NEWFOUNDLAND AND LABRADOR HYDRO

2005 CAPITAL BUDGET

SUBMISSION TO PUBLIC UTILITIES BOARD

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO
2005 CAPITAL BUDGET

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IN THE MATTER OF the *Public Utilities Act*, (the “Act”); and

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2005 capital budget pursuant to s.41(1) of the Act; (2) its 2005 capital purchases, and construction projects in excess of $50,000 pursuant to s.41 (3) (a) of the Act; (3) its leases in excess of $5,000 pursuant to s. 41 (3) (b) of the Act; and (4) its estimated contributions in aid of construction for 2005 pursuant to s.41 (5) of the Act and for an Order pursuant to s. 78 of the Act fixing and determining its average rate base for 2003.

TO: The Board of Commissioners of Public Utilities (“the Board”)

THE APPLICATION of Newfoundland and Labrador Hydro (“Hydro”) (“the Applicant”)

STATES that:

1. The Applicant is a corporation continued and existing under the *Hydro Corporation Act*, is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Section A to this Application is Hydro’s proposed 2005 Capital Budget in the amount of $42.4 million prepared in accordance with the guidelines and conditions outlined in Order No. P.U. 7 (2002-2003).

3. Section B to this Application is a list of the proposed 2005 Construction Projects and Capital Purchases in excess of $50,000 prepared in accordance with Order No. P.U. 7 (2002-2003).

4. No projects meeting the Guidelines for Minimum Filing Requirements for New Generation and Transmission Projects on the Island Interconnected System as set out in the Board's letter of August 19, 1999 have been identified for 2005 for inclusion in Section C.

5. New Leases in excess of $5,000 per year for 2005 are listed in Section D.

6. Section E to this Application is a Schedule of Hydro's Capital Expenditures for the period 1999 to 2008.

7. Section F to this Application is a report on the status of the 2004 capital expenditures including those approved by Orders Nos. P.U. 29 (2003), P.U. 5 (2004), P.U. 13 (2004), P.U. 16 (2004) and P.U. 28 (2004), projects under $50,000 not included in these Orders, and the 2003 capital expenditures carried forward to 2004.

8. Section G to this Application contains the supplementary reports referred to in various capital budget proposals.

9. Section H to this Application shows Hydro's actual average rate base for 2003 of $1,422,412,000.

10. The proposed capital expenditures for 2005 as set out in this Application are required to allow Hydro to continue to provide service and facilities for its customers which are reasonably safe, adequate and reliable as required by section 37 of the Act.

11. The Applicant has estimated the total of contributions in aid of construction for 2005 to be approximately $270,000. The information contained in the 2005 Capital Budget (Section A) takes into account this estimate of the contributions in aid of construction to be received from customers. All contributions to be recovered from customers shall be calculated in accordance with the relevant policies as approved by the Board.

12. Communications with respect to this Application should be forwarded to Maureen P. Greene, Q.C., Vice-President and General Counsel, P.O. Box 12400, St. John's, Newfoundland and Labrador, A1B 4K7, Telephone: (709) 737-1465.

The Applicant requests that the Board make an Order as follows:

(1) Approving Hydro's 2005 Capital Budget as set out in Section A hereto, pursuant to section 41 (1) of the Act;

(2) Approving 2005 Capital Purchases and Construction Projects in excess of $50,000 as set out in Section B hereto, pursuant to section 41 (3) (a) of the Act;

(3) Approving 2005 Leases in excess of $5,000 as set out in Section D hereto, pursuant to section 41 (3) (b) of the Act;

(4) Approving the proposed estimated contributions in aid of construction as set out in paragraph 11 hereof for 2005 as

required by section 41 (5) of the Act, with all such contributions to be calculated in accordance with the policies approved by the Board; and

(5) Fixing and determining Hydro's average rate base for 2003 in the amount of $1,422,412,000, pursuant to section 78 of the Act.

DATED at St. John's, Newfoundland, this day of August, 2004.

NEWFOUNDLAND AND LABRADOR HYDRO

____
Maureen P. Greene
Vice-President and General Counsel

Newfoundland and Labrador Hydro
P.O. Box 12400
500 Columbus Drive
St. John's, Newfoundland and Labrador
A1B 4K7
Telephone: (709) 737-1465

IN THE MATTER OF the *Public Utilities Act*, (the "Act"); and

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2005 capital budget pursuant to s.41(1) of the Act; (2) its 2005 capital purchases, and construction projects in excess of $50,000 pursuant to s.41 (3) (a) of the Act; (3) its leases in excess of $5,000 pursuant to s. 41 (3) (b) of the Act; and (4) its estimated contributions in aid of construction for 2005 pursuant to s.41 (5) of the Act and for an Order pursuant to s. 78 of the Act fixing and determining its average rate base for 2003.

TO: The Board of Commissioners of Public Utilities ("the Board")

AFFIDAVIT

I, Fred Martin, Professional Engineer, make oath and say as follows:

1. That I am the Vice-President of Transmission and Rural Operations of Hydro and as such I have knowledge of the matters arising in the within matter.

2. That I have read the contents of the attached Application and those contents are correct and true to the best of my knowledge, information and belief.

SWORN TO in the)
City of St. John's, in the)
Province of Newfoundland and Labrador)
this ____ day of August, 2004,) ______________________
before me:) Fred H. Martin
)
)
)
______________________________)

Maureen P. Greene
Barrister (Nfld.)

SECTION A

NEWFOUNDLAND & LABRADOR HYDRO

2005 CAPITAL BUDGET - OVERVIEW

($,000)

	Exp To 2004	2005	Future Years	Total
GENERATION	1,733	5,986	1,815	9,534
TRANSMISSION & RURAL OPERATIONS	0	19,820	787	20,607
GENERAL PROPERTIES	5,273	15,625	9,119	30,017
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	0	1,000
TOTAL CAPITAL BUDGET	7,006	42,431	11,721	61,158

NEWFOUNDLAND & LABRADOR HYDRO

2005 CAPITAL BUDGET - SUMMARY BY CATEGORY

($,000)

	Exp To 2004	2005	Future Years	Total
GENERATION				
HYDRO PLANTS				
Construction Projects	102	1,641	1,815	3,558
Tools & Equipment	0	198	0	198
THERMAL PLANT				
Construction Projects	1,553	1,800	0	3,353
Property Additions	78	2,002	0	2,080
Tools & Equipment	0	16	0	16
GAS TURBINES				
Construction Projects	0	329	0	329
TOTAL GENERATION	1,733	5,986	1,815	9,534
TRANSMISSION & RURAL OPERATIONS				
TRANSMISSION	0	3,590	0	3,590
SYSTEM PERFORMANCE & PROTECTION	0	468	0	468
TERMINALS	0	598	0	598
DISTRIBUTION	0	9,559	0	9,559
GENERATION	0	2,372	787	3,159
GENERAL				
Metering	0	192	0	192
Properties	0	1,023	0	1,023
Tools & Equipment	0	2,018	0	2,018
TOTAL TRANSMISSION & RURAL OPERATIONS	0	19,820	787	20,607

NEWFOUNDLAND & LABRADOR HYDRO

2005 CAPITAL BUDGET - SUMMARY BY CATEGORY

($,000)

	Exp To 2004	2005	Future Years	Total
GENERAL PROPERTIES				
INFORMATION SYSTEMS & TELECOMMUNICATIONS	4,156	13,472	9,119	26,747
ADMINISTRATIVE	1,117	2,153	0	3,270
TOTAL GENERAL PROPERTIES	5,273	15,625	9,119	30,017
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	0	1,000
TOTAL CAPITAL BUDGET	7,006	42,431	11,721	61,158

NEWFOUNDLAND & LABRADOR HYDRO
GENERATION
2005 CAPITAL BUDGET - DETAIL

($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
HYDRO PLANTS						
CONSTRUCTION PROJECTS						
Upgrade Slope Stabilization - Upper Salmon Power Canal	102	1,003		1,105	Oct. 05	B-5
Replace Underground Fuel Tanks - Upper Salmon Generating Facility		327		327	Sep. 05	B-9
Upgrade Controls Spherical Valve No.6 - Bay d'Espoir		196		196	Nov. 05	B-11
Replace Penstock - Snook's Arm Generating Station		115	1,815	1,930	Oct. 06	B-13
TOTAL CONSTRUCTION PROJECTS	102	1,641	1,815	3,558		
TOOLS & EQUIPMENT						
Purchase Dry Ice Cleaning System - BDE		59		59	Oct. 05	B-15
Purchase Wedge Tightness Detector - BDE		49		49	Nov. 05	
Purchase & Replace T & E Less than $ 50,000		90		90		
TOTAL TOOLS & EQUIPMENT	0	198	0	198		

NEWFOUNDLAND & LABRADOR HYDRO
GENERATION
2005 CAPITAL BUDGET - DETAIL
($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
THERMAL PLANT						
CONSTRUCTION PROJECTS						
Upgrade Control System - Holyrood	1,553	1,034		2,587	Aug. 05	B-16
Purch/Inst Anti-Fouling System for Cooling Water Systems - Holyrood		705		705	Oct. 05	B-19
Purch/Inst Fire Protection System - Microwave Radio Room - Holyrood		61		61	Oct. 05	B-20
TOTAL CONSTRUCTION PROJECTS	1,553	1,800	0	3,353		
PROPERTY ADDITIONS						
Upgrade Civil Structures	78	2,002		2,080	Oct. 05	B-21
TOTAL PROPERTY ADDITIONS	78	2,002	0	2,080		
TOOLS & EQUIPMENT						
Purchase & Replace Tools & Equipment Less than $ 50,000	0	16	0	16		
TOTAL TOOLS & EQUIPMENT	0	16	0	16		
GAS TURBINES						
CONSTRUCTION PROJECTS						
Install Main Fuel Line Valve - Hardwoods		91		91	Oct. 05	B-24
Installation of Diesel Generating Set - Stephenville		87		87	Jun. 05	B-25
Replace Battery Bank - Hardwoods		58		58	Sep. 05	B-27
Purchase/Install Reconciliation Flow Meters - Stephenville		26		26	Jul. 05	
Purchase/Install Reconciliation Flow Meters - Hardwoods		24		24	Jul. 05	
Replace Control Module HVAC Unit - Hardwoods		24		24	Jul. 05	
Automate Diesel Backup System - Hardwoods		19		19	Jun. 05	
TOTAL CONSTRUCTION PROJECTS	0	329	0	329		
TOTAL GENERATION	1,733	5,986	1,815	9,534		

NEWFOUNDLAND & LABRADOR HYDRO
TRANSMISSION & RURAL OPERATIONS
2005 CAPITAL BUDGET - DETAIL
($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
TRANSMISSION						
Replace Wood Poles - Transmission		2,588		2,588	Dec. 05	B-28
Upgrade TL221 - (69kV Peter's Barren - Hawkes Bay)		774		774	Oct. 05	B-30
Replace Insulators TL243 - (138kV Hinds Lake - Howley)		228		228	Sep. 05	B-32
TOTAL TRANSMISSION	0	3,590	0	3,590		
SYSTEM PERFORMANCE & PROTECTION						
Provide Remote Control - Farewell Head Terminal Station		127		127	Jun. 05	B-33
Purch/Install Digital Fault Recorder - Bottom Brook		122		122	Aug. 05	B-35
Purch/Install 66Kv Breaker Fail Protection - Massey Drive TS		81		81	Oct. 05	B-36
Upgrade Protection 66Kv Lines - Peter's Barren , Daniel's Harbour		78		78	Oct. 05	B-37
Upgrade Breaker Controls - BBK/MDR Terminal Station		33		33	Aug. 05	
Purch/Install 66Kv Breaker Protection Upgrade - Bay d'Espoir		27		27	Oct. 05	
TOTAL SYSTEM PERFORMANCE & PROTECTION	0	468	0	468		
TERMINALS						
Install Motor Drive Mechanisms on Disconnect Switches - East Coast		183		183	Oct. 05	B-38
Replace Battery Banks		166		166	Oct. 05	B-40
Replace Instrument Transformers		75		75	Dec. 05	B-42
Replace Surge Arrestors		68		68	Dec. 05	B-44
Purch/Install Conduit and Cable - (Bay d'Espoir TS - Powerhouse)		61		61	Aug. 05	B-46
Construct Yard Extension - Conne River Substation		45		45	Jul. 05	
TOTAL TERMINALS	0	598	0	598		

NEWFOUNDLAND & LABRADOR HYDRO
TRANSMISSION & RURAL OPERATIONS
2005 CAPITAL BUDGET - DETAIL
($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
DISTRIBUTION						
Interconnect - Rencontre East		3,250		3,250	Nov. 05	B-47
Provide Service Extensions		1,728		1,728	Dec. 05	B-48
Upgrade Distribution Systems		1,601		1,601	Dec. 05	B-50
Insulator Replacements		971		971	Dec. 05	B-52
Upgrade Distribution Line - Cook's Harbour		718		718	Oct. 05	B-54
Upgrade Distribution System - L'Anse au Loup		636		636	Oct. 05	B-56
Relocate Substation- Roberts Arm/Triton		319		319	Oct. 05	B-58
Purchase and Install Reclosers - Makkovik & Hopedale		125		125	Oct. 05	B-65
Distribution Line Pole Replacements		168		168	Oct. 05	B-66
Relocate Regulator Bank - Happy Valley		43		43	Oct. 05	
TOTAL DISTRIBUTION	0	9,559	0	9,559		
GENERATION						
Increase Generation - L'Anse au Loup		392		392	Sep. 05	B-67
Replace Diesel Generating Unit No. 266 - Williams Hr.		304		304	Sep. 05	B-70
Replace Dam - Roddickton Mini Hydro		232		232	Oct. 05	B-71
Installation of Fall Arrest Equipment - Hydro facilities		206	787	993	Nov .08	B-77
Install Shut-Off Valves - Diesel Plants		165		165	Sep. 05	B-78
Install Fuel Storage Tanks - Hopedale & Paradise River		152		152	Oct. 05	B-79
Replacement of Circuit Breakers - Hawkes Bay Diesel		111		111	Oct. 05	B-81
Upgrade Cooling System - Black Tickle		107		107	Jul. 05	B-82
Install Day Tank and Fuel Meter - Ramea		106		106	Aug. 05	B-83
Upgrade Building System North Plant - Goose Bay		99		99	Aug. 05	B-84
Raise Stack Heights - St. Brendan's, Black Tickle, Cartwright		96		96	Sep. 05	B-88
Purch.& Inst. Digital Metering - Francois, McCallum, Grey River, Little Bay Isl		90		90	Oct. 05	B-89
Upgrade Diesel Plant - Black Tickle		85		85	Sep. 05	B-90
Purchase Data Acquisition Software - Diesel Plants		70		70	Mar. 05	B-96
Install Intermediate Fuel Storage Tank - Charlottetown		66		66	Aug. 05	B-97
Modify Heating System - Hopedale		54		54	Nov. 05	B-99
Replace Battery Banks - L'Anse au Loup & Hawkes Bay		37		37	Sep. 05	
TOTAL GENERATION	0	2,372	787	3,159		

NEWFOUNDLAND & LABRADOR HYDRO
TRANSMISSION & RURAL OPERATIONS
2005 CAPITAL BUDGET - DETAIL
($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
GENERAL						
METERING						
Purchase Meters & Equipment - TRO System		159		159	Dec. 05	B-100
Purchase Metering Spares - Bulk Electrical System		33		33	Dec. 05	
TOTAL METERING	0	192	0	192		
PROPERTIES						
Install Central Air Conditioning - Whitbourne & Stephenville		289		289	Oct. 05	B-101
Warehouse Renovations - St. Anthony		147		147	Jul. 05	B-102
Upgrade Line Depot/Storage Shed - Baie Verte, Sop's Arm & Bay d'Espoir		151		151	Jul. 05	B-103
Replace Line Depot Building - Mary's Harbour		74		74	Oct. 05	B-104
Purchase Global Positioning System		57		57	Feb. 05	B-105
Replace Fence Daniels Harbour Terminal Station		52		52	Jul. 05	B-106
Construct PCB Storage Building - Wabush		52		52	Aug. 05	B-107
Legal Survey of Distribution Line Right-of-Ways		50		50	Oct. 05	B-108
Extend Fence - Quartzite Terminal Station		49		49	Jul. 05	
Provide Security System - Port Saunders Office		43		43	Oct. 05	
Construct Storage Ramp - Stephenville & Whitbourne		36		36	Aug. 05	
Replace Wooden Gantry Crane - Salvage Stores		16		16	Jul. 05	
Construct Lube Oil Storage Ramp - Williams Harbour		7		7	Oct. 05	
TOTAL PROPERTIES	0	1,023	0	1,023		
TOOLS & EQUIPMENT						
Replace Nodwell V7600 & Boom V6067 - Stephenville		798		798	Jul. 05	B-109
Purchase Mobile Oil Reclaimation Unit		531		531	Oct. 05	B-110
Replace Doble F2000 Relay Test Equipment - BFL, WBN, STV & BDE		362		362	Jun. 05	B-112
Purchase & Replace Tools & Equipment Less than $ 50,000	0	67		67		
Replace Light Duty Mobile Equipment Less than $ 50,000		260		260		
TOTAL TOOLS & EQUIPMENT	0	2,018	0	2,018		
TOTAL GENERAL	0	3,233	0	3,233		
TOTAL TRANSMISSION & RURAL OPERATIONS	0	19,820	787	20,607		

NEWFOUNDLAND & LABRADOR HYDRO
GENERAL PROPERTIES
2005 CAPITAL BUDGET - DETAIL
($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
INFORMATION SYSTEMS & TELECOMMUNICATIONS						
SOFTWARE APPLICATIONS						
Infrastructure Replacement						
Replace Energy Management System - Energy Control Centre	3,110	5,522	3,646	12,278	Oct. 06	B-114
New Infrastructure						
Applications Enhancements		311		311	Dec. 05	B-120
Security Program - Secure Remote Access	75	76		151	Dec. 05	B-122
Upgrade of Technology						
Corporate Applications Environment		274		274	Dec. 05	B-124
Cost Recovery CF(L)Co		(52)		(52)		
TOTAL SOFTWARE APPLICATIONS	3,185	6,131	3,646	12,962		
COMPUTER OPERATIONS						
Infrastructure Replacement						
iSeries Replacement		1,398		1,398	Nov. 05	B-125
Cost Recovery CF(L)Co		(266)		(266)		
End User Evergreen Program - 2005		711		711	Nov. 05	B-127
New Infrastructure						
Peripheral Infrastructure Replacement		118		118	Nov. 05	B-131
Security Strategy Deployment		99		99	Dec. 05	B-132
Cost Recovery CF(L)Co		(19)		(19)		
Upgrade of Technology						
Server & Operating Systems Evergreen Program - 2005		212		212	Nov. 05	B-134
TOTAL COMPUTER OPERATIONS	0	2,253	0	2,253		

NEWFOUNDLAND & LABRADOR HYDRO
GENERAL PROPERTIES
2005 CAPITAL BUDGET - DETAIL
($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
INFORMATION SYSTEMS & TELECOMMUNICATIONS						
NETWORK SERVICES						
Infrastructure Replacement						
Replace VHF Mobile Radio System		2,915	5,473	8,388	Nov. 06	B-137
Replace Battery System - Multiple Sites		364		364	Dec. 05	B-139
Microwave Site Refurbishing		294		294	Dec. 05	B-141
Replace Remote Terminal Unit for Hydro - Phase 6		150		150	Oct. 05	B-143
Replace Air Conditioners - Stoney Brook & Deer Lake		55		55	Dec. 05	B-144
Replace Voice and Data Communications - Berry Hill		15		15	Oct. 05	
Upgrade of Technology						
Replacement of Operational Data & Voice Network - Phase 2	971	1,247		2,218	Oct. 05	B-145
Upgrade Site Grounding - 2005		48		48	Dec. 05	
TOTAL NETWORK SERVICES	971	5,088	5,473	11,532		
TOTAL INFORMATION SYSTEMS & TELECOMMUNICATIONS	4,156	13,472	9,119	26,747		

NEWFOUNDLAND & LABRADOR HYDRO
GENERAL PROPERTIES
2005 CAPITAL BUDGET - DETAIL
($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
ADMINISTRATIVE						
Vehicles						
Replace Vehicles - Hydro System - 2004	1,081	450		1,531	Jun. 05	B-147
Replace Vehicles - Hydro System - 2005		878		878	Jun. 06	B-149
ADMINISTRATION						
Electronic Metering Reading	36	224		260	Dec. 05	B-151
Replace Chiller - Hydro Place		213		213	May. 05	B-152
Security Assessment of System Operations		110		110	Dec. 05	B-153
Upgrade Standby Diesel Fuel System - Hydro Place		91		91	Jul. 05	B-154
Re-Construct Storage Ramps - Bishop's Falls		73		73	Dec. 05	B-155
Purchase & Replace Admin Office Equip less than $50,000		114		114		
TOTAL ADMINISTRATIVE	1,117	2,153	0	3,270		
TOTAL GENERAL PROPERTIES	5,273	15,625	9,119	30,017		

SECTION B

NEWFOUNDLAND & LABRADOR HYDRO

2005 CAPITAL BUDGET - OVERVIEW

($,000)

	Exp To 2004	2005	Future Years	Total
GENERATION	1,733	5,738	1,815	9,286
TRANSMISSION & RURAL OPERATIONS	0	19,124	787	19,911
GENERAL PROPERTIES	5,273	15,448	9,119	29,840
ALLOWANCE FOR UNFORSEEN EVENTS	0	1,000	0	1,000
TOTAL CAPITAL BUDGET	7,006	41,310	11,721	60,037

NEWFOUNDLAND & LABRADOR HYDRO
GENERATION
2005 CAPITAL BUDGET - PROJECTS OVER $50,000 BY CATEGORY

($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
Upgrade Slope Stabilization - Upper Salmon Power Canal	102	1,003		1,105	Oct. 05	B-5
Replace Underground Fuel Tanks - Upper Salmon Generating Facility		327		327	Sep. 05	B-9
Upgrade Controls Spherical Valve No.6 - Bay d'Espoir		196		196	Nov. 05	B-11
Replace Penstock - Snook's Arm Generating Station		115	1,815	1,930	Oct. 06	B-13
Purchase Dry Ice Cleaning System - BDE		59		59	Oct. 05	B-15
Upgrade Control System - Holyrood	1,553	1,034		2,587	Aug. 05	B-16
Purch/Inst Anti-Fouling System for Cooling Water Systems - Holyrood		705		705	Oct. 05	B-19
Purch/Inst Fire Protection System - Microwave Radio Room - Holyrood		61		61	Oct. 05	B-20
Upgrade Civil Structures	78	2,002		2,080	Oct. 05	B-21
Install Main Fuel Line Valve - Hardwoods		91		91	Oct. 05	B-24
Installation of Diesel Generating Set - Stephenville		87		87	Jun. 05	B-25
Replace Battery Bank - Hardwoods		58		58	Sep. 05	B-27
TOTAL GENERATION	1,733	5,738	1,815	9,286		

NEWFOUNDLAND & LABRADOR HYDRO
TRANSMISSION & RURAL OPERATIONS
2005 CAPITAL BUDGET - PROJECTS OVER $50,000 BY CATEGORY
($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
Replace Wood Poles - Transmission		2,588		2,588	Dec. 05	B-28
Upgrade TL221 - (69kV Peter's Barren - Hawkes Bay)		774		774	Oct. 05	B-30
Replace Insulators TL243 - (138kV Hinds Lake - Howley)		228		228	Sep. 05	B-32
Provide Remote Control - Farewell Head Terminal Station		127		127	Jun. 05	B-33
Purch/Install Digital Fault Recorder - Bottom Brook		122		122	Aug. 05	B-35
Purch/Install 66Kv Breaker Fail Protection - Massey Drive TS		81		81	Oct. 05	B-36
Upgrade Protection 66Kv Lines - Peter's Barren , Daniel's Harbour		78		78	Oct. 05	B-37
Install Motor Drive Mechanisms on Disconnect Switches - East Coast		183		183	Oct. 05	B-38
Replace Battery Banks		166		166	Oct. 05	B-40
Replace Instrument Transformers		75		75	Dec. 05	B-42
Replace Surge Arrestors		68		68	Dec. 05	B-44
Purch/Install Conduit and Cable - (Bay d'Espoir TS - Powerhouse)		61		61	Aug. 05	B-46
Interconnect - Rencontre East		3,250		3,250	Nov. 05	B-47
Provide Service Extensions		1,728		1,728	Dec. 05	B-48
Upgrade Distribution Systems		1,601		1,601	Dec. 05	B-50
Insulator Replacements		971		971	Dec. 05	B-52
Upgrade Distribution Line - Cook's Harbour		718		718	Oct. 05	B-54
Upgrade Distribution System - L'anse Au Loup		636		636	Oct. 05	B-56
Relocate Substation- Roberts Arm/Triton		319		319	Oct. 05	B-58
Purchase and Install Reclosers - Makkovik & Hopedale		125		125	Oct. 05	B-65
Distribution Line Pole Replacements		168		168	Oct. 05	B-66
Increase Generation - L'anse Au Loup		392		392	Sep. 05	B-67
Replace Diesel Generating Unit No. 266 - Willlams Hr.		304		304	Sep. 05	B-70
Replace Dam - Roddickton Mini Hydro		232		232	Oct. 05	B-71
Installation of Fall Arrest Equipment - Hydro facilities		206	787	993	Nov .08	B-77
Install Shut-Off Valves - Diesel Plants		165		165	Sep. 05	B-78
Install Fuel Storage Tanks - Hopedale & Paradise River		152		152	Oct. 05	B-79
Replacement of Circuit Breakers - Hawkes Bay Diesel		111		111	Oct. 05	B-81
Upgrade Cooling System - Black Tickle		107		107	Jul. 05	B-82
Install Day Tank and Fuel Meter - Ramea		106		106	Aug. 05	B-83
Upgrade Building System North Plant - Goose Bay		99		99	Aug. 05	B-84
Raise Stack Heights - St. Brendan's, Black Tickle, Cartwright		96		96	Sep. 05	B-88
Purch.& Inst. Digital Metering - Francois, McCallum, Grey River, Little Bay Isl		90		90	Oct. 05	B-89
Upgrade Diesel Plant - Black Tickle		85		85	Sep. 05	B-90
Purchase Data Acquisition Software - Diesel Plants		70		70	Mar. 05	B-96
Install Intermediate Fuel Storage Tank - Charlottetown		66		66	Aug. 05	B-97
Modify Heating System - Hopedale		54		54	Nov. 05	B-99
Purchase Meters & Equipment - TRO System		159		159	Dec. 05	B-100
Install Central Air Conditioning - Whitbourne & Stephenville		289		289	Oct. 05	B-101
Warehouse Renovations - St. Anthony		147		147	Jul. 05	B-102
Upgrade Line Depot/Storage Shed - Baie Verte, Sop's Arm & Bay D'Espoir		151		151	Jul. 05	B-103
Replace Line Depot Building - Mary's Harbour		74		74	Oct. 05	B-104
Purchase Global Positioning System		57		57	Feb. 05	B-105
Replace Fence Daniels Harbour Terminal Station		52		52	Jul. 05	B-106
Construct PCB Storage Building - Wabush		52		52	Aug. 05	B-107
Legal Survey of Distribution Line Right-of-Ways		50		50	Oct. 05	B-108
Replace Nodwell V7600 & Boom V6067 - Stephenville		798		798	Jul. 05	B-109
Purchase Mobile Oil Reclaimation Unit		531		531	Oct. 05	B-110
Replace Doble F2000 Relay Test Equipment - BFL, WBN, STV & BDE		362		362	Jun. 05	B-112
TOTAL TRANSMISSION & RURAL OPERATIONS	0	19,124	787	19,911		

NEWFOUNDLAND & LABRADOR HYDRO
GENERAL PROPERTIES
2005 CAPITAL BUDGET - PROJECTS OVER $50,000 BY CATEGORY
($,000)

PROJECT DESCRIPTION	Exp To 2004	2005	Future Years	Total	In-Ser Date	Explanation Page Ref.
Replace Energy Management System - Energy Control Centre	3,110	5,522	3,646	12,278	Oct. 06	B-114
Applications Enhancements		311		311	Dec. 05	B-120
Security Program - Secure Remote Access	75	76		151	Dec. 05	B-122
Corporate Applications Environment		274		274	Dec. 05	B-124
Cost Recovery CF(L)co		(52)		(52)		
iSeries Replacement		1,398		1,398	Nov. 05	B-125
Cost Recovery CF(L)Co		(266)		(266)		
End User Evergreen Program - 2005		711		711	Nov. 05	B-127
Peripheral Infrastructure Replacement		118		118	Nov. 05	B-131
Security Strategy Deployment		99		99	Dec. 05	B-132
Cost Recovery CF(L)Co		(19)		(19)		
Server & Operating Systems Evergreen Program - 2005		212		212	Nov. 05	B-134
Replace VHF Mobile Radio System		2,915	5,473	8,388	Nov. 06	B-137
Replace Battery System - Multiple Sites		364		364	Dec. 05	B-139
Microwave Site Refurbishing		294		294	Dec. 05	B-141
Replace Remote Terminal Unit for Hydro - Phase 6		150		150	Oct. 05	B-143
Replace Air Conditioners - Stoney Brook & Deer Lake		55		55	Dec. 05	B-144
Replacement of Operational Data & Voice Network - Phase 2	971	1,247		2,218	Oct. 05	B-145
Replace Vehicles - Hydro System - 2004	1,081	450		1,531	Jun. 05	B-147
Replace Vehicles - Hydro System - 2005		878		878	Jun. 06	B-149
Electronic Metering Reading	36	224		260	Dec. 05	B-151
Replace Chiller - Hydro Place		213		213	May. 05	B-152
Security Assessment of System Operations		110		110	Dec. 05	B-153
Upgrade Standby Diesel Fuel System - Hydro Place		91		91	Jul. 05	B-154
Re-Construct Storage Ramps - Bishop's Falls		73		73	Dec. 05	B-155
TOTAL GENERAL PROPERTIES	5,273	15,448	9,119	29,840		

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Slope Stabilization - Upper Salmon Power Canal

Location: Upper Salmon Generating Station

Division: Production

Classification: Hydro Plants

Project Description:

This project for 2005 is the continuation of a project for which the Board approved funds for 2004. The project is proposed to be carried out in two phases over a two-year period. The first phase consists of an engineering study during 2004 to determine the most appropriate method to address concerns with slope instability at a section of the Upper Salmon power canal. The study will evaluate options and prepare the final design and cost estimate. During the second phase, in 2005, the repair will be completed. The Upper Salmon power canal is 3.8 km in length and was constructed through the excavation of overburden and bedrock and the building of earth fill dykes. Settlement, cracking and slumping has been identified over the past several years along a 400 m section of the north slope of the canal, which was constructed to a slope of 2.0 H: 1.0 V. As well, this area has a high ground water table and is subject to localized flash flooding and wave action from the adjacent lake. Hydro's Dyke Board of Consultants (the Dyke Board) has recommended that the canal's slope in this area be revised to 2.5 H: 1.0 V.

The cost estimates listed below for 2005 are preliminary and will be revised pending completion of the engineering study. By completing the engineering study in the first year, it will permit proper planning of all aspects of the work, thereby minimizing the impacts on the operation of the Upper Salmon plant. It is expected that outage schedules elsewhere on the system will be impacted depending on the length of the outage at Upper Salmon plant. As well, this will lessen the probability of spilling around the facility. Acres International Ltd. is carrying out this engineering study and a report is expected in late August of 2004. This project will require approval(s) from the Provincial Department of the Environment.

Project Cost: *($ x1,000)*	2004	2005	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	0.0	660.0	0.0	660.0
Engineering	90.0	90.0	0.0	180.0
Project Management	0.0	45.0	0.0	45.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	12.0	208.0	0.0	220.0
Total	**102.0**	**1,003.0**	**0.0**	**1,105.0**

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Upgrade Slope Stabilization - Upper Salmon Power Canal **(cont'd.)**

Operating Experience:

Problems encountered during the construction of the power canal in 1982 included erosion along the canal slopes and localized slope failures. To reduce these problems a drainage system was incorporated into the final design. The canal has been in continuous operation since construction, with no interruption of service.

Since construction of the canal, concerns have persisted with repeated formation of cracks, minor slumping of the slopes, runoff carrying silts and debris from the adjacent hillside and the blockage of the drainage ditches with snow, ice and vegetation growth. As well, numerous washouts along the canal slope have had to be repaired. Remedial measures have included cleaning the drainage ditches and construction of beams on the upper slope to intercept silt moving down from the main borrow area. A number of means have been employed to monitor the situation including: the installation of settlement monuments to quantify movement of the slope; the installation of piezometers to monitor water levels in the slope; underwater inspections of the canal; and cross sectional surveys.

Over the past five years, at the recommendation of the Dyke Board, Hydro has retained consultants to conduct a slope stability assessment of the area, investigate possible movement of the slope and recommend remedial measures that might be taken to alleviate any further movement. These measures, in addition to the maintenance work outlined above, cost in the order of $130,000.

Project Justification:

Since the construction of the power canal in 1982, the Dyke Board in their annual reports has on fourteen occasions made reference to the condition of canal. Over the past several years, the Board has become increasingly concerned with the continued operation of the canal based on their observations and review of Hydro's annual inspection reports, particularly considering the consequences of a slope failure causing a partial or complete blockage of the canal. This, in turn, could lead to a failure or breach of the dyke on the south side of the canal.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Slope Stabilization - Upper Salmon Power Canal **(cont'd.)**

Project Justification:

The following are excerpts from the Dyke Board Report:

"This 400 m long section is located adjacent to high ground which required an excavation to accommodate the canal. Two notable aspects of the hillside are its height which rose about 40 m above the canal, and the high ground water it contained.

The high ground water presented some difficulty during the construction of the canal in 1983. This difficulty was compounded by inclement and sometimes stormy weather. It was necessary to control the outflow of ground water into the canal excavation by means of a drainage system installed in the left side. Also a change in soils in the hillside was noted from dense impervious glacial till to pervious sand and gravel. Various measures were undertaken in this area to defend against adverse conditions. By and large, the canal and associated elements have performed satisfactorily over the past twenty years. The relatively low seepage from the canal and the satisfactory piezometric level are indicative of excellent impermeability containment of the canal.

However, some concerns persisted after construction over the repeated formation of cracks, minor slumping of slopes, runoff carrying silts and debris from the hillside, and the blockage of drainage ditches with snow, ice and growth. The concern of the Dyke Board in this area began to grow in the last several years, particularly in light of consequences, which could result from a blockage in the canal.

Among other factors, the 11.25 m high underwater slope is central to the Board's concern. A report dated October 1999 by Agra of St. John's examined the stability of the left bank, and concluded that the 2.0 H : 1: 0 V lower slope has low and marginal stability and reaches a factor of safety of 1.0 only by assuming an unrealistically high strength for the slope.

The main thrust of the solution must be to induce greater stability in the lower slope. Accordingly, deformations and resulting creep of the lower slope has been continuing sporadically for many years, and must be arrested before a significant slump occurs.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Slope Stabilization - Upper Salmon Power Canal **(cont'd.)**

Project Justification: (cont'd.)

It is recommended that the lower slope of the canal be flattened to 2.5 H: 1.0 V, from station 1 + 700 to station 2 + 100".

This particular section of the canal has received much attention over the years. However, continued problems associated with the formation of longitudinal cracks, slumping of the slopes and washouts due to loss of ditching has now prompted the Dyke Board to recommend significant work. The Dyke Board believes that the slope should now be flattened as soon as possible before a large slump occurs. This section of the canal is showing "early" signs of slope instability and Hydro has made several efforts to determine the cause and to correct the slope deterioration. A decision not to stabilize this section of the canal as recommended would result in continued deterioration until a failure occurs. This would result in costly repairs and damage to the local environment with the Upper Salmon generating unit out of service for the duration which depending on the time of year could be for up to four or five months which would impact the supply of power to customers. Besides the loss of significant capacity (84 MW), a blockage and extended outage would result in lost energy production at Upper Salmon, as the plant would have to be bypassed to ensure sufficient water for operations at the downstream Bay d'Espoir plants. As well, there would be lost energy production if the failure were to result in a breach on the south side of the canal. An outage to the Upper Salmon Plant of this duration would mean additional thermal energy production at Holyrood at a cost of approximately $12.2 million assuming fuel at $32.20 per barrel.

Future Plans:

All work associated with this project is expected to be completed by the end of 2005.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Underground Fuel Tanks - Upper Salmon Generation Facility

Location: Upper Salmon Powerhouse, North Salmon Spillway, West Salmon Spillway

Division: Production

Classification: Hydro Plants

Project Description:

This project involves the replacement of three existing underground bulk fuel storage tanks and associated day tanks at the Upper Salmon Powerhouse, North Salmon Spillway and West Salmon Spillway. It includes the design, supply and installation of aboveground double wall bulk storage fuel tanks along with day tanks at each site. Construction activities at each location include site work, concrete foundations, tank installation, fuel piping modifications, and instrumentation. The original tank capacity will be maintained at the Upper Salmon Powerhouse and West Salmon Spillway while at the North Salmon Spillway the bulk storage tank capacity will be reduced from 22,725 litres to 7,728 litres. The replacement systems will include provisions for secondary containment, leak detection, and fuel use reconciliation.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	84.0	0.0	0.0	84.0
Labour	145.0	0.0	0.0	145.0
Engineering	21.0	0.0	0.0	21.0
Project Management	28.0	0.0	0.0	28.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	49.3	0.0	0.0	49.3
Total	**327.3**	**0.0**	**0.0**	**327.3**

Operating Experience:

The 22,725-litre fuel storage tanks at the Upper Salmon Powerhouse and the North Salmon Spillway, and respective day tanks (1,137 litre and 909 litre) were fabricated and installed in 1982. The 7,728-litre fuel storage tank and 909-litre day tank at the West Salmon Spillway were fabricated and installed in 1987. All these facilities have been in constant operation without any significant maintenance work performed since they were installed.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Underground Fuel Tanks - Upper Salmon Generation Facility **(cont'd.)**

Project Justification:

The existing underground bulk storage at each of the 3 sites consists of single wall fiberglass tanks. None of these bulk storage tanks, the day tanks, or the piping systems have secondary containment or leak detection measures. As well, none of the three systems have any means of quantifying the amount of fuel used by the diesel generators for reconciliation purposes. Environmental compliance audits have identified that the installations are in contravention of the current Canadian Council of Ministers of the Environment (CCME) Environmental Code of Practice for Underground Storage Tank Systems Containing Petroleum Products and Allied Petroleum Products, and the Provincial Gasoline and Associated Products (GAP) Regulations. The replacement fuel storage systems will meet current CCME Guidelines and the Provincial GAP Regulations.

Future Plans:

No repairs, upgrades, or replacements are anticipated at either location in the near future.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Upgrade Controls Spherical Valve No. 6

Location: Bay d'Espoir

Division: Production

Classification: Hydro Plants

Project Description:

This project involves the upgrade of the control system for spherical valve No. 6 by replacing components, including control valves, piping, tubing and control panel. It is a continuation of a program started in 2001 to upgrade control systems on spherical valves at Bay d'Espoir. The Board has previously approved upgrades on four of six systems at Bay d'Espoir Powerhouse No.1. The new controls will have stainless steel mechanical components for corrosion protection and a programmable logic controller with manual over-rides.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	100.0	0.0	0.0	100.0
Labour	45.0	0.0	0.0	45.0
Engineering	3.0	0.0	0.0	3.0
Project Management	6.0	0.0	0.0	6.0
Inspection & Commissioning	3.0	0.0	0.0	3.0
Corp O/H, AFUDC, Esc. & Contingency	39.1	0.0	0.0	39.1
Total	196.1	0.0	0.0	196.1

Operating Experience:

Bay d'Espoir unit No. 6 along with the existing spherical valve and control became operational in January 1972. This generating unit typically operates for 5,500 hours each year. In the last five years there have been thirty-four maintenance events for this control system, which is much higher than expected for this type of system. Control systems on unit No.1, 2, 3 and 4 have been upgraded since 2001.

Project Justification:

The control System for spherical valve No. 6 is obsolete and unreliable. Replacement parts have to be reverse engineered and custom made. The spherical valve is the main valve controlling water flow to the turbine. The failure of the existing control system can result in the following events:

a) Single unit outage (75 MW) due to spherical valve not opening, with loss of generation and an extended outage;

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Controls Spherical Valve No. 6 **(cont'd.)**

Project Justification: (cont'd.)

b) Outage of two units (150 MW) on the same penstock and potential damage to the unit if the spherical valve stays open during a unit runaway condition forcing a head gate closure; and,

c) Loss of all six units (450 MW) in powerhouse No.1 if the spherical valve or seals fail while the turbine access door is open for maintenance resulting in the flooding of powerhouse No. 1, with the potential for the loss of life.

Depending on the time of year when a failure occurs, replacement capacity and energy, if available, would have to be obtained through increased thermal production at Holyrood or gas turbine sites at significantly higher cost. As well, a lengthy outage would increase the risk of spill during high inflow periods. The cost of replacement energy from Holyrood arising from an outage of two units (150 MW) is $184,000/day assuming fuel at $32.20 per barrel. It would be unacceptable to maintain the status quo and risk the loss of capacity given the significance of this generation capacity to the overall system.

Future Plans:

It is currently planned to have the control system upgraded on one more unit at Bay d'Espoir in the following year.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Penstock - Snook's Arm Generating Station

Location: Snook's Arm

Division: Production

Classification: Hydro Plants

Project Description:

This project consists of the design and construction of a penstock for the 590 kW generating station at Snook's Arm. The work includes the design, supply and installation of a new penstock including excavation, backfilling and anchoring as well as removal and disposal of the old wood stave penstock. The existing wood stave penstock is 750 mm in diameter and 930 m long and was constructed in 1956. Approvals and permitting from the Provincial Department of Environment will be required for the removal and disposal of the existing penstock and construction of the new penstock. Project design will be completed in 2005 with construction to be completed in 2006.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour *(Incl Const. Contracts)*	0.0	1310.0	0.0	1310.0
Engineering	102.0	58.0	0.0	160.0
Project Management	0.0	75.0	0.0	75.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	13.0	372.0	0.0	385.0
Total	**115.0**	**1,815.0**	**0.0**	**1,930.0**

Operating Experience:

Please refer to the report in section G, Appendix 1 titled " Snook's Arm Wood Stave Penstock - Evaluation, Recommendation and Estimated Cost for Replacement", January 2004.

Project Justification:

Typically, wood stave penstocks have a design life of 40 years. This penstock, if replaced in 2006, will be fifty years old. The penstock is significantly beyond its design life and has a number of identified problem areas. It continues to deteriorate with maintenance costs increasing. The risk of a collapse or failure of the penstock is increasing and unless the condition is corrected, continued deterioration will eventually lead to a rupture resulting in property damage, costly repairs and the potential for loss of life. A number of options to deal with the problems have been investigated and the recommended option is the replacement of the entire penstock. An economic analysis indicates

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Penstock - Snook's Arm Generating Station **(cont'd.)**

Project Justification (cont'd.):

a net present value benefit of between $585,923 and $862,672 at the end of the thirty-year analysis and a payback in ten to thirteen years. (See report in section G, Appendix I)

Future Plans:

No future commitments are required. The work will be completed in one construction season during 2006.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase Dry Ice Cleaning System

Location: Bay d'Espoir

Division: Production

Classification: Hydro Plants

Project Description:

This project consists of the purchase of a Minibar Dry Ice Cleaning System. This CO_2 cleaning system uses a combination of compressed air and dry ice to clean dirty equipment.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	55.0	0.0	0.0	55.0
Labour	0.0	0.0	0.0	0.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	3.6	0.0	0.0	3.6
Total	58.6	0.0	0.0	58.6

Operating Experience:

The rotors and stators of generating units collect brake dust from generator brakes and oil mist from thrust and guide bearing assemblies. This brake and oil residue has the potential to cause major operating problems and significantly reduce the life expectancy of generator units. Currently, Hydro has at least one unit cleaned each year under contract at a cost of $15,000 per unit.

Project Justification:

The purchase and use of the proposed cleaning system by internal staff will result in lower overall annual cost than contracting out the work. Even at a minimum rate of one unit per year the purchase will provide a payback in five years. A CO_2 Cleaning System is safe, environmentally friendly; very effective, and can reduce cleaning time by 50 - 60%. The alternative of cleaning with chemicals poses safety and health risks, environmental problems, and is not entirely effective, as many areas cannot be accessed for cleaning.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Control System

Location: Holyrood Generating Station

Division: Production

Classification: Generation - Thermal

Project Description:

This project for 2005 is the continuation of a project for which the Board approved funds for 2004. The Distributed Control System (DCS) for Units No. 1 and 2 are planned to be upgraded in 2004 and Unit No. 3, in 2005. This project involves the replacement of an obsolete DCS on the three Holyrood units, which provide control for the boilers, boiler auxiliary systems, station service, burner management, turbine and generator monitoring and control for other plant systems. Replacement parts for these existing controls are no longer available from the vendor and only limited vendor support is available. It is proposed that some parts of the overall system (cabinets, I/O cards and terminations) will be reused.

Project Cost: *($ x1,000)*	**2004**	**2005**	**Beyond**	**Total**
Material Supply	1,000.0	790.0	0.0	1,790.0
Labour	35.0	28.0	0.0	63.0
Engineering	277.0	30.0	0.0	307.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	240.6	186.1	0.0	426.7
Total	**1,552.6**	**1,034.1**	**0.0**	**2,586.7**

Operating Experience:

The existing DCS for Units No. 1 and 2 was implemented in 1988 and for Unit No. 3 in 1992. The manufacturer's commitment of support for these systems expired in January 2002 and January 2003 respectively. These systems are in use whenever the units are operating. Maintenance costs are increasing each year (less than $30,000 before 2001, $60,900 in 2001, $62,600 in 2002, and approximately $90,000 in 2003) and obsolete component stocks are being depleted. As the existing Unit No. 3 DCS is one level higher than the replaced control system, some critical components are not compatible to use as spares for Unit No. 3.

**2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS**

Project Title: Upgrade Control System **(cont'd.)**

Project Justification:

The manufacturer has informed Hydro that parts of the Distributed Control System (DCS) are obsolete and the system is no longer supported. Based on the spare parts available in Hydro's inventory and failure history, sufficient spare parts are available to maintain and operate the systems until 2005. Beyond this date, it is expected that only used or refurbished parts would be available for some repairs, however, their availability would be uncertain. The Holyrood units cannot operate without the DCS functioning properly and a replacement is necessary to maintain plant availability and reliability. An outage to a unit (150-175 MW) could affect Hydro's ability to supply customers. Depending on the time of year, replacement capacity, if available, may have to be obtained from gas turbines at significantly higher costs.

In the 2004 Capital Budget submission, Hydro had proposed to source the replacement to the original equipment manufacturer, Westinghouse Process Controls now Emerson. Since then, Hydro has kept abreast of the developments within the industry in an effort to arrive at the best decision on DCS replacement equipment. This involved a closer evaluation, which determined that sourcing to Foxboro was a also viable option. Eventually, proposals were received from both the original equipment manufacturer (Emerson) and Foxboro. All other DCS vendors would have had to replace cabinets and terminations, which would drastically increase the cost and extent of work required for this project. It was decided to source the replacement to Foxboro and not Emerson for the following reasons:

1) Foxboro's proposal included new Input/Output (I/O) cards that will fit into our existing cabinets without having to re-terminate field wiring. New I/O cards would improve system reliability due to age related failures. Emerson's proposed to use existing I/O cards although they are developing a program for 2005 to migrate their older I/O cards to new technology. They do not currently plan to declare the older I/O cards obsolete, but it is believed that maintenance costs for existing I/O cards will escalate once a migration program is in place;

2) Foxboro has a more flexible service agreement. Foxboro will allow a 10% cost overrun on equipment replacement and provides flexibility to transfer funds between service modules and into future years. Emerson provides some flexibility to transfer funds between service modules but an additional module must be purchased when equipment replacement limits are reached. Year-end balances would be forfeited under the proposed Emerson service agreement;

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Control System **(cont'd.)**

Project Justification: (cont'd.)

3) Emersons proposed to use conversion tools to automatically upgrade software. This is a proven labour saving process although the converted software is tedious to interpret and maintain. Foxboro will re-write software which will result in a more organized product that will be easier to maintain;

4) Recent clients of both migration processes were contacted and were pleased with their new systems. One Emerson client suggested re-writing software instead of using the tools and plans a re-write in the next phase of his migration. Foxboro clients were more enthusiastic about the migration process and their system; and

5) Foxboro has a superior history of long- term support commitment through their "backwards compatibility" policy - new equipment is designed to be compatible with all older equipment in the same system family. Emerson has a 10-year support commitment policy that guarantees support for 10 years after a component is no longer the current technology.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase/Installation Anti-Fouling System for Cooling Water Systems

Location: Holyrood Generating Station

Division: Production

Classification: Generation - Thermal

Project Description:

This project includes the supply and installation of anti-fouling systems for the cooling water systems on Units 1, 2 and 3 at the Holyrood Generation Station. The anti-fouling systems will be located in the Stage I and II pump houses and will use the copper ion injection method.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	390.0	0.0	0.0	390.0
Labour	117.0	0.0	0.0	117.0
Engineering	12.4	0.0	0.0	12.4
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	45.0	0.0	0.0	45.0
Corp O/H, AFUDC, Esc. & Contingency	140.1	0.0	0.0	140.1
Total	**704.5**	**0.0**	**0.0**	**704.5**

Operating Experience:

The Holyrood plant has been in operation since 1969. The current method used for removal of mussel infestation consists of manual cleaning using several laborers and a vacuum truck. The cooling water systems for each unit are cleaned once per year.

Project Justification:

Mussel infestation can gradually restrict flow and reduce the efficiency of cooling systems. In more extreme cases, pipes can become completely blocked, resulting in unit outages. Additionally, the yearly cost associated with lower generation efficiency and the manual cleaning and removal of mussel infestation for the three units amounts to $185,000. This installation will eliminate these costs and be more cost effective with a payback in five years.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase/Install Fire Protection System - Microwave Radio Room

Location: Holyrood Generating Station

Division: Production

Classification: Generation - Thermal

Project Description:

This project consists of the supply and installation of an Inergen fire protection system to protect the communications equipment in the Holyrood microwave radio room. It includes the modification of the existing sprinkler system to remove two water sprinkler heads from the room. The project's design will require approval by Hydro's insurance underwriter prior to installation.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	7.0	0.0	0.0	7.0
Labour	35.0	0.0	0.0	35.0
Engineering	0.0	0.0	0.0	0.0
Project Management	5.0	0.0	0.0	5.0
Inspection & Commissioning	3.0	0.0	0.0	3.0
Corp O/H, AFUDC, Esc. & Contingency	11.0	0.0	0.0	11.0
Total	**61.0**	**0.0**	**0.0**	**61.0**

Operating Experience:

The microwave radio room has fire protection sprinkler heads, which would prevent a fire from spreading to the remainder of the plant. However, should it ever operate, water from the sprinklers would damage the communications equipment in the room.

Project Justification:

The proposed Inergen fire protection system would extinguish a fire in the room without damaging the communications equipment. This equipment is important to the operation of the system as it provides SCADA, JDE, Lotus Notes and telephone telecommunication circuits for the Holyrood Generating Station as well as teleprotection circuits for transmission lines TL242, TL218 and TL217. Loss of this equipment due to fire would result in loss of all Hydro-owned telecommunication facilities to the Holyrood Plant and the Holyrood Terminal Station.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Civil Structures

Location: Holyrood Generating Station

Division: Production

Classification: Generation - Thermal

Project Description:

This project for 2005 is the continuation of a project which the Board has approved funds for 2004. The project consists of two components:

1. Boiler Stack

   The main components of Stack No. 2 are: concrete shell, steel liner, stack breeching and associated utilities. The scope of work involves the replacement of the interior steel liner. The liner consists of ¼" thick steel shell and has a diameter of 13.5 ft. and height of 302 ft. It is supported at the base by 35 ft. high steel framing. The Board approved a similar replacement of the stack liner on Unit No. 1 in 2003.

2. CW Screen Structure

   There are four Circulating Water (CW) screen structures located in pump house #1 and their function is to screen the salt water required for plant cooling. The Board has approved replacement of two of the structures in 2003. The scope of this proposal involves the replacement of the two remaining steel structures that support the traveling screens. Each structure is 32 ft. high and fabricated from 3/8" thick angle iron and has a foot print of 5 ft. x 7 ft.

Project Cost: *($ x1,000)*	**2004**	**2005**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	0.0	1,355.0	0.0	1,355.0
Engineering	70.0	100.0	0.0	170.0
Project Management	0.0	140.0	0.0	140.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	8.5	406.5	0.0	415.0
Total	78.5	2,001.5	0.0	2,080.0

Operating Experience:

1. Boiler Stack

   The stack and steel liners are thirty-four years old and are in use whenever the unit is operating. The cost to provide inspection and emergency maintenance for the steel liner during the last six years was $232,300.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Civil Structures **(cont'd.)**

Operating Experience: (cont'd.)

2. CW Screen Structure

The CW Screen structures are thirty-four years old and are located in 20 ft. of salt water. They are in use whenever the units are operating. In 2000 the traveling screens and rollers were replaced because of increased operating and maintenance costs.

Project Justification:

1. Boiler Stack

   Regular annual inspections revealed the need for major upgrade work for Stack No. 2. Stack inspections in 2001 and 2002 identified increased metal loss and thin spots on the steel liner. The probability of liner buckling and failure continues to increase. Emergency repairs undertaken during the last several years involved covering holes with steel patches or rings. This approach is believed to be no longer sufficient to prevent buckling or to provide the level of reliability required.

   Several options to upgrade the steel liner were explored. Each of the options results in a similar overall cost to extend the life of the steel liner to 2020, however, replacement of the steel liner will provide the best reliability over the remaining plant life. The liner replacement will be done during the major outage to Unit No. 2 and therefore will have minimal impact on its availability for generation.

   Failure to replace the liner as recommended would result in continued deterioration of the steel liner until buckling occurs and then failure. This would result in costly repairs with the unit out-of-service for the duration of the repairs, which would impact the supply of power to customers.

   An analysis of the possible options report titled "Evaluation of Options to Refurbish Stack Liner #2" was provided in Hydro's 2004 capital budget submission to the Board in Section G, Appendix 3.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Civil Structures **(cont'd.)**

Project Justification: (cont'd.)

2. CW Screen Structure

   Inspections done in 1999 and 2000 confirm severe corroding, metal loss and the need for planned replacements of the CW screen structures. The probability of structure failure is increasing with time, corrosion, and mechanical wear.

   The failure to replace the structures as recommended would result in continued deterioration of the structures until their failure. This would result in costly repairs and reduced unit availability for the duration of the repairs, which would impact the supply of power to the customer.

   To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all material and external labour.

Future Plans:

Work associated with this project is expected to be completed by 2005.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Install Main Fuel Line Valves

Location: Hardwoods Gas Turbine

Division: Transmission & Rural Operations

Classification: Gas Turbines

Project Description:

This project consists of the supply and installation of two motorized valves at Hardwoods Terminal Station in the main fuel pipeline between the storage tank and the fuel forwarding module on the gas turbine.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	23.0	0.0	0.0	23.0
Labour	42.0	0.0	0.0	42.0
Engineering	5.0	0.0	0.0	5.0
Project Management	3.5	0.0	0.0	3.5
Inspection & Commissioning	1.0	0.0	0.0	1.0
Corp O/H, AFUDC, Esc. & Contingency	16.5	0.0	0.0	16.5
Total	**91.0**	**0.0**	**0.0**	**91.0**

Operating Experience:

The gas turbine fuel system does not meet the requirements of the Provincial Gasoline and Associated Products Regulations.

Project Justification:

The Provincial Gasoline and Associated Products Regulations as administered by the Department of Environment, Government of Newfoundland and Labrador, for operation of the fuel storage and distribution systems requires that the system be designed to limit the fuel leakage (in case of a line failure) to less than 2,300 litres. The proposed modifications will ensure compliance of the system with the Regulations.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Installation of Diesel Generating Set

Location: Stephenville Gas Turbine

Division: Transmission & Rural Operations

Classification: Gas Turbine

Project Description:

This project consists of the installation of a 40 kW diesel generator to provide reserve capability for the DC power systems. The project includes the construction of a new building to house the generator and associated equipment which have been removed from Petites.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	27.4	0.0	0.0	27.4
Labour	18.8	0.0	0.0	18.8
Engineering	11.8	0.0	0.0	11.8
Project Management	5.4	0.0	0.0	5.4
Inspection & Commissioning	7.4	0.0	0.0	7.4
Corp O/H, AFUDC, Esc. & Contingency	15.8	0.0	0.0	15.8
Total	86.6	0.0	0.0	86.6

Operating Experience:

The black-start capability at the Stephenville Gas Turbine has been compromised by the inability to maintain a full charge on the station batteries. For example, on March 4, 2003, the gas turbine was operating as a synchronous condenser and was approximately one hour into the ninety-minute post-lube process. At that time, a system power interruption occurred and a black-start of the gas turbine was requested. When the interruption occurred, the post-lube process automatically switched to the station batteries for the remainder of the ninety-minute shutdown cycle. Approximately ten minutes after the switch to battery reserve, a low DC voltage trip occurred and locked out any attempt to start the turbine.

Project Justification:

The installation and automation of a diesel generator will enhance the reliability of the DC systems at the Stephenville Gas Turbine by providing the capability to maintain a full charge on the battery system at all times. Whenever the diesel starts it will function as a DC source for the gas turbine

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Installation Diesel Generating Set **(cont'd.)**

Project Justification: (cont'd.)

systems and will prevent the station batteries from discharging. A fully charged battery system will ensure that the gas turbine can be safely rundown at all times without risk of interrupting the necessary shutdown sequences. This increased assurance of battery integrity will enhance the gas turbine's reliability and black-start capability. In addition, the diesel will also be used to recharge the gas turbine air start system and provide a virtually unlimited number of starting attempts, should they be required.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Battery Bank

Location: Hardwoods Gas Turbine

Division: Transmission & Rural Operations

Classification: Gas Turbine

Project Description:

This project consists of the purchase and installation of a replacement 125 volt, 900 ampere hour stationary battery bank for the Hardwoods Gas Turbine. The existing battery charger does not need to be replaced at this time.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	40.0	0.0	0.0	40.0
Labour	5.0	0.0	0.0	5.0
Engineering	2.0	0.0	0.0	2.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	10.7	0.0	0.0	10.7
Total	57.7	0.0	0.0	57.7

Operating Experience:

The Valve Regulated Lead Acid (VRLA) batteries at Hardwoods were installed approximately ten years ago. Routine maintenance and inspections involve conductance, specific gravity and load discharge tests. In the past year, the conductance tests indicated erratic results from cell to cell which indicates a high probability of failure when the bank is placed under load. This increased rate of deterioration indicates that the battery bank is at the end of its life. The normal expected life of this type of VRLA battery bank is ten to twelve years.

Project Justification:

This battery bank provides the DC supply for the gas turbine's protection and controls and auxiliary equipment operation. This DC source is an integral component to the DC lube pumps for the generator's main bearings. If the batteries are not replaced at this time, the DC lube pumps may not function properly which could lead to extensive damage to the gas turbine. In addition, should the DC supply to switchgear equipment fail, the system protection and control equipment will not function and system reliability will be compromised.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Wood Poles - Transmission

Location: Various Sites

Division: Transmission & Rural Operations

Classification: Transmission

Project Description:

The project is the first year of a multi-year program of inspection, treatment and replacement of line components (poles, conductor and hardware) on Hydro's transmission system.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	382.0	0.0	0.0	382.0
Labour	1,492.0	0.0	0.0	1,492.0
Engineering	278.0	0.0	0.0	278.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	435.6	0.0	0.0	435.6
Total	**2,587.6**	**0.0**	**0.0**	**2,587.6**

Operating Experience:

Hydro operates approximately 2800 km (26,000 poles) of wood pole transmission lines operating at 69, 138 and 230 kV. Historically Hydro's pole inspection and maintenance practices followed the traditional utility approach of sounding inspections, only. In 1998, Hydro decided to take core samples on selected poles to test for preservative retention levels and pole decay. The results of these additional tests raised concerns regarding the general preservative retention levels in wood poles. Between 1998 and 2003, additional coring and preservative testing confirmed that there were a significant number of poles which had a preservative level below what was required to maintain the design criteria for the lines. During this period, certain poles were replaced because the preservative level had lowered to the point that decay had advanced and the pole was no longer structurally sound. These inspections and analysis confirmed that a more formal wood pole line management program was required.

Project Justification:

The report titled "Wood Pole Line Management Using RCM Principles" is contained in Section G, Appendix 2. This report recommends that a formal program be established to manage wood pole line assets. The program consists of visual inspection, non-destructive testing and selected treatment of the wood poles. Poles that are deteriorated beyond the point where treatment could

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Wood Poles - Transmission **(cont'd.)**

Project Justification: (cont'd.)

extend the life, are identified for replacement. Field data is collected and stored electronically, and a comprehensive data base of the program results is maintained.

The study concludes that the program will extend the life of the wood pole assets by an average of ten years with a net benefit of $4.5 million in deferred replacement costs over that same period.

Future Plans:

This is an ongoing program that will provide for all poles to be inspected and treated and any poles rejected will be replaced.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade TL221 - (66 kV Peter's Barren - Hawkes Bay)

Location: Peter's Barren to Hawkes Bay

Division: Transmission & Rural Operations

Classification: Transmission

Project Description:

This project consists of the upgrade of a 27 km section of line TL221 from Peter's Barren to River of Ponds. This upgrade will include all work necessary to replace existing insulators and wood cross arms for the entire 27 km section. Guying will be added to selected structures to improve the stability of the line.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	272.7	0.0	0.0	272.7
Labour	292.9	0.0	0.0	292.9
Engineering	25.8	0.0	0.0	25.8
Project Management	37.4	0.0	0.0	37.4
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	145.3	0.0	0.0	145.3
Total	**774.1**	**0.0**	**0.0**	**774.1**

Operating Experience:

TL221 was constructed in 1970 and is 53.2 km long. It was built with single wood pole structures and is operating at 69 kV. The line is located generally parallel to the coast resulting in exposure to extreme wind and heavy salt contamination. These conditions have led to frequent outages due to flashovers caused by the salt accumulation on the insulators. The operating experience is that a severe salt accumulation event occurs approximately every three years. An engineering site assessment conducted in the fall of 2003 confirmed the poles to be in good condition and should continue to provide dependable service for at least another twenty years.

Project Justification:

The site assessment and review of the outage statistics confirmed that replacement of the insulators and crossarms is the most prudent course of corrective action to take. The outage frequency rate for the 1999-2003 period was 18.79 per 100km/year for both momentary and sustained. The Hydro average for this class of line is 7.11 and the CEA All Canada Rate is 5.71. Implementing these improvements will result in a reduction in the outage frequency.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade TL221 - (66 kV Peter's Barren - Hawkes Bay) **(cont'd.)**

Project Justification: (cont'd.)

The Acres International report "System Performance Review Great Northern Peninsula" (June 2003) submitted to the Board in June, 2003 and included in the response to IC-231 NLH at Hydro's 2003 General Rate Application, also recommends implementing corrective measures for the most exposed sections of TL221.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Insulators TL243 - (138 kV Hinds Lake - Howley)

Location: Hinds Lake to Howley

Division: Transmission & Rural Operations

Classification: Transmission

Project Description:
TL243 is a 15 km 138 kV radial transmission line running from Hinds Lake to Howley. It consists of 74 H-Frame wooden pole structures. The line was constructed in 1978 to connect the Hinds Lake Generating Station to the system. This project consists of the replacement of all the remaining Canadian Ohio Brass (COB) insulators on the line.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	65.0	0.0	0.0	65.0
Labour	64.0	0.0	0.0	64.0
Engineering	34.0	0.0	0.0	34.0
Project Management	12.0	0.0	0.0	12.0
Inspection & Commissioning	10.0	0.0	0.0	10.0
Corp O/H, AFUDC, Esc. & Contingency	43.2	0.0	0.0	43.2
Total	228.2	0.0	0.0	228.2

Operating Experience:
The preventative maintenance (PM) cycle inspections, over the last four years, shows an increase in the number of defective COB insulators on this line.

Project Justification:
These insulators were manufactured by the Canadian Ohio Brass Company, and were installed during the original construction. They are a part of a group of insulators that have experienced industry wide failures due to cement growth resulting in moisture intrusion and causing radial cracks. The percentage of defective insulators is expected to increase with each PM cycle (i.e. five years) making the replacement of only the defective insulators cost prohibitive and a poor long-term maintenance strategy. The most cost effective remedy at this time is to replace all remaining units.

The Hinds Lake plant has a capacity of 75 MW and the loss of this line would isolate that capacity from the system and impact the supply of power to customers via an under-frequency load shedding event. Until the failed section is found and corrected and depending on the time of year, replacement capacity, if available, would have to be supplied by more expensive thermal generation.

Future Plans:
None.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Provide Remote Control

Location: Farewell Head Terminal Station

Division: Transmission & Rural Operations

Classification: System Performance & Protection

Project Description:

This project consists of the purchase and installation of equipment at the Farewell Head Terminal Station to provide supervisory control and power system equipment monitoring and alarms to the Energy Control Centre (ECC).

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	75.0	0.0	0.0	75.0
Labour	15.0	0.0	0.0	15.0
Engineering	10.0	0.0	0.0	10.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	4.0	0.0	0.0	4.0
Corp O/H, AFUDC, Esc. & Contingency	22.7	0.0	0.0	22.7
Total	**126.7**	**0.0**	**0.0**	**126.7**

Operating Experience:

Presently, there is no provision for active system status or control for power equipment in the station. Hydro's Energy Control Centre cannot react immediately when a local system trip occurs nor can they attempt power restoration to the Farewell Head, Change Islands, and Fogo Island systems. The ECC is notified of power outage(s) on the Farewell Head system by Hydro customers who call in and report a power outage in their area. Only after these customer outage reports have been received from Change Islands and/or Fogo Island does ECC determine the extent of the system outage and whether there has been a complete system trip originating at Farewell Head Terminal Station. The five-year average for SAIFI on the Farewell Head system is 10.12 and for SAIDI is 31.7. The present system wide five-year average for SAIFI is 7.67 and for SAIDI is 12.08. There is a total of 1,743 customers on the Farewell Head system.

