J8	902 425-5101	902 421-1923
Ostby, Magne	CorrOcean Inc.	7700 San Felipe, Suite 360, Houston, TX 77063	713 266-0941	713 266-0172
Ottem, Mark L.	Trans Mountain Pipe Line Co. Ltd.	#900 - 1333 West Broadway, Vancouver BC V6H 4O2	604 739-5262	604 739-5003
Owen, Rob	BC Gas Utility Ltd.	1111 West Georgia St, Vancouver, BC V6E 4M4	604 443-6810	604 443-6850
Palm, Ismo	Amoco Canada Petroleum Co. Ltd.	Box 200 Calgary, AB T2P 2H8	403 233-6326	403 233-1195
Papavinasam, Sankara	CANMET/ Materials Technology Lab	568 Booth St., Ottawa, ON K1A OG1	613 947-3603	613 992-8735
Parab, Sudhir	Petro-Canada Oil & Gas	PO Box 2844, 21PCCW,Calgary, AB T2P 3E3	403 296-7103	403 296-5744
Parker, Kevin	Corexco Inc.	2113 Enterprise Drive, Mt. Pleasant, MI 48853	517 775-3076	517 775-3268
Parkins, Redvers	University of Newcastle Upon Tyne (Mat.	Herschel Bldg., Newcastle upon Tyne, England NE1 7RU	44 191 222-7905	44 191 222-8563
Paulson, Ken	Canadian Western Natural Gas Co.	909 11 Ave. S.W., Calgary, AB T2R 1L8	403 245-7538	403 245-7698
Persaud, Donald R.	Natural Resources & Energy	PO Box 6000, Fredericton, NB E3B 5H1	506 453-7166	506 453-3671
Pesta, Tom	Alberta Energy and Utilities Board	640 5 Avenue SW, Calgary AB T2P 3G4	403 297-8148	403 297-4117
Peterson, Eric J.	Conoco Pipeline	338 Hiwam 87 Easet, Billings, MT 59101	406 255-5614	201 255-5606
Peterson, Scott	Lakehead Pipe Line Company	21 West Superior St., Duluth, MN 55802	218 725-0530	218 725-0139
Petrusev, Alex	Union Gas Limited	PO Box 2000, 50 Keil Drive, Chatham, ON N7M 5M1	519 3532-3100	519 436-5210
Phipps, Ted	Canadian Western Natural Gas Co.	909 11 Ave. S.W., Calgary, AB T2R 1L8	403 245-7524	403 245-7405
Pick, Roy	University of Waterloo (Mech. Eng.)	200 University Ave., Waterloo, ON N2L 3G1	519 885-1211	519 888-6197
Pistone, Valentino	SNAM	Pza Vanoni 1, S. Donata Milanese, Italy 20092	39 2 520 24325	39 2 520 24435
Plesuk, Brian	Gulf Canada Resources Limited	Box 130, Calgary, AB T2P 2H7	403 233-5209	403 233-5449
Pollard, Christopher	BG Inspection Services, Inc.	7105 Business Park Drive, Houston, TX 77041	713 849-6300	713 937-0740
Powell, Donald A.	Amoco Canada Petroleum Co. Ltd.	240 - 4 Ave. S.W. P.O. Box 200, Stn M Calgary, AB T2P 2H8	403 233-6331	403 233-1195
Power, Robert	National Energy Board	311 - 6th Ave. SW, Calgary, AB T2P 3H2	403 299-2769	403 292-5876
Preston, Carolyn	CANMET/Western Research Centre	#1 Oilpatch Drive, Devon, AB T9G 1A8	403 987-8660	403 987-8690

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Attendee	Corporation	Address	Phone	Fax
Pussegoda, Nick	Fleet Technology	311 Legget Drive, Kenata, ON K2K 1Z8	613 592-2830	403 592-4950
Reid, Bob	TransCanada PipeLines	111 - Fifth Ave. SW, PO Box 1000, Stn. M, Calgary, AB T2P 4K5	403 267-8600	403 267-4878
Renton, Peter	Gulf Canada Resources Limited	Box 130, Calgary, AB T2P 2H7	403 233-3910	403 233-3370
Revie, Winston	CANMET/Materials Technology Laborato	568 Booth Street, Ottawa, ON K1A OG1	613 992-1703	613 992-8735
Reyes, Alesandro	NOVA Gas International Ltd.	PO Box 2535, Stn M, Calgary, AB T2P 2N6	403 261-5295	403 290-6090
Richardson, David	Neocorr Engineering Ltd.	1600, 736 - 6th Ave. SW, Calgary, AB T2P 3T7	403 531-4349	403 531-1927
Rinne, Norman	Trans Mountain Pipe Line Company	2355 TransCanada Hwy W, Kamloops, BC V1S 1A7	250 371-4011	250 371-4001
Ronsky, Darryl		12 Spruce Bank Cr. SW, Calgary, AB T3C 3B4	403 246-7734	403 246-7734
Roy, George	CANMET/ Materials Technology Lab	568 Booth St., Ottawa, ON K1N 1E2	613 992-0328	613 992-8735
Sage, Roy	CANMET/Materials Technology Laborato	568 Booth Street, Ottawa, ON K1A OG1	613 995-8248	613 992-8735
Sahney, Reena	TransCanada PipeLines	111 - Fifth Ave. SW, PO Box 1000, Stn. M, Calgary, AB T2P 4K5	403 267-6352	403 267-1029
Sambells, Harry	Kilborn Western Inc.	301 - 105 Ninth Ave. SE, Calgary, AB T2G OR3	403 221-9388	403 221-8758
Sawyer, Tom	BJ Pipeline Inspection Services	6920 - 36 St. SE, Calgary, AB T2C 2G4	403 531-5446	403 236-8740
Scott, Glen	BC Gas Utility Inc.	16705 Fraser Highway, Surrey, BC V3X 2X7	604 576-7033	604 576-7105
Scott, Ian	Canadian Assoc. of Petroleum Producers	2100, 350 - 7th Ave. SW, Calgary, AB T2P 3N9	403 267-1132	403 266-3261
Sekella, Walter	Canadian Western Natural Gas Co.	909 11 Ave. S.W., Calgary, AB T2R 1L8	403 245 7813	403 245-7698
Shapka, Robert	Anderson Exploration	333 - 50 Ave. SE, Calgary, AB T2B 2G3	403 255-5100	403 255-5171
Shrives, John S.	Environment Canada	17 Fl., 351 St. Joseph Blvd., Hull, Quebec KIA OH3	819 997 3580	819 997-5029
Sibbald, Barbara	Alliance Engineering & Inspection	333 - 50 Ave. SE, Calgary AB T2B 2G3	403 255-5100	403 255-5171
Siebert, Martin	BJ Pipeline Inspection Services	6920 - 36 St. SE, Calgary, AB T2C 2G4	403 531-5416	403 236-3476
Sikora, Val	Alberta Energy and Utilities Board	640 5 Avenue SW, Calgary AB T2P 3G4	403 297-3726	403 297-3520
Simpson, David	Union Gas Limited	PO Box 1180, Dresdon, ON NOP 1MO	519 683-3404	519 683-3429
Sinclair, Don	Westcoast Energy Inc.	Bag Service 6180, Fort St. John, BC V1J 4H7	250 262-3511	250 262-3450
Sinigaglia, Ennio	SNAM	Viale de Gasperi 2, S Donato Milanese, Milan, Italy	39 2 520 23450	39 2 520 99014
Smith, Charles E.	Minerals Management Serv. (Eng. & Res.	381 Elden St. MS4700, Herndon, Virginia 20170-4817	703 787-1559	703 787-1555
Smith, Ray	National Energy Board	311 - 6th Ave. SW, Calgary, AB T2P 3H2	403 299-2794	403 292-5876
Soderquist, Walter	Westcoast Energy Inc.	Bag Service 6180, Fort St. John, BC V1J 4H7	250 262-3480	250 262-3450
Sokol, Ben	Northwestern Utilities Limited	7th Fl., CU Centre, 10035 - 105 St., Edmonton, AB T5J 2V6	403 420-7581	403 420-5649
Sommer, Garry	Corpro Canada Inc.	10848 - 214 St, Edmonton, AB T5S 2A7	403 447-1209	403 447-1643
Spencer, Marc	Magi Engineering Ltd.	47 Deermeade Dr. SE, Calgary, AB T2J 5Z4	403 252-3436	403 271-6204
Springer, Arthur	Bovar Environmmental	1600, 555 - 4th Ave. SW, Calgary AB T2P 3E7	403 750-9333	403 737-7634
St-Laurent, Bruno	TQM Pipeline	Place Ville-Marie Suite 2220 Montreal, Quebec H3B3M4	514 874-8873	524 874-8888
Standish, Victor	Petro-Canada Oil & Gas	Box 32036, Regina, Sask. S4N 7L2	306 522-4886	306 781-7161
Staples, Larry	Russel Technologies Inc.	4909 - 25 Ave., Edmonton, AB T6B 2S3	403 469-4461	403 462-9378
Steeves, Jim	Proactive Technologies	3335, 550 - 11 Ave. SE, Calgary, AB T2R 1M7	403 262-7855	403 294-0755
Steneker, Casey	Imperial Oil Resources Ltd.	2002 - 4th St., Nisku, AB T9E 7W4	403 955-6132	403 955-6139
Stowkowy, Bonnie	Canadian Energy Pipeline Association	1650, 801 - 6th Ave. SW, Calgary, AB T2P 3W2	403 221-8777	403 221-8760
Sutherby, R.	NOVA Gas Transmission Ltd.	P.O. Box 2535, Station M, Calgary, AB T2P 2N6	403 261-8212	403 290-7178
Szklarz, Karol	Shell Canada Limited	PO Box 2506, Calgary, AB T2P 3S6	403 284-6550	403 284-6667
Tailor, Dilip	Shaw Industries Ltd.	22 Torrance Woods, Brampton, ON L6Y 2TL	416 744-5808	416 743-9588
Tennesey, Wayne	Test Labs International Ltd.	276, 167 Lombard Ave., Winnipeg, MN R3G OT6	204 942-4424	204 943-9872
Thompson, Richard M.	Chevron Research & Technology Compan	P.O. Box 1627, Richmond, CA 94802	510 242-1131	510 242-4614
Toth, Greg	Trans Mountain Pipe Line Co. Ltd.	#900 - 1333 West Broadway, Vancouver BC. V6H 4O2	604 739-5324	604 739-5003

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PIPELINE LIFECYCLE REGISTRATIONS
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Attendee	Corporation	Address	Phone	Fax
Trefanenko, Rod (in place of Kozlowski	Gulf Canada Resources Limited	1680 - 102 Avenue, Edmonton, AB T6P 1V7	403 464-9114	403 467-5046
Trusler, Norm	BC Gas Utility Inc.	16705 Fraser Highway, Surrey, BC V3X 2X7	604 576-7004	604 576-7105
Tsai, Siu	Imperial Oil - Upstream Projects	237 - 4th Ave. SW, PO Box 2480, Stn. M, Calgary AB T2P 3M9	403 237-2658	403 237-3335
Tyson, William	CANMET/Materials Technology Laborato	568 Booth Street, Ottawa, ON K1A OG1	613 992-9573	613 992-8735
Uzelac, Neb	Pipetronix	50 A Caldari RD, Concord, Ontario L4K 4N8	905 738-7559	905 738-7561
Van Boven, Greg	NOVA Research & Technology Corp.	2928, 16th St. NE, Calgary, AB T2E 7K7	403 250-0601	403 250-0633
Van Egmond, Trent	NOVA Gas International	P.O. Box 2535, Station M, Calgary, AB T2P 2N6	403 261-5280	403 290-6090
Wade, Ron	BJ Pipeline Inspection Services	6920 - 36 St. SE, Calgary, AB T2C 2G4	403 531-5410	403 236-3476
Wallbridge, Jim			403 243-7618	None
Wang, Yong-Zhi	CANMET/Materials Technology Laborato	568 Booth Street, Ottawa, ON K1A OG1	613 947-0248	613 992-8735
Ward, Clive	British Gas Research & Technology	British Gas Res. & Technol. Ctre, Ashby Rd., Loughbrough, England	011 44 509 283392	011 44 434 602326
Ward, Clive	British Gas Research & Technology	Gas Res. & Tech. Centre, Ashby Rd., Loughborough, England LE11 3	44 1 509 282-000	44 1 434 602-326
Warner, Jeff	Travis Chemicals Ltd.	19th Floor 777 - 8 Avenue S.W., Calgary, AB T2P 3R5	403 263 8660	403 233-7069
Watters, Rick	AEC Pipelines	3900, 421 - 7th Ave. SW, Calgary, AB T2P 4K9	403 691-8879	403 691-8856
Willems, Herbert	Pipetronix GmbH	Lorenzstr. 10, 76297 Stutensee, Germany	49 724 473-2167	49 724 473-2123
Williams, Allison	County of Mountain View, Planning Dept.	??	??	??
Williamson, Steve	Williamson Industries Inc.	7731 - 16 Street, Edmonton, AB T6P 1M1	403 440-6637	403 440-6637
Wilmott, Martyn	NOVA Research & Technology Corp.	2928 - 16 St. NE, Calgary, AB T7E 7K7	403 250-4714	403 250-0633
Wilson, Brian	Canspec Group Inc.	2805 - 12 St. NE, Calgary, AB T2E 7J2	403 291-3126	403 250-1015
Wilson, David	University of Alberta (Mech. Eng.)	Edmonton, Alberta T6G 2G8	403 492-5467	403 492-2200
Wong, Dennis	Shaw Industries Ltd.	25 Bethridge Rd., Rexdale, ON M9W 1M7	416 744-5807	416 743-9588
Wong, Jackson	Canadian Western Natural Gas Co.	80 Macewen Park, Manor NW, Calgary, AB T3K 4G6	403 245-7125	403 245-7698
Wong, Paul	NOVA Gas Transmission Ltd.	29th Fl., 801 - 7th Ave. SW, Calgary, AB T2P 2N6	403 294-2904	403 290-6222
Worthingham, Bob	NOVA Gas Transmission Ltd.	PO Box 2535, Stn. M, Calgary, AB T2P 2N6	403 290-7860	290-6773
Wozniewski, Andrew	Imperial Oil Resources Limited	237 - 4th Ave. SW, PO Box 2480, Stn. M, Calgary AB T2P 3M9	403 237-2271	403 237-4195
Yeomans, Mark	NOVA Gas Transmission Ltd.	PO Box 2535, Stn. M, Calgary, AB T2P 2N6	403 290-6170	403 290-6222
Yuen, Glenn	TransCanada Pipelines	P.O. Box 1000, Station M, Calgary, AB T2P 4K5	403 267-8738	403 267-6225
Yungblut, Glenn R.		43 Mapleburn Dr. SE, Calgary, AB T2P 1Y3	403 278-4785	403 225-1116
Zelensky, Michael J.	Bovar Environmmental	1600, 555 - 4th Ave. SW, Calgary AB T2P 3E7	403 750-9334	403 237-7634
Zheng, Wenyue	CANMET/ Materials Technology Lab	568 Booth St., Ottawa, ON K1N 1E2		

BANFF/97 PIPELINE WORKSHOP
MANAGING PIPELINE INTEGRITY -- PLANNING FOR THE FUTURE
Banff Centre for Conferences, Banff, Alberta

Workshop Co-Chairs:

Roland Andersson	Major Industrial Accidents Council of Canada
Don Currie	Alberta Chamber of Resources
Bob Hill	Canadian Energy Pipeline Association
Harry Lillo	Alberta Energy and Utilities Board
Doug Macdonald	Kilborn Western Inc.
Bruce Mitchell	Canadian Association of Petroleum Producers
Barry Broderick	Canadian Gas Association
Winston Revie	CANMET
Ian Scott	Canadian Association of Petroleum Producers
Ray Smith	National Energy Board

Workshop Objectives

- To provide an interactive forum where the management of the integrity and safety of Canada's pipeline infrastructure can be discussed.
- To provide an opportunity to focus on state-of-the-art technologies and past experiences related to the design, construction, operation, testing, inspection, maintenance, repair, and abandonment of pipelines.
- To facilitate and promote the sharing and exchange of information and the development of pipeline industry communication networks.
- To encourage the development and operation of working groups and task forces to address the future challenges associated with pipelines.
- To recognize areas where coordinated efforts could be implemented to enhance the pipeline safety management process.
- To raise awareness of and to reduce land use conflicts on both sides of the right-of-way.
- To identify new areas and initiatives for pipeline research and development.
- To publish the workshop proceedings and a final workshop report.

Workshop Benefactors:

Canadian Association of Petroleum Producers
Canadian Energy Pipeline Association

Workshop Patrons:

BJ Pipeline Inspection Services
British Gas
CANMET
National Energy Board
NOVA Gas Transmission Ltd.
OMAE Calgary Chapter
Pipetronix
TransCanada PipeLines
U.S. Minerals Management Service

Workshop Sponsors:

Alberta Energy and Utilities Board
Camrose Pipe Company
IEA International Centre for Gas Technology Information
Interprovincial Pipe Line Inc.
PanCanadian Petroleum Limited
Welland Pipe Ltd.

Workshop Supporters:

IPSCO Inc.
Prudential Steel Ltd.
Williamson Industries Inc.

Pre-Workshop Tutorials: Tuesday, April 15, 1997

8:30 - 10:30 **The Essentials of Stress-Corrosion Cracking (SCC 101)**
Max Bell Auditorium
Redvers N. Parkins, University of Newcastle upon Tyne, U.K.
A review and discussion of the basic aspects of stress-corrosion cracking of pipeline steels.

11:00 - 12:30 **Critical Assessment of Cracks (Fracture Mechanics, State of the Art)**
Max Bell Auditorium
Bill Tyson, CANMET/Materials Technology Laboratory, Ottawa
A brief review of effects of notches and cracks on failure stress, state-of-the-art in fracture mechanics testing for material properties, fracture toughness of linepipe steels and weldments, and a discussion of axial cracks in pipelines, including elastic and plastic fracture mechanics assessment.

11:00 - 12:30 **Land Use Planning Adjacent to Pipelines -- An Overview**
Max Bell Building, Room 252
Don Grossberndt, Amoco Canada, Calgary
A general overview of issues associated with encroachment of development on petroleum product pipelines, with some specific examples indicating roles and responsibilities of the pipeline industry and various levels of government, as well as planners and developers.

13:45 - 16:30 **Risk Management/Risk Assessment 101**
Max Bell Auditorium
Ian Dowsett, Alberta Energy and Utilities Board, Calgary
This tutorial is intended to provide an overview of an integrated approach for managing risk and safety. The material develops the relationship between risk and responsibilities for delivering public safety. Topics covered include: Setting the goals and objectives for risk management; the components of risk assessment (*qualitative and quantitative risk analysis, risk communications and public consultation*); operational and audit considerations. The tool kit for managing risks (*setbacks, emergency planning zones and response planning areas*) is outlined. Notes will be provided.

AGENDA

<u>Wednesday Morning, April 16, 1997</u>

<u>Plenary Session</u>: Max Bell Auditorium

9:30 **Opening Address**
Bob Reid, Canadian Energy Pipeline Association, Calgary

9:50 **NEB Public Inquiry on Stress-Corrosion Cracking of Canadian Pipelines -- A Regulatory Perspective**
John McCarthy, National Energy Board, Calgary

10:10 **NEB Public Inquiry on Stress-Corrosion Cracking of Canadian Pipelines -- An Industry Perspective**
Bob Hill, Canadian Energy Pipeline Association, Calgary

10:30 **Risk-Based Approaches to Pipeline Safety, Regulation, and Compliance**
Richard Felder, Office of Pipeline Safety, Washington, D.C.

10:50 **The Pipeline Risk Assessment Steering Committee (PRASC) - An Overview of Progress**
Doug Clark, Gulf Canada Resources Limited, Edmonton

11:10 **CAPP Perspective on Pipeline Encroachment**
Joanne Nutter, Imperial Oil, Calgary

11:30 **Risk Management as an Alternative to Prescriptive Regulation**
Keith Leewis, Gas Research Institute, Chicago
Andy Drake, PanEnergy Corp., Houston

11:50 Lunch

Wednesday Afternoon, April 16, 1997

Plenary Session: **Max Bell Auditorium**

13:00 **Future Trends in Pipelines -- A European View of Some Aspects**
Gerd Vogt, European Pipeline Research Group, Duisburg, Germany
Patrick Corbin, Gaz de France, Paris, France

13:30 **The Future of Pipeline Pigging (What is Needed for Future In-Line Inspection of Pipelines?)**
Harvey Haines, Gas Research Institute, Chicago

13:50 **How Does the Insurance Industry View the Pipeline Industry Today?**
Norman Nibber, Alexander & Alexander, Reed Stenhouse Limited, Calgary

14:10 **MIACC Process -- Canada's Voluntary Approach to Major Hazard Control**
Roland Andersson, Major Industrial Accidents Council of Canada, Ottawa

14:30 Break/Individual Contact Meetings

15:30 **Harmonization of Canadian Pipeline Regulations**
Rob Power, National Energy Board, Calgary

15:50 **New Technologies for Construction, Inspection, Repair, and Rehabilitation - Group Report**
Bruce Gray, Novagas Clearinghouse Ltd., Calgary

16:10 **SCC Working Group - Group Report**
Bob Sutherby, NOVA Gas Transmission Ltd., Calgary

16:30 **Information Exchange and Networking -- Group Report**
Pierre Brien, D'Aragon, Desbiens et Halde Ltée (DDH), Montréal

16:50 **Presentation of Plaques to Workshop Benefactors, Patrons, Sponsors, and Supporters**

16:55 **Facilitation of Working Group Sessions**
Doug Macdonald, Kilborn Western Inc., Calgary

17:00 Adjournment for the Day

PRE-WORKSHOP TUTORIALS

THE ESSENTIALS OF STRESS-CORROSION CRACKING (SCC 101)

(Slide Presentation - material not available)

PRE-WORKSHOP TUTORIALS

CRITICAL ASSESSMENT OF CRACKS (FRACTURE MECHANICS, STATE OF THE ART)

Tutorial: Critical Assessment of Cracks

Banff, 15 April 1997

W.R. Tyson, D. Mak and G. Shen

Materials Technology Laboratory, CANMET

Outline

- review of fracture mechanics concepts (LEFM, EPFM)
- material toughness testing
- integrity assessment: PD6493
- surface axial defects in pipe: levels 2, 3

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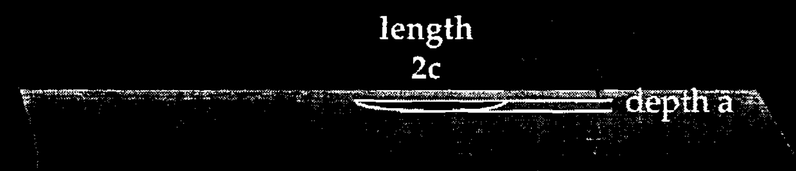
Mechanics of Cracking (Fracture Mechanics)

Defect assessment / fracture control

Context: reliability of pipe with long axial surface crack, e.g., SCC defect



Principal driving force: hoop stress

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Cracking Parameters

Mechanical: $\sigma = p \cdot \frac{R}{t}$

Crack tip conditions:

Stress concentration

Crack growth (sub-critical)

mechanical (from local stress)

environmental (from chemical attack or hydrogen embrittlement)

sub-critical $\rightarrow$ critical

Mechanical crack driving force:

Elastic: stress intensity factor K

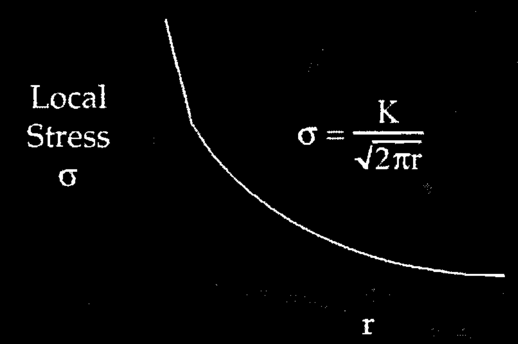
Elastic/plastic: J-integral, crack-tip opening displacement (CTOD)

Linear Elastic Fracture Mechanics (LEFM)

$$K = Y \sigma \sqrt{\pi a}$$

Energy release rate $G = \frac{K^2}{E'}$

Crack-tip stress distribution



Crack-tip plastic zone

$$\sigma > \sigma_y \quad \text{for} \quad r < r_y = \frac{1}{2\pi}\left(\frac{K}{\sigma_y}\right)^2$$

Validity of LEFM

ASTM E399: Minimum dimension $\geq 2.5\left(\frac{K}{\sigma_y}\right)^2$

$$\approx 15 r_y$$

Example: For $\sigma_y = 420$ MPa (X60)

$$K = 30 \text{ MPa} \sqrt{m}$$

$$\text{then} \quad r_y = \frac{1}{2\pi}\left(\frac{30}{420}\right)^2 \text{m} = 0.8\,\text{mm}$$

and size requirement $\geq$ 12 mm

Hence minimum crack depth and ligament for LEFM to be valid is 12 mm

Conclusion: For typical pipeline applications, LEFM valid only for very low stresses

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Elastic/Plastic Fracture Mechanics (EPFM)

J = crack-tip line integral

δ (CTOD) = crack-tip opening displacement

Equivalence to LEFM for low-stress limit:

$$J = G = \frac{K^2}{E'}$$

(but Caution: J loses energy-release-rate meaning at high stresses)

Equivalence of J, CTOD:

δ

$$\delta = d \cdot \frac{J}{\sigma_y}$$

$d \approx 0.3 - 1$ (plane stress or strain, also work hardening n in $\varepsilon \propto \sigma^n$)

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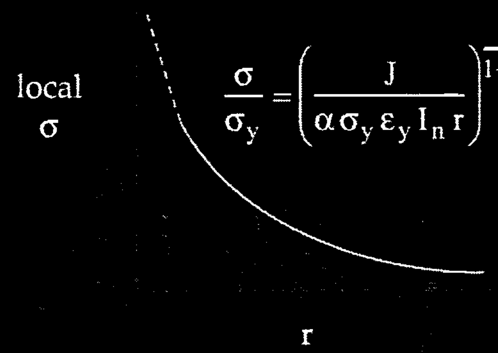
Crack-Tip Stresses



$$\frac{\sigma}{\sigma_y} = \left(\frac{J}{\alpha \sigma_y \varepsilon_y I_n r} \right)^{\frac{1}{1+n}} \tilde{\sigma}$$

Reduces to LEFM for $n = 1$

Strength of singularity reduced for $n > 1$ (stress reduced in crack-tip region)

Validity of EPFM:

ASTM E813: minimum dimension $\geq 25 \left(\frac{J}{\sigma_y} \right)$

Example: for $K = 30$ MPa$\sqrt{m}$, $\sigma_y = 420$ MPa
size req't ≥ 0.26 mm (vs 12 mm for LEFM)

Conclusion

EPFM required for typical linepipe ($t \sim 10$ mm)

K Estimation

Geometry Factors:

Centre-cracked plate (CCP): $K = \sigma\sqrt{\pi a}$

Finite CCP: $K = \sigma\sqrt{\pi a}\,\sqrt{\sec \frac{\pi a}{W}}$

Other common geometries:
- three-point bend
- edge-cracked tension
- compact tension
- surface semi-elliptical crack

Many solutions tabulated in standard handbooks (g.e., Tada, Paris, Irwin, "The Stress Analysis of Cracks Handbook")

J Estimation

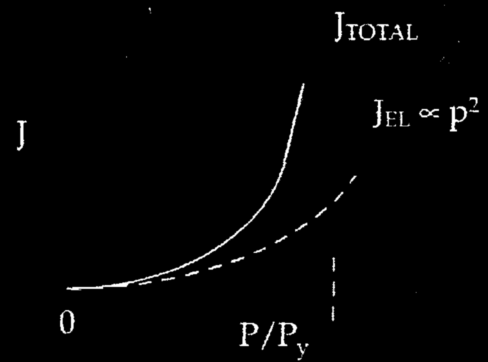
J a function of geometry and load, also yield stress and work hardening coefficient

EPRI estimation scheme:

$J_{TOTAL} = J_{ELASTIC} + J_{PLASTIC}$

from K   from FEM solutions

$J_{PLASTIC}$ Tabulated for common geometries and range of σ_y, n in EPRI Handbook



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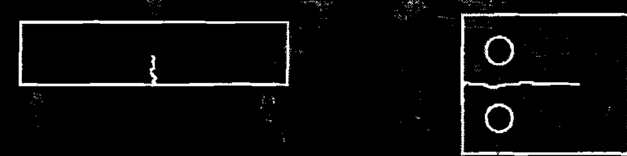
Testing, Material Characterization

Fracture Property: Value of K or J at fracture or crack growth

Standard Geometries:

Three-point bend   Compact tension



Method:

Introduce pre-crack (fatigue)

Measure load, load displacement

Measure crack mouth opening, crack growth (by unloading compliance or electric potential drop)

Calculate K, J, CTOD, Δa by standardized formulas (ASTM)

Result: K_{CRIT} or J resistance curve

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Standards:

BSi PD 6493 : 1991, "Guidance on methods for assessing the acceptability of flaws in fusion welded structures"

ASTM E 813, "Standard Test Method for J_{Ic}, A Measure of Fracture Toughness"

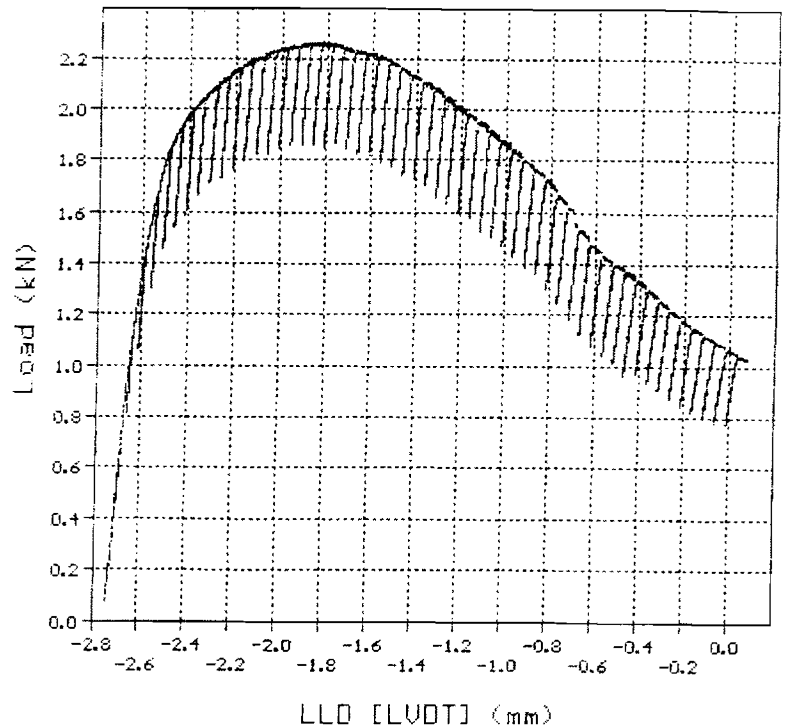
ASTM E 1152, "Standard Test Method for Determining J-R Curves"

ASTM E 1737, 'Standard Method for J-Integral Characterization of Fracture Toughness"

ASTM E 1290, "Standard Test Method for Crack-Tip Opening Displacement (CTOD) Fracture Toughness Measurement"

ASTM draft, "Standard Method for Measurement of Fracture Toughness"
- includes K, J, CTOD and R-curves

3-Point Bend
X52 Steel



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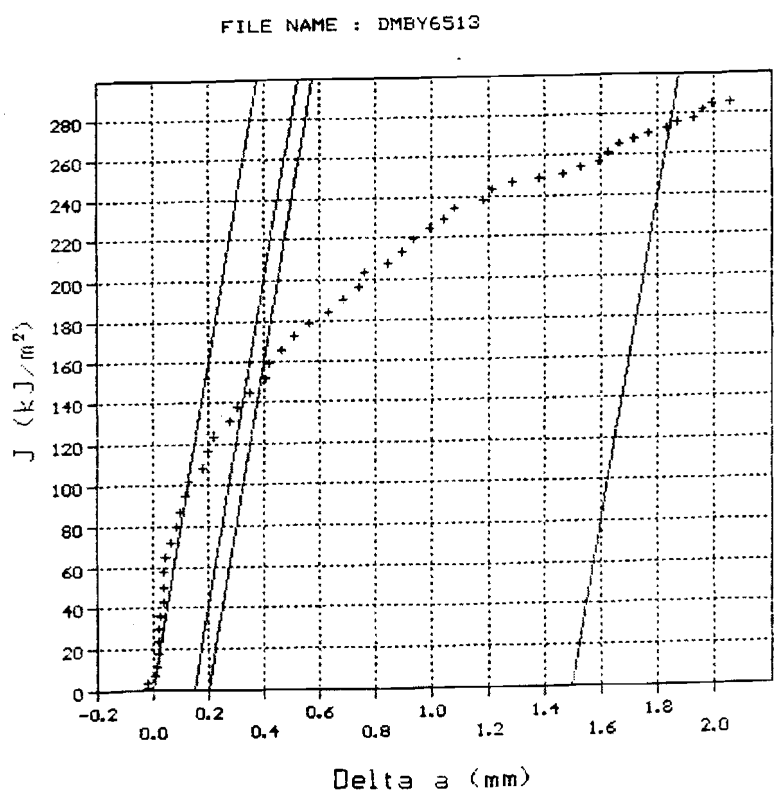
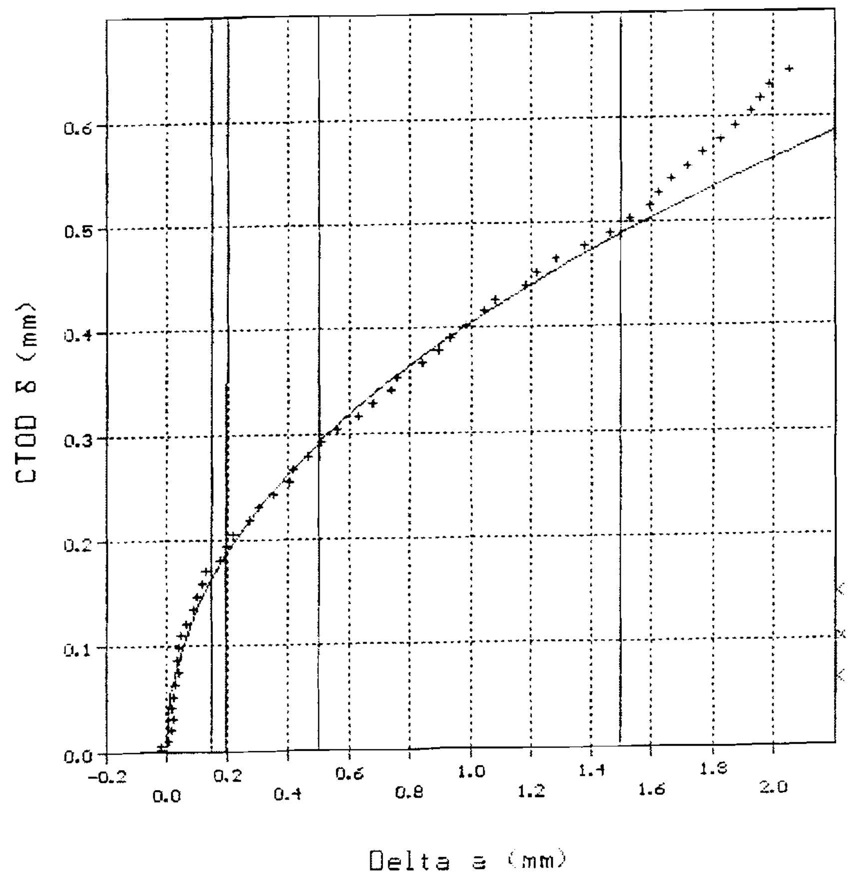
11-95-Tutorial-Tyson

J Resistance Curve



CTOD Resistance Curve

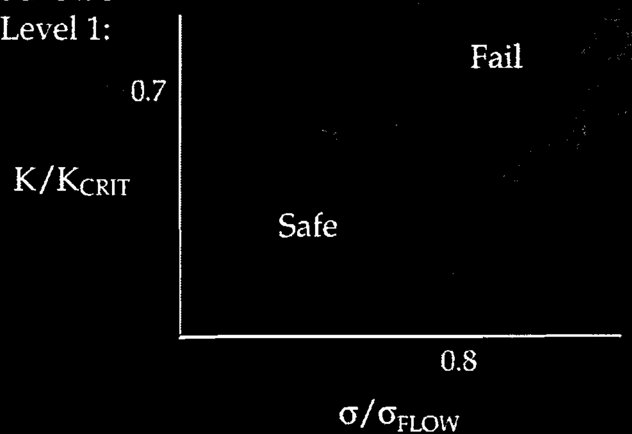


Integrity Assessment

Prediction of structural behaviour from small-scale tests

Applied J → crack growth as per resistance curve
→ fracture at critical J or at plastic collapse

Failure Assessment Diagram
PD 6493
Level 1:



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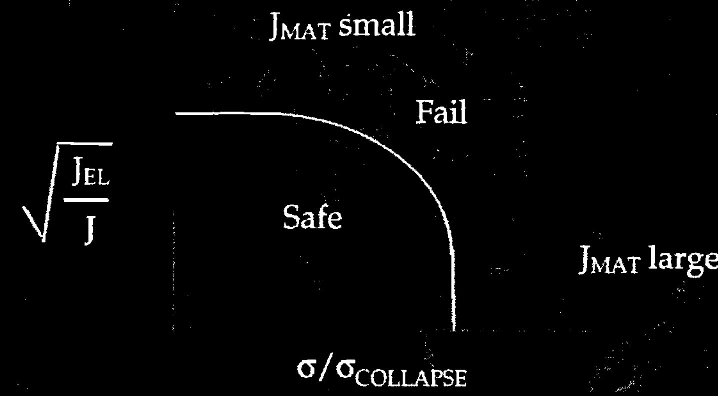
Level 2:



J_{MAT} ("toughness") - J at 0.2 mm crack growth in bend test recommended conservative limit

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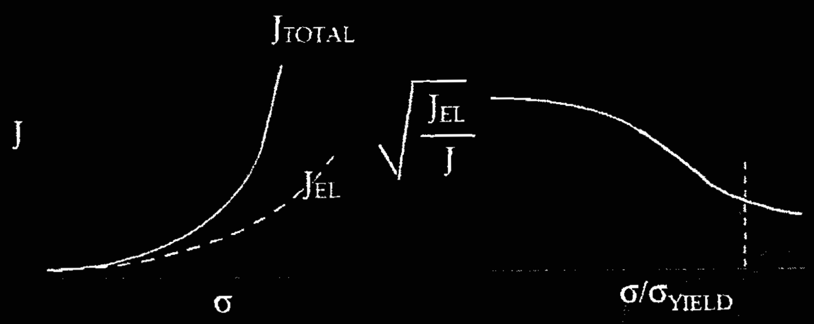
Level 3:



Cut-off imposed at collapse stress σ_{PC}

(net-section stress = flow stress)

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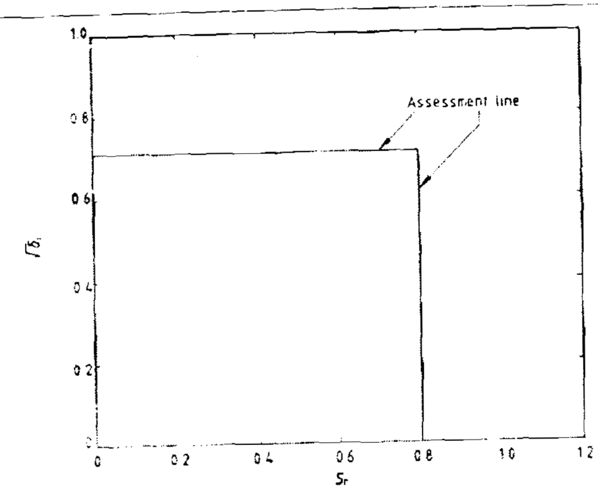
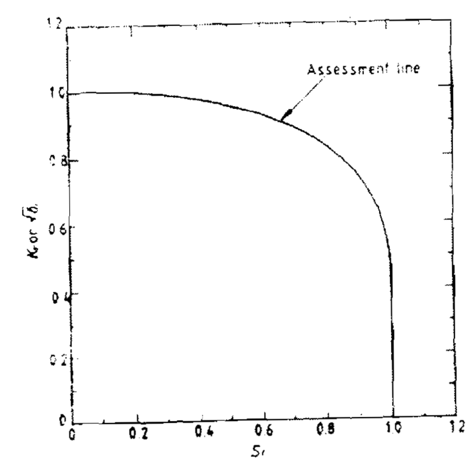


(a) Level 1 failure assessment diagram

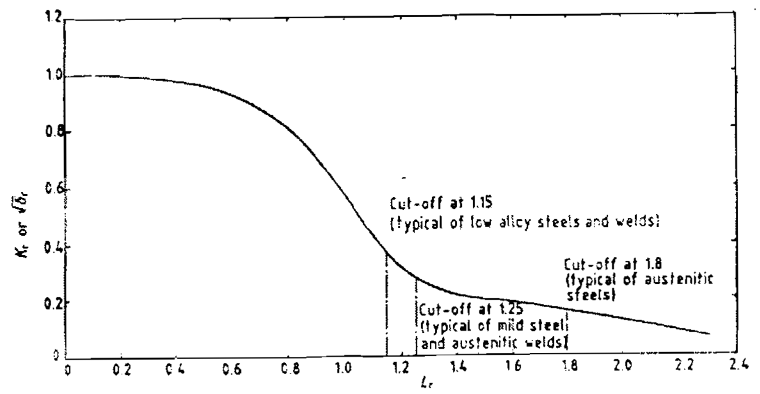


NOTE. The line is derived from the following equation

$$K_r \text{ or } \sqrt{\delta_r} = S_r \left[\frac{8}{\pi^2} \ln \sec\left(\frac{\pi}{2} S_r\right)\right]^{-0.5}$$

(b) Level 2 failure assessment diagram

Figure 13. Failure assessment diagrams



NOTE 1. The line is derived from the following equation

K_r or $\sqrt{\delta_r} = (1 - 0.14 L_r^2)\{0.3 + 0.7 \exp(-0.65 L_r^6)\}$

NOTE 2. A cut-off on the L_r axis (i.e. $L_r$max.) at $\frac{\sigma_y + \sigma_u}{2\sigma_y}$ for the region of interest is recommended.

(c) Level 3 failure assessment diagram for use when relevant stress strain data is available

Figure 13 Failure assessment diagrams *(concluded)*

Surface Axial Defects in Pipe

K estimation available (Raju, Newman)

J estimation feasible, but requires FEM calculations for specific geometry, mechanical properties

Collapse stress estimation:

- from empirical data (Battelle), used, for example, in B31G
- from analytical model (strip yield) (Shen, CANMET)

Material properties:

- not well known for old pipe (but being measured at MTL/CANMET)

CANMET

Sample Calculation: Level 2

Test pipe:
D = 24 in.
t = 0.25 in.
YS = 61 ksi
UTS = 86 ksi

Crack geometry:
2c = 1.4 in.
a = 0.14 in.

1. Stress intensity factor: semi-elliptical surface crack in plate

Newman/Raju

$$K = \frac{F}{E_1}\sigma\sqrt{\pi a}$$

$$E_1 = \left[1 + 1.464\left(\frac{a}{c}\right)^{1.65}\right]^{1/2}$$

$$F = M_1 + M_2\left(\frac{a}{t}\right)^2 + M_3\left(\frac{a}{t}\right)^4$$

$$M_1 = 1.13 - 0.09\left(\frac{a}{c}\right)$$

$$M_2 = -0.54 + \frac{0.89}{0.2 + \left(\frac{a}{c}\right)}$$

$$M_3 = 0.5 - \frac{1}{0.65 + \frac{a}{c}} + 14\left(1 - \frac{a}{c}\right)^{24}$$

2. Plastic Collapse:
Shen, Tyson: Ligament collapse stress

$$\sigma_{pc} = \frac{1.15\sigma_0}{M_p}$$

$$\sigma_0 = (\sigma_y + \sigma_{UTS})/2$$

$$M_p = \frac{1 - \frac{a}{tf}}{1 - \frac{a}{t}}$$

$$f = [1 + 0.150(c/t) - 0.022(c/t)^2 + 0.002(c/t)^3]^{1/2}$$

3. Fracture Stress:
Collapse-modified strip yield model

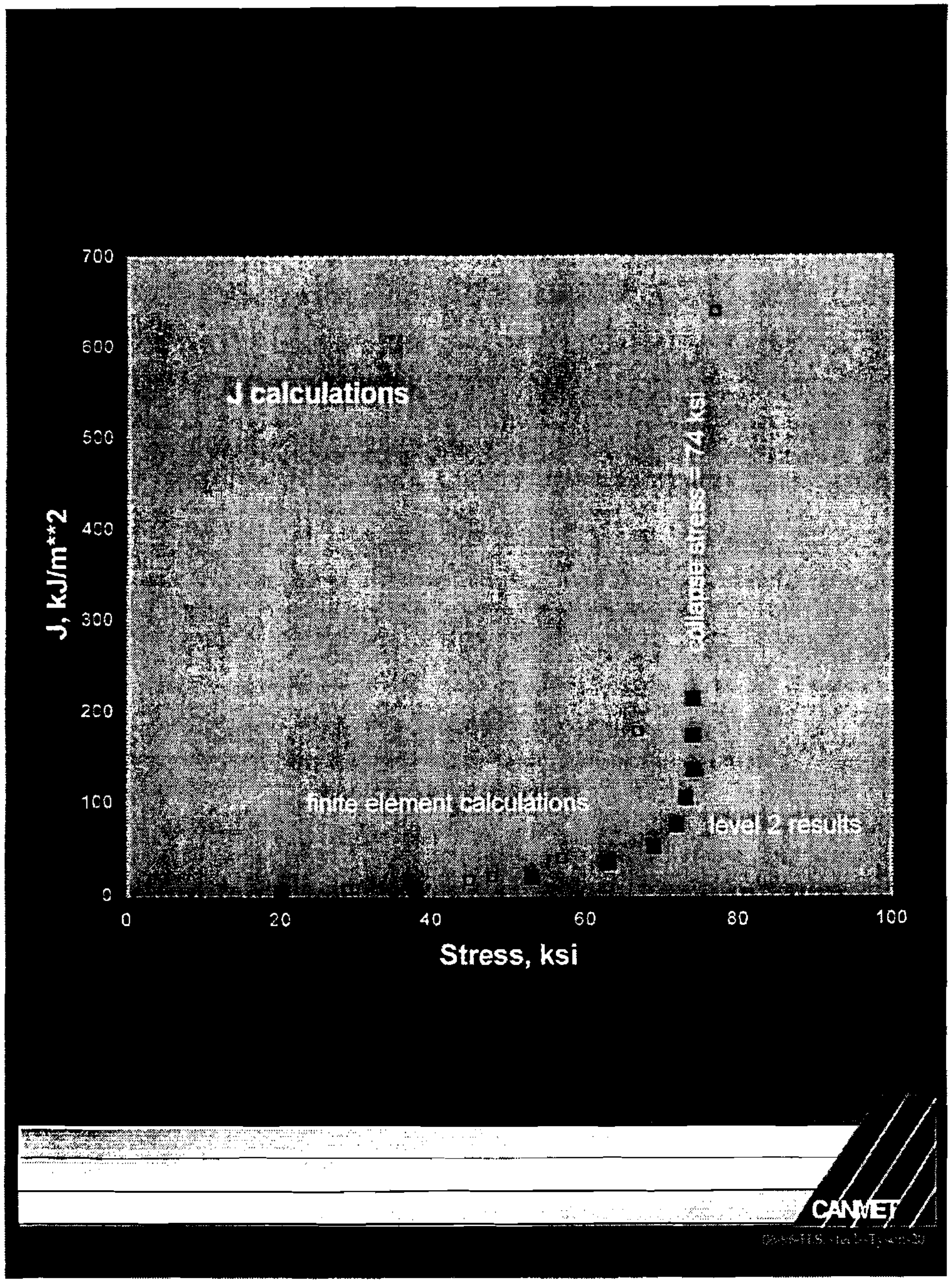
$$K_r = S_r\left[\frac{8}{\pi^2}\ln\sec\left(\frac{\pi}{2}\frac{\sigma}{\sigma_{pc}}\right)\right]^{-1/2}$$

$$K_r = \frac{K}{K_{mat}} = \frac{Y\sigma\sqrt{\pi a}}{K_c}$$

$$S_r = \frac{\sigma_n}{\sigma_0} = \frac{\sigma}{\sigma_{pc}}$$

Rearrange

$$\sigma = \frac{2}{\pi}\sigma_{pc}\arccos\left[\exp\left(\frac{K^2_{mat}}{\frac{8}{\pi}aY^2\sigma^2_{pc}}\right)\right]^{-1}$$



Results

σ (ksi)	K (ksi√in.)	J (kJ/m2)
63	79[1]	33
74	168[2]	150
74	194[3]	200

1 from $K^2/E = 2(CVN)^{3/2}$ with 3/2 CVN = 20 J

2 from typical J = 150 kJ/m^2

3 from J = 200 kJ/m^2

SCC-Type Flaws

$J_{el} = K^2 / E'$, K from Newman / Raju

$J_{pl} = ?$

Problems:

3-D geometry of crack

curvature effects: bulging

Few FEM solutions published

CANMET

J Approximations

Jaske (Cortest)

$$J = Q_f \; F_{sf} \left[\sigma^2 \pi a / E + f_3(n)\, a\, \varepsilon_p \sigma\right]$$

2c/ a   a/t $\varepsilon_p(\sigma)$ includes bulging

Leis (Battelle)

$$J = \frac{K^2}{E'}\left(1 + \frac{r_p}{a}\right)$$

Newman-Raju (flat plate)   - bulging effects small

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Results: (J in kJ/m²)

Pipe	**R = 305 mm, t = 6.4 mm**
Crack	**a/t = 0.7, 2c/a = 8**
steel (X52)	**σ_o = 420 MPa, n = 9**

p	σ_h	FEM		Jaske		Leis	
(psi)	σ_y	J_e	J_p	J_e	J_p	J_e	J_p
595	0.47	6.0	0.4	5.2	0.0	5.8	0.8
1010	0.94	17.3	8.3	14.8	3.9	16.7	6.6
1400	1.11	33	215	29	121	33	26

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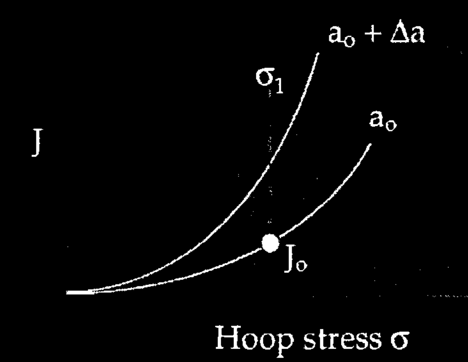
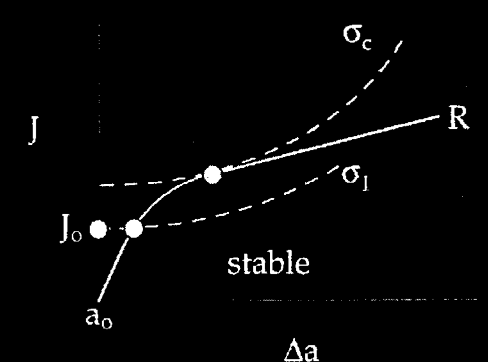
Tearing Instability





Unstable cracking occurs at σ_c, giving leak or rupture

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PRE-WORKSHOP TUTORIALS

RISK MANAGEMENT / RISK ASSESSMENT 101

Integrated Risk Management Process

Tutorial - BANFF97 Workshop

Ian Dowsett,
Senior Advisor, Risk and Public Safety,
Alberta Energy and Utilities Board

Michael J. Zelensky,
Manager, Air Quality and Risk Assessment,
BOVAR Environmental

Approach

- Part A: Ian Dowsett
  Overview of an
  Integrated Risk Management Process

- Part B: Michael Zelensky
  Detailed Look at
  Risk Assessment / Risk Analysis

- Part C
  Discussion

Objective - Part A

To Provide an Overview of an Integrated Approach to Public Safety & Risk Management

- ✓ The Basics
- ✓ Overview of the Process
- ✓ Detail - Specific Components

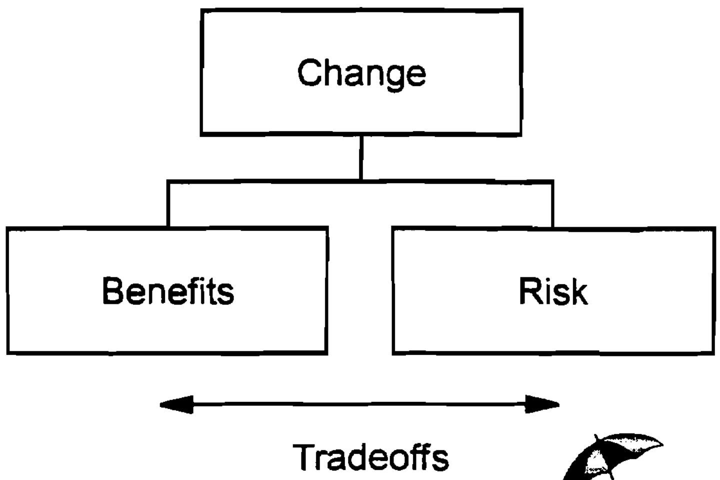
What is Safety?

✓ The Basics

- Safety is the Acceptability of Risk.
  - Acceptable to Who? Who Decides?
  - Both a Public and Industry Decision
  - Regulator Facilitates Decision-making and Ensures Provisions

(The Regulator Holds Ultimate Responsibility for the Decision)

Effects of Development



✓ The Basics

What is Risk?

- Risk is the Chance of an Adverse Outcome
  - Environmental / Public Safety / Financial
  - Individual / Societal

✓ The Basics

Environmental
Risk = Exposure x Effect

- Exposure: Low-level, Continuous Emissions
  (Ongoing, e.g. flaring / incineration)

- Effect: Long-term Chronic
  (e.g. damage to vegetation, soil acidification)

✓ The Basics

Public Safety
Risk = Frequency x Consequence

- Frequency: Accidental Releases
  (Infrequent)

- Consequence: Short-term Acute
  (e.g. fatality, injury, nuisance or other criteria)

(Note: to reduce risk, reduce the frequency , reduce the consequence or both)

✓ The Basics

CANADIAN STANDARDS ASSOCIATION
Z662-96-OIL AND GAS PIPELINE SYSTEMS

4.3.2 CLASS LOCATIONS

4.3.2 GENERAL

4.3.2.1.1-Class locations designations shall be **determined by way of class location areas and on the buildings, dwelling units, places of public assembly, and industrial installations contained in such areas.**

4.3.2.1.2-Class location areas shall **extend 200M on both sides of the centerline of any continuous 1.6KM length of pipeline.** (except as allowed by 4.3.2.6)

4.3.2.1.3-Each dwelling unit in a multiple dwelling unit building shall be counted as a separate unit.

4.3.2.2 CLASS 1
Class location areas that **contain 10 or fewer dwelling units** intended for human occupancy shall be designated as Class 1 locations.

CANADIAN STANDARDS ASSOCIATION
Z662-96-OIL AND GAS PIPELINE SYSTEMS

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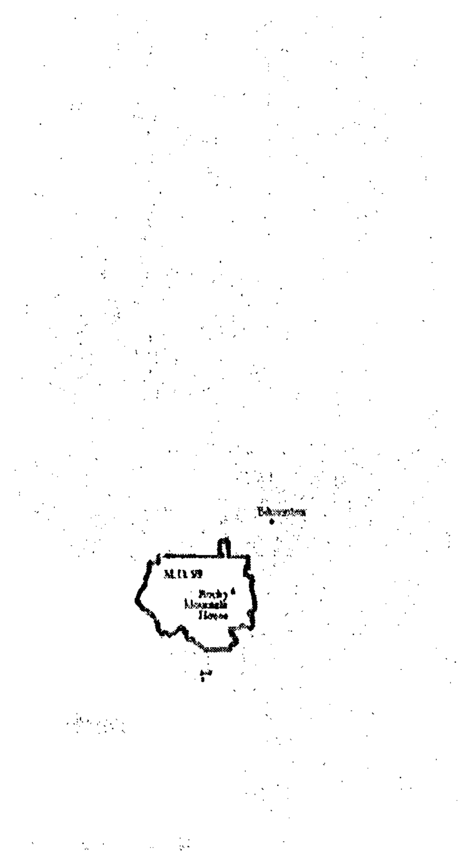
THE ALBERTA PLANNING PROCESS

MUNICIPAL GOVERNMENT ACT
SUBDIVISION & DEVELOPMENT REGULATION

MUNICIPAL DEVELOPMENT PLANS
AREA STRUCTURE PLANS
LAND USE BYLAWS

ZONING
SUBDIVISIONS
BUILDING PERMITS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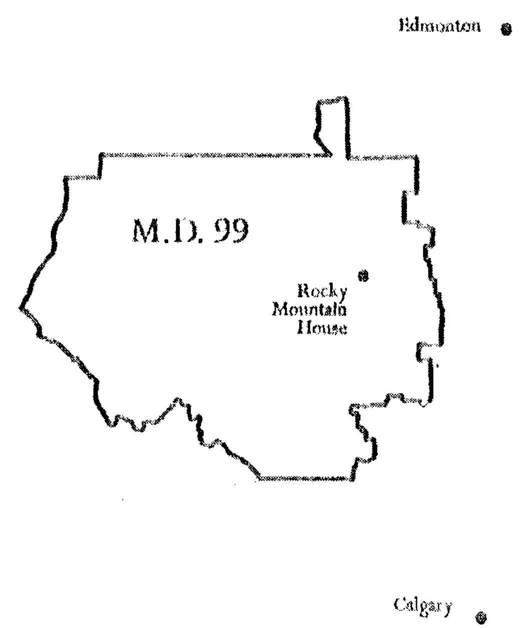
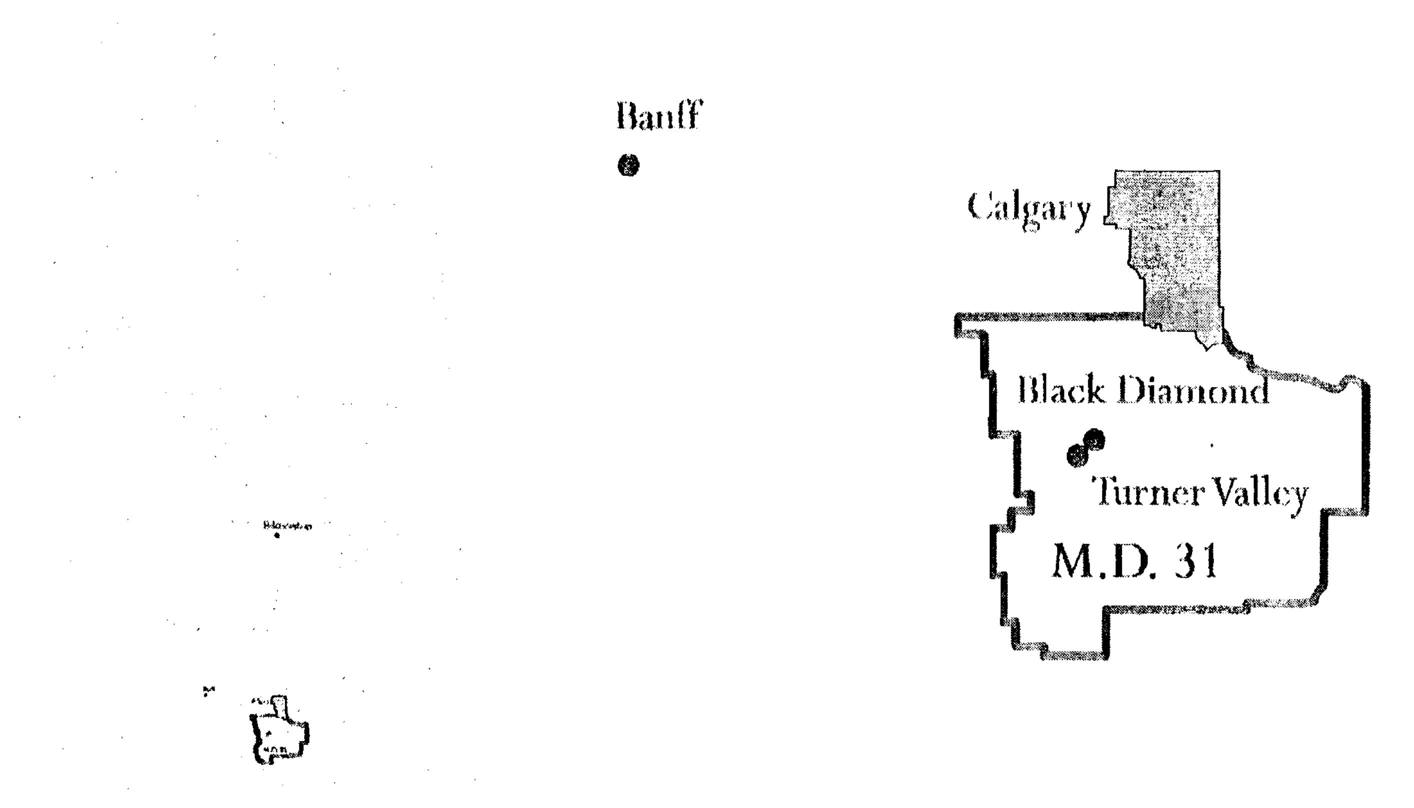
Mountain
House


Edmonton
M.D. 99
Rocky
Mountain
House
Calgary


Banff
Calgary
Black Diamond
Turner Valley
M.D. 31

CANADIAN STANDARDS ASSOCIATION
Z662-96-OIL AND GAS PIPELINE SYSTEMS (cont)

10.7.1- CHANGES IN CLASS LOCATION

10.7.1.1- **Where class locations change as a result of increases in population density or location development, pipelines in such locations shall be subject to all of the requirements for the higher class location, or shall be subjected to an engineering assessment** to determine the (a) design, construction, and testing procedures followed in the original construction, compared with the applicable requirements for this Standard; (b) condition of the pipeline by field inspections, examinations of operating and maintenance records, or other appropriate means, and (c) type, proximity, and extent of the development that has increased the class location, giving consideration to concentrations of people, such as those associated with schools, hospitals, small subdivisions, and recreation areas built near existing pipelines.

10.7.1.2-Where the engineering assessment (see clause 10.7.1.1) indicates that the section of pipeline is satisfactory for the changed class location, no change to the maximum operating pressure shall be required.

10.7.1.3- Where the engineering assessment (see clause 10.7.1.1) indicates that **the section of pipeline is not satisfactory for the changed class location, as soon as practicable either the pipe shall be replaced or a revised maximum operating pressure,** calculated according to the requirements of Clause 8.5 for the changed class location, shall be used.

10.7.1.4- Pipelines that may be subject to changes in class location shall be **inspected annually** by the operating Company in order to determine whether any change in class location has occurred. Records of such inspections and of any corrective action shall be retained.

CANADIAN STANDARDS ASSOCIATION
Z662-96-OIL AND GAS PIPELINE SYSTEMS (cont)

4.3.2.4 CLASS 3

4.3.2.4.1-Class locations that **contain more than 46 dwelling units intended for human occupancy** shall be designated Class 3 locations.

4.3.2.4.2-Consideration shall be given to designing class location areas that contain **institutions where rapid evacuation may be difficult, such as hospitals, or nursing homes** as Class 3 locations.

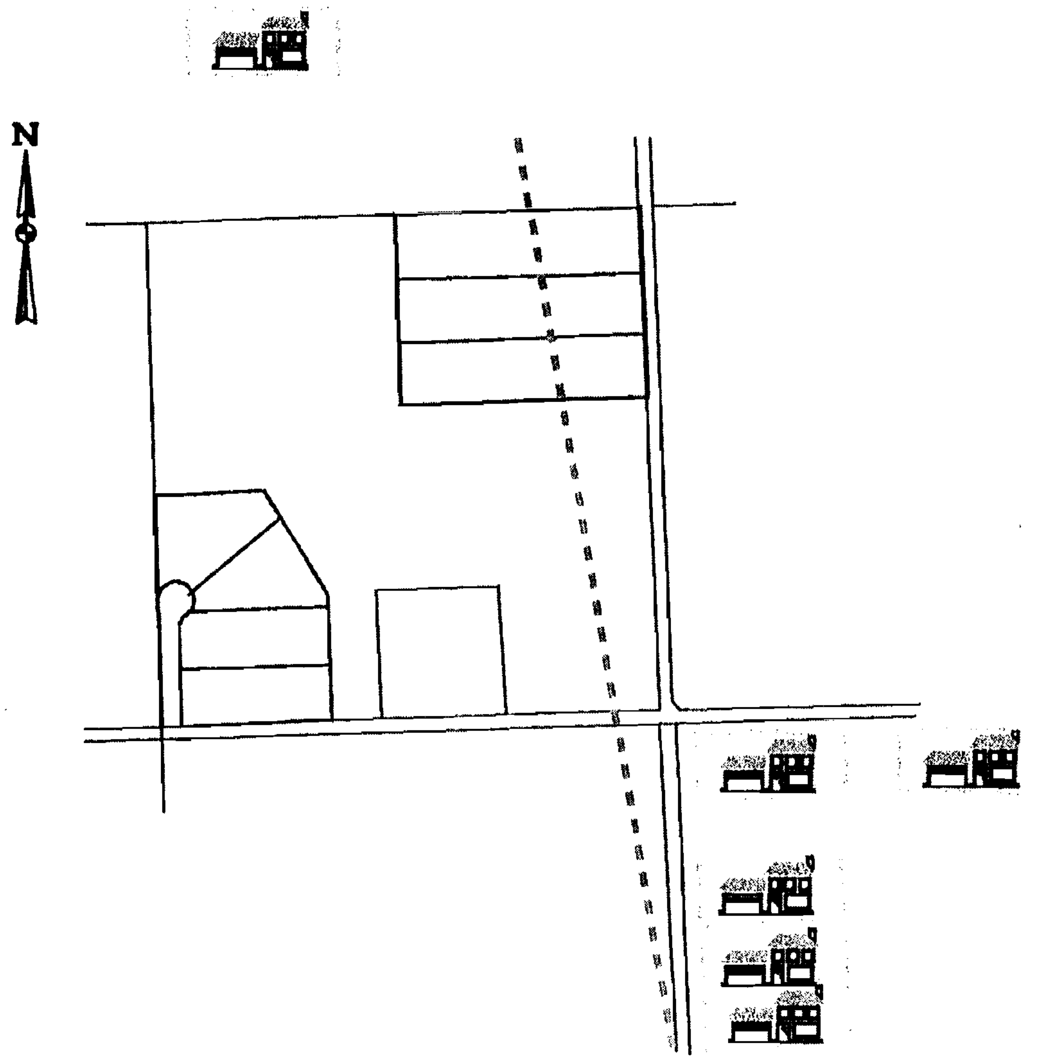
4.3.2.5 CLASS 4
Class location areas where **buildings intended for human occupancy with 4 or more stories above ground** are prevalent shall be designated Class 4 locations.

4.3.2.3 CLASS 2

4.3.2.3.1-Class location areas that **contain more than 10 but fewer than 46 dwelling units** intended for human occupancy shall be designated Class 2 locations.

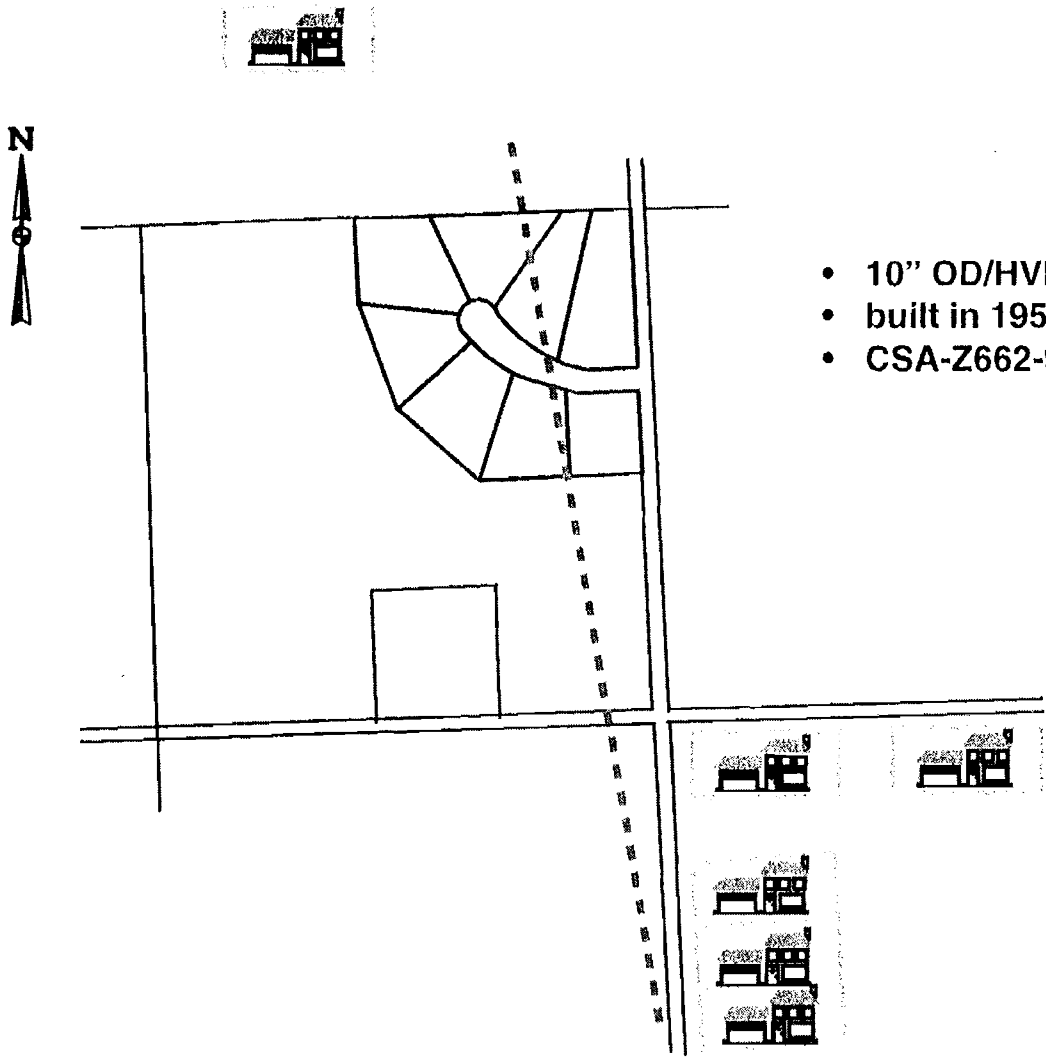
4.3.2.3.2-Class locations that contain the following shall be designated Class 2 locations:
(a) **a building that is occupied by 20 or more persons during normal use;**
(b) **a small, well defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theater,** or other place of public assembly;
or
(c) **an industrial installation such as a chemical plant or hazardous substance storage area,** where release of products from the pipeline could cause the industrial installation to produce a dangerous or environmentally hazardous condition.

CASE STUDY #1/MUNICIPAL DISTRICT OF FOOTHILLS



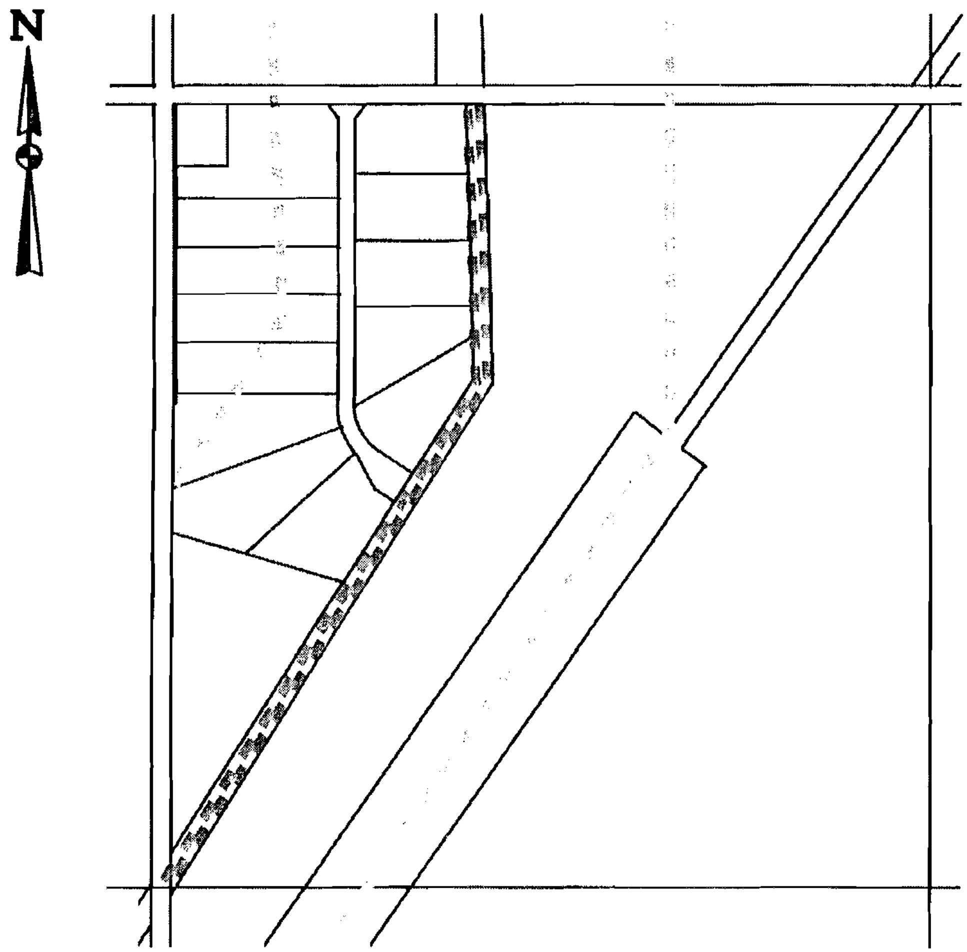
REVISED

CASE STUDY #1/MUNICIPAL DISTRICT OF FOOTHILLS



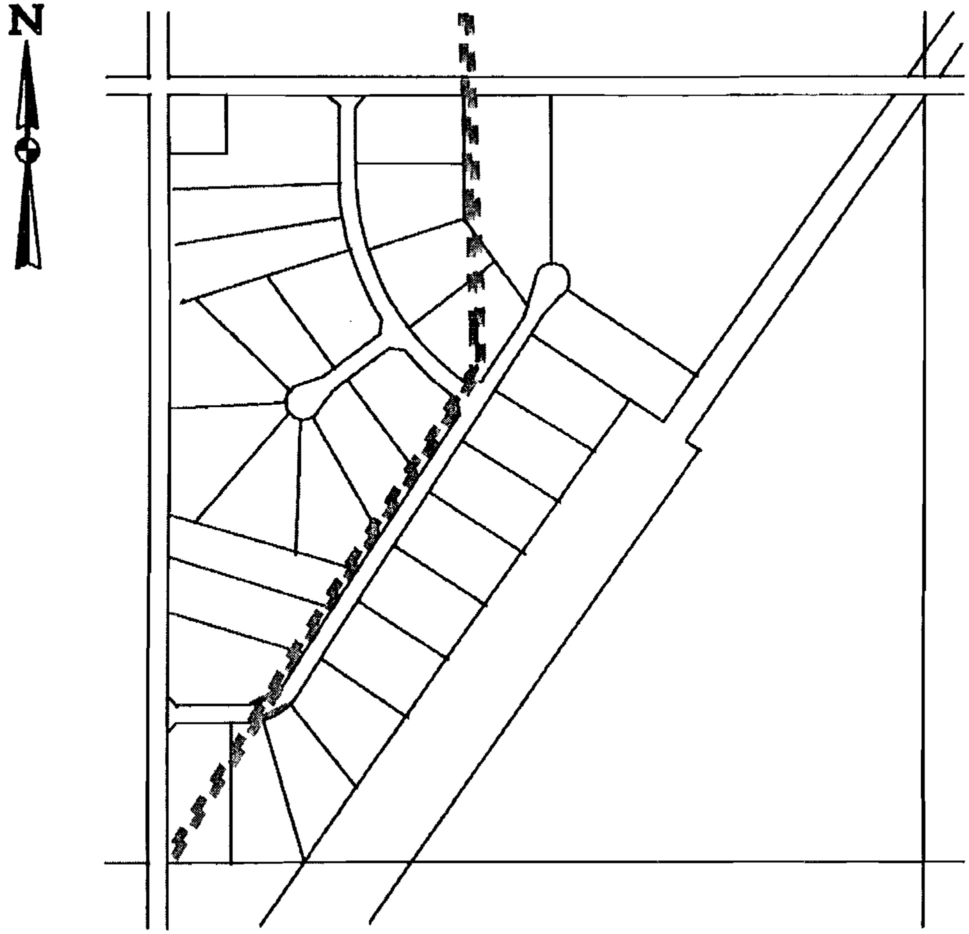
- 10" OD/HVP Product Pipeline/butane
- built in 1956
- CSA-Z662-96/class 1 designation

CASE STUDY # 2/MUNICIPAL DISTRICT OF CLEARWATER



REVISED

CASE STUDY # 2/MUNICIPAL DISTRICT OF CLEARWATER



- 10" OD/HVP Product Pipeline/NGLs
- 8" OD/LVP Product Pipeline/Condensate
- (10") built in 1960
- (8") built in 1961
- CSA-Z662-96/Class 1 designation

REVIEW OF THE ISSUES

- COMMUNICATION
- COST
- TRANSITIONAL CHANGE
- INCONGRUENT LEGISLATION
- DATA INTEGRITY
- RISK MODELLING?

OIL & GAS BUSINESS CYCLE

PLANNING

EXPLORATION

DEVELOPMENT

PRODUCTION

RESTORATION

THE LEGISLATION (BOILING IT DOWN!)

6.2 CODES & STANDARDS

PIPELINE REGULATION

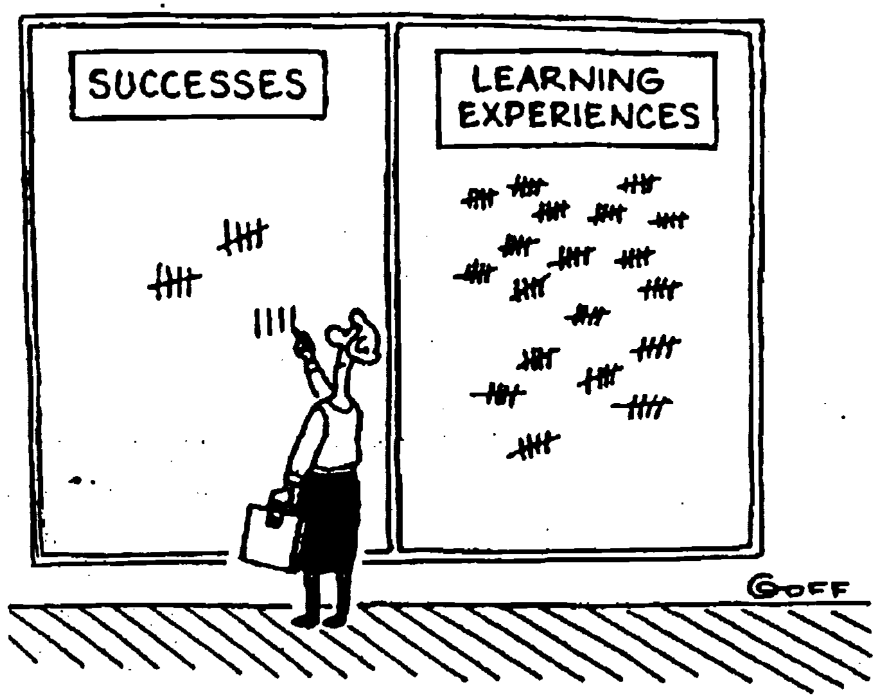
PIPELINE ACT

AEUB → **CSA-Z662-96-OIL & GAS PIPELINE SYSTEMS** ← NEB

NATIONAL ENERGY BOARD ACT

ONSHORE PIPELINE REGULATIONS

5.1 GENERAL


SUCCESSES
LEARNING EXPERIENCES
GOFF

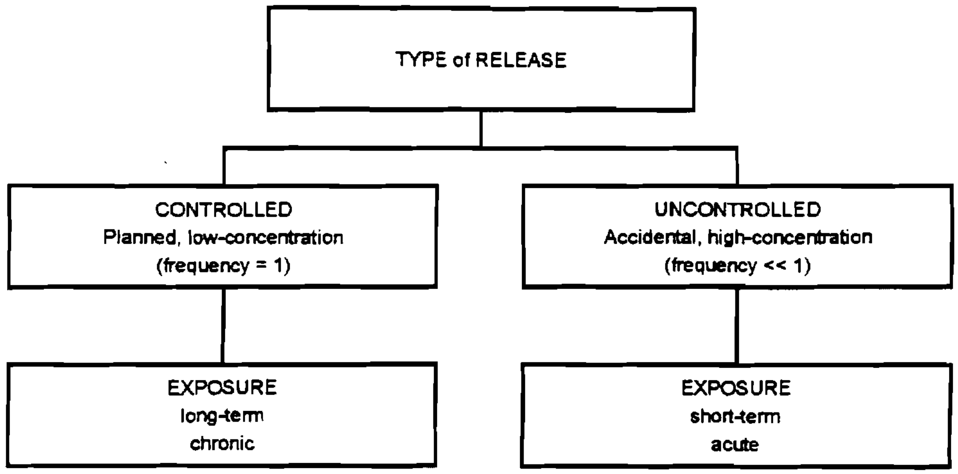
LAND USE PLANNING NEAR (HVP) PRODUCT PIPELINES

- **O&G (land use) PERSPECTIVE**
  - ⇒ **CASE STUDY #1**
    - ⇒ **MIACC INITIATIVE**
- **REVIEW (land use) PLANNING PROCESS**
  - ⇒ **CASE STUDY #2**
- **REVIEW OF THE ISSUES**
  - ⇒ **CAPP/EUB INITIATIVE**
- **Q & A**

PRE-WORKSHOP TUTORIALS

LAND USE PLANNING ADJACENT TO PIPELINES - AN OVERVIEW

Example of Difference Between:
Environmental & Health and Public Risk



✓ The Basics

Overview of the Process: "Integrated Risk Management"

– THE PROCESS ITSELF
MANAGEMENT AND ORGANIZATION

– RISK ASSESSMENT
- Risk Analysis
- Risk Communications
- Public Consultation

– RISK CONTROLS

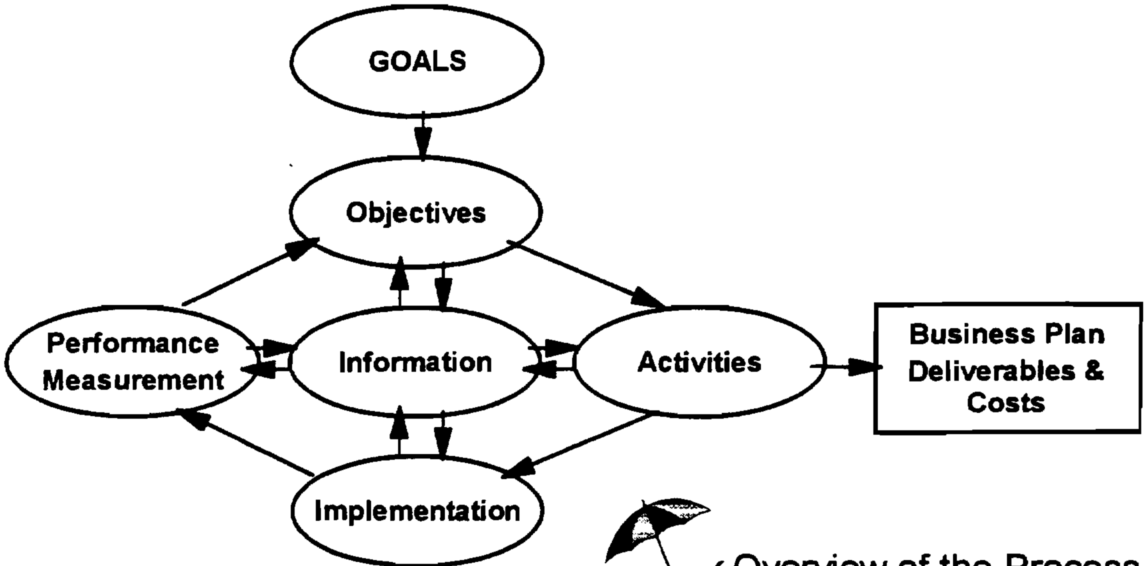
– AUDIT, INSPECTIONS AND MONITORING

Definition of an Integrated Risk Management Process

It is a process or framework that supports the systematic analysis, assessment communications, actions and accountability for risk.

✓ Overview of the Process

Management & Organization of the Process, High-level View



✓ Overview of the Process

Management & Organization of the Process

- VISION (EUB - Public Safety Review Initiative)
  - A society where risk and safety decisions are a shared responsibility based on consensus and result in the protection of the public and confidence in the system (PSRI).

- GOALS
  - Ensure that industry, through the regulatory process, protects the public's safety (3-yr Business Plan).
  - Support an integrated risk management process within the EUB that results in responsible, unbiased decisions about public safety and risk (PSRI).

✓ Overview of the Process

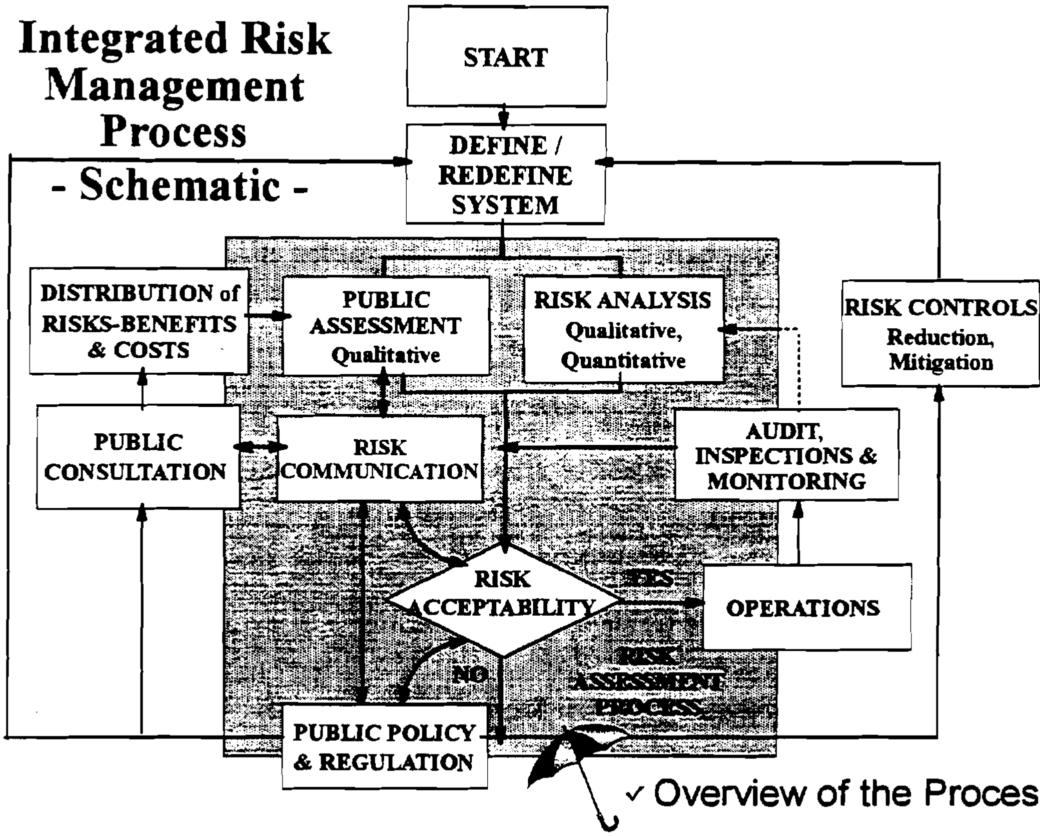
Management & Organization of the Process

- OBJECTIVES (PSRI)
  Ensure that Public Safety and Risk Management Policy:

- makes sense to the stakeholders and is supported by the facts;
- provides an effective, consistent and equitable approach to safety that includes all hazards and systems;
- produces noticeable improvement;
- shifts regulatory process to decision-support & audit role;
- promotes the development and maintenance of appropriate information & expertise and;
- maintains public confidence in the process.

✓ Overview of the Process

Integrated Risk Management Process
- Schematic -



✓ Overview of the Process

Risk Assessment

- The process of making a judgment about the acceptability of a risk .
- Risk Analysis
  - Hazard Identification
  - Frequency Analysis
  - Consequence Analysis
  - Risk Estimation
- Risk Evaluation
  - Risk Communication
  - Public Consultation

✓ Detail - Risk Assessment

Objectives of Risk Assessment

- To screen or bracket the range of risks for future study;
- To evaluate a range of risk reduction measures;
- To prioritize safety investments;
- To predict financial risk;
- To assess employee risk;
- To estimate public and environmental risk;
- To meet legal or regulatory requirements and;
- To assist with emergency planning.

✓Detail - Risk Assessment

Risk Analysis

- QUALITATIVE ANALYSIS
  - Checklist
  - Matrix

- QUANTITATIVE RISK ANALYSIS

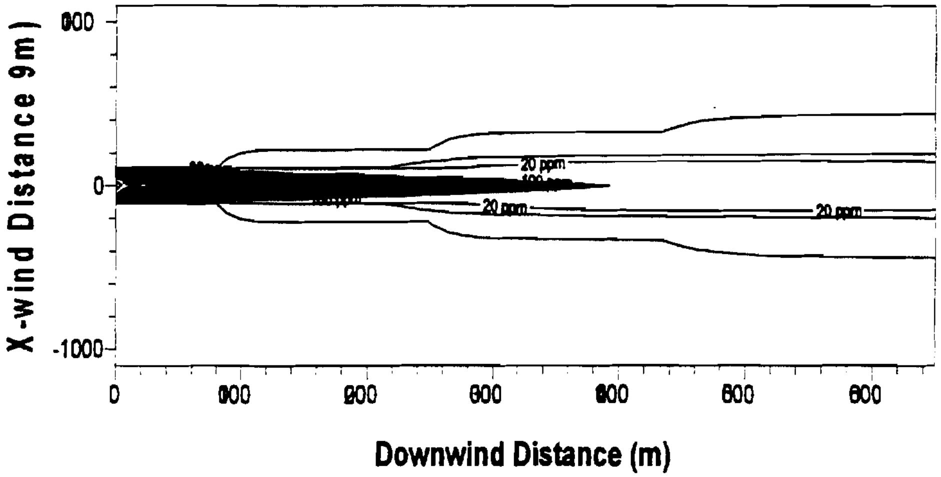
  (QRA - Numeric: e.g. 1 in 10,000 chances of fatality per year)
  - Frequency Analysis
  - Consequence Analysis

Source	(e.g. mass release rate calculations)
Transport	(e.g. dispersion modeling)
Receptor	(e.g. dose / exposure, PROBIT analysis)
	* GASCON2 COMPUTER MODEL

- UNCERTAINTY

✓ Detail - Risk Analysis

Example - Consequence Analysis



Detail - Risk Analysis

Risk Controls

- Prevention *(before the fact)*
  Activities and measures that ensure that a hazard is not released into the environment. Refers to measures applied to prevent releases from occurring (e.g., design standards, monitoring and auditing).

- Reduction *(during the fact)*
  Activities and measures that limit or alter the mechanisms, size, duration, or pathway of a hazardous release. Frequency reduction activities reduce the number of failures (e.g. corrosion inhibition, dehydration, etc.). Consequence reduction refers to measures that apply during an accidental release (e.g. E.S.D. valves reduce the mass released).

- Mitigation *(after the fact)*
  Activities and measures that reduce the severity or change the exposure pathway of a hazard once it has been released into the environment (e.g., sheltering or evacuation).

