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Information Systems

Project Title: **Meters**

Location: **Various**

Classification: **Distribution**

Project Cost: **$1,174,000**

This project consists of a number of items as noted.

(a) Regular Domestic Meters and Associated Equipment

Cost: $814,000

Description: Purchase and installation of meters and associated equipment for new customers and replacement meters for existing customers.

Operating Experience: The quantity of meters for new customers is based on the Company's forecast of customer growth. The quantity for replacement is determined using historical data.

Justification: This project is justified on the basis of customer requirements and Industry Canada regulations.

(b) AMR (Safety and Access)

Cost: $360,000

Description: This project involves installing energy and demand AMR meters in residential locations where access is restricted due to safety reasons and where meters are located inside customer premises or hard to read locations. These locations are identified across NP's service territory.

Operating Experience: Safety of Newfoundland Power employees is a number one priority. Meter readers are exposed to many hazardous environments that have serious safety implications for the reader. These result from weather conditions and inaccessible meters at customer premises.

Safety related incidents potentially result in harm to employees as well as operational costs related to investigations, staff replacement, and prevention of future incidents. AMR is an important tool to help reduce the risk of injury to employees as well as the associated cost of workplace injury. Newfoundland Power will continue to install AMR meters using RF technology in identified areas where meter reading is either unsafe or difficult to access. Existing installations in similar locations have proven successful in improving safety and meter reading accuracy.

Justification: This project will improve safety for employees and meter reading accuracy for these customers involved.

Project Title: **Rebuild Distribution Lines**

Location: **Various**

Classification: **Distribution**

Project Cost: **$4,137,000**

This project consists of a number of items as noted.

(a) Feeder Upgrades

Cost: $2,802,000

Description: This project consists of correcting deficiencies that were identified during feeder inspections. The following table gives a summary of the work identified:

	Components		
No. of Feeders	**Transformers**	**Insulators**	**Hardware**
56	1,000	17,000	9,000

Operating Experience: See the following reports outlining the deficiencies associated with various components:

Attachment	Title
Volume III, Distribution, Appendix 2, Attachment A	Newfoundland Power's Distribution Inspection Standard
Volume III, Distribution, Appendix 2, Attachment B	Distribution Lightning Arrestors
Volume III, Distribution, Appendix 2, Attachment C	Distribution Insulator Replacement Program
Volume III, Distribution, Appendix 2, Attachment D	Current Limiting Fuses
Volume III, Distribution, Appendix 2, Attachment E	Automatic Sleeve Replacement
Volume III, Distribution, Appendix 2, Attachment F	Porcelain Cutout Replacement
Volume III, Distribution, Appendix 2, Attachment G	Underground Distribution Replacement in the St. John's Area

Justification: The distribution inspection program identified selected structures, hardware, insulators and transformers on various feeders that need replacement. It was determined that a certain number of these components must be replaced in 2004 for reasons of public and employee safety and system reliability.

(b) KBR-05 and SLA-06 Feeder Upgrade

Cost: $410,000

Description: This project consists of the replacement of poles, conductor and hardware on the Stamps Lane-06 distribution feeder (SLA-06) which serves the Summerville, Anderson Avenue and Wishingwell Road areas and the Kings Bridge-05 distribution feeder (KBR-05) which serves the Circular Road and Hayward Avenue areas.

Operating Experience: In 2000, in conjunction with a review of feeders in the St. John's City core area a review of these feeders was conducted. For areas with large concentrations of old poles, a number of poles were sounded for an indication of hollow heart, soft or shaley surface, etc. Poles were also viewed for large splits, snowplow damage and holes. A number of poles that looked or sounded questionable were drilled for proof of rot or other problems. Crossarms were viewed for signs of rot, moss growth or large splits. Conductor was reviewed for reasonable sag, sizing and condition of weatherproofing, where applicable. As a result of the review, it was recommended that SLA-06 and KBR-05 be upgraded.

See Requests for Information, PUB-18, Newfoundland Power 2002 Capital Budget Hearing and PUB-15-1 and 15-2 Newfoundland Power 2003 Capital Budget Application for more information.

Justification: In September 2000 the Company completed a review of these feeders and identified selected poles, structures, hardware and conductor that need replacement. These components must be replaced in order to maintain public safety and system reliability.

(c) Replace Deteriorated Padmount Transformers and Underground Services

Cost: $120,000

Description: This project consists of the replacement of 30-year old direct-buried underground services and padmount transformers in the Virginia Park, Mount Pearl and Elizabeth Park areas of the St. John's metro area.

Operating Experience: In the early to mid-1970s, several large residential developments in the St. John's metropolitan area were serviced by way of underground distribution systems. These systems were installed using direct-buried underground cables, which have proven to be unreliable. The direct-buried systems were installed primarily in three areas: Virginia Park in the east end of St. John's, the Newtown (Whitely Drive/Munden Drive) area of Mount Pearl and Elizabeth Park in Paradise. Customers served by these systems have experienced faults since 1978. Initially, the faults were repaired on an individual basis, however, since 1998 a concentrated replacement program has been underway. In 2004, this program will continue. In addition, a five-year replacement program for padmount transformers, which also form part of these systems, will commence. These transformers are nearing the end of their 30-year lives and the number of padmount failures has been increasing. These transformers are filled with oil and failure due to rusting results in significant clean-up efforts which cost on average $2,700 per unit in 2002 as well as interruptions in service to customers.

Justification: This project is based upon improving reliability of service to customers in these areas, environmental stewardship, and reducing oil spill clean up cost. Please refer to Volume III, Distribution, Appendix 2, Attachment G, *"Underground Distribution System Replacements in the St. John's Area"*, for more information on this project.

(d) Install Support for Cable Termination – Bell Island

Cost: $70,000

Description: This project consists of the construction of a retaining wall adjacent to the Bell Island end of the submarine cable termination feeding Bell Island.

Operating Experience: The slope immediately adjacent to this cable termination is highly unstable, creating a safety hazard for employees and exposing critical equipment to damage from falling rock.

Justification: This project is required for reasons of employee safety, protection of equipment and distribution system reliability. The cable termination is located on the beach at the toe of a steep and highly unstable cliff. Rock fragments are continuously falling down the nearby cliffs. To protect employees and equipment from falling rock, a retaining wall or other slope retaining mechanism must be constructed.

(e) Upgrade Secondary Circuits – Grand Bank/Fortune

Cost: $130,000

Description: This project consists of the replacement and reconfiguration of transformers, secondary lines and services in the communities of Grand Bank and Fortune.

Operating Experience: A very high incidence of trouble calls have been experienced in recent years in the Grand Bank District. The majority of these calls relate to voltage problems, blinking lights and similar symptoms of deteriorated secondary circuits.

Justification: This project is based upon reliability and productivity improvements. It will address the issue by rebuilding and reconfiguring secondary circuits in these areas. This will reduce trouble calls and improve reliability for customers served by these lines.

(f) Projects < $50,000

Cost: $605,000

Description: There are approximately 20 other projects, estimated at less than $50,000 each, that will be completed in 2004.

Operating Experience: Inspections and technical assessments have identified minor projects that need to be completed.

Justification: These minor projects are necessary to address situations involving deteriorated equipment, overloaded equipment and/or line relocations that may have a negative impact on safety, reliability, customer service or the environment.

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Distribution Inspection Standards

DISTRIBUTION INSPECTION AND MAINTENANCE PROCEDURES

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Distribution Inspection Standards

DISTRIBUTION INSPECTION AND MAINTENANCE PROCEDURES

Policy Statement

Scheduled inspection and maintenance procedures shall be undertaken on all distribution lines to provide safe and reliable operation. Regional Managers shall be responsible for the required distribution line inspections and maintenance in each region.

The results of these inspections and the maintenance work that is completed to correct any deficiencies shall be recorded in the Company's Distribution Line Inspection Database. (DLID)

Inspection Procedures

Inspection Type and Frequency

All overhead primary distribution lines are required to have a minimum of one detailed ground inspection every five years. Climbing/bucket Inspections shall only be performed on distribution structures/lines to:

1) Verify questionable defects picked up from ground inspection.

2) Assess the condition of specific components (i.e. insulators, hardware, and cross-arms) where ongoing service problems exist.

Ground Inspections

Guidelines for detailed ground inspections of distribution lines and the associated record-keeping procedures are as follows:

- All personnel performing inspections on distribution lines shall have appropriate training.

- The inspection will cover poles, conductors, cross-arms including hardware, transformers, grounding (pole and transformers), anchors and guys.

- Personnel performing inspections shall use binoculars, plumb bob, hammer, core sampler, screw driver, crescent wrench, digital camera and all other equipment deemed necessary to assist in the evaluation of distribution line components.

- As distribution lines are inspected, a Distribution Line Inspection Report for each feeder will be completed (see Appendix 2). This information will then be entered into the DLID. The report shall then be reviewed by the appropriate Area/Regional Superintendent or designate.

- Inspection personnel shall assign a Maintenance Priority for each deficiency identified. This priority shall establish when corrective action is required (more information on assigning priority is given in the Maintenance Procedures section).

A deficiency list shall be established and updated as defects are corrected and when new defects are identified. The purpose is to provide an up-to-date list of outstanding defects on each distribution line. Inspection personnel shall use this list for each inspection to check the status of known defects.

Inspection Process

Distribution line inspections require evaluation of the following components:

Wood Pole Structures:

- Inspect and determine condition of pole(s) at ground line and above for rotting, deterioration, splitting, cracks, breaks, burns, woodpecker holes, insect infestation and plumbness. Ensure pole is properly backfilled and not undermined (More information is given in the section – Detailed Wood Pole Inspection).
- Where applicable, inspect condition of timber cribs. Ensure crib is properly rock filled.
- Check structure for plumbness or any degree of misalignment.
- Check for structure number tags.
- Record pole numbers for structures with deficiencies.

Guys and Anchors:

- Inspect guys and pre-forms for wear, breaks, slackness and corrosion. Ensure guy guards are installed in areas that are easily accessible by the public.
- Inspect anchor rod and backfill conditions. Check for anchor rod damage. Ensure anchor is not undermined or pulling. Ensure that anchor eye is above ground level.

Hardware:

- Inspect crossarms for rot, splits, cracks and twisting that may cause the conductor to fall to the ground. Also, inspect for burn marks.
- Inspect for broken, cracked, chipped, misaligned, flashed or defective insulators. Check non-dead end insulators for uplift.
- Check for improperly installed cutouts and problematic cutouts that have been known to fail.

- Check hardware for any visible deficiency that may result in conductor falling to the ground.

Conductors and Accessories:

- Check for excessive sag that could result in phases slapping together causing phase-to-phase faults.
- Inspect conductors for safe clearances from buildings, roads, ground, and other power/communication lines.
- Inspect conductor for broken or frayed strands, burn marks, foreign objects.
- Inspect dead-end assemblies for any abnormal condition.
- Where required, inspect for damaged or missing conductor warning markers.

Right of Way:

- Check for danger trees that may contact the conductor, or allow someone to climb the tree contact the conductor.
- Check for encroachments by foreign structures, unauthorized excavation or fill areas, etc.

Grounding:

- Check that each transformer contains at least two independent paths to ground.
- Ensure that pole grounds exist on all poles with transformers on them. Ensure that it is rigidly supported, it has not been cut and a ground guard is present.
- Ensure that any pole that has the neutral supported by a spool is properly grounded or is identified in the inspection for replacement with a neutral bracket.

Structures:

- Inspect for safety issues.
- Inspect vertical structure to horizontal structure transition points for lower cross-arms.

Transformers:

- Inspect transformers for rust and leaks. Questionable transformers must be noted for re-inspection.
- Ensure that all transformers have PCB identification tags installed. Particularly, transformers in Protected Public Water Supply Areas contain a green PCB identification tag.

DETAILED WOOD POLE INSPECTIONS

To complement the required inspection of wood poles discussed under the Inspection Process section, this section describes testing procedures to be used in determining the integrity of distribution line wood poles.

Wood Pole Testing Frequency

During each distribution line inspection, all wood poles require a detailed visual inspection and a sounding test.

If the visual inspection and/or the sounding test indicate a problem, a core-sampling test may be performed to aid in the evaluation of the pole.

Types of Wood Pole Tests

Visual Inspection:

Inspect the condition of the pole from the ground line to the top on all quadrants. The pole shall be examined for the following defects: pole top rot, external decay, woodpecker damage, fire damage, cracks, and sign of insect infestation.

Sounding Test:

Using a flat faced hammer, sound the pole surface at regular intervals on all quadrants from the ground line to 6 feet above grade. Care should be taken to detect any difference in sound. When the sound does differ (i.e. – hollow sound), it may indicate internal decay and further testing may be required. This test can be used to evaluate any portion of the pole above ground line.

Core Sampling Test:

This test is performed using an approved core-sampling device. By drilling through the centerline of the pole, a core sample can be extracted for evaluation. The location of boreholes shall be determined by the sounding test. All boreholes should be plugged with a tight fitting, wooden plug. Also, to avoid transfer of decay, the core sample must be cleaned with an approved fungicide.

MAINTENANCE PROCEDURES

Upon completion of a distribution line inspection, scheduled preventative maintenance shall ensure the distribution system maintains a high degree of integrity and reliability. This section establishes guidelines for maintenance procedures.

Maintenance Classification

Defects identified through the inspection process are all given one of four classifications based on the nature of the abnormal condition. Unless otherwise stated or directed, the response times shall be as follows:

CLASSIFICATION	RESPONSE TIME
Emergency Immediate security of the line is at risk	Immediate
Priority 1 Defects which if left could result in an interruption	One Month (approximately)
Priority 2 Defects of less consequence	Within 12 months
Priority 3 Defects of minor concern: no repairs necessary	Continue to monitor condition for possible upgrading of classification

• Table. Maintenance Response Time.

The responsibility for scheduling maintenance rests with the designated Area/Regional Superintendent. Defects defined, as Emergency shall be reviewed within 24 hours of identification for the purpose of initiating repairs immediately or downgrading the reported condition. This review may require a second field visit by designated operating personnel.

It is not possible to cover all conditions that inspection personnel may encounter. The table in **Appendix 1** gives a general guideline that can be used to assist in classifying defects.

MAINTENANCE REPORTS

To monitor maintenance performed on the distribution system, completion of a Maintenance Report is required for each distribution line. The report shall be a yearly cumulative list of maintenance work performed.

Appendix 1

ITEM	EMERGENCY	PRIORITY 1	PRIORITY 2	PRIORITY 3
Poles, Crossarms	Broken	Serious cracks or deterioration	Moderate cracks or deterioration	Minor cracks or deterioration
Insulators	Emergency or Priority 1 depending on extent of damage		Minor defects	
Conductor Damage	More than 1/4 strands broken	Less than 1/4 strands broken	1 or 2 strands broken	
Hardware	Missing or Damaged: High risk of causing interruption	Missing or Damaged: Moderate risk of causing interruption	Missing or Damaged: Low risk of causing interruption	Other minor defects: Very Low risk of causing interruption
Guys	Severely rusted, broken or disconnected on angle or deadend structures	Covered preforms on deadends; severely rusted, broken or disconnected on other structure types	Rusted, slack or ungrounded guys	
Anchors/Rod	Rod cut off on angle/deadend struc.	Anchor pulling out on angle/deadend struc. or rod cut off on other struc.	Anchor pulling out on other structure types or anchor eye underground.	
Transformers	Severely rusted XFMR with High risk of leaking, XFMRS without green PCB tags in PPWSA	Rusted XFMR with Moderate risk of leaking.	XFMR without two independent paths to ground	
Pole Grounding			Cut, or unsupported pole Grounds. No pole ground guard installed	
Corrosion (any component)		Severe cases	Moderate cases	Minor cases
Encroachments	Active operations with clearance concerns and/or high risk of causing interruption or injury	Non-active operations with clearance problem	Low risk cases	Cases deemed tolerable
Danger Trees	High risk of person climbing and touching line	Risk of falling on line		
Leaning Structures	Line clearance in question or high risk of falling over	Leaning over 6 ft.	Leaning between 2ft - 6ft	Leaning less than 2 ft
Abandoned Equipment	High safety hazard	Moderate safety hazard	Low safety hazard	
Underground Conduit	High safety hazard	Moderate safety hazard	Low safety hazard	
Missing Danger Signs	High safety hazard	Low safety hazard		
Vertical to Horizontal Transitions			Crossarm is not lowered at transition point	
Conductor Sag	Active operations with clearance concerns or high risk of phases slapping together	Non-active operations with clearance problem or moderate risk of phases slapping together	Low risk of phases slapping together	
Neutral Conductor			Attached to pole with spool, (Must be grounded or replaced)	

Appendix 2

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DISTRIBUTION FEEDER INSPECTION REPORT

Feeder #: ______________________

Date: ______________________

POLE #	STRUCTURE TYPE	PRIORITY	LOCATION	DESCRIPTION OF DEFECT	COMMENTS

Inspected By: ______________________ **Page:** _____ **of** _____

Distribution Lightning Arrestors

Newfoundland Power Inc.

June 2003

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Introduction

Damage to distribution transformers as a result of lightning storms has been a concern for Newfoundland Power for a number of years. In the early 1990's transformer losses due to lightning prompted the Company to review the installation of lightning arrestors on distribution transformers. Prior to this, arrestors were only installed on larger, more costly equipment such as substation power transformers, reclosers, regulators and main underground cables.

In 1995 a report entitled "A Study into the Feasibility of Installing Surge Arrestors on the Newfoundland Power Distribution System" was completed. This report was filed with the Public Utilities Board on November 28, 1997 in response to Request for Information, PUB-8. The report considered the number of transformer failures and evaluated the costs of installing arrestors on distribution transformers. The report recommended an arrestor installation program be implemented in Gander, Grand Falls, and Stephenville Areas based on transformer failure records which indicated that these three areas suffered the greatest number of transformer failures due to lightning, during the period 1990 to 1994. This report recommended that arrestors be installed on all transformers on selected feeders in those areas over a period of time.

In 2002 several intense lightning storms swept across the province resulting in transformer failures higher than any previously recorded year, with more than 300 transformers faulted. This experience prompted a review of the existing arrestor policy to determine whether it adequately addressed the lightning/transformer loss experience.

Isokeraunic Levels

Lightning is by far the leading cause of damaging overvoltages on distribution systems. Lightning need not come in direct contact with power lines to cause problems, since induced charges can be introduced on to the system from nearby lightning strikes to ground. A universally accepted measure to help utilities make some determination of the incidence of lightning in their service areas is the isokeraunic level (IKL) or thunder day (TD) – defined as the number of days in a year (or month) that thunder is heard in a particular location.

In some locations in Canada isokeraunic levels of 30 to 40 are experienced while levels of 100 are reached in Florida. In these areas, the use of lightning arrestors is common and considered a standard part of any electrical equipment installation.

Generally, the island of Newfoundland has relatively low isokeraunic levels. Environment Canada's Canadian Climate Normals 1971-2000 list the highest IKL at 6.4 in the Port aux Basques and Stephenville areas. Other areas of the province have lower levels, some less than 1. In St. John's an IKL of 4.5 exists. It is understandable with these levels that one might conclude that Newfoundland is not an area very prone to lightning.

However, IKL alone is a weak indicator of the damaging effects of lightning, as it does not measure the severity of lightning strikes. As such, it would be unwise to make recommendations based solely on an IKL. The number of transformers damaged by lightning storms in any one year have ranged from 22 in 2000 to 323 in 2002.

While it may be difficult to predict whether long term weather and lightning patterns in Newfoundland are changing, it certainly appears that the incidence and severity of lightning, at least in certain areas of the province, has increased over the past decade.

Utility Practices – Lightning Arrestors

Prior to the mid 1990's, Newfoundland Power did not install arrestors on pole mounted distribution transformers. There were several reasons for this. First, the reliability of arrestors prior to the 1990's was somewhat suspect. Porcelain housing was a safety concern for employees because catastrophic failure of arrestors resulted in the shattering of porcelain, potentially causing serious injury. However, the quality of arrestors has substantially improved in the past 10-15 years, one of the improvements being the change from a porcelain housing to a polymer housing. Today's arrestors are highly reliable, less expensive and no longer pose a safety concern from exploding glass.

Second, the island of Newfoundland was not considered to be a high isokeraunic area and protection of a relatively inexpensive piece of equipment such as distribution transformers was considered to be unnecessary. When this was considered along with the quality and safety issues, the benefits at that time were not considered great enough to warrant the installation of arrestors on pole mounted transformers.

The vast majority of North American utilities install lightning arrestors on every transformer installed and consider the lightning arrestor essential for the protection and reliable operation of transformers. Since October 2002, Newfoundland Power has considered an arrestor to be an integral part of the transformer and all new transformer installations since that time have an arrestor included.

In recent years Newfoundland Power has improved the standard of its pole mounted transformers. To combat the early deterioration of the transformer tank, which resulted in premature removal and costly oil spills, Newfoundland Power now uses stainless steel tanks. Similarly, arrestors will protect the transformer against damage from lightning and associated oil spills that can occur with lightning damage. Transformers are an important asset and these measures together will prolong the life of the asset, which in turn will lead to lower costs as well as increased reliability to the customer.

Transformer Failures due to Lightning

Within Newfoundland Power's service territory, the piece of equipment that has sustained the most failures due to lightning is the distribution transformer. Transformers range in sizes from 10 to 167 kVA for pole-mounted units, 50 to 100 kVA for 1-phase pad-mounted units and 150 to 2500 kVA for 3-phase pad-mounted units. Material costs range from $ 830 to $3560 for 10 to 167 kVA pole-mounted units; $2350 to $3240 for 50 to 100 kVA, 1-phase pad-mounted units; and $6000 to $36,960 for, 150 to 2500 kVA 3-phase pad-mounted units. The costs do not include the cost of installation which can be significant depending on circumstances.

Over the past 13 years Newfoundland Power has lost in excess of 1500 transformers that have failed due to lightning, with approximately 700 of these in the last 5 years. The annual number of units that have failed range from a low of 22 units in 2000 to a high of 323 units in 2002, and the average the past 5 years has been 139 units. This translates to an average annual cost in excess of $300,000[1] per year. Furthermore, it is likely that this average cost would have been higher, but for the arrestor installation program that began in 1996.

Existing Lightning Arrestor Installation Program

Following the 1995 study, funds were allocated annually beginning in 1996 to install arrestors on 31 feeders. The number of feeders identified for arrestor installation expanded to 72 in 1999. Approximately 5,000 transformers have arrestors installed to date under this program.

Our most recent transformer loss experience (which includes the August, 2002 lightning storms) indicates that the number of feeders under this program should be further expanded to include a total of 98 feeders, representing 33% of the Company's 300 feeders.

In addition to installing arrestors on transformers in service, in late 2002 Newfoundland Power began installing arrestors on all new transformers being installed regardless of location.

Alternatives

This report considers three alternatives to address the increasing rate of transformer failures due to lightning. Refer to Appendix A for details of costs and Appendix B for Net Present Worth Analysis.

The first alternative is not to install any more arrestors on distribution transformers. This is the "do nothing" alternative and would be expected to result in average annual transformer failures of 139 incurring costs of over $300,000 per year. The increased costs result in a cumulative present worth of annual revenue requirements over 30 years of $4,389,849.

A second alternative is to install an arrestor on every in-service and new transformer over a 5 year time frame at an estimated capital cost of $6,550,796 over the 5 year period. This would

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[1]Based on unit costs from Appendix A and 139 units.

involve retrofitting all existing installed transformers with arrestors. This second alternative has a cumulative present worth of revenue requirements of $6,894,379.

A third alternative is a variation of the second one. This alternative places more emphasis on the assessment that lightning in Newfoundland is variable in both where it strikes and its intensity. It also recognizes that to retrofit all transformers in a relatively short time period is expensive and probably unwarranted. Consequently alternative #3 proposes a two pronged approach. First, continue to retrofit those feeders that are prone to transformer damage from lightning and, second, on a go-forward basis, install arrestors on all new transformers. It should be noted that the labour cost is minimized when the arrestor is installed as part of the original installation of the transformer. The cumulative present worth of this alternative is $2,289,967.

The third alternative offers the most benefit. It both addresses the necessity of taking action in the immediate future to reduce the number of transformer failures on those feeders most prone to lightning damage and address the long term requirement of ensuring our entire distribution transformer system is adequately and reasonably protected. This alternative involves installing arrestors on feeders over the next five years as part of a Feeder Upgrade Program. This approach will minimize labour costs by combining arrestor installation with other planned feeder upgrading work. The feeders selected would be based on transformer failures due to lightning as well as the experience of operations personnel.

Summary of Recommendations

The following actions are recommended with respect to the installation of lightning arrestors on distribution transformers.

- As part of the annual Feeder Inspection Program identify transformers on feeders prone to lightning strikes that are not equipped with a lightning arrestor.

- In the year following the inspection, install lightning arrestors on the identified transformers.

- On an ongoing basis, continue to install lightning arrestors on all new transformer installations regardless of location.

Appendix A

Cost

Estimated Cost of a Transformer Failure

The following costs were calculated from data taken from the August 2002 lightning storms.

Material	
A. Transformers lost[2]	233
B. Replacement cost	$321,924.45
C. Average material cost (B/A)	$1381.65
Labour	
D. Costs	$195,592
E. Transformers	233
F. Average labour cost (E/D)	$839.45
Total average cost per transformer (C + F)	**$2,221.10**

[2] Number of transformers represents losses from August 13th to 27th, 2002.

Cost Estimate to Install Lightning Arrestor

Material

Arrestor Bracket -	$6.18 (with boss)
	$10.62 ($6.18 + $4.44 without boss)
Surge Arrestor -	9 kV - $38.30
	18 kV -$55.20 Average cost = $44.05**
Total Material = $44.05 + $10.62 =	$54.67

**Note: The transformer split is approximately 34/66 for 25 vs. 12.5 kV

Labour

Working Foreman -	$25.31/hour
Lineman -	$23.65/hour
	$48.96
Labour $48.96 * 1.30% =	$63.65/hour
Line truck @ (21% of labour) =	$13.37/hour
Engineering @ (25% of labour) =	$15.91/hour
Vehicle @ (21% of engineering) =	$3.34/hour
Total	$150.94

Cost to install a Lightning Arrestor as a part of the planned feeder upgrading work. Since arrestors would be installed as part of a combined group installation, costs for travel or set-up are not included.

- ~ 15 minutes for installation

Labour $63.65 hour =	$15.91
Trucking @ 21% =	$3.34
Engineering @ 25% =	$3.98
Vehicle @ 21% =	$0.84
Material =	$54.67
Total	$78.74

Cost of Alternatives

Alternative 1
Since this is a "do nothing" alternative, there are no costs for corrective measures. The costs under this alternative is the projected cost of losses.

Cost of Transformer Failures

Average annual number of transformer failure	139
Average cost per transformer	$2,221[3]
Average annual cost of failure	$308,719
Present value (30 years)	$4,389,849

Alternative 2
This alternative involves installing an arrestor on every transformer within Newfoundland Power's service territory as a stand-alone project.

Cost of Arrestor Installation

Number of Transformers	43,400
Average cost to install a lightning arrestor	$150.94[4]
Total cost	$6,550,796
Present value (30 years)	$6,894,379

Alternative 3
This alternative includes a five year program of installing an arrestor on every transformer on distribution feeders that have experienced 3 or more lightning caused failures from 1999 to 2002 in addition to feeders previously recommended. This includes 19,325 transformers on 98 feeders. The most economical way do this would be to combine the arrestor installation project with the other feeder upgrade initiatives. In this way cost efficiencies are maximized. With this alternative, the remaining feeders are estimated to have failed on average 21.75 transformers per year.

Cost of Arrestor Installation

Combined project:		
Number of Transformers	19,325	
Average lightning arrestor cost	$78.74[5]	
Total Arrester cost		$1,521,651

[3] From "Estimated Cost of a Transformer Failure"
[4] From "Cost Estimate to Install Lightning Arrestor"
[5] From "Cost Estimate to Install Lightning Arrestor"

<u>Cost of Transformer Failures</u>

Average number of transformer failures due to lightning	21.75	
Average cost per transformer	$2,221[6]	
Total Average annual cost of Transformer failures		$48,307
Total cost		$1,569,958
Present value (30 years)		$2,289,967

[6] From "Estimated Cost of a Transformer Failure"

Appendix B

Present Worth of Revenue Requirements Analysis

Alternative #1 - Status Quo

Present Worth Analysis

Weighted Average Incremental Cost of Capital		8.52%
Escalation Rate		1.70%
PW Year	2003	

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Generation Thermal 25.58 yrs 4% CCA	Generation Hydro 49.26 yrs 4% CCA	Generation Thermal 25.51 yrs 30% CCA	Generation Hydro 49.26 yrs 30% CCA	Transmission 30.6 yrs 4% CCA	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Telecommunication 15.0 yrs 20% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2004							308,000		45,823		0	-45,823	-42,225	-42,225
2005							313,236		88,118	0	0	-88,118	-74,824	-117,050
2006							318,561		130,269	0	0	-130,269	-101,932	-218,982
2007							323,977		172,264	0	0	-172,264	-124,210	-343,192
2008							329,484		214,090	0	0	-214,090	-142,248	-485,440
2009							335,085		255,735	0	0	-255,735	-156,578	-642,018
2010							340,782		297,185	0	0	-297,185	-167,671	-809,690
2011							346,575		338,430	0	0	-338,430	-175,951	-985,640
2012							352,467		379,457	0	0	-379,457	-181,792	-1,167,432
2013							358,459		420,255	0	0	-420,255	-185,530	-1,352,963
2014							364,553		460,811	0	0	-460,811	-187,463	-1,540,425
2015							370,750		501,113	0	0	-501,113	-187,853	-1,728,278
2016							377,053		541,152	0	0	-541,152	-186,935	-1,915,214
2017							383,463		580,914	0	0	-580,914	-184,916	-2,100,130
2018							389,982		620,389	0	0	-620,389	-181,977	-2,282,107
2019							396,611		659,565	0	0	-659,565	-178,279	-2,460,387
2020							403,354		698,432	0	0	-698,432	-173,963	-2,634,350
2021							410,211		736,978	0	0	-736,978	-169,152	-2,803,503
2022							417,184		775,192	0	0	-775,192	-163,954	-2,967,457
2023							424,276		813,063	0	0	-813,063	-158,463	-3,125,920
2024							431,489		850,579	0	0	-850,579	-152,760	-3,278,680
2025							438,824		887,731	0	0	-887,731	-146,915	-3,425,595
2026							446,284		924,507	0	0	-924,507	-140,989	-3,566,584
2027							453,871		960,895	0	0	-960,895	-135,033	-3,701,617
2028							461,587		996,886	0	0	-996,886	-129,092	-3,830,710
2029							469,434		1,032,467	0	0	-1,032,467	-123,203	-3,953,913
2030							477,414		1,067,628	0	0	-1,067,628	-117,397	-4,071,310
2031							485,530		1,102,359	0	0	-1,102,359	-111,699	-4,183,009
2032							493,784		1,136,647	0	0	-1,136,647	-106,131	-4,289,140
2033							502,179		1,170,481	0	0	-1,170,481	-100,710	-4,389,849

Alternative #2 - Full Arrestor Impelmentation Over 5 Years

Present Worth Analysis

Weighted Average Incremental Cost of Capital		**8.52%**
Escalation Rate		**1.70%**
PW Year	**2003**	

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Generation Thermal 25.58 yrs 4% CCA	Generation Hydro 49.26 yrs 4% CCA	Generation Thermal 25.51 yrs 30% CCA	Generation Hydro 49.26 yrs 30% CCA	Transmission 30.6 yrs 4% CCA	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Telecommunication 15.0 yrs 20% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2004							**1,310,159**		194,919		0	-194,919	-179,616	-179,616
2005							**1,332,432**		374,832	0	0	-374,832	-318,285	-497,901
2006							**1,355,083**		554,134	0	0	-554,134	-433,596	-931,497
2007							**1,378,119**		732,771	0	0	-732,771	-528,359	-1,459,856
2008							**1,401,547**		910,689	0	0	-910,689	-605,091	-2,064,948
2009									875,774	0	0	-875,774	-536,208	-2,601,156
2010									856,362	0	0	-856,362	-483,158	-3,084,314
2011									836,738	0	0	-836,738	-435,022	-3,519,336
2012									816,911	0	0	-816,911	-391,369	-3,910,705
2013									796,890	0	0	-796,890	-351,804	-4,262,509
2014									776,680	0	0	-776,680	-315,962	-4,578,471
2015									756,292	0	0	-756,292	-283,512	-4,861,983
2016									735,730	0	0	-735,730	-254,151	-5,116,134
2017									715,003	0	0	-715,003	-227,599	-5,343,733
2018									694,117	0	0	-694,117	-203,604	-5,547,337
2019									673,079	0	0	-673,079	-181,932	-5,729,269
2020									651,894	0	0	-651,894	-162,372	-5,891,641
2021									630,568	0	0	-630,568	-144,729	-6,036,370
2022									609,107	0	0	-609,107	-128,827	-6,165,197
2023									587,517	0	0	-587,517	-114,505	-6,279,702
2024									565,802	0	0	-565,802	-101,615	-6,381,318
2025									543,967	0	0	-543,967	-90,024	-6,471,341
2026									522,018	0	0	-522,018	-79,609	-6,550,950
2027									499,959	0	0	-499,959	-70,259	-6,621,209
2028									477,794	0	0	-477,794	-61,872	-6,683,081
2029									455,528	0	0	-455,528	-54,358	-6,737,439
2030									433,164	0	0	-433,164	-47,631	-6,785,070
2031									410,707	0	0	-410,707	-41,616	-6,826,685
2032									388,160	0	0	-388,160	-36,243	-6,862,929
2033									365,526	0	0	-365,526	-31,450	-6,894,379

Alternative #3 - Partial Arrestor Impelmentation

Present Worth Analysis

Weighted Average Incremental Cost of Capital		8.52%
Escalation Rate		1.70%
PW Year	2003	

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Generation	Generation	Generation	Generation	Transmission	Substation	Distribution	Telecommunication	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
	Thermal	Hydro	Thermal	Hydro										
	25.58 yrs	49.26 yrs	25.51 yrs	49.26 yrs	30.6 yrs	38.5 yrs	30.4 yrs	15.0 yrs						
	4% CCA	4% CCA	30% CCA	30% CCA	4% CCA	4% CCA	4% CCA	20% CCA						
2004							352,637		52,464		0	-52,464	-48,345	-48,345
2005							358,632		100,888	0	0	-100,888	-85,668	-134,013
2006							364,729		149,148	0	0	-149,148	-116,705	-250,718
2007							370,929		197,230	0	0	-197,230	-142,211	-392,929
2008							377,235		245,117	0	0	-245,117	-162,864	-555,793
2009							52,555		243,539	0	0	-243,539	-149,111	-704,904
2010							53,448		245,531	0	0	-245,531	-138,528	-843,432
2011							54,357		247,441	0	0	-247,441	-128,645	-972,077
2012							55,281		249,271	0	0	-249,271	-119,422	-1,091,499
2013							56,221		251,018	0	0	-251,018	-110,817	-1,202,316
2014							57,177		252,685	0	0	-252,685	-102,795	-1,305,111
2015							58,149		254,270	0	0	-254,270	-95,319	-1,400,430
2016							59,137		255,774	0	0	-255,774	-88,354	-1,488,784
2017							60,143		257,195	0	0	-257,195	-81,870	-1,570,655
2018							61,165		258,535	0	0	-258,535	-75,836	-1,646,490
2019							62,205		259,793	0	0	-259,793	-70,222	-1,716,712
2020							63,262		260,968	0	0	-260,968	-65,001	-1,781,713
2021							64,338		262,060	0	0	-262,060	-60,148	-1,841,861
2022							65,431		263,068	0	0	-263,068	-55,639	-1,897,501
2023							66,544		263,993	0	0	-263,993	-51,451	-1,948,952
2024							67,675		264,833	0	0	-264,833	-47,563	-1,996,514
2025							68,825		265,588	0	0	-265,588	-43,953	-2,040,468
2026							69,996		266,257	0	0	-266,257	-40,605	-2,081,073
2027							71,185		266,840	0	0	-266,840	-37,499	-2,118,571
2028							72,396		267,337	0	0	-267,337	-34,619	-2,153,190
2029							73,626		267,745	0	0	-267,745	-31,950	-2,185,140
2030							74,878		268,065	0	0	-268,065	-29,477	-2,214,616
2031							76,151		268,296	0	0	-268,296	-27,186	-2,241,802
2032							77,445		268,436	0	0	-268,436	-25,064	-2,266,867
2033							78,762		268,485	0	0	-268,485	-23,101	-2,289,967

Distribution Insulator Replacement Program

Newfoundland Power Inc.
June 2003

Prepared By: Peter Feehan, P.Eng.

Table of Contents

Introduction

Premature failure of porcelain insulators due to cement growth is well recognized throughout the utility industry. Most Canadian utilities, including Newfoundland Power, have experienced significant insulator failures due to this phenomenon.

Newfoundland Power began to experience abnormal failures of porcelain insulation in the early 1980's. Suspension insulators fail by radial cracks, which are sometimes contained inside the metal cap and are not visible. The crack causes a current path between the metal cap and pin and shorts out the insulator. Pin type and pin cap type (2-Piece) insulators fail by circumferential cracks. Failure is usually mechanical; the top shears off the insulator causing the conductor to float clear of the structure.

Since the late 1980s the Company has replaced a significant number of defective insulators. The impact on reliability to the end of 2002 has been positive. The SAIFI and SAIDI statistics for 2002 for insulator-related outages were 0.29 and 0.43 respectively. This compares with a 10-year Company average of 0.37 and 0.54 respectively.

While progress has been made in reducing outages due to insulator failure on trunk sections of distribution lines, suspension and two-piece pin-type porcelain insulators are continuing to cause outages on feeder taps. Replacement of these insulators should be performed in conjunction with the Feeder Inspections and Feeder Improvement Projects. The cost of implementing this approach is estimated at approximately $500,000 in 2004. A similar amount is anticipated in each of the next five years as these insulators are identified for replacement during feeder inspections.

1.0 History and Mode of Insulator Failure

Porcelain insulators with cement have been used since the turn of the last century. The cement is used to hold sections of porcelain together and to hold the porcelain to the steel hardware.

Premature failure of porcelain insulators due to problems with the cement growth has occurred over many years. By the early 1960's the term "cement growth" had been used to categorize the problem. In 1976 Ontario Hydro began an investigation into the poor performance of its transmission lines. By the early 1980's Ontario Hydro had produced papers, which indicated cement growth as the most likely reason for insulator failures. Most Canadian utilities, including Newfoundland Power, have experienced insulator failures due to cement growth.

Cement growth is the most accepted theory for premature failure of porcelain insulators. The volume expansion of the cement occurs in the presence of moisture and is attributed to a chemical change in the cement that occurs with age. The expansion occurs over 10 or more years. As the cement expands it produces stress on the porcelain that fails in tension by cracking. Two manufacturers have been identified as the source of the cement growth problem in Canada, Canadian Porcelain (CP) and Canadian Ohio Brass (COB). Both companies went out of business many years ago. The most common porcelain suspension insulator remaining in NP's distribution system is the CP8080.

Newfoundland Power first identified the problem on the distribution system in the early 1980's when distribution suspension insulators[1] were causing outages. In the 1990's, transmission suspension insulators began causing outages. While transmission insulators were also failing in the 1980s, because there are many more units in an insulator string, outages did not occur until many insulators in the same string failed. Pin type insulators[2] have also been failing. 69 kV pin types experienced significant failures in the 1980's and 23 kV and 34.5 kV pin type insulators experienced increasing failures in the 1990's. Pin-type insulators used in substations to support the bus and switches have also experienced failures since the 1980's.

2.0 Recent Experience

Since the 1980's a significant number of distribution insulators have been replaced. A 1997 report entitled the "Distribution Insulator Replacement Program" identified and prioritized critical sections of feeders for testing and replacement of insulators. The report also established a five year time period to complete the identified work. This report was filed with the PUB on December 1, 1997 in response to Request for Information NLH-10(a).

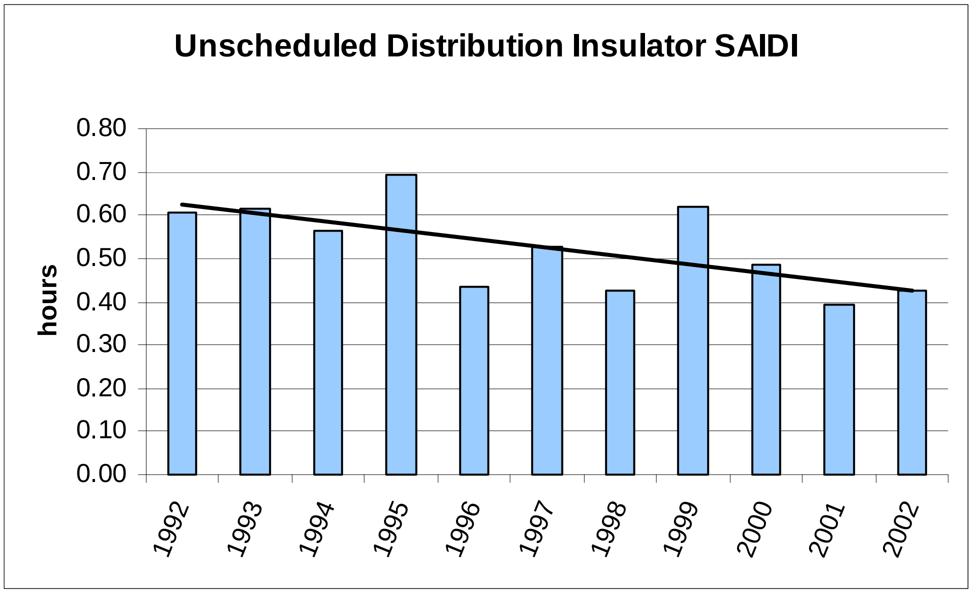
The project began in earnest after 1997 when NP began its Distribution Insulator Replacement Program. The impact on reliability to the end of 2002 has been positive as

---

[1] Suspension insulators are insulators that are commonly stacked together in a string to provide the necessary gap between an energized conductor and a pole to prevent electricity from traveling from a conductor to a pole.

[2] Pin Top insulators are insulators that sit on top of a crossarm to support an energized conductor and prevent electricity from traveling from a conductor to a pole. These insulators are typically not stacked on top of each other.

Shown in Figure 1. The SAIFI and SAIDI statistics for 2002 for insulator-related outages were 0.29 and 0.43 respectively. This compares with a 10-year Company average of 0.37 and 0.54 respectively.