Project Justification:

The addition of supervisory equipment to this terminal station will provide remote monitoring, alarms and control to ECC which will greatly improve the response time for power restoration and the dispatch of operating and maintenance crew(s) from Bishop's Falls to the area.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Provide Remote Control **(cont'd.)**

Project Justification: (cont'd.)

The ECC will also be provided with system fault information including possible cause and location which in turn, will be provided to the line crew(s) in order to shorten the time for isolation and/or repair of the faulted power system equipment. With this equipment in place, the SAIFI and SAIDI indices for this system are expected to be closer to the company's five-year average for the overall system.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase & Install Digital Fault Recorder

Location: Bottom Brook

Division: Transmission & Rural Operations

Classification: System Performance & Protection

Project Description:

This project consists of the purchase and installation of a 32 channel Digital Fault Recorder at the Bottom Brook Terminal Station.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	66.0	0.0	0.0	66.0
Labour	18.0	0.0	0.0	18.0
Engineering	15.0	0.0	0.0	15.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	22.5	0.0	0.0	22.5
Total	**121.5**	**0.0**	**0.0**	**121.5**

Operating Experience:

Statistics show that more than 10% (27% in 2001) of protection operations occurred in the Bottom Brook area and historically there has been a high number of transmission line outages. There is no fault recording equipment at this station at the present time.

Project Justification:

Fault recorders are required to provide real-time and historical information on equipment operation during faults which will be used in the identification of problems which, when corrected, will enhance performance thereby improving customer service and reliability. This information assists the System Performance & Protection personnel in determining if the protection operated correctly and provides useful information in determining the root cause of system events. Following this root cause analysis, remedial actions are documented and acted on. This recorder would be particularly valuable in the analysis of faults in the Stephenville area such as those affecting TL209 and Doyles/Port aux Basques, TL214, and local equipment in Bottom Brook and adjacent stations.

To ensure that this project is completed with the lowest possible cost, Hydro will solicit competitive bids for all materials.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase & Install 66 kV Breaker Fail Protection

Location: Massey Drive Terminal Station

Division: Transmission & Rural Operations

Classification: System Performance & Protection

Project Description:

This project consists of the purchase and installation of a 66 kV breaker failure protection at the Massey Drive Terminal Station.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	26.0	0.0	0.0	26.0
Labour	22.0	0.0	0.0	22.0
Engineering	17.6	0.0	0.0	17.6
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	15.8	0.0	0.0	15.8
Total	**81.4**	**0.0**	**0.0**	**81.4**

Operating Experience:

Presently there is no local 66 kV station back-up protection at Massey Drive Terminal Station to protect equipment and maintain system integrity in the event of a 66 kV breaker failure.

Project Justification:

Breaker failure is considered to be a low probability but a high consequence event. Without a breaker failure scheme, such incidents can cause a partial or complete collapse of the system due to extreme slow clearing of faults.

In recent years, Hydro installed 138 kV breaker failure schemes in various terminal stations to reduce the probability of a system collapse due to a breaker failure. The same protection philosophy is now being expanded to the 66 kV system. The first installation is at the Massey Drive Terminal Station.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Upgrade Protection 66 kV Lines

Location: Daniel's Harbour, Peter's Barren

Division: Transmission & Rural Operations

Classification: System Performance & Protection

Project Description:

This project consists of the purchase and installation of microprocessor based relays and associated equipment, to upgrade the protection on 66 kV lines TL262 and TL221.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	28.0	0.0	0.0	28.0
Labour	0.0	0.0	0.0	0.0
Engineering	16.0	0.0	0.0	16.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	26.0	0.0	0.0	26.0
Corp O/H, AFUDC, Esc. & Contingency	8.2	0.0	0.0	8.2
Total	78.2	0.0	0.0	78.2

Operating Experience:

The existing protection equipment for these lines is the older type electromagnetic relays, which are difficult to maintain and calibrate.

Project Justification:

This project will improve the protection on the 66kV lines which currently have electromechanical relays for both phase and ground protection. The relays will provide faster back-up clearing times, with enhanced capabilities for self-diagnostics and alarms in the event of an internal failure. These relays can be remotely interrogated thus enabling more timely analysis of problems on the lines or with the relays themselves. This is part of ongoing initiative to improve protection systems on the bulk transmission system.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Install Motor Drive Mechanisms on Disconnect Switches - East Coast

Location: Various Terminal Stations

Division: Transmission & Rural Operations

Classification: System Performance & Protection

Project Description:

This project consists of the purchase and installation of motor drive mechanisms on eight existing 230 kV disconnect switches in the East Coast Terminal Stations. The disconnects are located in the following stations: Western Avalon - 2, Oxen Pond - 4, Holyrood - 1, Long Harbour - 1.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	65.0	0.0	0.0	65.0
Labour	48.0	0.0	0.0	48.0
Engineering	16.0	0.0	0.0	16.0
Project Management	8.0	0.0	0.0	8.0
Inspection & Commissioning	18.0	0.0	0.0	18.0
Corp O/H, AFUDC, Esc. & Contingency	27.8	0.0	0.0	27.8
Total	**182.8**	**0.0**	**0.0**	**182.8**

Operating Experience:

Disconnects are used for equipment isolations either for system operations or for regular maintenance activities. These disconnects are the original 230 kV units that were installed with the stations when they were first constructed in the late 1960's. They are inspected regularly, lubricated as required and insulators are replaced when they fail in service.

Project Justification:

The normal design practice, in the late 1960's, was that disconnects be manually operated. The only motorized disconnects provided were those used for transformer protection and isolation. However, since that time, a workplace safety concern has identified the requirement for motorized disconnects.

The arrangement of the 230 kV disconnect switches is such that the operator has to stand directly under the switch to operate it. From this position, the operator does not have a full clear view of the switch and cannot observe strain or breakage on the associated station post insulators and other switch components and is therefore at risk of serious injury.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Install Motor Drive Mechanisms on Disconnect Switches - East Coast **(cont'd.)**

Project Justification: (cont'd.)
During the period from 1988 to 1999, Hydro experienced three incidents associated with the failure of station post insulators on 230 kV disconnects. This resulted in regular inspections being carried out to identify faulty insulators and have them replaced prior to in-service failure. However, this practice will not completely eliminate the risks associated with manual switching.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labor.

Future Plans:
This is the last year of a three-year program to install motor operators on all manual 230 kV disconnects on the system.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Battery Banks

Location: Various Stations and Lines

Division: Transmission & Rural Operations

Classification: System Performance & Protection

Project Description:

This project consists of the purchase and installation of new 60 cell, 125 volt, lead calcium flooded cell station battery banks for Stephenville (SVL) (200 A-Hr), Bay d'Espoir (BDE) (250 A-Hr), Corner Brook Frequency Converter (CBK FRC) (200 A-Hr), and Massie Drive (MDR) (250 A-Hr). The replacement batteries will be the same size and rating of the existing units as the station DC load requirements have not changed. The new batteries will be designed to be compatible with the existing chargers. These chargers are fully operational and do not need to be replaced at this time.

This project also includes the replacement of the storage battery banks for the aircraft markers on TL233 at the Grand Lake Crossing.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	80.0	0.0	0.0	80.0
Labour	50.4	0.0	0.0	30.4
Engineering	5.0	0.0	0.0	5.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	30.3	0.0	0.0	30.3
Total	**165.7**	**0.0**	**0.0**	**165.7**

Operating Experience:

Regular maintenance work involves voltage, specific gravity and load discharge tests. The batteries to be replaced under this proposal are approaching or beyond the normal expected service life. In SVL, the Valve Regulated Lead Acid (VRLA) batteries installed in 1990 and the batteries on TL233, have shown signs of deterioration and are currently beyond the expected ten-twelve year service life of this type of battery bank. For BDE, CBK FRC, and MDR stations the flooded cell batteries installed in 1982, 1983 and 1986 respectively have also shown signs of deterioration and are approaching or beyond their expected 18-20 year service life for a flooded cell battery bank.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Battery Bank Various Stations **(cont'd.)**

Project Justification:

The battery banks provide the dc supply for the station protection and controls, and equipment operation. This DC source is an integral component to the relay protection systems for the station equipment, the transmission lines and the EMS system. Routine maintenance tests and inspections are done on an annual basis. These tests and inspections have confirmed a deterioration in the battery cell conditions to the point that system reliability and integrity is compromised if replacement is not undertaken.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labor.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Instrument Transformers

Location: Various Terminal Stations

Division: Transmission & Rural Operations

Classification: Terminals

Project Description:

This project consists of the purchase and installation of replacement instrument transformers (potential transformers, capacitive voltage transformers and current transformers) at various terminal stations across the system.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	60.0	0.0	0.0	60.0
Labour	3.2	0.0	0.0	3.2
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	11.8	0.0	0.0	11.8
Total	**75.0**	**0.0**	**0.0**	**75.0**

Operating Experience:

Instrument transformers have a typical service life of thirty to forty years, depending on the service conditions. Units are inspected and tested regularly and replacements are made based on these maintenance assessments or on 'in-service' failures. The maintenance assessments for instrument transformers are visual inspection and voltage/current checks of the secondary circuits. Typically, approximately six instrument transformers fail or need to be replaced each year.

Project Justification:

Instrument transformers provide critical input to protection, control and metering equipment required for the reliable operation and protection of the electrical system. Instrument transformers which fail in-service can result in faults on the electrical system and outages to customers.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Instrument Transformers **(cont'd.)**

Project Justification: (cont'd.)

When these units fail, the normal utility practice is to replace, as they are not repairable and also to hold a reserve inventory sufficient to replace service units based on maintenance assessments or failure.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials.

Future Plans:

This is an annual allotment, which will be adjusted from year to year depending on ongoing performance.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Surge Arrestors

Location: Various Terminal Stations

Division: Transmission & Rural Operations

Classification: Terminals

Project Description:

This project consists of the purchase and installation of replacement surge arrestors at various terminal stations across the system.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	46.8	0.0	0.0	46.8
Labour	10.0	0.0	0.0	10.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	11.6	0.0	0.0	11.6
Total	**68.4**	**0.0**	**0.0**	**68.4**

Operating Experience:

Surge arrestors provide critical overvoltage protection of the power system equipment from lightning and switching surges. Throughout the regions there are surge arrestors in the 69 kV, 138 kV and 230 kV voltage classes. Replacements are typically required as a result of maintenance assessments, in-service failures, and equipment that has reached the end of its useful service life. Equipment manufacturers indicate the useful service life of surge arrestors as twenty years. Typically, fifteen surge arrestors will require replacement per year across the system.

Project Justification:

In-service failures due to severe lightning strikes and switching surges are unavoidable and require immediate replacement to ensure system overvoltage protection. Replacements based on maintenance assessments and the manufacturers' recommended useful service life are required to prevent additional in-service failures. Lightning arrestors can fail catastrophically resulting in system disturbances, and a high potential for damage to adjacent equipment. The timely replacement of surge arrestors prior to age or condition related in-service failures will improve system reliability.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Surge Arrestors **(cont'd.)**

Project Justification:

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials.

Future Plans:

This is an annual allotment, which will be adjusted from year to year depending on ongoing performance.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Purchase & Install Conduit & Control Cables

Location: Bay d'Espoir

Division: Transmission & Rural Operations

Classification: Terminals

Project Description:

This project consists of the purchase and installation of replacement conduit and control cable between the 230/69 kV Terminal Station and the powerhouse at Bay d'Espoir.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	15.5	0.0	0.0	15.5
Labour	24.0	0.0	0.0	24.0
Engineering	4.0	0.0	0.0	4.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	6.0	0.0	0.0	6.0
Corp O/H, AFUDC, Esc. & Contingency	11.2	0.0	0.0	11.2
Total	**60.7**	**0.0**	**0.0**	**60.7**

Operating Experience:

The existing direct buried control cables were installed in 1976, and have been damaged and severed on two occasions by construction activity. The most recent damage occurred in 2003. Temporary repairs were made at the time.

Project Justification:

This terminal station provides the station service supply for the Bay d'Espoir generation plant and any loss of service will critically affect the entire bulk electrical system. Repairs made to the cables are not of a permanent nature and are not adequate to ensure the long-term security and reliability of the Bay d'Espoir facility. Therefore, the existing damaged and spliced cables must be replaced.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials, and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Interconnect - Rencontre East

Location: English Harbour West Distribution Line to Rencontre East

Division: Transmission & Rural Operations

Classification: Distribution

Project Description:

This project consists of the construction of a single phase 14.4 kV distribution line from the English Harbour West distribution system to the community of Rencontre East. The project includes the installation of a voltage regulator, single-phase recloser and the conversion of the community of Rencontre East from the existing 7.2 kV to 14.4 kV.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	586.0	0.0	0.0	586.0
Labour	1,488.0	0.0	0.0	1,488.0
Engineering	365.0	0.0	0.0	365.0
Project Management	46.0	0.0	0.0	46.0
Inspection & Commissioning	155.0	0.0	0.0	155.0
Corp O/H, AFUDC, Esc. & Contingency	610.1	0.0	0.0	610.1
Total	**3,250.1**	**0.0**	**0.0**	**3,250.1**

Operating Experience:

This is a new interconnection to the Rencontre East distribution system. The community is currently served by a temporary diesel generation plant, which was installed when the permanent plant was destroyed by fire in 2002.

Project Justification:

The temporary generation plant was constructed as an emergency facility to re-power the community after the fire. It does not meet the various legislative and regulatory requirements for such facilities and thus is not acceptable for long-term operation. The “Rencontre East Interconnection Study – April 2004” (Section G, Appendix 3) identified this interconnection as the most cost effective method of servicing the community in the long-term.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Provide Service Extensions

Location: All Service Areas

Division: Transmission & Rural Operations

Classification: Distribution

Project Description:

This project is an annual allotment based on past expenditures to provide for service connections (including street lights) to new customers. This summary identifies the total budget for all three operating regions.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	804.0	0.0	0.0	804.0
Labour	772.0	0.0	0.0	772.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	152.0	0.0	0.0	152.0
Total	1,728.0	0.0	0.0	1,728.0

Operating Experience:

An analysis of average historical expenditure (i.e. 1999 - 2003) on new customer connections is shown in the following table. All historical dollars were converted to 2003 dollars using the GDP Implicit Price Deflator and a 5-year average calculated.

Region	**Avg. Yearly Expenditures (1999 - 2003) ($000)**
Central	$ 595
Northern	$ 484
Labrador	$ 581
Total	$ 1,660

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Provide Service Extensions **(cont'd.)**

Project Justification:

Based on the five-year average of service extension expenditures for the period 1999 - 2003 (in 2003 dollars) the following budget was developed assuming escalation in 2004 and 2005 of approximately 2.0%.

Region	2005 Budget ($000)
Central	$ 619
Northern	$ 504
Labrador	$ 605
Total	$ 1,728

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labor.

Future Plans:

This is an annual allotment, which will be adjusted from year to year depending on historical expenditures.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Distribution Systems

Location: All Service Areas

Division: Transmission & Rural Operations

Classification: Distribution

Project Description:

This project is an annual allotment based on past expenditures to provide for the replacement of deteriorated poles, substandard structures, corroded and damaged conductors, rusty and overloaded transformers/street lights/reclosers and other associated equipment. This upgrading is identified through preventive maintenance inspections or damage caused by storms and adverse weather conditions and salt contamination. This summarizes the total budget for all three regions.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	842.0	0.0	0.0	842.0
Labour	609.0	0.0	0.0	609.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	150.0	0.0	0.0	150.0
Total	**1,601.0**	**0.0**	**0.0**	**1,601.0**

Operating Experience:

An analysis of historical expenditures (i.e. 1999 - 2003) on distribution upgrades is shown in the following table. All historical dollars (table below) were converted to 2003 dollars using the GDP Implicit Price Deflator and 5-year average calculated.

Region	**Avg. Yearly Expenditures (1999 - 2003) ($000)**
Central	$ 555
Northern	$ 640
Labrador	$ 344
Total	$ 1,539

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Distribution Systems **(cont'd.)**

Project Justification: (cont'd.)
Based on this five-year average for distribution system upgrades for the period 1999 - 2003 the following budget was developed using an escalation in 2004 and 2005 of approximately 2.0%.

Region	2005 Budget ($000)
Central	$ 628
Northern	$ 616
Labrador	$ 357
Total	$ 1,601

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labor.

Future Plans:
This is an annual allotment which will be adjusted from year to year depending on historical expenditures.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Insulator Replacements

Location: Distribution Lines Hawkes Bay, Plum Point and Farewell Head

Division: Transmission & Rural Operations

Classification: Distribution

Project Description:

This project consists of the replacement of suspension and pin type insulators that were manufactured by Canadian Ohio Brass and Canadian Porcelain and installed on the following distribution lines:

1. Hawkes Bay Line 3, which serves the communities from Hawkes Bay North to Port au Choix and Eddies Cove. This line has been in service for approximately thirty years.

2. Plum Point Line 1, which serves the communities from Reef's Harbour to Castor's River South. The line has been in service for approximately thirty-five years.

3. Farewell Head Line 6, which serves seven communities on Fogo Island. This line has been in service for approximately thirty-five years.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	285.0	0.0	0.0	285.0
Labour	427.0	0.0	0.0	427.0
Engineering	48.5	0.0	0.0	48.5
Project Management	20.5	0.0	0.0	20.5
Inspection & Commissioning	52.0	0.0	0.0	52.0
Corp O/H, AFUDC, Esc. & Contingency	138.7	0.0	0.0	138.7
Total	**971.7**	**0.0**	**0.0**	**971.7**

Operating Experience:

The insulators on these lines were manufactured by Canadian Ohio Brass and Canadian Porcelain. These insulators have been a problem throughout the Hydro system where failures generally occur during adverse weather conditions and restoration times are impacted considerably. Inspections have identified hairline cracks in the porcelain and in the cement bondings between the porcelain.

Hawkes Bay L3 – For the period 2001 to 2003 there has been a total of 15,890 customer outage hours due to defective insulators.

Plum Point L1 – For the period 2001 to 2003 there has been a total of 5,570 customer outage hours due to defective insulators.

Farewell Head L6 – For the period 2001 to 2003 there has been a total of 15,030 customer outage hours due to defective insulators.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Insulator Replacements **(cont'd.)**

Project Justification:

The cracking porcelain and consequent decrease in mechanical strength has the potential of the insulator breaking apart during climbing activities, and thus presents a safety hazard for lineworkers.

A review of the performance indices reveals the potential for improvement of the composite indices, through insulator replacements on these lines as follows:

Hawkes Bay L3 – Expected reduction in SAIFI from 3.94 to 3.26 and lower SAIDI from 7.19 to 3.98.

Plum Point L1 – Expected reduction in SAIFI from 4.17 to 2.53 and lower SAIDI from 6.97 to 2.51.

Farewell Head L6 – Expected reduction in SAIFI from 11.20 to 7.41 and lower SAIDI from 28.97 to 18.64.

The average composite indices across the Hydro system are SAIFI = 7.58 and SAIDI = 11.94.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labor.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Distribution Line L7

Location: St. Anthony to Cook's Harbour

Division: Transmission & Rural Operations

Classification: Rural Systems

Project Description:

This project consists of the replacement of 7 km of 3-phase distribution line serving the communities of Cook's Harbour, Wild Bight, Boat Harbour and Cape Norman; and the installation of approximately 65 midspan poles between the communities of Cook's Harbour and Boat Harbour.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	165.0	0.0	0.0	165.0
Labour	290.0	0.0	0.0	290.0
Engineering	85.0	0.0	0.0	85.0
Project Management	24.0	0.0	0.0	24.0
Inspection & Commissioning	51.0	0.0	0.0	51.0
Corp O/H, AFUDC, Esc. & Contingency	102.5	0.0	0.0	102.5
Total	**717.5**	**0.0**	**0.0**	**717.5**

Operating Experience:

The Cook's Harbour line is one of the most exposed distribution lines on the GNP, and possibly in the province. This area is subjected to some of the harshest weather conditions on the Island due to the barren country with no protection from the elements. It is very common to get winds in excess of 100 kms/hour in this area. In the past ten to fifteen years, approximately six poles and many cross-arms have broken off, conductor has snapped and insulators have broken due to high winds and icing conditions. During a storm in January 1999, eleven cross-arms snapped and the conductor broke. The conductor has a steel core and is subject to corrosion due to salt spray. It has been damaged by slapping in the high winds, and has reduced strength and increased sag caused by heavy icing conditions. The section of line between the communities of Cook's Harbour and Boat Harbour have span lengths in excess of 100 meters, where as the design standard is 70 meters.

Project Justification:

This line area is one of the main causes for numerous momentary and sustained outages in the area. The many problems experienced has resulted in the indices for the area being SAIFI = 8.90

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Distribution Line **(cont'd.)**

Project Justification: (cont'd.)

and SAIDI = 30.13 as compared to the Hydro average of SAIFI = 7.58 and SAIDI = 11.94. The replacement of this section of line is expected to result in reducing the SAIFI and SAIDI indices for this system to a level closer to the Hydro average.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Distribution System

Location: L'Anse au Loup

Division: Transmission & Rural Operations

Classification: Distribution

Project Description:

This project consists of the replacement of:

a) approximately 1000 pin type and suspension insulators;
b) relocation of a section of distribution line from structure No. 58 to 386;
c) upgrading of a section of the distribution line from English Point to Forteau; and,
d) replacement of the river crossing structures at Forteau River.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	195.0	0.0	0.0	195.0
Labour	243.0	0.0	0.0	243.0
Engineering	43.0	0.0	0.0	43.0
Project Management	16.0	0.0	0.0	16.0
Inspection & Commissioning	44.0	0.0	0.0	44.0
Corp O/H, AFUDC, Esc. & Contingency	94.6	0.0	0.0	94.6
Total	**635.6**	**0.0**	**0.0**	**635.6**

Operating Experience:

Distribution lines L1 and L2 on the L'Anse au Loup System service 949 customers and include the entire distribution system servicing the area from L'Anse au Claire north 78 km to Red Bay.

The section of line to L'Anse Amour was constructed in 1965 with pre-cast concrete and wooden poles. Weather conditions have deteriorated the concrete poles to a point where approximately 60 - 70% of the outer shell is missing leaving the steel rebar exposed. Nearly every spring, a number of the poles have to be plumbed as a result of snow conditions over the winter. In May 2002, a late spring storm caused significant damage to several structures between the Forteau River bridge and English Point. In general, the L'Anse au Loup system has experienced a number of insulator and pole failure related outages in recent years resulting in poor reliability.

Project Justification:

Without this upgrade, there will be further deterioration and a worsening of the performance level for the L'Anse au Loup system and customers will experience increased outages. The performance indices indicate composite indices for this system of SAIFI = 27.44 and SAIDI = 23.57.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Distribution System **(cont'd.)**

Project Justification: (cont'd.)

These pole and insulator replacements provide the potential to reduce the SAIFI to 24.61and the SAIDI to 19.99.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Relocate Substation

Location: Robert's Arm/Triton System

Division: Transmission & Rural Operations

Classification: Distribution

Project Description:

This project consists of:

a) relocation of all equipment from the substation at Robert's Arm to the existing substation at Triton;
b) installation of a group operated disconnect in Line 5 outside the Triton station;
c) expansion of the Triton station by 15 m x 6 m to accommodate this move;
d) conversion of a section of L4 in the community of Robert's Arm to 25 kV; and,
e) relocation of the voltage regulators RA4-VR1 to a new location approximately 4 km from the Triton station.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	85.0	0.0	0.0	85.0
Labour	110.0	0.0	0.0	110.0
Engineering	51.0	0.0	0.0	51.0
Project Management	9.0	0.0	0.0	9.0
Inspection & Commissioning	5.0	0.0	0.0	5.0
Corp O/H, AFUDC, Esc. & Contingency	58.6	0.0	0.0	58.6
Total	**318.6**	**0.0**	**0.0**	**318.6**

Operating Experience:

The station was constructed in 1967. The pole structures have deteriorated to the point where it is unsafe to work. The location of this station makes it very difficult to access with a vehicle, particularly in winter and there is no room in the yard for maintenance vehicles. The access road is narrow and too steep to operate maintenance equipment safely. (Please see the pictures on the following pages.)

Project Justification:

The station is located between two steep hills and there is no room for expansion or to rebuild to current standards. The station grounding is below current standards and needs to be upgraded.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Relocate Substation **(cont'd.)**

Project Justification:

The station has to be completely rebuilt because all wood pole structures are deteriorated to the point where failure can occur and create a safety hazard for maintenance personnel. It is not practical to have the station reconstructed on the existing site, and it is proposed that it be relocated to the existing Triton substation. This will eliminate 5 km of 12.5 kV distribution line and increase the capacity of the Triton station. The Triton transformer is currently fully loaded, and with the load growth predicted it would have to be replaced in the next five years. Relocating the Roberts Arm transformer now will provide the additional benefit of adequate transformer capacity to address load growth into the foreseeable future.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Roberts Arm Substation

View showing structures and line terminals

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Roberts Arm Substation

View showing congestion in station limiting use of maintenance equipment

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Roberts Arm Substation

View showing deterioration of poles due to ant infestation

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

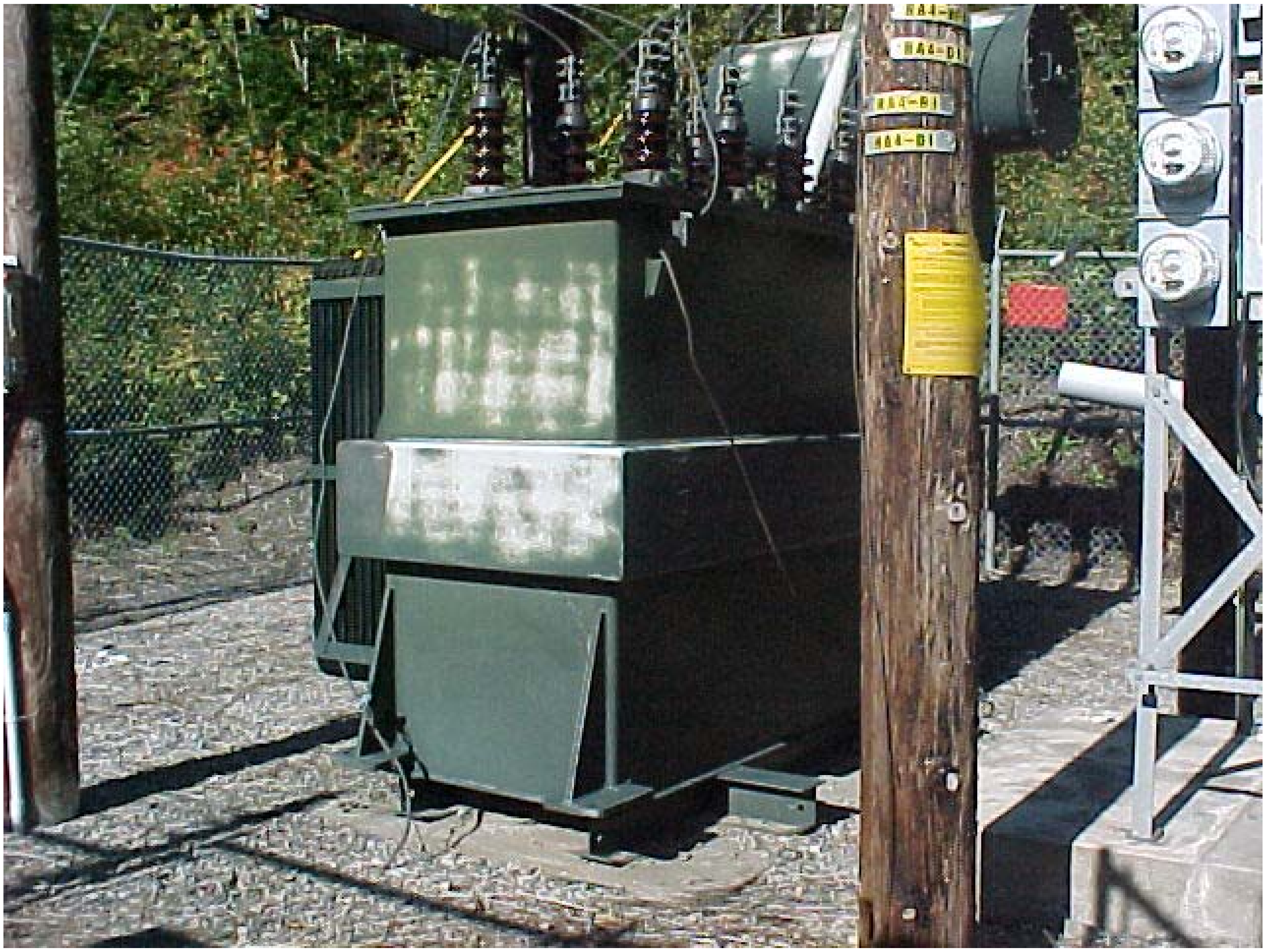
Roberts Arm Substation

View showing deterioration of crossarms

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Roberts Arm Substation

View showing equipment condition



2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase & Install Electronic Reclosers

Location: Makkovik & Hopedale

Division: Transmission & Rural Operations

Classification: Distribution

Project Description:

The project consists of the purchase and installation of electronic reclosers to replace the existing hydraulic reclosers at these two sites.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	75.0	0.0	0.0	75.0
Labour	20.0	0.0	0.0	20.0
Engineering	6.0	0.0	0.0	6.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	24.3	0.0	0.0	24.3
Total	**125.3**	**0.0**	**0.0**	**125.3**

Operating Experience:

The existing hydraulic reclosers are approximately thirty-years old and have failed in service and do not provide satisfactory protection levels for the distribution system.

Project Justification:

These hydraulic reclosers are the primary protection devices for faults on the distribution system and are required to be reliable. Due to age, and the harsh operating environment, failures of these reclosers have occurred causing customer outages and reliability issues. Replacement parts are also difficult to obtain. To correct this system reliability problem, 3-phase electronic reclosers will be installed to replace the hydraulic reclosers with the control panel installed inside the plant for more efficient operation and also phone modem interwiring, for remote monitoring.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials, and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Distribution Line Pole Replacements

Location: English Harbour West System

Division: Transmission & Rural Operations

Classification: Distribution

Project Description:

This project consists of the replacement of thirty-five deteriorated poles on the English Harbour West distribution system.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	38.0	0.0	0.0	38.0
Labour	55.0	0.0	0.0	55.0
Engineering	17.0	0.0	0.0	17.0
Project Management	8.0	0.0	0.0	8.0
Inspection & Commissioning	19.0	0.0	0.0	19.0
Corp O/H, AFUDC, Esc. & Contingency	30.9	0.0	0.0	30.9
Total	**167.9**	**0.0**	**0.0**	**167.9**

Operating Experience:

The system is operating satisfactorily, however as deteriorated poles fail, repair crews are dispatched to do the repairs, and customer outages occur during these repairs. Extensive outages have occurred on those occasions when it is difficult to gain access to the repair site.

Project Justification:

The Preventative Maintenance Program identified selected poles on this system which were rated "B" condition (replace within five years). It has been determined that a certain number of these poles must be replaced in 2005 in order to maintain service reliability. The remainder of the poles are regularly inspected to determine their deterioration rate and these will be replaced as required. A deteriorated pole represents a safety hazard to lineworkers in the event the pole has to be climbed. Failure of a pole has a significant impact on the performance for the system, especially under adverse weather conditions. Often, failures of deteriorated poles cause a domino effect resulting in more failures of consecutive poles, which might not be deteriorated.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labor.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Increase Generation

Location: L'Anse au Loup

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the transfer of existing Unit No. 2041 (1,100 kW) complete with radiator, from Nain to replace the existing 600 kW unit at the L'Anse au Loup Diesel Plant. The project will include purchase of a new 4,160 volt generator and an upgrade to the existing switchgear.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	149.0	0.0	0.0	149.0
Labour	101.9	0.0	0.0	101.9
Engineering	35.9	0.0	0.0	35.9
Project Management	5.0	0.0	0.0	5.0
Inspection & Commissioning	29.2	0.0	0.0	29.2
Corp O/H, AFUDC, Esc. & Contingency	70.7	0.0	0.0	70.7
Total	391.7	0.0	0.0	391.7

Operating Experience:

This unit was originally installed in Nain in 1994 and has been operated for approximately 35,000 hours. It has recently undergone a major overhaul and is suitable for continued service at L'Anse au Loup.

Project Justification:

For the isolated diesel systems, firm capacity is normally defined as the installed capacity of the diesel plant less the largest unit. However, with the interconnection to Hydro Quebec's North Shore and the resulting line capacity being treated as the largest unit on the system, the firm capacity on the L'Anse au Loup System is now the total installed capacity in the diesel plant.

Based on the most recent load forecast, the peak load for L'Anse au Loup will exceed firm capacity in 2005. The replacement of an existing 600 kW unit with a 1,100 kW unit will insure the firm capacity for the system beyond the forecast period.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Increase Generation **(cont'd.)**

Project Justification: (cont'd.)

Currently Installed: 1 - 1100 kW unit; 2 - 800 kW units; and 2 - 600 kW units yielding a system firm capacity of 3900 kW.

Proposed Installed: 2 - 1100 kW units; 2 - 800 kW units; and 1 - 600 kW unit yielding a system firm capacity of 4400 kW.

Forecast peak loads for L'Anse au Loup System are:

Year	2004	2005	2006	2007	2008	2009	2010
kW	3,869	3,944	4,020	4,096	4,173	4,250	4,328

Other options considered:

1. Purchase and install a new 1100 kW generator set, and radiator to replace the existing 600 kW unit in the L'Anse au Loup plant. The estimated cost for this alternative is $669,800 which is significantly higher than the recommended proposal, therefore, this option was not considered further.

2. Purchase and install a 1000 kW mobile generator set for L'Anse au Loup. The estimated cost for this alternative is $748,900 which is again significantly higher than the recommended proposal, therefore, this option was not considered further.

3. The opportunity for a Demand Side Management (DSM) based capital deferral was reviewed (refer to the attached) and it was determined that DSM was not a viable alternative resource in this particular circumstance.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Demand Side Management Analysis for Capital Budget Proposal

Project Title: **L'Anse au Loup - Increase Generation**

Description: Move 1100 kW unit from Nain to L'Anse au Loup 2005

Overview: NLH views DSM as an opportunity to defer or postpone capital costs. The deferral can be evaluated in economic terms as the difference in the present value of the utility revenue requirement under varying commencement years for the investment. The difference represents a DSM budget constraint and is the maximum amount of money that can be expended in order to defer the investment. The analysis proceeds by determing the necessary demand or energy savings required to defer the investment and then evaluates whether the DSM budget constraint can achieve the required saving. This DSM review represents a preliminary screening to ensure there are no obvious DSM opportunities missed.

The most economic peak demand DSM option, namely, domestic hot water (DWH) load control, is evaluated against the required demand savings with the calculated DSM budget.

Conclusion :
The DSM deferral budget does not provide sufficient funds to achieve the load deferral targets. DSM is not a viable alternative in this circumstance. The salient details of the DSM review follow below.

	Load Forecast (HR OPLF Spring 2004 Update)	**2005**	**2006**	**2007**	**2008**	**2009**
1	Peak Demand Forecast (kW)	3,944	4,020	4,096	4,173	4,250
2	Domestic Customers - #	755	759	763	767	771
3	Existing Plant Firm Capacity	3,900	kW			
4	Capital Budget Proposal for Increased Generation	$391,700	2005$			
		1 Yr	**2 Yr**	**3 Yr**	**4 Yr**	**5 Yr**
5=1-(.99*3)	Required Demand Savings for Capital Deferral (kW)	83	159	235	312	389
	(Difference of forecast peak demand and peak demand target of 1% below firm capacity)					
	DSM Budget Calculation (Calculated assuming 2% inflation and 6.8% isolated debt cost as per 2002/4 COS)					
6	Capital Budget Deferral Factors*	4.5%	8.8%	12.9%	16.8%	20.5%
7=6*(4/1.068)	Total DSM Deferral Budget (includes 1 yr discount)	$16,504	$32,275	$47,312	$61,616	$75,186
8=7/5	DSM Budget Per Required Demand Savings kW	$199	$203	$201	$197	$193
	* Percentage of capital cost that can be incurred to defer project for 1 to 5 years, and still be indifferent in economic terms.					
	DSM Supply Cost - $ per kW Achieved	$/kW*				
9	Domestic Hot Water (DHW) Load Control	$341				
	* includes provision for distribution losses.					
	Maximum Achievable Winter Peak Demand Reduction	**1 Yr**	**2 Yr**	**3 Yr**	**4 Yr**	**5 Yr**
	(Max kW reduction at lowest DSM supply cost and full DSM deferral budget)					
10	DHW Load Control - kW	48	95	139	181	221
11=10-5	Achievable DSM Less Required DSM Savings-kW	(35)	(64)	(96)	(131)	(168)

Calculation at line 7 includes a one year discount at 6.8% to align deferral factors and 2004 decision timeframe.
Source: Economic Analysis, NLH April 7 2004

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Diesel Generating Unit No. 266

Location: William's Harbour

Division: Transmission & Rural Operations

Classification: Generation

Project Description:
This project consists of the replacement of a 136 kW diesel generator, complete with radiator, unit switchgear, and exhaust modifications.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	165.0	0.0	0.0	165.0
Labour	40.0	0.0	0.0	40.0
Engineering	21.2	0.0	0.0	21.2
Project Management	15.0	0.0	0.0	15.0
Inspection & Commissioning	10.0	0.0	0.0	10.0
Corp O/H, AFUDC, Esc. & Contingency	52.8	0.0	0.0	52.8
Total	**304.0**	**0.0**	**0.0**	**304.0**

Operating Experience:
Unit No. 266 has been in service since 1975 and has been overhauled five times. Maintenance costs were nominal up to 2001, at which point the unit experienced failures. Maintenance costs from 2001 – 2004 averaged $11,200 annually. Average annual normal maintenance costs for this size diesel generator would be approximately $2,700.

Project Justification:
Replacement is justified on the basis of above average maintenance costs and the age of the unit. Unit No. 266 has been in service for twenty-nine years. It has been overhauled five times and is at the end of its useful life. Experience has shown that it is generally not practical to overhaul an engine more than five times, which makes this unit due for replacement in 2005. In addition to the initial savings on maintenance and overhaul costs, a new unit will provide greater fuel efficiency and reduced emissions. A direct replacement with no increase in generating capacity will be sufficient to meet demand as there is no requirement for additional capacity over the immediate peak period.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials, and external labour.

Future Plans:
None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Dam - Roddickton Mini Hydro

Location: Roddickton

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the removal and replacement of the existing rock filled timber crib dam. Due to environmental concerns, untreated timber will be used and the existing rock fill will be reused. No work is required for the penstock.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	150.0	0.0	0.0	150.0
Engineering	9.0	0.0	0.0	9.0
Project Management	5.0	0.0	0.0	5.0
Inspection & Commissioning	24.0	0.0	0.0	24.0
Corp O/H, AFUDC, Esc. & Contingency	43.5	0.0	0.0	43.5
Total	**231.5**	**0.0**	**0.0**	**231.5**

Operating Experience:

The dam was constructed twenty-three years ago and the timbers are deteriorating to the point where considerable difficulty was experienced in locating solid timber to attach the dam facing and decking. Engineering assessments indicated that, due to the homogeneous construction of the structure, it was not feasible to repair/replace individual section(s) of the dam but that it would have to be replaced in its entirety. (Please see the pictures on the following pages.)

Project Justification:

The existing dam is leaking a significant volume of water and since it is constructed with untreated timber, there is concern with respect to its structural strength. If the dam were to fail, there would be extensive damage to the penstock and powerhouse as well as the Roddickton water supply, which is directly downstream.

The annual energy production at Roddickton offsets approximately 1,600 barrels of oil at Holyrood each year. An economic analysis indicates that this project has a payback of nine years. The project has a net present worth preference of $287,000 over twenty-five years when compared to the plant retirement alternative.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Dam - Roddickton Mini Hydro **(cont'd.)**

Project Justification: (cont'd.)

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials, and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Roddickton Mini Hydro Dam

View showing dam

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Roddickton Mini Hydro Dam

View showing intake

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Roddickton Mini Hydro Dam

View looking upstream

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Roddickton Mini Hydro Dam

View looking upstream

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Installation of Fall Arrest Equipment

Location: Various Facilities

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the design, supply and installation of fall protection equipment at all Hydro locations, where required. These locations include fuel storage tanks, powerhouses, office buildings, terminal station control buildings, accommodation trailers, water control structures, power transformers and any auxiliary buildings. There are approximately 310 locations, and installations will be prioritized upon approval to proceed.

Project Cost: *($ x1,000)*	**2005**	**2006**	**2007**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0	0.0
Labour	150.0	138.0	138.0	138.0	564.0
Engineering	12.0	12.0	12.0	12.0	48.0
Project Management	5.0	5.0	5.0	5.0	20.0
Inspection & Commissioning	15.0	15.0	15.0	15.0	60.0
Corp O/H, AFUDC, Esc. & Contingency	24.2	43.9	66.2	166.6	300.9
Total	206.2	213.9	236.2	336.6	992.9

Operating Experience:

There is no fall arrest or restraint equipment at these locations at present. When work is undertaken, temporary arrest and restraint equipment is used.

Project Justification:

In 1999, the Provincial Government passed legislation requiring that fall arrest/travel restraint systems be used by all workers when accessing an elevated surface which is 3 m above the next lower level. Personnel need to access building roofs, fuel storage tank tops, water control structures and elevated equipment to perform operational and maintenance tasks. Some of these tasks, such as measuring depth of fuel via a roof top vent for reconciliation of fuel use records, are required by legislation.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Install Shut-Off Valves

Location: Various diesel Sites

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the installation of fuel shut-off valves in the plant fuel supply lines where they enter the plant building. Shut-off valves will be installed at the Black Tickle, Hopedale, Postville, Nain, North Plant, Norman Bay, Port Hope Simpson, St. Lewis, Mary's Harbour, St. Anthony, McCallum, Francois, Grey River and Ramea Diesel Plants.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	56.0	0.0	0.0	56.0
Labour	49.0	0.0	0.0	49.0
Engineering	30.8	0.0	0.0	30.8
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	28.8	0.0	0.0	28.8
Total	**164.6**	**0.0**	**0.0**	**164.6**

Operating Experience:

These plants are not currently equipped with these shut-off valves.

Project Justification:

Section 27(12) of the Provincial Storage and Handling of Gasoline and Associated Products Regulations, Newfoundland and Labrador Regulation 58/03, and the National Fire Code of Canada, Section 4.4.8.2(3), 1995, require that steel shut-off valves be provided on supply piping carrying combustible liquids where it enters buildings or structures.

The environmental compliance audit of the TRO regions identified that these diesel generating stations were deficient in this regard.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials, and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Fuel Storage Tanks

Location: Hopedale & Paradise River

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the replacement of the 9,000 ℓ fuel tank at Hopedale with a 22,700 ℓ Tank; and replacement of the two 45,400 ℓ tanks at Paradise River with one 45,400 ℓ tank.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	65.0	0.0	0.0	65.0
Labour	37.0	0.0	0.0	37.0
Engineering	5.5	0.0	0.0	5.5
Project Management	5.5	0.0	0.0	5.5
Inspection & Commissioning	12.0	0.0	0.0	12.0
Corp O/H, AFUDC, Esc. & Contingency	27.3	0.0	0.0	27.3
Total	**152.3**	**0.0**	**0.0**	**152.3**

Operating Experience:

At both sites, the existing dykes fill with snow and ice and are not able to fulfill the secondary containment function as required by the Provincial Storage and Handling of Gasoline and Associated Products Regulations. At Hopedale, deficiencies in the tank's construction result in malfunctions of the fuel depth measuring apparatus and the floating suction causing the engines to be deprived of fuel.

At Paradise River, the tanks are an older design consisting of cylinderical tanks mounted in open dykes. The mounting saddles have failed and damaged the dyke shells beyond repair. The situation has been stabilized until a new tank can be installed.

Project Justification:

At both sites, the existing tanks and dykes do not comply with the Provincial Storage and Handling of Gasoline and Associated Products Regulations, and hence must be replaced. At Paradise River, the tank farm is located close to the seashore and any significant spill would most likely reach the water.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Fuel Storage Tanks **(cont'd.)**

Project Justification: (cont'd.)
Only one tank at Paradise River will be required because the construction of the new highway allows for fuel truck deliveries from Cartwright, thus eliminating the need for a nine month fuel storage supply.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials, and external labour.

Future Plans:
None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replacement of Circuit Breakers

Location: Hawkes Bay Diesel

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the purchase and installation of two 5 kV, 1200 A vacuum breakers to replace the existing air breakers on the diesel generators.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	85.0	0.0	0.0	85.0
Labour	4.0	0.0	0.0	4.0
Engineering	2.0	0.0	0.0	2.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	19.6	0.0	0.0	19.6
Total	**110.6**	**0.0**	**0.0**	**110.6**

Operating Experience:

The existing Allis-Chalmers air circuit breakers were manufactured in 1970 and are in need of replacement because of age and wear on the breaker components. This type of air circuit breaker has been out of production for some time, thus original certified replacement parts are not available.

Project Justification:

The two 2.5 MW diesel units at the Hawkes Bay Terminal Station provide standby power for the Hawkes Bay, Port Saunders and Port au Choix distribution systems, voltage support for the Great Northern Peninsula transmission and generation capacity to add to overall system reserve. In order to maintain the integrity and availability of these diesel units in future, the replacement of these two unit breakers is essential.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Upgrade Cooling System

Location: Black Tickle

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the removal of an existing horizontal radiator and all associated piping and valves, and the purchase and installation of a new radiator, system piping, radiator supports, engine venting system and engine fill system.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	25.0	0.0	0.0	25.0
Labour	42.0	0.0	0.0	42.0
Engineering	9.0	0.0	0.0	9.0
Project Management	6.5	0.0	0.0	6.5
Inspection & Commissioning	5.7	0.0	0.0	5.7
Corp O/H, AFUDC, Esc. & Contingency	18.4	0.0	0.0	18.4
Total	**106.6**	**0.0**	**0.0**	**106.6**

Operating Experience:

The existing system is approximately thirty years old, and has a number of operating problems. The piping is poorly laid out and this results in air locking problems that result in engine overheating and plant outages. The existing horizontal radiator is in poor condition, the cowling is corroded, the cooling fins are damaged, and the core is leaking. The radiator is elevated for snow loading but does not have a proper maintenance platform or access ladder.

Project Justification:

The system has a number of inherent flaws which cause operating and maintenance problems and generally degrade reliability. A complete replacement of this system is the most practical solution to the problem.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Install Day Tank & Fuel Meter

Location: Ramea

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the purchase and installation of a 2,500 ℓ fuel day tank system and fuel meter in the Ramea Diesel Plant.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	43.3	0.0	0.0	43.3
Labour	23.6	0.0	0.0	23.6
Engineering	9.3	0.0	0.0	9.3
Project Management	5.0	0.0	0.0	5.0
Inspection & Commissioning	5.7	0.0	0.0	5.7
Corp O/H, AFUDC, Esc. & Contingency	18.7	0.0	0.0	18.7
Total	105.6	0.0	0.0	105.6

Operating Experience:

This plant does not have a fuel day tank to facilitate dipping the bulk storage tank for reconciliation purposes.

Project Justification:

Section 18(2)(b) of the Provincial Storage and Handling of Gasoline and Associated Products Regulations, Newfoundland and Labrador Regulation 58/03 requires aboveground storage tanks (other than a storage tank system connected to a heating appliance or a waste oil collection tank) to have dip or gauge readings reconciled with receipt and withdrawal records at least weekly. The environmental compliance audit of the TRO Central Region identified that the Ramea Diesel Plant did not have a means to reconcile fuel in the storage tank with the amount consumed, and thus did not meet the requirements of the regulations.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Building Systems- North Plant

Location: Goose Bay

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of removal of asbestos skirting, roof reconstruction and siding installation on the G5 generator and switchgear building and repainting of the access tunnel.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	58.0	0.0	0.0	58.0
Engineering	6.0	0.0	0.0	6.0
Project Management	5.0	0.0	0.0	5.0
Inspection & Commissioning	13.0	0.0	0.0	13.0
Corp O/H, AFUDC, Esc. & Contingency	16.6	0.0	0.0	16.6
Total	98.6	0.0	0.0	98.6

Operating Experience:

The asbestos skirting on the G5 generator module and the asbestos siding on the GM Switch Gear Building is cracked and frayed. It is no longer effective for its intended use and poses a health hazard. The G5 module roof is leaking and rain and snow is entering the unit. The access enclosure to the module is in poor condition and needs to be replaced. The metal access tunnel is leaking and corroded. (Please see pictures on the following pages.)

Project Justification:

Implementing these repairs will eliminate the health hazard caused by the asbestos, and secure the generation equipment from damage caused by the ingress of rain and moisture.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Goose Bay North Plant Upgrade Building Systems

View showing plant building

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Goose Bay North Plant Upgrade Building Systems

View showing G5 module damage

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Goose Bay North Plant Upgrade Building Systems

View showing access tunnel

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Raise Exhaust Stack Heights

Location: St. Brendan's, Black Tickle & Cartwright

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the purchase and installation of all materials necessary to raise the exhaust stack heights at these plants to be compliant with Good Engineering Practice (GEP) stack height guidelines.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	17.1	0.0	0.0	17.1
Labour	51.5	0.0	0.0	51.5
Engineering	9.8	0.0	0.0	9.8
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	17.3	0.0	0.0	17.3
Total	**95.7**	**0.0**	**0.0**	**95.7**

Operating Experience:

Currently, these sites have stack heights which are insufficient to be compliant under the Air Pollution Control Regulations.

Project Justification:

Based on air dispersion modeling, existing stack heights are not sufficient to provide adequate dispersion of emissions to be compliant with the Air Pollution Control Regulations under the Environmental Protection Act. Raising the stack heights will achieve compliance at these sites.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase & Install Digital Metering

Location: Various Sites

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the purchase and installation of digital metering equipment for the seven diesel generating units at the diesel plants in Francois, McCallum, Grey River and Little Bay Islands.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	35.0	0.0	0.0	35.0
Labour	30.0	0.0	0.0	30.0
Engineering	5.0	0.0	0.0	5.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	4.0	0.0	0.0	4.0
Corp O/H, AFUDC, Esc. & Contingency	15.8	0.0	0.0	15.8
Total	**89.8**	**0.0**	**0.0**	**89.8**

Operating Experience:

The seven diesel generating units at these four plants do not have the necessary accessories to collect operating data, required for effective production supervision.

Project Justification:

Digital metering equipment will be used for continuous remote access monitoring of each diesel unit and will be configured to automatically trip the unit(s) off-line for abnormal frequency, voltage and load unbalance conditions. Power calculations within the metering unit will be interfaced with electronic fuel metering to provide accurate unit efficiency calculations. Hydro has standardized on this digital metering equipment for all new generating units. This project will bring the remaining seven diesel generating units on the system up to that standard and provide enhanced data trending and event recording.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Diesel Plant

Location: Black Tickle

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the purchase and installation of materials for the upgrading of plant building, fuel line and chain link fence and repairs to the transformer storage ramp. The building upgrade includes new plywood sheeting, new asphalt roof shingles and metal siding. The existing fuel transfer shed and its associated fuel line will be removed.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	50.0	0.0	0.0	50.0
Engineering	8.0	0.0	0.0	8.0
Project Management	3.0	0.0	0.0	3.0
Inspection & Commissioning	8.0	0.0	0.0	8.0
Corp O/H, AFUDC, Esc. & Contingency	15.5	0.0	0.0	15.5
Total	**84.5**	**0.0**	**0.0**	**84.5**

Operating Experience:

The existing roof is leaking and needs to be structurally upgraded to accommodate heavy snow loading. The siding and girts are corroded, due to the marine environment and are damaged due to heavy snow loading. The girts need to be replaced and new ones added to give additional structural strength. The storage ramp has been damaged by heavy equipment loads and snow loads, in one section. The fence has been damaged extensively by heavy snow and ice loading on the top rails and the fence fabric. (Please see pictures on following pages.)

Project Justification:

The plant siding and roof repairs are required to protect and secure the generation equipment and provide reliable customer service. The fence repairs are required to provide security for the equipment and materials that must be stored outside.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Diesel Plant **(cont'd.)**

Project Justification: (cont'd.)

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Black Tickle Upgrade Diesel Plant

View showing plant

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Black Tickle Upgrade Diesel Plant

View showing building

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Black Tickle Upgrade Diesel Plant

View showing building

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Black Tickle Upgrade Diesel Plant

View showing fencing

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Purchase Data Acquisition Software

Location: Various Diesel Plants

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the purchase and installation of data acquisition software to enable interrogation of all digital power metering devices at the isolated diesel plants.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	50.0	0.0	0.0	50.0
Labour	5.0	0.0	0.0	5.0
Engineering	7.0	0.0	0.0	7.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	8.0	0.0	0.0	8.0
Total	70.0	0.0	0.0	70.0

Operating Experience:

The existing data acquisition software is a DOS based for the Labrador plants and Win 95 based for plants on the Island. These software packages are used to retrieve metering data from the remote diesel plants.

Project Justification:

The existing software packages are not compatible with the latest Windows platforms in use throughout Hydro's operations. The new software will provide network communications accessibility, which will enable up-to-date data acquisition from the remote sites to be used for planning and production management.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Install Intermediate Fuel Storage Tank

Location: Charlottetown

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the purchase and installation of an intermediate fuel storage tank between the bulk storage and the plant day tank.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	22.0	0.0	0.0	22.0
Labour	17.2	0.0	0.0	17.2
Engineering	8.8	0.0	0.0	8.8
Project Management	1.5	0.0	0.0	1.5
Inspection & Commissioning	5.7	0.0	0.0	5.7
Corp O/H, AFUDC, Esc. & Contingency	11.2	0.0	0.0	11.2
Total	**66.4**	**0.0**	**0.0**	**66.4**

Operating Experience:

The plant day tank is undersized and the piping is configured in such a way that the bulk storage tank deliveries must be interrupted to refill the day tank. This arrangement makes it impossible to perform fuel reconciliation as required by the regulations.

Project Justification:

Section 18(2)(b) of the Provincial Storage and Handling of Gasoline and Associated Products Regulations, Newfoundland and Labrador Regulation 58/03 requires aboveground storage tanks (other than a storage tank system connected to a heating appliance or a waste oil collection tank) to have dip or gauge readings reconciled with receipt and withdrawal records at least weekly. In order to be compliant, the system must have a means to reconcile fuel in the storage tank with the amount consumed. This deficiency was identified at this site in an environmental compliance audit of the regional operations. The existing plant day tank is too small to allow fuel reconciliation and there is insufficient space inside the plant for a larger day tank. Therefore, the intermediate fuel tank will be installed outside to correct this deficiency.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Install Intermediate Fuel Storage Tank **(cont'd.)**

Project Justification: (cont'd.)

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Modify Heating System

Location: Hopedale

Division: Transmission & Rural Operations

Classification: Generation

Project Description:

This project consists of the purchase and installation of materials required to modify the plant hydronic heating system to capture sufficient heat from the generating units to heat the diesel plant.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	14.0	0.0	0.0	14.0
Labour	18.2	0.0	0.0	18.2
Engineering	4.0	0.0	0.0	4.0
Project Management	2.5	0.0	0.0	2.5
Inspection & Commissioning	5.7	0.0	0.0	5.7
Corp O/H, AFUDC, Esc. & Contingency	9.7	0.0	0.0	9.7
Total	54.1	0.0	0.0	54.1

Operating Experience:

The existing system configuration cannot extract sufficient heat from the generators to heat the plant. Electric heating is being used to supplement the current hydronic heating system on an interim basis.

Project Justification:

This project will displace approximately 38,000 litres of fuel annually with an estimated average annual savings of $18,200.00. Based on this estimate the capital cost of this project will be recovered within four years.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase Meters & Equipment - TRO System

Location: All Service Areas

Division: Transmission & Rural Operations

Classification: General

Project Description:

This project consists of the purchase of demand/energy meters, current and potential transformers, metering cable and associated hardware for use throughout the Transmission & Rural Operations system.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	148.0	0.0	0.0	148.0
Labour	0.0	0.0	0.0	0.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	10.6	0.0	0.0	10.6
Total	**158.6**	**0.0**	**0.0**	**158.6**

Operating Experience:

Revenue meters and associated equipment are required for new customer services and the replacement of old, worn, damaged or vandalized meters.

Project Justification:

Demand/Energy meters are expected to last a minimum of twenty years. Each meter is evaluated after that time for condition and either retired from service or refurbished and returned to service. Failure to supply metering equipment as required could result in customer connection delays.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials.

Future Plans:

This is an annual allotment which will be adjusted from year to year depending on historical information.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Install Central Air Conditioning

Location: Whitbourne & Stephenville

Division: Transmission & Rural Operations

Classification: Properties

Project Description:

This project consists of the purchase and installation of central air conditioning equipment at the Whitbourne and Stephenville offices.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	180.0	0.0	0.0	180.0
Engineering	45.0	0.0	0.0	45.0
Project Management	4.5	0.0	0.0	4.5
Inspection & Commissioning	7.5	0.0	0.0	7.5
Corp O/H, AFUDC, Esc. & Contingency	52.1	0.0	0.0	52.1
Total	**289.1**	**0.0**	**0.0**	**289.1**

Operating Experience:

The Whitbourne and Stephenville offices were constructed in 1974 and do not have central air conditioning systems.

Project Justification:

There have been numerous complaints from employees that temperatures in the offices and other areas of the facilities are excessive during the summer months. Installation of central air conditioning equipment will alleviate these employee concerns.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Warehouse Renovations

Location: St. Anthony

Division: Transmission & Rural Operations

Classification: Properties

Project Description:

This project consists of renovations to the existing warehouse space at St. Anthony to provide: four fixed offices, two modular offices, a conference room, interior finishing and all associated work. No changes are required in existing water supply and septic facilities. The warehouse overhead door will be removed and new windows will be installed.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	100.0	0.0	0.0	100.0
Engineering	8.0	0.0	0.0	8.0
Project Management	3.0	0.0	0.0	3.0
Inspection & Commissioning	9.0	0.0	0.0	9.0
Corp O/H, AFUDC, Esc. & Contingency	26.5	0.0	0.0	26.5
Total	**146.5**	**0.0**	**0.0**	**146.5**

Operating Experience:

Business Improvement Initiatives in Customer Services and Materials Management have resulted in staff reductions and a reduction in warehouse space requirements. This provides the opportunity to accommodate all St. Anthony employees at one location in the proposed renovated warehouse, and eliminate the need for the rental facilities presently in use.

Project Justification:

The present agreement for the rental facilities at St. Anthony is $44,720.00 per year and the expiration date of this agreement is September 30, 2005. With these renovations, all Hydro operations in St. Anthony will be conducted from Hydro owned facilities and the capital cost for the renovations will be offset by savings in rental charges. This project has a payback of less than four years.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Upgrade Line Depot/Storage Sheds

Location: Baie Verte, Sop's Arm & Bay d'Espoir

Division: Transmission & Rural Operations

Classification: General

Project Description:

This project consists of roofing and siding repairs to the line depots at Baie Verte and Sops Arm and construction of storage sheds at both sites. At Bay d'Espoir, the project involves an extension to the existing line depot.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	7.0	0.0	0.0	7.0
Labour	82.0	0.0	0.0	82.0
Engineering	17.0	0.0	0.0	17.0
Project Management	7.0	0.0	0.0	7.0
Inspection & Commissioning	12.0	0.0	0.0	12.0
Corp O/H, AFUDC, Esc. & Contingency	26.0	0.0	0.0	26.0
Total	**151.0**	**0.0**	**0.0**	**151.0**

Operating Experience:

At Baie Verte and Sops Arm, the line depots are in excess of twenty-years old and have deteriorated to the point where the roofs, doors and windows leak and the siding is beyond repair. As well, there is insufficient and unsuitable storage space for the line maintenance equipment. At Bay d'Espoir, the line depot is insufficiently sized for the number of line maintenance staff operating from this location.

Project Justification:

At Baie Verte and Sops Arm, the condition of the depots require repairs in order to protect the integrity of the structures and provide a safe and dry environment for workers and maintenance equipment.

The operational re-alignments in 2003, resulted in a relocation of lineworkers from LaScie and Springdale to Baie Verte and from Bishop Falls to Bay d'Espoir. The increased numbers of lineworkers at these two sites necessitate the expansion of the depot to accommodate additional staff and the addition of a storage shed to accommodate the additional tools and equipment.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replacement of Line Depot Building

Location: Mary's Harbour

Division: Transmission & Rural Operations

Classification: Properties

Project Description:

This project consists of the removal and disposal of the existing line depot building and the erection of a new building. The new building will be wood framed measuring 6 m x 9 m with exterior metal siding and a shingled roof.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	47.0	0.0	0.0	47.0
Engineering	7.0	0.0	0.0	7.0
Project Management	2.0	0.0	0.0	2.0
Inspection & Commissioning	5.0	0.0	0.0	5.0
Corp O/H, AFUDC, Esc. & Contingency	12.9	0.0	0.0	12.9
Total	**73.9**	**0.0**	**0.0**	**73.9**

Operating Experience:

The existing building was constructed in 1970 and is located in a poorly drained, depressed area and is subjected to problems associated with frost heave and with flooding during periods of heavy runoff. The building's structure is twisted and not level. This prevents doors from closing and building movement has cracked window glass. The foundation timbers and exterior plywood sheathing are in a stage of advanced rot, the roof shingles have reached the end of their life and the building is poorly insulated.

Project Justification:

The condition of the existing building is deteriorating and it would be more cost effective to erect a new building on a solid, well-drained site, rather than attempt to upgrade the existing building and drain the existing site. The building will serve the two lineworkers, an apprentice and a mechanic stationed at Mary's Harbour with a suitable structure to accommodate staff and equipment.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase Global Positioning System

Location: St. John's

Division: Transmission & Rural Operations

Classification: Properties

Project Description:

This project consists of the purchase of a survey grade Real Time Kinetic Global Positioning System.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	50.0	0.0	0.0	50.0
Labour	0.0	0.0	0.0	0.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	6.6	0.0	0.0	6.6
Total	**56.6**	**0.0**	**0.0**	**56.6**

Operating Experience:

The equipment currently in use is ten years old, and costs an average of $4,000 per year to service and repair. This annual repair cost is expected to continue and increase. While the equipment is being repaired, the costs for rental replacements average $5,000 per year.

Project Justification:

This project will eliminate average annual repair and rental costs of approximately $9,000.00. Based on this analysis, the cost of this project will be recovered in approximately six years.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replacement of Fence

Location: Daniel's Harbour Terminal Station

Division: Transmission & Rural Operations

Classification: Properties

Project Description:

This project consists of the replacement of the existing fence at the Daniel's Harbour Terminal Station and widening the station on the north and south sides.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	3.0	0.0	0.0	3.0
Labour	25.0	0.0	0.0	25.0
Engineering	6.0	0.0	0.0	6.0
Project Management	3.0	0.0	0.0	3.0
Inspection & Commissioning	6.0	0.0	0.0	6.0
Corp O/H, AFUDC, Esc. & Contingency	8.8	0.0	0.0	8.8
Total	51.8	0.0	0.0	51.8

Operating Experience:

The existing fence is approximately 1.5 m high whereas Hydro's standard fence height for terminal stations is 2.5 m. There is congestion in the station due to the proximity of the fencing to the structures which prohibits the effective use of maintenance equipment in the station.

Project Justification:

This station is located inside the community of Daniel's Harbour. Its accessibility to the public creates a safety hazard for anyone who can gain access to the station particularly during winter when the snow depths allow walking in over the fence. Snow often completely covers part of the fence requiring it to be cleared away immediately to make the station inaccessible to the public. Extending the station and increasing the fence height will create the required room for the operation of maintenance equipment inside the station and eliminate the hazard to public safety.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Construct PCB Storage Building

Location: Wabush

Division: Transmission & Rural Operations

Classification: Property

Project Description:

This project consists of the construction of a 3 m x 7 m PCB storage building at the Wabush Line Depot. A chain link fence with gates which can be locked will be constructed around the building.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	24.0	0.0	0.0	24.0
Labour	6.0	0.0	0.0	6.0
Engineering	9.4	0.0	0.0	9.4
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	3.0	0.0	0.0	3.0
Corp O/H, AFUDC, Esc. & Contingency	9.1	0.0	0.0	9.1
Total	**51.5**	**0.0**	**0.0**	**51.5**

Operating Experience:

There are approximately 1,800 distribution transformers in the Labrador City/Wabush system. Approximately 50% remain to be tested for PCB contamination and typically 3 – 5% of the transformers will test positive for PCB contamination.

Project Justification:

Hydro takes PCB contaminated distribution transformers out of service when they are found and they are stored in a designated area at the line depots to await shipping to an approved storage site. The Environmental Regulations stipulate that an approved storage facility be used to store non-serviceable PCB equipment until it can be transshipped for disposal.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Legal Survey of Distribution Line Right-of-Ways

Location: Various Sites

Division: Transmission & Rural Operations

Classification: Properties

Project Description:

This project consists of the completion of legal surveys and the preparation of documentation to acquire Crown Lands easement rights for approximately 600 km of distribution line right-of-ways across Hydro's system.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	0.0	0.0	0.0	0.0
Engineering	40.0	0.0	0.0	40.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	9.6	0.0	0.0	9.6
Total	**49.6**	**0.0**	**0.0**	**49.6**

Operating Experience:

Prior to 1985, it was Hydro's practice to construct and operate transmission and distribution lines without obtaining easement rights over Crown Land as Hydro was an agent of the Crown. In 1985, it was decided to obtain easement rights for all property underlying newly constructed lines and to obtain easement rights for property for the pre-1985 lines. To-date, the easement rights to all property associated with transmission lines have been obtained and there is approximately 2,400 km of distribution lines left without easement rights.

Project Justification:

The project justification is based on: 1) the right-of-ways for the distribution lines occupy Crown Land contrary to the Crown Lands Act; 2) lack of easement rights presents a significant risk to Hydro operations should competing requirements for the land arise; and 3) appropriate rights are required for proper maintenance and upgrading of the lines.

Future Plans:

This is an annual program which began in 2004 and easement rights for the whole distribution system are planned to be in place by the end of 2008.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Nodwell V7600 & Boom V6067

Location: Stephenville

Division: Transmission & Rural Operations

Classification: Tools & Equipment

Project Description:

This project consists of replacing the 1973 model off-road track vehicle (No. V7600) and the 1977 model boom (No. V6067) with a similar unit and a 100 ft. reach boom/work platform.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	700.0	0.0	0.0	700.0
Labour	0.0	0.0	0.0	0.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	97.6	0.0	0.0	97.6
Total	**797.6**	**0.0**	**0.0**	**797.6**

Operating Experience:

The unit being replaced is a 31-year old Nodwell with a 26-year old boom with a 57 ft. reach. Average maintenance costs have been $25,000/year over the past three years.