✓ Detail - Risk Controls

Design Standards

- **CSA Z662**, provide initial level of reliability e.g.
- **CSA Z662 CLASS CODES,** provides additional reliability within 200 m of pipeline right-of-way, focus is on frequency reduction.

✓Detail - System Design

Risk Controls

✓ Detail - Risk Controls

- **LAND CONTROLS**
  - **EASEMENTS,** provide an area over a pipeline ensuring legal rights-of-entry and restrictions on land use.
  - **BUFFER ZONES,** an area that provides arbitrary distance for managing encroachment and planning issues (e.g. utility corridors).
  - **CAVEATS**, restrict allowable activities.
  - **SETBACKS**
    an area adjacent to a pipeline or hazardous facility used to reduce the number of provide potentially exposed to a hazard through land use planning requirements (e.g. EUB Sour Gas Setbacks, MIACC Guidelines - Focus is on Risk Reduction).

Risk Controls

✓ Detail - Risk Controls

- **PREPAREDNESS & RESPONSE**
  - **EMERGENCY PLANNING ZONE (EPZ) ***

    An area, inside which, actions can be taken that will result in the reduction or mitigation of consequences associated with a hazardous release. This area is defined by the extent of serious, irreversible adverse effects to people, using the most current understanding and reasonable and conservative assumptions. Expected actions should be documented and communicated directly to the public.

  - **RESPONSE PLANNING AREA (RPA, MIACC)**

    An area, inside which, developers (industry or other) should begin to consider public safety provisions. This area is defined by the extent of inconveniences or minor consequences to people (e.g., odour, noise, other nuisances), using the most current understanding and reasonable and conservative assumptions. Focus of RPA's is as a planning tool for municipal planners. Expectation for indirect communications.

* Under review.

Existing Approach for EPZ's

✓Detail - EPZ's

EPZ's = f {Consequence = f { Concentration}}

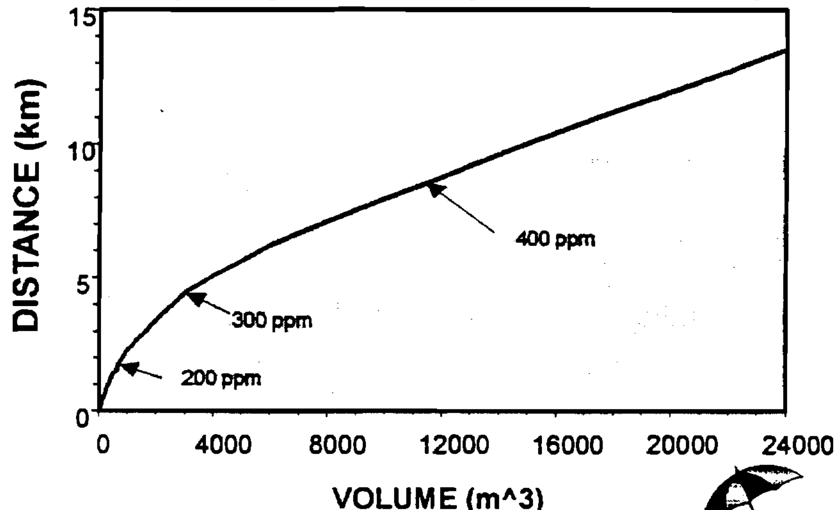
$$\text{Concentration} = \frac{m}{\text{PI} * \text{Sigma x} * \text{Sigma y} * U}$$

NOTE: End point considered is fatality. Evacuation is principle control measure applied. Ignition handled separately.

	SOURCE	TRANSPORT	RECEPTOR	METHOD
WELLS	constant rate (steady state)	F 2 Stability	100 ppm / 30 min.	equation
PIPELINES	declining rate (transient)	F 2 Stability	200 ppm / 30 min. 300 ppm / 30 min. 400 ppm / 30 min.	equation plus multiple-puff

Existing Approach

Emergency Planning Zones for Pipelines



✓ Detail - EPZ's

Suggested Approach for EPZ's

Consequence = f {Concentration, Fluctuating Load, Cumulative Toxic Load and, Event Time}

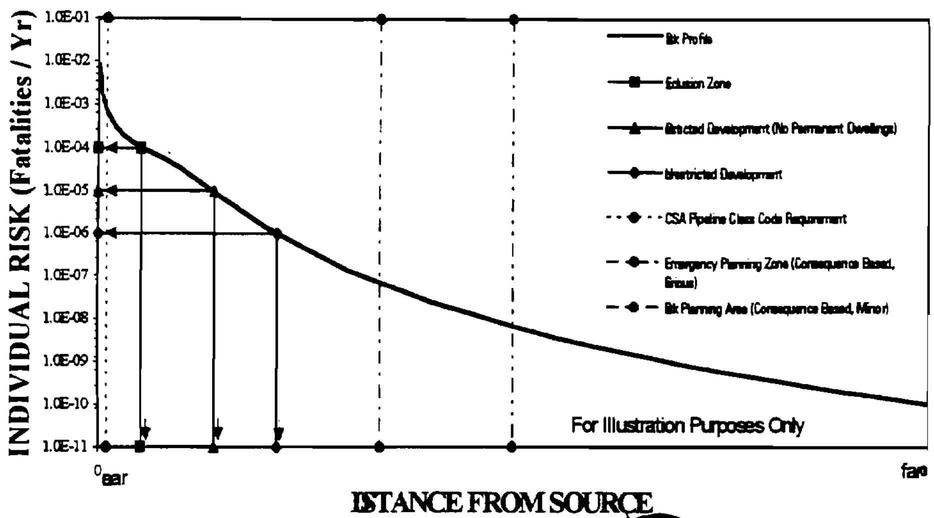
- *Selection of Appropriate End Point (e.g. Serious Irreversible Adverse Effects)*
- *Use of Elevated Release Equation*
- *Use of Accepted Consequence Model (e.g. GASCON2)*
- *Consideration of All Weather (F-2 may not produce highest GLC's.)*

EPZ's = Consequence Zone + Response Planning Area

- *Will allow consideration of SHELTER POLICY, IGNITION POLICY and ZONE MANAGEABILITY and EVACUATION.*

✓ Detail - EPZ's

Application of Risk Controls



✓ Detail - Risk Controls

Audit, Inspections & Monitoring

- **PHILOSOPHY of SAFETY**
  - Vision, Goals and Objectives
- **PROCESS to ENSURE SAFETY**
  - Description of the Process
  - Defined Roles and Responsibilities
  - Standards, Guidelines and Criteria

    (e.g. Emergency response Plans, Recovery Plans, etc.)
- **RESOURCES TO DELIVER SAFETY**
  - People (e.g. number, accountability to roles and responsibilities and, training)
  - Equipment
  - Money
- **DOCUMENTATION, INFORMATION & DATA**

✓Detail - Audit, Inspections & Monitoring

Risk Communication

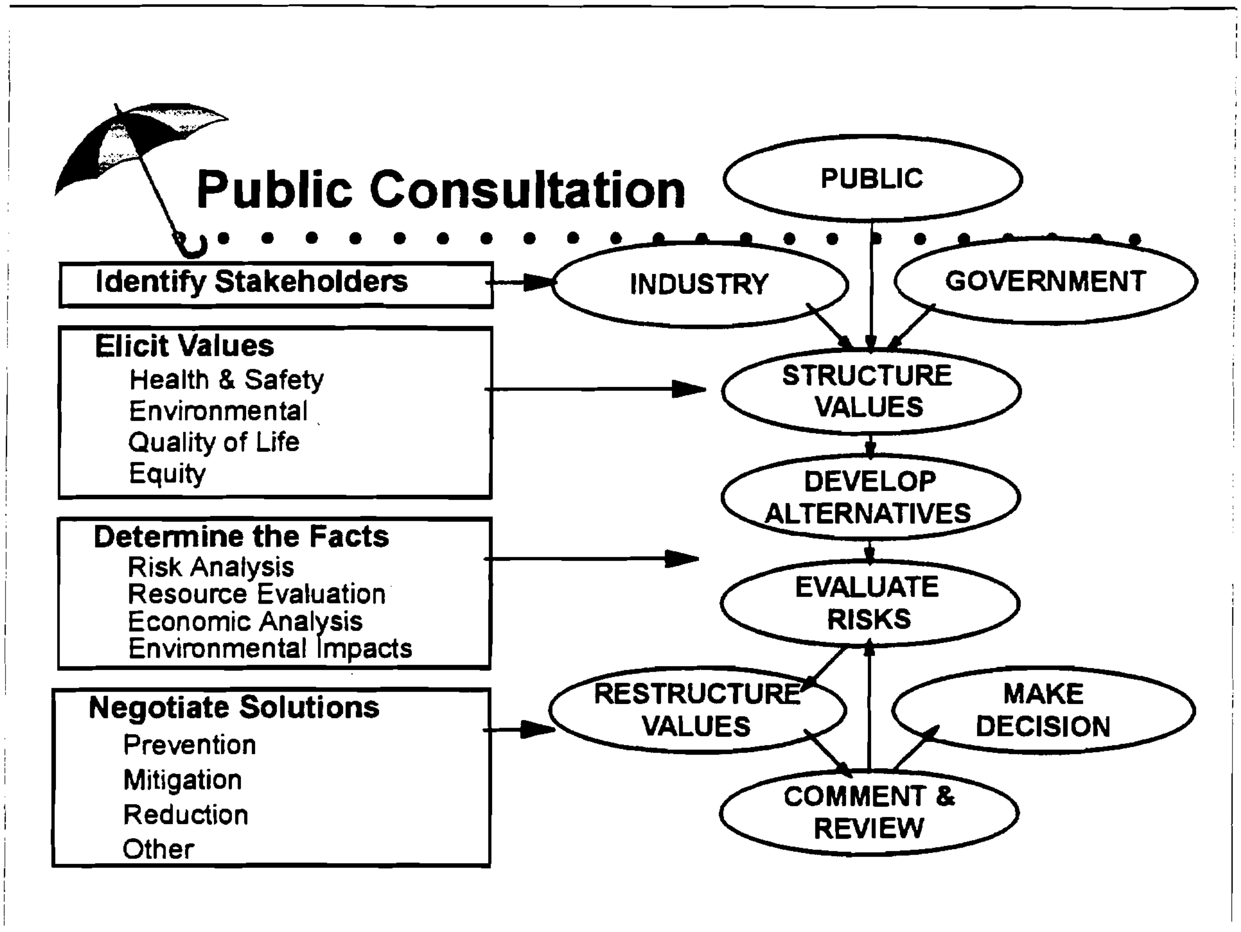
- Principles of Risk Communications
- Trust and Credibility
- Public Perceptions of Risk
- Public Meetings / Public Availability
- Non-verbal Communication
- Handling Tough Questions
- Risk Communication and the Media

✓ Detail - Risk Communication

Public Consultation

- Public Need to be Informed
- Access to Accurate and Timely Information
- Participation in the Decision Process
- Need to Communicate Earlier than Later
- Partnership in Planning
- Respect the Values of Others
- Recognize the Contributions of Others
- Build Consensus

✓ Detail - Public Consultation


Public Consultation
PUBLIC
Identify Stakeholders
INDUSTRY
GOVERNMENT
Elicit Values
Health & Safety
Environmental
Quality of Life
Equity
STRUCTURE VALUES
DEVELOP ALTERNATIVES
Determine the Facts
Risk Analysis
Resource Evaluation
Economic Analysis
Environmental Impacts
EVALUATE RISKS
Negotiate Solutions
Prevention
Mitigation
Reduction
Other
RESTRUCTURE VALUES
MAKE DECISION
COMMENT & REVIEW

Discussion

RISK ASSESSMENT METHODOLOGIES FOR PIPELINES

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ABSTRACT

Risk assessment is being increasingly used in safety-related decision-making across different industries around the world. Risk-based management recognizes that the chance of hazardous events may never be brought down to zero, and that solely consequence-based decisions will likely result in unnecessarily conservative designs, or in "sterilization" of unnecessarily large tracts of land near hazardous facilities such as pipelines carrying dangerous goods. The paper describes a generic risk management framework and risk assessment methodologies that are in common use today. A quantitative methodology is described which is compatible with the recent MIACC (Major Industrial Accidents Council of Canada) Risk Acceptability Guidelines and which is particularly suitable for risk-based decision-making. This methodology has also been adopted by the MIACC Risk Assessment Expert Committee.

Risk assessment comprises of several well defined and established steps. Beyond the **initiation** phase where a **scope** is defined through stakeholder participation, risk assessment consists of a **risk analysis** step where risks are identified and studied using various qualitative, semi-quantitative, and/or quantitative techniques, and then a **risk evaluation** step where an assessment of acceptability of risk is made. Within the risk analysis step, **risk estimation** refers to the rigorous quantification of risk profiles around a risk source, having already estimated the frequencies and consequences of hazardous events that are possible for a risk source. A risk source can be a dangerous goods transportation corridor (pipelines, rail lines, highways, waterways), or an industrial facility such as a chemical plant or storage facility.

The paper describes the qualitative, semi-quantitative, and quantitative techniques one can apply for pipelines. The basis of the rigorous risk estimation methodology for pipelines is also described. This methodology had first been developed for rail transportation of dangerous goods and later adapted for pipelines, waterways and fixed facilities.

Case studies are presented showing applications of these methodologies to pipelines, in conjunction with the new MIACC risk acceptability guidelines.

1. RISK-BASED MANAGEMENT

Risk is defined as a measure of frequency and severity of harm due to a hazard. In our context of pipeline systems, the hazard commonly is the presence of toxic, explosive and/or flammable chemicals in the pipeline or its associated systems. The objective of risk management is to prevent or reduce the loss of life, illness or injury, or damage to property or the environment, due to hazardous events that could take place during the operation of our pipeline system.

Generally, hazardous consequences of technological risks are thought of in six broad classes:

- *public* consequences, commonly measured in terms of "public" fatalities or injuries,
- *employee* consequences, measured in terms of fatalities, injuries, or lost time, which can also be translated into financial terms, and cost of potential law suits and fines for the company,
- *production loss*, measured in weeks or months of lost production, easily translated into financial terms,
- *equipment* damage, measured as capital loss in financial terms,
- *environmental* consequences, commonly measured in terms of clean-up costs and regulatory fines, but could also include categories such as loss of resource use,
- loss of *market share* as a result of loss of goodwill, measured in financial terms.

With so much at stake, companies and regulators have started paying a great deal of attention to understanding the risks of technological operations.

Once risks are understood (through *risk analysis*), they can be *evaluated* in terms of their acceptability, and, if deemed necessary, reduced through application of *risk control* measures. This process is shown in Fig. 1, where the continuous nature of *risk management* is emphasized through the feedback loops, also leading to continuous improvement. Where risk levels are deemed acceptable, vigilant periodic *monitoring* of the state of affairs is necessary.

A significant component of the risk management process is *stakeholder participation*. Stakeholders include management, employees, members of the public, regulatory bodies, industry associations, and shareholders. Involvement of *each and every* stakeholder at the appropriate stages in the process is imperative for successful functioning of the process.

2. RISK-COST-BENEFIT AND EVALUATING ACCEPTABILITY

The myriad of potential adverse consequences that could result from a major hazardous event in an operating facility *should not* preclude us from operating that facility, *provided that* we can demonstrate *acceptability* of the risks.

Here, we must differentiate between *voluntary* and *imposed* risks.

In case of voluntary risk, and with the pre-condition that the risk receptor understands the risk – we can deal with the issue of how this can be accomplished a little later – one can make one's own decisions regarding the level of risk one is comfortable with. In cases of imposed risks, such as for members of the public living near pipelines carrying hazardous materials, generally accepted minimum standards are necessary. The MIACC public risk criteria (Fig. 2) are one example of such standards.

Acceptability further implies a balancing of risks against real and perceived benefits of the undertaking. Cost of risk control measures (i.e., increasing wall thickness of a containment, limiting development of land near hazardous facilities) must be balanced against the amount of risk reduction afforded by these measures.

3. HOW TO *UNDERSTAND* RISK?

Understanding risk requires careful analysis. There are well-established techniques to do this. Perhaps the single most important step in understanding risk is *identification of hazards*, by answering the question: *"What can go wrong?"*

Available techniques include: examining historical records, checklists, what-if analyses, failure modes and effects analyses (FMEA), hazard and operability studies (knowledge-based or guide-word HAZOP), and fault and event trees (qualitative), in increasing order of sophistication.

Depending on the objective of the assessment, the focus may be on major incidents such as pipe ruptures (e.g., in public safety studies), or may include much lesser events such as equipment failure even though they may not have direct safety impacts (e.g., in developing reliability-based maintenance programs).

The next step in the process is for each event on the list to answer the question: *"Is this event worth spending money to reduce either its frequency, or consequence, or both?"*

To answer this question, we have a few broad options:

- Index methods
- Matrix methods
- Quantitative risk methods

The first two are very useful in ranking and prioritizing. They can also be used in deciding acceptability; however, consistency with the more universally applicable (at least fundamentally speaking) guidelines (such as in Fig. 2) is difficult to establish. The third approach directly addresses this problem while at the same time providing a solid basis for ranking and prioritization.

4. INDEX METHODS

In the context of pipeline systems, there is one established index method: that developed by Muhlbauer (1992). The method as adapted for the present paper is summarized in Fig. 3. The "relative risk index" (R) is formed by multiplying a "frequency index" (F) and a "consequence index" (C).

The frequency index consists of the inverse of the sum of four different indices ($F = 1 / (I_1 + I_2 + I_3 + I_4)$), each representing a different category of factors which would control the frequency of a rupture or leak occurring. The list of these controlling factors constitutes an excellent compilation and is quite comprehensive. It can be used as the basis of a checklist or to assist in building qualitative fault trees.

The consequence index is a measure of the impact potential of a release from the pipeline, taking into account factors such as toxicity and flammability (Hazard factor), and potential to form gas clouds (Dispersion factor).

Since the controlling factors for frequency and consequence are each represented by non-dimensional numerical weights which are somewhat arbitrary, the risk index can only be used in comparing one pipeline segment with another. R, F and C are all non-dimensional, and therefore are not true measures of the quantities they represent. Hence, although they *may* be useful in prioritizing which factor to go after first (only if the weights accurately represent the realities of a given operator), they *cannot* be used in deciding whether anything *should* be done regarding any or all factors to reduce risk in the context of the more universal risk acceptability guidelines for public safety. A case study involving the use of this index is presented later in the paper.

5. MATRIX METHODS

Our next option in our quest for understanding and evaluating risk is to apply the matrix methods. In this approach, the frequency and consequence of each event on our list of hazardous events are estimated in terms of commonly understood units (e.g., number of events/year for frequency, fatalities/event or \$ cost/event for consequence). The level of sophistication in establishing the magnitude of these parameters depends on the desired accuracy.

The options include (in the order of increasing sophistication):

- for frequency estimation: expert judgement, historical event data analysis, external event analysis, common cause event analysis, fault and event trees (quantitative),
- for consequence estimation: expert judgement, historical event data analysis, consequence modelling (which, in turn, may be done with varying degrees of sophistication).

It is *essential* that consequences are estimated in all categories of impact (public, employee, production, etc.).

Once the (frequency, consequence) pair is estimated for each event (f_i, c_i), then the event is classified into pre-established frequency and consequence categories, such as those shown in Tables 1 and 2. Here, we have used a 4 x 4 categorization scheme, but others are also possible. The significance of the event can then be evaluated by using a matrix such as shown in Fig. 4. Note the asymmetry in this matrix which reflects the higher importance we tend to give to low-frequency, high-consequence events.

The matrix approach is very commonly used in the chemical process industries, and is gaining popularity in pipeline applications.

The focus in the matrix approach is individual events, and therefore the approach is useful in ranking priorities for risk control measures designed for controlling specific events. The categorization and ranking are somewhat arbitrary, and decision-making is based on this arbitrary foundation. Also, a fundamental difficulty in pipeline applications of the matrix method is in the estimation of the frequency component: "Do we express this quantity in terms of events/year per kilometre of pipeline, per 100 kilometres, or over the whole pipeline network of each company?"

The approach does not deal with the cumulative nature of risk from different events that could occur at an industrial facility, and therefore does not lend itself to be used in conjunction with public risk acceptability guidelines.

6. QUANTITATIVE RISK METHODS

The third option we have for analyzing and evaluating risk is to apply what is commonly termed as Quantitative Risk Analysis (QRA) techniques.

This approach follows the same steps as those used in the matrix methods up to and including estimation of the (frequency/consequence) pair, using any of the methods mentioned above.

At this point the QRA method uses the following definition for estimating a risk measure:

R = FC,

which can also be interpreted as a "probability-weighted consequence".

A distinctive requirement for public risk estimation, however, is information on the variation of the potential damage level as a function of distance from the event location in all directions. For example, in the case of a pipeline rupture carrying a flammable gas followed by immediate ignition, the variation with distance of thermal radiation flux around the fire, and of injury or death probability for a human receptor (Fig. 5a) are required before we can proceed to the next step in the analysis. These curves are generally termed the "individual consequence profiles" for each event.

The next step, which is characteristic of the QRA approach, is the estimation of "individual risk", again as a function of distance, by multiplying the death probability curve (P_d) with the corresponding frequency of the event (Fig. 5b). This is termed the "risk estimation" step (see the steps in the "risk analysis" box in Fig. 1).

If there are more than one possible event contributing to the overall risk, then the individual risk at each distance from each event is added to account for the cumulative nature of risk.

For point sources of risk, and for hazards which do not depend on meteorology (e.g., most explosions), then estimation of individual risk at a receptor point is straightforward:

$$I(P;P') = F\,P_d(P;P') = \sum_h F_h\,P_{d,h}(P;P')$$

Here, P' indicates the risk source, h indicates hazardous events.

For linear sources, such as pipelines, the event can occur at any point on the pipeline, Therefore, at a receptor point P, the hazard level will be different depending on where the event occurs relative to the receptor. This is illustrated in Fig. 6. The total individual risk at P from events anywhere along the pipeline can be calculated through an integration along the pipeline. The integration needs to be only between two points on the pipeline beyond which the event would not impact the receptor P. The distance between these two points which determine the limits of integration is termed the "interaction length".

$$I(P) = \int F'(P')\,P_d(P;P')\,ds'$$

Here, F'(P') indicates the event frequency per unit length of the pipeline, P' indicates the functional dependency of accident frequency on location, i.e., event frequency can vary along the pipeline. This integration is usually taken numerically.

For hazards which depend strongly on meteorology and wind direction, such as gas clouds, the treatment is more complex. Joint frequency of occurrence of different atmospheric turbulence conditions with wind speed and direction needs to be introduced in both of the above equations.

The full rigorous treatment of this risk estimation step can be found in Alp and Zelensky (1996).

The individual consequence and risk profiles for each event are used for ranking the significance of that event and prioritizing risk control options.

The cumulative individual risk profile can be compared to the public risk acceptability guidelines, such as those shown in Figure 2, for making decisions on land use and other risk control decisions. An application of this approach to natural gas liquids pipelines is presented in Zelensky and Springer (1996). Another application to sour gas facilities is shown in Fig. 7.

7. CASE STUDY: AN APPLICATION OF THE INDEX AND QRA METHODS TO PIPELINE ENVIRONMENTAL RISK MANAGEMENT

Company X operates several thousand miles of pipelines carrying hydrocarbon liquids. Some sections of the pipeline are bare, others are coated, all with cathodic protection. The company is considering reconditioning, including coating the bare sections for a cost of $7.5 million, including the cost of infrastructure upgrading over a 40 year estimated life of the line. The cost of infrastructure upgrading for uncoated pipe for the same lifespan is $2.4 million. The decision to coat rests on an evaluation of the potential spill risk costs of reconditioned versus uncoated pipe. Based on the company's experience, each spill costs between $4 million and $8 million, including cleanup and litigation costs.

Application of the Index Approach

Considering the characteristics of the pipeline, and applying the weighting factors given by Muhlbauer (1992) to each of the controlling factors, the frequency index for the uncoated pipe was calculated to be F_1 = 1/288, and for the reconditioned pipe to be F_2 1/308 (the range for this index is from 1/0 to 1/400). These index values do not have any units and have to be converted to annual frequency units before further use.

Historical oil pipeline data indicate a failure frequency of 0.9×10^{-3}/yr.km (Andersen, 1983). No upper/lower range is available from this source. Assuming that this value corresponds to F = 1/200, that the leak frequency range for hydrocarbon pipelines is similar to the range given by CCPS (1989) for chemical industry piping, and that the upper and lower limits of frequency correspond to the upper and lower limits for the index, the index-based frequencies were estimated as 8×10^{-2} leaks over the length and lifespan of uncoated pipe, and as 6.4×10^{-2} for reconditioned pipe. Then the risk cost for the two options are:

$R_1 = 8 \times 10^{-2}$ leaks x $\$l + \$2.4$ million, for uncoated pipe, and

$R_2 = 6.4 \times 10^{-2}$ leaks x $\$l + \$7.5$ million, for reconditioned pipe.

Here, $\$l$ represents the cost of a major leak from the pipeline. The intersection point corresponds to $\$l \sim \$320$ million, indicating that if spill costs are larger than this amount, it would be advisable to recondition the line. Based on company experience with spills, this analysis would not favour reconditioning, but to accept the higher chances of leaks on an uncoated line.

Application of the QRA Approach

The weakness of the index approach, namely, the potential that the weighting factors and the frequency range limits may not be representative of the particular pipeline system being examined, suggested that we should examine the company leak performance using QRA techniques. The leak history of uncoated versus reconditioned pipe within the company's system was examined. The leak frequency was estimated as 4.3 leaks over the length and lifespan of uncoated pipe, and 0.44 leaks for reconditioned pipe. A similar analysis as above indicated that if spill costs are larger than $1.3 million per spill, it would be advisable to recondition the bare sections of the pipeline. Given the experience with cost of spills, the company decided to carry out the reconditioning without further delay.

8. LESSONS LEARNED

The index approach is very powerful in ranking the different types of pipeline systems in terms of their relative safety, *provided that* the weighting factors used with the leak frequency controlling factors do reflect the performance of the specific pipeline system under examination. A company is well advised to adjust these weights to reflect their performance before using the index approach.

The fundamental weakness of the index is that it does not measure a physically meaningful parameter, such as "events/year". The QRA approach, on the other hand, is directly based on such meaningful parameters, and quantification of risk by $R = FC$ (in proper units of measurement appropriate for the purpose of the analysis) directly lends itself to risk/cost/benefit analysis of competing risk control options.

The matrix approach provides a solid foundation for ranking, and further quantification and risk/cost/benefit analysis, but is not sufficient for such analysis. The list of controlling factors which are part of the index method provides an excellent starting point for identifying root causes when used with appropriate quantification techniques. The QRA approach is the only approach which can be used in risk/cost/benefit analyses and when making public safety related decisions using public risk acceptability guidelines.

REFERENCES

Muhlbauer, W.K. (1992) *Pipeline Risk Management Manual*. Gulf Publishing Co., Houston, Texas.

Alp, E. and Zelensky, M.J. (1996) Risk Quantification for Meteorology- and Direction-Dependent Hazards due to Point and Linear Risk Sources. Accepted for publication in J. Loss Prevention in the Process Industries.

Zelensky, M.J. and Springer, W.A.J. (1996) Public Safety Risk Assessment of Natural Gas Liquids Pipelines. Paper presented at the International Pipeline Conference, June 14-19, Calgary, Alberta.

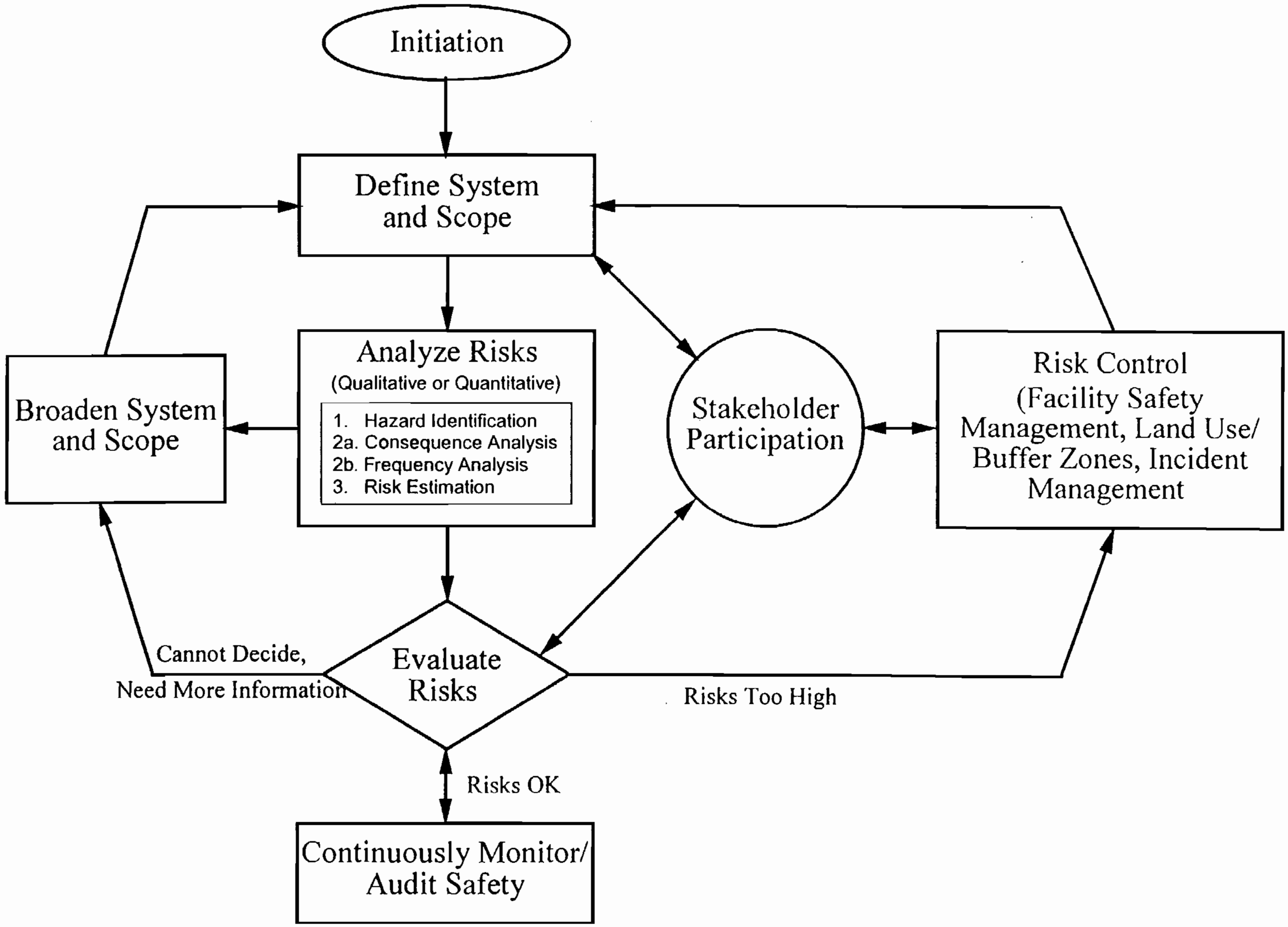


Figure 1 The General Risk Management Process

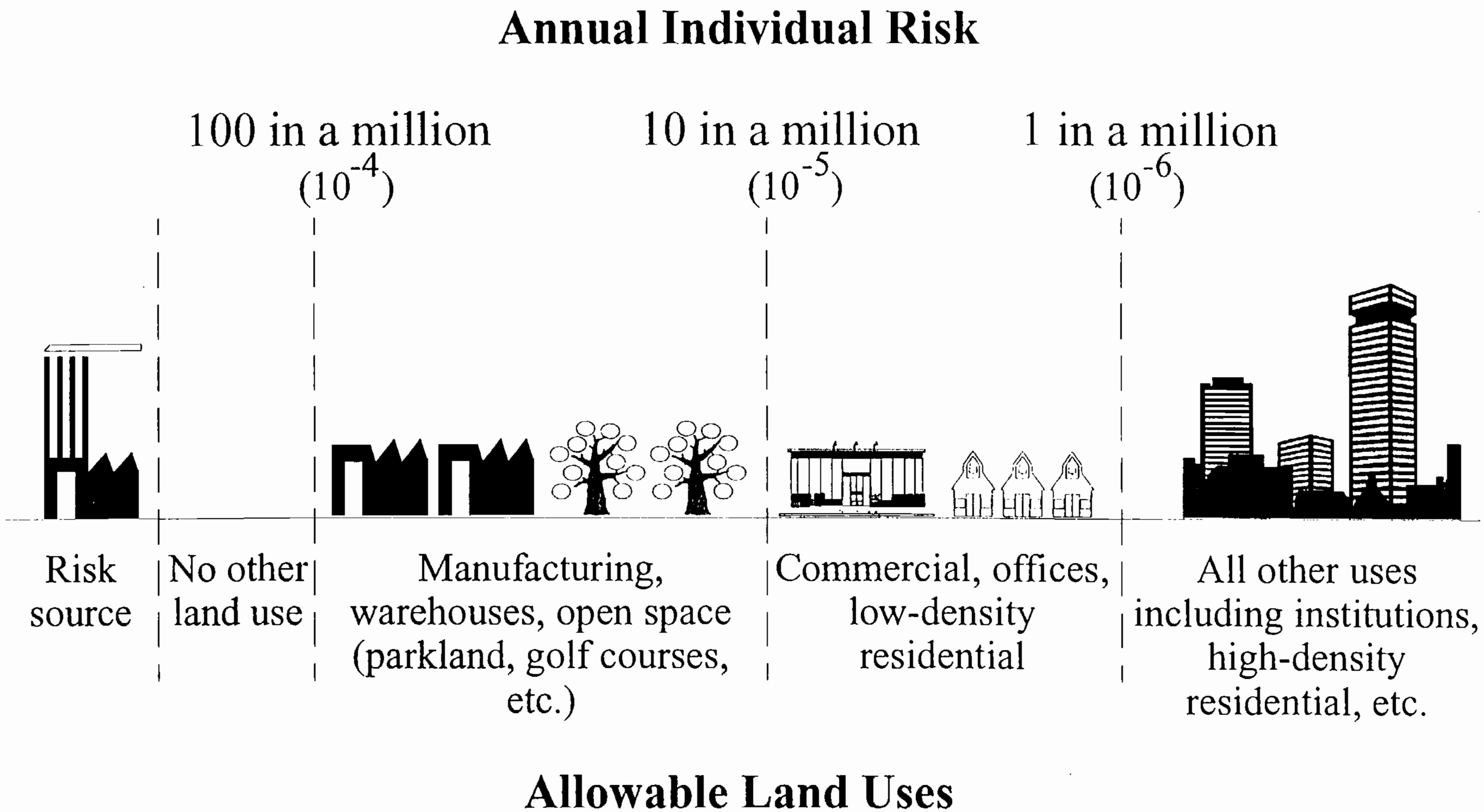
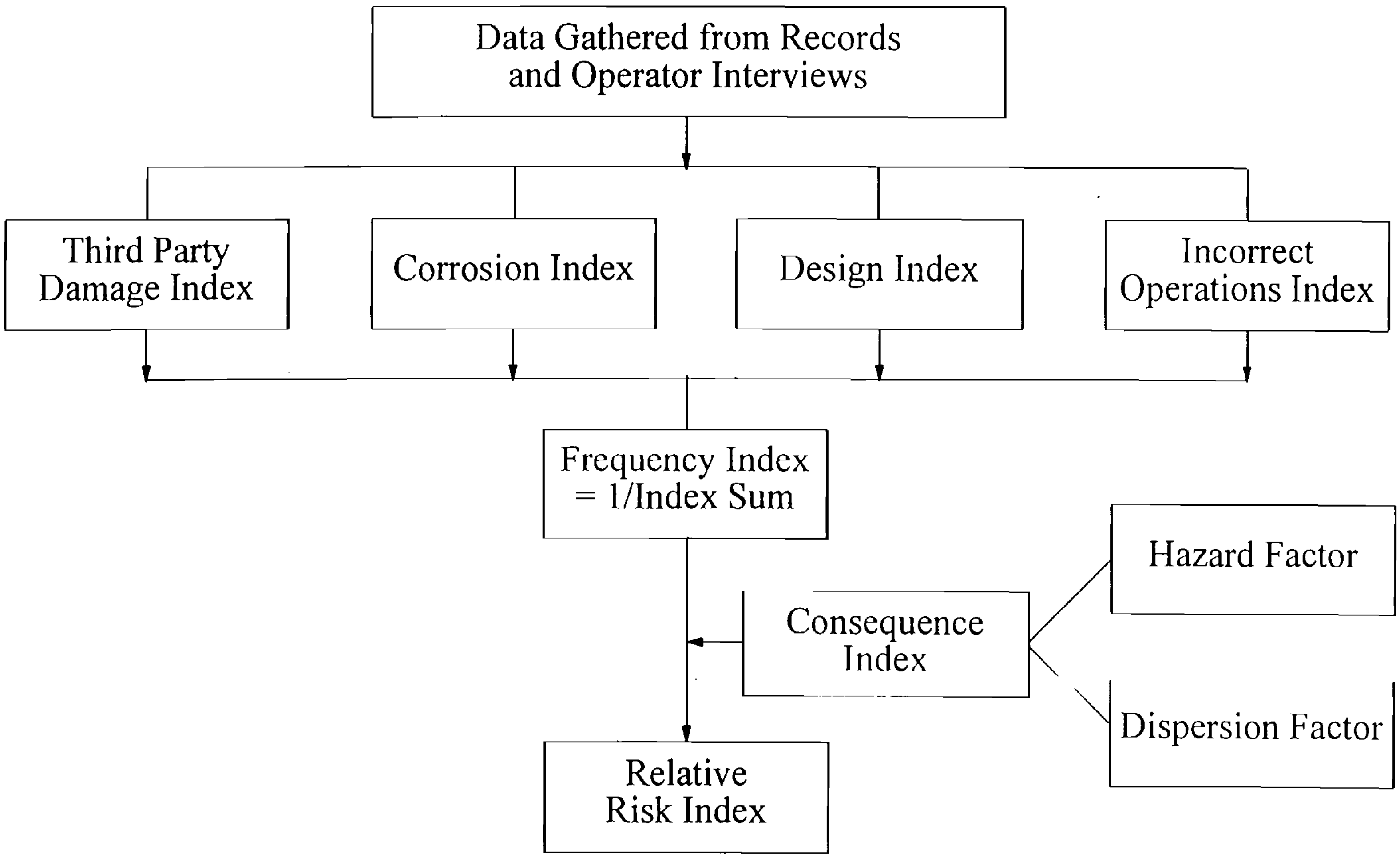


Figure 2 MIACC's Risk Acceptability Criteria

PIPELINE INDEX

COMPONENTS OF RISK RATING FLOWCHART



Relative Risk Index = Frequency Index x Consequence Index

Figure 3 Pipeline Index (Adopted from Muhlbauer, 1992)

Table 1 Example Frequency Categories

(CCPS, 1989)

Category	Description
1	Not expected to occur during the facility lifetime (<0.2/year)
2	Expected to occur no more than once during the facility lifetime (0.5 – 0.02/year)
3	Expected to occur several times during the facility lifetime (1 – 0.05/year)
4	Expected to occur more than once in a year (>1/year)

(BOVAR)

Category	Description
1	Less frequent than 1 in 1,000 per year (<0.001/year)
2	Between 1 in 1,000 and 1 in 100 per year (0.01 – 0.001/year)
3	Between 1 in 100 and 1 in 10 per year (0.1 – 0.01/year)
4	More frequent than 1 in 10 per year (>0.1/year)

CMA

Category	Description
1	1 in 1,000,000 years
2	1 in 100,000 years
3	1 in 1,000 years
4	1 in 10 years

Categorize Events:

- based on expert judgement
- collective judgement
- quantitative techniques

Table 2 Example Consequence Categories

Category	Public Consequences
1	No injury or health effects
2	Minor injury or health effects
3	Injury or moderate health effects
4	Death or severe health effects

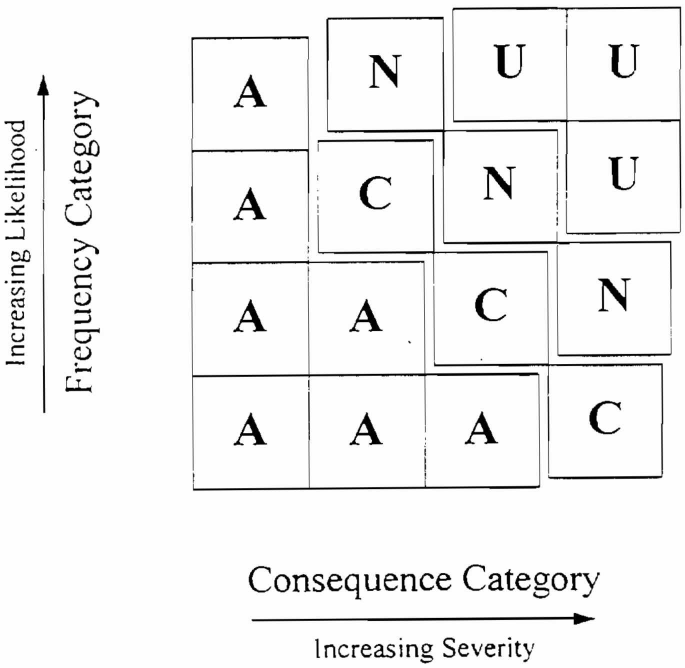
Category	Consequences in Terms of Employee Safety
1	No injury or occupational safety impact
2	Minor injury or minor occupational illness
3	Injury or moderate occupational illness
4	Death or severe occupational illness

Category	Consequences in Terms of Production Loss
1	Less than one week
2	Between one week and one month
3	Between one and six months
4	More than six months

Category	Consequences in Terms of Capital Loss, Facility/Equipment Damage
1	Less than $100,000
2	Between $100,000 – $1 million
3	Between $1 million – $10 million
4	Above $10 million

Category	Environmental Consequences (Dollars, Clean-up Cost/ Regulatory Fines)
1	Less than $1,000
2	Between $1,000 – $10,000
3	Between $10,000 – $100,000
4	Above $100,000

Category	Loss of Market Share
1	Less than 1% of Annual Revenue
2	Between 1% – 10% of Annual Revenue
3	Between 10% – 25% of Annual Revenue
4	More than 25% of Annual Revenue



Number	Category	Description
U	Unacceptable	Should be mitigated with engineering and/or administrative controls to a risk ranking of C or better within a specified time period such as six months
N	Not desirable	Should be mitigated with engineering and/or administrative controls to risk ranking of C or better within a specified time period such as 12 months
C	Acceptable with controls	Should be verified that procedures or controls are in place
A	Acceptable as s	No mitigation required

Figure 4 Example Risk Matrix

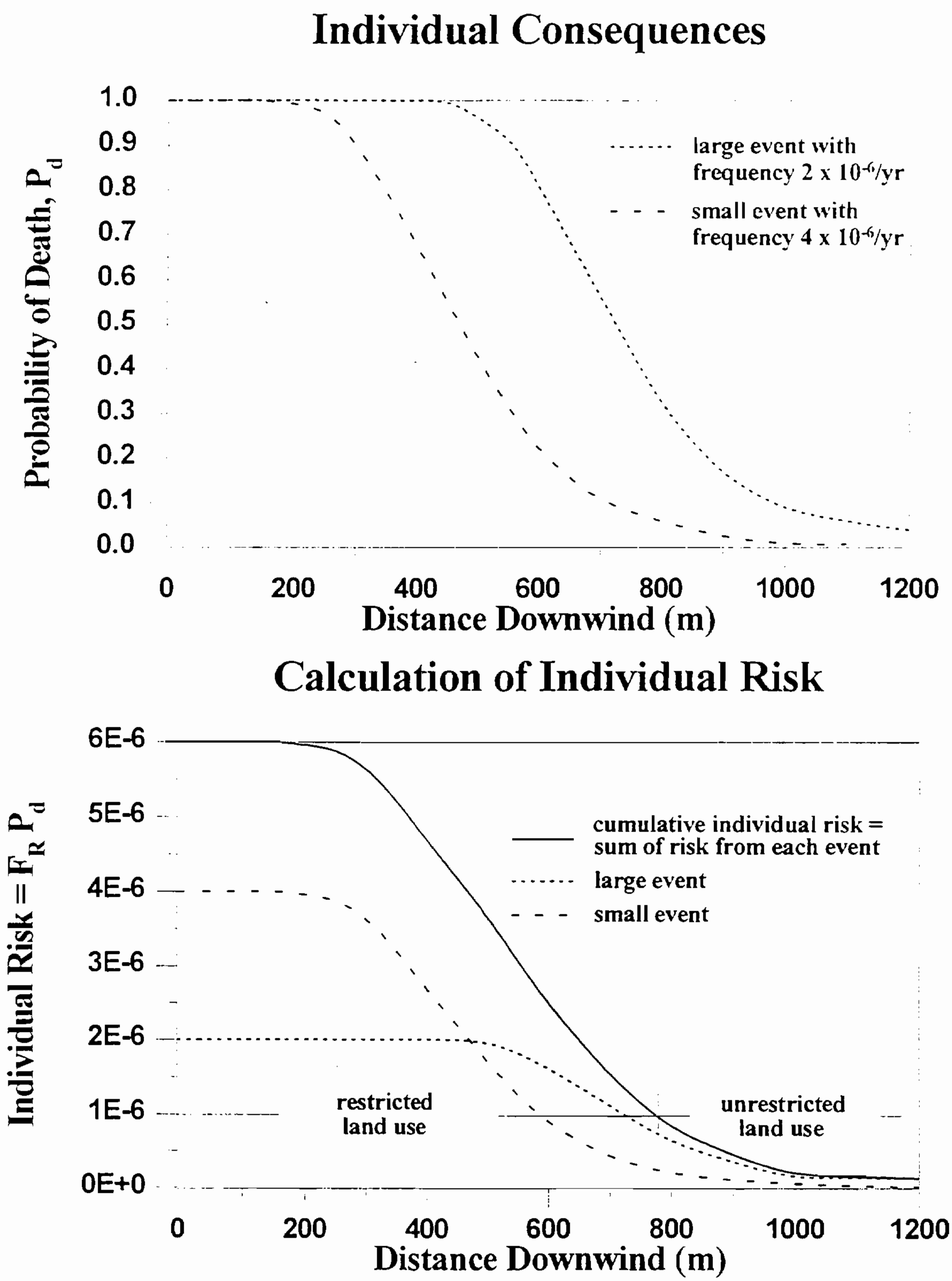
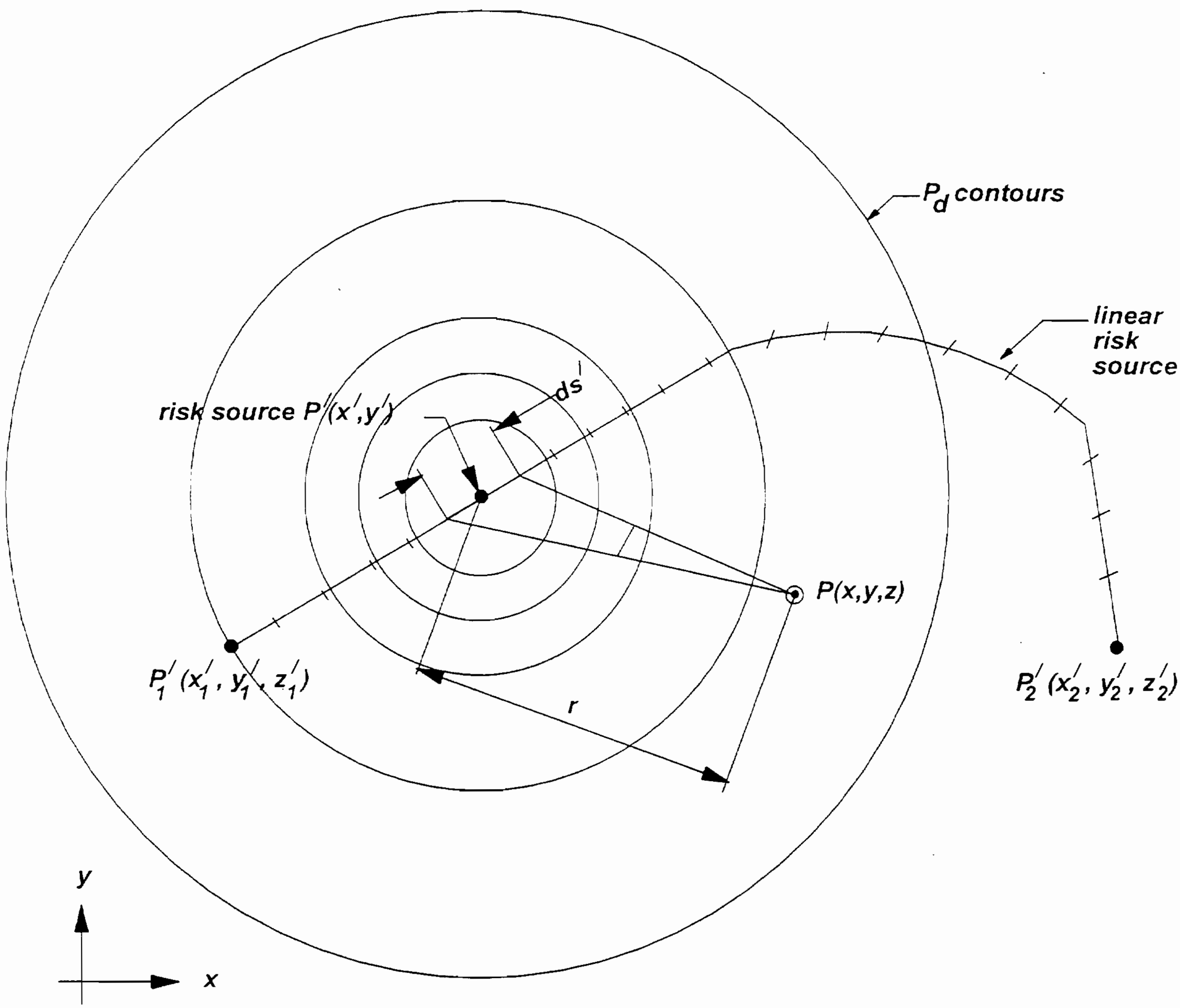


Figure 5 Calculation of Individual Risk



P' = risk source
P = risk receptor

Figure 6 Individual Risk for a Linear Risk Source

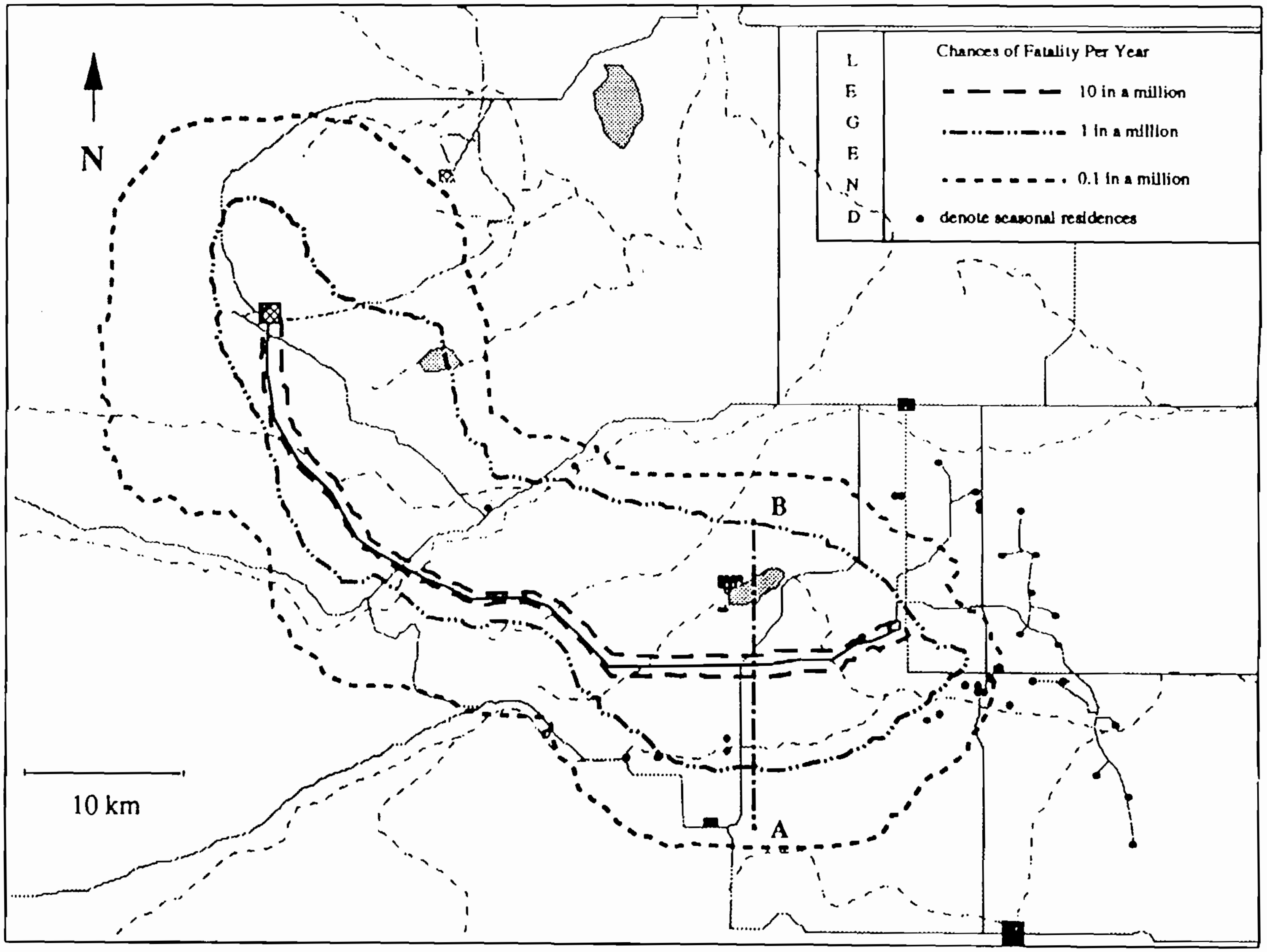


Figure 7 Individual Risk Contours for a Sour Gas Pipeline (the solid line represents the pipeline)

OPENING ADDRESS

by

Bob Reid
Canadian Energy Pipeline Association
Calgary, Alberta

Introduction

- **Firstly, I want to commend the Co-Chairs for pulling together an excellent program this year.**
- **I've looked over the Workshop Objectives, and note they contain key phases that highlight the high level of activity taking place in our industry and point the direction for the future.**
- **For the Pipeline industry, our future includes some difficult, long-term integrity issues. And I'm not just talking about the condition of our pipelines.**

- How we're perceived by the public is as important as how technically competent we are at ensuring pipeline safety.

- But let me first put pipeline safety into some context.

- It is a fact that the transportation of commodities by pipeline is by far the safest mode of transportation available today.

- Consider these statistics for three of the most common modes of transportation--air, marine and rail.

- This past January, the Transportation Safety Board of Canada reported that Canadian-registered aircraft were involved in 335 accidents in 1996, with 44 fatalities. There were 654 marine shipping accidents, with 22 fatalities. Railway accidents numbered 1,287, with 199 fatalities.

- Remember, that's for one year--1996--and it was a better than average year.

- Now contrast those numbers with the statistics for commodity pipelines. There were a grand total of 24 pipeline accidents last year, and no fatalities. In fact, there hasn't been a fatality reported over the past five years.

- From a safety point-of-view, our statistics are an order of magnitude better than the other forms of transporation.

- Having said that, we can't rest on our laurels. There is an upward trend in accidents and mandatorily reportable incidents involving commodity pipelines. And we've experienced an increase in significant in-service failures.

- With the increased frequency of failures comes an increased risk of injury, and the possibility of fatalities.

- A refocussing of our priorities is essential.

Changing Focus

- For TransCanada our change in focus was jump-started somewhat by the in-service failure of our system near Rapid City, Manitoba, in July 1995.

- The Rapid City incident marked several unfortunate firsts: the first time a 42-inch pipeline ruptured, the first rupture west of Winnipeg, the first rupture to damage a compressor station, and the first multiple-line rupture.

- That failure led to the NEB inquiry into SCC . I think everyone present here today would agree that the inquiry was a benchmark event for our industry.

- The inquiry was designed and managed to be a positive event with a fundamentally scientific focus--not an adversarial hearing. It presented a unprecedented opportunity for representatives from government, industry and the public to pool knowledge on a world-wide basis on this difficult issue.

- The result was a very thorough look at Stress Corrosion Cracking, and our industry has thoroughly embraced the NEB's recommendations.

- The SCC inquiry has provided an important vision for the future of pipeline integrity, and I commend the NEB for the leadership they have shown in undertaking this initiative.

- Later this morning John McCarthy of the NEB is going to be giving you that body's perspective on the inquiry. Also, Bob Hill will give you an industry view of what was accomplished.

Risk Assessment/Risk Management

- Over the past 10 years, TransCanada has been building a body of research on SCC. We've compiled a good deal of valuable information, including soil modelling and the results from investigative digs.

- This gathering, analysis and sharing of data is an integral part of risk assessment.

- TransCanada has also been examining pipeline risk analysis as an improved way of establishing integrity plans.

- Although overall pipeline risk is low, we have used risk assessment tools to determine both individual risk and societal risk measures for all known causes of pipeline failure. And we've done this analysis for all of our publics along the right-of-way.

- This has helped decision makers within TransCanada make objective choices among possible risk reduction measures. It's also helped us assign prioritities among the different maintenance activities.

- Another result of our risk assessment exercise has been a management decision to implement a "zero tolerance" policy regarding further preventable in-service failures.

- The use of risk assessment and risk management tools exemplify the proactive approach that our industry is taking.

- You're going to hear a lot about these topics at this workshop. Later this morning Richard Felder, from the Office of Pipeline Safety in Washington, is going to talk about Risk-based Approaches to Pipeline

Safety, Regulation, and Compliance. Doug Clark of Gulf Canada Resources is going to talk about the Pipeline Risk Assessment Steering Committee's progress.

- And Keith Leewis, from the Gas Research Institute, is going to speak to an issue that's at the forefront of our thinking: "Risk Management as an Alternative to Prescriptive Regulation."

- And that's where we're heading: we in the pipeline industry are commited to working together to build our own future.

- We're taking the initiative to bring together industry experts to build common stores of information, data that's accessible to whoever requires it for everyone's benefit.

- And this kind of initiative will lead to the development of tools to fight other threats, like general pipeline corrosion.

Technology

- We have made great strides in new technologies such as the use of in-line inspection tools. This technology is now proven and readily available for mechanical or metallurgical defects, and both internal and external corrosion.

- And an accelerated program of research and testing is now underway to enable SCC to be reliably detected by in-line inspection. CEPA and its member companies are strongly committed to this program.

- In the future we have to focus on where this technology needs to be improved: in areas such as data interpretation, turnaround time, and the ability to extract other information from the results.

- The new generation of pigs will be more efficient. They will have controls which will ensure a more constant speed, resulting in better data, while allowing excess flow to bypass. This gives us the advantage of not restricting our shipments to customers – more integrity surveys can be done with no impact on our customers.

- **We're also pursuing other new technologies, such as aerial leak detection, remote sensing of the right-of-way, remote monitoring of the pipeline, and enhanced predictive models.**

- **Over the next couple of days you'll have a chance to hear about future trends: the future of pigging, and new technologies for the construction, inspection, repair and rehabilitation of pipelines.**

Industry leadership and collaboration

- **Although the pipeline industry has been on the "hot seat" because of recent high-profile line failures, these problems have brought industry members together in a spirit of collaboration.**

- **Valuable synergies have resulted, there is more research and less duplication of results, and more sharing of information and best practices.**

- **CEPA took a major role in the SCC inquiry, and now it's playing a continuing role in helping to ensure that industry members keep their commitments.**

- **The production of an SCC industry database and Best Practices Handbook are both excellent examples of the synergy that I'm talking about.**

- **CEPA is also coordinating the funding of research into the next generation of this technology, which should be available in next year.**

Stakeholder Communications

- **But it's not enough to make gains in all of these areas if our stakeholders don't know what we're doing. Public perception of our responsiveness and competence is critical to our long-term success.**

- **TransCanada recently completed a landowner survey. It was conducted in Moose Jaw, Winnipeg, Vermilion Bay & Burlington.**

- **Impressions of TransCanada were almost "uniformly positive," but concerns were identified in the area of safety, and in particular, line breaks.**

- Information from our survey also shows that landowners' lack understanding about basic pipeline safety issues.

- So here's a good opportunity to take the initiative, to help the people who live and work along our right-of-way understand pipeline integrity and what the industry is doing to ensure their safety.

- In fact, one thing that we found from our experience in Vermilion Bay, where we have had two line failures in two years, was that we have to keep the community fully informed.

- TransCanada went to considerable effort to keep municipal officials in the loop. We were in constant contact with them, and after many meetings, they started to see us less as company representatives and more as individuals with the same goal as theirs.

- And we took some chances, inviting them to watch as we dug up sections of pipe. We let them see the shape it was in as it came came out of the ditch, we explained the purpose of hydrostatic testing, and we shared the test results with them.

- There is no question in my mind that this was a very worthwhile effort, and our credibility in the community increased as a result.

- The NEB has also taken a more active role in community relations, visiting communities along the pipeline to help answer questions, and to get feedback on company initiatives.

- Again, it's not one group working in isolation. We get input from everyone concerned – it's critical to our success as we continue to build our future, together.

Closing Notes

- It's an exciting time to be in the pipeline industry. Opportunities stretch as far as our pipe, and we're playing a vital role in the economic success of the country. This is no time to be timid.

- We are on the eve of another era of major pipeline expansion. The demand for new capacity out of the Western Canadian Sedimentary Basin has never been greater. Practically every week sees the announcement of another new project.

- As we move ahead with major new initiatives such as NEXUS, it is essential that we be able to confidently say that those pipelines will be capable of operating safely well into the next millenium.

- A commitment such as that can only be made if we are satisfied with the advances we've made in the areas of improved coatings, on-line monitoring, construction and operating procedures.

- In order to successfully seize the expansion opportunities that are before us, it is essential that we demonstrate that we can operate our existing pipelines with the high standards of safety and reliability the general public has come to expect.

- That challenge is ours to accept. Respect will be earned, not granted.

- **We've collaborated in a complicated, highly-technical enterprise to ensure our joint success. This gathering exemplifies this kind of effort.**

- **Let's take this opportunity to get the message out: we're looking forward with great optimism and confidence to playing an increasingly important role in the next millennium.**

- **The management of the integrity and safety of Canada's pipeline infrastructure must remain an important priority for our industry.**

- **I thank you for your attention.**

NEB PUBLIC INQUIRY ON STRESS-CORROSION CRACKING OF CANADIAN PIPELINES –A REGULATORY PERSPECTIVE

by

John McCarthy
National Energy Board
Calgary, Alberta

National Energy Board

Banff 1997 Pipeline Integrity Workshop

is Presentation will Address:

- extent of the SCC problem
- our understanding of SCC
- tools for dealing with SCC
- pressure reduction
- conceptual approach to our decision
- our recommendations

Process

Inquiry proceeded along 3 paths

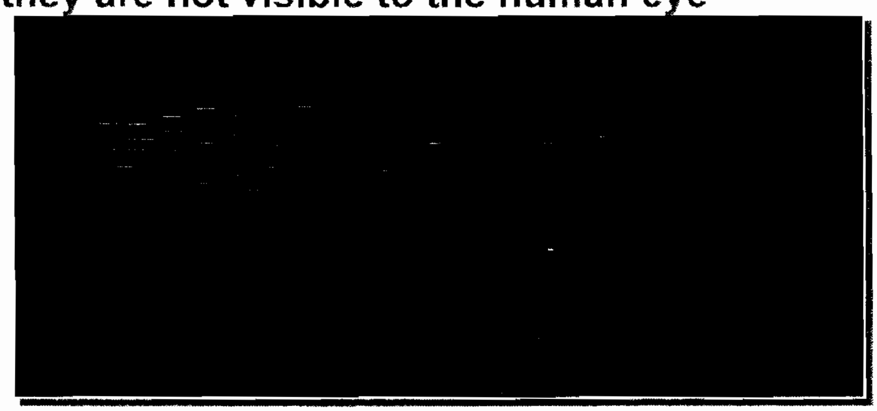
community meetings

technical information gathering

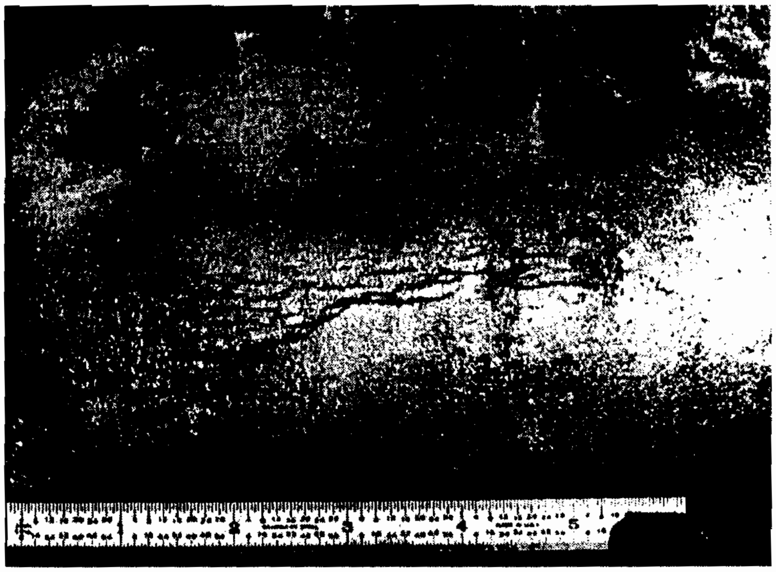
public hearing

at is SCC?

- it initiates as patches of small cracks - so small they are not visible to the human eye



- many cracks go dormant; even those that grow exist for many years without being a problem



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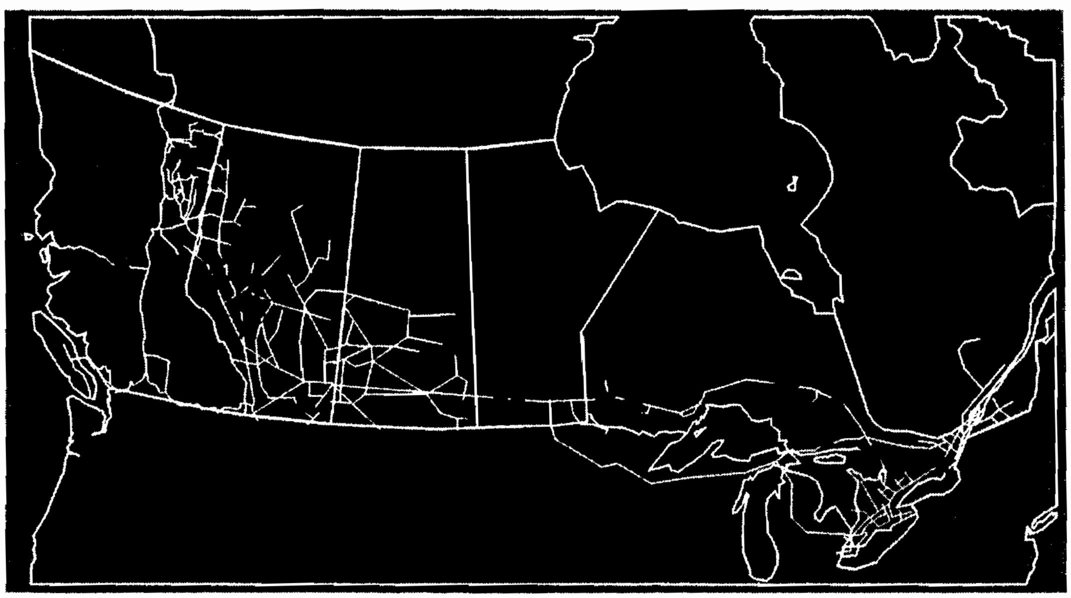
SCC Failures on Gas Pipelines



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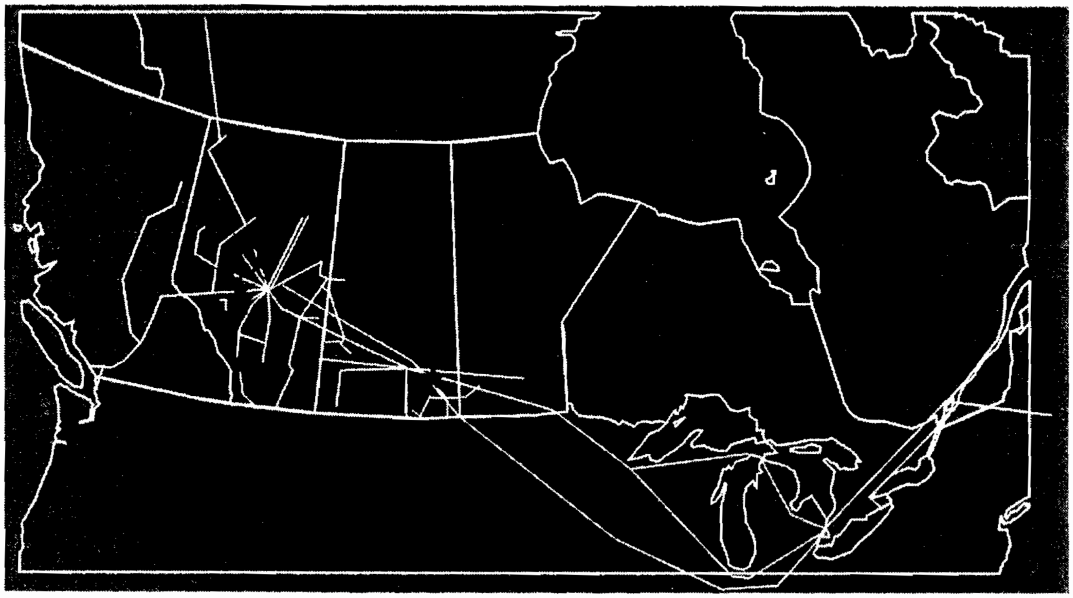
...ilures on Liquid Pipelines



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...nt of the SCC Problem

- 10 companies, 22 failures
- found on oil & gas pipelines
  - TCPL, NOVA, IPL, NUL, Rainbow, PN, Federated, Imperial, Rimbey, & Amoco
- has occurred mainly on tape coated pipe installed between 1968 and 1973
- failures in Australia, Iran, Iraq, Italy, Pakistan, Saudia Arabia, former Soviet Union, & U.S.

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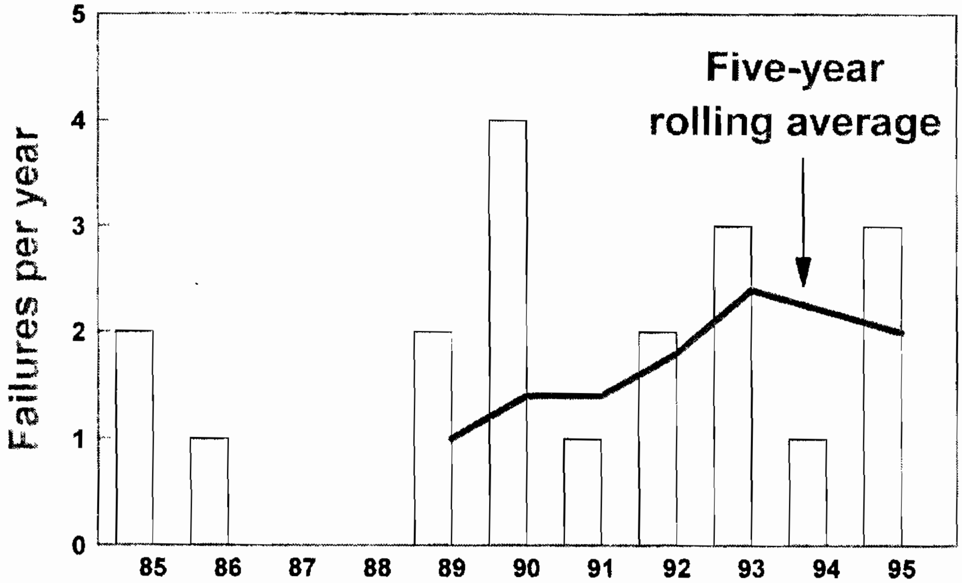

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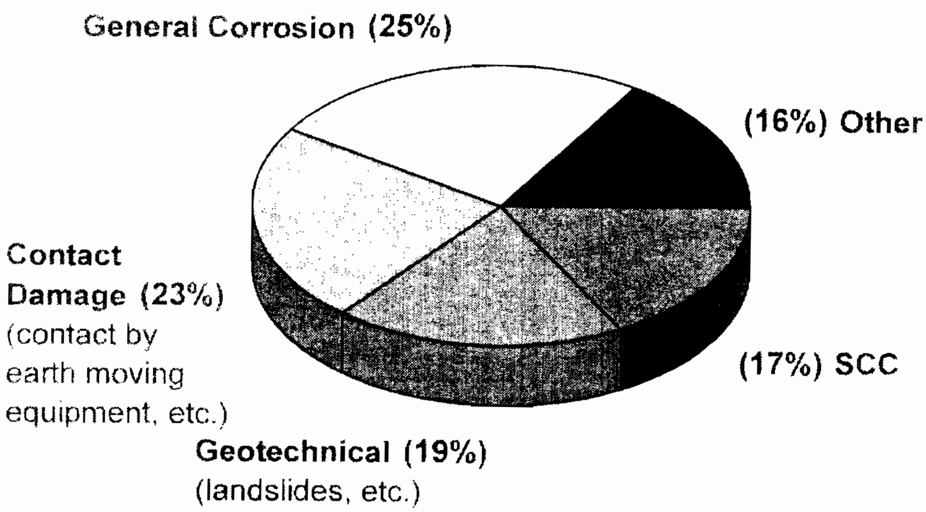

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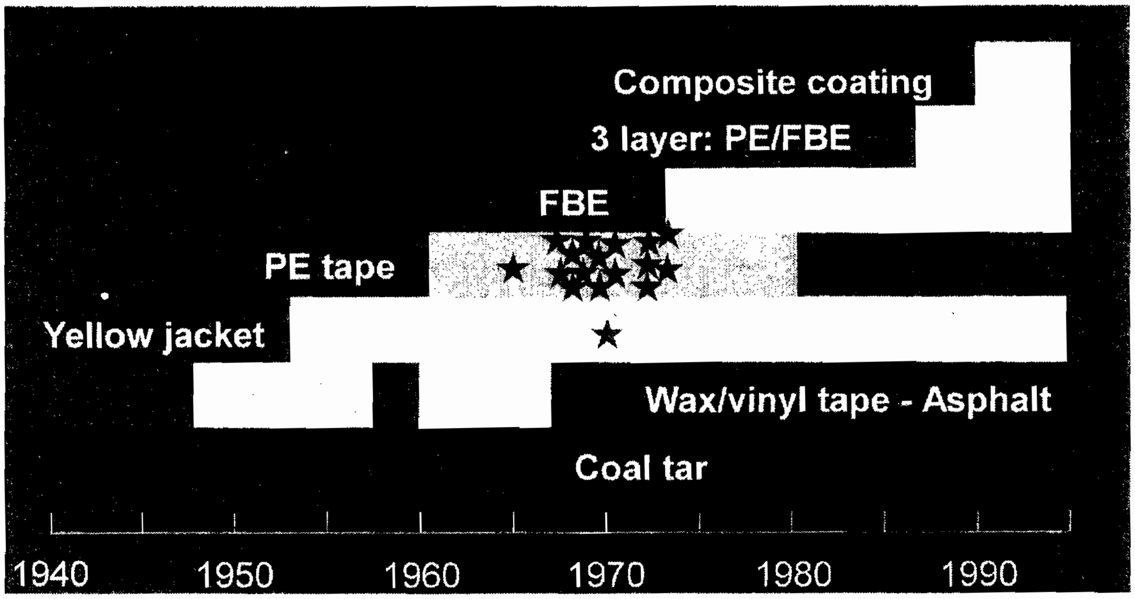
[illegible] Coating
[illegible] & Age



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Tape Wrapping Machine

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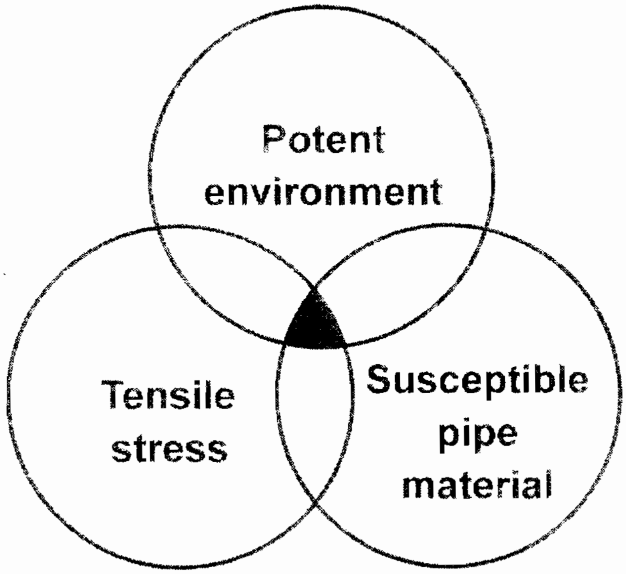

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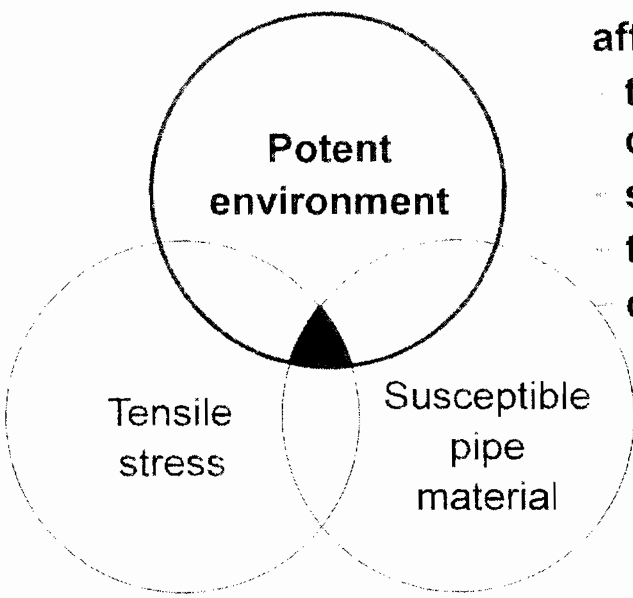
Understanding of SCC



affected by four factors:
- type & condition of coating
- soil
- temperature
- cathodic protection

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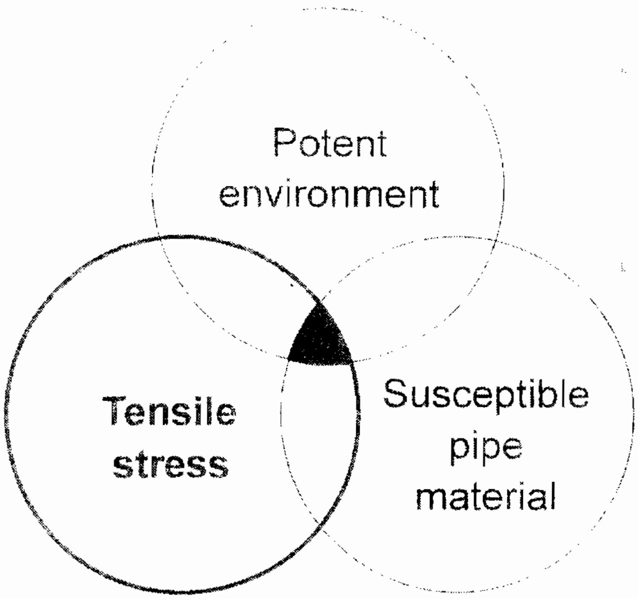
Understanding of SCC



- stress levels, fluctations and rate of change all play a role
- several sources of stress
  - residual
  - internal pressure
  - bending
  - temperature

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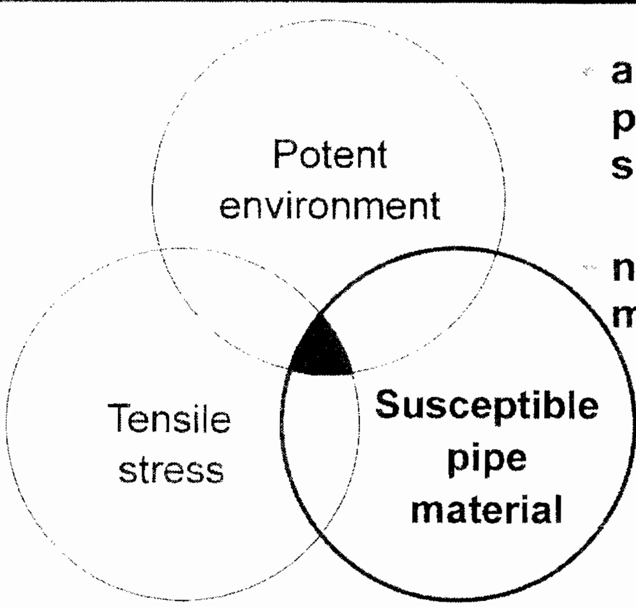
Understanding of SCC



- all commonly used pipeline steels appear susceptible
- non-metallic inclusions may play a role

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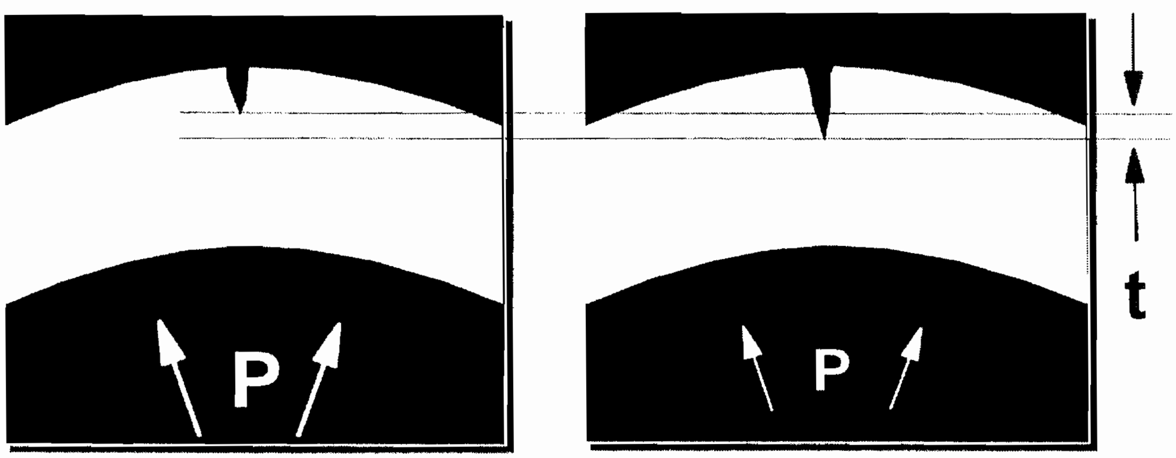
- effective coatings
- predictive models
- investigative excavations and repairs
- in-line inspection
- temporary pressure reduction
- hydrostatic retesting
- selective pipe replacement

Tools for Dealing with SCC

- temporary pressure reduction



- *lowering pressure will buy time until crack grows to the new critical depth*

[illegible] Reduction

benefits, if any, cannot be determined from the available research and field information

would be very inefficient in any event because potent environment exists on only a small portion of pipeline system (perhaps <4%)

does not remove any cracks

more systematic, efficient and effective tools are available

Other Perspectives about SCC

- SCC remains a serious problem for the industry
- time dependent; requires focused attention or problem may worsen

- SCC management program for all pipelines
- changes to the design of pipelines
- continued research
- establishment of SCC database
- improved emergency response practices
- continued information sharing

Recommendations in 6 Key Areas

- SCC management program for all pipelines
  - ***mandatory that all NEB regulated pipelines have an SCC management program in place by 30 June 1997***
  - ***16 recommendations set out the criteria for an acceptable program***

Recommendations in 6 Key Areas

1. SCC management program for all pipelines
2. **changes to the design of pipelines**
   - ***accommodate passage of pigs***
   - ***testing standards for coatings***

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Recommendations in 6 Key Areas

1. SCC management program for all pipelines
2. changes to the design of pipelines
3. **continued research**
   - ***annual status report to be filed with NEB***
   - ***analysis of expanding current program***

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[illegible]

- SCC management program for all pipelines
- changes to the design of pipelines
- continued research
- **establishment of SCC database**
  - ***continued development of CEPA initiative***
  - ***data trend analysis***

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Recommendations in 6 Key Areas

1. SCC management program for all pipelines
2. changes to the design of pipelines
3. continued research
4. establishment of SCC database
5. **improved emergency response practices**
   - ***training for first responders***
   - ***improved community communication***

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Recommendations in 6 Key Areas

- SCC management program for all pipelines
- changes to the design of pipelines
- continued research
- establishment of SCC database
- improved emergency response practices
- **continued information sharing**
  - ***industry led workshops and conferences***

Next Steps

- **the full Board has:**
  - **adopted all of the recommendations in the report;**
  - **established an SCC implementation team**
  - **issued specific directives to companies under its jurisdiciton.**

NEB Public Inquiry into Stress Corrosion Cracking, Nov. 1996

NEB PUBLIC INQUIRY ON STRES-CORROSION CRACKING OF CANADIAN PIPELINES – AN INDUSTRY PERSPECTIVE

by

Bob Hill
Canadian Energy Pipeline Association
Calgary, Alberta

BANFF 1997 PIPELINE WORKSHOP

NEB Public Enquiry on SCC of Canadian Pipelines - Industry Perspective

Presented by
R. A. Hill
April 16, 1997

CEPA Member Companies

- Transport 95 per cent of the crude oil and natural gas produced in Caada to domestic and export markets
- Transport products valued at $30 billion (Cdn)
- Operate 90,000 kilometres of pipeline in British Columbia, Northwest Territories, Alberta, Saskatchewan, Manitoba, Ontario and Quebec

CEPA MEMBERSHIP

Oil:	Interprovincial Pipe Line Trans Mountain Pipe Line Company Ltd. Trans-Northern Pipelines Inc.
Gas:	Alberta Natural Gas Company Ltd Cu Gas Foothills Pipe Lines Ltd. NOVA Gas Transmission Ltd. TransCanada PipeLines Trans Quebec & Maritime Pipeline Inc. Westcoast Energy Inc.
Technical:	AEC Pipelines Pembina Corporation Sun-Canadian Pipe Line Company Limited

NEB SCC INQUIRY

- Announced - August 11, 1995
- Terms of Reference - September 5, 1995
- Information Gathering - September-December, 1995
- Submissions - February 16, 1996
- Public Hearing - April 16, 1996
- Report - December 1996

CEPA Action

- Established Steering Committee
- Project Manager
- Legal Counsel
- Media
- World Experts
- Budget $600,000

CEPA

SCC Inquiry Issues

1. Extent
2. Initiation and Growth
3. Prevent of Initiation
4. Detection
5. Mitigation
6. Research
7. Safety and Awareness

CEPA

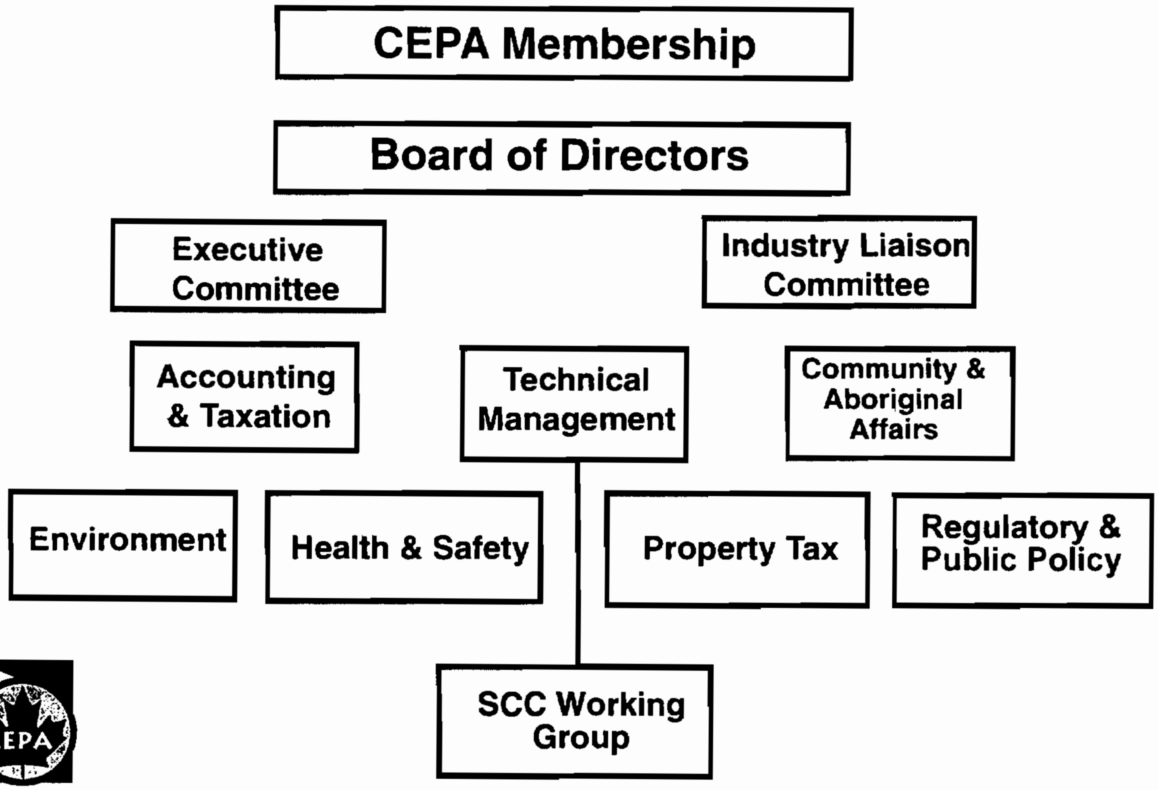
NEB Recommendations

- Implementation of an SCC management program by each pipeline company
- Changes to the design of pipelines
- Continued research
- Establishment of an SCC database
- Improved emergency response practices
- Continued information sharing

CEPA Response

- Generally supports recommendations
  - consistent with CEPA strategy
- Organization focused on SCC
  - Technical Management Committee
  - SCC Working Group
- Collaboration with industry and regulators
  - NEB implementation liaison group

CEPA Committee Structure



Status of CEPA Activities

Research
- British Gas Inspection Tool (CEPA/CGA/GRI/PRCI/BG)
- ERC (DOE) Material Factors
- High Performance Coatings
- Characterization of Pressure Changes

Note: Total value of SCC R&D, including CANMET, $10.5 million 10-15% CEPA or CEPA companies

Status of CEPA Activities

Integrity Management Program and Recommended Practices	May 15
Future SCC R&D requirements	June 30
Detection and Mitigation of Circumferential SCC	Dec 31
Database Trend Analysis	Aug 31
Information Sharing	IPC 1998

CEPA

CEPA Relationship with Non-CEPA Companies

- Integrity Management Program and recommended practices to be available to all
- SCC database terminology being standardized with PRCI, GRI, Mobil (Rainbow) - agreement in principle to share information
- Meetings held with CAPP
- CEPA sponsorship of technical conferences ongoing

CEPA

Summary

- NEB recommendations consistent with CEPA strategy
- Collaborative approach best option
- SCC issue manageable

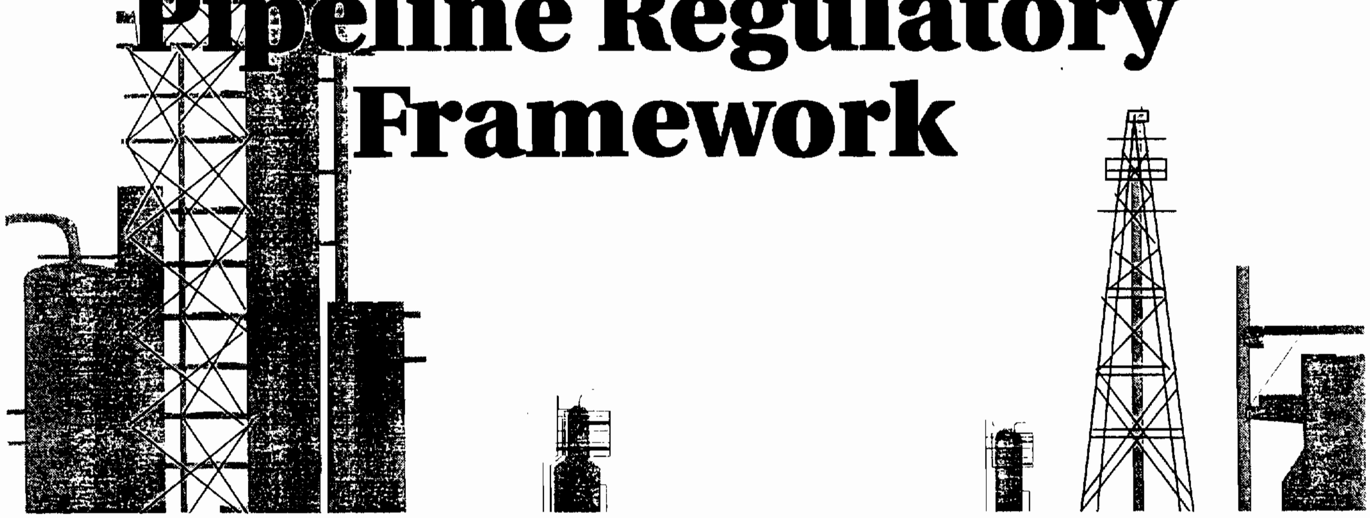
CEPA

RISK-BASED APPROACHES TO PIPELINE SAFETY, REGULATION, AND COMPLIANCE

by

Richard Felder
Office of Pipeline Safety
Washington, D.C.