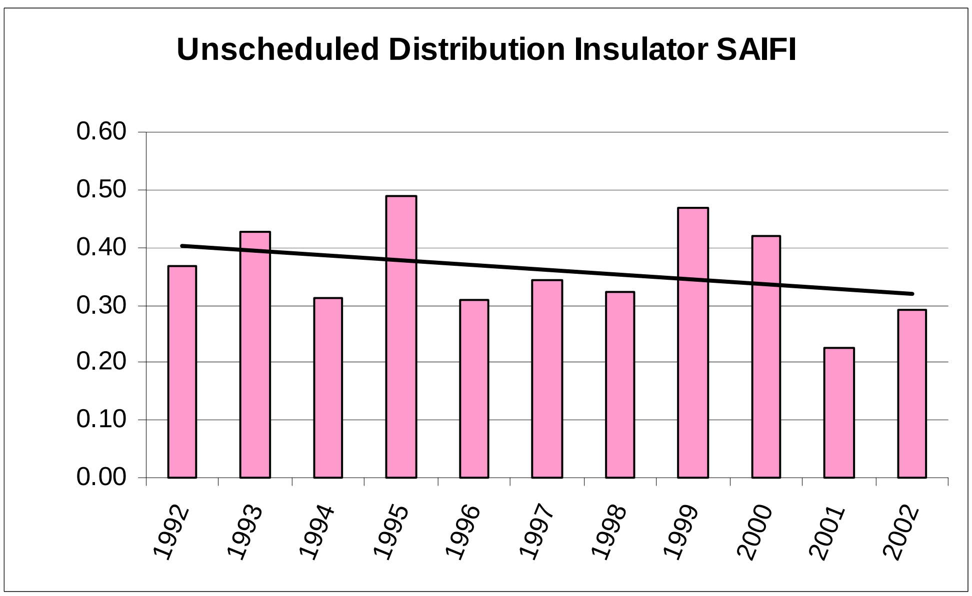


Figure 1: Insulator Related SAIFI & SAIDI

Considering the number of insulators changed out over the last five years and the overall improvement in SAIDI and SAIFI statistics related to distribution, a decreasing trend in the number of insulator related outages might be expected. Unfortunately this is not the case. As demonstrated in Figure 2, since 1992 there has not been any decrease in the number of insulator related outages. It seems likely that this is related to the fact that there are still a large number of CP8080 and 2-Piece insulators in the system on tap off lines. These are now five years older than they were when the Distribution Insulator Replacement Program started. As insulators age their failure rate goes up. Therefore, we have fewer insulators in the system but with a higher failure rate resulting in approximately the same number of outages in a year.

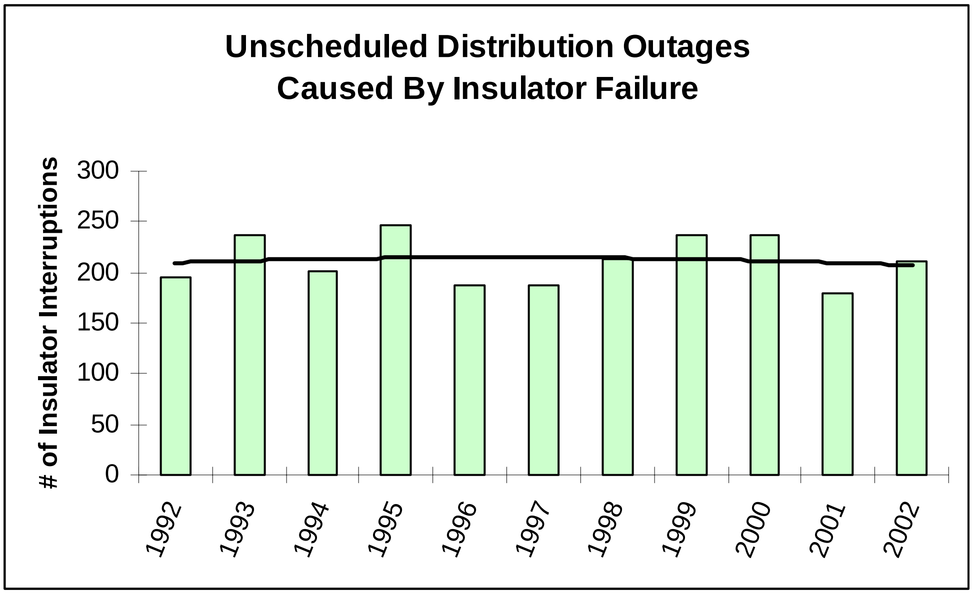


Figure 2: Number of Insulator Interruptions

The apparent inconsistency between the number of insulator outages and the SAIFI and SAIDI trends can be attributed to the focus the Company has been placing on replacing insulators on critical feeders and feeder trunks. An insulator failure on these sections of the distribution system impact more customers than do outages on feeder taps. As a result, while the number of insulator-related outages has remained the same, fewer customers are being impacted by the failures. This in turn results in a reduction in the average number of times a customer is impacted by an insulator outage as evidenced by the declining SAIFI statistic.

3.0 <u>Hazards of Faulty Insulators</u>

CP8080's and 2-Piece insulators have caused concern from an employee safety perspective. When working an a line containing insulators that are subject to the cement growth problems, caution is always required. If an insulator were to fail when a lineperson was working on an energized line, there is an increase in the risk of injury. As a result, there is additional diligence involved in working and repairing lines hot where these defective insulators are present. In certain situations, the presence of these insulators may result in the decision to complete the work through scheduled outages to customers to limit the hazard to employees. Failure of insulators also have the potential to create a public safety hazard if a failure results in the energized conductor becoming separated from the pole and falling to the ground.

4.0 <u>Testing vs. Replacement</u>

In the past an approach of testing CP8080 and 2-Piece insulators and replacing all or some based on the failure rate determined was considered to be a reasonable approach. Since

1999 a new approach has been followed that involves the complete change out of problem insulators without testing. It has been concluded that time spent testing insulators on the distribution system would be more effectively spent replacing insulators, since failure rates on these insulators remain abnormally high.

5.0 Future Work

The number of insulator related outages still remain unacceptable (an average of 216 per year for the last five years). The average outage duration experienced by customers is also still high at an average of 0.47 hours (28 minutes) per year over the last five years. The continued incidence of insulator failures have been confirmed by field staff who report that they are still seeing failures of two piece and CP8080 insulators. However in many areas staff have noted that these failures are becoming most common on feeder taps where the vast majority of remaining porcelain suspension and two-piece insulators remain.

Given the impact on reliability due to the continued high number of 2-piece and CP8080 failures and the hazards the insulators present to line workers, a continuation of a focused insulator replacement program is recommended.

This work should be completed in conjunction with the Feeder Inspections and Feeder Improvement Projects. Feeder inspections will be carried out on 20% of the feeders each year and these should identify locations where insulators should be changed out. This work should be budgeted for the following year.

Based on the 20% feeder inspection target, substantially all the problem insulators will have been replaced within the next five years

6.0 Cost of Insulator Replacement

In 2004, the Company plans on replacing 17,000 insulators, 11,000 in the Eastern Region and 6,000 in the Western Region.

The cost of changing these insulators is estimated at $500,000 in 2004. A similar amount is anticipated in each of the next five years as these insulators are identified for replacement during feeder inspections.

7.0 Recommendations

The following action is recommended with respect to the presence of CP8080 and 2-Piece insulators in the electrical system of Newfoundland Power:

> As part of the annual distribution feeder inspection program, identify all 2-piece and CP8080 insulator for replacement and replace them in the following year.

NEWFOUNDLAND POWER

January 11, 2000

Memo From: G.S. Durnford

To: Regional Managers
Supts. Area Operations

Subject: Current Limiting Fuses

File: PSD-0700.00

****

Attached is a report titled "Minimizing Pole Top Transformer Tank Failures" published by CEA in August 1997.

This report outlines potential hazards associated with pole top transformer failures. It indicates that while hazardous or eventful failures of pole top transformers are exceedingly rare events, from time to time they do occur.

Figure 6 on page 17 of the report outlines the probab~~ly~~ility of an eventful failure for a particular transformer versus fault current. The probability ranges from approximately 4×10^{-5} at 3000 amps, 8.6×10^{-5} at 5000 amps to 34×10^{-5} at 10,000 amps.

To put this in perspective, based on the 50,000 transformers we have in service it is probable that we could experience approximately 2 eventful failures if we limit the available fault current to 3000 amps. If we limit the fault current to 5000 amps, it could be approximately 4 and at 10,000 amps it could be approximately 17.

Our existing Standard, used to limit available fault current, is to install current limiting fuses on all transformers where the available fault current is in excess of 5000 amps. While we do not keep records of eventful failures, discussion with Superintendents of Area Operations indicate that to their knowledge, except for lightning, we have experienced very few eventful failures in the past several years.

Based on the experience at Newfoundland Power, the CEA Report, and the identified potential for personal injury,should a transformer fail in "Sensitive locations", we will take the following action:

1. Continue with the existing standard of installing CLF on new and replacement pole mounted transformers where fault levels exceed 5000 amps.

2. Revise the standard to include the installation of CLF's in all locations where the fault level exceeds 3000 amps and where there is a probability of public harm should any eventful failure occur. Examples would include bus stops, playgrounds, etc. CLF's would be installed only if the transformer is within 7 meters of these locations.

3. In 2000, each Region will develop a plan to commence in 2001 to install CLF's in all existing locations that meet the criteria outlines in 2. above.

Please contact K. Whiteway or myself if you would like further information.

GSD/lgw

CC J.G. Evans
E.A. Ludlow
R.K. Whiteway

149 D 491B

MINIMIZING POLE TOP TRANSFORMER TANK FAILURES

Prepared by:

ONTARIO HYDRO TECHNOLOGIES
Toronto, Ontario

Canadian Electricity Association
Association canadienne de l'électricité

August 1997

CEA RESEARCH & DEVELOPMENT DIVISION

The CEA R&D Program, created in 1974, coordinates and complements the research requirements of the Canadian electric utility industry.

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- Develop technologies to improve safety, reliability, performance, and predictable service life of electrical systems equipment and processes so as to reduce utility capital and operating costs.

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- Provide data, analysis, methodology and overall R&D perspective to aid the utility industry, the federal government and other policy setting bodies in present and future energy decision making.

- Maximize the benefits of resources allocated to research and development by CEA through the provision of joint R&D programs and liaisons with national and international organizations engaged in similar work.

- Promote and facilitate the transfer of information gained and technologies developed through the R&D Program to CEA member organizations and to government and the scientific, academic and industrial communities.

REPORT FOR THE

CANADIAN ELECTRICITY ASSOCIATION

Research & Development
Suite 1600, One Westmount Square
Montreal, Quebec
H3Z 2P9

CEA No. 149-D-491B

A Utility's Guide to

Minimizing Pole Top Transformer Tank Failures

PREPARED BY

ONTARIO HYDRO TECHNOLOGIES
800 Kipling Avenue, Toronto, Ontario M8Z 5S4

R.J. Piercy
R.F. Filter

AUGUST 1997

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Abstract

The guide is a practical tool to allow distribution engineers to determine if the risk of eventful failure of a particular pole top transformer is acceptable, and to specify an action plan to reduce the risk if necessary. An overview of failure modes and arc initiation mechanisms responsible for eventful transformer failures is presented. Various approaches to risk and hazard assessments for eventful transformer failures are described. Acceptable and unacceptable risks are defined in terms of other commonly assumed risks. Qualitative and quantitative approaches to risk and hazard assessment are explored with examples illustrating the usefulness of each approach. Strategies to reduce risk exposure with eventful transformer failures are reviewed. These measures include such things as optimizing transformer protection with fuses, lightning arresters, or with strategic replacement strategies, or purchasing decisions. A comprehensive example of a typical transformer installation is provided to illustrate the risk/hazard assessment procedures and to highlight the reductions in risk various mitigation strategies can provide. An annotated bibliography is provided. This guide is the first of three documents resulting from this project. A "Distribution Transformer Internal Pressure Withstand Test", and a project final report follow this guide.

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Acknowledgments

The authors wish to acknowledge the help and guidance provided by the project technical advisors, Mr. J. Zawadzki of Powertech Labs and Mr. E. Vienneau of Nova Scotia Power. This work would not have been as successful without Jan's probing questions and suggestions. A vote of thanks and acknowledgment is also due Claude Maurice and Walter Dal Din. This was a project based on statistics, and it was Claude and Walter who, day after day, week after week, carried out much of the repetitive and often tedious testing necessary to build up our statistics.

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Executive Summary

This guide will help reduce the risk of harm occurring to utility employees, equipment, or the public, by reducing the risk of eventful tank failure in pole top distribution transformers; and help reduce the associated costs to the utility. It provides a very quick method for an engineer to determine if a detailed analysis is necessary, and then presents all the information needed to perform the analysis. The possibilities for corrective action, when it is required, are summarized with references to more detailed instructions.

The guide presents an overview of the modes of failure and arc initiation mechanisms responsible for eventful transformer failures. The term "eventful" transformer failures encompasses all failures where significant potential exists either for hazards to utility staff or the public, or for concurrent equipment damage during a transformer failure. The issue of risk and hazard assessment is addressed by defining each term within the context of transformer failures and through the examination of the various factors which influence the results of an eventful transformer failure. Acceptable and unacceptable risks are examined from the viewpoint of other commonly assumed risks so that eventful transformer failures may be put into a risk perspective. Qualitative and quantitative approaches to risk and hazard assessment are explored with examples illustrating the usefulness of each approach. The various strategies a utility may take to reduce its risk exposure with eventful transformer failures are reviewed. These measures include such things as optimizing transformer protection with fuses, lightning arresters, or with strategic replacement strategies, or purchasing decisions. A comprehensive and detailed example of a typical transformer installation is provided to illustrate the risk/hazard assessment procedures and to highlight the reductions in risk the various mitigation strategies can provide. Summaries of eight good references for utility engineers charged with reducing the incidence of eventful transformers are provided in an annotated bibliography.

This guide is the first of three documents resulting from this project. The second project document, a "Distribution Transformer Internal Pressure Withstand Test", will follow this guide to provide utilities and transformer designers with a reliable test to assess transformer tank performance during eventful failure. At the completion of this project, a technical report will be available which contains the technical background and foundations, not only for the information presented in this guide, but also for the withstand test developed during this project.

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Engineering Summary

HOW DO I KNOW IF I NEED TO MINIMIZE TANK FAILURE?

Most pole top transformers fail without tank failure, but about 1 in 250 are eventful failures with expulsion of hot oil or flames, or flying debris. Action is required if the risk of harm to your employees, your equipment, or the public is unacceptably high. Risk is defined as follows:

$$RISK = P_{tankfailure} * P_{harm} | \, tank\, failure * COST(\$)$$

Risk is the probability of tank failure times the probability of harm occurring given that tank failure occurs times the dollar value of the harm. Risk can be reduced by reducing the value of either of the first two terms in the equation.

QUICK TEST

Action is not required if the probability of tank failure, when a person is near enough to be harmed, is less than the probability of a person being hit by lightning (a generally accepted risk). Conservatively assume that the dollar value of the harm from lightning is the same as that from transformer failure, so it is not required for the comparison of risk.

Step 1 Use Figure 6 (page 15) to determine the probability of eventful tank failure given available fault current (if unknown use $5x10^{-5}$ to be conservative)

Step 2 Determine the number of hours in a year a person is within 7 m of the pole and divide by the number of hours in a year (8760).

Step 3 Multiply the two numbers together. Is it less than 5×10^{-7} ? If yes, then no action is required. Note that the hours must be > 8 per year for action to be required.

If this quick test shows that the probability of harm is too great then a more detailed analysis (see Chapter 3) should be done to see if action is required to reduce the risk.

HOW DO I REDUCE THE RISK?

There are four main methods:

1 Move the transformer to a location where the hours of exposure will be acceptable
2 Install current limiting fuses
3 Install good lightning protection
4 Change the transformer before the normal end of life
5 Choose a transformer from a quality manufacturer, with no internal fuses or tap changers, and with 25% more air space than normal practice

More details of these methods are given in chapter 4.

In this guide the utility engineer will be offered a review of the causes and conditions which precipitate violent transformer failures, along with several strategies to assess the risks and hazards which may be associated with common pole top transformer installations. Methods to mitigate eventful transformer failures will be reviewed and a detailed example of a representative risk/hazard assessment, along with mitigation strategies will be provided. All in all, with this guide the utility engineer will position himself to make the best possible choices in the interests of public and utility staff safety. A word of caution however: as with all documents of this type, only overviews and relatively simple instructions can be provided. Application and design diversity in this area is extensive and will vary from utility to utility. Readers are encouraged to follow up their reading of this guide with perusal of the references provided in the annotated bibliography.

A second project document, the distribution transformer internal pressure rise test, will follow this guide to provide utilities and transformer designers with a reliable test to assess transformer performance during eventful failure. At the completion of this project, a technical report will be available which contains the technical background and foundations, not only for the information presented in this guide, but also for the withstand test developed during this project.

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ONE

An Introduction to Eventful Failures

Hazardous or eventful failures of pole top transformers are exceedingly rare events? Nevertheless, from time to time, such failures do occur with the result that utility staff or members of the public may be exposed to unacceptably high risks of injury from the energy release accompanying such failures or from debris or burning oil ejected from a transformer during failure. All utilities using significant numbers of pole top transformers have experienced such failures at some point, sometimes with attendant injuries. No utility is immune. One such incident which recently occurred on Ontario Hydro's distribution system illustrates how such a failure and injury to utility staff may occur.

> In March 1993 near Sudbury, Ontario, a squirrel climbed atop a heavily overloaded three phase bank of pole top distribution transformers and electrocuted itself. This initiated an external arc which damaged the nearby lightning arrester and blew the cutout fuse to isolate the affected transformer. Unfortunately the high voltage lead from the damaged lightning arrester dropped down to the open fused cutout's lower contact assembly, re-establishing a connection between the overhead line and the transformer. In effect, the fused cutout was shunted by the lightning arrester lead so that the transformer continued to operate without any protection.
>
> Upon hearing an unusual amount of spitting and arcing sounds staff from the firm being fed by the transformer bank called the local utility. Upon arrival at the scene, a power line maintainer in a bucket approached the transformer to inspect the problem when he noticed that he could hear the oil boiling inside the energized transformers. As he continued his inspection, the unprotected heavily overloaded transformer suddenly exploded near his face. Quantities of burning oil and other debris were ejected as a result of the transformer fault. Fortunately, the power line maintainer managed to quickly duck inside the bucket, limiting his injuries to burns to his forehead. Nevertheless, he was hospitalized for several weeks. The truck's upper boom was seriously damaged by burning oil ejected from the faulted transformer.

In this case, the simultaneous occurrences of several unlikely events resulted in a personal injury and bucket truck damages from an eventful transformer failure. Unlikely as these kinds of occurrences seem when they are considered by designers, operating staff and maintenance personnel, they do occur and they often present a serious and not inconsequential hazard.

Although pole top distribution transformers are very reliable components, eventually they do fail. The large majority of transformer failures are uneventful burnouts which simply blow the expulsion fuse, fail by open circuit, or cause voltage abnormalities, electrical noise, or other power quality deterioration. Sometimes, transformers fail due to electric arcing within the windings, either between layers within the same winding or between high voltage and low voltage windings. Only about 2% of transformers fail due to arcs in the open spaces in the tank, either in the air space or under the oil. These open arcs are the only transformer failure mode that can result in the rupture of the tank. This guide addresses those relatively few transformer failure modes which, on rare occasions, can result in transformer tank rupture, oil spillage, or other eventful side effects.

Pole top transformer tanks are cylindrical steel containers with a welded seam up the side and around the bottom. The lids are sealed to the sides with a rubber gasket and fastened with one of three techniques.

1. The *centre bolt design* has a bolt through the centre of the lid attaching to a metal brace in the top of the tank that is anchored to both sides of the inside wall. See Figure 1.

2. The *edge clamp design* has four to seven brackets welded to the outside of the tank wall so that the lid is retained by metal tabs bolted to these brackets. See Figure 2.

3. The *locking band design* uses a rolled lip on the top of the side walls to grip a "C" shaped channel that is wrapped around the tank and secured with a bolt that tightens the channel around the tank diameter. See Figure 3.

Utility operations experience has shown that roughly 2% of transformer failures involve arcing in the open spaces within the tank, and about one in every 250 (0.4%) will involve a tank failure, resulting in oil spills or lid or bushings ejection. This relatively rare type of failure is termed an "eventful" failure.

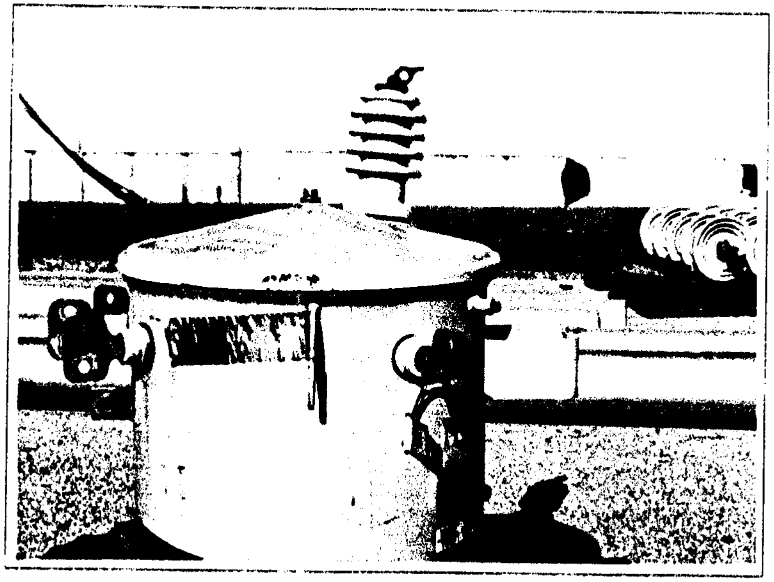

FIGURE 1

POLE TOP TRANSFORMER WITH CENTRE BOLT LID

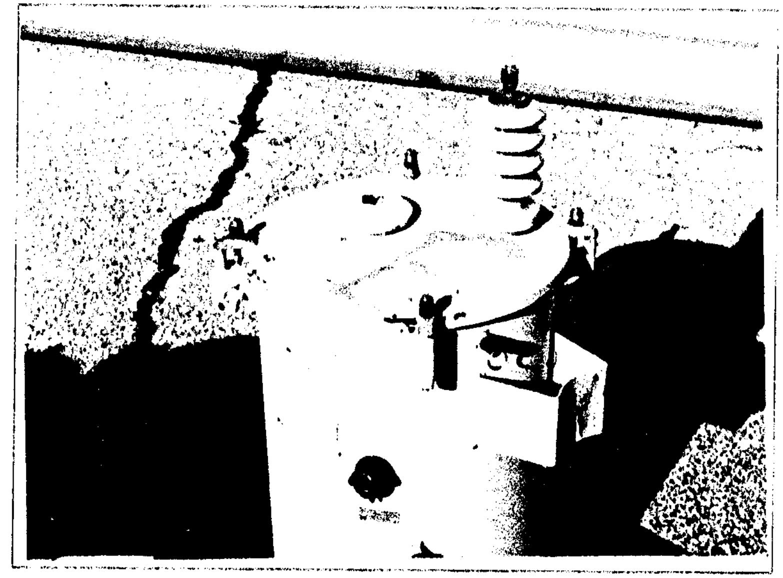

FIGURE 2

POLE TOP TRANSFORMER WITH EDGE CLAMP LID

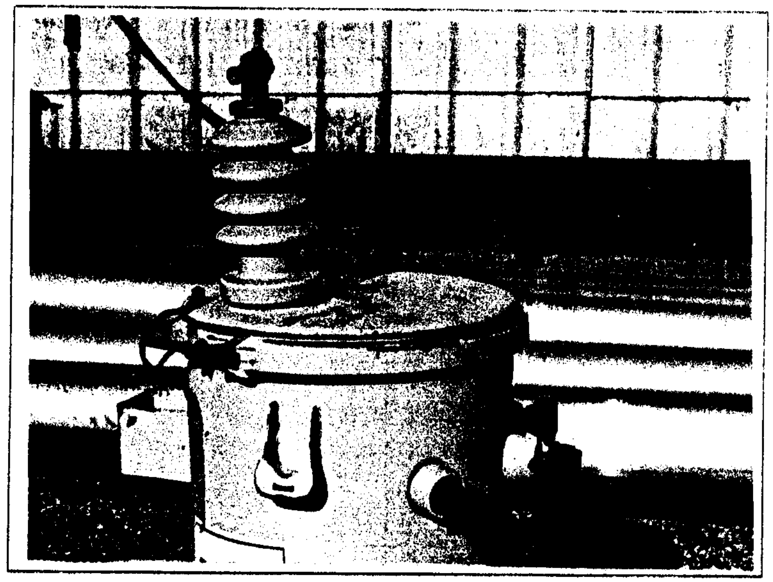

FIGURE 3

POLE TOP TRANSFORMER WITH LOCKING BAND LID

Eventful transformer failures can present a hazard. Fortunately, eventful transformer failures are extremely rare occurrences.

Historically, eventful tank failures have been termed as "violent" or "explosive" or "dangerous", but these types of failures are not all necessarily violent, explosive, or dangerous. A failure of a side seam which pours all the oil out of the transformer is not violent or explosive, yet it is highly undesirable both from a safety and from an environmental perspective. The actual "danger" presented by a failure depends on where the transformer is installed. Even a litre of oil spilled from a transformer over a bus stop or in a school yard could be dangerous, but the same "eventful" failure on a rural road might not even be noticed.

There are several techniques available to the distribution engineer to minimize the probability of an eventful tank failure. Not surprisingly, these techniques all increase costs and therefore must be used only when actually needed. This guide not only describes *how* to minimize the occurrence of eventful failures, but perhaps more importantly, it describes *when* to apply the available techniques.

TWO

Pole Top Transformer Tank Failure Processes

Eventful transformer tank failures can occur in several ways, some of which are more serious or hazardous than others. In all cases, the culprit which initiates an eventful failure is uncontrolled arcing within the transformer tank. Where the arcing is located inside the transformer tank, and under what conditions it evolved, determine the degree of hazard associated with the eventful failure. In the following sections, the dominant modes of failure which produce eventful transformer tank ruptures are discussed. A brief discussion of the ways arcing can initiate within a transformer tank is also presented to underscore the challenges facing the distribution engineer wishing to minimize the incidence of transformer failures of this kind.

2.1 Internal Arcing - The Primary Culprit

Internal arcing is the cause of all eventful transformer failures. The most severe form of internal arcing, the form which results in the transformer presenting the most hazard, occurs when that arcing takes place in the open spaces (air space or under oil) inside the transformer tank.

There are several mechanisms that can initiate an arc in the open spaces within a pole top transformer tank /3,9,14,16,17/. Arcing of the type which can cause eventful failures can occur in any transformer at virtually any time, but is made more likely by poor design, manufacture, or operating practices, or by oil contamination, loose parts, or transformer ageing. The most common way internal arcing is initiated involves voltage surges caused by lightning. Operating conditions such as overloads or severe imbalances can also precipitate a flash over and arcing by generating bubbles in the oil which can accumulate in critical locations or cause corona damage to insulation surfaces. The following is a summary of the most common ways arcing can start inside the transformer.

1. *A voltage impulse accompanying a nearby lightning strike* can result in arcing wherever the transformer insulation is weakest. Most often, this type of arcing starts within the primary windings where it will not result in the failure of the transformer tank. Sometimes however, these voltage surges can precipitate a flash over outside the windings between the high voltage drop lead and the neutral lead or leads from winding taps. Sometimes such an arc is drawn between the high voltage winding and the core. In all cases however, once the arc to ground is initiated, high fault current flows and eventful transformer tank failure can occur.

2. *An arcing fault within the winding*, if not cleared immediately by a fuse, will result in the production of large amounts of metal powder and hot gases. The hot gases rise in the oil carrying the metal particles with them. It is not uncommon for these winding fault by-products to become trapped near tap switches or under-oil fuses and then lead to an arc between high voltage leads and ground.

3. *The magnetic forces associated with a winding fault* can cause movement of the drop lead which may reduce clearances to the tank wall or the neutral lead so that a flash over becomes more likely. A winding that collapses or telescopes can also break the drop lead to initiate an arcing fault.

4. *Heavily loaded transformers can develop bubbles in the oil* that collect under the winding assembly. These bubbles are not re-absorbed into the oil and have a lower dielectric strength than the oil. This can lead to corona along the bottom surface of the windings, and eventually to an arc between the high voltage winding and the transformer core.

5. *Poor handling during transport and installation* can shift transformer internals to bring the drop lead too close to grounded parts. This may not cause an immediate failure when the transformer is energized, but any other stressor like lightning or magnetic forces accompanying other faults can precipitate an arcing fault.

6. In older transformers *sludge from the oxidation of the oil* which accumulates in the bottom of the tank can lead to arcs between the bottom of the high voltage winding and the tank bottom, tank sides, or low voltage windings. With the advent of sealed transformer designs in the late 1950's the incidence of this mechanism has decreased, but it can still play a role if the transformer is consistently overheated, if the tank is not properly sealed, or if debris from self clearing faults accumulates.

2.2 Eventful Modes of Failure

Eventful pole top transformer tank failures can be grouped into four failure modes: tank ruptures occurring as a result of static pressure build-up, tank wall burn through, ruptures resulting from dynamic air pressure effects, and tank ruptures resulting from dynamic oil pressure effects. Each of these failure modes is briefly described in the following sections.

2.2.1 Tank Rupture Resulting from Static Pressure Build-up

This failure mode involves the gradual build up of pressure due to normal operating conditions (thermal cycling, oil or paper decomposition, etc). If the pressure increases sufficiently, the tank lid may pop off, seals may fail, or, under extreme conditions, the tank seams may split. For many years, manufacturing standards have required pressure relief valves installed in the transformer tank to prevent this type of tank failure. All relatively new transformer designs incorporate such pressure relief valves. Only older transformer tanks do not have pressure relief valves and can still fail in this mode.

Both old and new tanks can fail from a static pressure build up resulting from the energy released by a high impedance fault which does not blow the transformer's high voltage fuse quickly enough. This kind of gradually increasing pressure build-up can be more rapid than the relief valve can accommodate. Under these conditions, it is possible for the tank lid to pop off. Today's manufacturing standards require that the lid retention mechanism be tested to 138 kPa (20 psi). Since making transformer tanks stronger and increasing the lid retention forces is invariably more expensive and may result in a higher energy failure when the tank does finally yield, all modern designs of transformers release their lids at similar static pressures. Under these conditions, when the lid yields, the failure is usually non-violent. Usually, the lid simply pops open, releases the internal pressure, and does not result in oil spills, component ejection, or flame outside the tank.

Of all eventful transformer tank failure modes, static pressure build-up is usually the most benign.

2.2.2 Tank Wall Burn-through

An arc from the low voltage winding to the transformer tank wall will often result in a low enough current to not blow the primary fuse immediately. The heat of the arc rapidly melts a hole in the tank wall resulting in oil draining from the tank. This is often accompanied by flames. As the oil is drained from the transformer, the insulation system is weakened. Eventually, high voltage arcing will result and the transformer's primary fuse will blow, de-energizing the transformer. Although this failure mode usually does not result in particularly violent expulsion of transformer internals or accessories, it is nevertheless an eventful transformer failure and often results in environmental contamination and in potential fire hazards, including the possibility of injury to anyone in the immediate vicinity of the failure.

Although this type of failure was not intensively studied in the research project upon which this guide is based, observations of thousands of failed transformers have established that this failure mode accounts for about 1 out of every 200 to 300 transformer failures. Of all types of eventful transformer tank failures, this mode of failure is perhaps the single most common type.

Eventful failures involving transformer tank wall burn-though almost always result in environmental pollution and may present a fire hazard.

2.2.3 Dynamic Air pressure

A high voltage arc inside the transformer tank, either in the air space or under the oil outside the windings can cause a pressure pulse in the air space above the transformer oil. Thc resulting pressure peak can vary from 0 to 350 kPa with a rise time of 1 to 45 ms and a duration of 6 to 100 ms. Typical characteristics for this pressure pulse are a peak of 70 kPa (10 psi) rising in 12 ms and returning to normal in 27 ms /1/. These air space pressures are caused either by a column of oil moving up like a piston within the tank and compressing the air space, or by heat and gases generated by the arc. Which mechanism dominates depends on the depth of the arc under the oil. The resulting forces can either bend the lid, or bend or break the lid retention mechanism. Most of the time, this results in a few liters of oil spilling from the tank and/or a small burst of flames from under the lid. Although the amount of oil spilled during this type of failure may be less than that spilled during tank burn-through failures, there may be considerable violence associated with this failure mode. The degree of hazard presented by this failure mode is further increased by the fact that transformer internals and/or accessories may be ejected. Figure 4 presents a view of a transformer which experienced this type of failure.

Based on information presented in two field failure surveys conducted in the 1980's, this type of eventful tank failure occurs about once in every 200 to 300 transformer failures. Earlier references /13,15,16/ suggest a much higher rate for this type of eventful failure, but improvements in modern transformer design and protection strategies have significantly lowered this failure rate.

Eventful failures resulting from dynamic air pressure pulses in the transformer air space can result in transformer internals or accessories being ejected. Serious potential hazards may be associated with this mode of failure.

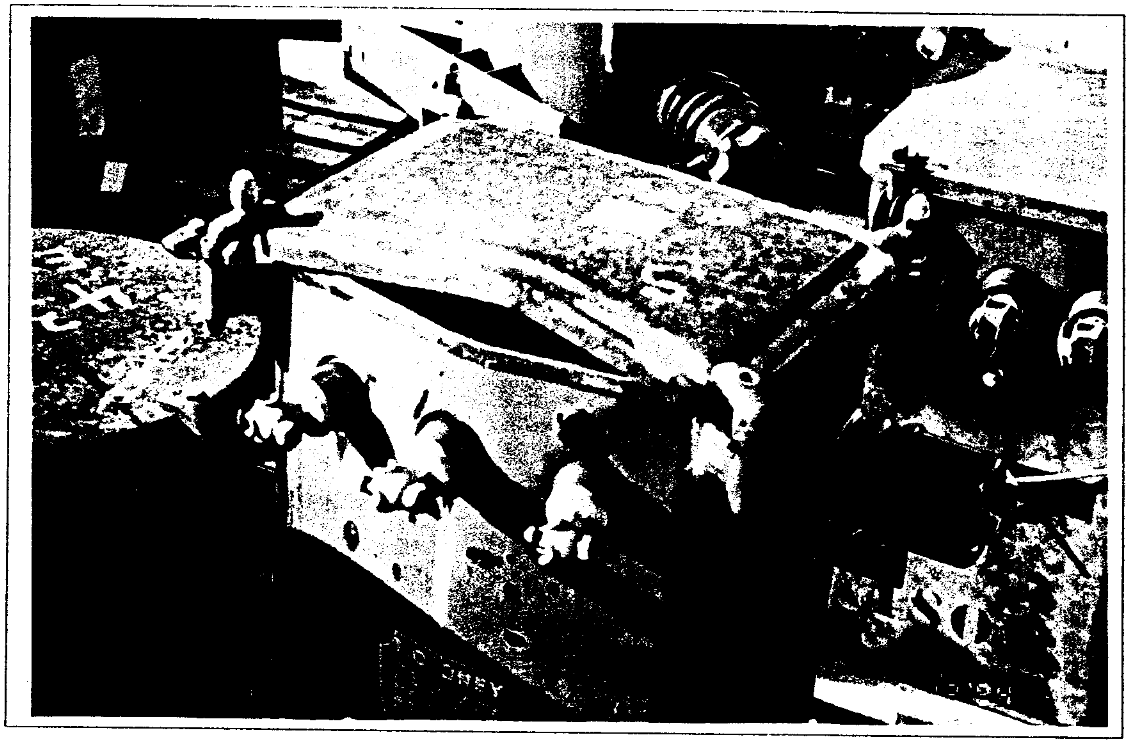

FIGURE 4

TRANSFORMER FAILURE - DYNAMIC AIR PRESSURE MODE OF FAILURE

2.2.4 Dynamic Oil Pressure

A high voltage arc occurring in the open space well under the surface of the oil will cause a shock wave to travel through the oil. This shock is characterized by a very high peak pressure, up to 3,000 kPa rising in as little as 10 µs/1/. This can split the welded side seam or bottom joint, especially if there are any weaknesses or defects in the weld. This tank failure always results in a major oil spill and sometimes in flames outside the tank as well. The potential hazard associated with this mode of failure is severe. Not only is it possible that transformer internals and accessories could be ejected, but, depending on where the tank rupture occurs, much of the transformer's oil may also be ignited and ejected. Figure 5 presents a view of a transformer which had experienced this type of failure.

Field failure surveys suggest that this mode of eventful failure is quite rare and occurs approximately once in every 1,400 to 2,000 transformer failures.

Eventful failures resulting from dynamic oil pressure pulses in the transformer can result in transformer internals or accessories being ejected. Significant quantities of burning transformer oil may also be ejected. Severe potential hazards are associated with this mode of failure.

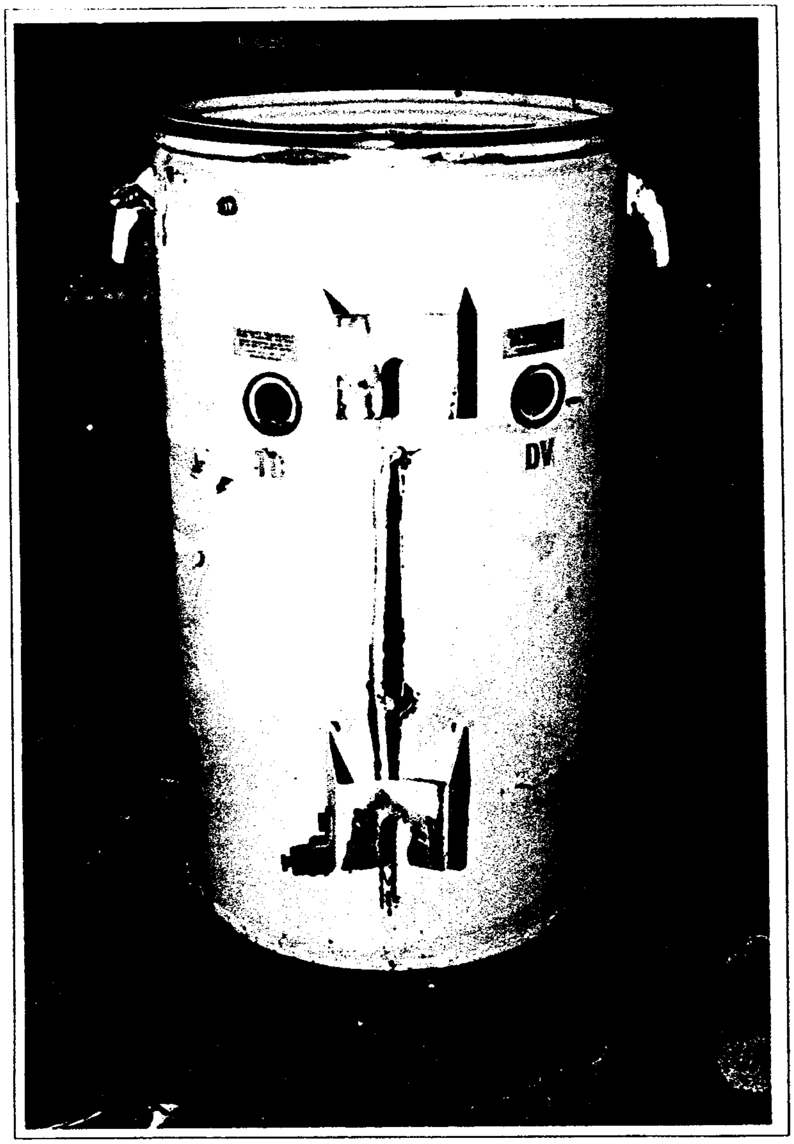

FIGURE 5

SEVERE TRANSFORMER FAILURE - DYNAMIC OIL PRESSURE MODE OF FAILURE

Three

The Assessment of Hazards and Risks

Reducing the frequency of eventful transformer failures will increase the cost of the transformer installation. Given that increase in cost, a clear incentive exists to apply failure minimization techniques only when they are necessary. An important question the distribution engineer must therefore answer is "When is failure minimization necessary?".

There are several approaches to answering this critical question, but no matter which approach is used, key concepts like "Risk Assessment" and "Hazard Assessment" must always play a dominant role. In the following sections, risk and hazard assessment concepts and procedures are explored in some detail.

3.1 Risk and Hazard Assessment

Risk can be defined as "the probability of loss or injury to people and property". Hazard, on the other hand, is often defined as "the maximum potential harm that can result from failure of a piece of equipment". In the case of transformer tank failure, risk is the probability of tank failure multiplied by the probability of harm occurring given that the tank fails, and multiplied by the degree or seriousness of the harm. Risk is not just a simple probability of failure.

"Risk" = the probability of failure X the potential harm.

"Hazard" is a measure of the potential harm.

Harm can be physical damage to people or equipment, psychological damage to individuals (reduction in "well being"), or social harm which applies to groups of people. Direct harm can be incurred by utility personnel, the general public, adjacent equipment, or the environment. Indirect harm could occur to the utility's public relations efforts and market position. If the hazard (i.e. the potential harm) is unacceptable then the hazard must be reduced, controlled, or contained if possible. The concept of risk incorporates these abilities to control a hazard into an overall assessment of the probability of harm. The alternative analysis is based on considering only the maximum potential harm.

The following steps illustrate the process of risk assessment.

Step 1 Identify the Hazards (establish dollar values if required).
Step 2 Determine the probability of harm occurring, given that equipment failure occurs.
Step 3 Analyze the probability of failure for each part that gives rise to each hazard.
Step 4 Combine the probability of failure and harm with the hazard level to estimate the overall risk.
Step 5 Compare the risk to socially acceptable levels of risk.

The risk assessment performed in these steps can be either qualitative or quantitative. A qualitative assessment uses a judgement-based method of risk assessment. A quantitative method uses probabilistic techniques to assign numeric values to the various risks and hazards based on the dollar cost of potential law suits, poor public or labour relations, accident investigations etc. Which method is suitable depends on a large number of factors. When events are "rare", for example, sufficient data may not be available to properly assess probabilities, in which case qualitative assessment is appropriate. Although the assignment of numerical values gives the appearance of being more rigorous, it may be just as susceptible to errors of judgement as a more qualitative approach unless rigorous numerical values are available. The trend in most risk analysis is toward the quantitative approach.

Risk and Hazard assessment may be qualitative or quantitative.
Choosing which approach to use depends on the availability of data.

The application of these steps to pole top transformer tank failure will be discussed in the following paragraphs. A risk assessment involves determining the probability of eventful tank failure at a given installation and combining that with the probability of direct harm, and with an estimation of the severity of that harm.

3.2 Assessing the Hazard

In poletop transformer failures, hazards that arise from the consequences of an eventful failure include: the presence of electric arcs, hot oil spray, possible projectiles such as pieces of porcelain bushing, the lid, or the entire transformer, and fire. The methods available for the control of these hazards are the tank itself (containment), fusing (severity reduction), and physical distance (containment). The harm from these hazards can occur to utility employees, utility equipment, or members of the public and can be either direct or indirect.

Harm to utility personnel can only occur when maintenance is being performed at the transformer location while it is energized. Opening the fused cut-out prior to transformer replacement or oil sampling is one of the windows of opportunity of harm. This is a very low probability event occurring only once or twice in the life of the transformer. On the other hand, because utility personnel are close to the equipment during the window of opportunity for harm to occur, the potential *direct* harm is very high. The *indirect* harm which may result depends on the labour relations between the company and its unions at the time of the accident and the previous safety record. It could be either very high or very low.

Direct harm can also occur to the public, anyone standing in a 7m radius of the pole.* However, because they are farther from the transformer the potential direct harm is less than it was for utility staff working near to the transformer. Nevertheless, because children could be playing under the transformer, or a person could be standing at a bus stop under the transformer, the probability of being in the wrong place at the wrong time is greater than it was for the utility staff. The *indirect* harm may also be greater since people who are not consciously assuming a risk are exposed to the possibility of being hurt. Generally speaking this reduces the acceptable risk by a factor of 1000/6/. In addition in the case of children, society exhibits a strong emotional reaction which increases the indirect harm. Although the hazard to the public is lower, the potential harm may be greater.

Table I lists some of the considerations which would be required in either qualitative or quantitative forms of the risk assessment. Table I is not exhaustive or complete. Each utility undertaking a detailed risk assessment must customize that assessment to suit its particular needs. In a quantitative (i.e. probabilistic) approach, actual dollar value estimates would be required.