Project Justification:

Both units have reached the end of their useful life. Transmission maintenance staff require a heavy-duty off-road vehicle equipped with a 100 ft. reach boom and work platform in order to access portions of the transmission line structures during icing conditions or when failed hardware makes a structure unsafe to climb. The replacement criteria for this type of heavy-duty off-road tracked vehicle is 20-25 years of age, condition, extent of repairs needed, and level of compliance with current safety standards. The current equipment is required to be replaced for reasons of employee safety and to permit effective repair and maintenance of the transmission system.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase Mobile Oil Reclamation Unit

Location: TRO Central

Division: Transmission & Rural Operations

Classification: Tools & Equipment

Project Description:

This project consists of the purchase of a self-contained mobile oil regeneration unit for refurbishing oil from power transformers. This includes a 48 ft. aluminum transport trailer with two parallel regenerative clay towers and computerized control. The unit is capable of providing 24 hour continuous processing of transformer oil until the required level of oil regeneration has been achieved.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	420.0	0.0	0.0	420.0
Labour	6.0	0.0	0.0	6.0
Engineering	6.0	0.0	0.0	6.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	98.9	0.0	0.0	98.9
Total	**530.9**	**0.0**	**0.0**	**530.9**

Operating Experience:

There are 161 power transformers on Hydro’s bulk electrical system with 67 showing parameters outside the guideline limits as specified under the ASTM D3487 standard. Of the 67 units outside the acceptable range, 17 are considered high priority and will need to undergo an oil regeneration process within the next five years. A recent service contract for an oil regeneration process performed on three transformers at Bay d’Espoir cost approximately $150,000, giving an average cost of $50,000 per transformer.

Project Justification:

With 67 transformers testing outside the ASTM guidelines and 17 units considered high priority, Hydro intends to conduct an annual oil regeneration program on all its power transformers. With a regeneration program of 4 – 5 units per year, it is more cost effective to purchase a regeneration unit, than to use outside service contractors.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Purchase Mobile Oil Reclamation Unit **(cont'd.)**

Project Justification: (cont'd.)

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Doble F2000 Relay Test Equipment

Location: Bishop's Falls, Whitbourne, Stephenville & Bay d'Espoir

Division: Transmission & Rural Operations

Classification: Tools & Equipment

Project Description:

This project consists of the replacement of three sets of Doble computerized relay test sets, for Transmission Operations and purchase of one set for Generation Operations at Bay d'Espoir.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	342.6	0.0	0.0	342.6
Labour	0.0	0.0	0.0	0.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	19.6	0.0	0.0	19.6
Total	**362.2**	**0.0**	**0.0**	**362.2**

Operating Experience:

The present computerized relay test equipment was purchased from Doble Engineering from 1986 to 1989, and since then have received regular hardware and software updates.

Project Justification:

In 1998, Doble Engineering started manufacturing a new generation of computerized test equipment, and announced that they would not support the present equipment (spare parts, repairs and updates to software) beyond 2004. Without the proper manufacturer's support, the present equipment is inadequate for maintaining the relaying and protection of the bulk electrical transmission system. In addition, the newer technology test equipment is more compatible with the new computerized relays and metering units that are being used by Hydro and will allow more comprehensive and efficient testing of new relaying.

With more sophisticated electronic equipment being installed in existing and new generating plants, there is a requirement for accurate and up to date test equipment to support the maintenance of this

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Doble F2000 Relay Test Equipment **(cont'd.)**

Project Justification: (cont'd.)

equipment. A modern 3-phase test supply capable of signal processing and simulation is required for testing: digital protection and control relays; digital fault recorders; new exciters; and electronic governors. As well, it can aid in testing and calibration of existing equipment such as 3-phase metering, synchronizing controls and auxiliary equipment

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Energy Management System - Energy Control Centre

Location: Hydro Place

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This project is the third year of a four-year project for which the Board has approved funds for 2003 and 2004. The project consists of the replacement of the existing Energy Management System (EMS) computer software and hardware infrastructure with state of the art hardware and software which provides greater flexibility for future technology changes and integration with Hydro's IT Infrastructure. The existing EMS is used by Hydro's Energy Control Centre to monitor, control and manage the power system and related water resources across the Province. The EMS is critical to the continued efficient and reliable operation of the electric power system and generation facilities owned by Hydro. The existing EMS is reaching the end of its projected life of 15 years with manufacturer supplied spare parts discontinued and technical support severely limited.

The cashflow for the EMS has changed from that submitted in the 2003 Capital Budget proposal. The 2003 Capital Budget proposal was prepared based on the report by KEMA with an anticipated contract signing in December 2003 and an in-service date of February 2006. Due to slower progress than anticipated in the KEMA report to address the rather complex nature of the contract, it was not signed until June 2004 and therefore the scheduled project completion milestone has changed to June 2006. As a result the estimated costs for 2004 and 2005 are forecasted down and estimated costs for 2006 are forecasted up. The total cost for the project has not changed.

Project costs are based on a joint procurement with Churchill Falls (Labrador) Corporation.

Project Cost: *($ x1,000)*	**2003**	**2004**	**2005**	**Beyond**	**Total**
Material Supply	7.7	1,321.3	3,204.8	1,461.3	5,995.1
Labour	0.0	45.0	68.0	118.2	231.2
Engineering	297.2	948.9	1,355.2	611.4	3,212.7
Project Management	49.4	158.7	190.6	48.4	447.1
Inspection & Commissioning	0.0	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	32.8	248.6	703.8	1,406.8	2,392.0
Total	387.1	2,722.5	5,522.4	3,646.1	12,278.1

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Project Title: Replace Energy Management System - Energy Control Centre **(cont'd.)**

Operating Experience:

The Energy Management System was purchased from Harris Controls (now a part of General Electric) on the 15th of March in 1988 and placed in service on the 20th of August in 1990. It has been in continuous operation since that time. In 1993 an Information System was added to allow the export of EMS data to a server platform to make information easily accessible to internal users over the corporate Local Area Network. Used parts were purchased over a period of time and in 1999 a spare computer was obtained when another utility retired its system. There have been no other upgrades or major repairs. The current operating status can be summarized as:

(1) System Availability has averaged 99.985% over the system's lifetime; (2) there are no functional deficiencies; (3) there is no vendor support available; and (4) new spare parts are not available.

Project Justification:

Please refer to the Energy Management System Replacement Project Justification on the following pages and a report by KEMA titled "Hydro Energy Management System Assessment" which was filed with the Board as part of Hydro's 2003 Capital Budget Application (Section G, Appendix 5).

Future Plans:

The KEMA report in Section 7.11 outlines the "Life Cycle Management" of the EMS. The new EMS will be using "non-proprietary" hardware and therefore will offer more flexibility for maintenance, upgrading and replacement. However, this type of equipment quickly becomes obsolete as vendors of computer hardware upgrade their systems. Therefore the EMS hardware will require an "Evergreening Program" similar to other IT Infrastructure. KEMA recommends that 20 to 33% of the base hardware costs be budgeted each year to keep hardware current. This is forecast to be $350,000 per year beginning in the third year following the system commissioning.

Similarly, software upgrades will be required periodically. This cost will depend on the frequency of vendor software upgrades. KEMA are suggesting this will amount to approximately $700,000 every 3 years following the project having been brought in service.

**2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS**

ENERGY MANAGEMENT SYSTEM REPLACEMENT

PROJECT JUSTIFICATION

August, 2002

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Introduction

An assessment of Hydro's EMS was conducted by KEMA Consulting, an industry leader in studying and assisting utilities in their EMS and SCADA projects. The results of the study are provided in the attached report entitled "Hydro Energy Management System Assessment". This report makes a strong recommendation to begin the process of replacement immediately because of the high risk of a failure of the EMS as the age of its electronic components is beyond their design life. Concurrent with the study on Hydro's EMS, KEMA performed a similar assessment for Churchill Falls (Labrador) Corporation (CF(L)Co) on their Supervisory Control and Data Acquisition (SCADA) system. This system was also identified to require replacement in the next several years.

Alternatives for this project were identified and discussed in Section 5 of the KEMA report. These are as follows:

1. Maintain Existing Systems and Process
2. Implement New EMS Independent of CF(L)Co
3. Implement New EMS Together with CF(L)Co
4. Purchase a Turnkey System implemented by the Vendor.

Cost of EMS Failure

In addition to the discussion in the KEMA report on the advantages and disadvantages of each of the alternatives the following highlights the critical nature of the EMS and the costs of a major failure of the EMS.

The EMS provides a mission critical function for Hydro and the operation of the Interconnected Power System. If this system failed for an extended period of time while a replacement was procured the reliability of the power system and electrical service to all of Hydro's customer would fall to unacceptable levels. Remote control of any station would be impossible and therefore all major stations would have to be staffed. There are eight stations that would have to be staffed 24 hours per day with 16 others having to be staffed for varying durations depending on the system condition. The eight stations alone would cost, provided staff are available, approximately

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$41,000 per week in overtime. This will result in a significant reduction in maintenance activity, as the staff performing monitor and control functions normally performs maintenance. In order to continue with routine maintenance additional staff would have to be hired and trained to replace those assigned to operating duties. This could add an additional $32,000 per week, while repairs or replacement are being done. If the failure was catastrophic and full replacement was the only option the cost of the foregoing could be as high as $3.8M per year.

In addition to the wage costs there would be a cost of lost efficiency due to the loss of economic dispatch functionality. At $28 per barrel this can quickly add a significant expense to the loss of the EMS. Economic Dispatch balances the load between all generating units so that the water at each plant is used as efficiently as possible with consideration to electrical losses from the plant to customer loads. Without Economic Dispatch this balancing between plants would be very difficult and ineffective resulting in loss of efficiency.

There would also be a severe loss in reliability. During the last major outage to the Avalon Peninsula in October 1998, customers were restored between 8 and 53 minutes using the EMS. Without the EMS this can be estimated to take at least two to three times longer if all stations on the Avalon Peninsula were staffed. If some stations were not staffed outages would extend for several hours allowing for contact and for travel. This would result in an intolerable level of service. Similar and more severe service deterioration would occur throughout the system particularly in remote areas and during poor weather conditions.

A delay in approving the project increases the probability of failure because as the electronic components age the likelihood of failure increases. A decision to delay is a risk assessment on how long the EMS could perform at an acceptable level. The failure rate cannot be estimated by KEMA as it does not have data on EMS systems failures because most other similar EMS computer systems have already been removed from service and replaced before this point in their service life. While we have done well to-date without major problems, KEMA have suggested in the report that this risk of failure is high, and we should not delay replacing the existing GE/Harris EMS system.

The alternatives mentioned above are highlighted in the KEMA report. The report clearly identifies the least cost option is alternative 3 which is to procure the system at the same time as CF(L)Co. In addition to the savings in system procurement costs identified by KEMA there are internal engineering and project management cost savings of $560,000 and corporate overhead, AFUDC, Escalation and Contingency savings of $390,000. Therefore the total savings for a joint procurement are approximately $1,500,000. Hydro has obtained a commitment by CF(L)Co for joint procurement and therefore the cost estimate has been prepared on that basis.

Operator Training Simulator

There is an option mentioned in the KEMA report that may be included in the EMS replacement depending on the purchase, implementation and operating cost. It is an Operator Training Simulator (OTS). An OTS is a power system simulator used to train power system operators. It is used by setting up scenarios on the EMS to train operators how to respond to certain incidents or conditions on the power system, similar to a flight simulator used by aircraft pilots. These scenarios would include replaying disturbances on the power system for staff that were not working at the time of the disturbance. In this way operator response to these incidents will be enhanced and customer service restoration improved during real situations.

The need for an OTS has increased with recent retirements of experienced staff. Many of the staff have not experienced black-outs to major portions of the power system such as the entire east or west coast because of reliability improvements and cooperative weather, however they must be ready at all times for such circumstance. An OTS would simulate these incidents and help train the operators for the appropriate response.

Safety Issues

There are no direct safety issues that require the EMS to be replaced. Safety issues may arise if there was a failure of the EMS. The EMS provides methods for the system operators to track workers on transmission lines for contact if any incident should arise. This functionality would be lost. However, a paper tracking system could be implemented to ensure safety. The impact would then be reflected in loss of work time and slower maintenance activities.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Applications Enhancements

Location: Hydro Place

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

The application enhancement project provides for:

(1) unforeseen modifications, enhancements and additions to software to address the required changes to business processes initiated by customers, stakeholders and regulators or to provide efficiencies to existing processes;

(2) the continuing design, and implementation of enhancements to Hydro's Corporate Intranet;

(3) enhancements to the Key Performance Indicator application to reflect business initiatives; and

(4) the addition of a Hydro facilities risk based analysis-modeling tool to predict the impact of failures.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	123.6	0.0	0.0	123.6
Labour	130.8	0.0	0.0	130.8
Engineering	0.0	0.0	0.0	0.0
Project Management	20.4	0.0	0.0	20.4
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	35.9	0.0	0.0	35.9
Total	**310.7**	**0.0**	**0.0**	**310.7**

Operating Experience:

N/A

Project Justification:

This project involves:

a) Various Minor Enhancements:

Hydro must be able to react to requests to provide enhancements to software applications in response to unforeseen requirements, such as legislative and compliance changes; vendor driven changes, and enhancements designed to improve customer service or staff productivity. Previous changes have included changes initiated by Canada Post, changes to income tax

2005 CAPITAL PROJECTS OVER $50,000
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Project Title: Applications Enhancements **(cont'd.)**

Project Justification (cont'd.)

calculations, providing equal billing to customers, and other enhancements to provide environmental and operational processes.

b) Intranet

This involves the continuing design, and implementation of enhancements to Hydro's Intranet to improve access to information to our employees. This will help to improve information flow, eliminate redundant processes, reduce the manual effort associated with distributing information and provide an enhanced level of customer service.

c) Key Performance Indicator

This is required to support enhancements to the Key Performance Indicator initiative which is directed at reporting on performance activities. This involves the continuing design, build and implementation of Hydro's KPI application.

d) Facilities Failure Model

This tool allows Engineering to develop realistic life-cycle asset management programs. Based on risk-based analysis, different modes of failures of Hydro facilities can be modeled and the impacts on life cycles and extent of destruction predicted. It can assist with identifying least cost intervention strategies and the timing for executing the intervention.

Future Plans:

Application enhancements are a continuing requirement.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Security Program - Secure Remote Access

Location: Hydro Place

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This project for 2005 is the continuation of a project for which the Board approved funds for 2004. The project will focus on the evaluation, design and implementation of a product(s) that will ensure a secure method of accessing corporate information technology resources from multiple locations. The product chosen will have to meet industry standards, address the inter-operability of existing and future applications, and incorporate existing in-house technology where possible. It must address both internal (employees accessing the company network) and external (vendors connecting to the Hydro Group's network for different transactions) concerns.

Project Cost: *($ x1,000)*	**2004**	**2005**	**Beyond**	**Total**
Material Supply	35.0	35.0	0.0	70.0
Labour	30.0	30.0	0.0	60.0
Engineering	0.0	0.0	0.0	0.0
Project Management	3.0	3.0	0.0	6.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	7.1	8.1	0.0	15.2
Total	**75.1**	**76.1**	**0.0**	**151.2**

Operating Experience:

N/A

Project Justification:

Providing secure remote access involves development of a solution for Hydro Group employees and vendors. This project will include recommendations and implementation of the most economical and secure solution for the Hydro Group. The solution may include one method of access or an effective combination to meet all corporate needs and will attempt to incorporate the Hydro Group’s existing investment in both RSA’s Secure ID technology and Virtual Private Network (VPN) technology where applicable.

**2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS**

Project Title: Security Program - Secure Remote Access **(cont'd.)**

Project Justification: (cont'd.)

The access to computer-based information in a timely manner from a mobile workforce is essential for business. Hydro Group employees benefit from the ability to access computer resources quickly and efficiently. Properly securing this remote access is essential to ensure that access is granted to the employees and vendors who are authorized and all other unauthorized attempts to access the information are denied.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Corporate Applications Environment

Location: St. John's

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This project includes all costs to apply modifications and test applications affected by a vendor upgrade. Software requiring upgrades are:

a) Metaframe Server operating system;
b) Network Management tools,
c) Helpdesk Management tools.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	183.7	0.0	0.0	183.7
Labour	36.6	0.0	0.0	36.6
Engineering	0.0	0.0	0.0	0.0
Project Management	20.2	0.0	0.0	20.2
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	33.8	0.0	0.0	33.8
Sub-Total	**274.3**	**0.0**	**0.0**	**274.3**
Less: Cost Recovery - CF(L)Co	**(52.1)**	**0.0**	**0.0**	**(52.1)**
NLH Cost	**222.2**	**0.0**	**0.0**	**222.2**

Operating Experience:

These software applications were installed in 2000/2001 and have not been updated.

Project Justification:

This project includes upgrades to currently held enterprise-wide software application products. Software must be regularly upgraded to maintain benefits in system functionality. As well, this provides for continued vendor support of applications and a stable application environment for Hydro's key business functions. Out-dated and non-maintained software would lead to breakdowns in business functions that would ultimately result in higher costs.

Future Plans:

Software vendor maintenance and upgrades is an on-going activity. Vendors will usually release a software upgrade each year. Hydro's plan is to implement the latest software version every second year, thereby insuring that our operating version of software is, at most, one version behind the current release level.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: iSeries Replacement

Location: Hydro Place

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

Project Description:

This project consists of the replacement of an existing AS400 Server which supports the Corporate integrated financial applications (JDE), and the Showcase Strategy Report Writer. The server will be replaced by an iSeries server which will be capable of connecting to and using the storage installed on Hydro's Storage Area Network (SAN) in 2003.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	983.0	0.0	0.0	983.0
Labour	0.0	0.0	0.0	0.0
Engineering	120.0	0.0	0.0	120.0
Project Management	16.0	0.0	0.0	16.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	278.4	0.0	0.0	278.4
Sub-Total	**1,397.4**	**0.0**	**0.0**	**1,397.4**
Less: Cost Recovery - CF(L)Co	**(265.5)**	**0.0**	**0.0**	**(265.5)**
NLH Cost	**1,131.9**	**0.0**	**0.0**	**1,131.9**

Operating Experience:

The current AS400 server was installed in 1997 and upgraded twice over the past seven years. In 2002 after being leased for five years, the AS400 computer was purchased and additional disk storage was added to meet corporate requirements. The current disk storage capacity is at a capacity level of 70 - 75% which is the maximum level recommended by IBM in order to ensure optimal performance of applications. This Project was included in the 2004 Corporate Budget Application as part of the End User & Server Evergreen Program but was not approved. It was not resubmitted as other components of that project were, as it was felt that if we could keep disk space growth at a minimum, we could continue to use the existing server for an additional year.

Project Justification:

This project will ensure the future of Hydro's core financial applications on a supported hardware and operating system platform.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: iSeries Replacement **(cont'd.)**

Project Justification: (cont'd.)

The workload from the AS400 system can be handled by the new iSeries Server. This new system can be attached to the shared disk system to provide less expensive and better managed disk storage. This proposed replacement for the AS400, has a projected life of five to seven years and will ensure continued and reliable service.

Future Plans:

None.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: End User Evergreen Program

Location: St. John's

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This is the third year of the end-user workstation evergreen program and will replace 211 desktop and laptop computers used by Hydro employees and continues with the implementation of thin client technology strategy. The proposed end user workstations are planned to be refreshed based on industry standard lifecycles (3 years-Laptop, 4 years-Desktop and 5 years-Thin Client) and the device (thin client, desktop, laptop) will be determined by an analysis of the work needs of each user.

The project will also upgrade the operating system that runs these computers to the 2005 standard. The project comprises the third year of Hydro's strategy to reduce the total cost of acquiring and supporting the computers used by employees. The thin client technology strategy is the least cost option and was approved by the Board for 2003 and 2004.

The computers to be replaced through the End User Evergreen Project are leased and must be returned to the vendor or purchased starting in the first quarter of 2005. Hydro plans to return the leased computers to the vendor and purchase new desktop, laptop and thin client computers. A thin client is a network computer without a hard disk drive and accesses and runs applications located on a shared server. In order to reduce ongoing support costs, Hydro also plans to install the current operating system on the new computers that is consistent with other computers at Hydro and which is supported by the vendor.

The planned distribution of the hardware, licenses and related purchase cost follow:

Device	Number	Cost ($)	Total ($)
Laptops	71	2,900	205,900
Desktops	40	1,650	66,000
Thin Clients	100	1,225	122,500
Servers	4	10,100	40,400
Thin Client Licenses	211	325	68,575
		Total	503,375

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: End User Evergreen Program **(cont'd.)**

Project Description: (cont'd.)

The third party installation cost of all equipment is $98,000 and includes travel expenses, return of leased equipment and cost to install software which is not part of the corporate standard (specialized limited applications).

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	503.4	0.0	0.0	503.4
Labour	98.0	0.0	0.0	98.0
Engineering	0.0	0.0	0.0	0.0
Project Management	24.0	0.0	0.0	24.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	85.1	0.0	0.0	85.1
Total	710.5	0.0	0.0	710.5

Operating Experience:

The End User Evergreen Program for 2005 is the third year of the program presented to the Board as part of the 2003 Capital Budget proposal. Through this program, Hydro plans to reduce the cost of acquiring and supporting the computers used by employees by using "thin client technology" and standard types of computers, operating systems and collections of applications.

This strategy is the least cost option and was approved by the Board for 2003 and 2004.

The anticipated efficiencies gained through standardizing computer hardware and software allowed Hydro to eliminate three Client Support Analyst positions in the IS&T department.

Project Justification:

The End User Evergreen Program for 2005 continues as Hydro's strategy to reduce the total lifecycle cost of acquiring and supporting the computers used by its employees. Hydro plans to return the 211 computers with leases that expire in 2005 to the vendor and purchase new desktop, laptop and thin client computers. Further, Hydro plans to install an operating system on the new units that is consistent with other computers at Hydro and which is supported by the vendor.

In setting the direction outlined for 2005, Hydro did consider the option of returning leased equipment and not replacing it. This option is not acceptable to the Corporation. The decision to not replace one-third of the computers used by employees would have a significant negative impact on Hydro's

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: End User Evergreen Program 2004 **(cont'd.)**

Project Justification: (cont'd.)
business. Computers are required for a range of tasks including monitoring and troubleshooting the power system, financial analysis, and communication. Without computers Hydro employees would not be able to perform the functions required to deliver services to our customers and manage our business.

Hydro also reviewed the options outlined in its 2003 capital budget submission. These options include:

1. Continue with the evergreen program with thin client technology;

2. Purchase the computers as leases expire off lease and upgrade the operating system (no thin client computers); and

3. Extend the lease and upgrade the operating system (no thin client computers).

The approach recommended by Hydro in 2003 and 2004, and accepted by the Board, was to move forward with the implementation of thin client technology. This approach is the least cost alternative of the 3 options and supports Hydro's strategy to reduce the total cost of ownership (TCO) for employee computers.

It should be noted that for each of the options outlined, the operating system would be upgraded to a version supported by the vendor. Not upgrading the operating system in one-third of the Corporation's computers will place the Corporation at risk because users will not have vendor support and security patches will no longer be available to defend against virus attacks.

In evaluating its options for 2005, Hydro again focused on identifying the direction that would provide the lowest total cost over the life of its computers. Continuing to use thin client technology will result in the least cost capital replacement alternative. Further, in order to achieve the projected financial benefits of the thin client technology, it is necessary to complete the remaining elements and years of the program. By maximizing the deployment of thin client devices, Hydro can achieve a lower total cost of ownership over the lifecycle of these devices and improved efficiency through standardization

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: End User Evergreen Program 2004 **(cont'd.)**

Project Justification: (cont'd.)

and reduced support requirements. This continued implementation of the thin client environment is fundamental in order for Hydro to continue to reduce the total cost of its IT infrastructure. A change in this strategy now will increase demands for additional computer support and would therefore increase Hydro's operating costs.

Future Plans:

This will be an on-going refresh program. The cycle will be over 3-5 years based on the device.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Peripheral Infrastructure Replacement

Location: Hydro System

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This project consists of the replacement of peripherals**.** In 2005 two multi-function devices (MFDs) and several smaller laser printers and projectors are scheduled to be installed.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	90.0	0.0	0.0	90.0
Labour	10.0	0.0	0.0	10.0
Engineering	0.0	0.0	0.0	0.0
Project Management	4.0	0.0	0.0	4.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	13.6	0.0	0.0	13.6
Total	117.6	0.0	0.0	117.6

Operating Experience:

As the age of the peripherals increase and usage accumulates so does the operating and maintenance expenses. Typical life for peripheral devices is five years.

Project Justification:

This is the continuation of the evergreen program to replace the peripheral devices as they reach the end of their useful life. This refresh will address printers, MFDs, scanners and projectors. It is estimated that two MFD's and several smaller laser printers and projectors will be replaced, however this is subject to change depending on failures and a reprioritization of the needs.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Security Strategy Deployment

Location: Hydro Place

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

The purpose of this project is to develop, implement, test, and maintain a disaster recovery plan (DRP) and site for the data center, and tie this into the overall corporate business continuity initiative. This project will develop the DRP for Hydro's enterprise servers using basic business recovery concepts - risk management, requirements identification, evaluation, plan development, plan testing, and maintenance. The project will include the development of an actual DRP site capable of accommodating our enterprise servers.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	18.0	0.0	0.0	18.0
Labour	45.0	0.0	0.0	45.0
Engineering	0.0	0.0	0.0	0.0
Project Management	25.0	0.0	0.0	25.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	11.4	0.0	0.0	11.4
Sub-Total	**99.4**	**0.0**	**0.0**	**99.4**
Less Cost Recoveries CF(L)Co	**(18.9)**	**0.0**	**0.0**	**(18.9)**
Total	**80.5**	**0.0**	**0.0**	**80.5**

Operating Experience:

Hydro currently has a contract with SunGard to provide a standby site to recover our production enterprise server. This agreement expires in July of 2005. This presents Hydro with the opportunity to re-assess our DRP strategy and direction.

Project Justification:

Disaster recovery planning is a necessity in today's automated world mainly due to the ever-growing dependency upon technology. There are a growing number of technology-related threats (viruses, worms, etc.) in addition to the number of threats from natural disasters (fire, water, power interruption, etc.). Finally, there are ever-increasing legal and regulatory requirements governing the protection of historical and personal information. Based on the renewal date of our agreement with SunGard, it is prudent to plan, develop, test and maintain a DRP and offsite facility, and integrate this

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Security Strategy Deployment **(cont'd.)**

Project Justification: (cont'd.)

with the corporate business continuity initiative. This site would allow the recovery of critical business applications.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Server & Operating Systems Evergreen Program - 2005

Location: Hydro Place

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This project is a part of the Corporation's evergreen program and involves the replacement, addition and upgrade of hardware components and software related to the Corporation's shared server infrastructure and upgrades to the server-based office productivity tools. Based on the age of existing servers, each year an appropriate number of servers will be refreshed. This infrastructure ensures that the Corporation has the reliable, secure infrastructure environment required to support efficient operations.

The Board has previously approved the evergreening approach in 2003 and 2004; 2005 will be the third year of the program. The scope of the proposed Server and Operating System Evergreen Program includes:

- Replacing six obsolete servers at Hydro Place data center and continuing to consolidate servers in a limited number of locations.

- Replacing four obsolete servers in four regional offices with print management devices.

Project Cost: *($ x1,000)*	2005	2006	Beyond	Total
Material Supply	132.5	0.0	0.0	132.5
Labour	42.0	0.0	0.0	42.0
Engineering	0.0	0.0	0.0	0.0
Project Management	12.0	0.0	0.0	12.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	25.4	0.0	0.0	25.4
Total	**211.9**	**0.0**	**0.0**	**211.9**

Operating Experience:

The Server and Operating System and Evergreen Program addresses the purchase and implementation of the hardware and software required to effectively operate the Corporation's shared servers. These servers are the computers that house the applications that have multiple users throughout the organization.

Hydro uses its existing servers for: office productivity tools (e.g. Word, Excel); e-mail; internet, intranet, various database systems as well as the software tools required to monitor and manage the

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Server & Operating Systems Evergreen Program – 2005 **(cont'd.)**

Operating Experience: (cont'd.)
servers, end user devices and the related security. Ten of Hydro's current servers are technically obsolete and cannot maintain the server operating system software supported by the vendor.

Project Justification:
Hydro needs to keep its server and operating systems current in order to adequately support and protect the IT infrastructure required to operate its business. Failure to keep this infrastructure current will put Hydro at risk. The replacement, addition and upgrading of hardware components to achieve this goal requires investment over the lifecycle of the infrastructure.

The factors that are driving Hydro's proposal to replace/upgrade its server environment include:
- Addressing obsolescence/maintaining vendor support;
- Providing security/managing the Infrastructure;
- Supporting current versions of applications; and,
- Exploiting technology advances.

<u>Obsolescence/Vendor Support</u> - Without vendor support, the functions and services reliant on the server infrastructure are at risk as security and support patches for the operating system will no longer be available. As a result, Hydro's ability to support and ensure continuation of the functions and services is impeded.

<u>Servers</u> - Industry standards indicate that due to technical and physical obsolescence, server devices have a useful life of five years and beyond that timeframe, reliability and continued support become issues. While Hydro has extended the life of many of its servers, 25% of the shared servers are five years of age or older and at this time ten servers are proposed for replacement. The disc storage capacity of these servers cannot be upgraded due to technical obsolescence. As well, the server infrastructure cannot be integrated with the disk storage in the storage area network (SAN) because of physical and technical obsolescence. Of the ten servers proposed for replacement, none can support the version of the operating system that will be current in 2005.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Server & Operating Systems Evergreen Program – 2005 **(cont'd.)**

Project Justification: (cont'd)

Summary

The replacement, addition and upgrade of hardware components and software related to the Corporation's shared server infrastructure will allow Hydro to operate in a supported environment to the 2008-2009 time frame and allow Hydro to take advantage of the functionally and enhancements included within the new release. There will however be ongoing investment required in the server environment to ensure the ongoing reliability of the applications required to conduct our business efficiently.

Servers - Hydro is proposing that ten existing servers be replaced. These servers meet or exceed the life expectancy of five years and are not capable of supporting current server operating system. This replacement effort will also involve the continued consolidation of servers in St. John's.

Operating System - Hydro is proposing that the operating system on all servers be upgraded to the current release that will be supported by the vendor until 2008-2009.

Future Plans:

This will be an on-going refresh program. The cycle will be over five years. Costs will vary slightly from year to year as servers reach the end of their life cycle. On going efforts will look to further the consolidation process both at the location and hardware levels.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace VHF Mobile Radio System

Location: Various

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This project involves the replacement of the Corporation's existing VHF mobile radio system with a new system that will meet the coverage and access requirements of the user group. The scope of work will include the replacement of a central switch located in Gander, equipment at 29 repeater sites, approximately 300 mobile and base station radios, and approximately 100 portable radios. The proposed system will expand to 39 sites in order to provide the additional coverage as identified by the user group.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	2,194.9	3,342.3	0.0	5,537.2
Labour	152.0	307.5	0.0	459.5
Engineering	216.6	160.1	0.0	376.7
Project Management	79.9	78.5	0.0	158.4
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	271.4	1,585.2	0.0	1,856.6
Total	**2,914.8**	**5,473.6**	**0.0**	**8,388.4**

Operating Experience:

The existing system was purchased in 1989. The components of the current system are manufacturer discontinued and spare parts are no longer available for many critical subsystems. The system has experienced an increasing rate of failure in recent years, resulting in reduced availability. Trained resources, knowledgeable about the system are no longer present at Aliant, who maintain a substantial portion of the system under contract, which puts the system at risk.

Project Justification:

The increased failures over the last few years, the manufacturer discontinued equipment, the unavailability of spare parts, the lack of trained resources, and operational issues with the existing coverage as identified by the user group justifies the replacement of the existing VHF mobile radio system. The intent is to replace the existing system with a standards-based mobile radio system, which will protect the Corporation's investment in the long term since the system would not be tied to a single manufacturer.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Replace VHF Mobile Radio System **(cont'd.)**

Project Justification: (cont'd.)

The required documentation addressing the Board's Order No. P.U. 29 (2003) is attached in Section G, Appendix 4.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Replace Battery System - Multiple Sites

Location: Cat Arm, Godaleich Hill, Plum Point & Bear Cove

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This project consists of the supply and installation of five 48 VDC battery systems at the Cat Arm Intake, Cat Arm Plant, Godaleich Hill Microwave Site, Plum Point Terminal Station and Bear Cove Terminal Station. This includes 48 VDC rectifiers, battery banks, battery racks and associated cabling. For small sites, the rectifier rack replacement also includes replacement of the 48 VDC distribution.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	183.2	0.0	0.0	183.2
Labour	66.8	0.0	0.0	66.8
Engineering	25.0	0.0	0.0	25.0
Project Management	11.4	0.0	0.0	11.4
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	77.6	0.0	0.0	77.6
Total	**364.0**	**0.0**	**0.0**	**364.0**

Operating Experience:

The flooded cell battery banks being proposed for replacement are all at least twenty years old. The non-flood cell battery banks being proposed for replacement are ten years old. Yearly capacity and conductive tests confirm the natural, expected degradation with time for these types of batteries.

Project Justification:

This replacement is necessary to provide emergency power to equipment required for the remote control and monitoring of Hydro’s transmission and generation system and is justified on reliability considerations. Failure to replace this equipment is likely to result in a battery bank failure or reduced reliability which could extend or cause customer outages. The flooded batteries have been in operation for at least twenty years and have exceeded the twenty-year design life which is the industry standard life expectancy of large stationary batteries of the flooded cell type. In some sites, cell plates are warping and showing signs of deterioration or there is significant corrosion of battery terminals. As well, the capacitors in some older types of rectifiers are deteriorating as expected with equipment of this age. A failure is likely after the battery design life is exceeded.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Battery System - Multiple Sites **(cont'd.)**

Project Justification: (cont'd.)

The non-flooded batteries at Plum Point and Bear Cove will be ten years old in 2005. Non-flooded batteries have demonstrated service life in the range of seven - eight years depending on the conditions in which the battery operates.

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Microwave Site Refurbishing

Location: Mary March Hill

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This project involves the refurbishing of the West Coast microwave site at Mary March Hill. In particular the work includes:

1. the tower painting;
2. anchor heads field galvanized;
3. guys at level 4 will be replaced; and
4. a detailed electrical system assessment.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	224.4	0.0	0.0	224.4
Labour	0.0	0.0	0.0	0.0
Engineering	1.6	0.0	0.0	1.6
Project Management	5.3	0.0	0.0	5.3
Inspection & Commissioning	6.8	0.0	0.0	6.8
Corp O/H, AFUDC, Esc. & Contingency	55.7	0.0	0.0	55.7
Total	293.8	0.0	0.0	293.8

Operating Experience:

The tower and building at Mary March Hill were installed in 1980. The Mary March Hill site has not been refurbished since being constructed twenty-five years ago.

Project Justification:

The Mary March Hill Microwave site requires some upgrading to ensure that the site's infrastructure condition does not further deteriorate. The microwave sites are a major part of the critical infrastructure that supports the operation and control of the Provincial electrical grid. In order to maximize the useful life of its microwave infrastructure, Hydro periodically evaluates the condition of its towers and associated infrastructure. Included in this evaluation are tower and anchor foundations, guy wires, paint, radomes, wave-guides, light and electrical systems, air conditioners, structure integrity of building and building foundations plus any miscellaneous components that may need repair or replacement. To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Microwave Site Refurbishing **(cont'd.)**

Project Justification: (cont'd.)

To ensure that this project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

This project is part of an IS&T program to refurbish and extend the life of the microwave sites infrastructure. Other locations will be proposed for refurbishment once identified through inspection.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Remote Terminal Units for Hydro - Phase 6

Location: Bay d'Espoir Plant and Bay d'Espoir Terminal Station

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This project consists of the replacement of two Quindar Remote Terminal Units (RTUs) used for remote monitoring and control of plants and terminal stations from the Energy Control Center. The sites are the Bay d'Espoir Plant and the Bay d'Espoir Terminal Station. This is phase 6 of a 9-phase plan to replace all obsolete RTUs.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	75.2	0.0	0.0	75.2
Labour	30.2	0.0	0.0	30.2
Engineering	12.5	0.0	0.0	12.5
Project Management	4.2	0.0	0.0	4.2
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	27.4	0.0	0.0	27.4
Total	**149.5**	**0.0**	**0.0**	**149.5**

Operating Experience:

The existing RTUs were installed in 1990. Third party spares and repair services are not available.

Project Justification:

This replacement is necessary to ensure control and monitoring capabilities of Hydro's transmission and generation facilities as the equipment is no longer supported by the equipment manufacturer and spares are no longer available for these systems. Failure to replace this equipment will result in reduced reliability and extend or cause customer outages. Failures of RTUs can prevent the Energy Control Center from being able to dispatch generation at those particular sites or not being able to control the water at the various structures at the Bay d'Espoir facility. The RTUs permit the operation of these systems without having people present twenty-four hours a day. The Bay d'Espoir RTUs are located at one of the most critical system sites with the largest generation capacity.

Future Plans:

None in this phase.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Replace Air Conditioners

Location: Stoney Brook & Deer Lake

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This project consists of the replacement of the air conditioning systems in the communications rooms at Stoney Brook Terminal Station and the Deer Lake Office.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	34.5	0.0	0.0	34.5
Labour	1.7	0.0	0.0	1.7
Engineering	7.2	0.0	0.0	7.2
Project Management	0.7	0.0	0.0	0.7
Inspection & Commissioning	0.3	0.0	0.0	0.3
Corp O/H, AFUDC, Esc. & Contingency	10.9	0.0	0.0	10.9
Total	**55.3**	**0.0**	**0.0**	**55.3**

Operating Experience:

The air conditioner at Stoney Brook is an original unit installed and is approximately fifteen years old. Heating and humidification are not functioning and cannot be repaired because the required parts are not available.

The air conditioning at Deer Lake Office is inadequate and does not meet the requirement of indoor Air Quality Assessment.

Project Justification:

These units will need to be replaced because they have reached the end of their serviceable life and are required to maintain an environment that is suitable for the operation of communications and control equipment used to support Hydro's transmission and generation facilities. These units are obsolete and parts are no longer available.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Replacement of Operational Data & Voice Network - Phase 2

Location: St. John's

Division: Production

Classification: Information Systems & Telecommunications

Project Description:

This proposal is a continuation of a project for which the Board has approved funds for 2004. This project is a two-year program to plan, design and install a wide area network (WAN) communications infrastructure to replace the existing operational data (SCADA) and operational voice network. This will provide an architecture that can support the operational data, administrative data and voice traffic over a standard network infrastructure.

Project Cost: *($ x1,000)*	**2004**	**2005**	**2006**	**Beyond**	**Total**
Material Supply	512.0	503.0	0.0	0.0	1,015.0
Labour	180.0	228.0	0.0	0.0	408.0
Engineering	199.0	199.0	0.0	0.0	398.0
Project Management	33.0	37.8	0.0	0.0	70.8
Inspection & Commissioning	0.0	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	47.0	279.0	0.0	0.0	326.0
Total	971.0	1,246.8	0.0	0.0	2,217.8

Operating Experience:

The existing operational data network was installed in 1988, and is now fifteen year-old technology. The equipment was designed to carry the operational data between the RTUs and the Energy Management System (Harris) at Hydro Place, and operational voice traffic between the sub-stations & plants and the Energy Control Centre (ECC).

The equipment is at the end of its useful life and the manufacturer no longer supports the software.

Project Justification:

The Telecommunications Plan (Table 5, page 19), which was submitted to the Board as part of Hydro's 2003 Capital Budget Application (Section H), indicates that the equipment Hydro has installed over the past fifteen years is no longer under development and many components have been manufacturer discontinued for a number of years.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replacement of Operational Data & Voice Network - Phase 2 **(cont'd.)**

Project Justification (cont'd):

The operational, administrative and voice traffic currently run on separate communications equipment and standards. This upgrade would combine these services into one communications system with common equipment and standards. This would decrease the demands on staff to be trained to support different communications protocols and equipment.

This upgraded communications network will support all applications and devices that have a standard protocol (IP centric). All existing administrative applications support this protocol and the upgrade to the Energy Management System will have this as a requirement. All new RTU devices will have IP as a communications protocol. This new technology will provide added functionality, reliability and manageability.

Integrating all applications and devices, including SCADA, onto a single communications platform will streamline operational activities and improve overall management and control of the WAN. The improved reliability will benefit the power grid management, provide better control and reduce operational costs.

To ensure that the project will be completed at the lowest possible cost, Hydro will solicit competitive bids for all materials and external labour.

Future Plans:

There are no further plans under consideration at this time.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Vehicles - 2004

Location: System Wide

Division: Transmission & Rural Operations

Classification: Administrative

Project Description:

This project for 2005 is the continuation of a project for which the Board approved funds for 2004. The project involves replacing twenty-six light vehicles (cars, pick-ups and vans) and seven medium/heavy vehicles (line trucks and boom trucks).

Project Cost: *($ x1,000)*	2004	2005	Beyond	Total
Material Supply	1,020.0	300.0	0.0	1,320.0
Labour	0.0	0.0	0.0	0.0
Engineering	10.0	10.0	0.0	20.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	51.2	140.0	0.0	191.2
Total	1,081.2	450.0	0.0	1,531.2

Operating Experience:

It has been Hydro's experience that vehicles experience increased downtime and decreased reliability as they reach the replacement criteria outlined below.

REPLACEMENT CRITERIA VEHICLES			
Category	**Description**	**REPLACEMENT CRITERIA**	
		Age	**Other**
1000	Cars/Mini-vans	5-7 yrs.	>150,000 kms, maintenance cost, condition
2000	Pick-ups/Service Vans	5-7 yrs.	>150,000 kms, maintenance cost, condition
3000	Light Trucks	6-8 yrs.	>180,000 kms, maintenance cost, condition
4000	Medium/Heavy Trucks	7-9 yrs.	>200,000 kms, maintenance cost, condition

Category 1000 and 2000 vehicles being replaced will generally have an average age of six years and 150,000 km, while category 3000 will have an average age of eleven years and 100,000 km and category 4000 will have an average age of ten years and 200,000 km.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Vehicles - Hydro System - 2004 **(cont'd.)**

Project Justification:
New vehicle replacements are required in order to ensure maximum reliability with minimum equipment downtime. Having work crews equipped with reliable and technologically current work vehicles, ensures their safety while at the same time enhancing efficient delivery of services. Operating vehicles beyond their economical life cycle will result in delays to work crews and have a negative impact on customer service.

Vehicles are screened against the replacement criteria before being identified for replacement. When a unit has met the age or kilometer criteria, the unit is further evaluated for its condition and maintenance history.

The budget allocations for each class of vehicle is shown below.

Vehicle Class	Budget Amount
1000 (Cars/Mini-vans)	$ 300,000
2000 (Pick-up/ Service Vans)	711,200
3000 (Light Trucks)	80,000
4000 (Medium/Heavy Trucks)	300,000
Contingency	140,000
Total	**$ 1,531,200**

New vehicles are acquired through competitive tendering with a lease/purchase analysis used to determine the least cost alternative.

Future Plans:
Categories 1000, 2000, and 3000 vehicles were purchased and delivered in 2004. However due to long delivery schedules of category 4000 vehicles, these vehicles will not be delivered until 2005.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Vehicles - 2005

Location: System Wide

Division: Transmission & Rural Operations

Classification: Administrative

Project Description:

This project involves replacing thirty light vehicles (cars, pick-ups and vans) and one medium/heavy vehicle (line trucks and boom trucks).

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	771.0	0.0	0.0	771.0
Labour	0.0	0.0	0.0	0.0
Engineering	10.0	0.0	0.0	10.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	96.6	0.0	0.0	96.6
Total	**877.6**	**0.0**	**0.0**	**877.6**

Operating Experience:

It has been Hydro's experience that vehicles experience increased downtime and decreased reliability as they reach the replacement criteria outlined below.

REPLACEMENT CRITERIA VEHICLES			
Category	**Description**	**REPLACEMENT CRITERIA**	
		Age	**Other**
1000	Cars/Mini-vans	5-7 yrs.	>150,000 kms, maintenance cost, condition
2000	Pick-ups/Service Vans	5-7 yrs.	>150,000 kms, maintenance cost, condition
3000	Light Trucks	6-8 yrs.	>180,000 kms, maintenance cost, condition
4000	Medium/Heavy Trucks	7-9 yrs.	>200,000 kms, maintenance cost, condition

Category 1000 and 2000 vehicles being replaced will generally have an average age of seven years and 165,000 km, while category 3000 will have an average age of seven years and 220,000 km and category 4000 will have an average age of ten years and 200,000 km.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Replace Vehicles - Hydro System - 2005 **(cont'd.)**

Project Justification:
New vehicle replacements are required in order to ensure maximum reliability with minimum equipment downtime. Having work crews equipped with reliable and technologically current work vehicles, ensures their safety while at the same time enhancing efficient delivery of services. Operating vehicles beyond their economical life cycle will result in delays for work crews and have a negative impact on customer service.

Vehicles are screened against the replacement criteria before being identified for replacement. When a unit has met the age or kilometer criteria, the unit is further evaluated for its condition and maintenance history.

The budget allocations for each class of vehicle is shown below.

Vehicle Class	Budget Amount
1000 (Cars/Mini-vans)	$ 275,000
2000 (Pick-up/ Service Vans)	465,500
3000 (Light Trucks)	60,000
4000 (Medium/Heavy Trucks)	0
Contingency	77,100
Total	**877,600**

New vehicles are acquired through competitive tendering with a lease/purchase analysis used to determine the least cost alternative.

Future Plans:
None.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Electronic Metering Reading

Location: Hydro Place

Division: Finance

Classification: Administrative

Project Description:

This project for 2005 is the continuation of a project for which the Board approved funds for 2004. This project consists of a study to provide recommendations on a replacement system for the currently used meter-reading units (the Radix FW200) in 2004 and to purchase equipment and install the system in 2005.

Project Cost: *($ x1,000)*	**2004**	**2005**	**Beyond**	**Total**
Material Supply	0.0	180.0	0.0	180.0
Labour	35.0	35.0	0.0	70.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	0.8	8.5	0.0	9.3
Total	**35.8**	**223.5**	**0.0**	**259.3**

Operating Experience:

A total of twenty-eight metering-reading software were purchased in 1998 and since that time, five have been repaired, three in 2002 and two in 2003.

Project Justification:

The handheld meter-reading units facilitate meter reading and billing processes. Hydro has been notified by the Radix Corporation that the FW200 handheld meter-reading unit presently being used by Hydro was phased out in 2003, however, they will support Hydro's system through 2005. The equipment estimate used for this budget is based on prices provided by the Radix Corporation to upgrade to the FW300 handheld model but other suppliers will be evaluated. As well, Hydro is currently evaluating an automatic meter-reading option using power line carrier technology.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Replacement of Chiller

Location: Hydro Place

Division: Human Resources & Legal

Classification: Administrative

Project Description:

This project involves the disposal of existing Trane HVAC chiller at Hydro Place and replacement with a chiller unit which complies with revised government regulations for refrigerants.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	200.0	0.0	0.0	200.0
Labour	0.0	0.0	0.0	0.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	13.3	0.0	0.0	13.3
Total	**213.3**	**0.0**	**0.0**	**213.3**

Operating Experience:

The existing Trane chiller is original equipment installed in 1989 and is normally operational from May through September each year. The HVAC chiller is under an annual service agreement with Johnson Controls Ltd and has been periodically upgraded to meet changes in regulations governing its operation.

Project Justification:

The installed Trane chiller uses R-11 refrigerant, a chlorofluorocarbon (CFC), the production of which was banned in Canada as of December 1995 and its use and refill in existing chillers is prohibited after January 2005. The normal life expectancy of a chiller is between 20 - 25 years and the existing unit is 15 years old. The cost to retrofit the existing chiller from R-11 is estimated at between $120 to - $150 thousand. Johnson Controls Ltd. recommend a replacement rather than retrofit the fifteen-year old Trane HVAC chiller unit in light of the concern with respect to the refrigerant and future availability of replacement parts. A cost benefit analysis indicates it is more cost effective to replace the unit.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Security Assessment of System Operations

Location: Hydro Place

Division: Finance

Classification: Administrative

Project Description

This project consists of having a consultant perform a security risk assessment of critical facilities on the interconnected and isolated systems.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	100.0	0.0	0.0	100.0
Engineering	0.0	0.0	0.0	0.0
Project Management	10.0	0.0	0.0	10.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	0.0	0.0	0.0	0.0
Total	**110.0**	**0.0**	**0.0**	**110.0**

Operating Experience

The interconnected and isolated systems have been operating for approximately forty years. Hydro has had several major outages, mainly due to weather-related causes on the Avalon and Great Northern peninsulas. In addition, there have been three isolated system outages that were fire-related. Finally, our terminal stations and microwave sites have been subjected to theft and vandalism on many occasions. The theft incidents besides endangering the public and Hydro's ability to provide service also is an added risk to our employees, as the focus of these thefts is the copper grounding systems.

Project Justification

This project will be the first risk assessment of their facilities. This information will assist in developing risk management techniques to eliminate or reduce the potential exposures and increase security at critical facility locations.

Future Plans

Future costs for security improvements will be determined by this project. By completing the risk assessment, it will permit an orderly planning of the work necessary to eliminate or reduce the exposures to our facilities. It is expected this will increase operational reliability and employee safety.

2005 CAPITAL PROJECTS OVER $50,000 EXPLANATIONS

Project Title: Upgrade Standby Diesel Fuel System

Location: Hydro Place

Division: Human Resources & Legal

Classification: Administrative

Project Description:

The project involves upgrading the existing fuel system for the Hydro Place standby diesel generator to meet provincial regulations for Storage and Handling of Gasoline and Associated Products. The project consists of:

- obtaining necessary permits;
- performing site environmental testing (site remediation, if required, is not covered under this proposal;
- replacing primary storage tanks, day tanks, and fuel transfer piping with approved equipment; and,
- Installing compliant fuel metering system and approved automatic fuel transfer system and controls.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	40.0	0.0	0.0	40.0
Labour	25.7	0.0	0.0	25.7
Engineering	6.0	0.0	0.0	6.0
Project Management	1.5	0.0	0.0	1.5
Inspection & Commissioning	0.3	0.0	0.0	0.3
Corp O/H, AFUDC, Esc. & Contingency	17.3	0.0	0.0	17.3
Total	**90.8**	**0.0**	**0.0**	**90.8**

Operating Experience:

The existing diesel fuel storage system is designed with sufficient capacity to provide fuel to power the Energy Control Center for seven days. Due to the system configuration, fuel usage cannot be reconciled.

Project Justification:

A 2002 environmental audit, highlighted that the existing fuel storage system does not comply with provincial regulations with regards to fuel reconciliation requirements. As well, the existing day tanks are not ULC certified and there is no secondary containment designed into the day tank system.

Future Plans:

None.

2005 CAPITAL PROJECTS OVER $50,000
EXPLANATIONS

Project Title: Reconstruct Storage Ramps

Location: Bishop's Falls

Division: Human Resources & Legal

Classification: Administrative

Project Description:

This project consists of the re-construction of two outside storage ramps, 3 m by 60 m at the Bishop's Falls Central Stores facility. The ramps are to be constructed of steel posts supporting steel beams with treated timber decking.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**Total**
Material Supply	35.0	0.0	0.0	35.0
Labour	35.0	0.0	0.0	35.0
Engineering	0.0	0.0	0.0	0.0
Project Management	0.0	0.0	0.0	0.0
Inspection & Commissioning	0.0	0.0	0.0	0.0
Corp O/H, AFUDC, Esc. & Contingency	2.8	0.0	0.0	2.8
Total	**72.8**	**0.0**	**0.0**	**72.8**

Operating Experience:

The existing all wood ramps in the Central Stores yard are twenty-five years old and are in a deteriorated condition.

Project Justification:

Equipment and materials stored on these ramps are both heavy and costly. Given the deteriorated condition, there are concerns regarding personnel safety and protection of the stored assets.

Future Plans:

None.

SECTION C

HYDRO

PROJECTS SUBJECT TO MINIMUM FILING REQUIREMENTS - OVERVIEW

There are no projects in the 2005 Capital Budget that meet the minimum filing requirements

SECTION D

HYDRO

2005 LEASING COSTS

ITEM	***2005 COST***
Office Space – Happy Valley/Goose Bay	63,581
It is anticipated that this lease will be renewed in 2005	

SECTION E

Capital Expenditures/Budgets 1999 - 2008
($000)

	ACTUALS 1999	ACTUALS 2000	ACTUALS 2001	ACTUALS 2002	ACTUALS 2003	FORECAST 2004	BUDGET 2005	BUDGET 2006	BUDGET 2007	BUDGET 2008
GENERATION	8,185	3,463	3,956	5,233	5,572	4,780	6,142	6,543	15,387	1,004
TRANSMISSION & RURAL OPERATIONS	24,711	28,658	28,929	29,560	9,961	13,082	20,422	18,916	10,370	7,803
GENERAL PROPERTIES	3,757	6,442	14,616	5,424	16,973	10,903	15,867	17,082	8,086	8,452
TOTAL CAPITAL EXPENDITURES	36,653	38,563	47,501	40,217	32,506	28,765	42,431	42,541	33,843	17,259

SECTION F

NEWFOUNDLAND & LABRADOR HYDRO

2004 CAPITAL EXPENDITURES - OVERVIEW

FOR THE QUARTER ENDING JUNE 30, 2004
($,000)

	Expenditures Prior To 2004	PUB Approved Budget 2004	2004 Expenditures To June 30	Expected Remaining Expenditures 2004	Expected Total Expenditures 2004	Var. from Approved to Expected Expenditures
GENERATION	191	4,049	1,160	2,897	4,057	8
TRANSMISSION & RURAL OPERATIONS	1,159	11,999	3,126	8,976	12,102	244
GENERAL PROPERTIES	2,633	11,350	1,808	6,654	8,968	(2,382)
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	0	1,000	1,000	0
PROJECTS APPROVED BY PUB	62	2,703	648	1,797	2,445	0
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	18	189	44	149	193	4
TOTAL CAPITAL BUDGET	4,063	31,290	6,786	21,473	28,765	(2,126)

Approved PU 29 (2003)	27,316
Approved PU 5 (2004)	1,534
Approved PU 13 (2004)	303
Approved PU 16 (2004)	465
Approved PU 28 (2004)	258
Carryover Projects	1,255
New Projects Under $ 50,000 Approved by Hydro	159
Revised TOTAL CAPITAL BUDGET	31,290

NEWFOUNDLAND & LABRADOR HYDRO

2004 CAPITAL EXPENDITURES - OVERVIEW

FOR THE QUARTER ENDING JUNE 30, 2004
($,000)

	Expenditures Prior To 2004	PUB Approved Budget 2004	2004 Expenditures To June 30	Expected Remaining Expenditures 2004	Expected Total Expenditures 2004	Var. from Approved to Expected Expenditures	
GENERATION							
HYDRO PLANTS							
Construction Projects	191	1,474	451	1,036	1,487	13	3
Tools & Equipment	0	194	126	63	189	(5)	3
THERMAL PLANT							
Construction Projects	0	2,281	582	1,699	2,281	0	3
Property Additions	0	78	1	77	78	0	3
Tools & Equipment	0	22	0	22	22	0	3
TOTAL GENERATION	191	4,049	1,160	2,897	4,057	8	
TRANSMISSION & RURAL OPERATIONS							
TRANSMISSION	401	3,926	318	4,216	4,534	608	4
SYSTEM PERFORMANCE & PROTECTION	0	303	103	203	306	3	4
TERMINALS	165	1,690	194	1,355	1,549	0	4
DISTRIBUTION	0	5,153	2,063	2,816	4,879	(274)	5
GENERATION	593	238	94	124	218	(20)	5
GENERAL							
Metering	0	104	15	90	105	1	5
Properties	0	49	3	46	49	0	5
Tools & Equipment	0	536	336	126	462	(74)	5
TOTAL TRANSMISSION & RURAL OPERATIONS	1,159	11,999	3,126	8,976	12,102	244	
GENERAL PROPERTIES							
INFORMATION SYSTEMS & TELECOMMUNICATIONS	1,495	8,512	964	4,701	6,171	(2,341)	6
ADMINISTRATIVE	1,138	2,838	844	1,953	2,797	(41)	6
TOTAL GENERAL PROPERTIES	2,633	11,350	1,808	6,654	8,968	(2,382)	
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	0	1,000	1,000	0	8
PROJECTS APPROVED BY PUB	62	2,703	648	1,797	2,445	0	8
PROJECTS APPROVED FOR LESS THAN $50,000	18	189	44	149	193	4	8
TOTAL CAPITAL BUDGET	4,063	31,290	6,786	21,473	28,765	(2,126)	

NEWFOUNDLAND & LABRADOR HYDRO
GENERATION
2004 CAPITAL EXPENDITURES - DETAIL
FOR THE QUARTER ENDING JUNE 30, 2004
($,000)

PROJECT DESCRIPTION	Expenditures Prior To 2004	PUB Approved Budget 2004	2004 Expenditures To June 30	Expected Remaining Expenditures 2004	Expected Total Expenditures 2004	Var. from Approved to Expected Expenditures	Variance Explanation Reference
HYDRO PLANTS							
CONSTRUCTION PROJECTS							
Replace Vibration/Data System - Bay D'Espoir	179	18	19	0	19	1	
Replace Unit 7 Exciter - Bay D'Espoir	10	760	195	565	760	0	
Replace Gate Hoist No. 2 - Ebbegunbaeg Control Structure	2	513	42	471	513	0	
Upgrade Controls Spherical Valve #3 - Bay D' Espoir		183	195	0	195	12	
TOTAL CONSTRUCTION PROJECTS	191	1,474	451	1,036	1,487	13	
TOOLS & EQUIPMENT							
Replace Loader/Backhoe - Bay d'Espoir	0	124	119	0	119	(5)	
Purchase & Replace Tools & Equipment Less than $50,000	0	70	7	63	70	0	
TOTAL TOOLS & EQUIPMENT	0	194	126	63	189	(5)	
THERMAL PLANT							
CONSTRUCTION PROJECTS							
Upgrade Control System - Holyrood		1,553	570	983	1,553	0	
Purch/Inst Ambient Monitoring System Enhancement		728	12	716	728	0	
TOTAL CONSTRUCTION PROJECTS	0	2,281	582	1,699	2,281	0	
PROPERTY ADDITIONS							
Upgrade Civil Structures - Holyrood		78	1	77	78	0	
TOTAL PROPERTY ADDITIONS	0	78	1	77	78	0	
TOOLS & EQUIPMENT							
Purchase & Replace Tools & Equipment Less than $50,000	0	22	0	22	22	0	
TOTAL TOOLS & EQUIPMENT	0	22	0	22	22	0	
TOTAL GENERATION	191	4,049	1,160	2,897	4,057	8	

NEWFOUNDLAND & LABRADOR HYDRO
TRANSMISSION & RURAL OPERATIONS
2004 CAPITAL EXPENDITURES - DETAIL
FOR THE QUARTER ENDING JUNE 30, 2004

($,000)

PROJECT DESCRIPTION	Expenditures Prior To 2004	PUB Approved Budget 2004	2004 Expenditures To June 30	Expected Remaining Expenditures 2004	Expected Total Expenditures 2004	Var. from Approved to Expected Expenditures	Variance Explanation Reference
TRANSMISSION							
Upgrade TL214 - (138kV Bottom Brook - Doyles)	401	2,546	284	2,870	3,154	608	NOTE 1
Replace Insulators TL233 - (230kV Buchans - Bottom Brook)		1,055	18	1,037	1,055	0	
Replace Wood Poles - Transmission		325	16	309	325	0	
TOTAL TRANSMISSION	401	3,926	318	4,216	4,534	608	
SYSTEM PERFORMANCE & PROTECTION							
Purch/Install 138Kv Breaker Fail Protection Addition - Deer Lake/Sunnyside		150	25	125	150	0	
Replace Digital Fault Recorder - BDE		77	40	37	77	0	
Purchase and Install Remote Relay Data Acquisition Equipment		46	23	23	46	0	
Upgrade Breaker Controls - Western Avalon & Holyrood Terminal Stations		30	15	18	33	3	
TOTAL SYSTEM PERFORMANCE & PROTECTION	0	303	103	203	306	3	
TERMINALS							
Purchase and Install Transformer Addition - Happy Valley Terminal Station	6	1,245	102	1,096	1,198	(47)	
Install Motor Drive Mechanisms on Disconnect Switches - West Coast		207	0	121	121	(86)	NOTE 2
Replace Instrument Transformers		77	37	40	77	0	
Replace Surge Arrestors		70	28	42	70	0	
Upgrade Breaker Controls - Sunnyside Terminal Station	18	15	7	0	7	(8)	
Replace Digital Fault Recorder - Holyrood Terminal Station	70	6	6	0	6	0	
Upgrade Station Services - Long Harbour TS	71	12	8	4	12	0	
Replace 125V Battery Banks - Bottom Brook and Holyrood Terminal Stations	0	58	6	52	58	0	
TOTAL TERMINALS	165	1,690	194	1,355	1,549	(141)	

NEWFOUNDLAND & LABRADOR HYDRO
TRANSMISSION & RURAL OPERATIONS
2004 CAPITAL EXPENDITURES - DETAIL
FOR THE QUARTER ENDING JUNE 30, 2004
($,000)

PROJECT DESCRIPTION	Expenditures Prior To 2004	PUB Approved Budget 2004	2004 Expenditures To June 30	Expected Remaining Expenditures 2004	Expected Total Expenditures 2004	Var. from Approved to Expected Expenditures	Variance Explanation Reference
DISTRIBUTION							
Service Extensions		1,558	714	844	1,558	0	
Distribution Upgrades		1,471	987	484	1,471	0	
Pole Replacements		993	125	739	864	(129)	NOTE 3
Insulator Replacements		945	209	648	857	(88)	NOTE 4
Purchase and Install Recloser L6 - Bear Cove		85	15	64	79	(6)	
Replace Substation Transformer - Rigolet		76	5	22	27	(49)	
Purchase and Install Recloser L1 - Conche		25	8	15	23	(2)	
TOTAL DISTRIBUTION	0	5,153	2,063	2,816	4,879	(274)	
GENERATION							
Protection Upgrades - Isolated Systems	593	33	13	0	13	(20)	
Upgrade Generator Relaying - Happy Valley North Plant		170	79	91	170	0	
Purchase and Install P.T.'s - Ramea		35	2	33	35	0	
TOTAL GENERATION	593	238	94	124	218	(20)	
GENERAL							
METERING							
Purchase Meters & Equipment - TRO System		98	15	83	98	0	
Purchase Metering Spares - Bulk Electrical System		6	0	7	7	1	
TOTAL METERING	0	104	15	90	105	1	
PROPERTIES							
Survey of Hydro's Primary Distribution Line Right-of-Ways		49	3	46	49	0	
TOTAL PROPERTIES	0	49	3	46	49	0	
TOOLS & EQUIPMENT							
Purchase & Replace Tools & Equipment Less than $ 50,000 (Carryover 2003)	0	45	60	0	60	15	
Purchase & Replace Tools & Equipment Less than $ 50,000	0	102	62	40	102	0	
Replace Light Duty Mobile Equipment Less than $50,000		389	214	86	300	(89)	NOTE 5
TOTAL TOOLS & EQUIPMENT	0	536	336	126	462	(74)	
TOTAL GENERAL	0	689	354	262	616	(73)	
TOTAL TRANSMISSION & RURAL OPERTIONS	1,159	11,999	3,126	8,976	12,102	103	

NEWFOUNDLAND & LABRADOR HYDRO
GENERAL PROPERTIES
2004 CAPITAL EXPENDITURES - DETAIL
FOR THE QUARTER ENDING JUNE 30, 2004
($,000)

PROJECT DESCRIPTION	Expenditures Prior To 2004	PUB Approved Budget 2004	2004 Expenditures To June 30	Expected Remaining Expenditures 2004	Expected Total Expenditures 2004	Var. from Approved to Expected Expenditures	Variance Explanation Reference
INFORMATION SYSTEMS & TELECOMMUNICATIONS							
SOFTWARE APPLICATIONS							
INFRASTRUCTURE REPLACEMENT							
Replace Energy Management System - Energy Control Centre	387	5,120	430	2,293	2,723	(2,397)	NOTE 6
NEW INFRASTRUCTURE							
Corporate Applications Environment		540	40	500	540	0	
Applications Enhancements		463	23		463		
Security Program - Centralized Log Monitoring & Analysis System	71	69	3		69		
Security Program - Secure Remote Access		75	0	75	75	0	
TOTAL SOFTWARE APPLICATIONS	458	6,267	496	2,868	3,870	(2,397)	
COMPUTER OPERATIONS							
INFRASTRUCTURE REPLACEMENT							
NEW INFRASTRUCTURE							
Peripheral Infrastructure Replacement		101	47	54	101	0	
TOTAL COMPUTER OPERATIONS	0	101	47	54	101	0	
NETWORK SERVICES							
INFRASTRUCTURE REPLACEMENT							
Replace Powerline Carrier Equipment - Transmission System - West Coast	1,037	391	53	338	391	0	
Replace Battery System - Multiple Sites - 2004		274	171	137	308	34	
Replace Remote Terminal Unit for Hydro - Phase 5		314	57	257	314	0	
Replace Telephone Isolation Equipment - Doyles		49	2	69	71	22	
Upgrade Site Grounding at Telecontrol Site - Phase 5		49	1	48	49	0	
NETWORK INFRASTRUCTURE							
Purchase Test Equipment		48	48	0	48	0	
Upgrade Local Area Networks (LANs) - Multiple Sites - 2004		48	10	38	48	0	
UPGRADE OF TECHNOLOGY							
Replacement of Operational Data & Voice Network - Phase II		971	79	892	971	0	
TOTAL NETWORK SERVICES	1,037	2,144	421	1,779	2,200	56	
TOTAL INFORMATION SYSTEMS & TELECOMMUNICATIONS	1,495	8,512	964	4,701	6,171	(2,341)	

NEWFOUNDLAND & LABRADOR HYDRO
GENERAL PROPERTIES
2004 CAPITAL EXPENDITURES - DETAIL
FOR THE QUARTER ENDING JUNE 30, 2004
($,000)

PROJECT DESCRIPTION	Expenditures Prior To 2004	PUB Approved Budget 2004	2004 Expenditures To June 30	Expected Remaining Expenditures 2004	Expected Total Expenditures 2004	Var. from Approved to Expected Expenditures	Variance Explanation Reference
ADMINISTRATIVE							
VEHICLES							
Replace Vehicles - Hydro System - 2003	1,138	1,588	586	1,002	1,588	0	
Replace Vehicles - Hydro System - 2004		1,081	258	823	1,081	0	
ADMINISTRATION							
Purchase Cash Remittance Processor		60	0	60	60	0	
Electronic Metering Reading		36	0	36	36	0	
Purchase & Replace Admin Office Equip less than $50,000	0	73	0	32	32	(41)	
TOTAL ADMINISTRATIVE	1,138	2,838	844	1,953	2,797	(41)	
TOTAL GENERAL PROPERTIES	2,633	11,350	1,808	6,654	8,968	(2,382)	

NEWFOUNDLAND & LABRADOR HYDRO
OTHER APPROVED FUNDS
2004 CAPITAL EXPENDITURES - DETAIL
FOR THE QUARTER ENDING JUNE 30, 2004
($,000)

PROJECT DESCRIPTION	Expenditures Prior To 2004	PUB Approved Budget 2004	2004 Expenditures To June 30	Expected Remaining Expenditures 2004	Expected Total Expenditures 2004	Var. from Approved to Expected Expenditures	Variance Explanation Reference
ALLOCATION FOR UNFORESEEN EVENTS							
Allocation for Unforeseen Events		1,000	0	1,000	1,000	0	
TOTAL ALLOCATION FOR UNFORESEEN EVENTS	0	1,000	0	1,000	1,000	0	
PROJECTS APPROVED BY PUB							
Carryover							
Load Research - Island and Labrador Interconnected Systems	62	143	68	75	143	0	
Wind Generation - Ramea	9	89	72	17	89	0	
Contribution	(9)	(89)	(58)	(31)	(89)	0	
New							
Upper Salmon Slope Stabilization		102	41	61	102	0	
Office Server & Productivity Tools Evergreen		639	10	629	639	0	
End User Evergreen Program		793	511	282	793	0	
Increase Generation - Port Hope Simpson		303	1	302	303	0	
Holyrood Marine Terminal - Security Upgrade		465	3	462	465	0	
Diesel Generating Unit - Hopedale		258					
TOTAL PROJECTS APPROVED BY PUB	62	2,703	648	1,797	2,445	0	
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO							
Carryover							
Project Review - Replace VHF Mobile Radio Systems	18	30	34	0	34	4	
New							
Purchase Site License for Proworx 32		33	1	32	33	0	
Replace Battery Bank - Grand Lake Crossing		26	9	17	26	0	
Purchase VHF Radios		27	0	27	27	0	
Replace Air Conditioning Unit - Hardwoods Terminal Station		24	0	24	24	0	
Preliminary Engineering - Rencontre Interconnection		49	0	49	49	0	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDR(	18	189	44	149	193	4	

TRANSMISSION & RURAL OPERATIONS:

1. **Upgrade TL214 – (138KV Bottom Brook – Doyles)**
   The variance is a result of additional funds being required for the transmission line construction contract and for the structural steel supply. Costs for the transmission construction were substantially higher than what was forecasted in the original project estimate, primarily due to the compressed construction schedule required for system operations.