Integrating Risk Factors in the Pipeline Regulatory Framework



Risk Management for Pipelines

- Which action or set of actions will best reduce pipeline risks?
  - Determination of overall risk reduction.
  - Implementation costs considered.
- Achieve the most risk reduction for level of resource expended.

OPS Risk Initiatives

- **Risk-based Prioritization Planning (RAP).**
- **Risk-based Regulations.**
- **Risk Mangement.**

Reg. Framework
tech. standard
performance measures
training
communications

Results Expected

- **Risk-based systems program-wide.**
- **Few universal requirements.**
- **Provides operators more flexibility to place resources on high risks.**
- **OPS assures methods are appropriate.**

New Program Direction& Approaches

- **Damage Prevention Public Education.**
- **Risk-Based Compliance Policy.**
- **Mapping.**
- **Defining Environmental Priorites.**
- **MMS MOU.**

"DAMQUAT" Team

- **Govt/industry "QUAT" model; broad representation.**
- **Education focus: define specific audience needs to improve safety behaviors.**
- **Evaluate existing materials.**
- **ID & implement effective strategy.**
- **Bring other parties to legislative table.**

New Compliance Policy in Development

- Set national inspection goals on risk basis w/industry input & streamline activity.
- Improve planning w/probability, consequence, & geographic data.
- Tie inspection record to incident analysis.
- Move from checklist to engineering evaluation.
- Systematize rating procedures.
- Credit remedial action to long-term OPS program impact.

National Pipeline Mapping System

- Partnership effort assessed options to depict pipelines w/people, water, & environment.
- Defined requirements & elements of mapping standard.
- Recommended phased strategy: decentralized access w/quality central.
- States to play key role.
- 500' accuracy, extensive coverage, & data integration key values.
- Next: Finalize standard & operations

Unusually Sensitive Areas (USAs)

- Using workshop process to define "guiding principles", terms, filtering criteria.
- Considered uniqueness.
- Concerns drinking water, ecology, & cultural resources.
- Working closely w/Federal agencies, industry & public.
- Once Feds define geographic areas, industry applies risk assessment.

MMS MOU Customer Oriented

- Reduces burden on industry. Establishes new boundaries. Eliminates duplication, puts priority on safety.
- Operators self designate for greater efficiency.
- Maximizes use of Federal $. MMS acts as DOT agent. Increases inspection capability w/out cost.

Change Led to New OPS Priorities

- R&D.
- Other technical studies support operations.
- More participation in consensus standards organizations.
- Leverage through partnerships.

Cooperation Evident

- Industry/Government joint "R&D agenda".
- Pooling resources for Risk Management, Mapping, Data, Studies.
- Gas Research Institute MOU.

OPS R&D Objectives

- Improve analysis for risk-based decisions.
- Analyze alternatives & depict pipelines in relation to people, environment, water.
- Improve use of NDE/in-line inspection technology to detect mechanical damage & stress corrosion.

OPS R&D Objectives

- Define operational requirements for leak detection systems.
- Evaluate operations & maintenance vulnerabilities.
- Develop a structured method to prioritize federal resources.

Technical Studies/Operations

- Identify geographic areas likely for severe consequences from natural disasters.
- Recommend ways to improve data analysis & compare US standards with other countries.
- Define environmental priorities, collect & index data.

More Participation in Consensus Standards Organizations

- Increase use to address technical issues & gain broad-based support in non-regulatory manner.
  - Evaluating pig data.
  - Pipe toughness.
  - Fatigue & fracture behavior.
  - Underground storage.

Leverage Partnership With Outside Organizations

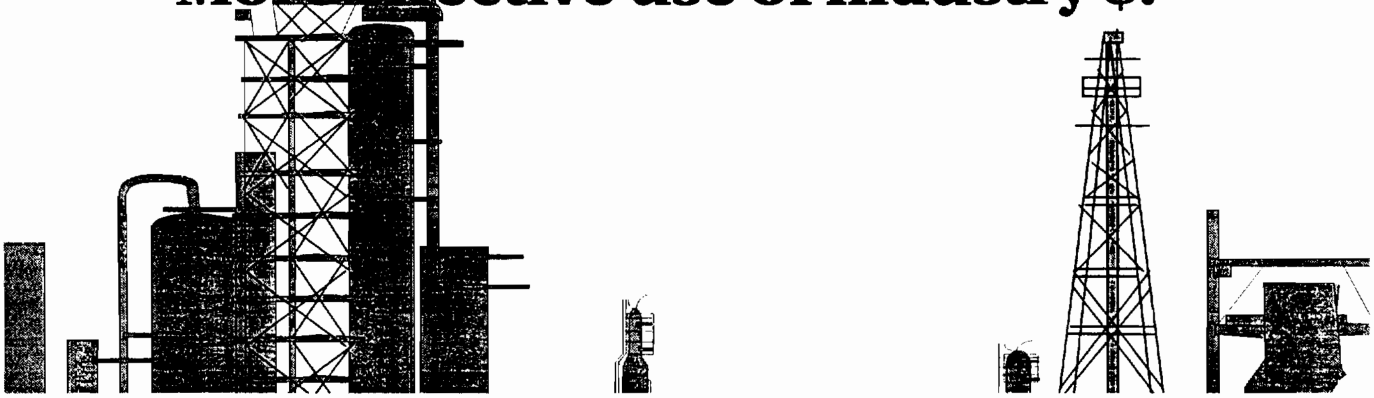
- Use of automated valves: INGAA/GRI.
- Data analysis improvements: INGAA/GRI/API.
- Controlling mechanical damage: INGAA/GRI.
- Offshore issues: MMS/USCG/EPA.
- Applications of Plastics and Composites: AGA/PRCI.

Conclusions

- Optimistic we're in the right path.
- Access to technical support improving.
- Collaborative approach well received by Industry & DOT.

Conclusions

- **Everyone benefits:**
  - **Better safety &**
  - **More effective use of industry $.**



THE PIPELINE RISK ASSESSMENT STEERING COMMITTEE (PRASC) AN OVERVIEW OF PROGRESS

by

Doug Clark
Gulf Canada Resources Limited
Edmonton, Alberta

PIPELINE RISK ASSESSMENT

STEERING COMMITTEE

presentation to

Managing Pipeline Integrity -

Planning for the Future

April 1997

presented by:

Douglas A. Clark, PEng

Gulf Canada Resources Limited

Good morning and welcome to Banff! Here we are in a beautiful facility in the center of the most wonderful scenery in the world... and we're at what I consider is the most constructive workshop on our highest priorities. I'm even getting paid to be here! Can life get any better than this?

I am pleased to have been a member of the Pipeline Risk Assessment Steering Committee since it's inception after the Banff workshop in 1994, and to be representing the committee here today. I sincerely feel that the group has been instrumental in implementing your desires concerning risk assessment and management and we're excited about our future endeavours.

The first Managing Pipeline Integrity Workshop was held in Red Deer in 1993 under the guidance of CanMet and the National Energy Board. From there it quickly grew to capacity (do you moving the venue may have helped?) and centered on industry concerns and industry participation. This year is the culmination of effort from a group of about 50 volunteers, the majority of whom are from pipeline operational companies.

Pipeline Risk Management

It was at the 1994 workshop that the industry interest and concern about risk assessment was clearly expressed. Whether you're working with new system designs, managing urban encroachment or optimizing maintenance practices risk assessment plays a role. We have the honour of being the safest transportation systems in existence, and with this comes nationwide media interest whenever a public safety incident. Risk assessment allows each of us to demonstrate the level of safety we afford to the Canadian public, and to improve on that level.

This public safety concern is not only a domestic one, nor an issue restricted to pipeline operations. Risk is a common word in our news media these days, whether the concept is dealing with hormones in beef production, Amtrak derailments, or re-election chances. The pollsters have also tried to educate us on the concepts of statistical variation, however I wouldn't recommend that any of us respond to a reporter by saying that; after polling 342 aspects of our pipeline operations, safety is at a level of 97% plus or minus 3% 18 out of every 20 times. We have to come up with a useable, defensible, and understandable standard.

In the global pipeline community we have seen the Europeans develop acceptable public risk levels and standards, the Australians work on the concept of "acceptably safe co-existence". The U.S. as well have been working on initiatives in both gas pipelines and liquid pipelines, and more recently have been combining these efforts. Pipelines safety, and risk management, is a global issue.

Out of the interest in the 1994 workshop also came the realization that we must co-ordinate the numerous efforts on the development of risk determination methods. A group of industry, regulatory and standards representatives met that summer to form what is now known as PRASC... the Pipeline Risk Assessment Steering Committee. The purists in our group wanted to use the term "risk management" instead of "risk assessment", but none of us could properly say PRMSC.

Subsequent Banff workshops have echoed the concerns expressed in 1994. Risk management is high on all of our priority lists. Urban encroachment is very real to many of us, and is lurking in the shadows for the rest. We all live in an era of continuing pressure on operating costs, whether in a de-regulated intra-provincial system, or in an inter-provincial system with incentive tolling. These pressures are balanced with another desire... to demonstrate that we are operating safe systems, and to improve that level of safety.

We have seen regulatory agencies turning from on-site inspection and giving strict directives to the concept of corporate audits. We are all expected to have the programs in place to assure public safety, and we are expected to be adhering to these practices on an unfailing basis.

This change requires the industry to be pro-active. We cannot merely design and construct a system safely and then wait to re-act to the first occurrence of a concern. We cannot set a low priority on the variety of emerging issues from urban encroachment to stress corrosion cracking and wait for a failure to spur us into action. We are expected to be safe now, and to be planning to be safe under all circumstances in the future.

Not only will our regulators not accept a passive approach to integrity management, but the public is also unforgiving. Public awareness of safety issues is greater than ever before, and their tolerance is less. We must take care of our own shops.

PRASC Membership

The Pipeline Risk Assessment Steering Committee is dedicated to such causes. We do not deal with company specifics, though we recognize that isolated company non-performance will affect the entire industry. The efforts of the Committee are intended to benefit the entire industry, from feeder pipelines through majour transmission systems to LDC's. Thus the membership is chosen to represent the entire pipeline community.

Our industry representation is through the three major organizations in which we are all members. In this way each pipeline operator is represented at PRASC and can influence what goes on there.

Our regulatory members are from both the National Energy Board and the Alberta Energy and Utilities Board. Other provincial regulators have been invited to participate, and at this time have chosen to monitor our efforts and progress, rather than to become directly involved.

Additional representation from organizations which affect the introduction of risk methods are also members. The CSA Z662 Technical Committee is represented, as is MIACC.

PRASC is not a closed shop. We intend to properly represent and guide the industry, and as other organizations desire to directly make a positive contribution to the committee they will be included.

PRASC Terms of Reference

PRASC's mandate is to guide the orderly development of a process to determine and manage the risk of pipeline operations to the general public. Our focus is the protection of public safety, but the tools which are developed will no doubt find applicability in other areas of our operations. The protection of the environment and the optimization of maintenance practices come to mind as two obvious areas.

The development of these tools is primarily accomplished by the industry stakeholders in this interest. We have seen the tools being developed, and the education being accomplished, by different groups who are participating under the guidance of PRASC.

These Banff workshops are particularly important to PRASC. Not only is this our venue to share with you the accomplishments and plans we have, but more importantly to get your feedback and direction. The Banff workshop has been very successful in gathering expert peers from pipeline operation companies, from the regulators and the consultant industry. This week's schedule includes seven working sessions which, though they will serve as education for many, will also be effective in sharing experiences and concerns regarding risk management. We eagerly anticipate participating in the discussions over the next three days and in hearing what you consider to be our priority for the next year. Though PRASC normally meets on a quarterly basis we have scheduled a special meeting in May to ensure we capture the outcomes from your input this week.

PRASC Achievements

If I may, let me re-cap what PRASC has accomplished since the 1984 workshops, and a bit of what we currently see as our future direction.

As we discussed, the PRASC group was formed in the latter half of 1984, after gauging the interest of this group. Evident in the initial meetings was the enthusiasm, not only for developing these tools to demonstrate and improve the safety of our operations, but the spirit of co-operation. Here in Canada we have the enviable ability to work with our regulators, our competitors and the standards organizations to the benefit of all. This is a significant aspect of how the Canadian pipeline industry is managed, and should never be taken lightly or for granted.

The efforts in the year 1995 worked to build on this co-operation. We worked with CSA and with MIACC to ensure that their efforts were complementary and consistent with the overall direction given at this workshop.

The work with CSA and MIACC continued in 1996. PRASC was instrumental in securing funding for work needed for the MIACC efforts. Though PRASC has no direct funds to access we can provide assistance in this area through our influence with the industry associations. The three industry association members provided the funds for this work.

We also recognized that, if the industry was to move toward probabilistic risk management, that a reliable and meaningful incident database would be required. PRASC struck a sub-committee to initiate this work, again to be funded by the industry associations.

1996 also saw the issuance of the risk assessment appendix to CSA Z662, a majour first step. As well, through an arduous process of ensuring the consensus of a large group of volunteers the MIACC land use planning guidelines were nearing completion.

PRASC Current Efforts

Our first accomplishment in 1997 is the issuance of the MIACC guidelines. As I mentioned, this is the culmination of many, many hours of intensive discussion and preparation. This guide, though not entrenched in regulation, should set the standard for how municipal planners ensure their plans are consistent with the level of pipeline safety that the public expects.

The CSA risk assessment work is also proceeding, building on 1996's accomplishments. The Z662 sub-committee chairman sits with us on PRASC and is working towards the integration of risk methods in the body of the standard. This work is consistent with, and will benefit from the database development.

The risk assessment incident database framework is currently being developed. The work to build the software framework is currently under way and is expected to be complete in June of this year. Following this, the software will be tested and refined with the data from an industry participant. We expect that we'll be coming to each of you in the latter half of the year for your commitment to populating and maintaining the database.

PRASC Timeline

Beyond 1997 we expect to build further on this foundation. We will continue to encourage and guide the implementation of probabilistic risk assessment and management into the Canadian pipeline industry. We will continue our work with CSA to upgrade the Z662 standard to incorporate the risk process as an integral part of pipeline design, construction and operation. We also will work with MIACC and regulators whenever we can positively assist their work.

Again, I must emphasize that the PRASC members consider ourselves representatives of a much larger group. We are here to listen and participate in the discussions this week, and to act on the priorities and concerns expressed here.

I consider it an honour to be here, and am much looking forward to the next few days. Thank-you.

PIPELINE RISK ASSESSMENT STEERING COMMITTEE

PRASC in our fourth year

Pipeline Risk Management

Public safety
- Industry awareness
- Public awareness

nternational awareness

Co-ordination of efforts

Regulatory enforcement changes
- Need for Industry to be pro-active

PRASC MEMBERSHIP

- Regulators
  - National Energy Board
  - Alberta Energy & Utilities Board
- Industry
  - Canadian Assoc. of Petroleum Producers
  - Canadian Energy Pipelines Association
  - Canadian Gas Association
- Standards Organizations
  - Canadian Standards Association
  - Major Indust. Accidents Council of Canada

PRASC Terms of Reference

- Mandate
  - to guide the development of a process to determine and manage the risk of pipeline operations to the general public
- Objective
  - the staged implementation of risk assessment and risk management into the pipeline industry

PRASC Achievements

994

- established the Steering Committee, its membership and mandate

995

- supported the CSA Risk Assessment Appendix B to Z662
- supported the MIACC draft Land Use Planning Guidelines

PRASC Achievements

- 1996
  - industry associations funded support to MIACC zoning work
  - secured funding for database development
  - continued support to MIACC and CSA
  - CSA issued the Risk Assessment Appendix to CSA Z662

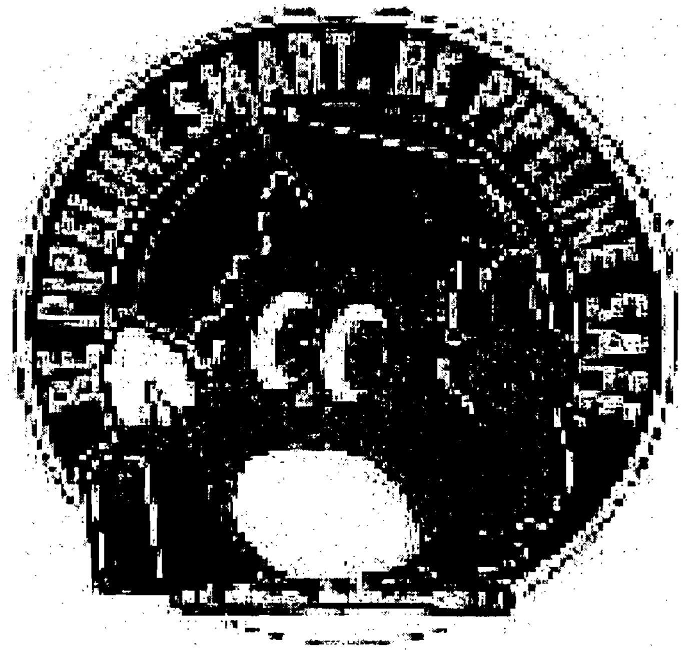
PRASC Current Efforts

- 1997
  - issuing MIACC Land Use Planning Guidelines
  - further support to the CSA & MIACC work
  - development and testing of the risk assessment incident database
  - initial database population

PRASC Timeline

1998 and beyond

- CSA standard to include risk assessment and risk management as an integral part of the standard
- continued risk database population
- CSA standard upgraded to a fully probabilistic process utilizing database information



CAPP PERSPECTIVE ON PIPELINE ENCROACHMENT

by

Joanne Nutter
Imperial Oil
Calgary, Alberta

CAPP Perspective On Pipeline Encroachment

Banff/97 Pipeline Workshop

April 16, 1997

Joanne D. Nutter

Good morning ladies and gentlemen. I'm here to talk to you about the Canadian Association of Petroleum Producer's perspective on pipeline encroachment and the issues that it raises for our industry. I want to give you some questions to think about this morning. What do we mean by encroachment? Why is it of concern? Why now? What do we do about it?

You have heard and will continue to hear a lot about risk assessment and risk management at this workshop. It is clearly in the minds of the regulators and public as well as operators. Examples of pipeline failures are in the news more often than anyone wants to hear about them. Fortunately, while these occurrences are rare and while incidents have damaged physical property they have not resulted in direct harm to the public - inconvenience has been involved but there have been no injuries or deaths.

Yet most of the risk that we address is prevention from a technical perspective - by that I refer to the design, construction and operating parameters and conditions of the pipelines. Little reference is made in this process to the risk of damage to pipelines from third parties or the increased risk associated with pipelines from encroachment of other developments near to and over our pipelines.

Prevention of the risk of damage to pipelines from third parties is a large part of what Alberta One-Call and our pipeline signage addresses. However, encroachment issues begin at the planning stage of a development not at it's point of construction. Awareness of pipelines from a developer's and planner's perspective is not addressed by signage and Alberta One-Call and is minimally addressed for certain sour gas pipelines by the regulatory process.

Industry is often advised of planned developments at the stage where the planning is thought to be complete - but where existing pipelines have often not been taken into consideration. This lack of consultation with pipeline operators can result in roads, lots and buildings being planned for the pipeline right-of-way or so close to the right-of-way and pipeline that modifications to the pipeline would be required under CSA Z662-96. This can result in confrontational discussions because of timing constraints rather than co-operative discussion. Industry's goal is to initiate communication very early in the planning of any development that may encroach upon a pipeline. This will allow for co-operative discussions between the developer and a pipeline operator that can result in development design that takes into account both parties concerns and issues.

Public safety is a factor that cannot be overlooked or underestimated from a consequence perspective. We manage this risk well from a technical perspective - designing and constructing pipelines to strict standards, providing thorough and continuous inspection and maintenance programs, integrity testing, repair and replacement programmes. All of this can and does sometimes operate in a vacuum from the public perspective. Also, this process does not always take into account the encroachment of other development onto or near our pipelines. As an industry we need to be aware of the changing landscape around us and be proactive in the management of this issue.

Historically, as encroachment occurs industry has often borne the cost of pipeline modification and/or re-routing, as appropriate. While there is no legislated requirement for industry to bear this cost it has seemed reasonable in the past to do so based on the level of expenditures and frequency of requirement. This practice may no longer be reasonable.

Country residential has become a preferred development /living style for people. This means that smaller communities outside of the major centres are expanding as well as country residential and acreage living. Increased communication and transportation capabilities are allowing people to live where they want to as opposed to near their workplace. This development continues to put regulatory pressure on our pipelines to meet standards such as CSA Z662-96 in this changing environment. We continue to want to be good neighbours without solely bearing the cost of the change.

Municipalities and planners are faced with increasing pressure from developers to place more land into residential, commercial and industrial development without all the information available to them - they are not familiar with our industry and sources of reliable information - and industry has not made itself available to them on a proactive basis to address these issues.

To address these issues CAPP together with the Energy and Utilities Board established the Pipeline Encroachment Task Force in April 1996. This Task

Force is initially only dealing with high-vapour pressure pipelines but it will potentially lead to a process to address all pipelines.

The objectives of the Task Force are several. Raising awareness with municipalities and counties regarding high vapour pressure pipelines in their area of jurisdiction is an essential first step. Addressing the implications of developments near to or surrounding HVP pipelines and developing a process with municipalities, developers, pipeline operators, publics and regulators that will ensure 'safe' development near HVP pipelines is fundamental to co-operative co-existence. This includes ensuring that municipalities, developers and planners are informed as to sources of information about HVP pipelines as well as are part of a process for developing, implementing and utilizing a consultative communications process for developments near to or surrounding these pipelines.

The Task Force has several proposals for meeting the objectives. All of the proposals deal with enhanced communication. The proposals include the development of a 'model' by-law that municipalities and counties can use regarding a consultation process for development near to or surrounding HVP pipelines. The Task Force will stay linked with the Major Industrial Accident Council of Canada and its *Guidelines For Land Use Control Adjacent To Pipelines* which is currently under development. There are plans to develop an EUB Informational Letter to increase awareness on this issue; it would require pipeline operators to be involved in the municipal planning and development process when potential encroachment occurs and would introduce the concepts and expectations of the MIACC *Guidelines For Land Use Control Adjacent To Pipelines*. The Task Force has begun this process by contacting municipalities, planners and developers through their offices and associations to make presentations regarding encroachment.

Municipal Districts, planners and developers are interested in and prepared to address this issue - not all of them - but not all of us are there yet. The need is clear and present and the interest is growing . It's time - past time to address these issues.

I leave you with these questions to consider -

What is my level of understanding of this issue?

What is it's impact on my operations?

What is my liability?

What am I doing about it?

Canadian Association of Petroleum Producers Perspective on *"Pipeline Encroachment"*

Presented by

Joanne Nutter
Manager
Surface Rights and Survey
Imperial Oil

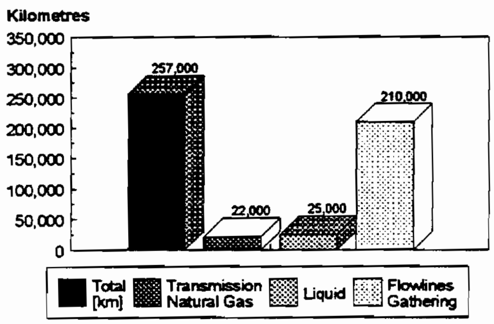
April 16, 1997

CAPP

- CAPP represents 190 members which explore for, develop, produce and transport natural gas, natural gas liquids, crude oil, bitumen and elemental sulphur throughout Canada.
- CAPP also has 115 associate members which provide a broad range of services that comprise the infrastructure of Canada's upstream petroleum industry.
- CAPP's members produce approximately 95% of Canada's natural gas and oil.

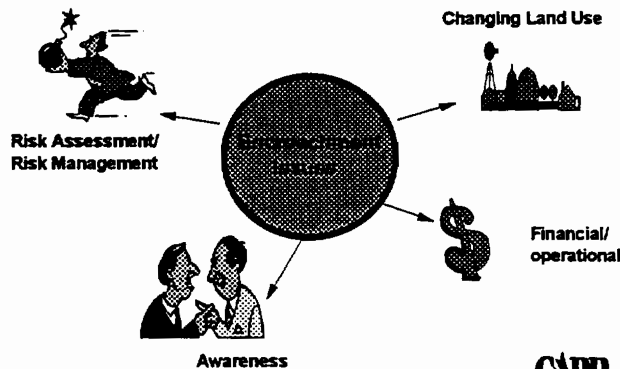
CAPP

Pipeline System Infrastructure in Alberta



CAPP

Encroachment Issues



CAPP

Encroachment Issues

- Risk Assessment & Risk Management
- Awareness
  - ⋆ Third Party Damage
  - ⋆ Developers' and Planners' pipeline knowledge is low
  - ⋆ Industry knowledge of planned development and land use policies is low
- Financial/operational consequences of encroachment - CSA Z662-96

CAPP

Changing Landscape

- Country Residential Developments.
- Small & large communities are expanding their boundaries.

CAPP

Pipeline Encroachment Task Force

- Joint CAPP and Alberta Energy and Utilities Board initiative to address issues raised by pipeline encroachment.
- Established April 1996.

CAPP

Task Force Objectives

Raise Awareness with municipalities and counties.

Address implications of developments.

Develop a process that ensures 'safe' development.

Inform municipalities, developers and planners about sources of pipeline information.

Utilize a **consultative communications** process.

CAPP

Task Force Proposals

Enhanced Communication through:

* Devlopment of model by-laws or additions to land use policies.
* Linkage with MIACC and its "*Guidelines for Land Use Control Adjacent to Pipelines*".
* Development of EUB Informational Letter.
* Communication with municipalities, planners and developers regarding encroachment issues.

CAPP

Questions to Consider

- What is my level of understanding ?
- What is its impact on my operations?
- What is my liability?
- What am I doing about it?

CAPP

RISK MANAGEMENT AS AN ALTERNATIVE TO PRESCRIPTIVE REGULATION

by

Keith Leewis
Gas Research Institute
Chicago, IL
and
Andy Drake
PanEnergy Corp.
Houston, TX

Risk Management an Alternative to Prescriptive Regulation

Banff April 1997

Keith Leewis, GRI

kleewis@gri.org

GRI

Purpose

- Safer Alternatives to "One Size Fits All" Regulations
- Encourage Innovation
- Show Benefits of Risk Management

GRI

Approach

- Teams Created
- Gas and Liquid Teams Theorized
- Joint Team Created
- Rules Developed

GRI

Joint Industry/DOT Quality Action Teams

- Government and Industry Partnering
- 1994 Liquid Risk Assessment Team
- 1995 Gas Risk Assessment Team
- 1996 Joint Risk Assessment Team
  - Steering Committee/Sponsors
  - Coordinating Committee
  - Program Standard Committee

GRI

Risk Management Demonstration Program

- Products Shown Jan/1997
- the JRAQAT's Standard
- the Regulator Expectations
- Joint Performance Measures
- Communications

GRI

Successful Program

Decision Process Becomes Normal Daily Operation

- Risk Assessment
  - Identify and Evaluate Risks
- Risk Control and Decision Making
  - Identify Prevention and Mitigation Methods
  - Allocate Resources
- Performance Measurement
  - Monitor and Evaluate Effectiveness
  - Continually Modify & Improve

GRI

Risk Management Elements

- Program Framework
- Program Standard
- Performance Measures
- Communications Plan
- Training

GRI

Overview in the Framework

- ISO 9000 Like Approach (TQMS)
- Organizational Requirements
- Risk Management Guidance
- Consultative Evaluation
- Performance Monitoring and Feed-back

GRI

Risk Management Demonsration Standard

- Defines Key Terminology
- Guideline - Not a Manual or Toolbox
- Assessment Basis - Not a Checklist
- Elements to be Addressed - Not Prescriptive
- Flexible to Meet Varying Local Needs
- Allows Program Evolution

GRI

RM Guiding Principles

- Decision Support Process
- Risk Cannot be Eliminated
- Encourage Innovation
- Allows Custom Approaches
- Provide Superior Protection
- Cost Effective Regulation Impact

GRI

RM Demo Standard

- Program Elements
  - Administration
  - Communication
  - Documentation
  - Program Evaluation and Improvement
- Process Elements
  - Risk Assessment
  - Risk Control and Decision Support
  - Performance Monitoring and Feedback

GRI

Performance Measures

- Prove Alternative Regulation Works
  - Superior Infrastructure Safety
  - More Affective Use of Resources
  - Communication and Partnership
- Project Specific
  - Recognize Each Location May be Different
- Program Wide
  - Common to all Participants

GRI

Performance Measurement Objectives

- Show Greater Safety, Environmental Protection and Service Reliability
- Better Prioritization and More Effective Application of Resources
- Have The Agency and Industry been able to
  - Improve Mutual Understanding of How Risk is Managed
  - Partnership in Addressing Issues and Communication

Project Specific Measures Address

- Support Equal or Greater Overall Safety
- Relevant to Control Decisions and Track Effectiveness
- Document Starting Conditions
- Establish Expected Outcomes (Values-Ranges)
- Enable Auditing, Monitoring, & Documentation

Program Wide Measures Address
(Public & Operator)

- Safety and Reliability
  - Incidents, Risk Awareness, Customer Service
- Resource Effectiveness
  - Level of Participation, Innovation
- Communication and Partnership
  - Parallel Surveys to Measure Growth in Understanding & Participation
  - Survey Toolkit

RM Demonstration Process

- Letter of Intent
- Screening
- Pre-Consultation
- Consultation/Negotiation
- Approval
- Monitoring
- Modification/Termination

Characteristics of the Process

- Structured but Flexible
- Regulated Risk Management OPS Approval
- Accountability Built-in Throughout
- Promotes Interaction, Discussion, Openness, and Communications

Operator Suggests Alternative

- Company Formulates a Plan to Address a Safety Issue
- Uses the RM Demo Standard to Develop and Support their Case
- Submits a Letter of Intent to DOT Outlining Expected Commitment and Growth
  - Program within the Company
  - Progress to other Locations

Submits Letter of Intent

- Project for Demonstration
  - Alternative with Performance Audit
- Information for Screening
- Confirms Company Commitment

GRI

OPS Screening Process

- Resources Limit the Number
- Achieve a Range of Projects
- Prepare for Consultations

GRI

Joint Consultations

- Prove Alternative's Technical Merit
- Establish Proprietary Information
- Preconsultations Optimize Activity
- Regulator Project Review Team
- Review wrt Five Building Blocks
- Agree on Performance Measurements

GRI

Application and Approval

- Final DOT/Operator Agreement
  - Work Plan
  - Audit Plan & Contingency
  - Communications Plan
  - Termination: Time/Compliance
- Approved by OPS
- RM Order Issued

GRI

Checks and Balances

- Currently cfr 192 & 195 etc.
  - Codes & Standards
  - Inspectors & Audits
  - Accident Reports and Investigations
- Risk Management
  - Same Activities in the Approved Plan
  - Performance Audits
    - Did You Do What You Agreed to Do
  - Growth of Process and Program

GRI

Process has Begun

- Called for Letters of Intent
- Consultations & Approvals
- First Participants Start July/97
- Yearly Review of Performance
- Report to Congress 2001

GRI

FUTURE TRENDS IN PIPELINES
A EUROPEAN VIEW OF SOME ASPECTS

by

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FUTURE TRENDS IN PIPELINES

- A EUROPEAN VIEW OF SOME ASPECTS -

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Foreword

The high level of pipeline safety achieved so far can be further increased by modified design, operational measures and use of new materials. Simultaneously, a cost reduction is aimed at. The following paper, which is the opinion of two companies of the European Pipeline Research Group (EPRG), is concerned with new trends in design and materials. It is devided into two parts. Part I will cover improved design of gas transmission pipelines and part II the current status and new materials trends. However the scope of this paper does not permit all the relevant aspects to be dealt with and remains therefore limited.

PART I / IMPROVED DESIGN OF GAS TRANSMISSION PIPELINES

Current European Design Practices

The progress towards better steel grades evolved more rapidly than pipeline design approaches. The current general design approach in Europe experienced little change in the last 25 years, and is similar to the American one. It consists of imposing a design factor which decreases stepwise as a function of increasing local population density at the moment of pipeline construction. Most countries use one, two or three design factors standing for rural areas (0.72) and suburban and/or urban areas (0.625 to 0.4).

This basic practice has shown evident advantages :
- its safety record is good all over Europe, making gas transmission pipelines the safest means of energy transportation
- it offers a simple design basis.

Nevertheless, some limitations became visible in the last ten years, with the general trend towards more industrial safety :
- responsibility shifts from the regulator towards the operator, so the latter has to demonstrate that he deals satisfactorily with the safety issue

- it is difficult to demonstrate or guarantee an outstanding level of safety for new pipelines only based on past experience
- there is no simple way to quantify the increase in safety for a set of specific design measures ; e. g. increasing the wall thickness or choosing a higher grade.

In spite of the high safety level of gas pipelines in Europe, the european regulators try to put pressure on the industry to move definitely towards a more quantified safety assessment like it was the case for other industries.

For these reasons, the european gas transmission industry updated its design practices mainly by itself, and discussed these improvements with regulators. Of course, this statement reflects only a general trend, and particular conditions always existed in some countries.

We illustrate possible ways of improving safety by three examples :

- EPRG recommendations for pipeline resistance to third party damage
- Gaz de France design approach based on risk assessment
- A common methodology for safety assessment : Gaz de France, Ruhrgas and SNAM.
- There exist different approaches in other European countries.

They all have in common to rely on a result from the analysis of past incidents, which showed that third party damage is the most frequent cause of incidents with gas loss (52 %). A pipeline operators group, EGIG, is in charge of updating and interpreting this incident data base [7]. The other causes have a lower frequency :

- external interference:	52%
- corrosion:	14%
- construction defect:	17%
- ground movement:	7%
- others:	10%.

This evidence led to consider third party damage as the worst case loading factor in addition to internal pressure that pipelines would have to resist. It is thus expected that pipelines that take into account third party damage at the design stage would be also able to withstand other secondary failure causes. In addition, the specific measures to treat other failure causes (e.g. corrosion) are sometimes out of the scope of mere mechanical design.

EPRG recommendations for pipeline resistance to third party damage

EPRG has conducted in recent years extensive full scale experimental work in order to determine pipeline resistance to dent and puncture under static conditions [1, 2, 3]. This work consisted mainly in static dent and puncture tests with both new and worn teeth. Semi-empirical relations were derived for both denting and puncture pipe resistance.

In the puncture case, they resulted in the correlation of the static normalized puncture force with a pipe 'resistance parameter' for new teeth [4]. To take into account the decrease in puncture resistance to worn teeth, the new teeth correlation was weighted by a safety factor, which resulted in a relation of the type :

$$F_p/(L+l) = a\,(t\ \mathrm{UTS})^b$$

where a and b are constants, t is the pipe thickness, F_p the static puncture force for any teeth and tooth width L and tooth thickness l are the standard wedge-type new tooth dimensions (see Figure 1). It is noteworthy that puncture resistance is linked in the same way to pipe thickness and to material grade, which enhances the need for high strength steels.

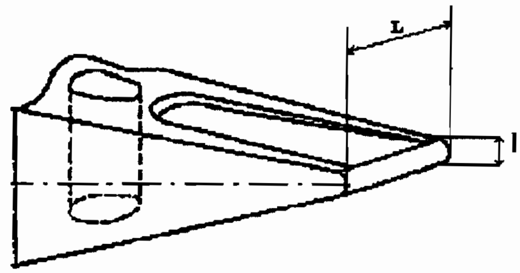

Figure 1. Wedge type new excavator tooth geometry.

The validity of this relationship was also tested in the rapid loading case, when an excavator impacts the pipe with significant momentum. The full scale experimental checks were performed on four pipes of different diameters (219, 406, 914, and 1219 mm), which span the current gas transmission pipeline diameter range [5,6]. These tests showed that loading velocity has only limited local effects, but no significant global influence on puncture force

Nevertheless, the puncture force is not an available parameter under rapid loading. Whereas in static loading the force is imposed by the excavator, under dynamic conditions, the energy available for impact is imposed by the excavator, but the puncture force is a result of the dynamic interaction between excavator and pipe. In other terms, two different puncture criteria are needed : normalized puncture force $F_p/(L+l)$ in the static case and normalized puncture energy $E_p/(L+l)$ in the dynamic case.

In order to establish puncture criteria, we have to compare under both static and dynamic loading conditions the excavator damage capacity and the pipe puncture resistance. The main effort of EPRG consisted until recently in characterizing pipe resistance, but ongoing developments about excavator damage capacity yielded already preliminary results reported in [6]. These show how to treat the available excavator data in order to use the static resistance criterion as a representative one for both static and dynamic loading cases.

The relations giving the pipe puncture force and the static excavator force can be applied for preventing punctures either :

- during operation of existing pipelines by specifying the maximum mass for an excavator to be allowed in the vicinity of an operating pipeline
- or at design stage, by specifying a puncture proof pipeline for a given size of excavator and tooth.

As an example of use of the above approach, the maximum allowable excavator weight can be related to a pipe of given diameter (see Figure 2).

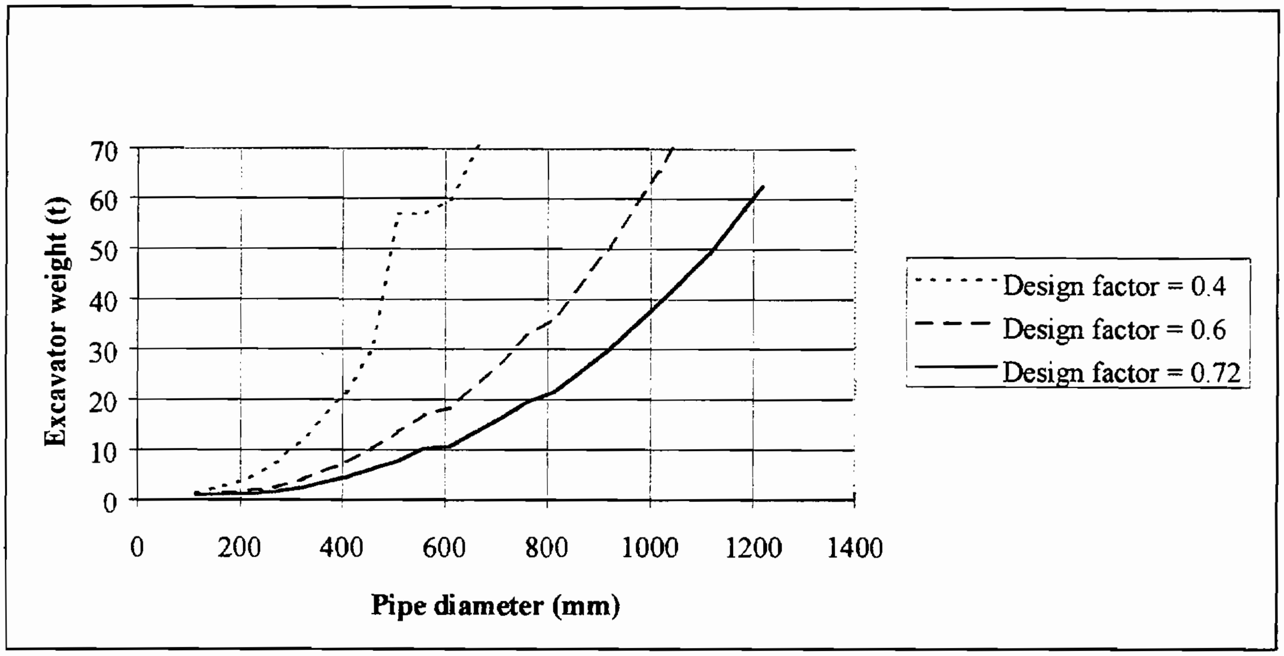

Figure 2 : Puncture proof excavators in the vicinity of gas transmission pipes as a function of diameter.

Such an approach can be also conducted for denting resistance, once an acceptable dent depth is defined.

These are examples of how to use deterministic third party pipe damage resistance criteria in order to improve gas transmission pipeline safety. Whereas they are very simple to implement, their actual **systematic** use for design or operations may raise some problems, as they would result in eventually overconservative measures (see Figure 2) : for instance, only 800 mm diameter pipes with a design factor of 0.72 are puncture proof for 20 tons excavators, and lowering the design factor to 0.4 makes pipes puncture proof down to a diameter of 400 mm. The problem of small diameter pipes cannot be easily dealt with in this manner.

Indeed, the operating feed-back indicates that small diameter pipes are not the main stake, as the consequences are significantly more limited than for large diameter pipes. The following approach will illustrate a more comprehensive way to deal with the problem.

Gaz de France design approach based on risk assessment

The first step of safety oriented design takes into account deterministic assessment on either of two levels :

- prevention level : design to prevent an undesired event, like in the previous paragraph
- protection level : design as a function of undesired consequences.

More realistic approaches combine consequences weighted by failure probabilities in order to evaluate risk as a rational measure of the exposure to hazards. We briefly present here the main features of such a risk assessment procedure which is used currently at Gaz de France. It includes :

- pipeline environment description in terms of housing and activities
- failure probabilities from operational data bases (EGIG, [7] and Gaz de France data)

- consequences evaluation :
  - time-dependent gas flow-rate
  - thermal radiation fluxes calculated with a steady-state integral flame model
  - thermal radiation effects on constructions and persons including doses evaluation [8], escape strategies and sheltering alternatives

- individual and societal risk evaluations.

The main data and results of such an approach are illustrated in the case of a large diameter pipeline at 67 bar MAOP for the rupture scenario :

- Urbanization survey. Figure 3 gives an example of the data obtained on the urbanization (different types of buildings, land use, etc.).

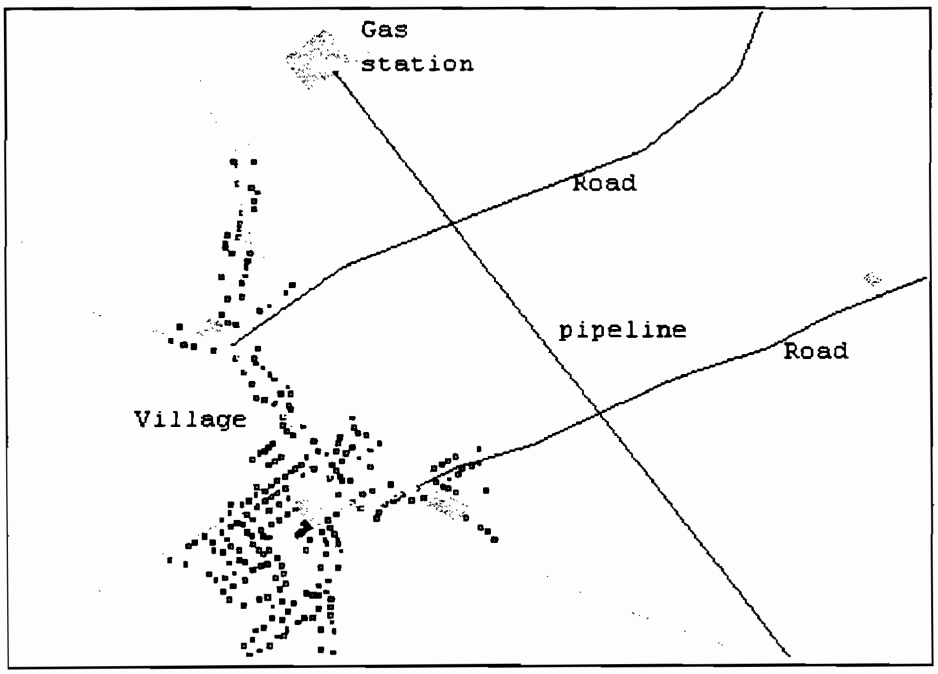

Figure 3. Data on urbanization

- Individual risk and inhabitant risk are represented on Figure 4 as a function of the distance to the pipeline.

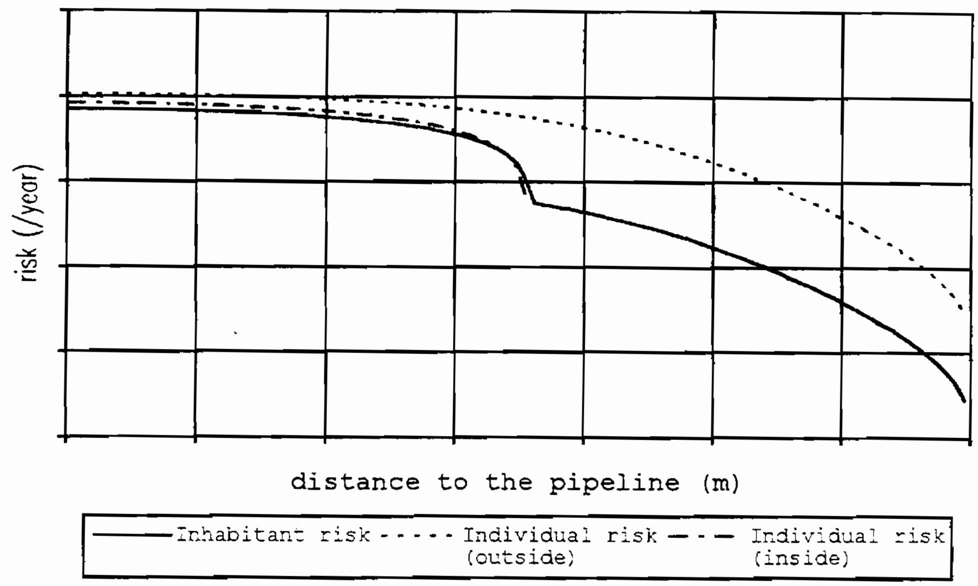

Figure 4. Individual and inhabitant risk

- Societal risk. The urbanization data were collected along a certain 40 km long pipeline section. The number of potential casualties along this pipeline is presented in Figure 5.

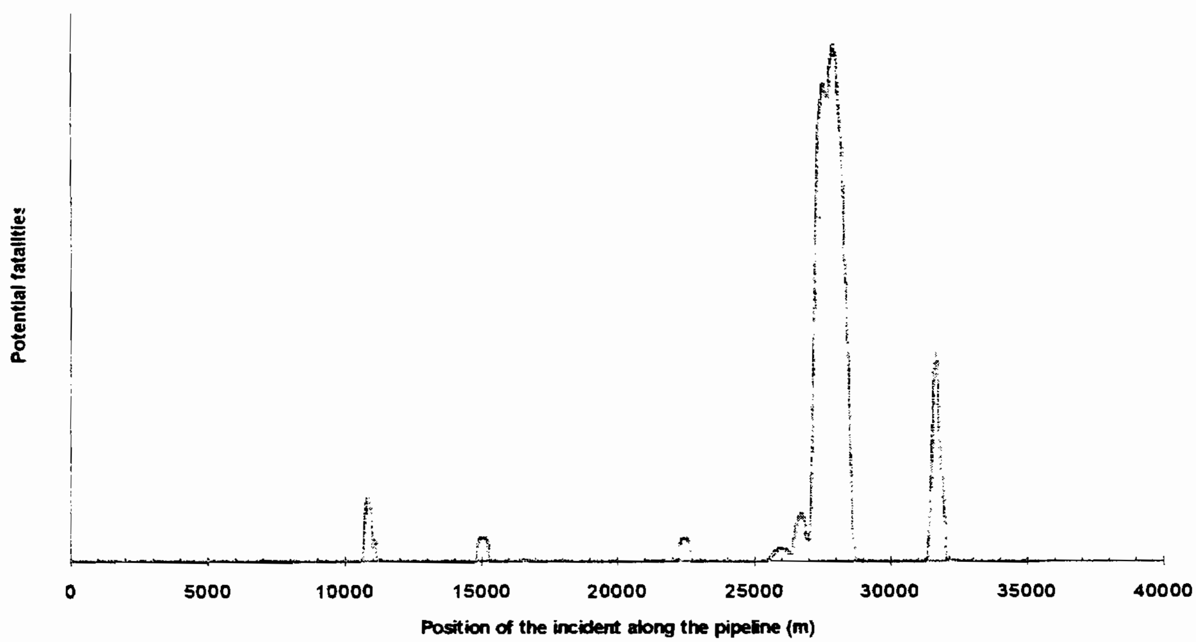

Figure 5. Number of potential casualties before mitigation

The last result indicates points on the route where the exposure is larger than in the surroundings. For some of these points, safety might have to be improved. Efficient countermeasures are known, like those indicated in the preceding paragraph. Unfortunately, as failure probabilities are derived from operational data bases gathering rare events, some quantitative indication of the expected safety improvement is not available.

Only a specific model of failure probability as a function of both pipe and environmental parameters can give quantitative indications about the relative safety improvement. Hence, a collaborative work was performed by Gaz de France, Ruhrgas and SNAM in order to elaborate a general safety assessment methodology which includes a failure probability model for third party damage.

A common methodology for safety assessment : Gaz de France, Ruhrgas and SNAM.

This common methodology was already presented in a general form [9]. It has a large common ground with the previously presented approach, except that it is richer in terms of input and output. It was developed to allow both a deterministic safety assessment as well as a probabilistic analysis, i.e. quantitative risk calculations by determining the possible types of failure, their probabilities and damage to people or property for each type of failure.

The methodology follows a logic chart (see Figure 6) to estimate different results.

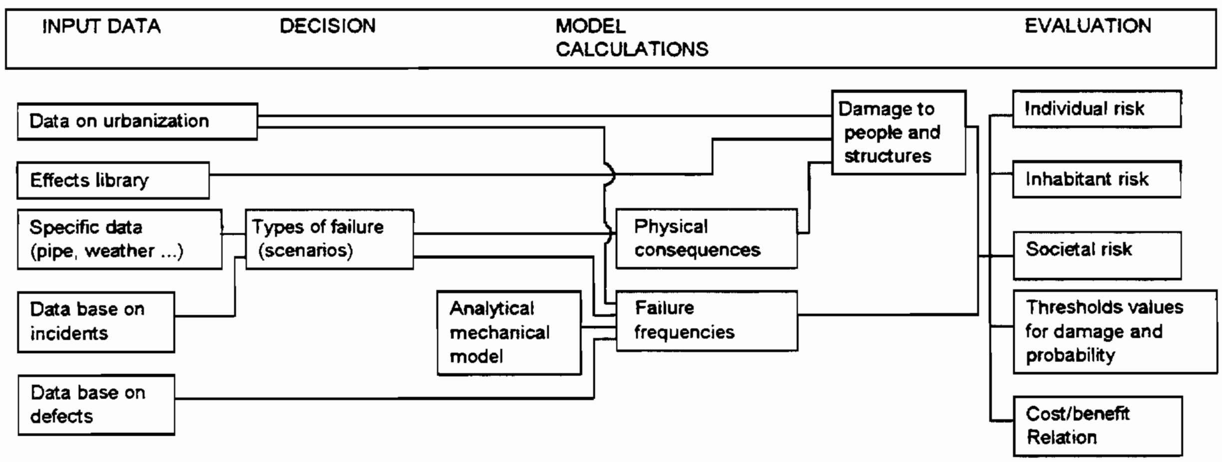

Figure 6. Logic chart for the safety assessment methodology

From the specific data on the pipeline (diameter, pressure, thickness, etc.) and from a historical data base on incidents, a number of failure modes are determined. Both the type of failure and the probability of occurrence are considered.

The physical consequences (flow-rate, heat radiation, over-pressure, missiles, etc.) for each failure mode are calculated.

Damage to people and structures is quantified by different methods which are applied to the real surroundings of the pipeline, thus requiring a survey of the urbanization around the pipeline. This survey is made by remote data acquisition techniques or by using numerical topographic databases. The present methodology incorporates the possibility of escaping when considering the hazard to people. These methods indicate the population distribution around the pipeline and the definition of special buildings (distance from the pipeline, number of people, fraction of time of person being present).

The failure frequency is determined from a historical database on incidents and with an original analytical mechanical failure probability model. It is based on the assumption that the most likely failure

cause for a gas pipeline is third party damage, which accounts for more than 50% of pipeline incidents [7].
It includes a statistical description of the ground working equipment as a function of land use in the area around the pipeline, damage creation models and damage stability criteria in order to calculate the leak/break probability. In addition, the damage creation models were validated on full scale damage creation experiments performed with a new dynamic and static Pipe Agression Rig (see [10] for more details).

The present methodology allows performing both a deterministic and a probabilistic safety assessment study depending on the needs of the operator, and leads to the following results :

Individual risk. Risk associated with the pipeline for a man standing permanently at a given distance from the pipeline.

Inhabitant risk. Risk associated with a pipeline for an inhabitant living at a given distance from the pipeline. That risk is weighed by probabilities of presence.

Societal risk. Societal risk is defined as the probability to have a certain number of casualties due to a pipeline incident for a given pipeline. Societal risk is calculated by considering the population in the area around pipelines. Societal risk can be expressed with different forms : number of fatalities and probability as a function of the position of the incident along the pipeline ; for the whole pipeline, frequency (F) of an incident leading to more than N fatalities as a function of N (F/N curves) ; for the whole pipeline, a single figure giving the statistical expectation value of fatalities per unit time (year) anywhere due to a pipeline incident.

Threshold values. Assessment criteria may be also threshold values for the maximum credible damage or probability of occurrence.

Cost/benefit analysis. Analysis that links for example the benefit of some additional solutions in terms of societal risk and the cost of this solution, allowing an optimization of the resources available for further improving the level of safety of the pipeline.

Such a global methodology is well suited to perform Safety Assessment analyses, in order to define a consistently safe pipeline design and help allocate resources on a rational basis.

CONCLUSION

The different approaches for designing transmission pipelines described above illustrate the current trend towards optimizing the allocation of limited resources. They show that :

- improving the steel grade (UTS) can be equivalent to increasing the wall thickness when it comes to pipe puncture resistance ;
- risk assessment based design helps define in a consistent way the points on the route where mitigating actions have to be taken ;
- taking into account in the safety assessment methodology a model for failure probabilities allows to evaluate the impact of different mitigating strategies, as it links the risk reduction to changes in the design parameters.

These recent developments show how evolving operator know-how about safety assessment can join the industry offer of higher steel grades to assure an even higher level of safety for gas transmission pipelines.

PART II / CURRENT STATUS AND MATERIALS TRENDS

General remarks

Modern pipelines have reached a very high level of safety, and pipelines are the safest and most economic means for transporting oil and gas over long distances. As the energy sources have shifted to more and more remote areas, there is a strong need to lower the cost of transportation. To reach this goal, many measures can be taken into consideration such as the use of high strength materials, higher operating pressures, lower safety factors and the like. It is understood that any change in the technical concept in comparison to existing rules for design has to maintain, or even improve, the safety level of the pipeline.

The technical challenges for the future are directed mainly towards higher internal pressure, lower operation temperatures, greater water depth or higher external pressure, better corrosion resistance and a longer life of the pipeline. It is even expected that pipe properties such as toughness, pipe geometry and homogeneity will also be improved in the future.

The ideal goal would be a high strength pipe with very low DWTT transition temperature, high ductility, good toughness, low carbon equivalent, high corrosion resistance and with a perfect geometry. There are physical reasons that these requirements cannot be fulfilled at once.

This paper tries to highlight briefly the current status of development and to provide some of the future trends. Special attention will be devoted to new materials and some operational aspects. The paper however is not intended to cover all the aspects.

Steel development from the past to today

During the 70's new rolling processes involving thermomechanical treatment came up and have, together with new, improved steel compositions, opened up completely new possibilities, Figure 7. This permitted the production of higher-strength steels with lower contents of alloying elements and in particular with reduced sulphur and carbon contents and decreased carbon equivalent. These steels have lower transition temperatures, high toughness and significantly improved field weldability. Since 1970/71 this rolling technology has permitted the production and employment of high strength micro-alloyed steels.

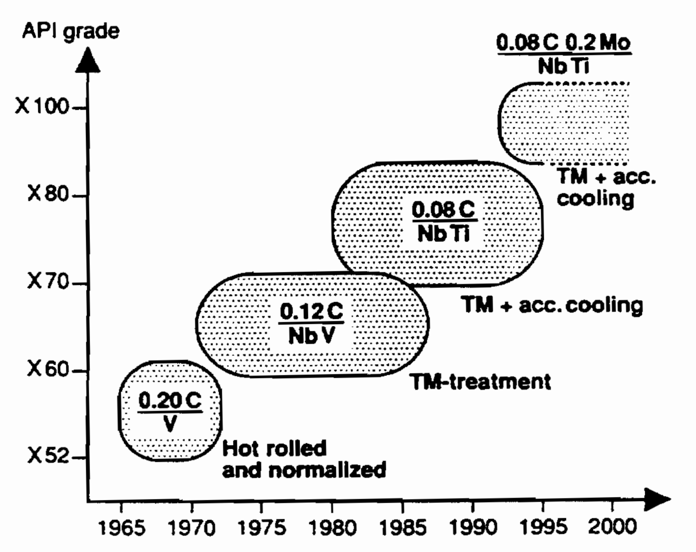

Figure 7 Development in linepipe steels

As illustrated in Figure 7, a jump in steel grades from X 52 to X 60, X 70 and X 80 was made about every seven years [11]. However, this reveals only part of the development, since at the same time wall thicknesses also became heavier. Figure 8 shows as a further example the trend for the growing wall thickness in offshore pipelines, based on a list of orders for a European pipe manufacturer. The heavier the wall, the more difficult it is to attain the required yield strength. If both are increased then the development effort is doubled. The obvious possibility of elevating yield strength by increasing alloy content is sharply limited by the demand for a low carbon equivalent, which is still equated in too direct a manner with good field weldability. As will be shown later, this kind of steel development is an extremely complex, sophisticated process which calls for extensive experience. A remarkable status has been reached now as can be seen later on.

Projekt	Grade	MAOP (barg)	WT (mm)	Use	Year
Britoil Amethyst	X52		19.1-25.4	Gas	88
Shell Sole Pit	X60		17.5-19.1	Gas	88
BP Miller	X65	174	23.8	Sourgas pH 3	89
BP Forties	X65	143.7	28.6	Souroil pH 3	89
Statoil Zeepipe	X65	156	23.8-24.2	Gas	90
Amoco Cats	X65	110	28.4-33.9	Gas	91
Tomec Bruce	X65		28.7-29.0	Gas	91
Hamilton Liverpool Bay	X65	140	20.6-25.4	Sourgas pH 3	93
Statoil Europipe	X65	156	23.8-24.6	Gas	93
Shell Troll	X65		31.0	Gas	94
Statoil Zeepipe II a+b	X65	191	26.1-28.9	Gas	94/95
Britannia	X70	180	15.1-23.7	Gas	96
Statoil Norfra	X65	191	25.3-30.3	Gas	96
Statoil Europipe II *)	X70	191	22.3-28.7	Gas	97
Statoil Asgard *)	X65	200	30.4-32.8	Sourgas	97

*) planned

96.16870

Development of the requirements for North Sea projects

Figure 8

Actual status of development of line pipe steels

In Europe the properties for line pipe materials have reached a very high level. Various materials with adequate properties are available for different applications. Figure 9 is a simplified presentation of the possibilities for today's line pipe supply, based on orders of statistically significant sizes.

	Wall thickn.	Grade	Carbon equiv. PCM	Charpy toughn. CV (J)	Corrosion resistance	Lowest operation temp. (DWTT)
Onshore pipelines	32 mm	X 80	0.24	150	-	- 20 °C
Offshore pipelines	25 mm	X 70	0.22	> 150	Non sour	- 25 °C
Offshore pipelines involving corrosion	35 mm	X 65	0.16	> 150	HIC and SSC resistant	- 10 °C
Offshore pipelines for deep sea	45 mm	X 70	0.21	150	Non sour	- 10 °C
Onshore pipelines involving corrosion	35 mm	X 65	0.16	> 150	HIC and SCC resistant	- 10 °C
Clad or corr. resistant materials	30 mm	X 65	0.16	> 100	Resistant to weightloss corrosion	- 10 °C

97.17071

Today's standard delivery for linepipe in Europe
(max. diameter up to 64")

Figure 9

Of course exceptions for special cases would be available but are not considered here and quenched and tempered pipe will also not be dealt with in this paper.

The table indicates the different kinds of applications and the most important and decisive properties .

The highest grade is X 80 in normal case for onshore pipelines [12, 13], whereas thickwall pipes for sour service are limited to grade X 65, [14]. The welding properties are excellent and, depending on wall thickness, the transition temperatures from brittle to ductile fracture fulfill the demands of usual application.

In most cases the pipes are manufactured by the UOE process, and for wall thickness much below 20 mm also spirally welded pipes are available for grades up to X 80, [15].

For deap sea applications heavy wall pipes have been developed up to grade X 70 and wall thickness exceeding 40 mm, [16].

For the special application against weightloss corrosion highly corrosion resistant or clad pipe is available with favourable properties up to grade X 65, [17].

Potential for steel and pipe development in the future

For future projects it is of great interest to know the possibilities in pipe manufacturing. New materials may help in reducing the cost for pipelines and in increasing the safety level in the desired aspect. This outlook from the view of the pipe manufacturing companies in Europe will be based on a short-term development and on realistic goals. It will not include exotic materials with pipe costs exceeding remarkably the price level of current materials.

Figure 10 is a summary of what can be expected in near future. For onshore pipelines grade X 100 will be available in the near future with good weldability and very high toughness. Offshore pipelines for non sour service will be designed in grade X 80 and for sour service in grade X 70 and heavy wall.

	Wall thickn.	Grade	Carbon equiv. PCM	Charpy toughn. CV (J)	Corrosion resistance	Lowest operation temp. (DWTT)
Onshore pipelines	**20 mm**	**X100**	**0.25**	**170**	**Non sour**	**-15 °C**
Offshore pipelines	**32 mm**	**X80**	**0.25**	**>150**	**Non sour**	**-20 °C**
Offshore pipelines involving corrosion	**35 mm**	**X70**	**0.16**	**>150**	**HIC and SSC temporarily**	**-10 °C**
Onshore pipelines involving corrosion	**35 mm**	**X70**	**0.16**	**>150**	**HIC and SCC temporarily**	**-10 °C**

97.17070

Expected properties in the future for linepipe in Europe
(max. diameter up to 64")

Figure 10

There is no deterioration of the weldability and toughness and the transition temperature can even be improved in some cases.

It is important to know the crucial points for the new grade X 100, [11, 18]. This material possesses a high yield-to-tensile ratio, exceeding 90 %, an elongation at fracture around or even below 18 % and it requires extensive investigations of the fitness for purpose. This refers especially to the necessary toughness for crack arrest and to the safety of girth welds. From the pipe manufacturer this material requires very low scatter of the material properties in the pipe body and in the full order. Moreover, projects with such a new material have to be designed in very close cooperation with the pipe manufacturer, the pipelaying contractor and the pipeline operator from the very beginning, thus enabling the potential of such a new material to be exploited optimally.

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THE FUTURE OF PIPELINE PIGGING (WHAT IS NEEDED FOR FUTURE IN-LINE INSPECTION OF PIPELINES?)

by

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The Future of In-Line Inspection Pigging

BANFF/97
PIPELINE
WORKSHOP

Harvey Haines
Principal Project Manager
NDE

April 16, 1997

Outline

- **Vendor & Research Organization Perspective**
  - Who is developing what?
- **Technology Perspective**
  - What technologies are available in other industries?
- **Regulatory Perspective**
  - Where have the reportable accidents been occurring?
- **Historical Perspective**
  - Why are we doing things the way we do them?
- **Competitive Perspective**
  - How can we reduce the cost of maintaining a safe pipeline?

GRI NDE Projects

- Mechanical Damage
- Corrosion
- Stress Corrosion Cracking

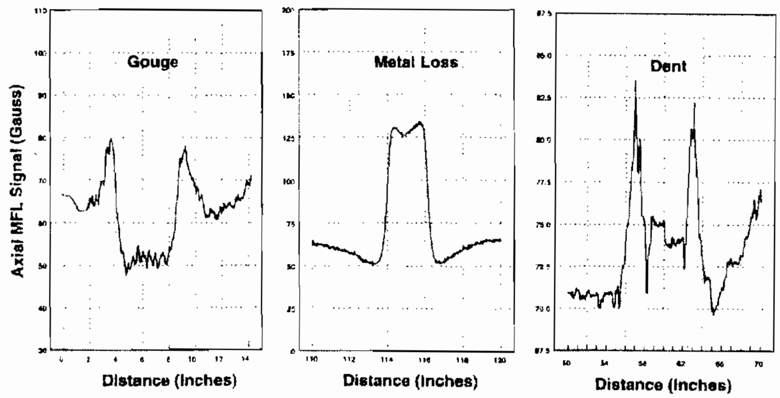
Most of the effort

- Coating Disbondment
- Weld Defects
- Real-time Monitoring
- Operational Limitations (unpiggable lines)
- Stress and Strain

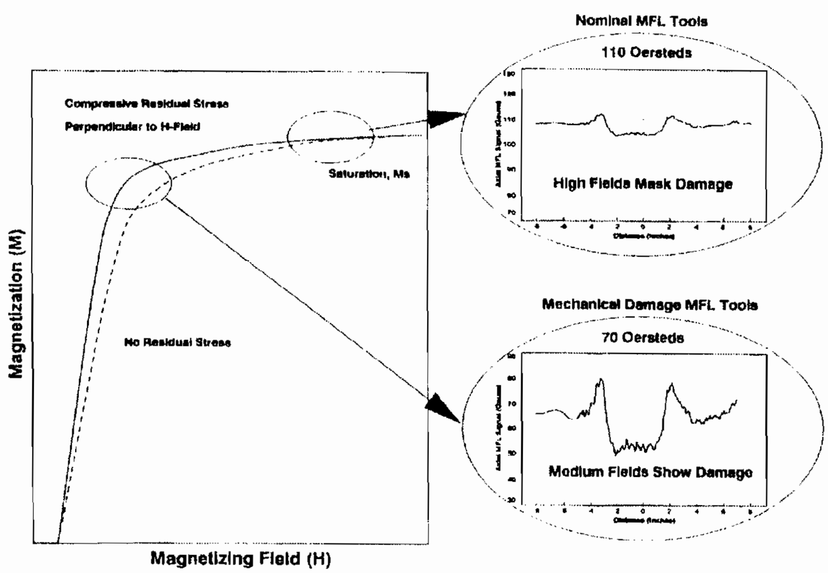
Mechanical Damage

- Most Vendors State they have found Damage with Intelligent Pigs
- Some Operators Report Intelligent Pigs have Missed Damage Subsequently Found Through Other Means
- Other Operators Report Success Finding Damage Using a Combination of Older MFL Technology and Caliper Pigs

Mechanical Damage Results



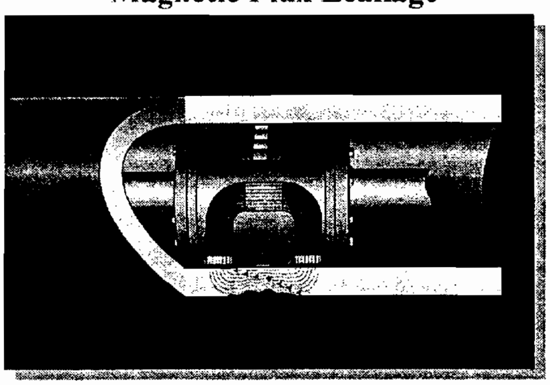
Mechanical Damage Results



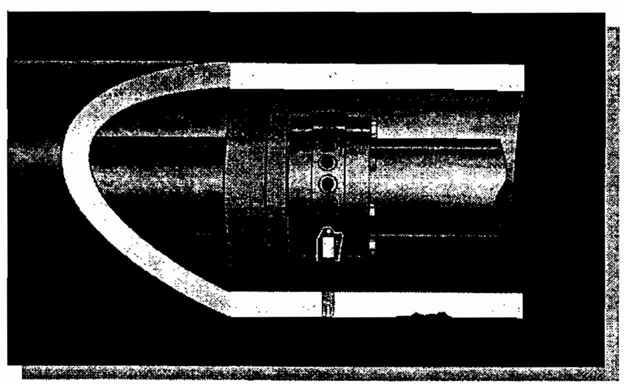
Corrosion

- Newer Higher Resolution MFL tools with greater dynamic range are available
- Better Algorithms for Inverting MFL Signals to Corrosion Geometry (Depth, Length, Width)
  - GRI will transfer the results of its investigations to vendors in the next year
- A Circumferential MFL Tool is Now Available from BG plc
- Ultrasonic Tools are Available from Pipetronix and NKK

Magnetic Flux Leakage



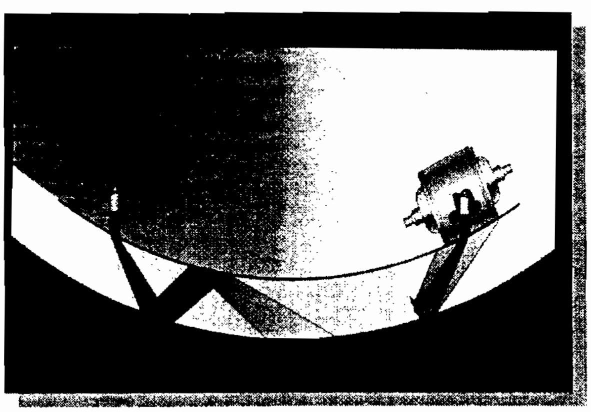
Normal Beam Ultrasonics



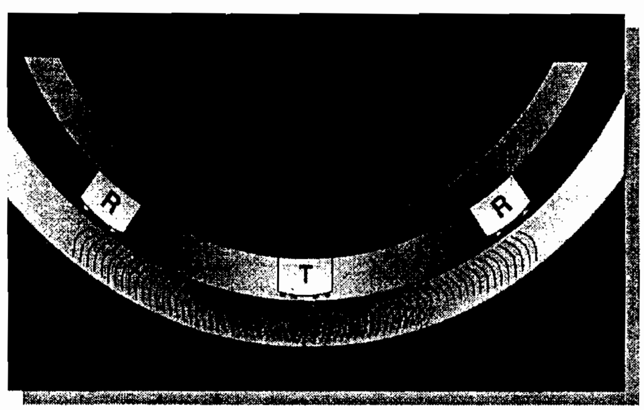
Stress Corrosion Cracking

- **BG plc – Elastic Wave Vehicle**
  - Currently have 30"-36" pig
  - Build 24" & 42" pigs
    - » Travel at speeds up to 10 mph
    - » Traverse 1½ D bends in 24"
    - » Allow gas bypass for gas flow rates of 15-20+ mph
- **TDW – EMATs**
  - Completing prototype 24" pig.
- **Pipetronix – UltraScan CD**
  - Have Inspected a Range of Pipelines
  - Requires Liquid Couplant thus Expensive to Use in Gas Pipelines

Angle Beam Wheel Probes



EMATs

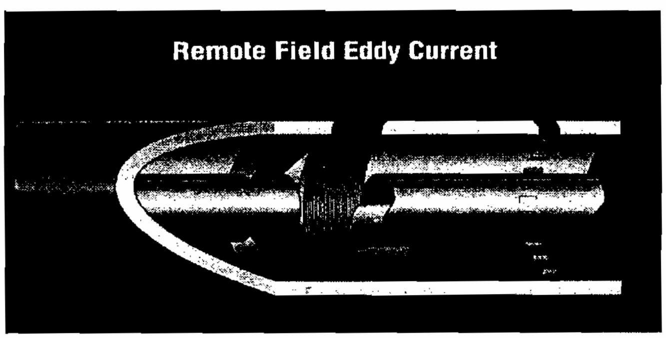


Coating Disbondment

- **BG plc – Elastic Wave Vehicle (Crack Pig)**
  - Detect Coating Disbondment
  - Differentiate Different Types of Coating

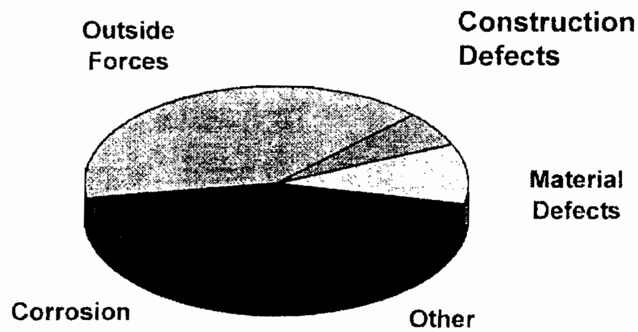
What Other Technologies Are Available

- **Remote Field Eddy Currents**



- **Other Methods of Transmitting Ultrasonics**
  - Lasers
  - Capacitance
  - High Pressure Gas Coupling of Conventional Ultrasonics

Where Have Accidents Been Occurring



Jones & Eiber, 1992

Better Pigs May Reduce Some Costs

(17 Companies Interviewed)

Benefit	$ Benefit (annual in millions)	Mentions out of 17 Companies
Eliminate Class Changes	$158	9
Reduce Incident Costs	$14	11
Replace Hydrostatic Testing	$16	4
Reduce In-service Repairs	$23	5
Avoid Costly Regulations	$6	2
Optimally Sched. Outages	$5	5
Other (6 categories)	$4	4
Total	$226	

Represents ~170,000 miles of pipeline in U.S. & Canada

Other Opportunities

- If Safety can be Maintained by Pigging in Potential Class Location Changes.

- Can Pressure be Increased on Properly Designed Pipelines with Better Inspection?

Conclusions

- Newer Technologies are Becoming Available for Inspecting Pipelines
  - Better resolution with Magnetic Flux Leakage
  - Ultrasonics for inspection of cracks
  - Ultrasonic inspection for corrosion in liquids
- What Current Practices Can be Changed to Reduce Cost resulting in Equal or Better Safety?
  - Can pigging replace hydrotesting?
  - Can pigging replace class location changes?
  - Can pigging allow for increases in operating pressure?

MIACC PROCESS – CANADA'S VOLUNTARY APPROACH TO MAJOR HAZARD CONTROL

by

Roland Andersson
Major Industrial Accidents Council of Canada
Ottawa, Ontario

MIACC PROCESS
CANADA'S VOLUNTARY APPROACH TO MAJOR HAZARD CONTROL

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Abstract

Major industrial accident hazards are not as prescriptively regulated in Canada as compared with most other industrialized countries. Some aspects are partially addressed by various federal and provincial regulations, but not to the extent of the USA and the European Community, for example, which have enacted comprehensive regulations covering prevention and preparedness not only on the plant site but also in the surrounding community.

In Canada, a review after the Bhopal accident in 1984 revealed extensive gaps in coverage here, and a follow-up ten years later showed that despite much progress a lot still remained to be done. Even this was not easy to quantify, because some of the key players in preventing or preparing for major accidents appeared to be unaware of Canada's comparatively weak position. It seemed that, because of the absence of the publicity and support which have typically accompanied regulation elsewhere, the stakeholders did not recognize the vulnerabilities existing in many industries and communities in this country.

This situation appears to have worsened in 1995-97, as industry and governments have continued to lose many of their experienced resources through organizational re-engineering or restructuring.

Before a disastrous accident happens in Canada and creates public outrage which would pressure governments to impose legislation, MIACC is endeavouring, using a voluntary approach, to reduce the risk of major industrial accidents involving hazardous substances through effective prevention, preparedness and response (PPR).

Through this voluntary process, MIACC will undertake to identify all MIACC List 1 Priority Hazardous Substance inventory sites or locations with significant potential population exposure to major transportation hazards from hazardous substances.

List 1 is a short list of "top priority" substances commonly found in Canada both in fixed facilities and transport situations. List 1 substances in quantities larger than the listed threshold quantity, if released, have a high probability of causing fatalities off site.

These identified List 1 site communities will be encouraged to implement joint community and industry emergency preparedness programs. To accomplish this, MIACC stakeholders and champions will have to bring about behavioural change in many of the organizations:

- having control over hazardous substances;
- which may be called on to respond if something goes wrong; and
- that regulate the manufacturing, handling, transportation or disposal of hazardous substances.

Background: Emergence of MIACC

MIACC traces its beginnings to the tragic accident at Bhopal, India, in December 1984, when deadly gases were accidentally released from a chemical plant, resulting in the death of 2,000 - 15,000 people and injuries to hundreds of thousands more. This accident and its devastating consequences focussed world attention on the many risks involved in manufacturing, storing, transporting and using hazardous substances.

Formed in 1987, MIACC is a uniquely Canadian, not-for-profit organization. It works through a voluntary, consultative and consensus-building process with the primary mission of reducing the frequency and severity of major industrial accidents involving hazardous substances. MIACC is a multi-stakeholder group that includes industry, government, NGOs, academia and other organizations. Task forces, committees and teams staffed by stakeholder volunteers develop standards, guidelines and information exchange fora aimed at prevention, preparedness and response to major industrial accidents. Today, MIACC operates as the "Internet" of PPR professionals.

MIACC is governed by a Board of Directors and, in 1996, it's annual one million dollar budget funding was derived 60% by memberships (industry associations, industry, government (federal, provincial, municipal), NGOs, academia) and 40% by sales of PPR tools (products, services). Ten people are employed at the MIACC Secretariat in Ottawa.

In Canada, responsibility for management of environmental emergencies is shared by federal, provincial and municipal governments. In practical terms, this means that the first response to an emergency is usually made by local or regional authorities. Thereafter, if the scale of the emergency warrants, provincial and federal authorities may become involved. If a coordinated effort among local industry officials, municipal and provincial authorities is required, the efficient use of all resources is maximized when all parties have integrated their individual emergency preparedness programs.

MIACC's second mission is to promote harmonization of prevention, preparedness and response programs in every jurisdiction and community in Canada. This will help to ensure that PPR efforts are better coordinated, that the administrative burden on industry is reduced, and that costs to government are reduced. An increased level of protection will be achieved for the public and the environment.

Phase II - Implementation of Hazard Control Measures at the Community Level

In addition to developing a national strategy that sets out the organization's objectives, MIACC has produced a Business Plan (1997 - 1999) outlining the framework within which those objectives might be achieved. This is based on the needs of the stakeholders and anticipates the organization's growth and development.

Under MIACC's original workplan, Phase I concentrated on developing practical tools for PPR which can generally be categorized into: Risk Management; Land Use Planning; Process Safety Management; Life-Cycle Management; Emergency Planning; Education and Training; and Proceedings.

Phase II will concentrate on the distribution of products and the implementation of a national strategy. This means, amongst other things, bringing about actual change in the prevention and preparedness programs of industry, carriers and communities across Canada. It is here, at the grass-roots level, that MIACC products are likely to have the most value and where significant risk reductions can be made. Phase II will be implemented through the support of provincial governments, regional based MIACC chapters, communities, industry and industry associations, and carrier sectors. At present, regional MIACC chapters are operating in Alberta, Saskatchewan, Manitoba, the Montreal Urban Community, Ontario and British Columbia.

The success of the implementation phase depends upon the co-operation and support of those organizations that produce or otherwise deal with hazardous materials (industry and carriers) as well as those that must respond when something goes wrong (municipalities and regions).

Implementation of hazard control measures relies on local community awareness, co-operation and voluntary participation. Communities must have access to information concerning both risks and measures for prevention, preparedness and response, including the emergency response plans of the organization(s) that control hazardous substances.

Phase II Implementation Strategy

Although the primary control for major accident prevention lies with site operators and to a lesser extent transporters, these organizations, in the 1990's, are subject to rapid and frequent changes in ownership and direction, and in the personnel responsible for operational safety.

For this reason, the suggested control strategy, while targeted also at site operators and transporters, is based primarily on the community - where the presence of clearly defined and relatively constant boundaries aids greatly in keeping track of hazardous installations and their progress. In addition, communities, through their municipal administrations, are responsible for community emergency preparedness, which should include an assessment of the risks from those installations and appropriate response measures in case an accident occurs.

The challenge facing MIACC in attempting to bring communities, site operators and transporters up to a desired standard of PPR performance is that no single approach is likely to be effective in addressing the variety of situations found in Canada.

Every community presents a different set of factors. In some, the municipality may have an active emergency plan under the fire chief, while site operators may oppose efforts to involve them in the process. In others, one or more industries may have taken the lead - sometimes with the support but occasionally with the resistance of - response agencies. Some carriers may be well prepared, while others are not. Emergency medical services often vary greatly, even in the same community.

The strategy proposed, and endorsed by the MIACC Board of Directors, is therefore directed simultaneously at the three principal groups, since we do not know in any given community which of these may take a leadership role. These groups are:

Site Operators
This target group includes companies which operate hazardous sites, and also organizations representing those companies (e.g., Syncrude, The Canadian Chemical Producers' Association).

Transporters
This group consists of companies which transport large quantities of hazardous substances and organizations representing those companies (e.g., CP Rail, Ontario Trucking Association).

Communities
In this sense, the term "community" is used loosely to describe geographically defined zones such as a municipality, but also a county, mutual aid network area, etc. (e.g., City of Regina, Montreal Urban Community, Lambton County). Elected officials, city administrators, town clerks, responders such as fire, police, ambulance and public works, are typically covered in this group, as are hospitals despite their independence from the municipal administration.

A cornerstone of the MIACC process is the policy of working with existing organizations, acting as a facilitator and coordinator of activities rather than attempting to take over or duplicate the efforts of others (except as a last resort or in response to a request from the organization concerned).

The proposed strategy therefore aims at reaching out to the targets – site operators, transporters and communities – via existing organizations and channels wherever possible rather than by direct contact. Any community, therefore, may be influenced by provincial emergency measures organizations, associations of fire chiefs, municipal planning organizations, industry trade associations and carriers, to mention only a few.

Managing the Voluntary Approach to Hazard Control

The MIACC voluntary initiative to prevent and prepare for a major industrial accident involving hazardous substances is driven primarily by the List 1 Priority Hazardous Substances and managed voluntarily by three teams: Hazardous Installations, Transportation Systems and Community Preparedness.

Team Responsibilities

Hazardous Installations Team

- identify List 1 inventory sites
- develop industry PPR criteria
- communicate / sensitize targets
- assess status and receptivity by industry
- champion and promote

Transportation Systems Team

- identify hazardous transport corridors
- develop transportation industry PPR criteria
- communicate / sensitize targets
- assess status and receptivity by transport industry
- champion and promote

Community Preparedness Team

- identify List 1 inventory site communities
- develop community PPR criteria
- communicate / sensitize target communities
- assess status and receptivity by communities
- champion and promote

Conclusion

The recommendation, by MIACC members and supporters, is that each community should establish a joint community and industry committee to promote the development of a coordinated emergency preparedness program. Participants should have a clear understanding of the committee's mandate and their respective roles.

The committee should be formally established as the competent authority to:

- determine the risk to the community;
- gather and share information;
- integrate municipal and industry emergency response plans;
- identify and obtain communications equipment, systems and procedures;
- develop the methods and procedures for communicating with the public and media;
- develop and carry out joint training, exercises and emergency simulations; and
- develop mutual aid or assistance agreements

Benefits of Joint Community and Industry Emergency Preparedness

The benefits of joint community and industry emergency preparedness are substantial and include:

- ensuring the safety of workers, emergency responders and the public;
- reducing property and environmental damage and reducing costs and recovery delays;
- inspiring public confidence in authorities in both the industry and public sector; and
- promoting confidence among emergency responders in the community and industry.

As of March 1997, 1075 List 1 inventory sites had been identified by the Hazardous Installations team.

Ultimately, it will be up to the targeted communities to either act upon the emergency preparedness recommendations or leave the situation as it currently exists.

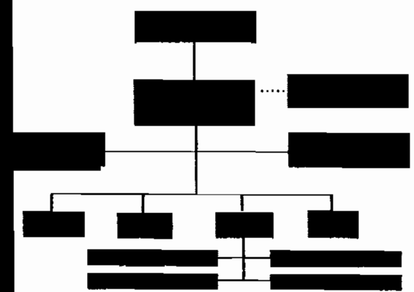
Mission & Goals

- As the national focus for leadership and co-operative activities to:
  - reduce the frequency and severity of major industrial accidents involving hazardous substances
  - achieve harmonization in the implementation of prevention, preparedness and response (PPR) fields in Canada

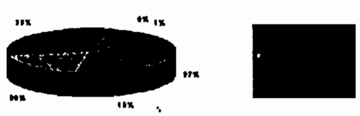
Process

- neutral, non-profit, independent forum
- Stakeholders (industry, government)
- Secretariat
- PPR the common linkage
- MIACC the "internet" of PPR

Organization



Funding of Process



MIACC Partners (Sample)

Alberta	Environment Can
AB Fire Training School	Imperial Oil
Alexander & Alexander	NEB
Amoco Canada	NOVA
BC Gas	Petro-Canada
BOVAR Env	PGAC
CAPP	Suncor
CEPA	Syncrude
CGA	Westcoast Energy
Edmonton	

PPR Tools

- Process Safety Management
  - Process Safety Management Guide
  - Process Safety Management - Course
  - Process Safety Management - Tools and Training
  - Centre for Chemical Process Safety (CCPS)
- Life-Cycle Accident Prevention Workshops
  - Chlorine
  - Liquefied Petroleum Gases (LPG)
  - Ammonia

PPR Tools

- Training and Education
  - Emergency Response Training Inventory
  - Meeting the Standard
- Emergency Planning
  - Guiding Principles for Joint Municipal and Industry Emergency Preparedness
  - Z731 Emergency Planning for Industry

PPR Tools

- Risk Management
  - Risk-Based Land Use Planning
  - Lists of Hazardous Substances
  - Risk Assessment Mini-Guide
  - Risk Assessment Guidelines
  - Risk Assessment - Basic Course
  - Risk Assessment and Management - Advanced Course

Pipeline Land Use Planning

- community planners & ER target audience
- product pending; forecast for 3Q (1997)
- consequence based
- Response Planning Area (RPA)
  - public affected (conservative estimate)
  - Natural Gas, Sour Gas, HVP and LVP hydrocarbon mixtures

PPR Tools (pending)

- Mutual Aid Agreements (Industry)
- Cross Border ER Guide
- Risk Assessment methodology - Vers II
- Gasoline Workshop
- ER 2000+
- Land Use Planning Adjacent to Pipelines
- Dangerous Goods Routes in Communities
- Shelter-in-place vs Evacuation

Risk Communications

CAPP	CCPA	CEPA
CPPA	CPPI	
AEUB		NEB
Coast Guard	EPC	Environment
Health		Transport

- consensus driven process
- consistent with CSA Q850
- for all PPR Stakeholders

Harmonization

- Z731 Emergency Planning for Industry
- Process Safety Management
- Land Use Planning
- Spills Notification (one window)
- Chemical Marine Response Org
- ER 2000+
- Risk Communications

MIACC Phase II (1997 - 1999)

- From PPR tool development to awareness and implementation
  - Lays the foundation for an effective system for major hazard control in Canada
  - Allows for regional and sectoral flexibility
  - Use of a voluntary approach, consistent with the spirit of MIACC

MIACC Phase II (1997 - 1999)

- Identification of industries and communities that handle MIACC List 1 hazardous substances
- Identification of transport routes with significant population exposure to potential hazardous substances accidents
- promotion of joint community / industry preparedness at all identified sites

Phase II Strategy

- Bring about behavioural change in:
  - those organizations having control over hazardous substances
  - those organizations which may be called on to respond if something goes wrong
  - those organizations that regulate the manufacturing, handling, transportation or disposal of hazardous substances

Phase II Implementation

- Hazardous Installations team
  - List 1 inventory sites identification
  - industry criteria / communication / feedback / promotion
- Transportation Systems team
  - transportation criteria / communication / feedback / promotion
- Community Preparedness team
  - community criteria / communication / feedback / promotion

List 1 Priority Hazardous Substances

Examples (32 in total)

	tonnes
Methane	100
Propane	100
Gasoline	200
Cyclohexane	200
Ethylene Oxide	50
Chlorine	10
Hydrofluoric Acid	50
Sulphuric Acid (fuming)	10
Hydrogen Sulphide	10

Joint Coordinating Committee

- determine the risk
- gather and share information
- integrate emergency response plans
- identify communications equipment and systems
- develop communications procedures
- carry out joint training and exercises
- develop mutual aid agreements

Benefits of Joint Emergency Preparedness

- ensure safety of workers, ERs and public
- reduce property damage
- reduce environmental damage
- reduce costs and recovery delays
- inspire public confidence in authorities in industry and public sector
- promote confidence among community emergency responders and industry

Benefits for Municipalities

✓ Increase public safety via PPR
✓ Assess risk of hazardous substances
✓ Develop sound land use planning
✓ Reduce and harmonize regulatory burden
✓ Access a valuable network of experts
✓ Stay current in latest PPR information

Benefits for Industry

✓ Reduces regulatory burden
✓ Reduces costs of PPR programs via harmonization. Direct input of members
✓ Membership / participation demonstrates due diligence (insurers, financial advisors)
✓ Provides easy-to-use PPR tools
✓ Invaluable network of PPR professionals
✓ Stay current in latest PPR information

HOW DOES THE INSURANCE INDUSTRY VIEW THE PIPELINE INDUSTRY TODAY?

by

Graeme King
Greenpipe Industries Ltd.
and
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AON Reed Stenhouse
Calgary, Alberta

How Does The Insurance Industry View The Pipeline Industry Today?

by

Graeme King, Greenpipe Industries Ltd

and

Norman Nibber, AON Reed Stenhouse

GREENPIPE

Alexander & Alexander
Reed Stenhouse

Mission of Pipeline Insurance

- To use insurance to manage catastrophic (rather than normal everyday) risks that cannot be managed in other ways
- To identify gaps in pipeline risk management programs from an insurance perspective
- To manage the identified gaps using insurance programs based on sound risk financing strategies

GREENPIPE

Alexander & Alexander
Reed Stenhouse

Objectives of Pipeline Insurance

- To clarify and quantify the risks of owning and operating oil and gas pipelines
- To reliably gauge and account for differences in the quality of pipeline integrity maintenance programs
- To provide uniform insurance coverage to pipeline operators as the risk profiles of their assets change with age

GREENPIPE

Alexander & Alexander
Reed Stenhouse

Changing Risk Profiles

- Failures in pipeline systems are affected by:
  - Third-party contact
  - Internal and external corrosion
  - Cathodic protection deficiencies
  - Coating degradation, etc
- These are all well managed by experienced pipeline operators who appreciate how aging affects maintenance requirements but aging also affects risk management and insurance

Today's Situation

- Most companies self-insure against normal everyday operational risks such as:
  - Cost of repairs and loss of production
  - Business interruption during repair
- Catastrophic risks are not well defined and are generally not well insured
- Catastrophic risks can be unknowingly transferred to insurance companies, third-party contractors, and purchasers of assets

GREEN PIPE
Alexander & Alexander
Reed Stenhouse

Catastrophes and Consequences

- Catastrophic losses can be caused by:
  - Long term leaks that pollute the environment
  - Explosions that destroy real property & cause loss of life
  - Major accidents during repair of "hot" lines causing loss of life and business interruption
- Catastrophic losses can result in:
  - Bankruptcy or serious loss of business opportunity
  - Fines and legal action against the company
  - Legal action against senior company management
  - Loss of corporate image

Banff/97 Pipeline Workshop

How Did We Get Here?