Potential for injury or damage to:	Issues and Considerations
Utility worker	medical expenses law suit (pain and suffering) workmen's compensation lost time and productivity accident investigation negative impact on labour relations
Member of Public	law suit (pain and suffering) accident investigation public relations Negative impact on public image
Adjacent Equipment	broken leads or bushings (secondary hazards) loss of service contamination clean up repair costs
Environment	collection/disposal of contaminated soil fire

Table I: Considerations in Risk and Hazard Assessment for Eventful Pole Top Transformer Failure

3.3 Determining the Probability of Harm

The probability of harm occurring given that an eventful failure occurs depends on the amount of time that the potential for harm exists. In the case of adjacent equipment or the environment, the probability is 1 since they are always present. In the case of harm to people, the probability of someone standing within range of harmful effects of an eventful transformer failure can be calculated by estimating the fraction of time spent in that location, and assuming that the failure is equally likely at all times of day. Alternatively, if the failure is not deemed equally likely during a time period (i.e. more likely during lightning storms and less likely at other times), then the analysis could be done separately for two or more time periods with different conditions. In general, as the probability of harm assessment becomes more complex, significantly more detailed knowledge about actual conditions will be required. For example, eventful failures are much more likely during storms, but the probability of someone being nearby is much less.

As an example consider a school yard with an overhead transformer. A reasonable assumption might be that there is a child under the transformer for 15 minutes before school, at two recesses, and after school, and another 30 minutes at lunch; for a total of 7.5 hours a week. Evenings and weekends might contribute another 5 hours. This is 650 hours per year for a probability of 650/8760=0.074.

3.4 Assessing the Tank Failure Probability

The overall probability of eventful failure can be calculated from the fraction of transformer failures that involve tank failure, approximately 1 in 250 /1/. Industry statistics suggest that transformer failure probability is usually between 0.02 and 0.05 per year depending on utility practices, so the overall probability of any particular transformer experiencing an eventful failure is usually somewhere between 8×10^{-5} and 2×10^{-4} per year. This probability can be adjusted for individual situations of available fault current and the transformer tank size, based on the results of extensive tank failure testing. The detailed calculation procedure is given in /1/.

An alternative, simpler procedure, can also be derived from the test results. The graph in Figure 6 shows the effect of available fault current on probability of eventful failure. Failure probability can be estimated from Figure 6 for typical conditions (i.e. an asymmetry factor of 1.2 and a transformer failure rate of 0.03) or calculated using equation 1 for different system conditions.

1×10^{-4}

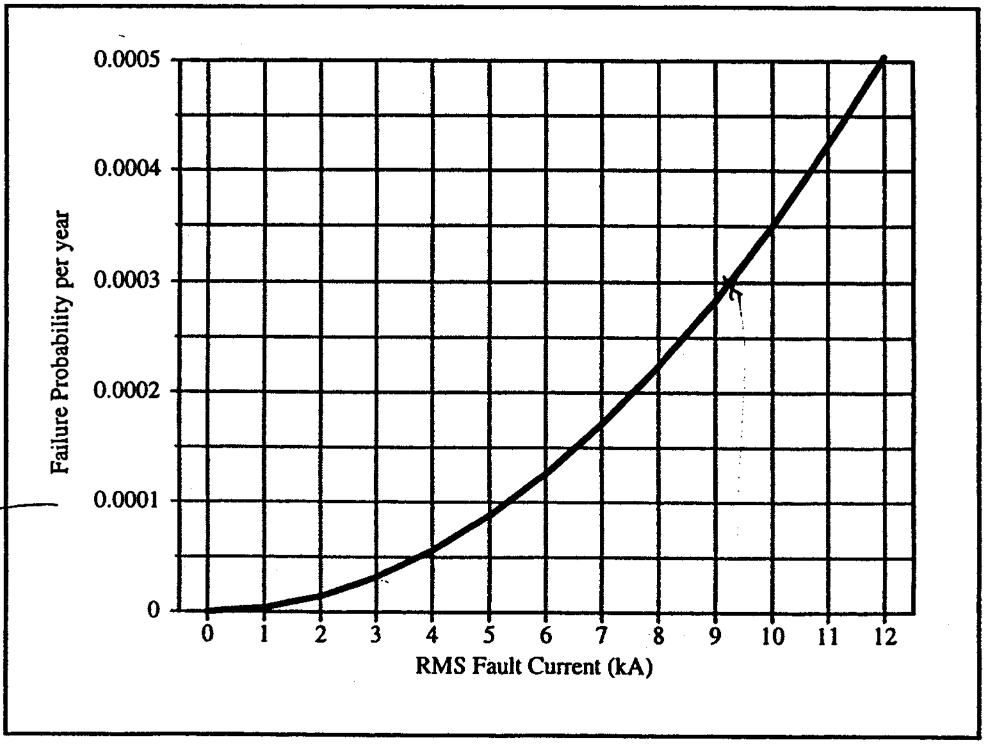

Figure 6 Eventful Tank Failure Probability Vs RMS Fault Current

Motor Vehicle

Equation 1

$$P = 8.0x10^{-5}\, I^2\, AF^2\, \lambda_T$$

Where
- P = probability of eventful failure
- I = available rms line to ground fault current in kA
- AF = asymmetry factor (based on x/r ratio, typically =1.2)
- λ_T = transformer overall failure rate (not necessarily tank failures) (λ_T typically = 0.03)

If the X/R ratio at the location is known, then the following table can be used to give the appropriate asymmetry factor.

X/R Ratio	Asymmetry Factor *
0.6	1
1.0	1
2.5	1.1
4	1.2
6	1.3
10	1.45
12	1.5
20	1.6
40	1.65

* The asymmetry factors are taken from reference 11.

Table II: X/R Ratio and Asymmetry Factors

To illustrate the use of Figure 6 or equation 1, consider an example using typical values for the parameters. In this case, consider that a transformer with a 30 year life ($\lambda = 0.03$) is installed at a location with a 5 kA fault current and AF=1.2. Using either Figure 6 or equation 1, the probability of having an eventful transformer tank failure is $8.6x10^{-5}$. This is the lower end of the average range of $8x10^{-5}$ to $2x10^{-4}$. If 10 kA is available the probability of eventful failure becomes $3.4x10^{-4}$, larger than the overall average value. To put these two values in perspective, over 30 years and 1000 transformers the lower one corresponds to 2 eventful failures and the higher one corresponds to 10 eventful transformer failures. Whether these rates are acceptable depends, of course, on the consequences of failure.

3.5 Assessing Risk

The probability of each harm per year can be multiplied by the probability of tank failure per year and the dollar value of the harm to obtain an *expected value of that harm (ie risk) in any one year period.* The expected dollar values are then summed to give a total for all harms.

The establishment of "acceptable" levels of risk is difficult. Generally this is done by calculating the risk of other activities that occur in society without much concern. An important consideration in these assessments is that risks that are voluntarily assumed, such as traveling in an airplane or mountain climbing, are usually allowed to be 1000 times greater than risks that are assumed involuntarily, such as being hit by a plane as it crashes, or being exposed to industrial pollutants.

Another important consideration in any comparison of risks is that society tends to find a risk more acceptable when it occurs over many events that affect few people, rather than a single event that can kill millions. Fortunately, pole top transformer tank failure falls in the former category and so comparisons do not need to be made with risks of nuclear or chemical plant disasters, or plane crashes. Table III presents the probability of an individual being killed in any one year due to a number of causes. As the probability of being killed falls below 10^{-6} per year most people and risk rating organizations cease to be concerned. Most people do not walk around in fear of being hit by lightning.

To illustrate the process of risk assessment, consider a transformer installed over a bus stop in an area with 10 kA available fault current (a possible "worst case"). The probability of transformer tank failure has been calculated in a previous example to be 3.4×10^{-4}. Assume that there is someone waiting for the bus half of the time for 16 hours of the day, leading to 8 hours out of 24 or a probability of exposure to harmful effects accompanying an eventful failure of 0.333. Multiplying these together, the probability of harm (i.e. the risk) is 1×10^{-4}. This level of risk is comparable to that accompanying death by motor vehicle accident and should be a concern to the utility.

Cause of Death	Probability of Early Death in a year
All Accidents	6×10^{-4}
Motor Vehicle	3×10^{-4}
Fall	9×10^{-5}
Fire	4×10^{-5}
Drowning	3×10^{-5}
Poison	2×10^{-5}
Firearms	1×10^{-5}
Airplanes (1 flight per year)	1×10^{-6}
Electrocution	6×10^{-6}
Lightning	5×10^{-7}

Table III: Accidental Death Probabilities (Ref. 6)

The other factor that is required for comparison of risk is the dollar value that can be assigned to a life. There are several methods of obtaining such a value: previously accepted estimates, lifetime income, life insurance coverage people find worthwhile buying, court awards, or surveys of willingness to pay. Typical estimates range around $300,000. A further consideration in assigning a dollar value is that courts award larger sums for maiming than for killing, since they consider lifetime medical costs, pain and suffering etc. In the previous example, although the probability of harm from transformer tank failure is almost as high as being killed in a car accident, the most likely harm is a minor burn from spilled oil, which might have a dollar value closer to $10,000, and hence reduce the utility's risk exposure.

In some cases it may be desirable to compare the probability of harm on a numerical basis and then factor in the level of harm in a subjective way.

Four
Techniques to Reduce the Probability of Eventful Failures

If a risk assessment concludes that the risk is unacceptable, there are several techniques available to the distribution engineer with which he may reduce the risk of eventful transformer tank failure. The following sections briefly explore and summarize these techniques. An example is provided at the end of this section to illustrate how a representative transformer installation may be assessed for risk and hazard and how it may be protected to minimize the possibility of an eventful transformer failure.

There are five areas in which actions can be taken or choices can be made by the utility which will minimize the incidence of eventful transformer failures: dealing with the fault (current limiting fuses), minimizing fault initiation opportunities (lightning protection), strategic operation and replacement, and design considerations.

4.1 Changing Transformer Location

The easiest method of reducing risk in new transformer installations, and possibly in some retrofits, is to move the transformer to a location that minimizes the length of time that a person is within range of the hazard. The examples in this guide illustrate several places that maximize the time such as school yards, bus stops, or over an alley or sidewalk.

> Moving the transformer further from things that can be harmed is often the easiest way to reduce risk.

4.2 Current Limiting Fuses

Current limiting fuses (CLF) are designed to protect equipment from the damage potential of high power arcing faults. Research in the 1960s and 1970s has shown that current limiting fuses can reduce the number of eventful failures, but not entirely eliminate them. **Current limiting fuses will operate in about 30 - 50% of all transformer faults, including in virtually all types of faults likely to result in an eventful failure.**

In tests recently carried out /1/, it has been shown that the I^2t of the fault does not correlate very well with the probability of eventful failure. This is rather unfortunate because the I^2t is the only published fuse characteristic available to apply current limiting fuses. Nevertheless, in 645 tests involving 138 eventful failures, the minimum I^2t that caused an eventful failure was 38,000 A^2sec. Using I^2t as the primary application criteria then, this suggests that any current limiting fuse rated at less than a general purpose CLF of 65A (or a backup CLF of 40 A) should be sufficient to prevent eventful failure, since the let-through I^2t of these fuses is less than 38,000 A^2 sec. Since poletop transformers are only rated up to 167 kVA, their load current should always be less than 40A and therefore CLF protection should be effective. Detailed descriptions of how to apply current limiting fuses are contained in the CEA Fuse Application Guide available from CEA offices /8/.

> Applying optimal protection strategies, such as the use of current limiting fusing, will greatly reduce the risks and hazards associated with eventful transformer failures

4.3 Lightning Protection

Since many eventful failures are the result of lightning strokes, another step to reducing eventful transformer tank failure is to ensure proper lightning protection. The following steps can be taken to reduce the eventful failure rate:

1) specify higher BIL equipment
2) select a lower rated surge arrester
3) improve grounding system
4) reduce arrester lead lengths
5) increase surge arrester class
6) parallel two metal oxide arresters
7) use scout arresters on adjacent poles
8) the use of overhead shield wires

All of the above techniques are described in detail in the CEA Arrester Application Guide available from CEA offices /7/.

Eventful failures are often initiated by lightning effects. Reducing lightning vulnerability will significantly reduce eventful failure rates.

4.4 Replacing Transformers Before Normal End of Life

Several of the mechanisms of under oil arc initiation are enhanced by the normal ageing processes occurring in the transformer. For example, the short circuit strength of windings can be lessened by degradation of the paper insulation, the oil can become contaminated, the insulation surfaces can become damaged by corona discharges, etc. Transformer failures follow the usual "bathtub" curve, with higher probability of failure at the beginning and end of the transformer's life. If a transformer in a critical location is replaced at an estimated 70% of its life (with a unit that has been tested at full voltage to eliminate early failures), then the high failure probability region can usually be avoided. The remaining life of transformers, and the increased cost of change out before end of life can be calculated using the methods of CEA Transformer Loading Guide available from CEA offices /10/.

Replacing a transformer before its normal end of life will reduce the probability of a weakened part causing an eventful failure.

4.5 Transformer Design Considerations

There are three design considerations to be kept in mind which will reduce the vulnerability of the transformer to eventful failure. Following is a list of these three key points which should be considered when making a purchasing decision.

1. Several of the arc initiation methods relate to parameters of transformer design and manufacture. The design and installation of the high voltage drop leads, clamping arrangements, and coil assemblies are critical to reducing eventful failures. Manufacturers with proven commitments to reliability and high quality in this area should be chosen for transformers in critical locations.

2. During a recent field failure survey /1/, it was found that a larger proportion of eventful failures than expected involved transformers with tap changers or under oil fuses mounted above the windings. This is probably due to debris from winding faults or bubbles from overloads becoming trapped in the tap changer mechanism or around the fuse, and leading to low impedance arcing faults in the oil. This type of transformer could be avoided in critical locations to reduce the probability of eventful failure.

3. Increasing the air space inside the transformer will increase the ability of the tank to contain arcing faults/1/. Selecting a transformer design with the largest available air space will maximize that particular transformer's ability to contain an arcing fault without eventful failure. Roughly a 25% increase in the air space above the normal size will reduce the probability of failure by a factor of two. Further increases in air space have a smaller effect.

All transformer designs are not equal when it comes to eventful failure vulnerability. ***Caveat Emptor.***

4.6 Tying it all Together - An Illustrative Example

Following is an example illustrating many of the points made in the previous sections of this guide. Although every effort has been made to make the example representative of a real life situation, the reader should bear in mind that because of the complex nature of carrying out hazard/risk assessments, not all bases can be covered in a single example and further review of the various papers cited in the annotated bibliography may be required for particular situations.

Example:

Twenty-five years ago, ABC manufacturing, a producer of fine office furniture and accessories, decided to expand its facilities and move into the then relatively un-occupied industrial park of Weatherfield's east end. At that time, ABC management, along with Weatherfield PUC staff decided that present and future load growth for the foreseeable future could be accommodated by a three phase bank of 50 KVA pole top transformers operated at the then common primary voltage of 13.8/8 kV with a three phase secondary voltage of 600/347 (industrial) and single phase taps stepped down inside the plant to 240/120 levels for plant and office service.

Over the last 25 years, however, business has been better than originally expected with plant demand load steadily increasing from the original 150 KVA (three phase) to today's level of 500 KVA three phase. Furthermore, the industrial subdivision has by now been completely filled, so that car, bus and truck traffic along Rockton and Harbour Rd has increased substantially and the town of Weatherfield has designated both streets as high density, arterial. To complicate matters further, Rockton Collegiate, an education institution specializing in training industrial skills such as welding, sheet metal fabrication, industrial electrician, etc has, over the last two years re-located from downtown Weatherfield to the NW corner of Rockton Ave and Harbour Rd. To take advantage of the nearby bustling industrial park for its student's work terms. Rockton Collegiate offers full day courses to 1600 students and a host of evening courses until 11:00 pm to another 650 part time students. To meet the load demand in this area a new substation has been installed within 1 km of ABC manufacturing.

You are the distribution engineer charged with designing the new transformer installation at ABC Manufacturing. In keeping with modern design practices, you are required to carry out a risk/hazard assessment to develop appropriate installation and transformer protection strategies.

Figure 7 presents an overview of the site.

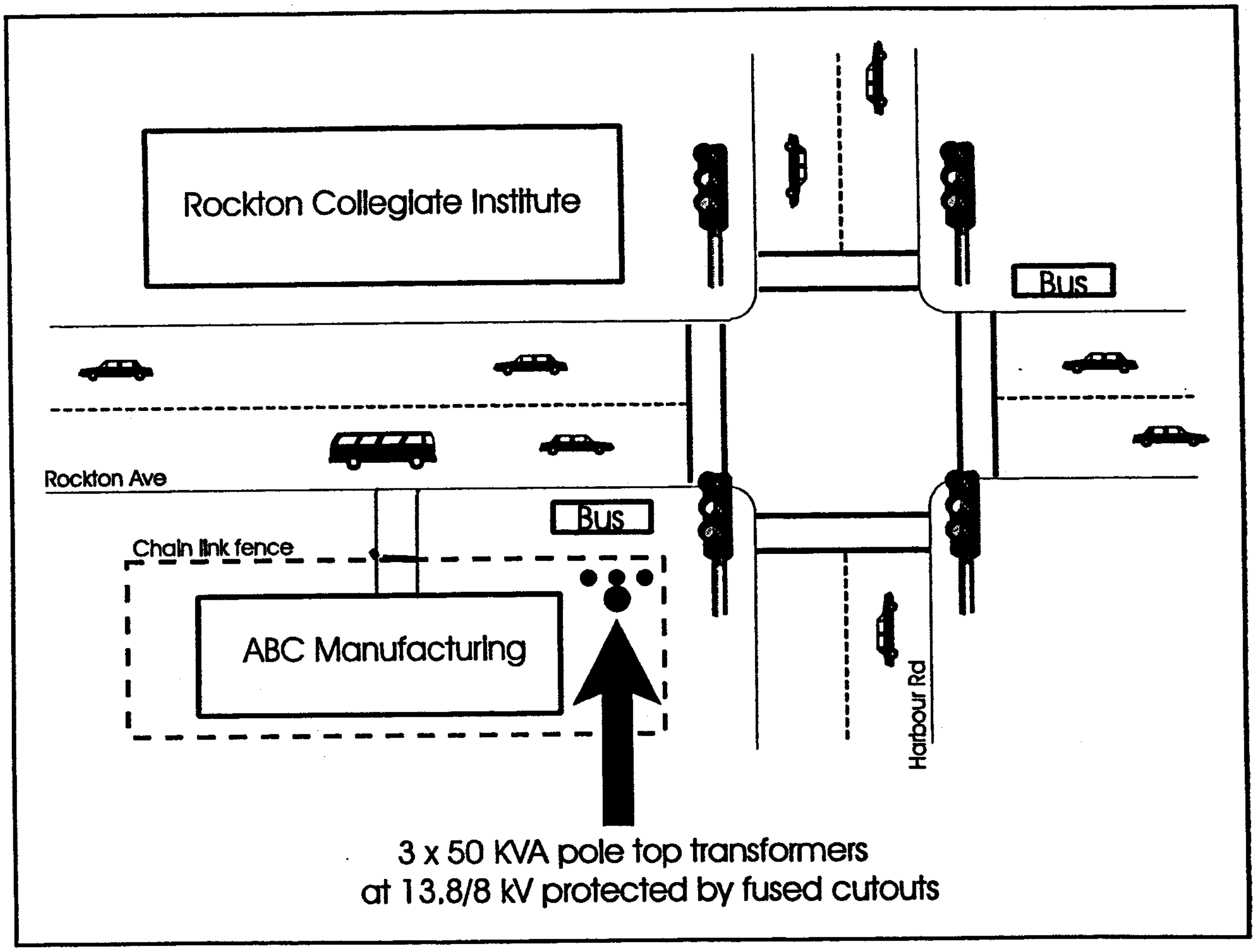

Figure 7 Example - ABC Manufacturing Site Overview

Step 1 Identify the Hazards (establish dollar values if required)

The hazards are the usual set for pole top transformer eventful failure:

- spill of hot oil
- projectiles (lid, bushing parts, entire transformer falling)
- electric arc and/or flame

These hazards can cause harm to the following:

Direct harms:

- utility employees
- members of the public
- the adjacent stop light
- cars parked in the ABC lot

Indirect harms:

- utility public image
- accident investigation/media response

These harms can have the following estimated dollar values:

•utility employees	serious injury/death	$1,000,000
•members of the public	minor injury	$50,000
•the adjacent stop light	minor damage	$1,000
•cars parked in the ABC lot	minor damage	$1,000
•utility public image	response to media	$50,000
•accident investigation	staff time	$10,000

The harm to the utility employee is much higher since close proximity to the transformer is possible. Members of the public could be burned by hot oil or hit by falling debris, but they will not be killed, since a falling transformer would be on the inside of the chain link fence and fire or arc flash will not reach ground level.

The harms to utility employees and the public are not likely to happen in the same event, so these cost can be separated. The utility public image should only be affected in case of injury to the public. Overall estimate for potential harm from an eventful failure is $1,000,000 if utility personal injury is involved, $100,000 if personal injury to the public is involved, and $12,000 if no personal injury is involved.

Step 2 Determine the probability of harm occurring given that equipment failure occurs

The probability of the equipment harm is 1, since the adjacent equipment is always present.

The probability of utility employee personal injury is:

Assume transformer needs service 5 times in a 20 year life (fuse replacement etc.)
Assume that an employee is within range of harm 30 minutes each time.
Calculate probability 5×0.5 hrs / $(8760 \times 20) = 1.4 \times 10^{-5}$ per year

The probability of public personal injury is:

Assume someone is standing at the bus stop, or walking on the sidewalk, half the time from 7:00 am to 11:00 pm on weekdays and for a total of 4 hours per day on weekends.

Calculate probability $\{(8\times5)+(4\times2)\}\times52 = 2496$ hrs/yr
$2496 / 8760 = 0.285$ per year

Step 3 Analyze the probability of tank failure

The available fault current is calculated to be 5 kA.
The X/R ratio is 12, for an asymmetry factor of 1.5
$\lambda_T = 0.03$

$P=8\times10^{-5} \times (5)^2 \times (1.5)^2 \times 0.03 = 1.34 \times10^{-4}$

This is the probability of tank failure of one transformer but there are three at the location.

$P_{total}=P \times 3 = 4 \times10^{-4}$

Step 4 Combine the probability of failure and harm with the hazard level to estimate the overall risk

Case 1 Harm to Equipment Only
Risk = $4 \times10^{-4} \times 1 \times \$12,000 = \$4.80$ per year

Case 2 Harm to Utility Employee
Risk = $4 \times10^{-4} \times 1.4 \times10^{-5} \times \$1,000,000 = \$0.57$ per year

Case 3 Harm to a Public Person
Risk = $4 \times10^{-4} \times 0.285 \times \$100,000 = \$11.46$ per year

If a qualitative risk assessment is desired, instead of quantitative, then the probability of personal injury could be calculated without the dollar values:

$$P_{\text{injury to public}} = 4 \times 10^{-4} \times 0.285 = 1.1 \times 10^{-4}$$
$$P_{\text{injury to worker}} = 4 \times 10^{-4} \times 1.4 \times 10^{-5} = 5.7 \times 10^{-9}$$

Step 5 Compare the risk to socially acceptable levels of risk

The probability of public personal injury, 1×10^{-4}, is larger than the probability of being hit by lighting, 5×10^{-7}. It is similar to the probability of being killed in a car accident. This may be an acceptable level of risk, given that a member of the public is likely to be burned not killed if a transformer tank fails.

The probability of utility employee personal injury is 100 times lower than the probability of being hit by lightning, and is certainly an acceptable level of risk.

The dollar values of risk show that an amount up to $1146 per year could be spent to reduce the risk. This would certainly make current limiting fuses, better lighting protection, or moving the transformer farther from the sidewalks, worthwhile responses to reduce the risk.

Annotated Bibliography

Eight Really Good Sources of Useful Information

1 Filter R., Piercy R.J., "Distribution Transformer Internal Pressure Withstand Test", Canadian Electrical Association, Report No. 149-D-491A, Montreal, 1997.

This report contains the details of the laboratory test program, data analysis, and statistical calculations upon which this guide is based. It provides background information that explains where the equations and data used in the guide come from.

2 Cuk, N.P., "Oil Tank Explosion Resistance", Canadian Electrical Association, Report No. 149 D 491, Montreal, 1990.

The violent ruptures of transformer tanks that can occur as a consequence of internal arcing faults, continue to pose a major safety concern to distribution engineers. The research work performed for this project was initiated to investigate alternatives for further improvement of measures intended to prevent eventful failures of transformer tanks. The principal achievements of the project are:

1 The pressure increase in the air space will rarely damage the tank, but it can easily pop the lid

2 The tank itself can be ruptured by a shock wave propagating under the oil.

3 Tanks of padmount transformers are less prone to rupture, although fault currents of 5 kA for 5 cycles will certainly cause failure. The use of current limiting fuses appears to be the best solution.

4 The protection against tank rupture can be improved by ensuring short duration faults, providing adequate volume in the air space, and by designing the insulation of transformers to prevent faults in critical locations.

3 Barkan P., Damsky B.L., Ettlinger L.F., Kotski E.J., "Overpressure Phenomena in Distribution Transformers with Low Impedance Faults: Experiment and Theory", IEEE TPAS Vol. 95 No. 1, January 1976, page 37.

While the problem of disruptive failure of distribution transformers has received much recent study, uncertainty still remains as to the precise phenomena which cause cover blowing or tank distortion. This paper presents some new insights into the mechanisms of cover blowing based on a comprehensive study and highly instrumented test program. Unique contributions from this study should help clarify many points which have been the subject of much discussion during the last few years. Besides observing and correlating the effects of various arcs drawn inside several different transformers, some actual failed transformers were tested and the effects of the failures observed and measured, giving a better understanding of what occurs while a transformer is in the process of failing. Special tests using high speed photography have confirmed the existence of failure modes which up to now have been only suspected. In addition, measurements from these tests have verified theoretical studies and so have helped provide a more complete picture of the diverse phenomena involved. Practical solutions to the cover blowing phenomena are discussed.

This is a good summary of the failure mechanisms in pole top transformer tanks. It combines data and knowledge from many previous papers. It recognizes the importance of arc location, and air space volume as well as arc energy or I^2t.

4 Ristuccia D.J., "Ten Most Asked Questions on Violent Transformer Failure", Transmission And Distribution, 1975.

This two page summary provides concise answers to questions such as the following:

- What determines the severity of arcing faults?
- What protection does a pressure relief device provide?
- What is the significance of pre-pressurization?
- When should current limiting fuses be used?
- What error results from using I^2t as a measure of fault current?

5 Harner R.H., Gray D.M., "Energy Control Devices and Internal Transformer Faults", Proceedings of the American Power Conference, Vol. 36, Page 921, 1974

The effectiveness of fault limiters and current limiting fuses at reducing transformer tank failures is demonstrated by a series of tests. If this reference is unobtainable, the same data is reported by Gray in the IEEE PES Summer Meeting, 1974.

6 Henley E.J., Kumamoto H., "Probabilistic Risk Assessment", IEEE Press, New York, 1992.

This book presents an overview of risk assessment that is easily understood and gives a good appreciation for the concepts involved. Typical risk numbers are presented for comparison purposes.

7 Lat M.V., Carr J., "Application Guide for Surge Arresters on Distribution Systems", Canadian Electrical Association, Report No. 077D184A, September, 1987.

This is a comprehensive application guide for the selection of surge arresters for use on distribution and subtransmission systems. The guide is organized in five sections that outline respectively (a) characteristics of surge arresters, (b) system characteristics related to surge arresters, © surge arrester selection, (d) evaluation of surge protection, and (e) shop and field testing methods for surge arresters. Background information is given to assist with both unusual applications and more routine cases.

This is a very comprehensive guide. If improved lightning protection is required to reduce the risk due to transformer tank failure it would be a very valuable resource. The information it contains is far to extensive and detailed to be included in this guide.

8 Cress S.L., "Fusing Application Guide", Canadian Electrical Association , 1997

This guide provides application instructions and information for all types of distribution and power fuses. It includes fuse characteristics, fuse selection and coordination, effects on the power system, factors that affect fuse performance, nuisance fuse blowing, and background information on fault types and on other types of protective equipment. The detailed information includes coordination between current limiting fuses and expulsion fuses, and how to apply current limiting fuses in parallel to increase the current rating.

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9 Cohen R.S., Ettlinger L.F., "Pressures in Distribution Transformers Caused by Low Impedance Faults", IEEE PES Winter meeting, January 1973.

10 Cress S.L., "Economic Loading of Distribution Transformers", Canadian Electrical Association, Report No. 161D456A, 1993.

11 Dewbury, R. A., "Electric Distribution Systems Engineering Manual", Vol 3, page 287, McGraw Hill, NewYork, 1982.

12 Dougher R.E., "A Transformer Protective System Designed to Prevent "Eventful" Transformer Tank Failures", IEEE Underground Transmission and Distribution Conference, September 1976, page 173.

13 Gray D.M., Harner R.H., "Tests Determine Transformer Withstand", Electrical World, page 50, February, 1974.

14 Kaufmann G.H. "Gas Bubbles in Distribution Transformers", IEEE PES Winter Meeting, January, 1977.

15 Pablo P.A., Razovsky A.M., "Prevention of Distribution Transformer Explosions", IEEE Summer Meeting, 1971.

16 Risticcia D., "Can Your O.H. Transformers Take Faults", Electrical World, page 60, August 1970.

17 Ristuccia D., "Preventing Catastrophic Transformer Failures", Power Engineering, page 42, January 1971.

CEA 149 D 491B

MINIMIZING POLE TOP TRANSFORMER TANK FAILURES

AUGUST 1997

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Automatic Sleeve Replacement

Newfoundland Power Inc.

Prepared by
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June 2003

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Introduction

Automatic sleeves (splices) were introduced to the utility industry in the 1980's. Previous to their introduction the main method of splicing (joining) conductors was by means of compression sleeves. These compression sleeves required the use of a specialized compression tool and were relatively labour intensive. The introduction of automatic or "quick" sleeves provided two main advantages over compression sleeves. One was the elimination of the compression tool; the automatic sleeve was installed without any tool. The other advantage was its ease of installation. It was very quick and easy to install. While the automatic sleeve was more expensive to purchase, the additional cost was more than compensated for by the gain in productivity. Newfoundland Power adopted automatic sleeves for use on a limited basis in 1993 and in 1999 approved automatic sleeves for use on the whole distribution system. However after nine years in service these automatic sleeves began showing signs of premature deterioration, in large part due to our severe environmental conditions.

In late 2002, due to these problems with deterioration, Newfoundland Power discontinued the use of automatic sleeves. This report reviews the requirement for a 5-year replacement program for all in-service sleeves beginning in 2004.

Newfoundland Power's Experience

The automatic sleeve was first used on the Newfoundland Power distribution system in 1993. In that year these sleeves were introduced for limited use, i.e. for one specific size conductor (#1/0) and specific applications (emergencies and hot line work). As operations personnel became more familiar with and recognized the ease of installation of these sleeves they received widespread use. By 1999 the automatic sleeve was approved for use on all distribution conductors without restriction. Refer to Appendix A for a picture of an in-service automatic sleeve.

The first indication of a problem surfaced in early 2002 when an automatic sleeve failed (electrically) on a neutral conductor in the Avalon Area. An investigation showed corrosion inside the sleeve. This incident lead to the checking of additional sleeves in the area. Two were subsequently removed for inspection and both showed internal corrosion.

During the fall of 2002, Newfoundland Power conducted a more comprehensive investigation into the issue of premature deterioration of automatic sleeves. A total of 35 sleeves were removed from various areas throughout the Company, both coastal and inland areas, and recently installed sleeves as well as older ones. The results from this investigation indicated widespread internal deterioration of automatic sleeves. 71% of the sleeves removed showed at least some corrosion with 37% being severely corroded. Refer to Appendix B for pictures of several of the more corroded sleeves.

In addition to the corrosion problem, Newfoundland Power has experienced several mechanical failures due to improper installation of the sleeve. While the sleeve is relatively easy to install, installation requires the following of specific procedures to ensure the conductor is fitted securely into the sleeve jaws.

Other Utilities' Experience

Generally the experience of other utilities with automatic sleeves has been good up to this point in time. However, as a result of several recent mechanical failures of lines in service, B.C. Hydro is currently reviewing its use of automatic sleeves because of excessive corrosion and is preparing a plan to replace existing automatic sleeves in service. Similarly, Wisconsin Public Service Corp. has identified corrosion in automatic sleeves to be of concern to them and is planning further investigation.

Given the relatively recent introduction of the use of automatic sleeves to the electrical industry, we may be seeing the early stages of a potentially serious problem developing for utilities. Internal corrosion will initially cause electrical failure of the automatic sleeve and eventually lead to mechanical failure (separation of the line). Automatic sleeves are in widespread use throughout utilities in North America and millions of these have been installed over the past 15-20 years.

Automatic Sleeve Manufacturers

When Newfoundland Power initially experienced sleeve failure due to corrosion, one of the manufacturers (Fargo) was contacted to provide an evaluation and comments. After their analysis of two corroded sleeves returned to them by Newfoundland Power, the manufacturer stated, in reference to a sleeve in service for just 5 years, "the evidence suggests that the (automatic sleeve) was nearing or had exceeded its service life in this harsh environment". The manufacturer further states, "At the present time, we do not have an automatic (sleeve) designed specifically for these harsh environments". The corrosion is not limited to one specific manufacturer. Deterioration occurs due to the inherent design of the automatic sleeve. There is not a sufficiently tight seal at the mouth of the sleeve to prevent the entry of moisture and contaminants into the sleeve itself.

Hazards of Automatic Sleeves

The main risk associated with corroded automatic sleeves is mechanical failure. This would result in line separation and the resulting hazard of an energized line dropping to the ground. This presents a public safety hazard. Additionally there is a risk to line personnel who perform energized work on lines as the separation of conductors would create a hazard to those workers.

For line personnel, in addition to the risk of mechanical failure, there is the risk of electrical failure of the sleeve. This is particularly hazardous if a sleeve on a neutral conductor fails. A lineman would not normally expect a sleeve to be electrically “open” and may place himself in a position to be seriously injured. Dangerously high voltage differences could be present across an electrically open sleeve on a neutral conductor.

Conclusion

Over the course of the past nine years approximately 10,000 automatic sleeves have been installed on Newfoundland Power’s distribution system, the majority of which were installed in the past 4-5 years. These automatic sleeves pose a serious safety hazard to employees and the public, as well as a potential to reduce customer service reliability.

Based on this assessment, the sleeves should be removed from service on a scheduled basis over the next five years. The estimate to carry out the program to replace the 10,000 sleeves is $1,000,000.

Recommendations

The following action is recommended with respect to automatic sleeves.

- In keeping with the decision of October 2002, discontinue automatic sleeves from further use, remove all automatic sleeves from line trucks and warehouses and return to suppliers.

- As part of the annual distribution line inspection program, identify automatic sleeves for removal from service in the following year. (20% annually of feeders are inspected).

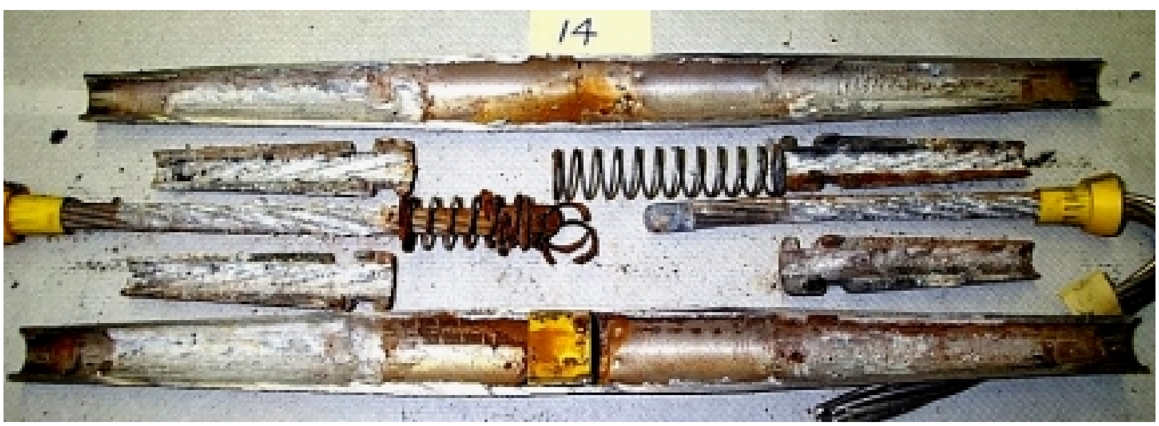
APPENDIX A

In-service Automatic Sleeve

APPENDIX B

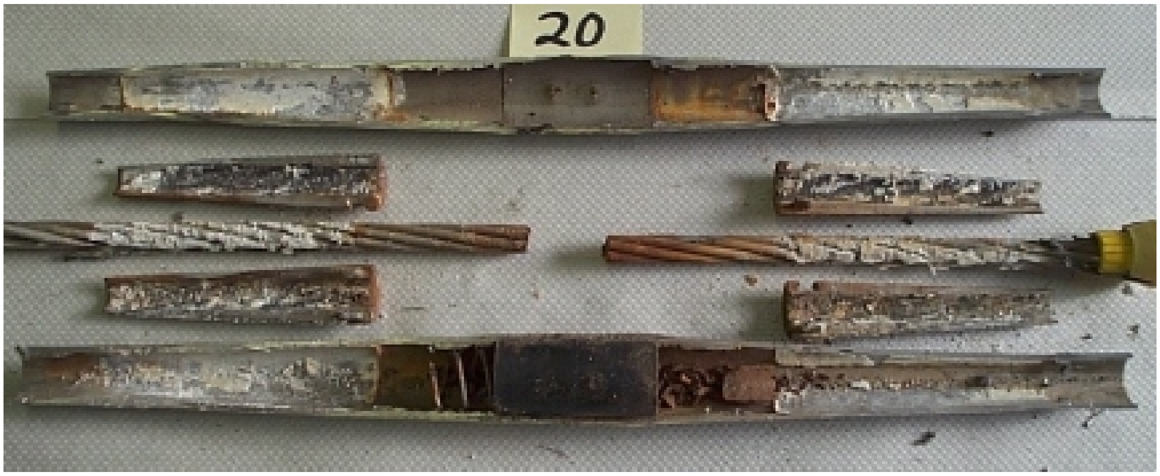
Automatic C Sleeve – Topsail Road

This sleeve is a Reliable 7653 for 1/0 aluminum conductor and is date coded 93. It was removed from tap off Topsail Road, St. John’s. There is severe corrosion inside the sleeve with significant salt contamination on the jaws and conductor. The spring has rusted and almost turned to powder. This is very similar to the sleeve removed from Placentia following the open neutral.



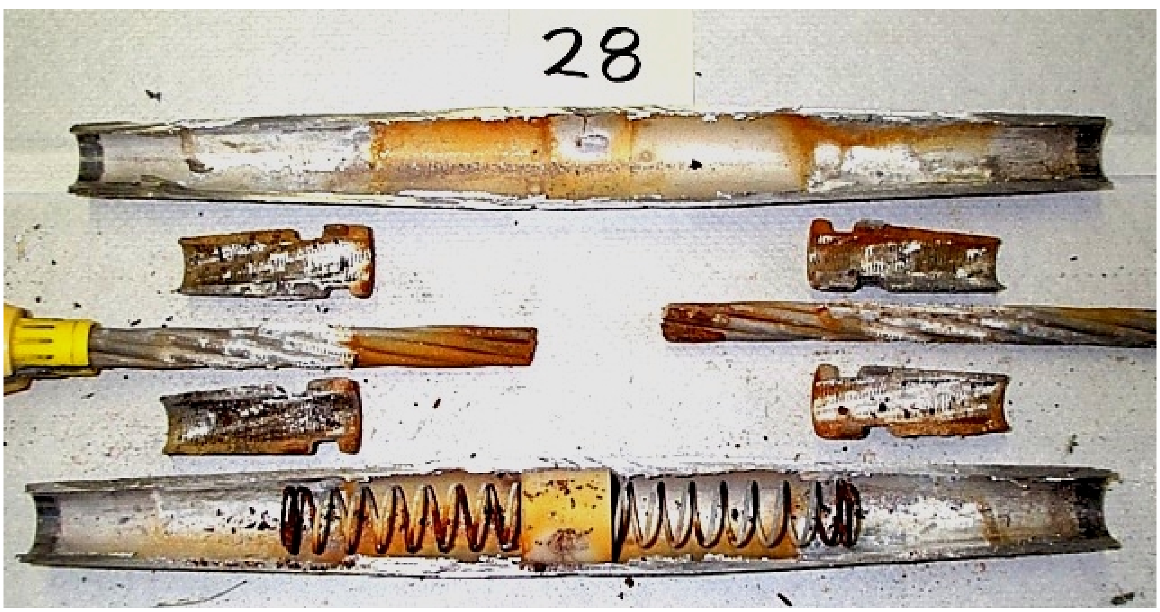
Automatic Sleeve - Glovertown

This sleeve is a Fargo GL-406 for 1/0 aluminum conductor and is date coded 01 99. It was removed from Glovertown. It was installed in 1997. There is severe corrosion on the jaws and conductor. The spring and guide cap is rusted on the left.



Automatic Sleeve – Turk's Cove

This sleeve is a Reliable 7653 for 1/0 aluminum conductor and is date coded 93. It was installed in Turk's Cove on NCH-02 around 1993. There is severe corrosion on the jaws and conductor. The springs have rusted away.



Automatic Sleeve – Grand Bank

This sleeve is a Fargo GL-406A for 1/0 aluminum conductor and is date coded 02 98. It was installed in Grand Bank on GRH-01. There is significant corrosion on the jaws and conductor.

Porcelain Cutout Replacement

Newfoundland Power Inc.

Prepared by
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May 2003

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Introduction

Porcelain insulated cutouts have been in use in the electrical industry for many decades. The cutout is a pole-mounted device used to disconnect or reconnect equipment to a source of electricity. Throughout that time the designs and manufacturing processes have changed somewhat but the basic insulating material used has always been porcelain. Porcelain was the material of choice by manufacturers not just for cutouts but for most electrical equipment that required an insulating value, for example, insulators, arresters and bushings. Porcelain, being composed primarily of sand, was an abundant raw material, was inexpensive to manufacture, was durable and didn't require any specialized or advanced technology. However, porcelain for all its advantages did have drawbacks. In the early 1980's large numbers of porcelain insulators began failing. "Cement growth" was causing insulators to crack. The expansion and contraction of the adhesive interface which joined the porcelain to the hardware (connector) caused stresses on the porcelain. These stresses caused small cracks to appear in the porcelain which eventually lead to an electrical and/or mechanical failure of the porcelain insulator. This problem was discussed in the report "Distribution Insulator Replacement Program" which was filed with the Board on December 1, 1997, in response to Request for Information NLH-10(a).

Transmission and distribution insulators had been the focus of the industry's attention throughout most of the 1980's and 1990's. Many tens of millions of dollars have been spent in Canada to rectify the problem of defective porcelain insulators. During the past several years many utilities throughout North America have seen increasing failures of their porcelain insulated cutouts. The mode of failure is very similar to that of insulators. Small cracks in the porcelain initially appear near the interface between the porcelain and hardware. These fractures eventually lead to a mechanical failure of the cutout. Cement growth is the likely cause of the initial cracks. Refer to Appendix A for pictures of broken cutouts.

The breakage of porcelain insulated cutouts at Newfoundland Power is of concern from a safety and reliability perspective. During cutout operation the porcelain can break causing the cutout to separate into two parts. This creates a hazard to line personnel operating the cutout and can cause outages to customers.

This report reviews the requirement for a replacement program for defective porcelain cutouts.