2. **Install Motor Drive Mechanisms on Disconnect Switches – West Coast**
   Based on experience gained on the installations of motor drive mechanisms in 2003, a more efficient work plan was derived from what was presented in the budget. This more efficient plan resulted in the reduction in costs as shown by the variance.

3. **Pole Replacements**
   The Capital Budget Proposal estimates were based on cost data for projects completed in years prior to 2003. In 2003, the nature of distribution line construction work in the province resulted in a significant reduction in construction costs as compared to previous years. This trend of lower construction costs continues to prevail in 2004. The variance reflects the reduction in costs due to current construction trends which are significantly lower than the original budget estimate.

4. **Insulator Replacements**
   The Capital Budget Proposal estimates were based on cost data for projects completed in years prior to 2003. In 2003, the nature of distribution line construction work in the province resulted in a significant reduction in construction costs as compared to previous years. This trend of lower construction costs continues to prevail in 2004. The variance reflects the reduction in costs due to current construction trends which are significantly lower than the original budget estimate.

5. **Replace Light Duty Mobile Equipment Less Than $50,000**
   The 2004 Capital Budget Proposal was based on the purchase of forty-nine units of light duty mobile equipment. A review of fleet requirements identified a reduction in light duty mobile equipment units from forty-nine to thirty-six. The budget variance is the result of the reduction in the number of units required.

GENERAL PROPERTIES:

6. Replace Energy Management System - Energy Control Centre

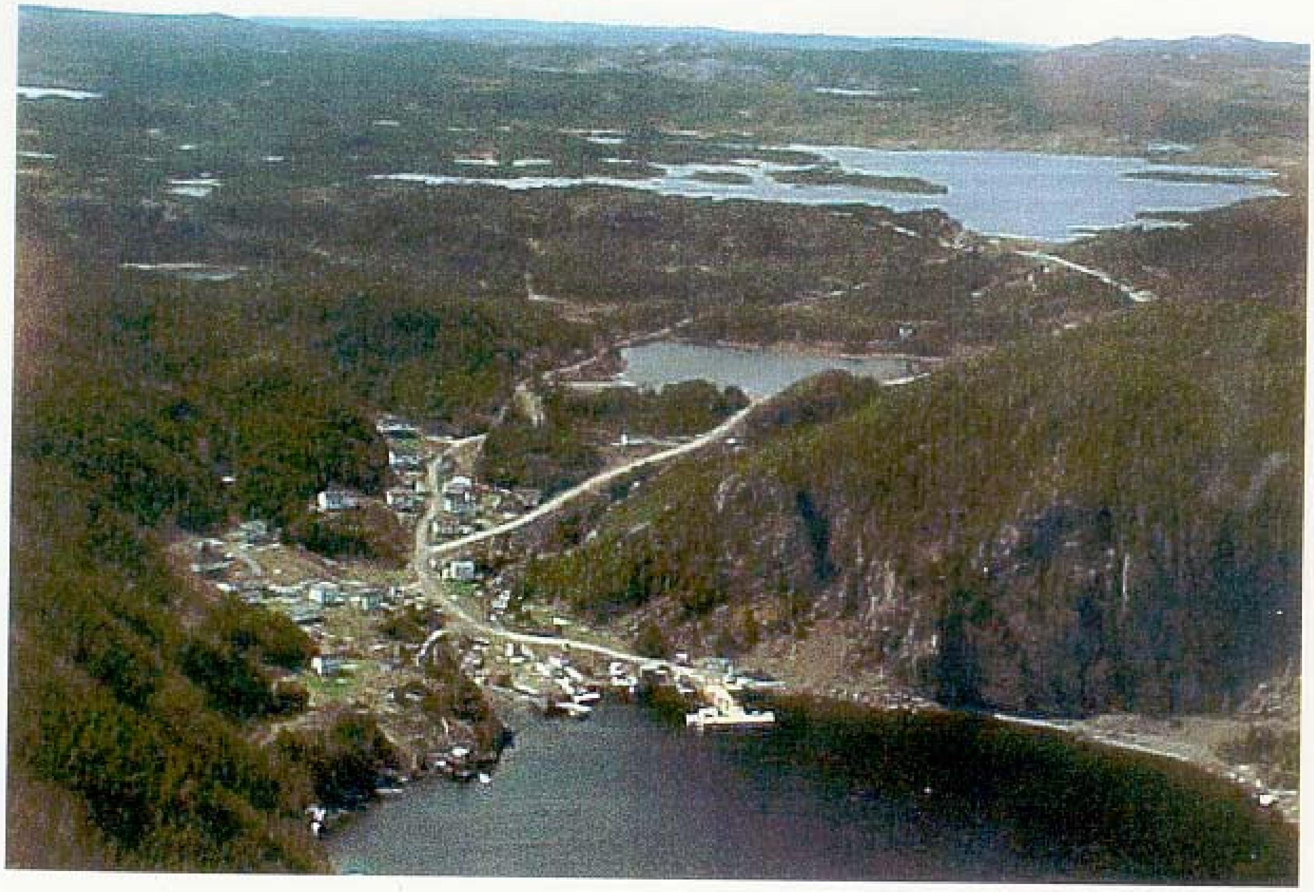
The cashflow for the EMS has changed from that submitted in 2003 Capital Budget proposal. The 2003 Capital Budget proposal was prepared based on the report by KEMA with an anticipated contract signing in December 2003 and an in-service date of February 2006. Due to slower progress than anticipated in the KEMA report to address the rather complex nature of the contract, it was not signed until June 2004 and therefore the scheduled project completion milestone has changed to June 2006. As a result the estimated costs for 2004 and 2005 are forecasted down and estimated costs for 2006 are forecasted up. The total cost for the project has not changed.

SECTION G
Tab 1

NEWFOUNDLAND & LABRADOR HYDRO

Snook's Arm Wood Stave Penstock

Evaluation, Recommendation and Estimated Cost for Replacement



Prepared By:

Newfoundland and Labrador Hydro
Generation Engineering

January 26, 2004

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Appendix A
Map of Snook's Arm Penstock

Appendix B
Photos

Appendix C
Detailed Economic Analysis

Appendix D
Project Schedule

1.0 Introduction

.1 Project Location

The Snook's Arm hydroelectric development is located on the Baie Verte Peninsula, approximately 80 km from the Trans Canada Highway. A map showing the location of the penstock in relation to the community of Snook's Arm is provided in Appendix A.

.2 Project Description

.1 General

The hydroelectric development was constructed in 1956 for the Maritime Mining Corporation and was purchased by Newfoundland & Labrador Hydro in 1968. The development has a watershed of approximately 11.8 mi^2 and includes Armchair Pond, Red Cliff Pond, West Pond and East Pond. The main dam and intake is located on the south side of East Pond. The unit has a rated output of approximately 590 kW and produces an average of 3,500,000 kWh/year.

.2 Penstock

The penstock was built in 1956 by the Pacific Coast Pipe Co. The penstock has an inside diameter of 30" and a length of 3050 ft.

The wood staves were machined from nominal 2" x 4" Douglas Fir with tongue and groove radial side joints, double tenon end joints, and creosote pressure treated to 8 lbs/ft^3 net retention or rejection. As a result of damage during shipment, many stave ends (double tenon end joints) were cut square and field jointed with metal splines.

The bands are ½" dia x 9-2" long, 1 piece with button head one end and rolled thread on the other, and ½" x 36" pipe shoes. There are approximately 12,000 steel bands with spacing varying from 10" on centre at the intake to 3" on centre at the powerhouse. The penstock is supported on chock block cradles (6" x 6" chock on 4" x 6" sill) on 8-foot centers.

There is a 4" air release valve and a 4" drain valve on the line.

.3 Summary of Reports

Several reports have been prepared over the years, describing the condition of the penstock and associated components. These reports have been used to determine the problems that have been identified over the years and the condition of the penstock. The reports include:

Inspection Report of Venam's Bight and Snook's Arm Wood Stave Penstocks, Prepared by Canbar Inc., Sept. 3-4, 1998.

Inspection Report of Venam's Bight and Snook's Arm Wood Stave Penstocks, Prepared by Canbar Inc., Aug. 15-16, 2000.

Snook's / Venam's Penstock, Prepared by L. Kearley, Civil Technologist - Newfoundland & Labrador Hydro (Interoffice Memo), April 12, 2001.

Snook's Arm Penstock Enclosure, Prepared by G. Poole, P. Eng. - Newfoundland & Labrador Hydro (Interoffice Memo), June 28, 2001.

Snook's / Venam's Penstock Assessments, Prepared by L. Kearley, Civil Technologist - Newfoundland & Labrador Hydro (Interoffice Memo), Dec. 21, 2001.

.4 <u>Maintenance History</u>

Detailed records of maintenance history were not kept or are unavailable, however, since the early 1990's significant efforts have been undertaken to maintain the penstock. This includes:

- Patching of leaks;
- Replacement and addition of steel bands;
- Repair and replacement of penstock cradles;
- Removal of vegetation and growth;
- Improvement of drainage around penstock.

2.0 Identified Problem Areas

Described below are areas of the penstock that have been identified as problem areas.

.1 Penstock Design and Profile

The wooden penstock is 3050 ft long and has a head of 300 ft and there is no surge tank available. The lack of a surge tank causes limitations on the operation of the Plant and also stresses the penstock. In the event of a unit trip, a sudden water hammer surge would occur, which causes pressure on the joints between the wooden staves. Typically after such a water hammer event, additional leaks appear in the penstock.

The penstock profile has several flat sections and one reverse section in the mid to upper half of the penstock, see photos #1 & #2. The reverse grade increases the probability of the penstock collapse during operation, when the Plant is fully loaded. The only protection from collapse is a vacuum breaker valve located at the mid-point of the line. This valve is designed to break any vacuum that may cause a collapse. It is critical that this valve is kept in good working condition to ensure that it will operate as required. Recent problems experienced include a fire in the valve enclosure and a malfunction of the valve.

.2 Penstock Material

The penstock is constructed from 2” x 4” Douglas fir timbers machined to create the diameter of the penstock. Steel bands spaced on 3” – 10” centers, hold the wood stave material together and maintain the shape of the penstock.

.1 Wood Staves

Various inspections of the penstock have indicated that there is joint leakage between the staves, brooming at stave ends and between steel bands and crushing of the staves along the spring line or top of the penstock. The brooming and crushing is worse at the lower end of the penstock, which is subject to higher pressures. The crushing and brooming indicates delamination between the wood fibers and deterioration of wood, see photos #3 & #4. The rate and areas of deterioration continues to grow with the age of the structures.

Also along the length of the penstock, areas of moss and other vegetation are growing directly on the penstock; see photos #5 & #6. Vegetation growth typically retains moisture and cause stave deterioration. In some cases the vegetation can be parasitic to the wood stave. Vegetation thrives because of continuous water supply leaking from the penstock. The cost of removing the vegetation continues to increase.

.2 Steel Bands

There are approximately 12,000 steel bands used to maintain the shape and integrity of the penstock. All of the bands show various signs of rusting, corrosion and deterioration. Also, in recent years some bands have been observed with significant corrosion below the threads on the band, see photos #7 & #8. These bands are required to be replaced or new ones installed adjacent to the old ones (where possible). In addition, there is bright, visible corrosion on the majority of the steel bands that do not receive direct sunlight. These areas include the penstock enclosure, buried section of the penstock and at the road crossings. In these same areas it is difficult if not impossible to replace the steel bands because of the limited access. Also, in several locations it is impossible to replace the bands unless the penstock is dewatered, because of the decreased band spacing and the higher pressure on the lower half of the penstock. However, frequent dewatering of the penstock is not recommended because of its aged and deteriorated condition.

.3 Leaking Water from Penstock

Leaking of the penstock joints have been observed since at least 1968, see photos #9, #10 & #11. The leaks were sometimes repaired by driving nails into the leaking area, this method however tends to promote deterioration of the wooden staves, see photo #12. The more common method of sealing the leaks involved the installation of small steel plates under the existing steel bands or by adding new bands between the existing ones in the area of the leak, see photo #13. The penstock has been dewatered approximately 4-5 times since 1989 to repair the leaks. During one event, the penstock was dewatered for approximately 5-6 days, which allowed the wood staves to dry out and shrink in size. When the penstock was watered up there were a significant number of additional leaks of various sizes, which required lengthy time and effort spent to correct and seal the new leaks. Based on this experience, the penstock has been dewatered and watered up during the same day to repair any leaks in the penstock. However, each time the penstock is dewatered, additional leaks appear when the penstock is watered up again. Overall, the dewatering of the penstock is a significant activity that creates just as many or more leaks than those that are repaired.

The leakage of water from the penstock has caused an accelerated rate for:

- Wood penstock to deteriorate;
- Metal bands to corrode and rust;
- Increase growth of vegetation;
- Deterioration of wood supports and enclosures; and
- Increase maintenance cost for control, sealing and patching of leaks.

.4 Ice Buildup

All leaks from the penstock result in significant ice formation during the winter. The ice formations are becoming an increasing problem for Hydro because of its danger/risk to local residents.

The formation of ice was investigated during the winter of 2001 and several observations were made. The ice formations were fed from the penstock by the constant flow of running (leaking) water. The ice formations extended down over the sides of the penstock to the ground. One ice formation observed was 8 ft high and 3 ft long at its base, the average ice formation was 5 – 6 ft in height, see photo #14. The danger caused by the ice formations is that the ice loads or large ice chunks could severely damage or rupture the weakened penstock. Another key area of ice formation was under the penstock enclosure. The leaking water causes large ice formations under the enclosure around the area of the access road, see photo #15. Besides adding a substantial load to the penstock and its support structure, it also interrupts local traffic (this sometimes leads to unsupervised demolition of the ice).

.5 Steel Section of Penstock

The first section of the penstock, from the intake to approximately 80 ft downstream, is fabricated from riveted steel plate; refer to location #1 on map SA-1 and photos #16 & #17. Because of the age of this steel section of penstock plus the fact that it has been partially or totally submerged for years, it continues to deteriorate. In addition, the concrete saddles for this section are also damaged. This section of penstock will likely be required to be replaced at the same time as the adjacent wooden penstock.

.6 Enclosure Over Access Road

There is a section of the penstock, located just above the community, which crosses over a small access road, refer to location #2 on map SA-2. There are two critical areas with this location; the support structure and enclosure, see photos #18 & #19.

.1 Support Structure

The support structure for the penstock is supported by 8" x 8" timbers at roughly 8.5 ft centers. At the upstream end, the enclosure is practically on the ground and it rises off the ground until it reaches the road where it is supported 10 ft off the ground by 8"x 8" and 6" x 6" timbers. The penstock is supported horizontally by two poles spanning the road. Some of the timbers appear to be creosote treated while others do not show any signs of protective coating. This structure is original and is showing its age. This structure supports the penstock, the enclosure, snow loads and substantial ice loads, while providing daily access to local residents.

.2 Penstock Enclosure

The penstock is enclosed for a length of 75 ft in the vicinity of the access road; the enclosure was built to reduce ice formation during the winter. The penstock invert was heat traced to reduce ice buildup inside of the structure; however, ice buildup inside and outside of the enclosure is still an ongoing problem. There are several concerns associated with this structure including the old and deteriorated condition of the enclosure, reliability of the heat tracing, and the limited access for inspection and maintenance of the penstock inside the enclosure. In general, the structure is becoming more of a safety concern as it ages.

.7 Buried Section of Penstock

The penstock passes through the middle of the community and at times, is within a few feet of the adjacent houses; see photos #20 & #21. Also a considerable length of the penstock, approx. 200 ft is buried, refer to location #3 on map SA-2 and see photo #22. In 1998, a section of the buried penstock was excavated and it was observed that the penstock is supported on cradles, similar to the rest of the penstock. Buried penstocks are designed to be fully supported along their length, the discovery of cradles supporting the penstock in the buried section, suggests that the penstock was not designed to be buried. The burial of the penstock subjects it to additional loads from the overburden soil and live loads from vehicles, skidoos, woodpiles, etc. In addition, there is very poor drainage around the penstock causing the penstock to be submerged in water. The risk associated with this section of penstock is high because of additional loading, moist conditions and lack of maintenance; there is a high probability of failure of this section of the penstock.

.8 Road Bridge

A section of the penstock (approximately 30 ft) crosses under the main access road through the community, refer to location #4 on map SA-2. There are two key items at this location, the support structure and penstock condition.

.1 Bridge Structure

Some of the existing bridge components were constructed in 1971 and they are showing obvious signs of deterioration. The bottom section (approx. lower ¾) of the bridge abutments are constructed from local untreated timbers and they are deteriorating, see photo #23. It appears that the only thing keeping the abutments from collapsing is a framework of pressure treated timber braced between the existing abutments, which were installed several years ago, see photo #24. The department of Works, Services and Transportation have indicated that they have no plans to replace this structure in the near future.

.2 Penstock

It is extremely difficult to inspect the condition of the existing penstock due to the limited access under the bridge and around the penstock. However, from the limited inspections it has been observed that several steel bands are severely deteriorated and there are several leaks. There has been very little or no maintenance to this section of the penstock because of the limited access.

.9 Road Crossings

There are a total of four locations where the penstock crosses various access roads. Two of the four have been identified above (penstock enclosure and road bridge), at the remaining two locations the penstock passes under the roads. The first location is near the intake and is the access road for the Nugget Pond gold mine and was constructed in the early 1990's. The penstock is enclosed in a culvert for a length of 65 ft. The second location is near the powerhouse and crosses the main access road to the community. The penstock is buried for a length of 130 ft. At this location, the penstock is buried and is heavily covered in vegetation. The type of structure used to protect the penstock from additional loads caused by the road crossing is unknown, however, it is assumed to be a culvert. In both of these locations it is impossible to inspect or perform any maintenance on the wooden penstock or steel bands.

.10 Penstock Coating

The original wooden penstock components were coated with creosote to provide protection from deterioration and sunlight. Typically a wood penstock would be recoated with creosote every 5-10 years to maintain the protective coating. This penstock has not been coated for at least 15 years (due to environmental restrictions on the use of creosote) and as a result the majority of the wooden penstock has no protection coating, especially along the top, see photo #25. The lack of protective coating has accelerated the deterioration of the wooden staves.

.11 Use by Residents of Community

As indicated earlier, the penstock passes through the community and in several locations the penstock is within a few feet from homes and roadways. The proximity of the penstock to the homes has encouraged many residents to tap into the penstock for a source of water, see photos #26 & #27. These taps were constructed without any permission from Hydro and in several locations have been abandoned and leaking water, see photo #28. In addition, all terrain vehicles and skidoos travel over and under the penstock, which imposes additional loads and stresses on the penstock. In the upper half of the penstock, there is firewood stacked adjacent to the penstock, see photo #29, and in several places there are cuts in the penstock from chainsaws. The use (or abuse) of the penstock by local residents has lead to increased deterioration of the penstock.

.12 <u>Summary</u>

A significant number of these identified problems are located in the high-pressure section of the penstock that runs through the community. In addition, there is more than 300 feet of covered or buried penstock, located within this section, which had very minimum maintenance over the years due to the limited access. This section has a potential for high liability in case of a failure.

3.0 Significant Historical Events

During the operating history of the Plant, several events have occurred which have caused damage or had potential to damage the penstock.

.1 Flood Damage – 1992

The lower section of the penstock passes under the main access road to the community and then proceeds along the side of a brook towards the powerhouse, refer to location #5 on map SA-2. In 1992 high water levels in the brook caused a section of the embankment under the penstock to erode. Untreated timber cribbing was installed along side of the brook to support the penstock, see photos #30 & #31. The timber support is 15 years old and is still subject to brook damage. The penstock has also developed a noticeable dip in elevation at this location resulting in more leaks.

.2 Flood Damage – 1996

In 1996 water overtopped Snook's Arm main dam and caused flooding downstream. The flooding caused a 200 ft section of the access road to the Nugget Pond gold mine to be washed away. The flooding caused a significant amount of rock and debris to move downstream and adjacent to the penstock. Though, the majority of the rock debris was removed, however some of the rocks remain next to the penstock, see photos #32 & #33. This rock debris probably has and will continue to impose stresses on the penstock and, which over time, may displace the penstock transversely. Another similar event would likely have a major impact on this section of the aged and weakened penstock.

.3 Fire Damage

In 2002 a fire occurred in the valve enclosure around the vacuum breaker valve, see photos #34 & #35. The fire was caused by a malfunction of the heat tracing and caused the destruction of the valve enclosure and damage to the valve. Luckily, there was no apparent damage to the penstock. However, the vacuum breaker valve did require repair. And, as stated earlier, if this valve fails to operate when required, the penstock may collapse.

4.0 Reliability

.1 General

Wooden stave penstocks typically have a design life of 40 years. The Snook's Arm penstock has been in operation since 1956. Numerous assessments of the penstock condition have been conducted and are summarized in Table 1.

Report	Author	Date	Comments
Inspection Report of Venam's Bight & Snook's Arm Penstocks	Canbar Inc.	Sept. 1998	"This pipe is 42 years old but is still expected to provide several more years of service, provided proper maintenance practices are still observed."
Inspection Report of Snook's Arm & Venam's Bight Penstocks	Canbar Inc.	Aug. 2000	"Should icing up become unmanageable or potential liability become significant, due consideration should be given to the replacement of all or part of this pipe prior to the end of the pipe's otherwise practical and safe service life."

Table 1: Summary of Penstock Inspection Reports and Recommendations

.2 Summary

The normal design life of most wooden penstocks is 40 years. This penstock is 47 years old and when replaced, in 2006, will be 50 years old.

This penstock is significantly beyond its original design life, has many identified problem areas, continues to deteriorate and maintenance costs are increasing. The probability of failure and its impact on generation, as well as, loss of life and property will continue to increase. It is recommended to replace the penstock as soon as possible.

5.0 Safety

.1 General

The penstock is 3050 ft long and approximately half of its length travels through the community. In several places it is only a few feet away from adjacent homes. The penstock is 47 years old and considering its age, condition and known problems, the probability of failure is increasing with time.

.2 Failure Analysis

A computer simulated failure of Snook's Arm main dam was completed in 2001 and revealed that there would be potential damage to structures and injury to those individuals in the immediate area. The majority of the flooding may be confined to the river valley that runs along the east side of the community and the area around the harbour.

A major break in the upper portion of the penstock is expected to cause flooding in a similar area to that of a dam failure. Damage would also be expected to occur to the balance of the penstock and to nearby property.

However, if a major break occurred in the lower half of the penstock, it is expected that the water would flow through the middle of the community. Due to the proximity of the homes adjacent to the penstock, it is expected that significant property damage and personal injury would occur.

It is important to note that the extent of flooding would depend on numerous factors, including:

- Time of year;
- Time of day;
- Weather conditions;
- Location of break or leak;
- Time between break occurring and break detected;
- Amount of time between break and stopping flow of water.

.3 Summary

As the age of the penstock increases so does the probability of a major break. It is recommended to replace the penstock as soon as possible.

6.0 Alternatives

.1 General

The penstock is currently 47 years old and beyond its normal design life. It has deteriorated and must be replaced. The following alternatives were studied:

i.) Do Nothing;
ii.) Retire Plant;
iii.) Replace Penstock;
iv.) Phased Replacement of Penstock.

.2 Do Nothing

This alternative is available in any project. However, in this case, a break in the penstock is most likely to occur in the lower section of the penstock, which is subject to the highest pressure. Due to the proximity of the community to the lower half penstock, significant damage would occur to private property, community infrastructure and the potential exists for personal injury. Based on this risk to Hydro, this alternative is not recommended.

.3 Replace Entire Penstock

This alternative would involve replacing the existing penstock with a new penstock from the intake to the Plant. The detailed design for the new penstock would consider the least cost consistent with reliable service. The material used may be steel, fiberglass or high-density plastic products. The estimated cost for the replacement penstock with steel in 2006 is $1,930,000 (in 2003 dollars).

.4 Phased Replacement of Penstock

Under this alternative the penstock will be replaced in two phases. The lower, high-pressure section of the penstock which runs through the community (from mid point of the penstock to the powerhouse approximately 1500 ft long) will be replaced in 2006. This would reduce the higher potential liability to Hydro, caused by a failure in the high-pressure section. The design of the phased replacement of the penstock would consider a method(s) to reduce the impact to the community in the event of break in the upper portion of the penstock. In addition, the work will include maintenance to the upper section of the existing wood stave penstock. In the second phase, under this alternative, the upper remaining section of the penstock will be replaced in 2016.

.5 Retire Plant

Under this alternative the existing Plant and associated facilities would be retired. However, there would be a cost associated with the retirement of the Plant, including:

- Removal of powerhouse and equipment;
- Removal of penstock;
- Removal of dam structures (in a controlled manner);
- Remediation of the environment.

It is estimated that it would cost approximately $500,000 to remove the existing structures and remediate the sites. Also, an Environmental Impact Statement would have to be prepared and submitted to the Provincial Government for review and approval.

It is recommended that this alternative be considered for further evaluation.

.6 Environmental Considerations

Snook's Arm generation displaces thermal generation at Holyrood and represents a direct reduction in fossil fuel emissions. With the heightened profile of the Kyoto protocol and other environmental initiatives there will likely be interest in the emissions reductions associated with this and similar projects. The following table presents an estimate of annual CO_2, N_2O and SO_2 reductions attributable to Snook's Arm.

Alternative	Estimated Emission Reductions (Tonnes per year)		
	CO_2	N_2O (CO_2e)	SO_2
Snook's Arm	2,796	0.06 (18)	32

While it is difficult to estimate the exact nature of future emissions control programs and the resulting value of any emissions credits, the following representative values have been used for sensitivity analysis:

- $10/tonne for CO_2 based on Government of Canada estimates; and
- $200/tonne for SO_2 based on recent emissions trading experience in the US.

7.0 Cost Evaluation

.1 General

Four alternatives are identified in the previous section.

Three alternatives, except "do nothing", are further evaluated. Listed below are the cost estimates, assumptions and analysis of the data:

.2 Cost Estimates

Direct capital cost estimates for each alternative is listed in Table 2.

Alternative		Est. Cost (2003 $'s)
1.)	Replace Entire Penstock	$1,930,000
2.)	Phased Replacement of Penstock	$2,140,000
3.)	Retire Plant	$500,000

Table 2: Summary of Cost Estimates for Penstock Alternatives

.3 Assumptions

Several assumptions were made in order to complete the cost analysis for each alternative. These include:

- Average escalation rate of 2%;
- Average interest (discount) rate of 8.5%;
- Project contingency rate of 10%;
- Corporate overheads at a rate of 6%;
- Unit Output: 590 kW;
- Average annual production of 3.5 GWh
- Annual Operator Cost: $15,000;
- Annual O & M Costs: $25,000;
- Runner Maintenance: $7,500 every ten years.

Additional assumptions were required for each alternative investigated, these include:

Alternative #1 (Replace Entire Penstock)

- Engineering Costs of $115,000 in 2005;
- Construction Costs of $1,815,000 in 2006.

Alternative #2 (Phased Replacement of Penstock)

- Engineering Costs of $90,000 in 2005;
- Construction Costs of $1,100,000 in 2006;
- Engineering Costs of $50,000 in 2015;
- Construction Costs of $900,000 in 2016;
- Annual penstock maintenance for upper section until replaced in 2016: $20,000.

Alternative #3 (Retire Plant)

- Retire Plant and Remediate Site(s) at a cost of $500,000 in 2006;
- Replace energy from Holyrood.

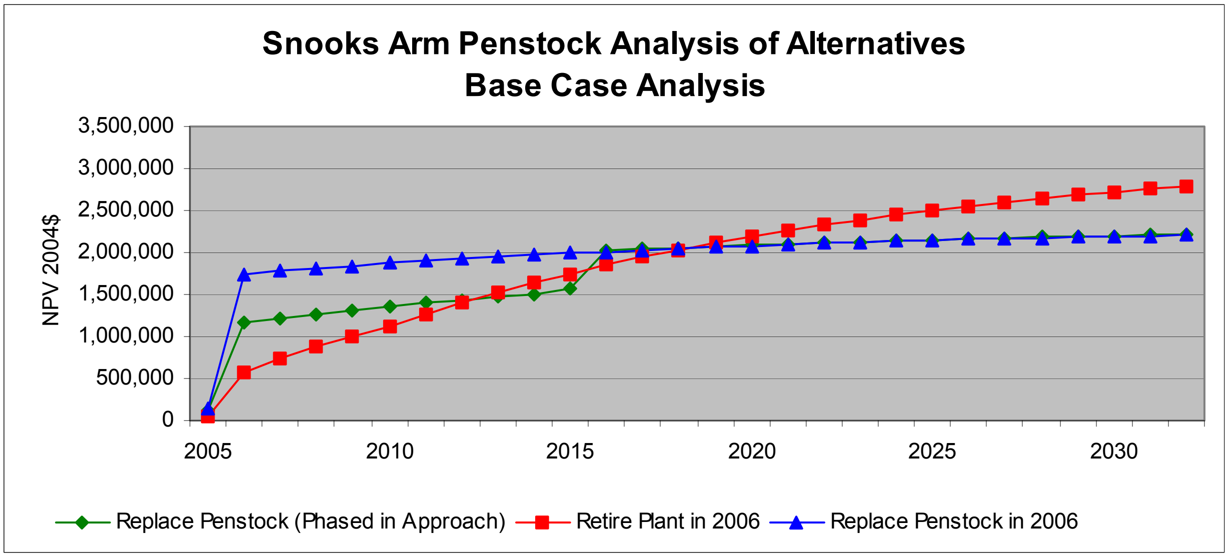
.4 Economic Analysis

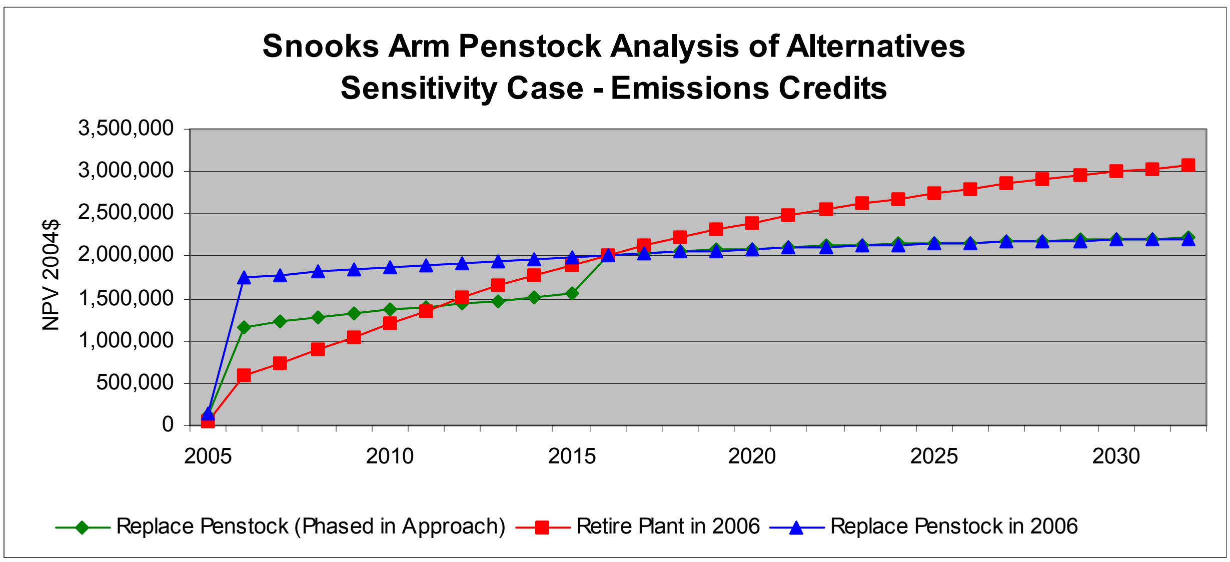
The economic analysis compared the cumulative present worth cost (capital and operating) of each of the penstock replacement alternatives against each other and against the plant retirement alternative. In addition to the base case analysis, a sensitivity case addressing the inclusion of emissions related costs was also prepared.

A summary of the detailed economic analysis found in Appendix C is presented in the following table and the graphs that follow:

Table 7-1

Snook's Arm Penstock Replacement Comparison of Alternatives		
	CPW Preference Against Plant Retirement Alternative	
	CPW (2004$)	Payback Period
Base Case:		
Full Replacement in 2006	$585,923	13 Years
Phased in Replacement (2006 & 2016)	$577,488	Phase 1 - 7 Years Phase 1+2 – 13 Years
Sensitivity Case – Emissions Costs:		
Full Replacement in 2006	$862,672	10 Years
Phased in Replacement (2006 & 2016)	$854,237	Phase 1 - 6 Years Phase 1+2 – 11 Years





Based on this analysis, it is evident that the replacement of the penstock is preferred over the plant retirement alternative. While the phased in replacement of the penstock shows an initial payback of 7 years on the first replacement phase, the payback on the complete project in both replacement alternatives is 13 years. Further, there is a negligible difference in the cumulative present worth costs of either of the replacement alternatives after 13 years.

Sensitivity analysis indicates that the inclusion of emissions related costs improves the preference for the penstock replacement alternative over the plant retirement alternative and also shortens the payback period for the full replacement alternative by 3 years.

8.0 Results

The results of the economic analysis indicated that the phased replacement of the penstock could provide the greatest net positive result. However, there are several disadvantages associated with this alternative, these include:

1. The upper section of the penstock would be 60 years old if replaced in 2016; this will be approximately 20 years beyond the design life of the penstock. Therefore, the upper portion of the penstock will remain a potential liability to Hydro.

2. The phased replacement of the penstock would require the entire penstock to be dewatered. Some method would have to be implemented to ensure the wood staves in the upper portion of the penstock do not dry out. The methods could include installing a bulkhead at the end the section of penstock, to be reused, and then keeping the penstock watered up or installing a sprinkler system (or similar system) to provide a continuous flow of water over the wooden staves. All of the methods would require the existing penstock to be dewatered for some period of time, which will cause some leakage when the penstock is put back into operation.

3. This alternative would also include the construction of a dam or similar structure near the joint between the new and existing penstocks to allow any water from the failure or rupture of the penstock to be diverted away from the community.

4. There would be additional costs associated with the upgrade of the existing penstock in 2006 to ensure an additional ten years of service life. In addition there will be annual operating maintenance costs associated with the existing penstock until it is replaced.

Based on the disadvantages associated with the phased replacement of the penstock, it is recommended that this alternative not be considered.

The next alternative with the greatest net positive result is the entire replacement of the penstock. The advantages of this alternative include:

1. Substantial reduction of potential liability to Hydro from potential failure or rupture of wood stave penstock.

2. Increased reliability of penstock.

3. Decreased energy losses, such as water loss from wood stave penstock and head loss (friction) in new penstock material.

4. Use of a renewable resource;

5. A design life in excess of 30 years for the new penstock;.

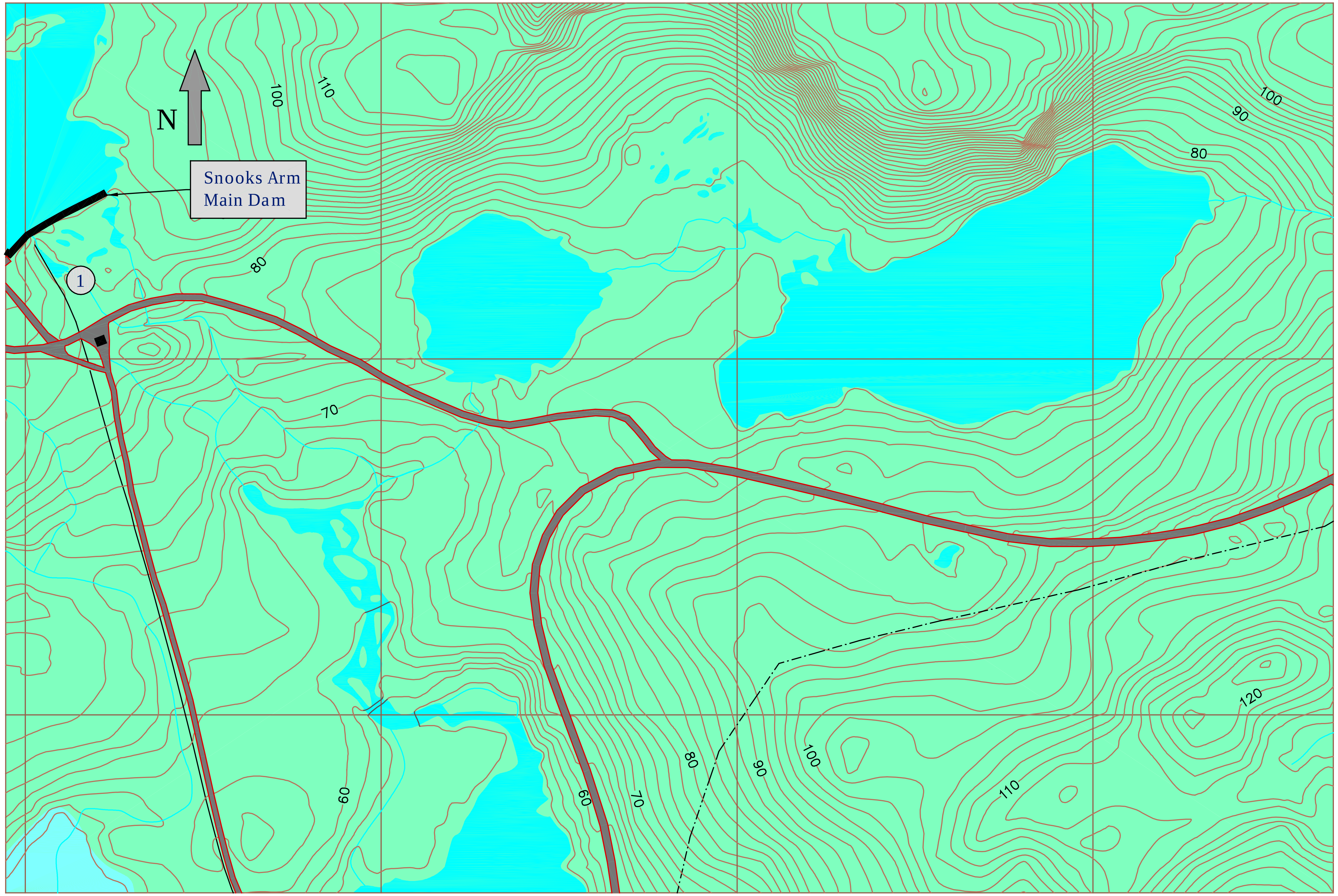
The entire replacement of the penstock will provide the lowest overall cost to Hydro while providing an acceptable level of reliability for the production of electricity.

9.0 Recommendations

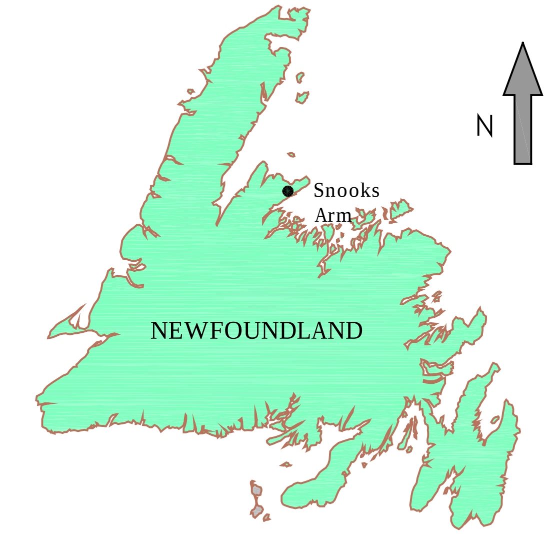
Based on the review of the available alternatives and the economic analysis, it is recommended to replace the entire Snook's Arm penstock. The design should be completed in 2005 and the replacement completed in 2006. A proposed project schedule for the penstock replacement is included in Appendix D.

APPENDIX A

MAP OF SNOOK'S ARM PENSTOCK



MATCH TO SHEET "SV1-2"



LEGEND :

- ROAD
- STREAMS / ORIGINAL WATER LEVEL
- HOUSES / CABINS / BUILDINGS
- 50 ELEVATION (m)
- WHARFS / PIERS / SLIPWAYS
- PENSTOCK
- 1 REFERENCE LOCATION

NOTES:

1. MAP ORIGIN, AIR PHOTO AND MAP LIBRARY, GOVERNMENT SERVICES AND LANDS. SCALE 1: 2500
   CONTOUR INTERVAL 2 m.

SCALE

0 100 200 m.

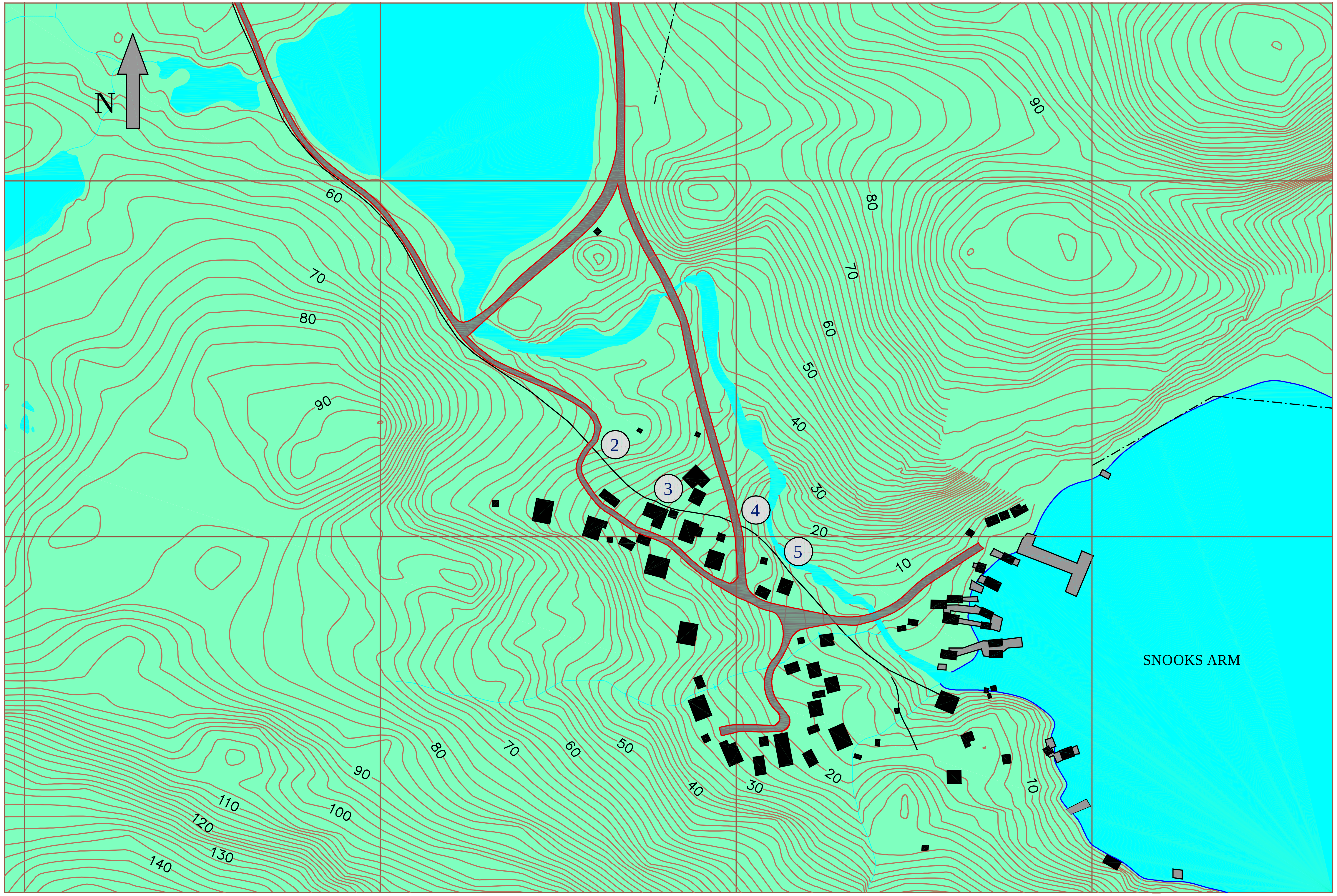
0 500 ft.

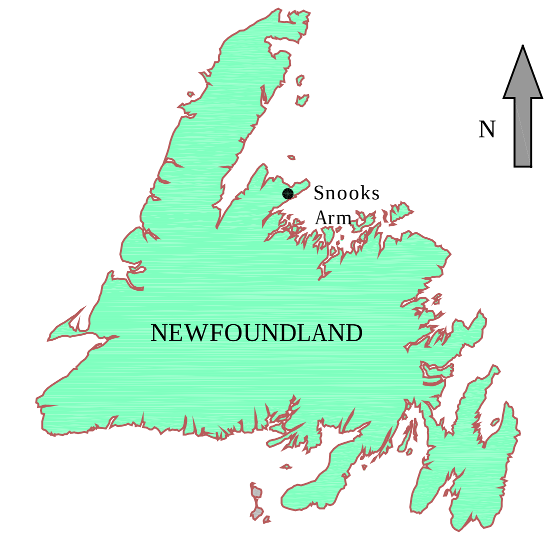
NEWFOUNDLAND AND LABRADOR HYDRO

SNOOKS ARM PENSTOCK TOPO MAP

km 0.0 to km 0.5

Date : Mar. 2001	Design: J. Phillips	Map No. SA-2
Dwn.: D. Oliver	App.:	Sheet 1 of 2





LEGEND :

- ROAD
- STREAMS / ORIGINAL WATER LEVEL
- HOUSES / CABINS / BUILDINGS
- 50 ELEVATION (m)
- WHARFS / PIERS / SLIPWAYS
- PENSTOCK
- 1 REFERENCE LOCATION

NOTES:

1. MAP ORIGIN, AIR PHOTO AND MAP LIBRARY, GOVERNMENT SERVICES AND LANDS. SCALE 1: 2500 CONTOUR INTERVAL 2 m.

SCALE

0 100 200 m.

0 500 ft.

NEWFOUNDLAND AND LABRADOR HYDRO		
SNOOKS ARM PENSTOCK TOPO MAP km 0.5 to km 1.2		
Date : Mar. 2001	Design: J. Phillips	Map No. SA-1
Dwn.: D. Oliver	App.:	Sheet 2 of 2

APPENDIX B

PHOTOS

Photo #1: View of penstock, August 2000.

Photo #2: View of flat and reverse section of penstock, August 2000.

Photo #3: View of brooming between metal bands, August 2000.

Photo #4: View of crushing and brooming of wooden staves, August 2000.

Photo #5: Vegetation growth around and on penstock, June 2001.

Photo #6: Moss and other vegetation growing directly on penstock, June 2001.

Photo #7: View of corrosion below threads, August 2000.

Photo #8: View of corrosion on metal bands, August 2000.

Photo #9: Water leaking from penstock, August 2000.

Photo #10: Water leaking from penstock, August 2000.

Photo 11: View of water leaking from penstock, August 2000.

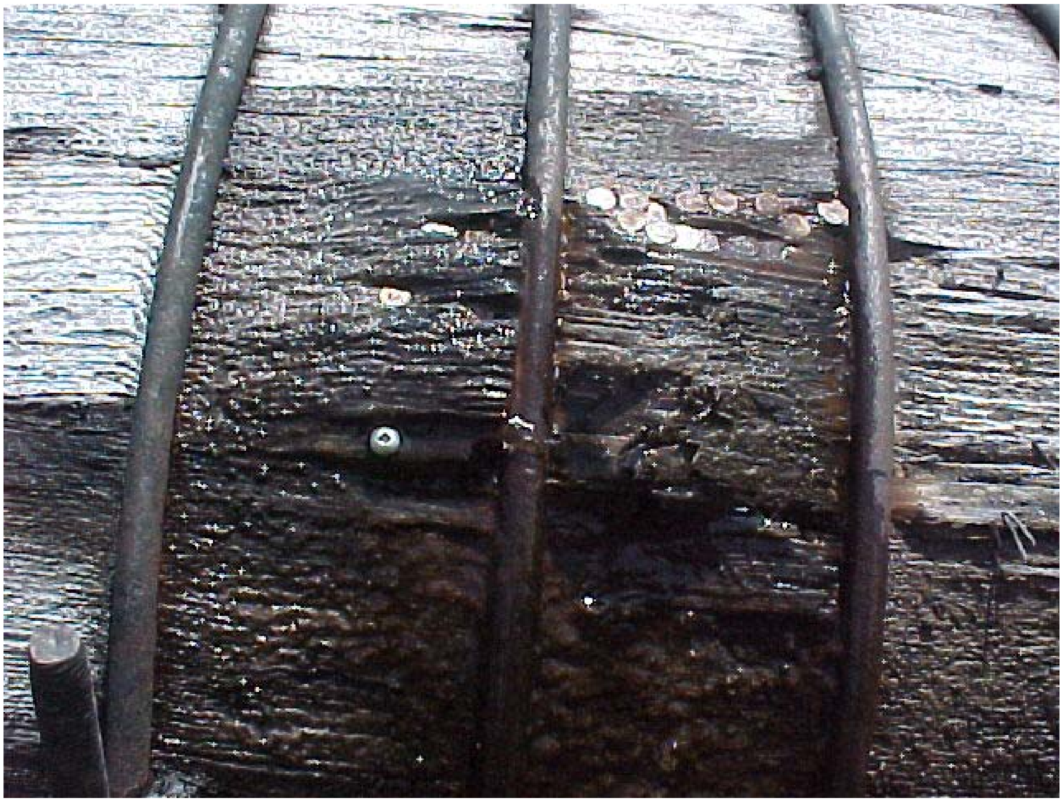


Photo #12: Nails driven into penstock to stop leaks, June 2001.

Photo #13: Metal patches placed under new bands to stop leaks, October 2003.

Photo 14: Ice formation above penstock, April 2001.

Photo 15: Ice formations under penstock enclosure, April 2001. For location of ice formation refer to Photo #18.

Photo #16: Accumulation of water behind concrete cut-off dam, June 2001.

Photo #17: Steel section of penstock, partially submerged in water, June 2001.

Photo 18: Penstock enclosure over access road, July 2002. Highlighted area indicates location of ice formation shown in Photo #15.

Photo 19: Support structure for penstock enclosure, July 2002.

Photos #20 & #21: View of penstock passing through community, October 1992.

Photo #22 Buried section of penstock in community, June 2001.

Photo 23: View of bottom portion of bridge abutment, June 2001.

Photo 24: Road bridge over penstock, note timber reinforcement between abutments, July 2002.

Photo #25: Loss of protective coating on penstock and bleaching of the wood, August 2000.

Photos #26 & #27: Water take-offs to adjacent homes (left) and Nugget Pond gold mine security building (right), August 2000.

Photo #28: Location of abandoned water tap in penstock, June 2001.

Photo #29: View of access road and firewood adjacent to penstock, August 2000.

Photos #30 & #31: Timber support added under penstock after erosion of embankment, October 1992.

Photo #32: View of rocks and gravel washed up against penstock, April 1996.

Photo #33: View of rocks and gravel under penstock, August 2000.

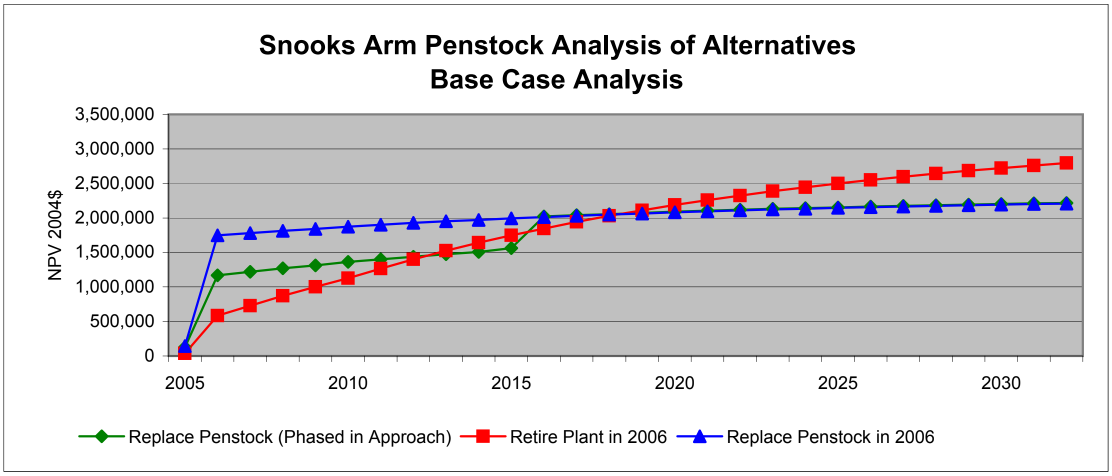
Photo 34: Fire damage to vacuum breaker valve enclosure, July 2002.

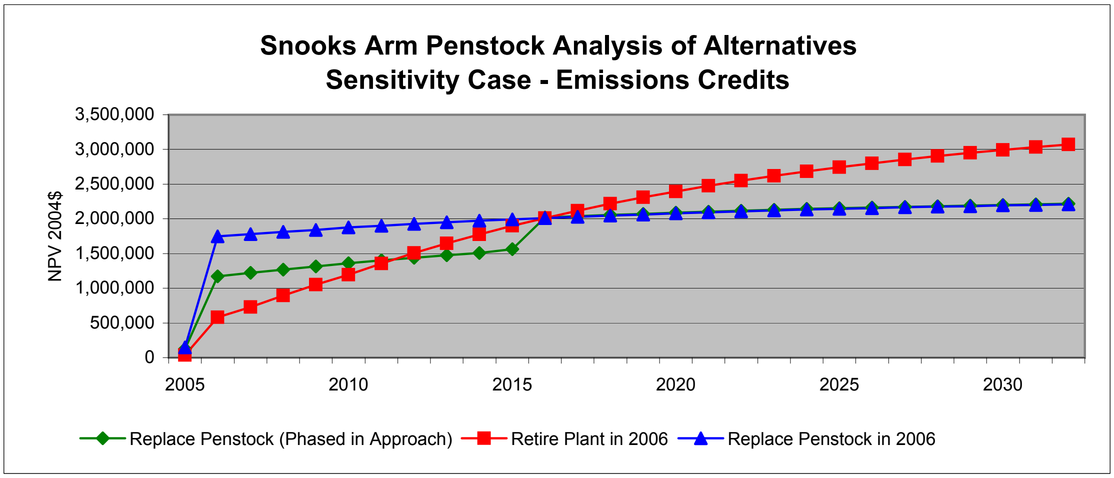
Photo 35: Vacuum breaker valve after fire, July 2002.