- The oil and gas pipeline infrastructure has been built in the last forty years
- Many systems are operating beyond their originally anticipated design life and are becoming increasingly unsafe with age
- Encroachment has not been balanced by additional safety measures
- New legislation requires that pipeline companies assume greater responsibility

Communicating Risks Is Not Easy

РИСКОВЫЕ ЛЮДИ НАЧИНАЮТ РИСКОВОЕ ДЕЛО

Джеймс УЭЙД, президент акционерной корпорации «БАЙТЕК», которая начинает инвестиции в нефтегазовый бизнес Иркутской области, дал пресс-конференцию в одном из холлов гостиницы «Интурист» 13 ноября

Нынешний приезд представителей «БАЙТЕКа» в Иркутск — второй. В июле 1992 года они подписали протокол о предварительных намерениях с акционерной компанией «РУСИА-Петролеум». В ноябре привезли специалистов-газовиков, которые с высоты вертолетного

рит о своей корпорации, как об «очень активной и агрессивной». Доля участия «БАЙТЕКа» в нефтегазовом проекте «РУСИА-Петролеум» будет предположительно равна пятидесяти процентам.

Главный вопрос журналистов к Джеймсу Уэйду — чем выгоден канадской компании иркутский проект? Не станем же мы расплачиваться газом через океан! На что Уэйд ответил, что «есть миллион путей», по которым можно получить свою часть дохода. Однако расшифровывать это заявление

более высоким, чем Ковыктинское, давлением. Главное препятствие он видит в том, что газопроводу придется пересекать реки Ангару и Лену. Горы же не потребуют больших взрывных работ — они не высоки. Технико-экономическое обоснование газоконденсатного месторождения будет выполнено совместными усилиями. «Жигаловский район очень похож на Се-

Pipeline Data

- Transport Board of Canada statistics based on 24 oil and 30 gas pipeline companies with over 30,000 km of pipeline shows an average incident rate of 2.4 per 10^{18} joule (about 1 incident per 10 billion litres of gasoline)
- Pipeline incident rates are lower than other modes of transportation (that is, rail and road)
- Alberta insurance records show no pipeline incidents with a loss more than $50,000,000

The Insurance Industry's View

- The insurance industry has traditionally viewed oil and gas pipelines as inherently safe operations
- The move towards outsourcing means that risks can no longer be reliably assessed and managed in traditional ways
- The insurance industry is increasingly searching for gaps in the risk management programs of pipeline operators

Gaps in Today's Risk Management

- The identification of risks and responsibilities with regard to:
  - The transfer of facilities to new owners
  - Third-party contractors working on maintenance of operating (or "hot") pipelines
- Funds to cover costs of possible catastrophes to be set aside by new owners, operators who self-insure, third-party contractors and consultants

Sound Risk Financing Strategies

- Pool money from many operators where it can be properly administered
- The amount of money to be deposited needs to be related to the maximum expected catastrophic loss rather than the risk (where risk = frequency x loss)
- Guard against using insurance as an alternative to safe operating practices

Available Options

- Pipeline operators can manage catastrophic losses by self-insuring, or by using insurance brokers to spread losses throughout society
- Using insurance brokers is advantageous because it:
  - facilitates collection of funds in protected accounts to cover rare catastrophic events
  - encourages proactive response to new and growing risks
  - enables inclusion of the cost of catastrophic losses in the tariff

Recommendations

- Use the existing insurance industry to manage catastrophic risks
- Actively search for gaps in risk management programs
- Use sound risk financing strategies
- Establish criteria for rating the quality of safety and integrity maintenance programs as it affects insurance

HARMONIZATION OF CANADIAN PIPELINE REGULATIONS

by

Rob Power
National Energy Board
Calgary, Alberta

Pipeline Regulation Harmonization...

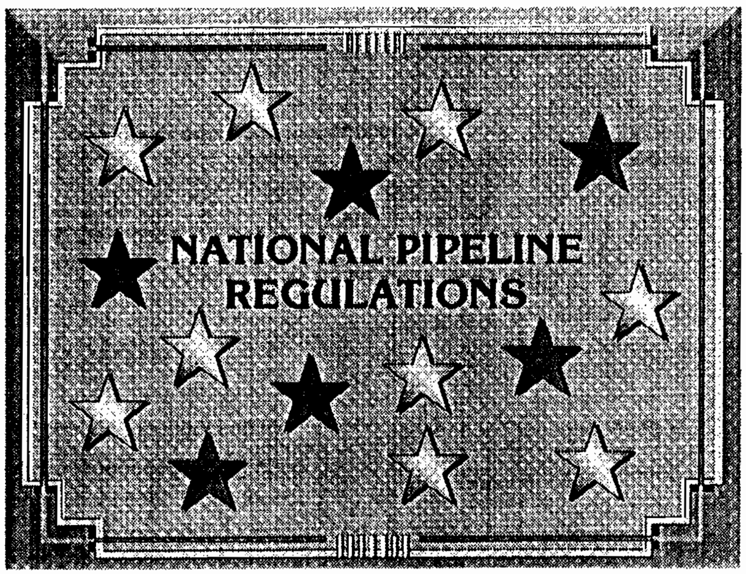
What's the Prize and Is It Worth Pursuing??

Joint NEB/EUB Presentation at Banff Pipeline Integrity Workshop

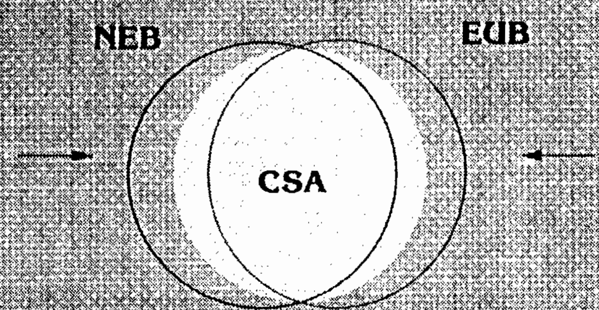
16 April 1997

Reconnaissance

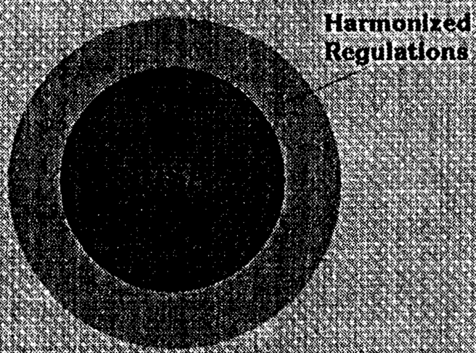
97/2/17 - NEB I
97/2/19 - CEPA I
97/3/21 - NEB/CEPA II
97/3/24 - EUB
97/3/26 - CAPP
97/4/16 - Banff Workshop



Current Scenario



Ideal World



Sampling of Issues

Pipeline Safety Regulations
Environmental Expectations
Plethora of Regulation
Jurisdictional Boundaries
OSH Regulation

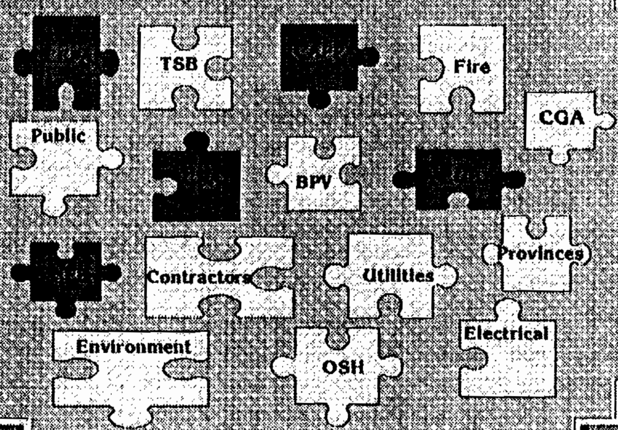
Perceived Benefits

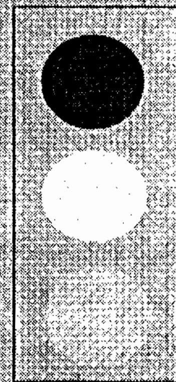
Reduce/eliminate duplication
Ease of understanding
Lowered cost of compliance
Portrayal of leadership

Complicating Factors

Differing legislative mandates
Differing pipeline populations
"Non-negotiables"
Resource constraints
Multitude of players

Prospective Players





READY . . .

SET . . .

GO ? ! ?

The Fundamental Questions

What are the "friction" points?
Would the effort be justified?
Will there be sufficient buy-in?
How do we tackle?

Preliminary Feedback

Boards looking for an industry pull
Industry hasn't pulled...yet

NEW TECHNOLOIES FOR CONSTRUCTION, INSPECTION, REPAIR, AND REHABILITATION GROUP REPORT

by

Bruce Gray
Novagas Clearinghouse Ltd.
Calgary, Alberta

BANFF/97 PIPELINE WORKSHOP

New Technologies for Construction, Inspection, Repair & Rehabilitation

Group Report - April 16, 1997

Group Focus & Objectives

- Origin
- Focus
- Inspection, Repair & Rehabilitation
- Information Exchange - Candid, Open Discussion

Group Format

- Informal
- Rotating Chair
- No defined affiliations - Pipeline Operators
- Representation from both CAPP/CEPA member companies

Group Activities & Issues

- Pipeline Repair Coatings
- New technologies - Internal Inspection
- Pressure reduction during repairs
- Codes and Standards
- Repair Sleeves & Techniques
- Repair Assessment and Criteria
- Gel Plugs
- Hydrostatic testing
- GPS Applications - Pipeline Repair Programs
- HIC Experience
- Pipeline Repairs - Recommended Practices

Future Activities

- Continue to build on experience
- Small diameter crack inspection tool
- Banff/97 - Sleeve Repairs

Summary

- Informal format/Info Exchange
- Open to interested parties
- email - future meetings, information
  - grayb@energystore.net
  - bruce.dupuis@foothillspipe.com
  - kpaulson@cul.ca

SCC WORKING GROUP GROUP REPORT

by

Bob Sutherby
NOVA Gas Transmission Ltd.
Calgary, Alberta

CEPA
SCC WORKING GROUP
STATUS OF ACTIVITIES

April 1997

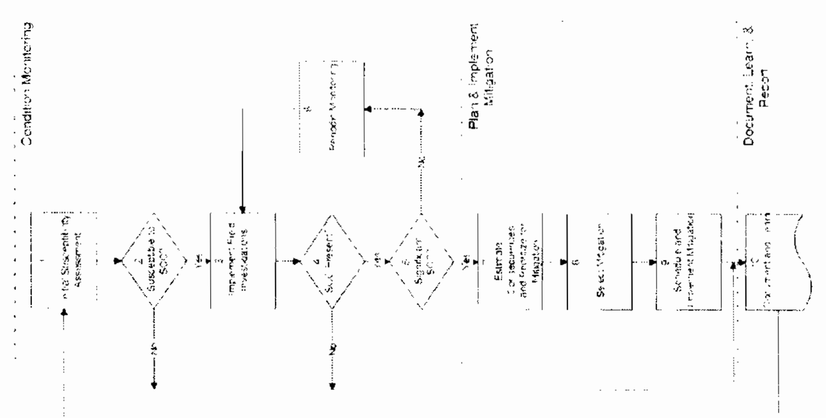
The Working Group

- Formed in 1994
- 14 Full and Technical Members
- Forum for the exchange of information on SCC and its management
- CEPA vehicle for implementation of NEB recommendations

NEB Recommendations

- Integrity Management and Recommended Practices — May 15, 1997
- R&D Plan — June 30, 1997
- SCC Database & Trending — Aug 31, 1997
- Circumferential SCC — Dec 31, 1997

SCC Integrity Management Program



Recommended Practices

- SCC Integrity Management Program
- SCC Assessment of Existing Pipelines
- Inspection for SCC
- Data Collection
- Engineering Assessment
- Prevention Mitigation and Repair
- Risk Assessment in SCC Integrity Management

R&D

- **Current Research**
  - CEPA Committment: $1.6 Million
  - CEPA/GRI/British Gas Crack Tool Development
  - CEPA/AOSTRA SCC Initiation Study
  - Coating Performance Study
  - Characterization of Pressure Fluctuations

R&D

- **5 Yr Plan**
  - Identify & Prioritize Development Areas
  - Involvement of Other Industries
  - Level of Effort Required
  - Organizations and Funding Strategy

CEPA SCC Database

- Second Edition Database
  - additional data fields
  - new data entry program
- Available to companies
- Share SCC data
- First trending analysis - Aug 31, 1997

- SCC Activities
  - Forum for sharing information
  - R&D
  - Database
  - Recommended Practices
- Broader Integrity Focus

INFORMATION EXCHANGE AND NETWORKING GROUP REPORT

by

Pierre Brien
D'Aragon, Desbiens e Halde Ltée (DDH)
Montréal, Quebec

Quebec Pipelines in a multi-modal context.

Pierre Brien

Vision Statement

In the Montreal Urban Community area in the transportation of dangerous goods task force report, pipelines are part of the multi-modal approach; therefore, we must position pipelines in a state of the art exercise and make sure of the harmonization of the different modes.

Goal and Objective

- Our desired goal was to attempt to present a broad perspective over the issue and seek for relevant solutions.
- The objective was to assess certain assumptions and to question ourselves on the importance of safety practices with pipelines' operators.

Today's Situation

- Some pipelines start from the docks in the harbour;
- Other pipelines start from the State of Maine(Montreal Pipelines) passing under the St-Lawrence River or fromOntario;.
- Ultramar has prefered trains and boats to pipelines;
- Metropolitan Gas has a pipeline attached to Jacques-Cartier Bridge

How Did We Get Here?

- Economic reasons were behind Ultramar decision
- Metropolitan Gas has expanded and now covers a large part of the province
- This brought the creation of Info-Excavation
- Small pipelines were established between companies and between Montreal-Varennes

Available Options

- Quebec Trans Maritime is now contemplating delivering services for natural gas to New England states, a cost benefit project
- NEB does cover most of our pipelines,but our Quebec natural resource Office should be more involved in setting up standards
- More linkage with Ontario and the West

Recommendation

Strategies must rely on a multi-modal context

Info-excavation should play a more direct role in supporting industries and municipalities

The action plan has to be more Quebec and eastern Canada oriented without forgetting linkage with the USA and Ontario/West

SESSION A and B
Working Group #1

NEW TECHNOLOGIES FOR CONSTRUCTION, INSPECTION, REPAIR AND REHABILITATION

LIST OF PARTICIPANTS (44)

Working Group #1: **New Technologies for Construction, Inspection, Repair and Rehabilitation**
8:15

NAME	ORGANIZATION
Raynold Hinger	Trans Mtn
Paul Wang	Nova
Mark Yoemans	Nova
Greg Toth	Trans Mtn
Dave Harper	Trans Mtn
Roy Sogie	Conmet
Mo Mohitpour ✓	Nova
Ken Ball ✓	Alta Econ. Dev.
Ernie Aikens	Fleet Technology
Bill Hederman	Int'l Centre for Gas Technology
Phil Nidd ✓	AEC Pipelines
Dexter Dakin	Suncor Energy
Al Forster	Williamson Ind. Inc.
Bruno Stlaurent	TQM Pipeline
Jim Hose	Canusa
Dilip Tailor	Canusa / Shaw Ind.
John Beck	Sure Seal Protection Systems
Barry Anderson	BC Gas
Glen Scott	BC Gas
Bernie Frost	AEUB
Denis Trudeau	Corrpro Canada Inc.

21

Ron Cooper	Northstar Energy / Morrison
William Jarvis	Williamson
Scott Peterson	Lakehead Pipe Line Co.
Ralph Mayer ✓	Maritimes & Northeast Pipel.
Gord Johanson	Can. West Nat Gas
Duane Cronin	Univ. of Waterloo
Roy Pick	Univ of Waterloo
Ray Goodfellow	Chevron Canada Resources
Alebachew Demoz	CANMET/WRC
Frank Christensen	FMCMCI
Rod Trefanenko	Gulf Canada Resources
Dave Simpson	Union Gas Ltd.
Paul Huddleston	TMPL.
Norm Rinne	TMPL
Greg Hill	TMPL
Jim Horner	TMPL
Ed Palukorhko	Alberta Research Council
Joe Konecny	Wascana Energy Inc.
Ken Paulson	Canadian Western Nat Gas
Sandra McDonald	CWNG
Yvanna Ireland	TCPL
Jim Griffin	TCPL
Don Persaud	DNRE F'ton NB

44 Total

46

LIST OF PARTICIPANTS

Working Group #1: **New Technologies for Construction, Inspection, Repair and Rehabilitation**
10:30

NAME	ORGANIZATION
Roy Sage	
Paul Wang	Nova
Reynold Hinger	Trans Mtn
Phillip Nidd	AEC
Mark Yeomans	Nova
MO MOHITPOUR	NOVA
KEN BALL	EDAT
Bruno [illegible]	TQM Pipeline
AL FORSTAR	WILLIAMSON IND. INC.
Dexter Dakin	Suncor Energy
DAVE SIMPSON	Union Gas Ltd
BARRY ANDERSON	BC GAS
KASHMIR GILL	NATIONAL RESEARCH COUNCIL
John Beck	Sure Seal Protection System
DILIP TAILOR	CANUSA / SHAW INDUSTRIES
JIM HOPE	CANUSA (SHAW) IND.
William Jarvis	Williamson
RON COOPER	NORTHSTAR ENERGY / MORRISON PET.
Ken Benoit	Seagull Energy Canada Ltd
DENIS TRUDEAU	CORRPRO CANADA INC.
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Donald R Persaud	Natural Res & Energy, NB.
Casey Steneker	Imperial Oil Ltd.
Scott Peterson	Lakehead Pipe Line Co.
J.C. Hamilton	T.D. Williamson, Inc
Dennis Langen	IPL
Phil Michailides	BJ Pipeline Inspection
Larry Lai	Nova Chemicals Ltd.
Len Danyluk	Imperial Oil Resources Ltd.
Frank Christensen	FMC MCI
Anton Kacicnik	Consumers Gas Co. Ltd.
Catherine Hoffman	U.S. Minerals Management Service.
Mark Ottem.	TMPL.
Paul Huddleston	"
Chris Mitskopoulos	UCISCO Canada
Rod Trefanenko	Gulf Canada Resources
Dave Harder	Trans Mountain
Greg Toth	Trans Mountain
Jim Horner	TMPL
Norm Rinne	TMPL
Greg Hill	TMPL.
Jim Griffin	TCPL
Yvanna Ireland	TCPL
[illegible]	
Ken Paulson	CWNG

24/24

Presentation #1 - Minutes

Epoxy Filled Steel Reinforcement Sleeves - Trans Mountain Pipeline

Presenters: Greg Toth and Dave Harper

- Developed by BG in early 1980's.
- Developed by IPL in mid 1980's.
- Trans Mountain installed their first sleeve in 1992.
- Modified the sleeve design in 1996.
- Sleeves are an acceptable repair method according to CSA Z662-96 to repair metal loss defects (includes dents - grind out stress concentrators first).
- Materials include sleeve halves and epoxy (rapid cure, low viscosity, high stiffness)
- 35-45% of the hoop stress is transferred to the sleeve.
- Sleeves can be fit over small bends, welds, etc.
- A bonding cable is installed around the sleeve to insure electrical continuity.
- Sequence of welds: 1. Long seam welds 2. Fillet welds
- Two vents are used; one to fill the sleeve and the other to vent air from the sleeve.
- Epoxy is not injected but fed by gravity into the sleeve.
- Protective equipment is required with using the epoxy (fumes).

Epoxy Sleeve Modifications and Improvements

- Discussed improvements that Trans Mountain has made with epoxy filled sleeves.
- Use teflon spacers.
- Do not use steel collars anymore. Use shrink sleeves on the outer edges of the steel sleeve. Therefore, no fillet welds are required.
- Teflon spacers are placed at 2:00 and 10:00 on the pipe.
- Shrink sleeves, filled with epoxy, are placed over the ends of the steel sleeve.
- Sleeves are not an acceptable permanent repair for SCC.
- A 50% pressure reduction is implemented when installing sleeves. The reduction is also used to transfer the stress to the sleeve.
- It was found that only one 2" vent is required to fill the sleeve with epoxy and to vent air.
- The shrink sleeves over the edges of the steel sleeve are installed before the sleeve is filled with epoxy.
- The cure time for the epoxy at 4 degC for a strength of 25 MPa is 3 days at 32 degC the cure time is 8 hours for the same strength. After 28 days the epoxy will reach a strength of 80 MPa.
- A hole is poked in the top of the shrink sleeve to force air out.
- Tape coat is sometimes wrapped around the edges of the shrink sleeve to prevent the epoxy from leaking out.
- With these modifications discussed some advantages include:
    - Only one welder is required.

- No fillet welds are required, therefore, the sleeve can welded up before the repair.
- Cannot inspect the defects underneath the sleeve with the MFL tool. Probably can inspect the defect with an ultrasonic tool.
- Group discussion around the type of epoxy and its properties(cure time, strength).
- One problem discovered by accident is that the epoxy might fail if the pipe experiences extreme shifts in temperature. Trans Mountain has found no temperature problems with their pipelines.
- The sleeve material is of the same or greater grade and wall thickness as the pipe.
- Destructive hydrotests have shown that the pipe not covered by the sleeve is what bulges and fails.
- A screw in plug is used to seal the vent hole.
- The steel sleeve can be pre-bent to accommodate bends in the pipeline.
- Question raised: Possibly use an external ultrasonic tool to inspect the corrosion defect?

Epoxy Filled Steel Reinforcement Sleeves

Presentation to Banff /97
Pipeline Workshop
April 16-18, 1997

Greg Toth, Manager, Technical Services
Dave Harper, Manager, Central Division
Trans Mountain Pipeline Co. Ltd.

Epoxy Filled Structural Reinforcement Sleeves

History

Earliest reference to the epoxy filled structural reinforcement sleeve is found in field trials performed by British Gas in 1983. Following the initial development, the epoxy sleeve was installed on a 250 mm diameter line to repair a defect which consisted of a sharply kinked dent 9% of the outside diameter with coincidental corrosion to a depth of 21% of wall thickness. The repair was later cut-out and pressure tested to confirm its effectiveness.

In 1988, Interprovincial Pipelines completed the development of a defect repair system which included an epoxy filled structural reinforcement sleeve. The impetus for the project was the failure and subsequent investigation of the Camrose incident in 1985, a pipeline failure which was a result of toe cracking in the fillet weld of a full encirclement sleeve. The structural reinforcement sleeve provided for the repair of non-leaking surface defects without the intrusive effects of welding on the pipeline.

Largely based on the initial efforts of British Gas and Interprovincial Pipeline, Trans Mountain began its use of the epoxy filled structural reinforcement sleeve in 1992. The initial installations used the IPL system of butt welded collars to provide the stand-off between the sleeve and pipe. In 1996, the sleeve procedure was modified with the incorporation of Teflon spacers to provide the stand-off. In total, seventeen (17) epoxy filled sleeves repairs have been installed on Trans Mountain's system.

Code Requirements

The Canadian pipeline code, CSA Z662 Oil and Gas Pipeline Systems, permits the use of steel reinforcement repair sleeves (epoxy filled or interference fit) as a permanent repair of pipeline defects characterized by pipe wall metal loss or for the permanent repair of some dents. The epoxy filled structural reinforcement sleeve can be used as a permanent repair for corrosion defects between 10% and 80% deep which either exceed the maximum allowable depth or length criteria established by the code or which impair the pipeline integrity based on an engineering assessment of remaining strength. Similar to corrosion, metal loss defects which result from the complete grinding removal of gouges, grooves, arc burns and cracks and exceed the maximum permissible metal loss geometry can be permanently repaired with an epoxy filled sleeve. The sleeve is also permitted as a permanent repair for dents located on the pipe body which are considered by the code to be defects. These include dents which exceed the criteria for depth based on pipe size and dents with stress concentrators, with the stress concentrator removed through grinding prior to the sleeve installation.

Epoxy Filled Sleeve Description

Epoxy filled structural reinforcement sleeves are fabricated from two halves of a pipe cylinder or specially rolled plate which are installed with full penetration butt welded side seams. The major difference between the epoxy filled and pressure containment sleeve is the lack of the full circumferential fillet welds on the ends of the epoxy filled sleeve. The epoxy filled sleeve is installed with an annular space between the carrier pipe and sleeve which is filled with a high stiffness epoxy grout. Various methods are available to achieve stand-off of the sleeve from the carrier pipe including centring bolts, butt welded collars (no welding to the carrier pipe) and Teflon spacers. Because of the stand-off, the epoxy filled reinforcement sleeve is less sensitive to fit-up and the sleeve can be used in applications which bridge girth and mill seam welds and some bends.

The epoxy filled reinforcement sleeve prevents failure of the defect through stress relief of the carrier pipe as a result of the partial transfer of the hoop stress through the epoxy grout to the sleeve material as well as by providing restraint to localized bulging in the area of the defect. Studies by British Gas have shown that the amount of stress sharing between the carrier pipe and sleeve is influenced by the elastic modulus and thickness of the epoxy grout. With a high modulus grout and suitable sleeve geometry, stress reductions in the carrier pipe between 30% and 40% are achievable.

Epoxy Filled Sleeve Installation

As a rule of thumb, an effective choice of sleeve material is a thickness and grade that matches the carrier pipe. Desired properties of the epoxy grout include high stiffness for effective load transfer and restraint of bulging, a rapid cure to promote a quick repair, a long working life when gelled, low viscosity to promote filling of the complete void and good bonding ability. It should be noted that epoxies are subject to a time-temperature dependent cure and that many epoxies require a minimum of seven days to obtain their full compressive strength.

Surface preparation should include sandblasting of the area to be covered by the sleeve as well as the inside surface of the sleeve to a specification which ensures an effective bond of the epoxy filler to both the carrier pipe and sleeve. Fit-up of the sleeve should ensure that the sleeve extends a minimum of 50 mm beyond the ends of the defect.

Pressure reduction, aside from being a safety consideration, should be employed during final fit-up, sealing of the sleeve ends and injection and curing of the epoxy grout. Again the level of pressure reduction will have a minor effect on the transfer of hoop stress to the sleeve, with the reduced operating pressure most likely determined on the basis of safe work practices.

Installation of the sleeve requires fit-up and welding of the sleeve halves. Similar to the interference fit sleeve, the side seam welds are less sensitive to weld defects in comparison to a pressure-containment sleeve. Welding of the side seams can be either by single-vee butt welds with or without backing strips or by overlapping strips fillet welded to the sleeve halves. Non-destructive examination of the sleeve shall be performed to ensure weld integrity.

With the completion of welding, the sleeve shall be centred on the carrier pipe. The end gaps between the sleeve and the pipe should be sealed with trowelled filler or fast-curing resin to facilitate retention of the epoxy grout within the sleeve. Vents and fill holes, previously installed on the top sleeve half at 12:00, are used to inject the epoxy grout and to vent the air displaced by the grout. Once filled, the fill and vent holes should be plugged. A sample of the grout should be maintained at comparable ambient conditions and monitored to ensure a proper cure. As a final step, a bonding cable should be installed between the sleeve and carrier pipe to ensure electrical continuity between the sleeve and pipe.

Trans Mountain Epoxy Filled Sleeve Modifications

Trans Mountain's initial efforts with the epoxy filled sleeve included the installation of butt welded steel collars to achieve the stand-off of the sleeve halves from the carrier pipe as shown in Figure 1. Installation of the steel collars required a close tolerance fit-up of the collars on the carrier pipe, including grinding removal of the long seam weld reinforcement cap, and required that machined relief grooves and backing strips be employed to ensure no penetration of the root bead into the carrier pipe.

The steel collars, while effective as a method of achieving stand-off between the sleeve and carrier pipe, contributed significantly to the overall duration of the sleeve repair and created a potential corrosion cell between the collar and pipe. Fit-up and welding of the collars, in addition to fillet welding of the sleeve halves to the collars, accounted for a large part of the time required for completion of the repair and the resultant loss of system capacity. Given conditions conducive to corrosion and the ineffectiveness of the cathodic protection system under the collars, failure of the collar to pipe seal could potentially lead to integrity concerns with an inability to monitor through in-line inspection the areas masked by the steel collars.

As a result of these concerns, Trans Mountain developed a modified sleeve procedure which employs Teflon spacers to achieve the stand-off of the sleeve from the carrier pipe as shown in Figure 2. Use of the Teflon spacers provides the opportunity to perform the butt welding of the sleeve halves prior to a shutdown of the system, providing additional flexibility in the timing of the repair and the ability to install multiple epoxy sleeve repairs over a shorter shutdown period.

An obstacle to overcome with the modified epoxy filled sleeve was how to seal the end of the sleeve and provide retention of the epoxy grout? Through various trials, it was determined that shrink sleeves were the best alternative for providing the required seal. Sectioning of test sleeves showed that the shrink sleeve was effective in retaining the epoxy grout and that a weep hole in the shrink sleeve at the 12:00 o'clock position at the edge of the steel sleeve was adequate to vent any trapped air under the shrink sleeve.

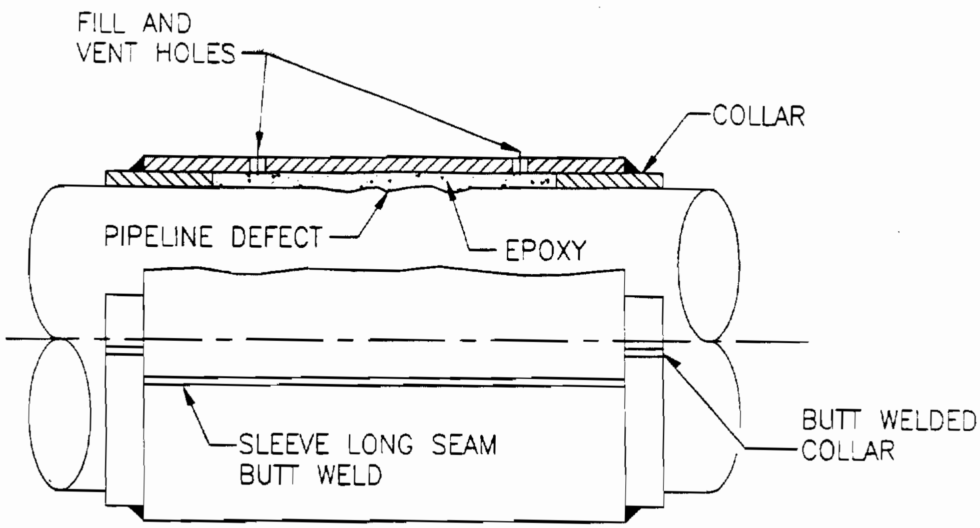


FIGURE 1

EPOXY FILLED STRUCTURAL REINFORCEMENT SLEEVE

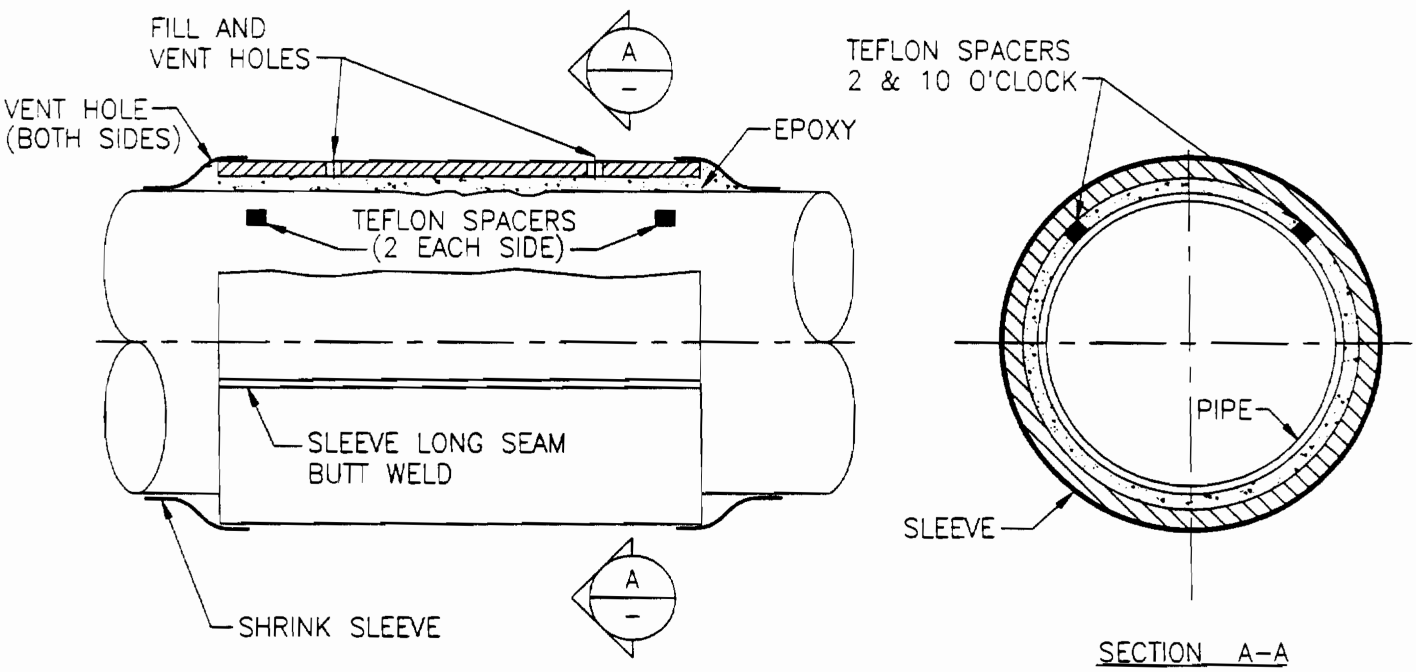


FIGURE 2

TRANS MOUNTAIN EPOXY FILLED STRUCTURAL REINFORCEMENT SLEEVE

Presentation #2 - Minutes

Pipeline Composite Repair Sleeves - AEC Pipelines

Presenter: Phillip G. Nidd

- AEC has been installing clocksprings for 2 years.
- Installed close to 400 clocksprings.
- AEC's Fort McMurray mainline (22") has no possibilities of having an outage for pipeline repairs.
- Because of muskeg, the Fort McMurray mainline has only 60 working days/year when the pipeline can be excavated.
- A temperature of 12 degC is maintained in the tented environment after excavation.
- AEC does not use clocksprings for the repair of dents only for the repair of metal loss defects.
- Benefits of clocksprings include easy installation, relatively fast cure time, can still inspect the metal loss defect with in-line inspection, easy to handle and no need for welders.
- Curing is dependent on the ambient temperature. AEC has sometimes raised the ambient temperature to 35 degC to reduce the curing time (4 hours at 35 degC).
- The clockspring is made of longitudinal fibers (no horizontal fibers).
- The clockspring requires no field preparation before installing.
-Filler material is applied to the metal loss defect before installing the clockspring.
- AEC has no data on what the life of the clockspring is, but it is thought to be approximately 50 years.
- Rock shields are put over top all clockspring repairs, because of problems from previous installations. One clockspring repair was excavated a year later and preliminary corrosion was found at the transition between the clockspring and the pipe (coating failure).
- Several coating methods have been used to coat the clockspring. A moldable mastic is used to fill the transition between the clockspring and the pipe.
- For temperatures above 23 degC, a Denso Protal 7000 is used to coat the clockspring. Curing time is between 2 and 3 hours. AEC has plans to excavate one repair using this coating this winter.
- The clockspring is lightly sanded and the corners are ground slightly at the transitions before a coating is applied.
- Fumes from the adhesive theoretically do not present any health hazards below 100 ppm, but AEC's safety regulations require workers to wear safety masks in a tented environment.
- Group discussion around the fact that code requires that sleeves must overlap the corroded area by 51 mm. Therefore, it often necessary to use multiple sleeves to meet this requirement (e.g., corrosion defect is less than 51 mm from a girth weld - requires two extra clocksprings).
- Preliminary research results from the cycling of the pressure from 0 to MOP and to 50% MOP show that there is no failure of the clockspring bond.

- AEC documents all their clockspring repairs and stores the information into their database.
- AEC decided to handle their own in-house clockspring training and certification program.
- Presently, the NEB only allows for clocksprings to be installed in Class 1 locations.

PIPELINE COMPOSITE REPAIR SLEEVES

PRESENTATION TO BANFF / 97 PIPELINE WORKSHOP APRIL 16-18, 1997

Phillip G. Nidd
AEC Pipelines Integrity Group
April, 1997

Items For Discussion

- 1.0 AEC Pipelines System Overview
- 2.0 Introduction To Clock Spring Repair
- 3.0 AEC Pipelines Application Procedures And Specifications
- 4.0 AEC Pipelines Training And Certification Approach
- 5.0 Clock Spring Application Considerations And Concerns

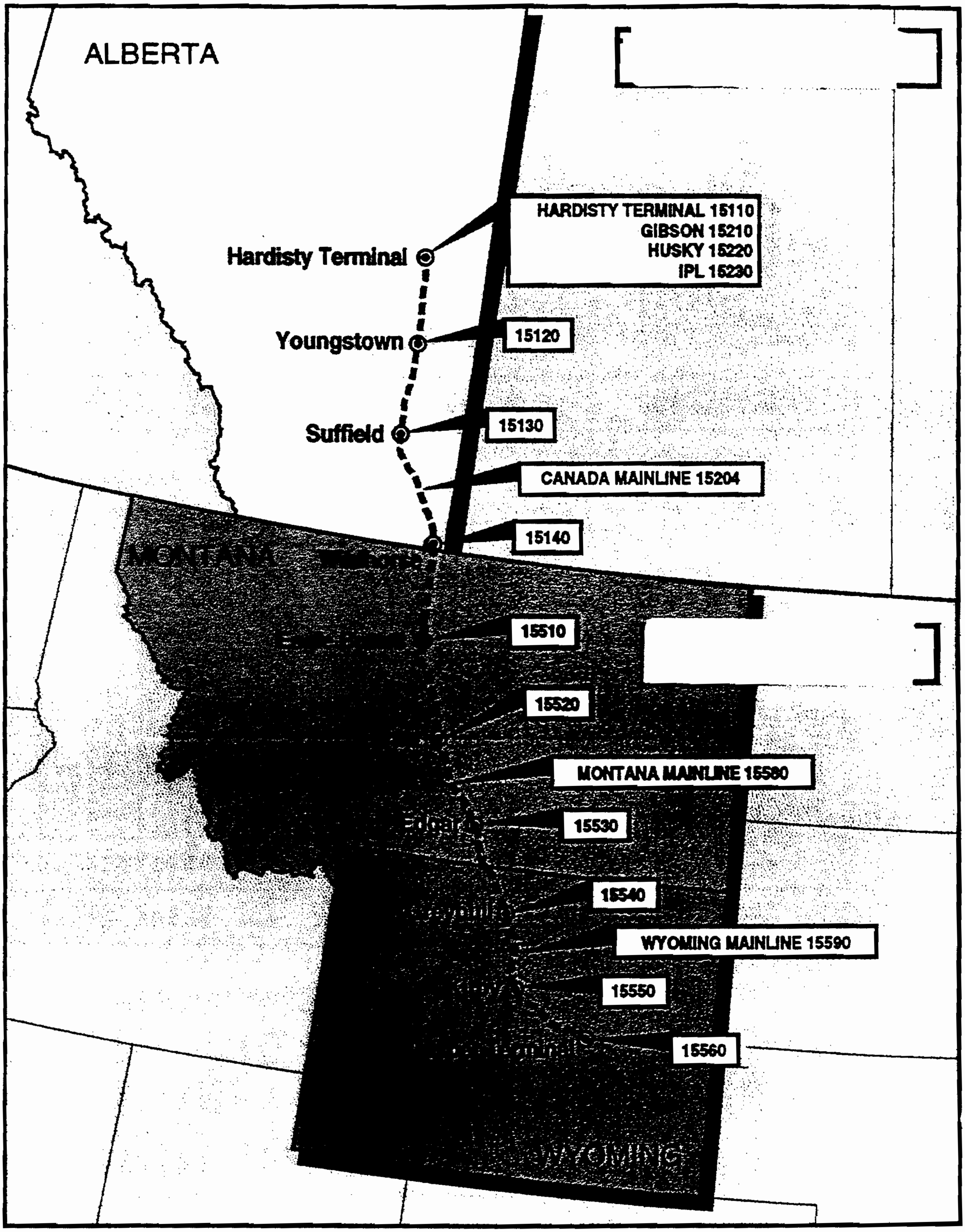
1.0 AEC Pipelines Overview

- Division of Alberta Energy Company
- Owns and operates 1600 km of Alberta based pipelines in 2 systems
  - Cold Lake Pipeline system
  - AOSPL Pipeline system
- Partner With TCPL in Express Pipeline
- Operates Canadian portion of 950 Km Express Pipeline extending from Hardisty, AB. To Casper, WY.

1.1 EXPRESS PIPELINE SYSTEM MAP

- Photo Insert

Express Pipeline



400C5010, NOV 25/96

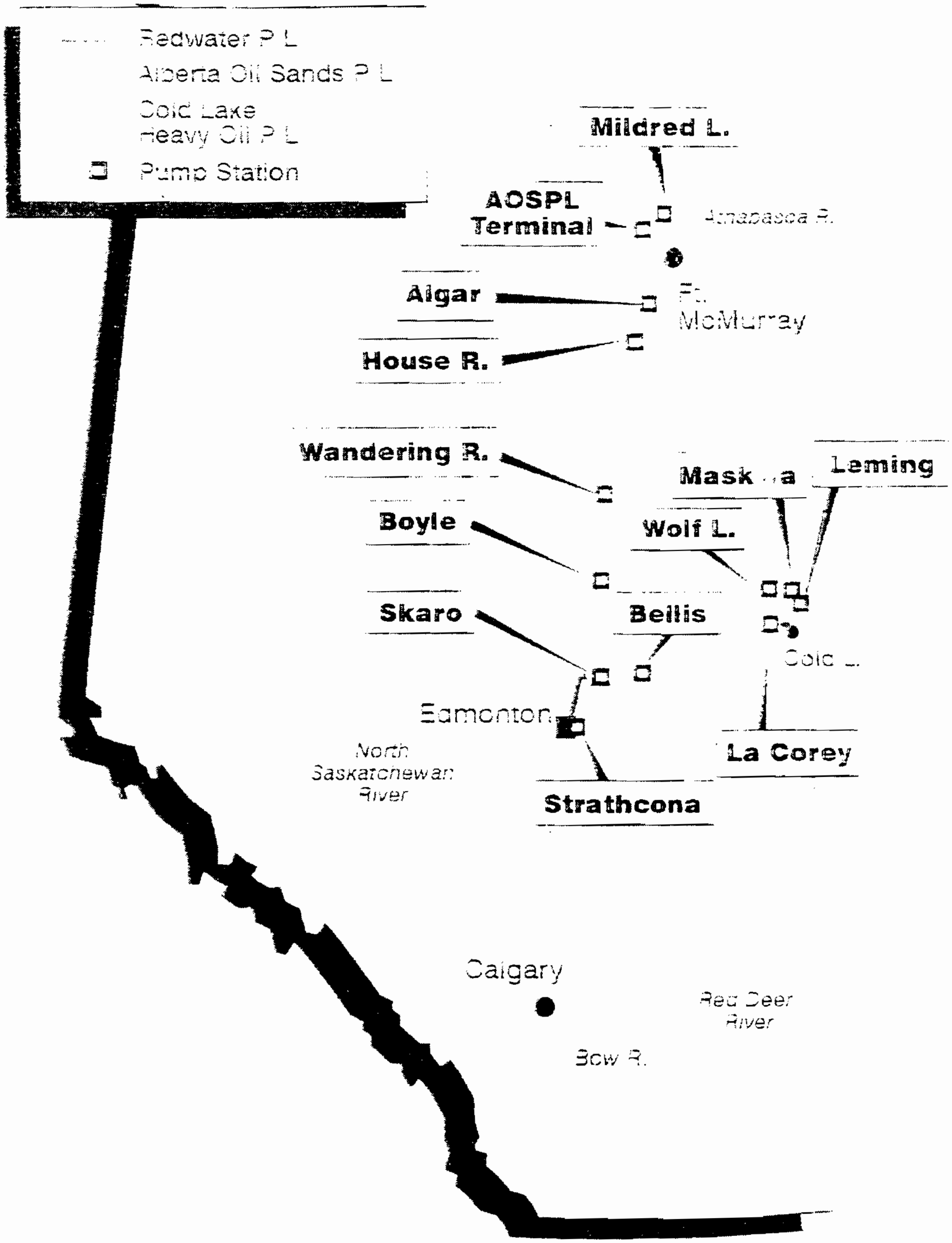
1.2 AEC PIPELINES SYSTEM MAP

- Photo Insert

1.3 559 MM. O.D AOSPL PIPELINE GIRTH WELD COATING

- Photo Insert

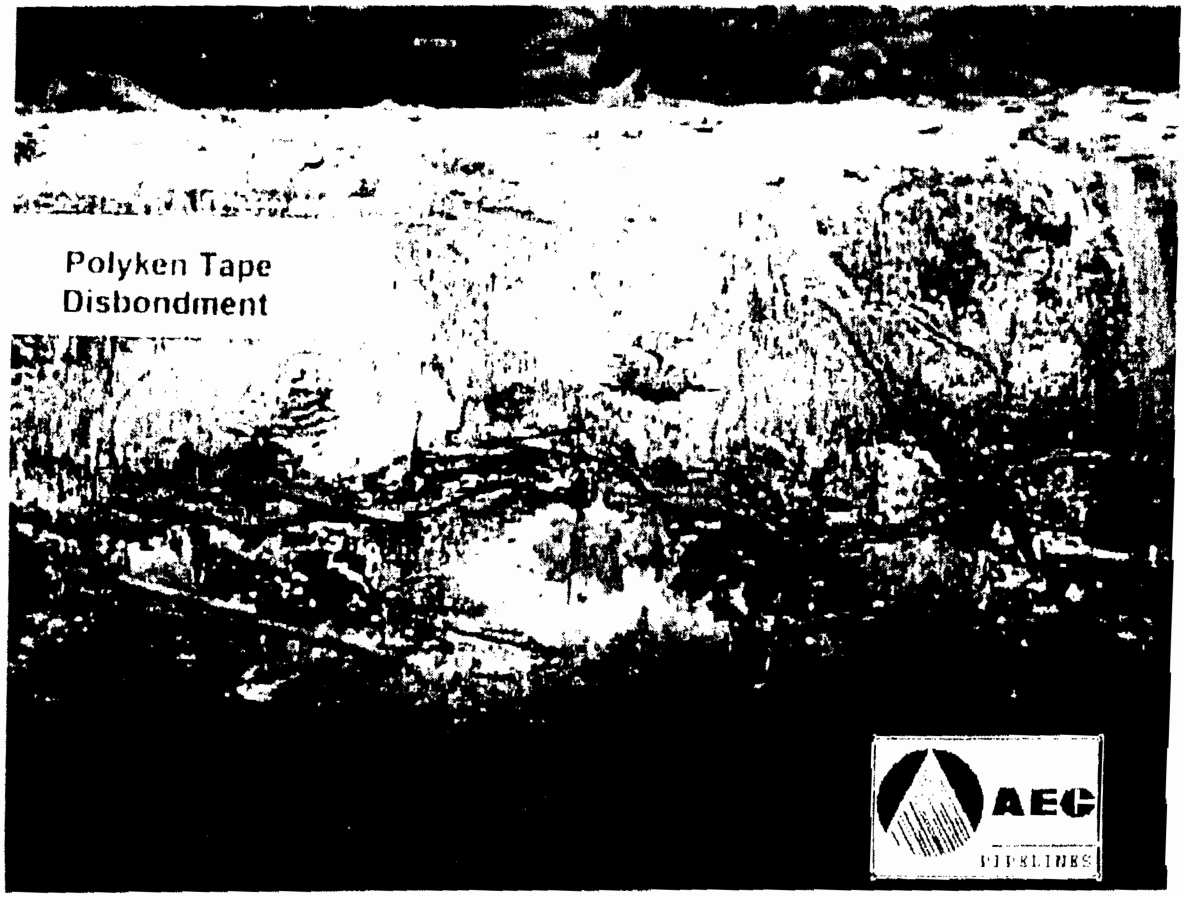
Figure 1.1 AEC SYSTEM MAP



Pipeline Integrity Status/ Inspection Capable Pipelines

559 mm. O.D. AOSPL Pipeline

- Coating

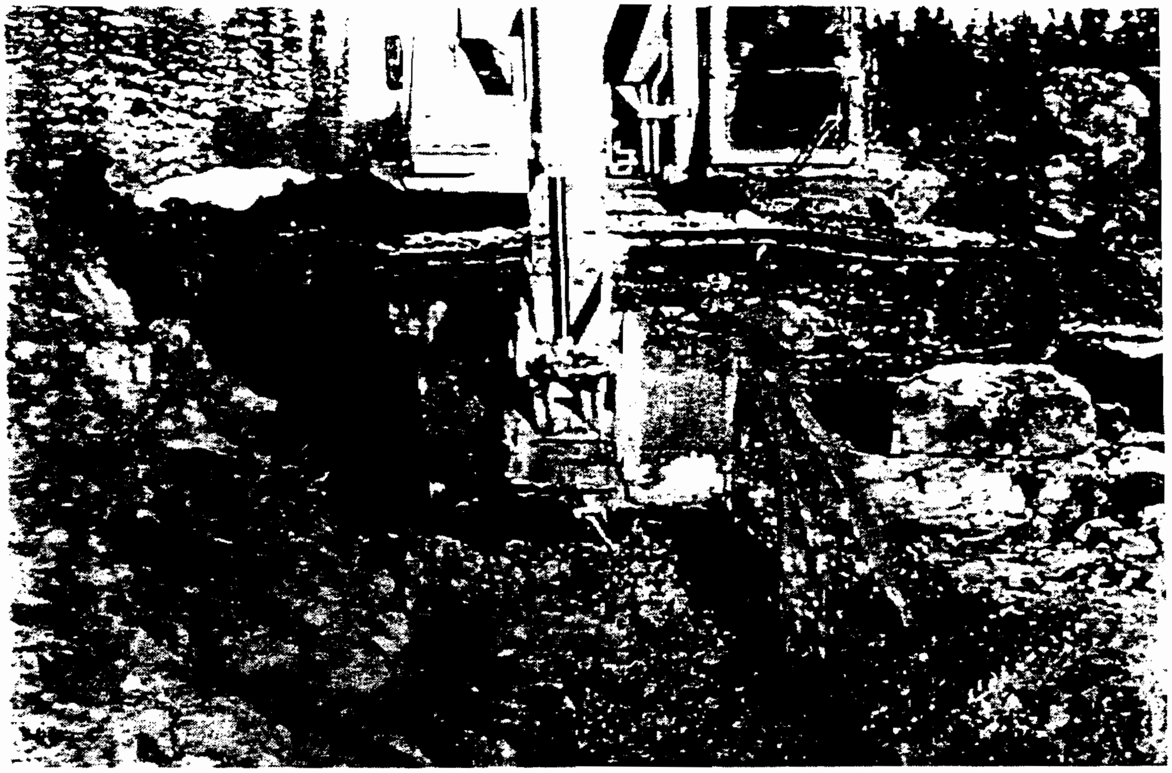


1.4 GENERAL CONDITIONS/559 MM. O.D. AOSPL PIPELINE

- Photo Insert

1.5 GENERAL CONDITIONS/559 MM. O.D. AOSPL PIPELINE

- Photo Insert

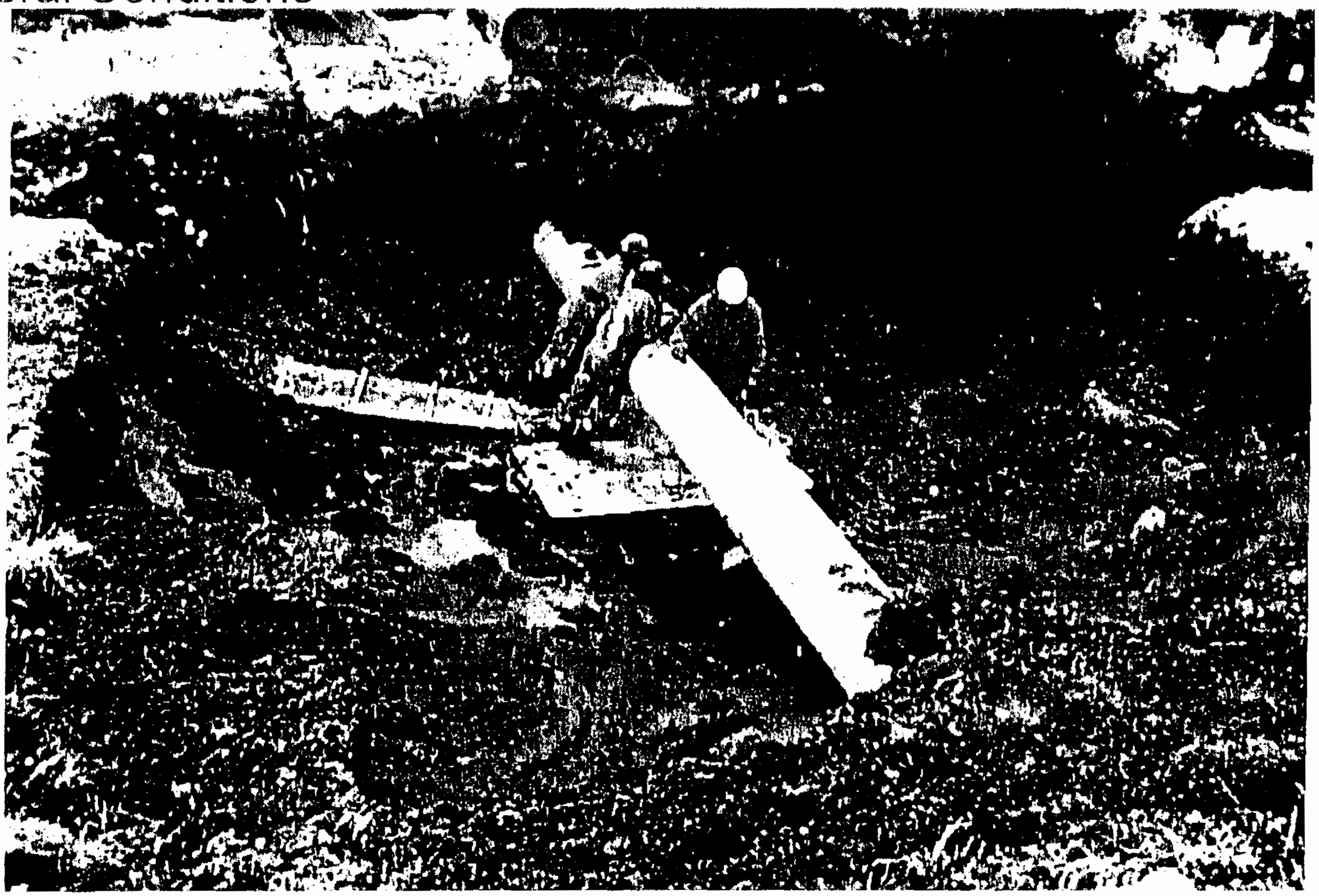


TYPICAL AOSPL EXCAVATION

3.2 DEFECT EVALUATION & REPAIR

559 mm. O.D. AOSPL Pipeline Rehabilitation

- General Conditions



1.6 TENTING IN/559 MM. O.D. AOSPL PIPELINE

- Photo Insert

2.0 INTRODUCTION TO CLOCK SPRING REPAIR SYSTEM

- A 3 component pipeline sleeve repair system designed to provide reinforcement repair for external wall loss defects.
- Clock Spring repair system consists of the following:
    - Composite repair sleeve that measures approximately 394 mm/12" in width and 7 circumferential wraps in length.
    - Two component adhesive/adhesive and activator
    - Two component filler/ filler and activator

6.0 559 mm. O.D. AOSPL Pipeline Rehabilitation

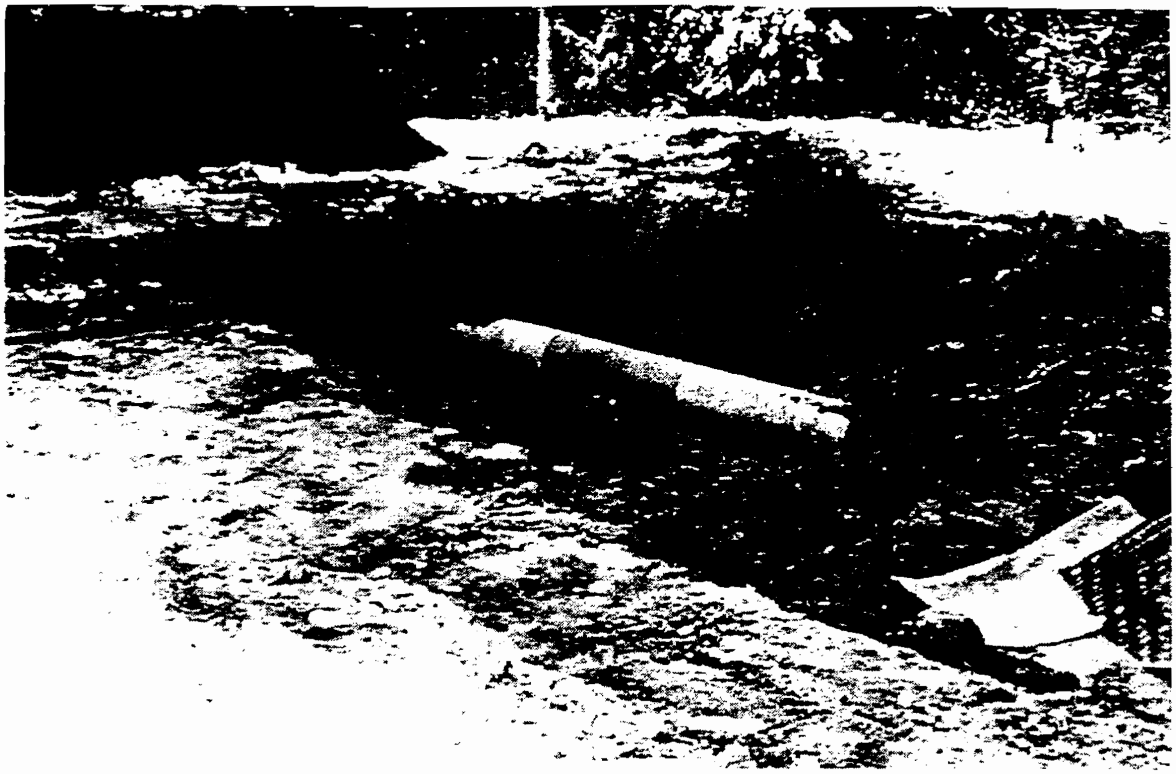
Tenting In

2.1 INTRODUCTION TO CLOCK SPRING REPAIR SYSTEM /BENEFITS

- No welders on standby
- No welders on standby
- No welders on standby

2.2 INTRODUCTION TO CLOCK SPRING REPAIR SYSTEM /PIPE PREPARATION

- Photo Insert



TYPICAL PIPE PREPARATION

3.3 DEFECT EVALUATION & REPAIR

2.3 INTRODUCTION TO CLOCK SPRING REPAIR SYSTEM /OUTSIDE APPLICATION

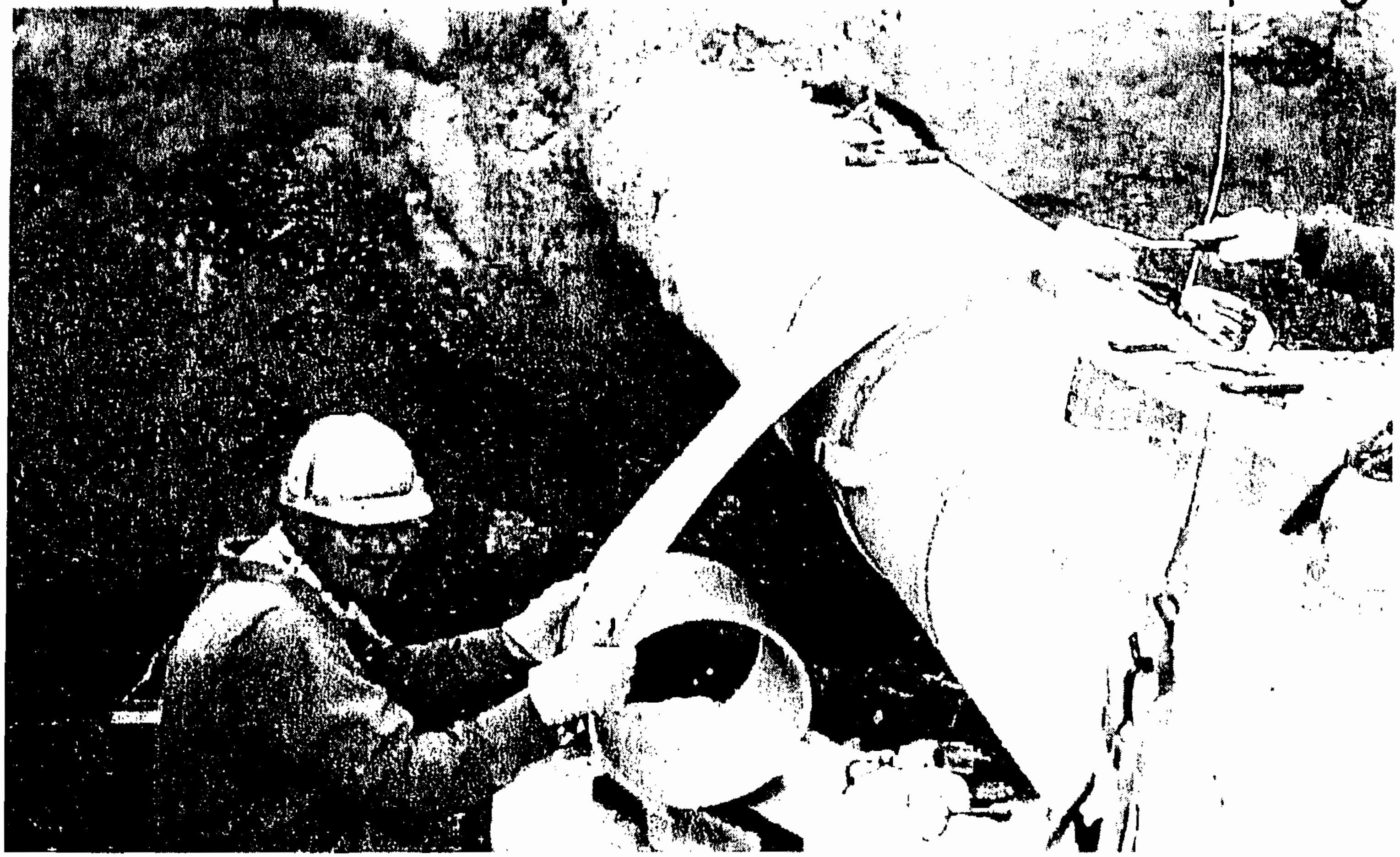
- Photo Insert

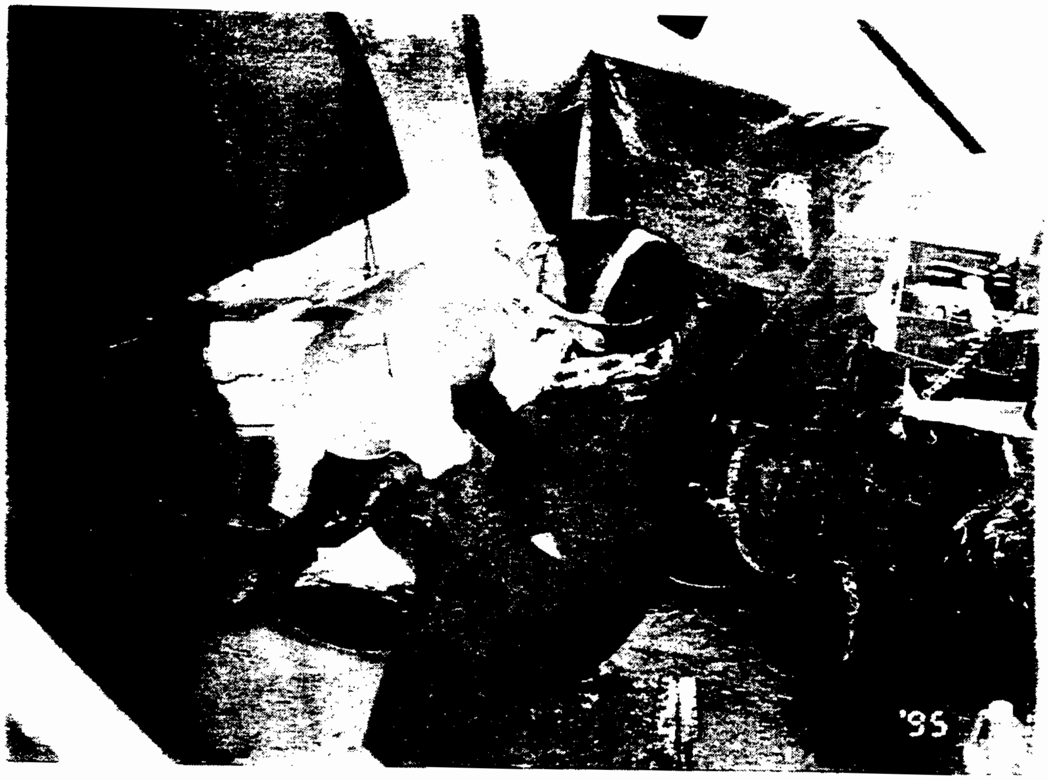
2.4 INTRODUCTION TO CLOCK SPRING REPAIR SYSTEM /TENTED IN APPLICATION

- Photo Insert

Pipeline Repair Alternatives

- Composite Repair Sleeves / Clock Spring

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2.5 INTRODUCTION TO CLOCK SPRING REPAIR SYSTEM /TAPE WRAP

- Photo Insert

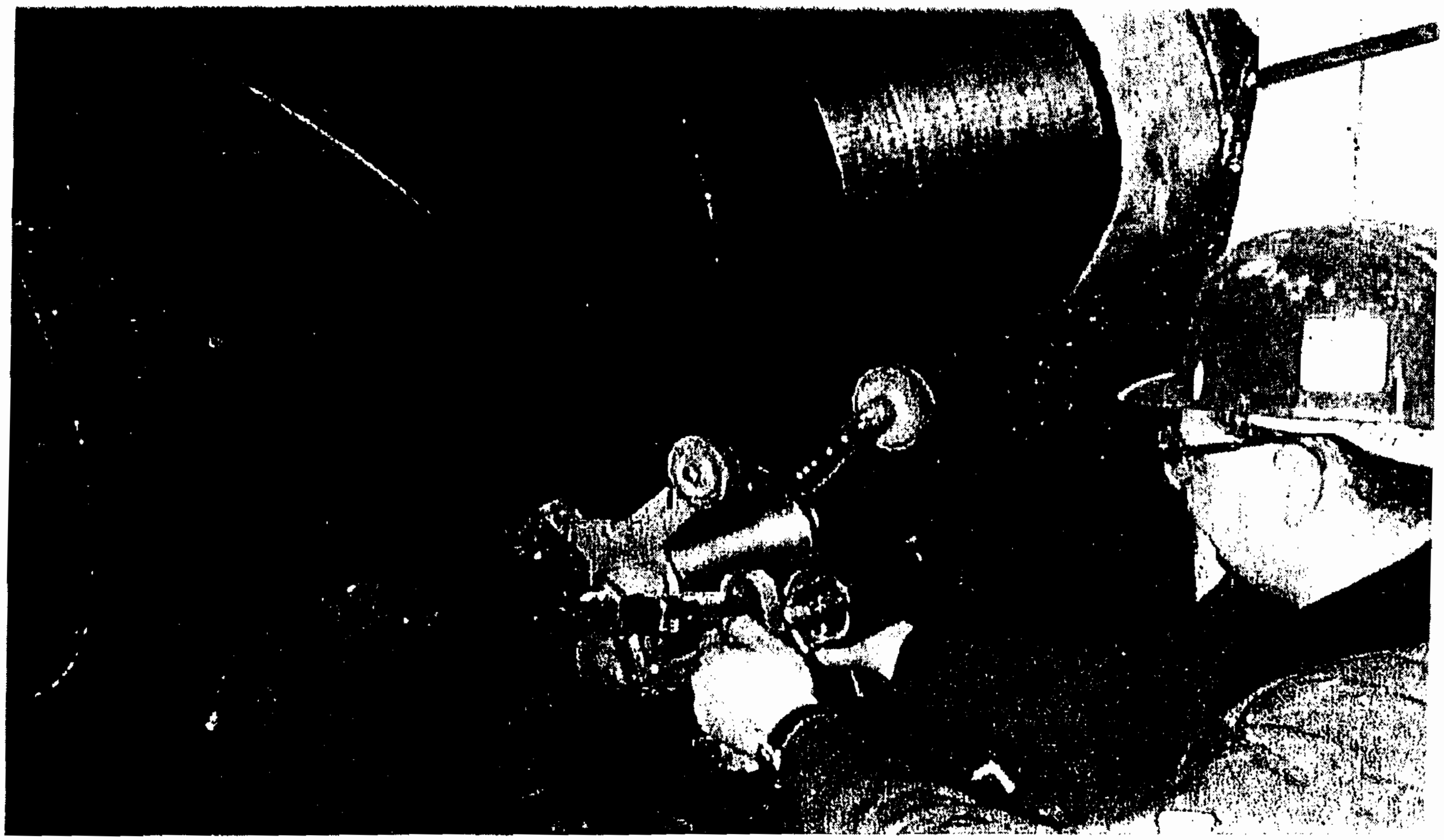
2.6 INTRODUCTION TO CLOCK SPRING REPAIR SYSTEM /EPOXY COATING

- Photo Insert

Technology Overview

Pipeline Repair Alternatives

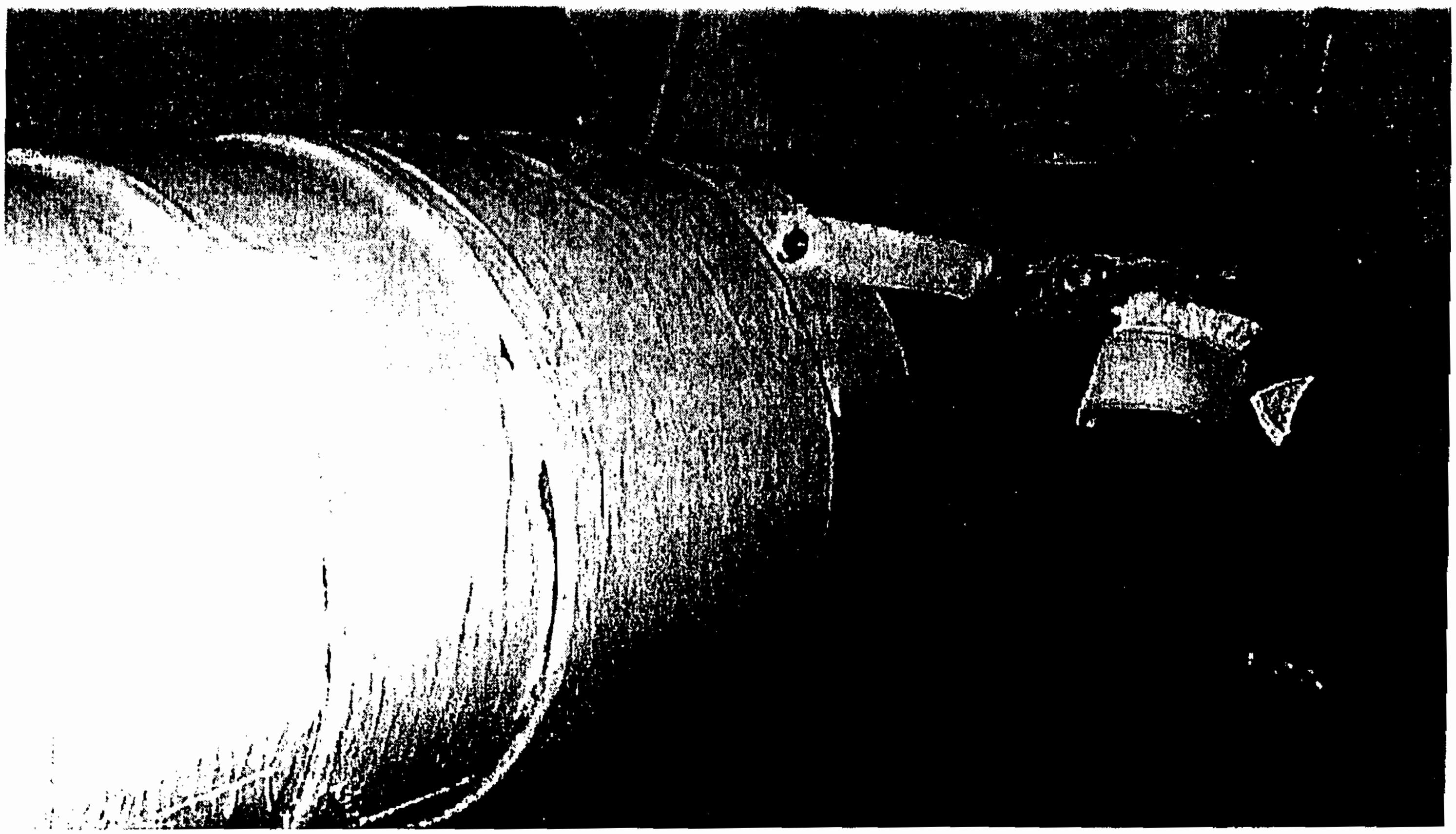
- Coating Repair / Tape



Technology Overview

Pipeline Repair Alternatives

- Coating Repair / Epoxy



3.0 APPLICATION PROCEDURE AND SPECIFICATIONS

– Primary components AEC procedure are:
  - Personnel
  - Safety
  - Material Storage
  - Pipe Preparation
  - Installation/Design Parameters
  - Inspection
  - External coating

3.1 CLOCK SPRING APPLICATION/PERSONNEL

- Personnel must be trained and certified in accordance with the AEC Pipelines certification program.
- A minimum of 3 installers must be present on each crew.
  - 2 AEC certified installers
  - 1 trainee installer or general assistant

3.2 CLOCK SPRING APPLICATION/SAFETY

- Tented in application.
  - Air quality monitors in use at all times;
  - Tent must have adequate ventilation
  - Protective masks must be warn at all times

3.3 CLOCK SPRING APPLICATION/MATERIALS

- Materials must be maintained at a minimum temperature of 12 degrees Celsius for:
  - Storage;
  - Transportation;
  - Installation.

3.4 CLOCK SPRING APPLICATION/PIPE PREPARATION

- Blast cleaning to a N.A.C.E. 2 commercial finish.
- Removal of pipe surface spatter and weld slag by wire brushing.
- Adjacent coating is given a methanol wash.
- Continued protection from the elements.
- Final area methanol wash to remove moisture

3.5 CLOCK SPRING APPLICATION/INSTALLATION

- Sleeves must overlap corroded area by 51 mm./2". Adjacent sleeve installation is permitted.
- Girth weld coverage requires a bridge approach.
- Pressure reduction of 15% of pipeline section M.O.P. / defects less than 50% W.T. penetration
- Pressure reduction of 50% of pipeline section M.O.P./ defects greater than 50% W.T. penetration.
- Maximum allowable operating temperature for installation-57 degrees Celsius

3.6 CLOCK SPRING APPLICATION/COATING

- Clock Spring Coating shall not initiate until the installed Clock Spring adhesive has cured to a measured Shore hardness of 40.
- Approved coating materials are Polyguard RD 6 and Denso Protal 7000.
- Use of Polyguard RD 6 requires that primer be applied and the Clock Spring transition edge be filled with a moldable sealant material.

3.7 CLOCK SPRING APPLICATION/DOCUMENTATION

- Insert Chart

AEC PIPELINES
a Division of ALBERTA ENERGY COMPANY LTD.

CLOCKSPRING INSTALLATION DATA & INSPECTION RECORD

Revised: *08/07/96 8:18 PM*

Pipeline Owner:		**Project:**	
Site:	**Chainage:**		**Date:**
Pipe Diameter:	**Grade:**	**W.T.:**	**Defect Type:**
Control Center Contact:		**MAOP:**	**%MAOP:**
Contractor Company:		**Inspection Company:**	
Installer #1:	**Installer #2:**		**Installer #3:**
Outside Air Temp:°C:	**Ambient Tmp°C:**		**Pipe Surface °C:**

MATERIALS.

#	Clock Spring™		Adhesive		Catalyst		Filler		Activator		Insp
	Batch	ID	Batch	Date	Batch	Date	Batch	Date	Batch	Date	Init
1											
2											
3											
4											

INSTALLATION

#	Times			Location			Starter	Curing		Shore	Insp
	Start	Stop	Duration	U.S.	D.S.	Bridge	Pad @	Time	Temp	Hard	Init
1											
2											
3											
4											

High / Low U.S @. O'clock	mm Max	**High / Low D.S @** O'clock	mm	
# Extra Filler Used:	Filler Btc	Filler Dte	Actv. Btc	Actv Dte
Type & Quantity of Coating Used:				
Inspector: Print/ Sign.			Comments - See reverse of form	

10/30/ 56 PM Aec

4.0 APPLICATION TRAINING AND CERTIFICATION

- Installer training and certification
- Inspector training and certification
- Installer trainer and instructor certification
- Valid for a 12 month period

4.1 TRAINING AND CERTIFICATION/ INSTALLER

- Clock Spring theory training course
  - Clock Spring basic concepts
  - Basic explanation of corrosion/SCC/other defects
  - Basic explanation of wall loss/ hoop stress relationship
  - Basic explanation of load transfer concept
  - Applicable C.S.A. Code requirements
  - Proper pipe preparation requirements
  - Curing/coating/time-temperature /documentation
  - Clock Spring advantages and disadvantages
- Observation of one field installation;
- 5 installations under observation of AEC Certified Trainer.

SESSION A
Working Group #4A

RISK ASSESSMENT / RISK MANAGEMENT - GENERAL

be produced into tanks for longer periods of time. proper shut in procedures can be used in the future. Occasionally smaller pipes are pulled through larger pipes to increase flow rates to safe levels.

8. Can Material changes solve the problem?

   Consider a case where this is an option. A cost analysis must be done comparing the cost of material change to that of using chemical inhibitors. If a material change is a favorable option then go to step 9.

9. Material changes.

   This becomes a matter of choosing the proper material for the application. For example. plastic liners are often pulled through pipe sections for this purpose.

10. Inhibitors are needed; this usually implies that some form of monitoring will also be used.

    The two parties must work together to establish the requirements of this program.

11. Monitoring recommendations.

    The extent and intensity of monitoring must be chosen jointly because both parties are effected by the needs of a monitoring program. BPC's preferred options are discussed in Attachment # 3.

12. Chemical treatment program recommendation.

    BPCI will take the producer's requirements and initiate lab studies and product selection mechanisms to choose the best inhibitor program.

2. Lab studies and product selection

Once product types and treatment methods are agreed to, the process of product selection begins. Experience and lab testing are used for this stage. BPC maintains an extensive data base which contains all our products and the situations in which they are used. This data base plus the specifics of the system in question are used to select several best candidates. A three phase test protocol is used to select the winner.

Phase I: Behavior Test

The following characteristics are identified: compatibility, fouling, foaming, gunking, emulsion forming tendency, dispersibility, film formation, hydrophobic nature, and stability. These are all important characteristics that may effect different parts of the system.

Phase II: Static Tests

Sparge beaker and static autoclave tests are done using weight loss and electrochemical measurements (DC and AC techniques).

Phase III: Dynamic Tests

Wheel tests, rotating cage autoclaves, autoclaves fitted with rotating electrodes and a flow loop fitted with AC/DC sensors and weight loss capabilities are all available if needs be.

3. Presentation of completed treatment program to customer

The completed treatment program is presented to the customer to ensure that all requirements will be met. Changes are made if necessary.

4. Program installation

All field modifications are made to accommodate the program. Specific tasks are divided between the two parties and are included in the daily work plans of the personnel involved. A data base is constructed to receive all relevant data and work plans are designed to include the continual maintenance of this base. All other arrangements with accounting departments and ordering personnel are initiated.

5. Program optimization

Once treatment starts and pumps are set, data collection begins.

(a) Strategic samples are taken for inhibitor residual determinations

(b) Corrosion monitoring begins (or is continued) and data accumulated (see Attachment # 3 for discussion on monitoring techniques).

(c) Treatment levels are adjusted as required

6. Presentation of long term plan to customer

After the program is optimized and debugged, a long term plan needs to be agreed upon and incorporated into the work plans of the personnel involved. The success of any program depends on adherence to the work plan. Changes to this long term plan must be signed off by both parties.

Notes:

1. This methodology assumes that the customer has adequate, reliable corrosion detecting devices installed in their systems. If this is not true, it should be installed before treatment begins so that success can be measured. Common methods for corrosion measurement are described in Attachment # 3 and are presented in order of BPC's preferences.

2. The reader will note that useful and well maintained data bases are an integral part of this proposed methodology. BPC has significant experience in this area and can assist its customers as needed. Very often, good data is taken and stored by producers but not in a useful fashion. BPC's *Corrtrax™* has proven to be extremely useful in this area.

3. Corrosion monitoring devices can not be installed everywhere in a pipeline. Typically, they are never installed at locations where failures usually occur. However, results from a well designed monitoring system that are recorded in a useful manner can be used to

detect problems with treatment programs or operating practices. An even more powerful tool results when this data is combined with a simple risk assessment type flow modeling program. There are several on the market but BPC can provide their customers with this feature in *Corrtrax*™. Please see Attachment # 4 for more information.

ATTACHMENT 1

FIELD SURVEY

A thorough and accurate field survey is the starting point for any treatment program. BPCI is experienced at organizing this information and can be of great help. This information is fed into a decision tree designed to extract the right decisions and actions for each situation. No two fields are the same; therefore, the decision criteria may vary slightly from system to system. It is up to both parties to verify that they have done the analysis correctly. No fixed methodology should be completely substituted for rational thought and common sense.

History

1. What treatment programs are have been used and the results

2. All previous corrosion monitoring data which will be used to find problem spots and for benchmarking the new program

3. Failure frequencies and locations for the past three years

4. Production from the past five years for all wells

5. System conditions such as temperatures and pressures for the past three years

6. Previously identified corrosion mechanisms or new ones that need to be identified

7. Pigging procedures, schedules and pig types

8. Scaling problems or production of solids

9. What has been done with acid jobs and what is the current practice

10. Are either polysulfides or elemental sulfur present in the fluids

11. Operator observations over the past six months or more

Current System Configuration and Conditions

1. Field map and schematic diagram including all pipeline lengths and sizes, coupon locations and topographical information

2. Current status of the chemical storage and injection pumping facilities

3. Current problems that need to be addressed by a new program

4. Reservoir and formation information

Design and Performance of Corrosion Inhibition for Multiphase Pipelines

The design of a corrosion inhibition program for a multiphase pipeline and the subsequent evaluation of that program involves is more than just a technical excercise. A joint and cooperative effort between the producer and the chemical supplier is needed for a successful program which will evolve during the life of the asset.

Methodology

Outline

1. Field survey and analysis (should include historical monitoring data as benchmark for future metrics).

2. Lab studies and product selection.

3. Customer presentation to ensure all requirements are met and that no other parts of the system will be upset.

4. Installation of program.

5. Optimization of program using monitoring tools.

6. Long term plan presented to customer which should be included in their daily defined work plans.

Detailed Explanations

1. Field survey analysis, and decision making procedure.

   A completed field survey is the starting point for any treatment program (see Attach. # 1). Information from this field survey is fed into a decision tree which is used to determine what product types and appropriate actions are needed. It should be noted that both parties must participate in this process so that the required treatment program is selected the first time. A written description of a typical decision tree is given below and a schematic diagram for that text is given in Attachment # 2. The numbering of the text below is keyed to the numbering in the schematic diagram.

   1. Is oxygen present?

      Knowledge of the system will reveal if oxygen is a possibility. If yes, it should be verified by:

      (a) Measuring oxygen levels in fluids or gases,
      (b) Installing galvanic probes (very sensitive to oxygen),
      (c) Visual and/or instrumental inspection of pipe sections that contain examples of the corrosion.

2. Appropriate action for oxygen protection.

   If oxygen is detected, the source must be found and eliminated. Examples of oxygen ingress are:

   (a) Improperly blanketed storage tanks.
   (b) Defective packing on centrifugal pumps,
   (c) Trucked in fluids.
   (d) Use of river water.
   (e) Air breaking through into the production fluids in a fireflood.

   If the source can not be eliminated. degassing plants and/or oxygen scavengers can often be applied.

   Material changes might be possible; fiberglass or lined pipe is routinely used when oxygen is present.

   If these measures are not possible, inhibitors must be used. A lab testing protocol must be designed to create a reasonable analog to the actual system and then inhibitor candidates compared within that structure.

3. Are bacteria involved?

   Pipe fluids can be cultured or pipe samples can be analyzed for the presence of bacteria. There are probes available that detect bacterial activity but these are not in common use.

4. Appropriate action for bacteria

   If bacteria are present, a biocide must be used. Pigging is beneficial if possible.

5. Determine the corrosion mechanism if neither bacteria nor oxygen are implicated.

   The following information is usually sufficient to identify corrosion mechanisms or root causes.

   (a) Visual inspection of actual corrosion examples.
   (b) Analysis of the flow regime at the trouble spot.
   (c) Review of all parameters gathered in the field survey.
   (d) Review of the historical corrosion monitoring record to see if significant parameters have changed.
   (e) Have acid jobs been flushed through the system (or the tail ends of acid jobs).
   (f) Has the line been shut in without following proper procedures.
   (g) Has the TDS increased in the recent past.

6. Can this corrosion be stopped by adjusting parameters?

   Possibly.

7. What actions can be taken?

   Adjusting parameters or operating practices can help if they are the root causes of the problem. For example, flow rates can sometimes be adjusted. acid jobs can

How Can Success be Measured?

1. What are the *requirements*?

   No Corrosion or corrosion related problems!

   - No failures
   - No iron sulfide (clogs filters and creates emulsions)
   - No emulsions (dry oil, clean water)
   - Free (with service)

2. *Measurements* are needed

   This means monitoring

   - To determine the effectiveness
   - To determine the application frequency

3. We have to keep meaningful data

Fluids Monitoring

1. Total Iron

   - Dissolved iron in brine
   - Solid iron sulfide in brine
   - Solid iron sulfide in oil
   - Solid iron sulfide at the interface

2. Chloride levels and pH of brine

3. Inhibitor residuals

   - In the oil (tracks return of inhibitor)
   - In the brine (should not be much)
   - On the coupons

4. Filter Change frequency

5. Treater problems (emulsions, foaming)

Pig Trap Debris Monitoring

1. Note quantity and nature

2. Analyses of liquids and solids which should be compared to results from routine samples

Physical Monitoring

1. Flush mounted coupons

   - Corrosion assessment
   - Film residuals

2. Flush mounted ER probes

3. LPR probes, if possible, in a water trap or fish belly

4. Electrochemical noise monitors where possible (gaining popularity)

5. Flush mounted, but intrusive, hydrogen probes

6. Mass balance tallies of the applied inhibit or verses the amount returned

Compressed Version of Overheads Used in the Presentation

This is an extensive topic which involves a joint and cooperative effort between the producer and the supplier.

A text is provided which deals with the entire process.

Presentation will focus on the following topics

1. Batch type corrosion inhibitors
2. Pigging
3. Continuous type corrosion inhibitors
4. Combinations of the first three

Batch Type Corrosion Inhibitors

Batch inhibitors are neither water soluble nor appreciably soluble in the produced hydrocarbon (oil in this discussion)

Batch inhibitors create a measurable film on the pipe wall that displaces any water and "oil wets" the surface (contradiction!)

1. When should they be used?
2. Why should they be used?
3. How should they be used?
4. How can success be measured?

When Should They be Used?

1. When a new pipeline is put into service
    - Usually done between pigs which also insures that all the debris will be cleaned out
    - Installs a hydrophobic film on the entire surface
    - Helps defend against the onslaught of "new" production

2. When the flow regime is such that not all surfaces of the pipe come in contact with inhibited fluids

    - corrosive vapor spaces

    - Inefficient transport of continuous inhibitors, especially in the water phase

    - It can take several days for continuous, water soluble inhibitors to be carried through a pipe but water can condense well ahead of the water front

3. When something unusual happens to a pipeline such as the following

    - An acid job gets produced through the pipe

    - Production is scheduled to be interrupted and a stagnant condition will arise.

Why Should They be Used?

1. They can be cost effective, especially if combined with a pigging schedule

2. No other choice (top of the line)

3. Augment a continuous inhibitor for severe conditions

How Should They be Used?