Newfoundland Power's Experience

During the past several years Newfoundland Power has experienced an increase in the number of broken porcelain cutouts being reported. Initially, in 2000 and 2001, most reporting was done verbally by line crews who reported incidents of failed cutouts to supervisors. There were few statistics on the actual number during that period since most of the reports were not formally documented. It was becoming clear however, through anecdotal reports and discussion with line crews, that there was an upward trend in the quantity of porcelain cutouts that were failing. In 2002, in order to better quantify the extent of the problem, Newfoundland Power focused on getting written documentation from operations personnel on every cutout failure. In 2002, there were 105 cutout failures reported. Between Jan 1 and Apr 30, 2003, there were 115 failed cutout reports. At this rate, the annual number for 2003 would be 345 failed cutouts which is a substantial increase over 2002. Part of this increase may be explained by the better reporting of failures however it may also reflect an increasing rate of cutout failure as cutouts age.

During this period line personnel were becoming increasingly concerned with incidents of cutout failures. The issue was raised during the annual Corporate Safety Council meeting in October, 2002 as the most prominent safety issue brought forward at Area safety meetings during the fall of 2002 and winter of 2003.

Other Utilities' Experience

Other utilities in the Atlantic region including Nova Scotia Power, Maritime Electric and New Brunswick Power have experienced similar problems with porcelain cutouts during the past few years. Throughout North America, utilities such as B.C. Hydro, American Electric Power and Public Service Electric & Gas have been concerned with the increased rise in the number of cutouts failing on their distribution systems. A survey of Canadian utilities conducted in 2001 by B.C. Hydro identifies the increasing concern of several utilities about this trend.

Hazards of Porcelain Cutouts

The cutout is a pole mounted device used to disconnect or reconnect electrical equipment to a source of electricity. Every transformer has a cutout attached to it. Each cutout has a fuse built into it designed to melt when an overload occurs in the transformer itself or the wires serving the customers attached to the transformer. Throughout the Company many hundreds of cutouts are opened and closed every week. Each one of these operations is done while the cutout and the lines and other equipment adjacent to the cutout is energized, therefore each time the cutout is operated there is a potential hazard from cutout breakage. The lineperson typically operates the cutout using a 10' long "hotstick" while they are positioned in the pole or the bucket of a line truck. This puts the lineperson in close proximity to the cutout. Should the cutout break while being operated the lineperson may be placed in a dangerous and unsafe situation.

To date, no lineperson at Newfoundland Power has been injured as a result of a cutout breaking while being operated. However, there have been several near misses, a recent one having occurred in December/02 in Grand Falls Area when a lineperson operated a cutout while standing in the pole. In this incident the cutout broke and the top part (still energized) struck the transformer, caused an electrical flash and an outage to a number of customers. Fortunately, the lineperson escaped without any serious injury.

CEA Study

The Canadian Electricity Association (CEA) commissioned a research study of the porcelain cutout breakage issue in 2002. This study was initiated because there was enough concern by many Canadian utilities to warrant further investigation into the problem. The objective of this research was to determine whether a method is available or could be developed to effectively evaluate the "in situ" condition of a cutout prior to operation. The research concluded that there was no reliable existing instrument or method that could reasonably detect incipient failure of a porcelain cutout. The report has been completed by Powertech Labs and is scheduled for release in August, 2003.

Alternatives to Porcelain Cutouts

During the past 20 years there have been advances in the development of non-ceramic or synthetic material for use as insulators in the electrical industry. This material is most often polymer based. At the distribution level, the main focus of manufacturers has been directed to the replacement of porcelain with polymer material in insulators and lightning arresters. The industry has been quite successful in this regard with most suspension insulators and lightning arresters manufactured today being of a polymer design.

As far as cutouts were concerned, until very recently there was no real alternative to the porcelain cutout. However, in 2000 an American company, PLH Manufacturing Co., developed the first polymer insulated cutout. Since then two other manufacturers have developed or are developing polymer type cutouts in response to the growing demand by utilities throughout North America. One of the advantages of polymer material is that it is not brittle like porcelain and therefore it will not develop cracks and shatter in the way porcelain does. This reduces the risk to linepersons.

Safety and Reliability

The two principal drivers for change to the polymer insulated cutout standard are safety and reliability. Polymer cutouts can effectively eliminate the hazard to linepersons that now exists when porcelain cutouts fail. However, there may still be a risk to linepersons operating the many thousands of existing porcelain cutouts in service. Newfoundland Power can mitigate risk as much as possible by ensuring an increased risk assessment and awareness among linepersons and a review of work methods.

As with safety, the increased use of polymer cutouts can have a positive effect on customer reliability, as each broken cutout, in most instances, represents as outage in excess of two hours.

Replacement of Porcelain Cutouts with Polymer Cutouts

As a result of the increasing rate of porcelain cutout failures and the associated safety risk to employees and the general public, as well as reduced reliability to customers, Newfoundland Power has decided to adopt the polymer insulated cutout as its new cutout standard and eliminate any further installation of porcelain insulated cutouts. The new polymer cutouts will be used for all new installations on a go forward basis and for replacement of failed or defective cutouts.

The Company's distribution inspection program requires that all distribution feeders be inspected on a 5 year cycle. Part of this inspection process should be the identification of defective porcelain cutouts i.e. ones that have evidence of cracks but have not yet failed. These defective cutouts will be replaced as part of the feeder upgrade project in the year following their identification.

Newfoundland Power should closely monitor future porcelain cutout failures to determine whether additional measures such as an accelerated cutout replacement program is warranted in the future.

Cost to Implement a New Cutout Standard

The Company purchases on average approximately 2,400 cutouts per year at an annual cost of approximately $140,000. By way of comparison, 2,400 polymer cutouts would cost approximately $240,000.

In addition to the above, as part of the annual inspection process, it is anticipated that approximately 1,000 defective cutouts will be identified per year. The annual cost of the material and labour to replace these additional units would be approximately $140,000.

Recommendations

The following action is recommended with respect to porcelain cutouts.

- Adopt polymer insulated cutouts as the new cutout standard.

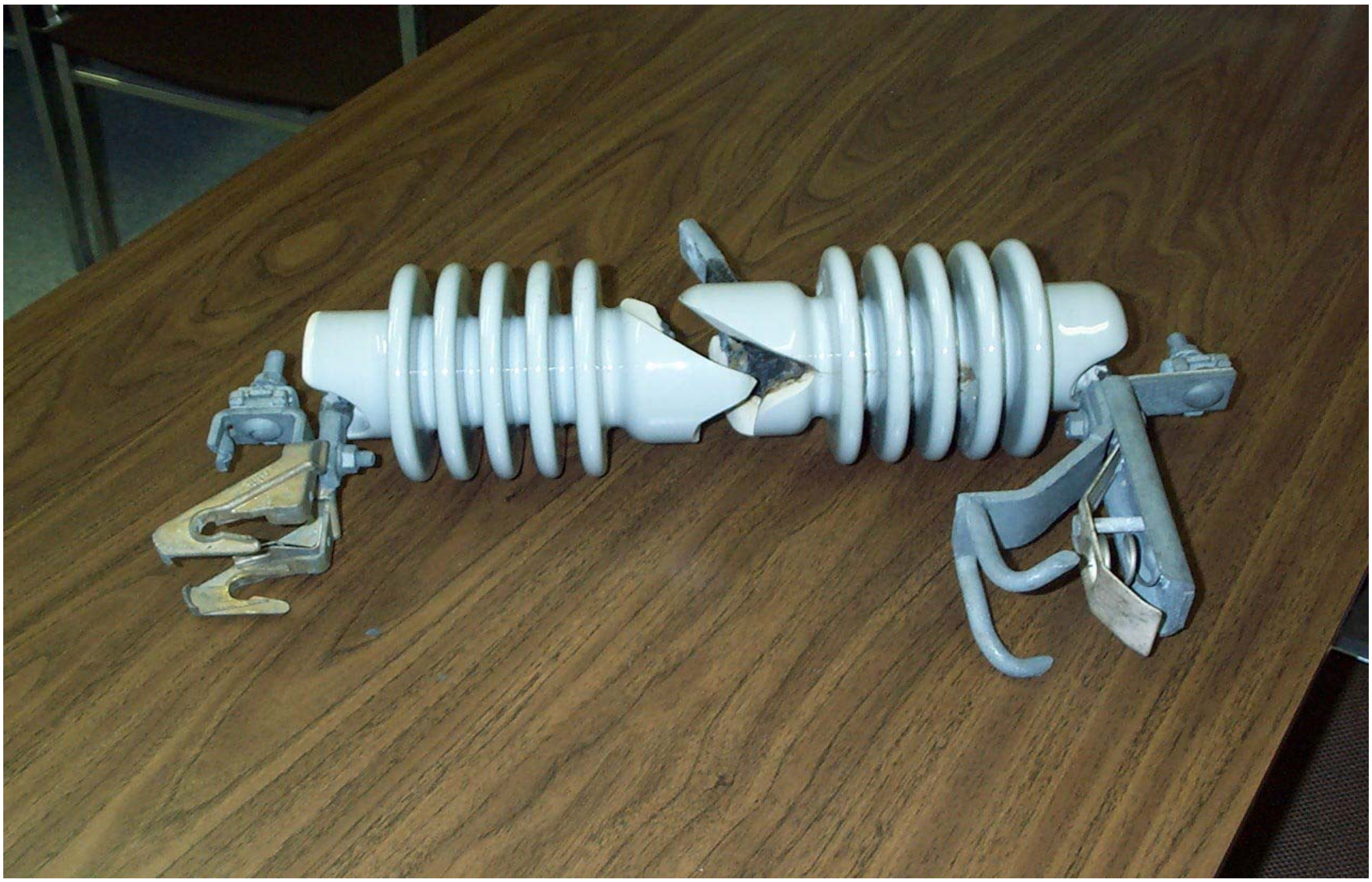
- Discontinue the use of porcelain cutouts.

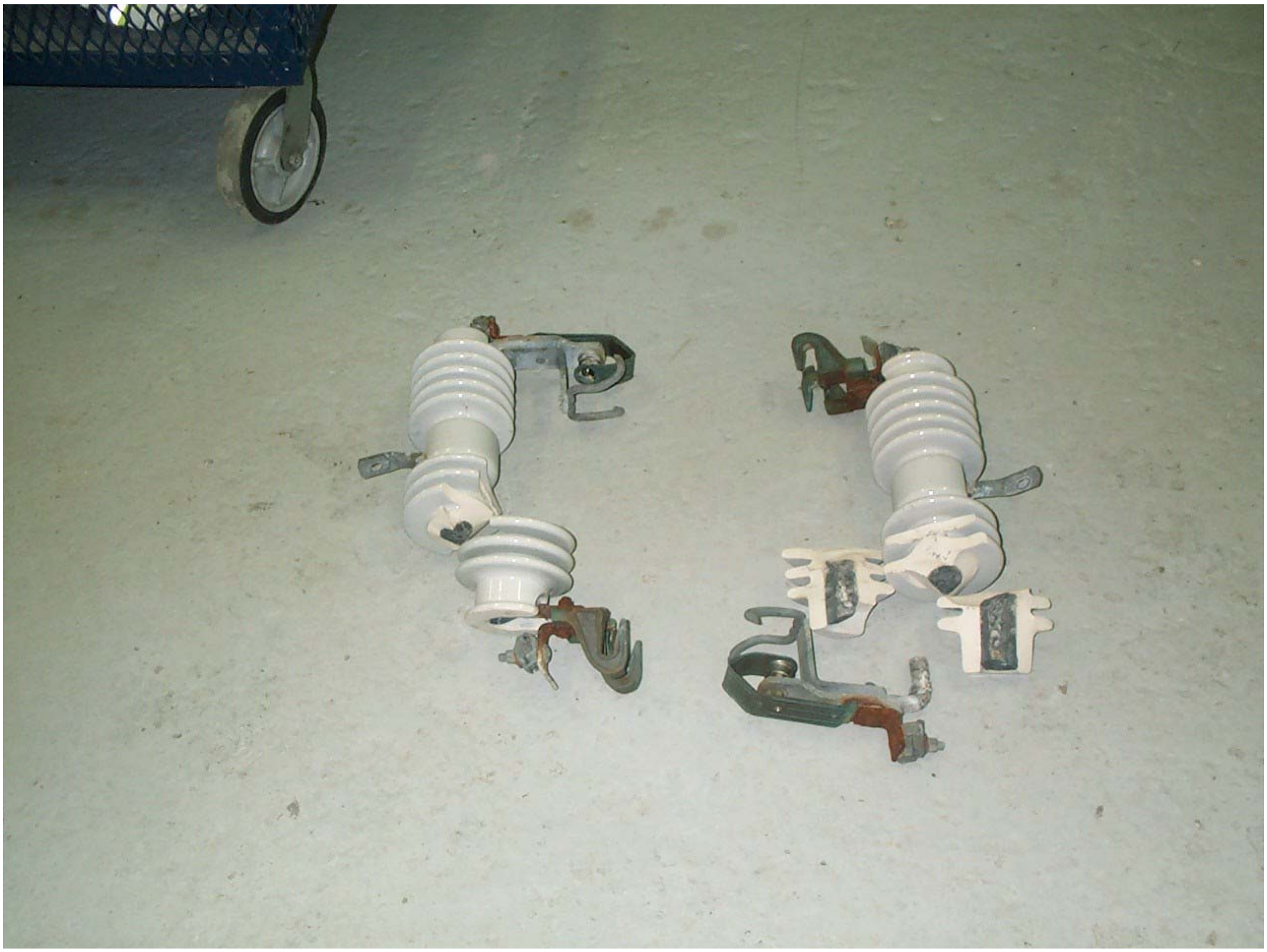
- As part of the annual distribution line inspection program identify defective cutouts i.e. ones that have visible evidence of cracks.

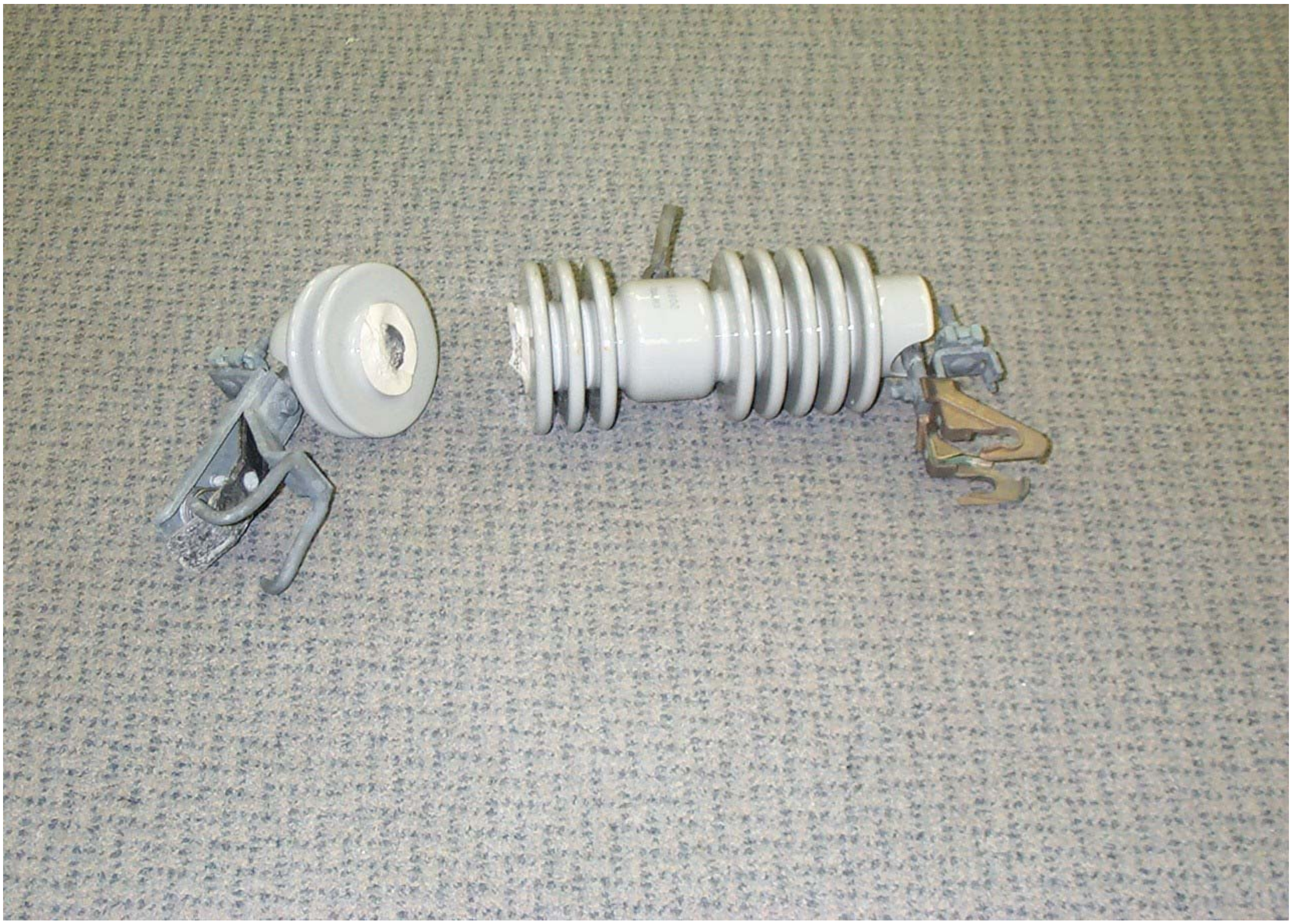
- In the year following the annual inspection remove the defective cutout from service.

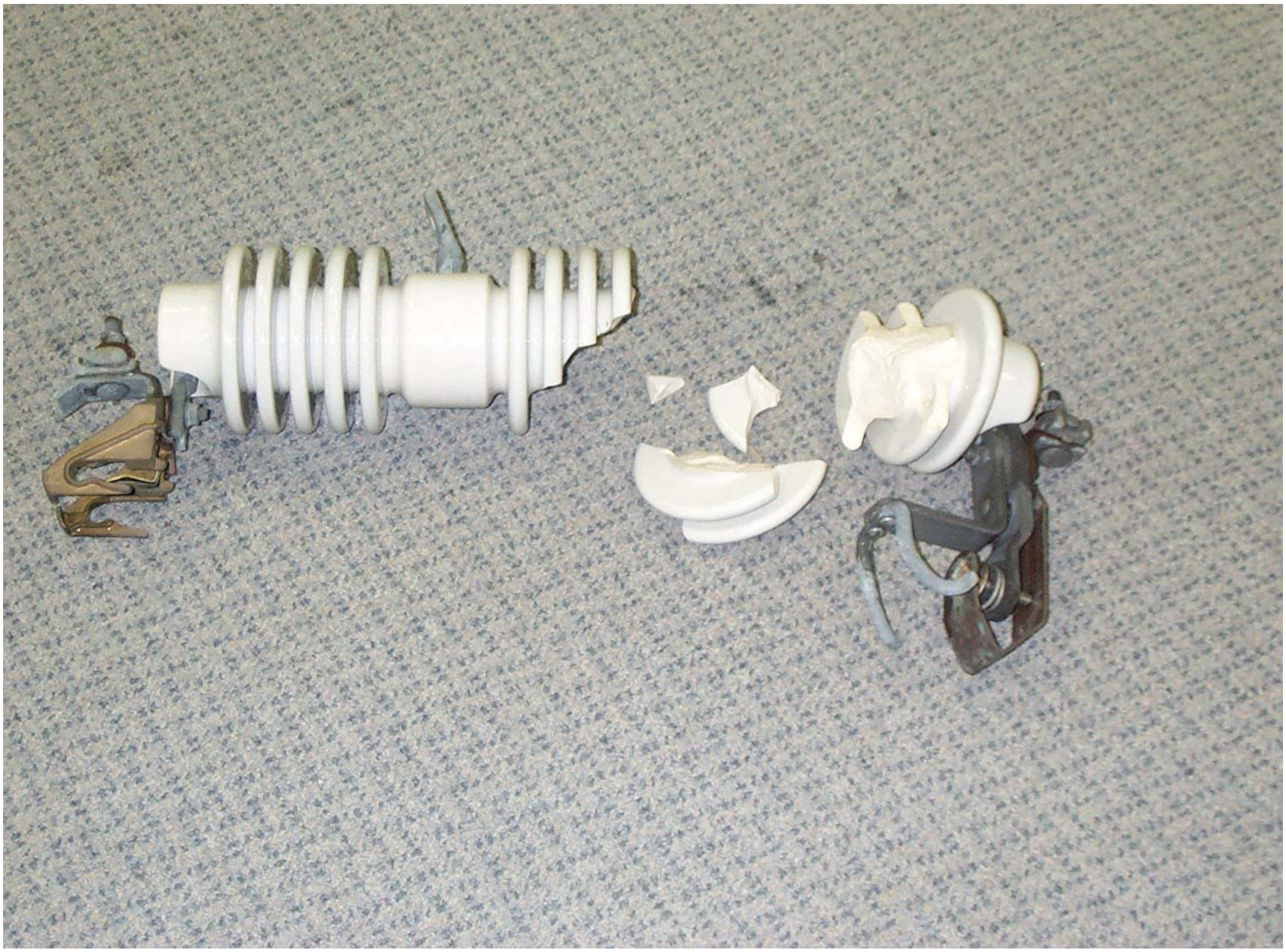
- Monitor future porcelain cutout failures to determine whether additional measures such as an accelerated replacement program is necessary.

APPENDIX A









Underground Distribution System Replacements in the St. John's Area

Newfoundland Power Inc.

June, 2003

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1.0 Introduction

In the early to mid-1970s, several large residential developments in the St. John's metropolitan area were serviced by way of underground distribution systems. These systems were installed using direct-buried underground cables, which have proven to be very unreliable. The direct-buried systems were installed primarily in three areas: Virginia Park in the east end of St. John's, the Newtown (Whitely Drive/Munden Drive) area of Mount Pearl and Elizabeth Park in Paradise. Customers served by these systems have experienced frequent faults and Newfoundland Power has been repairing faults and replacing these services since 1978.

In a report titled "No Splicing Policy and Accelerated Replacement Program in the Virginia Park Underground Distribution System" filed with the Public Utilities Board in September, 1997, the Company recommended an accelerated service replacement program starting in 1998. The Company had followed through on this recommendation and plans to continue for the next few years until such time that all services that have experienced a fault have been replaced. In addition, a five-year replacement program for padmount transformers, which also form part of these systems, will commence. These transformers are nearing the end of their 30-year lives and the number of padmount failures has been increasing. These transformers are filled with oil and failure due to rusting results in costly clean-up efforts and interruptions in service to customers.

This report will describe the problems associated with these underground systems and the programs proposed to address these problems.

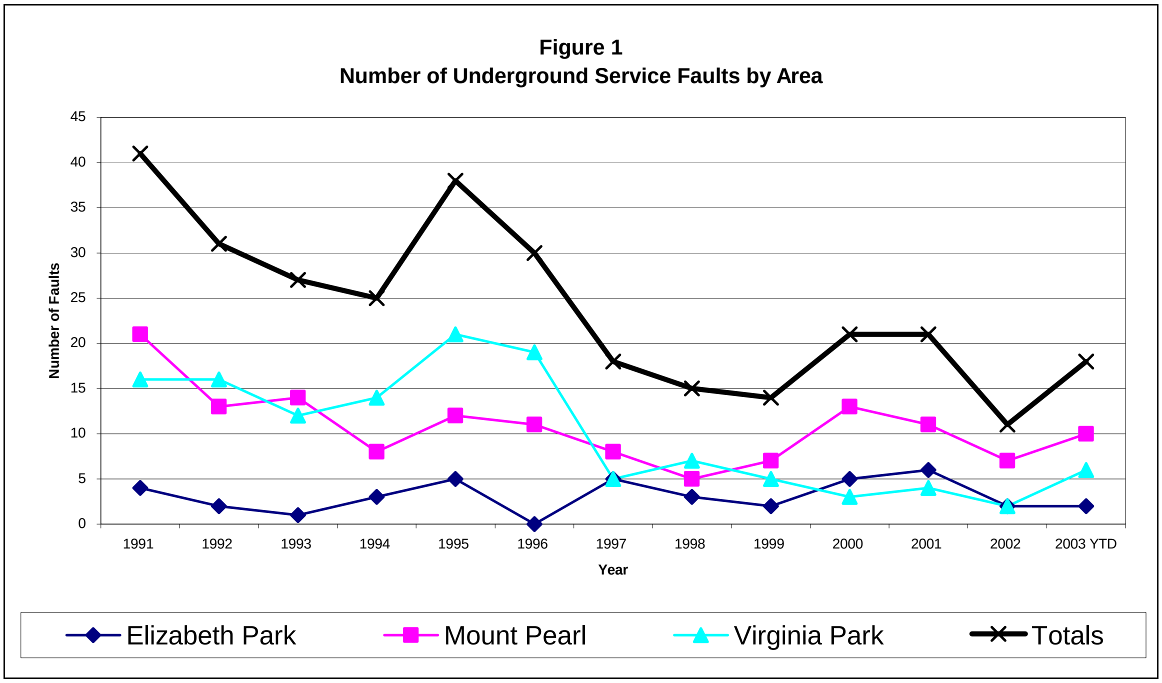
2.0 Underground Service Faults

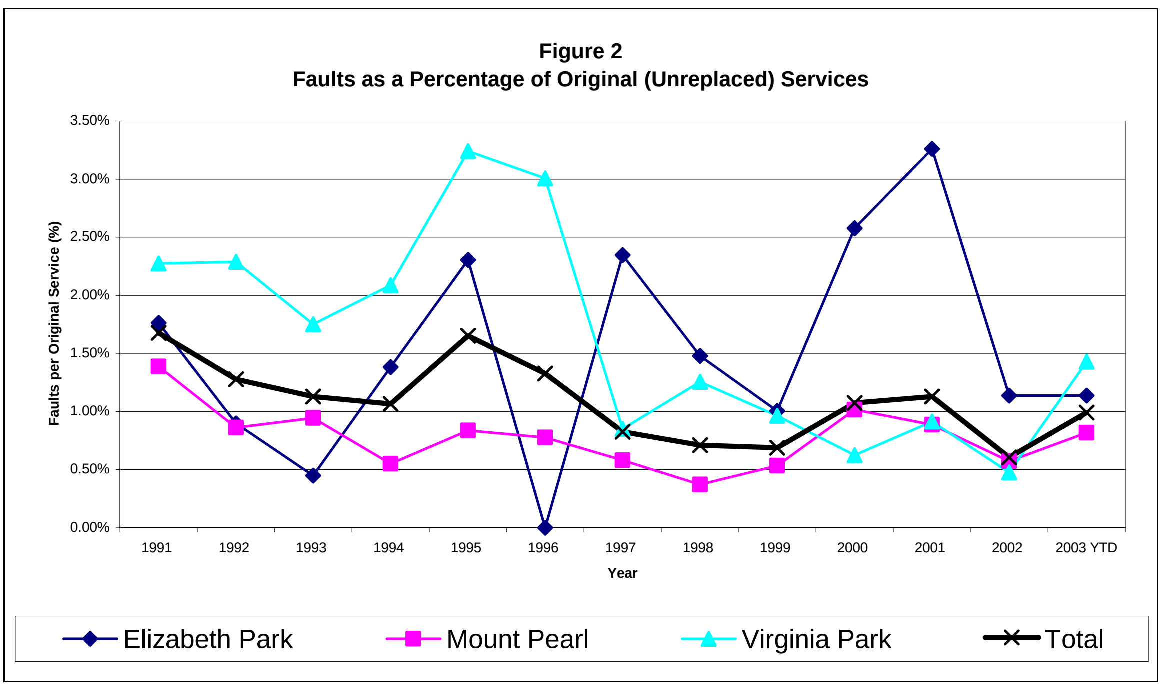
Within a very short time after the initial installations, it became apparent that direct-buried underground distribution systems were not well suited to the climate and geography of Eastern Newfoundland. A breakdown of the original number of underground services installed in each of these areas, the number of faults experienced to date and the number of services replaced are presented in the table below.

Area	Services Installed	Faults to Date	Services Replaced
Elizabeth Park	237	91	61
Mount Pearl	1,571	790	349
Virginia Park	803	521	383
Totals	2,611	1,402	793

Replacing these services requires careful excavation of the existing cable run, installation of new conduit and conductor and restoration of the property with topsoil, sods, asphalt, concrete, and/or paving stones. As many of these faults occur during the winter months when frozen ground conditions do not permit replacement, temporary connections by "daisy-chaining" with an adjacent service is often necessary. Such temporary connections are costly and can present safety concerns due to the potential for mechanical damage to the exposed, at-grade cable. For these and reliability reasons, the preferred alternative is to replace these direct-buried services in a planned manner.

As indicated in Figure 1 below, the numbers of faults appears to be declining. However, Figure 2 illustrates that the number of faults as a percentage of the original installations still in service remains relatively constant.





3.0 Padmount Transformer Failures

The padmount transformers installed in conjunction with the underground distribution systems in Virginia Park, Mount Pearl and Elizabeth Park are nearing the end of their 30-year lives. These transformers are exposed to service conditions that significantly shorten their useful lives including: backfilling around the base of transformers by property owners (see Figure 3), exposure to road salt and mechanical damage from snowplows or other sources.

Figure 1

Oil spills related to these aging padmount transformers have been occurring in recent years and the costs associated with each spill cleanup have been increasing. The table below summarizes the frequency of spills and the costs of cleanup for padmount spills in these areas since 2001.

Description\Year	2001	2002	2003 YTD
Number of Spills	8	6	2
Average Year of Xfmr Installation	1979	1977	1975
Total Cleanup Costs	$8,823	$16,625	$4,280
Average Cost/Spill	$1,103	$2,771	$2,140

The cost presented above includes cleanup costs only and does not include the labour, materials or other costs associated with the padmount transformer replacements. Only incidents in the three underground distribution areas were included in this table. In all approximately 400 padmount transformers are in operation in these areas.

4.0 Proposed Replacement Projects

The underground service replacement program is expected to continue for the next five years. Much of the costs associated with this project are incurred in property restorations following service replacement. A breakdown of the estimated annual and total cost of this program is provided below:

Project Cost ($ x 1,000) – Underground Service Replacement:

Cost Category	2004	2005-2008	Total
Material	42		
Labour – Internal	16		
Labour – Contract	12		
Engineering	-		
Other	-		
Total	**$70**	**$280**	**$350**

Of the 400 padmount transformers in service in these areas, approximately 300 will be replaced over the 5-year life of this program (approximately 60 units per year). A breakdown of the estimated annual and total cost of this program is provided below:

Project Cost ($ x 1,000) – Replace Aging Padmount Transformers:

Cost Category	2004	2005-2008	Total
Material	15		
Labour – Internal	31		
Labour – Contract	2		
Engineering	2		
Other	-		
Total	**$50**	**$200**	**$250**

Note that these costs do not reflect the replacement costs of the padmount transformers themselves. Based on an annual quantity of 60 units, the cost of these transformers would be approximately $240,000 annually and is included in the transformer project.

5.0 Conclusions

A proactive replacement program for direct-buried underground services and padmount transformers will minimize the risk of spills and will be more cost-effective than replacement upon failure due to the associated cleanup costs and emergency repair costs if no action were taken. In addition, replacement of this plant will avoid the safety concerns associated with above ground temporary service fixes and improve reliability by preventing unscheduled outages to customers that occur due to failure of this equipment.

Summary of Recommendations

The following action is recommended with respect to underground services and padmount transformers.

- Continue the program of scheduled underground service replacements for the next five years or until completed.

- Implement a program to replace approximately 60 padmount transformers per year on a scheduled basis for the next five years or until all deteriorated units have been replaced.

Project Title: **Distribution Reliability Initiative**

Location: **Lumsden, Cape Freels (WES-02), Bay Roberts/Port de Grave (BRB-04) and Torbay (PUL-03)**

Classification: **Distribution**

Project Cost: **$949,000**

This project consists of a number of items as noted.

(a) Lumsden/Cape Freels (WES-02)

Cost: $699,000

Description: This project involves the replacement of poles, conductor and hardware on various sections of WES-02. This is a 2-year project at a total cost of $1,099,000, consequently $400,000 will be required for 2005.

Operating Experience: The reliability of this feeder is below the company average. See *"A Review of Reliability Wesleyville-02 Feeder"*, Volume III, Distribution, Appendix 3, Attachment A.

Justification: This project is justified on the basis of reliability improvements.

(b) Bay Roberts/Port de Grave (BRB-04)

Cost: $120,000

Description: This project involves the replacement of poles, conductor and hardware on two sections of BRB-04.

Operating Experience: The reliability of this feeder is below the Company average. See "*A Review of Reliability – Bay Roberts-04 feeder*", Volume III, Distribution, Appendix 3, Attachment B.

Justification: This project is justified on the basis of reliability improvements.

(c) Install New Feeder – PUL-03

Cost: $130,000 – Distribution, $94,000 - Substations

Description: This project involves the construction of a distribution feeder from Pulpit Rock substation in Torbay, along Country Drive and Manning's Hill to Torbay Road.

Operating Experience: The extended length of the Pulpit Rock feeders and high customer growth is a contributing factor to the inferior service reliability in the Torbay, Flatrock and Pouch Cove area.

Justification: An engineering review, *"Pulpit Rock Substation, Loading and Reliability Review"* indicates that this project is the low cost alternative to address growth and reliability issues. (See Volume III, Appendix 3, Distribution, Attachment C).

A Review of Reliability

Wesleyville-02 Feeder

Reliability Review – WES-02 Feeder

1. Executive Summary

In March 2001, the Company completed a review of transmission line related outages affecting various areas of the province that were served by long radial transmission lines. The resulting report "Salt Pond Gas Turbine – Relocation Project" filed with the Public Utilities Board in response to PUB-5.4 – 2002 Capital Budget Application, identified the Bonavista North (Wesleyville) area as an area significantly affected by transmission line outages. The report recommended that the Salt Pond Gas Turbine, which was underutilized at its existing location, be relocated to the Wesleyville area to provide improvements to service reliability. This project will be completed in 2003.

Unscheduled distribution line outages also have an effect on reliability. For the period 1998 to 2002, the five-year average of unscheduled distribution outages for the Wesleyville (WES-02) feeder, which services the areas from Pound Cove/Templeman to Lumsden, was a SAIFI = 3.70 and a SAIDI = 6.31 hours. This feeder has been identified as having some of the worst reliability statistics in the Company.

The purpose of this report is to provide a plan of action to improve reliability of the Wesleyville ("WES-02") feeder. The feeder was examined in sections with a detailed look at outage records, their causes and the components that failed. This was combined with comments from local operations personnel to produce recommended actions to address the problems causing unsatisfactory reliability statistics.

WES-02 feeder originates in Wesleyville Substation in New-Wes-Valley. The feeder has been prone to failure mainly due to the environmental conditions associated with its location and its length (approximately 50 km). It extends along the north east coast of the island in a section known as Bonavista North and is subject to high winds, salt spray, ice loading, and lightning strikes. Significant upgrading is recommended to address those issues.

To improve the performance of this feeder, it is recommended to:

- Relocate / rebuild 10.4 km of three phase line
- Relocate / rebuild 8.5 km of one phase line
- Replace 30 poles / structures
- Address deficiencies identified in the 2003 Feeder Inspection Report

Completing these projects will have a positive effect on the performance of this feeder, resulting in fewer outages to customers and lower operating costs. Due to size of the project and nature of the work, the proposal involves completing the total project over a period of two years.

2.0 Introduction

This report provides a plan to improve the reliability of WES-02 feeder located in Bonavista North. This report compares the reliability statistics of WES-02 with other feeders in the company. Also included is WES-02 information regarding the outage history, the major causes of outages and trouble areas. Recommendations are made to improve WES-02 reliability performance with the most cost effective options considered.

3.0 Distribution Reliability (WES-02 Feeder)

A report titled "2003 Corporate Distribution Reliability Review" identified feeders that consistently exhibited below average reliability. The report reviewed such data as the average annual total number of customer minutes of interruption, System Average Interruption Frequency Index (SAIFI), and the System Average Interruption Duration Index (SAIDI). The report considered whether major work had been completed on the feeder during the past year or if work was scheduled for 2003. This report concluded that WES-02 was amongst the least reliable performers in the Company and should have work completed to improve its performance.

For the period 1998 to 2002, the five-year average unscheduled distribution outage statistics for WES-02 was 287,454 customer minutes, SAIFI was 3.70 and SAIDI was 6.31. The company average per feeder for the same time frame was 116,144 customer minutes, SAIFI was 1.81 and SAIDI was 2.85 hours. During 2002, the outage statistics was 420,678 customer minutes, SAIFI was 8.12 and SAIDI was 9.15 hours.

4.0 Construction Standards and Defective Materials

Design, construction and material standards play a significant role in the reliability of distribution systems. The proposed work on the WES-02 feeder will incorporate the changes that have taken place with respect to standards during the past number of years.

4.1 CP 8080 and 2 piece Insulators

Since the early 1980's, there have been many outages associated with the electrical/mechanical failure of two types of distribution insulators, Canadian Porcelain (CP) 8080 insulators and Pin Cap two piece insulators. Both of these types of insulators had been widely used throughout the company and have been discussed in previous reports. The latest report entitled “Distribution Insulator Replacement Program” completed in June of 2003 recommends these types of insulators be replaced on a go forward basis over the next 5 years.

4.2 Heavy Loading vs. Normal Construction

For areas that are subject to above normal loading conditions, heavy loading design standards should be used. The heavy loading standards adds increased strength to the pole hardware to combat problems associated with additional ice and wind loading on the conductor. Additionally, the increased voltage rating of the insulators decreases the risk of an outage due to salt spray flashover. Normal construction involves using Pin Type insulators and “Tie Wire” to secure the conductor to the insulator. In wind storms tie wires have been known to break or become “untied”. Heavy loading construction utilizes line post insulators and clamps to secure the conductor. Appendices A and B show the difference in the two types of construction.

4.3 Porcelain Cutouts

A report entitled “Porcelain Cutout Replacement” reviews the problems associated with this type of fuse holder. The report recommends the adoption of an inspection and replacement program to manage this problem. Should the cutout break while being manually operated, the lineperson is placed in a dangerous and unsafe position.

4.4 Lightning Arrestors

Lighting arrestors are placed on transformer to protect the equipment from failures due to a lighting strike. A report entitled “A Study into the Feasibility of Installing Surge Arrestors on Newfoundland Power Distribution System” recommended that all transformers on WES-02 be equipped with lightning arrestors.

5.0 WES-02 Feeder

Located in the Gander operating area of the Western Region, WES-02 feeder is a 12.5 kV line that originates at the Wesleyville substation located in New-Wes-

Valley and serves approximately 766 customers. The three phase portion of this line extends from Pound Cove / Templeman to Lumsden with a three phase tap to Newtown. Single-phase taps serve the communities of Cape Freels and Deadman's Bay.

This line was originally constructed over a two-year period:

Wesleyville Substation --- 1963
Newtown branch to Lumsden, Cape Freels and Deadman's Bay --------- 1964

The three phase section from Wesleyville Substation to Newtown branch has 4/0 AASC phase conductor with a 1/0 AASC neutral conductor. Newtown tap is 3 phase all 1/0 AASC. The 3-phase section from Newtown branch to Lumsden is 4/0 AASC center phase with 1/0 AASC side phases and neutral. The single-phase tap to Cape Freels was reconductored with 1/0 AASC in 1987. The single-phase tap to Deadman's Bay was reconductored with 4/0 AASC phase conductor and 1/0 AASC neutral in 1983.

This entire feeder is in an exposed area and is subject to salt contamination, very high winds, ice loading and lightning strikes. Sections of this line follow an old abandoned road and are not easily accessible.

A Distribution Feeder Inspection was completed on the feeder in early 2003. The inspection revealed a number of items to be addressed with the feeder. These include:

- The existence of two piece insulators, CP 8080 deadend insulators and porcelain cutouts.
- The requirement of lightning arrestors
- Grounding and guying issues. These include the use of design standards that have changed since the feeder was built along with items such as rusty or broken guys.
- The existence of deteriorated crossarms. These involve cracks developing in crossarms, rotting arms, woodpecker holes, etc.

6. Outage History for WES-02

The WES-02 feeder has a significant history of outages. The feeder is located 100 km from the Gander Service Centre. Sections of the highway in these areas are subject to heavy drifting, sometimes making the roads impassable for long periods of time, which has increased the outage durations.

A Newfoundland Power District Crew is located in the Town of New-West-Valley. This two-person crew usually completes emergency work on this feeder. In times of multiple or major problems, additional personnel and materials are sent from Gander. After regular hours during the winter months, one of the two-person district crew is normally on 24-hour Standby while in summer months, the Wesleyville and Glovertown district crews cover each other's areas on alternate weeks.

Sections of the main trunk of the feeder are located up to 450 meters off the road right-of-way (ROW), making damage difficult to find and repair during winter storms. A section of the single-phase distribution line that services Deadman's Cove is located along the old road, which is up to 650 meters from the existing road. Most of these sections must be accessed by ATVs in the summer months. All sections located along the old road must be accessed by snowmobile during the winter months.

Extreme weather plays a major role in the power outages to customers in this area. In the last 5 years, 1998 to 2002, 69% of all customer minute outages were directly related to sleet, wind, lightning and salt spray. Other problems such as service connection failure can be attributed to the effects of severe weather conditions on equipment over a prolonged period of time.

A winter storm on December 27, 2002 resulted in major outages in the area. Crews were dispatched from Gander, Grand Falls and St. Johns. Repair costs for the one-day storm were approximately $45,000.

6.1 WES-02 Feeder by Component that Failed

The chart below shows a listing of the 138 problem calls received for the period from 1998 to 2002. The listing is sorted by the "Component that Failed". In some occurrences, such as in sleet and wind storms, there are no components that failed permanently. The fuses and reclosers that operate under these conditions were operating properly. Typical of such circumstances would be wires coming too close due to wind gusts and 'flashing over' and similar occurrences where insulators flash over due to momentary salt spray without failing.

1998 - 2002

Component that Failed	Number of Outages	Customer Minutes
Conductor	5	140,642
Conductor Hardware	4	212,975
Regulators	1	14,817
Fuses[1]	59	102,788
Insulators	17	729,194
Other	4	70,780
Control Equipment at Sub[2]	5	86,165
Reclosers	2	19,490
Pole Hardware	2	5,000
Transformers	13	10,869
Service Wires	17	672
Cutout / Switch	8	43,877
Total	138	1,437,269

1 Fuses operated as a result of sleet, wind, and lightning.
2 Includes operations for Salt Spray.

6.2 WES-02 Feeder by Cause

The chart below also notes the 138 problem calls received for the period from 1998 to 2002. The chart sorts the problem calls by "Cause".

1998 - 2002

Cause	Number of Outages	Customer Minutes
Salt Spray[1]	5	96,428
Wind	17	365,278
Lightning	9	3,850
Sleet	5	632,694
Broken/Defective Equip.	75	291,221
Damage Outside Party	4	1,507
Unexplained	6	53,116
Other	8	19,442
Overloaded Equipment	1	559
Animals	5	629
Fire	1	72,485
Improperly Installed Equip	1	60
Total	138	1,437,269

1 Although only five outages were reported as salt spray, most of the outages reported as wind involved salt contamination also.

Broken and Defective equipment include items such as insulators, conductor and hardware.

7.0 Recommendations

Based on all the information gathered regarding WES-02, each feeder section was reviewed for location characteristics (i.e. exposed to extreme salt spray conditions, ice loading etc.). Each section of the feeder was then analyzed to see if specific causes of outages could be determined and appropriate solutions recommended.