APPENDIX C

DETAILED ECONOMIC ANALYSIS

Snook's Arm Penstock Replacement Comparison of Alternatives		
Base Case	**CPW Preference against Plant Retirement Alternative** **CPW (2004$)**	**Payback Period**
Full Replacement in 2006	$585,923	13 years
Phased in Replacement (2006 and 2016)	$577,488	7 & 13 years
Sensitivy Case - Emissions Credits		
Full Replacement in 2006	$862,672	10 years
Phased in Replacement (2006 and 2016)	$854,237	6 & 11 years

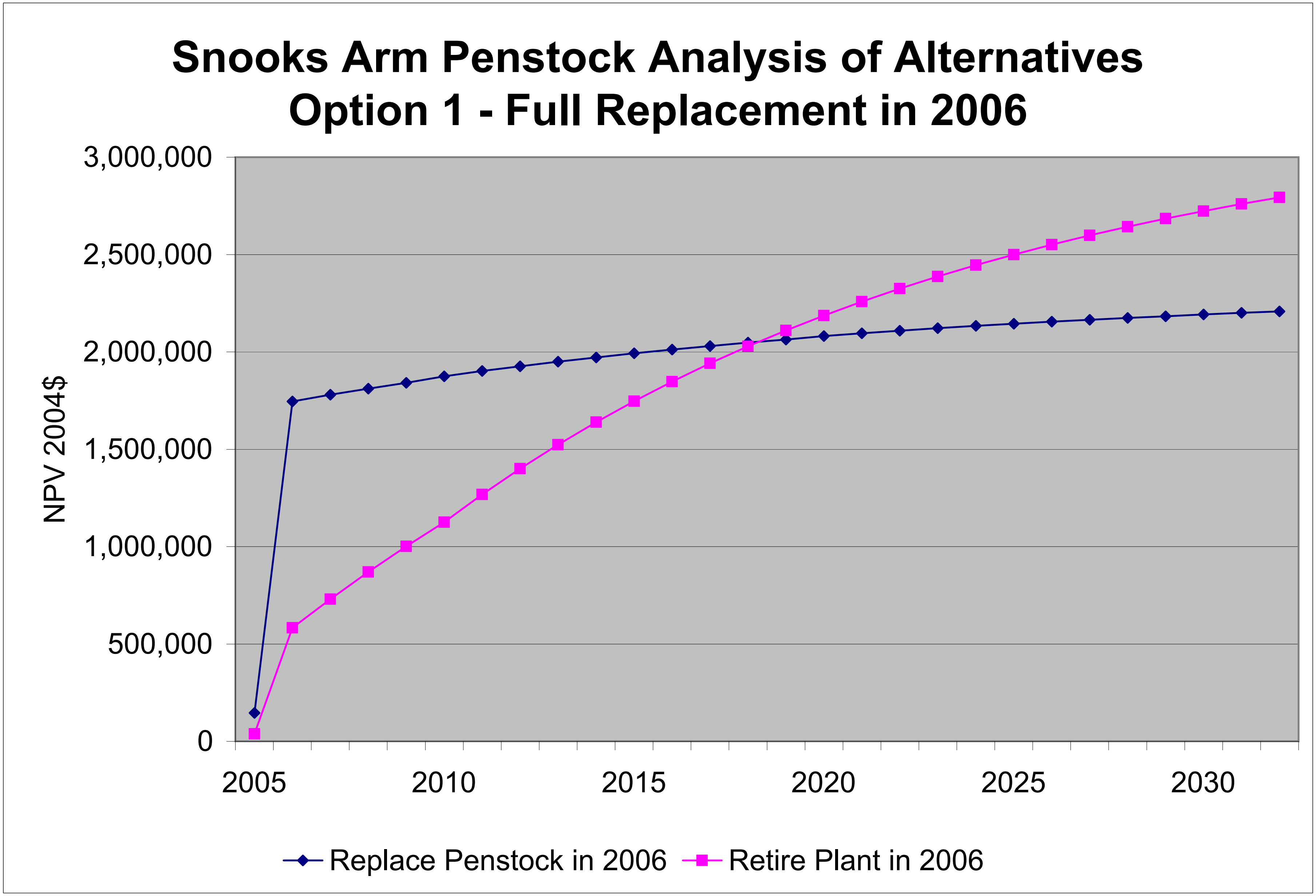




Snooks Arm Penstock Replacement
Option 1 - Full Replacement in 2005/6

Assumptions				
Annual Escalation:	2.0%		Engineering (2005):	112,000
Discount Rate:	8.5%		Construction (2006):	1,735,000
Installed Capacity:	590	kW		
Annual Energy:	3,500,000	kWh		
Holyrood Conversion:	624	kWH/BBL	Operator + O&M (2003$):	40,000
Holyrood Var O&M:	4.5	mills/kWh 2004$	Runner Maintenance (2003$):	7,500
Fuel Forecast:	Fall 2002	mills/kWh	Upper Penstock Maintenance (2003$)	20,000
Capacity Value (CT equiv.):	100	$/kW/yr 2004$	Retire Plant in 2006:	500,000

	Replace Penstock in 2006					Retire Plant in 2006							Difference	
			Runner &											
	Capital	Plant	Penstock	Sub-total		Capital			Holyrood		Sub-total		TOTAL	
Year	Cost	O&M	Maint.	Current$	CPW 2004$	Cost	Operator	Capacity	Var O&M	Fuel	Current$	CPW 2004$	Current$	CPW 2004$
2004														
2005	116,525	41,616		158,141	145,752		41,616				41,616	38,356	116,525	107,396
2006	1,841,196	42,448		1,883,644	1,745,823	530,604	21,224		8,193	81,190	641,211	583,036	1,242,433	1,162,787
2007		43,297		43,297	1,779,721				16,714	170,513	187,227	729,617	-143,930	1,050,104
2008		44,163		44,163	1,811,588				17,048	176,402	193,451	869,206	-149,287	942,382
2009		45,046		45,046	1,841,546				17,389	181,731	199,120	1,001,630	-154,074	839,916
2010		45,947	8,615	54,563	1,874,990				17,737	184,535	202,272	1,125,612	-147,710	749,378
2011		46,866		46,866	1,901,466			45,895	18,092	187,340	251,327	1,267,593	-204,460	633,873
2012		47,804		47,804	1,926,356			45,895	18,454	190,144	254,493	1,400,100	-206,689	526,256
2013		48,760		48,760	1,949,755			45,895	18,823	192,949	257,666	1,523,749	-208,907	426,006
2014		49,735		49,735	1,971,752			45,895	19,199	195,753	260,847	1,639,118	-211,112	332,634
2015		50,730		50,730	1,992,431			45,895	19,583	198,558	264,036	1,746,748	-213,306	245,683
2016		51,744		51,744	2,011,872			45,895	19,975	201,643	267,512	1,847,253	-215,768	164,619
2017		52,779		52,779	2,030,147			45,895	20,374	204,728	270,997	1,941,091	-218,218	89,057
2018		53,835		53,835	2,047,328			45,895	20,782	207,813	274,489	2,028,692	-220,655	18,637
2019		54,911		54,911	2,063,480			45,895	21,197	210,897	277,990	2,110,460	-223,078	-46,980
2020		56,010	10,502	66,511	2,081,511			45,895	21,621	213,982	281,499	2,186,773	-214,987	-105,262
2021		57,130		57,130	2,095,785			45,895	22,054	217,348	285,297	2,258,057	-228,167	-162,271
2022		58,272		58,272	2,109,205			45,895	22,495	220,994	289,383	2,324,697	-231,111	-215,493
2023		59,438		59,438	2,121,820			45,895	22,945	224,639	293,479	2,386,986	-234,041	-265,167
2024		60,627		60,627	2,133,679			45,895	23,404	228,566	297,864	2,445,254	-237,238	-311,574
2025		61,839		61,839	2,144,829			45,895	23,872	232,212	301,978	2,499,698	-240,139	-354,869
2026		63,076		63,076	2,155,310			45,895	24,349	236,138	306,382	2,550,608	-243,306	-395,299
2027		64,337		64,337	2,165,163			45,895	24,836	240,064	310,795	2,598,207	-246,458	-433,044
2028		65,624		65,624	2,174,426			45,895	25,333	243,990	315,218	2,642,700	-249,594	-468,274
2029		66,937		66,937	2,183,134			45,895	25,840	248,197	319,932	2,684,321	-252,995	-501,187
2030		68,275	12,802	81,077	2,192,855			45,895	26,356	252,404	324,655	2,723,248	-243,578	-530,393
2031		69,641		69,641	2,200,551			45,895	26,883	256,611	329,389	2,759,649	-259,748	-559,097
2032		71,034		71,034	2,207,786			45,895	27,421	261,098	334,414	2,793,709	-263,380	-585,923

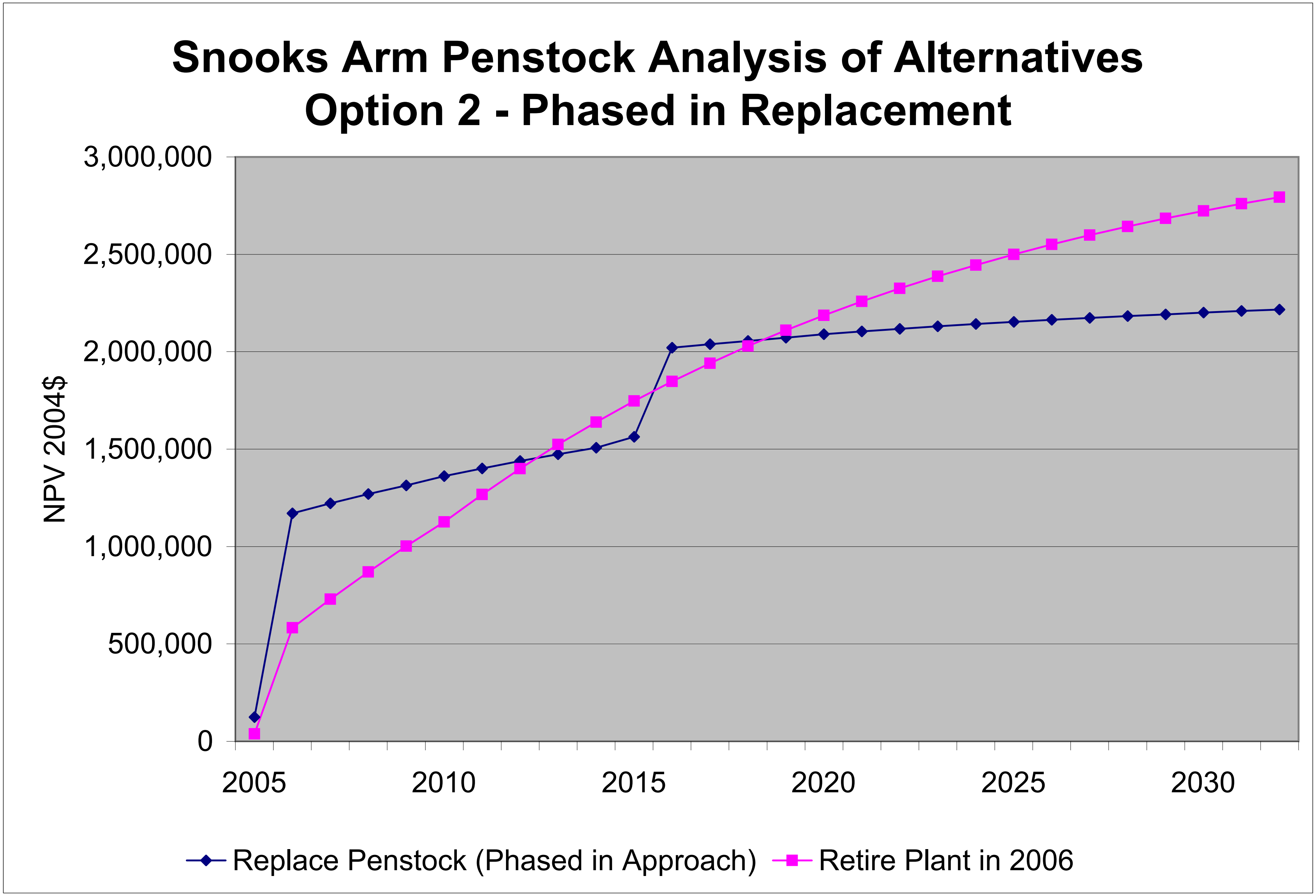

Snooks Arm Penstock Analysis of Alternatives
Option 1 - Full Replacement in 2006
NPV 2004$
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
2005
2010
2015
2020
2025
2030
Replace Penstock in 2006
Retire Plant in 2006

Snooks Arm Penstock Replacement

Option 2 - Phased in Replacement

Assumptions				
Annual Escalation:	2.0%		Engineering - High Pressure Section (2005):	90,000
Discount Rate:	8.5%		Construction - High Pressure Section (2006):	1,100,000
Installed Capacity:	590	kW	Engineering - Low Pressure Section (2015):	50,000
Annual Energy:	3,500,000	kWh	Construction - Low Pressure Section (2016):	900,000
Holyrood Conversion:	624	kWH/BBL	Operator + O&M (2003$):	40,000
Holyrood Var O&M:	4.5	mills/kWh 2004$	Runner Maintenance (2003$):	7,500
Fuel Forecast:	Fall 2002	mills/kWh	Upper Penstock Maintenance (2003$)	20,000
Capacity Value (CT equiv.):	100	$/kW/yr 2004$	Retire Plant in 2006:	500,000

	Replace Penstock (Phased in Approach)					Retire Plant in 2006							Difference	
			Runner &											
	Capital	Plant	Penstock	Sub-total		Capital			Holyrood		Sub-total		TOTAL	
Year	Cost	O&M	Maint.	Current$	CPW 2004$	Cost	Operator	Capacity	Var O&M	Fuel	Current$	CPW 2004$	Current$	CPW 2004$
2004														
2005	93,636	41,616		135,252	124,656		41,616				41,616	38,356	93,636	86,300
2006	1,167,329	42,448	21,224	1,231,001	1,170,337	530,604	21,224		8,193	81,190	641,211	583,036	589,790	587,301
2007		43,297	21,649	64,946	1,221,183				16,714	170,513	187,227	729,617	-122,281	491,566
2008		44,163	22,082	66,245	1,268,984				17,048	176,402	193,451	869,206	-127,206	399,778
2009		45,046	22,523	67,570	1,313,921				17,389	181,731	199,120	1,001,630	-131,550	312,291
2010		45,947	31,589	77,536	1,361,446				17,737	184,535	202,272	1,125,612	-124,736	235,834
2011		46,866	23,433	70,300	1,401,161			45,895	18,092	187,340	251,327	1,267,593	-181,027	133,568
2012		47,804	23,902	71,706	1,438,495			45,895	18,454	190,144	254,493	1,400,100	-182,787	38,396
2013		48,760	24,380	73,140	1,473,594			45,895	18,823	192,949	257,666	1,523,749	-184,527	-50,155
2014		49,735	24,867	74,602	1,506,589			45,895	19,199	195,753	260,847	1,639,118	-186,245	-132,528
2015	63,412	50,730	25,365	139,507	1,563,457			45,895	19,583	198,558	264,036	1,746,748	-124,529	-183,291
2016	1,164,246	51,744		1,215,990	2,020,307			45,895	19,975	201,643	267,512	1,847,253	948,478	173,054
2017		52,779		52,779	2,038,583			45,895	20,374	204,728	270,997	1,941,091	-218,218	97,492
2018		53,835		53,835	2,055,763			45,895	20,782	207,813	274,489	2,028,692	-220,655	27,072
2019		54,911		54,911	2,071,915			45,895	21,197	210,897	277,990	2,110,460	-223,078	-38,545
2020		56,010	10,502	66,511	2,089,946			45,895	21,621	213,982	281,499	2,186,773	-214,987	-96,827
2021		57,130		57,130	2,104,221			45,895	22,054	217,348	285,297	2,258,057	-228,167	-153,836
2022		58,272		58,272	2,117,640			45,895	22,495	220,994	289,383	2,324,697	-231,111	-207,058
2023		59,438		59,438	2,130,255			45,895	22,945	224,639	293,479	2,386,986	-234,041	-256,731
2024		60,627		60,627	2,142,115			45,895	23,404	228,566	297,864	2,445,254	-237,238	-303,139
2025		61,839		61,839	2,153,264			45,895	23,872	232,212	301,978	2,499,698	-240,139	-346,434
2026		63,076		63,076	2,163,745			45,895	24,349	236,138	306,382	2,550,608	-243,306	-386,864
2027		64,337		64,337	2,173,598			45,895	24,836	240,064	310,795	2,598,207	-246,458	-424,608
2028		65,624		65,624	2,182,861			45,895	25,333	243,990	315,218	2,642,700	-249,594	-459,839
2029		66,937		66,937	2,191,569			45,895	25,840	248,197	319,932	2,684,321	-252,995	-492,752
2030		68,275	12,802	81,077	2,201,291			45,895	26,356	252,404	324,655	2,723,248	-243,578	-521,958
2031		69,641		69,641	2,208,986			45,895	26,883	256,611	329,389	2,759,649	-259,748	-550,662
2032		71,034		71,034	2,216,221			45,895	27,421	261,098	334,414	2,793,709	-263,380	-577,488



Snooks Arm Penstock Analysis of Alternatives
Option 2 - Phased in Replacement
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
NPV 2004$
2005
2010
2015
2020
2025
2030
Replace Penstock (Phased in Approach)
Retire Plant in 2006

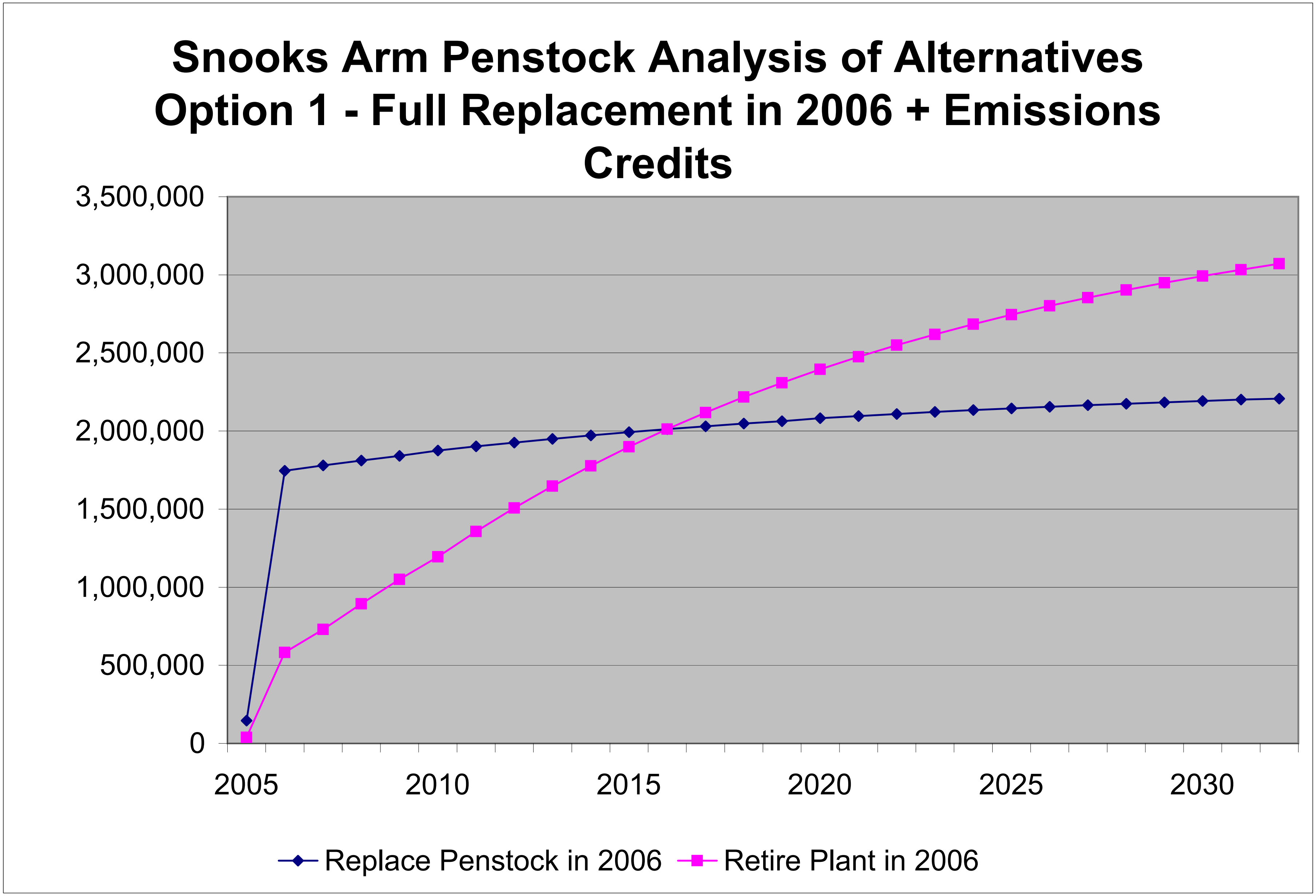
Snooks Arm Penstock Replacement

Option 1 - Full Replacement in 2005/6 + Emissions Credits

Assumptions				
Annual Escalation:	2.0%		Engineering (2005):	112,000
Discount Rate:	8.5%		Construction (2006):	1,735,000
Installed Capacity:	590	kW		
Annual Energy:	3,500,000	kWh		
Holyrood Conversion:	624	kWH/BBL	Operator + O&M (2003$):	40,000
Holyrood Var O&M:	4.5	mills/kWh 2004$	Runner Maintenance (2003$):	7,500
Fuel Forecast:	Fall 2002	mills/kWh	Upper Penstock Maintenance (2003$)	20,000
Capacity Value (CT equiv.):	100	$/kW/yr 2004$	Retire Plant in 2006:	500,000

	Replace Penstock in 2006					Retire Plant in 2006								Difference	
			Runner &												
	Capital	Plant	Penstock	Sub-total		Capital			CO_2 & SO_2	Holyrood		Sub-total		TOTAL	
Year	Cost	O&M	Maint.	Current$	CPW 2004$	Cost	Operator	Capacity	Emissions**	Var O&M	Fuel	Current$	CPW 2004$	Current$	CPW 2004$
2004															
2005	116,525	41,616		158,141	145,752		41,616					41,616	38,356	116,525	107,396
2006	1,841,196	42,448		1,883,644	1,745,823	530,604	21,224			8,193	81,190	641,211	583,036	1,242,433	1,162,787
2007		43,297		43,297	1,779,721					16,714	170,513	187,227	729,617	-143,930	1,050,104
2008		44,163		44,163	1,811,588				34,540	17,048	176,402	227,991	894,130	-183,827	917,459
2009		45,046		45,046	1,841,546				34,540	17,389	181,731	233,660	1,049,524	-188,614	792,022
2010		45,947	8,615	54,563	1,874,990				34,540	17,737	184,535	236,812	1,194,677	-182,250	680,313
2011		46,866		46,866	1,901,466			45,895	34,540	18,092	187,340	285,867	1,356,171	-239,000	545,296
2012		47,804		47,804	1,926,356			45,895	34,540	18,454	190,144	289,033	1,506,661	-241,229	419,695
2013		48,760		48,760	1,949,755			45,895	34,540	18,823	192,949	292,206	1,646,885	-243,447	302,870
2014		49,735		49,735	1,971,752			45,895	34,540	19,199	195,753	295,387	1,777,531	-245,652	194,221
2015		50,730		50,730	1,992,431			45,895	34,540	19,583	198,558	298,576	1,899,241	-247,846	93,190
2016		51,744		51,744	2,011,872			45,895	34,540	19,975	201,643	302,052	2,012,723	-250,308	-851
2017		52,779		52,779	2,030,147			45,895	34,540	20,374	204,728	305,537	2,118,520	-252,758	-88,373
2018		53,835		53,835	2,047,328			45,895	34,540	20,782	207,813	309,029	2,217,145	-255,195	-169,816
2019		54,911		54,911	2,063,480			45,895	34,540	21,197	210,897	312,530	2,309,072	-257,618	-245,592
2020		56,010	10,502	66,511	2,081,511			45,895	34,540	21,621	213,982	316,039	2,394,749	-249,527	-313,238
2021		57,130		57,130	2,095,785			45,895	34,540	22,054	217,348	319,837	2,474,663	-262,707	-378,878
2022		58,272		58,272	2,109,205			45,895	34,540	22,495	220,994	323,923	2,549,258	-265,651	-440,053
2023		59,438		59,438	2,121,820			45,895	34,540	22,945	224,639	328,019	2,618,878	-268,581	-497,058
2024		60,627		60,627	2,133,679			45,895	34,540	23,404	228,566	332,404	2,683,901	-271,778	-550,222
2025		61,839		61,839	2,144,829			45,895	34,540	23,872	232,212	336,518	2,744,573	-274,679	-599,744
2026		63,076		63,076	2,155,310			45,895	34,540	24,349	236,138	340,922	2,801,223	-277,846	-645,913
2027		64,337		64,337	2,165,163			45,895	34,540	24,836	240,064	345,335	2,854,111	-280,998	-688,948
2028		65,624		65,624	2,174,426			45,895	34,540	25,333	243,990	349,758	2,903,480	-284,134	-729,054
2029		66,937		66,937	2,183,134			45,895	34,540	25,840	248,197	354,472	2,949,594	-287,535	-766,460
2030		68,275	12,802	81,077	2,192,855			45,895	34,540	26,356	252,404	359,195	2,992,663	-278,118	-799,807
2031		69,641		69,641	2,200,551			45,895	34,540	26,883	256,611	363,929	3,032,880	-294,288	-832,329
2032		71,034		71,034	2,207,786			45,895	34,540	27,421	261,098	368,954	3,070,459	-297,920	-862,672

** Assumes value associated with reduction of 2814 tonnes CO_2 @ $10/tonne and 32 tonnes SO_2 @ $200/tonne annually


Snooks Arm Penstock Analysis of Alternatives
Option 1 - Full Replacement in 2006 + Emissions Credits
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
2005
2010
2015
2020
2025
2030
Replace Penstock in 2006
Retire Plant in 2006

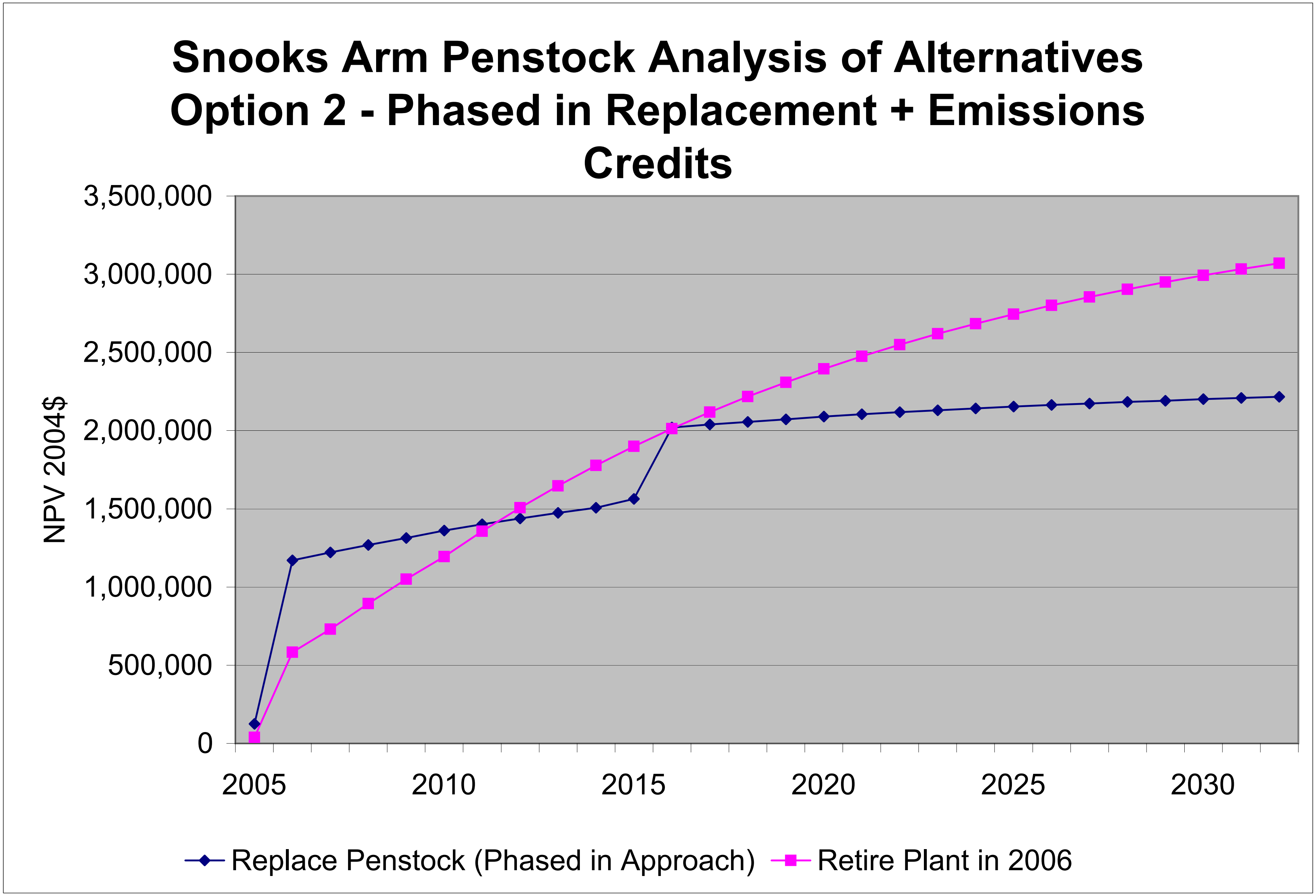
Snooks Arm Penstock Replacement

Option 2 - Phased in Replacement + Emissions Credits

Assumptions				
Annual Escalation:	2.0%		Engineering - High Pressure Section (2005):	90,000
Discount Rate:	8.5%		Construction - High Pressure Section (2006):	1,100,000
Installed Capacity:	590	kW	Engineering - Low Pressure Section (2015):	50,000
Annual Energy:	3,500,000	kWh	Construction - Low Pressure Section (2016):	900,000
Holyrood Conversion:	624	kWH/BBL	Operator + O&M (2003$):	40,000
Holyrood Var O&M:	4.5	mills/kWh 2004$	Runner Maintenance (2003$):	7,500
Fuel Forecast:	Fall 2002	mills/kWh	Upper Penstock Maintenance (2003$)	20,000
Capacity Value (CT equiv.):	100	$/kW/yr 2004$	Retire Plant in 2006:	500,000

	Replace Penstock (Phased in Approach)					Retire Plant in 2006								Difference	
	Capital	Plant	Runner & Penstock	Sub-total		Capital			CO_2 & SO_2	Holyrood		Sub-total		TOTAL	
Year	Cost	O&M	Maint.	Current$	CPW 2004$	Cost	Operator	Capacity	Emissions**	Var O&M	Fuel	Current$	CPW 2004$	Current$	CPW 2004$
2004															
2005	93,636	41,616		135,252	124,656		41,616					41,616	38,356	93,636	86,300
2006	1,167,329	42,448	21,224	1,231,001	1,170,337	530,604	21,224			8,193	81,190	641,211	583,036	589,790	587,301
2007		43,297	21,649	64,946	1,221,183					16,714	170,513	187,227	729,617	-122,281	491,566
2008		44,163	22,082	66,245	1,268,984				34,540	17,048	176,402	227,991	894,130	-161,746	374,854
2009		45,046	22,523	67,570	1,313,921				34,540	17,389	181,731	233,660	1,049,524	-166,090	264,397
2010		45,947	31,589	77,536	1,361,446				34,540	17,737	184,535	236,812	1,194,677	-159,276	166,769
2011		46,866	23,433	70,300	1,401,161			45,895	34,540	18,092	187,340	285,867	1,356,171	-215,567	44,990
2012		47,804	23,902	71,706	1,438,495			45,895	34,540	18,454	190,144	289,033	1,506,661	-217,327	-68,166
2013		48,760	24,380	73,140	1,473,594			45,895	34,540	18,823	192,949	292,206	1,646,885	-219,067	-173,291
2014		49,735	24,867	74,602	1,506,589			45,895	34,540	19,199	195,753	295,387	1,777,531	-220,785	-270,941
2015	63,412	50,730	25,365	139,507	1,563,457			45,895	34,540	19,583	198,558	298,576	1,899,241	-159,069	-335,784
2016	1,164,246	51,744		1,215,990	2,020,307			45,895	34,540	19,975	201,643	302,052	2,012,723	913,938	7,584
2017		52,779		52,779	2,038,583			45,895	34,540	20,374	204,728	305,537	2,118,520	-252,758	-79,938
2018		53,835		53,835	2,055,763			45,895	34,540	20,782	207,813	309,029	2,217,145	-255,195	-161,381
2019		54,911		54,911	2,071,915			45,895	34,540	21,197	210,897	312,530	2,309,072	-257,618	-237,157
2020		56,010	10,502	66,511	2,089,946			45,895	34,540	21,621	213,982	316,039	2,394,749	-249,527	-304,803
2021		57,130		57,130	2,104,221			45,895	34,540	22,054	217,348	319,837	2,474,663	-262,707	-370,442
2022		58,272		58,272	2,117,640			45,895	34,540	22,495	220,994	323,923	2,549,258	-265,651	-431,618
2023		59,438		59,438	2,130,255			45,895	34,540	22,945	224,639	328,019	2,618,878	-268,581	-488,622
2024		60,627		60,627	2,142,115			45,895	34,540	23,404	228,566	332,404	2,683,901	-271,778	-541,787
2025		61,839		61,839	2,153,264			45,895	34,540	23,872	232,212	336,518	2,744,573	-274,679	-591,309
2026		63,076		63,076	2,163,745			45,895	34,540	24,349	236,138	340,922	2,801,223	-277,846	-637,478
2027		64,337		64,337	2,173,598			45,895	34,540	24,836	240,064	345,335	2,854,111	-280,998	-680,513
2028		65,624		65,624	2,182,861			45,895	34,540	25,333	243,990	349,758	2,903,480	-284,134	-720,619
2029		66,937		66,937	2,191,569			45,895	34,540	25,840	248,197	354,472	2,949,594	-287,535	-758,025
2030		68,275	12,802	81,077	2,201,291			45,895	34,540	26,356	252,404	359,195	2,992,663	-278,118	-791,372
2031		69,641		69,641	2,208,986			45,895	34,540	26,883	256,611	363,929	3,032,880	-294,288	-823,894
2032		71,034		71,034	2,216,221			45,895	34,540	27,421	261,098	368,954	3,070,459	-297,920	-854,237

** Assumes value associated with reduction of 2814 tonnes CO_2 @ $10/tonne and 32 tonnes SO_2 @ $200/tonne annually

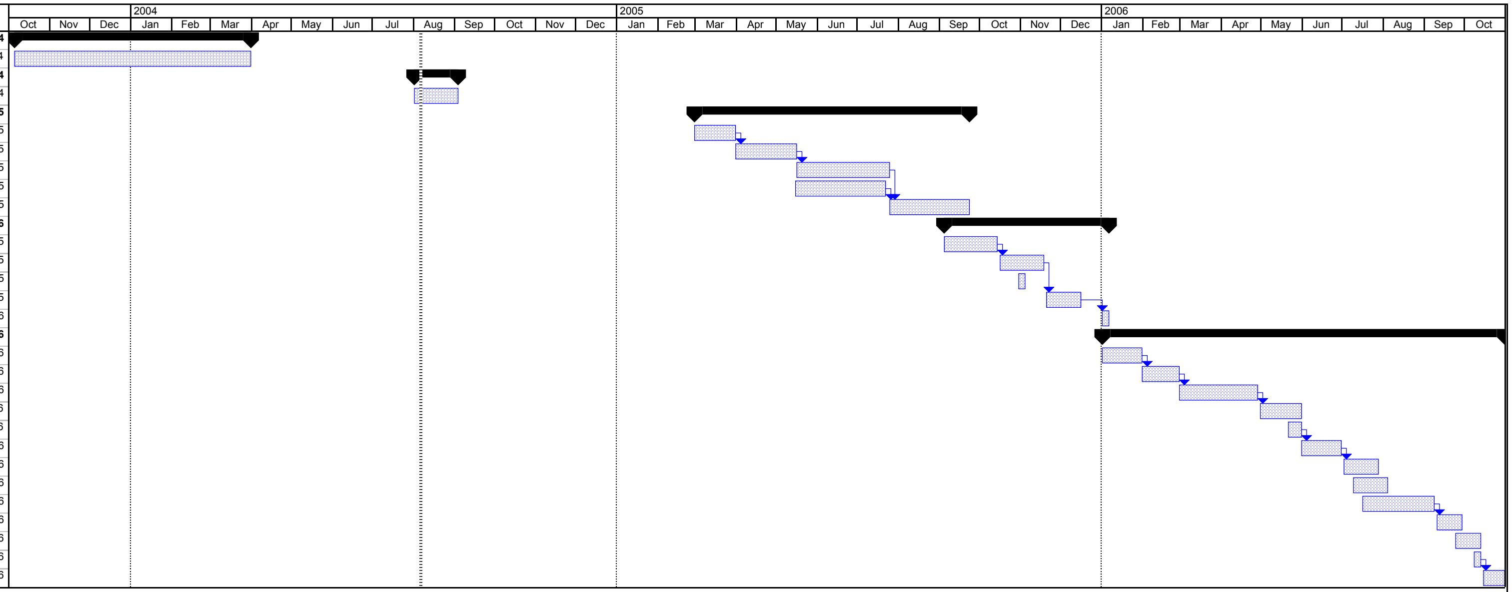


Snooks Arm Penstock Analysis of Alternatives
Option 2 - Phased in Replacement + Emissions Credits
NPV 2004$
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
2005
2010
2015
2020
2025
2030
Replace Penstock (Phased in Approach)
Retire Plant in 2006

APPENDIX D

PROJECT SCHEDULE

ID	Task Name	Duration	Start	Finish
1	**Project Review**	**128 days**	**Mon 10/6/03**	**Wed 3/31/04**
2	CBP Review	128 days	Mon 10/6/03	Wed 3/31/04
3	**PUB**	**25 days**	**Mon 8/2/04**	**Fri 9/3/04**
4	PUB Approval	25 days	Mon 8/2/04	Fri 9/3/04
5	**Pre-Construction**	**149 days**	**Tue 3/1/05**	**Fri 9/23/05**
6	RFP Engineering Services	23 days	Tue 3/1/05	Thu 3/31/05
7	Field Data	32 days	Fri 4/1/05	Mon 5/16/05
8	Options & Recommend.	50 days	Tue 5/17/05	Mon 7/25/05
9	Project Logic	50 days	Mon 5/16/05	Fri 7/22/05
10	Design & Spec	44 days	Tue 7/26/05	Fri 9/23/05
11	**Tender**	**90 days**	**Mon 9/5/05**	**Fri 1/6/06**
12	Prepare Tender	30 days	Mon 9/5/05	Fri 10/14/05
13	Issue Tender	25 days	Mon 10/17/05	Fri 11/18/05
14	Site Visit	5 days	Mon 10/31/05	Fri 11/4/05
15	Evaluation	20 days	Mon 11/21/05	Fri 12/16/05
16	Contract Award	5 days	Mon 1/2/06	Fri 1/6/06
17	**Construction**	**217 days**	**Mon 1/2/06**	**Tue 10/31/06**
18	Documentation	22 days	Mon 1/2/06	Tue 1/31/06
19	Shop Drawings	20 days	Wed 2/1/06	Tue 2/28/06
20	Fabrication	43 days	Wed 3/1/06	Fri 4/28/06
21	Delivery	23 days	Mon 5/1/06	Wed 5/31/06
22	Mobilization	8 days	Mon 5/22/06	Wed 5/31/06
23	Removals	22 days	Thu 6/1/06	Fri 6/30/06
24	Site Preparation	20 days	Mon 7/3/06	Fri 7/28/06
25	Road / Brook Crossings	20 days	Mon 7/10/06	Fri 8/4/06
26	Installation	40 days	Mon 7/17/06	Fri 9/8/06
27	Commissioning	15 days	Mon 9/11/06	Fri 9/29/06
28	Clean-up	15 days	Mon 9/25/06	Fri 10/13/06
29	Demobilization	5 days	Mon 10/9/06	Fri 10/13/06
30	Contract Completion	12 days	Mon 10/16/06	Tue 10/31/06



Project: SA Penstock Schedule
Date: Fri 8/6/04

Task		Progress		Summary		Rolled Up Split		Rolled Up Progress		Project Summary		Deadline	
Split		Milestone		Rolled Up Task		Rolled Up Milestone		External Tasks		External Milestone			

SECTION G
Tab 2

WOOD POLE LINE MANAGEMENT
USING
RCM PRINCIPLES

A Final Report Prepared for Engineering Department, TRO Division

Newfoundland and Labrador Hydro

Report Prepared By

Asim Haldar, Ph. D, P.Eng.

St. John's

Dated: January 9, 2004

EXECUTIVE SUMMARY

Hydro has completed a study entitled **"Wood Pole Line Management (WPLM)"** using **Reliability Centered Maintenance (RCM)** principles. This study covers the management of forty-three (43) wood pole lines across Newfoundland and Labrador of various voltage levels ranging from 69 kV - 230 kV. These lines consist of approximately 26,000 transmission size poles of varying ages, with the maximum age being **38** years. Almost two-thirds of transmission pole plant assets fall into two age categories; approximately 34% are at or over 30 years, and another 31% are 20 to 30 years old. The remaining asset age is less than 20 years old.

The integrity of a wood pole structure is normally compromised by fungi attack which causes decay. Insects and woodpeckers can also damage the wood poles extensively in certain areas. To prevent against fungi attack, poles are normally factory treated with preservatives at the time of purchase prior to installation. Loss of preservative is one of the primary reasons that a wood pole will be susceptible to fungi attack thus inducing decay (loss of sapwood and heartwood) and, if not detected and treated early, the integrity of the structure could be jeopardized. This would also affect the reliability of the line and introduce a safety issue during climbing inspections.

In the past, Hydro has performed pole inspections based on a 5-year interval using the sounding methodology only. It is also true that Hydro had not replaced any significant amount of transmission size poles until 1998 except for line failures due to ice storms. Hydro spent approximately $600,000 dollars to replace 78 poles on the Avalon Peninsula that were rejected (6.5% of the inspected poles) due to internal decay and rot during the 1998 inspection. Based on the inspection in 2000, Hydro also spent an additional $420,000 dollars in 2001 to replace poles in the Central region that were primarily damaged by ant infestation.

The recent pole inspection program on the Avalon Peninsula in 1998 and 2003 revealed that the preservative retention levels for a large portion of these poles fell well below the minimum threshold, which is required to maintain the "health" of the pole on a long-term basis. A quick comparison of Hydro's retention level data with those obtained from a major Canadian utility showed that the preservative amount left on these poles is not only well below this utility's data but also below the minimum threshold. **Fig. 1** depicts the comparison of this data where Zones 1 and 2 represent the other utility's data.

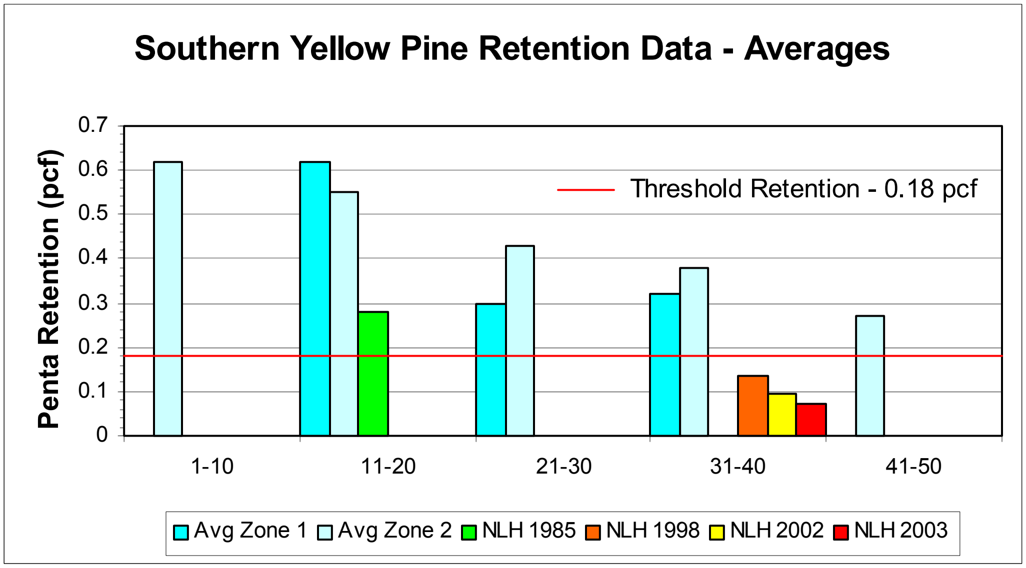


Fig. 1

Even when the inspection does not reveal useful information (i.e. at the early years of operation between 10 and 20 years), the future prediction on pole rejections and/or replacements can still be made using the likelihood of failure by using the pole life expectancy curve known as the IOWA curve, depicted in **Fig. 2**. The curve was validated initially for poles on the Avalon Peninsula using the 1985, 1998 and 2003 pole inspection data. Later, this validation process was extended to cover poles from the Central region based on 2000, 2002 and 2003 data. Although the rejection rate (1 – survival rate) is small in the early part of the 50-year IOWA curve, the rate changes drastically as the poles get closer to their service (economic) life i.e. near 40 years and beyond.

A limited number of full scale tests on in-service poles at the Memorial University also indicated that on average, these poles have lost 25% strength over a 35 year period with regard to their initial mean design strength of 8000 psi. It is not known at this time how fast the strength begins to deteriorate with regard to time once the pole preservative retention level falls below the threshold. It is also recommended that NLH starts implementing NDE as well as periodic full scale tests for all other major line components such as conductors, insulators and hardware particularly for those lines which are 30 years of age or older to develop a historical database on residual strength with regard to aging. This is of considerable importance for developing a sound strategy for asset replacement criteria as well as future life extension work for these wood pole lines. The report also presents a methodology to implement a condition based inspection (CBI) program considering the requirement of a specific line availability and the mean time between failure (MTBF) obtained from historical data.

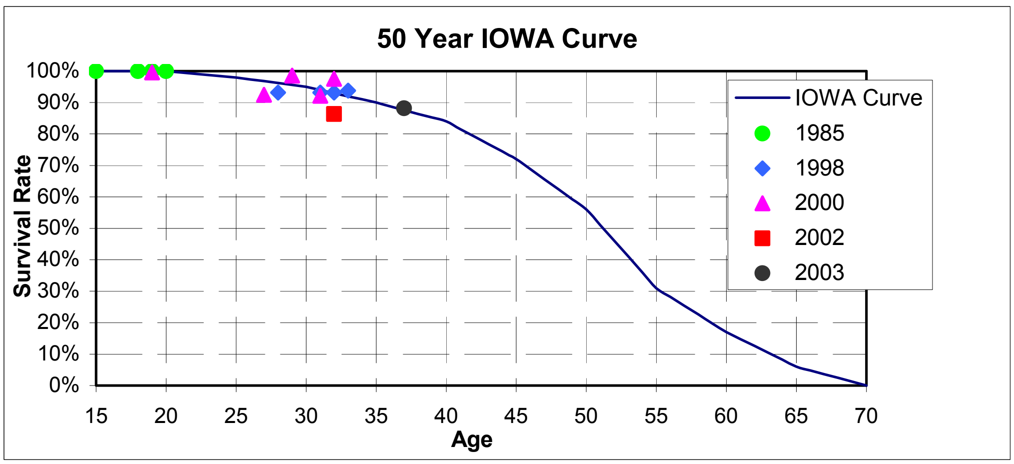


Fig. 2

<u>Deliverables</u>

The proposed annual inspection program will be primarily "visual" in nature**.** Under this program, all wood pole lines will be fully inspected within the next 10 years. Besides routine line inspection work, NLH will also implement a comprehensive pole inspection, test and treatment program, which will continue at least for two "10 year cycles".

The purposes of this Wood Pole Line Management (WPLM) program are:

- to develop a comprehensive RCM program of wood pole lines based on a condition based pole inspection program,
- to establish an inspection program for extending the average service life of all poles in the system by using the conventional sounding and boring techniques supplemented by (1) NDE test of each pole and (2) full scale destructive testing program for a limited number of in-service poles each year,

- to detect the “danger poles” early to avoid safety hazard and premature collapse,
- to implement a full treatment program to ensure an adequate preservative retention level is maintained both internally and externally at specific levels,
- to ensure the decay is arrested at an early stage thus extending the life of the pole plant assets, and
- to develop a comprehensive database to catalogue the inspection and maintenance data

In addition, ten percent (10%) of the poles inspected annually will be tested for preservative retention levels and the data will be analyzed to develop a trend line for future pole rejection and/or replacement criteria.

Since NLH wood pole plant assets are normally assumed to have a 40-year service (economic) life, it is important that these lines are well maintained not only within the service life, but also beyond its economic life. Hydro will be able to extend the asset’s life through maintenance with an effective treatment program, thus not only providing increased reliability but also deferring the cost of building new lines for replacement, once the normal service life has expired. Periodic inspection data will also provide early indication when a transmission line needs to be completely replaced based on the residual strength. This will help System Planning to develop long-term replacement criteria for transmission plant assets.

A detailed cost estimate has been prepared based on the assumption that all work will be done using in house resources and expertise with very limited requirement for external resources. All costs associated with this program are capitalized in view of the fact that the inspection and maintenance programs proposed would extend the life of the pole plant assets. Cost benefit analysis indicates a net benefit of $4.5 million dollars, which is due primarily to the rejection, and/or replacement of a fewer number of poles in future years due to application of remedial treatment. The budget estimate indicates that NLH will be required to commit $36 million dollars over a twenty-year period (two “10 year cycles”) to implement the RCM program for the wood pole plant assets.

Acknowledgements

I would like to thank the Operation Personnel from Bishop's Falls, particularly Howard Richards, Asset Manager for Central Region, Garland Smith, Transmission Specialist, and Garland Quinlan, RCM Analyst for providing me the necessary support and assistance for developing the cost structure for the Wood Pole Line Management Program. Sincere appreciation is expressed to Kyle Tucker, Transmission Line Design Engineer for providing the technical assistance as well as a constructive critique of the document. I would also like to thank Peter Thomas, Sr. Planning Engineer, for providing the technical input for the cost benefit analysis and for reviewing this document. Finally, my special thanks to Mr. Fred Martin, Vice President, TRO, and Mr. Gordon Holden, Acting Director, TRO Engineering for reviewing the document and providing many helpful comments.

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SECTION 1

Introduction

1.0 Background

During the past 15 years Hydro has consistently used the **Reliability Based Design (RBD)** methodology either in the upgrading of existing lines (TL 228, 230 kV steel lines on the Avalon Peninsula, Haldar, 1990, 1997) and/or building new lines (TL 263, TL 236). The RBD methodology takes into account the capital cost of investment in the upgrading of existing lines, or building of new lines, and balances this cost against any future cost of damage (discounted to the present value) and optimizes the design parameters such as span, reliability, etc. **Fig. 1.1** depicts the saddle point where the total cost is minimized.

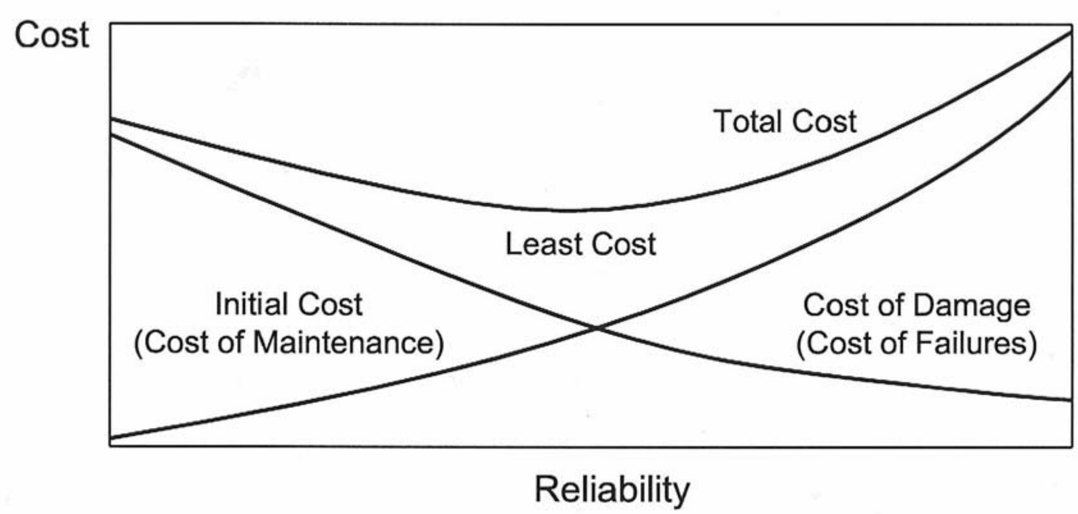


Fig. 1.1 – Optimum Cost Curve

Since 1997, Hydro has been working to implement a Reliability Centered Maintenance (RCM) program in which the cost of preventive and predictive maintenance is balanced against the cost of damage and service interruption. **Fig. 1.1** also captures this idea and shows that in principle, both RBD and RCM methodologies can complement each other to ensure that Hydro gets the best return on its investment during the service life of a transmission line asset.

1.1 Historical Perspective -Wood Pole Inspection Program

Avalon Wood Pole Lines – 1985 Inspection

A pole inspection program on the Avalon Peninsula was launched in 1985 after the sleet storm damage of 1984. This study was conducted by Hydro with the assistance from the Federal Forestry Laboratory at Pleasantville, NL. The inspection program was carried out during the summer of 1985 and the lines inspected were TL 201, TL 203 and TL 218/236. Although no poles were rejected at the time, the study concluded that a few poles had some sort of decay that was in the incipient or early stages. Recommendations were made to treat these poles.

Avalon Wood Pole Study - 1998 Inspection

The Avalon Upgrading study, completed in 1997, recommended the upgrading of the steel transmission line system from Sunnyside Terminal Station to Oxen Pond Terminal Station, and to further study the reliability of wood pole lines on the Avalon Peninsula considering the aging issue. During the study phase, an inspection program of 1500 in service poles (32 years old) on the Avalon Peninsula revealed a 6.5% rejection rate. These rejected poles were replaced in the same year for approximately $600,000 dollars.

A number of full-scale tests of in-service poles at Memorial University revealed they have lost, on average, 25% of their original mean design fibre strength over the past 35 years. However, this data alone was insufficient to predict the residual life of these lines and therefore, a re-conductoring option with an EHSS (Extra High Strength Steel) conductor was not pursued further. Subsequently, this latter study was completed in 2001 with a recommendation not to proceed with the upgrading of these wood pole lines (Haldar, 2001) because of insufficient data with respect to the strength deterioration of these lines.

Development of Current Wood Pole Line Management (WPLM) Program

In an effort to obtain more information on the deterioration of wood poles, Hydro conducted a study in 2002, and from this, a report entitled "Wood Pole Inspection Program-Budget, 2003 & beyond" was issued. This report recommended that Hydro should immediately develop and implement a full wood pole inspection program with Non Destructive Evaluation (NDE) techniques to collect more field data. A comprehensive test and treatment program for both interior and exterior sections of the poles was also proposed to extend their life. Accordingly, a multi-million dollar estimate was proposed based on a program to cover all transmission size poles (26,000 poles) over the next 10 years. The program will include inspection, testing, rehabilitation and, where necessary, replacement.

During the review of this estimate, Hydro decided to undertake the implementation of the program within the RCM framework to ensure that all inspection work associated with these wood pole lines (i.e. not only wood poles but conductors, insulators, hardware, cross braces, guy strands, etc) are completed in a coherent manner and that all wood pole line assets are managed in the most cost effective way. Since 2003, Operations and Engineering have been working closely to provide a "framework" to develop a Wood Pole Line Management (WPLM) program using RCM principles.

Since completion of the 1998 inspection program of poles on the Avalon Peninsula, Hydro has conducted detailed inspection programs: in 2000 lines in the central region; in 2002 TL 220 (Bay D'Espoir Terminal Station to Barachoix Terminal Station); and in 2003 a large number of lines on the Island. Results of these inspection programs are discussed in detail in Section 3 of this report.

1.2 Purpose of the Study

Hydro operates 43 high voltage (69 kV – 230 kV) wood pole transmission lines that total approximately 2400 km. **Fig. 1.2a, b and c** present the age of these lines. Approximately, 42% of Hydro's transmission lines are over 30 years of age and, without a careful assessment of their condition, Hydro's wood pole transmission network could be exposed not only to premature failure under design loading conditions but also to a major pole replacement program in the future.

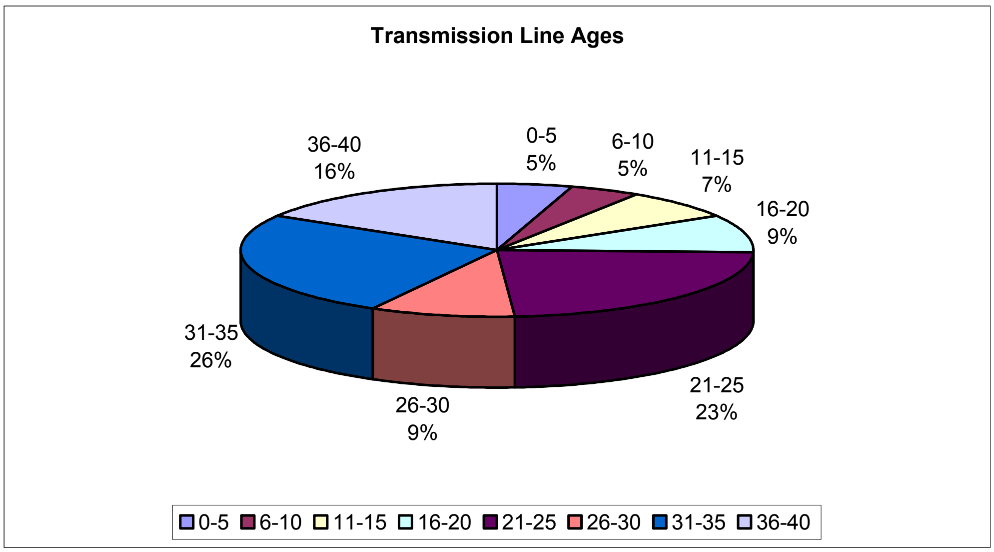


Fig. 1.2a - Transmission Line Ages

Careful planning for possible replacement of these assets is required otherwise Hydro could be exposed to a significant number of forced outages in the future. Therefore, the purpose of this study is to develop a comprehensive "Wood Pole Line Management Program" based on Reliability Centered Maintenance principles that takes into account the cost of inspection and maintenance versus risk scenarios and provides a value-based program which is quite flexible and easy to implement.

The purposes of this Wood Pole Line Management (WPLM) program are:

- to develop a comprehensive **RCM program** for wood pole lines based on a condition based pole inspection program,

- to establish a inspection program for extending the average service life of all poles in the system by using the conventional sounding and boring techniques supplemented by (1) NDE test of each pole and (2) full scale destructive testing program for a limited number of poles removed from service each year,
- to detect the "danger poles" early to avoid safety hazard,
- to implement a full treatment program to ensure an adequate preservative retention level is maintained both internally and externally, and
- to ensure that the decay is arrested at an early stage thus extending the life of the pole plant assets, and
- to develop a comprehensive database to catalogue the inspection and maintenance data for future record and condition based analysis.

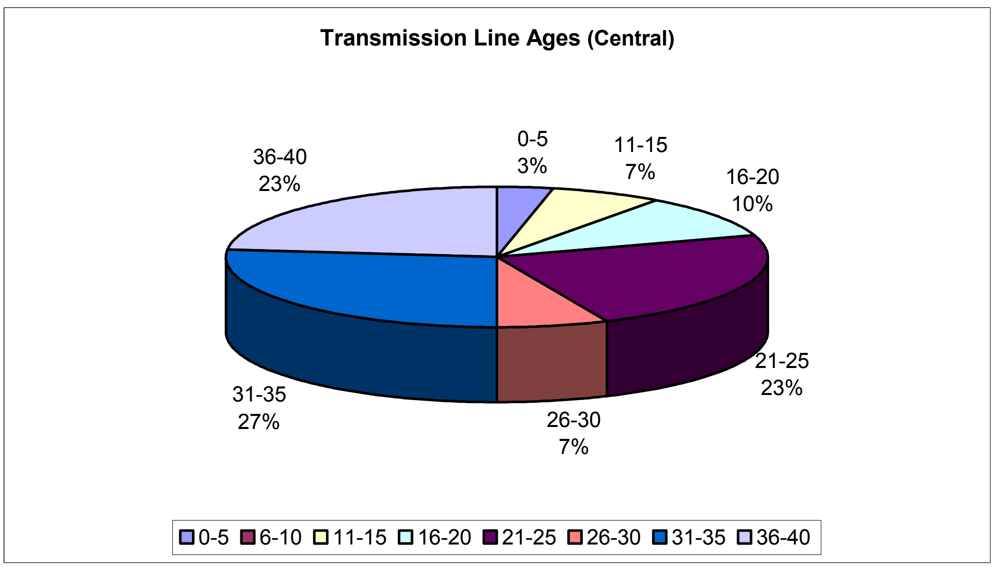


Fig. 1.2b - Transmission Line Ages (Central Region)

The advantages of an effective maintenance program for wood pole lines based on RCM principles are summarized as follows: (1) it provides a mechanism to replace the "danger poles" well in advance before they become problematic or hazardous and (2) Hydro will be able to extend the transmission line asset's life by replacing these poles early enough and maintaining a good treatment program to defer the cost of building new lines for replacement, once the normal service life is expired.

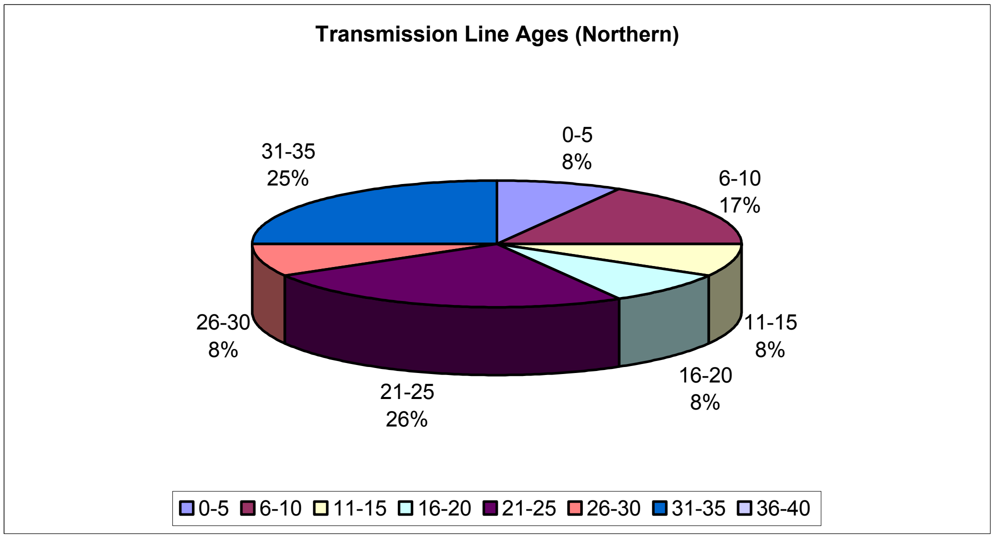


Fig 1.2c – Transmission Line Ages (Northern Region)

1.3 Scope of the Study

To complete this study in a systematic manner various tasks were identified and are listed as follows:

- RCM Methodology;
- Condition Based Inspection Program and Maintenance Strategy;
- Database Development;
- Program Schedule and Cost;
- Summary, Conclusions and Recommendations; and
- References.

SECTION 2

RCM Methodology

2.1 Reliability Centered Maintenance (RCM) of Wood Pole Lines

To understand the RCM principles with particular reference to wood pole lines, one needs to treat the line as a system which can be broken down into various sub-systems as shown in **Fig. 2.1.** The Asset Manager needs to know the condition of the asset (in this case, the condition of the various sub-systems e.g. structures, conductor-hardware etc. or its individual components such as wood poles, conductor, insulators, hardware etc) at present i.e. “year zero” of the future life cycle. The life cycle could be any period of time. A typical period, or life cycle for new wood pole lines is 40 to 50 years.

In order to preserve the system function as well as to optimize the maintenance cost, the manager needs to know the consequence of a failure, identify failure modes that cause the interruption of service and prioritize the function need, and to develop a strategy for specific maintenance tasks that will preserve the system reliability. The primary goal of RCM is to strike an appropriate balance between the cost of maintenance and the customer’s value of reliability (Power System Inc, 1998).

The current maintenance practice of NLH is primarily time based. That is, 20% of each line is inspected and maintained each year to ensure that all lines are fully inspected every 5 years, irrespective of their age. On the other hand, RCM emphasizes **condition based inspection and maintenance (CBIM**) practices where the focus is on preserving system functionality rather than preserving individual components.

Although in principle **RCM** will work for any system, one needs to distinguish one unique characteristic of a transmission line system with regard to other engineering systems, such as aircraft, power plants etc. In these systems, system functionality can be maintained even when a component has failed because of the high redundancy built into the system. Contrary to this, a typical transmission line, in general works as a "series system". That is transmission line failure is normally dictated by the "weak link component" of the system and the prediction of future failure is extremely complicated by the spatial extent of the line and its exposure to widely variable environmental conditions (such as extreme wind and/or ice, vibration, rotting of poles and knee braces, wearing of hardware etc.). Redundancy is only provided through the network system where parallel lines may exist to share the load although during ice storms both lines are exposed equally.

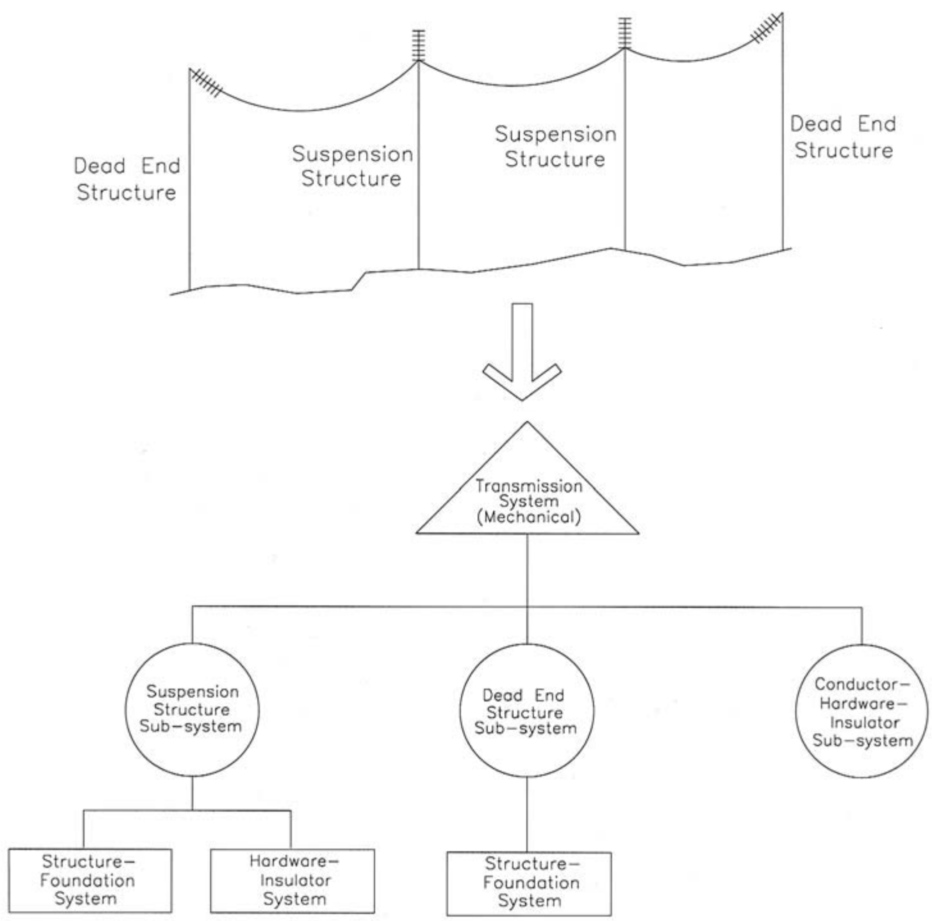


Fig. 2.1 - Transmission Line System

Of course, to implement the **RCM** methodology correctly, one needs to understand the intricate relationships of possible failure modes that could be encountered either due to overloading and/or inadequate strength due to aging. Although **RCM** allows, **"Run to Failure (RTF)"** under certain circumstances, one needs to be extremely careful before this is applied to transmission lines without a proper analysis of the system as a whole and the consequences.

2.2 Model

In **RCM**, it is important that a structured format be developed to evaluate a specific value-based option based on the inspection information provided by the field personnel. This can be accomplished by minimizing the net present value (**NPV)** of the annual expenditures for managing the Wood Pole Line Assets over a predetermined time period, t (e.g. service life). Normally the time period, t, could be identified as part of the estimated service life or the full service life. For a wood pole line, the service life is normally accepted as 40 years.

To ensure that one gets comparable results, future costs must be discounted to the present values.

$$NPV = \sum_{0}^{n} C_i /(1+r)^i \qquad \textbf{(2.1)}$$

where

- **NPV= net present value of the annual expenditures**
- **C_i = the annual expenditures in year i**
- r **= discount rate**
- **n = period undertaken in years**

C_i includes two components: deterministic cost (D_i) which is the planned annual expenditures for inspection and maintenance (historical) in year i, while the probabilistic cost (R_i) is the cost associated with the probability of failure in year, i. This could be failure of a structure (and/or pole), insulator, conductor etc.

$$C_i = D_i + R_i \qquad \textbf{(2.2)}$$

The " risk" is normally defined as the product of the probability of encountering an event (e.g. likelihood of the failure of a wood pole structure) and the consequence (monetary loss normally in dollars) due to this failure. This consequence needs to be assessed at the local level, at the system level and at the company level.

Cost associated with the local level will include the direct cost of replacing the structure and/or refurbishment to bring it to its original reliability level. At the system level, the risk and cost would be the impact on the system due to the loss of a specific line (loss of power sale, additional cost of generation, any penalty or legal consequences from the regulatory body etc.) The risk at the company level could be a major change or shift in the operational inspection and maintenance strategy (e.g. RCM implementation, change in the frequency of inspection) or a major upgrading scenario that may require a significant monetary investment. All these risk values could be potential for gain or exposure to loss.

Risk = (Probability of an event, p_e) X (Consequence, loss or gain L_i) (2.3)

For example, if the annual probability of an event (loss of a structure) is 1% and the consequence of this loss is $20,000 dollars then the annual risk is $200 dollars. By taking certain actions one can either increase or decrease the risk. Each one of these actions needs to be evaluated to ensure that the NPV of the annual expenditures is minimized. Various options can be weighted by assessing "risk" in an objective manner as well as in a quantitative manner provided one has sound data based on historical record.

2.2.1 Understanding Failure Probability and Consequence

Fig. 2.2 depicts the graphical representation of risk where four specific combinations of probability of occurrence and consequence are shown. This figure divides the coordinate system in four quadrants. The four arrows show the point of direction along which point "A" can move thus creating a change in the risk value. Obviously, Option III is most preferable while Option I is the least preferable.

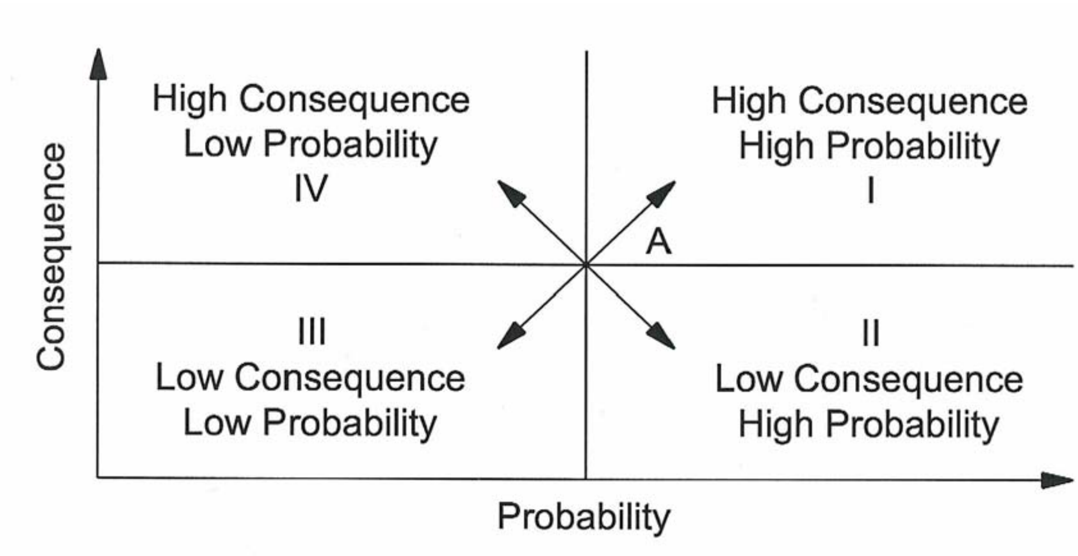


Fig. 2.2 – Risk Evaluation (Jones, 1995)

Through the collection of good quality data, Hydro can control the parameters in Equation 2.3 and thus reduce the uncertainty in the amount of risk exposure. Collection of meteorological data for example can provide for a better understanding of the probability of a severe icing event, and allow for measures to be taken to reduce the consequences, thus reducing the risk. Similarly, monitoring conductor vibration can provide information on the probability of wire fatigue allowing proactive measures to be taken to reduce this probability, and consequentially reduce the risk. Both events can lead to serious consequences through cascade failure; however better understanding through good quality information collection can reduce the risk of exposure.

For an overhead transmission line, risk of failure, R_i, during a time interval, Δt, (which can be part of or full service life) can be assessed in economic terms such as NPV and will be a function of time since both p_e and L_i will also vary with time. The Avalon Wood Pole Study report (2001) showed that p_e is time dependent because of the aging issue of strength deterioration over time. From the above discussion the risk can be controlled by either (CIGRE, 2000):

- Controlling the likelihood of the occurrence, p_e; or
- Controlling the magnitude of the resulting consequences, L_i.

In general, the risk of failure, R_i, is a function of the planned annual expenditures, D_i, which includes routine inspection, maintenance and operating costs. Sometimes the "risk" could be defined also in non-economic terms when strategic issues or policies are involved.

2.2.1.1 Example Problem

Assume a 230 kV line crosses the Trans Canada Highway (**TCH)** and there are two dead end structures on either side of the highway. The original design was based on 25 mm of ice with a 50-year load (annual probability, p_e =0.02) but recent experience has shown that this ice load was underestimated in the region and the new p_e is 0.10 (1 in 10 years). If the consequence of dropping the conductor is L_i = $ 1, 000,000 dollars (legal damage due to an accident which could cause an injury), then the risk of failure under the revised occurrence estimate is $ 100,000 dollars (p_e x L_i = 0.1 x $ 1, 000,000).