1. Should be diluted with diesel - not local condensate or sales oil.

2. Should be batched between pigs

3. Sufficient concentration and contact time for good film formation

4. Applied with a suitable frequency determined by experience

5. Proper records kept of all applications, chemical use and monitoring results

Design and performance of Corrosion Inhibitors for Multi-phase Pipelines

Banff/97 Pipeline Workshop

Working Group #4B (Producers)

Risk Management/Internal Corrosion

April 17, 1997

Presented by

John Lerbscher

Baker Performance Chemicals

Where Chemical Programs Fit into the Big Picture of Risk Management

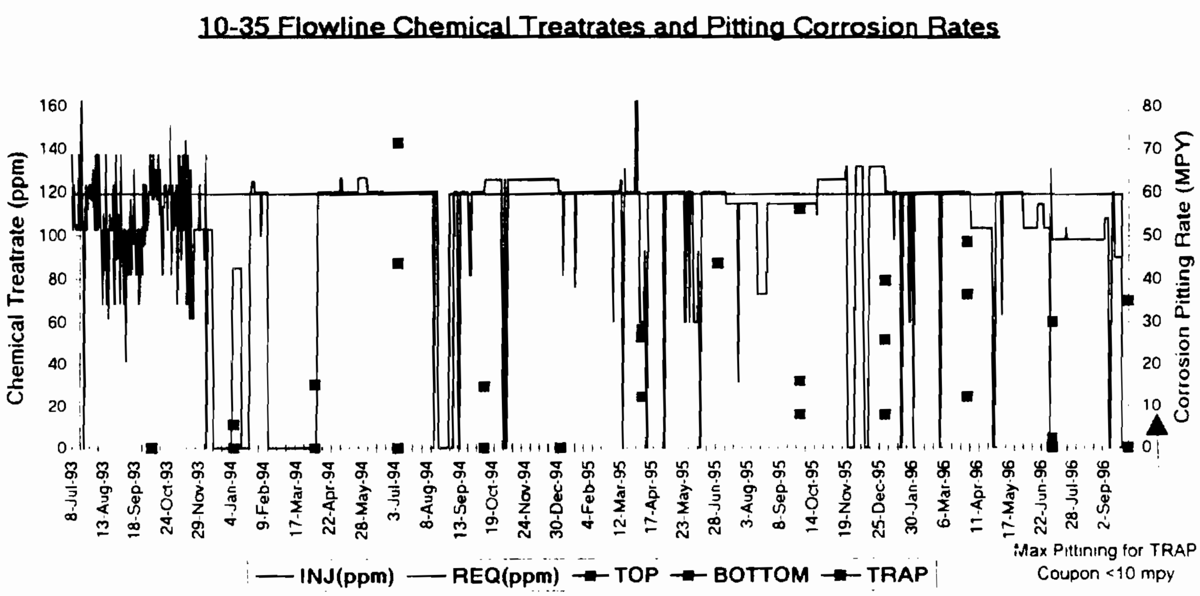
Corporation
Stakeholders
Customers, Employees,
Shareholders, Public

- Human Resources Plan
- Business Plan
  - Exploration Plan
  - Asset Management Plan
    - Risk Management
      - Physical Asset Integrity Mgemnt Plan
        - Likelihood Mitigation
          - Operating Envelopes
          - Materials Selection
          - Pigging Activities
          - Chemical Inhibition Programs
        - Consequence Mitigation
          - Repair / Replacement
          - Cleanup / Damages / Lost Production
  - Acquisition Plan
- Other Plans

LOCATION	Date	TEMP (C)	GAS (km3/d)	GROSS FLUID (m3/d)	OIL (m3/d)	WATER (m3/d)	W/O RATIO	INJ (mean b/d)	INJ (std dev b/d)	REQ (b/d)	INJ (mean ppm)	INJ (std dev ppm)	REQ (ppm)	SAMPLED (ppm)	I.D. DIA (mm)	LIQUID VEL (ft/s)	GAS VEL (ft/s)	FLOW REGIME	TOP	BOTTOM	TRAP	TOP (psi)	BOTTOM (psi)	TRAP (psi)
07 03 03	1 Aug 92	18	44.97	392.86	38.11	354.75	9	36.0	0.5	43	101	1	120	#N/A	127	1.19	18.33	STRATIFIED SLUG	0.5	[illegible]	0.01	[illegible]	79.9	[illegible]
07 03 03	2 Aug 92	46	41.67	396.49	38.56	387.93	9	30.0	14.9	43	96	42	120	#N/A	127	1.70	16.98	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	25 Aug 92	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	75	127	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	26 Oct 92	37	[illegible]	368.91	31.46	337.45	11	34.7	4.6	40	103	14	120	#N/A	127	1.11	17.65	STRATIFIED SLUG	0.99	[illegible]	[illegible]	102.5	[illegible]	[illegible]
07 03 03	[illegible]	41	40.12	[illegible]	31.79	324.21	10	32.0	4.6	39	99	14	120	#N/A	127	1.07	16.35	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	[illegible]	41	40.05	[illegible]	[illegible]	324.18	10	[illegible]	6.7	39	96	19	120	#N/A	127	1.07	16.65	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	8 Nov 92	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	47	127	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	26 Nov 92	45	9.48	341.22	22.53	318.69	14	22.8	18.2	38	72	57	120	#N/A	127	1.03	3.86	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	27 Nov 92	43	7.83	352.48	25.69	326.79	13	15.0	14.0	39	46	43	120	#N/A	127	1.06	3.19	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	28 Nov 92	45	9.16	380.91	30.31	350.6	12	0.0	21.5	43	0	60	120	#N/A	127	1.17	3.73	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	29 Nov 92	49	10.36	383.74	31.08	352.66	11	0.0	21.5	42	0	61	120	#N/A	127	1.16	4.22	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	30 Nov 92	45	8.83	393.59	32.48	361.11	11	28.0	7.5	43	78	21	120	#N/A	127	1.19	3.60	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	4 Dec 92	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	43	127	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	11 Dec 92	40	9.19	441.75	34	407.71	12	20.3	10.9	49	50	46	120	#N/A	127	1.33	3.75	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	12 Dec 92	40	8.81	432.75	33.37	399.38	12	40.0	2.1	48	100	5	120	#N/A	127	1.31	3.99	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	8 Jan 93	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	105	127	#N/A	#N/A		4.24	1.66	0.08	174.4	134.6	[illegible]
07 03 03	12 Feb 93	45	31.1	287.14	28.9	258.24	9	27.2	22.6	31	105	88	120	64	127	0.82	12.68	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	15 Feb 93	37	32.65	293.78	24.12	269.66	11	51.3	8.1	32	150	30	120	#N/A	127	0.89	13.31	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
07 03 03	18 Feb 93	35	33.09	276.93	22.25	254.68	11	23.5	15.6	31	92	61	120	#N/A	127	0.84	13.49	STRATIFIED SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
14 35 03	12 Aug 92	35	35.42	191.17	12.17	179	15	26.5	7.8	21	140	44	120	#N/A	76.2	1.60	40.10	ANNULAR SLUG	0.07	0.04	0.02	0.1	0	[illegible]
14 35 03	25 Aug 92	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	45	76.2	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
14 35 03	3 Sep 92	33	26.61	234.24	12.94	221.3	17	20.0	2.4	27	90	11	120	#N/A	76.2	1.96	30.75	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
14 35 03	4 Sep 92	35	21.09	239.61	4.72	234.89	50	17.7	3.3	28	75	14	120	#N/A	76.2	2.01	25.14	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
14 35 03	6 Oct 92	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	55	76.2	#N/A	#N/A		0.19	0.03	0.01	25.5	[illegible]	#N/A
14 35 03	24 Oct 92	30	32.32	192.59	12.53	180.06	14	18.0	2.5	22	100	14	120	#N/A	76.2	1.61	36.99	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
14 35 03	25 Oct 92	31	32.82	254.01	12.09	241.92	19	18.0	2.5	29	74	10	120	#N/A	76.2	2.14	37.16	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
14 35 03	12 Dec 92	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	43	76.2	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
14 35 03	7 Jan 93	28	33.76	215.59	12.49	203.1	16	15.7	5.4	24	75	27	120	#N/A	76.2	1.01	37.65	ANNULAR SLUG	0.79	0.05	0.02	[illegible]	18	6
14 35 03	8 Jan 93	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	270	76.2	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
14 35 03	18 Jan 93	30	31.14	198.82	11.91	186.91	16	19.7	7.5	22	105	40	120	#N/A	76.2	1.67	35.25	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
14 35 03	11 Feb 93	30	32.27	198.6	12.97	186.03	15	26.4	3.3	27	142	18	120	#N/A	76.2	1.66	36.53	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
14 35 03	17 Feb 93	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	114	76.2	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	6 Aug 92	48	29.68	207.17	84.69	122.48	1	17.2	1.6	15	140	13	120	#N/A	76.2	1.74	33.80	ANNULAR SLUG	0.03	0.04	0.05	2.6	0	6.9
10 35 03	25 Aug 92	45	24.22	206.95	89.35	117.6	1	18.6	2.4	14	150	20	120	125	76.2	1.73	27.42	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	4 Sep 92	45	27.65	215.94	84.11	131.23	2	14.7	4.1	16	117	31	120	#N/A	76.2	1.81	31.30	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	7 Sep 92	43	26.15	218.33	87.55	130.78	1	12.3	2.4	16	94	18	120	#N/A	76.2	1.81	29.60	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	6 Oct 92	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	200	76.2	#N/A	#N/A		0.01	0.01	0.01	0	0	0
10 35 03	8 Nov 92	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	400	76.2	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	4 Dec 92	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	330	76.2	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	12 Dec 92	42	41.54	203.65	78.98	124.67	2	13.6	6.6	15	109	53	120	#N/A	76.2	1.71	47.03	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	16 Dec 92	42	27.14	192.64	74.37	118.27	2	18.0	6.9	14	152	58	120	#N/A	76.2	1.61	30.73	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	7 Jan 93	43	29.86	196.5	75.88	120.62	2	7.3	8.8	14	65	73	120	#N/A	76.2	1.65	33.81	ANNULAR SLUG	0.01	[illegible]	[illegible]	[illegible]	0	[illegible]
10 35 03	9 Jan 93	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	425	76.2	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	19 Jan 93	43	26.62	195.17	74.48	120.69	2	9.4	6.6	14	78	55	120	#N/A	76.2	1.64	30.14	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	11 Feb 93	36	27.28	197.5	73.71	123.79	2	[illegible]	6.4	15	141	52	120	#N/A	76.2	1.65	30.08	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	12 Feb 93	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	120	52	76.2	#N/A	#N/A		###	#N/A	#N/A	#N/A	#N/A	#N/A
10 35 03	24 Feb 93	37	27.24	195.96	72.62	123.34	2	[illegible]	1.2	15	116	10	120	#N/A	76.2	1.64	30.84	ANNULAR SLUG	###	#N/A	#N/A	#N/A	#N/A	#N/A

MOBIL WIMBORNE GATHERING SYSTEM
13-10 SATELLITE 8" LP GAS

MONTH	GAS (KM3/D)	GROSS FLUID (M3/D)	OIL (M3/D)	WATER (M3/D)	W/O RATIO	GAS VEL (FT/SEC)	FLOW REGIME	MONTH	GAS (KM3/D)
Jul-92	172.24	783.4	76.57	706.83	9	27.4	STRATIFIED WAVE	Jul-92	172.24
Aug-92	162.9	713.1	66.15	646.98	10	25.9	STRATIFIED WAVE	Aug-92	162.9
Sep-92	172.07	837.4	79.56	757.82	10	27.4	STRATIFIED WAVE	Sep-92	172.07
Oct-92	211.37	1028	65.58	962.45	15	33.7	SEMIANNULAR	Oct-92	211.37
NOV-92	196.67	950.6	86.45	864.12	10	31.3	SEMIANNULAR	NOV-92	196.67
Dec-92	199.07	898	73.97	824.06	11	31.7	SEMIANNULAR	Dec-92	199.07
Jan-93	180.84	906	80.86	825.14	10	28.8	STRATIFIED WAVE	Jan-93	180.84
Feb-93	171.67	809.7	61.98	747.72	12	27.3	STRATIFIED WAVE	Feb-93	171.67
Mar-93	167.29	801.2	63.73	737.49	12	26.6	STRATIFIED WAVE	Mar-93	167.29



Typical Operating Envelope Boundaries Well Defined

- Temperatures, pressures relatively stable, predictable
- Flow dynamics understood
- Water chemistries consistent (formation water)
- WOR, GOR ranges established
- Minimum acceptable inhibitor treat rate verified
- Pig type and frequency required for each line known

Development of corrosion potential model primarily based on:

- Existing damage in pipeline
- Pigging frequency, capability, pig type
- Continuous inhibitor compliance to target injection rate
- Ability to predict/detect/communicate significance of changes in operating environment

Risk Assessment

- Each line corrosion potential rating - high, medium, low (likelihood)
- Proximity of residences and prevailing winds (exposure)
- Environmental, regulatory, financial (repair and production), safety (consequences)

Implementation

- Chemical pump budget approved, pumps purchased or repaired to improve reliability
- Mitigation team meets monthly to communicate key results/ suggestions for improvement, tracking of compliance, etc.
- New pigs and pig launchers purchased/installed

Mitigation Program Improvement Process

- Data acquisition and analysis
- Correlation of historical data to corrosion events
- Development of predictive model
- Evaluation of corrosion potential
- Input to risk assessment
- Development of management strategy
- Implementation of plan improvements

Data Acquisition

- Engineering data, schematics, materials
- Production volumes
- Water / gas analyses
- Failure history, failure analyses
- Internal (smart pig) inspections
- Chemical injection rates, residual analyses
- Operational Influences - Kill fluids, methanol, suspensions
- Pigging frequency and type
- Evidence of other corrodents such as bacteria, S8, etc.
- Pipeline monitoring data - coupons, electrochemical measurements
- Corrosion flow loop evaluations/results

Data Analysis

- Corrosion inhibitor - Residual vs. Target [ ] vs. Coupon results, Actual vs. Target Injection Rate vs. Coupon results
- Gas analyses - acid gas partial pressures vs. failure failure/inspection history
- Flow regime vs. failure/inspection history
- Slug severity (shear force potential) vs. failure/inspection history

Data Analysis (2)

- Failure analyses vs. evidence of bacterial growth, elemental sulfur deposition, other deposits
- Electrochemical measurements vs. coupon vs. hydrogen foil results vs. failure/ inspection data
- Operational practices vs. failure history

Characteristics of "typical" Wimborne Field Corrosion Failures

- Random pitting corrosion
- Water phase - stratified flow (3 - 9 o'clock)
- FeS in pits - no other deposits

Wimborne Field - Corrosion Inhibitor Program History

- 1977 to 1980 - continuous oil soluble/water dispersible plus batches (slugs) of oil soluble filmer
- 1980 - switch inhibitors/companies - types unknown - suspect similar to previous types
- 1981/82 - switch inhibitors/companies- continuous oil dispersible/water "soluble" plus batches (slugs) of oil soluble filmer
- 1990 - independant lab selection of inhibitors
- 1990-1991 field trials - flowloop evaluations
- 1991- present - highly water soluble inhibitor(s)

Wimborne Field - Corrosion Mitigation Program Priorities

- Eliminate unplanned events (failures)
- Reduce frequency of repairs and magnitude of repair costs/outages
- Concentrate on activities that provide highest leverage wrt program effectiveness/efficiency - "**Maximum production for minimum overall cost**"

Corrosion Mitigation Program Improvements

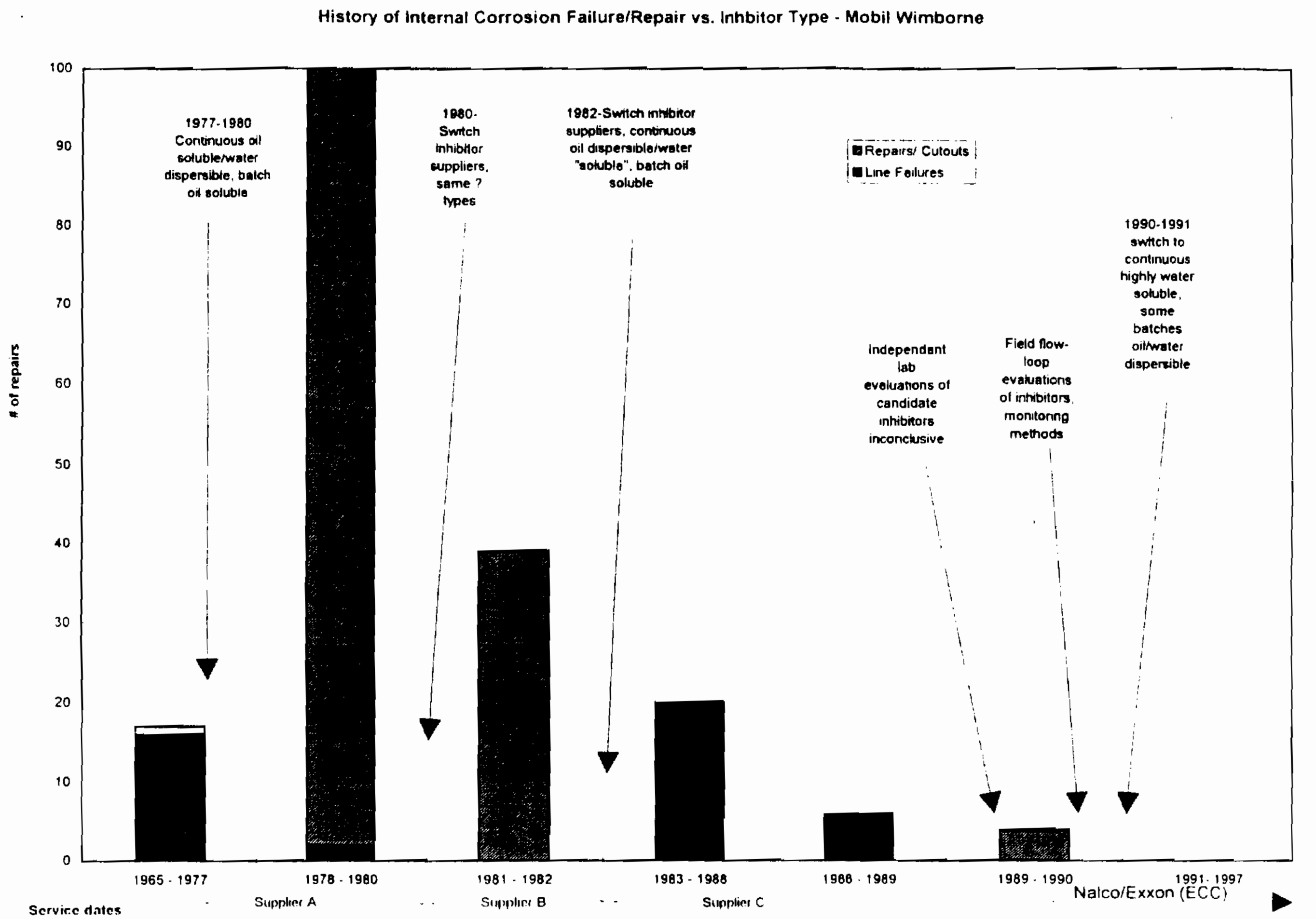
- Key indicators of change identified
- Risk or "confidence" based strategy for managing each pipeline developed
- Predictive capability of model validated by internal inspection of highest risk lines and total field failure rate

Wimborne Field - System Survey (2)

- All but 1 flowline internally bare
- Gas separation at field satellites, gas and liquids (pumped) in separate lines to plant.
- Gas is predominantly recycled gas for lift enhancement purposes.
- Acid gases: H_2S 18-28%, CO_2 3.5-4.5%
- Pressures: High 3400 kPa, Low 2000 kPa
- Temperatures: 20-70 C
- Brine Composition: 125K ppm Cl-, 220K ppm TDS

Wimborne Field - Corrosion Related Failure History

- System operating since 1960's
- 1965 to 1977 - at least 16 line failures in 6" and 8" grouplines
- 1977 - began internal pipeline inspection program
- 1978 to 1980 - 2 line failures and 98 line repairs (cutouts)
- 1980 to 1982 - 39 line cutouts
- 1982 to 1989 - various failures/repairs
- 1989 - 6 line failures/repairs
- 1991 - 1997 - 0 failures/repairs under "normal" field conditions, however....



1996 - 2 unpredicted failures in same pipeline under "unusual conditions"

BENEFITS OF RISK ASSESSMENT

- Determine Application Technique
- Pig Or Not To Pig
- Focus Monitoring
- Inspection Planning

⇨ Reduced Risk Of Pipeline Failure

FUTURE DIRECTION

- Incorporate Water Wetting Factor
- Water Holdup For Gas Systems
- Correlate Failure History
- Increase Usage Of Loops

PROBABILITY

- System Corrosiveness
- Design
- Service Life
- Flow Parameters
- Inhibitor Effectiveness

SUMMARY

- FLOW VS CORROSION INHIBITION
- FREQUENCY API RP14E
- PERFORMANCE STANDARDS
- PIPERISK

Managing Pipeline Integrity in an Oil Production System

Case Study:

Mobil Oil Canada

Wimborne Field

Presented to:

Banff Pipeline Workshop

April 17, 1997

by: Nalco/Exxon Energy Chemicals Canada Inc.

Wimborne Field - System Survey

- Location: Approx. 40 km NE of Olds in Central Alberta
- Production type: Sour oil, Leduc D2/D3 (38 API)
- Production Volumes: Oil - 500 M3/d, Water - 3000 M3/d, Gas - 800 E3M3/d
- # wells : 30 operating
- 22 gas lift 5 rod pump 3 electric submersible pumps
- Flowlines/grouplines: 76 mm to 203 mm carbon steel
- Water disposal lines: internally plastic coated or cement lined

CORROSION INHIBITION AND RISK ASSESSMENT IN MULTIPHASE OIL GATHERING SYSTEMS

PHIL FUKUDA
CHAMPION
TECHNOLOGIES LTD.

AGENDA

- FLOW REGIMES
- CORROSION INHIBITION
- PERFORMANCE STANDARDS
- RISK ASSESSMENTS
- FUTURE DIRECTION

FLOW REGIMES

- Laminar Flow
  - Separation of Phases
  - Solids, Biofilms
  - Pigging Required
- Turbulent Flow
  - ID Wet
  - Solids, Biofilms
  - Continuous Inhibition
  - Pigging Not Required

CORROSION PROGRAMS

- BATCH INHIBITION
  - Inhibitor Selection
  - Application
  - Frequency, API -14E Va/Ve
- CONTINUOUS INHIBITION
  - 25-100 ppm
- PIGGING
  - Underdeposit corrosion
  - Damage to Inhibitor films

PERFORMANCE STANDARD

- RCE TEST
  - Polarization Resistance
  - Relate Velocity/Rotation
  - Benefits
- WHEEL TEST
- AUTOCLAVE TESTING
  - LPR, AC impedance, ER, EC Noise
- FLOWLOOP TESTING
  - 2 Portable Test Spools

RISK ASSESSMENT

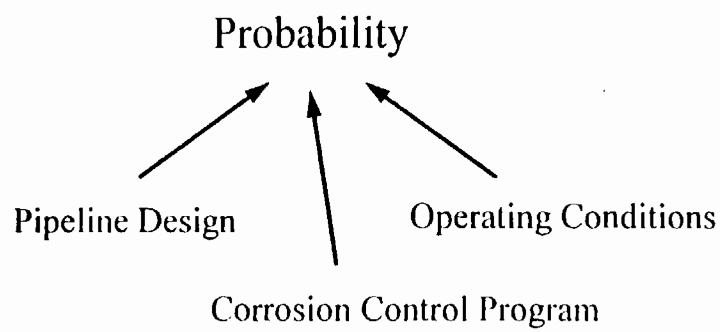
- OBJECTIVE

  Identify lines most susceptible to internal corrosion

  Implement corrosion control programs before failures occur

Probability Value

Champion Technologies, Ltd.



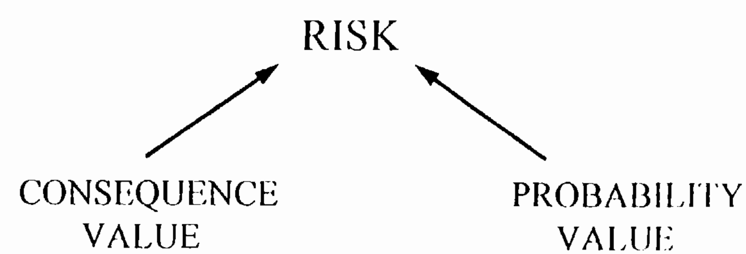
Analysis with PIPERISK

Champion Technologies, Ltd.

- PIPERISK is a tool.
- It ranks pipelines based on "<u>Risk</u>" associated with internal corrosion.
- We will discuss the methodology used in this risk assessment tool.

Overall Logic Flowchart

Champion Technologies, Ltd.



Critical watercut levels III

AST

Oil loss to oil attachment balance - ii

✔ Assumption 3 - Oil will stick and spread on oleophilic surfaces

- ➡ Clean metals are oleophilic when neutral
  - Local charges due to inclusions etc. promote hydrophilicity
  - Many clays and silicates are hydrophilic
- ➡ Some scales are oleophilic
- ➡ Stratification is dangerous
  - Low rate of oil droplet striking and sticking in the oil poor water layer will lead to loss of protective oily layer
    - Low flow rates
    - Low spots or rises in pipes
    - "Dead" spots near joints and valves
- ➡ Localized hydrophilic patches can create aggressive local chemistries.

✔ Previous history of pipe is important!

CWRC

CANMET Western Research Centre

Critical watercut levels IV

AST

Definitions

✔ At the critical watercut the oil losses from the pipe wall are equal to the hitting, sticking and spreading probability of oil droplets

✔ The supercritical region is very active

- ➡ Oleophilic, hydrophilic patches coexist
- ➡ Water can be trapped below oil
  - Very aggressive local chemistry possible
  - Inaccessible to inhibitor
- ➡ Thin, partially conductive oleophilic patches can become cathodes
  - High current concentration at anodic sites

CWRC

CANMET Western Research Centre

Predicting Critical Watercuts - I

AST

Three general methods

✔ Statistical
- ➥ With enough data correlations between some parameters and corrosion can be drawn
  - How to get the data

✔ Physical/Mathematical
- ➥ Mathematical modelling based on physical understanding
  - Physical understanding limited, hydrophilic/ oleophilic balance difficult to calculate
  - Hit, stick and spread extremely hard to model
  - Oil adhesion to pipe wall (thin film stability) a general problem

✔ Semiempirical
- ➥ Measure the oleophilic/ hydrophilic balance in the pipe
  - Experimental tools not readily available

CWRC

CANMET Western Research Centre

Predicting Critical Watercuts - II

AST

To date

✔ Statistical
- ➥ Not enough data available
  - Mainly as a result of failure
  - Pipe history often not clear

✔ Physical/Mathematical
- ➥ Not tried yet
- ➥ Measurements of viscosity, contact angles, interfacial tension possible and available

✔ Semiempirical
- ➥ Tools becoming available
  - Oil hit, stick and spread measurements

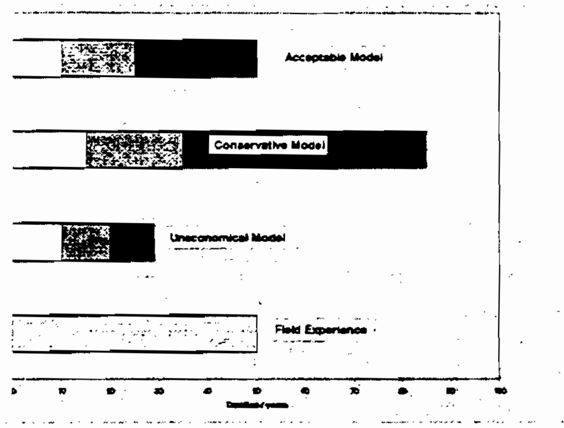
    Electrical impedance measurements

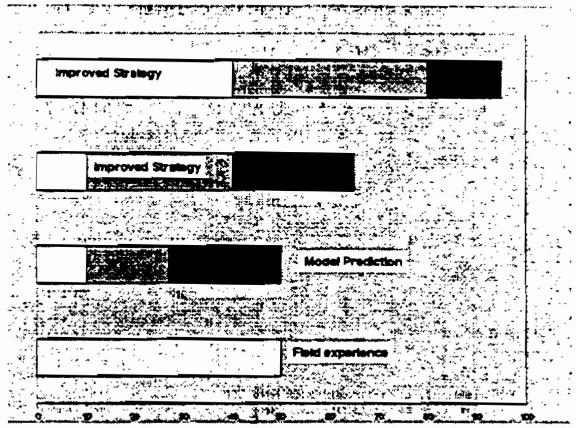
    Quartz microbalance

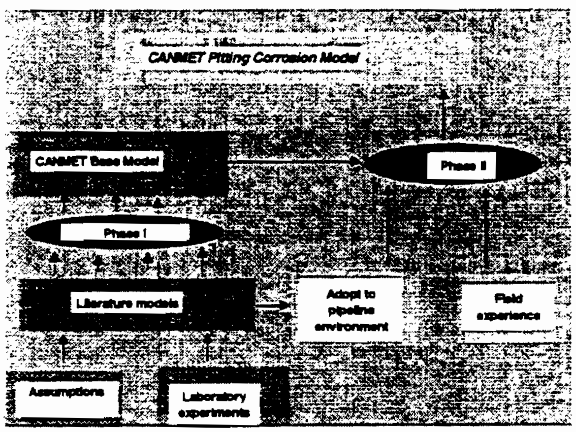
    Optical techniques / capillary waves

CWRC

CANMET Western Research Centre







Summary

- CANMET integrated model to predict the internal pitting corrosion of pipelines developed.
- Microsoft Excel Version 5 will be available in three months.
- Model verification will be performed.

Critical watercut levels
I

AST

Oilwet to Waterwet Transition

✔ Assumption I - Corrosion only happens when metal is in contact with water

- ➡ Allows metal in solution as Fe^{2+}
- ➡ Provides depolarizing reaction
  H_2 production from water
- ➡ Conducts ions to balance electron flow in metal
- ➡ Sustains changes in pH which promote corrosion

✔ Thus the Oilwet to Waterwet transition is also the onset of corrosion risk

Critical watercut levels
II

AST

Oil loss to oil attachment balance - i

✔ Assumption II - Oil is lost from the surface

- ➡ Competition with water
  - Carbonate scales more hydrophilic than metals
  - Oxidized sulphide surfaces also hydrophilic
- ➡ Removal due to dissolution
  - Role of naturally occurring surfactants
  - Role of high salt concentration
- ➡ Removal due to flow shear
  - Beading oil more susceptible
  - Area of high shear
  - Thin films stability issues (wave generation and thinning)

✔ Oil must be replaced

Predicting Pitting Corrosion of High Water Cut Pipelines

S. Papavinasam and W. Revie
CANMET/MTL
Ottawa, Ontario
&
J.C.Donini
CANMET/WRC
Devon, Alberta

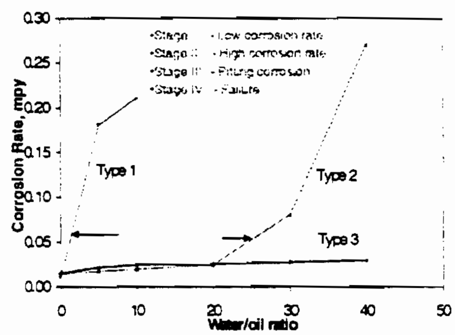
Outline

- Introduction
- Modeling of Internal Pitting Corrosion
- CANMET Pitting Corrosion Model
- Summary

Prediction of Internal Corrosion of Pipelines

- Time to add inhibitor
- Time to fail due to general corrosion
- Probability of pitting corrosion
- Time to fail due to pitting corrosion
- Life expectancy due to corrosion control strategies, e.g., inhibitors.

Types of Pipe based on Wettability



Stage I Low Corrosion Rate

- Wettability
- Oil wet ⟶ low corrosion rate

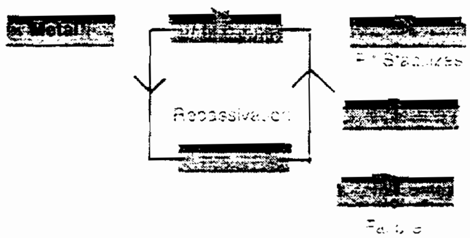
Stage II High Corrosion Rate

- **Water wet**
- Flow — Flow Models
- Pressure
- Chemical composition
- Steel composition
- Temperature
- pH

Corrosivity models

Stage III. Pitting Corrosion

- **Passive layer Pit Nucleation Pit Propagation**



Stage IV - Pipeline Failure

Introduction
Modeling - Stage IV
CANMET Model
Summary

- **A pipe fails when the first pit penetrates through the wall.**

CANMET Model

Introduction
Modeling
CANMET Model
Summary

- Phase I - Model Development
  - Life of a pipe divided into four stages.
  - A database of 432 references developed and analyzed.
  - Several models to describe the different stages incorporated.
  - An integrated model developed.
- Phase II - Model Validation

Phase I - Model Development

Introduction
Modeling
CANMET Model
Summary

- Excel 5.0 version will be available in three months time
- Basic model integrates knowledge from the pitting corrosion literature
- Model identifies required data and collection methodology

Phase II - Model Validation

Introduction
Modeling
CANMET Model
Summary

- Model to be refined and validated under pipeline operating conditions
- Model will predict the maximum pit growth rate

Phase II - Model Validation

Introduction
Modeling
CANMET Model
Conclusions

- Analysis of Failed Pipes
- State of the Existing Pipes
  - Pigging information
- Laboratory Experiments
  - Adopt constituent models to pipeline environment

Model # 2

Conditions	Probability
Fluid & Flow Properties < 50	Unlikely
Fluid & Flow Properties 50-70	Low
Fluid & Flow Properties 70-90	Moderate
Fluid & Flow Properties 90-110	Serious
Fluid & Flow Properties 110-160	Severe

Fluid Properties Factors (Max 80)

Chloride ion (max 10)
pH (max 10)
Temperature (max 10)
Acid gas (max 50)

Flowing Properties Factors (Max 80)

Water transit rate (max 15)
Solids factor (max 4)
Wetting factor (max 10)
FPF = (AxBxC) x 0.5

Line	Condition	Model 1	Model 2a	Model 2b
A	3	3	2	5
B	3	2	2	3
C	2	3	2	3
D	2	4	2	3
E	1	4	3	1
F	1	3	2	1
G	1	3	2	1
H	1	3	2	5
I	1	4	2	1
J	1	2	2	1
K	1	4	2	4

	Colmn 1	*Colmn 2*	*Colmn 3*	*Colmn 4*
Colmn 1	1			
Colmn 2	-0.3395	1		
Colmn 3	-0.2205	0.3614	1	
Colmn 4	0.5016	-0.0074	-0.3135	1

Environment		38.4 API		
		17% H2S		
		2% CO2		
		101,000 ppm Cl		

Line	Condition	Oil	Water	Cut
A	4	5.7	60.8	91.5
B	2	22.6	53.9	70.4
C	3	0.55	11.3	95.4
D	1	24.7	44	64
E	1	25.5	136.6	84.3
F	1	13.6	97.1	87.7
G	1	22.3	66.1	74.8
H	3	7	23.4	76.9
I	4	2.6	23.5	90

	Column 1	*Column 2*	*Column 3*	*Column 4*
Column 1	1			
Column 2	-0.851	1		
Column 3	-0.6188	0.627	1	
Column 4	0.5516	-0.7463	-0.0164	1

Environment		32.9 API		
		200 ppm H2S		
		2.5% CO2		
		11,000 ppm Cl		

Model # 1

Conditions	Probability
Water cut < 30%	Unlikely
Water cut 30% - 60%	Low
Water cut > 60%	Possible
Water cut > 60% Retention time > 4 hrs Hours/km > 1.5 hrs	Substantial
Water cut > 60% Retention time > 4 hrs Hours/km > 1.5 hrs Water production > 150 m3/d	Serious

B5.7 Risk Estimation

- Involves combining results of frequency (likelihood of occurrence) and consequence (severity of adverse effects) analyses to produce a measure of risk

- Appropriate methods include:

a) risk matrix methods, in which frequency and consequences are expressed in qualitative terms and combined in a two-dimensional matrix

b) risk index methods, in which points are assigned for specific characteristics related to frequency and consequences, and combined according to arithmetic rules

c) quantitative risk analysis methods, in which frequency and consequences are estimated quantitatively and combined on an arithmetical or statistical basis

Producers Group Model - Internal Corrosion

PIF = PT x CDP

PT = Mat x CL x PC

CDP = SC/PM

Line	Condition	PIF	PT	CDP
A	4	712,000	9600	74.2
B	2	307,000	3000	102.5
C	3	608,000	3000	202.7
D	1	272,000	3000	90.7
E	1	1,278,000	4200	292.3
F	1	1,155,000	3600	320.9
G	1	668,000	4800	139.1
H	3	944,000	3000	314.6

	Colmn 1	*Colmn 2*	*Colmn 3*	*Colmn 4*
Colmn 1	1			
Colmn 2	-0.1299	1		
Colmn 3	0.5088	0.0953	1	
Colmn 4	-0.2023	0.8381	-0.4091	1

Environment: 32.9 API
200 ppm H2S
2.5% CO2
11,000 ppm Cl

Working Group 4B

Risk Management / Internal Corrosion - Producers

10:30 - 12:00	Assessing probability of failure of multiphase pipelines due to internal corrosion
1:00 - 2:30	Reducing probability of failure of multiphase pipelines by corrosion inhibition

CSA Z662 "Oil & Gas Pipeline Systems"

- 1996 addition contains non-mandatory appendix (Appendix B) 'Guidelines for Risk Analysis of Pipelines'

- Revised Appendix B planned for 1998 addition of CSA Z662

- Time line:

Dec 1998	Publish Z662-98
June 1998	Last prior technical committee mtg
Feb 1998	Mail ballot revised appendix
Dec 1997	'Final' draft of revised appendix

- Chair of CSA Z662 Task Force on Risk Assessment

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Risk Management / Internal Corrosion of Multiphase Pipelines

- Issues:
  a) We cannot predict internal corrosion well enough
  b) Do not have coordinated industry action with respect to internal corrosion

- Recommendations:
  a) Develop a better predictive model
  b) Work through Producers Group and CAPP

  … And the model:
  - output must be able to be used with a risk matrix
  - must accommodate operational changes
  - must be cost effective for upstream pipelines
  - must have a certain level of accuracy
  - must properly assess 3 phase flow

Risk Management / Internal Corrosion of Multiphase Pipelines

- Issue:
  a) Inhibitors can be effective but we still have failures where they are applied

- Recommendation:
  a) Address the following technical issues:
  - system design for inhibitor application
  - reliable inhibitor injection
  - batch pig technology
  - monitoring of program and process change

NAME	GROUP 4B 13:00	COMPANY
R. MUKUL MUKHERJEE		ONTARIO HYDRO
LYLE GERLITZ		JLG ENGINEERING
ALEBACHEW DEMOZ		CANMET/WRC
MAGNE OSTBY		CorrOcean Inc., Houston
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LIST OF PARTICIPANTS

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Val Sikosa	EUB.
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WAYNE CHIPSSON	AEUB
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LIST OF PARTICIPANTS

Working Group #4B: Risk Management/Internal Corrosion--Producers 10:30

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SESSION B and C
Working Group #4B

RISK MANAGEMENT / INTERNAL CORROSION - PRODUCERS

SESSION B and C
Working Group #4B

RISK MANAGEMENT / INTERNAL CORROSION - PRODUCERS

Session 4A

Risk Assessment

Risk Management

Workshop Summary

Definitions: Risk / Reliability / Safety

- Frequency-of-Failure is Still a Big Issue
- Focus on Failures
- Little Control on Consequence
- Need to Focus Definitions on External, Public Safety
- Need Glossary to Expand CSA Z662 Definitions

Risk Analysis Tool Box

- Need to Be Able to Progress From Screening Matrix to Quantitative.
- Database Essential to Make Risk Analysis Tools Work Effectively.
- Producers Need Database

Uncertainty
Failure Statistics versus Predictive Models

- Tracking Failure Incidents (Rare, High Uncertainty)
- High Priority to Track Defects (Frequent, Low Uncertainty) to Prevent Failures
- Defect Tracking Needed for Mechanistic Models

Design Codes

- Codes Provide Lowest Common Denominators
- Risk-Based Codes are Good
- Improve Grey Areas within Code (e.g., "What is a cluster of dwelling?")
- Industry Generally Satisfied With Current Approach

Performance Measurement

- How is credit given by regulators?
- Individual Company Performance Estimates (NO!)
- Industry Wide Performance Record (YES!)

Risk Analysis Tool Box

- Risk Numbers (Quantitative)

  versus

- Expert Judgment (Qualitative)

(MZ)

Uncertainty

- Ignorance versus Natural Variability
- Historical versus Predictive Methods
- Frequency of Failure
- Consequence of the Failure

(DW)

Prescriptive Versus Flexible

- Codes versus Case-by-Case Design
- Good Business Practice Results in Safety?
- Company Liability when Not-to-Code

(DW)

Performance Measurement

- Individual Company Performance Claims
- Industry-Wide Performance Demonstration
- How is credit given by regulators?

(ID)

Risk Acceptability

- Public Consultation

versus

- Prescriptive Standards

(DW)

Working Group 4A Risk Assessment / Risk Management
Introductory Remarks by Ray Smith (NEB)

1) Good morning and welcome to the "General" Working Group Session on Risk Assessment / Risk Management - working group 4A.

2) Ian Dowsett has asked that I provide this working group an approx. 10 minute overview on the subject of Risk Assessment / Risk Management.

3) Over the last couple of days, starting with the Pre-Workshop Tutorials and followed by a comprehensive set of topics and presentations by our plenary session speakers, we have been bombarded with all kinds of phrases and terms that are in some fashion connected with our fundamental theme of this Workshop, namely "Managing Pipeline Integrity". (Please note the title on our banner and on our agenda).

4) I will now proceed to name several of these catchy-word, abstract and often rather lofty phrases and terms. These include:
    - Integrated Risk Management Process
    - Risk Assessment
    - Risk Analysis
    - Public Safety and Risk Management
    - What is Safety?
    - What is Risk?
    - Risk = Exposure x Effect (in terms of environmental impact)
    - Risk = Frequency x Consequences (in terms of public safety)
    - Risk Communication
    - Risk Controls
    - Audit, Inspection and Monitoring
    - Management and Organization
    - Decisions and Actions
    - Risk Decisions
    - Safety Decisions
    - Public Consultation
    - Risk Acceptability
    - Risk Evaluation
    - Qualitative Risk Assessment
    - Quantitative Risk Assessment
    - Design Standards (for example, CSA Z662) provide an "initial level of reliability"
    - Emergency Planning Zone (EPZ)
    - Response Planning Area (RPA)
    - Risk-based Regulations
    - Incident Database Development
    - Performance Measures
    - Training
    - Integrity Maintenance
    - Reliability
    - Maintenance of Reliability Levels

- Incident Reporting
- Pipeline Integrity Maintenance Program
- Prevention, Preparedness, Response

5) This is by no means a complete or exhaustive list, but it does tend to portray the variability in terminology, in concepts, in principles and in what may constitute the "Risk Management Process" or perhaps, in broader terms, the "Management of Pipeline Integrity".

6) Is there any chance, that with all of the attributes associated with each of these terms or phrases, that we can bring them together to mean something. Or have we simply proceeded to make the whole subject area of "Managing Pipeline Integrity" just too complex and too challenging to resolve? I am not going to attempt to answer that specifically but I may suggest to each and every one of us: "that the challenge is before us". I would expect, however, that much will be resolved with many years of painstaking and dedicated work!

7) Now, for a few minutes, I want to bring this subject matter back to the safety expression for risk: "Risk = Frequency x Consequences". In regard to consequences, many of our speakers the last couple of days have expressed that we have a fairly good handle on the consequences aspects of the equation and that, generally, the uncertainties associated with consequences are relatively small due to the accuracy of the modelling methods and practices, the results of laboratory testing, and the results of large scale field tests. It would appear then that the frequency part of the risk equation is what is probably presenting most of the major difficulties yet to be resolved. Let us then take a closer look at frequency and its implications.

8) Frequency is often expressed in terms of either Incidents or Probability of Failure. With pipeline incidents there always seems to be an inadequate number, that is, there is not enough incidents for the statistics to be meaningful, or the data base has not been collected or defined in a fashion appropriate for application to a risk analysis or the determination of risk. So the solution should then be: develop and generate a database which is relevant to the application or need! For your information, PRASC is currently undertaking an initiative in this area and, of course, would very much appreciate your input at this Workshop.

9) Now, I mentioned that frequency can also be expressed in terms of "Probability of Failure". There is a fundamental and very important distinction to be made here! Incidents rely entirely upon something which has already occurred, that is, a past event, such as a failure of some type, whereas, the probability of failure infers that failure has not yet occurred but that it does have a certain defined probability of occurring. Now the big question for pipelines is where do we go or how do we determine what that probability of failure may be?

10) Before I attempt to answer that question I would like to read the following statement from the Canadian Standards Association newsletter called "Perspectives" and dated Spring 1997:

> "Limit states design and risk analysis. Frank Christensen, a TC Z662 member, says new optional appendices lay the groundwork for applying limit states design and risk analysis to oil and gas pipelines. Mr. Christensen is the President of F.M. Christensen Metallurgical Consulting Inc.

For pipelines, a "limit state" is the condition beyond which the serviceability of the pipeline element or system would be considered impaired or unfit for use. Limit states design - an alternative to the working (or allowable) stress design method currently used - involves the '<u>determination</u>' of factored look and resistances '<u>based upon specified target levels of reliability</u>!'.

"Although limit states is the standard method used for buildings and offshore structures in Canada, it is not currently applied to pipelines," Mr. Christensen says. "As the industry becomes more comfortable with this method, the intention is to move the limit states requirements into the body of the standard".

11) It should be noted that in my last statement I mentioned "levels of reliability" whereas in my previous statement, before the quote, I mentioned "probability of failure". How are these terms related? Quite simply, the probability of failure is one minus the level of reliability or in terms of reliability, the level of reliability is one minus the probability of failure. This explicitly means, that for the design of new pipelines, using the CSA limit states design appendix, Appendix C of Z662, that since the probabilities of failures are explicitly defined, and since it can be assumed that we can readily ascertain the consequences from our present knowledge and understanding, the risk associated with a segment of a new pipeline design can be determined explicitly. Furthermore, since all pipelines experience various degrees of time-dependent material degradation, as demonstrated by the number of failures occurring in connection with aging pipelines in Canada, even though relatively few, we can therefore conclude that all pipelines or all segments of pipelines are subject to :

- a decreasing level of reliability;
- an increasing probability of failure; and finally
- an ever increasing level of risk!

12) Since, in an ideal world, as alluded to yesterday by Rob Power, the goal of the pipeline industry would be to experience no pipeline failures, then the incident data base would become nonexistent. This would result in a situation where the magnitude of the risk cannot be determined from the risk equation based on incident statistics. This, then further means to the pipeline industry that they are ensuring and are maintaining the level of reliability of every part or segment of the pipeline above that which would represent failure, that is, 10° which is equal to 1. In reality, this implies that the pipeline industry has developed and implemented "Pipeline Integrity Maintenance Programs" (PIMP's) which ensure reliability levels at any location along the pipeline are being maintained somewhere between the design target levels of reliability and above the reliability level, at which represents failure of the pipeline.

13) So, in conclusion, I would suggest that our challenge at this workshop and for some considerable time to come in the future will involve activities which address and integrate all of the factors associated with "Managing Pipeline Integrity" by implementing "Pipeline Integrity Maintenance Programs" (PIMP's) which maintain reliability levels of in-service pipelines as close as is practical to the "target levels of reliability" provided for or defined in the original design of the pipeline.

Session 4A

Risk Assessment

Risk Management

8:15 - 9:45, Room 251

Your Goal

Identify Areas Where Coordinated Efforts Could be Implemented to Enhance Pipeline Safety, Reliability and Risk Management.

(ID)

What are We Doing in This Session?

- Presenting Controversial Positions
- Participants Discuss Positions
- Participants Make Recommendations
- Prioritize Recommendations

(ID)

Definitions

- **Risk** = Frequency of Failures x Consequence
- **Reliability** = (1.0 - Failure Frequency)
- **Safety** = Acceptability of Risk.

(MZ)

LIST OF PARTICIPANTS

Working Group #4A: Risk Assessment/Risk Management--General

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VALENTINO PISTONE	SNAM
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KEITH CARR	NORTHSTAR / MORRISON
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Lisa-Henri Kirkland	Golder Associates

Ray Smith National Energy Board

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5. Well completion information

6. Temperatures, pressures and production for all wells

7. Fluid compositions; water phase (full water analyses), oil phase (hydrocarbon make up) and gas phase (mole percents of all gases present)

8. Current corrosive nature of fluids determined from existing electrochemical probes or from coupon pulls

Calculated Information

1. Flow velocities for all segments should be calculated

2. Scaling tendencies for all situations should be checked

Field Testing

1. Bacteria survey

2. Oxygen ingress survey

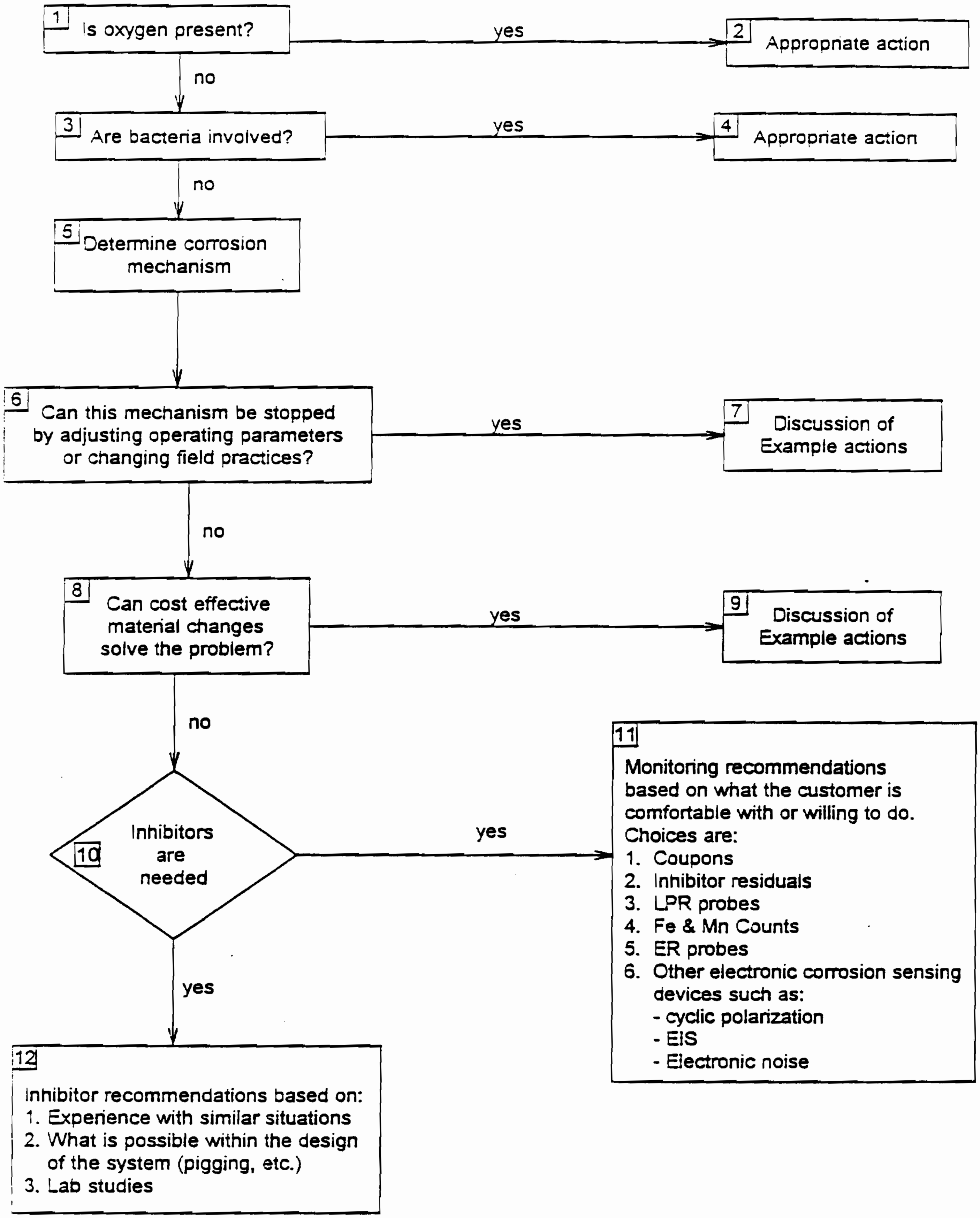
Field Visitation

1. Get to know the specifics of all accessible locations and how to get there

2. Photographs or video footage are taken so that specifics can be discussed with key people not able to become familiar with all aspects of the field.

ATTACHMENT 2

EXAMPLE DECISION TREE



4.2 TRAINING AND CERTIFICATION/INSPECTOR

- Must be an AEC certified installer
- Must be an AEC employee or representative
- Must have completed AEC Pipelines Integrity Program orientation training

4.3 TRAINING AND CERTIFICATION/TRAINER

- Shall have completed 20 Clock Spring installations as a certified installer.
- Shall have demonstrated a detailed understanding of the principles of Clock Spring repair, relevant AEC procedures and C.S.A. code requirements.
- Shall have demonstrated the skills required to effectively present the training material

5.0 CLOCK SPRING USE CONSIDERATIONS AND CONCERNS

- Coating of Clock Spring transition area.
- Extreme pressure fluctuations may result in cracking or disbondment
- Some other nightmare discovered through continued use and evaluation.

Buoyancy Control in Muskeg Terrain

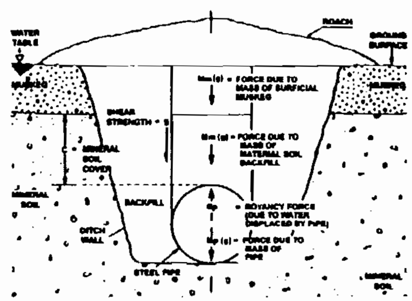
Presentation to Banff /97
Pipeline Workshop
April 16-18, 1997

Lance Thomas, Engineer
NOVA Gas Transmission Ltd.

Buoyancy Control in Muskeg Terrain

New Technologies for Construction

FORCES ACTING ON A SUBMERGED PIPELINE



Factors of Safety

- 5% negative buoyancy for muskeg
- 10% negative buoyancy for streams

Why is Buoyancy Control Required?

- Archimedes Principle:
  - Buoyant Force = Weight of Fluid Displaced

Concrete Pipe Weighting

- Bolt-ons (River Weights)
  - water filled trench
  - if erosion is expected
  - if poor backfill material
  - require extra booms and labour with or without wood lagging
- Swamp Weights (Set-ons)
  - Must dewater trench
  - Excavate with a wheel ditcher Vs. hoe

Muskeg Characteristics

- Covers 1.3km^2 of Canada
- 20% of Alberta
  - most of it north of township 50
- Organic soil
- Consists of surface material - living organic mat of mosses and sedges overlying mixture of partially decomposed material overlying overlying mineral soil.
- Generally the result of a raised water table

Physical properties Important to Pipeline Design

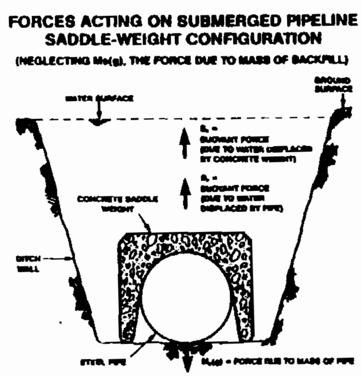
- High moisture content (up to 800%)
- Unit weight as low as 1040 kg/m³
- Variable depth

Mechanical Properties Important to Pipeline Design

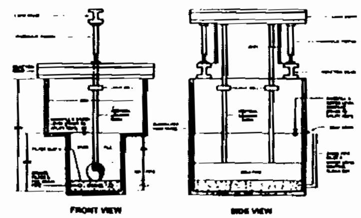
- Shear strength (key component for opposing pipeline buoyancy)
- Compressibility (usually prevents summer construction)

Forces on Pipelines Traversing Muskegs

An example



Test Apparatus



NPS 6 Pipe and Set-on Weight

- Diameter = 168.3mm x 3.2mm w.t.
- Pipe Mass/m = 13kg/m
- Pipe Displacement/m = 0.023m³/m (23L/m)
- Weight = 200kg
- Displacement/weight = 0.089m³ (83L)
- Desired negative buoyancy = 5%
- Weight spacing = 9.6m

Disadvantages

- Either mineral soil or muskeg - does not account for mix
- Neglects mass of backfill material
- Neglect strength of backfill material
- Overly conservative

Shear values were determined using laboratory testing

- Ellwood (1988) used commercial peat moss and mineral soil
- Rizkalla (88) used actual muskeg from the field in frozen, unconsolidated state
- Rizkalla concluded that "significant quantities of mineral soil within surficial organics will increase the density and shear strength of the material"

Results

- Column of soil approximately 1 diameter wide pulled out
- Resistant force varied with peat content
- Resistant force > weight of the soil column

How Much Soil Load Can We Incorporate?

- Failure modes
  - erosion
  - roach failure

Test apparatus

- Typical ditch profile
- NPS 12 pipe
- Plexiglas ends
- Unconsolidated fill
- Varied the ratio of peat from 0% to 100%
- Measured Force versus Displacement

Force due to mass of mineral soil/organic material

- Assumptions
  - mineral soil density = $1640 kg/m^3$
  - muskeg density = $1040 kg/m^3$
  - all muskeg - worst (conservative) case
  - roach is placed level with top of ditch

NPS 6 Pipe with Muskeg/Soil Mixture

- Pipe Mass/m = 13kg/m
- Pipe Displacement/m = $0.023 m^3/m$ (23L/m)
- Soil Unit Mass = $1650 kg/m^3$
- Muskeg Unit Mass = $1040 kg/m^3$
- Minimum Cover = 800mm
- Desired negative buoyancy = 5%
- Minimum mineral soil required = 133mm

Disadvantages

- Need more information from survey
  - muskeg length
  - depth
- Neglects strength of backfill material
- Ineffective for wet ditch
- Does not protect against erosion

Backfill shear strength

- Back calculated from test results (Hill, 1989)
- Lowest ϕ recorded was 28.2°

Advantages

- Can account for mix of muskeg and soil
- Can save or eliminate weights

Mohr - Coulomb Equation

$$\tau = c + \sigma \tan\phi$$

Where:

τ = shear stress
c = cohesion
σ = overburden stress
ϕ = internal angle of friction

NGTL Uses:

c = 5kPa
$\phi = 10°$

Muskeg/Soil Mixture With Shear

- Soil Unit Mass = $1650 kg/m^3$
- Muskeg Unit Mass = $1040 kg/m^3$
- Minimum Cover = 800mm
- Assume $\phi = 10^{o}$, $c = 5 kPa$
- Desired negative buoyancy = 5%
- Minimum mineral soil required = 60mm
- Or else, 200kg weights at 18.4m centres

Disadvantages

- Need more information from survey
  - muskeg length
  - depth
- Ineffective for wet ditch
- Does not protect against erosion

Drilling Program

- Follow clearing
- More easily anticipate water filled trench
- More expensive

Advantages

- Can account for mix of muskeg and soil
- Can account for backfill shear strength
- Can reduce or eliminate weights

Field Weighting Program

- Gouge auger during summer prior to construction
- Order weights ahead of time
- Conduct with engineer survey
- Bolt-on weight requirement difficult to estimate

Conclusions

- Inclusion of shear has decreased the number of weights significantly compared with previous NGTL practice based on rules of thumb.
- NGTL has used $Cu = 5$ and $\phi = 10^{o}$ for the past two years as part of design
  - no floating pipe if roach remains on ditch
  - 0.8m minimum cover

ATTACHMENT 3

BPC'S PREFERRED METHODS OF CORROSION MONITORING

1. **Coupons**

Multi-level coupon arrangements installed at critical and useful locations throughout the system to be protected. The frequency of coupon removal is determined by experience with the system.

Flush mounted coupons are used to monitor the film life of a batch treatment applied between pigs.

Third party companies are used to pull and analyze these coupons and BPC helps its customers design and maintain a data base for trending and historical purposes.

2. **Electrochemical Monitoring (LPR Preferred)**

This measurement is used to determine the relative corrosiveness of the aqueous phase in a system. Probes have to be placed in a spot where only the aqueous phase comes into contact with the electrodes. We like to install them in "fish belly" spool pieces designed for this purpose (examples are provided at the end of this attachment).

BPC considers this type of monitoring to be only relative unless it is benchmarked against coupon performance in the same environment. It does give a relative indication of the corrosiveness of the aqueous phase and how that is affected by an inhibitor. If monitored frequently, these probes can sense corrosive events such as chemical pump failures, finely divided solids slugging through the system, oxygen ingress, or an acid job that has been sent down the flow line.

Reading these probes frequently is essential. Recording the results into a useful data base is equally important. They should be installed at accessible locations or tied into an automatic data collecting system.

A very useful application is in the optimization of an inhibitor program if they are located at a point where water samples can also be obtained. Inhibitor residuals can then be correlated to the probe responses.

3. **Iron and Manganese Counts**

Iron and Manganese concentrations in the fluids. This approach can give meaningful data if the following criteria are followed:

a) Grab samples must be taken using a consistent procedure which always involves blowing down the sample port to free it from accumulated solids.

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b) The actual sample is collected by allowing a known volume to flow through a 0.45 micron *Millipore*™ filter. The pH of the fluid should be noted, it should then be acidified with hydrochloric acid and sent to the lab for dissolved iron and manganese analyses.

c) The *Millipore*™ filter can also yield useful data if it is handled properly. It can also be a fire hazard. Preferably, it is removed from the millipopre housing and placed immediately into a pre-measured volume of dilute hydrochloric acid which is sent to the lab with the water sample.

This procedure will give concentrations of dissolved iron and manganese in the aqueous phase of the fluids and estimates of the iron and manganese containing solids.

Other information can be gleaned from this procedure or a modified one if desired (crystalline nature of the solid on the filter, for example).

Again, religious recording of the results into a useful data base is imperative if trends are to be detected.

4. Downhole Corrosion Monitoring

Downhole corrosion monitoring is not easy, especially when well designs do not incorporate monitoring facilities. Tubing, rod and casing failures are often used by producers to monitor downhole corrosion activity.

Downhole coupons can be installed and subsequently monitored if rods or tubing are pulled periodically for other reasons. Wells can be selected for test treatment and coupons pulled periodically during the test period. Results from these selected wells can be applied to similar wells with good reliability.

Diligent monitoring of solids in the production fluids can also give useful data. These methods are rarely applied. For example, a drum of produced fluids can be collected from a side stream using acceptable safety procedures. These fluids can be diluted and demulsified after which solids can be collected, measured and investigated for corrosion products. This would not detect isolated pitting corrosion but would give data about general corrosion.

Monitoring Solids

Monitoring of corrosion related solids in treatment facilities is an obvious but often ignored indicator of corrosion problems in a gathering system. Field representatives and operators should be trained to note this phenomenon and record qualitative or quantitative observations. Guidelines should be established as to how these results are incorporated into the data base.

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6. **Other Options**

Other Corrosion Monitor Tools

These are many other ways to monitor corrosion in pipelines and process equipment. These can be expensive and usually require diligent interpretation based on assumptions which may or may not apply. BPC is aware of these other methods and can provide assistance to any producer who is interested in using them.

There is much work to be done in this area, especially at a place like Battrum. Both parties need to work together to develop low cost, useful and convenient downhole monitoring methods.

INHIBITOR RESIDUAL MONITORING

Inhibitor residuals are typically monitored by analyzing aqueous phase or oil phase samples for specific components of a given blend. The assumption is then made that all of the components in a product are present in their original proportions; the results are reported on this basis.

There are flaws in this logic. However, this approach has worked well in general and excellent optimization projects have been done. It is the best method available at this point.

Three generally accepted methods are used to measure these specific components, call them "markers".

1. The *wet method* which is based on traditional manipulations such as solvent extraction, "dye pairing" and ultra-violet absorbance. This is labor intensive but is still a useful method; it can be done in the field.

2. *Ultra-violet fluorescence spectrophotometry* is a purely instrumental method that has been shown to give accurate determinations of some water soluble active ingredients. This method is gaining favor in the industry because of the ease with which it can be done.

3. *High performance liquid chromatography (HPLC)* is another instrumental method that may or may not utilize other chemical manipulations. Industry experts agree that this is the best method because the active components are separated from contaminates and other interferences before they are measured. This method is capable of looking at oil soluble active ingredients as well as water soluble ones. BPCI published a definitive work on the oil soluble component measurement. This was disclosed to the public a CORROSION 95 (NACE Conference). This paper is included in Attachment # 5.

BPCI can perform any of these methods in its Calgary Foothills lab. The Houston analytical group is capable of evolving the HPLC method to suit the needs of almost inhibitor residual determination.

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ATTACHMENT 4

BPC's CHEMICAL APPLICATION PROGRAM: CORRTRAX ™

Corrtrax™ has been developed by BPC to manage chemical programs in the field. *Corrtrax*™ is custom designed specifically for any operating unit and can accomplish the following:

- Provide the basis for managing the corrosion control process,
- Identify the critical scaling tendency locations in a commingled production.
- Identify the performance of the fluid separation at different locations in the system.
- Provide a proactive approach, enabling wells and pipeline segments to be grouped or rank ordered based on corrosion or risk characteristics.
- Distribute the chemical program according to the potential risk.
- The program automatically adjusts classifications according to the updated production data. In the situation of a significant production change, *Corrtrax*™ will test the new data against the established criteria (velocity, oil wettability, flow, transition time, and fluid occupation) and will automatically re-classify the production system component.
- Provide us and the customer with an overview of the high risk potential points in the field versus the geographic location on the screen.
- Provide an expedient method of correlating field production parameters to monitoring data.
- Provide a summary report including the cost analysis and performance for all the chemicals applied in the system.
- Correlate the product performance/risk vs. production and cost.
- Calculates the remaining days of chemical inventory and indicates the current field inventory.
- Maintains inventory within predetermined parameters and provides a flagging system based on specific days required, depending on the field location.
- Calculates departure from recommended chemical usage.

Corrtrax™ is developed for each field by a joint effort between BPC and our partner. The main objective of using this tool is to have a cost effective program that is easily implemented, manages the cost and tracks pipeline integrity.

ATTACHMENT 5

CORROSION 9[illegible]

The NACE International Annual Conference and Corrosion Sh

DETERMINATION OF IMIDAZOLINE AND AMIDO-AMINE TYPE CORROSION INHIBITORS IN BOTH CRUDE OIL AND PRODUCED BRINE FROM OILFIELD PRODUCTION

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ABSTRACT

The classical method for the determination of corrosion inhibitors in oilfield brines is the dye transfer method. Within this method are many variations which the analyst may use to determine the amount of corrosion inhibitor in either water or crude oil. These methods, however, suffer from many interferences which result in both false positive and negatives for corrosion inhibitor content. These methods essentially detect all amines as corrosion inhibitors. Improved high pressure liquid chromatography (HPLC) methods have been developed for the analysis of quaternary salt type corrosion inhibitors in brine waters, however, these methods do not appear to work in crude oil or for other forms of corrosion inhibitors such as the imidazolines, and amido-amines.

This paper presents a method for the quantative analysis of the imidazoline and amido-amine type corrosion inhibitors in both oilfield water and crude oil samples by HPLC. The corrosion inhibitor of interest is first separated from the matrix on a small column, then derivatized to form a product which is both sensitive and selective on a fluorescence detector. Detection limits for imidazolines are around 0.2 mg/L, amides and amines are similar. The advantage of this procedure is it can be used to determine the amount of corrosion inhibitor in both oil and brine water phases as well as on solid surfaces.

Flowback data of corros... inhibitors in crude oil from tubing di... acements conducted at Prudhoe Bay are presented. Mass balances are investigated as well as historical treatment times. Oil / Water partitioning coefficients of various inhibitors are examined. Corrosion inhibitor film thickness on coupon data is also examined.

KEY WORDS

Analysis, HPLC, Fluorescence, Imidazoline, Amide, Amine, Partitioning Coefficient, Mass Balance, Tubing Displacement, Film Thickness, Corrosion Inhibitor, Corrosion inhibitor Analysis.

INTRODUCTION

Corrosion engineers have long sought a direct means by which to ascertain whether the proper amount of corrosion inhibitor is present in a system being treated. The usefulness of such a method would be enhanced if it could find the inhibitor in all the places it might be, including water, oil, and on metal and other surfaces. With such a method, rapid improvements in a corrosion mitigation program could be made by adjusting injection points, inhibitor volumes and injection techniques. More fundamental uses of such a technique would include improvement of the formulation of the inhibitor itself, through direct study of phase partitioning, filming, adsorption, desorption and transport phenomena. Combined with corrosion measurements, both in the laboratory and in the field, a direct relationship between the design attributes used to formulate corrosion inhibitors and the actual empirical corrosion measurements could be established. One could envision development of a rational design approach for improved inhibitors, rather than the more typical empirical Edisonian method primarily used today. Finally, there is the desire to be able to quantitatively measure the content of the active ingredients in a corrosion inhibitor formulation for Quality Assurance/Quality Control purposes, which actually was the original priority of this work.

Methods for measuring corrosion inhibitor content in produced oilfield waters have been available for many years. The classical method is by dye transfer whereby the amine complexes with a dye which can then be extracted from water into an organic solvent.[1] The color complex in the organic extract is then analyzed colorimetricaly. This method suffers from many drawbacks. It reports as corrosion inhibitor all amines present in a water sample, not just the species added to control corrosion. The classical method is also limited to analysis of amines in water. Modifications of this method have been adapted to oil soluble corrosion inhibitors but have met with very limited success.[2]

Recently, a method has been published for the analysis of quaternary ammonium salt type corrosion inhibitors by ultra violet spectroscopy (UV).[3,4] This method is superior to the dye transfer method, but is only applicable to quaternary salt type corrosion inhibitors in water. Other refinements have been made on this method whereby a HPLC separation of the sample is employed prior to UV analysis.[5] This modification allows for more accurate analysis of the corrosion inhibitor due to the analyte being separated from the background signals prior to analysis. However, these tests do not work at all on imidazoline, and amido-amine type corrosion inhibitors (amido-amines are defined as amides, amide-salts, amine and amine-salts) in either brine water or crude oil.

The problem of analyzing for amines in complex matrices has faced workers in other disciplines as well. Chen, *et al*, working on analysis of proteins and peptides, described a technique for analyzing amines using a reagent, fluorescamine, which reacted with the amine to form a fluorescent complex.[6,7] This method has been developed as the primary detection method for automated amino acid analyzers which are used for protein and peptide sequencing analysis. The detection limit for the method appears to be 10 ng., according to the work of Böhlen, *et al.*[8,9]

McKerrell and Lynes at Shell discussed a straightforward adaptation of the Chen, *et al* method for analyzing corrosion inhibitor amines in aqueous media using HPLC.[10] Their method, while promising in the laboratory, suffered in practice due to lack of sensitivity (lower detection limit > 25 ppm) and severe interferences with other species present in oilfield waters.

This paper covers a new method for the analysis of imidazoline and amido-amine type corrosion inhibitors in both crude oil and brine water matrices as well as on solid surfaces such as corrosion coupons and production pipe. These inhibitors constitute a large portion of the corrosion inhibitors used today in the oilfield. Examples of these data and their usefulness are shown as well as discussions on their relationship to corrosion rates.

BASIC PROCEDURE

The key to the analysis of imidazoline and amido-amine type corrosion inhibitors is to selectively trap the corrosion inhibitors on a solid phase extraction column while allowing the major portion of the sample (such as crude oil) to pass unretained. The corrosion inhibitor is then derivatized for selective analysis by HPLC. Since this procedure traps the active material in the inhibitor and removes it from the matrix, the detection limit is based on the amount of total sample passed over the trapping medium. Therefore, with a sufficiently large sample size (5-20 mL depending on the activity of the inhibitor) a detection limit of 0.2 mg/L of the active amine can be achieved. This equates to approximately1-4 mg/L as the final corrosion inhibitor depending on the activity of the inhibitor involved. Figure 1 shows the individual chromatograms (1-4) of the corrosion inhibitors discussed in this paper. Since they are all different and quantifiable, the test can be used to determine the amount of active material in a product from a Quality Assurance/Quality Control standpoint. Figures 2 and 3 show the chromatogram of an untreated oil sample and the same sample with 2.3 mg/L inhibitor "A" added. Figure 4 shows a calibration curve for the major amine salt in inhibitor "A". The complete procedure is listed in Appendix I in detail.

Silica gel was found to retain imidazoline and amido-amine type corrosion inhibitors selectively from crude oil. Silica gel traps polar functional groups such as primary amines and other corrosion inhibitors while allowing non-polar compounds to pass unretained. However, removing the corrosion inhibitor from the silica gel once it has been washed free from the relatively non-polar compounds in crude oil was found to be a problem. The corrosion inhibitors have a stronger affinity for the silica gel than any solvents used in attempts to wash them off. The solution to this problem was to convert the corrosion inhibitors to their fluorescent derivatives with fluorescamine while still retained on the column. This destroys the attraction the corrosion inhibitors have for the column, and allows them to be eluted into the methanol used as the solvent for the fluorescamine. The conversion of a corrosion inhibitor to its fluorescent derivative occurs quickly and is quantitative within 30 minutes. The derivatized samples are then injected onto a HPLC for separation and detection using a fluorescence detector.

This separation also allows the analysis of more than one type of corrosion inhibitor simultaneously if the inhibitors are of sufficiently different chemistry that they elute from the chromatograph at different times. Other media for analysis such as brine water, production pipe or solids suspended in crude oil or brine water only require a minor modification of the extraction process for the determination of corrosion inhibitors associated with them. In the case of brine water for example, the trapping medium used is C18 bonded silica gel in the place of the standard silica gel phase.

INHIBITOR ANALYSIS IN PRODUCED OIL

Analyses of crude oil returns of several tubing displacements over a 24 hour or greater period were done to estimate the lifetime of the corrosion inhibitor treatments in the well. Knowing how much corrosion inhibitor returned in the beginning and assuming a decay to a steady state loss, one can calculate the theoretical time until no corrosion inhibitor would be left. These data can be used to estimate when the next treatment is needed and the efficiency of the corrosion inhibitor. Figure 5 shows the amount of corrosion inhibitor "A" (an amine - fatty acid mixture of the macro-film forming type) found in returns after a typical tubing displacement treatment on Prudhoe Bay well 13-04. Inhibitor "A" was found in the produced crude oil but none was found in the produced water. This agrees with the results of partitioning corrosion tests which showed inhibitor "A" had no detectable water partitioning. The data indicate that 64% of the corrosion inhibitor placed in the tubing was returned within the first 26 hours. By assuming a steady state decay and a constant flow rate it was estimated that all the corrosion inhibitor would be removed by the 41st day of service. This result corresponds favorably with observed data from corrosion probes placed on similar wells in the past.

In a separate series of tests designed to simulate a tubing displacement treatment in order to rank the relative performance of different inhibitor candidates, the fluid was sampled during the flowback of a treatment with Inhibitor A on the flowline from well 04-35.[11] Corrosion rates were monitored using five flush-mount Electrical Resistance (ER) corrosion probes, each being read once an hour. The probes were spaced along the 6:00 o'clock position of the 2252 foot (686 m) long, 6" (15.2 cm) diameter, carbon steel flowline. The well's production consisted of 1100 BOPD (175,900 LOPD), 7000 BWPD (1,113,000 LWPD), and 8000 MSCFPD ($2.26X10^8$ m^3/D) gas containing 12% CO_2, with a mixture velocity of 17 ft/s (5.18 mps). This well has a history of aggressive corrosion and erosion-corrosion due to production of solids. The corrosion inhibitor residuals are reported in Figure 6, while the probe metal loss readings are displayed in Figure 7. As was the case in the first example, the initial high returns of inhibitor "A" quickly declined to a very low level. Only about 2 gallons (7.6 L) of the inhibitor returned during this "flush" period. Corrosion was abated entirely on four of the probes for a period of time until the rates dramatically increased, presumably corresponding to the breakdown of the protective film.

If one assumes that the film thickness on the pipe in this test is no greater than the 5 mg/cm^2 *(vide infra)* obtained in the laboratory tests on coupons, then from the rate of inhibitor removal reported in Figure 3, the approximate life of the treatment can be estimated. Assuming that the last measured inhibitor residual concentration after 48 hours represents a constant steady-state value of 2.5 kg/day, the calculated lifetime from this point on is 6.3 days for a total life of about 8-9 days. This compares quite favorably with the actual results obtained on four of the ER probes, as shown in Figure 7. The manifold probe is a special case; it was removed prior to the treatment and the inhibitor fluid was pumped through this fitting. The probe was replaced prior to well flowback, so it was exposed only to the flowback fluid. Apparently, the inhibitor film on this probe was removed more quickly than on the others.

OIL/WATER PARTITIONING

It is important to know how much of a corrosion inhibitor is water versus oil soluble so as to design and use the correct corrosion inhibitor for an application. Also important is to get the corrosion inhibitor into the phase where the corrosivity occurs and to coat the entire surface of the pipe. Inhibitor transport and phase partitioning properties heretofore have only been measured in the laboratory, usually by means of the Kettle or Bubble Test procedure.[12] By being able to measure the amount of corrosion inhibitor in both oil and field water samples, the inhibitor partitioning behavior under actual conditions is directly determined and a mass balance can be calculated. One of the significant drawbacks of the previous residual methods is that only the inhibitor in the water phase could be directly measured, forcing one to assume by difference that the rest went to the oil.[2,3]

It must be noted though, that if the inhibitor is applied as a slug or batch into the pipe and 100% of the corrosion inhibitor is recovered in the fluids, none of it will have been retained by the surface to prevent corrosion. It would be expected that some portion of the inhibitor would be oil soluble, another portion would be water soluble and still another portion would be not recovered at all. The portion not being recovered would be that which has been left behind on the pipe and other surfaces. For inhibitor continuously injected, the pipe wall should become saturated with inhibitor after a time with no further removal from solution, leaving only coating of entrained solids to account for the nonrecovered inhibitor. The entrained solids could be sampled and the amount of inhibitor coating them determined using this method. With a quantitative measurement of the amount of solids being transported a true mass balance between oil, water, transported solids and pipe wall can be calculated.

Two different imidazoline corrosion inhibitors, differing only in the salting and surfactant packages, were examined in nearby producing wells. These wells are known by acoustic solids monitoring to produce formation and other solids, although not necessarily at a steady rate. The amount of corrosion inhibitor found in both the oil and water was determined for both wells over a two day period. Inhibitor "B" was being continuously injected at 15 gal/D (57 L/D) while inhibitor "C" was continuously injected at 16 gal/D (61 L/D). Using the production data and the amount of corrosion inhibitor found in both phases, the percent recovery in oil, water and "lost" corrosion inhibitor can be calculated. Table 1 shows data for these two corrosion inhibitors and the percent of corrosion inhibitor lost to solids or presumed coated on the pipe. These types of data are very useful for determining if a corrosion inhibitor is the proper choice for an application or by pointing the direction for improving the formulation. In the above case, corrosion inhibitor "B" may not be the best choice in multiphase pipelines under particular flow regimes, though it might be an excellent choice for a water line. In either case, it is important to determine the amount of corrosion inhibitor in both oil and brine, so one can determine how much may be deposited on the pipe. Determination of the amount of corrosion inhibitor in only one component, such as brine, will not guarantee that the rest is on the pipe.

MEASUREMENT ON PIPE OR COUPON SURFACES

Another use for this test procedure is to determine corrosion inhibitor thickness on pipe or coupon surfaces. The ultimate question is how much corrosion inhibitor is on the surface to prevent corrosion. This can be determined by immersing the coated coupon or piece of pipe into a methanol solution containing the fluorescamine for derivatization and determining the amount of corrosion inhibitor present. Table 2 shows field data for the corrosion inhibitor thickness (expressed as mg/cm^2 total inhibitor for simplicity) on a string of coiled tubing installed in well 17-15 after a tubing displacement treatment with 55 gallons (208 L) inhibitor "A" diluted with 9 barrels (1431 L) of crude oil and displaced with crude oil at 1 barrel per minute (159 L/min). The details of the procedure used in this test are found in Appendix 2. The 2" coiled tubing was pulled out of the well, (after the treatment and return flow of approximately 100 barrels excess of crude oil) cut up and analyzed. The data indicate that the corrosion inhibitor was for the most part evenly placed throughout the tubing, except at 3025 feet (922 m) where significantly less was deposited. This location corresponds to the point in the well profile where it changes from horizontal profile to vertical. In addition, inhibitor was found all the way down the tubing, while the treatment volumes were designed to treat only down to about 8000 feet (2438 m). This suggests that the inhibitor pill is actually falling down the coiled tubing faster than the pumping displacement rate.

A modification of this technique was to explore various coating methods and determine which best films a steel corrosion coupon (or pipe). Table 3 shows data on one corrosion inhibitor's filming ability (inhibitor "A") at 1% and 10% concentration versus time. Each concentration of corrosion inhibitor was allowed to be in contact with an L-80 coupon for 10 seconds, 1 minute and 10 minutes respectively. Then the coupons were shaken free of the solution, dried and analyzed. These data indicate that the 1% solution coats as well or better over a 1 minute period of time as a 10% solution does in 10 seconds. Therefore, it would be possible to lower the treatment concentration if more time was given for the coating process to take place.

Due to the results from the above study, the effect various carrier solvents have on a similar inhibitor (inhibitor "D", also an amine - fatty acid mixture) was investigated. By changing carrier solvents, it is possible to increase (or decrease) the amount of corrosion inhibtor that can be coated onto a L-80 coupon. Table 4 shows the effect of using kerosene, arctic diesel and degassed crude oil as carrier solvents on the coating efficiency of inhibitor "D". The data indicate the nature of the diluent solvent produces significant differences in the initial film thickness on steel coupons. Exposure time of the inhibitor solution to the metal surface strongly controls the thickness as well. To the extent that greater film thickness is desirable for greater corrosion inhibition, the use of arctic diesel or kerosene as a carrier solvent for inhibitor "D" (and possibly inhibitor "A" due to its similar chemistry) seems to be beneficial, as seen in the results of Table 4. However, actual corrosion inhibition data has not been completed which would correlate these tests to other methods of measuring corrosion rates, therefore, no such conclusion can be made.

CONCLUSION

A procedure has been developed for the quantitative analysis of imidazoline, amido-amine type corrosion inhibitors in crude oil, brine waters and on solid surfaces as well as transported solids. The

SCC WORKING GROUP

- SESSION A
  - ILI FOR SCC MANAGEMENT
    - Companies have used crack detection ILI with good success
    - IPL and Mobil presented their recent findings
    - Found SCC/Fatigue/Shrinkage Cracks accurately or conservatively
    - These companies didn't get a good correlation with soils models and ILI
    - Soils models can be used when ILI is not available or to help in prioritization

SCC WORKING GROUP

- SESSION B
  - SCC INTEGRITY MANAGEMENT PLANS
    - Bob Sutherby presented the CEPA high level plan covering
      - condition monitoring
      - plan and implement mitigation
      - document learn and report
    - CEPA to finalize recommended practices by May 15
    - This will be available to the industry, but cost structure not finalized

Inspection Plans

- When to inspect
  - the number of segments with potential susceptibility
  - relative susceptibility
  - potential consequences
  - document the rationale
- SCC effort should balance need
- Integrated with management of other hazards

Inspection Plans

- Where/ How Much to inspect
  - Priority
  - Total length of that pipe
  - Estimated length of potential susceptibility
  - Possible consequences

Predictive Models

- Soil Models
- In-Line Inspection Data
- Specific Locations - eg. girth welds
- Comparison against systems with known concern

SCC WORKING GROUP

- OTHER ISSUES
  - If we have ILI data do we need to collect soil and water samples?
  - Can soil/environmental conditions be standardized to help small companies?
  - How do smaller companies develop a plan?
  - What is the need for such a plan for EUB regulated upstream companies?
  - What's the difference between gas and liquids transmission companies?
  - Why do some companies get SCC an corrosion and others only corrosion?

SCC WORKING GROUP

- RECOMMENDATIONS
  - Develop a protocol for use of ILI to replace hydrotest
  - Disseminate SCC information to small companies
  - Make CEPA Recommended practices readily available
  - Improve methods to help prioritize ILI data analysis
  - Is the CEPA Significant crack guideline too conservative

Prioritize and Inspect

- Prioritize: susceptibility
  - tape before coal tar/asphalt
  - older before newer
  - disbonded coating before intact
  - higher pressure before lower
  - susceptible soils before non-susceptible
- Prioritize: consequences
  - populated before non
  - populated before sensitive?
  - highly sensitive before less

Initial Susceptibility Assessment

- What's potentially susceptible?
  - COATING
    - TAPES (mid-60's to 1980)
    - COAL TAR
    - ASPHALT ENAMEL
    - Certain girth weld treatments (eg. shrink sleeves)
- Non-susceptible pipe
  - monitor developments in industry/system

What should I include in the plan?

- Most operators at Condition Monitoring
- System Inventory
  - What do I own/operate?
  - Location; Length
  - Coatings
  - Construction Year
  - Operating/discharge pressure; MOP
  - Product
  - Data Reliability/Verification

Possible Board Submission

- Pipeline Inventory - spreadsheet
- Initial Susceptibilty Assessment
- Prioritization
- Short Term Inspection Plan - worst of worst sites
- Longer Term Development Plans
- Suggest referencing CEPA Recommended Practices for mitigation

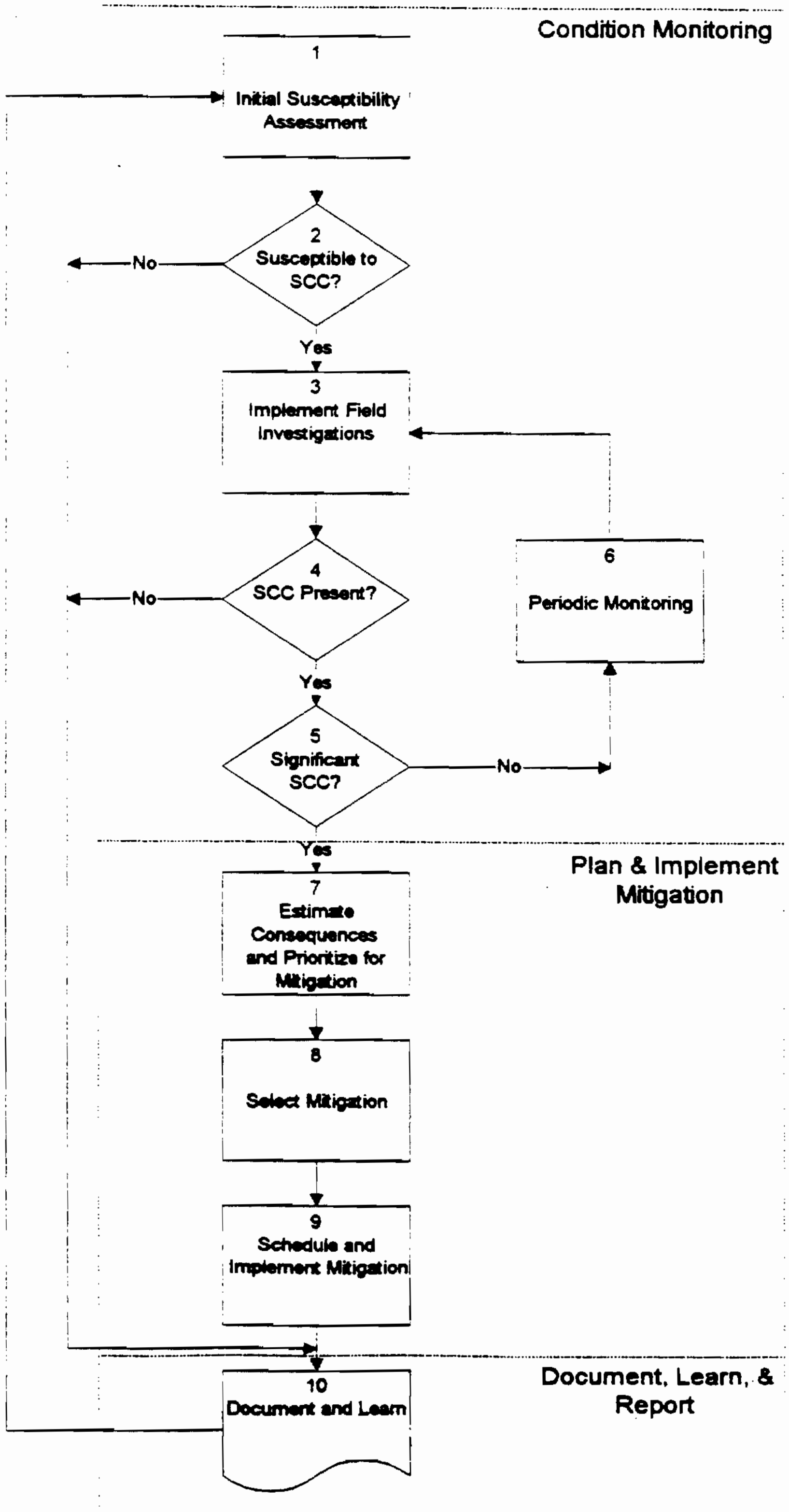
NEB REQUIREMENTS OF COMPANIES

- Prioritize on basis of probability and consequences
  - predictive models
- Report significant
- mandated sharing of data with CEPA Database

NEB REQUIREMENTS OF COMPANIES

- NEB accepted the CEPA SCC IMP model and philosophy
- Develop and implement an SCC management program
  - determine susceptibility
  - active monitoring (inspection)
  - mitigation and basis of
  - record data and share
- To cover entire system with updating

CEPA SCC Integrity Management Program



Results

- Depth categorization
  - 65% accurate
  - 35% overprediction
    - actual - 21%, 32 % wall; UT >40%
- Defects included the following
  - cracks in localized corrosion
  - cracks in very limited corrosion
  - cracks in longitudinal/valley corrosion

Conclusions & Future

- UT tool run was successful
  - critical to our SCC Mgmt
- Precluding hydrotest following further verification
  - Establish that areas not identified are
    - SCC free or SCC below threshold
- Establish inspection frequency
  - at 780 psi, 6 yrs; at 500, 15 yrs
  - redefine utilizing threshold defect dimensions
    - 30 mm length & 1 mm depth

Results

- Excavation Program
  - all colonies were characterized by
    - corrosion depth, length & location
    - crack colony length, width & location
    - selected colonies were ground (approx. 30% wall)
  - corrosion product analyses
    - XRD & EDS evaluation
  - coating morphology was recorded
  - nearly all sites were sleeved

Results

- Every defect prediction was accurate
  - Location (dist. from GW, degree)
  - Length (within 10%)
  - based on 32 joint excavations
    - 30 joints had cracks w/ various degrees of corrosion
      - nearly 2 to 3 SCC areas in each joint
    - 2 were valley corrosion (sharp edges) with no cracks
  - other colonies in same joint below threshold

Results - preliminary

- Soil Types
  - All were represented
  - Moraine Silt, Clay Till
    - 40%
  - Lacustrine, Clayely
    - 17%
- Drainage
  - Imperfect - 53%
  - Very Poor - 20%
- Topography
  - Level - 73%
- Corrosion Product
  - XRD & SEM EDS
    - nearly 60 samples
    - Iron Carbonate
    - Forms of Iron oxide
    - one sample trace 'S

Background & Status

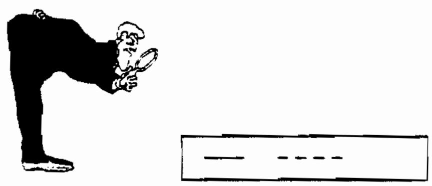
- SCC Management until now was driven by:
  - Fracture Mechanics model
  - Excavation Program
  - Hydrotest
- Inline UT inspection by "Pipetronix Ultrascan CD tool" - 1996
- Excavation Program - 1997
  - evaluate inline inspection
  - preclude hydrotest

Results

- Tool run
  - velocity less than 1 m/s
  - 254 km required 3 separate runs
  - only 100 km analyses completed
- Inspection threshold & results
  - depth > 1 mm; length > 30 mm
  - defect depth categorized by % wall
    - < 12.5, 12.5-25, 25- 40, > 40
  - dist. between cracks < 1mm, is a single colony
  - cracks, general & valley corrosion - various combination

SCC Management - 24" RPL
Impact of Inline SCC Inspection

Barry Martens - RPL
Ravi Krishnamurthy - Mobil
Peter Marreck - RPL



Objectives

- To redefine the SCC management program
  - inline inspection
  - fracture mechanics modeling
  - rehabilitation (sleeves & rewraps)
- Increased reliability of the integrity program

Interprovincial Pipe Line
1996 Line 3 SCC Program

- No significant SCC was found using a combination of ILI, Landscape Model digs and hydrostatic testing
- Insignificant SCC was seen at 7.3% of the total excavation sites, 7.5% of model-predicted susceptible sites and 6.5% of model-predicted non-susceptible sites

Interprovincial Pipe Line
1996 Line 3 SCC Program - Conclusions

- The incidence of SCC on Line 3 is very rare
- For Line 3, the best SCC detection methodology is the use of ILI
- The Landscape Model will be most useful in assisting to prioritize any locations not inspected with ILI where the consequences of failure will be unacceptable.

Interprovincial Pipe Line

1996 Line 3 SCC Program

- 449 joints of 34″ pipe examined for the presence of SCC in 1996
- no significant SCC was found during the excavation program
- 198 km of line, located in the area closest to the SCC-related failure were hydrotested
- no leaks or ruptures due to any cause occurred during the hydrotest

Interprovincial Pipe Line

1996 Line 3 SCC Program

- Line 3 Landscape Model for Edmonton, AB to Gretna, MB identifies 1039 discrete SCC sites
- The total length of pipe in "susceptible environments" is 210 km
- Over 10% of the "susceptible sites" have been excavated and assessed

Interprovincial Pipe Line
1996 Line 3 SCC Program

- Using the Elastic Wave Vehicle, data has been collected on 249 km of 34 inch line
- No SCC has been found on this line using the Elastic Wave Vehicle but cracks from other causes, such as fatigue and shrinkage, have been found using the ILI tool data
- Cracks as shallow as 5% through wall have been found using the Elastic Wave Vehicle

Interprovincial Pipe Line
1996 Line 3 SCC Program

- Failure in Feb '96 attributed to SCC inside severe corrosion
- Three elements of detection program: ILI, Landscape Model Digs, Corrosion Digs
- Hydrostatic testing for verification

14./ Martyn Wilmott (NRTC): Do the CAPP companies have a liability to prove that their pipes are safe to EUB?.
Tom Pesta (EUB): The EUB is working with the NEB and CAPP members at explaining the SCC management to make them aware of the timelines, expectations, etc.