7.1 All Sections of WES-02 Feeder

The following are recommendations that apply to each section of WES-02:

1. The whole feeder is exposed to extreme salt contamination. The following should be adopted as a minimum standard for this feeder.
   - Long bushing transformers
   - 34 kV clamp top insulators
   - Standoff brackets for all cutouts

2. Replace all 8080 and 2-piece insulators.

3. Installation of lightning arrestors on all transformers.

4. Review vertical to horizontal conductor phase spacing and correct any violations by installing mid-span poles.

5. Where extreme ice loading occurs, design new lines using heavy loading design standards.

6. Correct all deficiencies identified in the 2003 Distribution Inspection Report.

7.2 Newtown to Cape Freels (8 km)

This section of the main feeder trunk is located away from the road by much as 450 meters. It is located in a very open area, exposed to heavy wind and salt spray. It is recommended that the line be relocated to the road R-O-W. The new line should be built to heavy loading design standards. See Appendix C for a map showing this section. The cost of this work is estimated at $464,000.

Rebuilding the line to heavy loading design standards in the existing R-O-W would not improve the access to the line. Further, to rebuild in the existing R-O-W would require outages to customers, portable generation and or work using “Hot Line” methods. This would make the cost of the rebuild comparable to the cost to relocating it to the Road R-O-W.

7.3 Cape Freels to Lumsden (2.4 km)

This section of the main feeder trunk is located along the road. Most of the section is located along the wooded area in Windmill Brook. This area is exposed to heavy wind and salt spray. It is recommended that structures built to heavy loading design standards be installed together with reconductoring the existing side phases from 1/0 AASC to 4/0 AASC. By replacing the side phases, the potential for contact between conductors is minimized. See Appendix D for a map of the area involved. The estimated cost of this upgrading work is $117,000.

Since this is a radial feeder, using portable generation best facilitates rebuilding this section of the feeder with minimal interruption to customers. There are no alternative solutions for this section of the feeder.

7.4 Lumsden to Deadman's Cove

This single-phase section of the feeder can be broken down to three smaller subsections: one that can be relocated to poles owned by Fortis Inc.; another that should be relocated to the edge of road R-O-W. and the last section should be rebuilt in its current location.

Since this is a radial feeder, using portable generation facilitates rebuilding this section of the feeder.

7.4.1 Relocate 2.6 km to existing Fortis poles

Fortis currently owns a pole line along this subsection of the road. Newfoundland Power's existing line is located along the old road, and is inaccessible during the winter. It is recommended that a new line be built, attaching to the existing Fortis poles using heavy loading design standards and retire the existing line. Under the pole agreement, Newfoundland Power would purchase these poles from Fortis. See Appendix E for a map of the area involved. The cost of this work is estimated at $116,000.

Rebuilding the line to heavy loading design standards in the existing location would not improve the access to the line. To rebuild the existing line would require outages to customers, portable generation and/or work using "Hot Line" methods. This would make the cost of the rebuild comparable to the cost to relocate.

7.4.2 Relocate 2.4 km to the existing road

This subsection of line crosses very open areas and is subject to extreme salt spray and wind. The different components of this subsection are built away from the existing road and are difficult to work on. It is recommended that all components of this subsection that are located away from the road be relocated to the road ROW. All new structures would be built to heavy loading design standards using 4/0 primary conductor. See Appendix E for a map of the area involved. The estimated cost of this work is $97,000.

Rebuilding the line to heavy loading construction in the existing location would not improve the access to the line. The cost of the rebuild in the existing location is comparable to the cost to relocate.

7.4.3 Rebuild 3.5 km along the existing road

This subsection of line crosses very open areas and is subject to extreme salt spray and wind. The components of this subsection are built in the existing road ROW. It is recommended that all components of this subsection that are presently built in the road ROW be upgraded using heavy loading design standards. See Appendix E for a map of the area involved. The estimated cost of this work is $104,000.

There are no alternative solutions for this subsection of the feeder.

7.5 Rebuild 30 poles/structures Templeman /Pound Cove Area

This section of line crosses very open areas and is subject to extreme salt spray and wind. The 30 poles and structures in the Templeman / Pound Cove area have been identified as having problems such as deteriorated poles, deteriorated crossarms, etc. It is recommended that the 30 new structures be built to heavy loading design standards using the existing 4/0 primary conductor. Work on this section would be completed using hot line methods. The estimated cost of this work is $82,000.

8. Conclusion

All of WES-02 feeder should be rated as requiring the heavy loading design standard. Extreme weather conditions result in major outages to customers supplied via this feeder. To address these circumstances, all future work should adopt the following installation standards:

- Extra creepage bushing transformers
- 34 kV clamp top insulators, or insulators with equivalent insulation levels
- Standoff brackets on cutouts
- Replace all CP 8080 and Two-Piece Insulators
- Review conductor spacing between vertical and horizontal transition poles to identify and correct any problem areas
- Review pole span lengths and install mid-span poles if necessary
- Design and build new lines for heavy loading construction

Deficiencies noted in the 2003 Distribution Feeder Inspection Report should be corrected. These are known problems that could result in unscheduled outages or unsafe conditions to our customers and employees if not corrected. The cost for correcting the deficiencies in the 2003 Distribution Feeder Inspection Report is estimated to be $119,000.

The relocation of major sections of the trunk feeder along with the rebuilding of known problem areas using heavy loading design standards will result in a reduction in the number and duration of outages to customers along this feeder. This project should utilize portable generation to be located in Lumsden and Deadman's Cove to minimize the impact to customers. The estimated total cost to complete the work indicated in sections 7.2, 7.3, 7.4 and 7.5 is $980,000.

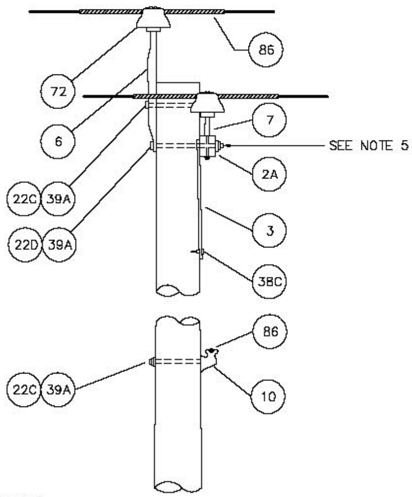
Overall, the $1,099,000 investment to improve areas of the feeder with known problems will result in an improved reliability for the customers. Due to the size of the project and nature of the work, it is proposed to complete all the work over a two-year period.

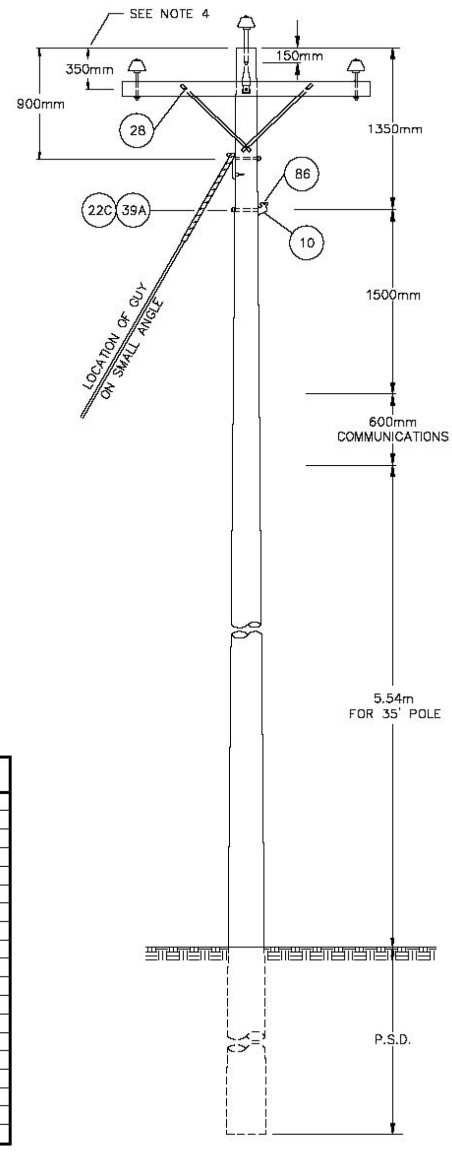
- 2004 – complete work in sections 7.2, 7.4.1 and address deficiencies as per the 2003 Distribution Feeder Inspection. $699,000

- 2005 – complete work in sections 7.3, 7.4.2, 7.4.3 and 7.5 - $400,000

Improved materials and design standards that meet the local environment conditions will improve the performance of this feeder.

Appendix A
Standard Construction





NOTES:

1. STRUCTURE TYPE "3A" IS A THREE PHASE TANGENT STRUCTURE. FOR SHORT SPAN CONSTRUCTION.
2. FOR SECONDARY DETAILS SEE SECTION 10-5.
3. FRAMING DIMENSIONS:
   (a) SHOWN FOR JOINT USE ON SHORT SPAN CONSTRUCTION.
   (b) SUITABLE FOR 12.5 kV & 25 kV CONSTRUCTION.
4. THIS SPACING SHALL BE INCREASED TO 600mm IF STRUCTURE IS ADJACENT TO A "3C" OR "3E" STRUCTURE.
5. THE NUT SHALL BE PLACED ON THE CROSSARM SIDE TO FACILITATE REPLACEMENT OF THE CROSSARM OR POLETOP PIN.

ITEM NO.	QUAN.	DESCRIPTION
1	1	POLE – TREATED, CLASS THREE OR FOUR
2A	1	CROSSARM – 2 PIN, 95mm x 120mm x 2100mm
3	2	BRACE – FLAT, 30"
6A	1	PIN – POLE TOP, 1" THD., 24" LONG
6B		PIN – POLE TOP, 1 3/8" THD., 24" LONG
7A	2	PIN – CROSSARM, 1" THD., 6" TOP
7B		PIN – CROSSARM, 1 3/8" THD., 8" TOP
10	1	BRACKET – NEUTRAL WIRE
22C	2	BOLT – MACHINE, 5/8" x 12"
22D	1	BOLT – MACHINE, 5/8" x 14" LONG
28	2	BOLT – CARRIAGE, 3/8" x 4 1/2" LONG
38C	1	SCREW – LAG, 1/2" x 4"
39A	3	WASHER – SQUARE, 2 1/4", 11/16" HOLE
72A	3	INSULATOR – PIN TYPE, 12.5kV
72D		INSULATOR – PIN TYPE, 25kV
86	3	GUARD – PREFORMED LINE (PRIMARY)
	1	GUARD – PREFORMED LINE (NEUTRAL)

REGISTERED PROFESSIONAL ENGINEER
G. Richard Spurrell
PROVINCE OF NEWFOUNDLAND

SIGNATURE

DATE

DISTRIBUTION STANDARDS

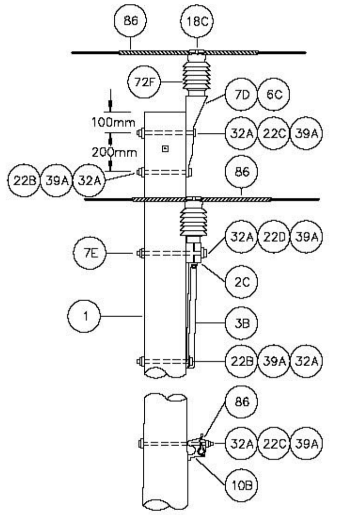
NEWFOUNDLAND POWER
A FORTIS COMPANY

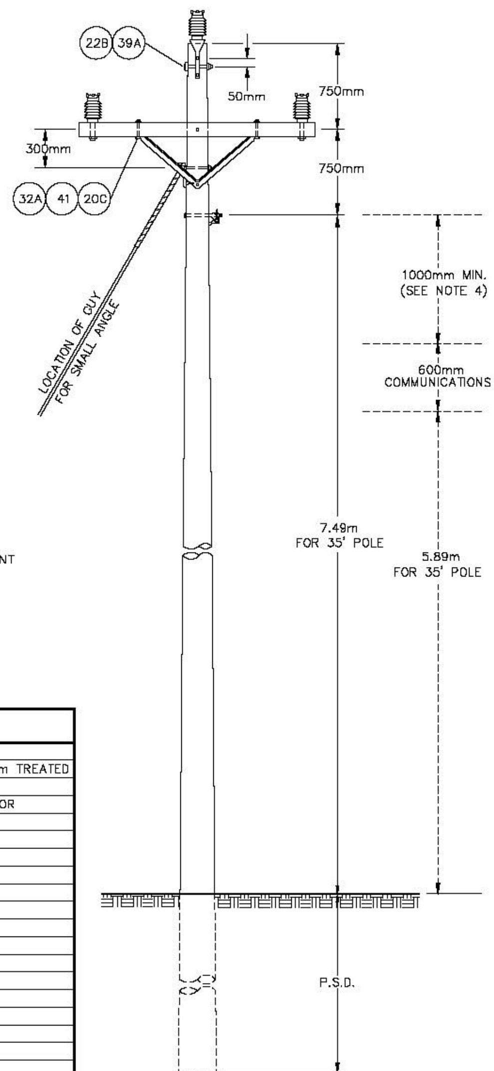
PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
Class "B"
This Permit Allows
NEWFOUNDLAND LIGHT & POWER CO. LIMITED
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by APEGN K0059 which is valid for the year 1998

**12.5 & 25kV
STRUCTURE TYPE "3A"
0°- 5° ANGLE**

Date:	98-10-30	Drawn:	K.L.S.
App:		STD No.	**11-20**

Appendix B
Heavy Loading Construction





NOTES:

1. STRUCTURE TYPE "3AS" IS A STANDARD THREE PHASE TANGENT STRUCTURE FOR HEAVY LOADING AREAS.
2. INSTALL STUD IN THE INSULATOR WITH LOCKWASHER BEFORE INSTALLING IN ARM OR BRACKET.
3. REFER TO SECTION 3 FOR MAXIMUM SPAN LENGTH.
4. REFER TO SECTION 4.10.3 OF THE C.S.A. STANDARD C22.3 (SECTION 2-5) FOR JOINT USE CLEARANCES.

ITEM NO.	QUAN. 25KV	DESCRIPTION
1	1	POLE – TREATED, CLASS THREE OR FOUR
2C	1	CROSSARM – SPECIAL, 105mm x130mm x2100mm TREATED
3B	1	BRACE – ANGLE V, CROSSARM, 48"
6C	1	BRACKET – POLE TOP, 35kV LINE POST INSULATOR
7D	1	STUD – LINE POST INSULATOR, 3/4" x 1 3/4"
7E	2	STUD – LINE POST INSULATOR, 3/4" x 7 1/2"
10B	1	CLAMP – NEUTRAL WIRE
18C	3	CLAMP – INSULATOR
20C	2	BOLT – MACHINE, 1/2" x 6"
22B	3	BOLT – MACHINE, 5/8" x 10"
22C	2	BOLT – MACHINE, 5/8" x 12"
22D	1	BOLT – MACHINE, 5/8" x 14"
32A	5	NUT – LOCK, 5/8"
32B	2	PALNUT – 1/2"
39A	8	WASHER – SQUARE, 2 1/4", 11/16"
41	2	WASHER – ROUND, 1 3/8" x 9/16" HOLE
72F	3	INSULATOR – LINE POST CLAMP TOP, 35kV
86	3	GUARD – PREFORMED LINE (PRIMARY)
86	1	GUARD – PREFORMED LINE (NEUTRAL)

SIGNATURE

DATE

DISTRIBUTION STANDARDS

NEWFOUNDLAND POWER
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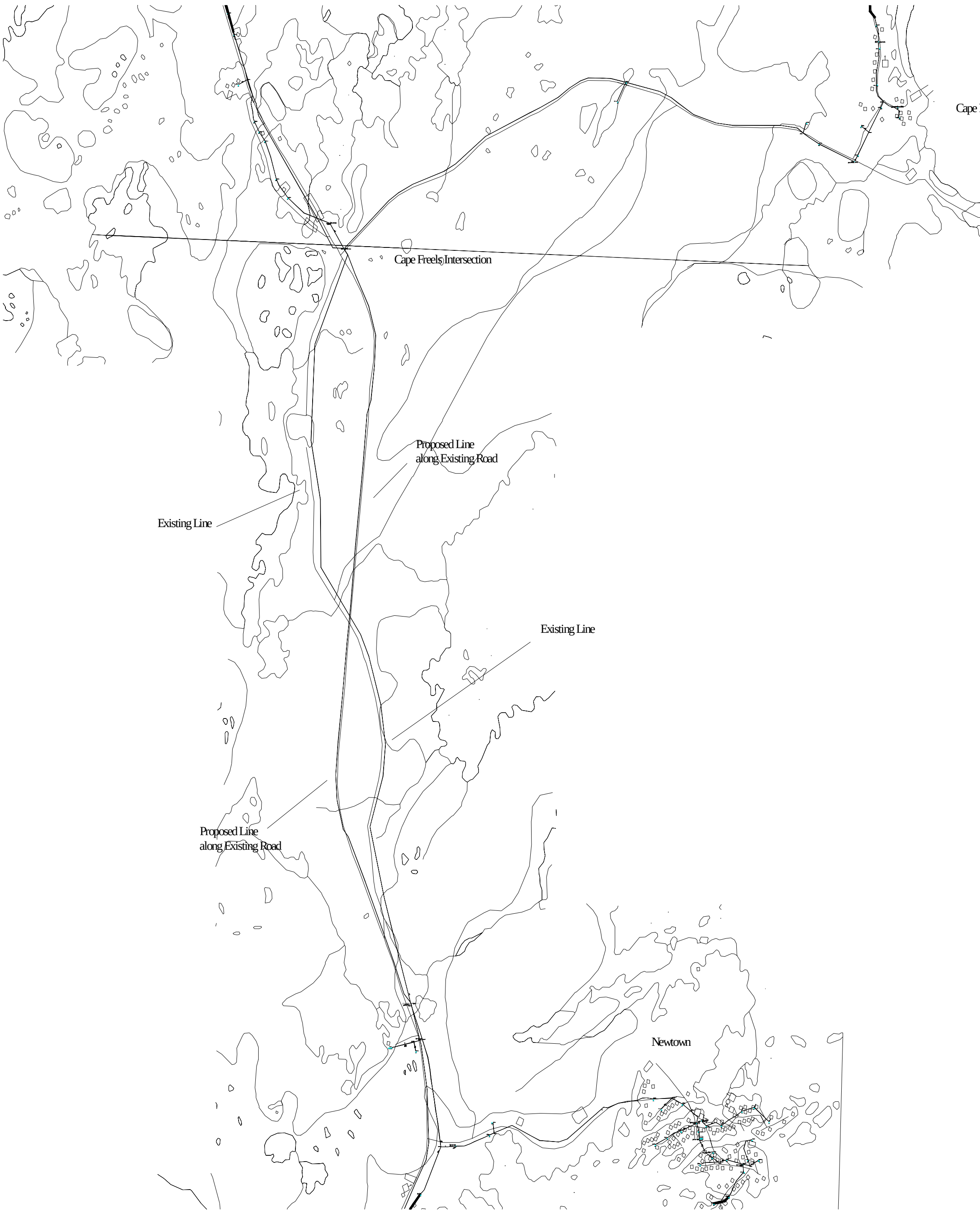
PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
This Permit Allows
NEWFOUNDLAND POWER INC.
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by APEGN F0032 which is valid for the year 1999

12.5 & 25kV
STRUCTURE TYPE "3AH"
0° - 3° ANGLE (HEAVY LOADING)

Date: 99-12-30		Drawn: K.L.S.
App:		STD No. **11-45**

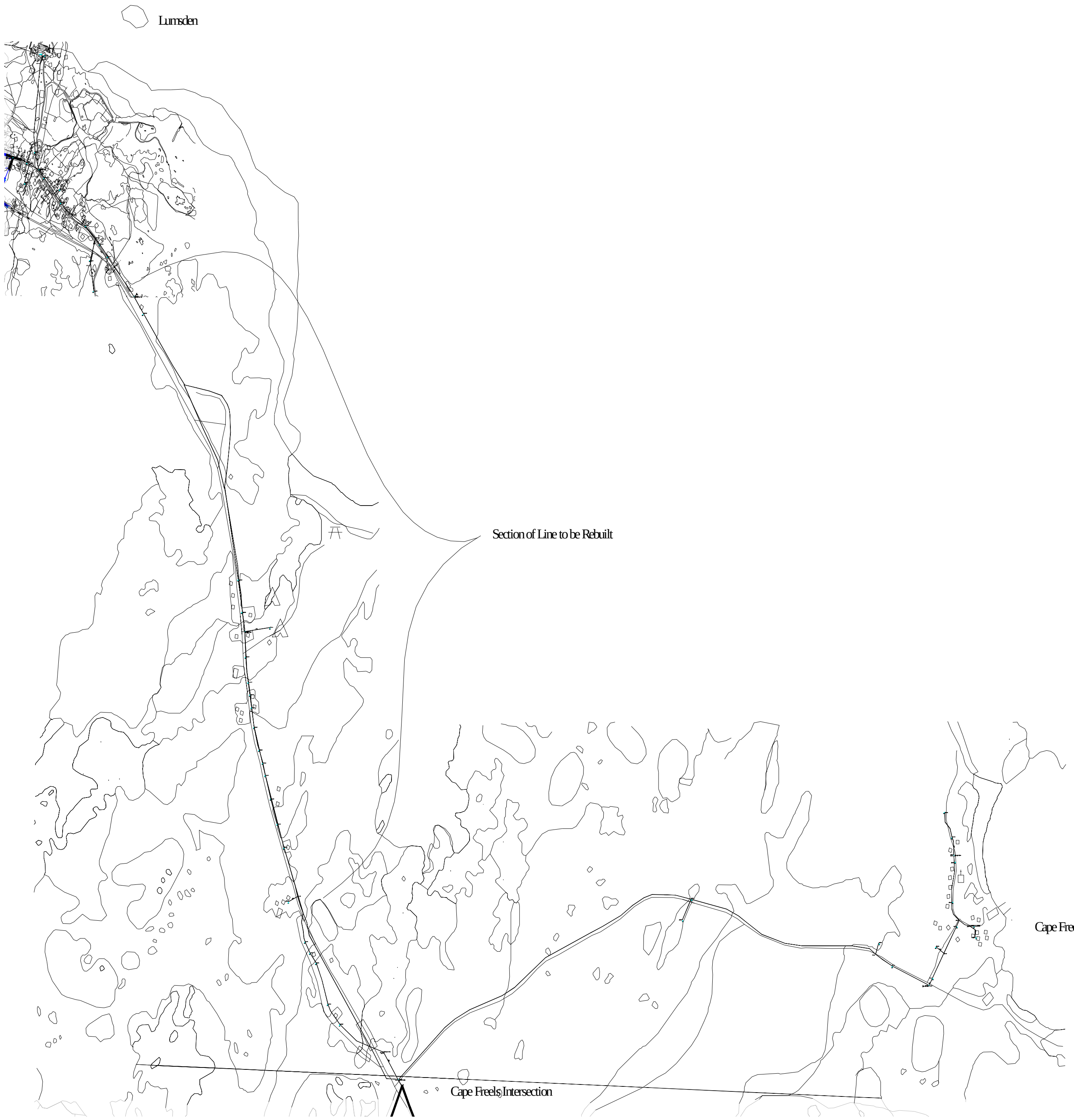
Appendix C

Section of Line
Newtown to Cape Freels



Appendix D

Section of Line
Cape Freels to Lumsden



Appendix E

Section of Line
Lumsden to Deadman's Cove

A Review of Reliability
Bay Roberts-04 Feeder

June, 2003

Table of Contents

Page

1.0 Introduction

Bay Roberts substation is located in the Conception Bay North town of Bay Roberts. This substation serves 3465 customers through 5 feeders. All five Bay Roberts feeders operate at a voltage of 12.5 kV.

The Bay Roberts-04 feeder begins at the Bay Roberts substation and serves the southern portion of the Town of Bay Roberts (in the Country Road area). It extends along Bareneed Road through Port de Grave, terminating in Hibb's Cove. The feeder services four fish plants, one of which is a very active plant in Port de Grave.

BRB-04 is a relatively long feeder at 28.6 km that is exposed to severe weather along two relatively short sections, known as "The Beach" and "Happy Jack's Hill". The average age of structures, conductor and hardware on this feeder is 26 years.

This report proposes a plan to improve the reliability of Bay Roberts-04 feeder (BRB-04). Reliability statistics for this feeder are presented and compared with those of other Newfoundland Power feeders. Initiatives for improving the reliability of this feeder are proposed and an action plan is recommended.

2.0 Distribution Reliability (BRB-04 Feeder)

A report titled *"2003 Corporate Distribution Reliability Review"* (the "Report"), indicates the reliability of each Newfoundland Power feeder. The reliability indices used are average annual customer-minutes of outage, System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI). The reliability indices shown in Report are based only on unplanned distribution related outages. The Report identifies feeders that had poor distribution reliability over the 5-year period from 1998-2002 and ranks the 25 worst feeders according each of these measures. Feeders that have had substantial upgrading over the 5-year period were excluded from the rankings. A listing of the rankings is provided in Appendix A.

The Report shows that customers served by BRB-04 feeder experienced an average annual SAIDI of 5.51 hours. This was nearly double the company average of 2.85 hours over the same period. BRB-04 ranked 19th in the list of worst feeders by SAIDI. The total customer minutes of outage experienced by BRB-04 customers was 327,000, almost triple the Company average of 116,000 customer minutes, and was the 17th worst performer amongst NP feeders using this measure. SAIFI for BRB-04 over this period was 1.52 interruptions/year, which is below the Company average of 1.81.

The commentary in the Report draws the following conclusions regarding this feeder:

April 99 storm resulted in 1,166,220 customer minutes of outage, representing 71% of the average for the past five years. Outages during 2002 brought attention to two sections of the feeder that have experienced problems in the past and need to be upgraded. Upgrading these sections of the feeder are required and while being completed defective insulators and some conductor sags problems will be addressed.

The following table lists by 'component that failed' the number of outages and customer minutes of outage on BRB-04 over a five-year period.

BRB – Outages by Component that Failed
1998 – 2002

Component that Failed	Number of Outages	Customer Minutes
Conductor	13	91,445
Conductor Hardware	3	323
Customer Equipment	1	10
Fuses	29	17,490
Insulators	5	204,061
Other	6	2,980
Pole	2	1,195,213
Pole Hardware	1	25
Transformers	21	120,899
Service Wires	45	2,006
Cutout / Switch	3	549
Total	129	1,635,001

In 1999, two outages caused by the failure of a number of poles along "The Beach" due to sleet can be seen to have caused a significant percentage (73%) of the total customer minutes of unscheduled distribution outages. However, a significant number of outages were also caused by conductor, insulator and transformer failures.

In 2002, customers on BRB-04 experienced 268,456 customer minutes of unscheduled distribution outages. This resulted in a SAIDI of 4.42 hours and a SAIFI of 3.13 interruptions. The following table lists by 'component that failed' the number of outages and customer minutes of outage on BRB-04 in 2002.

BRB – Outages by Component that Failed
2002

Component that Failed	Number of Outages	Customer Minutes
Conductor	4	17,769
Conductor Hardware	0	0
Customer Equipment	0	0
Fuses	8	8,830
Insulators	2	127,261
Other	0	0
Pole	0	0
Pole Hardware	1	25
Transformers	8	113,943
Service Wires	10	358
Cutout / Switch	1	270
Total	34	268,456

3.0 Proposed Upgrade

A review of this feeder has identified two specific areas of concern. "The Beach" and "Happy Jack's Hill". During the period 1998 – 2002, 66% of the outages affecting 50 or more customers occurred on these two sections of line. These incidents account for approximately 90% of all customer minutes of outages experienced during this period. Initiatives are proposed to address the two specific short sections of concern and the general performance of the feeder.

The two specific sections, "The Beach" (approximately 1 km long) and "Happy Jack's Hill" (approximately 1.5 km long), are to be addressed through relocating and rebuilding the line in these exposed and inaccessible areas to a higher design standard, and includes the relocation and rebuilding of approximately 25 spans of 3-phase line and re-sagging the conductor.

The general performance of the feeder from the table above indicates failures of conductor, insulators and transformers. These issues will be addressed through the replacement of all two piece and CP 8080 insulators, PCB transformer phase-out, replacement of faulty cut-outs and removal of automatic sleeves.

Upgrading these short sections will enhance reliability on the feeder as a whole at a relatively low cost. The cost of the proposed upgrade totals $120,000.

4.0 Conclusions

The proposed reliability upgrade at Bay Roberts-04 feeder represents an opportunity to substantially improve the reliability of the poorly performing feeder by upgrading two sections and replacing substandard items on the remainder of the line. It is recommended that this project be included in the Company's 2004 capital program.

APPENDIX "A"

Results of Ranking Feeders by Customer Minutes of Outage, SAIDI and SAIFI

Five Year Unscheduled Distribution Related Outages
1998-2002

Sorted by Customer Minutes pf Interruption

Feeder	Annual Customer Interruptions (Cust Int per year)	Annual Customer Minutes of Interruption (Cust Min per year)	RANK Customer Minutes	Annual SAIFI (int per year per cust)	RANK SAIFI	Annual SAIDI (hours per year per cust)	RANK SAIDI
BOT1	6,084	687,411	1	3.87	11	7.29	7
BCV2	5,632	618,516	2	3.57	14	6.41	9
PEP1	4,428	494,182	3	3.20	19	5.86	15
CHA2	3,720	480,828	4	2.16	41	4.67	30
BRB2	838	473,643	5	1.16	140	8.26	4
KEL2	2,339	471,024	6	1.61	90	5.40	20
PUL1	3,481	444,325	7	1.77	71	3.79	43
PUL2	3,982	433,719	8	2.75	27	5.00	22
LEW2	5,023	428,093	9	3.35	17	4.74	27
SUM1	2,284	416,074	10	1.60	92	4.85	25
HWD7	5,967	404,861	11	3.64	13	4.12	36
SCV1	3,268	374,822	12	2.29	37	4.49	32
LAU1	1,099	364,919	13	1.55	97	8.63	3
LET1	4,633	364,142	14	2.59	32	3.42	52
CHA1	2,107	363,382	15	0.74	214	2.13	110
DLK3	4,506	359,104	16	4.40	6	5.97	13
RRD9	2,104	333,728	17	1.96	54	5.28	21
GBY2	2,958	327,201	18	3.36	16	6.18	11
BRB4	1,518	327,000	19	1.52	103	5.51	17
HOL2	523	323,027	20	1.11	151	10.89	2
SMV1	3,148	304,478	21	3.04	21	4.95	23
WES2	2,813	287,454	22	3.70	12	6.31	10
GOU3	2,708	270,095	23	1.83	64	3.05	66
GFS6	4,792	264,187	24	3.03	22	2.77	84
SUM2	2,201	258,673	25	2.83	25	5.51	18
Company Average		116,144		1.81		2.85	

Five Year Unscheduled Distribution Related Outages
1998-2002

Sorted by SAIFI

Feeder	Annual Customer Interruptions (Cust Int per year)	Annual Customer Minutes of Interruption (Cust Min per year)	RANK Customer Minutes	Annual SAIFI (int per year per cust)	RANK SAIFI	Annual SAIDI (hours per year per cust)	RANK SAIDI
STX1	5,442	153,288	59	5.87	1	2.72	85
STG2	2,305	104,835	90	5.10	2	3.87	42
STG1	1,413	55,774	140	4.69	3	3.07	64
LGL2	3,303	255,771	26	4.67	4	6.04	12
BHD1	5,051	120,673	81	4.60	5	1.96	120
DLK3	4,506	359,104	16	4.40	6	5.97	13
HUM9	1,854	102,515	93	4.30	7	3.97	40
LGL1	2,149	182,189	46	4.29	8	5.74	16
ABC1	2,949	128,408	74	4.14	9	2.97	74
GBS2	1,764	78,456	111	4.07	10	3.11	62
BOT1	6,084	687,411	1	3.87	11	7.29	7
WES2	2,813	287,454	22	3.70	12	6.31	10
HWD7	5,967	404,861	11	3.64	13	4.12	36
BCV2	5,632	618,516	2	3.57	14	6.41	9
DLK1	3,074	61,541	129	3.40	15	1.11	175
GBY2	2,958	327,201	18	3.36	16	6.18	11
LEW2	5,023	428,093	9	3.35	17	4.74	27
CAB1	3,198	235,469	30	3.27	18	4.05	39
PEP1	4,428	494,182	3	3.20	19	5.86	15
GRH3	2,493	148,278	63	3.07	20	3.05	65
SMV1	3,148	304,478	21	3.04	21	4.95	23
GFS6	4,792	264,187	24	3.03	22	2.77	84
TRP1	2,092	116,311	85	3.00	23	2.84	81
GBS1	1,798	93,875	98	2.93	24	2.69	87
SUM2	2,201	258,673	25	2.83	25	5.51	18
Company Average		116,144		1.81		2.85	

Five Year Unscheduled Distribution Related Outages
1998-2002

Sorted by SAIDI

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	RANK Customer Minutes	Annual SAIFI	RANK SAIFI	Annual SAIDI	RANK SAIDI
	(Cust Int per year)	(Cust Min per year)		(int per year per cust)		(hours per year per cust)	
TRP2	16	9,688	235	2.64	31	32.64	1
HOL2	523	323,027	20	1.11	151	10.89	2
LAU1	1,099	364,919	13	1.55	97	8.63	3
BRB2	838	473,643	5	1.16	140	8.26	4
WES1	934	185,031	44	2.36	36	7.78	5
WES3	725	233,015	31	1.38	114	7.43	6
BOT1	6,084	687,411	1	3.87	11	7.29	7
QTZ1	0	1,298	272	0.13	281	7.21	8
BCV2	5,632	618,516	2	3.57	14	6.41	9
WES2	2,813	287,454	22	3.70	12	6.31	10
GBY2	2,958	327,201	18	3.36	16	6.18	11
LGL2	3,303	255,771	26	4.67	4	6.04	12
DLK3	4,506	359,104	16	4.40	6	5.97	13
GPD1	396	80,481	108	1.74	76	5.91	14
PEP1	4,428	494,182	3	3.20	19	5.86	15
LGL1	2,149	182,189	46	4.29	8	5.74	16
BRB4	1,518	327,000	19	1.52	103	5.51	17
SUM2	2,201	258,673	25	2.83	25	5.51	18
FER1	1,455	211,204	37	2.29	38	5.49	19
KEL2	2,339	471,024	6	1.61	90	5.40	20
RRD9	2,104	333,728	17	1.96	54	5.28	21
PUL2	3,982	433,719	8	2.75	27	5.00	22
SMV1	3,148	304,478	21	3.04	21	4.95	23
HBS1	7	1,078	274	1.83	61	4.92	24
SUM1	2,284	416,074	10	1.60	92	4.85	25
Company Average		116,144		1.81		2.85	

Pulpit Rock Substation Loading and Reliability

June, 2003

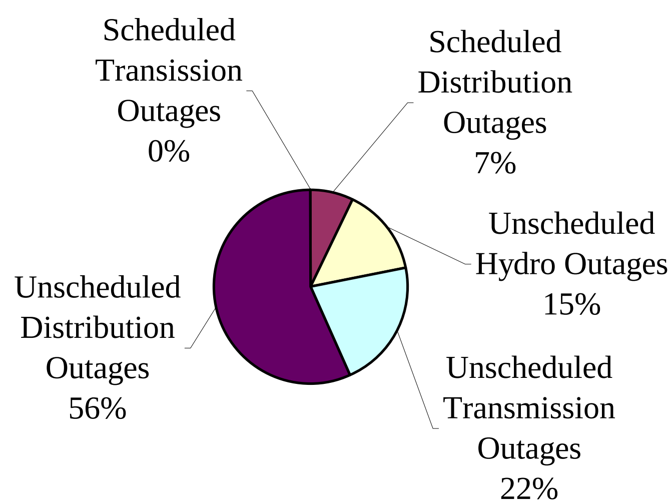
Table of Contents

1.0 Introduction

Pulpit Rock substation is located on the Northeast Avalon Peninsula in the Town of Torbay. The station is fed by a 7.7 km long 66kV radial transmission line (59L) from Virginia Waters substation. Pulpit Rock serves the communities of Torbay, Flatrock, Pouch Cove and Bauline. Two feeders are presently utilized to distribute power to customers from Pulpit Rock. Pulpit Rock-01 serves most of the Town of Torbay and south to the City of St. John’s as well as customers along the Bauline Line, including the community of Bauline. Pulpit Rock-02 serves the communities of Flatrock and Pouch Cove and a portion of Torbay. Both Pulpit Rock feeders operate at a voltage of 12.5 kV.

Over the period 1998-2002, customers served by this substation experienced an average annual SAIDI of 7.56 hours of outages and an average annual SAIFI of 4.80 interruptions. The breakdown of these interruptions into outage types is illustrated in Figures 1 below.

Figure 1: Interruption Type for Customers supplied through Pulpit Rock's distribution feeders (1998-2002)



2.0 Distribution Reliability

As figures 1 illustrates, distribution-related problems account for the majority of outages to customers served by these feeders. Based on rankings of NP feeders using 1998-2002 data, the Pulpit Rock feeders are the 7th and 8th worst performers in terms of customer minutes of unscheduled distribution outages. Table 1 shows the average annual customer minutes of outage, SAIDI and SAIFI for the individual feeders along with the Corporate average.

Table 1: Pulpit Rock Feeder Reliability Statistics (1998 – 2002)

Feeder	Average Annual Customer Minutes of Outage (mins)	SAIFI (interruptions / year)	SAIDI (hours / year)
PUL-01	444,325	1.77	3.79
PUL-02	433,719	2.75	5.00
Corporate Average	116,144	1.81	2.85

Appendix A shows how the Pulpit Rock feeders compare to other feeders in the Company's service territory.

3.0 Load Growth

Over the past 5 years, the areas served by the two Pulpit Rock feeders have seen substantial growth. With the construction of the Outer Ring Road and the development of the Stavanger Drive commercial area, the Torbay and Flatrock areas have become increasingly attractive for residential development. Subdivisions such as Pine Ridge Creek, Easterbrook Estates and Forest Landing have added significant load to these feeders. This trend is expected to continue as further infilling of the available land occurs.

In terms of peak loadings and based on 2003 forecasts, Pulpit Rock-01 and Pulpit Rock-02 are at 83% and 90% of their capacity, respectively (2002 actual peaks were 68% and 84%, respectively). Given current growth rates of approximately 4% and 3% respectively, these feeders have adequate capacity for the next three to four years.

Some of the relevant statistics for these two feeders are provided in the table below.

Feeder	2003 Forecast		Rating (A)	Number of Customers			Total Length (km)
	Peak Load (kVA)	Peak Current (A)		2002 Actual	NP Ranking	12.5kV Ranking	
Pulpit Rock 01	9,430	463	630*	1935	3	1	48.7
Pulpit Rock 02	8,110	398	441**	1427	22	13	60.2

* Limited by substation equipment rating
** Limited by conductor rating

This table shows how the number of customers supplied by the Pulpit Rock feeders rank in comparison to the other, approximately 300, Company feeders. The table indicates there are only two feeders that supply more customers than PUL-01 and that PUL-01 supplies more customers than any other feeder that operates at a voltage of 12.5 kV.

3.1 Maintenance and Backup Implications

Taking equipment out of service for either scheduled maintenance or for emergency repairs requires the Company to ensure some level of backup is available to minimize outages to customers. The ongoing load growth at Pulpit Rock Substation is now restricting the Company's ability to provide backup for maintenance or repair of reclosers at the Substation at certain times of the year.

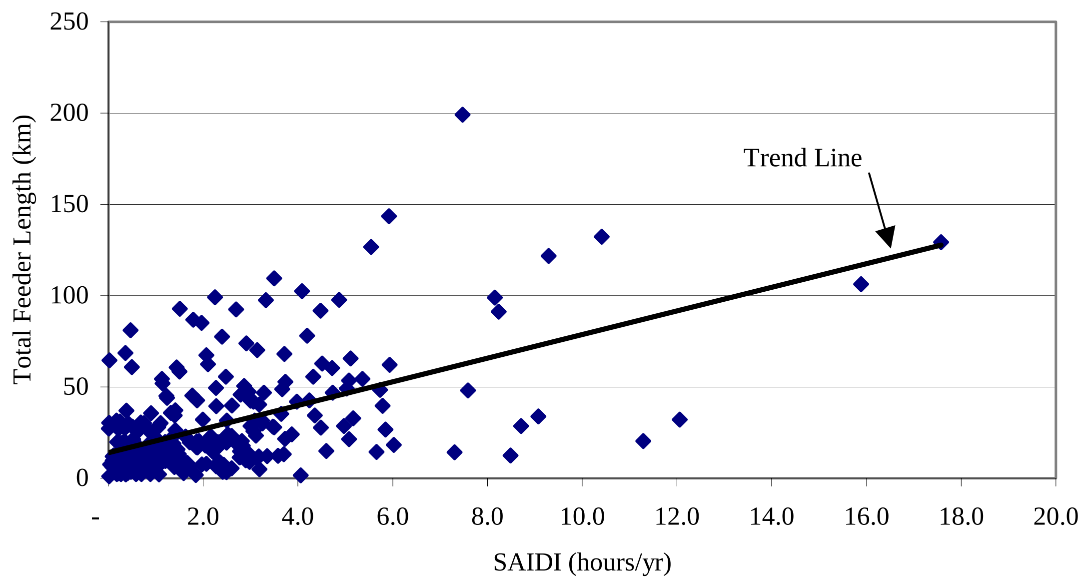
The combined peak load of PUL-01 and PUL-02 is forecast to be 860 Amps in 2003. This exceeds the emergency rating of either the PUL-01 recloser (850 Amps) or the PUL-02 recloser (800 Amps). As a result, the backup for recloser failure requires offloading customers from PUL-01 onto the Virginia Waters substation. However, restoring load near peak load conditions involves supplying load that temporarily exceeds normal peak load levels. This condition is referred to as cold load pick-up. This extra load will cause the total combined load to be well above 860 Amps, making the restoration of power difficult in the event of a failure of a recloser.

3.2 Reliability Implications

Growth on the Pulpit Rock feeders is also a contributing factor to the inferior reliability performance of the Pulpit Rock feeders. The longer a feeder grows in terms of total length and number of customers, the greater the exposure of all customers on the feeder to incidents or faults that interrupt the entire feeder. The correlation between the number of power interruptions and length of feeders is very apparent statistically. This is illustrated graphically in figure 3 below.

As noted in section 2.0, the performance of the two feeders supplied from the Pulpit Rock Substation ranks poorly against other feeders within the Company's system. Continued growth and consequent increase in feeder length will contribute to a worsening of the reliability along the feeders. A review of the condition of the feeders and a review of the outage statistics has not identified any upgrading that will significantly improve the performance of these feeders.

Figure 3: SAIDI vs Feeder Length



4.0 Alternatives

To address the concerns associated with load growth, feeder backup, and line length, three alternatives were considered. These are:

1. Construct a third feeder that will supply a portion of the load currently being supplied by PUL-01 and PUL-02.
2. Construct a new substation and associated feeders to serve a subset of the existing Pulpit Rock service area.
3. Reconductor Pulpit Rock-02 feeder and replace the two existing Pulpit Rock feeder reclosers with breakers to increase capacity.

The first alternative will reduce the load on the existing feeders, creating a significant increase in the ability of the Pulpit Rock feeders to meet future load growth. Splitting the load between three feeders, instead of two, improves the backup capacity available for maintenance and repair of equipment. It will also improve the overall capacity of the distribution system by approximately 50%. The reconfiguration of the feeders will also decrease the length of each feeder and consequently improve the reliability of the supply to customers. The overall cost estimate for this option is $224,000. A schematic showing the modification to the Pulpit Rock feeders is shown in Appendix B.

The second option requires constructing a new substation and splitting PUL-02 into two feeders. One of the new feeders would be capable of offloading a portion of PUL-01 and consequently increase the capacity of all the existing feeders. This option however, was not considered in detail as the cost of a new substation and associated transmission equipment would be in excess of $2 million, substantially more than the cost of option 1 or option 3.