However by replacing the conductor for one span with a high strength alloy conductor, the original design probability of failure p_e = 0.02 can be realized. If the cost of replacing the conductor is $20,000, this cost can easily be justified because of the net reduction in the annual risk is $80,000 (i.e. $100,000 - $20,000). In this case it is worth spending the money (planned operating expenditures, D_i) to minimize the potential future risk of failure, R_i.

However, if the consequence of dropping the conductor is = \$100,000 dollars (if it can

\$20,000). In this case it may not be beneficial to do the upgrade.

The above example problem shows conceptually the importance of this risk assessment for evaluating various economic options and making decisions with regard to the management of the overhead line assets.

2.3 Predictable Failure Events

Fig. 2.1 depicted a typical line system, which consisted of various subsystems, and each subsystem was further broken down into many components. To determine a predictable failure rate, the line can be modeled as a system and the strength of the weakest link can be equated to the load induced stress (Avalon Study report, 1998). In order to determine the in-service strength of each component, a proper inspection program is necessary to assess the present capability of the line. This is discussed in Section 3.

The probability of failure of a component can be estimated based on the analysis of load and strength distributions. However, whether a line will see a progressive failure or not will depend on the specific failure mode of a component, line characteristics (terrain), extent of the spatial load effect, etc. For example, failure of a "suspension" insulator string will drop the phase and the line will not see progressive damage. However, the failure of an insulator in the dead end structure could initiate a cascade effect and thus induce major line damage.

The most important thing is to know each component's residual strength based on a good condition-based inspection (CBI) program. Since the line components are made of different materials and are subjected to many types of deterioration such as wear, fatigue, vibration, deformation, corrosion etc, they will deteriorate at different rates. **Fig. 2.3a** depicts a typical failure rate curve (known as the "bath tub" curve) showing the expected failure rate of a component or a system. **Fig. 2.3b** shows a typical "bath tub" curve with two different deterioration rates obtained from past historical inspection records. As can be seen, one would expect that poles, having a shorter life, would have a high failure rates from 50 to 60 years, whereas conductor, having a longer life, would have an increased failure rates from 65 to 80 years.

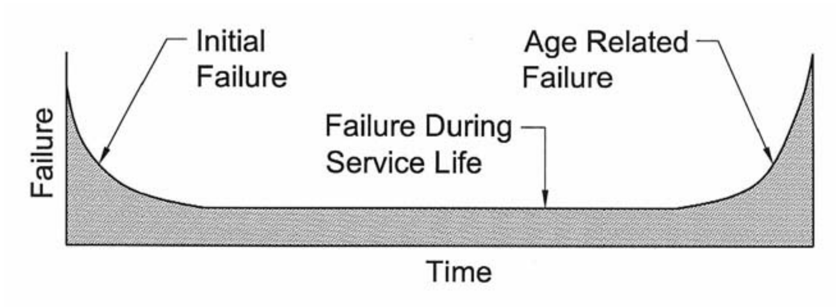


Fig. 2.3a - Typical Failure Rate "Bath Tub" Curve (Jones, 1995)

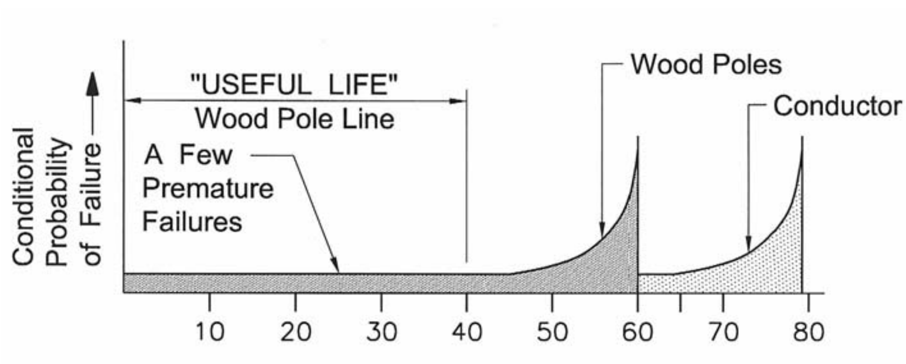


Fig. 2.3b - "Bath Tub" Curves for two components with different deterioration rates

It is important that a good database be developed with past history to ensure that the residual strength and performance of the component can be predicted and the new "weak link" can be established to assess the line reliability.

At any stage, NPV analysis can be carried out following the example shown earlier to justify whether a major component replacement program is necessary. NPV analysis can combine total expected annual expenditures due to ice load failure as well as hardware failure due to excessive wear in a comprehensive manner. The important thing is to analyze each failure's root cause and develop a systematic database to assess various information required to determine the failure rate.

2.4 Unpredictable Failure Events

The term "unpredictable" itself indicates that the failure probability cannot be estimated based on objective analysis. Natural disasters such as major ice storms (e.g. 1998 Quebec storm), typhoons, tornadoes, floods may have a very low probability of occurrence; however, proactive actions cannot be taken to withstand their effects because it may not be economically feasible. Therefore the probable occurrence level needs to be assessed based on judgment, any past experiences and the probability assigned on a subjective basis.

2.5 Consequences

Consequence evaluation depends primarily on the function of an overhead transmission line within the overall system. For example consequence of losing a radial line would be significantly different than to the loss of a line where there is redundancy. Consequences resulting from an extended outage of an overhead line are site and function specific and could be considerable. To develop the current line management program, a ranking of all lines was developed to set up the priority for inspection; details of this will be discussed in Section 6 under "Schedule and Cost". In general the failure effect of a line can be felt at three different levels. These are (a) Company level, (b) System level and (c) Local level. The following provides a list of items that could be considered under each of these levels (CIGRE, 2000).

Company Level

- Injury or death;
- Serious environmental damage;
- Frequent failures (perception problem, political implication); and

- Certain failures that could trigger a major outage in the system.

System Level

- Additional generation to support the system;
- Revenue loss;
- Penalties due to non supply of energy; and
- Regulatory problems; reliability issue if there are too many failures.

Local Level

- Replacement of a structure or any other components or a line that may have failed.

SECTION 3

Condition Based Inspection (CBI) and Maintenance Strategy

3.1 Component Life and Condition Monitoring

A wood pole transmission line consists of many components as shown in **Fig. 2.1**, structures, conductors and insulators are normally considered to be the major components. In this section, some of the issues related to the integrity of these components, how to inspect and monitor the condition of these components and how to develop an appropriate cost effective maintenance strategy are discussed. This section also provides information on various diagnostic, non-destructive tools that are available currently in the market to assist in the condition monitoring process.

3.2 Structural System

The structural system in a wood pole line normally consists of two or three poles, cross braces, knee braces and/or cross arms, connecting bolts and hardware. The primary damage that these poles are subjected to is the loss of mechanical strength. The loss of mechanical strength can be due to loss of fibre strength due to aging and decaying of wood and/or loss of shell thickness due to fungi attack, insects and woodpeckers. **Fig. 3.1** depicts some relative stress distributions for typical structure configurations. The shaded areas show where the stresses are severe.

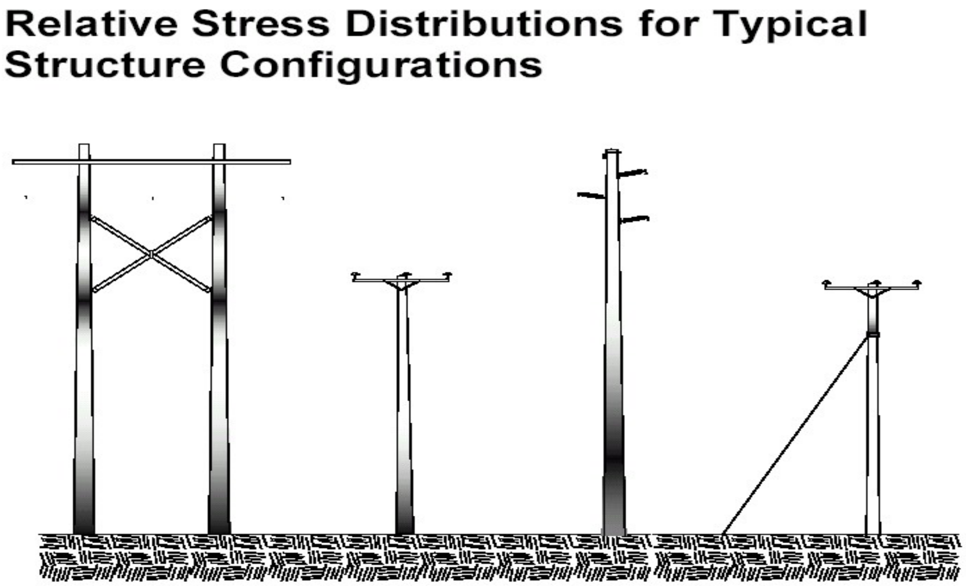


Fig. 3.1 - Relative Stress Distributions (EDM Presentation, 2003)

To guard against fungi attack, poles are normally treated with preservatives at the time of purchase prior to installation. In rare circumstances, untreated cedar poles are used in sensitive areas such as zones designated for community water supply. Treatment of wood poles is specified under the AWPA standard, which sets minimum levels of penetration and retention of preservatives for wood poles and define process limitations for each species. Within Hydro's transmission system, there are three (3) types of pole species, namely Douglas Fir (DF), Southern Yellow Pine (SYP) and Western Red Cedar (WRC). All three species are full-length pressure treated with either pentachlorophenol or creosote while some Western Red Cedar poles are only butt treated with creosote. Southern Yellow Pine poles in environmentally restricted zones are treated with Copper Chromated Arsenic (CCA) and, as stated above, untreated Western Red Cedar poles are now used in highly restrictive zones. **Table 3.1** presents the current minimum retention level for various preservatives based on each species. As shown in the table, creosote is no longer accepted at Hydro as a pole preservative; however the standard prior to removal has been provided.

Table 3.1 - Minimum Retention Levels For New Poles (NLH Standard)

Species	*Treatment (NLH Standard)*	*Retention kg/m3 (pcf)*
Western Red Cedar	Penta	12.8 (0.8)
	CCA	9.6 (0.6)
	Creosote (no longer accepted)	72 (4.5)
Coastal Douglas Fir	Penta	7.2 (0.45)
	Creosote (no longer accepted)	128 (8.0)
Southern Yellow Pine	Penta	4.8 (0.3)
	CCA	9.6 (0.6)
	Creosote (no longer accepted)	128 (8.0)

3.2.1 - Pole Age Distribution

Fig. 3.2a shows the distribution of all 26,000 transmission size poles on NLH system by age. This shows that approximately 34% of the transmission size poles (9000 in-service poles) are over 30 years age. **Figs. 3.2b** and **3.2c** present the age distributions for central and northern regions respectively.

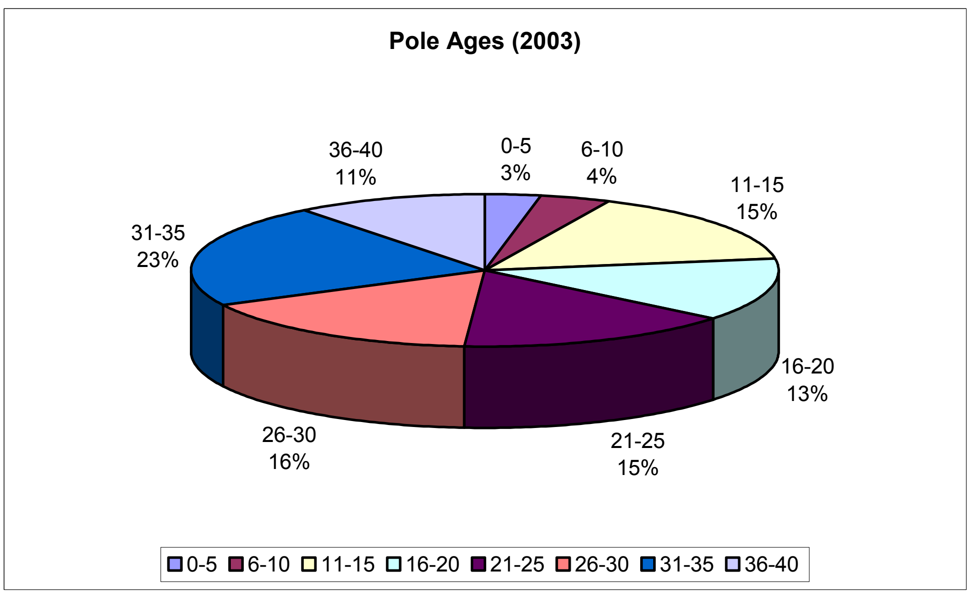


Fig. 3.2a - Pole Age Distribution (2003)

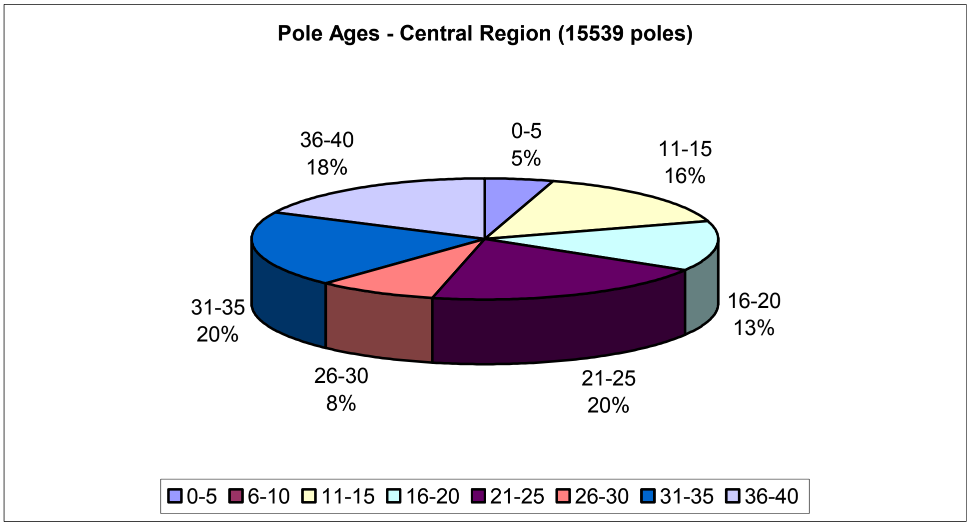


Fig. 3.2b - Pole Age Distribution (Central Region)

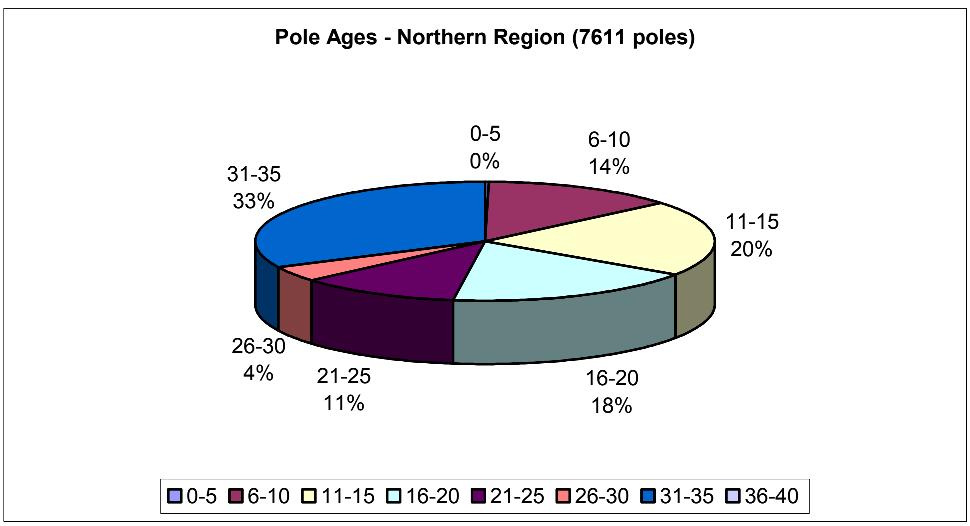


Fig. 3.2c - Pole Age Distribution (Northern Region)

3.2.2 Why Test and Treat Poles?

Fig. 3.3 depicts a typical graph, which shows how the preservatives deplete typically over time ("Yellow" line). The ordinate values in **Fig. 3.3** do not necessarily represent the actual amount of preservative (kg/m^3), but is only used to show the depletion trend. As the level of preservative depletes and falls below the threshold line ("Green" line), poles become more and more susceptible to fungi and insect attacks. For pentachlorophenol (penta) treated poles, the typical threshold value is 0.18 lb/ft^3. If the exposed pole does not have the preservative level restored early enough, particularly at 50% of their expected service life (20 to 25 years), the pole is exposed to decay which leads to degradation of strength (i.e. significant loss of sapwood for Southern Yellow Pine or heartwood for Douglas Fir) and make the pole structurally unsafe.

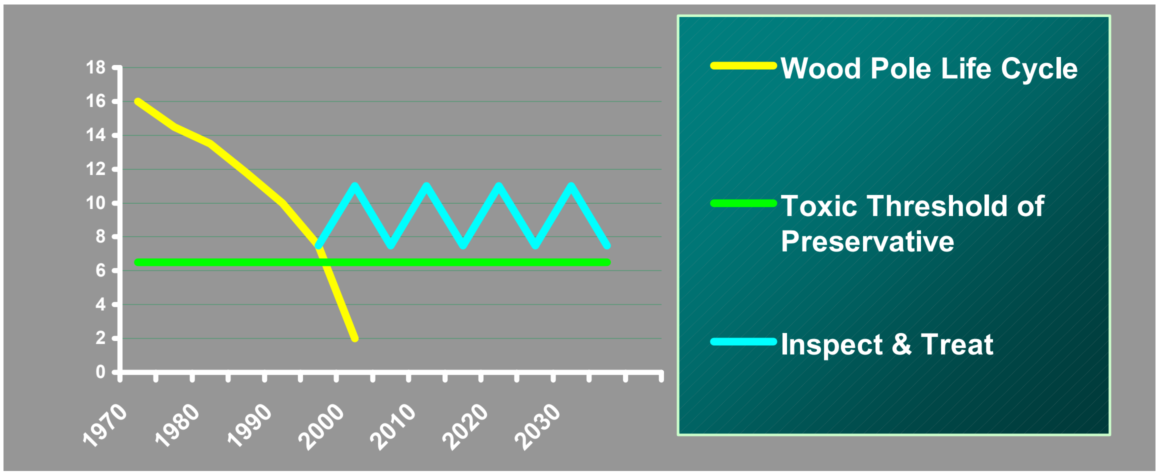


Fig. 3.3 – Typical Depletion Rate of Preservatives (GENICS, 1998)

By inspecting poles at a regular interval and treating the poles at critical zones before they have lost their preservatives to the threshold level **("blue line")**, one can extend the service life significantly. Through an inspection and treatment program, Hydro will be able to extend the transmission line asset's life by replacing and treating poles early enough to ensure not only increased reliability and safety, but also deferral of the cost of building new lines for replacement. Periodic inspection data will also provide early indication when a transmission line asset needs to be replaced completely based on the residual strength. This will assist System Planning to develop a long-term replacement criteria for wood pole transmission line assets. In addition, regular inspections will identify "danger poles" early and by replacing those poles, safety can be improved in the future through the avoidance of accidents.

The benefits of a pole inspection program are:

- to detect the "danger poles" early to avoid safety hazard;

- to detect the poles which are at early stages of decay so that corrective action can be taken to extend the life of these poles (treating with preservatives and/or additional support below ground line); and
- to establish a continuing maintenance program for extending the average service life of all poles in the system.

3.2.3 Inspection Techniques

The pole inspection program includes the following inspection techniques:

- Visual inspection from groundline to the top of the pole including
  - Climbing inspection;
  - Excavation near the ground line;
- Sound and bore (**Fig. 3.4a**);
- NDE measurement (strength) only for poles (**Fig. 3.4b** and **c**);
- Core samples and retention level analysis (samples); and
- Selected sample tests at MUN (destructive - **Fig. 3.4d**).

Fig. 3.4a depicts the tools required to carry out inspection based on sounding and boring. **Fig. 3.4b** depicts the Resistograph, which through the use of a 3mm drilling needle and resistance measurement, profiles the poles core. **Fig. 3.4c** shows the nondestructive PoleTest tool for strength evaluation based on ultrasonic principle. **Fig. 3.4d** depicts the full-scale test bench developed at Memorial University's Engineering laboratory for

Figure 3.4a - Inspection Tools

Figure 3.4b - Resistograph in Use

Figure 3.4c - PoleTest in Use

Figure 3.4d - MUN Test Bed

3.2.4 Past Inspection Programs

The following sections provide a brief summary of various NLH inspection programs conducted since 1985. These inspections are separate from the routine line maintenance inspection carried out by operation and maintenance personnel. The line maintenance inspection program is primarily a time based preventive maintenance program. Under the new RCM program, NLH will inspect every pole by sounding and boring to ensure that data is collected to estimate the internal and external rot conditions as well as residual strength. Preservative levels for a selected sample group will be collected and analyzed for remaining retention level.

Since 1998, NLH has added nondestructive inspection using PoleTest equipment to collect strength data for in-service poles. In addition, core samples are taken from 10% of the pole population for further retention analysis to determine the preservative level remaining. This field inspection program was augmented by carrying out limited destructive tests at MUN to determine the breaking strength of in-service poles. The purpose was to correlate the full-scale strength data with the preservative depletion rate to predict the estimated residual life of the pole plant assets.

The first inspection program was conducted on the Avalon Peninsula in 1985 after the 1984 sleet storm damage. The second program was completed in 1998-2000 and included poles on the Avalon Peninsula as well as selected lines from the Central region. The third program was completed in 2002 with the inspection, testing and treatment of poles on TL 220. In 2003, the inspection program was expanded to include poles from the Northern Peninsula, as well as in the Central region.

1985 Pole Inspection Program

Table 3.2 presents the results of the 1985 pole inspection and **Fig. 3.5** summarizes the primary defects. This program was performed on Avalon Peninsula poles only.

Table 3.2 - 1985 Pole Inspection Program – Summary

1985	*TL201*	*TL203*	*TL218*	*TL236*	*Total*
Constructed (Age at inspection)	1966(19)	1965(20)	1970(15)	1966(19)	
Total Poles on each line	754	424	93	125	1394
Poles Inspected	754	424	93	125	1394
Rejected	0	0	0	0	0
Poles to Monitor	22	27	5	6	60
	Prominent Defects				
External Decay	1	3	1	8	13
Major Shell Separation	15	28	1	3	47
Internal Decay	0	9	7	13	29
Ant Damage	0	1	N/A	N/A	1
Wood Pecker Holes	48	2	N/A	N/A	50

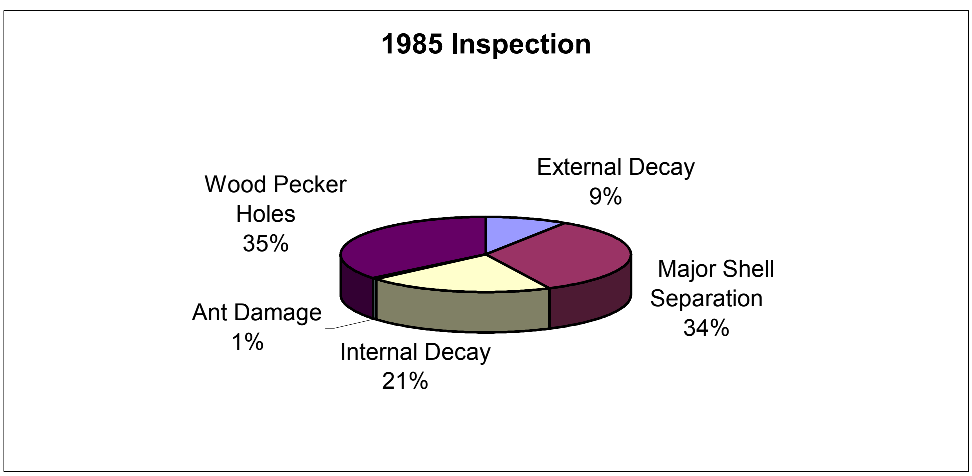


Fig. 3.5 – 1985 Pole Inspection Program – Primary Defects

Fig. 3.6 depicts the results of the retention analysis for pentachlorophenol (penta) treated poles. The analysis indicates that a small portion of this sample size did not meet the minimum preservative retention threshold in the 1985 inspection

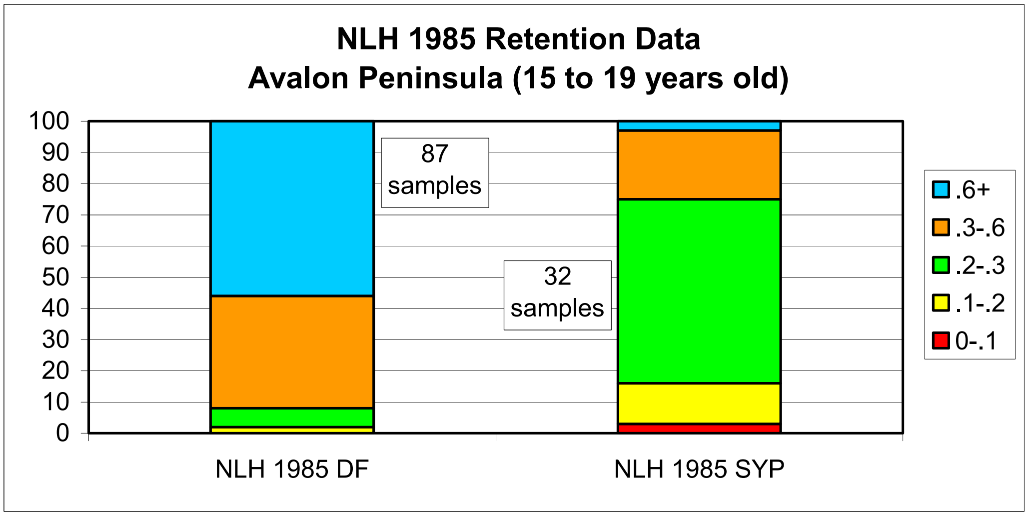


Fig. 3.6 - 1985 Pole Inspection Program - Retention Data

1998 Pole Inspection Program

In 1998, with inspection services provided by Genics Can. Inc., NLH inspected all 1445 in-service poles on the same lines as the 1985 inspection program. This number is higher than the 1985 inspection due to the upgrading of TL 201 at Hawke Hill and Brigus Junction. Of the poles that were inspected, 1201 were of original vintage, reduced from the 1985 inspection primarily by excluding the upgraded sections and the poles replaced during the 1994 failure of TL 201. **Fig. 3.7** depicts the causes of rejections. In this inspection, 6.5% of the poles of original vintage were rejected.

Table 3.3 - 1998 Pole Inspection Program – Summary

1998	*TL201*	*TL203*	*TL218*	*TL236*	*Total*
Constructed (Age at inspection)	1966(32)	1965(33)	1970(28)	1966(32)	
Total Poles on each line	806	422	88	129	1445
Poles Inspected	806	422	88	129	1445
Rejected	45	24	4	5	78
Poles to Monitor	10	2	0	0	12
	Prominent Defects				
External Decay	0	12	1	0	13
Major Shell Separation	28	15	1	0	44
Internal Decay	13	11	3	5	32
Ant Damage	7	4	0	0	11
Wood Pecker Holes	10	2	0	0	12

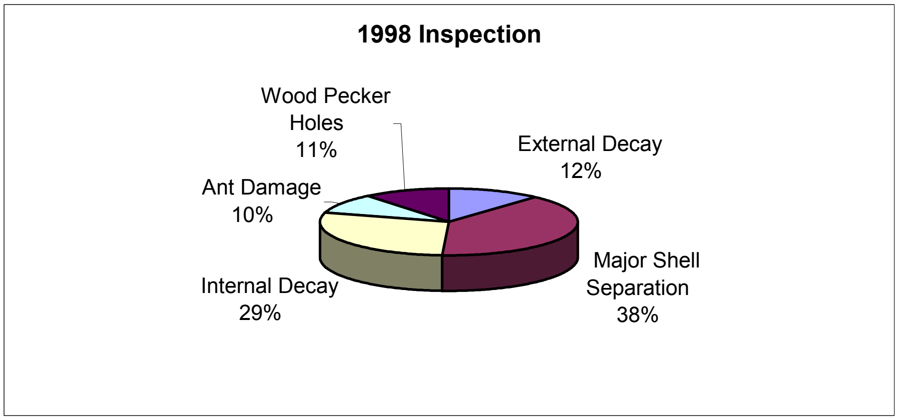


Fig. 3.7 – 1998 Pole Inspection Program - Primary Causes For Rejection

Preservative Depletion

In addition to inspection services, the contractor extracted 121 cores from randomly selected treated poles and the samples were analyzed for preservative retention levels. Sixty poles out of this sample size had full-length penta treatment. Based on the inspection program and core sampling, it was found that 48% of the penta treated poles of 1966 vintage sampled for retention level analysis did not meet the minimum threshold level ("Green Line" in **Fig. 3.3**) for preservative retention and therefore required immediate treatment to arrest the further progression of decay (GENICS, 1998). Only Douglas Fir (DF) and Southern Yellow Pine (SYP) poles are reported in **Fig. 3.8** as the Western Red Cedar poles were butt treated and yielded no results.

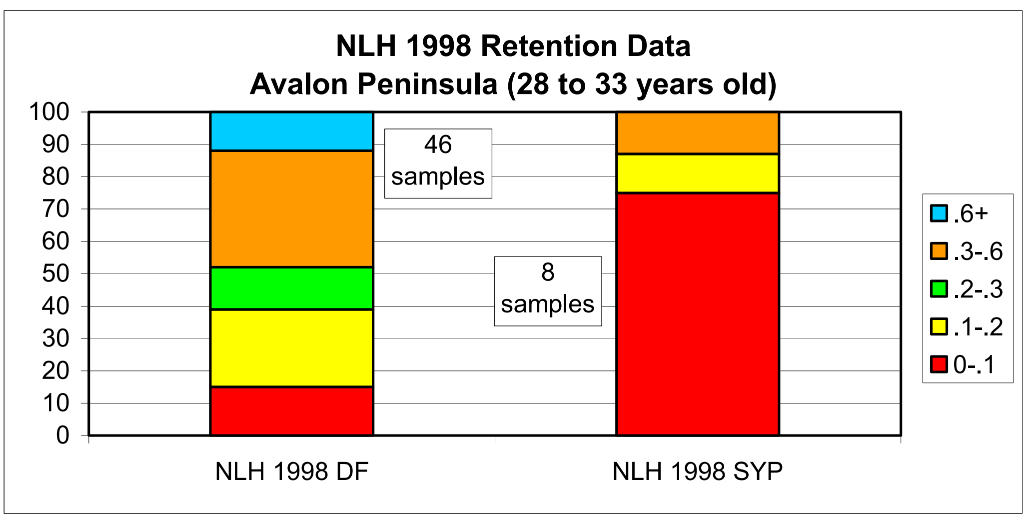


Fig. 3.8 - 1998 Pole Inspection Program – Retention Data

2000 Pole Inspection Program

In August of 2000, NLH contracted TSI to carry out an inspection and treatment program on several wood pole lines located in the central region of the island. **Table 3.4** depicts the results of this inspection and shows that 5.1% of the poles were rejected. **Fig. 3.9** depicts the primary rejection causes. No cores were extracted during this inspection year, so data on preservative retention levels are not available.

Table 3.4 - 2000 Pole Inspection Program – Summary

2000	*TL209*	*TL215*	*TL224*	*TL233*	*TL234*	*Total*
Constructed (Age at inspection)	1971(29)	1969(31)	1968(32)	1973(27)	1981(19)	
Total Poles on each line	185	437	825	1280	489	3216
Poles Inspected	74	257	331	637	243	1541
Rejected	1	20	8	48	1	78
Poles to Monitor	0	0	0	0	0	0
		Prominent Defects				
External Decay	0	0	0	0	0	0
Major Shell Separation	0	0	0	0	0	0
Internal Decay	1	8	7	4	0	20
Ant Damage	0	10	1	44	1	56
Wood Pecker Holes	0	2	0	2	0	4

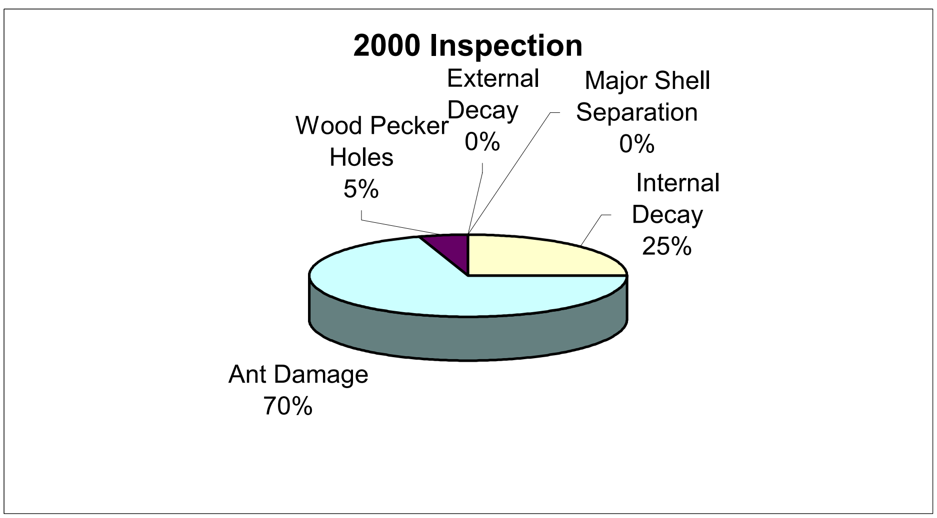


Fig. 3.9 – 2000 Pole Inspection Program – Primary Causes For Rejection

2002 Pole Inspection Program

In 2002, GENICS Can Inc. was contracted to provide inspection and treatment services for the inspection of TL 220. Details of the results of this inspection are tabulated below in **Table 3.5**. **Fig 3.10** provides the primary causes for rejection.

Table 3.5 - 2002 Pole Inspection Program – Summary

2002	*TL220*
Constructed (Age at inspection)	1970(32)
Total Poles on the line	786
Poles Inspected	273
Rejected	37
Poles to Monitor	0
Prominent Defects	
External Decay	1
Major Shell Separation	36
Internal Decay	10
Ant Damage	0
Wood Pecker Holes	0

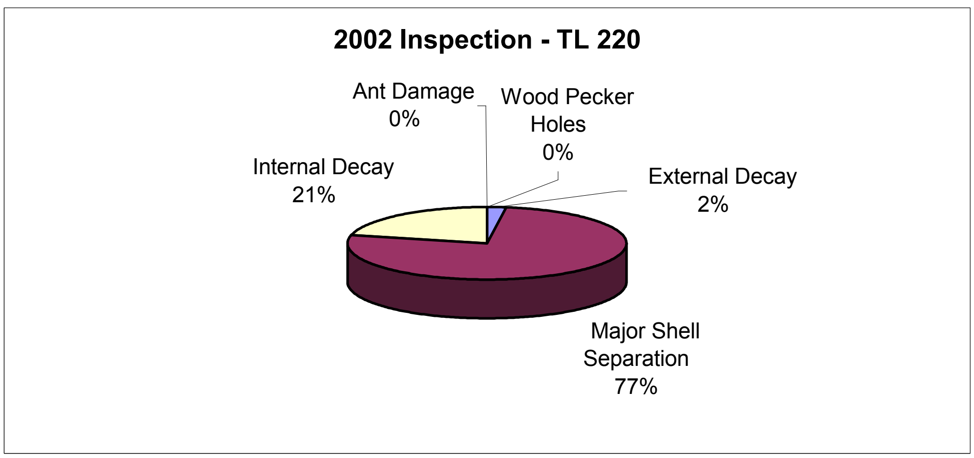


Fig. 3.10 – 2002 Pole Inspection Program – Primary Causes For Rejection

Fig. 3.11 depicts the preservative retention levels for poles on TL 220. It shows that 80% of the sample tested fell at or below the minimum threshold value.

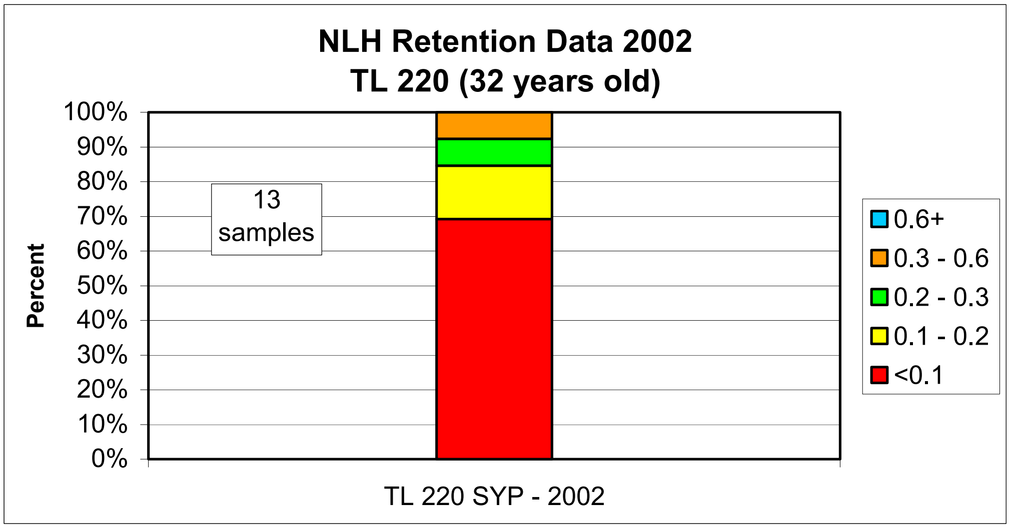


Fig. 3.11 – 2002 Pole Inspection Program – Retention Data

2003 Pole Inspection Program

In 2003, TRO Operations crews performed the inspection program. Although this program was spread across the island, with an estimated 1500 poles inspected, only Southern Yellow Pine and Douglas Fir data from TL 201 was extracted and tabulated in this report from the vast amounts of data collected due to the limited time available to process the paper forms.

Table 3.6 – 2003 Pole Inspection Program – Summary

2003	*TL201*
Constructed (Age at inspection)	1966(37)
Total Poles on the line	806
Poles Inspected	256
Rejected	10
Poles to Monitor	12
Prominent Defects	
External Decay	0
Major Shell Separation	3
Internal Decay	5
Ant Damage	2
Wood Pecker Holes	0

Fig. 3.12 depicts the primary causes of rejection, and **Fig. 3.13** depicts the results of the preservative retention level analysis for penta treated poles. **Fig 3.13** shows that a large

portion of this sample size, did not meet the minimum threshold level indicating that the poles are exposed to further decay. It should be noted that in the 1998 inspection 48% of the samples did not meet the threshold, but by 2003 this had increased to 71%, thus indicating a significant depletion of preservative over a five-year period.

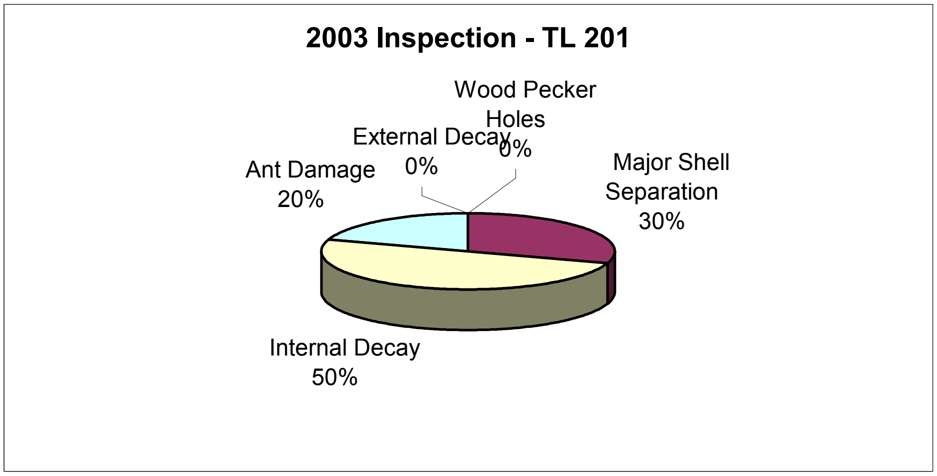


Fig. 3.12 – 2003 Pole Inspection Program - Primary Causes For Rejection

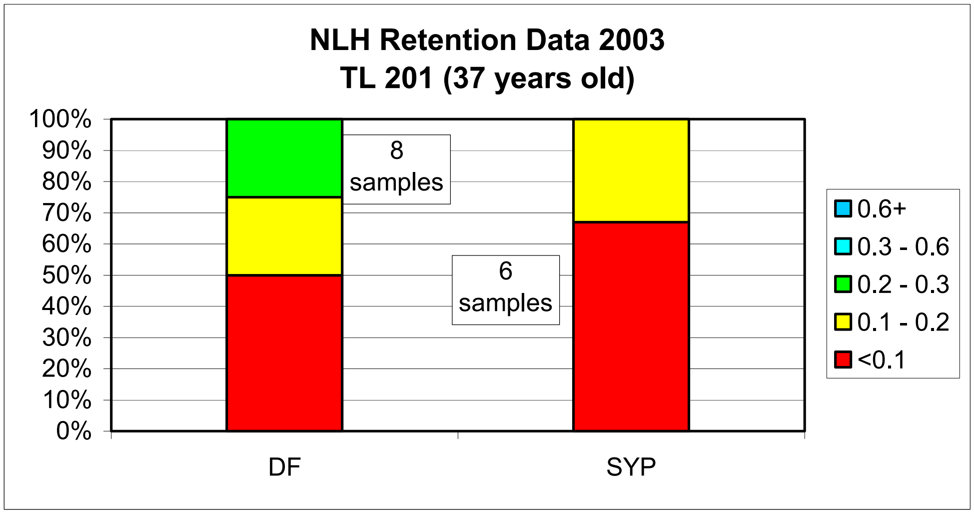


Fig. 3.13 – 2003 Pole Inspection Program – Retention Data

Table 3.7 – Summary of Pole Rejection Percentages by Lines and Inspection Years

	1985	1998	2000	2002	2003
TL 201	0%	6.8%	-	-	5.0%
TL 203	0%	6.2%	-	-	-
TL 209	-	-	1.4%	-	-
TL 215	-	-	7.8%	-	-
TL 218	0%	6.8%	-	-	-
TL 220	-	-	-	13.0%	-
TL 224	-	-	2.4%	-	-
TL 233	-	-	8.2%	-	-
TL 234	-	-	0%	-	-
TL 236	0%	5.4%	-	-	-

Table 3.7 provides a summary of the pole rejection results of all pole inspection programs carried out since 1985. This data will be used later in predicting the rejection rates for future years of pole inspections.

3.2.5 Comparison of Retention Levels For Avalon Poles

Since Hydro has the preservative retention level data for poles on the Avalon for three inspection years (1985, 1998 and 2003), an attempt was made first to understand the trend of the preservative depletion rate. **Fig. 3.14** depicts the average trend for poles on the Avalon Peninsula. The depletion rate trend can be compared with the "yellow line" shown in Figure 3.3.

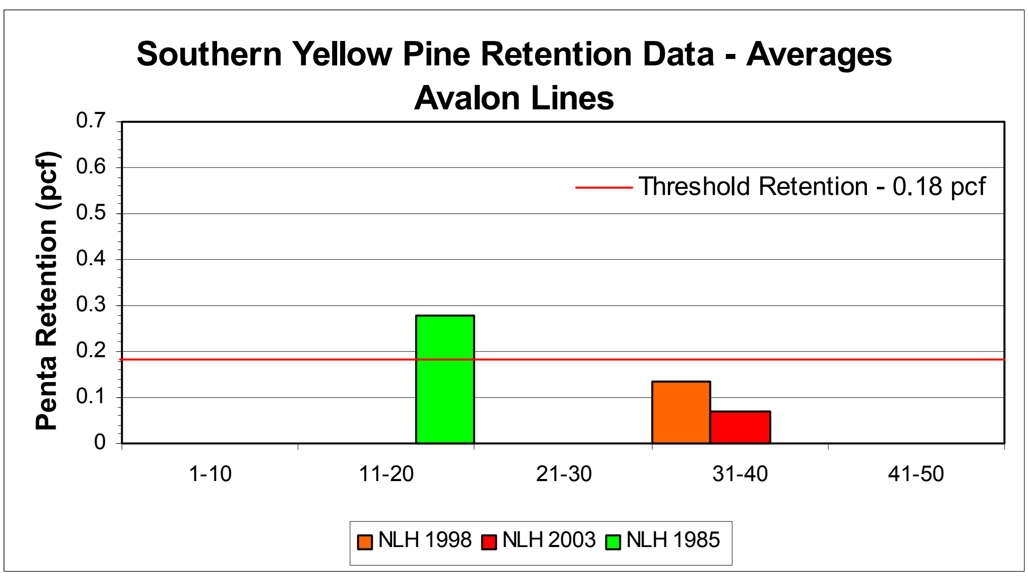


Fig. 3.14 – Multiyear Retention Data For Avalon Lines-Depletion Rate Trend

3.2.6 Comparison with Other Utilities' Practices

A major utility in Canada also carried out a test program to measure preservative retention level for distribution size poles (Southern Yellow Pine) in three different zones of the particular province. **Fig. 3.15** depicts the preservative retention levels at various in-service ages for two different zones. Zone 1 is comparable to the Avalon while Zone 2 could be compared to the Central region. It is shown that around 31-40 years, the average retention levels are 0.33 and 0.38 for Zones 1 and 2, respectively. **Fig. 3.15** also compares the same with the Avalon data (**Fig. 3.14**). The comparison validates NLH data, and shows that the preservative amount left in NLH poles is not only well below this utility's data, but also below the minimum threshold.

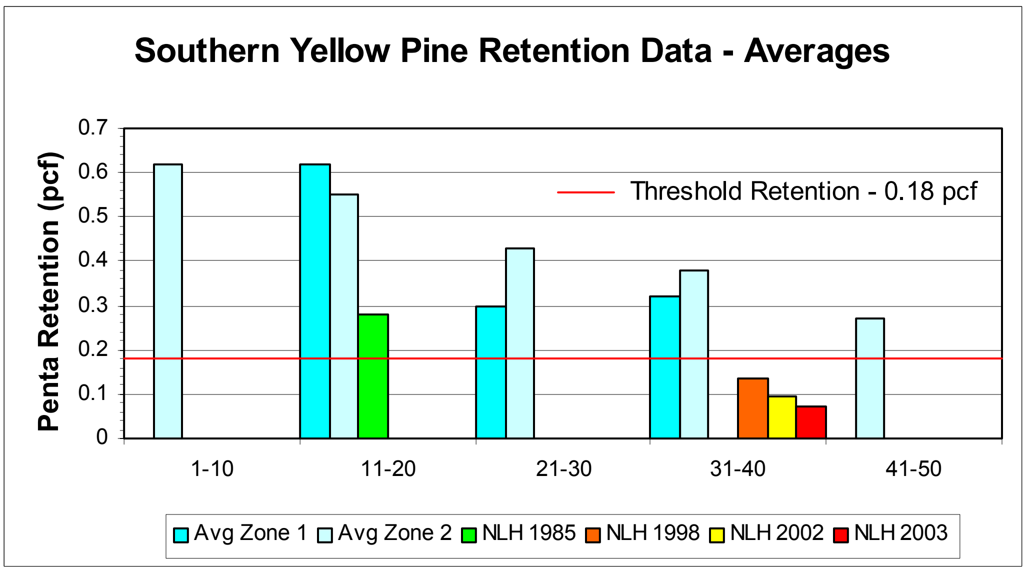


Fig. 3.15 - Preservative Retention Level With Respect To Age - External Utility Data

The comparison is made here merely to show the trend only and to validate the data collected by NLH. One can envisage the possible rate of depletion from these figures in future years if these poles are not treated. This is important information for managing the pole inventory and can be directly linked with the pole decay because these two parameters are highly correlated. **Fig. 3.16** shows such a conceptual curve developed to link these two parameters. The curve can be used in the data analysis when fully developed and validated by Hydro data.

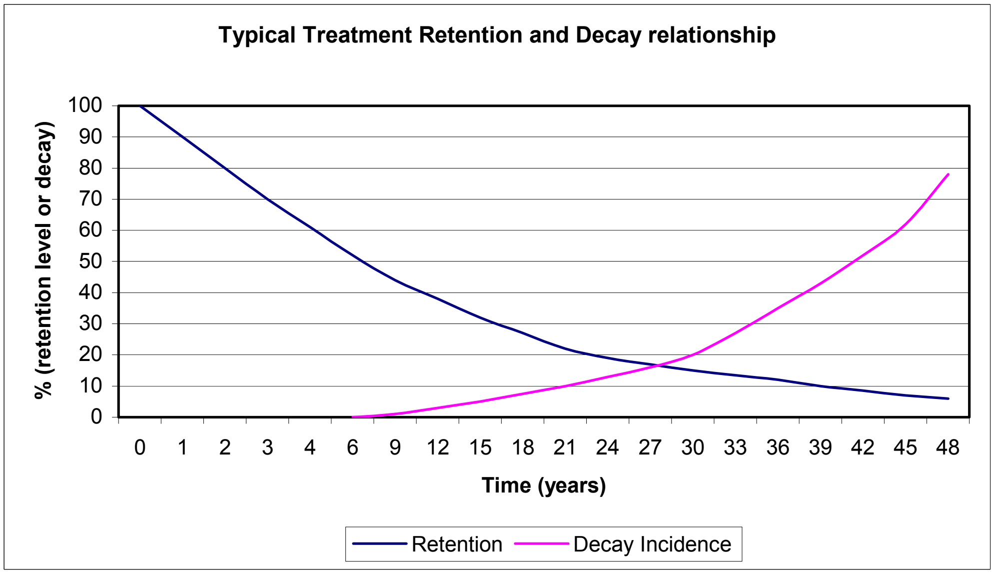


Figure 3.16 – Typical Treatment Retention / Decay Relationship (GENICS, 1998)

3.2.7 Full Scale Test at MUN – In Service Poles (SYP)

NLH undertook a separate study entitled **"Avalon Wood Pole Study"** (Haldar, 2000) where a number of transmission size poles were removed from service (from TL 201 and TL 220) and were tested with the NDE (Non Destructive Evaluation) technique as well as full scale breaking tests at the Memorial University. Since the numbers of poles tested were very limited in terms of population size, data from the other sources (e.g. EDM data) were also reviewed and compared. Results from this study showed that on an average, 25% of strength (**Fig. 3.17** – vertical axis) was lost over a period of 35 years (i.e. rate of degradation 0.7% per year for average strength of 8000 psi originally assumed).

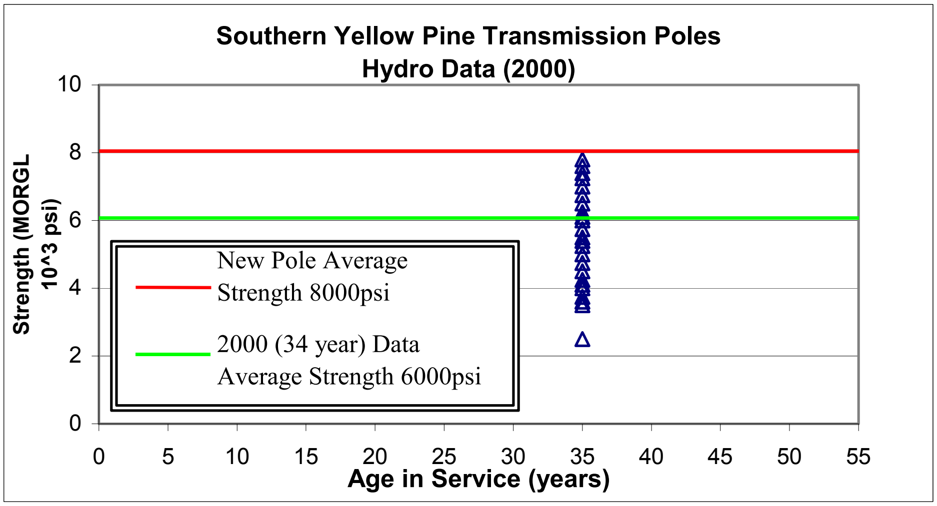


Fig. 3.17 - Strength Data From Full Scale Tests at MUN

3.2.8 NDE Field Tests – In service Poles (SYP) on Avalon Lines

Fig. 3.18 shows the typical NDE data for TL 201 collected during the 2000 and 2003 pole inspections. The results are quite consistent with those obtained from the full-scale test data depicted in **Fig. 3.17**.

During the recent upgrading work near the Hardwoods Terminal Station, a number of poles collapsed when isolated from existing 3-pole suspension structures. These poles were inspected in 1998 and were accepted because of having the adequate sapwood thickness. However inspection after the failures of the poles showed a rapid degradation of strength due to loss of sapwood on the outside shell. This is shown in **Fig. 3.19a.** This indicates that once the preservative is lost, degradation can happen rapidly **(slope of the "yellow" line below the threshold level in Fig. 3.3)** due to fungi attack and/or ant damage.

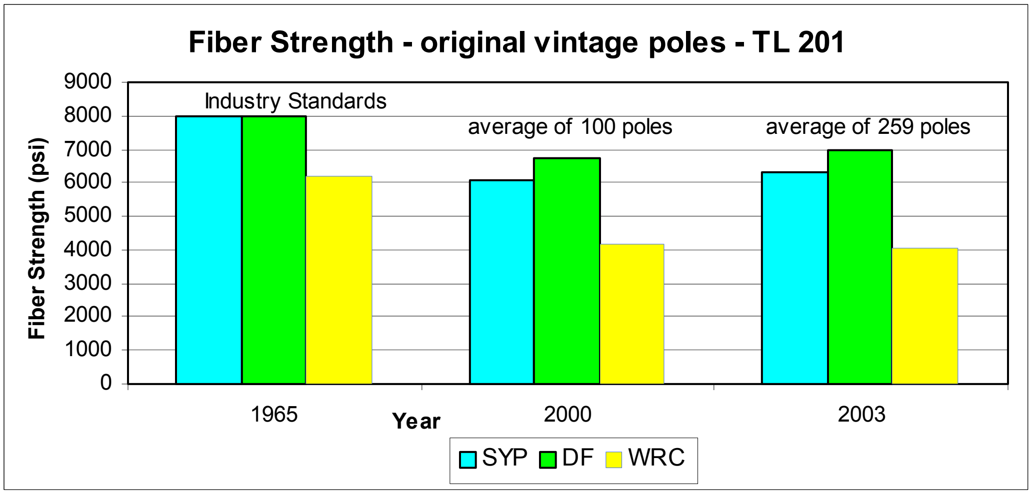


Fig. 3.18 - NDE Strength Data From Field- TL 201 (2000/2003)

Fig. 3.19a – Internal Decay **Fig. 3.19b – Carpenter Ant Damage**

Fig. 3.19a & b show the condition of the collapsed poles due to rot and carpenter ant damage. It also shows the importance of pole treatment and follow-up inspections to ensure that the poles are reliable for transmitting power and safe to climb for future inspections and maintenance work. NLH does not have a structured pole inspection, testing and treatment program at present with particular reference to life-extension of wood pole transmission lines. Therefore it is quite likely that many of the older poles may be exposed to severe decay due to fungi attack. Without a proper inspection and subsequent treatment program, the life of these poles cannot be extended significantly beyond 40 years.

3.3 Conductor

Conductor is the most expensive item in any overhead transmission line. The conductor system typically includes conductor, suspension clamps, spacers, dampers, dead end fittings and any other attachments. Major problems with the conductor deterioration are due to (1) corrosion and (2) vibration. Corrosion problems could be internal and/or external, and are mostly progressive loss of galvanization of the steel core and subsequent loss of steel strength. For ACSR conductor, the steel core is the primary load-carrying member, and any loss of steel strength due to corrosion could lead to catastrophic failure inducing considerable forced outage time. The vibration problem is related to the motion of the conductor and is classified as (1) Aeolian vibration (2) galloping, (3) sway oscillation or (4) unbalanced loading. Four common types of damage that normally occur and the clues to watch for in making line inspections are: (1) abrasion (2) fretting (3) fatigue breaks of strands and (4) tensile breaks. Vibration can also lead to external as well as internal aluminum strand fatigue and, if not detected early, failure can also have severe consequences.

A typical inner strand failure due to fatigue is shown in **Fig. 3.20** where it can be seen that the failures occurred where the inner strand surface had been subjected to fretting caused by contact between individual strands. Metallographic analysis of a large number of failures has shown that all cracks originated in these fretted areas. As fatigue inducing stresses occur near the bottom part of the conductor inside the clamp, they are impossible to measure directly. Thus, for purposes of expressing the severity of exposure to fatigue, it is necessary to represent the conditions at the contact points by means of a related parameter that is accessible to measurement such as the amplitude and the frequency of vibration (**Fig. 3.21b**). Alternatively, conductor samples can be removed from the clamp area at a certain interval and can be inspected further either by NDE or full-scale testing. One Canadian utility removes a conductor sample (typically 20 feet in length) from every 20 km of line inspected for further analysis and testing.

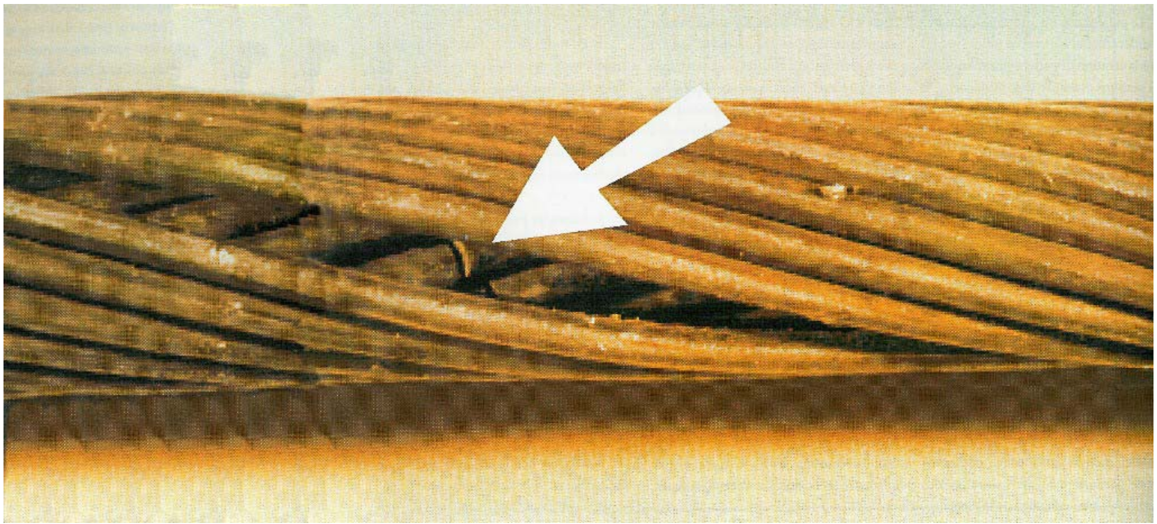


Fig. 3.20 – Broken Strand Due to Fatigue (IEEE, 2003)

3.3.1 Inspection Techniques

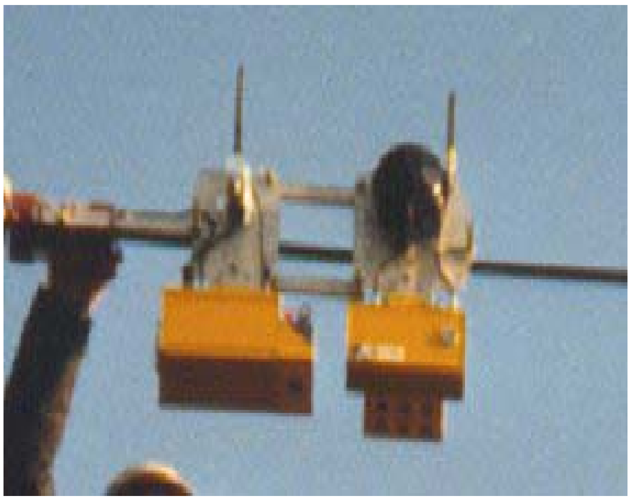
Visual inspection will not detect corrosion at an early stage. As the deterioration becomes pronounced an experienced line inspector will be able to detect this through bulging of the aluminum strands and possibly discoloration of these strands.

A corrosion detector (**Fig. 3.21a**) for steel strands works on the eddy current principle where the loss of galvanization is measured indirectly from a second coil sensitive enough to detect the change in the field patterns. The detector can sample even when it occurs within a few centimeters. Upon detecting the corrosion by NDE, samples can be taken from the line to determine the strand damage by additional testing (bending, twist of wires, etc.)

Potential damage due to Aeolian vibration can be detected by inspecting for the following:

- Dropping/missing/slipped vibration dampers;
- Missing nuts from suspension clamps;
- Cotter pins missing from their normal position;
- Broken outer conductor strands;

- Broken inner conductor strands;
- Loose or broken steel tower members; and
- Severe wear of suspension hardware.



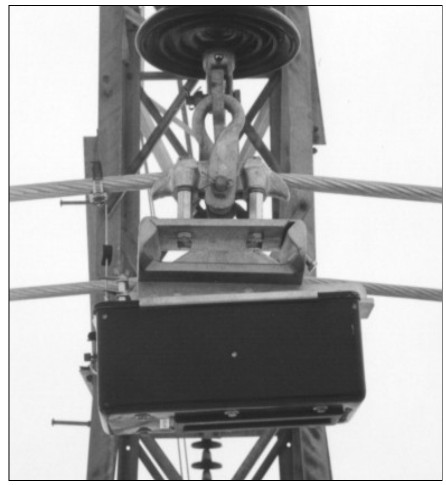


Fig. 3.21a - Corrosion Detector (CEA, 2003) **Fig. 3.21b - Vibration Recorder**

3.4 Insulator

Quite often, the primary cause of the insulator failure is the corrosion of the steel pin in the cap and pin assembly. In the pin area the surface leakage current is concentrated and this causes a dry band formation. Dry band formation leads to partial discharges and eventually causes severe spark erosion. This coupled with the natural corrosion process, reduces the net area of the pin to a point that it is no longer able to support the tensile load. In addition, the corrosion process creates stresses which tend to induce radial cracks in the porcelain insulator.

3.4.1 Inspection Techniques

Inspection techniques for insulators include:

- Visual Inspection;
- Insulator Voltage Drop Measure;
- Electric Field; and
- Infra red Thermography.

Fig. 3.22a – Flashed Insulator

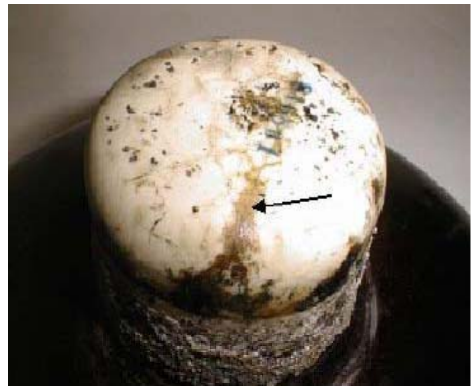


Fig. 3.22b – Cement Crack (CEA , 2003)

3.5 Hardware

Anchor Rod

Anchor rods are normally used in connecting guy wire to the foundation in order to transfer the proper tensile load to the ground. Corrosion is the primary cause of failure.

3.5.1 Inspection Techniques

Inspection techniques for anchor rods include:

- Visual Inspection; and
- Ultrasonic Pulse and Recorder.

Fig. 3.23 - Inspection Equipment (CEA, 2003)

3.6 Inspection Interval

Quite often, the question is asked as to what interval the inspection should be conducted and the resulting data analyzed to ensure that the line system can be maintained reliably and the asset managed adequately. In other words, to initiate a proactive maintenance program, one needs to know reasonably the expected failure interval of a component based on past inspection and to take actions early enough to prevent complete failure. It is well known that many of the failures are not necessarily related to age only and therefore a fixed "time based" inspection and maintenance program as pursued by **NLH** previously was not adequate and optimum with regard to cost.

For example, fatigue failure of a conductor strand is not related to age but is more prone to terrain exposure, inadequate damping in the system and even a wrong choice of the conductor for a specific location. In this case, a condition monitoring program with a vibration recorder will reveal a trend early enough to prevent a potential failure (P-F) of the conductor in the future. In RCM terminology, this is known as the ***P-F*** curve as shown in **Fig. 3.24**. Point "X", where the failure starts to occur, is not necessarily related to age, while point 'P" shows the potential failure point from the previous inspection, and point "F" is the location where it reaches the failure stage (functional failure).

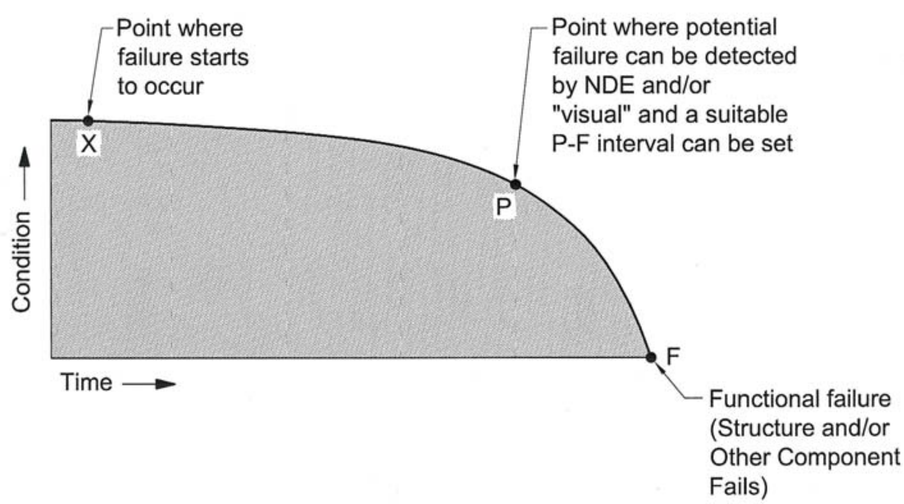


Fig. 3.24 - *P-F* curve (Moubray, 1997)

Fig. 3.25 depicts the P-F interval for two components such as a wood pole (decay) and conductor (fatigue). For a wood pole, service life is normally 40-50 years while for conductor it is normally 50-80 years depending on environmental factors. Since the conductor failure is less likely compared to wood pole failure, a shorter P-F interval for the wood pole will control the frequency of inspection (i.e. shortest interval broken down in various frequencies depending on the inspection and the condition monitored of the component).