RECOMMENDATIONS:

1./ Develop a protocol for the use of ILI as a replacement for hydrotesting.
2./ Drive to disseminate an understanding of SCC.
3./ Making the CEPA recommended practices readily available.
4./ Improved methods of prioritizing the ILI data due to lack of resources.
5./ Investigate the possibility of crack growth failure due to cyclic stress if they have not been ground out of the pipe. i.e. recoating, sleeving. as a mitigation method.
6./ Is the CEPA guideline for significant SCC too conservative (engineering assessment allowed in CSA may rule this out)
7./ What came first crack or corrosion?
8./ Getting info out to small companies - upstream pipelines by June 98, Dec 97 for downstream to having a schedule for management of SCC.

Ravi Krishnamurthy (Mobil):If we have ILI should look at wether we need to collect water samples, corrosion deposits. Is this sampling necessary for upstream companies, or should we just identify wether we have SCC.

Jim Burke (NOVA): Are environmental conditions standardized and identified for the small companies to use.
Bob Sutherby (NOVA): Smaller companies may not have the personnel and depth - how can we simplify the priorities? -They can use the recommended practices developed by CEPA.

Bob Sutherby (NOVA): I don't see a problem with grinding out all the cracks, although a new coating over superficial cracks will prevent them from growing. Practically it may be difficult to grind all cracks. Watch out for further fatigue growth of the crack.
Mark Spencer (Magi Eng.): Cracks are not allowed because the metallurgical defect remains. The susceptibility remains for further propagation. Recoating may make it potentially benign. The regulatory people recognize that SCC is different than the propagating cracks which CSA does not allow.
Bob Sutherby:: Perhaps there is a need to change the CSA code to allow some cracks to be left in.

8./ Alex Petrusev (Union Gas): The problem may be a risk of coating over the environment and allowing cracks to propagate.
John Beavers (Cortest) I don't feel that enough water will be left in a shallow crack to allow continued crack growth to cause a problem
Redver Parkins: It is difficult to remove all the environment except by baking or a vacuum. There is a danger of further propagation. The open circuit potential will not be changed by recoating.
Burke Delanty: (TCPL) With a 5-10 thou deep crack there surely can't be enough liquid left to cause a problem. If the colonies are less than the CEPA definition for a significant crack you should be allowed to recoat. Significant cracks at TCPL are ground or cut out.

9./Don Sinclair(Westcoast): How deep do you grind?.
Burke Delanty (TCPL): Grind within the limits of CSA. If deeper grinding is needed then we add a clockspring.

10./Don Sinclair (Westcoast): How deep do you grind under operating conditions?.
Burke Delanty (TCPL).TCPL always excavates at a 80% of the normal operating pressure for that pipe and then grind to CSA limit
Mark Spencer(Magi Eng.): Would you reduce the pressure from MAOP or maximum operating pressure?.
Burke Delanty (TCPL). Normal operating pressure refers to that particular pipes highest pressure in the last six months.

11./ Tom Pesta (EUB): Does the term "significant" apply to all line types, grades and wall thickness?.
Burke Delanty (TCPL):Yes as per the criteria stated in CEPA. There is a larger safety factor for smaller diameter lines.

12./ Alex Petrusev(Union Gas): Is any weighting parameter given to operating pressure (SMYS) and coating?. ie. Is a coal tar coated line at 72% more susceptible than a PET line at 60%?
Bob Sutherby (NOVA): Nothing published to distinguish these weighting parameters

13./ Alex Petrusev (Union Gas). What is the first priority that an operator should use?.
Bob Sutherby (NOVA): Coating is the first indicator, then the individual company must prioritize.
Burke Delanty (TCPL): Typically 75% of the SCC found is on tape coated lines. 15%of SCC is found on asphalt. As well the number of colonies on asphalt are five times less than on PET.
Bob Sutherby (NOVA) - For low pH SCC there is a need for ineffective CP under disbonded coatings.
Asphalt coatings deteriorate to allow CP to the pipe. As well in asphalt situations it must be moist underneath the asphalt but not in the ground to allow CP to the pipe. These oppose each other.

magnetic field applied
2nd choice - black on white - no darkness needed
one man crew
documentation is easier.

Discussion:

1./ Harvey Haines (GRI): Why does SCC in Canada occur under tapecoating as opposed to coal tar in USA.
Bob Sutherby (NOVA): Perhaps a function of the type of SCC observed such as high vs low pH. SCC.

2./ Walter Kresic (IPL). How do you decide which method to use to mitigate when you find a crack i.e. grind Vs sleeve Vs recoat.
Bob Sutherby (NOVA): CSA code guides when to grind and to what depth.
Mark Spencer (MAGI Eng.):The method of mitigation depends on the nature of the pipeline, wether it can be taken off-line or not may dictate the type of repair.

3./Sue Miller: When will the CEPA recommended practices be available through the CEPA office? Who are they available to.?
Bob Sutherby (NOVA): Will be available to all members <NEB, CEPA office. Initially 150 copies to be printed. Proposes a list of companies / sign up sheet to receive a copy. They are scheduled to be completed by May 15,1997.

4./ Walter Kresic (IPL): Is there a correlation between crack length and depth?
Bob Sutherby (NOVA): Remote cracks tend to be 1:2 depth to length. Differs for grouped cracks which can be much longer yet fairly shallow.
Redver Parkins: There are few profiles for length to depth ratios for low pH cracks. In early stage we see depth to length ratios of 1:10 as crack growth in the surface direction is more rapid. As the crack grows the depthwise growth increases 1:4. ratios and the crack becomes more semi-circular. As more and more cracks coalesce this leads to an increase in depth to length ratio. This follows a "C" shape pattern.

5./ Walter Kresic(IPL) The conditions that lead to SCC are not the same as the conditions that lead to corrosion.
Redver Parkins: If corrosion is faster than cracking - no cracks. From data available with X52 steel the SCC occurs over certain potential ranges and general corrosion over different ranges for high pH cracking.. Corrosion may be occurring at a different time than the cracking occurs. Pitting may occur before the high pH cracking. For low pH it may be dependent on seasonal variations with the environment causing the cracking or corrosion to occur at different periods.

General and localized corrosion occur at separate times

6./ Bruce Lawson (Westcoast) What was first corrosion or SCC
Redver Parkins: Corrosion occurs first. The corrosion will remove the crack.

7./ Bruce Lawson (Westcoast): Is it suggested that we grind out all the cracks or just significant cracks?.

Prioritize and Inspect

Prioritize: susceptibility
- tape before coal tar /asphalt
- older before newer
- disbonded coating before intact
- higher pressure before lower (potential consequences rather than mechanism)
- susceptible soils before non-susceptible soils

Prioritize: consequences
- populated before non -populated areas
- populated before sensitive?
- highly sensitive before less sensitive environments

Predictive Models
- soil models
- in-line inspection data
- specific locations - e.g. girth welds
- comparison against systems with known concern

Inspection Plans
What/How much to inspect
- priority

- total length of that pipe
- estimated length of potential susceptibility
- possible consequence

When to inspect
- the number of segments with potential susceptibility
- relative susceptibility
- potential consequences
- document the rationale

SCC effort should balance need
-companies which have never seen SCC problems but have other greater problems should integrate SCC management with overall plan .
Integrated with management of other hazards

Addendum:
Field Excavations - Practical aspects - Robert Sutherby

-Sampling the environment
-Remove coating - water blasting (25000-35000 psi)
-Other methods are available - sand blasting - removes deposits
water + baking soda high pressure

-Magnetic Particle Inspection (MPI)
1st choice - wet fluorescence MPI -water suspension + magnetic particles
black fluorescent light is used in dark

Session 2: Development of SCC Management Protocols

Speaker : Bob Sutherby NOVA Gas transmission

CEPA SCC Integrity Management Program

NEB Requirements of Companies
- NEB accepted the CEPA SCC IMP model and philosophy
- Develop and implement an SCC management program
  - determine susceptibility
  - active monitoring (inspection)
  - mitigation and basis of
  - record data and share
- To cover the entire system with updating
- Prioritize on the basis of probability and consequences
  - predictive models
- report Significant SCC
- Mandated sharing of data with CEPA database

Possible Board Submission
- Pipeline Inventory - spreadsheet
- Initial Susceptibility assessment
- Prioritization
- Short Term Inspection Plan - worst of worst sites
- Longer Term Development Plans
- Suggest referencing CEPA Recommended Practices for mitigation

What should I include in the plan?
- Most operators at condition monitoring
- System Inventory
  - What do I own /operate
  - Location/length
  - Coatings
  - Construction year
  - Operating/Discharge Pressure (MOP)
  - Product (consequences /risk)
  - Data Reliability / Verification (coatings etc.)

Initial Susceptibility Assessment
- What's potentially susceptible
  - Coating
    - Tapes (mid 60's to 1980)
    - Coal tar
    - Asphalt Enamel
    - Certain Girth Weld treatments (e.g.: shrink sleeves)
- Non-susceptible pipe
  - monitor developments in industry / system
  - FBE & Yellowjacket seem to be immune - but should be monitored into the future.

station, and everything else. it is the operators responsibility to identify areas of interest and threshold cutoffs (i.e. 50% through wall vs 10% through).

- Mark Spencer: There is a need to help the U/S producers in developing an SCC management program.

cracks should initiate first in such lines; the wrinkling problem should be same as with gas lines. The problem must be more environmental/regional driven.

21. Walter Kresic: did Mobil do any correlation with loading regime?
Ravi Krishnamurthy: not really - it is hard to quantify loading history at a particular point on the line (Sue concurs).

22. Stan Wong: Is there any correlation with SCC and type of CP system?
Sue Miller: in southern Ontario into Quebec, we have normal remote beds, no distributed beds.
Burke Delanty: TCPL have both remote and distributed - don't think CP has any effect as most SCC has been on tape lines
Alex Patrusev: Union has found no correlation, shielding negates the effects of CP.

Ravi Krishnamurthy: Is there the same crack morphology in the east as in the west? Sue Miller: More cracks associated with corrosion in the west than in the east.

23.Martyn Wilmott: Can Pipetronix -is there any correlation between cracking and inclusions.
Herbert Willems (Pipetronix): inclusions must be longer than our criteria of 30 mm; no correlation between inclusions and SCC.
Bruce Lawson: can Pipetronix detect circumferential cracks?
Herbert Willems: The tool is designed to detect axial cracks, not circumferential.

24. Mark Spencer: Is there a correlation with stress levels i.e. low elevation with SCC, or distance to pump station for liquid lines?
Ravi Krishnamurthy: Mobil found defects even at low pressure it doesn't seam to correlate with pressure.
Sue Miller: IPL used pressure to prioritize for looking for SCC ; we did not look (back in 89) at < 30% SMYS. Saw minor SCC at 35% SMYS. Weak correlation if any.

25. Jake Abes: why does Rainbow pipeline have more SCC than IPL other than differences in regulation?

Sue Miller Main difference on the Rainbow line was that cracking is right at 6 o'clock; whereas with IPL the cracking is usually at 3 or 9 o'clock. Type of terrain is very different: muskeg to compacted clay.
Ravi Krishnamurthy: I speculate construction practices may have caused these differences.
26. Martyn Wilmott: What is the turnaround time for ILI data?
Ravi Krishnamurthy: 6 weeks after had data for 100 km.

CONCLUSIONS
- Bruce Dupuis: identify to CEPA a requirement for trending on correlation of corrosion and SCC on regional basis.
- Clive Ward: collection of the data is becoming easier - but there is a resource issue to analyze the data. BG is asking industry to help analyze data using coating or soil models to prioritize locations first to aid in the analysis.
Sue: interpretation of data from crack tools requires very specialized level of analysis, where resources are limited. Need to identify priority: i.e. longseam, certain distance D/S from pump

13. Alex Petrusev (Union Gas) Is there any correlation between side bends and cold bends and SCC?;
Susan Miller: they did find some correlation between NAEC and cold bends (LS at 3 o'clock) in initial studies - but have concluded since then that there is no correlation.

14. Bruce Lawson: did IPL have problems with stringers like TCPL?
Susan Miller: we probably have some noisy joints, but the pipe is fairly acoustically clean.
Clive Ward (BG): every pipeline is different; the stringers need to be aligned in a certain way to cause problems.

15. Clive Ward: Is there an association between SCC and metal loss. The Inquiry said there was no correlation, but this morning seams to suggest that a correlation does exist? Ravi: Mobil have always stated that SCC/corrosion has always been a problem. The Pipetronix tool is designed to discriminate between inclusions and SCC.

16. Jake Abes: There is a move away from hydrotesting and towards ILI, what is needed to confirm the reliability of ILI?
Susan Miller: we're there, how do we convince YOU?!
Ravi Krishnamurthy: There are three to four years of correlations. More excavations are planned to identify non critical cracks to ILI data. We are close but not there yet.

17. Mark Spencer: have you excavated any sites where the tool said there were no indications, but soils models indicated that the site was susceptible to SCC?
Ravi Krishnamurthy: Most of the soil is susceptible on the Rainbow Line.

18. John Beavers: corrosion vs no corrosion in near neutral SCC, maybe there is a fundamental difference between liquids and gas liquid lines there is more association with corrosion in gas lines there is a 50/50 chance of corrosion plus SCC.
Sue: evidence on these differences and enough data is not presently available to make that distinction. IPL and Mobil work may help show this.

Bob Sutherby: Corrosion and SCC? at NOVA we have seen a failure from SCC and corrosion; this year we found SCC and corrosion during a MFL inspection/clockspring excavation which was significant. This may be a northern Alberta problem. Most of NOVA SCC has been very shallow <5%, but the problem that has resulted in rupture is SCC plus corrosion.

Alex Patrusev (Union gas) We have never found SCC within corrosion in Northern Ontario.

B. Delante, TCPL: Of the 700 SCC excavations at TCPL most SCC found is not associated with corrosion. We have seen some corrosion with SCC, but not significant wall loss which would be picked up by ILI tools. most of TCPL's problems have just been SCC.
Typically have seen corrosion in well oxygenated soils which are not really SCC conditions.

19. Martyn Wilmott: Can MFL tools be used to prioritize for SCC locations?
Bob Sutherby: in certain circumstances MFL tools are good for showing areas of coating disbondment.

20. Martyn Wilmott: should you use a soils model in conjunction with an MFL tool? Ravi Krishnamurthy: seems it is regional; with liquid line there is more cyclical loading, Therefore

3. Sue Miller (IPL): Has Mobil done any correlations of cracks in corrosion versus SCC out of corrosion?
Ravi Krishnamurthy: Majority of cracks, severe cracks, are typically found in corrosion; did find one SCC feature >40% through wall, outside of corrosion as well.; typically haven't found a correlation with corrosion.

4. Bruce Lawson (Westcoast Energy): Is Mobil planning on doing a hydrotest?
Ravi Krishnamurthy: No, shouldn't have to.

5. Bruce Lawson (Westcoast Energy): Has Mobil cut any of the large cracks out?
Ravi Krishnamurthy: No, the cracks were not that critical, so there was no need for cutouts.
Bruce Lawson (Westcoast Energy): Reason for the prior question is that the PRC has a program to determine criteria for SCC in corrosion- samples would be useful

6. Bruce Lawson (Westcoast Energy): What criteria did Mobil use to dig the cracks?
Ravi Krishnamurthy: Within the 100 km, each area was looked at separately: had 33 km not hydrotested, 33 km low pressure, 33 km which would be hydrotested. Small defects will be left for the rehabilitation program (recoat over the next few years)

7. Bruce Lawson (Westcoast Energy): Does Mobil think the length and depth accuracy is good enough to be confident to calculate growth rates if dug out 2-3 years later?
Ravi Krishnamurthy: No, not enough accuracy. Their general excavation programs in the future will be 6-12 years, should be enough growth to see.

8. Martyn Wilmott (NRTC): Are there any gas companies with experience in using the BG tool?
Trevor McFarlane (TCPL): TCPL has run the BG tool in 300 km of pipe; we have unique difficulties in using the tool: the pipe was constructed in 1972; the steel has lots of stringers that generate reflectors, therefore it was hard to distinguish between benign defects and SCC; have found 3 significant SCC flaws (one in 94, two n 95); subsequent hydrotesting following the runs passed.

9. Bob Eiber (consultant): How did Ravi (Mobil) establish the criteria for their re-inspection interval?
Ravi Krishnamurthy: Using crack growth rates which were a function of J as discussed in my International Pipeline Conference (IPC) 1996 paper.

10. Bob Eiber (consultant): Ravi, please comment on the inclusion issue?
Ravi Krishnamurthy: One site they didn't grind - found lot of inclusions behind SCC; their pipeline is pretty dirty.

11. Bruce Lawson (Westcoast Energy): Can the tool pick up corrosion without SCC?
Ravi Krishnamurthy: The tool is not designed to do this, but it has picked it up by chance.

12. Mark Spencer (Magi Engineering LTD):can you expand on the fracture mechanics model-and how to handle corrosion & SCC?
Ravi Krishnamurthy: assumed infinite crack in a cylinder & added corrosion depth.

Results:

- all defect predictions were accurate (32 excavations)
    - location (from GW, o'clock)
    - length (within 10%)
- for 32 joint excavations:
    - 30 joints had cracks with various degrees of corrosion
    - nearly 2 to 3 SCC areas in each joint
    - 2 were valley corrosion (sharp edges) with no cracks
    - other colonies in same joint below threshold
- depth characterization
    - 65% accurate
    - 35% overprediction (conservative)
- defects included cracks in: localized corrosion, very limited corrosion, longitudinal/valley corrosion

Preliminary results:

Soil types:	Moraine silt, clay till (40%) Lacustrine, clay (17%)
Drainage:	imperfect 53% very poor: 20%
Topography:	level 73%

Conclusion:
UT run was successful, critical to future SCC management plans
Precluding hydrotest following further verification
    establish that areas not identified are SCC free or SCC below threshold
Establish inspection frequency
    - at 780 psi, 6 yrs; at 500 psi, 15 yrs
    - redefine utilizing threshold defect dimensions: 30 mm length & 1 mm depth

QUESTIONS:

1. Dave Britten (IPSCO): what was definition of significant SCC versus insignificant SCC?
Sue Miller: We use the CEPA definition which is very generous and allows for several years of operation.

2. John Craig (Pacific Northern Gas): what was the weld type on the IPL Line 3? What was the condition of the tape coating, considering it was a primerless tape?:
Sue Miller: weld type was DSAW; there was natural tenting over longseam in areas of narrow axial external corrosion (NAEC); tape in area surrounding the longseam was in pretty good condition (good adhesion).

==

In-Line Inspection for SCC Management Ravi Krishnamurthy, Mobil Oil Canada

:

"Impact of Inline SCC Inspection: 24" Rainbow Pipeline System"
Experience Using the Pipetronix Ultrascan Tool

Objectives:
To redefine the SCC management program
- ILI
- fracture mechanics modelling
- rehab (Sleeves and rewraps)
Increased reliability of the integrity program

SCC management until now was driven by:
- fracture mechanics model
- excavation program
- hydrotest

ILI UT inspection using Pipetronix Ultrascan CD tool
Excavation Program - 1997
- evaluate inline inspection
- preclude hydrotest

RESULTS:
Tool run:
- velocity less than 1 m/s
- 254 km required 3 separate runs
- only 100 km of analysis completed

Inspection threshold & results:
- depth greater than 1 mm; length greater than 30 mm
- defect depth categorized by % wall: <12.5, 12.5-25, 25-40, > 40
- distance between cracks < 1 mm, is a single colony
- cracks, general & valley corrosion - various combination
-
Excavation program:
- all colonies were characterized by:
corrosion depth, length & location
colony length, width & location
selected colonies were ground (approx 30% wall)
- corrosion product analysis: XRD, EDS
- coating morphology was recorded
- nearly all sites were sleeved (after grinding)

SESSION A and B
Working Group #2

STRESS-CORROSION CRACKING

procedure has a detection limit an order of magnitude below that previously reported. The procedure has the following advantages over previously reported methods:

1. The method is applicable to a large variety of inhibitors which have not been well quantitated previously.
2. The detection limit of the method is based on the sample size used. With the proper sample size, a detection limit as low as 0.2 mg/L as the active inhibitor can be achieved. This equates to approximately 1-4 mg/L (or ppm) as the corrosion inhibitor package commonly used (depending on the dilution of the active inhibitor with the other parts of the corrosion inhibitor packages).
3. The method allows for field sampling and laboratory testing at a later time or different location.
4. The method is relatively quick to complete, on the order of one hour or less.
5. More than one corrosion inhibitor can be distinguished at once depending on their chemistries.
6. The method has many applications other than residual monitoring, which may be more important then the residual analysis alone.

Examples of uses other than residual analysis for this procedure are as follows:

1. The original purpose was as a Quality Assurance test for corrosion inhibitor manufacturing. This still is an important potential use of the test method.
2. Determination of oil / water partitioning coefficients to optimize inhibitor applications.
3. Determination of optimum application times and concentrations.
4. Measurements of corrosion inhibitor quantities on treated coil tubing or other surfaces.
5. Measurement of corrosion inhibitor loss to produced or transported solids.
6. Development of corrosion inhibitors based on optimizing coupon filming thickness.

Other uses for this test procedure can be developed. The above shows only the obvious uses based on the data produced in this paper. The relation of corrosion inhibitor quantity based on this analytical test versus corrosion inhibitor performance on other tests such as RCE, bottle tests, and field performance is still lacking. This will be the next aspect of the usefulness of this test that will be investigated.

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APPENDIX I

HPLC METHOD FOR THE ANALYSIS OF IMIDAZOLENE AND AMIDO-AMINE TYPE CORROSION INHIBITORS IN CRUDE OIL

EQUIPMENT NEEDED

1. High Pressure Liquid Chromatograph capable of pumping 2.0 mL per minute at 2000 psi or better. Solvent programming is not necessary.
2. Fluorescence detector capable of excitation at 278 nm and detection at 476 nm.
3. Small secondary pump for circulating 10 mL per minute over a solid phase extraction cartridge at less that 500 psi.
4. C-18 reverse phase HPLC column 3.9 mm X 300 mm 4 micron particle size.

REAGENTS NEEDED

1. Fluorescamine, analytical grade
2. Methanol, HPLC grade
3. Ortho-Xylene, HPLC grade
4. Water, HPLC grade
5. Disposable Silica gel cartridge type sample preparation column (for oil samples).
6. Disposable C-18 cartridge type sample preparation column (for water samples).

I. PREPARATION OF STANDARDS

1. Make up a series of standards of the corrosion inhibitor to be tested at levels of 4 - 200 mg/L in o-xylene. If the solutions are cloudy small amounts of methanol or chloroform may be added to insure solubility of the standards. A minimum of four standards is recommended.
2. Syringe 5.0 mL of the prepared standard onto the silica gel column, followed by 30- 50 mL o-xylene and 10-20 mL methanol.
3. Place 2 mL of a 2 mg/mL fluorescamine in methanol solution into a 10 mL volumetric. Add approximately 7 mL methanol to this and attach to the recirculating pump with the disposable cartridge containing the standard on it in line with the pump in such a manner as to circulate the methanol solution over the cartridge, into the volumetric and back through the pump. Circulate this solution over the cartridge for 30 minutes.
4. Pump all the solution into the volumetric and bring up to volume with methanol.
5. Inject 25 microliters of this solution onto the HPLC.
6. The peaks found in the standards are plotted versus concentration for all the standards. Example Chromatograms are shown in Figure 1. Calibration curve for inhibitor "A" is shown in Figure 5.

II. HPLC CONDITIONS

1. Solvent system is dependent on the corrosion inhibitor being examined. A good starting point for amines and most imidazolenes is 95% methanol and 5% water.
2. Flow rate should be 1.5 mL per minute.
3. The detector used is a variable wavelength fluorescence detector with the excitation set at 278 nm and the emission being observed at 476 nm.

4. Under these conditions all peaks of interest elute in 3-7 minutes as imidazolenes. Amines elute between 9 and 20 minutes as seen in chromatograms 1 through 4.

III. SAMPLE ANALYSIS

1. 5 mL of the crude oil is dissolved into 100 mL o-xylene and placed into a silica gel cartridge in the field. Excess o-xylene and methanol may be washed over the column in the field if desired. A silica gel cartridge that has had the corrosion inhibitor deposited on it is stable for months in the laboratory without being analyzed.
2. In the laboratory, wash the cartridge containing the sample with at least 50 mL o-xylene and 30 mL methanol. If color bodies are still eluting, continue the wash until no more color can be removed.
3. Place the cartridge into the recirculation pump system as described in section I above and inject onto an HPLC as indicated.

IV. ANALYSIS OF CORROSION INHIBITOR IN WATER

The analysis of corrosion inhibitors in water is similar to the analysis in oil with the following changes:

1. In place of silica gel cartridge use a C-18 cartridge. The sample is washed onto the cartridge followed by an excess of DI water.
2. Return to section I step 3 in the preparation of the standards.

V. ANALYSIS OF CORROSION INHIBITOR ON THE SURFACE OF PIPE OR SOLIDS

The analysis of corrosion inhibitors on solids or pipe is done with the following changes:

1. To accomplish this analysis the sample is treated as if it were the Silica gel cartridge.
2. The methanol containing fluorescamine is increased to 2-5 mL depending on the final volume needed.
3. Place the piece of pipe, or solids into a small beaker and add enough fluorescamine solution to cover the sample completely.
4. Using the pump described in section I, circulate the solution over the sample for 30 minutes then bring up to a specific volume and inject onto an HPLC as indicated.

APPENDIX II.
COILED TUBING INHIBITOR TUBING DISPLACEMENT TEST

Test Objective

The purpose of this test is to determine what sort of inhibitor film is left after a tubing displacemen (TD) inhibitor treatment, and how that film varies with depth in the string. Samples of the tubing will be removed at intervals along the tubing string as it is pulled and the film on the metal will be analyze: and measured at each of the locations. The well will be converted to injection after the coiled tubing is pulled.

Backround

The 17-15 well was originally designed as an injector well, but a long term production test of the Sag formation in the area was desired. The well was completed with 10,250 ft of 2 3/8" of coiled tubing inside of the 4.5 tubing which was connected to the flowline for the production test. The coiled tubing had four gas lift mandrels attached to assist lifting the well. Prior to pulling the coiled tubing at the termination of the production test, this corrosion inhibitor test was performed to gather data on the nature of filming of the TD inhibitor in a downhole environment.

Well Data
SBHP: 3650 psi @ 8800' TVD
SBHT: 195°F
Tubing: 4.5", 12.6# L-80, with 2 3/8" coiled tubing inside
Coiled tubing/ casing volume to bottom perfs @ 10449' = ~52 bbls.

Procedure:

1. Insure the tubing is open to the Sag Perforations. Bring the well on with gas lift for 4-6 hours to clear the coiled tubing (CT) & tubing and CT annulus of methanol-based freeze protection fluid.
2. Rig up hot oil truck and inject degassed crude oil for ~6 hours. Pump up to 4bpm @ 180 °F, not to exceed 3000 psi.
3. Treat the coiled tubing with a TD treatment consisting of 30 gallons Inhibitor A diluted with 5 bbl of degassed crude oil. Displace the inhibitor slug with degassed crude to bring the leading edge of the slug to within 500 ft. of the bottom GLM. Pump at 0.5 - 1.0 bpm so that the inhibitor slug will be in contact with the pipe surface for 6-10 minutes.
4. Produce the well back down the flowline to the test separator. Circulate ~100 bbls hot oil down the tubing x CT annulus. Pump 1 bpm at 160°F, which is ~35 °F cooler than the bottom hole temperature. This volume will displace the annulus plus 2-3 CT volumes. This will insure enough fluid flows past the inhibitor treatment to remove the excess inhibitor.
5. Take fluid samples for residuals analysis during the displacemnt and flowback.
6. Unload the tubing with gas lift and continue to produce until the CT unit is rigged up. Pump in seawater to kill the well if necessary and pull the coiled tubing.
7. During the pulling operation, cut out ~4 ft. sections of the coiled tubing at each of the following locations:
   - at the surface just below the tubing hanger,
   - at the upper XN nipple (2191' MD)

- at each of the 4 GLM's
  - 3025'
  - 5355'
  - 7806'
  - 10050'

Seal the tubing samples in plastic and transport to the field lab for analysis.

8. Rig up well for injection of seawater.

TABLE 1
OIL / WATER PARTITIONING

Corrosion Inhibitor	Oil Phase	Water Phase	Lost to Pipe
Inhibitor "B"	N. D.	39.0%	61.0%
Inhibitor "C"	12.6%	32.5%	54.3%

N. D. = None Detected

TABLE 2
CORROSION INHIBITOR DEPOSITION ON COIL TUBING

Tubing Depth in Feet (m)	Corrosion Inhibitor Found in mg/cm²
Surface	0.015
2191 (668)	0.008
3025 (922)	0.003
5355 (1632)	0.010
7806 (2379)	0.010
10050 (3063)	0.010

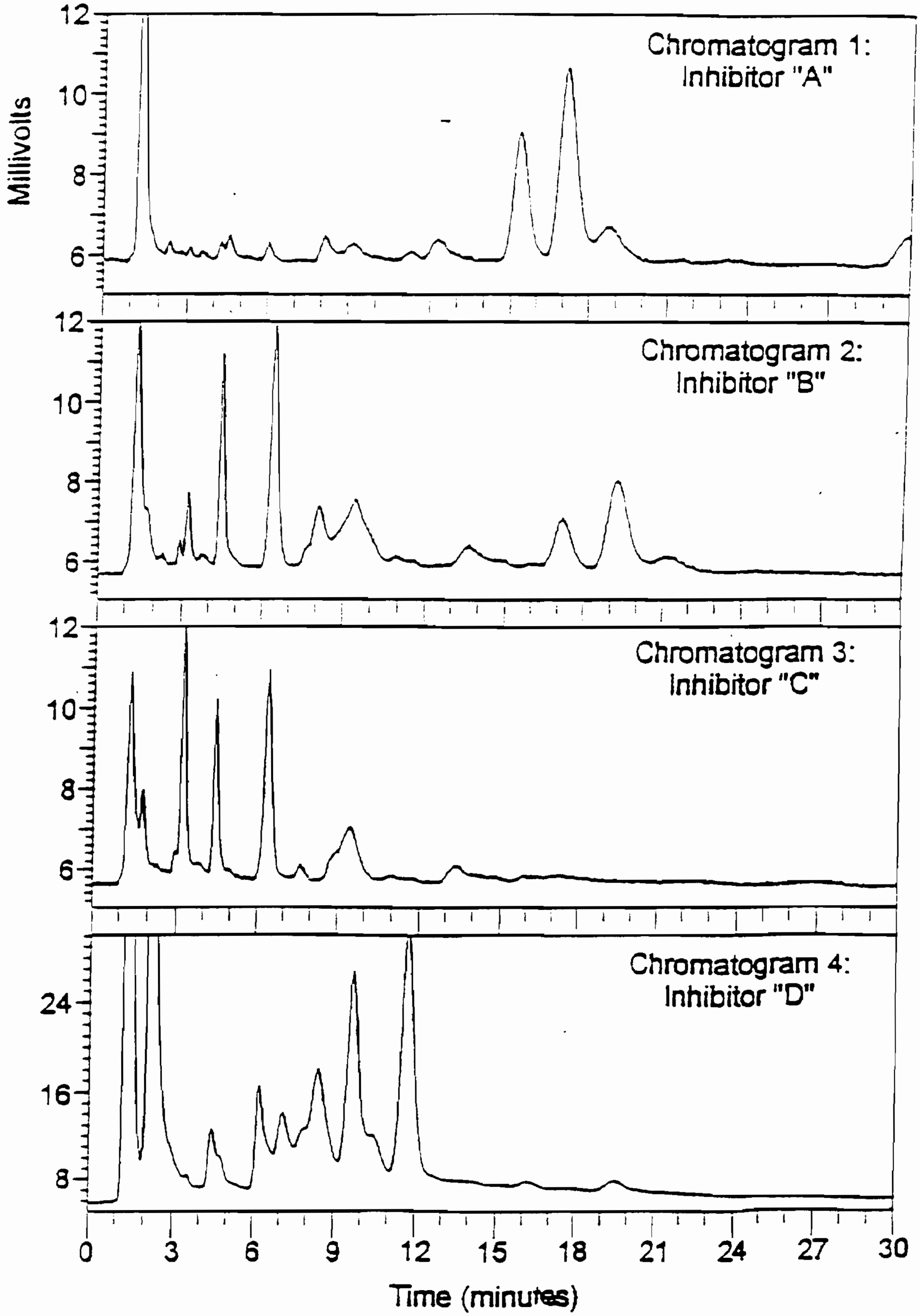
TABLE 3
COUPON COATING TIMES VERSUS CONCENTRATION

Test Discription	Corrosion Inhibitor Found in mg/cm²
1% Solution for 10 Seconds	0.50
1% Solution for 1 Minute	2.13
1% Solution for 10 Minutes	3.88
10% Solution for 10 Seconds	1.99
10% Solution for 1 Minute	4.22
10% Solution for 10 Minutes	5.00

TABLE 4
EFFECT OF CARRIER SOLVENTS ON FILM THICKNESS

	Kerosene in mg/cm²	Arctic Diesel in mg/cm²	Degassed Crude in mg/cm²
1% Solution Dip Time			
10 Seconds	1.76	1.73	0.17
1 Minute	2.70	2.76	0.44
10 Minutes	2.95	3.40	0.51
10% Solution Dip Time			
10 Seconds	2.82	2.35	0.27
1 Minute	4.16	2.60	0.40
10 Minutes	5.00	5.13	1.00

Figure 1
Chromatograms of Various Corrosion Inhibitors



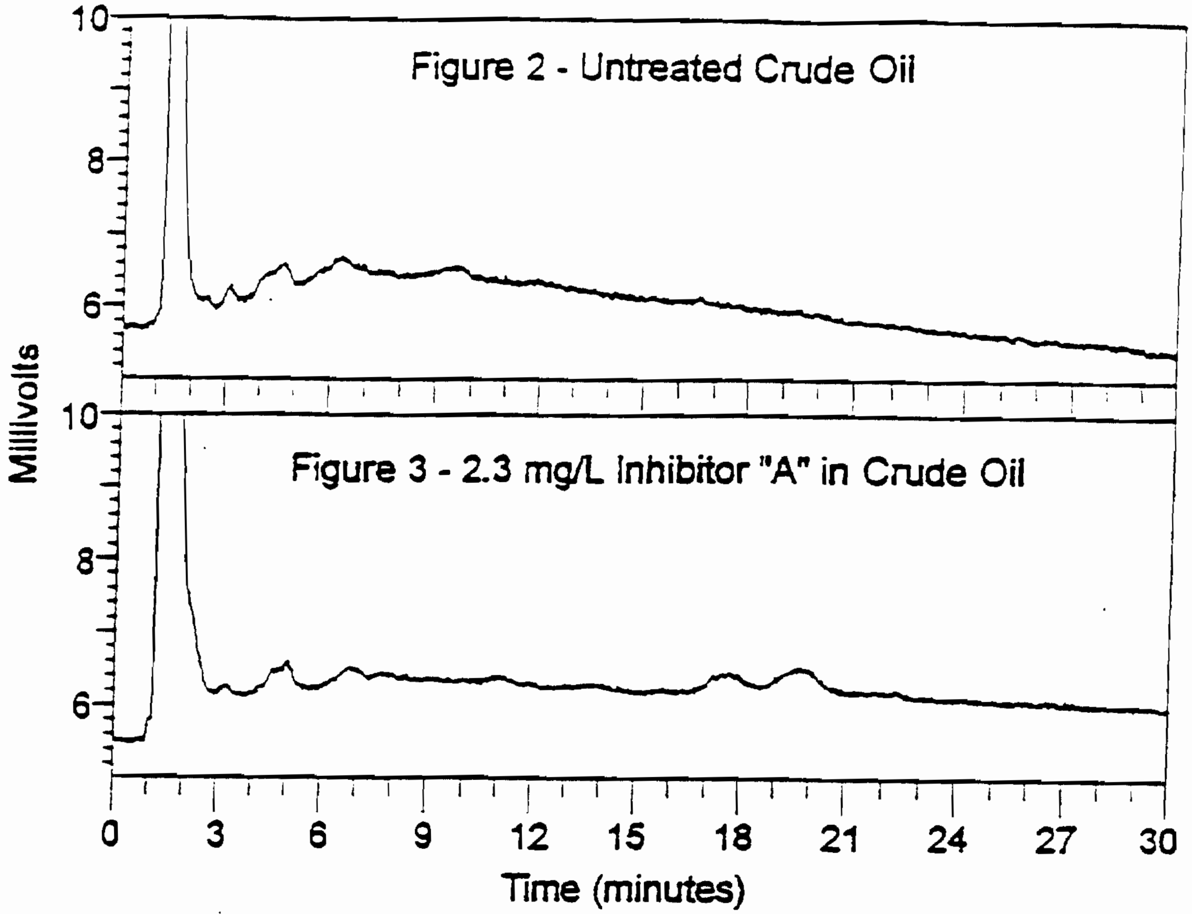


Figure 2 - Untreated Crude Oil

Figure 3 - 2.3 mg/L Inhibitor "A" in Crude Oil

Figure 4
Calibration curve for Inhibitor "A"

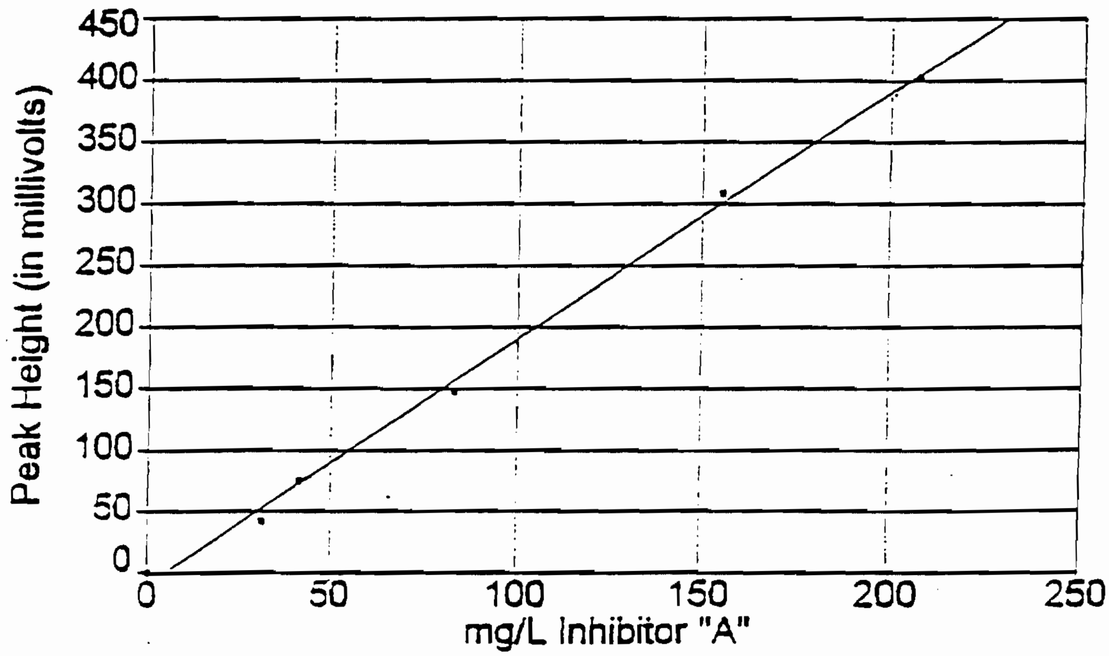


Figure 5

Tubing Displacement of Well 13-04

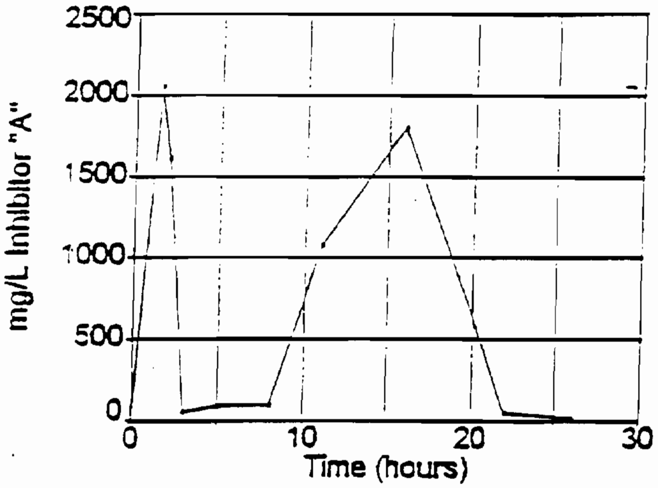


Figure 6

Tubing Displacement of Well 04-35

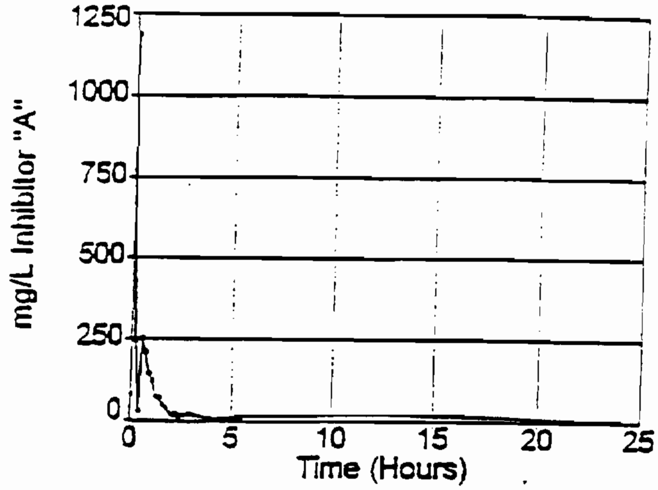
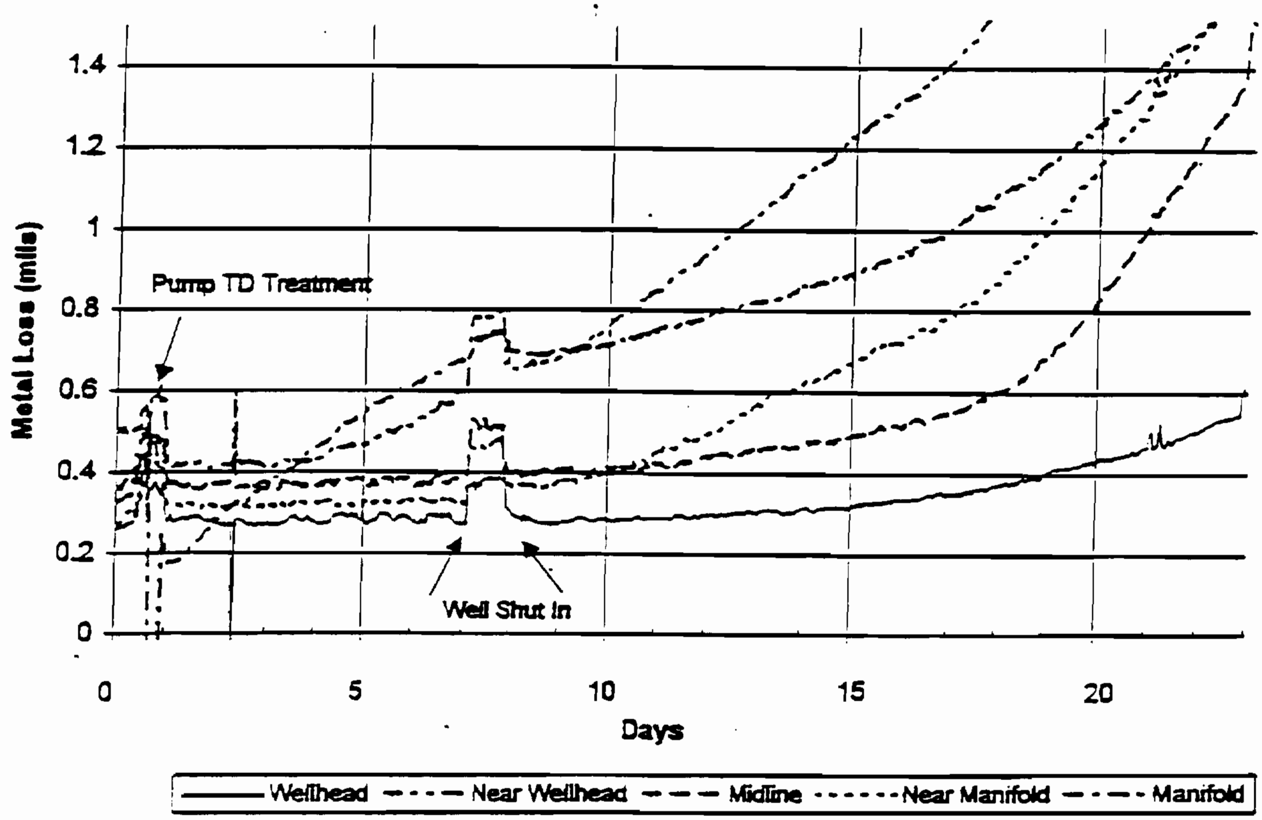


Figure 7

Inhibitor "A" Tubing Displacement Test on DS 04-35 Flowline



SESSION B and C
Working Group #4C

RISK ASSESSMENT / RISK MANGEMENT - TRANSMISSION

RISK ASSESSMENT / RISK MANAGEMENT
TRANSIMSSION
SESSION 4C - MORNING SESSION

Objectives of Session

Want to answer following questions:

- What needs to be done?
- How will it be done?
- Who will do it?

Above objectives outlined by Harry Sambells

General Issues

1) Need to follow up on agenda items of previous workshops that haven't been worked on.

In response to Hugh Allen's question about why items brought up in previous workshops have not yet been addressed. For example, some of PRASC's objectives.

2) Need to be more clear about "acceptable risk". Is it "what you have to do" (regulator's perspective) versus "what do people actually do" (industry perspective).

Comment by Keith Leewis; not really followed up on, but in response to terminology that appeared on slides.

3) General confusion regarding PRASC w.r.t. database and standards.

Canadian Western Nat. Gas, question was "what is the point of the PRASC database? Is it for qualitative or quantitative data collection?

Hugh Allen asked who PRASC was, and responded that PRASC is industry steering committee. Shouldn't / Doesn't put data together but just guide discussion w.r.t. risk standard.

4) Need for another group to look at risk standard issues.

Bruce Dupuis suggested that we need another committee, besides PRASC, to meet the detail levels required for setting risk standards.

Canadian Western Natural Gas suggested a CEPA like committee because we seem to have a steering group now, but without an actual working group.

Bruce Dupuis suggested that we need to candid discussion, possible with a working group that would be primarily for <u>information exchange</u>.

5) SCC is definitely <u>not</u> the most important issue but maybe is the most current issue.

Above comment by Hugh Allen.

Blaine Ashworth, responding to questions about the NEB SCC Report, commented that there are other integrity issues besides SCC, but they are scheduled to be examined in the future to look at other failure issues.

6) Regulatory boards want to continue "consultation" type process, but, without industry input, process becomes mandatory rather than consultative.

Above comment by Harvey Sambells in discussion following report on CSA Appendix; unless this group does it, someone else will do it for you. (We may not like that!)

Risk Standards

1) "Risk Standards" in CSA Z662, R.M. process section
   - need more focus
   - should tools be qualitative or quantitative

Canadian Western Nat. Gas, question about whether PRASC would provide us (industry) wit qualitative or quantitative tools?

Need better tools, but PRASC is not necessarily the best vehicle to develop specific tools.

Valentino Pistone unhappy with current mechanistic tools/models; one item that needs a lot of attention is development of better mechanistic tools that address how we affect safety /risk when we change operating procedures.

What is the method/vehicle group to focus on risk standards and who develops these standards.

Hugh Allen (NWU) asked whether this group in particular should be setting risk standards?

Led to 'challenge" points:

We should develop risk standards! (how and who to be determined)
Who? Appendix B Working Group
PRASC
full matrix participation by stakeholders
6 - 12 members

Hugh Allen (NWU) - maybe we should also see what producer's group has done?

Databases

1) Need integration.

Point reiterated several times is that we need to ensure that we are maximizing our utility of the data collected.

Canadian Western Natural Gas - when looking at site location data in particular, want to make sure we're not duplicating for CEPA or PRASC. Make sure data transfers are easy.

RISK ASSESSMENT / RISK MANAGEMENT
TRANSIMSSION
SESSION 4C - AFTERNOON SESSION

IPL CASE STUDY: INCIDENT REPONSE CASE 1 (Corey Goulet)

General Questions / Comments

What was inspection criteria?

For high resolution detailed data, criteria was to dig for any defect that had the potential to leak or the possibility of growing within the next five years. (for example, anything deeper than 50% metal loss was dug).

Concern is that eventually the ones that were left in will corrode.

Why two methods?

Magnetic flux leakage (MFL) can find these defects, but it can't determine the wall depth as accurately as ultrasound methods.

What would they have done differently in the process, looking back?

They had such a short time frame, so it was difficult to assess all the options!

They could have reduced pressure and then spent more time looking at options, but didn't have luxury to make that decision.

IPL is not recommending one tool over another! It depends on the particular pipeline and whether or not its appropriate to use two technologies. In this particular case, two tools were useful

TCPL CASE STUDY: INCIDENT RESPONSE CASE 2 (Burke Delanty)

General questions / comments.

What was NEB show cause letter for Vermillion Bay, and what as TCPL response?

Show cause letter focused on show cause whey pressure should NOT be reduced.

Response was that a) sections similar to failed section had been identified and that planned pig run would be adequate.

Was corrosion due to bacteria?

Analysis hasn't been completed yet.

Given environmental conditions (aerated soil conditions) its unlikely to be bacteria.

GENERAL COMMENTS

1) Want tools to be able to assess the affect of managerial decisions on safety and risk?

Valentino Pistone (Italy) commented on European situation, where there are very restrictive pipeline corridors. So, need to be able to show how we can reduce risk in other ways (besides moving pipeline!).

2) What are best practices?

Are we interested in setting limits for acceptable risk and then letting operations decide how they'll meet these standards? (comment by Susan, IPL).

Keith Leewis (GRI) suggested that "best practices" is what we were after, not "risk standards" - overall industry prefers best practices approach to mandatory regulations.

3) SCC working group may have the data.

Overall comment was that we get lots of information from digs and we want to be able to maximize the use of that data (eg: for both PRASC and CEPA databases, data needs to be transferable).

4) Even major companies like IPL and TCPL with their resources have to regroup and re-evaluate their approaches in a <u>short time</u>.

Above comment by Susan (IPL); also suggested perhaps a crisis management type approach when incidents occur.

5) New techniques for new lines.

Paul (Union Gs) suggested that perhaps we need two directions, one for existing pipelines and another, quite different criteria for new lines.

6) Communications versus operations integrity.

How much do you communicate to the public (as an aspect of risk management).

Banff 97
Risk Assessment / Risk Management - Transmission Lines

Risk Assessment - Transmission Lines

Objectives of Session

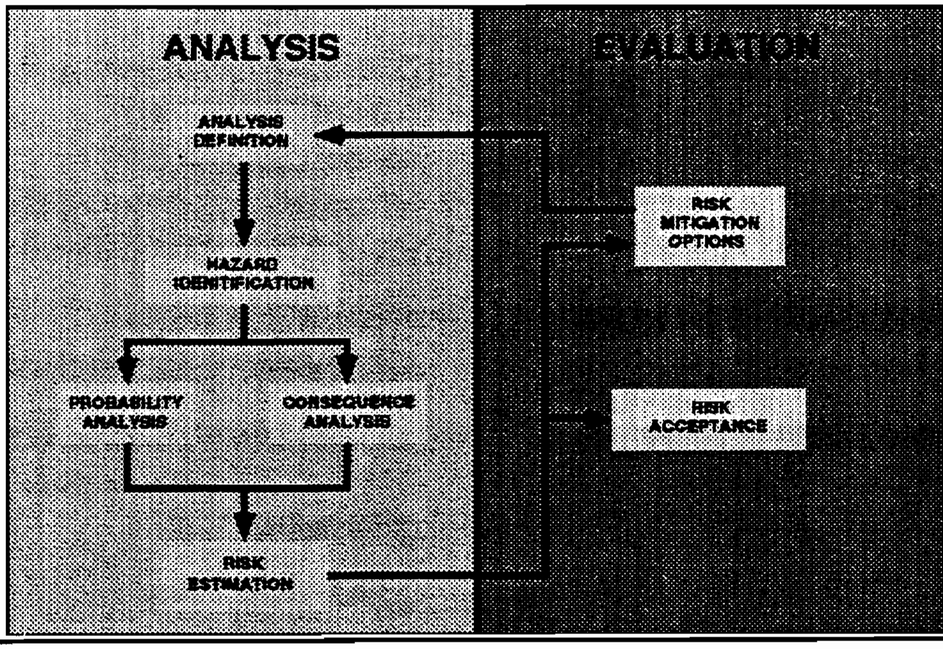
Road Map of 4 C Risk Assessment / Risk Management Sessions

Definitions *

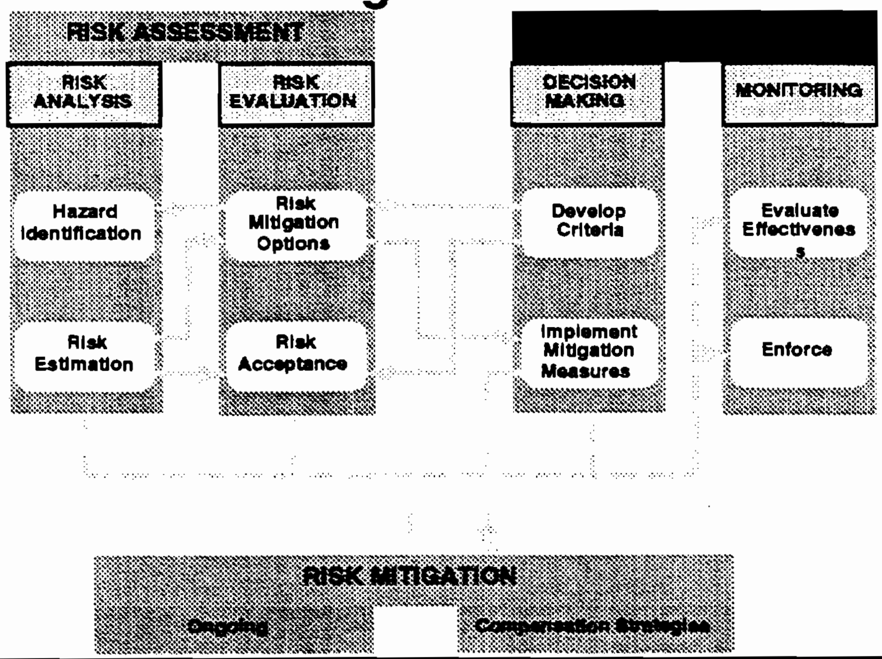
Risk	• Compound Measure (qualitative and quantitative) of Probability & Severity of an Adverse Effect.
Risk Assessment	• Process of Risk Analysis & Evaluation
Risk Management	• Integrated Process of Risk Assessment & Control

* CSA Z662-96, Q634-91

Risk Assessment Process



Risk Management Process



CSA Z662-96 Appendix B

Guidelines for Risk Analysis of Pipelines

Introduction

- Non-Mandatory
- Role of Risk Analysis
- Standard Terminology
- Risk Analysis Process
- References

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1997 Banff Pipeline Workshop

Working Group #2 - Stress-Corrosion Cracking: Session A

Co-chairs: Martyn Wilmott (NRTC), Walter Kresic (IPL)

"In-Line Inspection for SCC Management": Susan Miller, IPL

1996 Line 3 SCC Program:

- failure in Feb 96 attributed to SCC inside severe corrosion; corrosion was 78% thru wall, narrow, axial corrosion, NPS 34 pipe, near longseam
- therefore revamped inspection program: 509 excavations in 6 months
- three elements of detection program: ILI, Landscape model digs, corrosion digs
- Hydrostatic testing for verification
    - 200 km of line tested in year of failure
    - tested to 100% SMYS
    - no failures during hydro
    - 6 months since, no leaks or ruptures

- using the Elastic Wave Vehicle (BG), data has been collected on 249 km of 34 inch line
- no SCC has been found on this line using the EWV but cracks from other causes, such as fatigue and shrinkage, have been found using the ILI tool data
- cracks as shallow as 5% through wall have been found using the EWV (even less than 3% through wall)
- detection limits are good - results can be quantified

- 449 joints of 34" pipe examined for the presence of SCC in 1996.
- no significant SCC was found during the excavation program
- 198 km of line, located in the area closest to the SCC-related failures were hydrotested.
- no leaks or ruptures due to any cause occurred during the hydrotest

- Landscape model from Edmonton to Gretna MB identified 1039 discrete SCC sites
- the total length of pipe in "susceptible environments" is 210 km
- over 10% of the "susceptible sites" have been excavated and assessed.

- bottom line: no significant SCC was found using a combo of ILI, Landscape Model and hydrostatic testing
- insignificant SCC was seen at 7.3% of total excavation sites, 7.5% of model-predicted susceptible sites and 6.5% of model-predicted no-susceptible sites
- note model was developed to find "significant SCC"

Conclusion: the incidence of SCC on Line 3 is very rare
- for Line 3, the best SCC detection methodology is the use of ILI
- the landscape model will be most useful in assisting prioritization any locations not inspected with ILI where the consequences of failure will be unacceptable
- other use they see is to use the landscape model in conjunction with ILI tools: merge tool output with landscape model

SIGN-IN SHEET

STRESS CORROSION CRACKING - SECOND PART

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JIM MITCHELL	CAMROSE PIPE COMPANY
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EXPECTATIONS !

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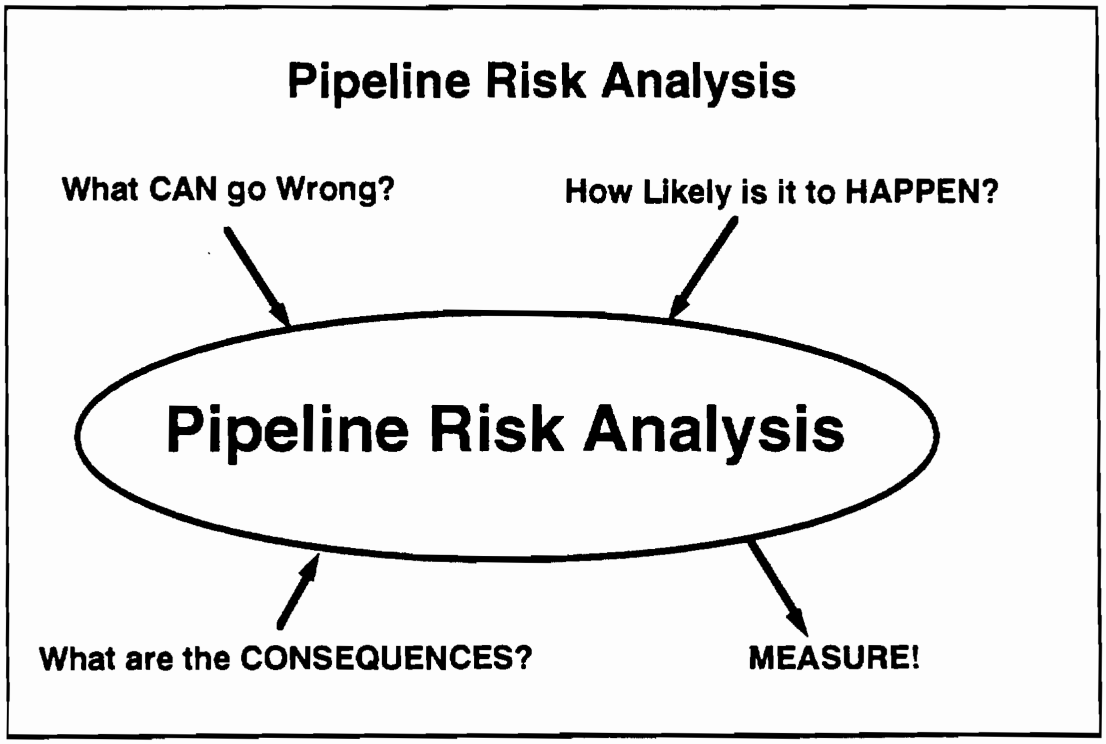
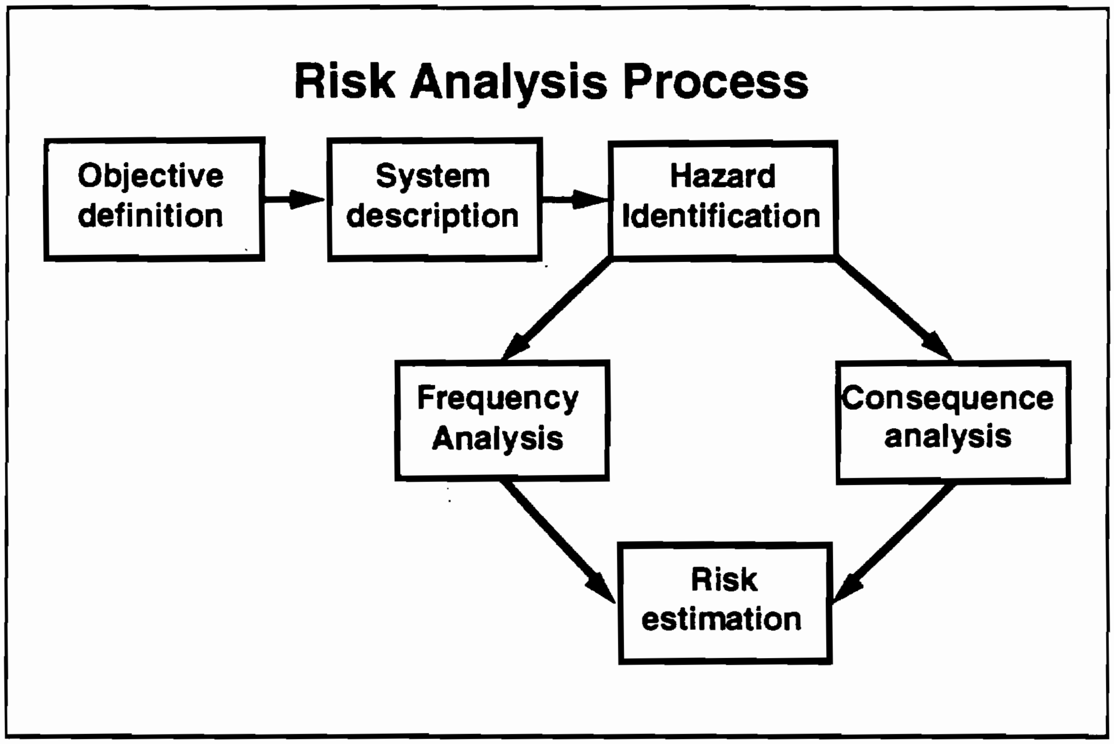
66.


Pipeline Risk Analysis
What CAN go Wrong?
How Likely is it to HAPPEN?
Pipeline Risk Analysis
What are the CONSEQUENCES?
MEASURE!


Risk Analysis Process
Objective definition
System description
Hazard Identification
Frequency Analysis
Consequence analysis
Risk estimation

IF INTERNET, WHAT SHOULD IT BE?

- Brokerage System
  - "Third party"
  - Fee for service

- Internet, a forum for information

- Web site must be well linked

- "Chat Room"

- New developments - ACCUMAP

HOW

- Likely a mix of methods
- PTAC can be an answer
- Internet site
- Videoconferencing
- Conventional publishing
  - alliance
  - focus on specific topics

CONCERNS

- Confidentiality
- Information Overload
- What is really useful
- What is cost effective
- What are benefits

INFORMATION EXCHANGE AND NETWORKING

WHAT

- Proceedings from various seminars
  East←West-World
- GIS/GPS data
- Technology - sleeving technology
- Conference data
- Case histories
- Exchange of best practices
- Incidents / near misses

Recommendation

Strategies must rely on a multi-modal context

Info-excavation should play a more direct role in supporting industries and municipalities

The action plan has to be more Quebec and eastern Canada oriented without forgetting linkage with the USA and Ontario/West

How Did We Get Here?

- Economic reasons were behind Ultramar decision
- Metropolitan Gas has expanded and now covers a large part of the province
- This brought the creation of Info-Excavation
- Small pipelines were established between companies and between Montreal-Varennes

Available Options

- Quebec Trans Maritime is now contemplating delivering services for natural gas to New England states, a cost benefit project
- NEB does cover most of our pipelines,but our Quebec natural resource Office should be more involved in setting up standards
- More linkage with Ontario and the West

Goal and Objective

- Our desired goal was to attempt to present a broad perspective over the issue and seek for relevant solutions.
- The objective was to assess certain assumptions and to question ourselves on the importance of safety practices with pipelines' operators.

Today's Situation

- Some pipelines start from the docks in the harbour;
- Other pipelines start from the State of Maine(Montreal Pipelines) passing under the St-Lawrence River or fromOntario;.
- Ultramar has prefered trains and boats to pipelines;
- Metropolitan Gas has a pipeline attached to Jacques-Cartier Bridge

Quebec Pipelines in a multi-modal context.

Pierre Brien

Vision Statement

In the Montreal Urban Community area in the transportation of dangerous goods task force report, pipelines are part of the multi-modal approach; therefore, we must position pipelines in a state of the art exercise and make sure of the harmonization of the different modes.

Ken Ball performed the introduction. Pierre Brien presented the results of the meeting held in Eastern Canada and Montreal in Particular. This is presented and included as overheads. The report is available in the original French from Pierre. Eric Lloyd of the Petroleum Technology Alliance of Canada (PTAC) presented information about PTAC and their web site. The overheads are included. Grant Gordon of Object Works presented an overview of internet and intranets. His slides are also included.
Discussion centered on four questions aimed at establishing the continuing usefulness of this working group and its possible future mission.
Question one was:

What requirements does the pipeline industry have for information exchange and networking?

- Publication of proceedings from various seminars for dissemination through all of Canada.
- GIS and GPS data could be available over the internet.
- Many other needs were identified but a method to disseminate awareness of the resulting database was identified.
- PTAC was identified as a possible partial answer as a repository for this information. Through fee paying members the conference can post on PTAC web site.
- Having an electronic mailing list to communicate is helpful.
- Some of the concerns voiced were:
- There is already information overload.
- Screening the useful information.
- Determining what is cost effective.
- What are the expected benefits.

Question two was

What are the best vehicles for achieving the requirements of the pipeline industry.

- Likely a mix of methods will be needed.
- Internet site.
- Video conferencing.
- Conventional publishing.
- Alliances with print media and special issues of trade magazine, which concentrate on specific topics.

Question three was

What action can we recommend.

- There was no widespread consensus. Some of the suggestions were:
- A few for service brokerage system.
- An internet forum which uses other standard common system to advertise.
- An internet chat room.

The last question was

Who will assist and follow through with the action items.

- PTAC and ICGTI can offer assistance.
- PTAC agreed to help in a transition phase until a new site is developed.
- A new nucleus must be established from existing organizations.
- A conventional publishing must be used.
- The working group had poor representation from industry.
- No firm conclusion was reached on the continuance of the working group.

Group 5

INFORMATION EXCHANGE & NETWORKING.

NAME (PLEASE PRINT)	COMPANY.
ALEBACHEW DEMOZ	CANMET / WRC
JOHN DONINI	CANMET/WRC
BILL HEDERMAN	INTL CENTRE for GAS TECHNOLOGY
DONALD R. PERSAUD	NATURAL Resources & ENERGY, NB
Dexter Pakin	Suncor Energy
Hejian Sun	CANMET/ WRC
Brad Gaulin	[illegible] Energy Group
Bain McMillan	CWNG
Ken Paulson	CWNG
GRANT GORDON	OBJECTWORKS INC.
ERIC LLOYD	PTAC
Wally Goeres	ED+T.
KEN BALL	ED&T

SESSION D
Working Group #5

INFORMATION EXCHANGE AND NETWORKING

RECOMMENDATIONS FROM SESSION TWO

1. MIACC's *Land Use Planning Adjacent to Pipelines Guidelines.*

    - more user-friendly
    - "Information Zone"
    - field test "draft"
    - referral service

2. Communications Strategy for the MIACC Document

    - education workshops across Canada
    - MIACC organized in cooperating with
        - CAPP
        - CEPA
        - NEB
        - AEUB

3. Endorse the MIACC Risk Communications Handbook

4. Use the experience of other industries (such as The Canadian Chemical Producers' Association) in dealing with risk

RECOMMENDATIONS FROM SESSION ONE

- bring representatives of the public/other stakeholders into future sessions of the pipeline conference, or to other conferences, and provide associated financial support for that participation

- CAPP, CEPA and regulatory agencies (e.g. NEB, AEUB) should develop public awareness / education programs

- develop a mechanism for companies to share/exchange lessons and learnings from public involvement / communication initiatives

- broaden resources list to include material from non-government and non-industry sources

- companies should ensure landowner information packages are communicated / distributed

- pipeline companies and associations should encourage employee training in public consultation / communication

SESSION 4D
COMMUNICATION AND PUBLIC CONSULTATION

* Communication: Lessons learned <u>about</u> the public from the public

* Existing Resources / Tools

* Briefing on: CAPP Public Involvement Guidelines
  MIACC Document - *Land Use Planning Adjacent to Pipelines* (draft)

* Discussion: Case Study - Sable Gas Pipeline
  MIACC document

* Consultation / Communication: Three Key Questions
  1. Who are the **stakeholders** that have an interest in the pipeline?
  2. What are the **interests**/concerns of those stakeholders?
  3. How could you apply communication/consultation practices to engage these **stakeholders** and deal with these **interests**?

* Recommendations

Recommendations from Session Two

1. MIACC's *Land Use Planning Adjacent to Pipelines Guidelines.*

   - need a better story on the document - put together a good initial dialogue - have to be honest, need to use plain language
   - make product more user-friendly (e.g. tables, pictures)
   - replace the Response Planning Area (RPA) name with "Information Zone"
   - test draft document with community planners, emergency responders, planning consultants, developers, Urban Development Institute, and the public
   - include an appropriate referral service where people can get information (organize before document is published)

2. Communications Strategy for the MIACC Document

   - MIACC, in cooperation and with the support of CAPP, CEPA, AEUB, and the NEB should run community educational workshops across Canada. Sponsorship funding will be required for community representatives to attend.
   - ensure that people understand that things haven't changed
   - include the fact that we can affect the rarity of the event - for e.g., compare with the risk of driving to demonstrate the rarity
   - mention some of the things the industry does to enhance safety
   - explain why the document is being produced
   - developers need to understand what their responsibility is when they develop near a pipeline - dialogue about setbacks needed

3. Endorse the MIACC Risk Communications Handbook

4. Use the experience of other industries (such as The Canadian Chemical Producers' Association) in dealing with risk

Property Owner Concerns

- the reality of the document isn't relevant, the public's perception of it is
- it is lent more credence by the organization that is publishing it

Community/Emergency Responders

- emergency planning zones might be over-extended - this is an information zone more than a response zone
- emergency crews want to know how often this is going to happen - they have to know what resources (equipment and training) they need to have available
- responders in areas where they are less familiar with the oil and gas industry may not be as comfortable with the pipeline, so this may present some problems in certain geographic areas
- emergency responders might decide that it would be easier not to have a pipeline in their area
- emergency responders may raise the question of funding

Community

- needs to know what the document means, how it should be applied, and how it will affect land policies (will it restrict land use? etc.)
- public will want to know who to talk to and what sources are available
- questions of what this will do for municipal assessment
- there is a lot of expertise in the public and they may be more expert than pipeline operators think
- concerns about safety
- concerns about monitory value of property
- questions about what is going to be done to prevent this happening / what is the emergency response plan? do we have to develop an emergency response plan?
- the risk is involuntary

SESSION TWO

Session Two focused on the Major Industrial Accidents Council of Canada (MIACC) *Land Use Planning Adjacent to Pipelines Guidelines.*

Several graphs from the draft MIACC *Land Use Planning Adjacent to Pipelines Guidelines* were displayed. The consequence-based Response Planning Area (RPA) distances, for both upstream and downstream materials were discussed.

Session participants identified the following issues and comments that might be of concern to previously identified stakeholders (from the stakeholders' perspectives):

Pipeline Operators

- there are 5 million Canadians within the affected zones who will now think they are in some sort of risk zone
- future ROW purchasing - landowners will want greater setback from the ROWs
- devaluation of property (existing property owners)
- may increase the number of affected landowners
- pipeline operators don't understand the document
- need to educate your staff on what to say to the public
- "if we put this document in front of the public, we probably won't build another pipeline in an urban area"
- may put us in the position of shutting down the system
- cost - where will it be passed on?
- inconsistent interpretation and/or by pipeline companies, stakeholders and regulators
- more compensation demands
- where is the zone compensation going to come from
- the product needs to be explained better to the public
- cost of regulating this
- business conflicts because of the zone of interest
- "the wrath of the public will be faced against the pipeline companies - not the developers"

COMMUNICATIONS & PUBLIC CONSULTATION
RESOURCES

Canadian Standards Association. 1996. *A Guide to Public Involvement: Environmental Technology. Z764-96.* CSA.

Available from the Canadian Standards Association
178 Rexdale Boulevard
Etobicoke, ON M9W 1R3

Canadian Standards Association. 1995. [Risk Management: Guideline for Decision-Makers. Q850] Draft. CSA.

Future availability from the Canadian Standards Association
178 Rexdale Boulevard
Etobicoke, ON M9W 1R3

Canadian Association of Petroleum Producers. 1996. [Guidebook for Effective Public Involvement] Draft. CAPP.

Future availability from the Canadian Association of Petroleum Producers (Summer, 1997)
2100, 350 - 7 Avenue SW
Calgary, AB T2P 3N9
ph: (403) 267-1100 fax: (403) 266-4622
e-mail: communication@capp.ca
homepage: www.capp.ca

Hance, B.J., Chess, C. & Sandman, P.M. 1990. *Industry Risk Communication Manual: Improving Dialogue with Communities.* Boca Raton, FL: Lewis Publishers.

Available at The University of Calgary Medical Library (Calgary, AB)
ph: (403) 220-6857
Or order from a bookstore

Major Industrial Accidents Council of Canada. 1997. [Land Use Planning Adjacent to Pipelines] Draft. MIACC.

Future availability from Major Industrial Accidents Council of Canada
265 Carling Avenue, Suite 600
Ottawa, ON K1S 2E1
ph: (613) 232-4435 fax: (613) 232-4915
e-mail: miacc@globalx.net

Mulligan, J. 1997. [Toward Proactive Management of Environmental Risk Communication: A Look at Alberta's Petroleum Industry] Draft. Master's Thesis. Faculty of Environmental Design. The University of Calgary.

Future availability at the Faculty of Environmental Design (May, 1997)
The University of Calgary
Calgary, AB T2N 1N4
ph: (403) 220-3176

Canadian Association
of Petroleum Producers

CAPP

PUBLIC INVOLVEMENT PRINCIPLES

Mission: *to achieve balanced decisions and results which respect the knowledge, values and rights of all affected interests.*

Public involvement processes which adhere to the following principles will improve the effectiveness, fairness and endurance of outcomes.

RESPECT:

Demonstrate respect for the participants and the process, by:
- honouring diverse cultures, perspectives, values, approaches and interests;
- interacting honestly, openly and ethically;
- bridging differences with integrity and courtesy;
- acknowledging participants' professional codes of practice; and
- adhering to objectives, expectations, commitments, and protocols agreed upon for the process.

RELATIONSHIPS:

Establish, maintain and enhance relationships, by:
- fostering trust and respect through performance;
- facilitating the voluntary building and maintaining of on-going, constructive relationships; and
- improving the quality of existing relationships among participants.

COMMITMENT:

Demonstrate commitment to the process and its results, by:
- engaging all affected interests in defining problems, expectations and objectives;
- building trust and relationships from the outset, with a long-term orientation;
- following through on commitments made during the process;
- incorporating input from all participants;
- fostering collaborative and voluntary agreements; and
- maintaining a constructive, problem-solving focus.

ACCOUNTABILITY:

Demonstrate accountability to affected interests and process participants, by:
- encouraging participants to solicit input from their constituents and to communicate regularly with them; and
- expecting participants to commit to and follow through on the negotiated process and its results.

SHARED PROCESS:

Negotiate a readily understood, shared process among participants, by developing together:
- scope and terms of reference,
- expectations and objectives,
- benefits and losses,
- constraints and boundaries,
- roles, responsibilities and protocols,
- timelines,
- control and enforcement,
- sharing of resources,
- monitoring and evaluation, and
- ways of handling disagreements.

COMMUNICATION:

Communicate effectively to develop shared understandings, by:
- listening carefully;
- being honest and open;
- using plain language; and
- providing opportunities for information exchange and mutual education about interests, objectives and values.

RESPONSIVENESS:

Demonstrate flexibility and responsiveness, by:
- recognizing that public involvement is a dynamic process;
- building flexibility into the process;
- balancing participants' and process needs;
- moving toward objectives and using resources effectively;
- building-in and using feedback mechanisms; and
- evaluating and modifying the process in an on-going manner.

TIMELINESS:

Recognize time as an important resource, by:
- sharing information early and often, to assist all interests to prepare and to act knowledgeably;
- providing early and adequate notice of opportunities for involvement;
- negotiating timelines among participants;
- establishing and adhering to realistic deadlines; and
- responding in a timely fashion to questions and requests for action.

Printed November 17, 1994

2100, 350 - 7 Avenue S.W., Calgary, Alberta, Canada T2P 3N9 *telephone* (403) 267-1100 *facsimile* (403) 261-4622

SESSION ONE

The session co-chairmen presented a sampling of resources for risk communication (next page):. Principles for risk communication were summarized from the CAPP Public Involvement Guidelines (subsequent page).

To develop an understanding of the complexity of issues involved in risk communication, a case based on the Sable Island pipeline was introduced in the first session. The following three questions were used to explore a potential communication plan for the project:

1. Who are the stakeholders that have an interest in the pipeline?
2. What are the interests/concerns of those stakeholders?
3. How could consultation practices to engage these stakeholders and deal with these issues?

Recommendations from Session One

- bring representatives of the public/other stakeholders into future sessions of the pipeline conference, or to other conferences, and provide associated financial support for that participation
- CAPP, CEPA and regulatory agencies (e.g. NEB, AEUB) should develop public awareness / education programs
- develop a mechanism for companies to share/exchange lessons and learnings from public involvement / communication initiatives
- broaden resources list to include material from non-government and non-industry sources
- companies should ensure landowner information packages are communicated / distributed
- pipeline companies and associations should encourage employee training in public consultation / communication

4D RISK ASSESSMENT/RISK MANAGEMENT: COMMUNICATIONS AND PUBLIC CONSULTATION

17 APRIL 1997

In a pre-workshop survey, participants indicated that their objectives in participating in the workshop included:

- gathering information;
- sharing information;
- finding tools appropriate for work-related situations; and
- meeting other needs.

The participants wanted the sessions to address the following:

- early stage definition of communication and participation difficulties;
- dealing with public fear;
- how to move from the risk and fear issues to constructive discussion;
- ways to communicate uncertainty;
- public attitudes toward risk, government and industry;
- effective risk communication strategies;
- encroachment of development on old pipeline ROWs; how to assure authorities and public that the pipeline system is safe;
- dealing with land use issues;
- a general tool for risk assessment useful for companies and accepted by authorities;
- communication with regulators;
- communication with company institutions;
- defining risk assessment;
- finding optimal ways of communicating with the public;
- pipeline route selection;
- compensation to landowners;
- environmental protection; and
- developing an awareness and acceptance that the pipeline industry is safe.

Ralph Mayer	Maritimes & Northeast Pipeline
ROD TREFANENKO	GULF CANADA RESOURCES
Doug Clark	"
ROB OWEN	BC Gas.
NORM TRUSLER	BC GAS
Franci Jeglic	NEB
Walter Sekella	CWNG

LIST OF PARTICIPANTS

Working Group #4D: Risk Assessment/Risk Management--
15:30 Communications and Public Consultation

NAME	ORGANIZATION
Jean Mulligan	W. Leiss + Assoc. Ltd
Lisa-Henri Kirkland	Golder Assoc.
SARAH ARULANANDAM	UNIV OF ALBERTA (MECH. ENG.)
DAVE SIMPSON	Union Gas
PAUL MEANWELL	UNION GAS
Doug Hannesen	Consumers Gas
KEITH LEWIS	GRI
GORDON JOHANSON	CWNG.
HUGH ALLEN	NORTHWESTERN UTILITIES LTD
Bruce Fowlie	Nu-Trac Management Consulting L
Victor Standish	Petro-Canada Oil + Gas.
Janice Luttin	TCPL
May Mah-Paulson	O'Connor Associates Environmental Inc
GORDON MILLER	AEUB
William Rambo	Yellowstone/Conoco Pipe Line
Arthur Springer	Bovar.
Dave English	Amoco Canada
ALLISON WILLIAMS	COUNTY OF MOUNTAIN VIEW.
Mike Zelensky	BOVAR
JOANNE NUTTER	IMPERIAL OIL RESOURCES LIMITED

Doug CLARK	Gulf Canada
ROD TREFANENKO	" "
Ralph Mayer	Maritimes & Northeast Pipeline
Ian Scott	CAPP
JAKE ABES	NEB
Karen Etherington	NOVA Gas Transmission Ltd
Roy Sage	CANMET/MTL
IAN FRASER	IMPERIAL OIL

LIST OF PARTICIPANTS

Working Group #4D: Risk Assessment/Risk Management--
13:00 Communications and Public Consultation

NAME	ORGANIZATION
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JOHN SHRIVES	ENVIRONMENT CANADA.
PIERRE BRIEN	PPH
ANTON KACICNIK	CONSUMERS GAS
Victor Standish	Petro-Canada Oil + Gas.
FRED BAINES	BC GAS.
Janice Lattin	TCPL
Sharon Coary	NEB
Bob Sotherby	NOVA.
PAT MASON	WESTCOAST ENERGY
JOANNE NUTTER.	Imperial Oil Resources Limited
ALLISON WILLIAMS.	COUNTY OF MOUNTAIN VIEW.
HARRY LILLO	EUB

SESSION C and D
Working Group #4D

RISK ASSESSMENT / RISK MANAGEMENT - CUMMUNICATIONS AND PUBLIC CONSULTATION

Risk Management Issues

- Best practices for evaluating in-line inspection data
- Risk Management strategies could be different for different pipelines (one size will NOT fit all)

Databases

- collecting data (SCC)
- design stage (PRASC)
- databases should use common elements
- minimize dupllication of data gathering
- need to develop communication process

General Issues

- Publicize work of PRASC between workshops
- Threats other that SCC need to be addressed
- Best practices required for communicating with public concerning pipeline risk and operations integrity

Banff 97
Risk Assessment / Management - Transmission Lines

Recommendations

Risk Standards

- risk criteria should be developed for both new and existing pipelines
- new working group (of 6 to 12) should be formed under PRASC (multi-stakeholder) to begin work on standards and best practices
- also an open working group for information exchange

Summary

- Following the incident at Rapid City, TCPL identified possible deficiences in its SCC Integrity Management Program and took the necessary corrective actions
- The Integrity threat posed by SCC can be effectively managed through industry collaboration and by individual companies developing and implementing SCC Integrity Management Programs for their pipeline systems

TransCanada

Improvement to Risk Management Process Arising from Incident (cont'd)

- CEPA is developing a Recommended Practises Document for the Management of SCC (completion date - May 15, 1997)
  - this document will assist companies in the development and implementation of their respective SCC Integrity Management Programs

TransCanada

Improvement to Risk Management Process Arising from Incident (cont'd)

- CEPA has developed a SCC Database
  - it is anticipated that the data collected and trended by this database will provide tremendous assistance to the industry in identifying and quantifying the various factors that affect SCC susceptibilty

TransCanada

Brief Summary of SCC Inquiry (cont'd)

- NEB recommended that every pipeline company develop and implement a SCC Integrity Management Program
- NEB recommended that the industry continue the development and verification of predictive models for the hazards and consequences assocatied with pipeline failures

TransCanada

Improvements to Risk Management Process Arising from Incident

- CEPA has developed a qualitative risk-based framework for SCC Integrity Mangement Programs
  - this framework will not only assist individual companies in developing their respective programs but will also ensure some consistency in the programs developed by CEPA member companies

TransCanada

National Energy Board's Response to Incident

- Issued several Information Requests to TCPL following the incident
  - historical summary of TCPL's SCC Integrity Management Program
  - TCPL's plan to expand it's SCC Integrity Management Program for entire system
- On August 11, 1995 announced that it would hold a wide ranging Public Inquiry into SCC on Canadian Pipeline Systems

Brief Summary of SCC Inquiry

- Estimated that SCC only affects a small portion of Canadian pipeline systems (<4%)
- SCC primarily limited to polyethylene tape coated pipe
- Predictive models have been successfully employed by some companies to identify SCC susceptible portions of their pipeline systems

TCPL's Response to Incident

- Implemented a "Zero Tolerance" Policy for SCC service failures
- Accelerated SCC Integrity Mangement Program west of Winnipeg and in other parts of the system
- Investigated all transition welds located immediately downstream of a compressor station on NPS 42 line
- Developed a database of all discrete tape coated sections and tape coated welds in the system

TransCanada

TCPL's Response to Incident (cont'd)

- Developed and implemented a program to address SCC susceptible discrete taped coated sections and tape coated welds located in close proximity to dwellings
- Modified hydrostatic retesting program to include all Class 1 pipe within test section
- Expanded its research initiative with British Gas to accelerate the development of a SCC In-Line Inspection Tool

TransCanada

Risk Management Issues Arising from Incident

- First SCC failure in TCPL system west of Winnipeg
- TCPL needed to expand SCC Integrity Management Program to include entire system
- TCPL need to identify all discrete tape coated sections and tape coated welds in the system

TransCanada

Risk Management Issues Arising from Incident (cont'd)

- TCPL needed to identify all SCC susceptible locations along system
- TCPL needed to modify it's hydrostatic retesting program to ensure the integrity of all Class I pipe within a test section

TransCanada

Overview of Incident

- Occurred on July 29, 1995
- Occurred 240m downstream of Rapid City, Manitoba compressor station
- Cause of rupture was SCC in a 3m tape coated NPS 42 tie-in pup
- Blast crater caused by the rupture exposed two adjacent pipelines

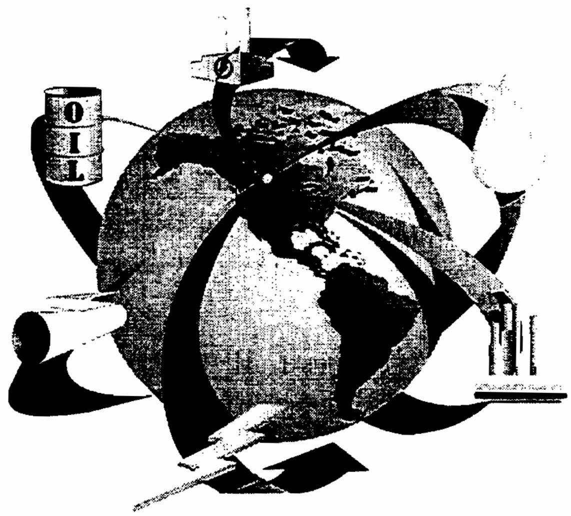
TransCanada

Overview of Incident (cont'd)

- Thermal radiation from the rupture resulted in the subsequent rupture of the adjacent NP 36 line
- Thermal radiation from the ruptures caused damage to compressor station and above ground piping in station yard
- Ruptures resulted in TCPL declaring Force Majeure for the first time in it's history

TransCanada

Natural Gas Pipeline Incident Response - Case Study



TransCanada

Presented by: Burke Delanty
April 17, 1997

Presentation Outline

- Overview of Incident
- Risk Management Issues Arising from Incident
- TCPL's Response to the Incident
- National Energy Board's Response to the Incident
- Improvements to Risk Management Process Arising from Incident
- Summary

TransCanada

Future Plans

- Plan to use in-line inspection and dig program in lieu of hydrostatic testing for this pipeline
- Program underway to conduct detailed corrosion growth assessments

NEB Directive

- Agreed with IPL plan
- Also directed IPL to reduce MOP between Cromer and Souris to 95% of authorized MOP

Results

- Ultrasonic, Transverse Field Inspection, and Elastic Wave in-line inspection
- 509 digs between Edmonton and Gretna
- All pressure tests between Odessa and Cromer were successful with no ruptures or leaks
- Board permitted IPL to raise operating pressures to 80% of test pressures

Risk Management Issues

- Safety of public
- Environmental impact
- Availability of pipeline system
- Existing integrity data
- Failure history of pipeline
- Operating history of pipeline
- Throughput losses for shippers
  - water movement
  - pressure test

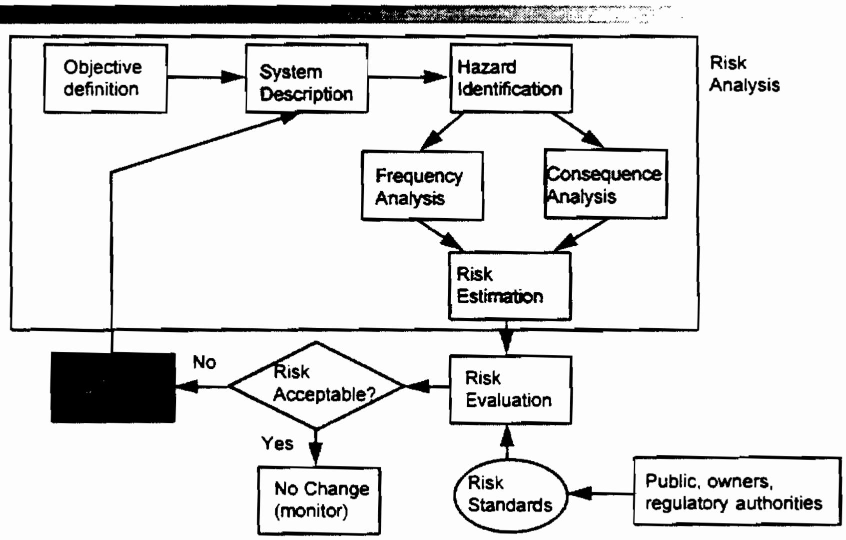
IPL Response

- Voluntary and immediate reduction of MOP between Odessa and Cromer to 80% of current authorized levels
- In-line inspection and dig program between Regina and Cromer
- Pressure testing program between Odessa and Cromer
- Future pressure testing program depending on results

NEB Show Cause Letter

- Reduce MOP between Regina and Gretna to 3530 kPa (80% of Glenavon Station discharge pressure at time of leak)
- Pressure test all portions of pipeline between Regina and Gretna
- Submit a pipeline integrity evaluation to the Board

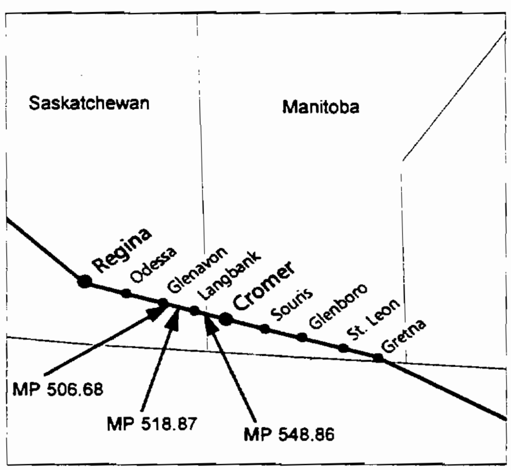
Risk Management Process



IPL Mainline Incidents

- June 16, 1995 - MP 518.87
  - narrow axial external corrosion
- November 13, 1995 - MP 548.86
  - fatigue crack
- February 27, 1996 - MP 506.68
  - corrosion with SCC

Map of Pipeline



Pipeline Risk Assessment Steering Committee (PRASC)

Mandate

- To guide the development of processes to determine and manage the risks associated with pipeline operation - a primary focus being the safety risk to the general public

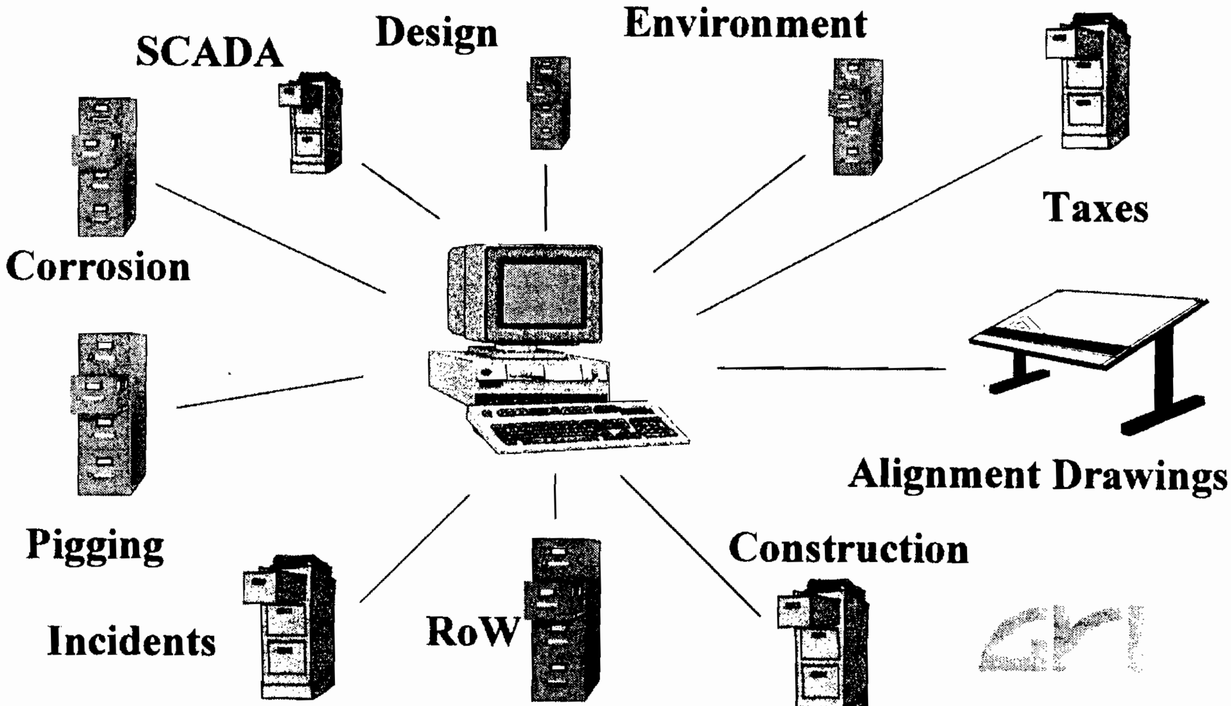
Support

- All segments of the Canadian pipeline industry are involved - from producers through transportation and distribution
- Cooperative effort of industry associations (CAPP, CGA, CEPA), regulatory bodies (EUB, NEB), standards association (CSA), and MIACC

Deliverables

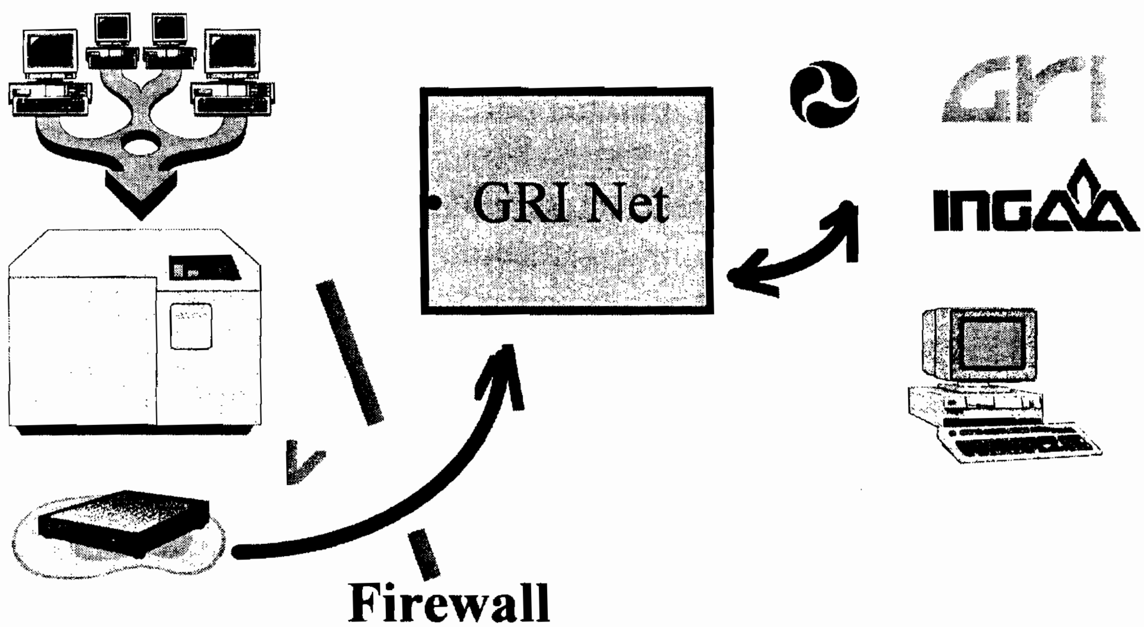
- Guide the development of processes to determine and manage risks associated with pipeline operations (database)
- Identify all essential database elements
- Define standards, measurement criteria and terminology
- Determine statistical and quantitative requirements
- Outline the process for data collection and reporting
- Estimate industry/corporate impact
- Act as a liaison with related industry initiatives/groups
- Evaluate and recommend an appropriate database and process

Paper Data



3

Data Protection



IRATS

- Started 1997 - 17 Transmission Companies
- Stand Alone Portable PC Application
- Written in Access for Windows 95
  - Standard 32bit Windows Reporting/Importing
- DOT Form 7100 the 1st Formal Output
- Modifications for API Use Started

Information Sharing

- Data Remains Company Owned
- Central Repository Under Discussion
  - Security & Confidentiality Concerns
  - Open Access and Interpretation Questions
- Interim: Collect And Share for Common Reports

Benefits Starting 1997

- Improved Accuracy & Consistency
- Determine Industry Trends
- Confirm Safe Industry Performance
- Suitable for Canadian Reporting

Pipeline Performance

- Existing Collections are
  - Inconsistent &
  - Incomplete
- Difficult to
  - Show Progress &
  - Determine a Baseline

GRI

GRI Solution

- Application Predicts Company Performance
  - Improve System Reliability
  - Track Safety Improvements
- Industry Consensus Dictionary
  - Set Pick Lists
  - Track Root & Multiple Failures
  - Incident, Failure, & Cause Screens

GRI

Incident Reporting and Trending System (IRATS)

- Improved Accuracy & Consistency
- Tracks Non-Reportable Events
- Tracks Precursors for Facility Performance
  - Incidents Are Too Infrequent
- Collects Data to Verify Models and Theories

GRI

- SCCdb V2 data fields communicated to GRI and PRCI

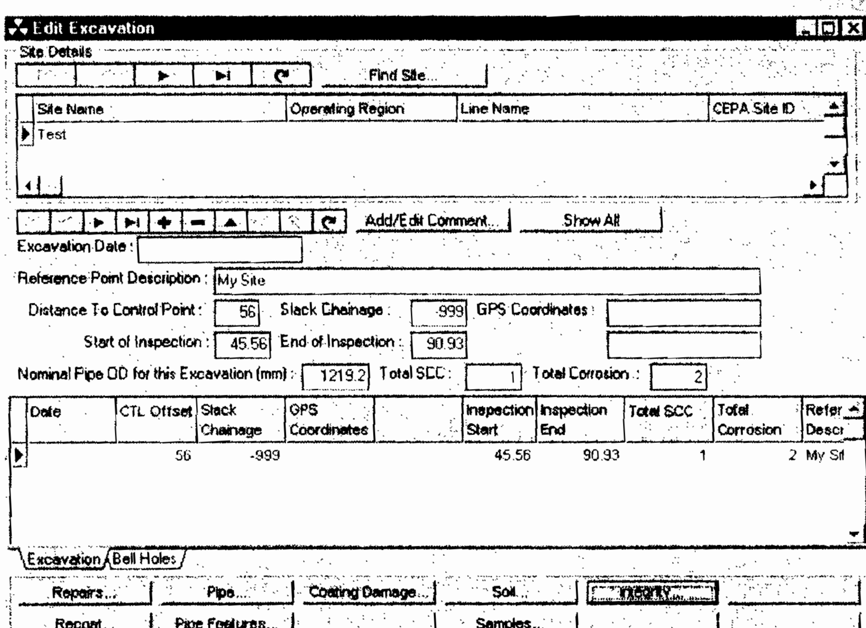
- Non-CEPA member participation in the data pool for trending and identification of correlations
- Need to determine minimum data set and the particulars of the participation contract

- The design and testing by CEPA SCC Working Group
- Programming by Chronologic Systems Inc.