A third option is to increase the capacity of PUL-02 by replacing the conductor along a major portion of the feeder (19 km), and replacing the reclosers at the substation with breakers. This option will nearly double the capacity of the existing distribution system and alleviate the concerns with backup. However, the option will not deal with feeder line length and consequently will not have as positive an impact on reliability as will option 1. The overall estimate for this option is $680,000.

5.0 Discussion

By comparing the alternatives the following observations can be made:

- Option 2 requires a new substation and is significantly more expensive than the other two alternatives. This option can be eliminated simply on the basis of cost.

- Both Option 1 and 3 will significantly increase the capacity of the existing distribution facilities. This will address the overloads that are projected within the next five years and will alleviate concerns over equipment backup. While option 3 provides the greater capacity increase, Option 1 should provide adequate capacity well into the future. Given the current growth rate of about 3.5 percent per year, it will be 15 to 20 years before further capacity additions are required to the distribution system.

- Option 1 will reduce the length of the Pulpit Rock distribution feeders and consequently improve the reliability

- Option 3 is more expensive than option 1 and will not reduce the length of either of the Pulpit Rock Feeders. Consequently, option 3 would not make a significant improvement to the reliability of the existing system.

6.0 Recommendations

Based on the above considerations, it is recommended that a third feeder be constructed out of Pulpit Rock substation in 2004 to improve reliability and provide greater capacity on the distribution system to handle growth in the area served.

APPENDIX "A"

Results of Ranking Feeders
by Customer Minutes of Outage, SAIDI and SAIFI

Five Year Average Unscheduled Distribution Related Outages
1998-2002

Sorted by Customer Minutes of Interruptions

Feeder	Annual Customer Interruptions (Cust Int per year)	Annual Customer Minutes of Interruption (Cust Min per year)	RANK Customer Minutes	Annual SAIFI (int per year per cust)	RANK SAIFI	Annual SAIDI (hours per year per cust)	RANK SAIDI
BOT1	6,084	687,411	1	3.87	11	7.29	7
BCV2	5,632	618,516	2	3.57	14	6.41	9
PEP1	4,428	494,182	3	3.20	19	5.86	15
CHA2	3,720	480,828	4	2.16	41	4.67	30
BRB2	838	473,643	5	1.16	140	8.26	4
KEL2	2,339	471,024	6	1.61	90	5.40	20
PUL1	3,481	444,325	7	1.77	71	3.79	43
PUL2	3,982	433,719	8	2.75	27	5.00	22
LEW2	5,023	428,093	9	3.35	17	4.74	27
SUM1	2,284	416,074	10	1.60	92	4.85	25
HWD7	5,967	404,861	11	3.64	13	4.12	36
SCV1	3,268	374,822	12	2.29	37	4.49	32
LAU1	1,099	364,919	13	1.55	97	8.63	3
LET1	4,633	364,142	14	2.59	32	3.42	52
CHA1	2,107	363,382	15	0.74	214	2.13	110
DLK3	4,506	359,104	16	4.40	6	5.97	13
RRD9	2,104	333,728	17	1.96	54	5.28	21
GBY2	2,958	327,201	18	3.36	16	6.18	11
BRB4	1,518	327,000	19	1.52	103	5.51	17
HOL2	523	323,027	20	1.11	151	10.89	2
SMV1	3,148	304,478	21	3.04	21	4.95	23
WES2	2,813	287,454	22	3.70	12	6.31	10
GOU3	2,708	270,095	23	1.83	64	3.05	66
GFS6	4,792	264,187	24	3.03	22	2.77	84
SUM2	2,201	258,673	25	2.83	25	5.51	18
Company Average		116,144		1.81		2.85	

Five Year Average Unscheduled Distribution Related Outages
1998-2002

Sorted by SAIFI

Feeder	Annual Customer Interruptions (Cust Int per year)	Annual Customer Minutes of Interruption (Cust Min per year)	RANK Customer Minutes	Annual SAIFI (int per year per cust)	RANK SAIFI	Annual SAIDI (hours per year per cust)	RANK SAIDI
STX1	5,442	153,288	59	5.87	1	2.72	85
STG2	2,305	104,835	90	5.10	2	3.87	42
STG1	1,413	55,774	140	4.69	3	3.07	64
LGL2	3,303	255,771	26	4.67	4	6.04	12
BHD1	5,051	120,673	81	4.60	5	1.96	120
DLK3	4,506	359,104	16	4.40	6	5.97	13
HUM9	1,854	102,515	93	4.30	7	3.97	40
LGL1	2,149	182,189	46	4.29	8	5.74	16
ABC1	2,949	128,408	74	4.14	9	2.97	74
GBS2	1,764	78,456	111	4.07	10	3.11	62
BOT1	6,084	687,411	1	3.87	11	7.29	7
WES2	2,813	287,454	22	3.70	12	6.31	10
HWD7	5,967	404,861	11	3.64	13	4.12	36
BCV2	5,632	618,516	2	3.57	14	6.41	9
DLK1	3,074	61,541	129	3.40	15	1.11	175
GBY2	2,958	327,201	18	3.36	16	6.18	11
LEW2	5,023	428,093	9	3.35	17	4.74	27
CAB1	3,198	235,469	30	3.27	18	4.05	39
PEP1	4,428	494,182	3	3.20	19	5.86	15
GRH3	2,493	148,278	63	3.07	20	3.05	65
SMV1	3,148	304,478	21	3.04	21	4.95	23
GFS6	4,792	264,187	24	3.03	22	2.77	84
TRP1	2,092	116,311	85	3.00	23	2.84	81
GBS1	1,798	93,875	98	2.93	24	2.69	87
SUM2	2,201	258,673	25	2.83	25	5.51	18
Company Average		116,144		1.81		2.85	

Five Year Average Unscheduled Distribution Related Outages
1998-2002

Sorted by SAIDI

Feeder	Annual Customer Interruptions (Cust Int per year)	Annual Customer Minutes of Interruption (Cust Min per year)	RANK Customer Minutes	Annual SAIFI (int per year per cust)	RANK SAIFI	Annual SAIDI (hours per year per cust)	RANK SAIDI
TRP2	16	9,688	235	2.64	31	32.64	1
HOL2	523	323,027	20	1.11	151	10.89	2
LAU1	1,099	364,919	13	1.55	97	8.63	3
BRB2	838	473,643	5	1.16	140	8.26	4
WES1	934	185,031	44	2.36	36	7.78	5
WES3	725	233,015	31	1.38	114	7.43	6
BOT1	6,084	687,411	1	3.87	11	7.29	7
QTZ1	0	1,298	272	0.13	281	7.21	8
BCV2	5,632	618,516	2	3.57	14	6.41	9
WES2	2,813	287,454	22	3.70	12	6.31	10
GBY2	2,958	327,201	18	3.36	16	6.18	11
LGL2	3,303	255,771	26	4.67	4	6.04	12
DLK3	4,506	359,104	16	4.40	6	5.97	13
GPD1	396	80,481	108	1.74	76	5.91	14
PEP1	4,428	494,182	3	3.20	19	5.86	15
LGL1	2,149	182,189	46	4.29	8	5.74	16
BRB4	1,518	327,000	19	1.52	103	5.51	17
SUM2	2,201	258,673	25	2.83	25	5.51	18
FER1	1,455	211,204	37	2.29	38	5.49	19
KEL2	2,339	471,024	6	1.61	90	5.40	20
RRD9	2,104	333,728	17	1.96	54	5.28	21
PUL2	3,982	433,719	8	2.75	27	5.00	22
SMV1	3,148	304,478	21	3.04	21	4.95	23
HBS1	7	1,078	274	1.83	61	4.92	24
SUM1	2,284	416,074	10	1.60	92	4.85	25
Company Average		116,144		1.81		2.85	

APPENDIX “B”

Proposed Pulpit Rock Feeder Modifications

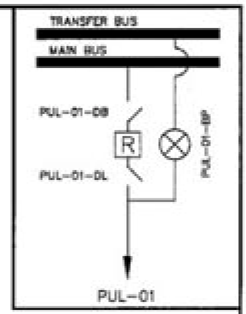
Existing PUL-01

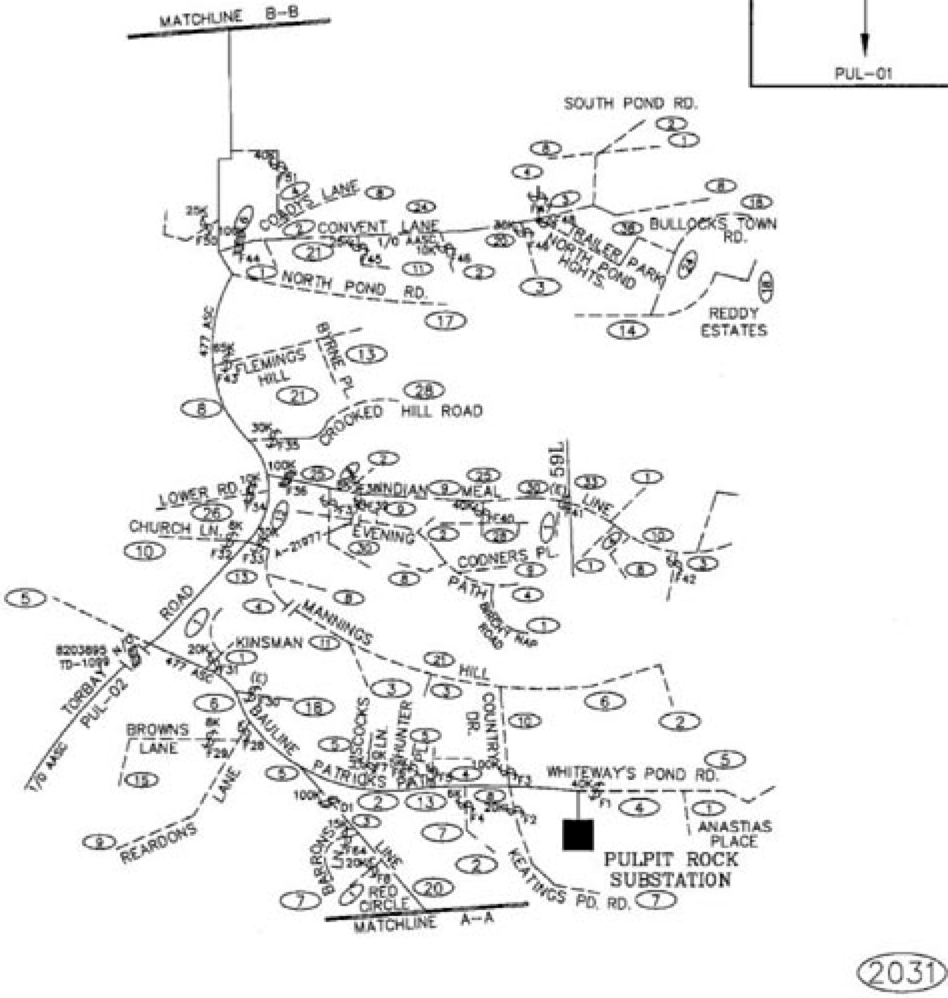
NOTE:

C.L. FUSES ARE REQUIRED WITHIN 1.02 KM OF THE SUBSTATION.

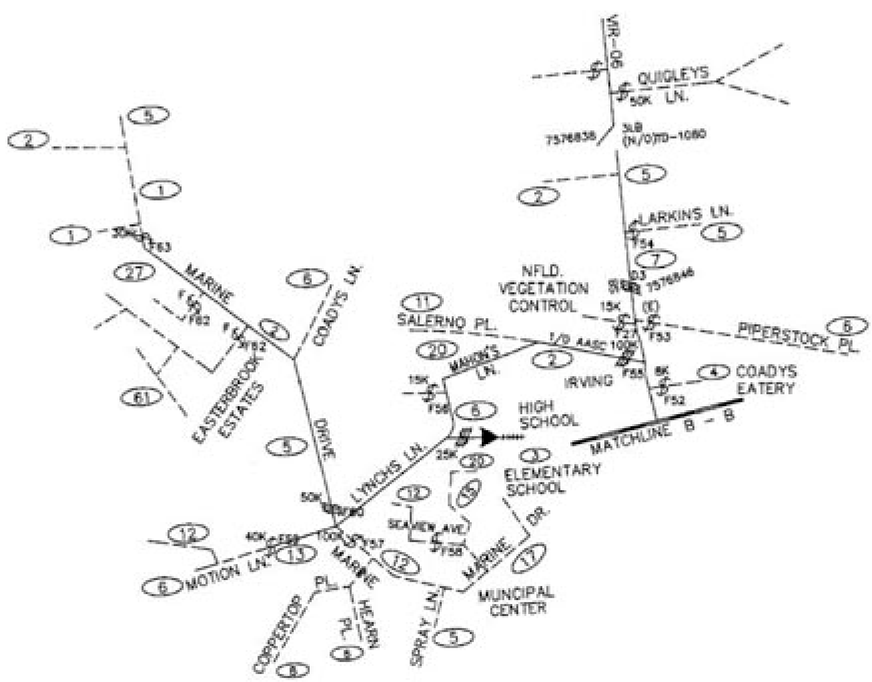
NOTE:

FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS



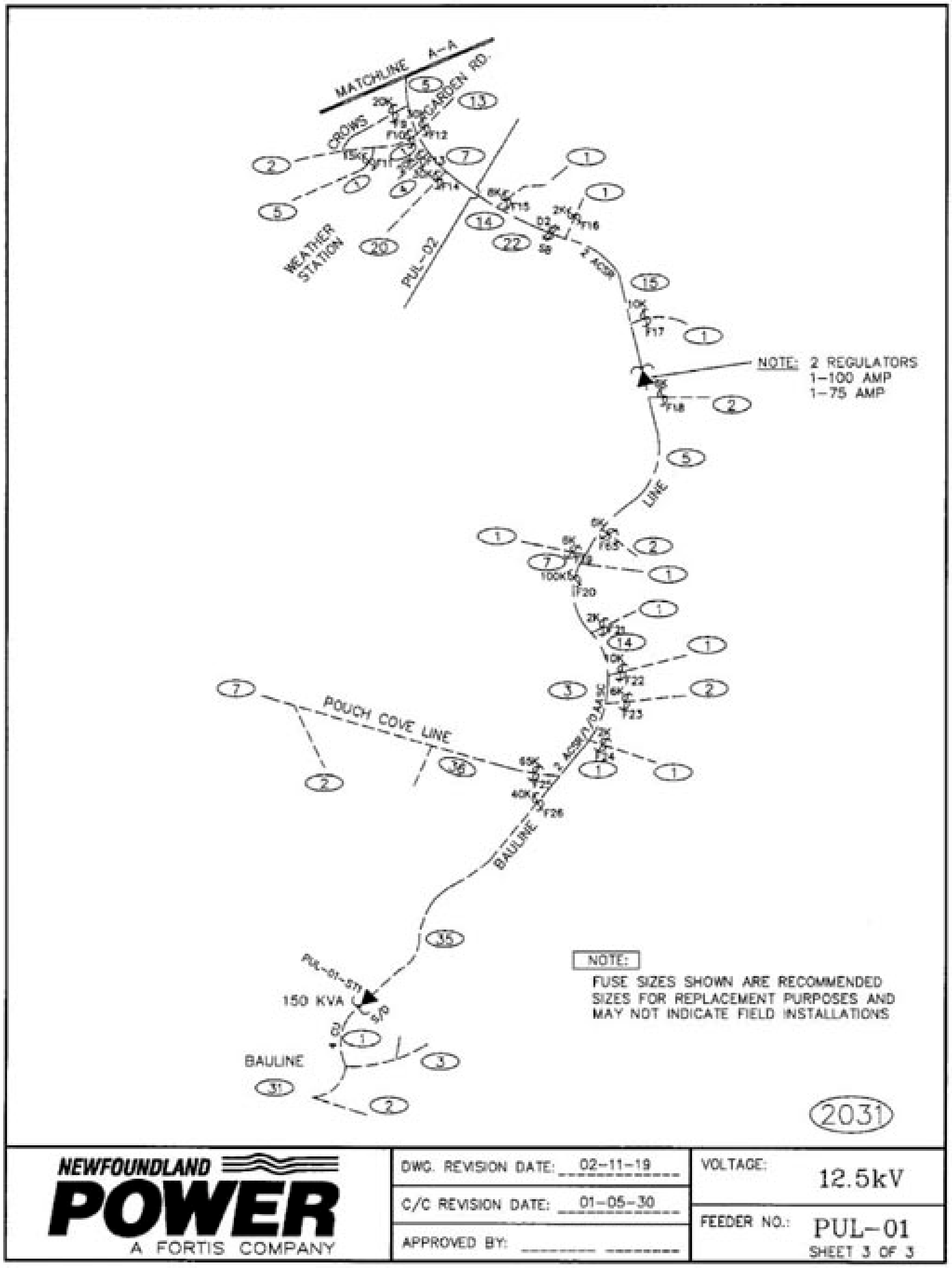


NEWFOUNDLAND POWER A FORTIS COMPANY	DWG. REVISION DATE: 02-11-19	VOLTAGE: 12.5kV
	C/C REVISION DATE: 01-05-30	FEEDER NO.: PUL-01
	APPROVED BY: ________ ________	SHEET 1 OF 3



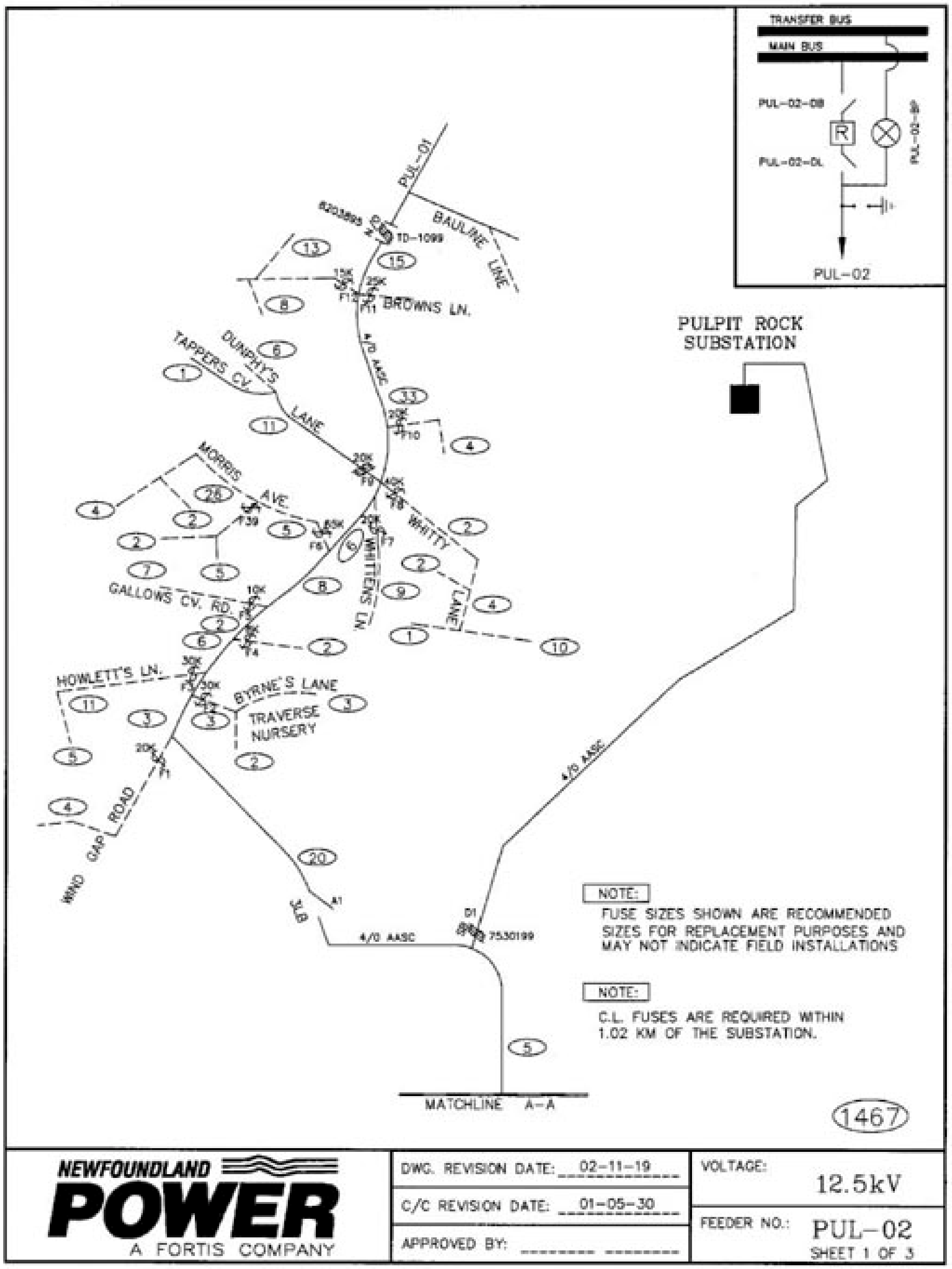
2031

NEWFOUNDLAND POWER A FORTIS COMPANY	DWG. REVISION DATE: 99-03-09	VOLTAGE: 12.5kV
	C/C REVISION DATE: 01-05-30	FEEDER NO.: PUL-01
	APPROVED BY:	SHEET 2 OF 3

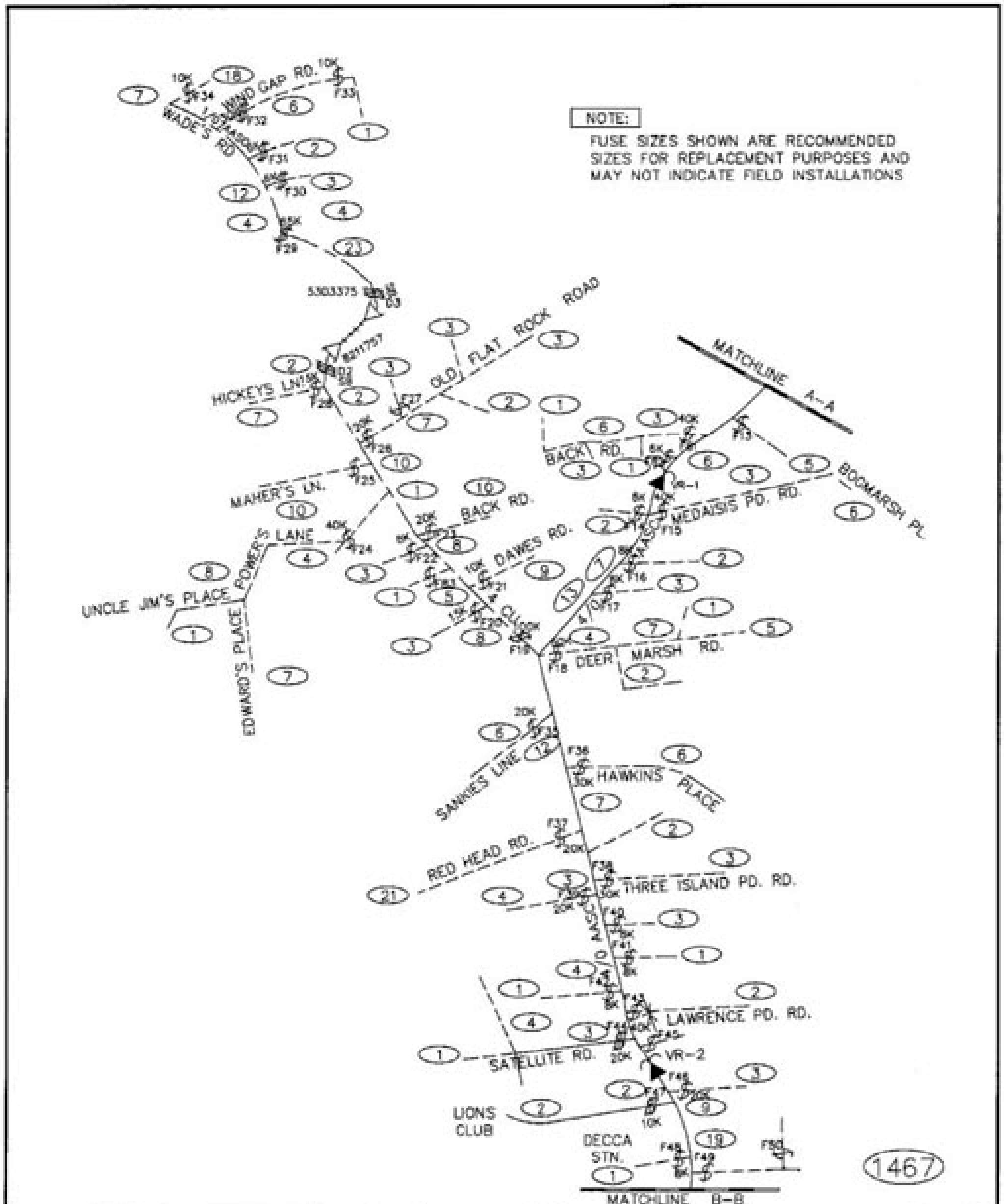


MATCHLINE A-A
CROWS
GARDEN RD.
WEATHER STATION
PUL-02
2 ACSR
NOTE: 2 REGULATORS
1-100 AMP
1-75 AMP
LINE
POUCH COVE LINE
BAULINE
PUL-01-ST1
150 KVA
BAULINE
NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS
2031
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 02-11-19
C/C REVISION DATE: 01-05-30
APPROVED BY:
VOLTAGE: 12.5kV
FEEDER NO.: PUL-01
SHEET 3 OF 3

Existing PUL-02



TRANSFER BUS
MAIN BUS
PUL-02-DB
PUL-02-DL
R
PUL-02
PULPIT ROCK
SUBSTATION
PUL-01
BAULINE LINE
TD-1099
BROWNS LN.
DUNPHY'S
TAPPERS CV.
LANE
4/0 AASC
MORRIS
AVE.
WHITTY
WHITTENS LN.
LANE
GALLOWS CV. RD.
HOWLETT'S LN.
BYRNE'S LANE
TRAVERSE
NURSERY
WIND GAP ROAD
3LB
7530199
NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS
NOTE:
C.L. FUSES ARE REQUIRED WITHIN 1.02 KM OF THE SUBSTATION.
MATCHLINE A-A
1467
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 02-11-19
C/C REVISION DATE: 01-05-30
APPROVED BY:
VOLTAGE:
12.5kV
FEEDER NO.:
PUL-02
SHEET 1 OF 3



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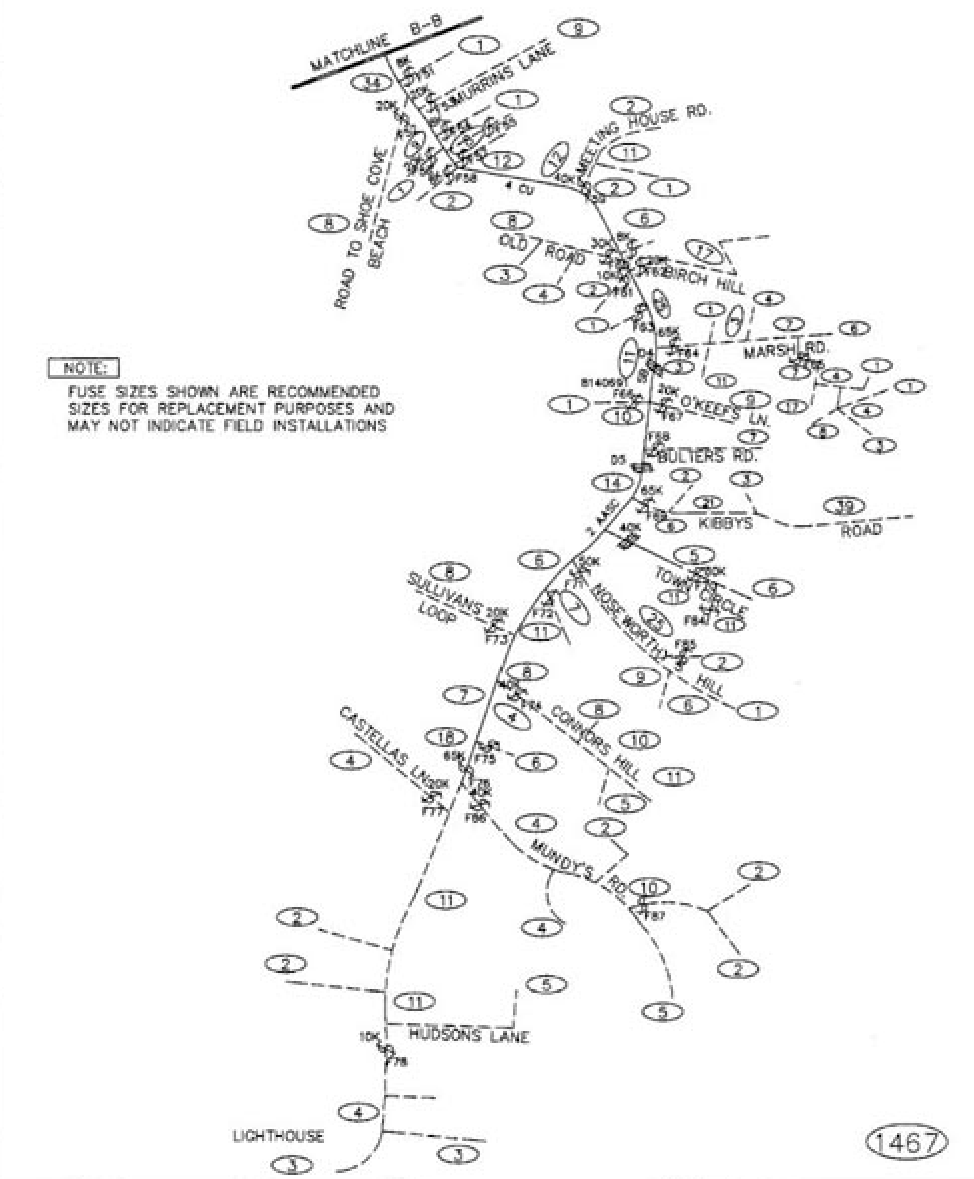
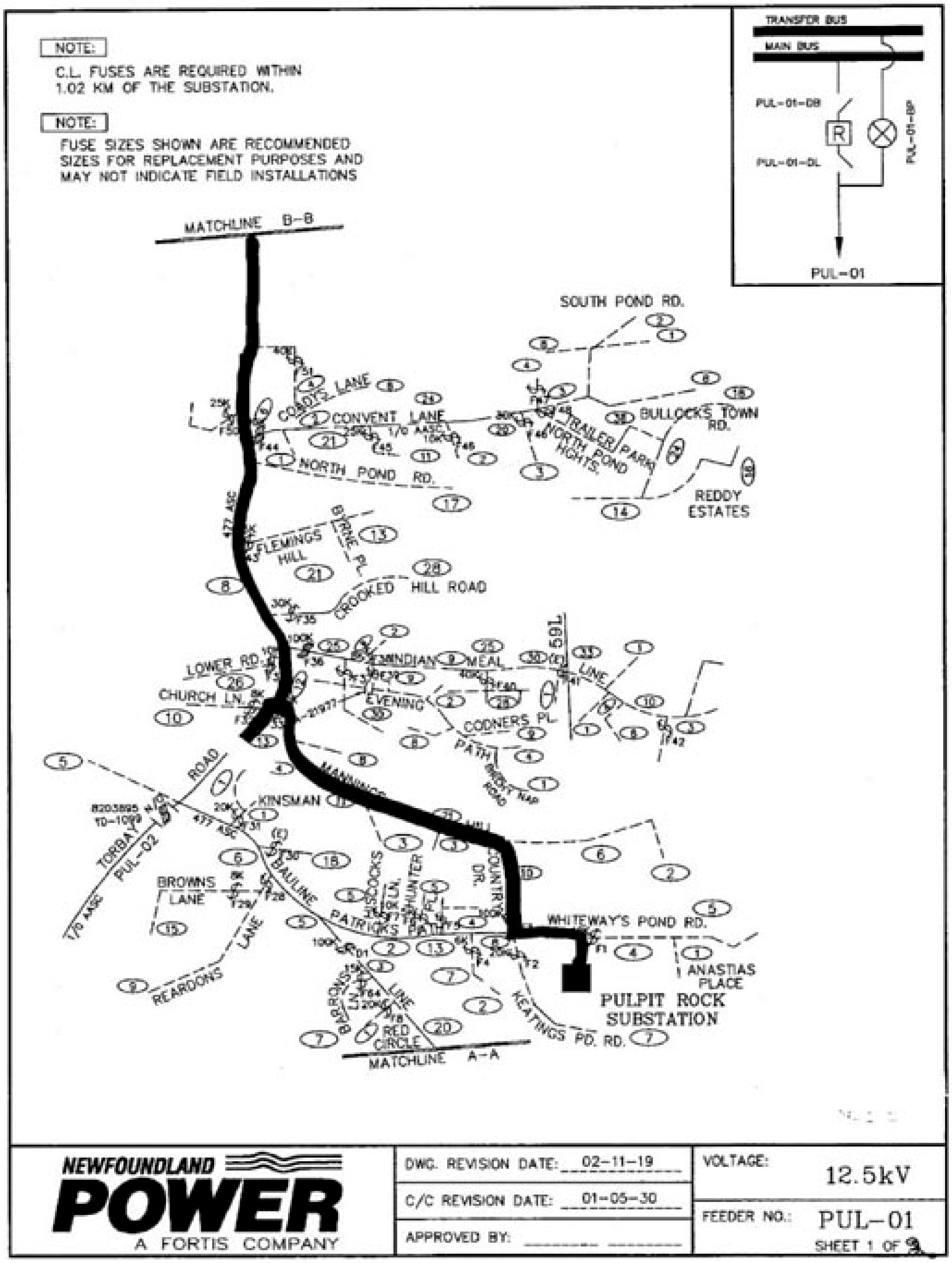
	C/C REVISION DATE: 01-05-30	FEEDER NO.: PUL-02
	APPROVED BY:	SHEET 2 OF 3

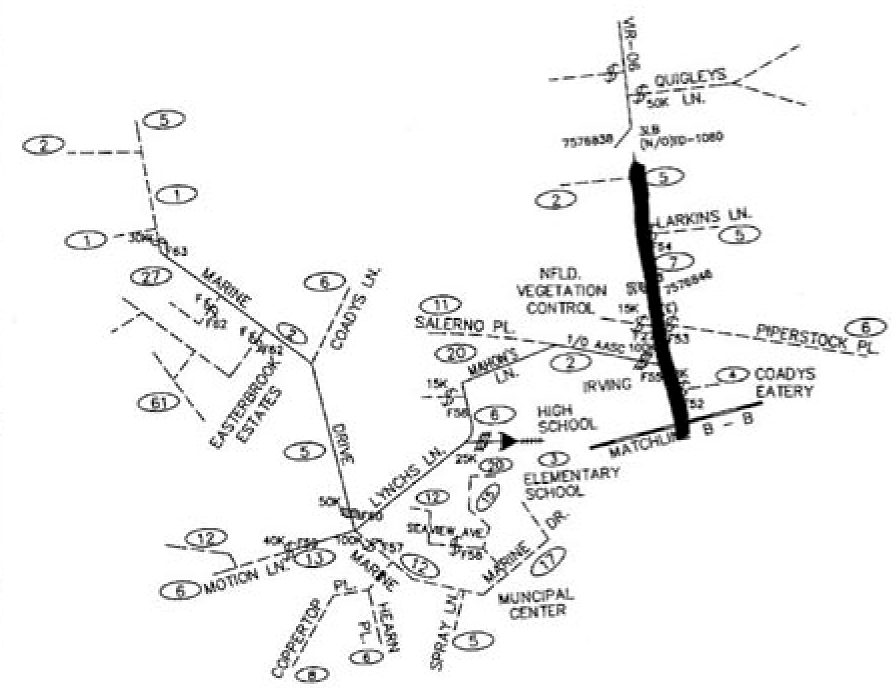


NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS

NEWFOUNDLAND POWER A FORTIS COMPANY	DWG. REVISION DATE: 02-11-19	VOLTAGE: 12.5kV
	C/C REVISION DATE: 01-05-30	FEEDER NO.: PUL-02 SHEET 3 OF 3
	APPROVED BY:	

Proposed PUL-01


NOTE:
C.L. FUSES ARE REQUIRED WITHIN 1.02 KM OF THE SUBSTATION.
NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS
TRANSFER BUS
MAIN BUS
PUL-01-DB
PUL-01-DL
PUL-01-BP
R
PUL-01
MATCHLINE B-B
SOUTH POND RD.
BULLOCKS TOWN RD.
TRAILER PARK
NORTH POND HGHTS.
CONVENT LANE
NORTH POND RD.
REDDY ESTATES
FLEMINGS HILL
BYRNE PL.
CROOKED HILL ROAD
LOWER RD.
CHURCH LN.
INDIAN MEAL LINE
EVENING
CODNERS PL.
KINSMAN
TORBAY RD.
PUL-02
BROWNS LANE
REARDONS LANE
PAULINE
PATRICKS PATH
COUNTRY DR.
HUNTER
WHITEWAY'S POND RD.
ANASTIAS PLACE
PULPIT ROCK SUBSTATION
KEATINGS PD. RD.
RED CIRCLE
MATCHLINE A-A
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 02-11-19
C/C REVISION DATE: 01-05-30
APPROVED BY:
VOLTAGE: 12.5kV
FEEDER NO.: PUL-01
SHEET 1 OF 3



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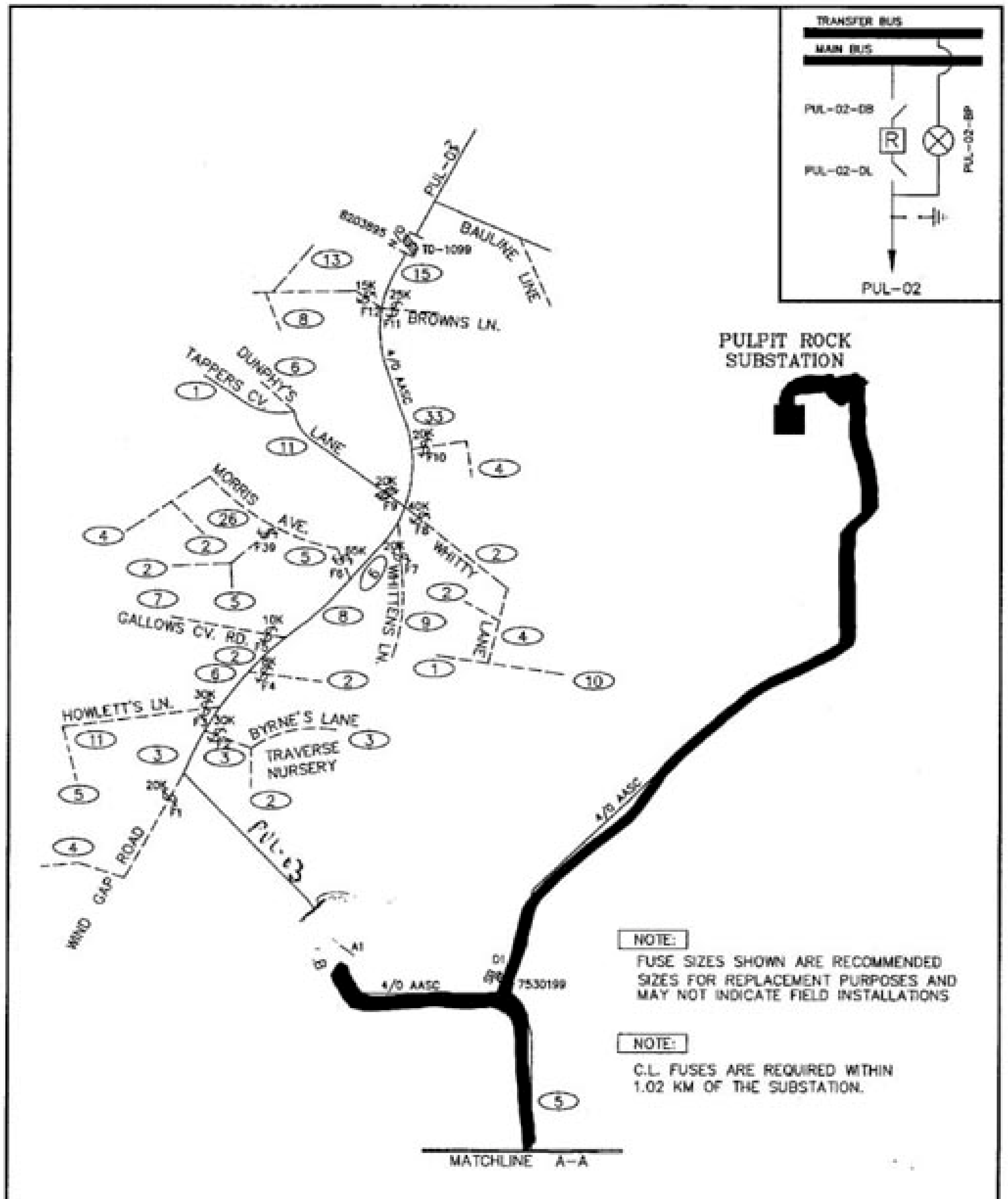
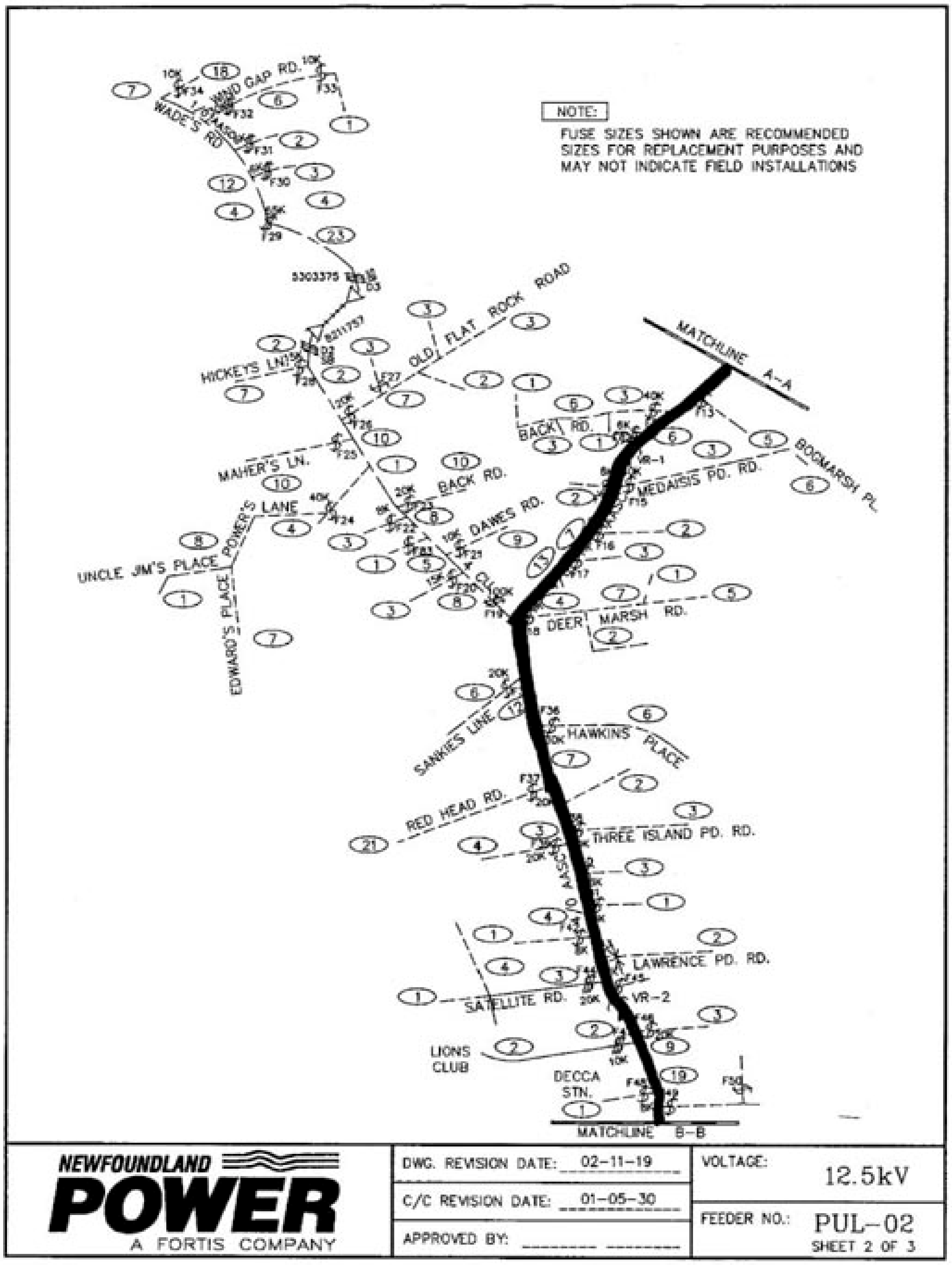
	C/C REVISION DATE: 01-05-30	FEEDER NO.: PUL-01
	APPROVED BY:	SHEET 2 OF [illegible]