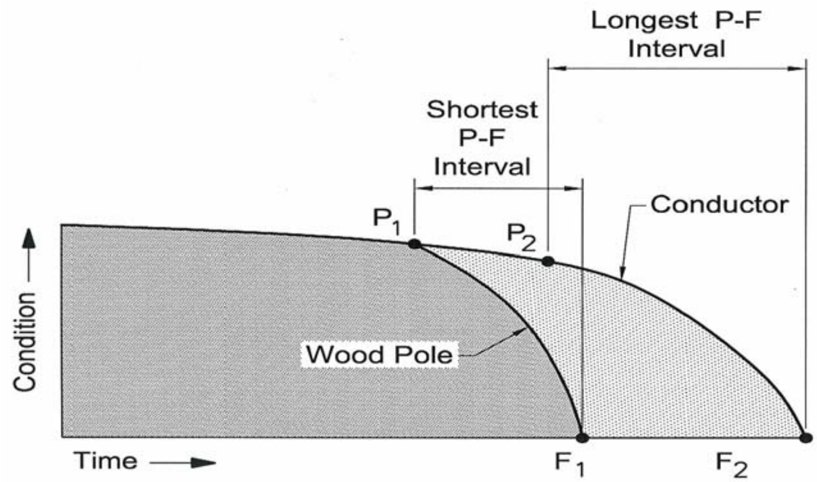


Fig. 3.25 - *P-F* curve – two components

If the objective is to prevent the failure early, then one should plan maintenance tasks based on the **Failure Finding Interval (FFI)** or the interval of inspection (i.e. time between *P-F* interval divided in certain periods). Obviously the frequency of inspection between P-F intervals does not need to be equal. The question becomes what is an appropriate frequency? Of course the answer to this question lies with the line availability and the mean time between failures (MTBF). A line which requires higher availability (radial line) and also has a small MTBF will certainly require a more frequent inspection and condition assessment, compared to a line which is located on a parallel corridor where less availability may be sustained with a similar MTBF. The following formula (Moubray, 1997) provides guidance to the above question:

$$\text{FFI} = 2 \text{ X Unavailability X MTBF} \qquad (3.1)$$

For example, a line with a 95% availability (5% unavailability) and a MTBF of 10 years will require a FFI of 1 year. However if one wishes to increase the availability to 99% (1 % unavailability) with same MTBF, the FFI will change to 2.4 months. **Table 3.8** presents the FFI as a percentage of the MTBF provided the availability requirement of a line is known (Moubray, 1997).

Table 3.8 - Failure Finding Interval

Availability Required	99.99%	99.95%	99.9%	99.5%	99%	98%	95%
FFI (as a % of MTBF)	0.02%	0.1%	0.2%	1%	2%	4%	10%

A typical example would be the TL 201 line failure in 1994 due to the breakage of a forged eyebolt on a dead end structure near Western Avalon Terminal Station. The initial failure triggered the cascading of a section of the line, which alone cost NLH $600,000 dollars in subsequent reconstruction. This group of forged eyebolts also failed in 1984 and therefore the MTBF in this case can be assumed as 10 years. If one wanted TL 201 to be available 99% of the time, then the frequency of inspection of these bolts should be 2.4 months (2 x 0.01 x 10 = 0.2 yrs = 2.4 months). On the other hand, if it is acceptable that this line could be out of service for 2 weeks annually (14/365 = 0.0383 unavailability), the frequency of inspection for these bolts should be 9.2 months (2 x 0.0383 x 10 = 0.767 yrs = 9.2 months). Therefore by inspecting these bolts every 5 years (time based), we should expect a very low availability for this line.

The above example assumes the frequency of the line inspection (i.e. inspection of components and its assessment) solely depends on the availability requirement of the line in question and prior information on MTBF. This simple example is also based on a single component assessment and on the assumption that the "weak link" component as identified is always the root cause of expected failure in the future. However, the transmission line system is quite complex and extends spatially in length and therefore FFI needs to be evaluated based on failure rate of various components (sometimes related in a complex manner) and this requires a good understanding of the root cause analysis of the failure event.

It also needs to be understood clearly that failure due to normal wear (such as vibration, fatigue, large displacement, decay, corrosion over a specified time period) will always be accompanied by a loss of strength and a component could fail prematurely even well below the design load if the strength is less than the load effect. On the other hand, if the component were predisposed to degradation, then the line located in a severe environment exposed to significant and/or frequent wind and ice loads would most likely fail when overloaded. Therefore, under RCM one may need to look at different FFI for lines located in harsh environments compared to lines that are not so severely exposed. With a proper condition based inspection procedure (CBI), it is possible to detect this likelihood quite early and a proper group replacement program can be initiated once the risk exposure has been assessed and the maintenance cost can justify the action.

Any data collection and assessment should first focus the actual condition of the line and its importance on local as well as network levels should a failure occur. This will ensure that the fund allocation can well be justified based on a value analysis as presented in **Section 2**. If done properly, the RCM method will provide a more coherent inspection and maintenance program to assess the various options for future maintenance, refurbishment or replacements thus saving money in the long term and avoiding costly outages.

3.7 Recommended Inspection Interval

Since NLH does not have sufficient historical data, **Table 3.9** provides a guideline for inspection interval with respect to line age. However, once the data is collected for one cycle of inspection, the methodology outlined in the previous Section can be used to adjust the frequency of inspection for certain areas. In addition, inspection and test data (both NDE and full scale) for older lines will also provide some insight to adjust the inspection interval as required.

Table 3.9 - Recommended Inspection Interval

Line Components (Service Life)	Lines less than 20 years old	Lines Between 20 and 30 years	Lines above 30 years
Wood Poles (40-50 years)	Typically 10 years	Initially 10 year but can be changed based on inspection data	Initially 10 year and will be revisited in 4 years time to collect sample data on pole preservatives. Adjustment may be necessary based on the condition and analysis
Other Components – Such as Knee braces, Cross arms and Cross braces (40 –50 years)	Same as above	Periodic testing at MUN to ensure adequate integrity- (sample%)	Mostly driven by Pole Inspection Program but requires periodic testing at MUN to ensure adequate integrity; (sample %) - Hydro is currently doing a number of in-service knee brace destructive tests for TL 236 and TL 234 to assess in-service residual capacity.
Conductor (60 – 80 years)	Mostly Visual but Use Vibration recorder as required	Use Vibration recorder to collect sample data in exposed areas supported by sample strand testing	Use Vibration recorder to collect sample data in exposed areas supported by sample strand testing – 5 year interval, Use also Corrosion Detector as a NDE tool to assess the integrity Collect periodic sample data in exposed areas supported by sample strand testing – 5 year interval
Insulators (30-50 years)	Visual	Visual and NDE test	Use Insulator tester to collect sample data in exposed areas supported by sample mechanical tests particularly insulators testing from Dead end Structures – 5 year interval
Hardware (40- 60 years)	Normally “visual” but the problem can be detected through vibration activity	Visual and NDE tests	Selected sample tested for cracks, particularly dead end hardware – 5 year interval
Guy Wire (50 –70 years)	Normally “visual” for corrosion problem;	Periodic checking of “slack” guy and corrosion	Sample test at MUN for pull out to assess the residual strength particularly the lines which are located to coastal areas.

3.8 Maintenance Strategy

Fig. 3.26 depicts a flow diagram to show how a successful maintenance program can be developed using **RCM** principles. It basically follows **Fig. 2.1** where a line is divided into various sub-systems and each sub-system is broken down into line components. A functional failure of a line can eventually be linked to a component by root cause analysis. Therefore condition assessment of a component is important in understanding failure mode evaluation analysis (FMEA). Condition assessment can be done at three different levels: (1) visual, (2) NDE and (3) full scale test. Following assessment, the impact on the sub-system and subsequent impact at the overall system level are evaluated to develop a balanced maintenance strategy, which can cover both preventive and proactive maintenance practices.

However, to develop such a strategy, one must collect condition assessment information for each line component on a historical basis to ensure a systematic evaluation of a line at any given period. Note that the health of the line can be evaluated based on its current condition and a proper future inspection interval can be planned based on the actual condition of the line (or a component which may be a "weak link"). **Section 4** deals with the development of a database based on component inspection. A typical data collection form developed for this project is presented in the Appendix.

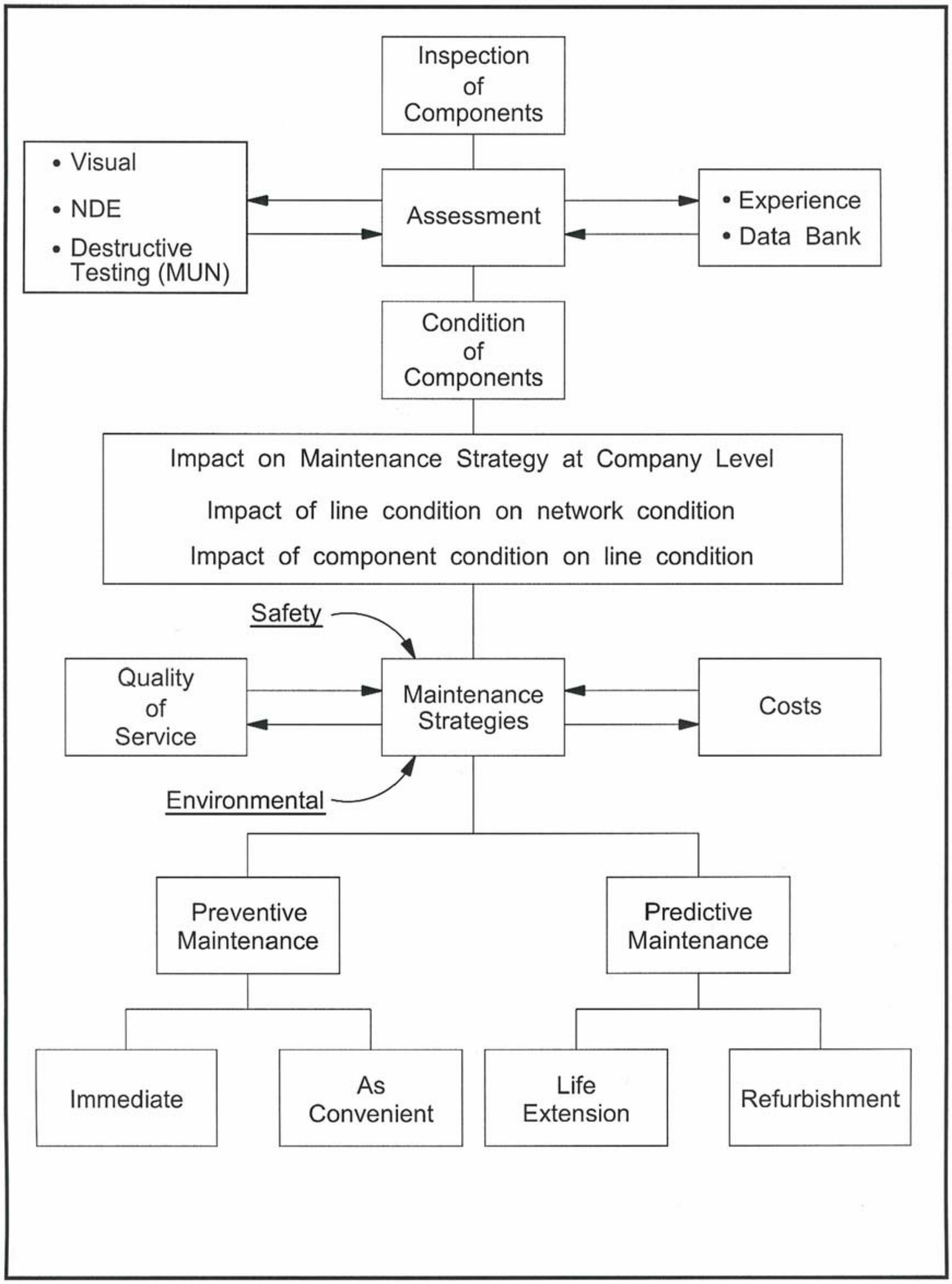


Figure 3.26 – Proposed Maintenance Strategy

SECTION 4

Database Development

4.0 Introduction

The success of the Wood Pole Line Management (**WPLM**) program will primarily depend on how accurately the data is collected in the field and how well it is analyzed. Any decisions made, based on risk assessment, require a proper analysis of data that is of high quality with regard to line performance, component condition, past failure history etc. Therefore, development of a good database is a key component in implementing a WPLM program using RCM principles.

There are three kinds of historical data that are pertinent to line assets. These are: (a) line modifications, (b) failure events and (3) inspections. In addition, all "as built" information defining line circuits, line subsystems and elements (components) and their present conditions should be available.

4.1 Data Collection at Different Levels (CIGRE, 2000)

Inspection can be performed on a typical line and the reporting of the data can be broken down at different levels. For example, data collected on a line at Level 1 can be for planned and forced outages while at Level 2, failure data are collected for sub-systems to assess the reliability. The data at level 2 should be also linked with the data at Level 3 for the element to ascertain the root cause of the failure event (i.e. failure due to strength degradation and/or excessive wear of the component). Suppose a line is hit by lightning and this causes a forced outage. Subsequent inspection reveals that the insulator subsystem is damaged with a burnt pin cap. The root cause of the forced outage is therefore strength degradation in a burnt pin cap due to a lightening strike. Data linkage at different levels is therefore extremely important to do a proper analysis of the system.

4.2 Replacement in Anticipation of Failure

RCM methodology provides a basis for predicting the likelihood of a component failure allowing replacement of a specific component or a group of elements (forged eye bolts, dampers etc.) before failure to ensure that forced outage time and lost revenue are minimized in the long term. Therefore, the question needs to be asked within the framework of *"P-F"* interval **(Section 3.6)**, how frequently, should a component be inspected? Even when the inspection does not reveal useful information (i.e. at the early years of operations between 10 and 20 years), the prediction can still be made using the likelihood of failure by using the pole life expectancy curve as shown in **Fig. 4.1**. A set of curves originally developed for asset replacement known as **IOWA curves** (see **Fig. 4.1**) is used here for wood pole asset replacement.

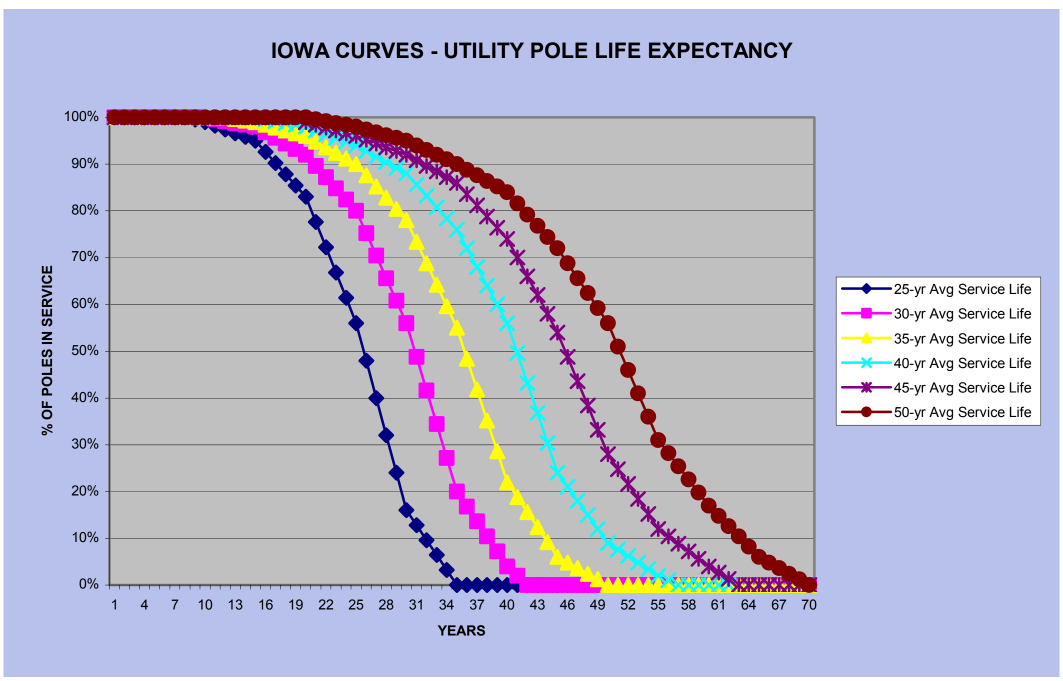


Fig. 4.1 - IOWA Curve

The ordinate of the IOWA curve represents the survival rate in percent while the abscissa represents the age of the pole. Expected service life is also shown on this curve through each average service life line. The 50-year IOWA curve was chosen for validation using the 1998, 2000 and 2003 pole inspection data because it supports the theoretical estimates. **Table 4.1** provides a summary of the rejection rate data described previously.

Table 4.1 – Inspection Results

Inspection Results – TL 201	*Rejected Poles (%)*
1985 Inspection (19 years old)	0 out of 678 (0.0%)
1998 Inspection (32 years old)	45 out of 661 (6.8%)
2003 Inspection (37 years old)	10 out of 199 (5.0%)

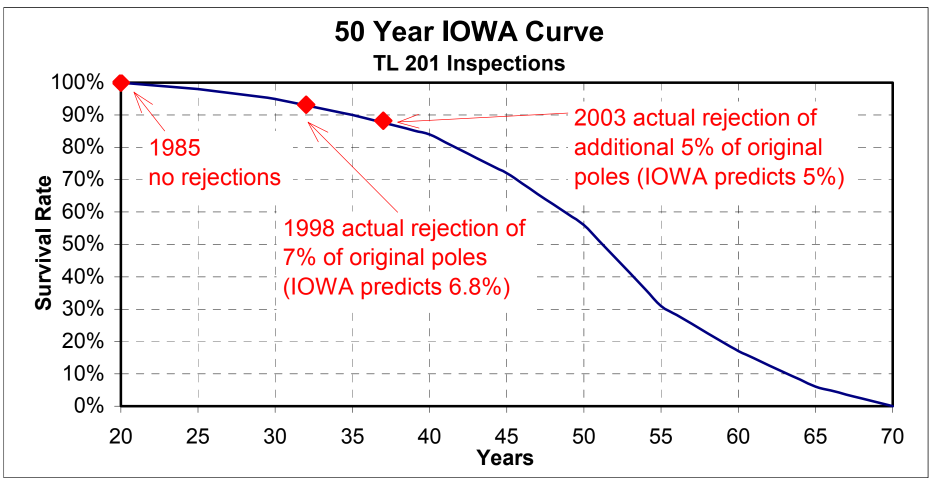


Figure 4.2 – Validation of IOWA Curve

Later, this validation process was also extended to cover poles from the Central region based on 2000, 2002 and 2003 data respectively (**Fig. 4.3**). Although the rejection rate is small in the early part of the 50-year IOWA curve, the rate changes drastically as the poles get closer to their service (economic) life (i.e. 40 years and beyond).

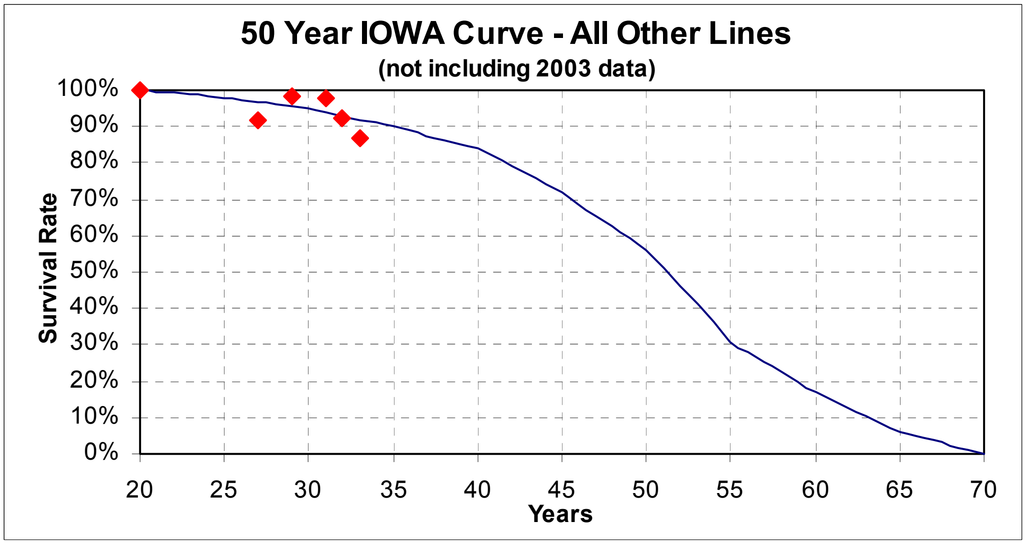


Fig 4.3 - Curve Validation for Non Avalon Poles in 2000 and 2002

4.3 Data Analysis For Wood Pole Inspection Program

The realistic expectation of any wood pole management program is to allow NLH to statistically upgrade the quality of its wood pole plant through a cyclical inspection program coupled with a thorough analysis of the inspection data. This will enable Hydro to predict and identify the risk of unexpected pole failures (i.e. safety issues) as well as reduce the probability of forced outages and loss of revenue (see **Fig. 1.1** - Cost Curve).

The program database can be directly linked to various in-house structural programs (HFRAME, POLE, SCAN, PLSCADD etc.) to assess the line reliability taking into account that the line is part of an overall system **(**Engineering Standard TD-12-001-R0). Any refurbishment, replacement and/or upgrading of a line will be based on the assessment of the quantitative risk associated with in-place strength not meeting the expected load effects (reliability and associated SAIFI and SAIDI exposures) or any associated safety concerns with respect to climbing hazards to operating personnel.

The program will include an annual report which will contain recommendations for refurbishment, replacement and/or upgrading of specific wood pole plant asset for the

Asset Managers. Although initially the program is envisaged for only transmission poles, the future objective is to include distribution size poles as well.

Ultimately, the database will be developed to identify each pole location and prior history. To address this, Engineering has worked with IS&T and the Properties Department to develop a **"Pole Cataloging"** database which will have coordinates of all poles in NLH's system through GPS. **Figs. 4.4a** and **4.4b** depicts typical "flow charts" prepared by IS&T which could be developed further to manage the wood pole line assets. Once this project is approved, IS&T will provide the necessary support to create this database for "Pole Cataloging" in the JD Edwards system with appropriate coordination with Environment & Properties for GIS application. Until the JD Edwards is functional, all data will be recorded on paper forms and manually entered into an Excel spreadsheet for analysis. Eventually, this data will be imported into the database for future record.

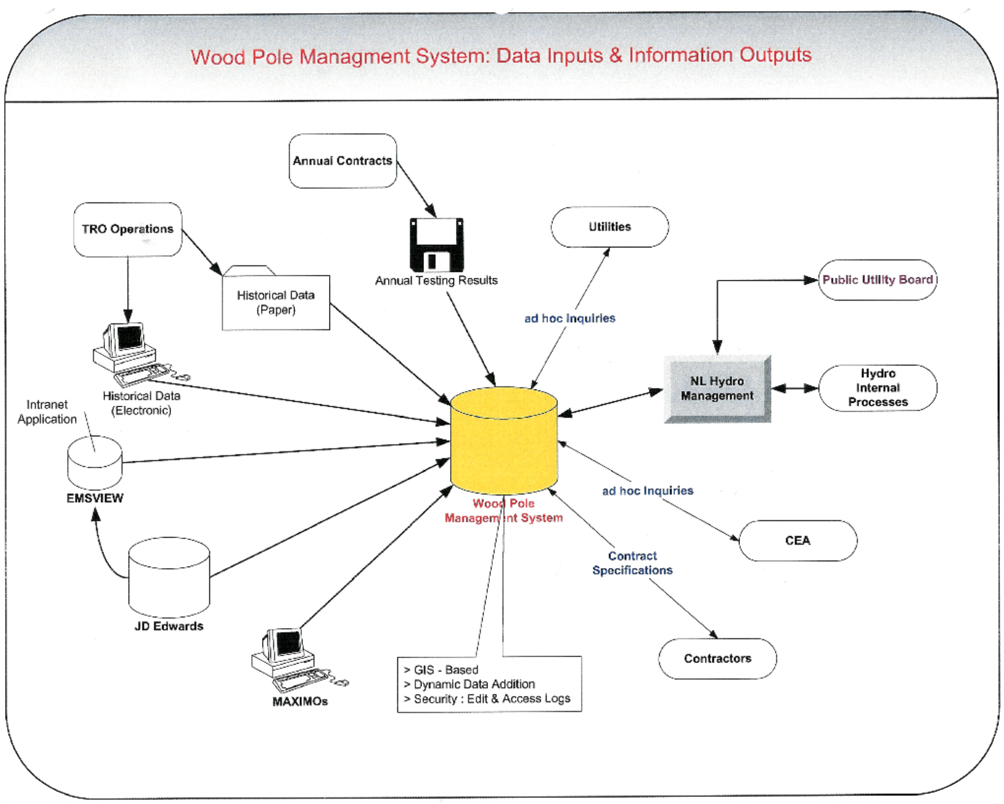


Fig. 4.4a – IS&T Flow Diagram – Data Input/Output

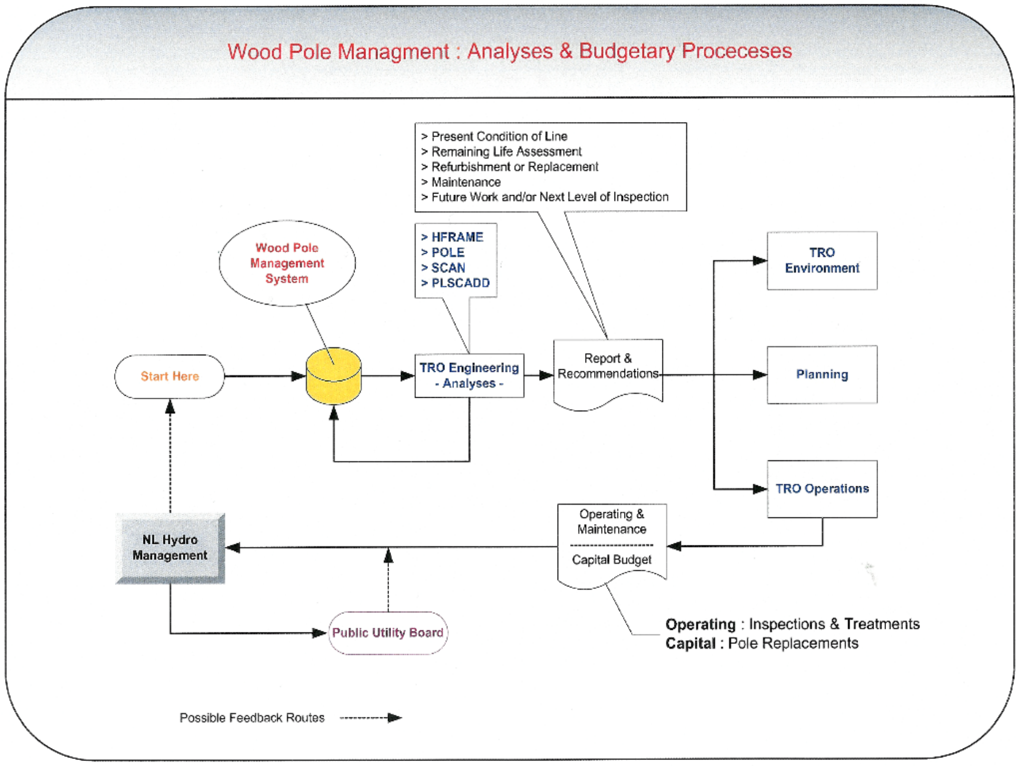


Fig. 4.4b - IS&T Flow Diagram – Analysis and Budget Processes

SECTION 5

Schedule and Cost

5.1 Background

The typical service life of wood pole lines is normally assumed to be 40 years. However, this is based on the criteria that poles are inspected and maintained properly during the service life and a thorough pole by pole inspection, testing and treatment program starts at an age when the poles have passed its 50% service life (i.e. typically 20 years after the installation). NLH's pole inventory data **(Fig. 3.2)** shows that approximately 34% of its transmission size poles (9000 poles) are over 30 years age. Therefore one third of Hydro's poles should have been exposed to a thorough inspection, testing and treatment program 10 years ago.

The pole inspection programs carried out on the Avalon in 1985, 1998 and in 2003 showed a significant loss of preservatives below the threshold value thereby exposing these poles to a greater degree of decay and loss of strength. Since Hydro does not have a formal testing and treatment program at present, it is important that a program be developed and implemented quickly to ensure: (1) the remaining poles in the system are caught early enough to arrest the decay further; and (2) that field data with respect to preservative retention level and decay are collected.

As illustrated in **Fig. 3.3** the depletion of preservative could be quite rapid once the retention has gone below the threshold level. The consequences of this depletion, and associated strength degradation have been shown in **Figs. 3.19a & b**.

In the past, Hydro has performed pole inspection based on a 5-year cycle using the sounding methodology only. It is also true that Hydro had not replaced any significant quantity of transmission size poles until 1998. This observation closely follows the IOWA curve presented in **Fig. 4.2,** as the rejection rate is very small until a pole group has reached 30 years of age for an assumed service life of 50 years. The rejection rate changes drastically as the poles get closer to their service (economic) life i.e. near 40 years and beyond. In 1998, Hydro spent approximately $600,000 dollars to replace 80 poles on the Avalon Peninsula that were rejected during the 1998 inspection. Hydro spent an additional $420,000 dollars in 2000 to replace poles in the Central region that were primarily damaged by ant infestation. All of these poles were detected during the wood pole inspections carried out in each respective year and the results match closely to IOWA curve predictions **(Figs. 4.2 and 4.3)**.

5.2 Inspection Schedule

This section provides a tentative schedule based on the assumption of a 10-year inspection period. It must be noted, as mentioned earlier, that the inspection interval will be a variable quantity depending on the analysis of the data collected, expected availability of the line and the MTBF. As well, the cost estimate for inspection and treatment will be based on a 10-year program and any necessary adjustments will be made in the future as more data is collected.

It is recommended that the inspection, testing and treatment of poles will be focused on those poles that are 30 years of age and older in the first 4 years of the program. A follow up inspection will be done to collect information on preservative retention levels to develop a database to correlate this information with pole decay rate (**Fig. 3.16**). This will enable Hydro to validate the preservative depletion rate (“blue line” shown in **Fig. 3.3**), both the downward and upward slope for predicting the strength degradation rate for future years.

In order to do a cost estimate one needs a tentative schedule for inspection of the lines during the next 10 years. A strategy was developed between Engineering, Operations, System Planning and System Operations to prioritizing the lines for inspection. Two approaches were used to develop the schedule. Operations prioritized the lines based on prior experience particularly with respect to age and on going problems of replacement of poles, insulators, knee braces, hardware etc. Recommendations from System Planning were primarily based on the "Load Flow" analysis and single line out contingency. **Table 5.1** presents the final list that was prepared based on the consensus among the various groups. This table presents the tentative schedule based on the ranking which takes into account both the age related issues as well as service continuity should we lose a line and its impact on the network system.

5.3 Cost of Inspection and Maintenance

Given the decision to carry out the inspection and maintenance program for the entire wood pole line system as per **Table 5.1**, the cost estimate includes the complete inspection of a line, primarily by "visual" inspection supported by field testing of each pole using NDE, limited full scale test at MUN to establish correlation and subsequent full treatment of poles internally. External treatment on poles will be done on an "as required" basis.

The initial cost study was carried out using a computer program that takes into account the entire pole inventory (i.e. 26,000 transmission size poles) and a distribution of these pole assets with respect to various age groups and a tentative schedule following **Table 5.1** in the first inspection cycle. This means that all poles will be inspected in the next 10 years, with the emphasis being placed on the older lines first. In the first 4 years Hydro will be inspecting poles at a rate of 4000 per year followed by 1600 poles per year for the remaining six years of the program (**Fig. 5.1**). This path was chosen to ensure that all old poles are inspected, tested and treated as soon as practical to avoid a large rejection rate in the future years, thereby minimizing the cost of the future year capital program for replacement.

It is assumed that a certain percentage of these poles inspected will also be rejected according to IOWA curve **(Fig. 4.2)** depending on their age and group. Poles rejected in the field will be analyzed with respect to reliability issues, and, if rejected after the structural analysis, a recommendation to refurbish and/or replace will be made. At present it is assumed that 33% of poles rejected can be refurbished, 33% of poles rejected require replacement and the remaining 33% of the rejected poles have sufficient residual strength after analysis such that no further action is required.

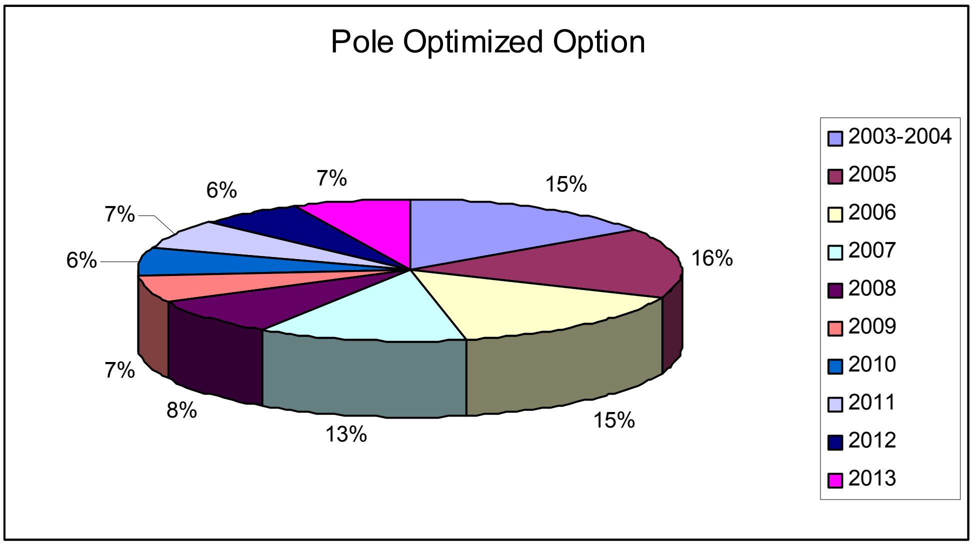


Fig. 5.1 – Annual Inspection

Therefore, the inventory of poles inspected in the first year will have some refurbishment and/or replacement work in the following year with the cost estimate based on the IOWA curve rejection rate and estimated service life. As this program provides for asset life extension, it has been agreed that all costs associated with the inspection, testing and treatment program will be done under a capital budget. It is recommended that NLH carry out some full-scale test program in each year in order to develop a Hydro database on pole strength versus age as per **Fig. 3.17.** This will enable Hydro to use an appropriate degradation rate (on a regional basis) with respect to aging and allow better predictions for future pole replacement, or if necessary a complete line upgrading or replacement

Based on the appropriate analysis, if a decision is made to replace, this will also be done in the following year under a Capital program.

Fig. 5.3 depicts the cost breakdown among inspection, test and treatment and material and engineering, with average dollar values displayed in **Table 5.2.**

Table 5.1 - Operations, System Planning and Merged Line Ranking

Operations Line Ranking	Planning Line Ranking	Merged List broken down by geographical region	
TL 215	TL 234	Central	TL 220
TL 220	TL 241		TL 234
TL 234	TL 243		TL 246
TL 209	TL 244		TL 243
TL 201	TL 250		TL 251
TL 246	TL 255		TL 252
TL 221	TL 256		TL 260
TL 243	TL 260		TL 210
TL 203	TL 215		TL 233 (½)
TL 251	TL 220		TL 222
TL 252	TL 221		TL 254
TL 229	TL 229		TL 223
TL 241	TL 246		TL 224
TL 218	TL 251		TL 253
TL 260	TL 252		TL 232
TL 210	TL 253		TL 263
TL 240	TL 254		TL 235
TL 244	TL 257	Eastern	TL 201
TL 225	TL 261		TL 203
TL 233	TL 209		TL 218
TL 250	TL 239		TL 212
TL 222	TL 245		TL 219
TL 254	TL 259	Western	TL 215
TL 212	TL 225		TL 209
TL 255	TL 201		TL 225
TL 239	TL 203		TL 233 (½)
TL 223	TL 218		TL 250
TL 224	TL 232		TL 255
TL 253	TL 233		TL 245
TL 226	TL 210		TL 238
TL 227	TL 212	Labrador	TL 240
TL 245	TL 219	Northern	TL 221
TL 232	TL 222		TL 229
TL 257	TL 223		TL 241
TL 219	TL 224		TL 244
TL 256	TL 226		TL 239
TL 259	TL 227		TL 226
TL 261	TL 262		TL 227
TL 262	TL 240 not ranked		TL 257
TL 263	TL 263 not ranked		TL 256
TL 238	TL 238 not ranked		TL 259
TL 235	TL 235 not ranked		TL 261
			TL 262

Table 5.2 - Distribution of Program Cost

Cost per pole (total $300)	*Cost*
Preventive Maintenance	$160 (54%)
Test and Treat	$40 (13%)
Treatment Materials	$30 (10%)
Engineering (including NDE)	$70 (23%)

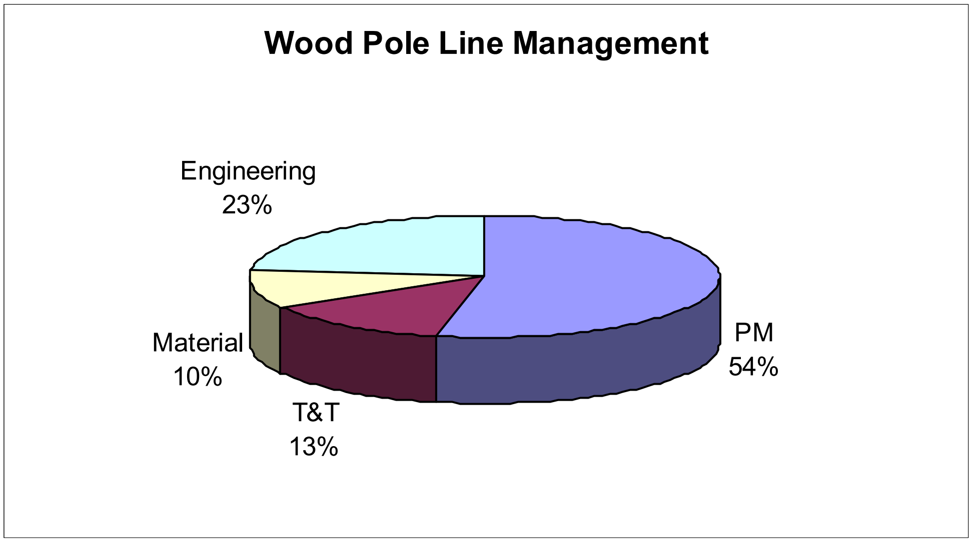


Fig. 5.2 - Average Cost Breakdown per pole

The application of remedial treatment to poles will provide a reduction in the rejection rate. This reduction is referred to as the "improvement rate" over the rejected poles without any treatment. A typical value of 60% has been recommended (GENICS, 2002) for the "second 10-year cycle". Note that during the "second 10 year cycle", poles are also 10 years older and therefore, one would expect a much higher rejection rate as per the IOWA curve (**Fig. 5.3**) than if the poles were not treated after the first inspection cycle. **Fig. 5.3** depicts a typical pole replacement curve developed with and without the treatment program and based on 10 year inspection cycle and 50 year service life.

It should be noted that the rejection of a pole does not necessarily mean that Hydro needs to replace the pole. Based on the structural reliability analysis, a decision will be made whether to replace the pole or not when the risk has been assessed with respect to reliability, security and safety.

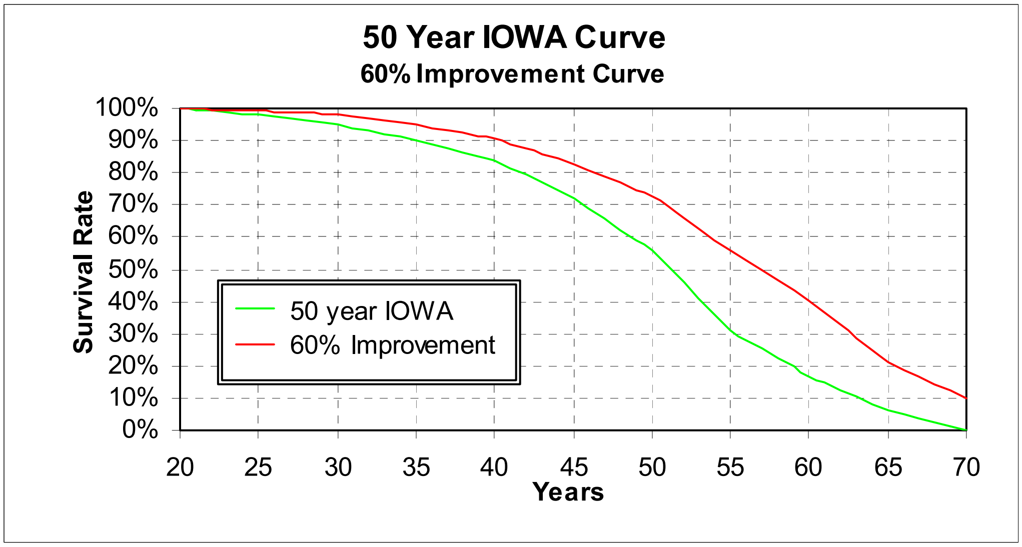


Fig. 5.3 - IOWA Curves with Improvement Rate

5.4 Cost Benefit Analysis – Typical Line Segment

Almost two-thirds of transmission pole plant assets fall into two age categories. Approximately 34% of the poles are at or over 30 years, and another 31% are 20 to 30 years old. The remaining asset age is less than 20 years old. Through the inspection and remedial treatment of these poles, it is predicted that a reduction in the future rejection rate of inspected poles will be realized. Based on the IOWA curves, and an assumed improvement in the expected failure rate of poles due to the application of remedial treatment, the cumulative present worth benefit of a remedial treatment program can be estimated. In order to estimate the cost and benefit, a number of assumptions were made:

- Cost model based on 100 poles;
- Cost to inspect, test and treat: $230 per pole based on 2003 productivity rates;
- Cost to inspect only, $160 per pole. (No Non-destructive Evaluation (NDE) or remedial treatment applied);
- Pole replacement cost: $7,000 based on 1998 and 2000 replacement of rejected poles;
- All costs are escalated using the November 2002 Electric Utilities Project Escalation Indices, prepared by Hydro's Economic Analysis Section;
- The discount rate is set at 8.5%;

- The base year is taken as 2003;
- Engineering time is not included in this estimate. Engineering input has an associated cost, but yields benefits in reduction of rejection through structural analysis and alternate refurbishment methods;
- It is assumed that the realization of a rejection rate improvement is based on poles treated in the first cycle being again treated in subsequent cycles;
- Rejection improvement is based on an industry suggested 60% improvement rate due to application of treatment. Sensitivity to the improvement rate is also reviewed;
- For ease of analysis, rejected poles are replaced in the same inspection year; and
- Future year rejection rates are estimated based on the IOWA curve.

5.4.1 Scope of the Cost Benefit Analysis

This analysis will consider the two age dependant treatment cycles: 1) starting at 25 years, and continuing every 10 years until 55 years, and 2) starting at 37 years, and continuing every 10 years until 57 years. This will cover the benefits of starting the program at the industry recommended start age of 25 years, and also starting later in the life of the pole (37 years plus). Combined, the two cycles will cover approximately 65% of Newfoundland and Labrador Hydro's pole plant assets (17,000 poles). Inspections will be performed on 10-year cycles, and the cost of performing the inspection, as well as the cost of replacing the poles will be tabulated.

For each of the cycles, two options will be reviewed and compared. Option one will be to provide inspection services only, and all poles rejected will be replaced. Option two will be to provide for inspection and remedial treatment, with the assumption of an improvement in the rate of pole rejection due to the treatment application. Both age group cycles will provide the cumulative present worth of the treatment versus no treatment options.

5.4.1.1 Age Dependent Treatment Cycle 1: Inspection commencing at 25 years

Thirty-one percent of Hydro's transmission pole inventory is approximately 25 years old. Ideally, a full inspection and remedial treatment program for these poles should commence at this age. In this way, a maximum improvement in the rate of rejection should be realized over the life of the poles. Inspections will be performed at the initial year (age 25) and every 10 years following (age 35, 45 and 55).

For option 1 (inspection only), application of the standard 50-year IOWA curve indicates that 69 of the original 100-pole sample would be replaced by the time the poles reach 55 years of age. The cumulative present worth cost of inspection and replacement is calculated at $164,500. For option 2 (inspection and remedial treatment), with an improvement rate of 60% due to treatment application, it is estimated that 45 of the original 100-pole sample would be replaced by the time the poles reach 55 years. The cumulative present worth cost of inspection, remedial treatment and replacement is calculated at $134,000. This provides for a net benefit of $30,500 for every 100 poles that enter the inspection and remedial treatment program at 25 years of age. Given an estimated 8000 poles in this age group, the total net benefit of providing an inspection and remedial treatment program for these poles is $2.4M.

5.4.1.2 Age Dependent Treatment Cycle 2: Inspection commencing at 37 years

Thirty-four percent of Hydro's transmission poles are over 37 years old. Using the IOWA curve, it is estimated that 74 poles will be replaced by the time the poles reach 57 years of age by option 1 (inspection only). The cumulative present worth cost for inspection and replacement is calculated at $284,000. For option 2 (inspection and treatment) it is estimated that 55 poles will be replaced over the life of the program. The cumulative present worth cost for inspection, remedial treatment and replacement is calculated at $243,000. This provides a net benefit of $41,000 for every 100 poles that enter the program at 37 years of age. Given a pole inventory of 8800 poles in this group, a net benefit of $3.6M will be realized over the life of the poles. Therefore, for the inspection of poles over 20 years of age, a total net benefit of $6.0M can be shown.

5.4.2 Sensitivity of Improvement Rate

As the rate of improvement due to the application of remedial treatment is subject to factors such as local climate, treatment effectiveness on older poles, etc., and without the benefit of detailed long-term data on improvement, sensitivity in varying this rate was addressed. As can be seen from **Fig. 5.4**, if the improvement rate is greater than 20%, a net benefit for the treatment program will be realized. Thus, if it is assumed that poles entering the program at 25 years have a 60% improvement, and poles 37 years or older have a 40% improvement, somewhat less than the example, a total net benefit of $4.46M will still be realized for the approximately 17,000 poles that fall into these two categories. The improvement rates can only be determined through the application of treatment, and the future analysis of the benefits based on actual costs.

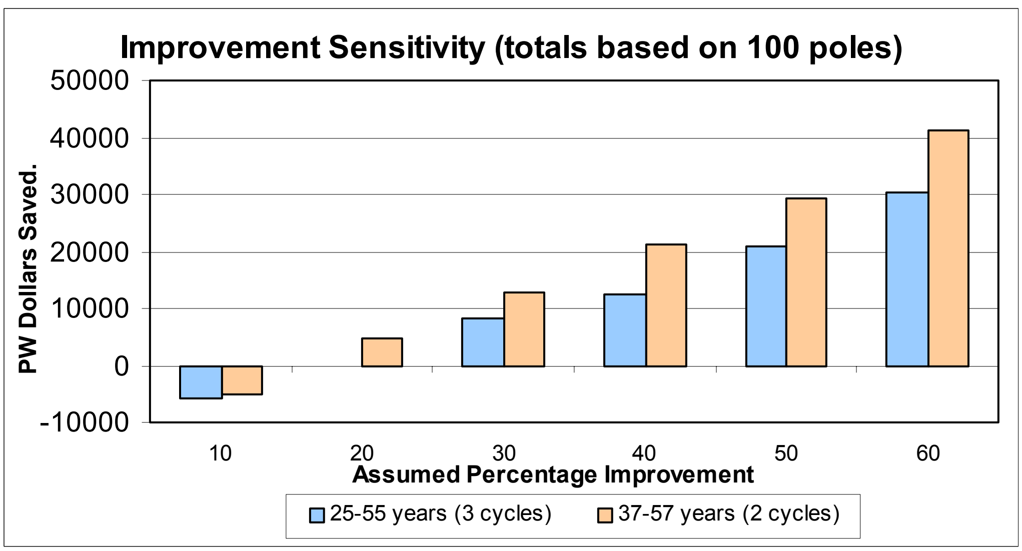


Figure 5.4 – Improvement Rate Sensitivity

The inspection program will also provide valuable information with respect to the present health of the wood pole lines. Based on the annual report of this inspection, testing and treatment program, a more "pro-active" maintenance and replacement plan can be established which, in the long run, will save Hydro a considerable amount of money due to proper planning and execution.

Based on the limited data collected in 1998, NLH has a large number of poles falling below the required preservative retention threshold level (retention level, refer to Avalon inspection report and Table 3.2 and Fig. 3.7 and Fig. 3.8). The current program will require a full pole-by-pole inspection, testing and treatment. The schedule & cost of this phase is also shown separately under "Cost and Budget" for 2005 to 2009 & beyond in **Table 5.3** with a cash flow in the Appendix.

5.5 Budget Cost Breakdown and Assumptions

The following information was used to prepare the budget estimate:

- Total cost of inspection, testing, treatment, data collection, material and providing engineering support is $300 per pole;
- All poles will be inspected in the next 10 years and the program is a 2 - "10 year" cycle program;
- Operations personnel have been involved to ensure the budget cost reflects the current cost of line inspection plus the additional expenditures needed to carry out a full pole inspection, test and treatment program;
- It has been agreed that Operations personnel will be responsible to carry out the regular line inspection work and in addition, they will also be responsible to carry out this inspection, test and treatment program. A specification and a terms of reference has also been agreed between Operations and Engineering;
- All work will be done each year, beginning early May and be completed by late October. This will give Operational personnel time to do any other preventive maintenance work in the reminder of the year;
- It has been assumed that each crew in the region will be able to do 10 poles per day based on Operations input and agreement;
- All five crews will be engaged each year particularly in the first few years when NLH will be covering a large number of poles per year **(Fig. 5.1)**;

- Referring to **Fig 5.1**, 60% of poles (16000 poles) will be inspected in next 4 years to ensure that all old poles are inspected first to avoid excessive rejection in subsequent years. This will minimize the capital program cost in the future years;
- Poles over 30 years age will be inspected again within 4 years of the treatment to collect data on depletion rate (**Fig. 3.3**) However this will be done on a selected sample to obtain the trend;
- Engineering will analyze the data and prepare an annual report. To do so Engineering should allocate adequate resources and this cost has been budgeted;
- The budget includes some replacement costs of other components such as conductors, insulators etc; However if the analysis of the field inspection data indicates that a major replacement is warranted for other major line components then this should be followed up through a separate study for capital replacement;
- Poles inspected in one year will encounter a certain percentage of rejection and upon engineering analysis, final recommendation to do nothing, refurbish and/or replace will be made to the respective Asset Manager. Budget estimate for the capital program has been included here; and
- It is assumed 33% poles rejected in the field will require no actions, 33% will be refurbished and the remaining will be replaced. However these numbers could change up or down depending on what is found in the field and the severity of deterioration of pole assets. Therefore this budget proposal needs to be flexible for future adjustment.

As indicated earlier, the original estimate is based on poles being optimized for inspection and treatment. It is estimated that in the initial phase of the program (i.e. at least the first 3 year period) many activities need to be completed to ensure that the program runs smoothly and the database is developed properly for full analysis.

Table 5.3 2005 to 2009 (and beyond) Capital Budget Proposal (2003 projection)

Costs (x $1,000)	2005	2006	2007	2008	2009	Beyond
External Engineering	$50	$50	$50	$50	$50	$700
Material Supply	$382	$470	$336	$154	$90	$2906
Labor	$1,492	$1,700	$1,265	$675	$465	$11,670
Engineering	$228	$228	$172	$114	$114	$1,602
Escal, Contingency & O/H	$436	$558	$462	$277	$221	$9,264
Total	$2,588	$3,006	$2,285	$1,270	$940	$26,142
Total Program Cost (20 year)						$36,231

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SECTION 6

Summary, Conclusions and Recommendations

6.1 Summary and Conclusions

The report describes the principles and plans for the wood pole line management (WPLM) program for Newfoundland and Labrador Hydro's **26,000** transmission size poles. This program is based on RCM principles and, by using internal resources, will replace the old time based inspection program. It is also emphasized here that the actual inspection interval for the program is determined on the basis of field data (condition of the line) and the proper analysis of this data, rather than a fixed time interval. Since NLH does not have long-term data at this time, it is recommended that the inspection interval proposed in **Table 3.8** be used to initiate the "new" program. Further, the inspection interval should be reviewed on an annual basis for subsequent adjustment once specific line inspection data is obtained.

The report also describes the methodology to be used to evaluate various options for line maintenance strategy systematically using a "risk" based criteria for the management of the wood pole lines. Based on the current year inspection data, the following year's capital program will be developed. This will "stream line" the budgeting process for managing the wood pole lines once the program is in place.

Although the current inspection technique is primarily "visual" in nature**,** it is identified that in some areas (for some components, e.g. conductor, insulators) Hydro should start using NDE to collect strength data on a more objective basis. The wood pole test program using NDE is a first step to achieve this objective. Hydro should be doing similar NDE for conductors, insulators, conductor joints, etc. Early detection of the potential failure initiation point (e.g. strand break near or below the clamp for conductor, deterioration of pin cap of insulator, knee brace crack etc.) could guide Hydro to predict the functional failure before it happens, thereby avoiding a costly forced outage. Also this information is of considerable importance with respect to the residual life of a line when one considers refurbishing and/or upgrading an existing line.

Finally, a schedule and a cost breakdown will be provided for each year of the inspection program and the capital program that will follow in the subsequent year. A cost benefit analysis of the inspection, testing and treatment program demonstrates that this cost can well be justified against the savings one would obtain by not only containing the line/structural failure in the future years, but also by extending the life of the older lines by a reasonable number of years thereby deferring the cost of building new lines in the future.

6.2 Recommendations

A number of recommendations are made to ensure that the wood pole line management program implemented based on RCM principles produces data in a structured format to ensure that a proper analysis can be completed annually to determine the program's trend and effectiveness.

- Implement the inspection, test and treatment program in 2005 and complete the entire inspection, test and treatment program for 26,000 poles by 2013.

- Repeat the program for the next 10 years i.e. between 2014-2023 to investigate the benefit in the second year cycle (improved rate of rejection in the second cycle) as per estimated data (**Figs. 4.1** and **5.3**) and future validation.

- Operations to carry out inspections of these poles on an annual basis and to send this data to Engineering for further analysis in a timely fashion. Engineering will carry out the analysis and make the appropriate recommendations to Operations for future refurbishment and/or pole replacement program under a capital budget proposal.

- If the analysis identifies that a large number of poles need to be replaced then a separate study should be undertaken considering full refurbishment and/or upgrading or even building a new line before a capital program is launched.

- The program should be expanded to investigate other component inspection data closely e.g. knee braces, conductor, insulators, hardware to confirm that other components have a considerable residual life left before any major pole replacement program is undertaken.

- Data to be analyzed to develop a "Replacement Criteria" for Wood Pole Lines based on a minimization of cost model as shown in **Fig. 1.1**. Some initial work has been completed as part of this study and this should be followed up further for validation of this model with additional field data.

- It is noted that any cost model developed should include the cost of deferral of building new lines in the future. To accomplish this, data must be collected to ensure that the rate of decay and the preservative depletion rate can be correlated (**Fig. 3.9**). It is important to know when treatment is no longer effective in life extension.

- In each year of this inspection program, a separate fund is allocated to do routine testing of components including the in-service wood poles of various ages to develop a long-term database. Hydro, in collaboration with MUN, has developed special benches to do this type of testing and this should be funded annually.

- Once the program is in place, all routine data analysis for the current inspection year should be completed by the year-end with appropriate recommendations made to justify replacement and/or upgrading for the subsequent year. This will provide documentation of the line inspected in a year and the various actions that have been taken to provide remedial measures. To do this in a systematic manner, proper resource allocation is needed and has been reflected in the CBP.

- A working group be formed within Hydro's **TRO** division, which should include one representative from each of Engineering, Operations, and System Planning. The primary role will be to review the annual Engineering report on the inspection results and its recommendation to ensure that if any major line replacement is required in the future based on the data trend, Hydro will be able to plan this program in advance to avoid a large capital expenditure in any given year and distribute the resources in an even and timely manner.

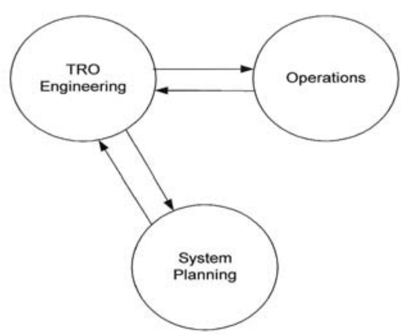

Fig. 6.1 Working Group For Line Management

SECTION 7

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SECTION G
Tab 3

Rencontre East

Interconnection Study

Newfoundland & Labrador Hydro

System Planning Department

April 2004

EXECUTIVE SUMMARY

As a result of the Rencontre East Diesel Plant burning down on September 02, 2002, Hydro has to provide a new permanent power supply for the community of Rencontre East. Two obvious alternatives are to build a new diesel plant or to interconnect Rencontre East to the Island grid. This report provides a summary of the findings of a study investigating the technical and economic feasibility of both alternatives. Currently, Rencontre East is being serviced by a temporary diesel power supply.

Two technically feasible interconnection alternatives have been identified for Rencontre East. They involve connecting to the English Harbour West distribution system via either a 38 km or a 41 km, 14.4 kV single-phase line. The 41 km line option ($3,250,100) is preferred, despite being marginally more expensive (~$75,000) than the 38 km option, as it has a number of operational and maintenance benefits over the 38 km option. For the continued diesel alternative, building a new diesel plant ($1,621,800: 2 new units + used “Harbour Deep” unit) to replace the one that burned is obviously technically feasible.

A present worth comparison of the costs for the continued diesel operation alternative and for the interconnection alternative indicates that the interconnection alternative would provide a 15-year payback under base case assumptions. At the end of the 31-year study period, the interconnection provides a CPW (cumulative present worth) cost preference of $1,042,907 over continued diesel operation. Further analysis indicates that the results are somewhat sensitive to capital cost estimates, with a 10% increase in capital cost for the interconnection increasing the payback period to 20 years.

An examination of the incremental change in revenue requirements indicates that 2006 is the only year where the revenue requirements for the interconnection alternative are higher than for the diesel alternative. Starting in 2007, revenue requirements from Hydro’s customers would be lower, if the interconnection alternative is constructed.

A review of the demographics of the community of Rencontre East gives reason to believe that it will be a viable community for the foreseeable future. Rencontre East holds a unique status among Hydro's Island Rural Isolated systems in that its population and customer base has not materially declined during the 1990s.

A check with Municipal Affairs indicates that they have had no representation from Rencontre East on re-location potential (as happened in Harbour Deep) and Government has not undertaken an independent analysis of the matter. Notwithstanding, if, in the future, economic and community circumstances change for Rencontre East for what ever the reason(s), a re-location risk exists. At present, such a risk is deemed low.

Discussions with the insurance company regarding payment of Hydro's claim for the replacement of the old diesel plant are still ongoing. The insurance payment will be the same whether the diesel plant is rebuilt or the interconnection constructed.

Thus, based on these results, it is recommended that the community of Rencontre East be interconnected to the Island grid with an in-service date of 2005.

It should be noted that construction of the interconnection is dependant on receiving the appropriate environmental permits. Indications are that this would not be a problem.

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1.0 INTRODUCTION

The community of Rencontre East is located in Fortune Bay on the south coast of the Island of Newfoundland at approximately 47° 37' N latitude and 55° 14' W longitude.

The Rencontre East Diesel Plant burned down on September 02, 2002. Hydro has put a temporary power supply in place, until a permanent replacement for the community energy supply can be determined. Two obvious alternatives are to build a new replacement diesel plant or to interconnect Rencontre East to the Island grid.

Rencontre East's peak demand for 2006 is forecast to be 323 kW assuming continued isolated operation with Isolated Diesel rates. For this alternative, by 2035, the peak demand is forecast to increase to 365 kW. Comparative projections for an Interconnection scenario with Interconnected rates are 329 kW in 2006 growing to 532 kW in 2035 (see Schedule 1).

The community's population was 212 in 1991, 215 in 1996 and 202 in 2001 and it is expected that the community will be viable for the foreseeable future (see *Commentary on the Viability of the Community of Rencontre East* in Appendix A). Hydro had 91 customers in the community in 2000, 89 in 2001, 91 in 2002 and 89 in 2003. In 2003, the customer breakout was 73 in Domestic and 16 in General Service, including one streetlight.

All costs, escalation and load forecast data used in the study represent the most recent projections. Costs of all alternative supply options are compared on a cumulative present worth basis discounted to January 2004 dollars.

2.0 STUDY METHODOLOGY

In order to determine the least cost method of servicing the load requirements of Rencontre East it is necessary to first identify technically feasible alternatives for supplying the community load. Once these alternatives have been identified, their cost effectiveness can be evaluated in terms of cumulative present worth (CPW) costs, over a period of time. The alternative offering the lowest CPW cost over the study time horizon is the preferred alternative.

To manage risk, Hydro has set a 15-year payback period for interconnection alternatives as a threshold for project consideration. The payback period gives the time for the higher investment of the interconnection to be offset by the higher operating costs of the continued diesel alternative. Thus, in order to reduce the risk that circumstances significantly change during the subsequent years (and consequently reduce the cost effectiveness), the CPW cost of an interconnection alternative must equal or better that of the continued diesel alternative within 15 years following completion of the interconnection, to be considered further.

In order to develop the CPW costs of diesel and interconnection alternatives, the following is required:

- setting a time horizon over which to perform the analysis;
- developing load forecasts covering the study period for interconnected and diesel alternatives;
- developing options for each alternative;
- preparing technical and economic data for each alternative;

- determining technical feasibility for each alternative;
- developing capital and operating costs for each technically acceptable alternative; and
- performing a cost effectiveness analysis.

Each of the above is discussed in further detail in the following sections.

2.1 General Assumptions

2.1.1 Study Time Horizon

This study used a 31-year time frame, covering the period from 2005 to 2035, inclusive.

2.1.2 Load Forecast

Load forecasts were prepared for the study time horizon by Hydro's Economic Analysis section for both the continued diesel operation and interconnected alternatives (see Schedule 1). For the interconnected load forecast, the interconnection was assumed to take place late in 2005.

2.1.3 Discount Rate

The study used an 7.0% discount rate, with all costs discounted to January 2004.

2.1.4 Escalation Rates

Escalation rates for operating and maintenance (O&M) costs were prepared by Hydro's Economic Analysis section (see Schedule 2).

2.2 Diesel Plant Operating Parameters

The following were used in developing annual operating and maintenance (O&M) costs for a new Rencontre East diesel plant.

1) Fixed O&M – This cost was set at $108,800 in 2006, which is consistent with costs incurred in previous years, and projected into the future using the O&M escalation series.

2) Variable O&M – The variable O&M rate was set at $0.0443/kWh in 2006 and escalated as above. This rate is based on average costs for Hydro's other diesel plants.

3) Energy Conversion Efficiency –An efficiency of 3.50 kWh/litre was assumed. This rate is based on an examination of the efficiencies in Hydro's newer diesel plants.

4) Diesel Fuel Cost – A forecast of fuel costs for Rencontre East over the study period was prepared by Hydro's Economic Analysis Section (see Schedule 3).

5) Lube Factor – The lube factor covers the cost of lubricating fluids used by the diesel generating units. It is expressed as a percentage of diesel fuel cost. The lube factor was set at 1.0211 (2.11%), which is consistent with average costs for Hydro's other diesel plants.

Table 1 on the next page summarizes the diesel plant operating parameters used for this study.

TABLE 1

Rencontre East Diesel Plant Operating Parameters	
Fixed O&M - $/year (2006)	$108,800
Variable O&M - $/kWh (2006)	0.0443
Lube Factor	1.0211
Efficiency - kWh/litre	3.50
Diesel Fuel Costs - $/litre (2006)	0.390

2.3 Interconnection Parameters

The following was used to develop annual operating costs for the grid interconnection.

1) Line Maintenance Cost – This study assumed a line maintenance cost of 2% of the interconnection capital cost to approximate the annual cost of maintaining the interconnection.

2) Energy Costs – Interconnection energy costs were based on a marginal Holyrood energy rate. This energy rate was developed using a fuel forecast provided by Hydro's Economic Analysis Section and assuming an incremental energy conversion rate at Holyrood of 624 kWh/bbl (See Schedule 3).

3) Losses – The forecasts used in this study are for the load at the bulk delivery point for the community: the high-voltage bus of the diesel plant or in the case of the interconnection, the location at which the distribution line enters the community. In addition to the load itself, transmission and distribution losses had to be added to the Rencontre forecast to determine the total amount of incremental energy that would have to be generated at Holyrood to supply Rencontre East, in the interconnection alternative. The interconnected forecast was increased by 7.2% in 2006, increasing to

9.9% in 2035, as the load increased over the study period, to account for expected additional losses over the interconnection and the transmission system that would not occur under the diesel alternative.

2.4 Development of Alternatives

The study evaluates two alternatives: building a new diesel plant or interconnecting the community to the Island grid through the English Harbour West distribution system. (see single line diagrams in Figures section). The following highlights any significant issues associated with each alternative:

2.4.1 Interconnection

As a single-phase distribution line would address community requirements, the more expensive option of a three-phase distribution line was not considered. There is one small three-phase customer in Rencontre East, who has not been active since 1998. This requirement, if it materializes, is expected to be met with a phase-converter. As well, the distribution system in Rencontre East will have to be converted to 14.4 kV from 7.2 kV instead of using a step-down transformer, to provide adequate fault levels for protection purposes. Two routes were studied for the interconnection: (see map *Rencontre East Interconnection* in Figures)

Route "A": This option involved connecting to the existing single-phase line to Poole's Cove and constructing a 38 km, single-phase, 14.4 kV, 1/0 AASC conductor distribution line to Rencontre East. A second phase would be added to the existing single-phase line to Poole's Cove to the tap-off point to Rencontre East. This would also involve the installation of two single-phase voltage regulators and a recloser.

Route "B": This option, which is geographically and electrically closer to the English Harbour West Terminal Station, involved connecting to the main distribution line approximately 4.5 km from the English Harbour West Terminal Station and constructing a 41 km, single-phase, 14.4 kV, 1/0 AASC conductor distribution line to Rencontre East. This would also involve the installation of a single-phase voltage regulator and a recloser.