Status of SCCdb V2

- Just completed Beta testing by CEPA SCC Working Group
- Will issue to the SCC Working Group next week
- SCCdb V2 will be publicly issued as part of the CEPA SCC Recommended Practices to be issued in June

- Expanded data fields in an attempt to capture all data that can be generated at an investigative excavation
- Expanded scope to fully include data associated with corrosion investigations
- Level of detail increased to capture data for each SCC colony or corrosion feature



CEPA SCC Database

SCCdb V2

- Originally created to ensure consistency of data
- The first version issued in 1995 was inadequate due to smearing data on a per joint of pipe basis

Comments on Workshop Issues and Recommendations for future action

A Gas Pipeline Risk Management Case

- presentation by Burke Delanty
  TransCanada PipeLines
- followed by questions and discussion

A Liquid Pipeline Risk Management Case

- presentation by Cory Goulet, Interprovincial Pipeline
- followed by questions and discussion

1995 Managing Pipeline Integrity Workshop held in Banff

- A new industry / regulator relationship will be required in part as a result of the reduced resources of the regulators,
- A new cooperative approach, with industry proactively providing guidance and realistic expectations to regulators, including management performance measures will be required.

Banff 95 Risk Management Process

- Identify areas of high failure probability
- Evaluate consequences
- Evaluate risk
- Decide on appropriate action
- Act
- Measure performance
- return to first step and repeat process

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- PRASC should

  - establish working groups to address specific issues, such as performance measures for Risk Assessment, level of risk acceptable to all stakeholders, minimum criteria for PRASC standards, and

  - establish a risk management process for both big and small pipeline operators.

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- establishment of an industry/regulator steering committee, (i.e., (PRASC))

  - to coordinate the research and development of risk assessment guidelines,
  - to support the development of guidelines for the development of a risk assessment database

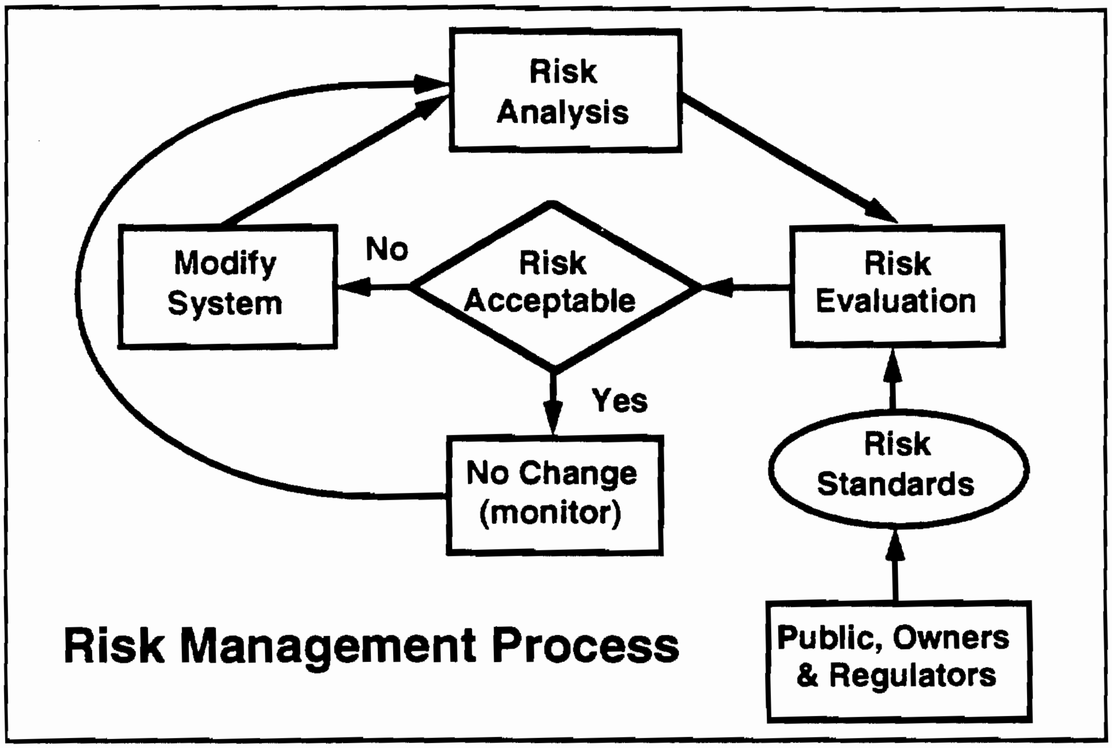
1993 Issues Workshop on Pipeline Lifetime held in Red Deer

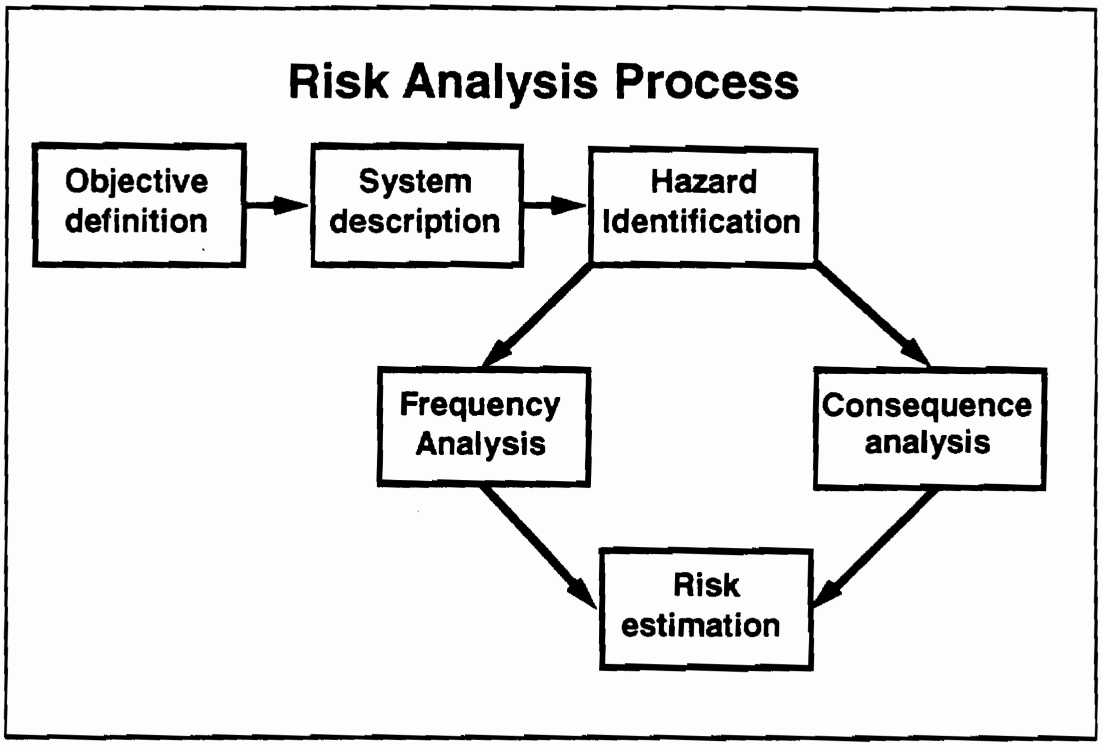
- Development of pipeline risk assessment guidelines
- Development of a database
- Establishment of acceptable risk levels
- Development of a tool kit
- Education.

Future Directions *

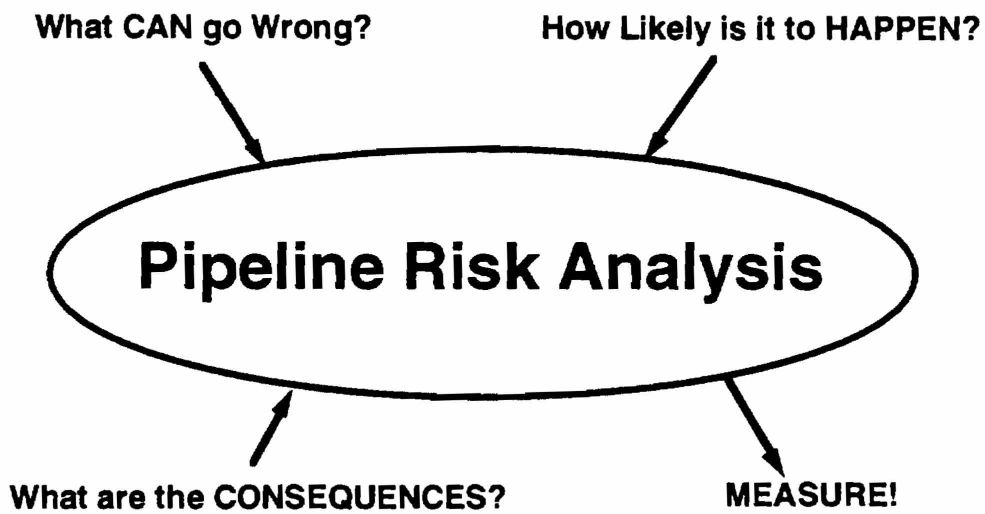
- Next Update in 1998
- Next edition will remain non-mandatory
- Technical committee looking for input
- Changes to be reviewed by end 1997
- Final technical changes by mid-1998

* Chairman of Technical Committee is Dave Kopperson, PanCandian


Risk Analysis
Modify System
No
Risk Acceptable
Risk Evaluation
Yes
No Change (monitor)
Risk Standards
Risk Management Process
Public, Owners & Regulators


Risk Analysis Process
Objective definition
System description
Hazard Identification
Frequency Analysis
Consequence analysis
Risk estimation

Pipeline Risk Analysis



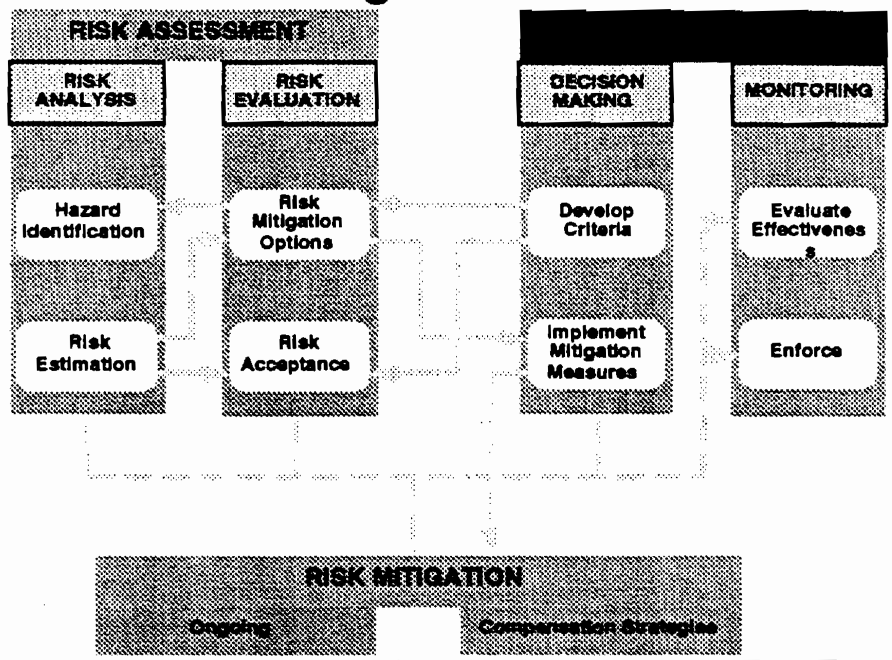
CSA Z662-96 Appendix B

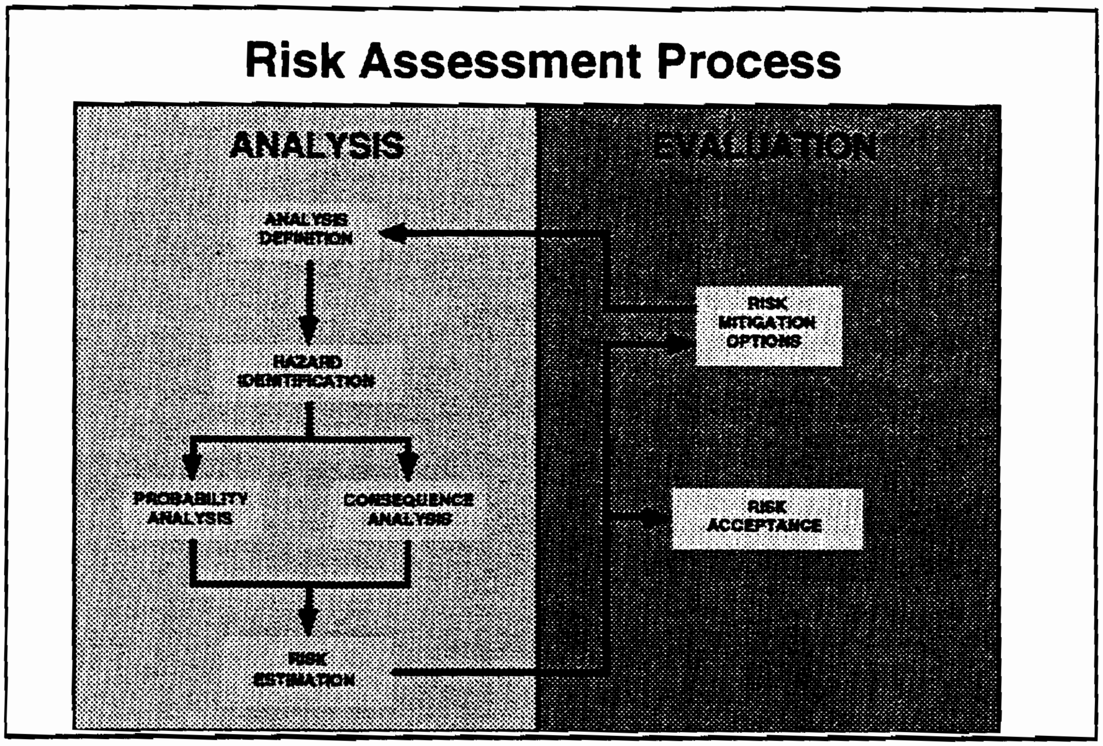
Guidelines for Risk Analysis of Pipelines

Introduction

- Non-Mandatory
- Role of Risk Analysis
- Standard Terminology
- Risk Analysis Process
- References

Risk Management Process





Risk Assessment Process
ANALYSIS
EVALUATION
ANALYSIS DEFINITION
HAZARD IDENTIFICATION
PROBABILITY ANALYSIS
CONSEQUENCE ANALYSIS
RISK ESTIMATION
RISK MITIGATION OPTIONS
RISK ACCEPTANCE

Definitions *

Risk	• Compound Measure (qualitative and quantitative) of Probability & Severity of an Adverse Effect.
Risk Assessment	• Process of Risk Analysis & Evaluation
Risk Management	• Integrated Process of Risk Assessment & Control

* CSA Z662-96, Q634-91

Road Map of 4 C Risk Assessment / Risk Management Sessions

Risk Management - Transmission Lines

Objectives of Session

Risk Assessment

- Future Directions

Related Databases

- CEPA SCC Database - Bruce Dupuis, Foothills
- GRI 'IRATS' Databse - Keith Leewis, GRI
- PRASC Database - Wayne Feil, Imperial Oil

NEB Report MH-2-95 Recomendations

- CEPA requested to continue to develop and maintain a database on SCC that is compatible with other international initiatives and to encourage the participation of non-member companies.

NEB Report MH-2-95 Recommendations

- CEPA to continue the development and verification of models that predict the hazards and consequences associated with pipeline failures for different service fluids, and
- to develop criteria for determining safe distances from the effects of pipelines failures

NEB Report MH-2-95 Rcommendations

- If there is reasons to believe that sections of a pipeline may be susceptible to SCC the company shall develop a predictive model to identify and prioritize sites for investigative ecavations
- CEPA to develop sampling criteria for verifying the accuracy of SCC predictive models

NEB Report MH-2-95 Recommendations

- SCC programs must contain 3 components:

  1. determination of SCC susceptibility and active monitoring of pipelines believed to be susceptible, and

  2. clear identification of the criteria the company considers in deciding among mitigative options and mitigation, if "significant" SCC is found, and

  3. recording and sharing of information on susceptible pipelines.

NEB MH-2-95 Report Recommendations

- SCC program to provide for the review of the company's entire pipeline system and is to be updated regularly
- SCC program is to consider the consequences and probabilities of a failure when establishing priorities for investigative, mitigative and preventive activities.

NEB MH-2-95 Report Recommendations

- Each pipeline company to develop and implement an SCC Management program
- Accountability for implementation of SCC program to be designated

1995 Managing Pipeline Integrity Workshop held in Banff

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- A new cooperative approach, with industry proactively providing guidance and realistic expectations to regulators, including management performance measures will be required.

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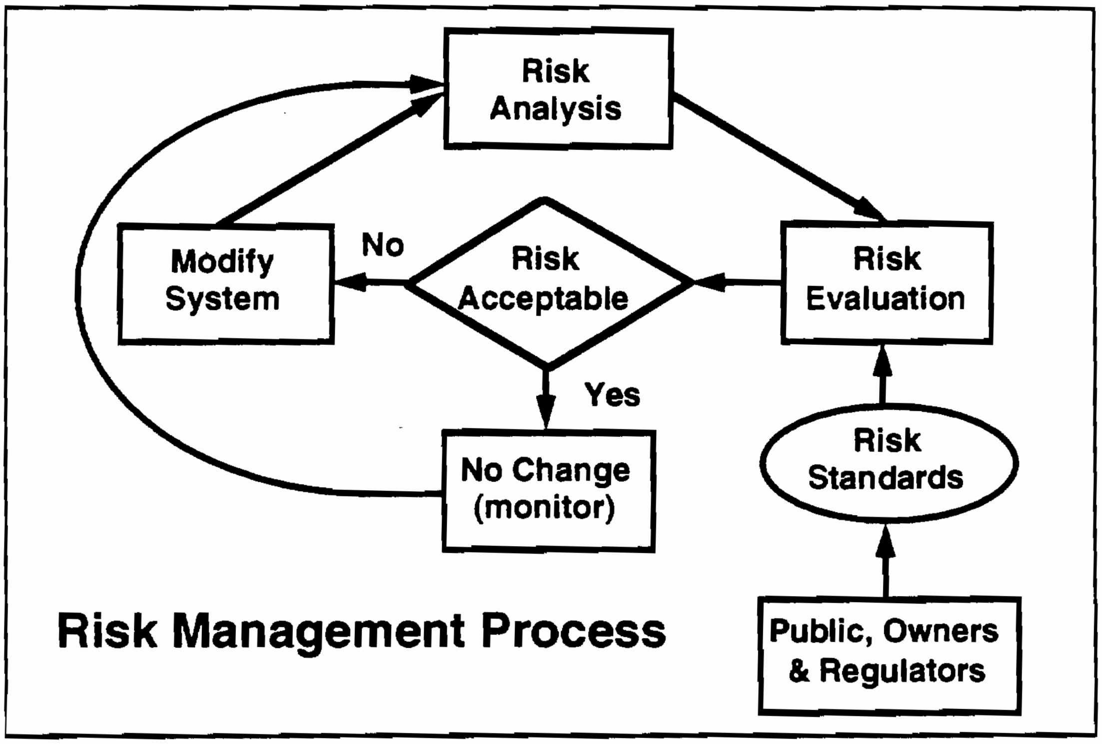


Risk Management Process

Internet and Intranet Communications: The New Corporate Weapons

Grant Gordon

ObjectWorks

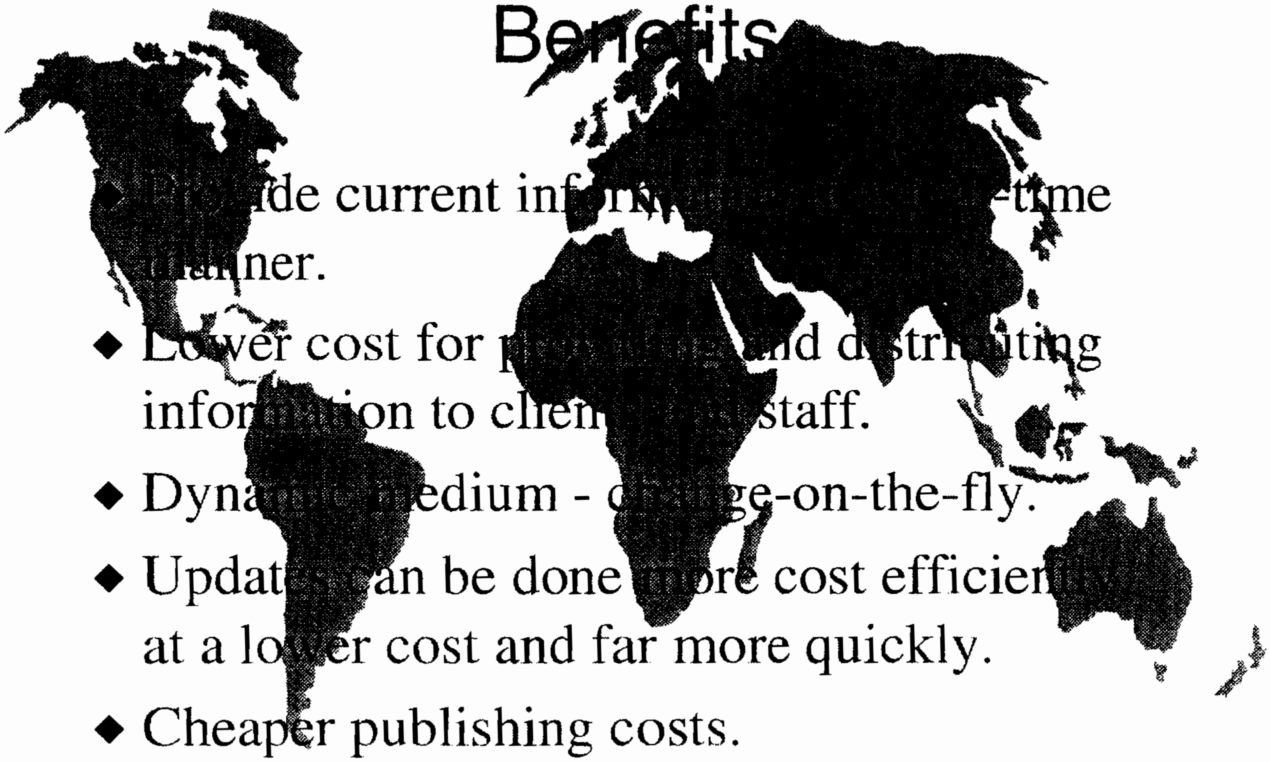
Internet/Intranet-What's the Difference?

- How can this technology be used in my business?
- Why should I use this type of technology?
- What benefits will I recognize?

RECOMMENDATIONS

- PTAC can be an answer
- Need a nucleus (who)
- PTAC/ICGTI - general assistance
- PTAC/Transition phase
- Need to establish/define/sell benefits
- No definite conclusion to continue

Benefits



- Provide current information in a real-time manner.
- Lower cost for producing and distributing information to clients and staff.
- Dynamic medium - change-on-the-fly.
- Updates can be done more cost efficiently, at a lower cost and far more quickly.
- Cheaper publishing costs.

Results

- Lower overall communication costs.
- Wider audience.
- More effective and interactive communication.

Internet Web Sites

- What can you put on a web site?
  - Annual and Semi-Annual Reports.
  - Investor Information.
  - Product/Pricing Catalogues.
  - On-line Order Processing.
  - Interactive Forums.
  - Remote Database Access.
  - Secure/Member Access Only Sections.

Intranets, The Internal Webs

- Human Resources.
  - telephone numbers, e/mail addresses.
  - benefit package information.
  - holiday schedules.
  - corporate events.
- Interactive Forums.
  - project collaboration.
  - database access.

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

Presentation to

Banff Pipeline Workshop

April 17, 1997 - Banff, Alberta

"PTAC: Chapter 1"

Prepared by Eric Lloyd, President, PTAC

PTAC Presentation to Banff Pipeline Workshop

- Reasons for Forming PTAC and Purpose
- History and Financing
- How PTAC Works
- Website and Current Activities
- Industry and Public Support

Technology Development Priorities in the Conventional Oil & Gas Industry

- What's Next for PTAC?/Conclusion

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

Conclusion

- Cost effective means of communication.
- Reduced communication costs.

PTAC History

- Initiative of Vice Presidents Breakfast Club
- Steering Committee formed in Sept '94
- 21 producers funded 3 phases
  - Situation Analysis - Murray Todd
  - Workshop - Oct '95
  - Designed Steering Committee - Dec '95
- PTAC commenced operations in Apr '96
- PTAC Website formally launched Dec' 96 (www.ptac.org)

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

Financing

- Annual membership fee schedule determined by membership category
  - All members receive non-proprietary description of all projects proposed and underway
  - Optional participation and funding of individual projects
- ERC/DOE commitment to PTAC for office space and support
- CBNC one time funding

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

Reasons for Forming PTAC

- New collaborative model needed
- R&D expenditures inadequate and decreasing
- R&D capability non-existent in juniors and intermediates

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

PTAC Purpose

- Leverage intellectual and financial resources to improve technology development, technology transfer, and industry performance
- Provide vehicle for conducting & funding joint projects
- Bring stakeholders together and prioritize needs
- Identify technology development opportunities and avoid duplication

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

How PTAC Works

Idea Sources

- Inventors or researchers may propose projects for funding
- Service/supply firms may request help in testing or commercializing their ideas
- Producers may invite help in solving problems or share new initiatives
- Technical Subcommittees may invite proposals for basic research or specific problems

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

Website
Public Section

- General informational material
  - R&D Project Index
  - R&D Project Proposals
  - Events Calendar

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

How PTAC Works

- PTAC is a not-for-profit organization with a volunteer Board
- PTAC model includes and integrates end users, suppliers, primary and secondary R&D providers, Government, inventors, and individuals
- Technology Development Policy Committee (TDPC) establishes framework for projects and identifies broad research areas
-

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

How PTAC Works

PTAC Technical Subcommittees

- Production and Processing of Natural Gas
- Oil Production
- Drilling
- Well Completion, Stimulation, and Workover
- Oil and Gas Transportation
- Reservoir Recovery
- Geoscience
- Basic Research

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

Industry and Public Support of PTAC

- Endorsement from industry associations
  - PSAC
  - CEPA
  - Alliance with CAPP under discussion
- Strong support from technical societies
  - SPE
  - The Petroleum Society of CIM
- Strong support from Producers, in particular the VP Breakfast Club

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

■

Industry and Public Support of PTAC

- R&D Providers participate to increase their exposure to industry problems/opportunities and to potential customers
- Strong participation from the Petroleum Service Sector in design of PTAC and representation on PTAC Board and Technical Subcommittees

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

Website
Members Only Section

- 74 Moderated Technical Forums

- Support Library with information re:
  - R&D Project Development and Documentation Process
  - Funding Sources for R&D, R&D Taxation
  - Effective Meeting Facilitation
  - Project Evaluation Software
  - Intellectual Property Protection
  - Standard R&D Project Agreement, Standard Confidential Disclosure Agreement

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

Current Activities

- Collaborative project progressing with U of C and Industry valued at $300,000

  ("Water Content and Physical Properties of Acid Gases") (Technology Tuesdays)
- Numerous new proposals and projects under development by members
- Ongoing Technical Subcommittee discussions
- Problem/Opportunity Definition Workshops

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

What's Next for PTAC?

- Several Technology Workshops planned during April 1997 to identify Conventional Oil and Gas Problems, and Research and Technology Development Opportunity areas
- "Technology Tuesdays"
- Evolve PTAC process
- Launch 10 collaborative projects in 1997

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

Conclusion

- PTAC facilitates information exchange and networking
- More new projects expected
- Successful R&D projects and new technology development should improve industry performance

PTAC
PETROLEUM TECHNOLOGY ALLIANCE CANADA

Technology Development Priorities in the Conventional Oil & Gas Industry

- Resource Life Extension
- Cost Reduction
- Exploration Enhancement
- Environmental Protection
- Well Productivity
- Improved Reservoir Characterization

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Technology Development Priorities in the Conventional Oil & Gas Industry

Environmental

- Greenhouse gases
- Reclamation
- Abandonment (diagnose/reuse)
- Integrity of operations (automation)
- Acid Gas
- Gas Flaring

PTAC
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SESSION B
Working Group #6

LAND USE PLANNING / ENCROACHMENT

TED PHIPPS CANADIAN WESTERN NATURAL GAS
Bain McMillan " " " "

LIST OF PARTICIPANTS

Working Group #6: Land Use Planning/Encroachment

NAME	ORGANIZATION
Dave English	Amoco
Joanne Nutter	IOL
Allison Williams.	Co. of Mtn View
Don Currie	ACR.
QISHI CHEN	C-FER
Doug Clark	Gulf
Brian Plesik	Gulf
PAT MASON	WESTCOAST
don grossberndt	Amoco.
JOHN SHRIVES	ENVIRONMENT CANADA.
PIERRE OBRIEN	DPH
ROB MINCHIN	NEB
JOHN HENDERSHOT	NEB
JAKE ABES	NEB
Ralph Mayer	Maritimes & Northeast Pipeline
David DeGagne	EUB
HARRY LILLO	EUB
Jean Mulligan	W. Leiss + Assoc.
GORDON MILLER	EUB.
Bruce MITCHELL	SHELL
IAN FRASER	IMPERIAL OIL
[illegible]	TCPL.

Issues

Lack of Communication amongst various groups, notice, mapping, detail relative to products and pipe specs, timing, risks.

Data Integrity (no single source of Data is complete or accurate).

Individual Company or CAPP Task Force to carry information forward.

Task Force to look beyond Alberta and consider Eastern Canada.

All Municipalities are not members of One Call organizations Similarly all Operators are not members of One Call organizations.

Legislation of One Call organizations as a consideration.

Interpretation of data is not consistent.

Companies may not respond to requests from Municipalities for input relative to changes in Land Use proposals. (at all or within time frame provided).

Municipalities have difficulty obtaining current ownership information from the Land Title review especially if the facilities have changed hands.

Regulators may not accept role of providing data relative to product pipelines for Municipalities.

Setbacks may raise issues of compensation for lost opportunities.

Operators may not enlighten landowners of encroachment issues when acquiring land rights.

There are no consequences for developers when developments are approved close to pipelines.

Claims for damages may increase because landowners cannot subdivide land.

Focus seems to be on consequence instead of probability.

Messages to public (municipalities, planners, developers, landowners, residents, operators) may not be consistent.

Municipalities and Operators looking for support from regulators to verify type of facilities, location of facilities etc.

Communication of Safety issues to Land owners requires enhancement.

Role of Task Force vs. Role of Individual Companies.

Land Use Planning/Encroachment
April 17, 1997
Working Group # 6

Agenda

Introduction

Industry Perspective (Dave English/Amoco Canada)

Regulators Perspective (Dave DeGagne/AEUB)

Planners Perspective (Allison Williams/County Of MountainView)

Brainstorming (Ideas, Issues, Concerns)

Next Steps (Action Plan)

Questions To Consider

1. What is my level of understanding?
2. What is its (encroachment) impact on my operation?
3. What is my liability?
4. What am I doing about it?

Roles and Responsibilities

Regulators

* expand or contract the role
* Setbacks

Planners

Developers

* developers suffer no consequences

One Call Organizations

* mandated

Compensation Issues

MIACC Guidelines

Priorities

Communication

* a shared responsibility.
* focus on safety of pipelines.
* needs to be a consistent message throughout industry to all Stakeholders
* data sources (technology).
* data integrity.

PERSPECTIVES OF PIPELINE INDUSTRY

How Encroachment Affects P/L Companies

- More activity near line - increased risk of 3rd Party damage (signs & One-call organizations still main deterrent to 3rd Party damage)
- For HVP and gas lines, density of residents affects design factor for p/l (CSA Z662) - Line may in fact have to be replaced with stronger pipe
- Due to lack of involvement in planning of some developments, company personnel must often object to some developments while trying to work with planners on future developments when obtaining easements for other new p/l projects.

Evolution of the Encroachment Problem

- Pipeline Route initially chosen to minimize cost while being reasonably careful to avoid potential growth areas
- Over the years, smaller communities, country residential and acreage developments are expanding
- P/L companies often find out about developments late in planning process

P/L Companies' Position Towards Encroachment

- Need for AEUB information letter similar to sour gas IL
- Need for Municipalities to appreciate P/L Company's position
- Urgency of situation- companies are facing increasing number of encroachment issues each year

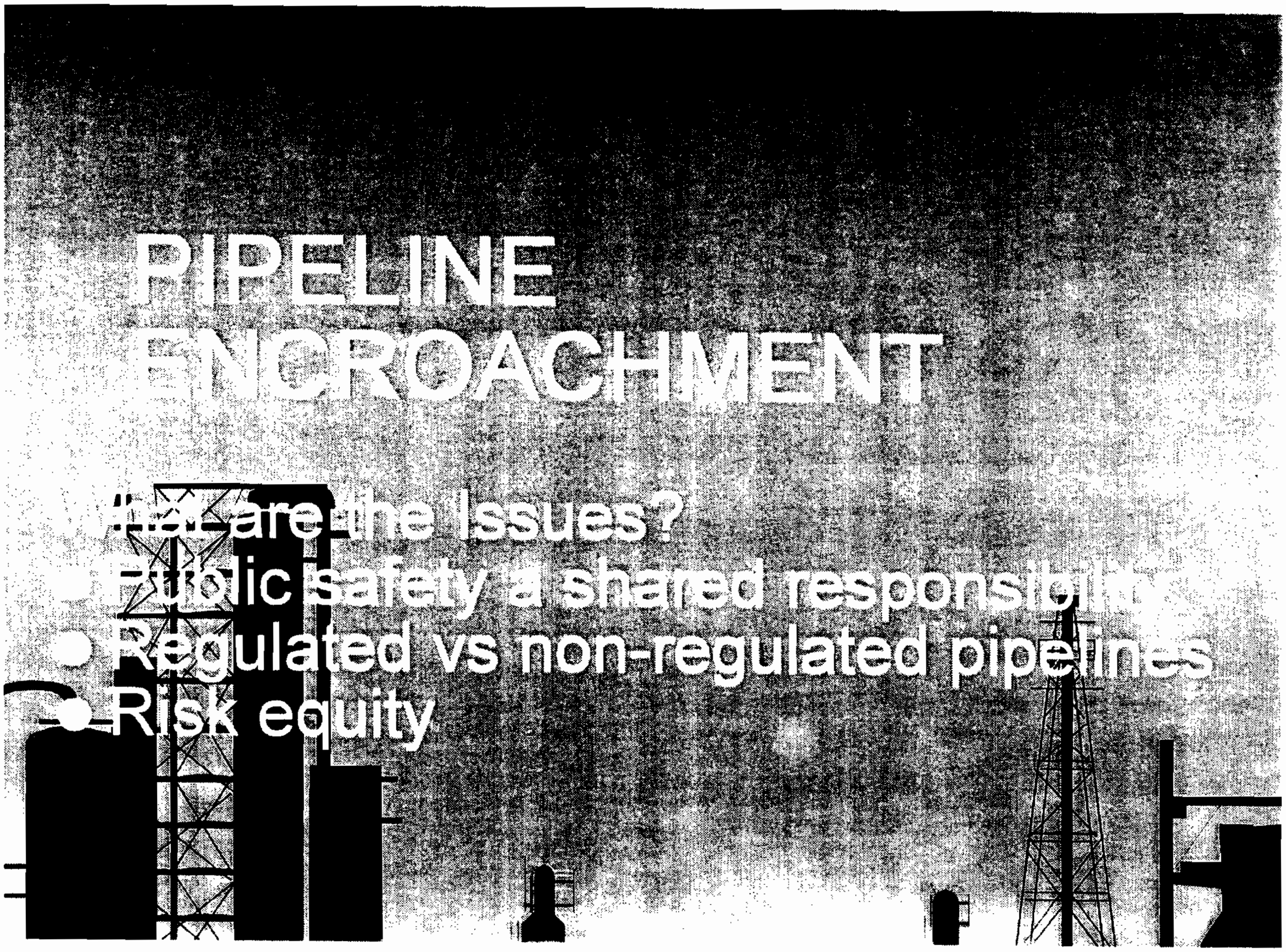
Task Force Action Plan

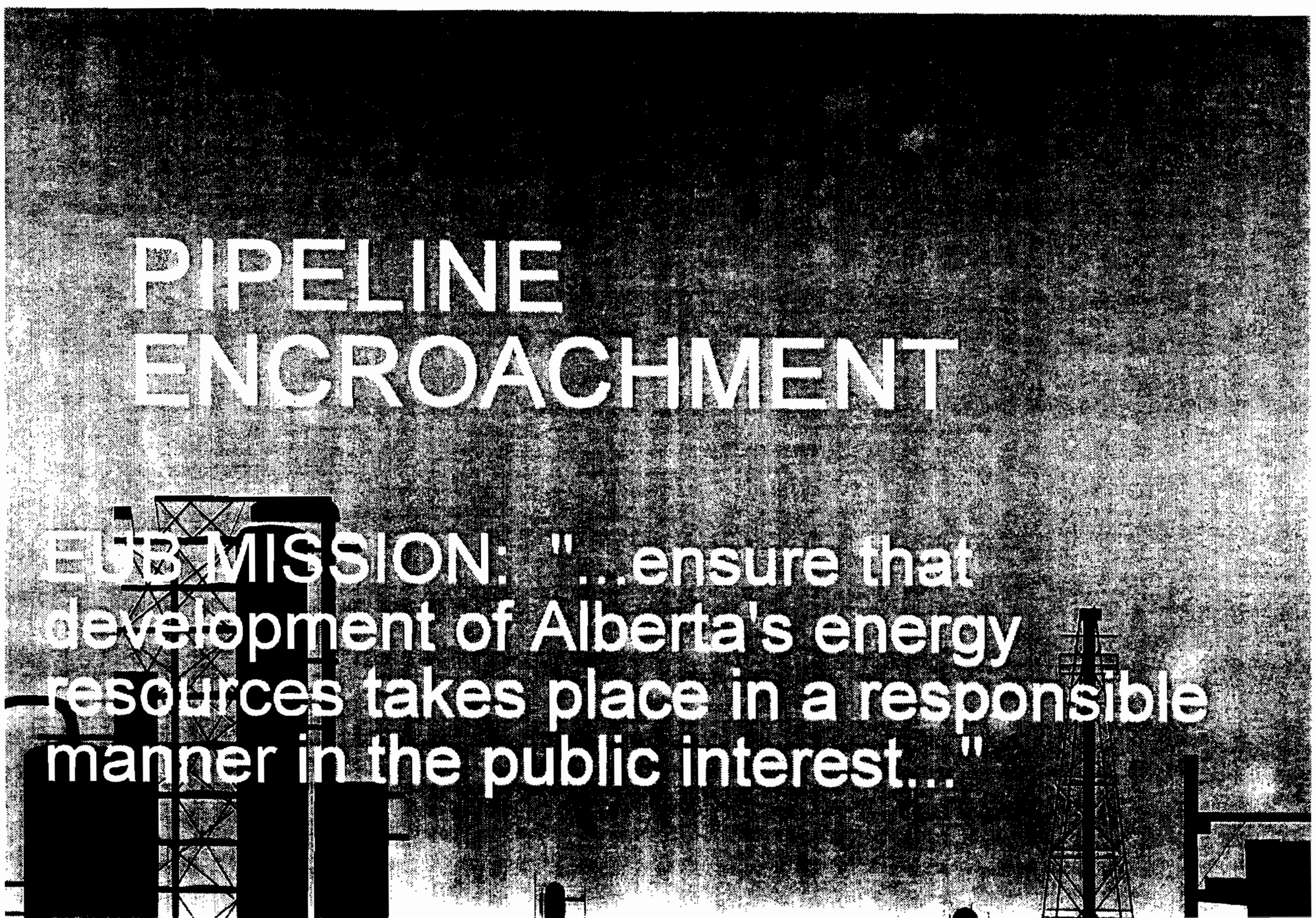
1. Willingness to Share Information With Other Organizations

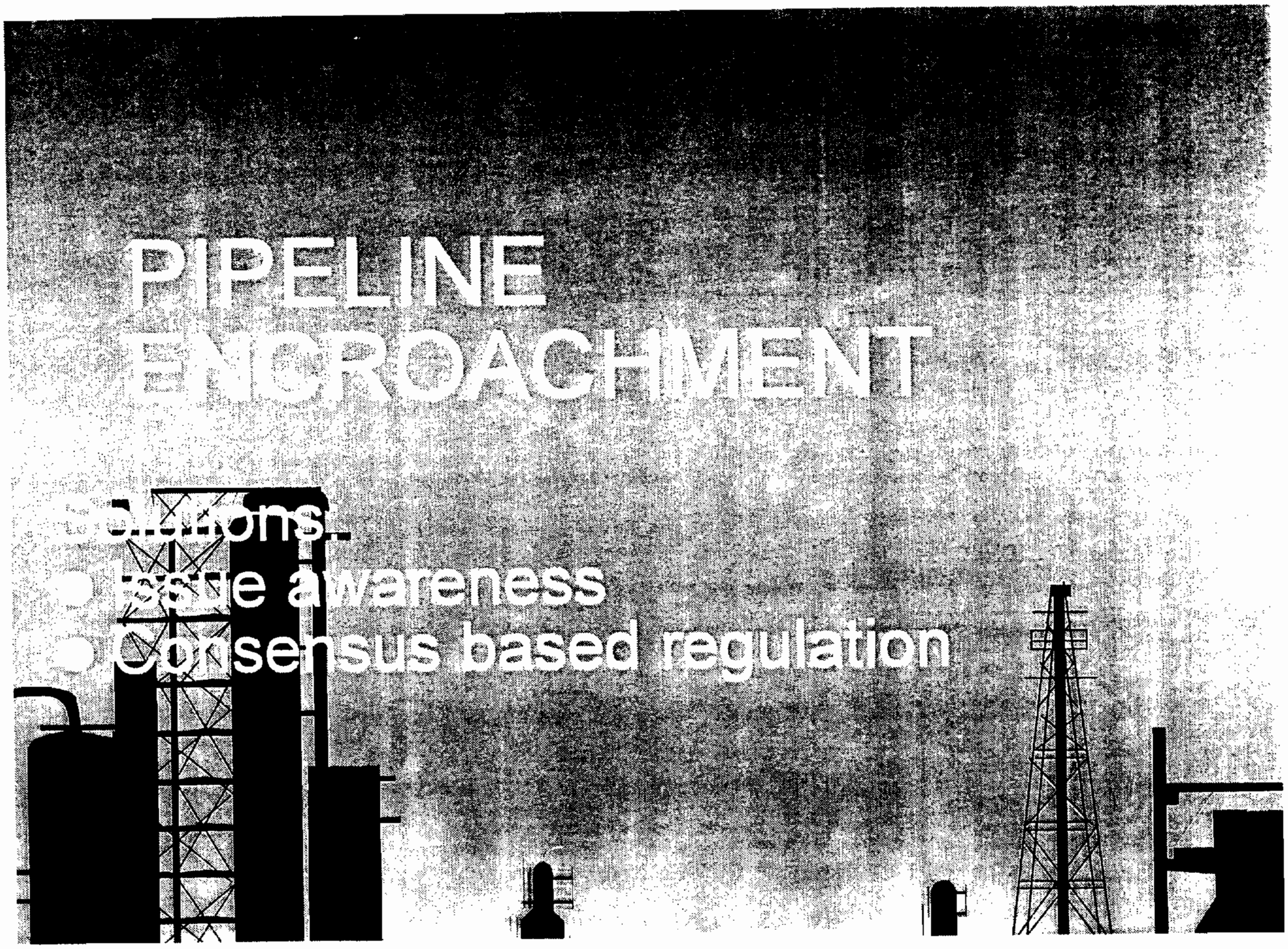
2. Communication must acknowledge risk, address probability, and plans to mitigate risk.

3. Role of Task Force is to communicate with Associations of Municipalities and Planners.
   Role of each individual Company to communicate on individual requests.

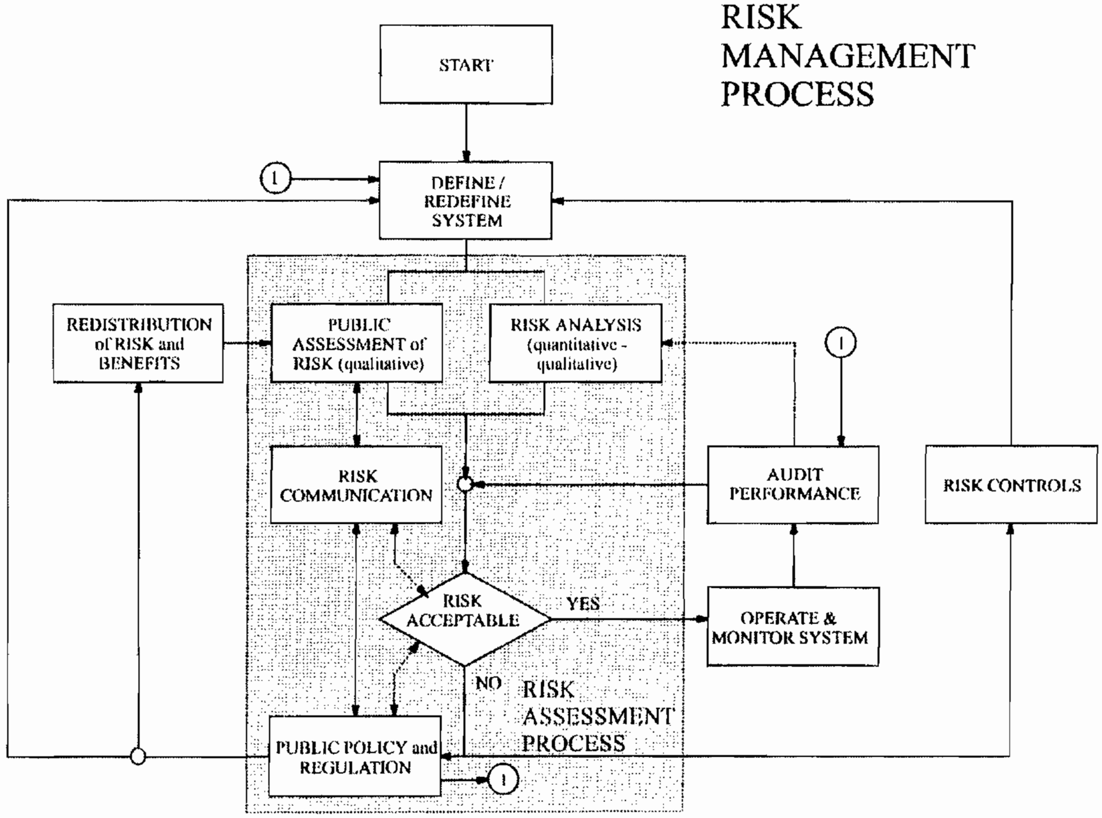
4. Reinforcement of Objectives of Task Force.


PIPELINE
ENCROACHMENT
What are the Issues?
● Public safety a shared responsibility
● Regulated vs non-regulated pipelines
● Risk equity


PIPELINE
ENCROACHMENT
EUB MISSION: "...ensure that development of Alberta's energy resources takes place in a responsible manner in the public interest..."



RISK
MANAGEMENT
PROCESS



Issues Regarding Oil and Gas Industry from Municipal Perspective:

- Municipalities rely on the Alberta Energy and Utilities Board (AEUB) for information regarding oil and gas industry specifically the location of pipelines, wells and related facilities (identification of setback requirements).

- There should be co-operation with oil and gas companies regarding location and type of development within municipality.

- Municipalities rely on information obtained from Certificate of Titles for use in considering applications for subdivision and development.

- Landowners are generally unaware of the development restrictions placed on property as a result of pipelines, wells, etc.

- Municipal Government Act requires municipalities address sour gas facilities specifically within planning documents.

- County of Mountain View Land Use By-law requires a setback from oil and gas facilities (some land use districts) that is greater than required by AEUB.

- There is a time element for referrals to AEUB.

HIERARCHY OF PLANNING DOCUMENTS AND LEGISLATION

Municipal Government Act
(Part 17)

Subdivision and Development Regulation
Provincial Land Use Policies

Municipal Development Plan

Area Structure Plan / Area Redevelopment Plan

Land Use By-law

PROCESSES:

* Redesignation
* Subdivision
* Development Permit
* Building Permit

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Issues Regarding Oil and Gas Industry from Municipal Perspective:
(Continued)

- There is a need for developers, landowners, oil and gas companies and municipalities to co-operate.

- There is a concern regarding impact of abandoned wells and pipelines on subdivision and development proposals.

- Municipalities need to consider issues of safety relative to the existence of oil and gas facilities, but also must consider landowner rights as well.

Priorities

Communication

* a shared responsibility
* focus on safety
* needs to be a consistent message throughout industry
* needs to focus on "probability" component of risk
* database developement
* data integrity

Roles and Responsibilities of Regulators

* Expand or Contract Setbacks

Roles of Planners

Roles of the Developer

Roles of One Call Organizations

Compensation Issues

MIACC Guidelines

Issues

Lack of Communication amongst various groups, notice, mapping, detail relative to products and pipe specs, timing, risks,

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Messages to public (municipalities, planners, developers, landowners, residents) may not be consistent.

Municipalities and Operators looking for support from regulators to verify type of facilities, location of facilities etc.

SESSION D
Working Group #7

EXTERNAL CORROSION

LIST OF PARTICIPANTS

Working Group #7: External Corrosion

NAME	ORGANIZATION
Don Currie	Alberta Chamber of Resources
MARTYN WILMOTT	NOVA RESEARCH + TECHNOLOGY.
Walter Kresic	IPL
DARYL BAXANDALL	NeoCorr Engineering Ltd
LYLE GERLITZ	JLG ENGINEERING LTD
QISHI CHEN	C-FER
BRIAN HOLTSBAUM	ASSOCIATED CORROSION CONSULTANTS
Kevin T. Parker	Corexco, Inc.
SANKARA PAPAVINASAM	CANMET/MTL
REDSTERS PARKINS	UNIV. NEWCASTLE U.K.
BRUCE DUPUIS	FOOTHILLS PIPE LINES
Stanley Wong	Canadian Western Natural Gas
Glenn Yungblut	OMAE
DELTON GRAY	NORTHWESTERN UTILITIES
Ben Sokol	Northwestern Utilities
CHRIS BILLINTON	BC GAS
Casey Steneker	Imperial Oil Ltd.
LEN DANYLUK	IMPERIAL OIL RESOURCES LTD.
WAYNE CHIASSON	AEUB
LARRY MAXWELL	AEUB.
SHU C. LEE	AEUB
ERROL BATCHELOR	WESTCOAST ENERGY LTD.
RON COOPER	NORTHSTAR ENERGY / MORRISON PET.
DON SINCLAIR	WESTCOAST ENERGY

Jules Chorney	TransGas Limited
PHIL SANDHAM	TRANSGAS LIMITED
ROB MINCHIN	NEB
PAUL TRUDEL	NEB
Mark Fawcett	SLRI Consultants Limited
GRAEME KING	GREENPIPE INDUSTRIES
PAUL WONG	NOVA GAS TRANSMISSION LTD.
Mark Yeomans	Nova Gas Transmission Ltd.
LARRY LAI	NOVA CHEMICALS LTD
GREG HILL	TRANS MOUNTAIN PIPE LINE CO.
Norm Rinne	TMPL.
Ray Smith	National Energy Board
DUANE CRONIN	UNIVERSITY OF WATERLOO
Roy Pick	UNIVERSITY OF WATERLOO
SCOTT PETERSON	LAKEHEAD PIPELINE Co.
Erwin Mackintosh	~~ESA Inc~~
FRANK CHRISTENSEN	FMCMCI
Rob Power	National Energy Board.
Mike Bell	Westcoast Energy
B. MUKUL MUKHERJEE	ONTARIO HYDRO
BRUNO ST-LAURENT	TQM PIPELINE
MARTIN FINGERHUT	RTD QUALITY SERVICES INC
Yvanna Ireland	TCPL
Jim Griffin	TCPL
BURKE DELANTY	TCPL.

	Test Labs International Ltd
Wayne Tennesen	IMPERIAL OIL RESOURCES
ANDREW WOZNIEWSKI	TCPL
Glenn Yuen	
Kevin Cicansky	TCPL
Ernie Sin [illegible]	[illegible]
VALENTINO PISTONE	SUAM
Jamie Cox	DuPont Canada

Working Group #7: External Corrosion

__Co-chairs:__
Susan Miller (Interprovincial Pipe Line Inc.)
Robert Worthingham (Nova Gas Transmission Ltd.)

Main topic: Corrosion growth
- round table on what approaches are being used for determining the rate at which corrosion is progressing
- emphasis on OLD pipelines

Presentations:

Tom Morrison, Morrison Scientific Inc. (presentation material attached)

Daryl Baxandall, NeoCorr Engineering (presentation material attached)

QUESTIONS:

SNAM: How do you match the ILI data considering the differences in quality of data over successive pig runs; i.e. different levels of accuracy in the tools over the years?
Tom Morrison: Morrison Scientific asked for the data output in a certain form and presently has been able to analyze low and high resolution data. Differences in tool accuracy over the years is not a big problem.

Burke Delanty: Are you trying to determine if there are different corrosion rates with different field conditions, soil models, coating types?
Bob Worthingham: Not yet; we don't have all the data analyzed to date, but that is one of the ultimate goals in the program.

Round Table Questions/Comments on Corrosion Growth Rates:

BC Gas: no comment.

Canadian Western Natural Gas (CWNG): CNWG have never done an ILI, but looks like it will happen within the next year or two; have line restriction problems which have to be dealt with before the runs.

Conoco: no comment.

Foothills Pipe Lines Ltd.: FPL's is in the process of developing when and how they will be doing their ILI program.

Gulf Canada Resources: no comment.

John Norris	TCPL
Catherine Hoffman	U.S. MMS
Mark Ottem.	TMPL.
Greg Toth	TMPL.
ART HARMS	CWNG
PAUL GRECO	UNION GAS
Alex Petrusev	"
ARNOLD BELL	FEDERATED PIPE LINES LTD.
SUDHIR PARAB	PETRO-CANADA OIL & GAS
DENIS TRUDEAU	CORRPRO CANADA INC.
DENNIS WONG	SHAW INDUSTRIES, LTD
JIM HOPE	CANUSA
DILIP TAILOR	CANUSA / SHAW INDUSTRIES.
DALE DYE	SHAW PIPE PROTECTION LTD.
RAY GOODFELLOW	CHEVRON CANADA RESOURCES.
RICH THOMPSON	CHEVRON RESEARCH + TECHNOLOGY CO.
PETER FERRIS	Indian & Northern Affairs
Terry Maccagno	Univ. of Alberta
Richard Kania	RTD Quality Services
DARYL RONSKY	CONSULTANT
BOB EIBER	CONSULTANT
ALEX ALVARADO	MMS
KEITH CARR	NORTHSTAR/MORRISON
Guy Desjardins	Morrison Scientific Inc
ARTI BHATIA	Interprovincial Pipe Line Inc
MAGNE OSTBY	CorrOcean Inc., Houston TX

Bob Worthingham: The key things are location of corrosion and its dimensions; you will have inherent error (bars) with any tools; just narrower with higher resolution tools. The operator must specify what they want reported to ensure consistency.

Bob Sutherby: Do you find on subsequent runs with a given tool that features get smaller; do you find accuracy different than the accuracy claimed by contractors?
Bob Worthingham: On occasion, some features get smaller. 2nd question: It depends on the method you use to measure the actual corrosion - is the error in the tool or in how you measure the actual corrosion? Overall, the tools and accuracy are pretty good.

Bruce Dupuis: Are the error bars used from those of the vendors or those determined from field excavations?
Bob Worthingham: The error bars used are those determined by ourselves the operators.

Audience: Do you ever take the pig data itself or rely on the vendor?
Bob Worthingham: We use what is supplied by vendor but provide feedback to vendor on the quality of data observed. We specify format the data needs to be supplied in and the specific items of data to be reported.

Audience: Have you noticed any effect of residual magnetism on negative growth rate?
Bob: No. Also may need to consider the effect of operating stress in the pipe wall at the time of inspection.
Susan Miller: We need to consider this problem as it may have an effect on signatures received.

Audience: Residual Magnetism: has anyone found a way to demagnetize before the run?
Susan Miller: Methods are not well defined.

SNAM comment: current pigs are very good over 30-40% wall thickness loss. Less accurate on 10-20% defects. Have also seen errors in location and tool saying there were internal defects (which were not there).
Bob Worthingham: Repair should be based on length <u>and</u> depth. Do you incorporate length as well?
SNAM: They excavate defects according to the B31G curve.
Susan Miller: There appears to be great differences between European and North American inspection defect populations/distributions: can likely attribute the effect to thicker coating types and thicker pipe used in Europe; North American operators may therefore have more challenges in prioritizing due to number of defects.

Audience: What criteria is used to determine as to when you conduct a repair?
Bob Worthingham: Project the growth rates forward in time for each pit to determine when they grow to an unacceptable size according to the failure criteria specified by the operator.

Imperial Oil Resources Limited: Planning based on data gathering and database development to get to a stage to determine when and where they will inspect.

Lakehead Pipe Line Company: Progress to be made in optimizing the reinspection interval and evolution of risk management programs.

Morrison Petroleums: Have a 5 year inspection program; this year will be the first using regular inspection intervals.

Pacific Northern Gas: no comment.

Shell Canada: no comment

IPL, NGTL: Using Morrison Scientific Inc. to determine site specific corrosion growth rates and optimize maintenance programs.

TCPL: Will use the NeoCorr program/growth rates to dig/repair in the event the defect would exceed a predetermined criteria. The intent is to extend reinspection frequencies.

Trans Mountain Pipe Line Co. Ltd.: Have 25 years of ILI history; presently in the third run of ILI tools; have run low and high resolution runs; problem with old data is that it is hardcopy.

Union Gas: Have been running the smart MFL tools for 3-4 years; before that, ran low resolution tools.

Federated Pipelines: Incorporate risk assessment in determining when and where for inspection runs; e.g. have run population-driven inspections. Have used low resolution tools in past, but are graduating to high resolution tools. Have not correlated between runs. Will be working with a consulting company to incorporate all corrosion problems in integrity program.

SNAM: 20 years experience; not yet decided to run pigs on regular basis.

QUESTIONS:

SNAM: Will we be able, in 10 years, to correlate these runs since tools are different (different manufacturers) and accuracy changes with time? Statoil has agreement on standard operating parameters with Pipetronix, therefore it is more likely data will be consistent between data runs.
Tom Morrison: This should not and has not been a problem. The operator has to consider, rather, the difference between knowing the growth rate (even below the tool accuracy) and not knowing anything at all.

Audience: Why is corrosion data not coming into a common database just like SCC?
Bruce Dupuis: The CEPA database does cover corrosion, dents, gouges, etc. so the platform is there. Growth rate data could be added, but there is no connection back to ILI data within the program.
Bob Sutherby: The fields in the CEPA database are the same as those used for collecting corrosion site information.

SNAM: How can we use data from piggable lines and apply it to unpiggable lines? SNAM is trying to use CP data.
Martyn Wilmott: That is the reason we developed the NOVAProbe to correlate to corrosion growth rate data to the on site conditions and then possibly extrapolate the data collected on larger lines to smaller diameter lines in similar soil conditions.

Susan Miller: What is the value in projecting pit by pit corrosion growth rates using two runs? Is it enough to develop a site specific integrity program?
Susan Miller: Probably not, but could help determine program for longer sections of pipe with a number of like defects.
Bob Worthingham: It could help you see a geographic distribution in longer sections and focus maintenance activities.

Martyn Wilmott: Need to correlate the ILI data with soil models, etc. and the value in this technology will be fulfilled when we take this step.

Arti Bhatia: Also sees value in going to the vendor, and outlining what the companies expectations are.

Martyn Wilmott: What kind of trends has Morrison Scientific seen over 3 inspection correlations?
Tom Morrison: Work is in progress.

Bob Worthingham: As an aside, NGTL plans on testing effect of pulsed CP and to use this matching program to verify its effect.

Session Questions:

Do you think there is value for the corrosion industry in determining corrosion growth rates? Overwhelming YES!

Would P/L operators be willing to run 2 sequential runs of high resolution ILI's? Not for R&D purposes; would do runs when required and therefore in time you would get this data.

How many people would like to see this growth rate calculation as a recommended practice?
Martyn Wilmott: If you can correlate to environmental conditions, upstream producers and other producers may find it very valuable.
John Beavers: Can only say that these may be the maximum growth rates but they will vary even within the same soil types, pipe conditions. The leap into using it for other lines may not be immediately possible.
Alex Potrusev: Recommended practice? Too close to a code . End user should have discretion on when to use.

Any interest in having more updates on these activities at future workshops? YES!

Burke Delanty: Would it be worthwhile to agree on common data and methodology to be gathered for comparison purposes? Yes.

Trigg was the NOVA technical liaison many years ago when the program began. Halsey Boyd, Paul McKerley, Zeenat Virani, Ron Hill, Naurang Mangat, Fatima Janmohamed, Steve Waker and Lois Clark of Morrison Scientific Inc. have all contributed to the methodology described in this paper.

1 Introduction

Many pipeline transmission companies use high-resolution in-line inspection tools as part of their corrosion mitigation programs. The objective of the use of the tools is to determine those corrosion features of high risk to the integrity of the line, and to remove them. From the viewpoint of growing corrosion features, the measurement situation (only given one inspection) is static in that only those features of low failure pressure *at the time of inspection* will be removed. Features of higher failure pressures that are growing at a fast rate (subsequently with lower failure pressures), will be missed due to the static nature of the situation, though it is possible to perform broad-scale analyses of the risk by estimating the growth of features and inputting this growth into a Markov chain model.

The timing between inspections is critical to the re-measuring of any quickly growing features before they grow to rupture or leak. Consider the advantage a company would have if they could determine, somehow, the best estimate of the growth of *each and every* corrosion feature between a current and a past inspection. Using this information the best estimate of the total risk to any particular pipeline that had been inspected twice could be determined.

NOVA Gas Transmission (NGT) asked Morrison Scientific to develop software capable of determining corrosion growth rates for each and every corrosion feature on a pipeline. The software contains the technology to automatically identify the same feature from one inspection to an inspection conducted at an earlier time and to determine the growth rate between the inspections. The software also determines the risk of the pipeline to every individual corrosion feature. The methodology requires ILI (in-line-inspection) high resolution data from one or more inspections.

The growing corrosion aspect of the problem of determining how to maintain a pipeline has been solved using this new technology. The pipeline is protected against ruptures and leaks at a minimum cost and the absolute maximum amount of information from the expensive inspection data is obtained. Using the individual growth rate results, the pipeline company is

Advantages of Exact Growth Information for Every Corrosion Feature on a Pipeline Using High Resolution In-Line Inspection Tools

Bob Worthingham
NOVA Gas Transmission
Calgary, Alberta

Tom Morrison
Morrison Scientific Inc.
Calgary, Alberta

Guy Desjardins
Morrison Scientific Inc.
Calgary, Alberta

Banff/97 Pipeline Workshop
April 14-18, 1997

Managerial Summary

It is possible to examine the growth of each and every corrosion feature on a pipeline. This information can be used to determine those features that should be removed after an in-line inspection, and also those that are expected to grow in the future. Error bars on estimates of growth and potential risk to the pipeline can be determined. The ultimate objective is to create an estimate of when the pipeline should next be inspected in order to keep the risk of a leak or rupture below some acceptable probability.

Much time has been spent determining error bars or confidence intervals of the accuracy of the magnetic flux leakage tools. The confidence intervals are important because it is not the "best estimate" of the failure pressure of a feature that is important, but rather the probability a particular feature will cause a rupture or leak. The confidence intervals aid in this latter determination.

Acknowledgements

Many people have helped develop the science and computer programming aspects of the corrosion feature matching and growing program. Alan

2 The Most Important Result: Exact Growth Rates for Each and Every Feature

2.1 The Failure Pressure Ratio

The FPR (failure pressure ratio) depends on the MAOP (maximum allowable operating pressure), and is given by

$$\text{FPR} = \frac{\text{Failure pressure of box, cluster or group}}{\text{1.25 MAOP or Test Pressure}}.$$

From here on the phrase "feature" represents a box, cluster or group. The FPR is an indication of severity of a feature. As the FPR increases, so does the severity. Where interaction is possible, it is examined. The interaction between two or more boxes may serve to *reduce* the pressure at which a rupture will occur, thus *raising* the FPR. Possible interaction is what creates clusters and groups from boxes.

A feature of the same size will have a different FPR if the MAOP is different on two different pipelines.

The hydrostatic test failure pressure ratio is 1.00. A rupture will occur if the FPR is equal to 1.25, the difference between 1.00 and 1.25 being due to safety factors and regulatory requirements. If the FPR of a feature is greater than 1.00 the feature requires repair.

The minimum detectable FPR of a feature depends on the pressure of the pipeline. For one of NGT's pipelines, operating at 820 psi, the minimum detectable FPR is about 0.76.

The most important aspect of the results of the work performed for this project is the better identification of problem areas of the two pipelines under consideration by including the growth estimate in the matching process versus simply examining the FPR's of the largest 100, 1000 features, or all features above a given FPR, etc. Inclusion of the growth of each individual feature makes better calculation of the future status of the line between now and the next proposed inspection.

The FPR is a reasonable concept to use as a repair guide for features where rupture is concerned. The maximum penetration, called %WT, is a reasonable concept to use as a repair guide for features where a leak is concerned.

also capable of making more rational decisions about what to remove, and when next to inspect the pipeline.

The major objective of the studies is to provide to a transmission company data such that the company is able to:

1. determine what to sleeve, re-coat, replace, etc., after the current state and growth of each corrosion feature is known,

2. prepare a best or accurate cost estimate for the inspection and maintenance program to any time in the future,

3. conduct a best or exact reliability analysis, giving information on when to next inspect a pipeline, given the reliability analysis, and

4. determine feature initiation and new feature growth rates.

This information gives the operator the ability save a considerable amount of money because of the best possible knowledge being extracted from the data.

Many current inspection and maintenance programs are *ad-hoc* in that they consist of

1. inspect after a rupture or leak, or

2. inspect at pre-set time intervals,

whichever comes first. It is the ability of the new in-line inspection tools developed over the last decade that has given the pipeline operator the chance to use this corrosion feature matching technology to better understand the situation on their pipelines.

Any high resolution ILI tool can be used to prepare the data in a format suitable for the matching process.

Interior corrosion growth and stress corrosion cracking can also be analyzed, so long as the measurement system has reasonable resolution to enable repeated identification of the same features.

4. Underwater and undersea pipelines where repairs are much more costly than for land pipelines.

5. Critical non-looped pipelines.

4 Status-Quo versus the New Methodology

There are two *very* different plans-of-action a transmission company can use as the centre point of the maintenance procedure for its pipelines with corrosion problems, *vis*

1. Use ILI (in-line-inspection) data after an inspection every given time period (determined by the company's engineers) and repair all features with FPR's (failure pressure ratio's) greater than some level, with the hope that between that time and that of the next inspection none of the remaining features will grow to rupture or leak, assuming one corrosion rate for all features in determining the next inspection.

2. Use the same ILI data, but analyze it in greater detail, to determine site-specific growth rates, using the automatic correlation, for *all* corrosion features and so determine site-specific replacement/sleeving, etc., portions of the pipeline, coupled with as complete as possible understanding of risks and costs. In short, this methodology uses the FPR after an inspection, and the measured growth rate for each feature on the pipeline in the risk analysis whereas the first method only uses the FPR after an inspection and a single assumed growth rate.

Both methodologies can be used for determining penetrations through the wall of the pipe—the first uses only the current penetration and the second can use the growth of the penetration.

It should be obvious that the first methodology does not give nearly the same quality of understanding as does the latter methodology.

The authors believe that use of the second methodology will enable a company to accurately estimate the frequency and costing of repairs. Use of the methodology will also enable the company to maintain its pipelines for an indefinite time period into the future.

In terms of using all available knowledge to assess the risk and costs of a pipeline, it is the potential of a low FPR but growing feature to rupture, associated with the inspection, shut-down, insurance, loss-of-face and other costs that justifies the automatic correlation program.

2.2 Best Estimate of Site Specific Growth

In Figure 1 the results of growth estimates for a 15 metre section of high pressure line pipe are illustrated. This type of output gives the transmission company the most detailed and site specific analysis of growth for any section of its pipeline.

3 When is This Type of Activity Warranted?

Consider a transmission company that has some sections of high pressure line pipe that are experiencing corrosion growth. In general, to date the method used to determine when the next inspection should take place was done using maximum growth rates experienced for those features that ruptured, or calculated based upon an "assumed" growth rate (perhaps from a laboratory study or past rupture data). The maximum growth rate is all that can be determined since the last inspection, rather than a distribution of growth rates, because the line is only repaired where a rupture occurred. The maximum growth rate forces the company to go through the expensive inspection process perhaps more often than they should.

Knowledge of the distribution of growth rates can give a much more accurate picture of the corrosion regime on the pipeline, and, with practice, can increase the confidence of the transmission company in the reliability of its pipelines. Government agencies can also be assured of higher reliability. In short, the probability of unplanned ruptures and leaks should be reduced substantially because the transmission company will be able to determine those features that have a probability of a rupture or a leak above some small value as determined from the exact matching process. Growth into the future (i.e. calculation of future failure pressure or maximum penetration) can be calculated, with confidence limits as well.

This type of activity is warranted under several conditions, some of which are listed below.

1. High corrosion growth rate regimes where the objective is to determine those features that are high risk.

2. Pipelines with a large amount of corrosion where a manual analysis is too prohibitive.

3. Critical pipelines in highly populated areas.

repeatability and resolution of the tool are important criteria for input into the analysis in order for the software to determine if two features differ in characteristics too much for a match to be possible.

Different maintenance schedules and repair philosophies can be modelled based on the growth of each feature.

7 Stress Corrosion Cracking, Interior Corrosion

Any aspect of pipeline integrity that can be measured using an ILI tool can be incorporated into the software because the matching procedure is robust.

8 Resolution and Repeatability of the ILI Tool

It is possible, using single box to single box matches, to determine the resolution and repeatability of the ILI tool, and using the results of the analysis yield valuable information to both the user of the tool and the creator of the tool. This has been done as part of this study.

The advantage of this analysis, as compared to a "laboratory study" of ILI tools is that this is a real world test as compared to a test of specifically shaped features in a wall of a pipeline.

There are several variables that can be analyzed in the resolution and repeatability analysis and they are

1. relative distance position in a weld,

2. orientation position in a weld,

3. length,

4. width,

5. maximum wall penetration (%WT) or maximum depth, and

6. failure pressure ratio (though this is a function of length, average depth, maximum depth).

What is most obvious is that there are indeed resolution and repeatability aspects of the tool that are important—and can be used as input into determining the parameter tolerances that are used in the automatic correlation.

To be more specific it is the belief of the authors of this paper that use of the ILI data can significantly reduce costs by

1. Determining those areas of the pipeline that should be replaced, thereby removing a high growth rate or high feature density area.

2. Enabling the company to show to regulators *what* was removed/repaired and *why* it was removed/repaired. This is a full demonstration of using the ILI data to minimize corrosion risk in the future rather than using a cursory and unsatisfactory set of explanations.

3. Fully determining the growth rate of every observed feature on the pipeline and being able to determine the risk to the pipeline due to every feature.

The first maintenance methodology is *reactive*, and rests on only removing high FPR features. The first methodology assumes one corrosion growth rate for all features in determining the next inspection. The second methodology—the feature matching and accurate individual growth of each feature methodology—is *proactive* and gives the best possible estimate of what is actually occurring on the pipeline.

5 Initiation of New Corrosion Features

The matching process can be used to determine those boxes that are new since the last inspection. The growth analysis can be used to determine their growth between inspections.

Given the number of new features on a section of line, and their growth distribution, an assessment of the future feature initiation can be made.

This is yet another valuable serendipitous product of the use of the automatic correlation or matching analysis.

6 Other Uses for the Data

Matching of the features enables the user of the ILI tool to determine in the best way the repeatability of the inspection tool—particularly where the characteristics of the feature *decrease* from one inspection to the next—such as length, width and wall penetration. This is very important information for the engineers that created the ILI tool and is a *real world* test instead of a laboratory test. The information also helps the users of the data because

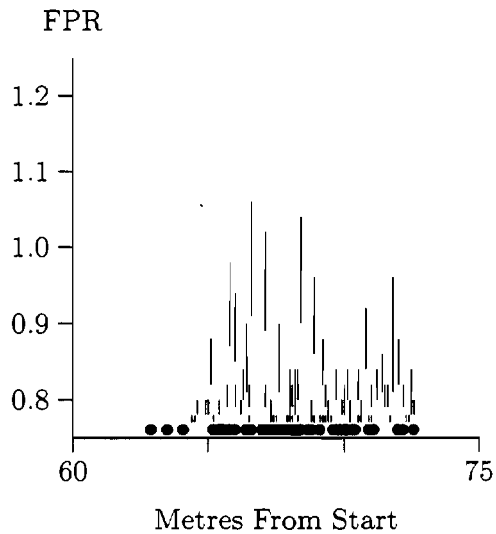


Figure 1: Growth of Individual Features

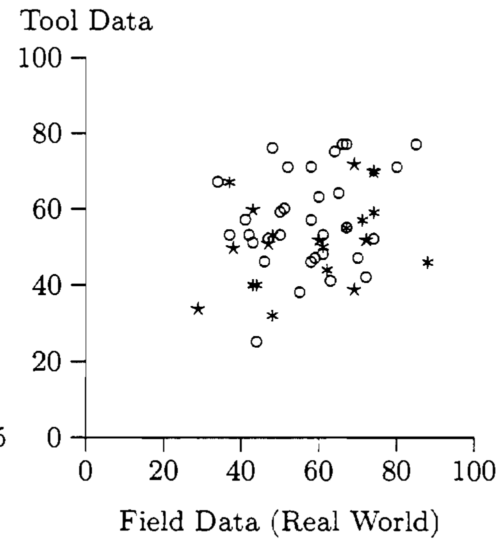


Figure 3: Tool Data vs. Real World

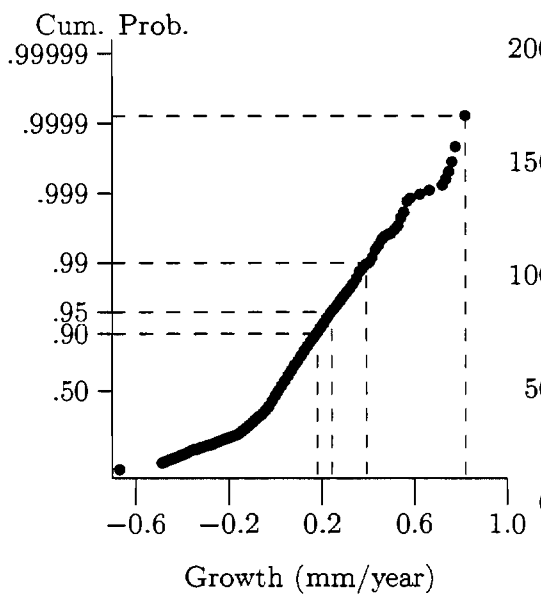


Figure 2: Distribution of Growth

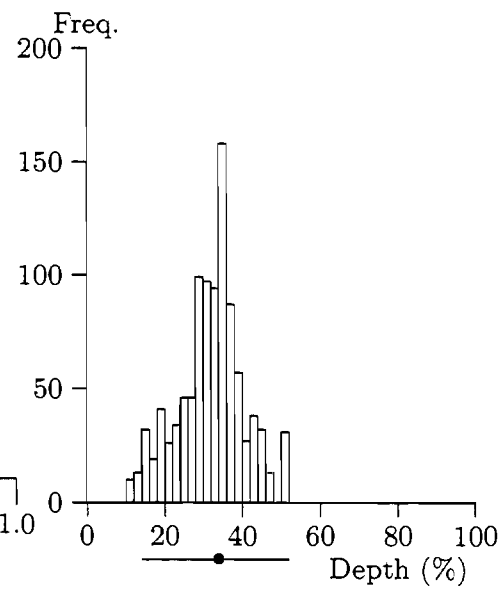


Figure 4: Confidence Interval for Depth

The relative distance positioning of single box feature to single box feature matches can change by up to 400 mm.

It has been noticed that on several occasions the orientation of a box is not the same between two inspections, being different by up to 25° or so.

The failure pressure ratio is a function of length, average depth and maximum depth. If any of these three variables changes, the failure pressure ratio will also change.

Length, width and maximum depth of the feature can decrease, sometimes substantially. (This is not a "matching problem" but rather is an interpretation problem of the tool.)

In order to illustrate the effect a decrease in maximum depth can have on the failure pressure ratio a correlation graph of decrease in FPR and the decrease in maximum depth has been prepared.

BANFF/97 PIPELINE WORKSHOP

Managing Pipeline Integrity - Planning for the Future

External Corrosion

LudaSTRENG - Pipeline Corrosion Defect and Growth Assessment Software

Daryl Baxandall - NeoCorr Engineering Ltd.

April 17, 1997

LudaSTRENG - Pipeline Corrosion Defect and Growth Assessment Software

- **The LudaSTRENG Software was developed to rapidly process large amounts of smart tool inspection corrosion defect data**

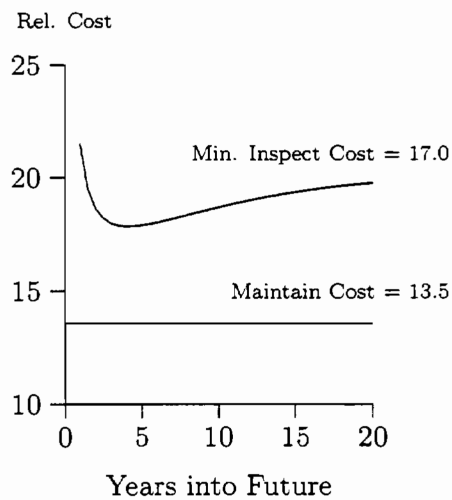


Figure 5: When to Inspect Next

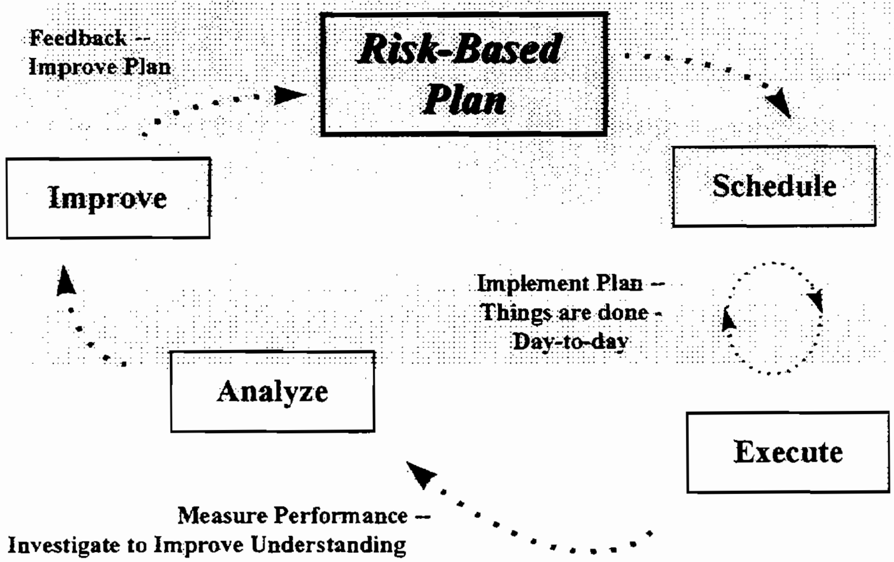
LudaSTRENG Criterion

- LudaSTRENG incorporates ANSI/ASME B31G and RSTRENG criterion to assesses the remaining strength of corroded pipe
- Calculates Effective Metal-Loss Area of the corrosion pit based upon various subsections of the total area of metal loss of the corrosion pit
- Corrosion Rate calculations based on work performed by Dr. Thomas J. Barlow

Parabolic River-Bottom Profile

- Mathematical algorithm to develop a parabolic river bottom profile based on the length and depth of the corrosion defect
- Algorithm capable of handling multiple cluster corrosion defects
- Length and depth values of the corrosion defect are used in the Burst Pressure Calculations
- Method develop by Jim Mihell and Kim Levitt of TransCanada Pipelines

Quality Pipeline Maintenance Model



Strength of the LudaSTRENG Software

- Prioritize specific Pipeline Defects for Immediate and Future Mitigation
- Non-linear corrosion rates are calculated on each individual corrosion defect and the corrosion defect is grown in yearly increments

LudaSTRENG Calculations Vs. RSTRENG Calculations

LudaSTRENG Calculations Vs RSTRENG Calculation

Item No.	Pipetronix' Burst Pressure (kPa)	LudaSTRENG 0.85 dL Area Burst Pressure (kPa)	RSTRENG 0.85 dL Area Burst Pressure (kPa)	% Deviation	LudaSTRENG Effective Area Burst Pressure (kPa)	RSTRENG Effective Area Burst Pressure (kPa)	% Deviation
	Single Pits - Comparison of Methods						
1265	5620	7433	7428	0.07	7706	7707	-0.01
2142	7820	7909	7905	0.05	8518	8522	-0.05
2155	5620	7436	7432	0.05	7713	7713	0.00
	Cluster Pits - Comparison of Methods						
536	8964	9529	9559	-0.31	9835	9902	-0.68
1061	8964	9536	9536	0.00	10018	10020	-0.01
1518	8964	8648	8698	-0.58	9998	10038	-0.40
1648	8447	8854	8796	0.66	9488	9539	-0.54
2468	8829	9324	9324	0.00	10089	9961	1.27

LudaSTRENG Pit Growth

LudaSTRENG Calculations Pit Growth Verification

Item No.	LudaSTRENG Burst Pressure Year 1	LudaSTRENG Burst Pressure Year 5	Manual Calculation Burst Pressure Year 1	Manual Calculation Burst Pressure Year 5	% Deviation of LudaSTRENG Vs Manual Calculations Year 5
	Single Pits - Comparison of Methods				
624	9834	9893	9947.00	9899.00	-0.06
924	9274	9183	9316.00	9210.00	-0.29
1647	10434	10416	10448.00	10428.00	-0.12
2047	10641	10639	10643.00	10641.00	-0.02
	Cluster Pits - Comparison of Methods				
625	8687	8570	8831.00	8720.00	-1.75
1648	8468	9392	9294.00	9203.00	2.01
2048	9255	9189	9587.00	9524.00	-3.87

Pit Growth and Corrosion Rate

$$D_{max} = At^n$$

Dmax = Maximum Pit Depth (mm)
A = First Year Pit Growth (mm) (t=1)
t = Time (years)
n = Soil Factor Constant

- Corrosion 96 Paper #203 - "Projecting Pipeline Pitting Rates and Cathodic Protection Requirements Using Corrosion Coupons" by Dr. Thomas J. Barlow

$$d(D_{max})/dt = n\,At^{n-1}$$

$d(D_{max})/dt =$ Corrosion Rate (mm/yr)

- First derivative method with respect to time

LudaSTRENG Verification

- LudaSTRENG Software was Evaluated against the RSTRENG Program
- Single Corrosion Pit average variance 0.05%
- Multiple Cluster Corrosion Pit average variance 0.35%

B31 Calculations cont...

Evaluating a Corroded Region

A given corroded region in a pipeline is evaluated on the basis of its maximum length, L, and maximum depth, d, via a transformation and combination of Equations 2 and 3.

$$L = 1.12\sqrt{\left(\frac{d/t}{1.1d/t - 0.15}\right)^2 - 1}\quad\sqrt{dt}$$

The corroded area L is acceptable if L is less than or equal to the value given by Equation 4.

The B31G document provides the relationship shown in Figure 3 and the equation

$$L \le 1.12B\sqrt{Dt}$$

B31G Calculations cont...