Proposed PUL-02

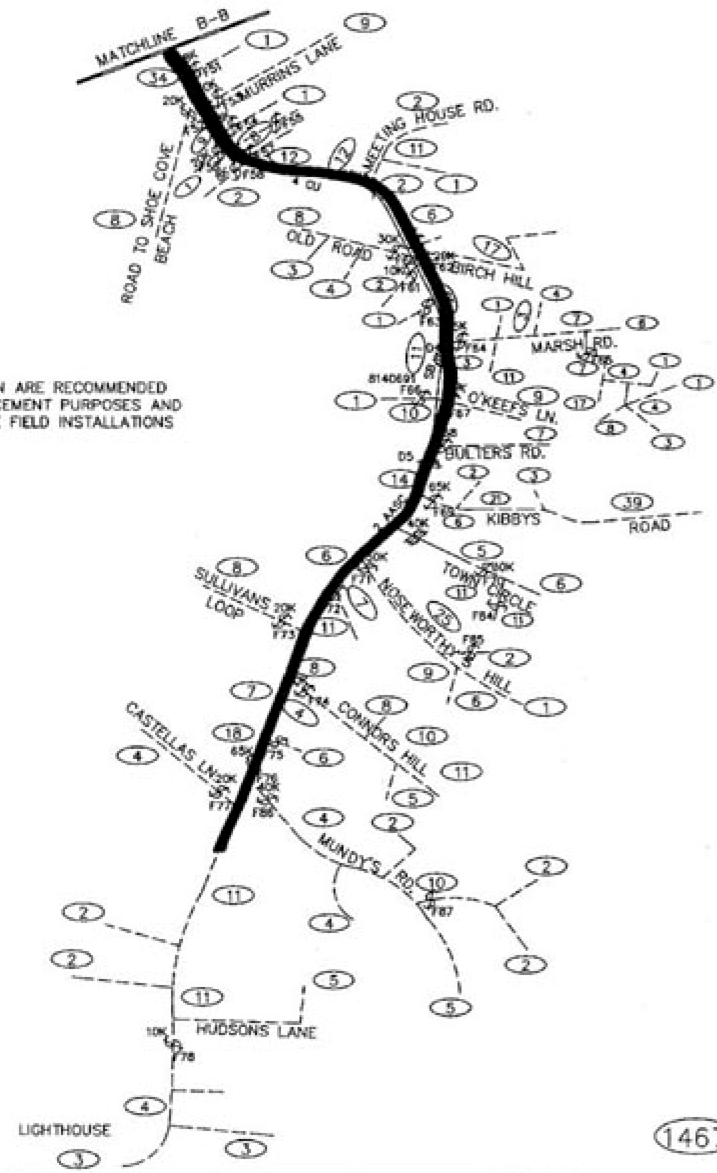


NEWFOUNDLAND POWER A FORTIS COMPANY	DWG. REVISION DATE: 02-11-19	VOLTAGE: 12.5kV
	C/C REVISION DATE: 01-05-30	FEEDER NO.: PUL-02 SHEET 1 OF 3
	APPROVED BY:	


NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS
WIND GAP RD.
WADE'S RD
OLD FLAT ROCK ROAD
HICKEYS LN.
MATCHLINE A–A
BACK RD.
BOGMARSH PL
MEDAISIS PD. RD.
MAHER'S LN.
BACK RD.
DAWES RD.
POWER'S LANE
UNCLE JIM'S PLACE
EDWARD'S PLACE
DEER MARSH RD.
SANKIES LINE
HAWKINS PLACE
RED HEAD RD.
THREE ISLAND PD. RD.
LAWRENCE PD. RD.
SATELLITE RD.
VR-1
VR-2
LIONS CLUB
DECCA STN.
MATCHLINE B–B
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 02-11-19
C/C REVISION DATE: 01-05-30
APPROVED BY:
VOLTAGE: 12.5kV
FEEDER NO.: PUL-02
SHEET 2 OF 3

NOTE:

FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS



NEWFOUNDLAND POWER A FORTIS COMPANY	DWG. REVISION DATE: 02-11-19	VOLTAGE:	12.5kV
	C/C REVISION DATE: 01-05-30	FEEDER NO.:	PUL-02 SHEET 3 OF 3
	APPROVED BY:		

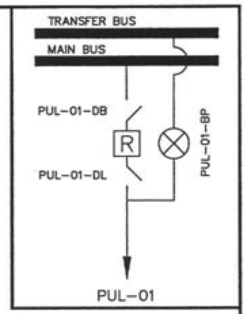
Proposed PUL-03

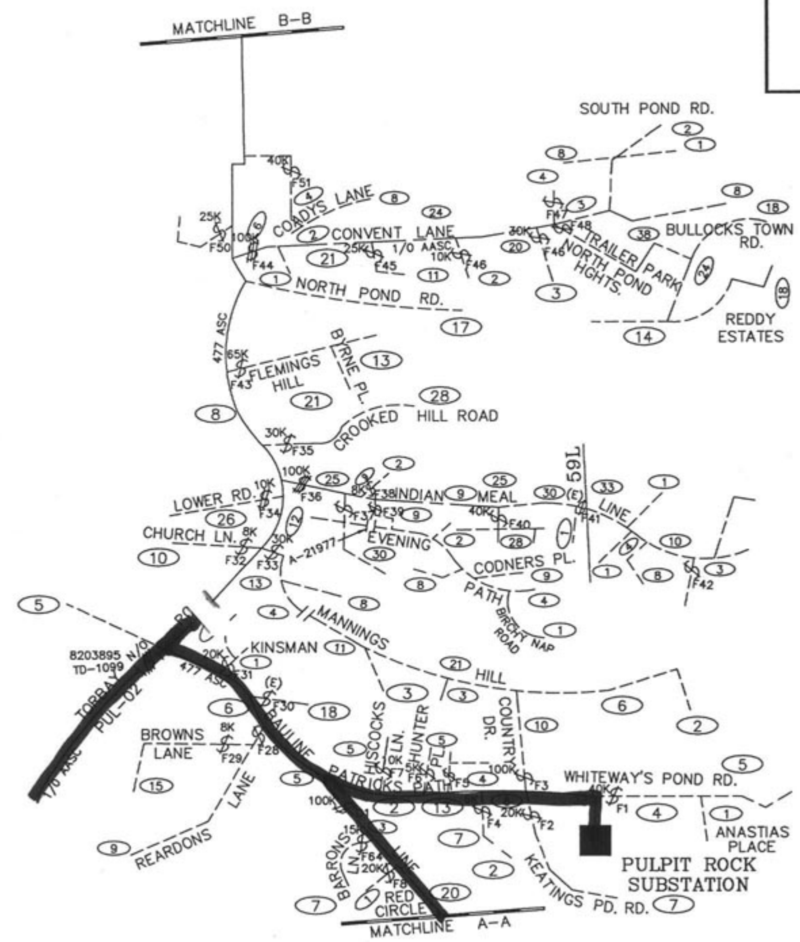
NOTE:

C.L. FUSES ARE REQUIRED WITHIN 1.02 KM OF THE SUBSTATION.

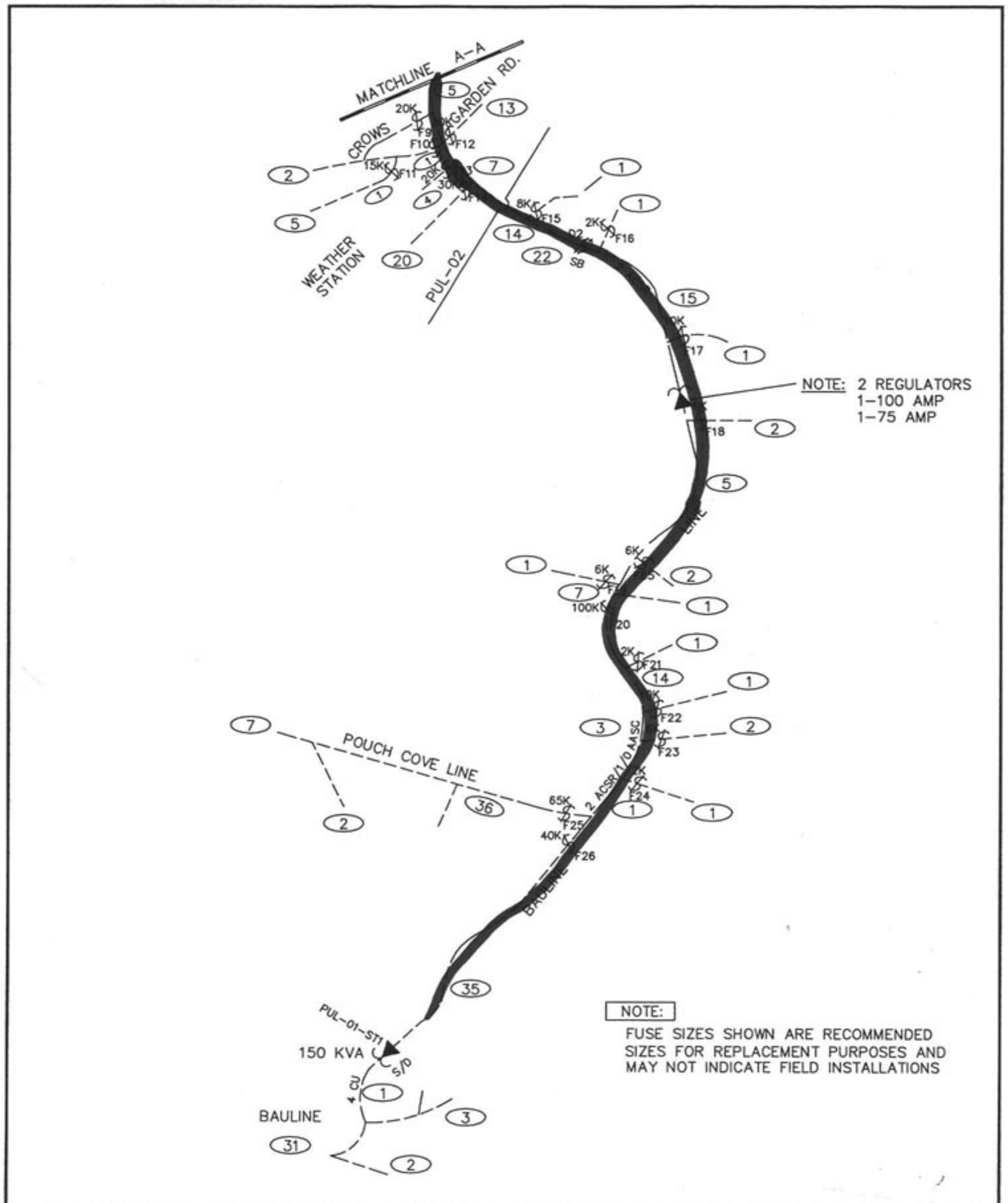
NOTE:

FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS





NEWFOUNDLAND POWER A FORTIS COMPANY	DWG. REVISION DATE: 02-11-19	VOLTAGE:	12.5kV
	C/C REVISION DATE: 01-05-30	FEEDER NO.:	PUL-03
	APPROVED BY:		SHEET 1 OF 3



NEWFOUNDLAND POWER A FORTIS COMPANY	DWG. REVISION DATE: 02-11-19	VOLTAGE: 12.5kV
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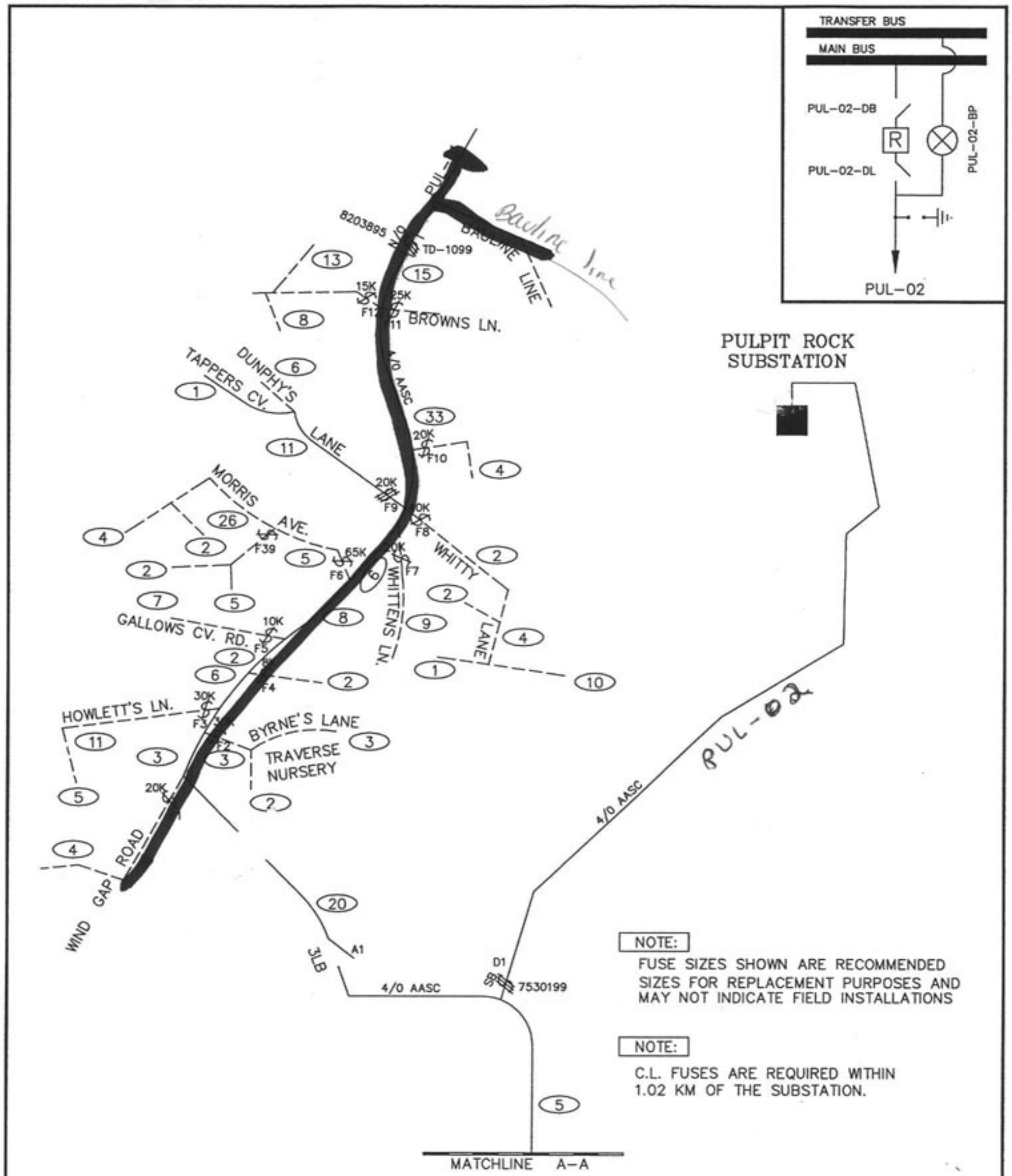
	APPROVED BY:	SHEET 2 OF 3



NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS

NOTE:
C.L. FUSES ARE REQUIRED WITHIN 1.02 KM OF THE SUBSTATION.

NEWFOUNDLAND POWER A FORTIS COMPANY	DWG. REVISION DATE: 02-11-19	VOLTAGE: 12.5kV
	C/C REVISION DATE: 01-05-30	FEEDER NO.: PUL-03
	APPROVED BY:	SHEET 3 OF 3

Project Title: **Feeder Additions and Upgrades to Accommodate Growth**

Location: **Various**

Classification: **Distribution**

Project Cost: **$677,000**

This project consists of a number of items as noted.

(a) Install New Feeder – CHA-03

Cost: $522,000 – Distribution, $106,000 – Substations

Description: This project involves the construction of a distribution feeder from Chamberlains substation on Fowlers Road. The new feeder will run south along Fowler's Road to the Conception Bay South bypass road (CBS) then west along the CBS to the intersection of Dunn's Hill Road and along Dunn's Hill Road for approximately 1 km. The project also includes the transfer of approximately 4.5 MVA of load from Kelligrews substation to Chamberlains substation.

Operating Experience: Load and customer growth in the Conception Bay South area is causing certain electrical system parameters to exceed recommended guidelines.

Justification: An engineering study, *"Conception Bay South –Planning Study"* indicates that this proposal is the low cost alternative to maintain electrical system parameters within recommended guidelines. (See Volume III, Appendix 4, Attachment A)

(b) Reconductor Section of GLD-01

Cost: $80,000

Description: Replace 1/0 AASC conductor with higher ampacity 477 ASC conductor on Glendale-01 (GDL-01) feeder along Old Placentia Road from intersection of Ruth Avenue to Royal Garage in Donovans Industrial Park where this feeder intersects Hardwoods-04 (HWD-04) feeder.

Operating Experience: Glendale-01 feeder and Hardwoods-04 feeders are adjacent to each other in Donovan's Industrial Park, with a normally open switch separating the two. Under various circumstances, in order to maintain service to customers in the area, it would be beneficial to offload either feeder onto the other. However, due to increasing load growth and the low capacity of the 1/0 AASC conductor on the GDL-01 feeder, this is now limited to periods of very light loading.

Justification: The completion of this project will improve reliability and mitigate transformer loading issue at the Hardwoods and Glendale substations by providing the ability to offload feeders in response to incidents affecting substation and distribution systems.

(d) Install Voltage Regulators – SPF-01

Cost: $75,000

Description: Install a bank of voltage regulators on SPF-01to permit the transfer of load from Bay Roberts to Springfield substations.

Operating Experience: The load forecast for the Bay Roberts area indicates that unless certain action is undertaken, the peak load will exceed the transformer capacity in 2004.

Justification: This project is required to add voltage regulation to the system in order to accommodate the transfer of approximately 1.0 MVA of load from Bay Roberts to Springfield without causing voltage problems for customers in the area. The load transfer is required in order to maintain loads on Bay Roberts substation transformer (T1) within its rated capacity and thereby defer the addition of new transformer capacity past this forecast period. The transformer is rated at 20.0 MVA and the 2003 forecast peak is 20.0 MVA. Springfield T1 transformer is rated at 20.0 MVA with a 2003 forecast peak load of 11.9 MVA.

Newfoundland Power Inc.

Conception Bay South

Planning Study

Memo From: G. Emberley

To: G. Durnford

Subject: Update to the Conception Bay South Planning Study

Date: July 3, 2003

The winter 2003 Conception Bay South Planning Study was based on load forecast completed in the fall / winter. Since that time the 2002/ 2003 winter peak demand has occurred and the peak demands experienced in the Conception Bay South substations of Kelligrews and Seal Cove were significantly higher than was expected and used in the report. As a result, the conversions necessary to prevent overloads on the Kelligrews and Seal Cove transformers must be constructed in 2004 rather than the 2007, as was noted in the report. The conversion will now be done in conjunction with the 2004 construction of the CHA-03 feeder. A copy of the St. John's area 2003 substation forecast is attached.

The rapid growth being experienced in the CBS area has increased the importance of building CHA-03 in 2004. The economic efficiency of doing so is now enhanced relative to the alternative in the Conception Bay South Planning Study whereby adding transformer capacity to 2007 would now be moved to 2004 if that alternative were chosen. Building the CHA-03 feeder in 2004 along with the conversion of Kelligrews load to 25 kV effectively defers the requirement to add transformer capacity at Kelligrews from 2004 to well beyond the 5-year capital budget period.

Eastern Region - St. John's Area
2003 Five Year Forecast

Substation (Notes)	Des.	Operating Voltage (kV)	Transformer Capacity - MVA Rating	Existing	2002 Peak MVA	Forecasted Undiversified Peak - MVA 2003	2004	2005	2006	2007	2008	Max. XFMR. Util.
Big Pond (13)	T1	12.47	8.4/11.2	11.2	7.5	8.0	8.0	8.0	8.0	9.2	9.3	83%
Broad Cove (8 & 10)	T1	12.47	15/20/25	25.0	22.9	24.7	25.0	24.3	24.7	24.4	24.9	100%
Cape Broyle	T1	12.47	5.0/6.7	5.0	2.3	2.5	2.5	2.5	2.5	2.6	2.6	52%
Chamberlains (6 & 11)	T1	24.94	15/20/25	25.0	24.2	13.2	15.7	16.0	16.5	19.0	19.7	79%
Chamberlains	T2	24.94	15/20/25	25.0		13.2	15.7	16.0	16.5	19.0	19.7	79%
Fermeuse	T1	12.47	3.0/4.0	4.0	2.6	2.8	2.8	2.9	2.9	3.0	3.0	75%
Glendale (3, 5 & 9)	T1	12.47	15/20/25	25.0	22.2	24.7	23.8	23.8	16.6	16.8	17.0	99%
Glendale	T2	12.47	15/20/25	25.0	22.2	24.9	24.0	23.9	16.7	16.9	17.1	99%
Glendale	T3	12.47	15/20/25	25.0					16.7	16.9	17.1	68%
Goulds (5 & 14)	T2	12.47	15/20	20.0	8.1	8.9	11.0	11.4	11.8	12.3	15.1	75%
Goulds	T3	12.47	10/13.3	13.3	8.4	9.0	9.2	9.2	9.4	9.5	9.7	73%
Hardwoods (3, 4 & 9)	T1	12.47	15/20	20.0	19.6	19.5	19.8	19.8	19.0	19.3	19.6	99%
Hardwoods	T2	12.47	15/20	20.0	19.6	19.4	19.7	19.7	18.9	19.2	19.5	99%
Hardwoods (8, 10 & 11)	T3	24.94	15/20/25	25.0	17.3	19.4	20.5	22.6	23.9	22.0	23.3	96%
Holyrood 02					1.7	1.8	1.8	1.9	1.9	1.9	1.9	
Kelligrews (6, 7 & 12)	T1	12.47	11.25/14.9	15.0	13.4	14.6	11.8	12.0	12.3	13.6	14.0	97%
Kenmount (4)	T1	24.94	15/20/25	25.0	16.9	18.4	18.7	18.7	18.9	19.1	19.4	78%
Kenmount	T2	24.94	15/20/25	25.0	17.3	19.2	19.4	19.5	19.7	19.9	20.2	81%
King's Bridge	T1	4.16	7.5/10	10.0	7.2	7.7	7.8	7.8	7.8	7.9	8.0	80%
King's Bridge	T2	4.16	7.5/10	10.0	7.2	7.7	7.7	7.7	7.8	7.9	8.0	80%
King's Bridge	T3	12.47	15/20/25	25.0	18.7	20.1	20.3	20.4	20.6	20.9	21.2	85%
Mobile (13)	T2	12.47	5.0/6.7	6.7	5.9	6.4	6.5	6.6	6.6	6.3	6.5	99%
Molloy's Lane (14)	T1	12.47	15/20/25	25.0	22.0	24.2	24.4	24.4	24.6	24.9	24.0	100%
Molloy's Lane	T2	12.47	15/20/25	25.0	22.0	22.9	23.1	23.1	23.3	23.5	22.7	94%
Oxen Pond	T1	12.47	10/13.3	13.3	8.5	9.1	9.3	9.3	9.4	9.5	9.7	73%
Pepperrell	T1	12.47	15/20/25	25.0	20.9	22.4	22.6	22.6	22.8	23.1	23.4	94%
Petty Harbour	T1	4.16	3.0/4.0	3.0	2.4	2.6	2.6	2.7	2.7	2.7	2.8	94%
Pulpit Rock	T1	12.47	15/20/25	25.0	17.5	18.9	19.4	19.6	20.0	20.4	20.9	84%
Ridge Road	T1	4.16	1.7/2.2	2.2	0.8	0.9	0.9	0.9	0.9	0.9	0.9	40%
Ridge Road	T2	12.47	15/20	20.0	13.6	15.9	16.3	16.6	17.0	17.5	18.1	91%
Ridge Road	T3	12.47	15/20	20.0	17.2	17.6	18.1	18.4	18.8	19.4	20.0	100%
Seal Cove (7 & 12)	T2	12.47	11.2	11.2	10.6	11.5	10.7	10.8	11.1	10.3	10.5	103%
St. John's Main	T4	4.16	7.5/10	7.5	2.1	2.2	2.3	2.3	2.3	2.3	2.3	31%

St. John's Main	T2	12.47	15/20/25	25.0	20.7	20.4	20.7	20.7	20.9	21.1	21.4	86%
St. John's Main	T1	12.47	15/20/25	25.0	19.4	22.5	22.8	22.8	23.0	23.3	23.6	94%
Stamps Lane	T1	4.16	10/13.3	13.3	10.0	10.7	10.8	10.8	10.8	11.0	11.1	83%
Stamps Lane	T3	12.47	15/20/25	25.0	19.8	22.8	23.0	23.0	23.2	23.5	23.8	95%
Stamps Lane	T4	12.47	15/20/25	25.0	18.4	19.8	20.2	20.3	20.6	21.0	21.4	86%
Virginia Waters	T1	12.47	15/20/25	25.0	22.1	16.4	16.9	17.3	17.8	18.5	19.2	77%
Virginia Waters	T2	12.47	15/20/25	25.0	21.6	15.0	15.5	15.9	16.3	16.9	17.6	70%
Virginia Waters	T3	12.47	15/20/25	25.0		16.4	16.9	17.3	17.8	18.5	19.2	77%
MEMORIAL UNIVERSITY					16.0	16.1	16.2	16.2	16.2	16.2	16.2	
TOTAL - MVA					**550.8**	**594.4**	**604.5**	**609.5**	**619.4**	**632.4**	**645.7**	

SYSTEM TRANSFORMER LOADINGS

(Base Case Load Flow Model)

		Operating	Transformer		2002							Max.
		Voltage	Capacity - MVA		Peak		Forecasted Undiversified Peak - MVA					XFMR.
Substation	**Des.**	**(kV)**	**Rating**	**Existing**	**MVA**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**Util.**
GOULDS	T1	66-33	10	10.0	3.4	2.3	2.3	2.2	2.2	2.1	2.1	23%

Notes:

(1) Substation forecast based on 2002 to 2007 energy forecast released Feb 4, 2003.
(2) 2008 data is based on the same load growth experienced in 2007.
(3) 2003 - Transfer 2.0 MVA from HWD-12.5 kW bus to GDL.
(4) 2003 - 1.0 MVA of HWD 12.5 converted to 25kV and transferred to KEN.
(5) 2004 - 2.0 MVA transferred from GDL to GOU-T2.
(6) 2004 - 4.0 MVA of KEL 12.5 converted to 25 kV and transferred to CHA - PENDING Final Approval of CBS Study.
(7) 2004 - 1.0 MVA transferred from SCV to KEL - PENDING Final Approval of CBS Study.
(8) 2005 - 1.1 MVA of BCV 12.5 converted to 25kV and transferred to HWD.
(9) 2006 - 2 MVA transferred from HWD 12.kV Bus to GDL and install 25 MVA unit at GDL.
(10) 2007 - 0.75 MVA of BCV 12.5 converted to 25kV and transferred to HWD.
(11) 2007 - 4.0 MVA of HWD T3 transferred to CHA.
(12) 2007 - 1.0 MVA of SCV transferred to KEL.
(13) 2007 - 1.0 MVA of MOB transferred to BIG and install Rads at BIG.
(14) 2008 - 2.5 MVA of MOL transferred to GOU-T2.

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Introduction

The purpose of this study is to recommend the distribution system alternative that best meets the electrical demands of Conception Bay South (CBS). The 2003 installation of an additional 25 MVA transformer at Chamberlains (CHA) substation addressed an existing transformer over loading issue. This study is initiated by two issues: concerns arising from the high number of customers supplied from CHA-01 feeder and transformer loading concerns for the Kelligrews and Seal Cove substations.

This study projects the electrical demands for the CBS area to the year 2022, develops alternatives to meet these demands, and ensures the alternatives meet acceptable technical criteria. Further, an economic analysis for each alternative establishes the relative ranking of the alternatives with respect to the least cost approach for customer revenue requirement.

Description of Existing System

Over the past ten years, the town of Conception Bay South (CBS) has experienced one of the fastest growth rates in the province. All indications are that this growth rate will be sustained into the future. As a result, Newfoundland Power must ensure that its infrastructure will service this community as it grows with a reliable and economic electrical distribution system.

Three substations, Chamberlains (CHA), Kelligrews (KEL) and Seal Cove (SCV) service the town of CBS with a total substation transformer capacity of 51 MVA. A schematic diagram of the transmission and distribution systems supplying the area is shown in Figure 1.

In the east end of CBS, Chamberlains substation (CHA) is located on Fowler's Road and has two feeders, CHA-01 and CHA-02, both operating at 25KV. The CHA-01 feeder services the developing subdivisions to the south of the substation and extends along the CBS highway as far as Dunn's Hill Road in Kelligrews. The CHA-02 feeder extends north from the substation and spans from Topsail Pond to Holy Spirit School along the CBS Highway. As of February 2002, CHA-01 and CHA-02 were supplying 3,082 and 985 customers respectively. At present there is no backup capability for the CHA-01 feeder. Chamberlains substation has a 66/25 KV 25 MVA power transformer connected via a loop system by transmission lines 49L and 79L from Hardwoods (HWD) substation and 51L from the KEL substation. An additional 2.2 MVA of capacity is also paralleled with CHA-02 from the Topsail Generating Plant.

The Kelligrews substation (KEL) is located on Middle Bite Road in Kelligrews with two feeders KEL-01 and KEL-02, both operating at 12.5 KV. The KEL-01 feeder extends north from the substation to the CBS highway and then it extends west as far as Hynes' Road in Seal Cove where it is back to back with the SCV-01 feeder. The KEL-02 feeder runs north from the substation to the CBS Highway and then it travels east where it is back to back with CHA-01 at Dunn's Hill Road. The Kelligrews Substation contains a 66/12.5 kV, 14.95 MVA power transformer and has a loop system via 51L and 52L transmission lines from Chamberlains and Seal Cove substations.

The Seal Cove substation (SCV) is located near Garden Road in Seal Cove along the Conception Bay Highway. This substation has two feeders, SCV-01 and SCV-02, both operating at 12.5 KV. The SCV-01 feeder travels east along the CBS highway as far as Hynes' Road in Kelligrews where it is back to back with KEL-01. The SCV-02 feeder runs west along the CBS highway where it is back to back with HOL-02 in the town of Holyrood. The Seal Cove substation uses a 66/12.5 KV 11.2 MVA power transformer. Power is delivered to the substation by transmission lines 52L from KEL substation and 38L from Duff's Steam Plant in Holyrood. There is also a pair of generators at the Seal Cove substation with a capacity of 4 MVA. They are generating power at 2.4 KV and are tied directly into the 66 KV bus. Since this only affects the transmission system and has no impact on the output of SCV-T2, it will not be a factor in this study.

As this area continues to grow, Newfoundland Power must ensure it has a sufficient supply of reliable power that meets the needs of the community. As Chamberlains substation demand has already reached the capacity of the existing 25 MVA power transformer, a new 66-25 KV, 25 MVA power transformer has been scheduled for installation at Chamberlains substation this year. Over the past few years, concerns have also been raised by operations personnel regarding the large number of customers (3,082) presently served through the CHA-01 feeder with little system backup. These concerns centre on the ability to re-energize the feeder under cold load situation and the reliability impact from serving such a large number of customers on one feeder.

Load Forecast and Growth Projections

Base case values for the load forecast for each individual feeder were based on historical data for years 1993 to 2002. Throughout the past ten years, the maximum yearly peaks for each feeder has varied. However, after analyzing all of the data, a base case historical demand was determined for each feeder. It was determined that some of the maximum yearly values were the result of cold pick up and appropriate adjustments were made.

Growth projections for the community of Conception Bay South were developed through the analysis of historical data provided by the town's development control coordinator. This information was then taken and used to create a load forecast for a 20-year period. In addition, from the base case, a medium, high and low forecast was projected. Most growth for the town in the past has been mainly as a result of residential development; any commercial expansion has been to service the residential sector. Therefore, the forecast was based mainly on the residential growth experienced over the past ten years. It was determined that the growth in the east end and the central part of the town has proceeded at a faster rate than that experienced in the west end of the town. This trend is expected to continue over the next five years. Based on these assumptions, a load forecast growth rate of 2% per year was used for Chamberlains and Kelligrews substations and a forecast of 1.2% per year was used for the Seal Cove substation. This same growth rate was used to project to the year 2022.

In addition, high and low forecasts were developed to judge the sensitivity of the alternatives analysis to load forecast variability. The base forecast is noted in Appendix A, with high and low forecasts noted in Appendix C.

Development of Alternatives

<u>Technical Criteria</u>

The following technical criteria were established to ensure acceptable operating standards for distribution feeders:

1. The minimum steady state feeder voltage should not fall below 116 volts on a 120-volt base.
2. The number of customers served through a distribution feeder without backup capability should not exceed 3000.
3. The steady state substation power transformer loading should not exceed the nameplate rating.
4. The recloser normal peak loading should be restricted to permit adequate cold load pickup. In the Kelligrews and Seal Cove instance this would be 500 amps per phase (10.8 MVA at 12.5 kV).
5. The conductor loading should not exceed the ampacity rating established in the Company's Distribution Planning Guidelines

<u>Planning Methodology and the Development of Alternatives</u>

The planning methodology is the process whereby the forecasted electrical demands are serviced through developing alternatives that meet the technical criteria. These alternatives are then evaluated using economic analysis and other judgement factors. Based on this analysis a preferred alternative is recommended. As the load forecast extended to 2022, capital additions are projected from 2004 to 2022.

The number of customers currently served by CHA-01 without backup at 3,082 now exceeds the technical criteria. Alternatives are developed that permit backup of CHA-01 as the number of customers supplied via this feeder continue to grow beyond 3,000. This is done by adding another feeder to Chamberlains substation (CHA-03) and extending it south along the new highway. As CHA-01 extends south along the old CBS highway, there will be tie points between CHA-01 and CHA-03, providing the backup to CHA-01. Kelligrews feeders cannot provide this backup, as the feeder voltages supplied through Chamberlains and Kelligrews substations are different.

In reviewing the load forecast, it is apparent that the Kelligrews substation transformer load is exceeding capacity in the short term (2007). The 2003 transformer capacity addition at Chamberlains has resulted in significant transformer capacity being available at Chamberlains. The 2007 transformer capacity deficit at Kelligrews can be met through either adding transformer capacity at Kelligrews or transferring load from Kelligrews substation to Chamberlains substation and deferring the transformer capacity addition to the Kelligrews substation. Three alternatives are developed and are grouped into these two categories.

Two of the three alternatives include the construction of a new CHA-03 feeder from the CHA substation. This is to address the large number of customers presently serviced through the CHA-01 feeder and to meet technical criteria number 2. However, alternative # 3 evaluates the system without the construction of this CHA-03 feeder in order to determine the cost of meeting this criterion.

A description of each alternative follows:

<u>Alternative #1</u>

The first alternative has as its initial element the 2004 construction of a new 25 kV feeder (CHA-03) from the Chamberlains substation. A 66-25/12.5, 15 MVA power transformer is added at the Kelligrews substation in 2007. A recloser is replaced with a breaker at the Kelligrews substation in 2014 to avoid overloading the recloser. To avoid adding additional transformer capacity at the Seal Cove substation, a transfer of 2 MVA of load from SCV-01 to KEL-01 would be required, starting with 1.0 MVA in the year 2007.

The new CHA-03 feeder would extend south along Fowler’s Road to the new CBS By-Pass Road, then it would extend west along the CBS By-Pass Road to the intersection of Dunn’s Hill Road. At the same time the section extending out Mineral Road where it intersects with Conception Bay Highway would be upgraded and re-conductored. This would permit CHA-01 & CHA-03 to be paralleled and provide backup. Construction of the new CHA-03 feeder would include the following:

1. The reconductoring of the existing line along Fowler's Road and Mineral Road to three phase 477 mcm.
2. The extension of the Cherry Hill subdivision tap to the intersection of the By-Pass Road. This would allow this new subdivision with a potential of 200 residential lots to be fed from this new feeder.
3. The upgrading of a section of line running down Southshore Drive from single phase to three phase and the construction of two spans of single phase line to connect Cambridge Crescent with Sweetenwater Avenue. This would allow for all of the existing residential development south of the substation to be fed from this new feeder.
4. The construction of a 3.8 km three phase line along the CBS By-Pass Road with 477 mcm conductor to Mineral Road.

The new CHA-03 feeder could tap into any of the various distribution lines that intersect the CBS By-Pass Road to balance the load between CHA-01 and CHA-03. The most important feature is the availability of backup on CHA-01 and the reduction of the number of customers on any one feeder.

Alternative # 1	**Cost [1]**	**Year**
Construction of CHA-03 feeder - (Distribution)	304,884	2004
Construction of CHA-03 feeder - (Substation)	106,000	2004
Add additional 66-25/12.5, 15 MVA transformer at KEL Substation - (Substation)	1,184,758	2007
Replace KEL-02-R with a breaker - (Substation)	112,994	2014
Transfer 1.0 MVA from SCV-01 to KEL-01		07 & 15
Total capital cost	**1,708,636**	

[1] Current dollars – see Appendix E.

Alternative #2

The second alternative is similar to alternative #1. The exception is the 2007 conversion of a portion (4.5 MVA) of KEL-02 load from 12.5 kV to 25 kV and transferring this converted load to CHA-01. This would delay the requirement of the new 66-25/12.5, 15 MVA power transformer at Kelligrews substation for 10 years. The section to be converted would include all of the KEL-02 feeder beyond the tap to Peachytown Road to the end of the feeder. This would be the maximum load that could be transferred at this time. If the actual load growth is somewhat greater than expected, the transformer capacity at Chamberlains substation would be fully utilized by 2022.

The 2004 construction of a new CHA-03 25 kV feeder would be extended to Dunn's Hill Road (an additional 0.9 km). To avoid adding additional transformer capacity at the Seal Cove substation, a transfer of 2 MVA of load from SCV-01 to KEL-01 would still be required starting in year 2007.

Alternative # 2	Cost [1]	Year Required
Construction of CHA-03 feeder - (Distribution)	342,000	2004
Construction of CHA-03 feeder - (Substation)	106,000	2004
Convert a portion of KEL-02 to 25 kV & transfer to CHA-01 - (Distribution)	180,000	2007
Add additional 66-25/12.5, 15 MVA transformer at KEL Substation - (Substation)	1,184,758	2017
Transfer 1.0 MVA from SCV-01 to KEL-01		07 & 15
Total capital cost	**1,812,758**	

[1] Current dollars – see Appendix E.

<u>Alternative #3</u>

The third alternative is similar to alternative # 1 without the construction of a new Chamberlains feeder. It does not change the existing feeders configuration, but adds additional transformer capacity at Kelligrews when required. Load from SCV-01 is transferred to KEL-01 as the transformer capacity at SCV reaches its limit.

Alternative #3 does not meet the technical requirement limiting the number of customers per feeder to 3,000. It is considered to judge the cost of meeting this criteria through comparison with the other two alternatives.

Alternative # 3	Cost [1]	Year Required
Add additional 66-25/12.5, 15 MVA transformer at KEL Substation - (Substation)	1,184,758	2007
Replace KEL-02-R with a breaker - (Substation)	112,994	2014
Transfer 1.0 MVA from SCV-01 to KEL-01		07 & 15
Total construction cost	**1,297,752**	

[1] Current dollars – see Appendix E.

Economic Analysis

In order to compare the economic impact of the alternatives, a net present value calculation of customer revenue requirement was completed for each alternative.

Capital costs from 2004 to 2022 were converted to revenue requirement and the resulting customer revenue requirement from 2004 to 2042 was reduced to a net present value using the corporate weighted average incremental cost of capital. The result for each alternative is indicated in the following table. The details of the net present value calculations are shown in Appendix B.

In comparing the two alternatives that meet the technical criteria, alternative #2 is the lowest cost.

Alternative	Net Present Value Revenue Requirement ($)
1	1,715,945
2	1,292,444
3	1,224,343

Sensitivity Analysis

In order to test the validity of selecting the lowest cost alternative, the sensitivity of the alternatives to varying load forecasts is calculated. These forecasts are shown in Appendix C and are denoted as high and low forecasts. The low forecast results in extending the time to when the construction is projected. Similarly, with a higher load forecast the time of the projects is advanced. Using these revised dates, the net present value of revenue requirement is calculated. The results of these calculations are shown in the following table and the details of the net present value calculations are shown in Appendix D. The details and costs for each alternative are shown in Appendix E.

In reviewing the table, the low forecast scenario results in alternative #2 being the low cost option. Under the high forecast scenario, alternative #3 remains the low cost option. However, it does not meet all the technical criteria.

Alternative	NPV RR Low Forecast Scenario	NPV RR Base Forecast Scenario	NPV RR High Forecast Scenario
1	1,436,569	1,715,945	1,959,403
2	673,174	1,292,444	1,622,697
3	882,988	1,224,343	1,469,775

Conclusions and Recommendations

A 20-year load forecast by feeder has projected the electrical demands for the community of Conception Bay South. The development and analysis of alternatives has established a preferred expansion plan to meet these needs. Further, a sensitivity analysis has confirmed the robustness of the recommended alternative to varying load growth.

The lowest cost alternative that meets all of the technical criteria is alternative #2. It includes the 2004 construction of the CHA-03 feeder, the 2007 conversion of 4.5 MVA of KEL-02 feeder load from 12.5 kV to 25 kV and the transfer of this converted load to CHA-01 and to CHA-03 feeders. This alternative, in addition to meeting the technical criteria and the projected loads, will defer the need for additional transformer capacity at Kelligrews and Seal Cove substations to well beyond the 5-year capital budget horizon.