After having reviewed technical and operating considerations, as well as cost, Route "B" was chosen as the preferred interconnection option, despite being approximately $75,000 more than Route "A", for the following reasons:

- Route "B", while being physically 3 km longer than Route "A", is electrically 9.6 km closer to the English Harbour West terminal station due to the difference in interconnection points. This provides better fault levels in Rencontre East, less energy losses and better voltage balance on the main feeder.

- The routing of this alternative is through less difficult terrain and not as exposed as Route "A", as well as being further from the coast, lessening the probability of salt contamination. This route should provide greater reliability and better accessibility for maintenance than Route "A".

An additional cost for the interconnection alternative is the environmental remediation of the old Rencontre East diesel plant site. It is estimated that this would cost $100,000. A site evaluation would have to be carried out to firm up the estimate. Even if a new diesel plant is constructed, some environmental remediation of the site may be necessary, but to a much lesser scale than if the interconnection is built and the old diesel plant site cleared.

It should be noted that construction of the interconnection is dependant on receiving the appropriate environmental permits. Indications are that this would not be a problem.

A cost estimate for Route "B" is contained in Appendix "B".

2.4.2 Diesel Plant

The alternative to an interconnection is to build a new diesel plant in Rencontre East. At present, the community is being supplied by a temporary power supply that was obtained, shipped to site, assembled and put on-line within 31 hours of the fire that destroyed the former diesel plant and its contents (the fuel storage tanks and the pole-mounted station transformers were not damaged). This supply consists of two mobile diesel-generating sets and a diesel unit released from Harbour Deep due to the relocation of that community. The units are housed in temporary structures that were to provide power to the community on a short-term basis, until such time as a permanent solution could be designed and implemented. As such, it was not designed and installed consistent with Hydro's standards for prime power installations and is lacking components that would provide appropriate control and protection for long-term operation.

Operation with the existing arrangement is not feasible, over the long term, as meeting regulatory, operation, and maintenance requirements would require significant upgrade or replacement of most equipment and systems currently installed. For example, the current building structure is a temporary shell built directly on the ground with limited services, and the trailers enclosing the mobile units make routine maintenance difficult because of limited space. While the mobile units can operate parked where they are in the short term, the lack of an adequate foundation means that settling of the units over time will cause problems. As well, the current power diesel plant is being operated on temporary environmental permits, as among other things, the exhaust stacks are not high enough and the fuel delivery system is not up to standard. Hydro has been allowed to operate up to this point, with the understanding that the diesel plant will be upgraded in the near future.

The diesel plant alternative could consist of constructing either a conventional diesel plant or a modular diesel plant, with three diesel generating units in the 200 kW size range.

"Conventional" Diesel Plant:
This option would involve constructing a diesel plant with the units and controls in a single building. This would be typical of the type of diesel plant Hydro has constructed over the last number of years.

One point to note is that if a new conventional diesel plant were constructed, the "Harbour Deep" diesel unit mentioned above (which is three years old) would be used in the new plant and only two new units purchased. The estimated cost to construct this new diesel plant would be $1,621,800. (See Appendix "B"). However, as the "Harbour Deep" unit could be used to displace future capital expenditures elsewhere within Hydro's systems, if it was not used in Rencontre East, a credit has been included in the Interconnected alternative in the economic analysis. This credit was arrived at as follows: In Hydro's 5-year plan, there is a proposal to purchase and install a new diesel unit to replace an obsolete unit in St. Lewis in 2006. As an alternative, an estimate to transport and install the "Harbour Deep" unit in St. Lewis was prepared. The difference between the two alternatives, $112,000 (2006$), is considered to be the incremental cost to Hydro of using the "Harbour Deep" unit in the new Rencontre East diesel plant rather than in St. Lewis.

The two mobile units currently being used in the temporary power supply would not be used in a new diesel plant. In order to incorporate them into a new diesel plant, they would have to be broken down into components: the diesel unit, controls, radiators, and switchgear and reassembled as part of the new plant. However, all of the components might not be usable in the new plant, as there might be incompatibilities with the other units. In the past, there have been no appreciable benefits realized by purchasing and installing new units, rather than by retrofitting. As well, if new units are purchased, the mobiles will be put back into system spares to be used as spares or as construction power on various jobs, as needed.

"Modular" Diesel Plant":
This option would involve constructing a diesel plant consisting of four enclosures, or modules, each housing generation or control equipment. Three of the enclosures would house generator sets, while the fourth would house the control equipment.

The estimated cost to construct this new modular plant would be $2,485,000. As the O&M costs for this plant would be similar to those for the conventional plant above, and the capital cost would be approximately 50% greater, no further consideration was given to this option.

2.4.3 Environmental Evaluation of Alternatives

This section discusses the environmental considerations for the alternatives considered. One key assumption is that with the interconnection alternative, the displacement of energy produced by a local diesel plant will be by generation at the Holyrood Thermal Generation Station.

The first consideration is Environmental Assessment Requirements. The interconnection will have to be assessed under the provincial and federal environmental assessment processes and will likely require an Environmental Preview Report with component Studies, while the diesel plant alternative will require permitting under *Gasoline and Associated Products Storage Regulations* and *Pollution Control Regulations*.

The interconnection and diesel plant alternatives both have a number of potential environmental effects. Construction of the interconnection may affect the “Heritage River” designation of the Bay du Nord River and other historic and geologic resources of the area. As well, generation of the energy at Holyrood to serve the Rencontre load will result in more SO_2, more CO_2 and less NO_x being produced, than if the diesel plant alternative was built and operated. On the other hand, local air quality may be adversely affected by particulate, if a new diesel plant produces the energy. As well, the diesel plant alternative will increase both the noise levels in the community and the risk of spills of petroleum product.

In the area of environmental protection planning requirements, the interconnection will require an environmental protection plan for construction, raptor and rare plant assessment and construction monitoring. The diesel plant will have no specific requirements.

In summary, the interconnection alternative will require substantially more resources for environmental assessment and construction monitoring, however the potential long term environmental effects of the two alternatives are not substantially different.

2.4.4 Insurance

Discussions with the insurance company regarding payment of Hydro's claim for the replacement of the old diesel plant are still ongoing. The insurance payment will be the same whether the diesel plant is rebuilt or the interconnection constructed. Therefore, as any payment would be common to either alternative, it has been excluded from the economic analysis. The payment is expected to be received in 2004 and be in the amount of approximately $250,000 to $300,000 after deductible.

2.5 Additional Capital Costs During the Study Period

It is expected that there would be no further capital costs for either the interconnection or diesel plant alternatives during the study period, due to load, given the load forecasts. There is minimal growth forecast under diesel rates and while there is more growth expected under interconnected rates, the minimum interconnection configuration identified at present is sufficient to handle this growth.

However, as the life of the diesel units is estimated to be 20 years, a cost was included in the analysis in 2025, to replace all three diesel units. This cost was adjusted to account for the remaining life left in the replacement diesel units, at the end of the study period.

2.6 Economic Analysis of Alternatives

The respective capital and operating costs of the interconnection and the continued diesel operation alternatives were analysed on a cumulative present worth basis. Alternatives were compared on the basis of:

(1) Cumulative Present Worth costs over the study period;

(2) Cumulative Present Worth preference;

(3) Pay Back Period; and

(4) Benefit/Cost Ratio

The CPW Preference is defined as the difference in present worth costs between alternatives at the end of the study period.

The Payback Period measures the time at which an investment is at risk to changes in the alternative or market. For interconnection studies, it is normal to plot the accumulated costs (capital investment plus operating costs) of the alternatives, discounted to a point in time. The payback period gives the time required for the higher investment in one project to be offset by higher operating costs and future investments of the alternative.
A sensitivity analysis was carried out to assess the impacts of changes in a number of key parameters: diesel plant capital cost, interconnection capital cost, fuel costs, discount rate and diesel plant site environmental cleanup cost.

The Benefit/Cost Ratio is defined as the sum of the Cumulative Present Worth and the Cumulative Present Worth Preference of the preferred alternative, over the study period, divided by the Cumulative Present Worth of the preferred alternative.

2.7 Revenue and Revenue Requirements

In addition to the economic analysis, the impact that choosing the interconnection alternative would have on Hydro's incremental revenue requirements was analysed over the study period.

3.0 RESULTS

The following presents a summary of the economic evaluation carried out for this study, as well as a revenue requirement analysis.

3.1 Economic Evaluation

A detailed spreadsheet showing the development of annual costs over the study period for each alternative can be found in Appendix C.

Table 2 summarizes the results of the analysis comparing the Continued Diesel alternative and the Interconnection alternative. As can be determined from the table (and in more detail in the table and graph in Appendix C), for the base case assumptions, the Interconnection alternative produces a 15-year payback period. At the end of the entire study period, the interconnection provides a CPW cost preference of $1,042,907 over continued diesel operations.

As well, the payback period is sensitive to capital cost changes for both the new diesel plant and the interconnection. The payback period is 20 years, with a 10% increase in the interconnection capital cost, and 10 years, with a 10% decrease. The payback period is 13 years, with a 10% increase in the diesel plant capital cost, and 17 years, with a 10% decrease. It is not very sensitive to changes in fuel costs, although a switch from 2.2% sulphur fuel to 1.0% sulphur fuel at Holyrood would extend the payback period to 16 years. An increase in the discount rate of 1.5% would increase the payback period to 17 years, while a similar decrease would reduce it to 13 years. The sensitivity for the diesel plant site environmental remediation was included, as that estimate has not been finalized. The payback period is not very sensitive within the +/- 50% range.

The benefit/cost ratio remained positive for the base case and all sensitivities considered, as noted in Table 2.

TABLE 2

Continued Diesel Versus Interconnection Sensitivity to Base Assumptions ($ x 000)							
Parameter Varied	Variation	CPW to 2035		CPW Preference (Interconnection) to 2035	Payback Period (Years)	Benefit/ Cost Ratio
		Continued Diesel	Interconnection			
Diesel Plant Capital Cost	-10%	5,339	4,438	901	17	1.20
	Base	5,481	4,438	1,043	15	1.24
	+10%	5,622	4,438	1,184	13	1.27
Interconnection Capital Cost	-10%	5,481	4,065	1,416	10	1.35
	Base	5,481	4,438	1,043	15	1.24
	+10%	5,481	4,810	671	20	1.14
Discount Rate	5.5%	6,504	4,906	1,598	13	1.33
	Base	5,481	4,438	1,043	15	1.24
	8.5%	4,704	4,070	634	17	1.16
Diesel Plant Site Environmental Cleanup	$50,000	5,481	4,397	1,084	14	1.25
	Base	5,481	4,438	1,043	15	1.24
	$150,000	5,481	4,479	1,002	15	1.22
Fuel Costs	-10%	5,307	4,361	946	15	1.22
	Base	5,481	4,438	1,043	15	1.24
	+10%	5,654	4,514	1,140	14	1.25
	1% S at HRD	5,481	4,622	859	16	1.19

3.2 Revenue and Revenue Requirements Analysis

Table 3 below outlines the incremental difference in annual costs and revenues each year between the interconnection and diesel alternatives. As can be seen from this data, 2006 is the only year where the annual revenue requirements for the interconnection alternative are higher than for the diesel alternative. This is primarily due to two one-time costs related to the interconnection alternative, which are projected to occur in 2006. When the diesel plant is shut down, as expected under the interconnection alternative, there is anticipated to be remediation costs of $100,000 at the diesel plant site and a loss on disposal of assets of an additional $100,000 in 2006. Subsequent years show a growing annual net benefit of the interconnection alternative. Commencing in 2007, overall customer rates would be lower as a result of reduced revenue requirements. Cost of service studies, however, are not available for the analysis period, 2006 to 2035, to quantify individual customer impacts.

Base data related to the diesel and interconnection alternatives is shown in Appendix D.

TABLE 3

Rencontre East Analysis - Annual Costs and Revenues

	Interconnection Over Diesel Alternative						
			Capital-Related				
Year	O&M	Fuels	Deprec	Loss on Disposal	Financing	Revenues	Total Difference
2006	9,432	(72,177)	21,647	100,000	103,155	14,561	176,619
2007	(92,815)	(72,958)	21,647		101,672	9,387	(33,067)
2008	(95,073)	(74,348)	21,647		100,189	7,852	(39,733)
2009	(97,179)	(75,608)	21,647		98,706	6,409	(46,026)
2010	(99,374)	(78,723)	21,647		97,222	5,105	(54,122)
2011	(101,595)	(80,571)	21,647		95,739	3,359	(61,421)
2012	(103,844)	(82,504)	21,647		94,256	1,936	(68,510)
2013	(106,177)	(84,376)	21,647		92,773	242	(75,891)
2014	(108,562)	(86,443)	21,647		91,289	(1,303)	(83,372)
2015	(111,000)	(88,609)	21,647		89,806	(2,803)	(90,959)
2016	(113,537)	(90,500)	21,647		88,323	(4,484)	(98,551)
2017	(116,130)	(92,478)	21,647		86,840	(6,425)	(106,547)
2018	(118,783)	(94,380)	21,647		85,357	(8,292)	(114,452)
2019	(121,495)	(96,435)	21,647		83,873	(10,183)	(122,593)
2020	(124,270)	(98,412)	21,647		82,390	(12,083)	(130,728)
2021	(127,107)	(99,944)	21,647		80,907	(14,169)	(138,666)
2022	(130,008)	(101,718)	21,647		79,424	(16,283)	(146,939)
2023	(132,975)	(103,260)	21,647		77,940	(18,409)	(155,057)
2024	(136,009)	(104,984)	21,647		76,457	(20,682)	(163,571)
2025	(139,113)	(106,537)	21,647		74,974	(23,238)	(172,268)
2026	(142,286)	(108,334)	36,837		(25,013)	(25,703)	(264,499)
2027	(145,531)	(110,082)	36,837		(27,537)	(28,166)	(274,480)
2028	(148,850)	(111,828)	36,837		(30,061)	(30,790)	(284,693)
2029	(152,244)	(113,600)	36,837		(32,585)	(33,696)	(295,288)
2030	(155,715)	(115,369)	36,837		(35,110)	(36,514)	(305,871)
2031	(159,264)	(117,086)	36,837		(37,634)	(39,580)	(316,727)
2032	(162,894)	(118,966)	36,837		(40,158)	(42,435)	(327,615)
2033	(166,605)	(120,711)	36,837		(42,682)	(45,761)	(338,923)
2034	(170,401)	(122,469)	36,837		(45,206)	(49,238)	(350,477)
2035	(174,283)	(124,241)	36,837		(47,730)	(52,506)	(361,923)

Notes:

1. Both the initial capital costs for the diesel alternative of $1,733,800, and the replacement diesel unit cost of $1,430,000 in 2025 are depreciated over 20 years.
2. Total capital costs for the interconnected alternative of $3,250,100 are depreciated over 30 years
3. Diesel plant site remediation of $100,000 is included as a one-time operating cost in 2006 for the Interconnection Alternative.
4. Asset additions are financed at the weighted average cost of debt of 6.852%, in accordance with the 2004 Forecast Cost of Service, Rev. 2 (Oct 2003).
5. The above amounts do not reflect full cost of service allocations or any re-allocations of existing costs.
6. Revenues for both alternatives are assumed to escalate at 2% per annum.

4.0 CONCLUSIONS AND RECOMMENDATIONS

This study analysed two alternatives for a long term power supply for the community of Rencontre East: rebuild and continue to operate the diesel plant in the community or interconnect Rencontre East to the English Harbour West distribution system via a 41 km, 14.4 kV single-phase distribution line. Based on this analysis, the interconnection alternative offers a cumulative present worth cost preference of $1,042,907 as compared to the continued diesel alternative at the end of the study period (2035). The payback period is 15 years.

A sensitivity analysis indicates that the results are somewhat sensitive to capital cost estimates, with a 10% increase in capital cost for the interconnection increasing the payback period to 20 years.

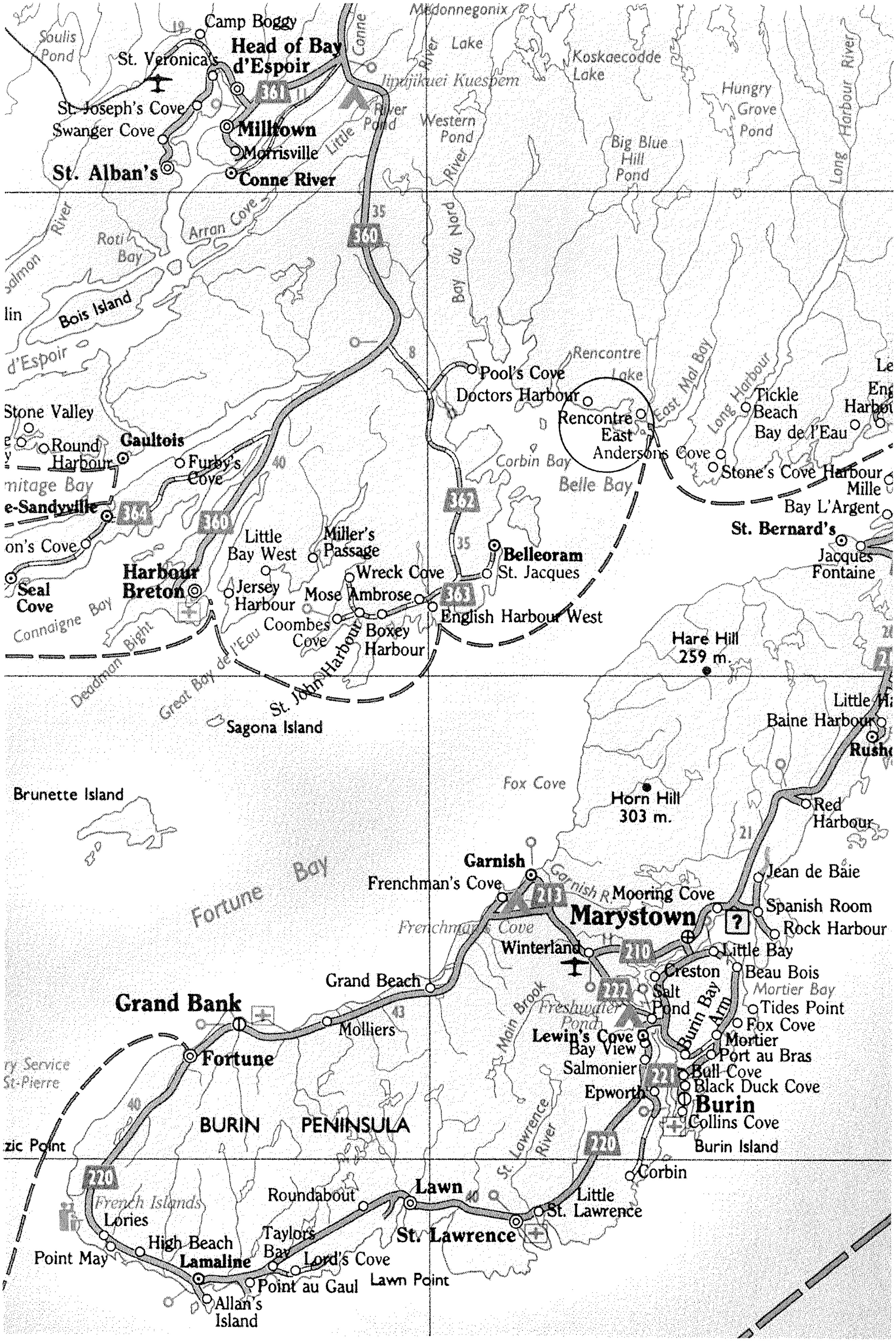
Looking at the incremental change in revenue requirements, 2006 is the sole year where the revenue requirements for the interconnection alternative are higher than for the diesel alternative. Starting in 2007, revenue requirements from Hydro's customers are lower, if the interconnection alternative is constructed.

A review of the demographics of the community of Rencontre East gives reason to believe that it will be a viable community, for the foreseeable future. Rencontre East holds a unique status as an Island Rural Isolated system in that its population and customer base has not materially declined during the 1990s.

A check with Municipal Affairs indicates that they have had no representation from Rencontre East on re-location potential (as happened in Harbour Deep) and Government has not undertaken an independent analysis of the matter. Notwithstanding, if, in the future, economic and community circumstances change for Rencontre East for what ever the reason(s), a re-location risk exists. At present, such a risk is deemed low.

Based on these results, it is recommended that the community of Rencontre East be interconnected to the Island grid in 2005.

FIGURES



Camp Boggy
Head of Bay d'Espoir
St. Veronica's
St. Joseph's Cove
Swanger Cove
Milltown
Morrisville
St. Alban's
Conne River
Soulis Pond
Conne River
Little River Pond
Western Pond
Koskaecodde Lake
Hungry Grove Pond
Big Blue Hill Pond
Long Harbour River
Bay du Nord River
Roti Bay
Arran Cove
Salmon River
Bois Island
d'Espoir
Rencontre Lake
Pool's Cove
Doctors Harbour
Rencontre East
Andersons Cove
East Mal Bay
Long Harbour
Tickle Beach
Bay de l'Eau
Stone's Cove
Harbour Mille
Bay L'Argent
St. Bernard's
Jacques Fontaine
Stone Valley
Round Harbour
Gaultois
Furby's Cove
Corbin Bay
Belle Bay
Little Bay West
Miller's Passage
Belleoram
St. Jacques
Wreck Cove
Harbour Breton
Seal Cove
Jersey Harbour
Mose Ambrose
English Harbour West
Coombes Cove
Boxey Harbour
Connaigne Bay
Deadman Bight
Great Bay de l'Eau
St. John Harbour
Hare Hill 259 m.
Sagona Island
Little Harbour
Baine Harbour
Rushoon
Brunette Island
Fox Cove
Horn Hill 303 m.
Red Harbour
Fortune Bay
Garnish
Garnish R.
Frenchman's Cove
Mooring Cove
Jean de Baie
Spanish Room
Rock Harbour
Marystown
Winterland
Little Bay
Creston
Beau Bois
Mortier Bay
Salt Pond
Tides Point
Grand Beach
Grand Bank
Molliers
Main Brook
Freshwater Pond
Burin Bay Arm
Fox Cove
Lewin's Cove
Bay View
Mortier
Port au Bras
Salmonier
Bull Cove
Black Duck Cove
Epworth
Burin
Collins Cove
Burin Island
Fortune
BURIN PENINSULA
St. Lawrence River
Corbin
Little St. Lawrence
French Islands
Lories
Roundabout
Lawn
St. Lawrence
High Beach
Taylors Bay
Point May
Lamaline
Lord's Cove
Point au Gaul
Lawn Point
Allan's Island
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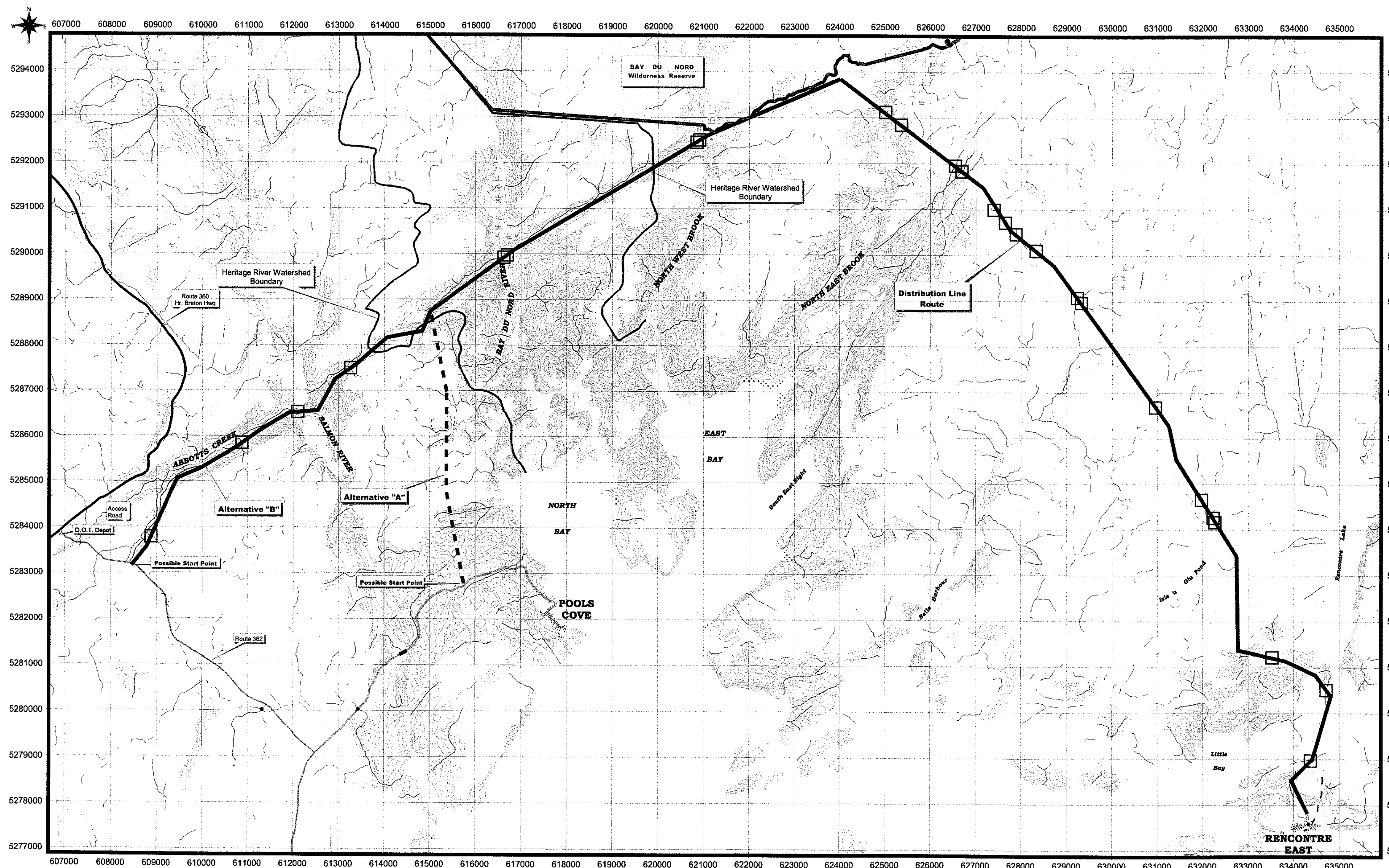


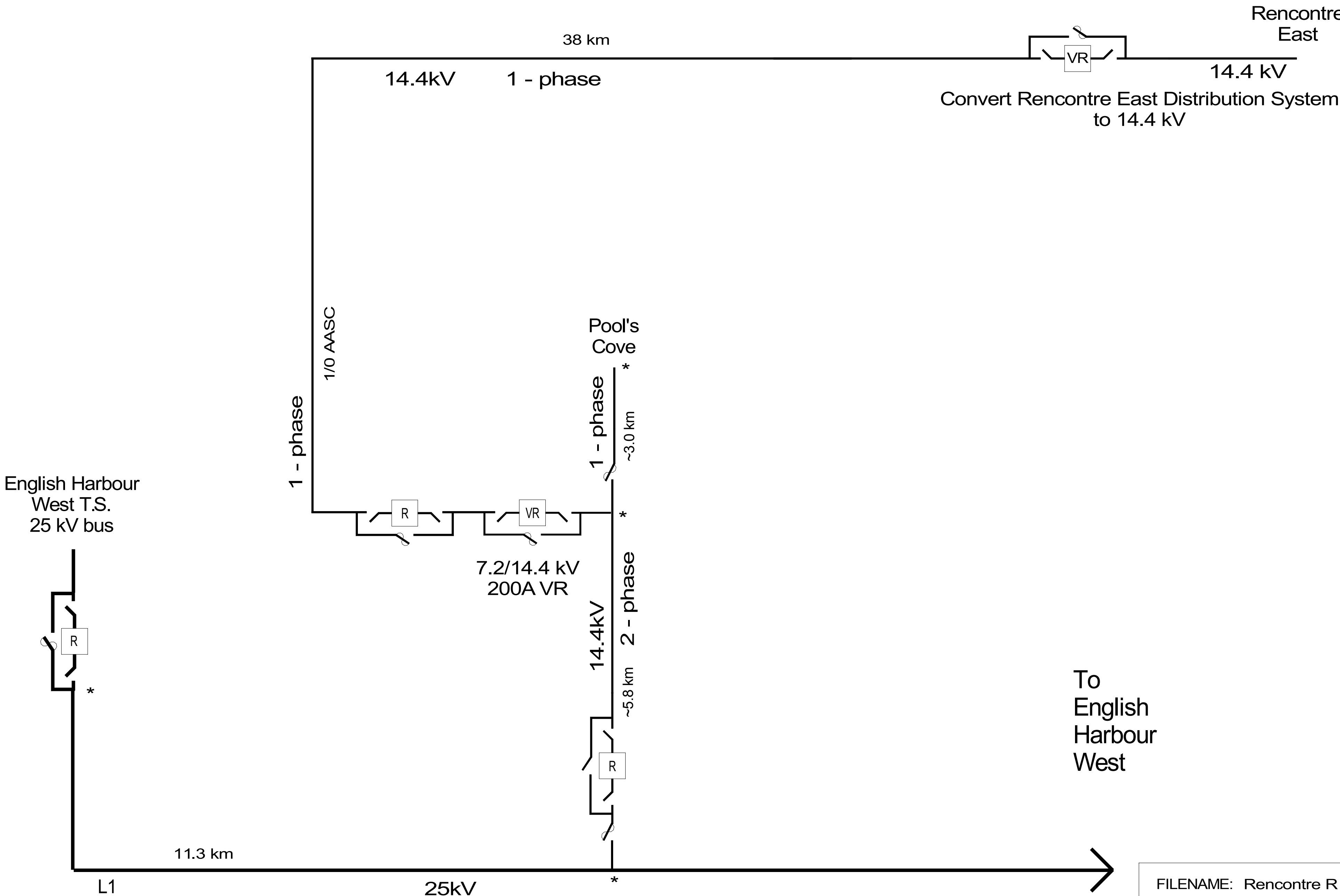
HYDRO
Environmental Services and Properties Department

LEGEND
☐ Fording Site

RENCONTRE EAST INTERCONNECT LINE
(PROPOSED)

ONE THOUSAND METRE
U.T.M. GRID ZONE 21
N.A.D.83

1000 0 1000 2000 Meters



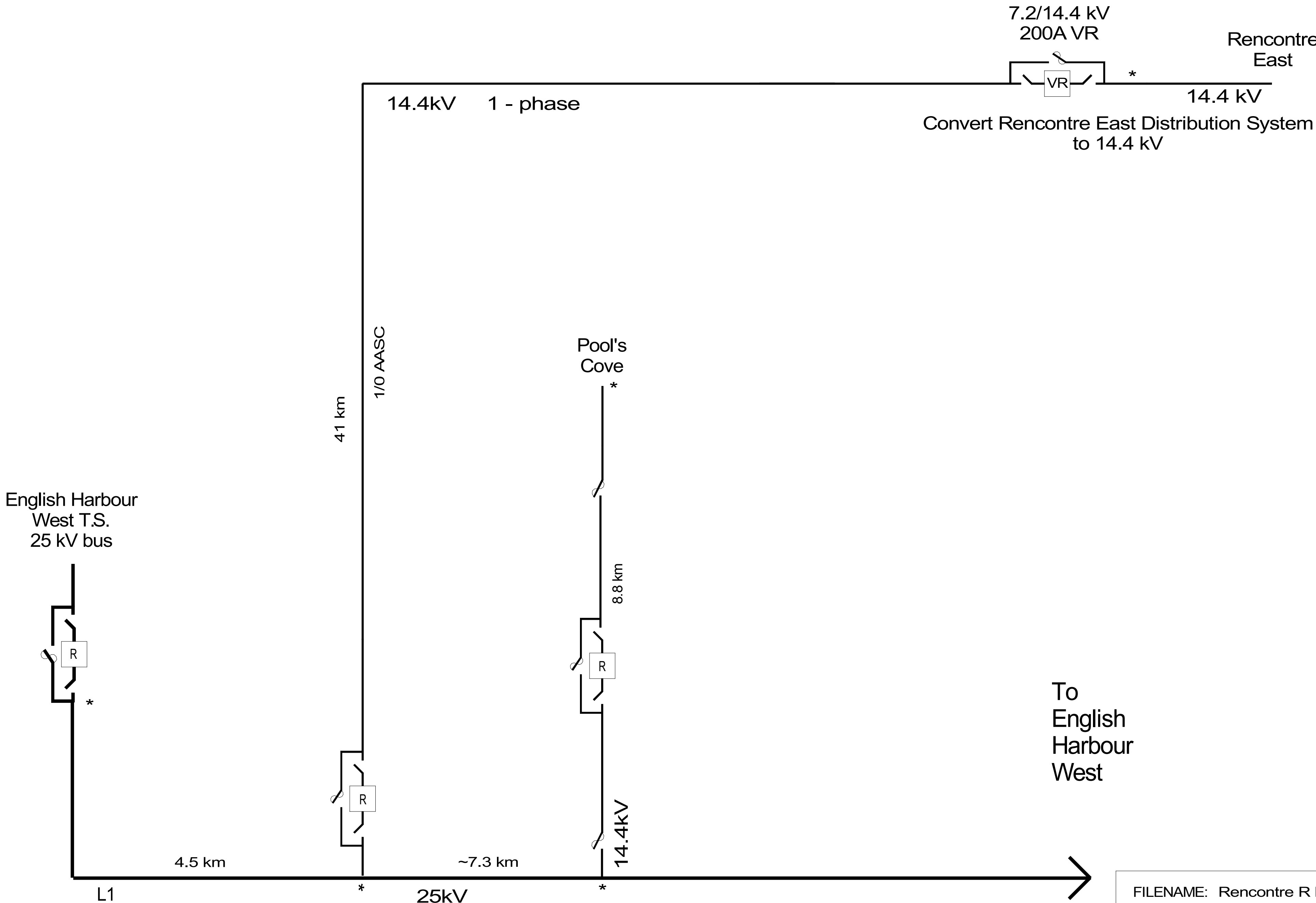
HYDRO	TITLE: RENCONTRE EAST INTERCONNECTION ROUTE "A"

FILENAME: Rencontre R A

SHEET 1 OF 1

DRAWN BY: B. Moulton

DATE: Jan. 17, 2003



HYDRO

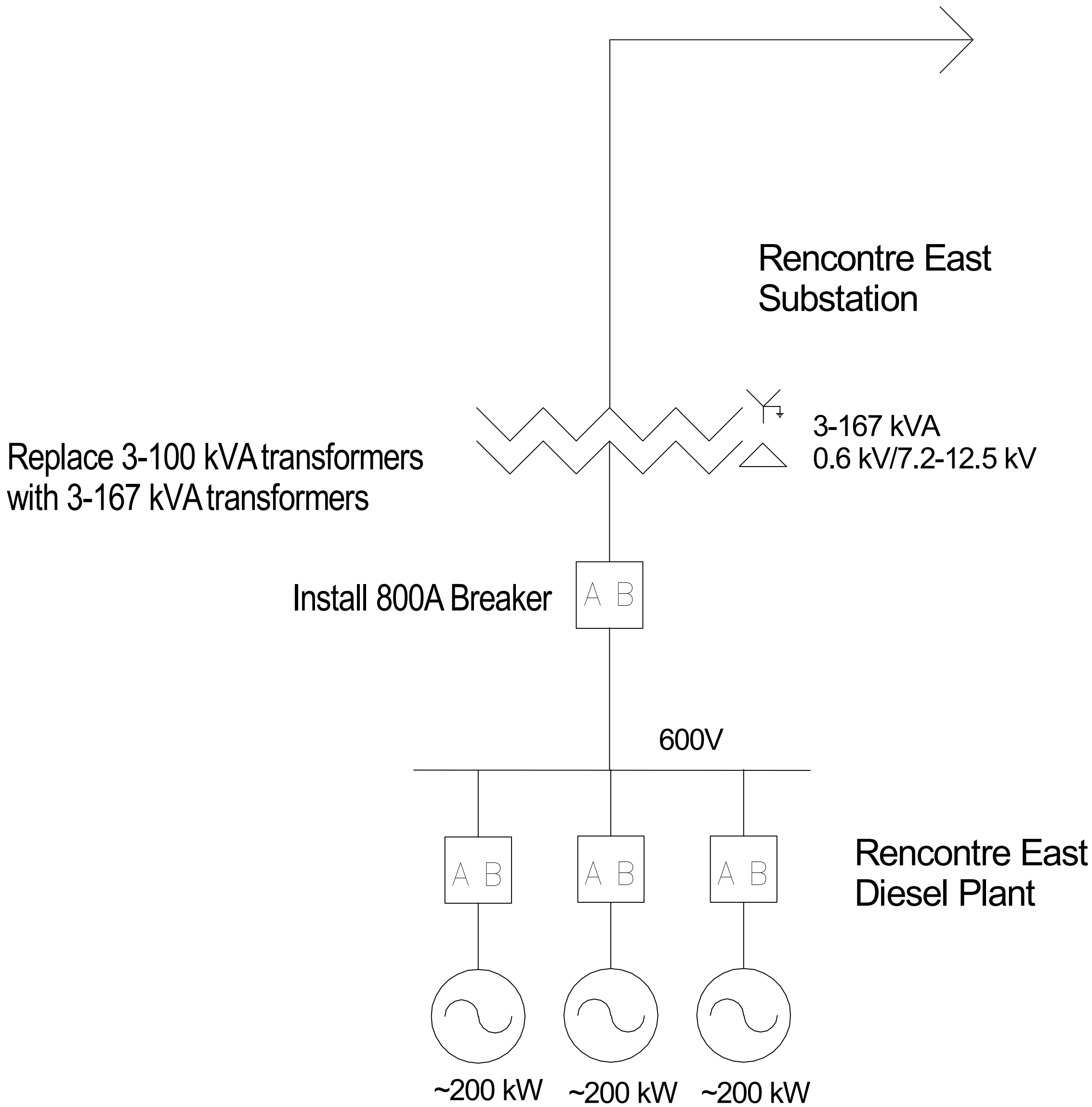
TITLE:
RENCONTRE EAST INTERCONNECTION
ROUTE "B"

FILENAME: Rencontre R B

SHEET 1 OF 1

DRAWN BY: B. Moulton

DATE: Jan. 17, 2003



Size plant for possible 800 A output.

Provide totalized metering for
fuel and energy measurement.

Provide protection as required.

HYDRO	TITLE: RENCONTRE EAST PROPOSED DIESEL PLANT	FILENAME: Rencontre DP SHEET 1 OF 1 DRAWN BY: B. Moulton DATE: Jan. 17, 2003

SCHEDULES

Rencontre East Load Forecasts

Year	Interconnection Forecast Peak kW	Interconnection Forecast Energy MWh	Diesel Forecast Peak kW	Diesel Forecast Energy MWh
2004	294	1,049	294	1,049
2005	319	976	320	1,001
2006	329	1,002	323	1,009
2007	338	1,029	326	1,018
2008	348	1,056	329	1,027
2009	355	1,075	330	1,031
2010	361	1,094	332	1,035
2011	368	1,113	333	1,039
2012	375	1,132	334	1,043
2013	382	1,152	336	1,047
2014	389	1,170	337	1,051
2015	396	1,188	338	1,055
2016	402	1,206	339	1,059
2017	409	1,224	341	1,063
2018	416	1,243	342	1,067
2019	423	1,261	343	1,071
2020	430	1,280	345	1,075
2021	436	1,299	346	1,079
2022	443	1,317	347	1,083
2023	450	1,336	349	1,087
2024	457	1,355	350	1,091
2025	464	1,374	351	1,095
2026	470	1,392	353	1,099
2027	477	1,410	354	1,103
2028	484	1,429	355	1,107
2029	491	1,447	357	1,111
2030	498	1,466	358	1,115
2031	504	1,485	359	1,119
2032	511	1,503	361	1,123
2033	518	1,522	362	1,127
2034	525	1,541	363	1,131
2035	532	1,560	365	1,135

Schedule 1

O & M Escalation Series (Annual Percentage Change)	
	Variable & Fixed
2004	2.255
2005	1.790
2006	1.978
2007	2.032
2008	1.985
2009	2.017
2010	2.061
2011	2.038
2012	2.017
2013	2.050
2014	2.050
2015	2.050
2016	2.089
2017	2.089
2018	2.089
2019	2.089
2020	2.089
2021	2.089
2022	2.089
2023	2.089
2024	2.089
2025	2.089
2026	2.089
2027	2.089
2028	2.089
2029	2.089
2030	2.089
2031	2.089
2032	2.089
2033	2.089
2034	2.089
2035	2.089

Schedule 2

Fuel Price Forecast

	Diesel Fuel at Rencontre East ($Cdn/litre)	#6 Fuel at Holyrood ($Cdn/bbl)
2004	0.400	27.65
2005	0.382	25.00
2006	0.390	24.85
2007	0.395	25.00
2008	0.407	26.25
2009	0.420	27.40
2010	0.435	27.95
2011	0.448	28.75
2012	0.461	29.55
2013	0.474	30.40
2014	0.488	31.25
2015	0.502	32.10
2016	0.516	33.00
2017	0.530	33.90
2018	0.545	34.85
2019	0.560	35.80
2020	0.575	36.80
2021	0.588	37.65
2022	0.601	38.45
2023	0.615	39.35
2024	0.628	40.20
2025	0.642	41.15
2026	0.657	42.05
2027	0.672	43.00
2028	0.687	43.95
2029	0.702	44.95
2030	0.718	45.95
2031	0.734	47.00
2032	0.750	48.05
2033	0.767	49.15
2034	0.784	50.28
2035	0.802	51.43

Schedule 3

APPENDIX A

Commentary on the Viability of the Community of Rencontre East

Commentary on the Viability of the Community of Rencontre East

Rencontre East holds a unique status as an Island isolated system in that its population and customer base has not materially declined during the 1990s. Hydro presently has 75 domestic accounts, an actual increase of 10 percent during the 1990s. In 2001 its population was 201 persons, down only marginally from the 1991 census count of 212. For the three census counts in the period 1986 to 1996, the population of Rencontre East was stable at an average of 215 persons per census year. Looking further back, post Confederation, Rencontre East had a population of about 300 during the 1950s and 1960s. It was actually during the 1970s when the population of Rencontre East contracted somewhat. Since that time, the relative stability of the community has been quite notable. Relative to the Province overall, Rencontre East has a younger demographic profile so it would not be true to characterize Rencontre East as a retirement community. About 25% of the population is school aged and currently enrolled in school. This school age population has also been noticeably stable in relative terms for a community of this size.

Changes to population across a forecast period are a function of births, deaths, and the net impact of in and out-migration. Generally, net-migration will be the key to the future population base for Rencontre East. The existing data trends would indeed suggest a lower population twenty years from now. But more importantly, the data suggest Rencontre East is a viable community that has not been materially contracting and/or re-locating due to economic circumstances like many other isolated rural communities.

The only primary economic activity is fish harvesting. The harvesting effort has been seemingly more diversified than strictly groundfish dependency (e.g. lobster) and this has likely contributed to the community's stability. As expected, government income transfers are an important source of community personal income.

Because Rencontre East is an isolated community, government provides year-round regular ferry and freight service that runs from Bay L'Argent (Burin Peninsula) to Rencontre East to Pool's Cove (Connaigre Peninsula). Both Bay L'Argent and Pool's Cove enjoy interconnected road access. While on the surface there may well exist an incentive to abandon this ferry service in favour of relocation buyouts, as was essentially the case with Harbour Deep, current government policy does not lead in such matters and responds only to a stated community's will. A check with Municipal Affairs indicates that they have had no representation from Rencontre East on re-location potential and government has not undertaken an independent analysis of the matter. Notwithstanding, if, in the future, economic and community circumstances change for Rencontre East for what ever the reason(s), a re-location risk exists. At present, such a risk is deemed low.

Rencontre East can be expected to remain a viable community as long as some primary fishing activity remains, and/or government transfers and subsidies continue to support the community, and/or the community chooses not to re-locate. These contributing factors are not matters that Hydro has any control over or expert judgement on. All Hydro can observe is that the community has been very stable in the past despite the fisheries moratoria and out-migration patterns apparent in other rural communities. Rencontre East's demographics are presently supportive of a sustained community presence. There is no information that stands out to indicate to Hydro that the community is not viable going forward.

Economic Analysis, NLH
December 2002

APPENDIX B

Alternatives – Cost Estimates

File: ______________

CAPITAL BUDGET PROPOSAL

Project Title:	New Power Supply - Rencontre East - Interconnection	Date Prepared	5-Mar-2004
Location:	English Harbour West Distribution Line to Rencontre East	Start Date	1-Feb-2005
Division:	Production	Completion Date	30-Nov-2005
Classification:	Rural Systems - Major Upgrading		

Asset(s) Retirement/Transfer is involved: Yes ___________ **No** ______________ ***If Yes, Attach Particulars***

Project Description:

This project consists of the construction of a single-phase 14.4 kV distribution line from the English Harbour West distribution system to the community of Rencontre East. The project includes the installation of a voltage regulator, single- phase recloser and the conversion of the community of Rencontre East from the existing 7.2kV to 14.4kV.

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**TOTAL**
Material Supply	586.0	0.0	0.0	586.0
Labour	1488.0	0.0	0.0	1488.0
Engineering	365.0	0.0	0.0	365.0
Project Management	46.0	0.0	0.0	46.0
Inspection & Commissioning	155.0	0.0	0.0	155.0
O/H, AFUDC, Esc. & Cont.	610.1	0.0	0.0	610.1
Total	**3,250.1**	**0.0**	**0.0**	**3,250.1**

Operating Experience:

This is a new interconnection to the Rencontre East distribution system. The community is currently served by a temporary diesel generation plant, which was installed when the permanent plant was destroyed by fire in 2002.

Project Justification:

The "Rencontre East Interconnection Study - April 2004" identified this interconnection as the most cost-effective method of servicing the community in the long term.

Future Plans:

None.

Project Initiator "Asset/Labour Manager"		Regional/Plant Manager "Initiating Dept."		Department Director "Managing Dept"	
Project Estimator "Asset or Labour Staff or Support Eng. Group'		Department Director "Initiating Dept."		Divisional Vice-President	

File: ______________

CAPITAL BUDGET PROPOSAL

Project Title:	New Power Supply - Rencontre East - New Diesel Plant	Date Prepared	4-Dec-2003
Location:	Rencontre East	Start Date	15-Jan-2005
Division:	Production	Completion Date	31-Oct-2005
Classification:	Generation - New Generation Source		

Asset(s) Retirement/Transfer is involved: Yes ___________ **No** √ ***If Yes, Attach Particulars***

Project Description:
To construct a new diesel plant to house three new gensets. The Work involves removing the existing foundations, grading site ,constructing a concrete block building, incorporating sound mitigation elements, installing an existing genset and switchgear (the Harbour Deep unit), supplying and installing two new gensets c/w switchgear and associated systems, supplying and installing a fire alarm system, supplying and installing 3 HVCTs and supplying and installing 3-167 KVA transformers to replace the existing 3-100 KVA substation transformers. Construction will be by contractor. Municipal and Environmental Permits will be required

Project Cost: *($ x1,000)*	**2005**	**2006**	**Beyond**	**TOTAL**
Material Supply	540.0	0.0	0.0	540.0
Labour	583.1	0.0	0.0	583.1
Engineering	74.5	0.0	0.0	74.5
Project Management	26.0	0.0	0.0	26.0
Inspection & Commissioning	110.0	0.0	0.0	110.0
O/H, AFUDC, Esc. & Cont.	288.2	0.0	0.0	288.2
Total	**1,621.8**	**0.0**	**0.0**	**1,621.8**

Operating Experience:
This is a new facility.

Project Justification:
In 2002, the Rencontre East diesel plant burned down requiring the use of a temporary facility to house the temporary diesels. A study (see "Rencontre East Interconnection Study") was conducted by System Planning into a permanent power supply for Rencontre East

Future Plans:
At present, there are no future commitments associated with this capital budget proposal.

Project Initiator "Asset/Labour Manager"		Regional/Plant Manager "Initiating Dept."		Department Director "Managing Dept"	
Project Estimator "Asset or Labour Staff or Support Eng. Group'		Department Director "Initiating Dept."		Divisional Vice-President	

Form 60-0521 Rev. 03/Nov

APPENDIX C

Base Case - Economic Analysis

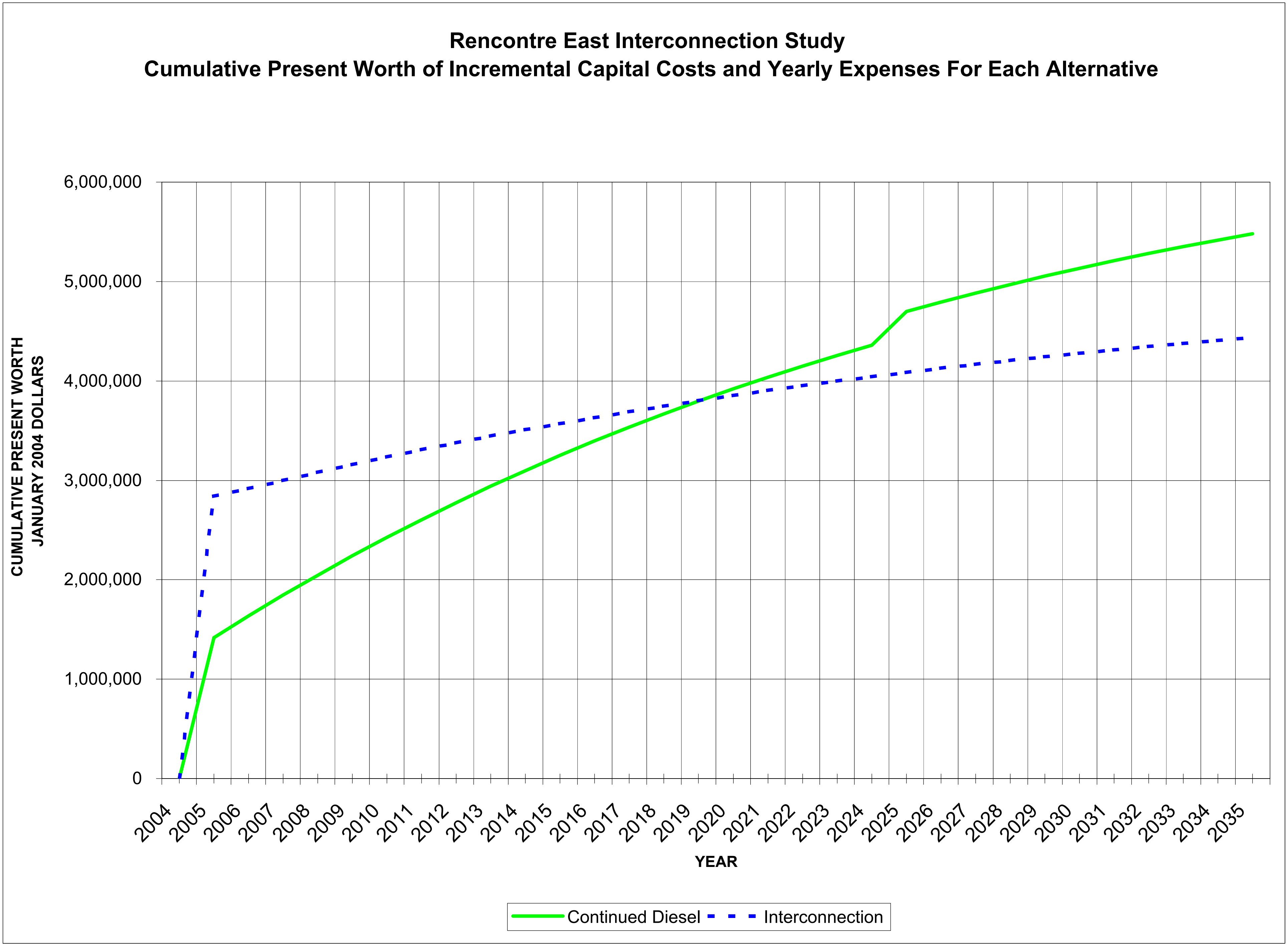
Rencontre East Interconnection Study
Economic Analysis

Base Case - New Diesel Plant with Harbour Deep Unit Diesel Plant versus Interconnection

Year	Diesel Alternative							Interconnection Alternative						Net Value of Interconnection Over Continued Diesel		
	ANNUAL			CONSTRUCTION		TOTAL Cont. Diesel $		CONSTRUCTION		ANNUAL		TOTAL INTERCONNECTION $				
	Fixed O&M	Variable O&M	Fuel & Lube	New Diesel Plant		$ For Year	CPW Jan-04	Dist. Line & DP Site Remediation	Credit for Harbour Deep Diesel	O&M	Energy 2.2% S Fuel	$ For Year	CPW Jan-04	Net $ For Year	Net CPW Jan-04	CPW Jan-04
2004	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	1,621,800		1,621,800	1,416,543	3,250,100	0	0	0	3,250,100	2,838,763	(1,628,300)	(1,422,220)	(1,422,220)
2006	108,800	44,731	114,943	0		268,474	1,635,698	100,000	(112,000)	62,963	42,766	93,729	2,915,274	174,745	142,644	(1,279,576)
2007	111,010	46,047	117,182	0		274,240	1,844,914			64,242	44,224	108,467	2,998,023	165,773	126,467	(1,153,109)
2008	113,214	47,376	122,045	0		282,636	2,046,429			65,518	47,698	113,216	3,078,744	169,420	120,794	(1,032,315)
2009	115,498	48,520	126,338	0		290,356	2,239,906			66,839	50,730	117,569	3,157,085	172,787	115,135	(917,180)
2010	117,878	49,712	131,434	0		299,024	2,426,123			68,217	52,711	120,928	3,232,393	178,096	110,909	(806,270)
2011	120,280	50,921	135,783	0		306,985	2,604,791			69,607	55,212	124,819	3,305,039	182,166	106,022	(700,248)
2012	122,707	52,149	140,275	0		315,130	2,776,201			71,011	57,770	128,781	3,375,088	186,349	101,361	(598,887)
2013	125,222	53,422	144,913	0		323,557	2,940,681			72,467	60,538	133,004	3,442,700	190,553	96,867	(502,020)
2014	127,789	54,725	149,703	0		332,218	3,098,515			73,953	63,260	137,213	3,507,889	195,005	92,646	(409,374)
2015	130,409	56,060	154,650	0		341,119	3,249,976			75,469	66,041	141,510	3,570,721	199,609	88,629	(320,745)
2016	133,134	57,448	159,475	0		350,057	3,395,237			77,045	68,976	146,021	3,631,315	204,036	84,668	(236,077)
2017	135,916	58,870	164,449	0		359,234	3,534,555			78,655	71,971	150,626	3,689,730	208,608	80,902	(155,175)
2018	138,755	60,326	169,575	0		368,657	3,668,173			80,299	75,195	155,494	3,746,088	213,163	77,260	(77,915)
2019	141,654	61,817	174,860	0		378,331	3,796,327			81,976	78,425	160,401	3,800,421	217,930	73,821	(4,095)
2020	144,614	63,345	180,306	0		388,265	3,919,241			83,689	81,894	165,583	3,852,841	222,682	70,495	66,401
2021	147,636	64,909	185,040	0		397,584	4,036,872			85,438	85,096	170,533	3,903,295	227,051	67,176	133,577
2022	150,720	66,510	189,895	0		407,125	4,149,446			87,223	88,177	175,400	3,951,795	231,726	64,074	197,651
2023	153,869	68,151	194,874	0		416,895	4,257,179			89,045	91,614	180,659	3,998,481	236,235	61,048	258,698
2024	157,084	69,831	199,982	0		426,897	4,360,280			90,906	94,998	185,904	4,043,379	240,993	58,203	316,901
2025	160,366	71,551	205,221	1,066,530		1,503,668	4,699,678			92,805	98,684	191,488	4,086,600	1,312,180	296,176	613,078
2026	163,717	73,313	210,594	0		447,624	4,794,103			94,744	102,260	197,004	4,128,158	250,620	52,868	665,945
2027	167,137	75,117	216,105	0		458,360	4,884,467			96,723	106,023	202,746	4,168,128	255,613	50,393	716,339
2028	170,630	76,965	221,757	0		469,352	4,970,945			98,744	109,930	208,674	4,206,576	260,678	48,030	764,368
2029	174,195	78,857	227,555	0		480,606	5,053,703			100,807	113,955	214,762	4,243,557	265,844	45,777	810,145
2030	177,834	80,794	233,501	0		492,129	5,132,901			102,914	118,131	221,045	4,279,130	271,084	43,626	853,771
2031	181,550	82,778	239,599	0		503,926	5,208,693			105,064	122,512	227,576	4,313,358	276,350	41,564	895,335
2032	185,343	84,810	245,853	0		516,006	5,281,224			107,259	126,887	234,146	4,346,270	281,860	39,619	934,954
2033	189,215	86,890	252,267	0		528,373	5,350,635			109,500	131,556	241,057	4,377,937	287,316	37,744	972,698
2034	193,169	89,020	258,846	0		541,035	5,417,059			111,788	136,376	248,164	4,408,405	292,870	35,957	1,008,654
2035	197,205	91,202	265,592	0		553,999	5,480,626			114,123	141,351	255,475	4,437,719	298,524	34,253	1,042,907
CPW 2004$	1,456,974	630,725	1,735,654	1,657,273	0	**5,480,626**		2,920,393	(91,425)	843,160	765,592	**4,437,719**		**1,042,907**		

Discount Rate = 7.0%

CPW Continued Diesel Cost - Jan 2004	5,480,626
CPW Interconnection Cost - Jan 2004	4,437,719
Cumulative Present Worth of Interconnection	1,042,907


Rencontre East Interconnection Study
Cumulative Present Worth of Incremental Capital Costs and Yearly Expenses For Each Alternative
CUMULATIVE PRESENT WORTH
JANUARY 2004 DOLLARS
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
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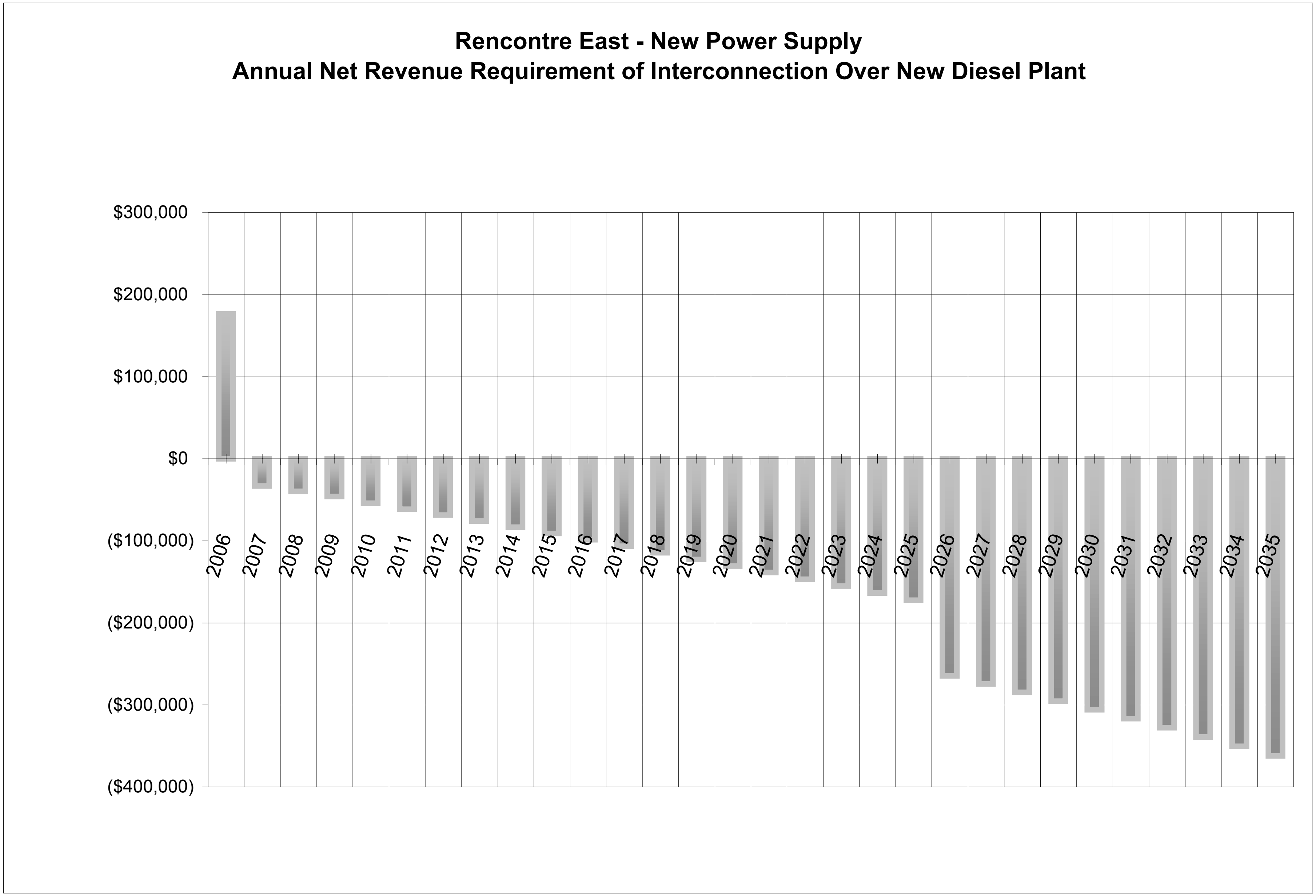
2035
YEAR
Continued Diesel
Interconnection

APPENDIX D

Base Data – Revenue and Revenue Requirement Analysis


Rencontre East - New Power Supply
Annual Net Revenue Requirement of Interconnection Over New Diesel Plant
$300,000
$200,000
$100,000
$0
($100,000)
($200,000)
($300,000)
($400,000)
2006
2007
2008
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2035

Rencontre East Analysis - Annual Costs and Revenues

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Diesel Alternative					Interconnection Alternative					
			Capital-Related Increases					Capital-Related Increases			
Year	Total O&M	Total Fuels	Deprec	Financing	Total Revenues	Total O&M	Total Fuels	Deprec	Loss on Disposal	Financing	Total Revenues
2006	153,531	114,943	86,690	115,830	(118,214)	162,963	42,766	108,337	100,000	218,985	(103,653)
2007	157,057	117,182	86,690	109,890	(117,928)	64,242	44,224	108,337		211,562	(108,540)
2008	160,591	122,045	86,690	103,950	(121,395)	65,518	47,698	108,337		204,139	(113,543)
2009	164,018	126,338	86,690	98,010	(124,326)	66,839	50,730	108,337		196,716	(117,917)
2010	167,590	131,434	86,690	92,070	(127,377)	68,217	52,711	108,337		189,292	(122,272)
2011	171,202	135,783	86,690	86,130	(130,264)	69,607	55,212	108,337		181,869	(126,905)
2012	174,855	140,275	86,690	80,190	(133,456)	71,011	57,770	108,337		174,446	(131,521)
2013	178,644	144,913	86,690	74,250	(136,670)	72,467	60,538	108,337		167,023	(136,428)
2014	182,515	149,703	86,690	68,310	(140,014)	73,953	63,260	108,337		159,599	(141,317)
2015	186,469	154,650	86,690	62,370	(143,381)	75,469	66,041	108,337		152,176	(146,183)
2016	190,582	159,475	86,690	56,430	(146,826)	77,045	68,976	108,337		144,753	(151,310)
2017	194,785	164,449	86,690	50,490	(150,204)	78,655	71,971	108,337		137,330	(156,629)
2018	199,081	169,575	86,690	44,550	(153,809)	80,299	75,195	108,337		129,906	(162,101)
2019	203,472	174,860	86,690	38,610	(157,498)	81,976	78,425	108,337		122,483	(167,681)
2020	207,959	180,306	86,690	32,670	(161,336)	83,689	81,894	108,337		115,060	(173,419)
2021	212,544	185,040	86,690	26,730	(165,200)	85,438	85,096	108,337		107,637	(179,370)
2022	217,231	189,895	86,690	20,790	(169,155)	87,223	88,177	108,337		100,214	(185,438)
2023	222,020	194,874	86,690	14,850	(173,268)	89,045	91,614	108,337		92,790	(191,677)
2024	226,915	199,982	86,690	8,910	(177,410)	90,906	94,998	108,337		85,367	(198,092)
2025	231,917	205,221	86,690	2,970	(181,648)	92,805	98,684	108,337		77,944	(204,887)
2026	237,030	210,594	71,500	95,534	(185,809)	94,744	102,260	108,337		70,521	(211,512)
2027	242,255	216,105	71,500	90,635	(190,316)	96,723	106,023	108,337		63,097	(218,481)
2028	247,594	221,757	71,500	85,736	(194,855)	98,744	109,930	108,337		55,674	(225,645)
2029	253,051	227,555	71,500	80,836	(199,312)	100,807	113,955	108,337		48,251	(233,007)
2030	258,628	233,501	71,500	75,937	(204,060)	102,914	118,131	108,337		40,828	(240,574)
2031	264,328	239,599	71,500	71,038	(208,997)	105,064	122,512	108,337		33,405	(248,576)
2032	270,153	245,853	71,500	66,139	(213,970)	107,259	126,887	108,337		25,981	(256,404)
2033	276,105	252,267	71,500	61,240	(218,855)	109,500	131,556	108,337		18,558	(264,617)
2034	282,189	258,846	71,500	56,341	(224,057)	111,788	136,376	108,337		11,135	(273,295)
2035	288,406	265,592	71,500	51,441	(229,465)	114,123	141,351	108,337		3,712	(281,970)

SECTION G
Tab 4

Mobile Radio System Replacement

Report

to be filed separately

SECTION H

HYDRO

2003 RATE BASE

($000s)

	2002	2003
Capital Assets	1,757,726	1,904,557
Less:		
Contributions in Aid of Construction	87,569	85,055
Accumulated Depreciation	433,572	456,695
Net Assets not in Service	115	4
Muskrat Falls	2,010	2,049
Net Capital Assets	1,234,420	1,360,754
Balance previous year	1,224,068	1,234,420
Average Capital Assets	1,229,244	1,297,587
Working capital	3,579	3,456
Fuel	17,715	18,310
Supplies Inventory	19,966	18,565
Average Deferred Charges	85,703	84,494
Average Rate Base	1,356,207 [1]	1,422,412

1 Approved by the Board, Order No. P.U. 14 (2004)