Calculating a Reduced Operating Pressure Level

The B31G criterion provides:

$$P' = 1.1P\left[\frac{1-(2/3)(d/t)}{1-(2/3)(d/t)(M^{-1})}\right] \le P\frac{1}{df} = \frac{1}{0.72}$$

Sources of Excess Conservatism

The sources of excess conservatism in the original B31G criterion are:

1. The expression for flow stress
2. The approximation used for the Folias factor
3. The parabolic representation of the metal loss (as used within the B31G limitations), primarily the limitation when applied to long areas of corrosion.
4. The inability to consider the strengthening effect of islands of full thickness or near full thickness pipe at the ends of or between arrays of corrosion pits

Modified Flow Stress

It was known even when the original B31G criterion was developed that 1.1 SMYS substantially underestimates the flow stress of a line-pipe material. In Reference 3, it was clearly demonstrated that yield strength + 10,000 psi (68.9 MPa) closely approximates the flow stress for line-pipe materials. Even if one takes yield strength to be SMYS, this latter value would exceed the 1.1 SMYS value for all available grades of line pipe. For the modified criterion, then, the value of flow stress will be taken as SMYS + 10,000 psi (68.9 MPa).

B31G Calculations

The B31G criterion is based upon Equation 1

$$S = \bar{S}\left[\frac{1 - A/A_0}{1-(A/A_0(M^{-1})}\right]$$

where

M is the "Folias" factor, a function of L, D, ant t
S is the hoop stress level at failure, psi (Pa)
$\bar{S}$ is the flow stress of the material, a material property related to its yield strength, psi, kPa = 1.1 x SMYS
A is the area of crack or defect in the longitudinal plane through the wall thickness, in^2 (mm^2)
A_0 is Lt, in^2 (mm^2)
L is the axial extent of the defect, inches (mm)
t is the wall thickness of the pipe, inch (mm)
D is the diameter of the pipe, inches (mm)

B31G Calculations cont...

Assumptions Embodied in the B31G Criterion

In adapting Equation 1 to predicting the remaining strength of corroded pipe, the following assumptions were made. First, the *Folies factor M* was represented as follows;

$$M = \left[1 + \frac{0.8L^2}{Dt}\right]^{1/2}$$

The format of Equation 1 used in the B31G criterion is;

$$S_f = 1.1\ SMYS\left[\frac{1-2/3(Ld/Lt)}{1-2/3(Ld/Lt)M^{-1}}\right]$$

$$= 1.1\ SMYS\left[\frac{1-2/3(d/t)}{1-2/((d/t)(M^{-1}}\right]$$

$$M = \left[1 + \frac{0.8L^2}{Dt}\right]^{1/2}$$

EXTERNAL CORROSION

- Objectives:
  - outline the state of the art in corrosion growth
  - determine industry experience in predicting external corrosion growth
  - ascertain what industry needs in order to advance this technology

EXTERNAL CORROSION

- Outline the state of the art in corrosion growth:
  - pit by pit corrosion growth from repeated ILI data
  - application of theoretical corrosion rate to single ILI data

B31G Calculations cont...

Modified Folias Factor

The two-term approximation for M, the Folias factor, used in the original B31G criterion has been presented herein in Equation 2. A more exact and less conservative approximation of M_T is as follows.

For values of $\left(L^2/Dt\right) \leq 50$:

$$M_T = \left[1 + 0.6275\frac{L^2}{Dt} - 0.003375\frac{L^4}{D^2t^2}\right]^{1/2}$$

For the values of $\left(L\ /Dt\right) > 50$

$$M_T = 0.032\left(L^2/Dt\right) + 3.3$$

EXTERNAL CORROSION

- Determine industry experience in predicting external corrosion growth:
  - majority of operators using an intuitive process based on judgement

EXTERNAL CORROSION

- Ascertain what industry needs in order to advance this technology:
  - updates on the progress of the state of the art
  - observed corrosion rates must be correlated to environmental and operating conditions
  - common database and methodologies for data collection required for comparison

SESSION A
Working Group #8

ABANDONMENT

It is felt that the arching model is probably the most accurate model/approach to round subsidence. Using the arching model, for negliable settlement (less than 1"), pipe could go as large as 300 mm. If allowing minimal settelement (1-4") could go larger than 400 mm.

The degree of settlement, is dependent upon the type of soils and their compaction.

The degree of settlement is also time dependent.

Settlement could be investigated much further using laboratory investigations and scale models. Another method would be computer models using finite analysis.

<u>Subsidence Issue from a Regulatory Perspective - B.J. Vickery</u>

Considerations Under EPEA:
- release of substance - pigging effluents and
  abandonment preparartion

- contaminations remediation - infrastructure and
  andoned pipe

- conservation and reclamation - infrastructure and
  pipe segemnt removal

Questions from Regulation
1. When will the pipe corrode and fail?
2. What conditions result in more rapid pipe corrosion?
3. How is the land surface affected by pipe failure?

Potential Factors affecting the pipe after abandonment
- Pipe corrosion rates
- pipe caoting deterioraition
- pipe diameter
- sub-surface water

Potential Factors resulting in subsidence after pipe failure
- rate of pipe failure
- pipe diameter
- sub-surafce water
- trench material

Pipe failure nd subsidence problems
- increased erosion potential - low energy vs high energy environements

BANFF/97 PIPELINE WORKSHOP
MANAGING PIPELINE INTEGRITY

PIPELINE ABANDONMENT
WORKING GROUP #8
SESSION A

Overview:

Two Abandonment Comittees were set up: Technical and Environmental, from a Steering Committee.

In 1993-94 the Abandonment Steering Committee was set-up. Subsequently, two underlying committees were developed: technical and environemental.

In 1996, a discussion paper was developed by the committee which was published.

Two main issues: ground subsidence and liability

<u>Ground Subsidence Due to Pipeline Abandonment - Milos Stepanik</u>

Improbable to have the collapse of a pipeline and have ground subsidence.

Initial investigations, did not find any problems with the abandonemnt of pipelines.

Turned to the mining industry. If a void colappses, it will fill with the surrounding soil. However, it will not nescessarily proprogate to the surface. As the void fills it will not be as compacted as the original material.

As a void/tunnel collapses it will not immediately migrate to the surface. Void migration will occur.

Using the Rectangular Soil Block Model, Active Soil Wedge Soils and Limit of Arching Models.

To say that zero subsidence is required, is impracticle. Rather, it should a amount of settlement that is tolerable.

Developed a table/graph showing the maiximum pipe diameter for negliable surface subsidence at 1.0 meter, depth of cover.

Policies and the law have to be flexible enough to handle both small and large diameter pipe.

Landowner contractual obligations to landowners may survive abandonment.

Tort Liability: Subsidence could result in law suits in the future.

Land Registartion Issues:
- Under Land Titles, an abandoned pipeline in place may not be immediately obvious. It only brings up the current registartions. However, it will always be kept on the records, so a past search would turn it up.

Workshop Discussions:

Large numbers of issues in abandonment.

Will try to focus mainly on the issues of the speakers: subsidence and liability.

Pipeline Abandonment Paper has been presented at a few major conferences.

Question and comments.

Joann
What liability is left with 1st Call with in place p/ls
- In alberta, liabilty is always there. Legally if a company is contacted they must go and locate the pipe.

In the Manitou, decsion, would it made a differnec if the pipe was larger diameter. Unsure on this.

What happens to the jurisdiaction, does fall back on the province. There is always the possibilty that the province could take action.

What about if a landowner whats the pipe out. Landowner may contractor laibility with landowner to remove pipe. Some landowners state up front that the pipe will be removed.

If the landowner needs to be notified, do they need to be notified?
Depends upon the regultory agency. In Alberta yes, and NEB yes. Would be a due diligence issue.

- land use disruptions - hay field vs irrigated fields. hay field don't care about elevations, however irrigated lands might be affected.
- soil and wtaer contamination
-localiized or widespread impact

Liability after abbandonment
- What is a reasonable time period for liability?
- How would liability for an abandoned pipeline be assigned to an operator?

For most EPEA activities, the probabilty of problems arising afetr abandonemnt (removal) decreases with time.

With in-situ abandonment, the probability of problems will increase with time.

Goverment Liability: Gov't has assumed lability for abandoned activities under past regulatory regimes where operator responsibilities were not clearly defined in legislation.

Pipe corrosion and subsidence need to be addressed in greater detail.

General criteria is required by the piepline industry, Gov'y and public

Criteria should identify site specific conditions for pipeline removal and abandonment.

<u>Liability of Abandoned Pipelines - Nick Schultz</u>

A legal Working Group on Abandonment was established last fall. A discussion paper in draft from has been developed and is being reviewed.

Basic Legal Issues:
1. Specialzed Laws
2. Common Law

Legal Group focused was how law was applicable to pipeline abandonment

NEB Act.
Manito decsion is that if a pipeline company abandons a pipeline and hen no longer wants the land, NEB jurisdication comes to an end.

Alberta
Licensee remains liable after abandonemnt.
EUB reserves the right to go back to the licensee if some occurs in the future.

3. If Regulators and Industry work together, need/require a process for closure Need details/general criteria.

4. Other Jurisdications - do research

5. Adequency of current legislation.
   - Risk based approach

6. Harmonization

7. Financial / Cost of Abandonment
   - Note that the Steering Committee is looking at a striking a Financial Group.

Milos addition: When looking at subsidnec, looked at ideal conditions. Should look also at more dynamic situations, (i.e. slopes, special terrains) and involve special conditions. Mainly looked at theoretical sistautions.

With sink holes (mining) being a possible, should they be addressed in deatail. Would have to be in a special category. Most pipelines have been in existance for long period s before abadonment. so the ditch has settled.

Sink Holes are a very complex question. Each case is specific. Have to develop a plan before abandonment and a continuing plan.

Has authorities asked for an abandonemnt plan along with original application and set up a bond to cover (bonding requirement). For original application have to provide a C&R plan upfront, for abandonment it would be the reverse of this plan. Bonds have not been addressed. In-situ pipe abandonment has not been addressed in legislation.

If make the assumtption that the operator wants to walk away at the end of the day, is this possible. The questions has been raised, but it would be the responsiblity of the policy makers. However, what ever is done, itmust be practicle, especially in the case of long, big inch pipelines.

Summary/Key Issues

What needs to be done?
- Subsidence
1. Require further Modeling - Specific cases, more dymanic areas
   - lab and computer.
   - possible university research.

2. Alternates to pulling the pipe out in areas of subsidence concern. - Can we fill the pipe.

3. Tolerability criteria - how much settlement is acceptable

4. Coating relationship to subsidence.

5. Alternates uses for the pipeline: electrical, water, telecommunications:

- Legal/Liabilitity
1. Legal committee presented the detail/ Need to address perpetuity vs lability today related to abandoned in place. (Operator/Regulatory)

2. Who pays

3. Miscellaneous

- Financial
  - Identification of costs associated with abandonment.
  - The previously identified Financial Comittee needs to be established to complete the abandonment discussion paper.
  - Financial responsibilities of all parties for pipelines abandoned in place.

- Additional work on the need to establish a fund for pipeline abandonment?

- Risk Assessment for Pipeline Abandonment.

- Review Alternate Use possiblilities for abandoned pipelines.

4. Regulatory

- Review of the effectiveness of current legislation
  - Risk Based Approach

- Develop Harmonized of rules and regulations between Regulatory Authorities.

- Potential for a Code of Practice for pipeline abandonment developed by a multi-stake holder group.

- There is a proposal to address pipeline abandonment in the next version CSA Z662.

BANFF/97 PIPELINE WORKSHOP
MANAGING PIPELINE INTEGRITY

PIPELINE ABANDONMENT
WORKING GROUP #8
SESSION A

The Workshop session identified the issues that require additional work and are as follows:

1. Subsidence

- Further subsidence information could be obtained through modeling (computer and laboratory).
- A set tolerability criteria needs to established to the degree of acceptable subsidence.
- The relationship between coating and subsidence.
- Mechanisims to minimze subsidence concerns (i.e. filling the pipe).

2. Legal

- Additional work must be performed to resolve the issue of perpetual laibility for pipelines abandoned in place.
- Flexability must be incorporated into the regulations to allow for site specific situations.(i.e. a 168.3 mm abandonment situation vs 1219 mm abandonment situation).
- Need to improve record keeping for abandoned pipelines. (i.e. location mapping, land titles).
- Companies need to ensure understanding of committments to landowners post abandonment.

SESSION C and D
Working Group #9

IN-LINE INSPECTIONS

Richard Morrissey	Northwestern Utilities Ltd
Greg Toth	Trans Mountain
Paul Huddleston	"
Barry Anderson	BC GAS
Stanley Wong	Canadian Western Natural Ga
Gordon Johanson	CWNG
Eric Peterson	Conoco Pipeline
William Rambo	Yellowstone/Conoco Pipeline
Chris Pollard	British Gas
Arti Bhatia	Interprovincial Pipe Line
Dennis Zanger	" "
Bob Lessard.	Welland Pipe Ltd
Guy Desjardins	Morrison Scientific Inc
Michael Miles	Miles Consulting
Sydney Harland	Ontario Hydro
Tom Sawyer	BJ Pipeline Inspection Services
[illegible]	
Jack [illegible]	
Richard Kania	RTD Quality Services
Alex Petrusev	Union Gas Ltd.
Paul Greco	Union Gas
George Kohut	Chevron
[illegible]	
Bruce Dupuis	[illegible]
Frank Christensen	FMCMCI
Dave Harper	Trans Mountain
Ravi Krishnan	Mobil Oil
Gilbert Grondin	University of Alberta
Casey Stengler	Imperial Oil Ltd
[illegible]	[illegible]

SIGN-UP SHEET (FIRST SESSION)
WORKSHOP #9. SESSION C.

13:00

NAME	COMPANY
John Craig	Pacific Northern Gas
Tom Cook	Pipetronix
ANDREW WOZNIEWSKI	IMPERIAL OIL RESOURCES
Clive Ward	British Gas
KASHMIR GILL	NATIONAL RESEARCH COUNCIL
Dexter Dakin	Suncor Energy
Harvey Haines	Gas Research Institute
Aida Lopez	Pembina Corporation.
SUDHIR PARAB	PETRO-CANADA OIL & GAS
J.C. HAMILTON	T.D. WILLIAMSON, INC.
JIM WALLBRIDGE	CONSULTANT
George ROY	CANMET / MTL
Mo MOHITPOUR	NOVA
BOB EIBER	ROBERT J EIBER CONSULTANT INC
MARC SPENCER	[illegible] ENGINEERING LTD.
Lynann Clapham	Queen's University
DAVID ATHERTON	Queen's University
Yvanna Ireland	TCPL
Mike Dolbey	Ontario Hydro.
Alex Kuharchuk	RUSSELL TECHNOLOGIES INC
GARRY SOMMER	CORRPRO CANADA, INC
JIM HORNER	TMPL
Norm Riane	TMPL

LIST OF PARTICIPANTS

Working Group #9: In-Line Inspection (SECOND SESSION)
15:30

NAME	ORGANIZATION
George ROY	CANMET/MTL
JIM WALLBRIDGE	CONSULTANT
Mike Dolby	Ontario Hydro.
[illegible]	[illegible]
David Atherton	Queen's University
Lynann Clapham	Queen's University.
MARC SPENCER	MAGI ENGINEERING LTD
John Hendershot	NATIONAL Energy Board
CHRIS MITSKOPOULOS	UCISCO CANADA
ERIC PETERSON	Conoco PIPELINE
GARRY SOMMER	CORRPRO CANADA, INC.
	IPL
DENNIS LARSON	
CHRIS POLLARD	BRITISH GAS
TED PHIPPS	CANADIAN WESTERN NATURAL GA.
PHILLIP NIDD	AEC PIPELINES
GLEN SCOTT	B.C. GAS.
BARRY ANDERSON	BC GAS
BILL TYSON	MTL/CANMET
PHIL MICHAILIDES	BJ PIPELINE INSPECTION SERVICES
DAVE HERTNER	" " " "
DOUG HILL	PETRO-CANADA OIL & GAS
ED KARPIEL	SCPL
JIM JUSTICE	JUSTICE CONSULTING
Bruce Lawson	Westcoast Energy Inc
WALTER SODERQUIST	WESTCOAST ENERGY
ED MCC[illegible]	[illegible]

WORKING GROUP # 9 13:00

NAME	COMPANY
JIM MITCHELL	CAMPIPE
Nick Pussegoda	Fleet Technology Ltd.
Dave English	Amoco Canada
DAVE HORTNER	BJ Pipeline Insp. Services
PETER MARRECK	RAINBOW PIPELINE CO. LTD
DUANE CRONIN	UNIV. OF WATERLOO
ROY PICK	UNIV. OF WATERLOO
Zack Florence	ARC-Veg.
Bob Worthingham	Nova Gas Transmission
Jamie Cox	Du Pont Canada
DARYL ROUSKY	CONSULTANT
Wayne Feit	Imperial Oil
TERRY KLATT	FOOTHILLS PIPE LINES

RESULTS OF IN-LINE CRACK INSPECTION USING THE ULTRASCAN CD TOOL

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1. INTRODUCTION

For many pipeline companies, damage due to cracking is becoming more and more a severe problem. In the past, particularly stress corrosion cracking (SCC) has caused a lot of (sometimes catastrophic) pipeline failures all over the world /1,2/. As no reliable in-line inspection tools for crack detection were available until recently, operators were utilizing hydrostatic testing to detect critical cracks in their pipelines. However, despite of being time and cost consuming, hydrostatic tests not only give incomplete information but also can enhance the growth of existing cracks and thus increase the probability of future ruptures /2/.

In order to provide an in-line inspection solution for crack detection, Pipetronix developed the UltraScan CD which is currently available for sizes between 22" and 56". Since its commercial introduction in autumn 1994, more than 1,000 km of operating oil and gas pipelines have been inspected with UltraScan CD tools. The results obtained so far show that the UltraScan CD meets all the requirements for sensitive and reliable crack inspection.

2. THE ULTRASCAN CD TOOL

2.1 Inspection Technique

The UltraScan CD (*Fig. 1*) is based on an ultrasonic technique since only ultrasound allows for the in-line detection of external as well as internal cracks with equal sensitivity and high resolution. The technique applied uses shear waves which are generated in the wall by angular transmission of the ultrasonic pulses through a liquid coupling medium (oil, water etc.). The angle of incidence is adjusted such that a propagation angle of 45° is obtained in steel (see *Fig. 2*). This technique had proven appropriate for crack inspection, and has been established as one of the standard techniques in ultrasonic testing /3/.

Because fatigue cracks as well as SCC are generally oriented perpendicularly to the main stress component, i.e. the hoop stress in a pipe, the ultrasonic pulses are injected in circumferential direction in order to obtain maximal acoustic response.

Bob Carnes	UT-Austin
Gilbert Grondin	U of Alberta
GEORGE KOHUT	CHEVRON.
Neb Uzelac	PIPETRONIX
Aleх Kucharcevic	RUSSELL TECHNOLOGIES
BARRY MARTENS	RAINBOW PIPE LINE
SIU TSAI	upstream Projects - IORL
PETER MARRECK	RAINBOW P/L
AIDA LOPEZ	PEMBINA CORP.
Harvey Haines	Gas Research Institute
AL FORSTER	WILLIAMSON IND. INC.
IAN FRASER	IMPERIAL OIL
Clive Ward	British Gas
Ed Poluhoshko	Alberta Research Council
Tom Cook	Pipetrans
John Craig	Pacific Northern Gas

Table 2: Defect specifications for the UltraScan CD

Defect Type	Stress corrosion cracks, fatigue cracks, welding defects, other crack-like defects with axial orientation (± 15°)
Wall Coverage	100 % (Longitudinal weld and base material)
Min. Defect Length	30 mm up to 1 m/s 50 mm at 2 m/s
Min. Defect Depth	1 mm
Accuracy in defect location: *axial:* *circumferential:*	 ± 10 cm ± 5°

The experience gained from the inspection runs performed so far has shown that the tool also detects laminations, dents, metal loss etc., provided the reflector length exceed the length criterion of 30 mm.

3. OPERATIONAL EXPERIENCE

Since its first commercial inspection run in autumn 1994, more than 1000 km of crude oil pipelines as well as gas pipelines have been successfully inspected with the UltraScan CD tools /4,5/. An overview of the inspection runs performed so far is given in Table 3. The objective of all but two of these inspections was to replace hydrostatic testing as can be seen from the remarks in *Table 3*. This holds in particular for German pipelines where the use of the UltraScan CD in combination with an in-line corrosion inspection is approved by TÜV as an appropriate means of pipeline integrity testing /6/.

Compared to hydrotesting, reliable in-line crack inspection offers several advantages to pipeline operators:

- Detailed information on crack and crack-like defects
- No shutdown time (liquid lines)
- No water disposal (liquid lines)
- Cost & time saving

The main objective of the inspection of two other pipelines listed in *Table 3* was detecting and sizing SCC damage as SCC had already caused ruptures in these pipelines. One was a 110 km/56" Gasprom/Tjumentransgas gas transmission line located in West Siberia, the other a 300 km/24" crude oil pipeline in Canada. Both pipelines exhibit near-neutral pH SCC /1/.

The sensor carrier of the UltraScan CD is designed such that the complete pipe circumference is uniformly scanned in both clockwise and counterclockwise direction using up to 892 sensors distributed on up to 28 sensor skids (56" tool). This arrangement provides a multiple wall coverage ensuring that relevant reflectors are detected by up to ten sensors (*Fig. 3*). Additionally, two sensors per skid serve to continually measure the actual wall thickness and to detect the girth welds in order to locate detected defects as precisely as possible with respect to the nearest girth weld. The sensors are mounted on a highly flexible sensor carrier made of polyurethane (see *Fig. 1*) ensuring that a constant distance to pipeline wall and correct angle of incidence is maintained during inspection.

2.2 Technical Data of the UltraScan CD

Two UltraScan CD tools are currently available for the range of pipeline sizes from 22" to 56" (see *Table 1*). As can be seen from the technical data given in *Table 1* up to 250 km can be inspected in a single run at a speed of 1 m/s. At higher speeds the inspection range is even larger but the minimum detectable defect lengths increase. At 2 m/s, however, crack-like defects as short as 50 mm will still be detected.

Table 1: Technical data of the UltraScan CD tools

Technique	Ultrasonic angle beam technique using 45° shear waves	
Available Sizes	22" - 34"	36" - 56"
Number of Ultrasonic Sensors	512	max. 896
Data Storage Capacity	24 Gbyte	64 GByte
Inspection Range at 1 m/s	> 100 km	250 km
Inspection Speed *min. defect size 30 mm* *min. defect size 50 mm*	 1 m/s 2 m/s	
Time Based Marker System	yes	

2.3 Defect Specification

The UltraScan CD is designed for detection of axial crack-like defects such as SCC or fatigue cracks. One of the motives for developing the tool was to replace hydrostatic testing as a means for proving pipeline integrity. Based on fracture mechanics calculations the requirements for the tool, minimum defect length of 30 mm and minimum crack depth of 2 mm (at 8 mm wall thickness) were established. The tools sensitivity, however, is such that even cracks with depths below 1 mm can be detected (for defect specifications see *Table 2*).

performed, and agreement between predicted and actual was very good, in particular, no false calls have been reported so far.

Some of detected SCC colonies were destructively examined after excavation. *Fig. 5* illustrates the agreement between an ultrasonic C-scan (*Fig. 5a* -crack inspection data projected on the pipe surface) and the corresponding metallographic image (*Fig. 5c*). In *Fig 5b* the main cracks within the colony are depicted along with the depths as found from destructive examination.

A similar example is shown in *Fig. 6*. In the C-scan individual cracks are identified in close correspondence with the metallographic image. In particular, the crack lengths are readily obtained from the ultrasonic data. The accuracy of crack length measurement is typically within ± 7 mm.

In order to assess the severity of cracks or crack colonies, reliable information on crack depth is required. It has been verified that the UltraScan CD data allow for estimation, in some cases even direct measurement of crack depths. An example of a crack is given in *Fig. 7* showing B-scans from three adjacent sensors. (Here, a B-scan is the sequence of signals as recorded in circumferential direction by an individual sensor when moving in axial direction.) The main reflection, i.e. the reflection with the highest amplitude (the so-called corner reflection), is recorded by sensor 1. Sensor 2 mainly ´sees´ the side of the crack while sensor 3 detects the crack tip. In the corresponding B-scan the scattering signals from the crack tip are clearly visible and the recorded indications represent the crack tip profile, i.e. the contour of the crack.

The deepest point of the profile in the B-scan of sensor 3 in *Fig. 7* represents the maximum depth of the crack, about 10 mm (65% wall thickness). This indication was one of the most striking indications found in that pipeline. After the inspection, part of the line including the corresponding pipe joint was hydrotested and a rupture occurred at exactly this crack. From the fracture surface the original crack profile could clearly be identified, and it was in agreement with the profile shown in *Fig. 7*.

5. VERIFICATIONS

More than 60 verification digs based on indications from UltraScan CD inspections have been performed up to now. In order to validate the performance of the tool as well as the quality of the data interpretation, indications not only from cracks but also from a variety of other (in a sense crack-like) reflectors such as grooves or weld defects have been examined during excavations allowing to compare predicted and verified results. An overview on the verification digs is given in *Table 4*. The majority of the digs were done at SCC indications and both these and the non SCC findings were verified by manual “in-the-ditch” inspection. In the only three cases where the interpretation was not quite clear, the indications were not really crack-like and the manual inspection did not yield a clear interpretation either.

Table 3: Inspection runs performed with UltraScan CD

Country	Pipeline Data			Remarks
	Length (km)	*Diameter (")*	*Type*	
Germany	22	26	Crude Oil	Instead of hydrotesting
Germany/Netherlands	102	24	Crude Oil	Instead of hydrotesting
Germany	270	26	Crude Oil	Instead of hydrotesting
Russia	110	56	Gas	SCC damage, batch technology
Germany	160	40	Crude Oil	Instead of hydrotesting
Canada	300	24	Crude Oil	SCC damage
Germany	160	40	Crude Oil	Instead of hydrotesting
Austria	90	40	Crude Oil	Instead of hydrotesting
Germany	175	28	Crude Oil	Instead of hydrotesting

4. STRESS CORROSION CRACKING (SCC)

Stress corrosion cracking (SCC) is a phenomenon gaining more and more attention as the rate of SCC-induced pipeline failures increases worldwide. In some cases failures have occurred, especially in gas pipelines, after only a few years of operation. SCC is generated under the influence of internal pressure and a corrosive environment, combined with a particular microstructural susceptibility found in some pipeline steels. The mechanisms of SCC initiation and growth are still not well known and are the subject of ongoing research. SCC can occur in various forms from small isolated cracks to large crack fields (colonies) containing hundreds of cracks /7/. SCC are usually found in the base material on the external pipe surface and are, like fatigue cracks, longitudinally orientated.

In September 1995, a 56" gas transmission line with individual section length of 110 km was inspected with the UltraScan CD (*Fig 4)*. In order to facilitate ultrasonic coupling, the tool was run in a slug of water (the performance of the tool has already been proven in crude oil and diesel, but other liquids can also be used) /8/. A significant number of pipe joints containing SCC were identified, and the indications were classified based on the amplitude and the length of the cracks. More than 40 excavations have already been the high inspection redundancy of the UltraScan CD, such features can reliably be detected and discriminated from cracks.

7. REPRODUCIBILITY

The reproducibility of UltraScan CD inspection data was checked under operational conditions */10/*. For example, to inspect the 24"/300 km crude oil pipeline in Canada (see *Table 3*), three runs were necessary with an overlap of several km between subsequent runs. Comparison of the data from the overlapping regions illustrates the reproducibility of inspection results. A typical example is depicted in *Fig. 11* showing two C-scans of the same line pipe section as recorded in two subsequent runs. Even though the damage shown in this example is only minor, it was detected in both runs in exactly the same way proving the reproducibility of results and hence the confidence level of the inspection method.

8. SUMMARY

The results obtained from inspections of more than 1000 kilometers of operational pipelines (crude oil & gas) confirm that the UltraScan CD meets the requirements for a sensitive and reproducible in-line crack inspection. Due to its high sensitivity, the new tool can reliably detect crack colonies as well as individual crack-like defects with lengths > 30 mm and depths > 1 mm. In particular, about 400 km pipeline with SCC was successfully inspected yielding very detailed information on damage sizes and distribution. The convincing performance of the tool is underlined by more than 40 excavations on SCC without any false calls. Based on its performance the tool was approved by the German TÜV for use as a substitution for hydrostatic testing.

9. ACKNOWLEDGMENT

The UltraScan CD was developed in close co-operation with the Fraunhofer-Institute for Nondestructive Testing (IzfP) in Saarbrücken and the Research Centre Karlsruhe (FZK). The authors express their gratitude to Prof. Y. Surkov, Institute of Metal Physics, Jekaterinenburg, for providing detailed results on destructive examination of SCC colonies.

10. REFERENCES

/1/ National Energy Board: Report of the Inquiry *Stress corrosion Cracking on Canadian Oil and Gas Pipelines*, Canada, November 1996.

/2/ Y.P. Surkov and A.V. Khoroshih, *Investigation of cases of corrosion cracking in operating gas pipelines*, 3R International 35 (1996), 396 - 403.

Fig. 9 shows the comparison of crack depth results obtained by destructive examination (in cases where pipe sections were replaced) with the estimations based on the UltraScan CD data. It can be seen that the agreement is within ± 20% wall thickness.

Table 4: Overview of verification digs (December 1996)

Type of Indication	Number of Digs	Remarks
Cracks & Crack Colonies (mainly SCC)	44	No false calls (ongoing)
Grooves, Scratches	5	No false calls
Undercut (Long. Weld)	3	No false calls
Slag Inclusions (Long. Weld)	2	No false calls
Lack of Fusion	2	No false calls
Weld Irregularities	3	In one case classification was *undecidable* (but *not crack-like*)
Other	2	Classification as well as verification result was *undecidable* (but *not crack-like*)

For the pipelines also inspected with the UltraScan WM (the corrosion detection tool) many features could be verified (without digging) by comparing the inspection data obtained from the two tools. This holds in particular for reflectors such as inclusions or laminations which can clearly be identified from the UltraScan WM data. The example in *Fig. 9* shows C-scans of a same lamination with varying depth as recorded by the UltraScan CD and the UltraScan WM.

6. NON-INJURIOUS REFLECTORS

Some pipeline steels contain inclusions and laminations normally considered non-injurious with respect to normal pipeline operation. Since however, these reflectors to some extent exhibit crack-like features they should be recorded by crack detection tools. The example in *Fig. 10* shows a pipe joint of ´dirty´ steel with an extremely high number of inclusions following a normal ´clean´ line pipe. It should be noted that each box visible in the C-scan in *Fig. 10* indicates a reflector with a length > 30 mm, i.e. there can be hundreds of indications per meter. Such elongated inclusions are a result of the rolling process during manufacture. However, due to the high-resolution signal recording and

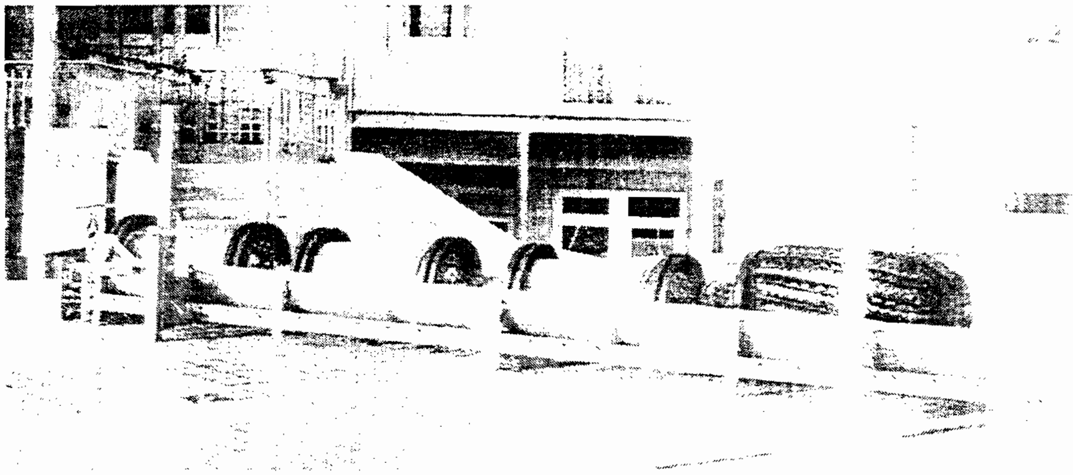


Fig. 1 UltraScan CD (24"-version) with battery unit, data storage unit, ultrasonic electronic unit and sensor carrier (from left to right)

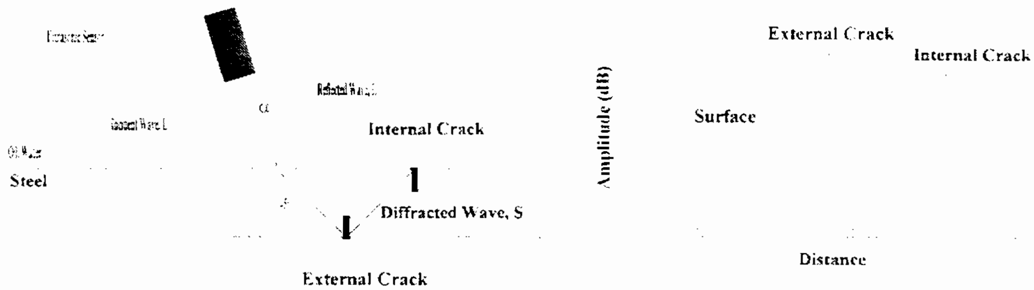


Fig. 2 Ultrasonic shear wave technique used for crack detection (schematic)

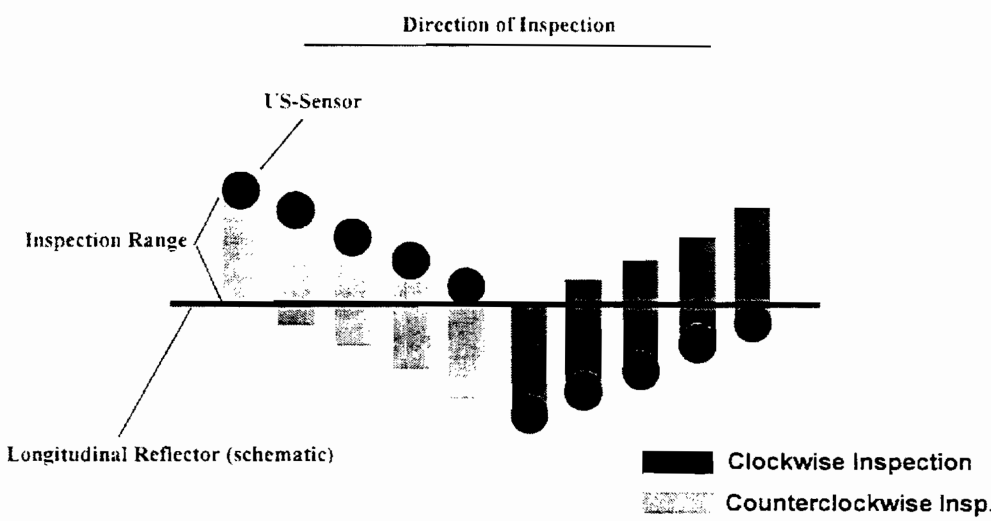


Fig. 3: View of sensor arrangement illustrating the multiple wall coverage

/3/ J. Krautkrämer and H. Krautkrämer. *Werkstoffprüfung mit Ultraschall (Materials Testing with Ultrasound),* 5. Edition, Springer Verlag (Berlin, 1986).

/4/ H. Willems and O.A. Barbian, *Crack Detection in Pipelines: Survey Experience Obtained with the UltraScan CD Tool,* 8th Int. Pipeline Pigging Conference and Exhibition, Houston, February 14-16, 1996.

/5/ H. Willems, O.A. Barbian and N.I. Uzelac, *Internal Inspection Device for Detection of Longitudinal Cracks in Oil and Gas Pipelines - Results from an Operational Experience,* ASME International Pipeline Conference, Calgary, June 9 - 14, 1996.

/6/ Verfahrensgutachten *Ultraschall-Rißprüfmolch "UltraScan CD" der Fa. Pipetronix GmbH,* TÜV Rheinland, Köln, August 1995.

/7/ T.A. Bubenik, D.R. Stephens, B.N. Leis, and R.J. Eiber. *Stress Corrosion Cracks in Pipelines: Characteristics and Detection Considerations*, Gas Research Institute, Topical Report GRI-95/0007 (Chikago, 1995).

/8/ H. Goedecke, G. Krieg, and H. Stripf. *UltraScan survey in gas pipelines with batch technology*, Proc. 2nd Int. Conf. on Pipeline Inspection, Moskau, 1991.

/9/ Y. Surkov et al., to be published

/10/ H. Willems and O.A. Barbian, *Ultrasonic Crack Detection in Pipelines by Advanced Intelligent Pigging,* Proceedings of the 2. International Conference on Pipeline Technology; Ostend (Belgium), September 11-14, 1995.

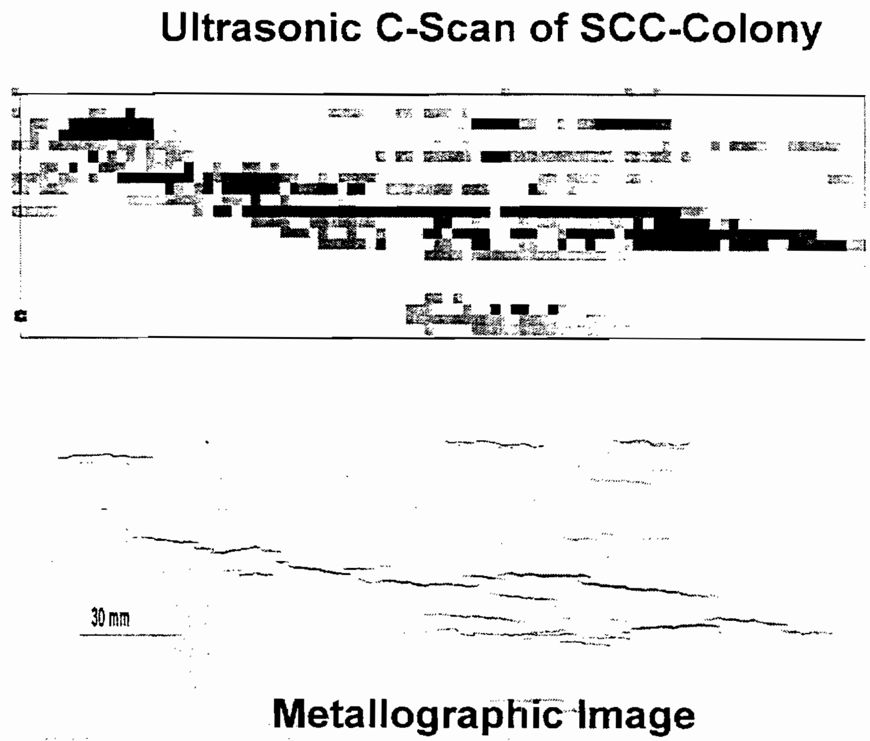


Fig. 6: Comparison between UltraScan CD indication of a SCC-colony and metallographic result (56" pipe joint)

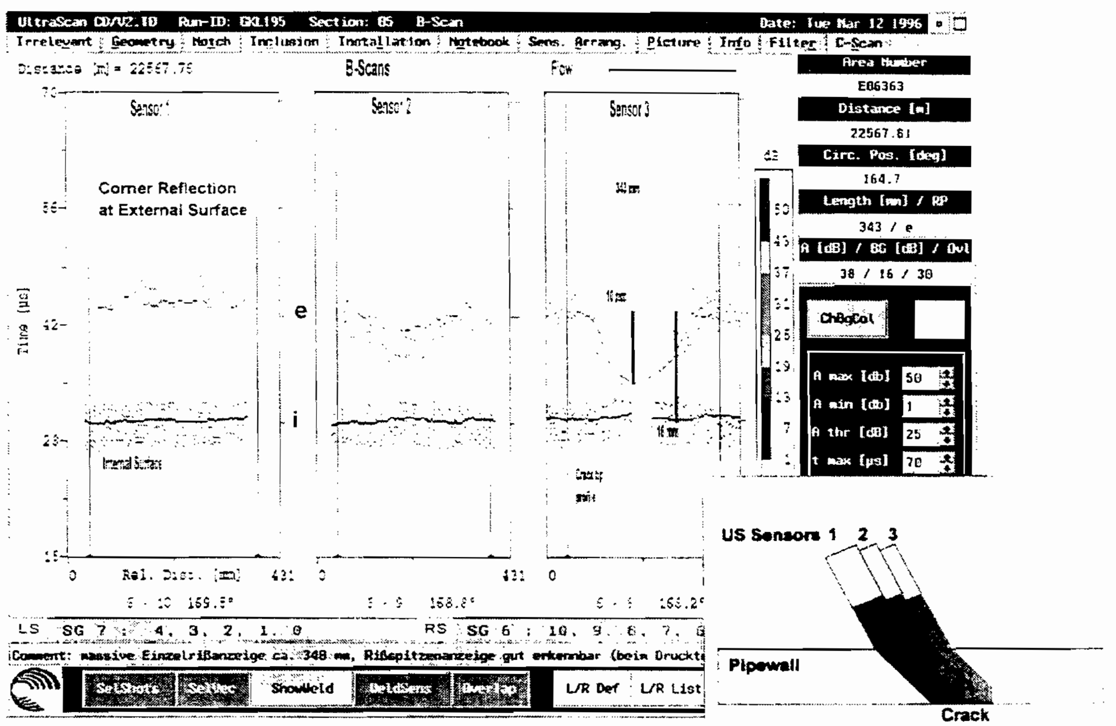


Fig. 7: B-scans of 10 mm deep crack in a 56" gas transmission line as recorded by three adjacent sensors. The B-scan from sensor 3 clearly shows the crack tip signal from which the crack depth is readily obtained.

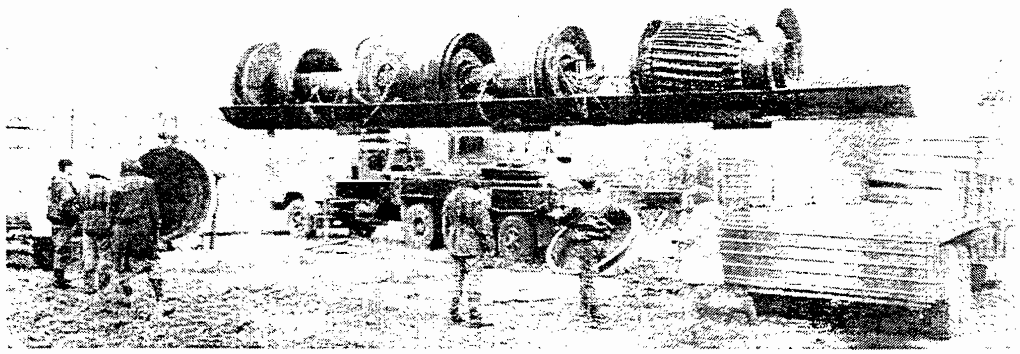
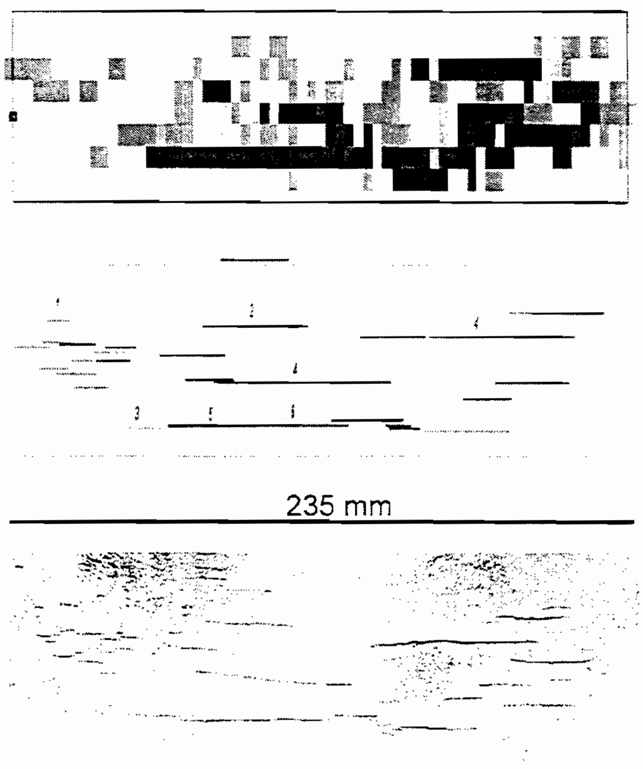


Fig. 4: Launching of the UltraScan CD into 56" gas transmission line



a: Ultrasonic C-Scan

b: Destructive Analysis

c: Metallographic Image

Fig.5: Comparison between UltraScan CD indication of a SCC colony and metallographic result. (Numbers in (b) indicate crack depth in mm)

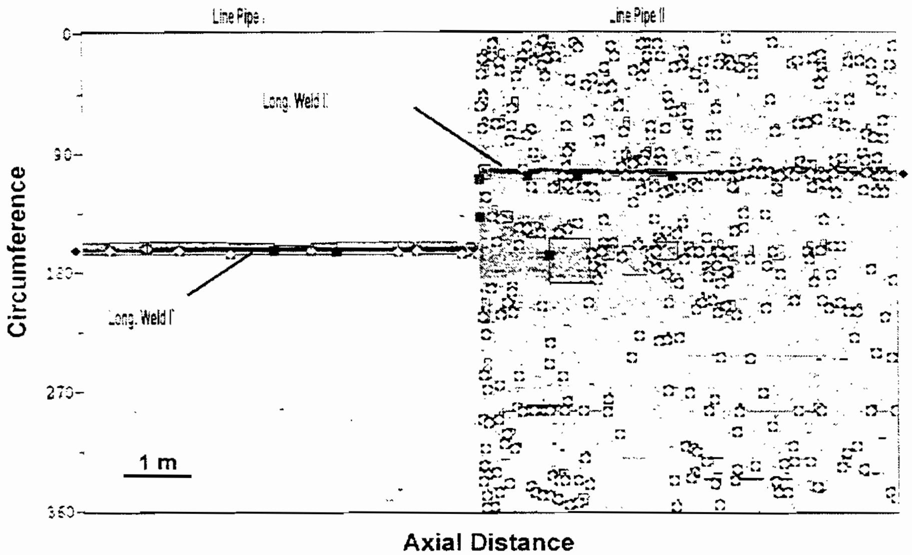


Figure 10 C-scan from UltraScan CD data showing part of clean line pipe (left) and part of line pipe containing numerous inclusions & laminations (right).

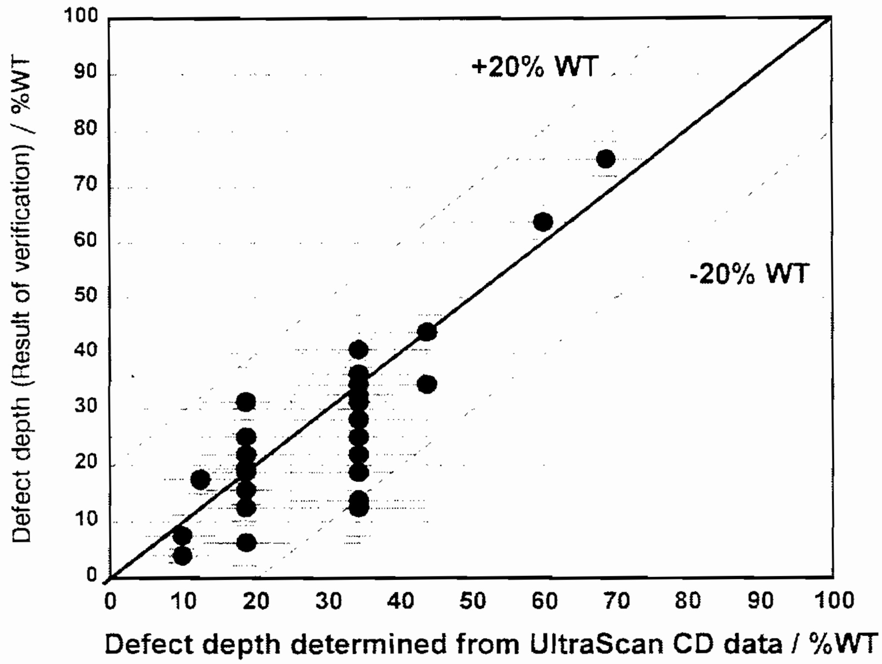
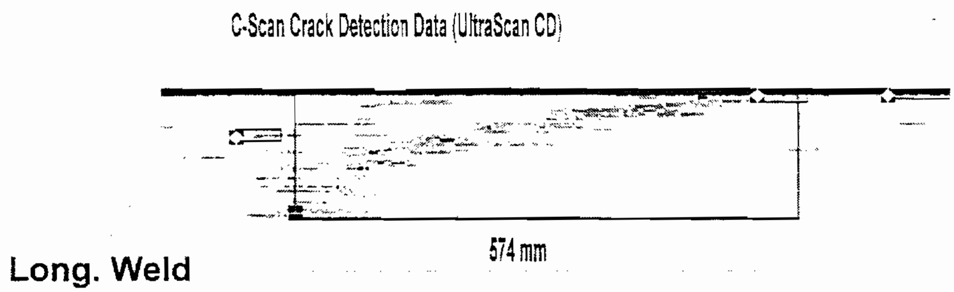


Fig. 8: Comparison between crack depth as determined from UltraScan CD data and the results obtained by manual inspection



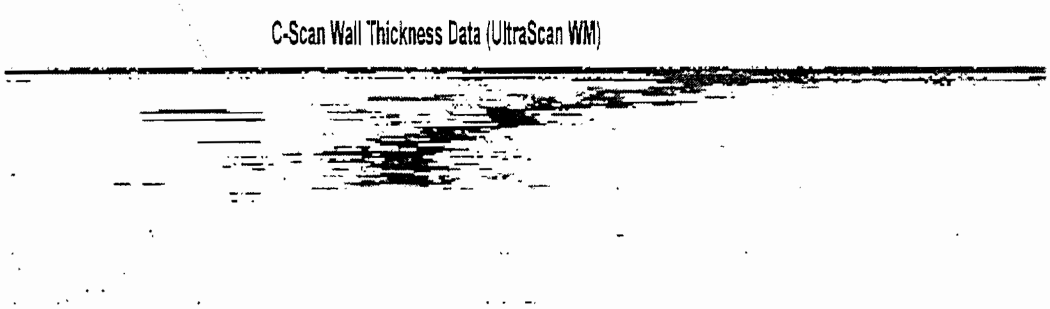


Fig. 9: Lamination with varying depth in 28" crude oil pipeline as detected by UltraScan CD (top) respectively UltraScan WM (bottom)

Speed Control Variables

- Pipe Diameter
- Gas Flow
- Gas Density (Pressure & Temperature)
- Orifice Size
- Bends & Fixtures
- Drag Force
  - Wall Thickness & Condition
  - Cups, Brushes & Wheels

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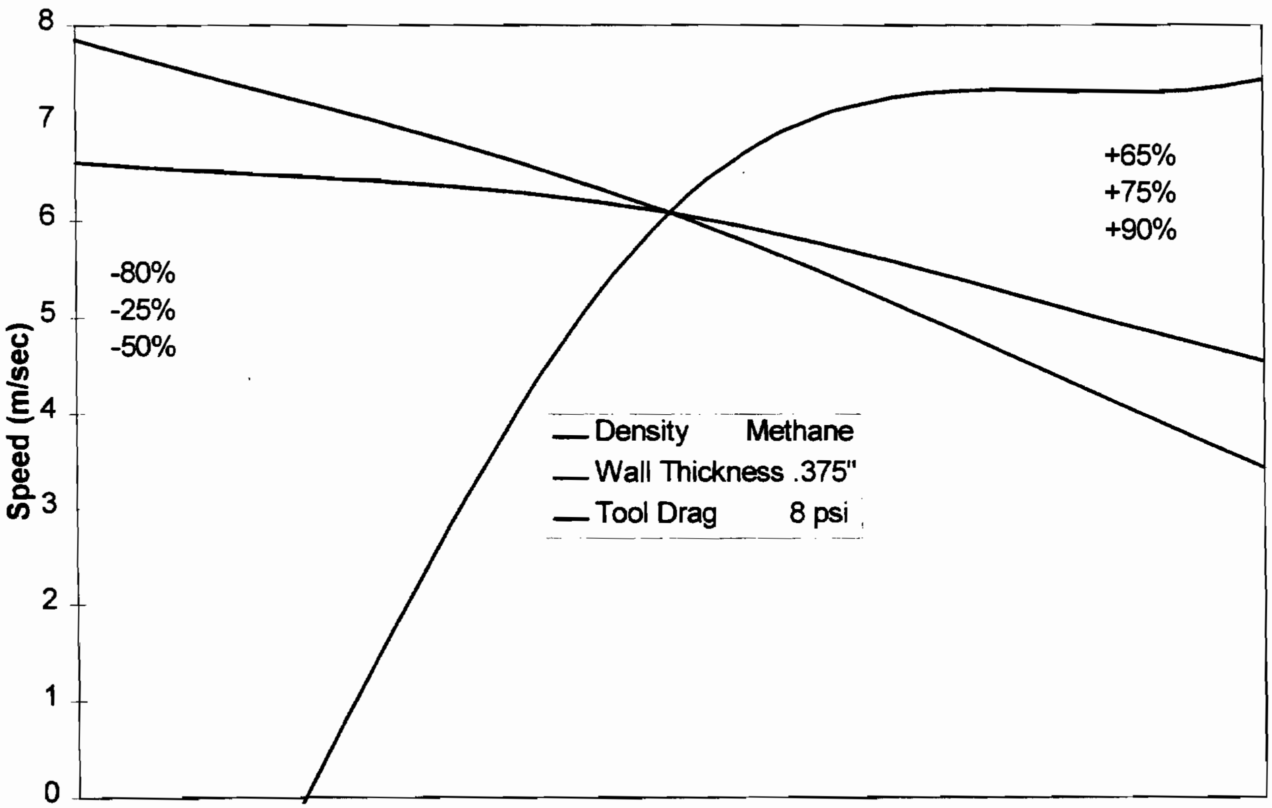

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MFL Metal Loss Inspection Tool
Gas By-Pass/Speed Control

Banff Pipeline Workshop
Work Group 9, In-Line Inspection
April 17, 1997

Design Criteria

- **Reduce the pig velocity in bullet gas pipelines**
  - **Reducing flow for inspection is costly to operator and often a major reason for not inspecting**
- **Maintain constant inspection velocity**
  - **Prevent Surging in Heavy Wall & at Valves, Bends**
  - **Optimum results at constant speed**
- **Integral Part of the Inspection Tool**
- **Eliminate chances of pig stopping in pipeline**
  - **Fail safe mechanism**
- **Minimize chances of damaging inspection tool**

Gas Bypass & Speed Control

Magnets (120)

N S

Carrier Wheels (20)

Odometer Wheels (2)

Universal Joint

Gas Bypass

Electronics
Data Storage
Inertial System

Drive Cup (2)

Hall Effect Sensor Array (56)

Eddy Current Sensors (56)

Gas Control Valve

Ultrasonic Wheels (2)

24 Inch MFL Metal Loss Inspection Tool

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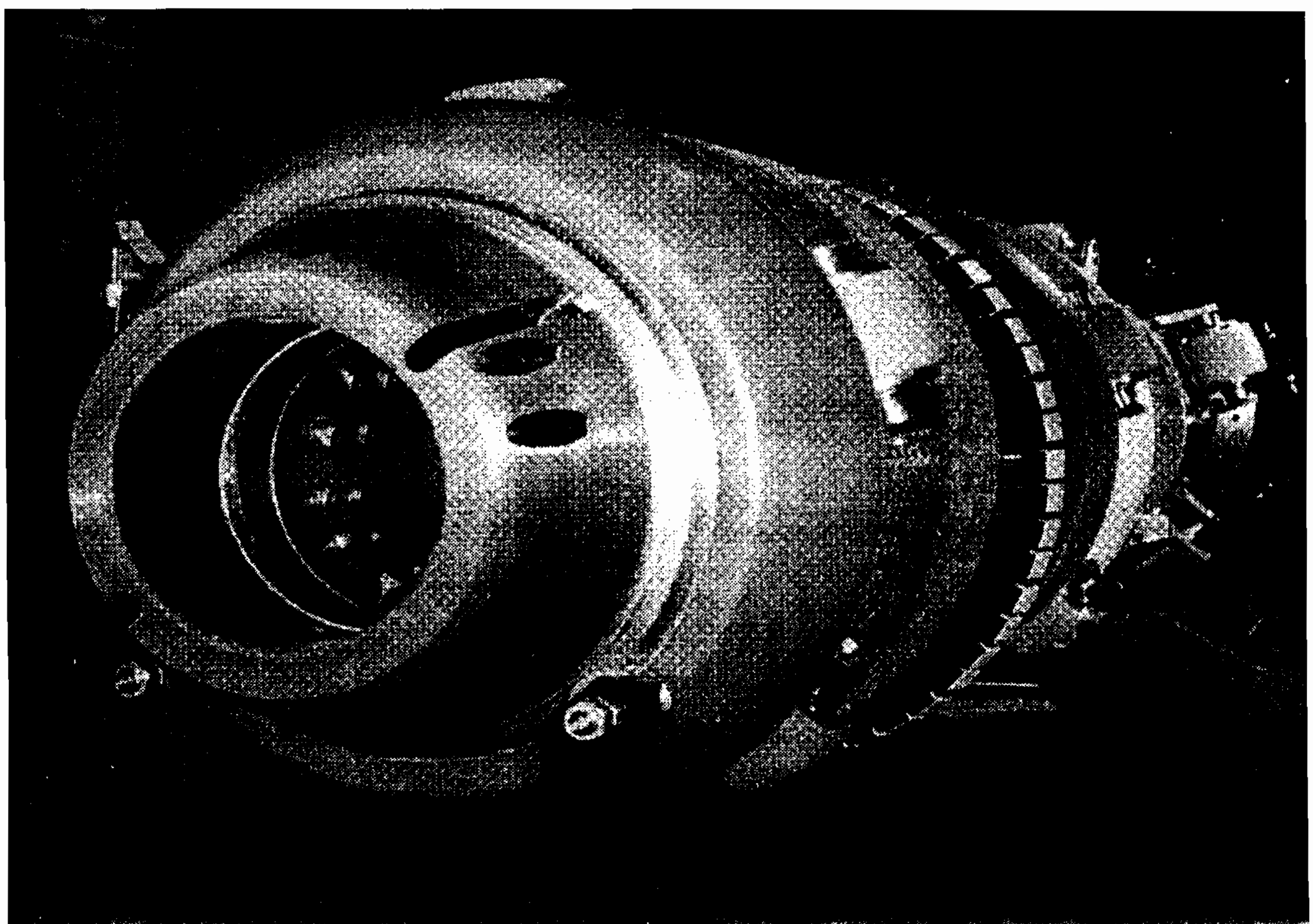

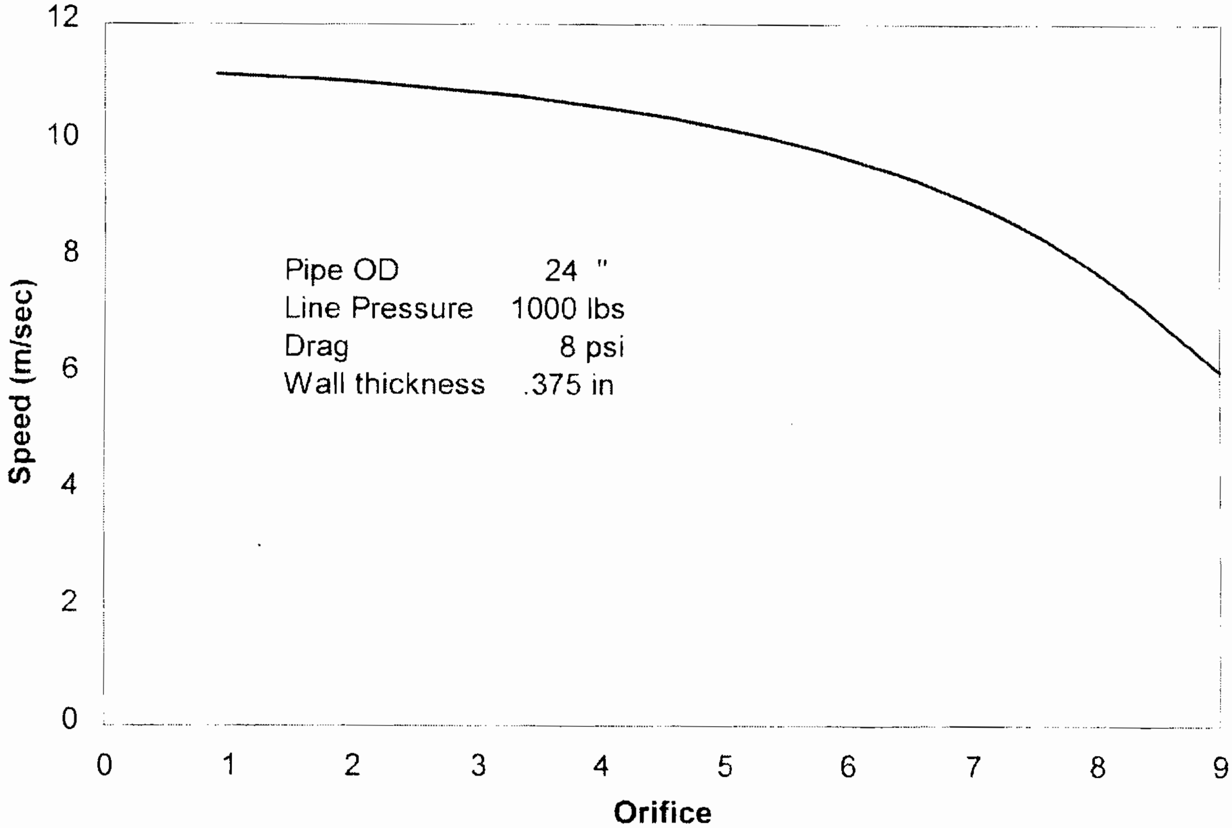

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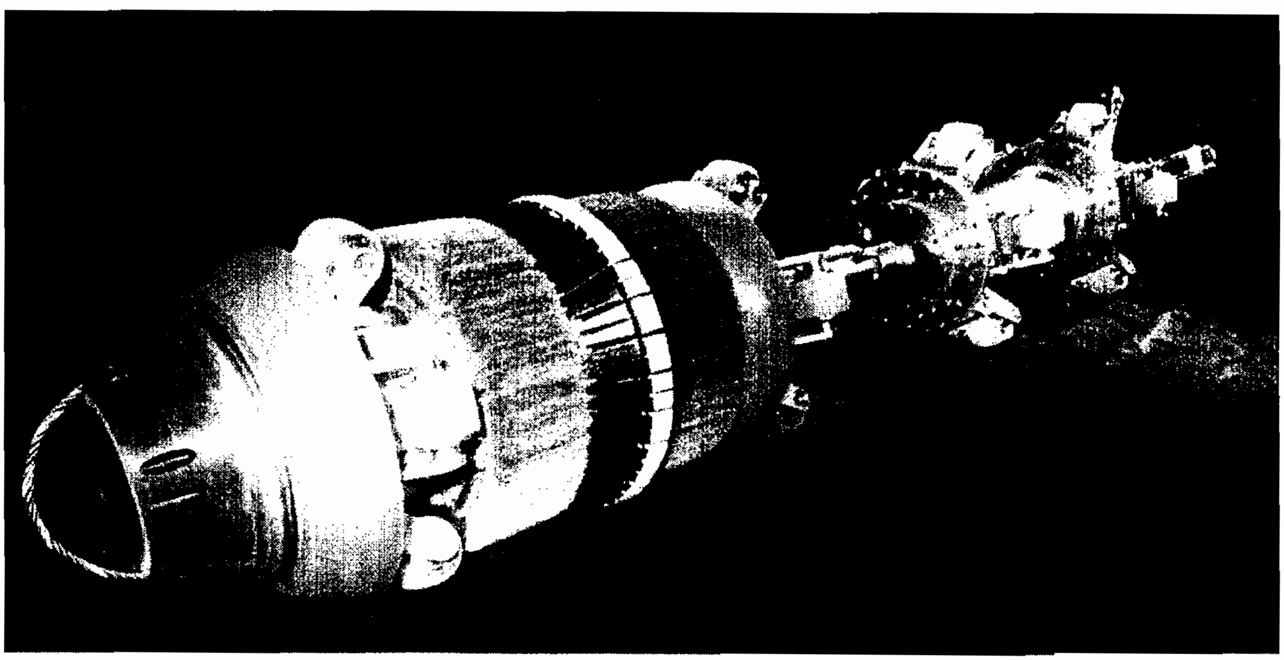
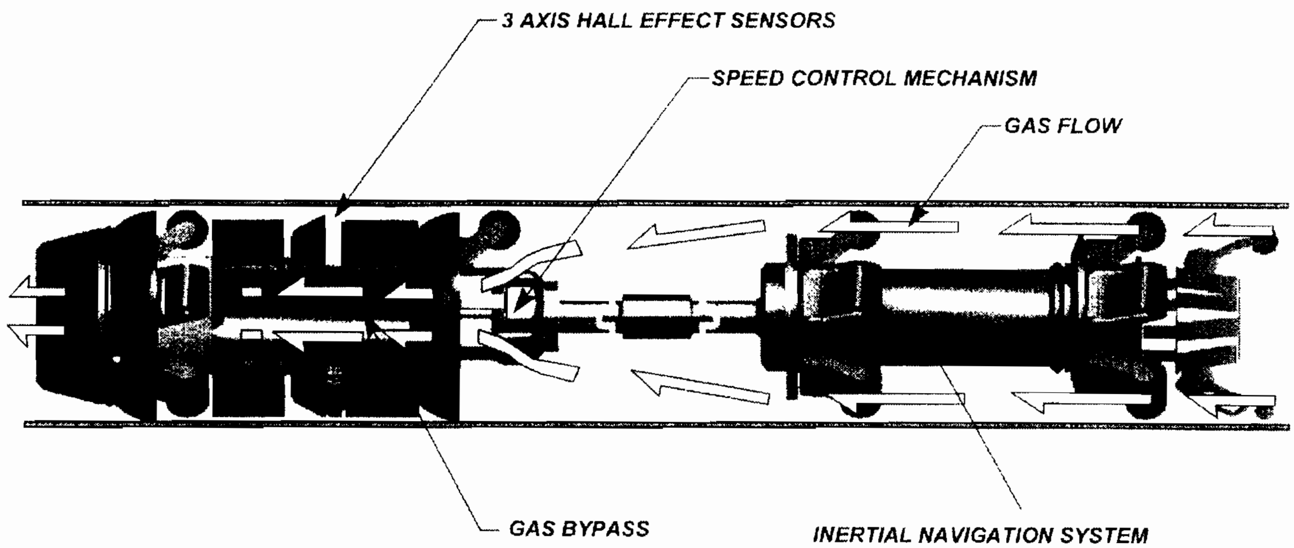
NPS 24 MFL Tool



Gas Bypass/Speed Control

NPS 24 MFL Metal Loss Inspection Tool



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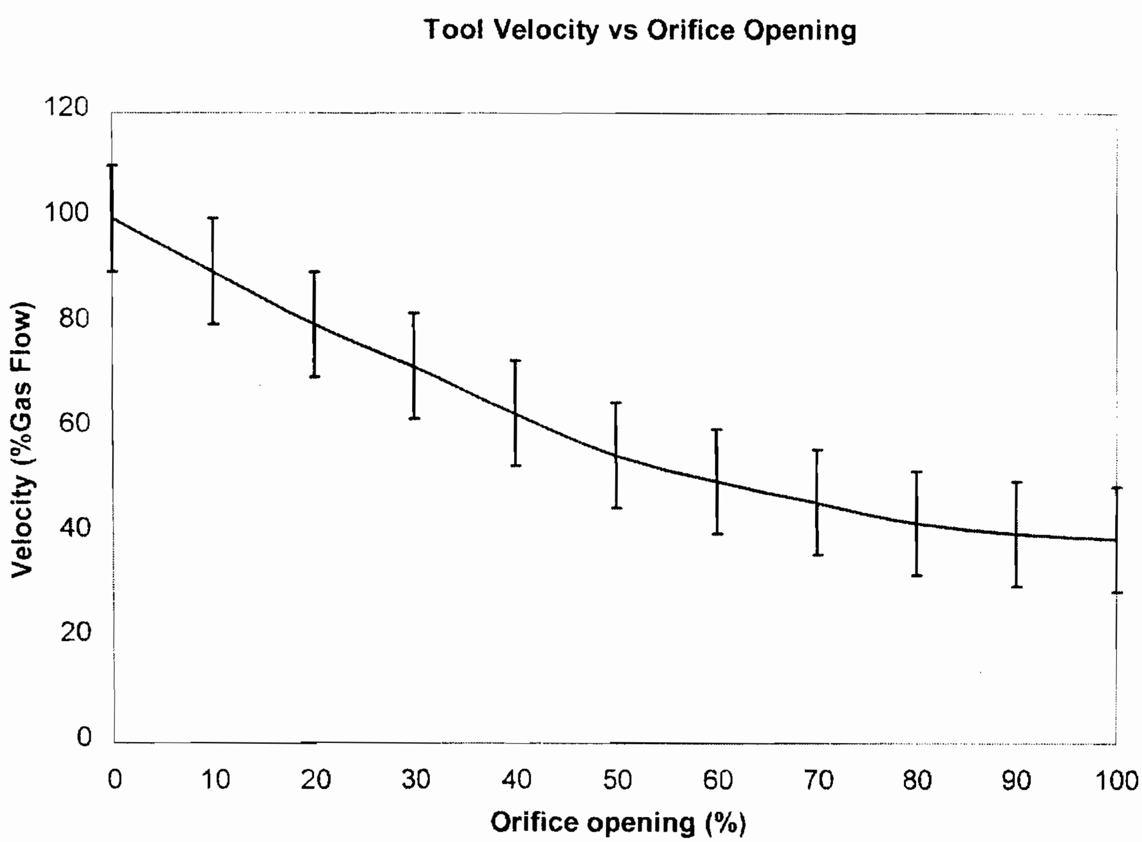

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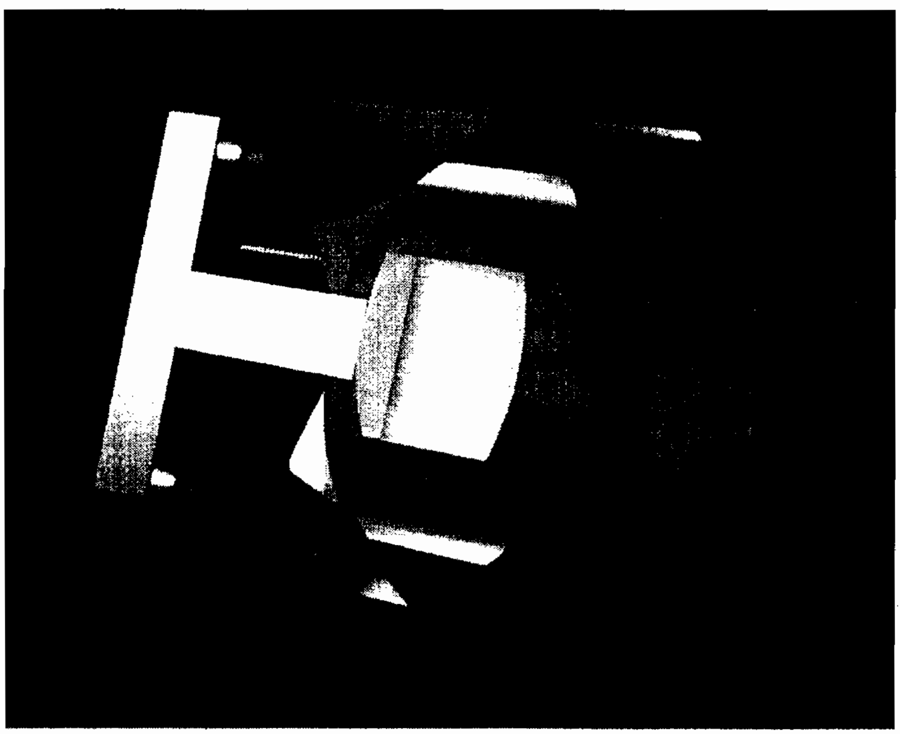
Speed Control Mechanism

- Variable Orifice
- Linear Actuated
- Shuttle/Cylinder Valve
- Cycle time 2.5 sec

Throttle Control



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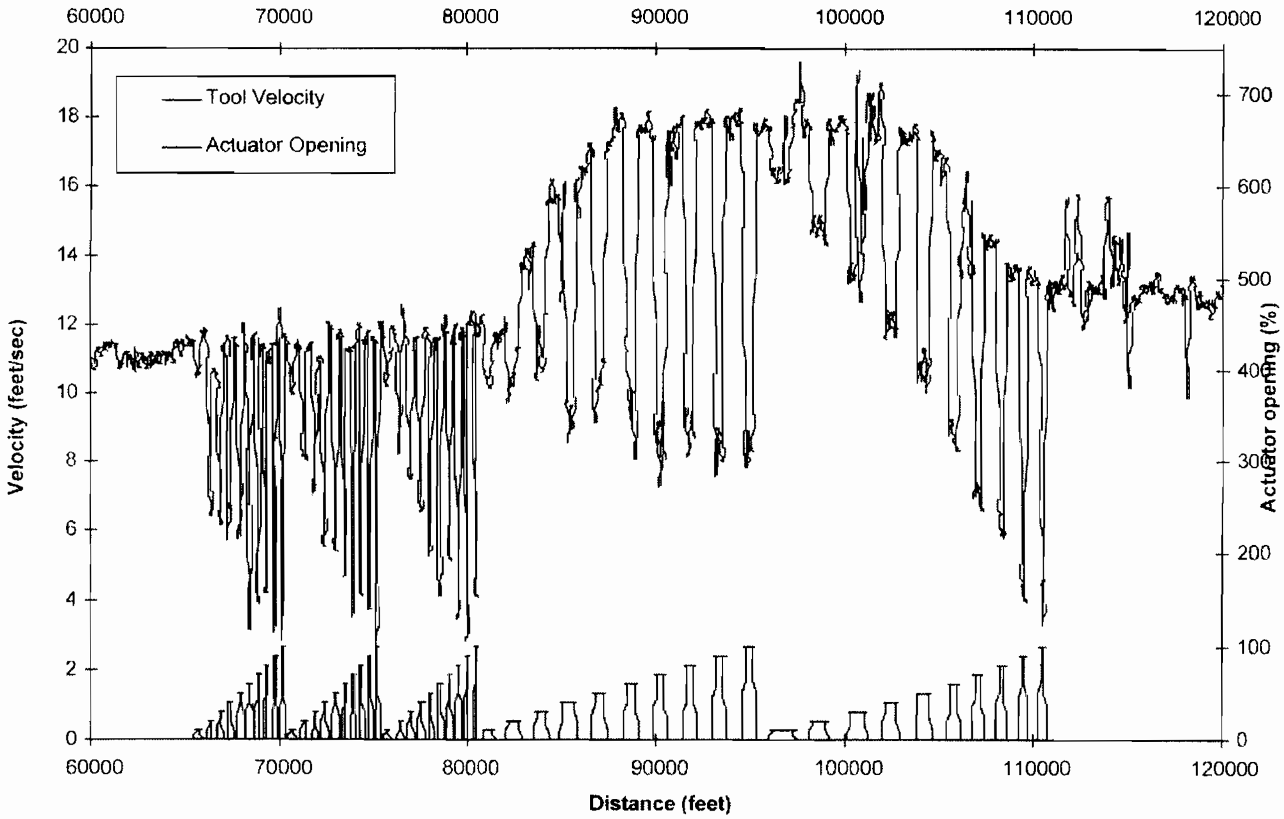
Fail Safe Mechanism

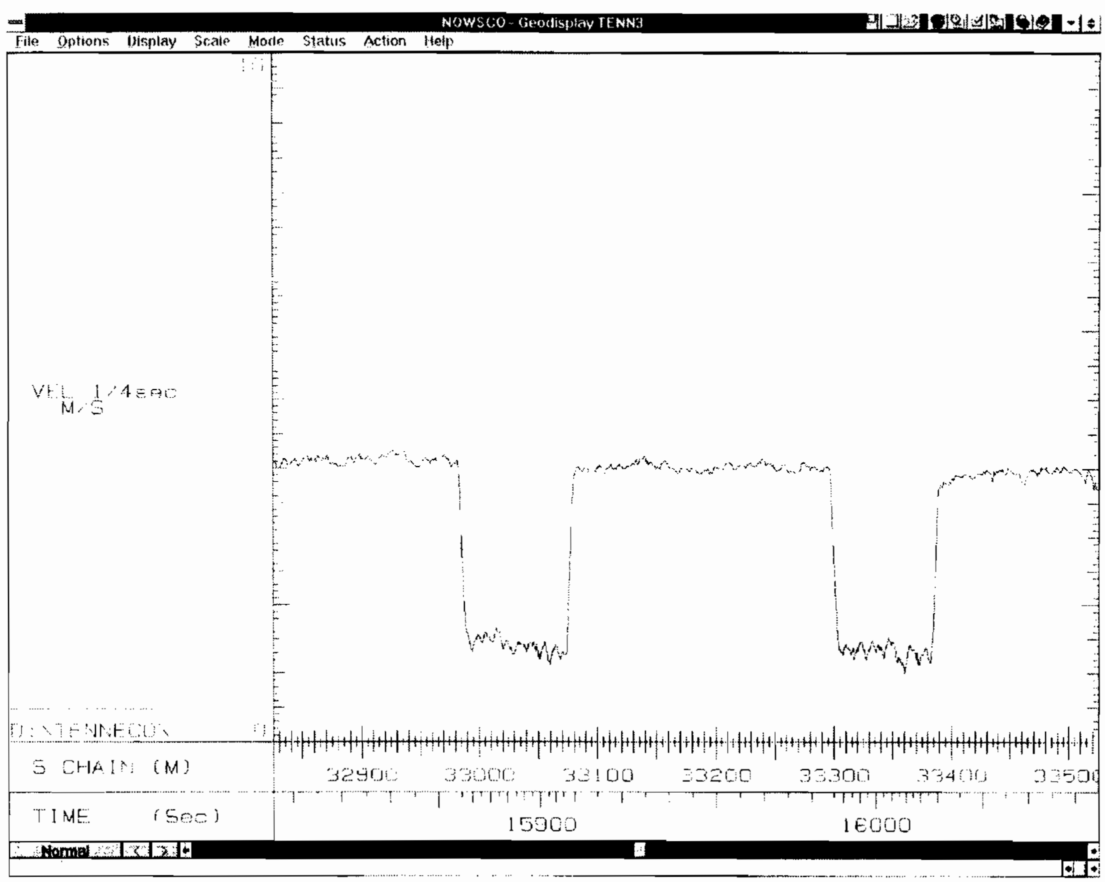
- Flapper Valve
- Independant Power Source
- Positive Close
- Time Based

Gas By-Pass/Speed Control

- De-coupling of Product Flow from Pig Speed
- Constant Inspection Speed - Improved Data Quality and Accuracy
- Maximize Gas Pipeline Flow Rates During Pipeline Inspection
- Reduce Product Delivery Interruption
- Independent Shut-off/Override Valve

Tool Velocity and Actuator Opening versus Distance
detailed view Run 3





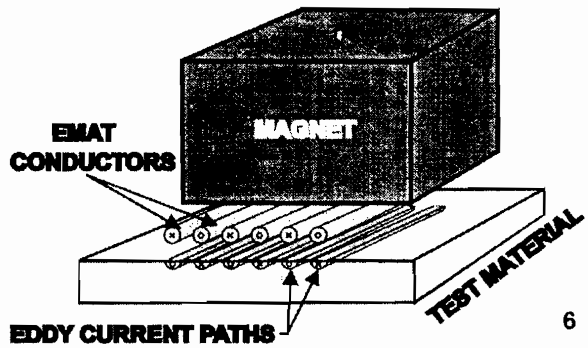
REQUIREMENTS FOR MATERIAL TO BE INSPECTED FOR SCC

- ELECTRICALLY CONDUCTING
- ELASTIC*

* In The Classical Sense

5

EDDY CURRENT INDUCTION



6

THE LORENTZ FORCE

$$\bar{F} = Q\bar{v} \times \bar{B}$$

Where Q = Electrical Charge

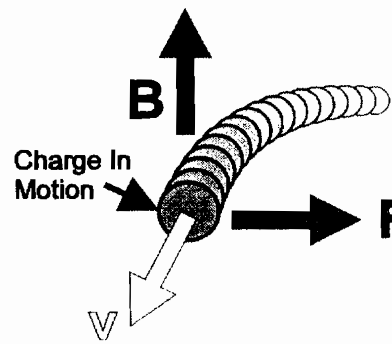
But $Q\bar{v} = \bar{i}$ (Electrical Current)

Hence,

$$\bar{F} = \bar{i} \times \bar{B}$$

7

FORCE ON MOVING CHARGE IN MAGNETIC FIELD



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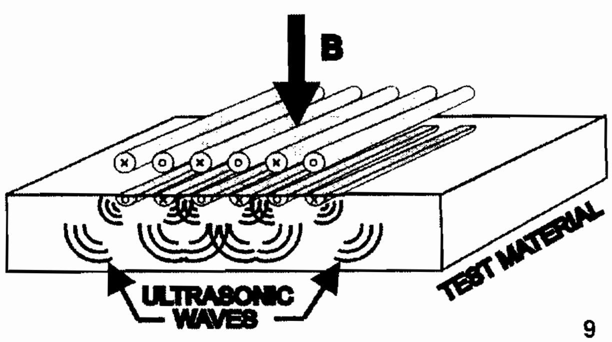
STIMULATION OF ULTRASOUND



9

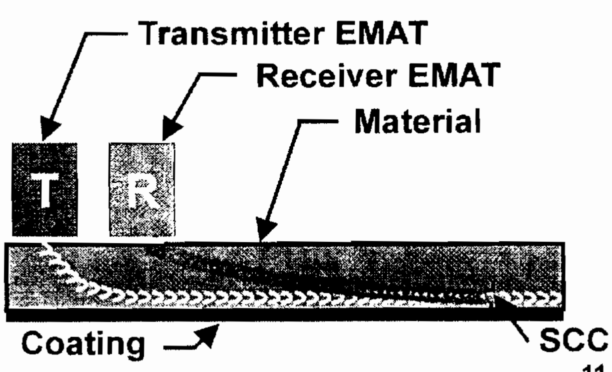
PROPAGATION OF ULTRASOUND

PROPAGATION IS VIA GUIDED WAVES
PROPAGATION MODE IS DETERMINED BY:

- **Elastic Constants of Material**
- **Thickness of Material**
- **Coil Driving Frequency**
- **Coil Geometry**

10

SCC DETECTION

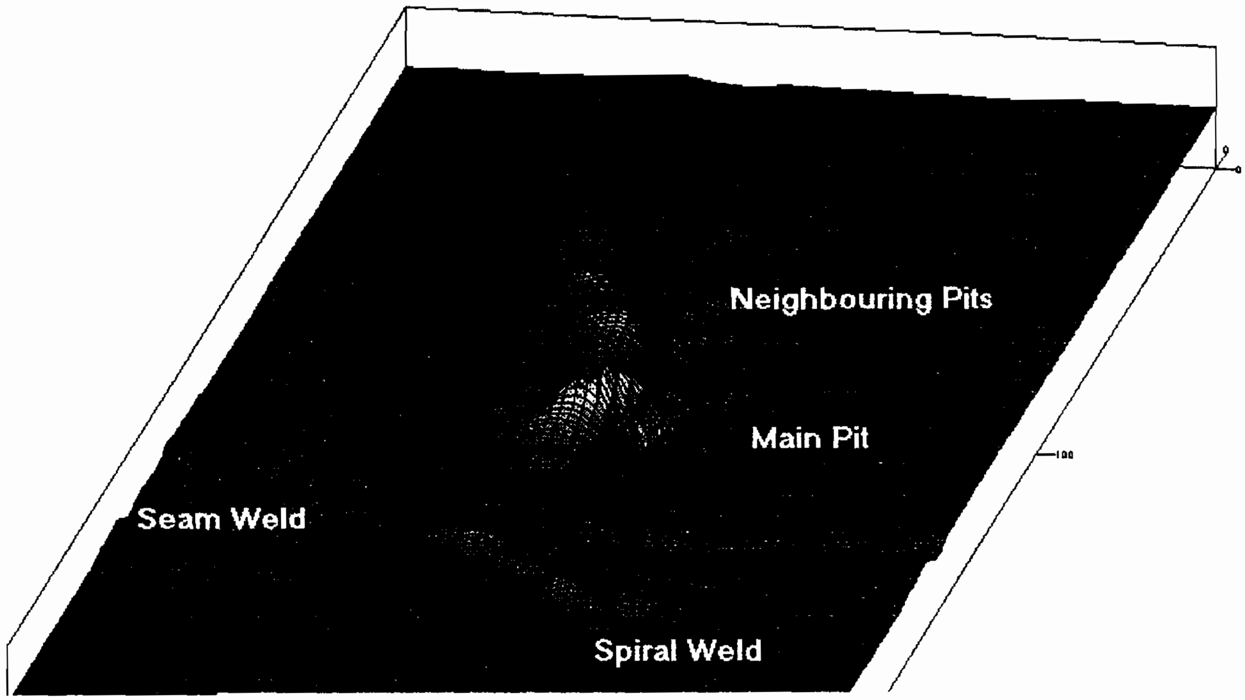


11

SCC DETECTION WITH EMATs

- **Choose A Propagation mode that is independent of coating**
- **Operate the EMAT in the reflection (Pulse-Echo) mode**

12



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EMAT BASED SCC DETECTION

IN

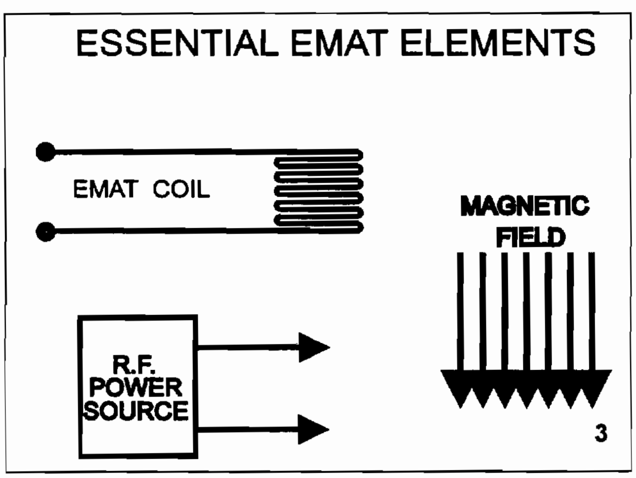
OPERATING PIPELINES

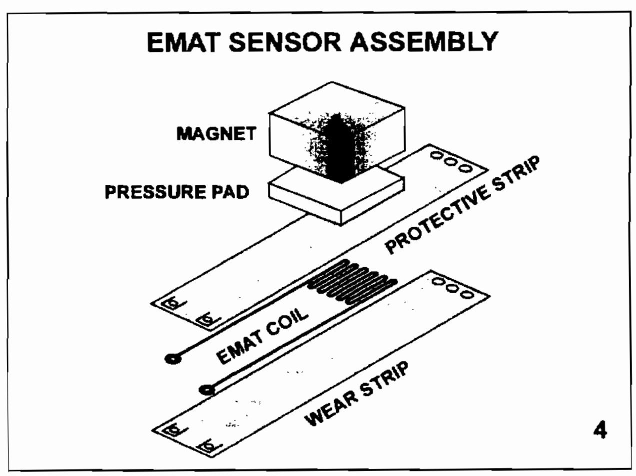
1

EMAT

ELECTROMAGNETIC
ACOUSTIC TRANSDUCER

2





WORKING GROUP #9

BANFF/97
PIPELINE WORKSHOP
April 16-18, 1997

REPORT TURNAROUND TIME

- Currently 1 to 2 month turnaround time for data
  - Adequate for 'regular' inspection but companies would pay a premium for faster data in some instants
  - 'Artificial Intelligence' and other technologies may improve turnaround time but some manual validation will still be required
  - Pipeline operators should plan inspection long before the dig window, to reduce requirements for quick data interpretation

PIPELINE INSPECTION
SYSTEM CONCEPT

- For 24" Diameter Pipe
- Detect SCC > 25% Into Pipe Wall
- Discriminate SCC From Miscellaneous Anomalies
- Capable of 25 mph Operation
- Operating Distance - Trap Spacing

13

PIPELINE INSPECTION
SYSTEM FEATURES

- Three Section Pig
- 4 EMAT Transmitter Unitsl
- 8 EMAT Receiver Units
- Signal Processing - 8 SHARC's
- Data Storage - High Cap. HD Drives

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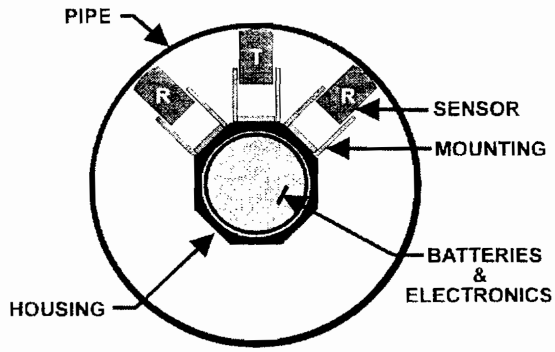
SENSOR GROUP ARRANGEMENT



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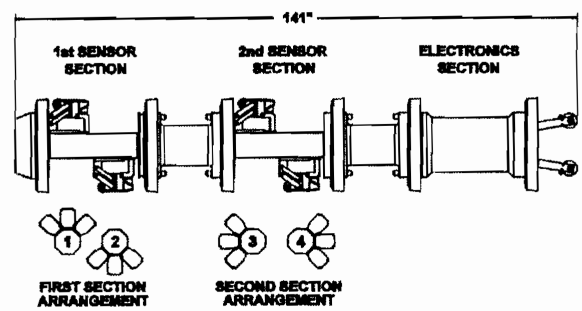
INSPECTION VEHICLE LAYOUT



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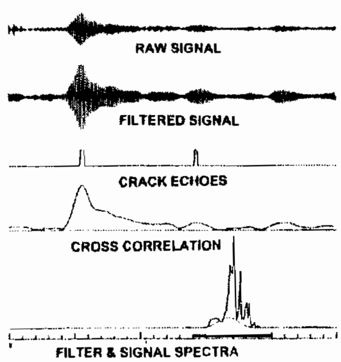
SAMPLE TEST DATA



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SMALLER TOOLS

- [illegible] tools available [illegible]
- Crack tools for n[illegible]
  - Current state of [illegible] supports smaller tool development
  - BUT [illegible] user must [illegible]ce development
  - Canadian industry m[illegible] initiate development [illegible] (Currently not a high priority issue in the United States)

CRACK DETECTION TECHNOLOGIES

- [illegible] major technologies
  - ULTRASONICS
    - British gas
    - [illegible]tronix
  - EM[illegible] Electro<u>mag</u>[illegible] <u>A</u>coustic <u>T</u>ransducer
- EMAT [illegible]ks promising but requires financ[illegible] backing from industry for commercial tool development

LOCATIONAL ACCURACY

- Pipeline operators would like to see more accurate methods to locate dig sites
- At least one vendor is planning on-board GPS technology for the near future

ACCURACY VALIDATION

- More investigative digs required to validate ILI tools - Should develop other methods to advance the validation process
- Tools are developed for specific integrity concerns - no plans to build a "super pig" designed to detect different anomaly types

CRACK DETECTION TECHNOLOGIES

- Pipetronix tool requires a liquid coupling
  - Currently developing a "dry" tool for gas pipelines
- Continued ILI development may allow elimination of hydrotests to improve integrity. (German regulator acceptance of Pipetronix crack tool)