Appendix A

Load Forecast

Estimated Load Forecast (Medium)

Feeders	Base Peaks	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018	2020	2022
SCV-01	7632	7919	8014	8110	8306	7495	7675	7861	8051	7233	7408	7586	7770
SCV-02	2232	2681	2713	2746	2812	2880	2949	3021	3094	3168	3245	3323	3403
Sub Total	**9864**	**10600**	**10727**	**10856**	**11118**	**10374**	**10625**	**10881**	**11144**	**10401**	**10652**	**10910**	**11173**
SCV T2 Capacity		11200	11200	11200	11200	11200	11200	11200	11200	11200	11200	11200	11200
TFMR Requirements		-600	-473	-344	-82	-826	-575	-319	-56	-799	-548	-290	-27
KEL-01	5107	5209	5313	5419	5638	6886	7164	7454	7755	9088	9455	9837	10235
KEL-02	8402	8570	8741	8916	9276	9651	10041	10447	10869	11308	11765	12240	12735
Sub Total	**13509**	**13779**	**14055**	**14336**	**14915**	**16537**	**17206**	**17901**	**18624**	**20396**	**21220**	**22077**	**22969**
KEL T1 Capacity		14950	14950	14950	14950	14950	14950	14950	14950	14950	14950	14950	14950
TFMR Requirements		-1171	-895	-614	-35	1587	2256	2951	3674	5446	6270	7127	8019
CHA-01	13969	15423	15731	16046	16694	17369	18071	18801	19560	20350	21172	22028	22918
CHA-02	9300	9663	9856	10053	10460	10882	11322	11779	12255	12750	13265	13801	14359
Sub Total	**23269**	**25086**	**25588**	**26099**	**27154**	**28251**	**29392**	**30580**	**31815**	**33100**	**34438**	**35829**	**37276**
CHA Capacity		50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
TFMR Requirements		-24914	-24412	-23901	-22846	-21749	-20608	-19420	-18185	-16900	-15562	-14171	-12724

SCV-01 is based on a 2001 peak of 7632 kva
SCV-02 is based on a 1994 peak of 2232 kva

CHA-01 is based on a 1997 peak of 13969 kva
CHA-02 is based on a 2000 peak of 9288 kva

SCV Substation Growth	1.20%
KEL Pond Substation Growth	2.00%
CHA Substation Growth	2.00%

New 25.0 mva TFMR being installed at CHA this year
1.5 mva of load was transferred from KEL-01 to SCV-01 in 1999
2.5 mva of load transferred from CHA-02 to HWD-08 feeder in 2001

Appendix B

Economic Analysis

Present Worth Analysis - Alternative #1- Medium Forecast

Weighted Average Incremental Cost of Capital 8.52%
Escalation Rate 1.70%

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2004	106,000	304,884	60,045	0	0	-60,045	-55,331	-55,331
2005			54,381	0	0	-54,381	-46,177	-101,508
2006			53,311	0	0	-53,311	-41,715	-143,223
2007	1,246,214		224,889	0	0	-224,889	-162,155	-305,377
2008			207,319	0	0	-207,319	-137,749	-443,127
2009			203,672	0	0	-203,672	-124,702	-567,828
2010			199,970	0	0	-199,970	-112,823	-680,651
2011			196,217	0	0	-196,217	-102,014	-782,665
2012			192,413	0	0	-192,413	-92,182	-874,847
2013			188,561	0	0	-188,561	-83,244	-958,091
2014	133,741		203,193	0	0	-203,193	-82,661	-1,040,753
2015			197,483	0	0	-197,483	-74,031	-1,114,783
2016			193,226	0	0	-193,226	-66,748	-1,181,531
2017			188,923	0	0	-188,923	-60,138	-1,241,669
2018			184,577	0	0	-184,577	-54,142	-1,295,811
2019			180,190	0	0	-180,190	-48,705	-1,344,516
2020			175,762	0	0	-175,762	-43,778	-1,388,294
2021			171,295	0	0	-171,295	-39,316	-1,427,610
2022			166,792	0	0	-166,792	-35,277	-1,462,887
2023			162,253	0	0	-162,253	-31,622	-1,494,509
2024			157,680	0	0	-157,680	-28,318	-1,522,828
2025			153,074	0	0	-153,074	-25,333	-1,548,161
2026			148,437	0	0	-148,437	-22,637	-1,570,798
2027			143,769	0	0	-143,769	-20,204	-1,591,001
2028			139,073	0	0	-139,073	-18,009	-1,609,011
2029			134,349	0	0	-134,349	-16,032	-1,625,042
2030			129,598	0	0	-129,598	-14,251	-1,639,293
2031			124,821	0	0	-124,821	-12,648	-1,651,941
2032			120,020	0	0	-120,020	-11,207	-1,663,147
2033			115,196	0	0	-115,196	-9,912	-1,673,059
2034			86,259	0	0	-86,259	-6,839	-1,679,898
2035			93,176	0	0	-93,176	-6,808	-1,686,705
2036			89,321	0	0	-89,321	-6,014	-1,692,719
2037			85,450	0	0	-85,450	-5,301	-1,698,020
2038			81,562	0	0	-81,562	-4,663	-1,702,683
2039			77,659	0	0	-77,659	-4,091	-1,706,774
2040			73,740	0	0	-73,740	-3,580	-1,710,354
2041			69,807	0	0	-69,807	-3,123	-1,713,477
2042			59,876	0	0	-59,876	-2,468	-1,715,945

Present Worth Analysis - Alternative #2 - Medium Forecast

Weighted Average Incremental Cost of Capital 8.52%
Escalation Rate 1.70%

YEAR	Substation (38.5 yrs, 4% CCA)	Distribution (30.4 yrs, 4% CCA)	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
	CAPITAL EXPENDITURE IN YEAR BY ASSET							
2004	342,000	106,000	63,154	0	0	-63,154	-58,196	-58,196
2005			57,151	0	0	-57,151	-48,529	-106,725
2006			56,158	0	0	-56,158	-43,942	-150,667
2007		189,337	83,318	0	0	-83,318	-60,076	-210,742
2008			79,648	0	0	-79,648	-52,920	-263,663
2009			78,081	0	0	-78,081	-47,806	-311,469
2010			76,494	0	0	-76,494	-43,158	-354,627
2011			74,888	0	0	-74,888	-38,934	-393,561
2012			73,264	0	0	-73,264	-35,100	-428,661
2013			71,622	0	0	-71,622	-31,619	-460,280
2014			69,964	0	0	-69,964	-28,462	-488,742
2015			68,290	0	0	-68,290	-25,600	-514,342
2016			66,600	0	0	-66,600	-23,006	-537,348
2017	1,475,034		269,259	0	0	-269,259	-85,710	-623,059
2018			248,042	0	0	-248,042	-72,758	-695,816
2019			243,306	0	0	-243,306	-65,765	-761,581
2020			238,507	0	0	-238,507	-59,407	-820,988
2021			233,647	0	0	-233,647	-53,627	-874,615
2022			228,730	0	0	-228,730	-48,377	-922,992
2023			223,757	0	0	-223,757	-43,609	-966,601
2024			218,730	0	0	-218,730	-39,283	-1,005,884
2025			213,652	0	0	-213,652	-35,358	-1,041,242
2026			208,525	0	0	-208,525	-31,800	-1,073,043
2027			203,350	0	0	-203,350	-28,577	-1,101,619
2028			198,130	0	0	-198,130	-25,657	-1,127,276
2029			192,867	0	0	-192,867	-23,015	-1,150,291
2030			187,561	0	0	-187,561	-20,624	-1,170,915
2031			182,216	0	0	-182,216	-18,463	-1,189,379
2032			176,831	0	0	-176,831	-16,511	-1,205,890
2033			171,410	0	0	-171,410	-14,748	-1,220,638
2034			157,578	0	0	-157,578	-12,494	-1,233,132
2035			156,185	0	0	-156,185	-11,411	-1,244,543
2036			151,021	0	0	-151,021	-10,168	-1,254,710
2037			130,868	0	0	-130,868	-8,119	-1,262,829
2038			132,963	0	0	-132,963	-7,601	-1,270,431
2039			128,355	0	0	-128,355	-6,762	-1,277,193
2040			123,722	0	0	-123,722	-6,006	-1,283,198
2041			119,065	0	0	-119,065	-5,326	-1,288,525
2042			95,077	0	0	-95,077	-3,919	-1,292,444

Present Worth Analysis - Alternative #3 - Medium Forecast

Weighted Average Incremental Cost of Capital **8.52%**
Escalation Rate **1.70%**

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Capital Revenue Requirement	Present Worth Benefit	Cumulative Present Worth Benefit
2004			0	0	0
2005			0	0	0
2006			0	0	0
2007	1,246,214		172,661	-124,496	-124,496
2008			156,188	-103,776	-228,272
2009			153,650	-94,075	-322,348
2010			151,071	-85,234	-407,581
2011			148,451	-77,180	-484,762
2012			145,792	-69,847	-554,608
2013			143,097	-63,173	-617,781
2014	133,741		158,895	-64,640	-682,421
2015			154,361	-57,865	-740,287
2016			151,290	-52,262	-792,548
2017			148,182	-47,169	-839,718
2018			145,040	-42,544	-882,262
2019			141,865	-38,346	-920,608
2020			138,658	-34,536	-955,144
2021			135,420	-31,082	-986,226
2022			132,152	-27,950	-1,014,177
2023			128,856	-25,114	-1,039,290
2024			125,533	-22,545	-1,061,835
2025			122,184	-20,221	-1,082,056
2026			118,810	-18,119	-1,100,175
2027			115,412	-16,219	-1,116,394
2028			111,991	-14,502	-1,130,896
2029			108,548	-12,953	-1,143,849
2030			105,083	-11,555	-1,155,404
2031			101,598	-10,295	-1,165,699
2032			98,094	-9,159	-1,174,858
2033			94,571	-8,137	-1,182,995
2034			91,029	-7,217	-1,190,212
2035			87,470	-6,391	-1,196,603
2036			83,895	-5,648	-1,202,251
2037			80,304	-4,982	-1,207,233
2038			76,697	-4,385	-1,211,618
2039			73,076	-3,850	-1,215,468
2040			69,440	-3,371	-1,218,838
2041			65,791	-2,943	-1,221,781
2042			62,129	-2,561	-1,224,343

Appendix C

High / Low Forecast

Estimated Load Forecast (Low Side)

Feeders	Base Peaks	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018	2020	2022
SCV-01	7632	7919	7967	8014	8111	8208	8307	7407	7496	7587	7678	7770	7864
SCV-02	2232	2681	2697	2713	2746	2779	2812	2846	2881	2915	2950	2986	3022
Sub Total	**9864**	**10600**	**10664**	**10728**	**10857**	**10987**	**11120**	**10253**	**10377**	**10502**	**10628**	**10756**	**10886**
SCV T2 Capacity		11200	11200	11200	11200	11200	11200	11200	11200	11200	11200	11200	11200
TFMR Requirements		-600	-536	-472	-343	-213	-80	-947	-823	-698	-572	-444	-314
KEL-01	5107	5209	5261	5314	5421	5529	5641	6754	6890	7028	7169	7314	7461
KEL-02	8402	8570	8656	8742	8918	9097	9280	9467	9657	9851	10049	10251	10457
Sub Total	**13509**	**13779**	**13917**	**14056**	**14338**	**14627**	**14921**	**16221**	**16547**	**16879**	**17218**	**17565**	**17918**
KEL T1 Capacity		14950	14950	14950	14950	14950	14950	14950	14950	14950	14950	14950	14950
TFMR Requirements		-1171	-1033	-894	-612	-323	-29	1271	1597	1929	2268	2615	2968
CHA-01	13969	15423	15577	15733	16049	16372	16701	17037	17379	17728	18085	18448	18819
CHA-02	9300	9663	9760	9857	10055	10257	10464	10674	10889	11107	11331	11558	11791
Sub Total	**23269**	**25086**	**25337**	**25590**	**26105**	**26629**	**27165**	**27711**	**28268**	**28836**	**29415**	**30007**	**30610**
CHA Capacity		50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
TFMR Requirements		-24914	-24663	-24410	-23895	-23371	-22835	-22289	-21732	-21164	-20585	-19993	-19390

SCV Substation Growth	0.60%
KEL Pond Substation Growth	1.00%
CHA Substation Growth	1.00%

New 25.0 mva TFMR being installed at CHA this year
1.5 mva of load was transferred from KEL-01 to SCV-01 in 1999
2.5 mva of load transferred from CHA-02 to HWD-08 feeder in 2001

Estimated Load Forecast (High Side)

Feeders	Base Peaks	2002	2003	2004	2006	2008	2010	2012	2014	2016	2018	2020	2022
SCV-01	7632	7919	8062	8207	7505	7777	8060	7335	7601	6877	7127	7386	6636
SCV-02	2232	2681	2729	2778	2879	2984	3092	3205	3321	3442	3567	3696	3830
Sub Total	**9864**	**10600**	**10791**	**10985**	**10384**	**10761**	**11152**	**10539**	**10922**	**10319**	**10694**	**11082**	**10467**
SCV T2 Capacity		11200	11200	11200	11200	11200	11200	11200	11200	11200	11200	11200	11200
TFMR Requirements		-600	-409	-215	-816	-439	-48	-661	-278	-881	-506	-118	-733
KEL-01	5107	5209	5365	5526	6863	7281	7724	9225	9786	11382	12075	12811	14621
KEL-02	8402	8570	8827	9092	9646	10233	10856	11517	12219	12963	13752	14590	15478
Sub Total	**13509**	**13779**	**14192**	**14618**	**16508**	**17514**	**18580**	**20742**	**22005**	**24345**	**25828**	**27401**	**30099**
KEL T1 Capacity		14950	14950	14950	14950	14950	14950	14950	14950	14950	14950	14950	14950
TFMR Requirements		-1171	-758	-332	1558	2564	3630	5792	7055	9395	10878	12451	15149
CHA-01	13969	15423	15886	16362	17359	18416	19537	20727	21990	23329	24749	26257	27856
CHA-02	9300	9663	9953	10251	10876	11538	12241	12986	13777	14616	15506	16451	17452
Sub Total	**23269**	**25086**	**25839**	**26614**	**28235**	**29954**	**31778**	**33713**	**35767**	**37945**	**40256**	**42707**	**45308**
CHA Capacity		50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
TFMR Requirements		-24914	-24161	-23386	-21765	-20046	-18222	-16287	-14233	-12055	-9744	-7293	-4692

SCV Substation Growth	1.80%
KEL Pond Substation Growth	3.00%
CHA Substation Growth	3.00%

New 25.0 mva TFMR being installed at CHA this year
1.5 mva of load was transferred from KEL-01 to SCV-01 in 1999
2.5 mva of load transferred from CHA-02 to HWD-08 feeder in 2001

Appendix D

High / Low Economic Analysis

Present Worth Analysis - Alternative #1 - High Load Forecast

Weighted Average Incremental Cost of Capital 8.52%
Escalation Rate 1.70%
PW Year

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2004	106,000	304,884	60,045	0	0	-60,045	-55,331	-55,331
2005	1,204,899		221,318	0	0	-221,318	-187,930	-243,262
2006			204,321	0	0	-204,321	-159,876	-403,138
2007			200,784	0	0	-200,784	-144,774	-547,912
2008			197,194	0	0	-197,194	-131,022	-678,934
2009			193,551	0	0	-193,551	-118,505	-797,439
2010	125,020		207,180	0	0	-207,180	-116,890	-914,329
2011			201,787	0	0	-201,787	-104,910	-1,019,239
2012			197,747	0	0	-197,747	-94,737	-1,113,976
2013			193,658	0	0	-193,658	-85,494	-1,199,470
2014			189,522	0	0	-189,522	-77,100	-1,276,570
2015			185,343	0	0	-185,343	-69,480	-1,346,050
2016	133,741		199,650	0	0	-199,650	-68,967	-1,415,017
2017			193,619	0	0	-193,619	-61,633	-1,476,649
2018			189,044	0	0	-189,044	-55,452	-1,532,101
2019			184,426	0	0	-184,426	-49,850	-1,581,951
2020			179,768	0	0	-179,768	-44,776	-1,626,727
2021			175,072	0	0	-175,072	-40,183	-1,666,910
2022			170,337	0	0	-170,337	-36,027	-1,702,937
2023			165,567	0	0	-165,567	-32,268	-1,735,205
2024			160,762	0	0	-160,762	-28,872	-1,764,077
2025			155,924	0	0	-155,924	-25,805	-1,789,882
2026			151,055	0	0	-151,055	-23,036	-1,812,918
2027			146,155	0	0	-146,155	-20,539	-1,833,457
2028			141,225	0	0	-141,225	-18,288	-1,851,745
2029			136,268	0	0	-136,268	-16,261	-1,868,006
2030			131,283	0	0	-131,283	-14,436	-1,882,442
2031			126,273	0	0	-126,273	-12,795	-1,895,237
2032			121,237	0	0	-121,237	-11,320	-1,906,557
2033			116,178	0	0	-116,178	-9,996	-1,916,553
2034			87,007	0	0	-87,007	-6,898	-1,923,451
2035			93,688	0	0	-93,688	-6,845	-1,930,296
2036			89,599	0	0	-89,599	-6,032	-1,936,329
2037			85,492	0	0	-85,492	-5,304	-1,941,632
2038			81,368	0	0	-81,368	-4,652	-1,946,284
2039			77,229	0	0	-77,229	-4,068	-1,950,353
2040			73,074	0	0	-73,074	-3,547	-1,953,900
2041			68,905	0	0	-68,905	-3,082	-1,956,982
2042			58,737	0	0	-58,737	-2,421	-1,959,403

Present Worth Analysis - Alternative #2 - High Forecast

Weighted Average Incremental Cost of Capital 8.52%
Escalation Rate 1.70%

	CAPITAL EXPENDITURE IN YEAR BY ASSET T							
	Substation	Distribution	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
	38.5 yrs 4% CCA	30.4 yrs 4% CCA						
YEAR								
2004	106,000	342,000	65,567	0	0	-65,567	-60,420	-60,420
2005		183,060	86,619	0	0	-86,619	-73,552	-133,971
2006			82,885	0	0	-82,885	-64,856	-198,827
2007			81,184	0	0	-81,184	-58,537	-257,364
2008			79,462	0	0	-79,462	-52,797	-310,161
2009			77,720	0	0	-77,720	-47,585	-357,746
2010			75,959	0	0	-75,959	-42,856	-400,602
2011			74,180	0	0	-74,180	-38,566	-439,168
2012	1,355,805		260,228	0	0	-260,228	-124,671	-563,839
2013			240,492	0	0	-240,492	-106,170	-670,009
2014			235,901	0	0	-235,901	-95,967	-765,976
2015			231,249	0	0	-231,249	-86,689	-852,665
2016	138,327		245,703	0	0	-245,703	-84,876	-937,541
2017			239,108	0	0	-239,108	-76,113	-1,013,653
2018			234,004	0	0	-234,004	-68,640	-1,082,293
2019			228,844	0	0	-228,844	-61,856	-1,144,150
2020			223,630	0	0	-223,630	-55,701	-1,199,851
2021			218,363	0	0	-218,363	-50,119	-1,249,970
2022			213,046	0	0	-213,046	-45,060	-1,295,030
2023			207,681	0	0	-207,681	-40,476	-1,335,506
2024			202,269	0	0	-202,269	-36,327	-1,371,832
2025			196,813	0	0	-196,813	-32,572	-1,404,404
2026			191,314	0	0	-191,314	-29,176	-1,433,580
2027			185,775	0	0	-185,775	-26,107	-1,459,686
2028			180,196	0	0	-180,196	-23,335	-1,483,021
2029			174,579	0	0	-174,579	-20,832	-1,503,853
2030			168,926	0	0	-168,926	-18,575	-1,522,428
2031			163,238	0	0	-163,238	-16,540	-1,538,969
2032			157,517	0	0	-157,517	-14,708	-1,553,677
2033			151,764	0	0	-151,764	-13,058	-1,566,735
2034			118,959	0	0	-118,959	-9,432	-1,576,166
2035			111,902	0	0	-111,902	-8,176	-1,584,342
2036			114,298	0	0	-114,298	-7,695	-1,592,037
2037			110,216	0	0	-110,216	-6,838	-1,598,875
2038			106,112	0	0	-106,112	-6,066	-1,604,941
2039			101,989	0	0	-101,989	-5,373	-1,610,314
2040			97,846	0	0	-97,846	-4,750	-1,615,064
2041			93,684	0	0	-93,684	-4,191	-1,619,255
2042			83,520	0	0	-83,520	-3,443	-1,622,697

Present Worth Analysis - Alternative #3 - High Forecast

Weighted Average Incremental Cost of Capital **8.52%**
Escalation Rate **1.70%**

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Capital Revenue Requirement	Present Worth Benefit	Cumulative Present Worth Benefit
2004			0	0	0
2005	**1,204,899**		166,937	-141,753	-141,753
2006			151,010	-118,161	-259,915
2007			148,557	-107,116	-367,030
2008			146,063	-97,049	-464,079
2009			143,530	-87,879	-551,958
2010	**125,020**		158,281	-89,302	-641,259
2011			154,021	-80,076	-721,335
2012			151,126	-72,402	-793,737
2013			148,193	-65,423	-859,160
2014			145,224	-59,079	-918,239
2015			142,221	-53,314	-971,553
2016	**138,327**		158,349	-54,700	-1,026,253
2017			153,452	-48,847	-1,075,100
2018			150,072	-44,020	-1,119,121
2019			146,658	-39,641	-1,158,762
2020			143,211	-35,670	-1,194,432
2021			139,732	-32,072	-1,226,504
2022			136,224	-28,812	-1,255,316
2023			132,687	-25,860	-1,281,176
2024			129,122	-23,190	-1,304,366
2025			125,531	-20,775	-1,325,140
2026			121,914	-18,592	-1,343,733
2027			118,273	-16,621	-1,360,353
2028			114,608	-14,841	-1,375,195
2029			110,921	-13,236	-1,388,431
2030			107,212	-11,789	-1,400,220
2031			103,482	-10,486	-1,410,705
2032			99,732	-9,312	-1,420,017
2033			95,963	-8,257	-1,428,274
2034			92,175	-7,308	-1,435,582
2035			88,370	-6,456	-1,442,039
2036			84,548	-5,692	-1,447,731
2037			80,710	-5,007	-1,452,738
2038			76,856	-4,394	-1,457,132
2039			72,987	-3,845	-1,460,977
2040			69,104	-3,355	-1,464,331
2041			65,207	-2,917	-1,467,248
2042			61,296	-2,527	-1,469,775

Present Worth Analysis - Alternative #1 - Low Load Forecast

Weighted Average Incremental Cost of Capital 8.52%
Escalation Rate 1.70%

	CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE							
	Substation	Distribution	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
YEAR	38.5 yrs 4% CCA	30.4 yrs 4% CCA						
2004	**106,000**	**304,884**	60,045	**0**	**0**	-60,045	-55,331	-55,331
2005			54,381	0	0	-54,381	-46,177	-101,508
2006			53,311	0	0	-53,311	-41,715	-143,223
2007			52,228	0	0	-52,228	-37,658	-180,881
2008			51,131	0	0	-51,131	-33,973	-214,854
2009			50,021	0	0	-50,021	-30,626	-245,481
2010	**1,310,857**		230,517	0	0	-230,517	-130,057	-375,538
2011			212,055	0	0	-212,055	-110,248	-485,786
2012			208,241	0	0	-208,241	-99,765	-585,551
2013			204,372	0	0	-204,372	-90,224	-675,775
2014			200,450	0	0	-200,450	-81,545	-757,321
2015			196,477	0	0	-196,477	-73,654	-830,974
2016			192,456	0	0	-192,456	-66,482	-897,456
2017			188,387	0	0	-188,387	-59,967	-957,424
2018			184,274	0	0	-184,274	-54,053	-1,011,476
2019			180,117	0	0	-180,117	-48,685	-1,060,162
2020			175,919	0	0	-175,919	-43,817	-1,103,979
2021			171,681	0	0	-171,681	-39,405	-1,143,384
2022			167,406	0	0	-167,406	-35,407	-1,178,790
2023			163,093	0	0	-163,093	-31,786	-1,210,577
2024			158,745	0	0	-158,745	-28,510	-1,239,086
2025			154,364	0	0	-154,364	-25,546	-1,264,633
2026			149,950	0	0	-149,950	-22,868	-1,287,500
2027			145,505	0	0	-145,505	-20,448	-1,307,948
2028			141,029	0	0	-141,029	-18,263	-1,326,211
2029			136,526	0	0	-136,526	-16,291	-1,342,502
2030			131,995	0	0	-131,995	-14,514	-1,357,016
2031			127,437	0	0	-127,437	-12,913	-1,369,929
2032			122,854	0	0	-122,854	-11,471	-1,381,400
2033			118,246	0	0	-118,246	-10,174	-1,391,574
2034			89,527	0	0	-89,527	-7,098	-1,398,673
2035			96,659	0	0	-96,659	-7,062	-1,405,735
2036			93,020	0	0	-93,020	-6,263	-1,411,997
2037			89,363	0	0	-89,363	-5,544	-1,417,541
2038			85,689	0	0	-85,689	-4,899	-1,422,440
2039			81,999	0	0	-81,999	-4,320	-1,426,760
2040			78,293	0	0	-78,293	-3,801	-1,430,560
2041			74,572	0	0	-74,572	-3,336	-1,433,896
2042			64,852	0	0	-64,852	-2,673	-1,436,569

Present Worth Analysis - Alternative #2 - Low Forecast

Weighted Average Incremental Cost of Capital **8.52%**
Escalation Rate **1.70%**

YEAR	CAPITAL EXPENDITURE IN YEAR BY ASSET ' Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2004	106,000	342,000	65,567	0	0	-65,567	-60,420	-60,420
2005			59,384	0	0	-59,384	-50,425	-110,845
2006			58,210	0	0	-58,210	-45,548	-156,393
2007			57,022	0	0	-57,022	-41,115	-197,508
2008			55,818	0	0	-55,818	-37,088	-234,595
2009			54,601	0	0	-54,601	-33,431	-268,026
2010			53,371	0	0	-53,371	-30,112	-298,137
2011		202,544	82,261	0	0	-82,261	-42,768	-340,905
2012			78,173	0	0	-78,173	-37,451	-378,356
2013			76,338	0	0	-76,338	-33,701	-412,057
2014			74,485	0	0	-74,485	-30,301	-442,359
2015			72,614	0	0	-72,614	-27,221	-469,580
2016			70,727	0	0	-70,727	-24,432	-494,012
2017			68,824	0	0	-68,824	-21,908	-515,919
2018			66,905	0	0	-66,905	-19,625	-535,545
2019			64,971	0	0	-64,971	-17,562	-553,106
2020			63,023	0	0	-63,023	-15,698	-568,804
2021			61,062	0	0	-61,062	-14,015	-582,819
2022			59,087	0	0	-59,087	-12,497	-595,316
2023			57,099	0	0	-57,099	-11,128	-606,444
2024			55,100	0	0	-55,100	-9,896	-616,340
2025			53,089	0	0	-53,089	-8,786	-625,126
2026			51,066	0	0	-51,066	-7,788	-632,913
2027			49,033	0	0	-49,033	-6,891	-639,804
2028			46,990	0	0	-46,990	-6,085	-645,889
2029			44,937	0	0	-44,937	-5,362	-651,251
2030			42,874	0	0	-42,874	-4,714	-655,966
2031			40,803	0	0	-40,803	-4,134	-660,100
2032			38,722	0	0	-38,722	-3,616	-663,716
2033			36,633	0	0	-36,633	-3,152	-666,868
2034			7,515	0	0	-7,515	-596	-667,464
2035			18,631	0	0	-18,631	-1,361	-668,825
2036			17,680	0	0	-17,680	-1,190	-670,015
2037			16,726	0	0	-16,726	-1,038	-671,053
2038			15,769	0	0	-15,769	-901	-671,954
2039			14,808	0	0	-14,808	-780	-672,734
2040			13,843	0	0	-13,843	-672	-673,406
2041			-3,127	0	0	3,127	140	-673,267
2042			-2,253	0	0	2,253	93	-673,174

Present Worth Analysis - Alternative #3 - Low Forecast

Weighted Average Incremental Cost of Capital **8.52%**
Escalation Rate **1.70%**

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Capital Revenue Requirement	Present Worth Benefit	Cumulative Present Worth Benefit
2004			0	0	0
2005			0	0	0
2006			0	0	0
2007			0	0	0
2008			0	0	0
2009			0	0	0
2010			0	0	0
2011	**1,333,142**		184,705	-96,029	-96,029
2012			167,082	-80,047	-176,075
2013			164,368	-72,564	-248,639
2014			161,609	-65,744	-314,383
2015			158,806	-59,532	-373,915
2016			155,962	-53,876	-427,791
2017			153,078	-48,728	-476,518
2018			150,156	-44,045	-520,563
2019			147,197	-39,787	-560,350
2020			144,203	-35,918	-596,268
2021			141,175	-32,403	-628,671
2022			138,115	-29,211	-657,882
2023			135,023	-26,316	-684,198
2024			131,901	-23,689	-707,887
2025			128,751	-21,308	-729,194
2026			125,573	-19,150	-748,344
2027			122,369	-17,196	-765,541
2028			119,139	-15,428	-780,969
2029			115,885	-13,828	-794,797
2030			112,607	-12,382	-807,180
2031			109,307	-11,076	-818,255
2032			105,986	-9,896	-828,151
2033			102,643	-8,832	-836,983
2034			99,281	-7,872	-844,855
2035			95,900	-7,007	-851,861
2036			92,500	-6,228	-858,089
2037			89,082	-5,527	-863,615
2038			85,648	-4,896	-868,512
2039			82,198	-4,330	-872,842
2040			78,732	-3,822	-876,664
2041			75,251	-3,366	-880,030
2042			71,755	-2,958	-882,988

Appendix E

Alternative Detailed Costs and Scheduling

CBS Long Term Study

Alternative # 1	Distribution	Substation	Total Cost	Year of Expenditures Required for each Forecast: Low	Medium	High
Construct new feeder (CHA-03) along new By-Pass Road						
1 Up Fowlers Road, Out By-pass Road, down Mineral Road & connect Cherry Hill Subdivision	277,884		**277,884**	2004	2004	2004
2 Southshore Drive & connect Sweetenwater Drive to feeder on Fowler's Drive with 3 Phase	27,000		**27,000**	2004	2004	2004
3 Terminate a new feeder CHA-03 at CHA substation		106,000	**106,000**	2004	2004	2004
Add an additional 66-25/12.5, 15 MVA transformer at KEL substation		1,184,758	**1,184,758**	2010	2007	2005
Replace KEL-02-R with a breaker		112,994	**112,994**	NR	2014	2010
Replace KEL-01-R with a breaker		112,994	**112,994**	NR	NR	2016
Transfer of 1.0 mva from SCV-01 to KEL-01				2012	07 & 15	06, 11, 16 & 21
Total			**1,821,630**			

CBS Long Term Study

Alternative # 2		Distribution	Substation	Total Cost	Year of Expenditures Required for each Forecast: Low	Medium	High
Construct new feeder (CHA-03) along new By-Pass Road							
1	Up Fowlers Road, Out By-pass Road, down Mineral Road & connect Cherry Hill Subdivision	315,000		**315,000**	2004	2004	2004
2	Southshore Drive & connect Sweetenwater Drive to feeder on Fowler's Drive with 3 Phase	27,000		**27,000**	2004	2004	2004
3	Terminate a new feeder CHA-03 at CHA substation		106,000	**106,000**	2004	2004	2004
Convert a portion of KEL-02 to 25kv & transfer to CHA-01		180,000		**180,000**	2011	2007	2005
Add an additional 66-25/12.5, 15mva transformer at KEL substation			1,184,758	**1,184,758**	N/R	2017	2012
Replace KEL-01-R with a breaker			112,994	**112,994**	NR	NR	2016
Transfer of 1.0 mva of load from SCV-01 to KEL-01					2012	07 & 15	06, 11, 16 & 21
Total				**1,925,752**			

CBS Long Term Study

Alternative # 3	Distribution	Substation	Total Cost	Low	Medium	High
				Year of Expenditures Required for each Forecast		
Add an additional 66-25/12.5, 15mva transformer at KEL substation		1,184,758	**1,184,758**	2011	2007	2005
Replace KEL-02-R with a breaker		112,994	**112,994**	NR	2014	2010
Replace KEL-01-R with a breaker		112,994	**112,994**	NR	NR	2016
Transfer of 1.0 mva from SCV-01 to KEL-01				2012	07 & 15	06, 11, 16 & 21
Total			**1,410,746**			

Project Title: **Tools & Equipment**

Location: **Company offices, service buildings and vehicles**

Classification: **General Property**

Project Cost: **$535,000**

This project consists of a number of items as noted.

(a) Regional Tools and Equipment

Cost: $235,000

Description: Replacement of tools and equipment utilized by line and support staff in the day-to-day operations of the Company.

Operating Experience: Line tools and equipment include those used by line staff, electrical maintenance staff, and engineering and field technical staff. These tools are maintained on a regular basis, however, over time they degrade and wear out, especially hot line equipment which must meet rigorous safety requirements. Concerns have also been expressed by linepersons related to the difficulty of using certain types of cutting & compression hand tools. Where feasible, such tools will be replaced with battery and hydraulic alternatives to improve productivity and working conditions.

Justification: Proper tools and equipment are required for the efficient and effective management of the electrical system as well as the safety of line workers and the public.

(b) Head Office Tools & Equipment

Cost: $250,000

Description: This project includes both engineering test equipment and tools typically used by electrical maintenance personnel.

Engineering test equipment includes items to perform systems calibration, commissioning and testing of protection equipment and data communications testing and analysis. The 2004 equipment requirements are one Relay Test Set, one Antenna Tester, and one Communication Protocol Test set**.**

Equipment for the electrical maintenance personnel is required for staff at the Electrical Maintenance Centre (EMC) and at various smaller shops across the island. The following are the items required for 2004:

1 – Motion Analyzer (c/w adaptors and controller)
1 – Transformer Turns Ratio Tester
3 – 10 A Ductor (c/w long leads)
2 – 5 kV Megger
1 – Oil Test Set
2 – Compression Tool
1 – Metal thickness Meter
3 – 1 kV Handheld Megger / Multimeter
1 – 20" 30 ton Spreader Bar
1 – Variac
1 – Load Cell Tester

Operating Experience:

Engineering test equipment is used to verify the operation of the protection and remote control of the power system. The protection and remote control is required to create a safe working environment for field staff. The relay test equipment is used to verify a protection system's operation prior to its going into service and to diagnose problems once the protection equipment is in operation.

Engineering test equipment is also required to verify data communications systems for wireless communications and serial communications. The antenna system test equipment is used to verify proper installation and operation of antenna systems. Newfoundland Power is using wireless communications for SCADA control in a number of areas. At present we do not have test equipment of this type so the response to correcting problems is not optimum. The PC-based protocol analyzer is used for serial communications installations and for trouble shooting the SCADA remote control systems.

The electrical maintenance group is responsible for the integrity and reliability of the equipment located in 137 substations across the Company's service territory. The electrical maintenance equipment includes power transformers, breakers, reclosers, voltage regulators, metering tanks, three phase pad mount transformers and step down transformers. The main repair facility is the EMC while smaller repair shops are located at other strategic geographic locations. Diagnostic testing and repair of the various types of equipment requires specialized tools and test equipment such as circuit breaker motion analyzers, insulation resistance testers (meggers), oil dielectric testers, recloser testers, transformer ratio testers, low resistance ohmmeters (ductors), SF6 gas reclaimers, vacuum pumps, oil filters, hand held gas monitors, potential indicators, fault locators, battery testers, etc. Innovations in tools and test equipment often lead to better diagnostic tools that result in less equipment failures. As well, normal deterioration and the inability to maintain obsolete test equipment require that some of these items be replaced every year.

Justification: The test equipment noted above are the base tools required to design, verify and maintain reliable operation of the electric power system and associated equipment.

The relay test set is required to design, verify and maintain a reliable protection system that properly isolates power system faults and maintains worker safety.

The communications test equipment is required to design, verify and maintain a reliable SCADA communications network.

The electrical maintenance test equipment is required to ensure the integrity and reliability of the equipment located in the Company's 137 substations across its service territory.

(c) Furniture

Cost: $50,000

Description: Replacement of chairs and furniture that have deteriorated.

Operating Experience: The Company has approximately 660 full time employee equivalents. The office furniture utilized by these employees deteriorates through normal use and needs to be replaced.

Justification: Proper furniture is necessary for a safe and productive work environment.

Project Title: **Real Property**

Location: **Electrical Maintenance Facility, Salt Pond Service Building, Gander Office, Corner Brook Service Building, And Stephenville Office**

Classification: **General Property**

Project Cost: **$174,000**

This project consists of 1 item greater than $50,000 and several items estimated at less than $50,000 each.

(a) Stephenville – Replace Roof

Cost: $65,000

Description: Replace the roof of the Stephenville office building.

Operating Experience: The existing roof has developed leaks and is showing signs of damage. Following a severe windstorm in the spring of 2003 approximately 3000 sq ft had to be replaced.

Justification: In order to provide a safe and healthy work environment the existing roof system has to be replaced. The existing system was damaged by high winds (winter 2003) and 3000 sq ft. has been replaced. The remainder of the roof was identified at that time to be in jeopardy of failing if not replaced.

(b) Projects < $50,000.

Cost: $109,000

Description: Listed are projects estimated at less than $50,000.

1. Gander – Replace Roof
2. Electrical Maintenance Facility – Retractable Enclosure
3. Salt Pond – Renovations to Service Building
4. Corner Brook – Transformer Ramp

Project Title: **Purchase Vehicles and Aerial Devices**

Location: **Various**

Classification: **Transportation**

Project Cost: **$3,487,000**

Operating Experience: See Volume III, Transportation, Appendix 1, Attachment A for details on the vehicles being replaced in 2004.

REVISED - SUMMARY 5 YR CAPITAL VEHICLE BUDGET

Year	Proposed Yrs to be Replaced Heavy Fleet	# Units/Yr Heavy Fleet	Budget $$ Heavy Fleet	Proposed Yrs to be Replaced Passenger Fleet	# Units/Yr Passenger	Budget $$ Passenger	# Units Off Road	Budget $$ Off Road	Overall Totals
2004	1990	4	$2,901,677	1996	2	$432,135	9	$153,188	$3,487,000
	1991	1		1997	5				
	1992	5		1998	3				
	1993	2		1999	5				
2005	1993	1	$1,025,318	1999	48	$1,406,369	6	$113,042	$2,544,729
	1994	2							
	1995	4							
2006	1995	7	$1,253,473	2000	28	$832,899	5	$46,191	$2,132,563
2007	1995	2	$1,085,234	2001	32	$968,232	5	$47,021	$2,100,487
	1996	4							
2008	1996	1	$1,208,041	2002	38	$1,168,408	5	$47,822	$2,424,271
	1997	6							
Overall 5 Yr Totals:		39	$7,473,743		161	$4,808,043	30	$407,264	$12,689,050

DETAILS - 2004 CAPITAL VEHICLE BUDGET

Heavy Fleet

Unit #	Dept Name	Year	Make/Model	Vehicle Type	Aerial Info	Last Odom Reading Date	Odom Reading	Maint Hist May 02-Apr 03
066B	EASTERN ST. JOHN'S	1990	GMC CAB & CHASSIS	Light Duty Aerial		May-03	123521	**$14,166.64**
113B	EASTERN ST. JOHN'S	1990	INTERNATIONAL	Medium Duty Aerial	Altec 450H DBL Bucket Material Handler	May-03	161803	**$23,894.24**
311B	WESTERN CLARENVILLE	1990	INTERNATIONAL	Medium Duty Aerial	Altec 450H DBL Bucket Material Handler	May-03	257397	**$8,862.11**
354B	WESTERN CLARENVILLE	1990	INTERNATIONAL	Medium Duty Aerial	Pitman 1342 Digger Derrick	May-03	193227	**$12,096.33**
088B	WESTERN STEPHENVILLE	1991	INTERNATIONAL C&C	Medium Duty Aerial	Altec AM450H Material Handler	May-03	103487	**$23,507.83**
135C	WESTERN STEPHENVILLE	1992	GMC TOPKICK CAB & CHASSIS	Medium Duty Aerial	Altec AM550H DBL Bucket Material Handler	May-03	319979	**$19,685.56**
116B	WESTERN CLARENVILLE	1992	GMC TOPKICK CAB & CHASSIS	Medium Duty Aerial	Altec 550H DBL Bucket Material Handler	May-03	208993	**$16,747.87**
008C	WESTERN GANDER	1992	INTERNATIONAL C&C	Medium Duty Aerial	Altec Am438H Material Handler	May-03	309868	**$21,866.55**
245B	EASTERN CARBONEAR	1992	GMC TOPKICK CAB & CHASSIS	Medium Duty Aerial	Altec 550H DBL Bucket Material Handler	May-03	231505	**$17,134.87**
277B	WESTERN GRAND FALLS	1992	GMC TOPKICK CAB & CHASSIS	Medium Duty Aerial	Altec AM550H DBL Bucket Material Handler	May-03	207021	**$18,055.57**
355C	WESTERN GANDER	1993	INTERNATIONAL C&C	Medium Duty Aerial	Altec AM550H DBL Bucket Material Handler	May-03	287022	**$26,269.30**
218B	WESTERN GRAND FALLS	1993	FREIGHTLINER	Medium Duty Aerial	Altec Am438H Material Handler	May-03	199976	**$31,141.01**
Totals:	**12**							

Passenger

Unit #	Dept Name	Year	Make	Model	Vehicle Type	Last Odom Reading Date	Odom Reading	Maint Hist May 02-Apr 03
117D	EASTERN ST. JOHN'S	1996	FORD TRUCK	RANGER P/UP	LIGHT DUTY TRUCK	2003/05/05	142120	**$1,637.06**
317C	MATERIALS MANAGEMENT	1996	FORD TRUCK	E150 C/V	VAN	2003/03/07	63967	**$1,693.49**
151D	HUMAN RESOURCES	1997	FORD TRUCK	WINDSTAR	VAN	2003/04/22	152240	**$2,153.48**
714A	MATERIALS MANAGEMENT	1997	PONTIAC	TRANSPORT	VAN	2003/04/28	99763	**$2,036.04**
111C	EASTERN ST. JOHN'S	1997	FORD TRUCK	F150 P/UP	LIGHT DUTY TRUCK	2003/05/05	164840	**$1,982.27**
234D	EASTERN CARBONEAR	1997	CHEVROLET	CHEV S10 4X4	LIGHT DUTY TRUCK	2003/04/03	157484	**$3,064.80**
288B	WESTERN GANDER	1997	FORD TRUCK	RANGER P/	LIGHT DUTY TRUCK	2003/03/31	155870	**$2,510.42**
264D	INFORMATION SYSTEMS	1998	CHEVROLET	BLAZER 4X	SUV	2003/03/21	203350	**$1,710.88**
361D	EASTERN ST. JOHN'S	1998	FORD TRUCK	F150 P/UP	LIGHT DUTY TRUCK	2003/03/19	176410	**$3,339.83**
089D	WESTERN GRAND FALLS	1998	FORD TRUCK	FORD F150	LIGHT DUTY TRUCK	2003/03/21	169980	**$4,007.62**
297E	EASTERN BURIN	1999	CHEVROLET	CHEV S10	LIGHT DUTY TRUCK	2003/04/25	169380	**$9,117.05**
212E	WESTERN CLARENVILLE	1999	FORD TRUCK	F150 P/UP	LIGHT DUTY TRUCK	2003/05/08	180930	**$5,428.95**
239C	WESTERN STEPHENVILLE	1999	DODGE TRUCK	RAM 1500	LIGHT DUTY TRUCK	2003/03/14	189040	**$6,599.66**
185D	EASTERN BURIN	1999	DODGE TRUCK	RAM 1500	LIGHT DUTY TRUCK	2002/12/16	158620	**$6,904.68**
166E	WESTERN GRAND FALLS	1999	CHEVROLET	CHEV S10	LIGHT DUTY TRUCK	2003/05/07	193350	**$6,796.56**
Totals:	**15**							

Off Road

Unit #	Dept Name	Unit Type	Comments
	EASTERN/ WESTERN	5 ATVs	
	EASTERN/ WESTERN	3 Snowmobiles	
	EASTERN	1 Reel Trailer	
Totals:	**9**		